Cleaner but Volatile Energy? The Effect of Coal Plant Retirement on Market Competition in the Wholesale Electricity Market

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Abstract

Energy transition from coal to gas is reshaping the power sector to rely more on gas generation that is cleaner but has a more variable input cost of generation. Using counterfactual analysis, I study the competitive effects of this transition, considering several paths of transition that vary in the types of firms involved in the retirement of coal plants and the investment in gas plants. I show that the variable nature of the marginal cost of gas generation creates an environment in which the market power could increase after the transition. However, the transition's impact depends on the characteristics of the firms involved in the investment of new gas generation; the adverse impact is mitigated under a well-planned transition that leads to a more competitive industry structure.

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1 Introduction

The conventional baseload generation using coal and nuclear power is rapidly retiring from the grid, and the cleaner natural gas and renewables are emerging as an energy source replacing the retired generation in the U.S. wholesale electricity market. An important factor responsible for the transition of the grid, besides the environmental regulation, is the increasing economic pressure that coal power plants face from cleaner energy, especially natural gas generation. Due to a significant drop in natural gas prices over the past decade, which lowered the price of natural gas close to coal prices, coal power plants are losing their cost advantage over gas power plants and are being driven out of the market.

While the retirement of coal power plants draws attention regarding the environmental benefits and grid stability issues, this paper focuses on the competitive aspects of this transition. That is, will the changing grid conditions – into a heavily natural gas-concentrated industry – affect the competition between firms in the wholesale electricity market? For a comprehensive analysis of the true cost and benefit of transitioning to cleaner energy, it is important to examine the consequences of the energy transition on market power, accounting for various aspects of the transition that might affect the strategic competition between firms.

In that respect, a specific feature of cleaner energy that is particularly relevant for competition is that cleaner energy tends to have more variable input costs than conventional energy. Unlike coal, the price of which is always low and stable, the price of natural gas is volatile, being subject to shocks resulting from the pipeline congestion caused by cold weather. Therefore, the industry's transition towards natural gas is making the industry more vulnerable to input cost shocks, by replacing consistently low-cost generation with a generation characterized by a more variable marginal cost.[1]

I show that an adverse market power impact of the transition can be of a greater concern, particularly when the input cost of gas generation is higher than normal due to its variable nature. That is, the energy transition from coal to gas, which involves replacing a retired coal plant with a new gas power plant, disturbs the distribution of marginal costs among electricity-generating firms, more so when the gas price rises above the normal level due to its variability. Such a disturbance changes the supply responses of firms, thereby affecting the degree of competition by changing the firms' residual demand. Whether market power increases or decreases due to the transition, and the market conditions under which it occurs more often, is an empirical question.

Another important aspect of the transition, which has implications for competition, is that the structure of the industry– a critical determinant of market power – could change throughout the transition process, depending on how retirement and investment occur (e.g., path of transition). The transition involves firms with diverse characteristics, and depending on which firms install new gas generation capacity to replace the retired generation, and by how much, the production

[1] Although the decision to transition away from coal to natural gas is driven by the economic conditions of the normal, low-gas price situation, which occurs more frequently, the industry remains susceptible to abnormally high gas prices post-transition, though with a lower frequency compared to the normal days.

scale and the number of firms in the post-retirement industry may differ from those before the transition. For instance, if the investment happens mainly by a dominant firm, market concentration worsens after transition, whereas the industry becomes more fragmented if fringe suppliers enter with new capacity, replacing the retired generation of large-scale firms. Nevertheless, little attention has been given to the *firms* involved in this transition process and how the characteristics of both firms and the industry are changing as a consequence, which are important determinants of market competition.

Incorporating these aspects of the transition, this paper studies the impact of the energy transition from coal to natural gas on market power, with natural gas serving as a cleaner but variable energy source. I carefully examine how strategic interactions between firms change once coal plants retire and are replaced by gas plants, accounting for the variation in the cost of gas generation resulting from volatile gas prices. Additionally, I consider several transition paths that differ in how the retired generation is marginally replaced by the new gas generation and show under which case the market would end up with the most competitive form of the industry. While the findings suggest that market power would increase after the transition, particularly in situations with higher gas prices, the adverse market impact is largely subdued when accompanied by a change in industry structure achieved through a better-designed transition path. This finding emphasizes the importance of industry structure as a means of addressing the problems that the market may confront from having an industry that is more exposed to variable input costs. It also offers policy suggestions to market regulators on how to properly incentivize the installation of cleaner generation capacities, so as to keep the market competitive.

I study this in the context of the New England wholesale electricity market, one of several U.S. electricity markets that frequently experience surges in natural gas prices. Despite having this problem, several large coal and nuclear plants have retired from the New England grid, mostly to be replaced by gas power plants. I use data on the retirement of baseload power plants in New England, which were planned (and announced) as of 2013 (five plants with a total capacity of 3,700 MW), along with rich data on bidding and generation at the firm-generator-level.

Using a model of quantity competition, I conduct a counterfactual analysis to examine the slightly longer-term impact of the transition and to better disentangle the strategic component influencing changes in market outcomes. The main idea is to construct the counterfactual market environment that would emerge in the near future after all the planned retirements of baseload power plants have occurred, and the installations of new generation capacities replacing them are completed. I only take the final form of the counterfactual industry that would emerge once the retirements and investments occur according to the transition path assumed in the analysis, which allows me to maintain a static equilibrium analysis instead of making the analysis dynamic. All other market conditions, such as the demand and marginal cost of generators (natural gas prices), are held constant at the levels observed before the retirement. Then the impact of the transition can be identified by comparing the static equilibrium of the counterfactual post-retirement environment to that before the retirements. As I construct the counterfactual environment separately for each day within the selected sample from the winters of 2013 and 2014 when daily gas prices were volatile, comparing the equilibrium differences (between the pre- and post-retirement states) across days that differ in gas prices reveals how the impact of the transition changes with the increase in gas prices. To compute the counterfactual equilibrium, I mainly use the Cournot model, which well describes the competition between firms in the wholesale electricity market (Bushnell, Mansur and Saravia, 2008; Ito and Reguant, 2016). However, for estimating parameters used in the counterfactual analysis (e.g., marginal cost), I employ the empirical auction model, which relies on the necessary condition of profit maximization to estimate parameters, using rich bidding data.

I make a set of assumptions on how the new gas generation capacity will be installed to marginally replace the retired baseload generation, introducing variation in the industry structures into the analysis. I begin with the baseline case, where the same firm that operated the retired generation (i.e., retired firm) installs the new generation with the same capacity as the retired one, ensuring that the industry structure does not change after the transition. I then examine three additional cases by varying the type of firms installing the new capacity – either new entrants or incumbents, fringe or large firms, and firms that own the retired generation or not – as well as the size of the capacity being installed. Comparing the results across these different cases will show how the impact of the transition varies with changing industry structures.

From the baseline case analysis, I find that market power – measured by how much the Cournot price departs from the competitive level – increases after the transition, raising the strategic price additionally by about \$9.8/MWh, on average. This suggests that in the event of the same degree of gas price shock occurring in the transformed industry, the price of electricity would rise more than before, primarily due to the increased market power. When examining the change in market power across different demand and gas price levels, two main patterns emerge. First, market power increases more in the low-demand (off-peak) sample than in the high-demand (peak) sample. Second, and notably, market power increases more as gas prices are higher above the normal level.

How can we rationalize the findings from the baseline case? Intuitively, the replacement of a coal plant with a gas plant – namely, the transition – is more costly when the marginal cost difference between the coal and gas generation is large, which occurs under high gas prices and during low-demand hours when the coal plant is pivotal. Indeed, I find that the marginal cost of a group of strategic firms increases, on average, especially more under these market conditions, leading them to reduce the quantity supplied. If the decrease in strategic quantity is met by an elastic supply from non-strategic firms, the market price will not increase much. However, the non-strategic supply turns out to be relatively price-inelastic, especially on days with higher gas prices, offering a more favorable environment in which strategic firms can exercise market power and raise the price. Among these strategic firms, the large-scale gas-intensive firms, with a significant share of gas generation and no baseload generation, are those most active in exercising market power more often than before the transition. They become the relatively low-cost suppliers among strategic firms after the competitors' coal plants retire, thereby facing less competitive pressure from other strategic firms. Therefore, the change in the competitive environment due to the transition, as described in the baseline case, gives this type of firm an increased ability to exercise market power by profitably withholding the quantity more than before.

However, the results from the three additional cases – in which the industry structure changes after the transition – demonstrate that a well-planned installation of new gas generation capacity can effectively mitigate the adverse impact of the retirement on market power. For instance, when the retired capacities are replaced entirely by new capacity installed by fringe suppliers, market power even decreases after the transition, leading to an average reduction in price of electricity by \$2.7/MWh. Notably, even without new entry, market power increases by less than in the baseline case if the retired firm – a competitor of the gas-intensive firms – installs new gas generation with 50% larger capacity than the retired plant, resulting in an average price increase of \$6.5/MWh. In both cases, the pattern of market power increasing more with higher gas prices also weakens. The most concerning situation arises when large, gas-intensive incumbent firms expand their capacity by installing new gas generation; market power increases more than in any other case. The findings suggest that new capacity should be installed in such a way that either makes the industry more fragmented or curbs the market power of the type of firms that particularly benefit from changes in the competitive environment – namely, the gas-intensive firms, as identified in the baseline case.

The findings of this paper have important policy implications for market regulators preparing for the clean energy transition within the electric power sector. First, the paper offers new insights into the volatile nature of the provision of cleaner energy sources and its implications for market competition. Instead of focusing on the energy transition under ideal (low-cost) conditions, I examine the market consequences of the transition in situations where the supply of natural gas is interrupted, leading to variable gas prices. As the grid looks beyond the integration of large-scale renewable generation – known for supply interruptions due to intermittency – into the market system, the findings of this paper may have implications for the design of the future grid, making it both timely and policy-relevant. Second, this paper highlights the significance of steering the energy transition towards a competitive path, acknowledging that the type of firms involved in the transition process is crucial. Based on the findings, it is concerning that, currently, we more often observe installation of new generation capacity by gas-intensive incumbent firms, with lack of new entries by smaller firms. This emphasizes the need for a careful examination of incentive schemes in the capacity market, assessing whether they are designed to induce investments by firms that would increase their dominance throughout the transition.

Literature Review Contributing to several strands of literature, the paper first expands upon the extensive body of literature that empirically studies competition in the wholesale electricity market (Borenstein, Bushnell and Wolak, 2002, and others). This literature has shown that various factors can affect competition in this market, including forward contracting (Bushnell, et.al, 2008), transmission congestion (Borenstein, Bushnell and Stoft, 2002; Ryan, 2021), and dynamic costs (Reguant, 2014). This paper contributes to the literature by examining how the energy transition – involving changes in the generation mix resulting from the retirement and investment of power plants – affects competition and market power in the wholesale electricity market.[2]

Although this paper does not explicitly focus on renewables, it studies the energy transition to gas, which is relatively cleaner than coal and exhibits a variable nature – a feature shared by renewables. This connection places the paper in the context of recent studies that explored market power and competition upon the entry of renewable generation. Genc and Reynolds (2019) demonstrate that the market impact of renewable expansion depends on the ownership of low-cost renewable generation and find a smaller impact on prices when renewables are owned by large firms. Fabra and Llobet (2023) study competition among renewable generators in auctions where their capacities are private information. Jha and Lesley (2023) show that overlooking the fact that high market rents in the hours after sunset reflect the start-up costs of gas plants needed to replace the large decline in solar generation could overstate market power. My paper differs from these studies by examining the energy transition itself, demonstrating why the variability of generation costs matters for its impact on market power. Additionally, this paper places a greater emphasis on the characteristics of firms that own the generation, considering not only their scales or shares. This focus sets the paper apart from other studies that investigate the importance of ownership influencing the price impact of renewables.

Since the paper exploits the volatile nature of natural gas prices, it also relates to papers investigating the relationship between market power and gas price variation, such as Kim (2022) and Marks, Mason, Mohlin, and Zaragoza-Watkins (2017). Lastly, as the retirement of coal plants is partly driven by environmental regulations, the paper broadly relates to the literature that studies how the industry/market responds to environmental regulation/policy (Ryan, 2012; Fowlie, Reguant and Ryan, 2014; Shapiro and Walker, 2018, and others.).

2 Institutional Background

2.1 The retirement of baseload power plants and the energy transition

In the wholesale electricity market, the supply-side firms generate electricity using power plants that fuel on different energy sources: coal, natural gas, oil, nuclear power, and renewables. The coal and nuclear power plants have been considered as the *baseload* generation: the low-cost power plant that starts generating early on to serve the base of the electricity demand.

Over the last several years, the U.S. wholesale electricity market has been experiencing a dramatic increase in the retirement of conventional baseload power plants, particularly coal power plants. On the national level, the coal generation has decreased by almost 15% (about 47 GW in size) between 2011 and 2016 (EIA, *2017 Annual Energy Outlook*). Nuclear power plants are also

[2] While Davis and Hausman (2016) empirically study the market impacts of nuclear power plant closure, this paper differs from theirs in that I not only look at the closure of plants but also replacements and focus more on strategic competition.

Plant Name	Capacity (MW)	Fuel type	Date of shutdown
Salem Harbor Station	749	coal/oil	June, 2014
Mount Tom Station	143	coal	Oct. 2014
Vermont Yankee	604	nuclear	Dec., 2014
Brayton Point Station	1,535	coal/oil	May, 2017
Pilgrim Nuclear Station	677	nuclear	May, 2019

Notes: Table shows the retirements of baseload power plants in New England that were announced as of 2013 (*Source*: EIA, ISONE)

Table 1: Major Power Plant Retirements in New England

rapidly retiring from the grid; about 25% of nuclear power generation currently operating in the grid announced their plans to retire.[3]

This increase in retirements has expedited the electricity grid's transition towards cleaner energy sources because new generation capacity added to the grid to replace the retired baseloads comes mostly from natural gas and renewable generation. In particular, natural gas, which is relatively cleaner than coal (emitting 50% less carbon dioxides than coal), is the dominant energy source among the newly installed or planned generation capacities and is thus the primary energy source replacing coal, at least until the near future. In 2018 alone, 19.2 GW of gas generation capacities were added to the grid at the national level, whereas wind and solar additions were 6.6 GW and 4.9 GW, respectively.[4]

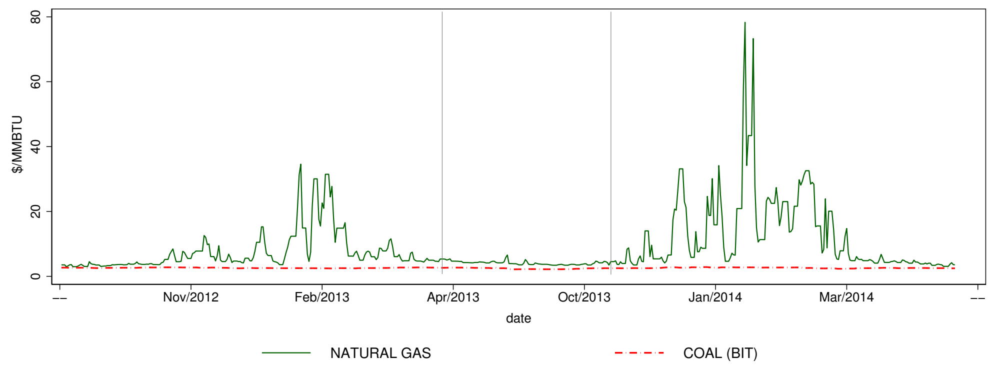
Broadly two factors are responsible for the ongoing energy transition in the electric power sector. First is the stringent environmental regulations that target highly-polluting coal power plants.[5] A more important factor, however, is the economic pressure that coal generation faces from cleaner energy sources, especially natural gas generation. Due to the shale gas boom, the price of gas has decreased to a level comparable with the price of coal. Once the emissions cost is factored in, the marginal cost of gas generation is close to (or sometimes even lower than) that of coal generation. Since the fixed cost of coal power plants is larger than that of gas power plants, coal generation is no longer more efficient than gas generation, both in terms of the marginal operating cost and fixed (startup) cost. The increased penetration of zero-cost renewable generation also puts competitive pressure on coal generation.[6]

[3]These nuclear power plants have not renewed the license for operation, indicating that they will stop operation and go out of business. https://www.eia.gov/todayinenergy/detail.php?id=31192

[4]The share of gas generation among the capacity additions is much higher in the Northeast region where the penetration rate of renewables is lower than in the Southern and the Western parts of the U.S. Figure H.3 of the Appendix for regional variation in new generation capacity additions.

[5]EPA regulations such as Mercury and Air Toxics Standards (MATS) and Cross-state Air Pollution Rule (CSAPR) affect coal plants. While nuclear generation is free of emissions, it faces stringent safety regulations that are burdensome to implement and adhere to.

[6]As a result of the decline in the marginal cost of generators clearing the market, the wholesale electricity price has substantially decreased, even during peak hours. The revenue earned by baseload generators under this low market price is insufficient to cover the large fixed costs of conventional baseloads (ISO-NE, 2016; EIA- today in energy).



Notes: Figure shows the spot prices of natural gas (source: *Natural Gas Intelligence*) and spot prices of coal (source: *SNL Energy*) in the New England region from 2012-2014.)

Figure 1: Spot Prices of Natural Gas and Coal in New England

2.2 Baseload power plant retirements in the New England electricity market

The New England wholesale electricity market is one of the regional markets undergoing the energy transition. There are a total of 85 electricity-generating firms of different capacities and fuel technologies, supplying electricity to six states in the Northeast. About one-third of the firms are considered large-scale firms that operate multiple power plants (multi-unit firms), and the rest are fringe suppliers operating either a single power plant or a few power plants of small scales. These firms together operate a total of 305 generating units (i.e., power plants).[7]

The market had several baseload power plants retired recently, shown in Table 1. More than 3,700 MW of baseload generation – a size equivalent to about 15% of the average daily demand – have retired or are expected to retire by 2020. These retirements will not pose a significant threat to the market operation, as the grid is prepared with enough reserve generation.[8] Nevertheless, in order to guarantee a reliable supply of electricity, more generation capacity would be installed in the longer term to replace the lost capacity from the retired generation. A substantial portion of planned (or approved) capacity additions in the New England grid – especially those installed by major firms, at a large scale – is of natural gas generation. For instance, the total capacity of gas-fired generation approved for installation between 2013 and 2017 is five times larger than that of renewables, as shown in Table H.1.[9]

2.3 Volatile natural gas prices and the marginal cost of generation

An important feature that distinguishes conventional energy sources, such as coal, from cleaner energy sources, such as natural gas and renewables, is the (fuel) price volatility driven by interruptions in energy supply.

The spot prices of coal in the U.S. have historically been low and stable over time. In contrast,

[7] Table F.1 of Appendix F summarizes the capacities of power plants in New England by their fuel type.

[8] Reserve margin in New England was about 70% in 2018-2019 (NERC Winter Reliability Assessment, 2019).

[9] A detailed summary of planned capacity additions by fuel type and by ownership is provided in Table H.2. Also, more discussion on the feature (characteristics) of renewable generation installation can be found in Appendix H.2.

	Year	Total	\$4 -\$10	\$10-\$20	\$20-\$30	>\$30 (MMBtu)
% (N/365)	2013	28 %	16.2 %	8%	1.6 %	2.2 %
	2014	30.7 %	8 %	8.2 %	10.1 %	4.4 %

Notes: The table reports the percentage (%) of days when gas prices rose above the normal level (shock) in 2013 and 2014. Percentages are calculated based on the total number of days in a year. The last four columns report these percentages separately by the severity of the shock (level of gas price).

Table 2: Summary of Days with Gas Price Shock (New England)

natural gas spot prices are subject to upside volatility, meaning that the price does not always stay low as observed during normal periods but can fluctuate between low and high levels. This is because the spot (citygate) price of natural gas, at which local power plants purchase gas, is sensitive to the condition of the pipeline delivering gas to the region. The pipeline often experiences congestion during winter due to increased natural gas demand from the residential heating sector, which increases the total volume of gas flowing through the pipeline. When congestion occurs, spot gas prices (citygate prices) surge above the normal level as a result of this *shock*, with the magnitude of the increase corresponding to the level of congestion.[10]

The difference in the price variability between natural gas and coal is depicted in Figure 1, which shows the spot prices of gas and coal in the New England region from 2012 to 2014. Under normal conditions, gas prices are typically low at around \$4/MMBtu, and are comparable to coal prices (as indicated by the plots between the lines). However, gas prices could suddenly increase to a substantially higher level, as shown by the fluctuating price paths. In contrast, coal prices have remained relatively stable over time, exhibiting almost no fluctuations in their price paths.

As fuel costs account for the largest portion of electricity generation costs, the difference in fuel price variability indicates that the marginal cost of gas-fired generation is more prone to fluctuations compared to the relatively stable marginal cost of coal-fired generation. Moreover, unlike coal, which can be stored on-site, natural gas cannot be stored and must be delivered through pipelines at the time of use. The difference in storage options makes the marginal cost of gas generation particularly susceptible to day-to-day variations in spot gas prices. [11]

The variability of gas prices is most severe and frequent in the Northeast, particularly in New

[10]This weather-related shock to the local natural gas prices is an industry-wide shock, affecting all firms in a regional electricity market that purchase natural gas from the spot market. Firms and power plants purchasing gas through a long-term contract with gas suppliers remain unaffected by the shock, implying that their procurement prices would not increase as much as the spot prices (represented by the spot price index). To account for such differences in gas prices among firms and power plants due to different procurement channels, which are not observed in the data, I estimate marginal costs (which reflect gas prices) from firm-plant level bidding data. For further discussion, refer to Section 5.3 and Kim (2022).

[11]While there are other ways to procure natural gas (e.g., long-term contract), the spot market remains the most popular procurement channel for gas in the power sector. For instance, most gas-fired power plants in New England prefer purchasing gas from the spot market (Northeast Gas Association; FERC, Nov 2020) rather than through long-term contracts (e.g., 'firm' gas pipeline capacity). The spot market provides greater flexibility in both quantity and price for firms and power plants to procure gas compared to long-term contracts, which require power plants to commit to purchasing a specified amount of gas daily over a long period.

England, which suffers the most due to inadequate pipeline capacity.[12] Table 2 shows that nearly 30% of the days in the 2013-2014 sample experienced shocks that substantially raised gas prices in New England, above the normal level of around $4/MMBtu.[13] Whether these shock events will persist in the future depends on several factors. On one hand, the increased gas demand from the power sector, which becomes more reliant on gas-fired generation as baseloads retire, could exacerbate the problem of pipeline congestion. On the other hand, congestion could be alleviated as the pipelines in the Northeast undergo upgrades and expansions.[14]

The issue arising from variable marginal cost is not limited to gas-fired generation; the intermittency of renewable energy also implies that the marginal cost of renewable generation fluctuates. While the price of renewable energy remains constant, a multi-unit firm that operates renewable generation as part of its strategic assets would experience varying marginal opportunity costs (or expected marginal costs) due to the intermittent nature of their supply. However, this paper specifically focuses on natural gas and does not attempt to draw direct parallels with renewables. For a more discussion of the common characteristics shared by these energy sources and how this analysis can be extended to renewables, please refer to Appendix H.2.

3 The energy transition and the market competition

This section describes the basic mechanism and intuition that explain how the energy transition can impact the level of competition in this market. This understanding serves as the basis for the empirical strategy.[15] While various factors can potentially affect competition in this market, I focus primarily on the marginal changes in market variables that are directly associated with the energy transition.

3.1 Competition in the wholesale electricity market

In the wholesale electricity market, both the supply and demand sides sell and buy electricity in an hourly market organized as auctions.[16] The electricity-generating firms compete by submitting a supply schedule, consisting of price-quantity pairs, that reflects the marginal costs of their

[12]Other parts of the U.S. tend to have larger pipeline capacity, thus less congestion occurring in general. However, due to a constant increase in the use of natural gas over time, the gas prices have reached a record high level in the 2018-2019 winter season, even in Southern California.

[13]The market impact of these abnormal days with high gas prices was rather significant; the increase in wholesale electricity prices caused by the high gas prices was passed onto retail electricity prices, resulting in an average retail price increase of about 20% in the subsequent year (EIA, 2018).

[14]For instance, four pipelines in the New England area are currently undergoing capacity expansions of 350 MMcf/d, equivalent to 6% of the region's total pipeline capacity as of 2020, with completion expected by 2023 (EIA, New England Dashboard, March 6, 2020).

[15]I explain the intuition with an example where only the coal power plants retire, though our main analysis also uses the retirement of nuclear power plants. Furthermore, the decision to retire a coal power plant (i.e., energy transition) which is based on the overall efficiency of power plants is taken as given.

[16]This applies to markets that have undergone restructuring and are operated by independent system operators (ISO). The regional markets in the Northeast (ISO-NE, NYISO), Midwest (PJM, MISO), Texas (ERCOT), and California (CAISO) have undergone restructuring and implemented competitive market mechanisms.

power plants and their strategic positions.[17] Among these firms, only the multi-unit firms with considerable production scale are capable of strategically bidding in the auction. Each firm makes a strategic supply decision, considering its own residual demand, which is the market demand net of the supply schedules submitted by other firms, thus making the competition close to an oligopoly. Note that fringe suppliers tend to behave as non-strategic price takers, supplying at their marginal costs.

A unique feature of this market is the (almost) perfectly inelastic demand for electricity from retail companies (electric utilities).[18] Due to this inelastic demand, strategic interactions (competition) between *suppliers* become a more important determinant of market power than the demand itself. In other words, the ability of electricity generating firms to exercise market power, which is governed by the elasticity of their residual demand, primarily depends on how elastic or inelastic the supply from their competitors is.

3.2 The competitive effects of the energy transition

The energy transition, in general, involves the removal of a power plant from a firm's generation set and its replacement with another power plant that utilizes a different energy source. Since these adjustments are carried out by electricity-generating firms, the focus of the analysis should be the *firms*, rather than the plants, that play a crucial role in this transition process. This section discusses how the competitive environment in which these firms operate would be impacted by power plant retirements and investments.

3.2.1 Volatile gas price and the impact of the transition in the low-cost and high-cost regimes

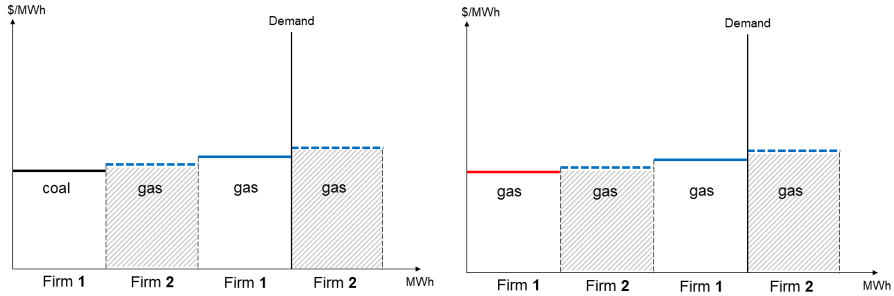
The market variable that is directly affected by the removal and addition of power plants, and is relevant to market competition, is the distribution of marginal costs among firms; which firms are relatively low-cost and high-cost firms at a given production level. The change in the distribution leads to a change in the supply responses of firms, thereby affecting the degree of competition through changes in the elasticity of the firm's residual demand.

This, in turn, implies that energy transition would have an impact on competition only when it causes a significant change in the firm-level marginal cost distribution. In the case of coal to gas transition, whether, and to what extent the distribution of marginal costs is affected by the transition depends on the *relative* marginal costs of the retiring coal power plant and the gas power plant that replaces it.

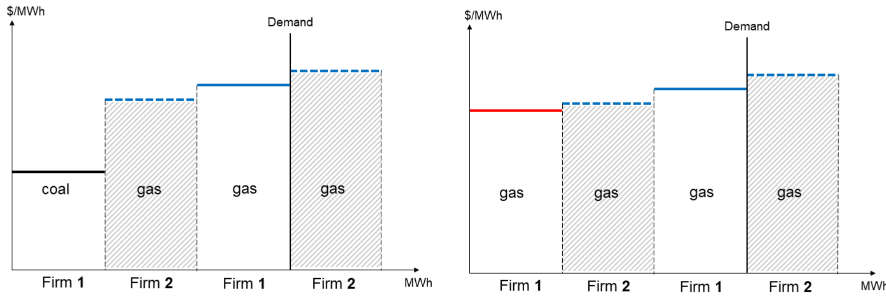
In this respect, the volatile nature of the replacing fuel, in this case, gas, creates a situation where the coal to gas transition could potentially affect the market power exercised by the electricity-

[17] Electricity-generating firms submit a supply curve for each of their generating assets. The supply curve (i.e., price-quantity pairs) specifies the price at which the generating asset (power plant) is willing to supply a specified amount of electricity.

[18] Demand-side firms submit bids without specifying the price they are willing to pay, resulting in an almost perfectly inelastic short-term demand. This is due to the retail companies being obligated by long-term supply contracts with residential customers.



(a) Low-cost regime: before retirement (b) Low-cost regime: after retirement



(c) High-cost regime: before retirement (d) High-cost regime: after retirement

Notes: These graphs illustrate a simple example of marginal cost distributions with two firms: Firm 1 and Firm 2. Firm 1 operates the coal plant, while Firm 2 does not. Panels (a) and (b) depict the distributions in the low-cost regime (a sample day-hour market without a gas price shock), while panels (c) and (d) depict the distributions in the high-cost regime (a sample day with the gas price shock). Panels (a) and (c) display the distribution before the retirement of Firm 1's coal plant, while panels (b) and (d) show the distribution after Firm 1 retires its coal plant and replaces it with a equal-sized gas power plant (i.e., Baseline case transition). The marginal cost of a newly installed gas power plant in the post-retirement scenario is represented in red. Across all panels, the aggregate market demand (denoted as 'Demand') remains constant.

Figure 2: Impact of Transition from Coal to Gas on Marginal Cost Distributions: Low-Cost vs. High-Cost Regimes

generating firms. Specifically, due to the variability of the gas price, two distinct regimes emerge: a *low-cost* regime in which the gas price remains stable within a normal range, and a *high-cost* regime in which the gas price rises above the normal price range. I will provide a conceptual explanation that the retirement-induced energy transition could have a stronger impact on market power, particularly in the abnormal 'high-cost' regime.

Suppose that a firm replaces its retired coal power plant with a gas power plant having the same capacity as the retired plant. This situation is depicted in Figure 2, which displays the distributions of marginal costs for two firms, Firm 1 and Firm 2, before and after the coal plant of Firm 1 retires and is replaced by an equivalent-sized gas power plant. Panels (a) and (b) show the pre- and post-retirement distributions in the low-cost regime, respectively, while panels (c) and (d) display those in the high-cost regime. The extension of this figure to the industry-level marginal cost distribution, using actual marginal costs of generators in the dataset, can be found in Figure G.1 in the Appendix.

In the low-cost regime, where the gas price is within the normal range and close to the price of coal, the marginal costs of generating electricity using coal and gas are similar. For instance, when the gas price is at the normal level of around \$4/MMBtu, the average marginal cost of a gas power plant is \$45.6/MWh, which is comparable to that of a coal power plant at around \$45/MWh. Since these plants have similar marginal costs, a marginal change in the energy source from coal to gas would not impact the distribution of marginal costs in the low-cost regime. This is illustrated in Figure 2, where the marginal cost distributions in panels (a) and (b) are identical at both the firm and industry levels, indicating that strategic production decisions would remain the same before and after the transition.

However, the relative marginal costs between the two energy sources can change due to the variability of gas prices. If gas prices increase above the normal level due to upside volatility, while coal prices remain unchanged, the marginal cost of a gas power plant differs from, and becomes significantly higher than that of a coal power plant (e.g., \$45/MWh). In this 'high-cost' regime, replacing a coal plant with a gas plant not only changes the affected firm's cost structure but also impacts the entire distribution of marginal costs among firms, implying a change in the competitive environment. Moreover, the extent of this distribution change also varies with the level of gas prices.

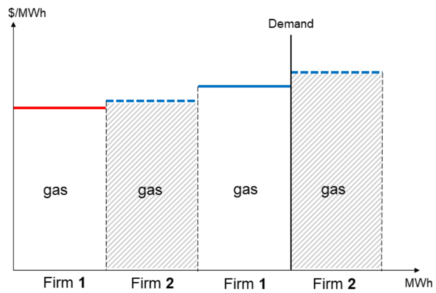
This is shown in Panels (c) and (d) of Figure 2 which display the distributions of marginal costs before and after retirement in the abnormal 'high-cost' regime. Due to the marginal cost difference between the coal and gas power plants in this high-cost regime, the distributions significantly differ between panels (c) and (d). As a result, not only would the strategic production decision of Firm 1 – owner of the retired coal plant – change in panel (d) compared to panel (c), but Firm 2's strategic response would also differ between panel (d) and panel (c). In other words, we expect differences in the bidding curve or production curve between panels (c) and (d), although these are not depicted in Figure 2, which only shows the marginal costs.

Note that the high-cost regimes occur less frequently than the low-cost regime.[19] This is why a firm's decision to retire a plant and invest in a new one is primarily based on the profitability and strategic situation of the low-cost regime. However, if a high-cost regime occurs in the industry after these retirement and investment decisions (transitions) have been made, the market power outcomes could significantly differ from the pre-retirement situation.

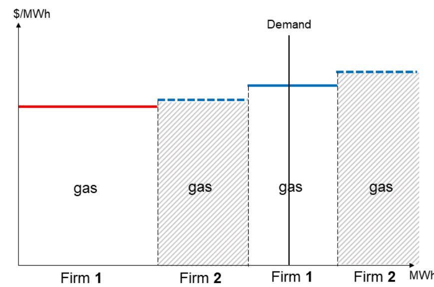
3.2.2 Installation of new generation capacity and the industry structure

The specific way in which the transition occurs is another crucial aspect concerning competition. That is, depending on which firms are installing the new gas generation capacities and by how much, the industry's structure – characterized by the number of firms and their production scales – could change throughout the transition process. Moreover, given that firms are heterogeneous in various dimensions – including their generation mix and ability to exercise market power – which firms install new capacity to expand their scale would change the competitive environment of the industry. Therefore, a careful examination of how the industry's structure and the characteristics of its firms change throughout the transition process is crucial for assessing the

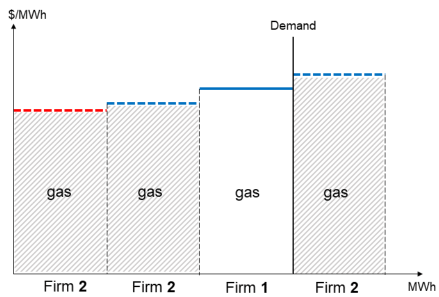
[19] For example, in New England, gas prices rose above the normal level for about 30% of the days, as summarized in Table 2.



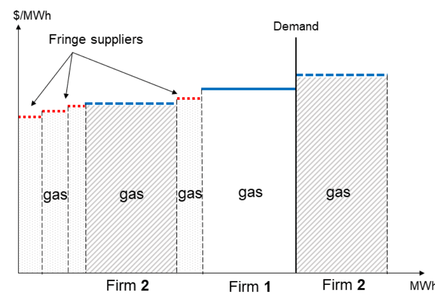
(a) Baseline: Firm 1 installs capacity



(b) Firm 1 installs larger capacity



(c) Firm 2 installs capacity



(d) Fringe suppliers install capacity

Notes: Each panel shows the *post-retirement* marginal cost distribution for the *high-cost* regime. Firm 1's coal plant retired in all cases, but how the new gas generation capacity is installed differs across these panels. The marginal cost of a newly installed gas power plant in the post-retirement scenario is represented in red. Panel (a) is the baseline case, where Firm 1 which previously owned the retired coal plant replaces it with an equal-sized gas plant. Panel (b) shows where Firm 1 installs a new gas plant having a capacity larger than the retired one. In panel (c), Firm 2 installs a gas plant of the same capacity as the retired coal plant of Firm 1. Panel (d) represents the entry of fringe suppliers with capacities matching the size of the retired plant. Across all panels, the aggregate market demand (denoted as 'Demand') remains constant.

Figure 3: Post-Retirement Marginal Cost Distributions: Different Gas Plant Investment Patterns in High-Cost Regime

competitive effect of the transition.

For instance, in the earlier example, I assumed that the same firm operating the retired coal plant (Firm 1) replaces it by installing a new gas power plant of equal capacity. In this *baseline* case, the industry structure remains unchanged after the transition. However, it is not always the case that the firm owning the retired plant installs new gas generation capacity. Different types of firms, such as incumbent firms that do not operate the retired generation, or new fringe firms, could construct a new gas power plant. Moreover, the capacity of the new power plant could exceed that of the retired plant, thereby increasing total capacity at both the firm and industry levels.

These cases are illustrated in Figure 3, which shows the 'post-retirement' marginal cost distributions of the 'high-cost' regime that would arise under different installation patterns. Panel (a) depicts the baseline case, while subsequent panels show the marginal cost distributions when Firm 1 installs new capacity larger than the retired one (panel (b)), a firm not owning the retired coal plant (Firm 2) installs the new capacity (panel (c)), and fringe firms enter with new capacity (panel(d)). Changes in the scales and number of firms, accompanied by changes in marginal cost distributions, are observed across the panels. This implies that the competitive effects of the transition would vary greatly depending on the installation patterns of the new capacity.

4 Empirical Strategy

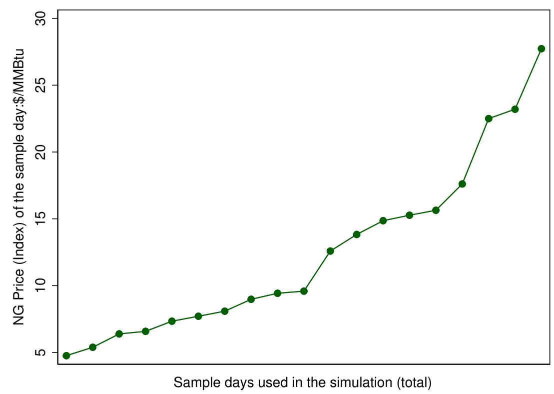
The empirical strategy of this paper is motivated by the insights discussed in Section 3. First, the transition from coal to gas is expected to have a meaningful impact on competition in the 'high-cost' regime. Hence, I restrict our empirical analysis to the higher-gas-price sample and examine how the impact of the retirement-induced transition varies with increasing gas prices. In addition to the variation in gas prices, I also examine how the impact of the transition varies across different industry structures that could emerge under various transition scenarios. Because projecting the long-term trajectory of capacity installation is challenging, I consider several stylized paths of transition.

Counterfactual Analysis To examine the impact of the energy transition on market competition, I conduct a counterfactual analysis based on a structural model that describes quantity competition among electricity-generating firms in the wholesale electricity market. The idea is to construct a counterfactual industry that is likely to emerge in the near future, after all planned retirements of baseload generation have occurred, and new generation capacities replacing the retired ones have been installed. Specifically, I consider only the final industry structure resulting after a series of (planned) retirements and hypothetical investments. Instead of modeling the complete transition process (paths) and endogenizing the investment decisions in a dynamic setting, I compute a *static* equilibrium for a counterfactual industry (i.e., post-retirement) and compare it to the static equilibrium observed in the industry before any retirements occurred (i.e., pre-retirement).

When constructing the counterfactual environment, all other market variables, except for power plant retirements and investments, remain the same as in the pre-retirement sample. Specifically, I construct a counterpart of an actual day-hour market (t, h) from the pre-retirement sample, keeping variables such as electricity demand, fuel spot prices, and the marginal costs of existing power plants at their pre-retirement levels, rather than making arbitrary adjustments within the model. This ensures that the strategic and market environment closely resembles the one observed before the transition, with changes limited to industry components directly related to the transition.

Baseload power plant retirements I use the actual baseload power plants retirements in New England that were announced as of 2013, summarized in Table 1. The list includes five power plants, comprising both coal-fired and nuclear power plants, with a total capacity of 3,700 MW. These plants are operated by four major firms and collectively represent approximately one-fifth of the average daily electricity demand, which is large enough to affect the market outcome.[20]

[20] I did not allow all existing baseloads to retire in the counterfactual scenario because it is challenging to analyze the underlying forces driving the change in firms' strategic incentives when the industry undergoes a drastic shift in the generation mix. Moreover, understanding the marginal changes in incentives associated with a partial transition of the grid is a prerequisite for a more comprehensive, long-term transition.



Notes: The horizontal axis shows the selected sample days aligned in an increasing order of gas price (index data) of the day, shown in the vertical axis.

Figure 4: Gas Price Index Values of the Selected Sample Days

Although the actual timing of these retirements varies, these plants are removed altogether from the firm's generation set when establishing a counterfactual environment.

New gas generation capacity installations While power plants may retire from operation without immediate replacements in the short term, new generating capacity will be installed in the long run to maintain a reliable grid. In counterfactual scenarios, I make assumptions about the type of firm installing the capacity and the size of the capacity.[21]

As discussed in Section 3, the *baseline* case of installation involves the firm that owns a retired baseload power plant, which I denote asthe *retired* firm, replacing it by installing a hypothetical natural gas-fired power plant of the same capacity as the retired one. This scenario serves as a baseline because it keeps the industry structure unchanged, with only the fuel mix of generation assets and the corresponding marginal cost distribution of firms changing as a result.[22] In Section 7, I extend this baseline case by considering various installation patterns. These patterns are designed to provide a better understanding of the factors influencing changes in competition as we vary the industry's structure.

The marginal cost of the hypothetical natural gas power plant is computed using the heat rate of the latest gas generation technology and the daily gas spot price (index). Note that identical marginal cost values were applied to all hypothetical gas power plants, regardless of their owners.[23]

[21]Since the new power plant constructions are yet to be completed, with most of them still in the planning stage, there is substantial uncertainty over the type of firms installing the new capacity as well as the size of the capacity.

[22]While the baseline assumption may appear to be strong, actual capacity installations observed from data (EIA-860) show that many of the retired coal plant sites are, in fact, being converted for the use of gas power generation, making the assumption reasonably realistic. See Section 7 for more details.

[23]I use the same heat rate (hr =7MMBtu/MWh) for all hypothetical gas power plants. This is done to avoid arbitrarily assigning different levels of marginal costs to hypothetical plants owned by different entities, which could unintentionally introduce a relative cost advantage during the replacement process. Assigning identical marginal cost values regardless of ownership or scale could potentially be problemtatic if significant economies of scale were present. That is, a large-scale firm might procure gas at a lower price through negotiations with gas suppliers, compared to smaller fringe suppliers. However, the marginal cost estimates for gas power plants from dominant firms and fringe

Pre-retirement sample (t, h)	Retirement & Installation	Post-retirement sample (t, h)
(S:pre) Cournot equilibrium	$\rightarrow$	(S:post) Cournot equilibrium
Observed equilibrium (SFE)		
(C:pre) Competitive equilibrium	$\rightarrow$	(C:post) Competitive equilibrium

Notes: S denotes the strategic Cournot equilibrium and C denotes the competitive equilibrium. The term *post*- refers to the sample in which counterfactual adjustments regarding power plants retirements and new installations have been made. The market outcomes observed in the data, which is before the retirements occur, are generated from the SFE.

Table 3: Summary of Equilibrium Computations

Accounting for the volatile gas price: selection of sample days The pre-retirement sample consists of actual days during the winter seasons between 2012 and 2014 (November - February). This period is chosen because major power plant retirements had not occurred by this point, and, most importantly, because spot gas prices in New England were volatile during this winter period. Figure 4 displays the spot gas prices (price index) of the selected days, which exhibit an increasing pattern across the days.[24] The sample consists of 19 days, each with 19 hourly markets, from 5AM to 11PM ($T = 19, H = 19$).[25]

To examine how the transition's impact varies with different gas price levels, I leverage the *observed* cross-day gas price variation in the pre-retirement sample data. I identify the transition's impact for each market (t, h) by comparing the (counterfactual) post-retirement and pre-retirement equilibria while keeping the day's gas price level constant.[26] Holding the gas price level fixed in the counterfactual environment is achieved by using the same daily marginal cost parameters as those estimated from the pre-retirement sample. Then, comparing the identified impacts *across* different days reveals how the transition's impact varies with gas price levels.

Counterfactual equilibrium computation Because firms in the wholesale electricity market compete for production in the multi-unit uniform auction, their behavior is best described by Supply Function Equilibrium (SFE) model. However, conducting a counterfactual analysis within an SFE framework is challenging due to the well-known problem of multiple equilibria, along with the difficulty of characterizing those equilibria. To overcome this challenge, counterfactual analysis in the wholesale electricity market setting relies on computing the Cournot equilibrium, which has been shown in many empirical studies to reasonably approximate the strategic equilibrium (Bushnell et.al., 2008; Ito and Reguant, 2016; Ryan, 2021).[27]

firms did not significantly differ, suggesting that economies of scale is not a major concern in this industry.

[24] The same figure with actual *dates* of the selected days listed in the horizontal axis can be found in Figure G.2 in Appendix. I selected days with similar average daily demand and hourly demand patterns to ensure homogeneity in conditions other than the gas price.

[25] I dropped hours from 12AM to 4AM in which the firm's production decision may be influenced more by the fixed cost. More details to follow in Section 5.1 and Appendix C.

[26] In the counterfactual scenario, the price of natural gas may increase compared to the level observed before the transition due to rising demand from the power sector as more natural gas power plants come online. However, my analysis does not account for this endogenous change in natural gas prices.

[27] This leverages the findings of Klemperer and Meyer (1989), which suggest that multiple Supply Function Equilibria (SFE) are bounded by the Cournot equilibrium and the competitive equilibrium. However, note that the market

Following the literature, I use Cournot model to compute the counterfactual strategic equilibrium. Additionally, I compute the counterfactual competitive equilibrium to use as a competitive benchmark for assessing unilateral market power.[28] The difference in equilibrium outcomes between these two market structures reflects changes in firm incentives and market power. I compute Cournot and competitive equilibria for both the pre-retirement and post-retirement samples to maintain consistent competition forms when comparing pre- and post-retirement outcomes.[29] Table 3 summarizes the equilibrium computations. The impact of the retirement-induced transition is measured as a difference between [*S*:post - *C*:post] and [*S*:pre - *C*:pre], where *S* denotes the strategic Cournot outcome and *C* denotes the competitive outcome.

However, the parameters used in the counterfactual analysis, such as marginal cost of generators, will be estimated within a multi-unit uniform framework, exploiting the equilibrium property of the observed SFE in the pre-retirement sample. This approach differs from standard structural estimation, where the same model is used for both estimation and counterfactual analysis. As long as strategic components are removed during the estimation process, using the estimated parameters for counterfactual equilibrium computation with a different model is acceptable. For more details on parameter estimation, please refer to Section 5.3.

5 Description of Model, Data and Parameters

5.1 Model

The Cournot model used for counterfactual equilibrium computation is simlar to that developed by Bushnell, Mansur and Saravia (2008), which was tailored to the wholesale electricity market environment. The model does not account for transmission congestion.

Firm's problem In the (day-ahead) market held in time t and hour h, each strategic firm $i \in \{1, \ldots, N_{st}\}$ simultaneously decides on the profit-maximizing amount of electricity generation, q_{ith}, facing a constraint that q_{ith} cannot exceed its total capacity $q_{i,max}$. The firm's problem is summarized below:

$$\max_{q_{ith}} \; \pi_{i,th}(q_{ith}\,, \mathbf{q}_{-ith}) \;=\; p_{th}\,(q_{ith}\,, \mathbf{q}_{-ith})\,[q_{ith} - q^f_{ith}] \;+ p^f_{ith}\, q^f_{ith} \;-\; C(q_{ith}) \tag{1}$$

$$s.t. \quad q_{ith} \geq 0 \quad \text{and} \quad q_{ith} \leq q_{i,max}$$

impacts of the transition quantified in this paper using the Cournot equilibrium represents the maximum possible effect because the Cournot equilibrium serves as an upper bound for a likely counterfactual SFE.

[28] This method of measuring market power (margin) is widely adopted in the literature, including Borenstein, Bushnell and Wollak (2002), Wolfram (1999), Mansur (2007), Reguant (2014), and etc.

[29] Inconsistencies arise when comparing the market outcomes observed in the pre-retirement sample data, generated from the SFE, to the simulated post-retirement equilibrium outcomes.

where p_{th} is the market equilibrium price, which is a function of equilibrium quantities of firm i and other strategic firms (q_{-ith}), and $C(q_{ith})$ is the cost.[30] A common practice among the electricity-generating firms is to forward contract a certain amount of their generation with the demand side (retail companies), shown as q^f_{ith}, at a predetermined price of p^f_{it}. As the contracting happens long before the actual generation happens, the forward contracted quantity and the price are exogenous at the time of production decision. Because q^f_{ith} does not respond to market price p_{th}, it must be subtracted from the final quantity produced by the firm.[31] Details of how I construct the forward contracted quantity, q^f_{ith}, is provided in Section 5.3.

Residual demand curve The residual demand is the demand faced by N_{st} *strategic firms* together, which is required to compute the market price, p_{th}, within the model. The residual demand, $Q_{s,th}$, equals the aggregate market demand ($\overline{D}_{th}$) less the electricity generated by *non-strategic* suppliers together ($Q_{ns,th}$), as shown below.[32]

$$Q_{s,th}(p_{th}) = \overline{D}_{th} \ - Q_{ns,th}(p_{th})$$

While the aggregate demand ($\overline{D}_{th}$) is almost perfectly price inelastic, the quantity supplied by non-strategic firms together ($Q_{ns,th}$) is responsive to the market price, making the residual demand to be price responsive as well.

Strategic firms are chosen from among the large-scale firms that operate several power plants (i.e., multi-unit firms). I categorize small-scale *fringe* suppliers, most of which operate a single power plant, as non-strategic firms. The non-strategic firm category also includes firms with considerable scale that operate several power plants, but identified as not capable of behaving strategically in a given market environment. These non-strategic firms, therefore, supply electricity at the marginal cost. Section 6.2.2 provides more details of the categorization of strategic and non-strategic firms.

Since I observe the complete set of price and quantity bids of firms in the market, I can construct a residual demand curve for the market (t, h) directly from the bids in a non-parametric way. Specifically, I generate the supply schedule of non-strategic firms ($\sum Q_{ns,th}(p_{th})$) from their supply bids and then subtract it from the aggregate demand ($\overline{D}_{th}$) to form a residual demand curve.

However, for computational purposes within the model, it is preferable to use a smooth, parametric functional form for the residual demand curve. Therefore, I adopt a log-linear demand

[30] As I do not account for transmission congestion in the model, the equilibrium price computed here corresponds to the system clearing price (i.e., Energy Component Price), not the nodal price (i.e., Local Marginal Price).

[31] Because p_f disappears from the F.O.C. after differentiating the profit with respect to q_{ith}, we only need q^f_{ith} information when solving the equilibrium.

[32] To be precise, $\overline{D}_{th}$ is the aggregate market demand net of the ex-post net imported amount of electricity (import – export). The net imported electricity in New England does not respond much to the price (difference), with little departure from the maximum level allowed by the transmission capacity. For additional details on how I treat import/export quantities in the construction of the residual demand, please refer to Appendix B.4.2.

specification as shown below.

$$Q_{s,th} = \alpha_{th} - \beta_{th}\, ln(p_{th}) \quad \Leftrightarrow \quad p_{th} = \exp((\alpha_{th} - Q_{s,th})/\beta_{th}) \tag{2}$$

While the log-linear specification is widely used in the literature (including Bushnell et al. (2008)), it also provides a good fit for the shape of the actual residual demand curve constructed from bids. Appendix B.4.1 contains examples showing the fit between the actual residual demand and the log-linear demand curve.

The parameters α_{th} and β_{th} are estimated before running the counterfactual simulation. α_{th}, the intercept of the residual demand, α_{th}, is obtained by plugging in the observed price and the sum of strategic quantities (P_{th}, $Q_{s,th}$) from the pre-retirement sample into the specified demand curve. The slope of the residual demand, β_{th}, is estimated from the actual demand curve constructed from bidding data. Further details on the estimation of the residual demand slope are provided in Section 5.3.1. Throughout the analysis, I assume that strategic behavior and marginal costs of non-strategic firms do not change due to the transition. This implies that the bids of non-strategic suppliers also remain constant throughout the transition. The assumption allows me to use the residual demand curve estimated from the pre-retirement sample data in the computation of post-retirement equilibrium.

Cost function A firm operates generating units (or power plants) that have different marginal costs.[33] I specify the marginal cost of each generating unit to be constant over quantity, so that the cost function of a firm to be a piece-wise linear function.[34] If a firm operates a total J number of generating units, the marginal cost function is represented as below:

$$C'(q_{it}) = mc_{ijt} \qquad \text{if} \qquad q_{it} \in (\sum_{k=1}^{j-1} q_{ikt}, \sum_{k=1}^{j} q_{ikt}) \tag{3}$$

The unit-specific marginal cost, mc_{ijt}, is estimated from the bidding data using the optimal bidding model, the estimation procedure of which is detailed in Section 5.2 and Appendix B.2.[35]

The fixed cost of a power plant, which includes start-up or ramping costs, is also an important component of a power plant's cost, especially for baseload generators known for their high fixed costs. When a plant has a high fixed cost, shutting it down and restarting becomes costly, reducing the flexibility of a power plant's quantity adjustment. In this case, the firm's operating decisions

[33]While the power plant is used interchangeably with the generating unit, a power plant can contain multiple generating units. I use the term "generating unit" in this section because the bidding data, from which the marginal costs are estimated from, is reported by generating units.

[34]This is a functional form commonly used in electricity market studies (Bushnell et.al., 2008; Ito and Reguant, 2016). Generating units, especially the coal-fired ones, can have a non-linear component in their cost curve associated with the ramp-up cost, in which case the marginal cost would increase with quantity. Instead of estimating the coefficient of the quadratic term of the cost function, I approximate this term with actual price bids and quantity bids of the higher-order step bids of a coal plant. The higher-step price bid of a coal plant usually reflects its ramping cost (which increases with the quantity), thus notably higher than the lower-step price bids. See Appendix C for more details.

[35]While it is common to generate marginal cost out of fuel price and heat rate data, estimating better captures the dispersion of marginal costs that arises when the natural gas market is affected by a shock (i.e., illiquid gas market). See Appendix B.2 for a detailed discussion.

may become dynamic, making the static profit maximization framework used in this paper unsuitable for analysis. Despite this potential issue, I do not incorporate fixed costs into the analysis. While this is a limitation, developing a model that fully accounts for this intertemporal linkage and estimates fixed costs is challenging. Instead, I excluded the hours of very low-demand (12 am to 4 am) from the sample, as these are the hours during which the presence of fixed costs could affect the marginal production decisions of baseload power plants the most.[36] By doing so, the analysis can put more emphasis on the impact of the changing relative marginal costs, resulting from the energy transition, on firms' *marginal* production decisions. In Appendix C, I provide further discussion on the cases in which omitting start-up and ramping costs could be an issue, as well as the potential biases that may arise from omitting these costs in the analysis.

Equilibrium computation I solve strategic firm i's profit maximization problem (shown in equation (1)) in market (t, h) to obtain the first-order conditions shown below:

$$\begin{aligned} \frac{\partial p_{th}}{\partial q_{ith}} [q_{ith} - q^f_{ith}] + p_{th} - C'(q_{ith}) - \lambda_{ith} \leq 0 \quad &\perp \quad q_{ith} \geq 0 \qquad \forall i \in \mathcal{F}_s \\ q_{i,max} - q_{ith} \geq 0 \quad &\perp \quad \lambda_{ith} \geq 0 \qquad \forall i \in \mathcal{F}_s \end{aligned} \tag{4}$$

These complementarity conditions are similar to those derived in Bushnell et al. (2008). More details of the derivation can be found in Appendix A. The Cournot equilibrium quantities, denoted as $\mathbf{q}^*_{th} = [q^*_{1th}, \ldots, q^*_{Nth}]$, is the set of firm-specific quantities that simultaneously solves the system of complementarity conditions. I numerically solve $\mathbf{q}^*_{th}$ that satisfies the system of first-order conditions of N_{st} strategic firms.[37] Once the equilibrium quantities are solved, the market price can be obtained by substituting these values into the residual demand curve given in Equation (2).

In the competitive model, firms supply electricity from their lowest-cost generators, absent of strategic considerations, aiming to minimize production costs given the market equilibrium price: $p_{th} - C'(q_{ith}) \geq 0$. Then the competitive equilibrium price is the price at which the aggregate supply equals the aggregate demand which is fixed to the level observed in the data (perfectly inelastic $\overline{D}_{th}$). Once the equilibrium price is determined, firm-level quantities and other market variables can be readily obtained.

5.2 Data

The primary dataset used is the *Day-Ahead* Energy Market Data by the ISO-New England for the winter seasons between 2012 and 2014 (Nov-Feb).[38] Electricity-generating firms participate

[36] These are the hours where I observe the market price of electricity being lower than the coal plant's marginal cost. This suggests that the marginal production decisions of coal plants in these hours would be driven more by considerations of fixed costs than marginal costs.

[37] To obtain the solution, I use the PATH algorithm, known for its effectiveness in solving mixed complementarity problems (Kolstad and Mathiesen, 1991; Dirkse and Ferris, 1998). This computing method has been widely used in previous studies, including Bushnell et al. (2008).

[38] ISO New England operates the wholesale electricity market, which includes the day-ahead and real-time markets. I primarily focus on the day-ahead market because it accounts for the majority of electricity trading and is where

in hourly day-ahead market auctions, where they submit bids (i.e., energy offer) for each of their generating units. These bids include price and quantity information, represented as $< p_{ijht}, q_{ijht} >$, indicating the minimum price p_{ijht} at which unit j is willing to supply quantity q_{ijht}. This high-frequency bidding data is available at the firm-unit level and is used to measure equilibrium quantities, as well as to estimate the parameters needed for the counterfactual analysis, as explained in Section 5.3. Aggregate electricity demand is derived from demand bids submitted by retail companies in the day-ahead auction. The market clearing price used is the Energy Component Price, which clears the entire system before considering local transmission congestions.

Additional data, such as power plant fuel types and nameplate capacities, is sourced from Seasonal Claimed Capability data (from forward capacity auction). Data on planned power plant retirements and installations is collected from the ISO-NE website and EIA website (U.S. Energy Information Administration). Fuel price data is obtained from various sources. The daily natural gas spot price data (index) is sourced from Natural Gas Intelligence, and the coal spot price data is obtained from SNL Energy.

5.3 Parameter Estimation

Three main parameters are estimated for used in the counterfactual analysis: the residual demand slope (β_{th}), generator marginal costs (mc_{ijt}), and forward contracted electricity quantities (q^f_{it}). These estimations are conducted using the *optimal bidding* model and data from the hourly day-ahead market auction, leveraging the equilibrium properties of the Supply Function Equilibrium (SFE) from which the bidding data is generated. Note that the model used for estimating parameters differs from the Cournot model used for counterfactual equilibrium computation. This section provides an overview of the estimation process, with detailed estimation procedure available in Appendix B.

5.3.1 Residual demand slope

The parameter β_{th} in Equation (2), representing the price elasticity of non-strategic supply, is estimated using a strategy similar to that employed in Ito and Reguant (2016). That is, I construct the actual residual demand curve from the bids in a non-parametric way and then fit it with a parametric function. Specifically, for each market (t, h), I construct the supply schedule of non-strategic firms ($\sum S_{ns,th}(p_{th})$), which is possible since I observe the entire distribution of bids submitted by non-strategic firms, not only the equilibrium price and quantity. Subtracting this supply schedule from the aggregate demand ($\overline{D}_{th}$) forms a residual demand curve.[39] Then, I fit a log-linear function, shown in equation (2), to the constructed curve to estimate the slope,

strategic interactions between firms are most active.

[39] Note that $\overline{D}_{th}$ already accounts for imports and exports, as I subtracted the ex-post net imported electricity (i.e., net interchange) from the aggregate demand to obtain this value. Therefore, I can omit import and export bids when calculating the slope of the residual demand curve. For additional details on why omitting these bids would not critically impact the slope estimates, please refer to Appendix B.4.2.

β_{th}.[40] I estimate β_{th} separately for each market (t, h) to account for potential variations in the price responsiveness of the non-strategic supply under different market conditions.[41]

5.3.2 Marginal cost

The most common approach to obtaining marginal costs of (thermal) electricity generators (power plants) is to measure the marginal costs using the fuel price index data (aggregate-level data) and the heat rate of generators (as seen in studies by Wolfram, 1999; Borenstein et al., 2002, among others.). This approach, however, fails to capture the differences in marginal costs among gas-fired plants, which result from the increasing dispersion in their gas procurement prices when pipeline congestion leads to stress in the gas spot market.[42]

To address this issue, I employ the estimation techniques developed in the empirical auction literature (Wolak, 2001; Reguant, 2014; Ryan, 2021; Kim, 2022) to estimate the marginal costs that rationalize the bids submitted by firms in electricity auctions. Although this approach requires modeling the optimal bidding decisions of firms and additional computation effort, it performs better in capturing the dispersion of the marginal opportunity costs at the firm-plant level than the marginal cost measured from data. The estimation exploits the fact that the equilibrium bid observed in the data maximizes a firm's (expected) profit, leading to the following first-order condition: $b_{ijt} = mc_{ijt} + \text{markup}_{it}$. Utilizing the rich bidding data together with this estimation technique enables me to estimate the firm-unit-specific marginal cost parameter, mc_{ijt}, from the first order condition, at the daily level. Note that estimating marginal cost is not feasible for generating units located far away from the market clearing price (i.e., not marginal), including some fringe and baseload units (e.g., nuclear).[43] I use the price bid as a measure of marginal costs for these units, exploiting the fact that firms have no incentives to add markup when bidding for a non-marginal generating unit.[44] For more details on the bidding model and the estimation procedure, please refer to Appendix B.

Figure 5 summarizes the marginal costs of gas units, coal units, and the hypothetical gas units,

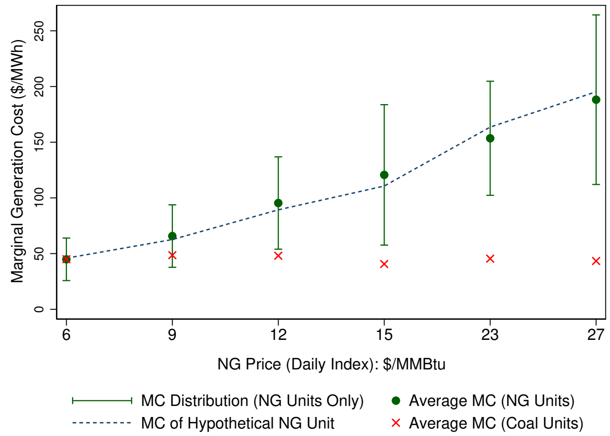
[40]The log-linear specification effectively captures the non-linear shape of the actual residual demand curve. An example of the estimated curve fitted to the original curve is shown in Figure B.2 in Appendix B.4.1. As explained in Appendix B.4.1, the log-linear specification offers a better fit compared to the linear specification, particularly when the original RD curve exhibits lumpiness. Moreover, the log-linear curve effectively smoothes the curve, achieving a level of smoothness similar to that achieved with Gaussian-kernel smoothing. More details can be found in Appendix B.4.1.

[41]This method differs from that in Bushnell et al. (2008) which used only the equilibrium price and quantities for their estimation and estimated a single slope parameter for the entire sample.

[42]The fuel price index, the only available data on fuel prices, represents a weighted average (or median) of fuel procurement prices at the firm-plant level. This average value can serve as a good proxy for plant-level spot procurement prices when individual-level price differences are small, but not when the dispersion in individual prices increases. Using the fuel price index in the latter case could lead to measurement errors. For more details, please refer to Appendix B.2.3 or Kim (2022).

[43]The optimal bidding model allows us to estimate marginal costs for units that are close to being marginal, meaning they have a positive probability of being used in a firm's strategic decisions. However, this estimation technique cannot be applied to fringe units that submit excessively high bids to avoid dispatch and baseload nuclear plants that submit bids close to zero.

[44]The marginal costs relevant for our equilibrium computations are those of generating units that are close to being marginal. Therefore, my approach to handling the marginal cost of non-marginal units does not significantly affect the results.



Notes: The graph shows the distribution and the mean of marginal costs of NG-fired generating units (excluding the top and bottom 1 percentile), coal-fired generating units, and hypothetical NG-fired units used in the counterfactual analysis. The values are plotted across the six selected days that have different levels of NG prices which are displayed on the horizontal axis.

Figure 5: Marginal Cost Summary

plotted against the gas price levels (price index) of the days in the sample. The daily estimates of marginal costs for the gas units are shown as a distribution, verifying the existence of dispersion in their marginal costs. The average pattern of the estimates shows that the relative marginal cost of gas generation versus coal generation changes along with the increasing gas prices.

5.3.3 Forward contracted electricity

Data does not exist for the forward contracted position as it is determined through confidential bilateral negotiations between the electricity-generating firms and the demand side (retail companies). I impose a structure on the forward contracted quantity by assuming that it is a percentage (γ_{ih}) of the firm's actual hourly generation, represented as $q^f_{ith} = \gamma_{ih} q_{ith}$. I estimate hourly forward contract rates, γ_{ih}, from the bidding data, utilizing the estimation procedure of Kim (2022) and Reguant (2014), the details of which are in Appendix B.3.

Although the contracted rate differs by firm and hour, the average of firm-level rates is about 75% during off-peak hours (roughly from 11PM to 6AM), and it is about 30% during peak hours.[45] Table B.1 in Appendix B.3 summarizes the forward contract rate estimates for a subset of firms. While the firm-specific rate parameter remains constant for each hour, the contracted quantity q^f_{ith} could vary across days due to variation in firm's daily production level (q_{ith}).

I use the same q^f_{ith} estimates from the pre-retirement sample when computing the post-retirement counterfactual equilibrium, although the extent of contracting may change in the counterfactual environment.[46] However, the misspecified forward contracted quantity will not significantly af-

[45]Note that the forward contracting rate can be estimated only for the large-scale firm operating a substantial number of generating units. The mean rate reported here includes 11 strategic firms having estimates with a 5% significance level.

[46]For example, research indicates that forward contracting incentives can be affected by changes in market structure. Relevant studies, such as Brown and Eckert (2017) and Miller and Podwol (2020), have demonstrated that forward

fect the main results since I have excluded, from the analysis, the hours of very low-demand (from 12AM to 4AM) during which the forward contract is high and binding. Section B.3.3 provides a detailed discussion of how the energy transition might impact forward contracting incentives of firms.

6 Baseline Results

I first report the results computed for the baseline case in which the industry structure does not change as a result of the transition process. The results of each day-hour market, (t, h), in the sample are summarized by aggregate demand and gas price levels, which vary across markets. Note that it is common in electricity market studies to analyze results separately by demand (e.g., *peak* hours vs.*off-peak* hours), as the market characteristics and competitiveness are known to differ by the demand level.[47]

I group the demands into four bins (D1 to D4) and the gas prices into three bins (G1-low, G2-med, and G3-high), then report the average values within each bin.[48] The numbers assigned to D (D1 to D4) represent increasing levels of demand, with D1 indicating the lowest demand level and D4 the highest. Similarly, the numbers assigned to G (G1-low to G3-high) indicate increasing gas price levels.

6.1 Residual demand slope estimates

Panel (A) of Table 4 summarizes $\hat{\beta}_{th}$, the estimated slopes of residual demand curves of each day-hour market (t, h); the mean is around 4.04 GWh/\$ with some variation across markets.[49] To examine how the slope differs by the demand and gas price levels of the market, we run a simple regression of $\hat{\beta}_{th}$ on demand and gas price variables. Panel (B) reports the coefficients of the regression. One interesting finding is that $\hat{\beta}_{th}$ is smaller when the gas price is higher, shown by a negative coefficient of the "NG price" variable in Panel (B). This indicates that the supply from the non-strategic firms becomes relatively more price-inelastic on days with higher natural gas prices. Because the supply bids of non-strategic (fringe) firms reflect their marginal costs, the inelasticity of the residual demand can be linked to the dispersion of marginal costs among gas

contracting incentives tend to decrease following a horizonal merger within the market. In Appendix B.3.3, I provide a detailed discussion of how these findings can be applied to my setting, along with some conjectures about how the incentives may change in response to the energy transition.

[47] In a typical market, absent of gas price shock or any disruption, the off-peak hours are when market power is less exercised, whereas the peak hours are when the market power is most likely to be present (Borenstein and Bushnell, 1999; Borenstein, Bushnell and Wolak, 2002). Here, (D1) and (D2) roughly correspond to the off-peak hour demand levels (5AM-10AM and 11PM), and (D3) and (D4) to the peak hour (11AM-10PM) demand. Cut-off values for the bins are determined after examining the distribution of demand and gas prices.

[48] Table F.2 and Figure G.4 in the Appendix provide the summary and details of the categorization of demand and gas price variables, respectively.

[49] We also computed demand elasticities evaluated at the observed pre-retirement equilibrium, and find that market-level elasticities range between 0.15 and 2.87, with a mean around 0.64. Also, variations in elasticities across demand and gas price levels are similar to those of β.

(A) Summary statistics of $\hat{\beta}_{th}$							
mean:	4.04	s.d.:	1.02	min:	2.52	max:	8.30
(B) Regression result of $\hat{\beta}_{th}$ on demand and NG price of the market (t,h)							
	Demand:	0.004		NG price:	-0.04		
		(0.02)			(0.01)		

Notes: $\hat{\beta}_{th}$ is the estimated slope of the residual demand curve of day t-hour h (*unit*: GWh/\$). Section (B) reports the estimates of OLS regression of $\widehat{\beta_{th}}$ on Demand$_{th}$ and NG price$_t$ variables. Demand is the aggregate market demand of the day t- hour h market (*unit*: GWh). Gas price is the spot gas price index of day t (*unit*: \$/MMBtu). Standard errors in the parenthesis. N = 348.

Table 4: Residual Demand Slope Estimates ($\hat{\beta}_{th}$)

generators, which increases further as the overall gas price increases, as documented in Figure 5.[50] Note that I do not find a strong (significant) correlation between $\hat{\beta}_{th}$ and the demand.

6.2 Counterfactual equilibrium prices

6.2.1 Competitive prices

Table 5 summarizes the competitive prices simulated for the pre- (*Before*) and post-retirement (*After*) samples. The competitive prices changed overall after the transition, indicative of a change in the marginal cost distribution resulting from the transition. The first two rows of the table show that competitive prices increase the most in the lowest-demand sample (D1) and decreases the most in the highest-demand sample (D4). Subsequent panels from (G1-low) to (G3-high) show that the higher the gas price is, competitive prices tend to increase more after the transition, although some variation exists across the demand.

6.2.2 Selection of strategic firms

In order to compute the Cournot equilibrium, the set of strategic firms need to be determined. While it is common to assume that large-scale firms with high market share are strategic players, it difficult to pin down several that would indeed behave strategically when the shares are relatively balanced across many of these firms and if there is no explicit cutoff values used for shares or scales deeming a firm to be strategic. Moreover, even a large-scale firm can behave quite competitively depending on the market condition, because firms compete in the multi-unit uniform auction in this market. In this uniform auction setting, a firm has an incentive to behave strategically only when its generator (or power plant) is close to being marginal, the probability of which depends critically on the demand and supply conditions of the market.[51]

To address these concerns, I select strategic firms based on what the data and the model

[50] The source of the documented marginal cost dispersion is explained more in Appendix B.2.3.

[51] For example, when the market demand is high, a large-scale firm that only operates the low-cost generators will not bid strategically, despite having a high market share, as none of its generators are close to being marginal. If so,

	Competitive Price				
		Low Demand		⇒	**High** Demand
	Total	(D1)	(D2)	(D3)	(D4)
Before	98.5	75.9	87.4	88.0	124.9
After	97.8	81.8	88.7	87.3	118.9
Further Controlling for the Daily Gas Prices					
(G1-low) Low Gas Price					
Before	60.3	51.1	52.4	53.8	75.7
After	57.9	50.9	52.3	52.3	69.7
(G2-med) Med Gas Price					
Before	90.4	75.4	79.0	81.4	119.4
After	89.1	81.9	76.7	79.01	112.0
(G3-high) High Gas Price					
Before	151.1	115.0	132.4	154.1	164.5
After	153.0	129.4	137.7	155.2	159.8

Notes: *Before* and *After* refer to simulated prices for before and after retirement situtations. Average of the simulated prices are reported in the table. The cut-off values for the demand bins are; (D1) demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The cut-off values for the gas price bins are: days with gas price index between \$4 and \$9/MMBtu (G1-low), between \$9 and \$15/MMBtu (G2-med), and above \$15/MMBtu and up to \$27/MMBtu (G3-high). The number of observation in each demand-gas price bin is roughly the same. N = 348.

Table 5: Competitive Price Result

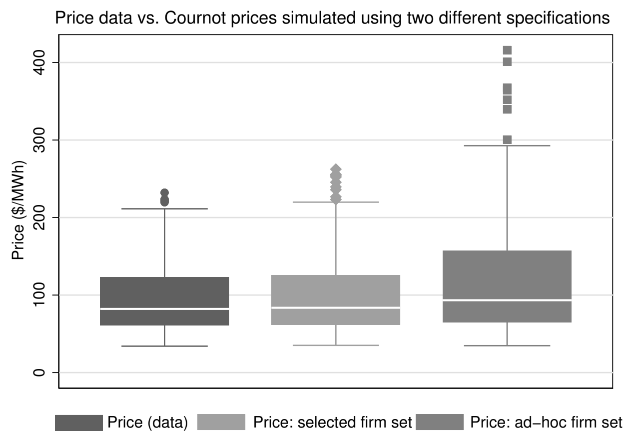
predicts, among large-scale firms with considerable market share (calcuated based on their infra-marginal quantity).[52] I select firms identified as behaving strategically in the actual equilibrium (SFE of the pre-retirement sample), whose quantity, as *observed* from the data (generated from the SFE), considerably differs from and is smaller than the counterfactual *competitive* quantity of the pre-retirement sample. The deviation of the actual quantity from the competitive benchmark indicates that the firm was making strategic production decisions under the given market conditions.[53] The rest of the firms not selected are categorized as *non-strategic* firms that behave competitively, supplying at a cost-minimizing fashion. I select firms separately for each market (t, h), and the size and composition of the group of strategic firms differ across markets, with a total of 20 firms identified as strategic throughout the entire sample.[54] I assume that the strategic firm set will not

treating this firm as a strategic player in the Cournot computation could exaggerate the strategic outcome.

[52]While I did not specifically limit the set of firms to those with high market shares during the selection process, a majority of the firms chosen through this method had considerably high market shares. In this regard, this selection method proves particularly useful for excluding firms that possess a high infra-marginal quantity (e.g., through ownership of a large nuclear power plant) but do not operate marginal units that can be used for bidding strategically. Note that I have limited the set of firms to those with a capacity greater than 200MW in this selection process.

[53]The underlying idea behind my approach, which involves selecting firms based on information about their strategic behavior reflected and observed in data, is similar to that of Ryan (2021). To justify the selection of strategic firms over non-strategic firms, Ryan (2021) showed that the bids submitted by strategic firms responded significantly to transmission congestion – the cause of strategic behavior in his paper – while the bids of non-strategic firms did not.

[54]The number of strategic firms at the market level (t, h) ranges from 7 to 13. For a summary of firm characteristics, refer to Table 8 and Table D.1.



Notes: The figure displays three price distributions for the 'pre-retirement' situation. The left distribution represents actual equilibrium (SFE) prices observed in the data. The middle distribution shows Cournot prices simulated using a 'selected' set of strategic firms. The right distribution shows Cournot prices simulated using the fixed set of firms (8 firms with the largest scales) that are chosen in an ad-hoc way and fixed throughout the sample.

Figure 6: Observed Prices vs. Cournot Prices Simulated using Selected Firm Set and Ad-hoc Firm Set

change in the counterfactual environment.[55] For a detailed discussion of the selection method, please refer to Appendix D.

Model Fit Figure 6 presents, from left to right, the distributions of equilibrium prices observed from data (SFE), Cournot prices simulated with the 'selected' strategic firms, and Cournot prices simulated with an ad-hoc set of strategic firms, all for the *pre-retirement* sample. The ad-hoc firm set, which consists of a total of 8 firms with the largest scales, represents a firm set arbitrarily chosen solely based on the scale of firms. The ad-hoc firm set is fixed throughout the sample unlike the selected firm set, the composition of which differs slightly across the sample accounting for the variation in market conditions.

First, when comparing the distribution of observed prices (left) with Cournot prices simulated using the selected firm set (middle), I find that simulated Cournot prices closely align with the observed equilibrium prices, indicating a good fit. Additionally, I find a good fit between the firm-level quantity computed and the Cournot model and the actual firm-level quantity, as shown in Figure H.7 of the Online Appendix. These findings validate the use of the Cournot equilibrium to approximate the actual strategic equilibrium (SFE).

Comparing of all three distributions, including the last one simulated with a fixed set of large-scale firms (ad-hoc firm set), reveals that the selected firm set performs relatively better than the alternative firm set in terms of model fit. Specifically, the distribution of prices simulated with the

[55]Since the selection process relies on information observed from the pre-retirement market conditions, it is possible that a previously non-strategic firm could start behaving strategically in the counterfactual environment. To address this concern, I have imposed additional measures to account for the differences in market environments between the pre-retirement and post-retirement situations, aiming to make the selected firm set as comprehensive as possible. Besides that, it is common in the literature implementing Cournot simulations to fix the set of firms throughout the counterfactual simulations, unless they study explicitly considers entry and exit of firms in a dynamic setting.

		Strategic Price			
		Low Demand		⇒ **High**Demand	
	Total	(D1)	(D2)	(D3)	(D4)
Before	112.6	81.2	95.5	99.7	149.0
After	122.1	96.4	108.1	108.8	153.5
Further Controlling for the Daily Gas Prices					
(G1-low) Low Gas Price					
Before	67.0	53.5	58.4	58.4	87.2
After	69.8	58.8	59.9	61.8	87.7
(G2-med) Med Gas Price					
Before	100.5	83.0	84.3	88.2	137.2
After	108.6	98.1	91.6	96.7	138.8
(G3-high) High Gas Price					
Before	178.1	121.5	144.7	168.8	195.1
After	196.5	152.0	173.5	192.4	202.0

Notes: *Before* and *After* refer to simulated prices for before and after retirement situtations. Average of the simulated prices are reported in the table. The cut-off values for the demand bins are: (D1) demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The cut-off values for the gas price bins are: days with gas price index between \$4 and \$9/MMBtu (G1-low), between \$9 and \$15/MMBtu (G2-med), and above \$15/MMBtu and up to \$27/MMBtu (G3-high). The number of observation in each demand-gas price bin is roughly the same. N = 348.

Table 6: Cournot Price Result

selected firm set (middle) aligns more closely with the distribution of observed prices (left) than the distribution of prices simulated with the ad-hoc firm set (right).

Strategic Cournot prices Table 6 summarizes the Cournot prices simulated for the pre- (*Before*) and post-retirement (*After*) samples.[56] As shown in the first two rows of the table, strategic prices increase more in the low-demand sample (D1 and D2) than in the high-demand sample (D3 and D4), on average. When examining the pattern across different gas price levels, I find that strategic prices, on average, increase more under higher gas price levels (from (G1-low) to (G3-high), for *Total*).

6.3 Measuring the change in market power

The market power is measured as the extent to which the strategic Cournot price departs from the competitive level. The market power of each day and hour market, (t, h), is as follows:

$$\Delta P_{T,th} = \text{markup}_{\ T,th} = P_{\text{Cournot},T,th} - P_{com,T,th}$$

[56]While the Cournot price well approximates the actual equilibrium price (as shown in Panel (a) of Figure 6), the Cournot prices reported here represent upper bounds of strategic prices likely under the SFE, according to the findings of Klemperer and Meyer (1989). For detailed comparisons of prices (competitive, Cournotm and the observed equilibrium) in the pre-retirement sample, refer to Table H.3 in the Online Appendix.

where, T denotes whether the sample is pre-retirement or post-retirement.[57] Since my focus is on measuring the *change* in market power resulting from the transition, I use $\Delta\Delta P_{th}$ as the primary measure of interest:

$$\Delta\Delta P_{th} = \Delta P_{post,th} - \Delta P_{pre,th}$$

This represents the difference between the pre-retirement market power and the post-retirement market power. A positive (negative) value of $\Delta\Delta P_{th}$ indicates an increase (decrease) in market power after the transition, which results in incresing (decreasing) the strategic price by $\$\Delta\Delta P_{th}/\mathrm{MWh}$ more relative to a change in the competitive price.

Result Table 7 reports the $\Delta\Delta P_{th}$ of each day-hour market (t, h) summarized by demand (columns D1 to D4) and gas price level (rows G1-low to G3-high) of the market.[58] On average, the market power increases after the transition, raising the price additionally by $9.8/MWh relative to the change in competitive prices (shown in the first row of the column *Total*). When examining the pattern across different demand levels, shown in the first row of the table, $\Delta\Delta P_{th}$ is higher in the low-demand sample (columns (D1) and (D2)) than in the high-demand sample (columns (D3) and (D4)), though not distinctive. This indicates that the energy transition is expected to increase the market power more in the low-demand sample than in the high-demand sample.

However, it is important to note that the *absolute* level of market power, ΔP_{th}, remains lowest during low-demand (off-peak) hours and highest during high-demand (peak) hours in both pre-retirement and post-retirement cases, which corresponds to the well-established findings in the literature. Figure G.6 in the Appendix presents the absolute market power levels, averaged within each demand bin (D1 to D4), for the pre-retirement sample (panel (a)) and the post-retirement sample (panel (b)). Note that $\Delta\Delta P_{th}$ quantifies the level difference between these panels.

A more distinct pattern emerges from the summary across the gas prices, presented in rows from (G1-low) to (G3-high). $\Delta\Delta P_{th}$ consistently shows a positive value, with a notable increase as we move from (G1-low) to (G3-high) in the *Total* column, with $\Delta\Delta P_{th}$ rising from 4.9 to 16.6, on average. This indicates that energy transition is expected to increase the market power more when the gas prices are higher.

To summarize, two patterns emerge from the baseline results: first, market power increases more due to the transition when gas prices are higher; and second, low-demand hours suffer more from the increased market power than the high-demand hours. The result can be interpreted as follows; if an industry transitioning to having a higher share of gas generation were to experience the same gas price shock seen during the winters of 2013-2014, wholesale electricity prices would rise even more than before the transition, primarily due to increased market power. The market

[57] A similar measure was used in Borenstein, Bushnell and Wolak (2002), Wolfram (1999), Mansur (2007), and Reguant (2014) though a percentage measure was used in some of these papers.

[58] Table F.5 reports the percentage change of $\Delta\Delta P_{th}$ taken over the original equilibrium price before the transition, which shows patterns qualitatively similar to those of the level changes. I will keep reporting the results in *level* changes because our sample consists of days that vary significantly in terms of the average price of electricity, which results from the variation in the gas prices. In this case, comparing the percentage change of the $\Delta\Delta P_{th}$ across days would mislead the variation in the extent of market power change.

	$\Delta\Delta P = \Delta P_{\text{post}} - \Delta P_{\text{pre}}$				
		Low Demand		$\Rightarrow$	**High** Demand
	Total	(D1)	(D2)	(D3)	(D4)
$\Delta\Delta P$	9.8	9.2	11.3	10.7	8.9
Further Controlling for the Daily Gas Prices					
(G1-low) Low Gas Price					
$\Delta\Delta P$	4.9	5.4	1.6	5.0	6.4
(G2-med) Med Gas Price					
$\Delta\Delta P$	9.4	8.4	9.6	10.8	8.9
(G3-high) High Gas Price					
$\Delta\Delta P$	16.6	16.1	23.4	21.9	11.5

Notes: Table reports the average market-level $\Delta\Delta P_{th}$. Demand is categorized into four bins: (D1) below 14 GW, (D2) between 14 and 15.5 GW, (D3) between 15.5 and 17 GW, and (D4) above 17 GW. The number of observations in each demand bin is roughly the same. The gas price bins are defined as follows: (G1-low) for days with gas price index between \$4 and \$9/MMBtu, (G2-med) for days between \$9 and \$15/MMBtu, and (G3-high) for days above \$15/MMBtu up to \$27/MMBtu. Since I selected days in the high-cost regime, even the "Low Gas Price" category includes days with gas prices higher than the normal (lowest) level of \$4/MMBtu. N = 348.

Table 7: Change in the Market Power, $\Delta\Delta P_{th}$

power increase due to the transition would be more intense when the gas price shock is more severe, as indicated by the increase in $\Delta\Delta P_{th}$ from (G1-low) to (G1-high), and more prevalent during the low-demand hours (D1 and D2) as shown earlier.

These patterns are also documented from a simple regression of $\Delta\Delta P_{th}$ on the market-level demand and gas price levels, shown in Table F.4 in the Appendix. The coefficient estimate of the gas price variable is 0.81 and significant, capturing the positive correlation between the gas price and the $\Delta\Delta P_{th}$. The coefficient for the demand variable is negative at -0.07, but not significant, implying that the relationship between $\Delta\Delta P_{th}$ and the demand is not as strong as that with the gas price.

6.4 Firm-Level Analysis: Exploring the Source of Market Power

Given that the results of the baseline case indicate a change in the strategic behavior of firms resulting from the energy transition, it is important to examine the factors that may have contributed to these findings. I investigate how the relevant market variables and the strategic responses of firms are affected by the retirement, accounting for the heterogeneity among firms. Once the mechanism behind the baseline results is established, we can more effectively identify the underlying forces contributing to changes in outcomes in the additional counterfactual cases considered in Section 7, which are marginal departures from the baseline scenario.

Firm Type	No. of Firms	Total Capacity (MW)	Firm Capacity (MW)		No. of Units
			mean	s.d.	mean
Retired firm	4	6,245	1,561	665	8.3
Non-retired firm					
Gas-intensive	8	9,308	1,163	988	4.4
Balanced	8	9,890	1,236	709	10.1

Notes: The table summarizes the characteristics of strategic firms, categorized into three types: retired firms, gas-intensive firms, and balanced firms. The 'No. of firms' column reports the total number of firms in each firm type and 'Total capacity' column reports the sum of the capacity of all firms by firm type. The 'Firm capacity' columns provide the mean and standard deviation of the *firm-specific* capacities by firm type. The 'No. of units' column reports the average number of generating units (plants) operated by each firm within the respective firm type category.

Table 8: Summary of Strategic Firms: by Firm Type

How does the retired firm's production change? I begin by examining how the production of *retired firms* (i.e., firms that own the retired baseloads) changes as their retired plant is replaced with a gas power plant of the same capacity. In Figure G.5 of the Appendix, I plot the average quantity produced by retired firms together, before and after the transition, separately by demand and gas price levels of the market. While the total capacity of each retired firm remains unchanged, their combined production decreases, particularly during lower-demand hours (D1 and D2) and under higher gas prices (G1-low → G3-high). In other words, during low-demand hours, production increasingly shifts away from retired firms toward other firms the higher the gas prices are.[59]

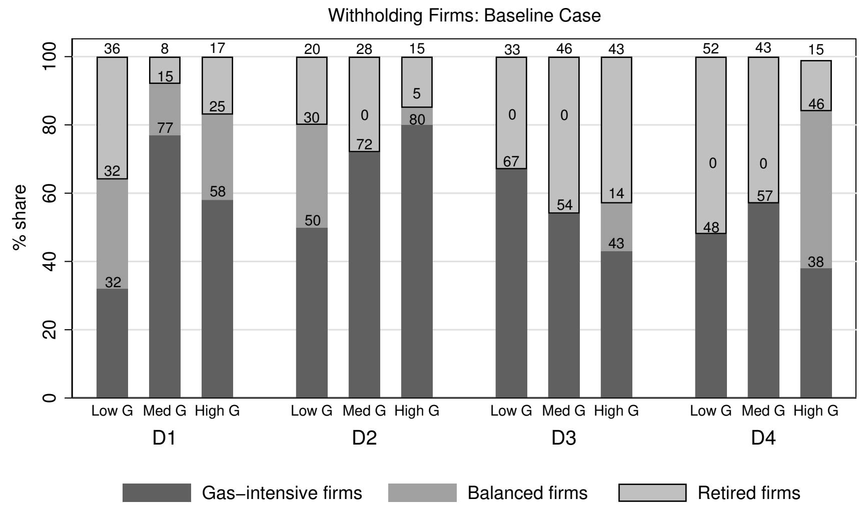
Which types of firms are active in exercising market power? The strategic firms used in the analysis are mostly large-scale firms with considerable market shares, yet they exhibit heterogeneity in characteristics, including the composition of fuel technologies. Therefore, I investigate which *type* of strategic firms more actively exercise market power in response to the changes in the competitive environment resulting from the grid's transition.

I categorized strategic firms into three groups that differ in their fuel technology composition. The 'Retired firm' refers to firms that previously owned the retired power plants, whose generation mix is directly affected by the transition. Among firms not part of the retired category, those with more than 80% of their generation coming from gas power plants are categorized as 'Gas-intensive' firms. The rest of the firms, labeled as 'Balanced', are those generating electricity using relatively diverse fuel technologies. Table 8 summarizes the characteristics of firms by their type.[60]

A strategic firm exercising market power would profitably *withhold* the quantity relative to the level produced if it instead behaved as a price taker. Therefore, I measure the firm-level withholding – or the net strategic quantity – as a difference between a firm's Cournot quantity, $q_{i,st}$, and the competitive quantity, $q_{i,com}$. The negative net strategic quantity (i.e., $q^*_{i,st} = q_{i,st} - q_{i,com}$) indicates

[59] The reduction in quantity that I document for the retired firms is not a result of fixed cost differences between a baseload power plant and a gas power plant. This is because the model used for computing these quantities does not account for fixed costs.

[60] Balanced firm's generation set is a mix of coal, nuclear, natural gas, oil, hydro, and biomass. Summary of the fuel mix of balanced firms can be found in Table H.7 of the Online Appendix.



Notes: Demand is categorized into four bins, (D1) to (D4), with (D1) representing the lowest demand level and (D4) the highest demand level. Gas prices are categorized into three bins, (G1-low), (G2-med), and (G3-high). The graph reports the percentage of each firm type out of the total number of firms identified as exercising greater market power. For example, an 80% value for 'Gas-intensive firms' in the (D2)-(G2-med) category indicates that among the firms identified as exercising market power in the (D2)-(G2-med) sample, 80% of them were gas-intensive firms.

Figure 7: Percentage of Selected Strategic Firm: by Firm Type

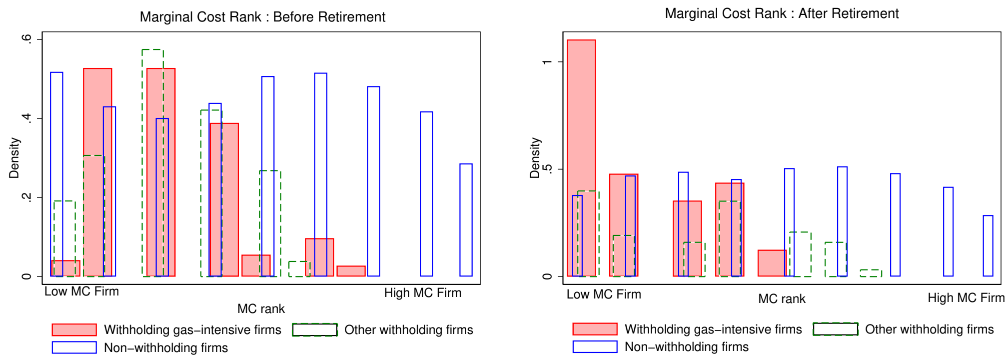
a withholding of production at the firm level.

As I am interested in the *change* in the firm's strategic behavior due to the transition, I select firms that *additionally* withhold their net strategic quantity ($q^*_{i,st}$) after the transition, but enjoy a higher markup by doing so. That is, for each (t, h) market, I find firms whose (i) net strategic quantity is negative in both pre- and post-retirement states ($q^*_{i,st,pre} < 0$ and $q^*_{i,st,post} < 0$), (ii) the extent of withholding *increases* in the post-retirement state compared to the pre-retirement state ($q^*_{i,st,post} < q^*_{i,st,pre}$, or $\Delta q_{i,wh} = |q^*_{i,st,post}| - |q^*_{i,st,pre}| > 0$) and (iii) markup increases further as a result of the additional withholding ($\text{markup}_{i,post} > \text{markup}_{i,pre} > 0$).[61] The method allows me to identify firms that more actively exercise market power throughout the transition process, among those with a reasonably large market presence.[62]

Figure 7 reports the percentage share of each firm type among the identified *withholding firms*, summarized over different demand and gas price levels of the market (the same categories used in Table 7). On average, the "Gas-intensive" firms take up almost 60% share of the withholding firms, though some variation exists across categories: they profitably withhold the quantity even more after the transition compared to other types of firms, more so when the demand is lower

[61]Condition (iii) is necessary to ensure that the profit loss from withholding the quantity is offset by a profit gained from a large increase in the price-cost margin. I also verified that an increase in the price-cost margin (markup) of selected firms is associated with an overall increase in their profits. For this exercise, I computed the lower bound of net profit gain measured by Δ profit = $\Delta markup \times q_{af} + markup_{bf} \times \Delta q$. This is the lower bound of the net profit gain as the computation does not fully account for the piece-wise linear feature of the marginal cost curve, treating the marginal cost to be flat over all infra-marginal quantity.

[62]I select firms among those with at least a 10% share of the total strategic supply (Q_{st}). This selection approach based on quantity comparison is conceptually similar to selecting firms with high-market power based on the firm-specific Lerner index (i.e., firm-specific markup) or market share. About 50% of the selected withholding firms are those with the highest market share, and the rest are all among the top three market share firms.



(a) MC rank before retirement

(b) MC rank after retirement

Notes: Graphs show the distribution of relative rank of the marginal cost at a firm level, before and after the industry transition. Relatively lower cost firms are assigned a low rank, thus located towards the left portion of the graph.*Withholding* firm refers to firms identified as withholding the quantity *more* after the transition ($\Delta q_{i,wh} > 0$). Panels (a) and (b) shows the (relative) rank of marginal cost of (i) gas-intensive withholding firms, (ii) other withholding firms, and (iii) non-withholding firms that are not identifiied as withholding the quantity more after the transition.

Figure 8: Marginal Cost Rank: by Firm Type and the Withholding Status

and gas prices are higher.[63] In Column (1) of Table 9, I also examine the size of withholding by firm type, where I find that the extent of withholding is significantly greater for gas-intensive firms compared to others. This suggests that changes in market conditions resulting from the retirement and replacement process under the baseline case provide gas-intensive incumbent firms with increasingly more ability to exercise market power.

Firm-level marginal cost distribution analysis I examine the exogenous change in the marginal cost distribution, $C'(\mathbf{q}_{st}) = \{C'(q_1), \ldots, C'(q_{N_{st}})\}$, by comparing distributions before (C'_{pre}) and after (C'_{post}) the transition, fixing each firm's quantity to its pre-retirement Cournot quantity, $\mathbf{q}_{st,bf} = \{q_1, \ldots, q_{N_{st}}\}$.[64]

I begin by analyzing how the relative order (rank) of firm-specific marginal costs is affected by the transition. In each (t, h) market, firms are ranked in an increasing order based on their marginal costs (from low cost to high cost) for both the pre- and post-retirement cost distributions. The distribution of assigned ranks at the firm level are then plotted for different firm groups: with-

[63] While the gas-intensive firms are identified as most frequently withholding the quantity throughout the transition process, their status as withholders does not display a clear pattern when examined against the demand and gas price levels, as shown in Figure 7. One possible explanation for this finding is that our equilibrium computation relies on the actual supply and demand curves generated from the data, making the strategic environment noisier than in the controlled setting. The set of potential marginal units and strategic competitors of a firm, namely the strategic environment, is determined jointly by the demand level and the shape of the supply curve that could vary significantly with the change in gas prices. It is, therefore, difficult to obtain a clear-cut pattern regarding the withholding behavior as in a controlled simulation. Additionally, Figure 7 summarizes the percentages at the demand-gas price bin level, which is of a smaller sample, thus could be noisier than a summary over a single category.

[64] The change in marginal cost resulting from the endogenous change in a firm's quantity due to re-optimization is not considered. That is, while firms will find a new profit maximizing quantity after an exogenous change to marginal cost distributions, the re-optimized quantity is not used when evaluating the cost distribution in the post-retirement situation (C'_{post}). By doing so, I capture the distribution change solely resulting from the retirement and installation of plants, before the firms reoptimize based on the new distribution.

	(1) $\Delta q_{i,wh}$	(2) $\Delta\Delta P_{th}$	(3) $\Delta\Delta P_{th}$
Residual demand slope (β_{th})	-0.07	-3.77	-2.68
	(0.03)	(0.59)	(0.57)
Gas-intensive firm$_i$	0.35		
	(0.06)		
Balanced firm$_i$	-0.05		
	(0.09)		
$\Delta q_{i,wh}$		9.55	
		(1.09)	
Δ MC mean$_{th}$			0.89
			(0.20)
ΔMC mean$_{th}$ $\times$ β_{th}			-0.17
			(0.05)

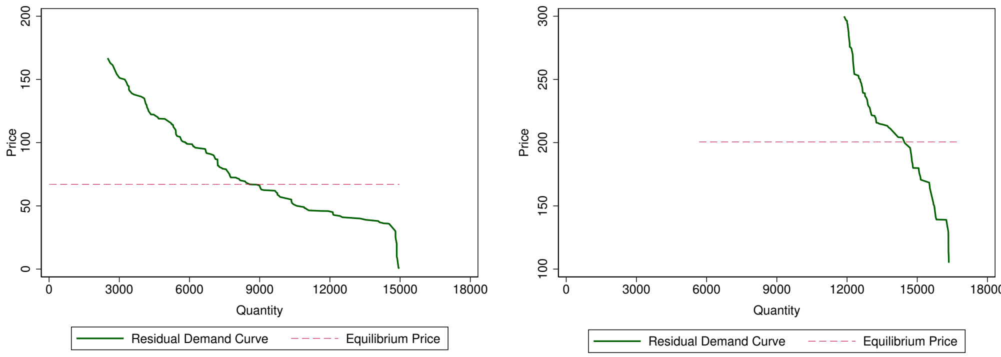
Notes: Column (1) regression is at the firm level. $\Delta q_{i,wh}$ is the change in withholding firm i's withheld quantity in absolute value (*unit*: GW)."Gas-intensive firm" and "Balanced firm" are dummy variables assigned to the withholding firms that are categorized into each firm group. Columns (2), (3) regressions are at the market level. $\Delta\Delta P_{th}$ is the change in market power (*unit*: \$/MWh). Δ MC mean$_{th}$ is the average change in marginal costs of strategic firms, i.e., $\overline{MC}_{th,post} - \overline{MC}_{th,pre}$ (*unit*: \$/MWh). Standard errors in parenthesis. N =334.

Table 9: Regression of Stategic Outcomes on Firm- and Market-Level Variables

holding firms, further divdied into gas-intensive and non-gas-intensive, and non-withholding firms. Figure 8 displays these rank distributions, with Panel (a) representing the ranks for the pre-retirement cost distribution, $C'(\mathbf{q}_{st,bf})_{\text{pre}}$, and Panel (b) for the post-retirement cost distribution, $C'(\mathbf{q}_{st,bf})_{\text{post}}$. Comparing the panels reveals that withholding firms, especially the gas-intensive ones, become relatively low-cost suppliers after the transition. That is, the shaded distribution of ranks, representing that of withholding gas-intensive firms, shifts more towards the lowest rank (skewed more to the right) in Panel (b) compared to Panel (a). The decrease in their relative marginal costs is more pronounced in low-demand (D1) and high gas price (G3-high) scenarios, as shown in Figure H.8 of the Online Appendix.

The change in rank is accompanied by an overall increase in the marginal costs of strategic firms. In Figure G.3 of the Appendix, the average change in marginal costs of strategic firms due to the transition is shown across demand (Panel (a)) and gas prices (Panel (b)). The extent of the marginal cost increase is more significant during low-demand hours (D1), when the retired baseloads are the marginal plants of the retired firms, and in high gas price scenarios (G3-high), where the marginal cost difference between the retiring plant and the replacing gas plant is large.

The price elasticity of non-strategic supply The elasticity of non-strategic supply, captured by the slope of residual demand, β_{th}, also affects the decisions of strategic firms. Specifically, the more elastic the non-strategic supply, the more constrained is the ability of strategic firms to profitably withhold quantity. This relationship is confirmed by the first row estimates in Table 9, showing a negative correlation between β_{th} and the additionally withheld firm-level quantity ($\Delta q_{i,wh}$) as well



(a) Low NG price day (\$9/MMBtu) (b) High NG price day (\$22/MMBtu)

Notes: Figure shows the actual residual demand curve of the market, generated from the non-strategic firms' bidding data.

Figure 9: Residual Demand Curve: Low vs. High Gas Price Days

as the extent of market power change ($\Delta\Delta P_{th}$), both of which serve as indicators of market power exertion.

As previously documented with $\hat{\beta}_{th}$ in Table 4 and shown in Figure 9, the residual demand becomes more price *inelastic* on days with higher gas prices. This suggests that the competitive constraint imposed by non-strategic suppliers is reduced on days with higher gas prices, which explains why I find $\Delta\Delta P_{th}$ to be larger under higher gas prices.

Summary: understanding the baseline case result of $\Delta\Delta$P The examinations offer explanations for the findings from the baseline case analysis. First, the analysis shows that the retirement and replacement process causes a more significant disturbance to the market environment when the demand is lower and the gas price is higher. For example, the reductions in production by retired firms and the disturbances in the marginal cost distribution are more pronounced in samples characterized by low demand and high gas prices. This explains the why the transition has a stronger impact on market outcomes in these situations.

Then why does market power increases after the transition? Examining the strategic interactions between firms helps us unravel the mechanism behind these findings. The first type of strategic interactions invovles a group of strategic firms and the non-strategic firms. The analysis reveals that the marginal costs of strategic firms increase after the transition, leading to a decrease in the quantity produced by these firms collectively. While a reduction in strategic quantity does not necessarily lead to an increase in market power if met by an elastic supply from non-strategic firms, our analysis reveals that non-strategic supply is *inelastic* particularly on days with higher gas prices. The inelastic non-strategic supply gives strategic firms an increased ability to withhold quantity beyond what is implied by the marginal cost increase, contributing to the increase in market power.

Another type of strategic interaction occurs among strategic firms, as reflected in changes in their withholding levels throughout the transition. As shown in Column (2) of Table 9, the extent of firm-level withholding is strongly correlated with the increase in unilateral market power. The analysis reveals that gas-intensive firms of large scale are the type of firm exploiting the retirement situation the most by withholding quantity more in the post-retirement period than before, especially in the lower-demand and higher gas price scenarios. Further analysis of firm-level cost distribution explains this finding by revealing that gas-intensive firms become relatively low-cost firms among strategic firms after the transition, particularly in lower-demand and higher gas price samples. This implies that they face a more inelastic firm-specific residual demand after the transition.

7 Industry Structure and the Capacity Installation

This section introduces variations in industry structure by considering several stylized paths of energy transition that differ in installations of new gas generation capacities. Note that we do not endogenize the capacity investment decision within the model, but instead take the decision as given and focus on the final form of the industry that will emerge if the investments happen accordingly to the assumed scenario.

Actual installation pattern observed from the data While the installations of new generation capacity are still ongoing, several patterns emerge from planned capacity installations observed from the EIA-860 data.[65] First, a substantial portion of the new gas generation capacity is proposed by the large-scale incumbent firms that expand their existing gas generation facility. Second, not many firms enter the industry, with almost no entry by the small fringe suppliers. Third, some firms convert the site of the retired coal power plant into a new gas generation facility, indicating that re-using the infrastructure (e.g., transmission lines) and facilities of the retired power plant may be economical for firms, and also for the grid. This makes the baseline case assumption fairly realistic. However, the capacity of the new gas generation is likely to be larger than that of the retired plant due to a substantial difference in the fixed cost and the capital cost between coal and gas power plants.[66] While these installation patterns coexist in the current situation, I isolate elements from each pattern to design the counterfactual scenarios.

Additional industry structures to simulate I examine the impact of transition on market power under three additional counterfactual cases that differ in how the retired coal plant is marginally replaced by the new gas power plant. Each case is designed to incorporate some features of the actual capacity installations observed from data. Additionally, the cases considered are designed to better identify the underlying forces leading to a change in competition relative to the baseline case. The firm scale, capacity and the number of firms change as we allow for different ways of

[65]EIA-860 form's section 3: Generator, "*proposed*" capacity data is used. Table H.6 in the Online Appendix reports the summary of *proposed* gas power plants in the New England electricity market (ISO-NE), from year 2013 to 2019.

[66]The capital cost spend on kW capacity of the new coal power plant is \$5,212/kW, much larger than that of a standard combined cycle gas power plant which is \$650/kW (*Annual Energy Outlook 2019 (EIA)*).

Case	Which firm installs new gas generation capacity?	Size of the new capacity installed (industry level)	Firm scale change
(1)	small fringe suppliers (entrants)	= total retired capacity	retired firm (↓), others (–)
(2)	retired firms (incumbent)	> total retired capacity	retired firm (↑), others (–)
(3)	firms not operating the retired generation (incumbent)	= total retired capacity	retired firm (nuclear plant owner: ↓, coal plant owner: –), others (↑)

Notes: Note that *retired* firms refers to strategic firms that used to operate the retired baseload generation. The size of the new capacity installed shown in the second column refers to the accumulated sum of capacities of new gas generators installed in each counterfactual scenario. *Firm scale* column shows whether or not the scale of firms have increased (↑), decreased (↓) or unchanged (–) after the retirement.

Table 10: Description of Capacity Installation Counterfactual Cases

installing new capacity, which are summarized in Table 10.

In case (1), hypothetical fringe suppliers enter the industry with new gas power plants, replacing the total capacity of the retired baseload generation. While this scenario differs from the actual trend, it serves as a benchmark for a competitive path of transition. Each fringe plant has a capacity of one of the following, $q_{i,\text{fringe}} = \{50, 80, 100\}$ MW, thereby introducing about 50 new fringe suppliers to the industry.[67] The marginal cost of these new gas power plants is generated using the gas price index data and the heat rate information of the most up-to-date gas turbine technology, similar to how I constructed the marginal cost of a hypothetical gas power plant in the baseline case.[68] Because fringe suppliers are not strategic players, they affect the market outcome only through a change in the residual demand curve (faced by strategic firms together). Therefore, the slope (β_{th}) of the new residual demand curve, after adding the hypothetical fringe firms to the market, must be re-estimated. See Appendix E.1 for the estimation details of the new residual demand curve.

Case (2) is similar to the baseline case, as it let the retired baseload generation to be replaced by the same operating firm (i.e., *retired* firm). However, it differs from the baseline case in that the newly installed gas generation has a capacity 50% greater than that of the retired plant.[69] As a result, the capacity of firms that previously operated the retired baseloads and the overall industry capacity increase.

In case (3), I let the large-scale incumbent firms that *do not* operate any of the retired baseload generation (i.e., not one of the *retired* firms) to expand the capacity of their existing gas generation. Specifically, approximately 400 MW of additional gas generation capacity (hypothetical gas power plants) is allocated to each of the incumbent strategic firms, starting with the largest gas-intensive firm.[70] The capacity added by these incumbent firms together replaces that of the retired 'nuclear'

[67] The capacity sizes are chosen based on actual capacities of fringe power plants that enter the New England grid (*source*: EIA-860).

[68] To avoid having a flat region in the residual demand curve, I randomly perturbed the marginal cost values of these power plants between 80 to 120% of the representative marginal cost.

[69] The 50% capacity expansion is consistent with the observed rate of expansion by retired firms in the data (EIA-860).

[70] Priority was given to large-scale firms categorized as gas-intensive among the non-retired firms when allocating additional capacities. Since the set of strategic firms can vary across markets, the identity and total number of selected gas-intensive firms are not fixed throughout the sample period. The choice of 400 MW for the hypothetical power plant

power plants but not the retired coal plants.[71] That is, the retired coal plants are replaced by the same firm operating them, with new gas power plants having the same capacity as that of the retired coal plant.

Results Figure 10 summarizes the average values of the change in market power ($\Delta\Delta P_{th}$) for each of the counterfactual scenarios. A more detailed summary of these values can be found in Table F.3 in the Appendix. In Panel (a) of Figure 10, the average value is plotted across different demand levels (D1 to D4) and Panel (b) shows the average value plotted across different gas price levels (G1-low to G3-high).[72] The graph overlays the results of each counterfactual scenario with the baseline results to provide a clearer comparison across cases.

The most pro-competitive scenario is the case (1) where the industry becomes significantly more fragmented after the transition. The average $\Delta\Delta P_{th}$ is \$-2.7/MWh, indicating that market power even decreases after the transition (see Table F.3). The pattern of $\Delta\Delta P_{th}$ also differs from that in the baseline case. As shown in the case (1) plot in Panel (a), the market power increases the least in the lower-demand hours (D1), which is in contrast to the baseline case. Importantly, the market power decreases further as gas prices become higher, as shown by a decreasing path of the case (1) plot shown in Panel (b). Adding fringe suppliers to the industry as in case (1) restrains the market power of strategic firms by making the residual demand significantly more elastic than before (β_{th} increasing by about 50%, on average), especially on higher gas price days which had particularly more inelastic residual demand before the adjustment.[73] As a result, the adverse impact we found from the baseline case is reduced, even on days hit by a large gas price shock.

In case (2), where the retired firms add larger gas generation capacity to replace its owns retired generation, the overall increase in market power is greater than when letting fringe firms to enter (case (1)), but less than in the baseline case; the average $\Delta\Delta P_{th}$ is \$6.5/MWh. When examining the pattern across demand, I find that market power does not increase as much as in the baseline case during the lower-demand hours (D1-D2), though it increases slightly more when the demand is high (D4).[74] Notably, market power does not increase as much as in the baseline case when gas prices rise further; the slope of the case (2) plot in Panel (b) is less steep than in the baseline case.

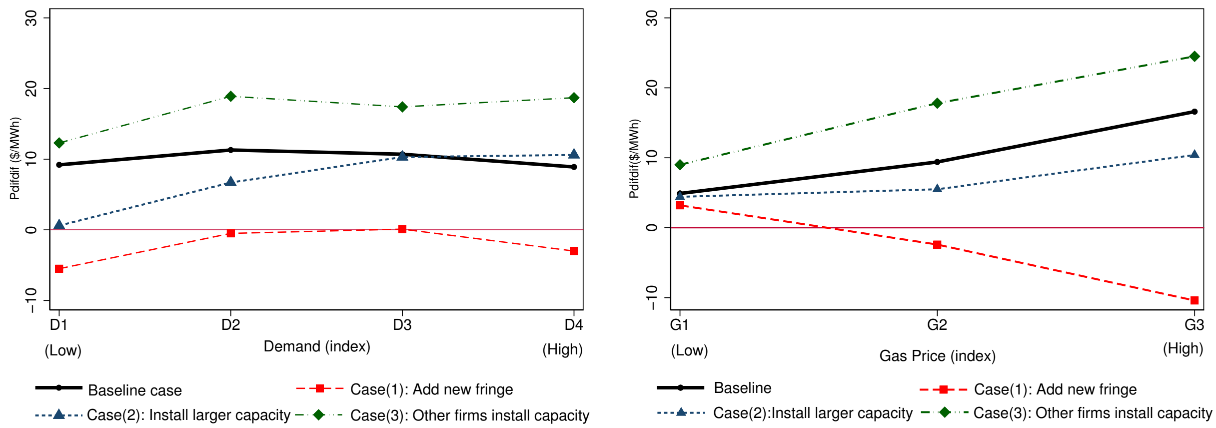
capacity is based on the mean capacity of proposed natural gas generation from EIA-860 data. The marginal cost of the hypothetical power plant was measured in a similar manner as in the baseline case.

[71] While reusing nuclear plant sites for other generation technologies is generally challenging due to significant technical differences, most of the coal plant sites can be converted into new gas generation sites, as evident from observed installation patterns (see Table H.6 in the Online Appendix). Additionally, there is a practical rationale for this approach. The number of strategic incumbent firms to which I allocate additional gas generation is small compared to the total retired capacity, including both coal and nuclear plant retirements.

[72] Please note that in Panel (a), gas price differences are not controlled for within each demand bin, and in Panel (b), demand differences are not controlled for within each gas price bin. A complete summary of the average $\Delta\Delta P$ values, controlling for both demand and gas price levels, is available in Table F.3 in the Appendix.

[73] See Appendix E.1 for a detailed summary of the new slope estimates (β_{th}).

[74] This occurs because a higher proportion of *retired* firms are identified as withholding firms during the highest demand hours (D4) in the baseline case. Thus, increasing the scale of retired firms more than in the baseline case, as in the case (2) scenario, results in an even more substantial increase in market power within this demand range, as depicted in Panel (a) of Figure 10. Note that retired firms operate not only baseloads but also the gas-fired and oil-fired units that can be utilized during high-demand (peak) hours.



(a) Averaged Over Demand

(b) Averaged Over Gas Price Shock

Notes: The average change in market power, $\Delta\Delta P_{th}$, is displayed across demand (panel (a)) and gas price (panel (b)). The results for three additional cases are plotted together with the baseline case, which is displayed in a bold line. Case (1) is when adding new fringe, Case (2) is when the retired firm installs a larger capacity than the retired generation, and Case (3) is when other firms (non-retired firms) install capacity (green, dash-dot line, diamond marker). The demand index represents demand bins from D1 (lowest) to D4 (highest), and the Gas Price index denotes categories G1(low), G2(medium), and G3(high). These indices were previously used when reporting the results for the baseline case.

Figure 10: Summary of $\Delta\Delta P_{th}$ of Capacity Counterfactuals

How can we explain these findings? Allowing retired firms to add larger capacity makes their supply marginally more price-responsive (elastic) compared to the baseline case. This implies that the residual demand of *competitors* of the retired firms – mostly the large gas-intensive firms identified as major withholders – becomes more elastic. As a result, the gas-intensive withholding firms cannot exercise as much market power as in the baseline case.

In case (3), where gas-intensive incumbent firms install new gas generation, the overall increase in market power is higher than that of all other counterfactual cases, even exceeding the baseline case; the average $\Delta\Delta P$ is \$16.4/MWh. This pattern holds across all demand and gas price levels, with the case (3) plots in Panel (a) and (b) consistently above the plots of other cases. Moreover, market power increases further as the gas price increases, shown by the steep increasing path of the case (3) plot in Panel (b). Why does market power increase the most after the transition when incumbent firms, especially the large-scale gas-intensive ones, are allowed to expand their capacity at the margin? These firms are identified as exercising market power to a relatively greater extent throughout the transition process in the baseline case. Allowing them to increase their gas generation capacity is equivalent to expanding the scale of the firms that are already dominant, resulting in even greater market power than in the baseline case. At the same time, the scale of retired firms, which compete with other incumbent firms, decreases in this case, further strengthening the dominant position of the large gas-intensive firms.

The results of this capacity counterfactual analysis have policy implications given that the ongoing capacity installations in the New England grid is far from the ideal situation (e.g., fringe entry) and instead, often involve the capacity expansion of large-scale incumbent firms that have the potential to exert market power. While some retired firms appear to replace their own generation with larger gas power plants (as in case 2), a more common form of installation involves other incumbent firms, already heavily concentrated on gas generation, expanding their existing facilities.[75]

Therefore, the results highlight the importance of properly incentivizing the replacement (installation) of capacity following retirement, based on a careful consideration of the change in strategic interactions between firms upon transition. Case (1), while not necessarily realistic, demonstrated a pro-competitive outcome, highlighting the need to investigate potential barriers or disincentives that might discourage small-scale entries into the industry. Surprisingly. there has been limited attention given to this important aspect of the transition; how firm characteristics and industry concentration may change throughout the process. The question of how market authorities can effectively incentivize capacity entries to guide the industry toward a smoother transition path remains a subject for future research.

8 Conclusion

An increasing number of baseload coal and nuclear power plants are retiring from the grid, and the U.S. wholesale electricity industry is undergoing a major transition towards cleaner natural gas and renewable energy. Most of the discussions regarding the transition centers around the environmental benefits or concerns over the reliable supply of energy following the transition. This paper highlights the importance of considering the impact of this transition on market competition, focusing on the volatile input cost of cleaner energy. That is, the costs associated with generating electricity with gas or renewables are low but could substantially increase depending on fuel market conditions or the weather. This feature differentiates the clean energy from the traditional baseloads characterized by having low and stable input costs. What will the market competition be like if the cost of clean energy sources increases again in an industry that has already transformed into using proportionally more of these energy sources? Will the change in industry structure (which depends on how the clean generation replacing the retired ones is installed) following the transition also affect the competition? For a comprehensive cost-benefit analysis of transitioning to cleaner energy, understanding how such a transition affects the competitive incentives of firms and restructures the whole industry is fundamental.

I study this question in the context of New England wholesale electricity market which is awaiting retirements of major coal and nuclear power plants, despite having volatile gas prices. With a counterfactual analysis based on the model of quantity competition, I show that market power increases after the transition, especially more so when gas prices are higher. However, the expected market power increase can be mitigated if the new capacities are installed in a way to make the industry more fragmented or to curb the scale expansion of incumbent firms that are gas-intensive

[75]However, our observations are limited in definitively determining the direction of capacity installations. For instance, one of the retired coal plants used in the analysis is being converted into a gas power plant by the same company, while another is sold to a different company. Additionally, I do observe that some of the gas-intensive and balanced incumbent firms are expanding their gas generation facilities. Therefore, the pattern of installations planned in this market represents a combination of cases considered in the analysis.

in their generation. The result, therefore, emphasizes the importance of a well-planned transition towards cleaner energy, which comes through a carefully incentivized installations of new capacities, as means of keeping the market competitive even under the increased exposure to the cost volatility.

While these findings have strong policy implications, it is worth mentioning that the results presented here is the upper bound of the likely outcome, and that the equilibrium computation would differ from the complicated clearing process of the market organizers (ISO) that fully accounts for the transmission congestion. Having said that, the primary goal of the paper is to understand firm's changing incentives, together with the market conditions that contribute to these changes so as to give policy suggestion to regulators.

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Appendix

A Cournot Model

Firm i's profit maximizing problem is shown below:

$$\mathcal{L}_i \equiv \pi_{it} + \lambda_{it}(q_{i,max} - q_{it})$$

$$\frac{\partial \mathcal{L}_i}{\partial q_{it}} = \frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it} \leq 0, \quad q_{it} \geq 0, \quad \frac{\partial \mathcal{L}_i}{\partial q_{it}}\, q_{it} = 0 \tag{A.1}$$

$$\frac{\partial \mathcal{L}_i}{\partial \lambda_{it}} = q_{i,max} - q_{it} \geq 0, \quad \lambda_{it} \geq 0, \quad \frac{\partial \mathcal{L}_i}{\partial \lambda_{it}}\, \lambda_{it} = 0 \tag{A.2}$$

We can rewrite equations (A.1) and (A.2) by plugging in the actual specifications, which are shown below in equations (A.1a) and (A.2a):

$$\frac{\partial p_t}{\partial q_{it}}\, [q_{it} - q_{it}^f] + p_t - C'(q_{it}) - \lambda_{it} \leq 0, \;\; q_{it} \geq 0, \;\; \frac{\partial p_t}{\partial q_{it}}\, [q_{it} - q_{it}^f] + p_t - C'(q_{it}) - \lambda_{it}\, q_{it} = 0 \tag{A.1a}$$

$$q_{i,max} - q_{it} \geq 0, \quad \lambda_{it} \geq 0 \quad (q_{i,max} - q_{it})\, \lambda_{it} = 0 \tag{A.2a}$$

As the derived conditions become a mixed complementarity problem (MCP), I rewrite these using complementarity symbols:

$$\begin{aligned} \frac{\partial p_t}{\partial q_{it}}\, [q_{it} - q_{it}^f] \; + \; p_t \; - \; C'(q_{it}) \; - \; \lambda_{it} \leq 0 \;\; \perp \;\; q_{it} \geq 0 \qquad & \forall i \in \mathcal{F}_s \\ q_{i,max} \; - \; q_{it} \geq 0 \;\; \perp \;\; \lambda_{it} \geq 0 \qquad & \forall i \in \mathcal{F}_s \end{aligned} \tag{A.3}$$

These complementarity conditions are similar to those derived in Bushnell, Mansur and Saravia (2008).[1] The Cournot equilibrium quantities, $\mathbf{q}_t^* = [q_{1t}^*, \ldots, q_{Nt}^*]$, is the set of firm-specific quantities that simultaneously solves the system of complementarity conditions. That is, we stack the first-order conditions, shown in (A.3), for all strategic firms, and then numerically solve a vector of quantities of strategic firms that satisfies the entire system of conditions. To obtain the solution, we use PATH algorithm, which is effective in solving the mixed complementarity problem (Kolstad and Mathiesen, 1991; Dirkse and Ferris, 1998).[2] Once we find the equilibrium quantities, the market price can be obtained by plugging these values into the residual demand curve in Equation (2). More details can be found in Online Appendix H.1

B Estimating the Parameters

I estimate the slope of the generator-specific marginal cost, firm-specific forward contract, and the market-specific residual demand slope parameters from the high-frequency bidding data

[1] We can also convert these conditions into a new form by removing the multiplier λ_{it} from the equations. Details can be found in the Online Appendix.

[2] This simulation method has been used in other papers including Borenstein et.al (1999), Bushnell, Mansur and Saravia (2008), Ito and Reguant (2016), Acemoglu, Kakhbod and Ozdaglar (2017), Brown and Eckert (2018), Bahn, Samano and Sarkis (2019) and etc.

which exists for every hourly market auctions. This section explains the empirical methodology used for estimating these parameters.

B.1 Optimal Bidding Model

The following model describes the bidding decisions of the firm in a multi-unit uniform auction (Kim, 2022; Reguant, 2014). Suppose there are $i = \{1, \ldots, N\}$ firms that each operates J_i number of units, indexed by $j = \{1, \ldots, J_i\}$, that can generate electricity using multiple energy sources. In the daily auction, a firm submits hourly price bids (b) and quantity bids (q) – which consist of multiple steps (k) of bids – for each of its generating units. Therefore, the k^{th} step of a bid submitted for firm i's unit j in the auction held at hour h of day t is $\mathrm{b}_{ijkht} =< b_{ijkht}, q_{ijkht} >$. Given the market clearing price P_{ht}, the (ex-post) profit function of firm i in the hourly auction (ht) is shown below:

$$\pi_{iht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht}) = \ P_{ht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht}) \ \left(Q_{iht}(P_{ht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht})) \ - \nu_{iht} \ \right) \ - \sum_{j=1}^{J_i} C_{ijt}(\ q_{ijht}(P_{ht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht})) \ ) \tag{B.1}$$

The main idea behind the estimation is that the equilibrium bids submitted by firms – which we observe in data – are the ones that maximize their expected profits. Therefore, we can derive the first-order condition, shown in Equation (B.2), from which the parameters are estimated.

$$\mathbb{E}_{-it} \left[\frac{\partial P_{ht}}{\partial b_{ijkht}} \ [\ (Q_{iht}(P_{ht}) - \nu_{iht}) \ + \ (b_{ijkht} - \ C'_{ijt}) \ \frac{\partial RD_{iht}}{\partial P_{ht}} \ ] \ \right] = 0 \tag{B.2}$$

The empirical analogue of the first-order condition is shown in Equation (B.3), which includes an expectation over the bids of other firms ($\mathbf{b}_{-it}$) that are uncertain to firm i. More details of the estimation is explained in Kim (2022).

$$m_{ijkht}(\theta \ ; S) = \frac{1}{S} \sum_{s=1}^{S} \frac{\partial \widehat{P^s_{ht}}}{\partial b_{ijkht}} \Big(\ (Q^s_{iht} - \nu_{iht}(\gamma_{ih}) \ ) \ + \ (b_{ijkht} - mc_{ijt} \ ) \ \frac{\partial \widehat{RD^s_{iht}}}{\partial P_{ht}} \Big) \tag{B.3}$$

B.2 Marginal Cost

B.2.1 Estimation of marginal cost

A common practice in the electricity market studies is to measure the marginal cost of power plants using the fuel price index data, which is a weighted-average value of firm-level spot gas prices. However, such practice may not be accurate when the natural gas market is illiquid so that the gas prices become volatile. For example, the difference between the procurement price of gas at the firm level and the index value grows further as the spot gas prices become more volatile. Section B.2.3 will provide more details of the sources of the measurement error.

To overcome this empirical challenge, I utilize the high-frequency bidding data and estimate the marginal cost that rationalizes the bids, which reveals the opportunity cost internalized by the firms in their bids. I estimate the marginal cost of a generating unit j, operated by firm i, at a daily level, i.e., C'_{ijt}.

The estimation employs the GMM estimation based on the empirical analogue of the first-order necessary condition of optimization, shown in Equation (B.3). I assume that the marginal cost of a generating unit j of firm i is constant over quantity, i.e., $C'_{ijt}(q_{ijt}) = mc_{ijt} + \epsilon_{ijkht}$. More details of the estimation procedure can be found in Kim (2022).

Note that marginal costs can only be estimated for units having a positive probability of becoming marginal. For those units not having the estimates, I use the price bid data as a proxy for marginal cost. In principle, firms typically bid their marginal cost for units that are far from being marginal, as these units cannot be used for strategic purposes, making the use of price bids as marginal cost proxies valid. [3]

B.2.2 Marginal cost of hypothetical gas power plant

The marginal cost of a hypothetical natural gas power plant, which replaces the retired generation in our analysis, is constructed from available data. I use the heat rate of 7MMBtu/MWh based on several web page sources reporting that the new combined-cycle unit's base heat rate is close to 7 MMBtu/MWh.[4] However, the heat rates of future gas-fired power plants could be different from the assumed 7 MMBtu/MWh, though the difference is not expected to be significant. Note that the average heat rate of *existing* natural gas generators (combined cycle) is close to 7.6 MMBtu/MWh, as reported by the EIA.[5] The marginal cost consists of two parts: fuel cost and emissions cost. I calculate the fuel cost part by multiplying the assumed heat rate with the fuel price index data. The emissions cost part is measured by multiplying the assumed heat rate to the emissions factor of the natural gas, reported by the EPA, and to the emissions permit (RGGI) prices of the sample period, also reported by the EPA.[6]

B.2.3 Marginal Cost Dispersion

This section discusses the reasons why the dispersion in marginal costs among natural gas power plants increases, especially more so as the intensity of the natural gas price shock (degree of pipeline congestion) increases.[7] This also explains why the residual demand curve (non-strategic supply) becomes more inelastic as the natural gas price further increases. That is, the residual demand curve is generated from the supply bids of power plants owned by non-strategic suppliers, most of which are gas-fired plants. And since the bids submitted by non-strategic firms would be close to marginal cost, the residual demand elasticity is closely related to the marginal cost dispersion. Additionally, the sources discussed here explain why the measurement error arises when using the index gas price data to measure the marginal cost of gas power plants, which justifies estimating the marginal costs instead of measuring them using the data.

First, some of the gas-fired units are equipped with dual generation technology that enables the generation of electricity with fuels other than gas, called *dual* gas units. For example, more

[3] Even when a generating unit submits an extremely high price bid to avoid dispatch, the bid reflects the firm's high marginal opportunity cost rather than extremely high markups added over the marginal cost.

[4] For example, see https://www.transmissionhub.com/articles/2016/05/hawaiian-electrics-kahe-project-to-consist-of-three-ge-combustion-turbines.html

[5] https://www.eia.gov/electricity/annual/html/epa_08_02.html

[6] Emissions factor table can be found in the following link. https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf

[7] The increase in dispersion of gas-fired generators' marginal costs has been documented in Figure 5 as well.

than 28 percent of gas generators in New England were dual units (as of 2014). As these generators can switch to using oil when the gas price increases substantially, the cost of a dual gas unit increases by less than that of a non-dual gas unit, especially on days with a large shock. The marginal cost measured for these dual units without identifying their switch decisions –which are difficult to observe – could significantly mismeasure their costs.

Second, firms can purchase gas from two different channels (i) from the daily spot gas market, or (ii) through a long-term contract with a gas supplier. Firms that enter into a long-term contract with gas suppliers can secure gas at the contracted price. Unlike spot gas prices that change every day and moment based on the gas market condition, the pre-committed contracted price is not affected by day-to-day spot gas market conditions. Therefore, especially on days with severe gas price shocks, the cost difference between gas units that purchase gas via a long-term contract and those buying from the spot market could be substantial.

Third, when the spot gas market is under shock (caused by severe pipeline congestion), the gas spot prices vary throughout the day by fluctuating over time, even within a single day. Since the timing of gas procurement differs across firms, significant fluctuations in spot gas prices over time results in differing firm- and unit-level gas prices. Figure B.1 depicts a substantial cross-sectional differences in firm-specific spot gas prices in New England area experiencing the gas price shock. In this case, the gas price index data (which is a weighted-average measure) cannot accurately represent the gas price that applies to each firm, thus using index data to measure marginal cost becomes problematic.

B.3 Forward Contract

B.3.1 Forward contract rate estimation

It is common for electricity generating firms to engage in a forward contracting where they sell a certain amount of electricity to the demand side at a committed price (i.e., forward price) in advance of the auction. Therefore, the forward contracted quantity, ν_{iht}, is not affected by the market price, and must be subtracted from the total quantity, Q_{iht}.

I estimate ν_{iht} within the model exploiting the method similar to Reguant (2014), due to the difficulty in obtaining data on the forward contracts.[8] I assume that firms forward contract a certain percentage, γ_{ih}, of their hourly output production and that this forward contract rate is constant over time.[9]

The estimation employs the GMM estimation based on the empirical analogue of the first-order condition of profit maximization, shown in equation (B.3). I assume that the forward contracted quantity of firm i for the hour h of the day t is, $\nu_{iht} = \gamma_{ih} Q^*_{iht} + \varepsilon_{iht}$, where Q^*_{iht} is the actual quantity of electricity generated by firm i in auction ht, which is observed in the data. Within

[8] Bushnell et.al.(2008) have shown that electricity generating firms in the New England wholesale electricity market indeed enter a forward contract with the demand side. As they had access to confidential information of firm-level forward contracts, they did not estimate the forward contracted quantity in the analysis.

[9] The constant forward contract rate assumption is common in the wholesale electricity market studies, as seen in Bushnell et.al.(2008) and Reguant (2014). The fact that the constant rate specification is used even in Bushnell et al. (2008), where the researchers had access to confidential information of the firm's forward contracts, gives justification to our assumption. As forward contracts derive from vertical intergration between the supply and retail companies, forward contracted quantity would have to be adjusted flexibly to the changes in retail customer demand. In this respect, it is reasonable to assume that suppliers contract a fixed *rate* of their daily generation over time, than a fixed amount, given that the total market demand from the retail sector changes every hour and day.

Sample	mean	s.d.	p50	min	max	N
Offpeak	0.75	0.33	0.9	0.12	1	11
Peak	0.27	0.1	0.3	0.15	0.4	11

Notes: Off-peak hours: 23 pm - 6 am, though the actual range of hours categorized as off-peak slightly differ across firms. Peak hours include the rest of the hours.

Table B.1: Forward contract rate of a subset of strategic firms: summarized by off-peak / peak

the model, Q^*_{ht} is treated as exogenous, where the value is fixed for the given hour.[10] For a more detailed description of the estimation and identification of the parameter, please refer to Kim (2022).

B.3.2 Summary of forward contract rate estimates

Table H.4 summarizes the firm-specific hourly forward contract rates (γ_{ih}) by off-peak and peak hours.[11] The table reports estimates of 11 large strategic firms which have significant estimates of the rates. The actual range of hours categorized as off-peak and peak differ across firms, but the off-peak hours span roughly from 23 pm - 6 am. The summary statistics are taken within off-peak and peak hours. The average rate of forward-contracting is about 75% ($\gamma = 0.75$) during the off-peak hours and about 27% ($\gamma = 0.27$) during the peak hours. Since the forward contracted electricity is assumed to be a certain percentage (rate) of the actual hourly production, and because the production level is higher during the peak hours than in the off-peak, it is natural to estimate a lower rate for the peak hours, by construction. Moreover, firms usually have more incentives to forward contract during off-peak hours when both the demand and wholesale price is low. While there is no distinctive pattern in the estimated rates across firm types, the retired firms' contracted rates are lower than others, and the rates of balanced firms are slightly higher than others during the off-peak hours.

B.3.3 How would the forward contracting incentives change after the transition?

Throughout the analysis, I fixed the forward contract rate (quantity) to the level estimated from the pre-retirement sample. However, the forward contracted rate and quantity could change in the future, adapting to the changes in the market environment caused by the energy transition.

Studies have shown that forward contracting incentives are affected by changes in market structure. Relevant papers, such as Brown and Eckert (2017) and Miller and Podwol (2020), have shown that forward contracting incentives would decrease following horizontal mergers. Since mergers lead to increased market power and concentration in general, their findings suggest that firms engage less in forward contracting when market concentration and market power rise.

Building upon the findings from these studies and considering my analysis, which demonstrates an overall increase in market power following the energy transition, it is expected that electricity-generating firms would have reduced incentives for engaging in forward contracting

[10] While Q_{iht} varies as the marginal unit (j) and bid step (k) change within the model, the ex-post quantity generated by firm i, Q^*_{iht}, does not vary.

[11] Hourly pattern of the cross-sectional average of the forward rates can be found in Figure H.4 in the Online Appendix.

in the counterfactual environment. The reduction in forward contracting would, in turn, exacerbate the exercise of market power.

However, there are limitations when applying the findings from these studies to my empirical setting. First, the change in market structure considered in my analysis differs from that in a horizontal merger case. Second, since abnormal gas price days represent a smaller portion of the entire sample compared to normal days, forward contracting, which involves long-term commitments lasting at least a year, may not be significantly affected by the change in market power during abnormal periods. While I do observe an increase in market power in this subsample after the transition, the market power does not increase much during the days when gas prices fall within the normal range, which make up a larger portion of the sample. Since firms' contracting decisions account for the market conditions throughout the entire year, the decision to adjust the contracting rate may be more influenced by market conditions during periods of normal gas prices.

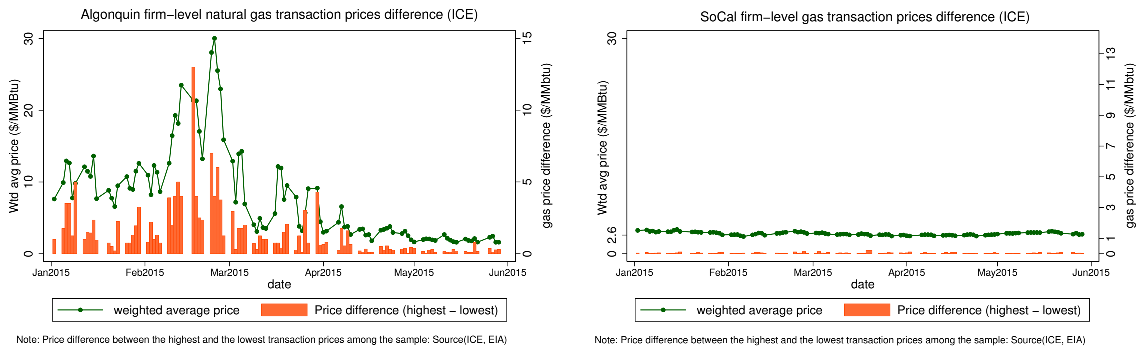
I explore several other factors that may affect the forward-contracting incentives of both electricity-generating firms and retail firms, providing conjectures on how forward contracting incentives might change after the energy transition, although these conjectures are not supported by a formal equilibrium analysis.

Fixed Cost Firms are more inclined to enter into forward contracts when they operate power plants with high startup costs especially during hours when spot prices are too low. This is because the fixed cost of operating a power plant limits a firm's ability to flexibly adjust its production responding to price incentives in the spot electricity market.

As the transition involves the phase-out of high fixed-cost plants, which are subsequently replaced by low fixed-cost gas power plants, firms are expected to have reduced incentives for forward contracting after the transition. Moreover, according to the main result of my analysis, spot prices in low-demand hours are expected to increase more after the transition. This makes the spot market options more appealing than the forward market, thus reducing the incentive for forward contracts.

Heterogeneity in firms' strategic positions The change in forward contracting incentives could vary across firms, depending on their strategic positions. Firms with an increased ability to exercise market power after the transition (e.g., gas-intensive firms) may lower their forward contract rates. This is because their strategic position allows them to profitably raise prices in the spot market more than before, making the forward-contracting option less attractive. Furthermore, this type of firm will no longer face competition from conventional baseloads that oversupply during low-demand hours, which are typically the hours with the strongest incentive to contract forward. Firms that become less capable of exercising market power may also choose not to increase their contract coverage. Although these firms cannot increase spot prices themselves, they still benefit from a spot price increase resulting from market power exercised by other firms.

Price or load uncertainty Both retailers and wholesalers would be more inclined to contract forward if spot prices becomes more variable, as it allows them to secure a stable and predictable electricity procurement and revenue stream through contracting. In my case, while spot prices and generation (at the firm level) may become slightly more variable after the transition, the



(a) Algonquin city gate

(b) SoCal city gate

Notes: Data source is over-the-counter individual transaction-level gas spot prices at two city gate points, provided by Intercontinental Exchange (ICE). The line in the figure shows the weighted average values of transaction-level gas prices, and the bars show the difference between the highest and the lowest among transaction-level gas prices. Only the subset of transactions is available as data.

Figure B.1: Over-the-Counter Gas Spot Prices: Year 2015

increased variability occurs only for a part of the sample (about one third of the entire year). Therefore, the role of the variability factor in changing the forward contracting incentive may be relatively small.

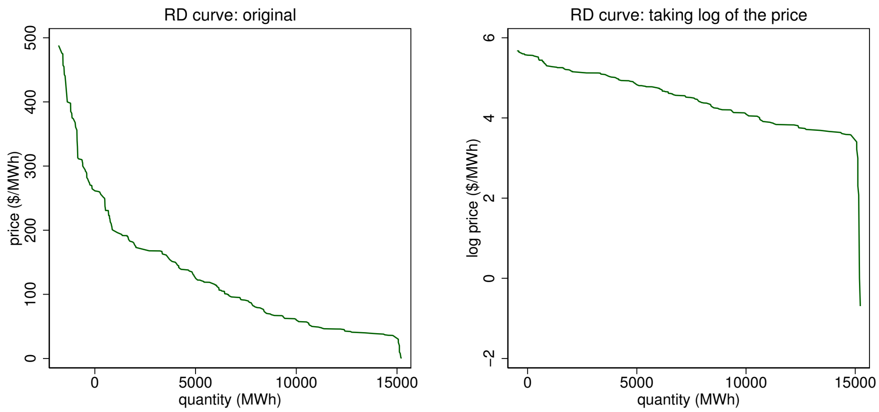
Retailer incentive change While this paper's analysis primarily focuses on the supply side, it is worth considering how retailer's incentives for forward contracting may change after the transition. Although the wholesale prices will increase more after the transition, retailers cannot shield themselves from this spot price increase by setting up forward contracts, as the forward prices are typically slightly higher than the spot prices. The forward price remains relatively stable in relationto spot price fluctuations, potentially being slightly higher during normal periods (low-cost regime) but lower during abnormal shock periods (high-cost regime). Therefore, retailers' decisions to increase their forward contract rates may hinge on their expectations regarding the frequency and severity of high-cost regimes following the transition.

B.4 Residual Demand Curve

B.4.1 Assessing the fit of the residual demand estimate

I can directly construct the residual demand curve faced by a group of strategic firms using the equilibrium supply bids of non-strategic firms observed from data, which is the residual demand curve for the pre-retirement period. Then, I fit this curve with a parametric function – a log-linear demand specification as depicted in Equation (2) – to use it throughout the Cournot model computation. I employ a spline regression with 1 or 2 knots, chosen based on the curve's shape, to fit a broader range of the curve. I use the same curve when employing a counterfactual simulation, which is based on the assumption that these non-strategic firms would keep behaving non-strategically even in a post-retirement situation by bidding their marginal costs.

The selection of log-linear specification follows the literature (e.g., Bushnell et al. (2008), but is also based on the visual inspection of the shape of the non-parametric curve. Figure B.2a shows an actual residual demand curve, $RD(p) = \overline{D} + D(p) - S(ns, p)$, which is nonparametrically con-



(a) RD curve: original

(b) RD curve: taking log of price

Figure B.2: Residual Demand Curve: original vs. logged ($t = 97, h = 11$)

structed from bids, and Figure B.2b shows the curve after taking log values to the price bids which exhibits an almost linear shape. This observation provides support to the claim that the original residual demand curve has a log-linear shape, thereby justifying the use of a log-linear demand function in the analysis.

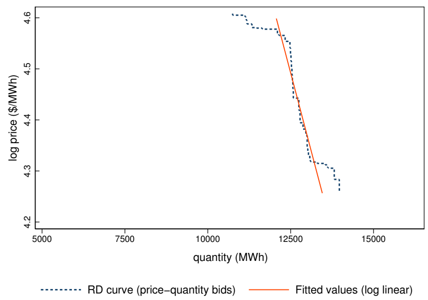
The log-linear specification also outperforms other parametric specifications, such as linear specification, in terms of the fit. The original curve exhibits uneven sections, which are unavoidable due to the step-like nature of bids. Fitting the curve after applying the log transformation appears more convenient and less influenced by these lumpy sections. Figure B.3 provides an example for a one sample market ($(t, h) = (383, 16)$), with panel (a) displaying the original logged curve overlaid with the estimated log-linear demand curve, and panel (b) showing the original curve overlaid with the estimated linear demand curve. Notably, the linear curve exhibits a much steeper slope (indicating higher elasticity), especially when fitting the non-linear sections of the original RD curve.

Taking log of the price also serves as a method of smoothing the curve. For example, panels (c) and (d) compare the fit of a log-linear curve and a linear curve to a curve smoothed using a Gaussian kernel – a common approach for smoothing a nonlinear function. The slope of the log-linear curve in panel (c) aligns more closely with the slope of the kernel-smoothed residual demand curve (represented by the dashed line) compared to the linear curve shown in panel (d). While the linear specification is widely used and provides a good fit for the local slope evaluated around the local equilibrium, the log-linear specification turns out to be more suitable for capturing the rough shape of the demand curve over a broader range around the equilibrium, which is necessary for our counterfactual analysis that may involve non-local equilibrium computation.

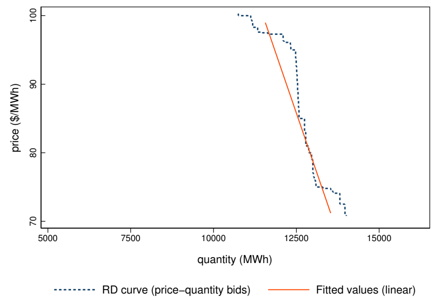
B.4.2 Import/export bids

I have omitted the import and export bids when nonparametrically constructing the residual demand curve. Instead, I accounted for the ex-post size of net import – net interchange – by excluding that amount from the total demand, $\bar{D}$.

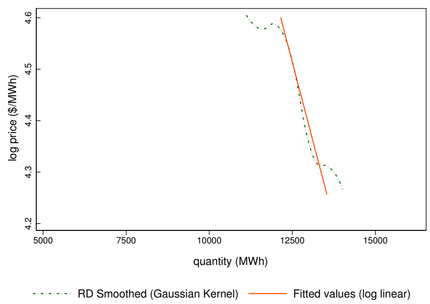
Omitting these import/export bids will not critically affect the slope estimates to a great extent.



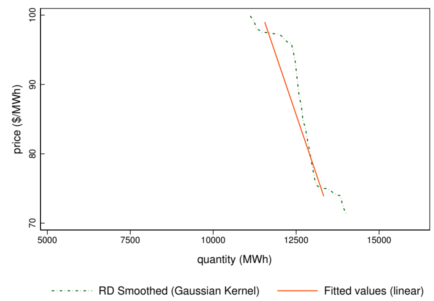
(a) Log-linear fit: $t = 383$, $h = 16$



(b) Linear fit: $t = 383$, $h = 16$



(c) Log-linear fit to kernel smoothed: $t = 383$, $h = 16$



(d) Linear fit to kernel smoothed: $t = 383$, $h = 16$

Figure B.3: RD curve: Log-linear and Linear fit comparisons

First, the ISO-NE is interconnected with three balancing authorities and trades the largest amount with Hydro Quebec (HQT). New England imports electricity from HQT for most hours, nearly at full transmission capacity.[12]

Second, I confirm also from the import/export bids data (published by ISO-NE) that the net import does not respond much to price changes. In other words, the proportion of price-responsive import/export bids is small. Import/export bids can take two different forms: fixed-price bids and price-responsive bids. The former category of bids consists only of quantity bids with no price specified (denoted as "fixed" in the dataset), while the latter is submitted with price bids. As the size of the export bid is very small, I will discuss mainly about the import bids. On average, import quantities associated with the fixed-price import bids make up almost 86.5% of the total import quantity, and price-responsive bids account for less than 15%, which is only about 425MWh in size. Even among these price-responsive bids, the portion of the bids that have price bids close to equilibrium price, which are the import bids that can potentially impact the estimation of RD slope, is very small, with an average of 30MWh and being zero in nearly 50% of the sample.

B.4.3 Caveats: Sensitivity of RD slope to the strategic firm set

The slope of the residual demand depends on the selected set of strategic firms. This may bring concern as I use a different set of strategic firms for each market, (t, h). In this section, I will discuss the sensitivity of the RD slope estimate to the selection of strategic firm set and demonstrate

[12]Source: EIA-930 data. https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/ISNE

that it is not a big problem in my case.

The number of strategic firms could affect the slope of the residual demand. For example, having a larger number of strategic firms makes the RD more inelastic, by construction, as fewer firms are categorized as non-strategic. However, there exists a trade-off (compromise) between strategic firm selection and RD slope. For example, including one more firm in the strategic category increases the total number of strategic firms competing in the Cournot model, which reduces overall market power, offsetting the effect of a more inelastic residual demand. Thus, having a greater number of strategic firms in a specific market, and consequently a more inelastic residual demand slope than in other markets, does not necessarily imply higher market power.

The slope of RD could also change with the composition of the firm set. For this reason, accurately selecting the set of strategic firms is important. I provide a detailed justification of the strategic firm selection in Appendix D. Nevertheless, the strategic firm selection is not the only determinant of the slope of residual demand. The steepness of the slope is largely driven by the overall shape of the original supply curve (merit order curve) rather than the strategic firm set. To confirm this, I re-estimated the slope of the RD curve constructed using a fixed set of strategic firms for the entire sample.[13] I was able to replicate the important pattern – RD slope becomes more inelastic with the increasing gas price levels – that contributes to finding that the impact of transition on market power increasing further with the gas price levels.

C Startup cost and ramping cost

C.1 Startup cost

Fixed start up cost is an important part of the cost of a power plant, especially for the baseload power plants (coal and nuclear) characterized by having a high startup cost compared to others such as natural gas and oil power plants. However, this paper abstracts from the fixed cost because estimating and modeling the fixed cost requires a dynamic framework, thus not suitable in the static model adopted in this paper.

Also, note that the equilibrium difference between the pre-and the post-retirement samples, which we identify as the impact of retirement, is not affected by the fixed cost. That is, our analysis compares the pre-retirement Cournot equilibrium to the post-retirement Cournot equilibrium, both computed without accounting for the Fixed Cost. Therefore, the market power impact of retirement identified in our analysis is less contaminated (biased) by the absence of fixed cost. The bias in the market power measure is known to occur when the market power is measured by comparing the actual market outcome to the counterfactual outcome computed without the fixed startup cost (Reguant, 2014; Mansur, 2008).

C.2 Ramping Cost

Although I did not explicitly model the ramping cost in my analysis, I incorporated the proxy of ramping costs for the coal plants using information revealed in their bids. A price bid submitted by a coal power plant consists of a part that reflects the marginal operating cost and another part that reflects the ramping cost. The price bid that is suspected of associated with the ramping cost

[13] I used a fixed set of eight firms having the largest scale.

is significantly higher than the price bid values of the lower-step bid which reflects the marginal cost. Thus, I can identify these ramping-cost bids from examining the bids data and also from their probability weights ($\partial p/\partial b$, probability of the bid being marginal) assigned within the marginal cost estimation.[14] I included the pair of price and quantity bids of these higher-step ramping cost parts in the cost function, treating it as a separate generating unit of a coal plant. Nevertheless, this does not perfectly account for the presence of the ramping cost and the higher-step ramping cost bids are just a proxy for an actual ramping cost.

C.3 Cases in which omitting startup cost or ramping cost could be problematic

During very low-demand hours (e.g., 2 am), a power plant with a high fixed cost may continue to generate electricity at a price below marginal cost, with the expectation that it will eventually operate during later hours when it can sell at a price above marginal cost and recoup the loss. As the plant is already in operation mode, temporarily shutting down the plant and restarting it in a few hours inefficient. Therefore, a high-fixed-cost plant's decision to operate below marginal cost during very low-demand hours is driven more by fixed cost considerations (based on dynamic decision making).

Another case is when either demand or supply experiences a discontinuous increase or decrease by a large amount during the daytime (regular operating hours). In the case of a demand increase, the firm may struggle to quickly ramp up the plant and therefore, will keep generating the same amount as before. In the case of a decrease, even if it is profit-maximizing for a firm to reduce its generation significantly to match lower demand, high start-up costs and the expectation of demand rebounding in subsequent hours may lead the firm to maintain its current level of generation. In such cases, the production decision becomes dynamic.

Finally, in the event of a sudden and substantial drop in supply (generation), generators with a high ramping cost may not start increasing their generation, even if it is profit-maximizing to do so when disregarding the ramping cost. Such production decisions cannot be explained by the static model. However, a significant decrease in supply (merit order) is most likely to occur in a grid with a substantially high penetration of renewables, as studied by Jha and Lesley (2022).

The only case relevant to my analysis is the first case, involving production decisions made during very low-demand hours. To address this, I adopted the approach of excluding the very low-demand hours from the sample. The second case is less relevant as my sample does not exhibit discontinuously large changes in either demand or supply. The last case is also not relevant because I did not incorporate renewable generation into my analysis, considering it comprises less than 10% of total supply in the New England grid during the chosen study timeframe.

C.4 Potential bias in market power assessment when excluding fixed costs

Various studies (Reguant, 2014; Bushnell et al., 2008; Mansur, 2008) have discussed and documented potential biases in market power assessments that arise from omitting start-up and ramping costs and not adopting a dynamic decision-making. Although I have excluded hours when fixed costs have the most significant influence, there is still a chance of dynamic decision-making

[14] As these units rarely get utilized, especially in the normal-gas price sample, the higher-step bids are assigned with a weight close to zero when estimating the marginal cost of a coal power plant.

being present even after making such adjustment.

What bias may arise if the supply decisions of retired firms are driven by dynamic considerations involving start-up costs, while our model relies on a static framework? In such instances, a 'retired' firm operating a coal plant could produce a higher quantity in the actual pre-retirement market than what the static model computes. This means that the withholding level of quantity (i.e, $q_{\text{com, pre}} - q_{\text{cour, pre}}$), which is indicative of market power) for this firm in the pre-retirement situation would be smaller than the prediction of our static model. Therefore, our analysis, which overlooks the startup cost, could be understating the impact of retirement on the retired firm's exercise of market power.

The overestimation of market power during high-demand hours may arise when marginal plants have high ramping costs, but the model does not account for it. However, the generating units that are marginal during high-demand hours are mostly gas-fired units that have low ramping costs. As a result, high-demand hours are less susceptible to bias in the market power compared to low-demand hours.

D Selecting Strategic Firms

D.1 How other papers define strategic firms

The conventional method of categorizing Cournot firms appears to rely on market share, firm scale or local market segmentation. The most common approach is to identify the dominant firms (typically those with large-scale operations and high market share) and model them as strategic firms. This approach has been employed in studies such as Bushnell et al. (2008), Ito and Reguant (2016), and Ryan (2021). [15]

This approach of categorizing firms as strategic based on their large scale or high market share implicitly assumes that the firm's capability to exert market power is strongly dependent on its size or share. While this assumption generally holds true, it may not be perfectly applicable to my analysis, making this categorization method less suitable for my research. I will further elaborate on the reasons behind this in the following section.

Moreover, most papers using static Cournot model in the electricity market setting treat the strategic firm set as fixed. That is, these studies do not endogenize the existing firms' decisions to behave strategically or not in the counterfactual simulations, and assumes that the strategic firm set is exogenous and remains fixed throughout the analysis. The firm set is usually not the part of the counterfactual adjustments, unless the analysis explicitly considers entry and exit of firms.

D.2 Why is the selection process necessary?

I select the strategic firms among the large-scale firms to refine the set of strategic firms used in the Cournot equilibrium computation. Because the electricity-generating firms compete in the

[15] In Bushnell et al. (2018), for instance, five major firms were used as strategic firms in the Cournot computation, although the criteria for selecting these firms were not explicitly mentioned in the paper. In Ito and Reguant (2016), the four largest players were chosen as strategic firms, reflecting the relatively concentrated structure of the Spanish electricity market. Ryan (2021) selected a total of 13 firms that accounted for over 1% of the total offered sell volume between Nov 2009 and April 2010, collectively representing a market share of approximately 70%. Ryan (2021) justified the selection of these firms by demonstrating that bids submitted by these non-strategic firms did not significantly respond to congestion (this paper studies the impact of transmission congestion on market power).

	mean	med	min	max	s.d.	N
Strategic Firms						
(A) Market-level (t, h) **Sample**						
No. of firms	8.9	9	7	13	1.4	334
(B) Total Sample (18 firms)						
Total Generating Capacity (MW)						
All firms	1,272	918	415	3,372	799	20
Retired firms	1,561	1,619	712	2,295	665	4
Gas-intensive firms	1,163	779	415	3,372	988	8
Balanced firms	1,236	1,012	569	2,381	709	8
Generating Units (firm level)						
No. of units (total)	7.5	4.5	1	21	6.4	20

Notes: Panel (A) summarizes the number of firms selected as strategic firms in each market (t, h). Panel (B) summarizes the characteristics of the final list of strategic firms throughout the market sample by their type.

Table D.1: Strategic Firm Characteristics Summary

multi-unit uniform auction setting, a firm has an incentive to behave strategically only when its generating unit (or power plant) has a probability of setting the price (i.e., close to being marginal). This implies that indicators such as firm size and market share are not sufficient to categorize a firm as a strategic player, as such probability varies with the market condition. For example, when the market demand is high, a large-scale firm that only operates the low-cost generators will not bid strategically, despite having a high market share, as none of its generators are close to being marginal. On the other hand, when the market demand is low, a large-scale firm that mainly operates the high-cost generators (e.g., oil-fired power plants) does not have incentives to bid strategically. If so, treating these firms as strategic players in the Cournot computation could exaggerate the strategic outcome. Furthermore, even a firm with a low market share has a strong incentive and the ability to bid strategically if several of its generators are close to being marginal under the given market condition.

To address these concerns, I select firms that are *observed* to behave strategically in the actual equilibrium (SFE), whose quantity observed from the data (generated from the SFE) considerably differs from the counterfactual *competitive* quantity of the pre-retirement sample. The selection of firms is possible because I can compute the (counterfactual) competitive quantity at the firm level in the pre-retirement sample period. The deviation of the actual quantity from the competitive benchmark indicates that the firm was making strategic production decisions under the given market conditions. The method also allows me to select a different set of strategic firms for each market, accounting for the differences in the strategic environment across markets.

D.3 Details of the selection procedure

For each market, (t, h), I compute the competitive quantity at the firm level of pre-retirement sample. I then compare this competitive quantity to the actual quantity that a firm produced in the market, which is observed from data. I select firms whose observed quantity is smaller than the counterfactual competitive quantity. Quantity difference must be at least 5% of the competitive quantity and must be larger than 50 MW in absolute value.

Note that *retired firms* operating the retired baseloads are included in the strategic firm sets in every market, even if not selected through this process, because their generation mix will be affected by the adjustments made in the counterfactual environment. The rest of the firms not selected are categorized as non-strategic firms. Therefore, the non-strategic firm group includes not only single-plant owners but also large-scale firms (with considerable market share) unable to position their generators close to the market-clearing point.

The market environment could change slightly after the counterfactual adjustment, while the selection relies on information from the observed pre-retirement market. To account for the possibility, I also find firms that are not observed to behave strategically in the current (pre-retirement) situation but could potentially do so in the counterfactual environment (i.e., having a generating unit that could become marginal). Specifically, for some large-share firms that did not meet the first selection criterion, I further examined whether they operate generators included in an expanded set of potentially marginal units. While the generating units of these firms may not be close enough to be considered marginal in the factual before-retirement equilibrium, they could become closer to marginal under the new counterfactual supply curve and around the counterfactual equilibrium. To account for this limitation, I expanded the set of potentially marginal units to cover a wider range around the original equilibrium point in order to define marginal units. I selected firms that operate generators with marginal costs within the $\pm$20MW range around the original equilibrium price or generators positioned on a supply curve within the $\pm$1,000MW range around the original equilibrium point. If these firms have enough residual capacity (at least 10% of the total capacity remaining) within the given demand range, I finally include them as strategic firms.

D.4 Summary of strategic firms

Table D.1 provides a summary of market-level strategic firms. The composition of the strategic firm group (i.e., the identity of the included firms), although not reported in the table, differs across markets. As shown in Panel (A) of Table D.1, the size of the strategic firm set also varies across markets, with a median size of 9 firms. There is no strong correlation between the number of strategic firms and market demand or gas prices. A total of 20 firms appear as strategic firms throughout the sample, and their characteristics are summarized in Panel (B) of Table D.1.

E Details of the Capacity Counterfactual

E.1 Case (1): Adding new fringe suppliers

The total capacity of the retired baseloads (about 3,700 MW) is met by new fringe suppliers that enter with a gas-fired power plant. The capacity sum of the new power plants entering equals the total capacity of the retired baseloads. The capacity of the *retired* firms decreases as the lost capacity is not replaced. Three different capacity sizes, { 50 MW, 80 MW, 100 MW }, are assigned to hypothetical power plants, leaving about 50 fringe firms to enter in each market. The capacity sizes used here are chosen based on the capacity of actual fringe power plant (single power plant entry) in New England, as observed in the EIA-860. The marginal cost of the hypothetical power plant ($mc_{hypo,t}$) is generated as described in Section B.2, but to avoid having a flat region in the supply curve, I randomly perturbed the values between 80 to 120% of the representative marginal cost, $r \in [0.8, .12]$, $mc_{j,t} = r\ mc_{hypo,t}$ and assigned to each hypothetical plants.

The entry of fringe suppliers affect the market outcome mainly by changing the slope of the residual demand curve (β_{th}). As the estimation of residual demand parameters relies on constructing the residual demand curve out of the actual bids submitted in the auction, I first create the hypothetical bids of these fringe firms and incorporate them into our new residual demand curve. The hypothetical bids are created using the capacity ($q_{i,fringe}$) and the marginal cost ($mc_{i,fringe}$) of fringe suppliers, exploiting the fact that non-strategic players would bid their marginal cost in the auction. The new residual demand curve after adding fringe suppliers becomes significantly more price responsive, with the slope estimate (β_{th}) increasing by about 50%, on average, and the extent of slope increase was larger on higher gas price days and in lower demand hours. Also, I re-calculated the intercept (α_{th}) by removing the production from retired generation from the total strategic quantity, Q_{st}.

The slope estimate β_{th} increased by about 49.9%, on average, after small fringe suppliers enter with new gas power plants, and the extent of slope increase was larger on higher gas price days and lower demand hours. Table H.4 and Table H.5 in the Online Appendix show how the original slope estimates and the new slope estimates changes with the aggregate demand and gas price levels of the market. The pattern is reversed in the new slopes, which is also indicated by the change in slope regression. Figure H.6 in the Online Appendix also shows an example of the new residual demand curve for two different markets.

E.2 Case (2): Retired firms add 50% larger gas-generation capacity

The second counterfactual is a close extension of the baseline case, where the *retired* firms now install the natural gas-fired generation having a 50% larger capacity than the one retired. The marginal cost of the hypothetical power plant ($mc_{hypo,t}$) is generated as described in Section B.2. I use the same marginal costs for all hypothetical power plants, regardless of their ownership.

In sum, the capacity increases for the *retired* firms, while stays the same for other firms. The total capacity at the industry level is larger than in the baseline case.

E.3 Case (3): Other gas-intensive incumbent firms add gas generation capacity

The third counterfactual scenario is where I let the other incumbent firms, particularly the gas-intensive type of firms, to install new gas-fired generation to replace the retired baseload generation. I select three firms among the strategic firms of each market, (t, h), giving priority to the gas-intensive type.[16] These firms expand their existing gas generation capacity by installing 400

[16] In markets where more than three gas-intensive firms exist in the strategic firm set, I selected three from the highest to lower capacities among them. Some markets only have two gas-intensive firms in the strategic firm set, in which case the last 400 MW capacity is allocated to the balanced firm. However, the strategic firms are still the majority in this

MW sized hypothetical gas-fired power plants, replacing 1,200 MW of the lost generation from the retired baseloads together. While the set (composition) of selected firms allocated additional capacity differs across the markets, two major gas-intensive firms appear most frequently. The marginal cost of the hypothetical power plant ($mc_{hypo,t}$) is generated as described in Section B.2. I use the same marginal costs for all hypothetical power plants, regardless of their ownership.

An important assumption I make here is that only the total capacity of the retired *nuclear* power generation, about 1,200 MW in total, is replaced by the incumbent firms' new gas-fired generation. In other words, the lost generation from the nuclear power plant is replaced by the new gas generation capacity added by the gas-intensive firms, not by the retired firms. On the other hand, the retired coal-fired generation is replaced by the *retired firm*, with a new gas power plant of the same capacity as the retired one.[17] There is a practical reason behind the assumption. If including the retired coal plants as well, the total capacity that must be replaced by incumbent firms together is too large. Given that the number of gas-intensive incumbent firms in each market is not large, it is practically infeasible to replace the generation lost from both coal and nuclear power plants.

In sum, the capacity increases for the gas-intensive firms chosen for additional capacity allocation, while that of other incumbent firms stays the same. Also, the capacity of firms operating the retired nuclear power plant decreases, whereas that of firms operating the retired coal power plant stays the same. The total capacity at the industry level does not change, the same as in the baseline case.

case.

[17]The assumption I make is partially motivated by the fact that converting the nuclear generation facility to a new generation site of different technology is challenging, whereas converting is easy for the coal plant sites. Salem Harbor station (coal-fired) in New England would be an example.

F Additional Tables

	generators	
	(1)	(2)
Fuel	capacity (MW)	% of total capacity
gas	10,735	31.81
gas/oil dual	6,195	18.36
oil	4,384	12.99
coal	2,314	6.86
nuclear	4,452	13.22
hydro	3,066	9.09
other	268	0.79
total	31,424	100

Notes: The table summarizes the capacity of power plants (generators) by their fuel type. Data of power plants operating in the New England grid in the winter period of 2012 is used (*Source*: SCC data, 2012, ISO-NE)

Table F.1: Summary of Generation Capacity by Fuel Type in the New England Market

	Demand (GW)				
		Low Demand	$\Rightarrow$	High Demand	
	Total	(D1)	(D2)	(D3)	(D4)
mean	15.785	11.665	14.819	16.289	18.752
med	16.057	11.873	14.826	16.297	18.372
s.d.	2.958	1.632	0.459	0.536	1.385
min.	8.107	8.107	14.073	15.500	17.022
max.	22.776	13.978	15.477	16.996	22.776
N	348	83	61	83	121

Notes: (D1) is demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The number of observation in each demand bin is roughly the same.

Table F.2: Summary Statistics: Aggregate Demand

		$\Delta\Delta P = \Delta P_{af} - \Delta P_{bf}$				
			Low Demand		$\Rightarrow$	High Demand
	CF	Total	(D1)	(D2)	(D3)	(D4)
$\Delta\Delta P$	(*)	9.8	9.2	11.3	10.7	8.9
	(1)	−2.7	−5.5	−0.5	0.1	−3.1
	(2)	6.5	0.6	6.7	10.3	10.6
	(3)	16.4	12.3	18.9	17.4	18.7
Further Controlling for the Daily Gas Prices						
(G1) Low Gas Price						
$\Delta\Delta P$	(*)	4.9	5.4	1.6	5.0	6.4
	(1)	3.2	1.1	1.3	1.9	7.9
	(2)	4.4	4.2	−0.1	2.5	9.8
	(3)	9.0	9.9	5.7	6.4	12.6
(G2) Med Gas Price						
$\Delta\Delta P$	(*)	9.4	8.4	9.6	10.8	8.9
	(1)	−2.4	−6.2	0.3	0.2	−0.6
	(2)	5.5	−2.5	7.8	10.7	12.2
	(3)	17.8	10.7	24.6	21.2	21.2
(G3) High Gas Price						
$\Delta\Delta P$	(*)	16.6	16.1	23.4	21.9	11.5
	(1)	−10.4	−14.5	−3.4	−2.9	−15.5
	(2)	10.4	0.07	14.2	21.1	10.5
	(3)	24.5	18.2	31.0	26.5	23.6

Notes: Table summarizes the mean of $\Delta\Delta P_{th}$ within each demand-gas price bin (D-G). Each row presents the results from different capacity installation scenarios: baseline case (*), CF (1): add new fringe, CF(2): retired firms installing larger capacity, and CF(3): expand incumbent's capacity. (D1) is demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The number of observation in each demand bin is roughly the same. The cut off values for the gas price bins are: days with gas prices between \$4 to \$9/MMBtu (G1: Low G), between \$9 and \$15/MMBtu (G2, Med G), and above \$15/MMBtu and up to \$27/MMBtu (G3, High G). As we selected days only among those with daily gas prices above the normal level of \$4/MMBtu, even the "Low Gas Price" category includes the sample days with gas prices higher than the normal (lowest) level. N = 348.

Table F.3: Price difference, $\Delta\Delta P$: capacity installation counterfactuals

	Baseline $\Delta\Delta P_{th}$	CF(1) $\Delta\Delta P_{th}$	CF(2) $\Delta\Delta P_{th}$	CF (3) $\Delta\Delta P_{th}$	RN(1) $\Delta\Delta P_{th}$	RN(3) $\Delta\Delta P_{th}$
Demand	-0.07	0.85^{***}	1.62^{***}	0.98^{***}	2.34^{***}	1.36^{***}
	(0.17)	(0.19)	(0.24)	(0.24)	(0.27)	(0.23)
Gas price	0.81^{***}	-1.15^{***}	0.38^{**}	1.04^{***}	-1.19^{***}	0.58^{***}
	(0.08)	(0.09)	(0.12)	(0.12)	(0.13)	(0.11)
constant	9.85^{***}	-2.68^{***}	6.54^{***}	16.5^{***}	-5.22^{***}	12.6^{***}
	(0.52)	(0.59)	(0.74)	(0.73)	(0.80)	(0.68)

Notes: Market level $\Delta\Delta P_{th}$ values are regressed on the demand and gas price levels of the market. Each column shows the resgression result of $\Delta\Delta P_{th}$ obtained under different counterfactual scenarios. CF(1), CF(2), and CF(3) refer to the additional capacity counterfactuals examined in Section 7, and RN(1) and RN(3) are renewables counterfactual examined in Appendix H.2. *Demand* is the aggregate market demand of the day t-hour h market (*unit*: GWh). *Gas price* is the spot gas price index of day t (*unit*:$/MMBtu). Both variables are demeaned. Standard errors in the parenthesis. N = 348.

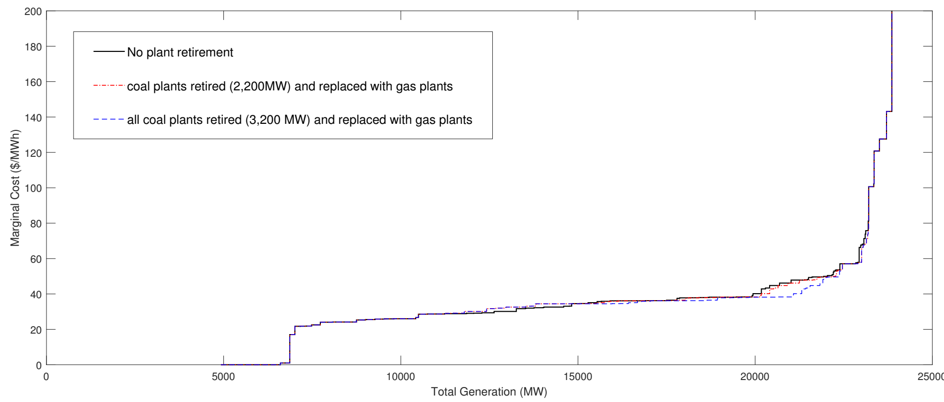
Table F.4: $\Delta\Delta P_{th}$ regression: pattern over demand and gas price

		$\Delta\Delta P(\%) = \Delta P_{\text{post}} - \Delta P_{\text{pre}}$			
		Low Demand		$\Rightarrow$	High Demand
	Total	(D1)	(D2)	(D3)	(D4)
$\Delta\Delta P(\%)$	9.6	11.0	9.8	11.3	7.4
Further Controlling for the Daily Gas Prices					
(G1) Low Gas Price					
$\Delta\Delta P(\%)$	7.9	10.6	2.5	9.0	8.2
(G2) Med Gas Price					
$\Delta\Delta P(\%)$	10.1	10.2	10.4	12.4	7.5
(G3) High Gas Price					
$\Delta\Delta P(\%)$	11.3	13.0	17.6	13.7	6.6

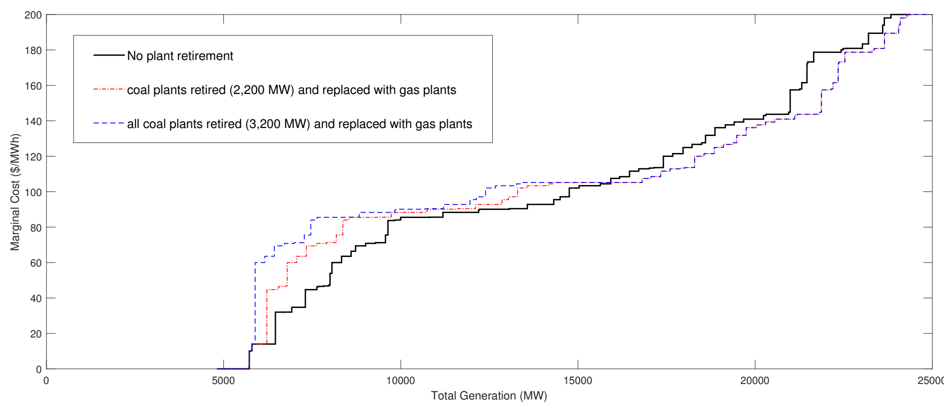
Notes: Average values of the percentage of $\Delta\Delta P$ out of the original pre-retirement equilibrium price (P_0) are reported in the table. (D1) is demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The number of observation in each demand bin is roughly the same. The cut off values for the gas price bins are: (G1) gas prices between $4 to $9/MMBtu, and (G2) between $9 and $15/MMBtu and (G3) gas prices higher than $15/MMBtu (up to $27/mmbtu). N= 348.

Table F.5: unilateral market power change, Percentage $\Delta\Delta P$ (%)

G Additional Graphs



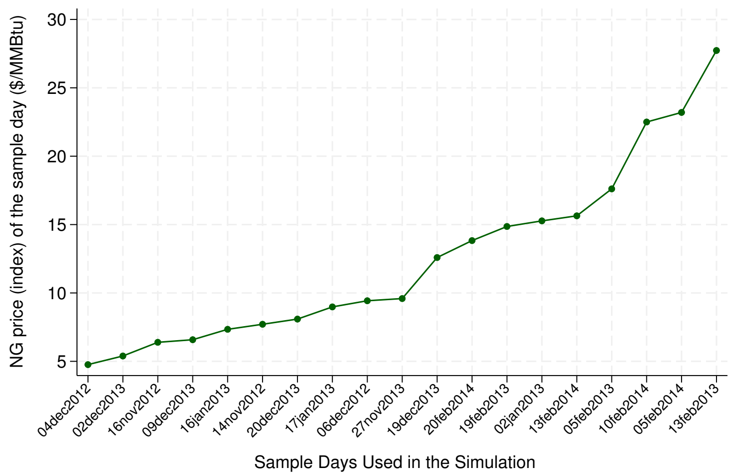
(a) normal day without the gas price shock: gas price =$/4/MMBtu



(b) day with the gas price shock: gas price = $15/MMBtu

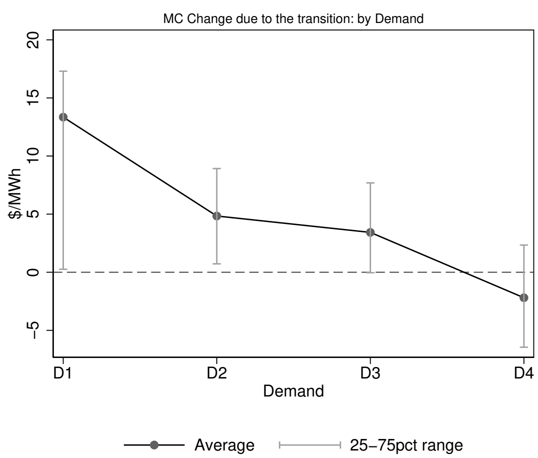
Notes: The graph is generated with the generator-specific marginal costs. The original curve is indicated as "No plant retirement". In the "plant retiremet" situation, the retired coal power plant is replaced with a hypothetical gas power plant of the same capacity. Red dash-dot line shows the case where a total of 2,200 MW of coal generation retires, and the blue dash line shows where a total of 3,200 MW of coal generation retires.

Figure G.1: The effect of the retirements on the industry-level marginal cost curve

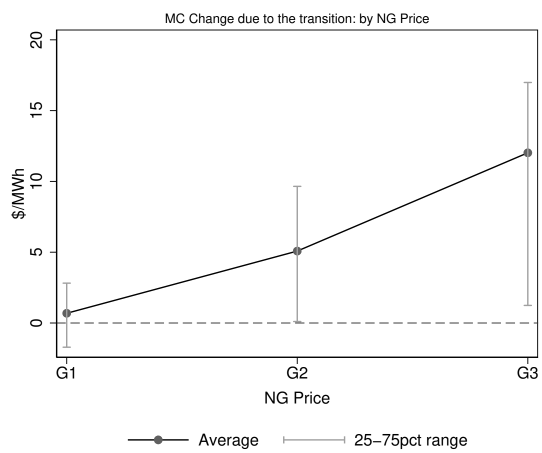


Notes: The horizontal axis displays the dates of selected sample days arranged in increasing order of the day's gas price (index data), shown in the vertical axis.

Figure G.2: Gas Price Index Values of the Selected Sample Days: With Dates



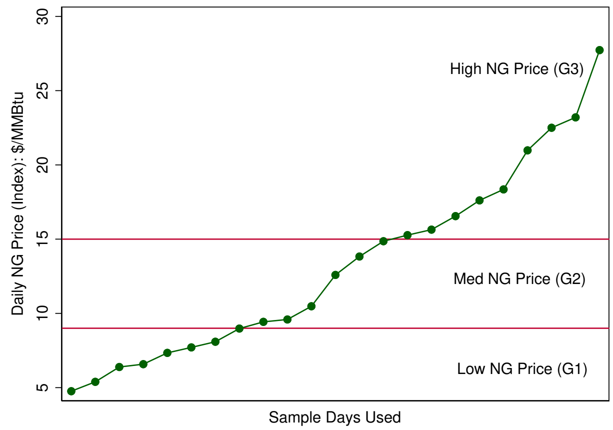
(a) ΔMC mean$_{th}$: by demand



(b) ΔMC mean$_{th}$: by NG price

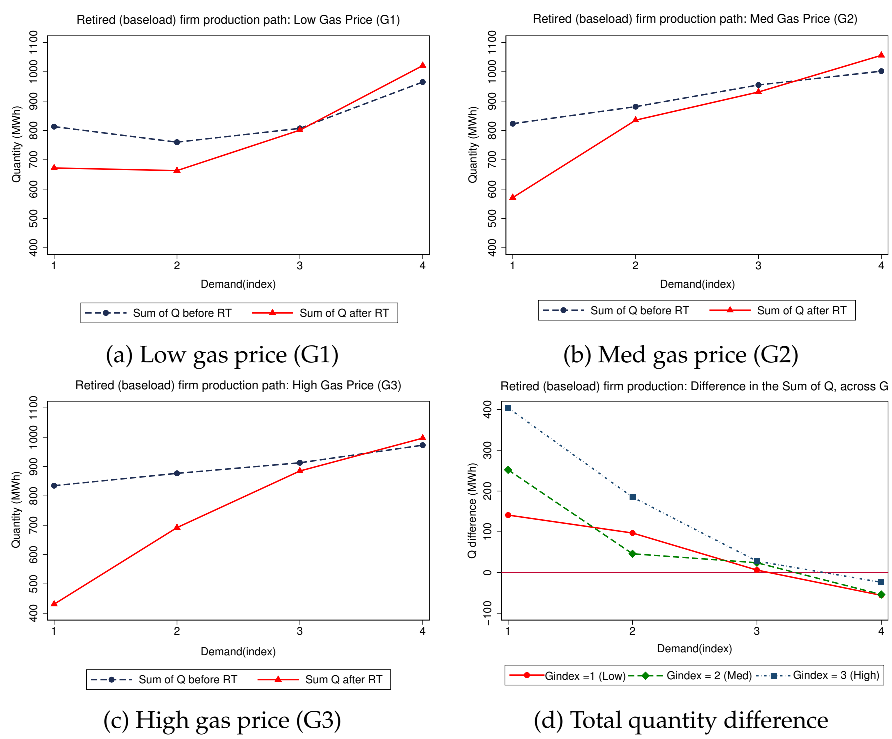
Notes: ΔMC mean$_{th}$ is the difference between the market level average marginal costs of strategic firms before and after the transition, i.e., $\overline{MC}_{th,post} - \overline{MC}_{th,pre}$ (unit: \$/MW). A *positive* value indicates an *increase* in the average marginal costs after the transition. The graph plots the average (shown in dots) and the distribution (25-75 quantiles, shown in bars) of ΔMC mean$_{th}$ taken within each sample.

Figure G.3: Average change in the MC of strategic firms due to the transition



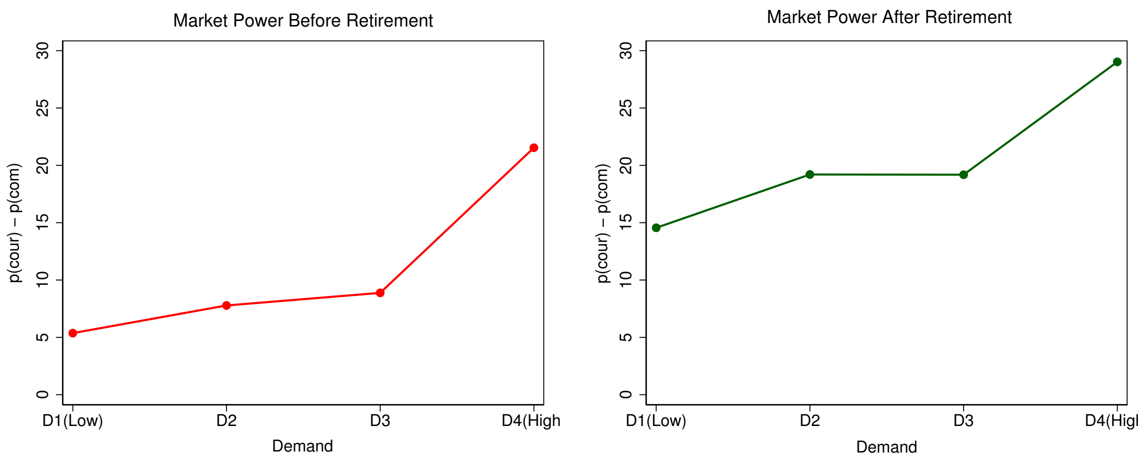
Notes: The horizontal axis shows the selected sample days aligned in an increasing order of gas price (index data) of the day, shown in the vertical axis. We divide the sample into three groups: days with NG price index below \$9/MMBtu (G1: Low G), between \$9 and \$15/MMBtu (G2: Med G), and above \$15/MMBtu (G3: High G). We selected days only among those with daily NG prices above the normal level of \$4/MMBtu. Therefore, even the "Low G" category includes the sample days with NG prices higher than the normal (lowest) level.

Figure G.4: NG price levels of the selected sample days used in the analysis: G index categorization



Notes: Total quantity produced by "retired firms" together is plotted across demand (D1-D4), over different gas prices (G1 - G3). The dashed line shows the quantity path before the retirement and the bold line shows the quantity path after the retirement. Panel (d) summarizes the total quantity difference ($Q_{before} - Q_{after}$) across D and G, in a single plot.

Figure G.5: Retired firm's (average) production paths before vs. after the retirement



(a) Market Power Before Retirement

(b) Market Power After Retirement

Notes: Figure shows the markup (ΔP) averaged within each demand bin (D1 to D4) for the pre-retirement (panel (a)) and the post-retirement (panel (b)) samples.

Figure G.6: Absolute level of Market Power (ΔP): before and after retirement

H Online Appendix

H.1 Mixed Complementarity Problem

The Bushnell, Mansur and Saravia (2008) version of the mixed linear complementarity problem (MCP) can be re-arranged into a more compact expression. The original expressions are as follows:

$$\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it} \le 0, \quad q_{it} \ge 0, \quad \left(\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it}\right) q_{it} = 0 \tag{H.1}$$

$$q_{it,max} - q_{it} \ge 0, \quad \lambda_{it} \ge 0, \quad (q_{it,max} - q_{it})\lambda_{it} = 0 \tag{H.2}$$

First, if $q_{it} \in (0, q_{it,max})$, $\left(\frac{\partial \pi_i}{\partial q_{it}} - \lambda_{it}\right) = 0$ is implied by the third condition of equation (H.1) because $q_{it} > 0$. Also, because $q_{it,max} - q_{it} > 0$, $\lambda_{it} = 0$ is implied by the third condition of equation (H.2). Thus, $\frac{\partial \pi_{it}}{\partial q_{it}} = \lambda_{it} = 0$ holds as $\left(\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it}\right) = 0$.

Second, if $q_{it} = q_{it,max}$, then $\lambda_{it} \ge 0$ from the third expression of equation (H.2), and since $q_{it} > 0$, it must be that $\left(\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it}\right) = 0$ from the third condition of equation (H.1). Therefore, $\frac{\partial \pi_{it}}{\partial q_{it}} = \lambda_{it} \ge 0$ holds.

Finally, if $q_{it} = 0$, then $q_{it,max} - q_{it} > 0$ unless $q_{it,max}$ is zero which is not the case. Therefore, $\lambda_{it} = 0$ from the last condition of equation (H.2). And since $\frac{\partial \pi_{it}}{\partial q_{it}} \le \lambda_{it}$ holds as implied by the first condition of equation (H.1), $\frac{\partial \pi_{it}}{\partial q_{it}} \le \lambda_{it} = 0$ holds.

As a result, we have an expression for mixed complementarity problem (MCP):

$$\begin{aligned}
&\text{For } \forall i \in \mathcal{F} \\
&\qquad 0 < q_{it} < q_{i,max} \quad \Rightarrow \quad \frac{\partial \pi_{it}}{\partial q_{it}} = 0 \\
&\qquad q_{it} = 0 \quad \Rightarrow \quad \frac{\partial \pi_{it}}{\partial q_{it}} \le 0 \\
&\qquad q_{it} = q_{i,max} \quad \Rightarrow \quad \frac{\partial \pi_{it}}{\partial q_{it}} \ge 0
\end{aligned} \tag{H.3}$$

This matches the standard specification of MCP problem. Three pieces of data are necessary which are the upper bounds u, lower bounds l and the function F. The general form of MCP problem is described as below:[18]

(MCP) Given lower bounds l, upper bounds u and a function $F : R^n \to R^n$, find $z \in R^n$ such that precisely one of the following holds for each $i \in \{1, \dots, n\}$:

$$\begin{aligned}
F_i(z) = 0 \quad &\text{and} \quad l_i \le z_i \le u_i \\
F_i(z) > 0 \quad &\text{and} \quad z_i = l_i \\
F_i(z) < 0 \quad &\text{and} \quad z_i = u_i
\end{aligned} \tag{H.4}$$

Therefore, the function F that enters the PATH solver must be $-\frac{\partial \pi_{it}}{\partial q_{it}}$.

[18] Descriptions are taken from Ferris and Munson (1998).

H.2 Renewable Generation

H.2.1 Importance of the coal to natural gas transition

In our analysis, we used natural gas generation as an example of the energy with a volatile input cost, and have thus considered only the transition from coal to natural gas. However, renewable generation using wind and solar has also rapidly grown over the course of years and replaced a considerable size of the retired generation capacity. It is indisputable that the electric grid should ultimately transition away from fossil fuels and towards clean renewable energy to meet the deep decarbonization goals.

Nevertheless, that does not make the transition from coal to natural gas less important. While natural gas is a fossil fuel, it is much cleaner than coal and is an important bridge to the clean renewable energy. Importantly, studies show that (the price drop of) natural gas played a critical role in the massive retirements of coal power generation (e.g., Linn and McCormack, 2019). As long as electricity-generating firms find natural gas as a close substitute for coal, the transition from coal to natural gas may continue for a while.

H.2.2 Extension: intermittent renewable energy and the volatile marginal cost of generation

While natural gas and renewable energy differ in many aspects, similarities emerge between the two when viewing these energy sources from the perspective of an electricity-generating firm during the time of the interrupted energy supply. That is, the volatile nature of the natural gas supply, caused by the exogenous weather shock, is somewhat similar to the intermittent nature of renewable generation, which also stems from the exogenous variation in wind speed and solar irradiation. This implies that the source and the pattern of the marginal cost variation are similar between the gas-fired generation and renewable generation, which enables us to extend the findings of this paper more generally to the case of transition towards renewables.

How does the intermittent supply of renewable energy translate into the volatile marginal generation cost? It is important to note that the marginal cost relevant for our analysis is the marginal opportunity cost (or the expected marginal cost) that the multi-unit firms account for in their strategic dispatch decisions in the day-ahead market. The marginal cost of a renewable generator itself is close to zero when renewables are available. When renewable generators become inoperable (or expected to be inoperable in the real time) due to the weather shock, a multi-unit firm that operates these renewable assets would consider replacing them with the high-cost reserve (backup) generation, in which case the firm's marginal opportunity cost is different from and above zero. This implies that the marginal cost of a renewable generator, as perceived by the firm, is not standalone constant at zero but variable due to the intermittency.

Note that such parallelism between gas-fired generation and renewable generation draws from the assumption that renewable assets are part of a firm's strategic assets that participate in the day-ahead market (most of which are dispatchable), thus not supported under the current market system where renewables are not dispatchable and participate only in the real-time market. However, the current system and the market rules are likely to change as the market operators look for better ways of integrating the intermittent renewables. For instance, the New England electricity market operator (ISO-NE) proposed a plan to require intermittent hydro and wind powered generators with a capacity supply obligation to start offering (i.e., submit supply offer

	Proposed capacity		Approved capacity	
Fuel type	Total sum	firm-specific (largest)	Total sum	firm-specific (largest)
Renewables	1,362 MW	450 MW	850 MW	402 MW
Natural gas	5,190 MW	1,597 MW	4,003 MW	1,597 MW
Other	166 MW	42 MW	58 MW	16 MW

Notes: Table summarizes the capacities proposed and approved for construction between 2013 and 2017. *Renewables* includes Solar and Wind generation. *Other* includes diesel fuel (DFO), other waste and biomass generation (OBG), hydro (WAT) and etc. Firm-specific capacity column shows the capacity of the largest project proposed by a single firm. Capacity cleared approval is indicated by the "status" column of the dataset where I grouped U (approved and construction less than 50 %) V (approved and construction more than 50 %) and TS (construction completed and ready for operation) into those approved. Capacity is caculated using the nameplate capacity. *Source*: EIA-860.

Table H.1: Proposed Generation Capacity in New England (ISONE): by Fuel Type

bids) in the day-ahead energy market (ISONE Newsletter, 2019).[19]. Therefore, the analogy between natural gas and renewable generations, which I demonstrated earlier, is not an overstretch.

H.2.3 Challenges in incorporating renewable generation into the analysis

There are some practical challenges in incorporating renewable generation assets into our empirical analysis. First and foremost, incorporating renewables as the *volatile-cost* energy in the analysis is practically challenging. Note that the focus of this study is on periods when the supply of renewable energy is disrupted because the fluctuation in the marginal cost of renewable assets stems from intermittency. However, we do not yet have sufficient data (on production, marginal costs) nor an understanding of how firms would strategically utilize their renewable assets, especially in abnormal situations in which the supply of renewable energy is interrupted. This is especially so given that the non-dispatchable renewable assets were not participating in the day-ahead electricity market where strategic actions are most active. As these assets were not participating in the market, the bidding data from which we can estimate marginal opportunity costs does not exist for renewable generation assets.

Second, despite the rapid growth, the size of the existing and the planned installations of renewables is so far much smaller than that of the gas generation, especially in the Northeast where volatility is the biggest concern. For example, the total capacity of the gas-fired generation approved for installation between the years 2013- 2017 in the New England grid is almost five times larger than that of renewable generation, as shown in Table H.1 of the Appendix. According to EPA, renewable resources still play a limited role in offsetting natural gas consumption in the New England power sector, especially during the extreme weather conditions, which is the focus of the paper, as wind and solar resources are not available during extreme weather conditions (EPA, 2019 Regional System Plan ISO-NE).

Moreover, renewable generation enters on a small-scale and has not been the primary energy source installed by the major strategic firms. Table H.2 provides a detailed summary of the proposed (or approved) generation capacities at the firm- and project level, by energy source. We

[19]This was part of the "Do not Exceeed (DNE)" dispatch project which was effective June, 2019. *Source*: https://isonewswire.com/2019/06/04/wind-and-hydro-resources-incorporated-into-the-day-ahead-energy-market-with-second-phase-of-do-not-exceed-dispatch-project/

Firm-level capacity (approved): MW	Total	mean	min	max	p25	p50	p75	p99
Natural gas	4,003	445	1.4	1,596	3.7	200	680	1,596
Renewable	850	13	1	402	2	3.9	8.1	402
Among Renewables (approved): MW								
Wind	588	39	1.5	385	1.5	9.1	30	385
Solar	260	5	1	20	2	3	5	20

Table H.2: Firm-level Proposed (and approved) Capacity in New England: NG vs. Renewables

find that, except for one project, almost all of the renewable project has a scale less than 30 MW (75th quantile), with the median scale being 4MW, whereas that of natural gas has an average project size of 445 MW with 75th and 50th quantiles being 680 MW and 200 MW, respectively.[20] This indicates that renewable projects are less likely to be operated by large-scale firms as part of their strategic assets. Since the main focus of the paper is the strategic behavior of electricity-generating firms, the available data and institutional features at this point do not support the use of renewables as a primary replacement of coal generation.

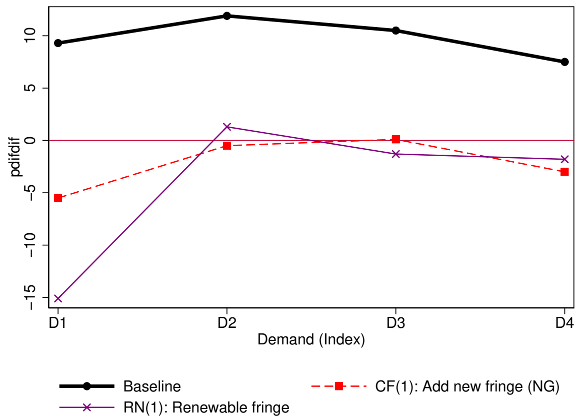
H.2.4 Additional Counterfactuals with Renewables

In this section, we examine additional cases where the retired baseloads are replaced with a constantly *zero-cost* renewable generation – absent of intermittency issues – while maintaining the assumption that natural gas generation is the only volatile-cost generation. The situation is likely if the events that raise marginal costs of natural gas and renewables are not strongly correlated with each other. For example, wind energy supply is known to be less affected by the cold weather – the primary cause of the natural gas price shock – and has a fairly constant supply across hours.[21] However, note that this additional analysis using renewables has little relevance to our main research question; replacing the retired baseload with the constantly zero-cost renewables is analogous to replacing them with another baseload generation. That is, examining how the competition changes when baseloads are replaced with renewables, and when renewables become unavailable due to intermittent nature, would correspond more to our main question.

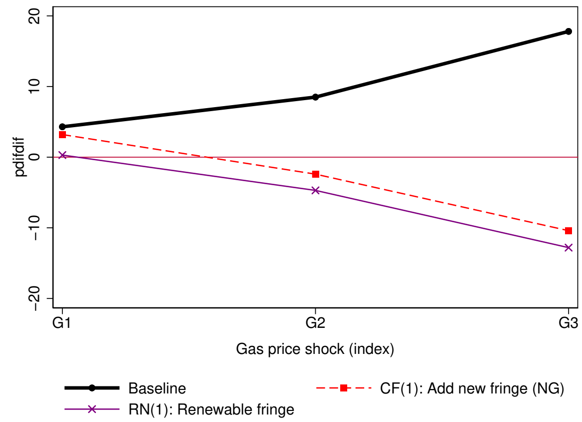
Results Figure H.1 summarizes the results of $\Delta\Delta P$ of RN(1), which is an augmented case of CF(1). Here, we let the fringe suppliers enter by installing the zero-cost renewables, instead of the gas-fired generation, to replace the retired baseload generation. On average, the market power decreases when the zero-cost renewables enter, even more than in the CF(1) case, but the differ-

[20]When examining the capacities proposed by firms that appear in the bidding data (with significant shares), NG fired plant capacity has the mean of 340 MW, with a maximum of 1,596MW. On the other hand, renewable generation capacity has a mean of 0.63 MW, with the maximum capacity being 4 MW. Also, the number of projects proposed by these firms is four times larger for gas-fired projects than renewables projects.

[21]However, wind generation is also not immune to the extremely cold weather, as wind farms are typically designed to operate properly under temperatures up to $-20C^{\circ}$ (*2019 Regional system plan*, ISO-NE). There have been numerous occasions in which wind power generation dropped significantly during the extreme weather events (e.g. Ercot in Feb. 2011, PJM in Jan. 2014, and Miso in Jan 2019), which also causes natural gas prices to surge. The overall electricity generation from solar energy is known to be smaller in winters than in other seasons, and the supply can be cut out entirely by the snowfall. In that respect, wind energy performs better in winters than solar energy. See https://www.powermag.com/prepare-your-renewable-plant-for-cold-weather-operations/ for details.



(a) Average Over Demand



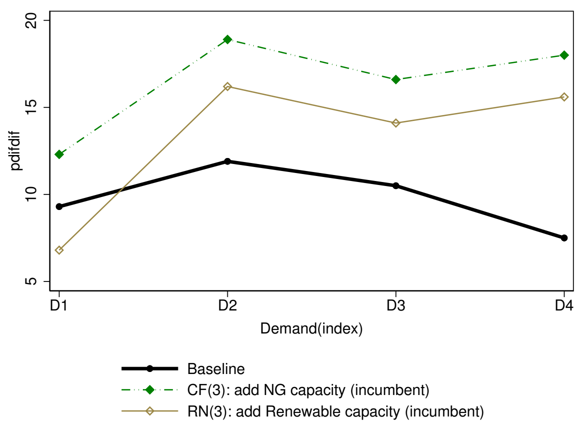
(b) Average Over Gas Price Shock

Notes: Original setting (bold line, circle marker) is the result of the baseline case. CF(1) – Add new fringe (square marker) – is the case we let the retired baseloads replaced with NG power plants owned by fringe suppliers, whereas RN(1) – Add Renewable fringe (cross marker) is the case where renewable generation owned by fringe suppliers replace the retired baseloads. Demand Index denotes D1-D4 category and gas price index denotes G1-G3 category, which were used earlier when reporting the baseline case results.

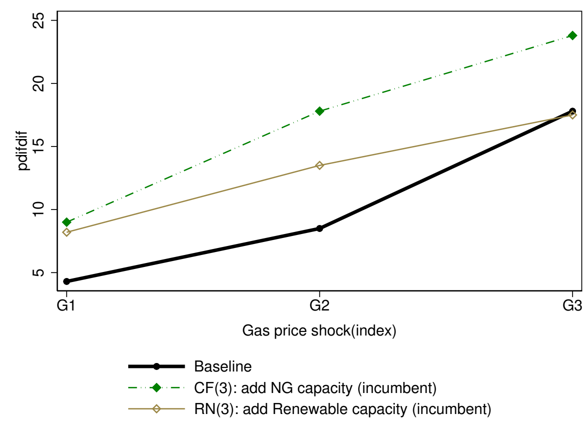
Figure H.1: Summary of $\Delta\Delta P$ of CF(1) vs. RN(1): NG fringe vs. Renewable fringe

ence between the results obtained under RN(1) and CF(1) is not too large. One very distinctive difference between the two cases is the large drop in the market power in the low-demand sample (D1), where we find the average change in the market power being close to -5 in CF(1) but almost -15 in RN(1). A significant drop in low-demand market power can be explained by the fact that the entry of zero-cost renewables reducing the net demand faced by strategic firms the most in the low-demand sample. Except for the low-demand sample result, the overall pattern of the change in market power obtained under the RN(1) scenario is similar to the pattern obtained under CF(1).

Figure H.2 summarizes the results of $\Delta\Delta P$ of RN(3), which is an augmented case of CF(3). Here, we let gas-intensive firms to install zero-cost renewables instead of NG generation. We find that, when firms install zero-cost renewables, market power does not increase as much as in the original CF(3) case but increases more than in the baseline case. Again, a distinctive difference between RN(3) and CF(3) occurs in the low-demand sample, where the extent of market power increase ($\Delta\Delta P$) is even less than in the baseline case. Moreover, the market power does not increase much in the higher gas price sample (G3) when compared to the original case CF(3). This implies that gas-intensive firms' ability to exert market power is subdued if they install zero-cost renewables instead of gas-fired generation.



(a) Average Over Demand



(b) Average Over Gas Price Shock

Notes: Original setting (bold line, circle marker) is the result of the baseline case. CF(3) – expand incumbent capacity (diamond marker) – is the case we let the gas-intensive incumbent firms to expand their capacity by adding new NG generation, whereas RN(3) is the case where the gas-intensive incumbent firms expand capacity by adding renewable generation instead. Demand Index denotes D1-D4 category and gas price index denotes G1-G3 category, which were used earlier when reporting the baseline case results.

Figure H.2: Summary of $\Delta\Delta P$ of CF(3) vs. RN(3): Gas-intensive firms adding NG vs. Renewables

H.3 Additional Tables

	Total	Strategic Price Low Demand (D1)	(D2)	⇒ (D3)	High Demand (D4)
P_{com}	98.5	75.9	87.4	88.0	124.9
P_0	105.7	80.5	93.3	94.4	134.8
P_{cour}	112.6	81.2	95.5	99.7	149.0
Further Controlling for the Daily Gas Prices					
(G1) Low Gas Price					
P_{com}	60.3	51.1	52.4	53.8	75.7
P_0	65.5	52.8	57.1	57.6	84.6
P_{cour}	67.0	53.5	58.4	58.4	87.2
(G2) Med Gas Price					
P_{com}	90.4	75.4	79.0	81.4	119.4
P_0	97.3	82.6	83.4	87.3	128.3
P_{cour}	100.5	83.0	84.3	88.2	137.2
(G3) High Gas Price					
P_{com}	151.1	115.0	132.4	154.1	164.5
P_0	161.0	120.2	140.7	165.3	175.8
P_{cour}	178.1	121.5	144.7	168.8	195.1

Notes: All prices reported here is of the pre-retirement (*Before*) sample. P_0 is the observed equilibrium price, P_{com} is the counterfactual competitive price, and P_{cour} is the counterfactual Cournot price. Average of simulated prices are reported in the table. (D1) is demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The number of observation in each demand bin is roughly the same. The cut off values for the gas price bins are: (G1) gas prices between \$4 to \$9/MMBtu, and (G2) between \$9 and \$15/MMBtu and (G3) gas prices higher than \$15/MMBtu (up to \$27/MMBtu).

Table H.3: Price Comparisons for the pre-retirement sample: competitive vs. actual vs. Cournot

	(1) Slope (original)	(2) Slope (addfringe)	(3) Δ Slope
Demand	0.004	-0.24^{***}	-0.26^{**}
	(0.02)	(0.08)	(0.07)
Gas price	-0.04^{***}	0.17^{***}	0.25^{***}
	(0.01)	(0.04)	(0.03)

Notes: Slope (β_{th}) is the estimated slope of the residual demand curve of day t-hour h (*unit*: GWh/\$). Table reports the estimates of OLS regression of β_{th} on "Demand (GW)" and "Gas price" variables. Column (1) is the slope of the orginal (used in the baseline case) RD curve and (2) is the slope of the RD after adding new fringe suppliers of capacity equivalent to the retired generation in total. (3) is for the change in slope (Δ Slope = Slope (addfringe) - Slope (original)). Demand is the aggregate market demand of the day t- hour h market (*unit*: GWh). Gas price is the spot gas price index of day t-hour h market (*unit*:\$/MMBtu). Standard errors in the parenthesis. Hours from 5h to 23h included. N = 348.

Table H.4: Residual demand slope: original vs. CF(1)

Slope $\hat{\beta}_{th}$ ($/ GW)	mean	min	max	s.d.
original	4.04	2.52	8.30	1.02
CF (1) - new fringe entry	10.1	3.43	28.5	4.31
Δ New - Original ($/GW)				
level change	5.91	-3.12	22.9	4.6
% change	49.9	-67.7	88.1	28.3

Table H.5: Summary of $\hat{\beta}_{th}$: original vs. CF (1) new fringe entry

		New Entrants	
Firm name	Proposed plant	NG capacity	Description
CPV company	Towantic Energy Center	805 MW	operates large-scaled projects in other states
NTE Connecticut	Killingly Energy Center	650 MW	operates large-scaled projects in other states
Loring Power Plant, llc	Loring Power Plant	80 MW	small scaled, does not operate in other market
		Existing Firms	
Firm name	proposed plant	NG capacity	Description
Exelon	Medway Power Station	200 MW	adding new gas-oil dual capacity to the existing plant site
PSEG	Bridgeport station	575 MW	replacing the coal plant (383 MW) that plans to retire by 2021
NRG	Canal station	330 MW	adding new gas power plants to the existing gas generation plant
Salem Harbor	Salem Habor station	1,680 MW	converting the retired coal plant site (749 MW) to gas power plant
Wallingford Energy	Waligford station	100 MW	adding new gas plant to the existing plant site

Notes: Capacity is caculated using the nameplate capacity. For Salem Harbor, the firm (operator) has changed once in the data so I dropped the capacity proposed by the previous owner to avoid duplication.

Table H.6: Proposed Capacity in New England: Natural Gas Generation

H.4 Additional Graphs

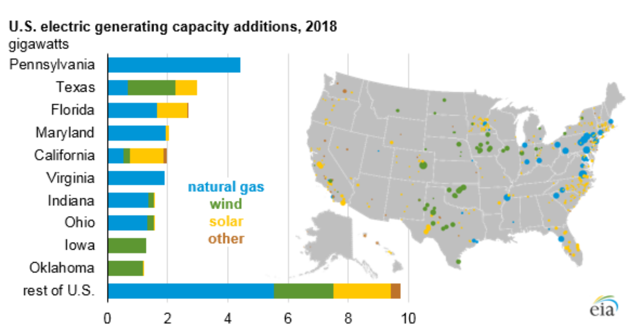
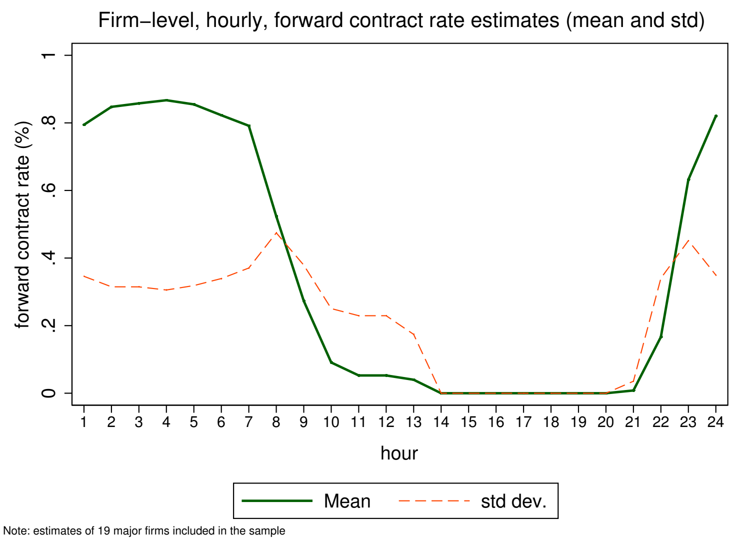


Figure H.3: U.S. Capacity Additions by Region: 2018 (source: EIA)

				Generation share (%)		
Firm No.	Total Cap (MW)	Coal	Oil	Nuclear	Natural Gas	Other
1	2,381	0	32.4	51.0	13.6	3.0
2	2,264	0	0	81.3	18.7	0
3	1,201	0	0	0	49.1	50.1
4	1,146	0	82.0	0	18.0	0
5	877	54.5	33.2	0	0	12.3
6	873	52.3	2.0	0	45.7	0
7	577	0	94.5	0	5.5	0
8	569	0	0	0	0	100

Notes: Table summarizes the generation mix composition of firms categorized as 'Balanced' firms, with each firm assigned an arbitrary index (Firm No.). The 'Other' category includes generation with fuel types indicated as other biomass solid (OBS), landfill gas (LFG), municipal solid waster (MSW), wood waste solid (WDS), and hydroelectric (WAT).

Table H.7: Balanced firm characteristics

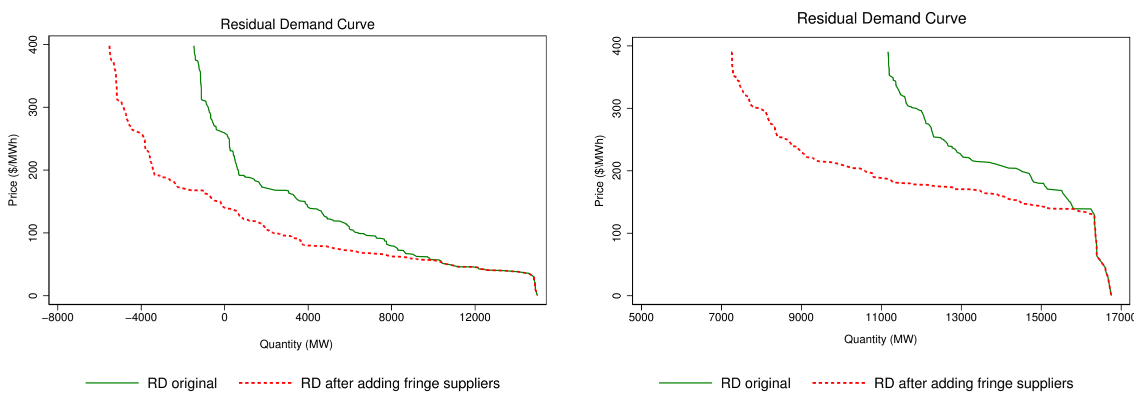


Notes: The graph above shows the cross-sectional average and standard deviation of firm-level hourly forward contract rates, γ_{ih}, estimated from the model.

Figure H.4: Forward Contract Rates: Summarized Across Firms

Notes: The original price comes from data and the price after the transition is the simulated Cournot price. The x-axis shows the actual date of sample days used in the counterfactual analysis.

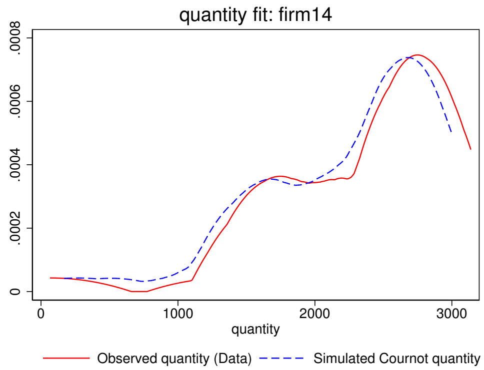
Figure H.5: Wholesale electricity prices: before and after the transition



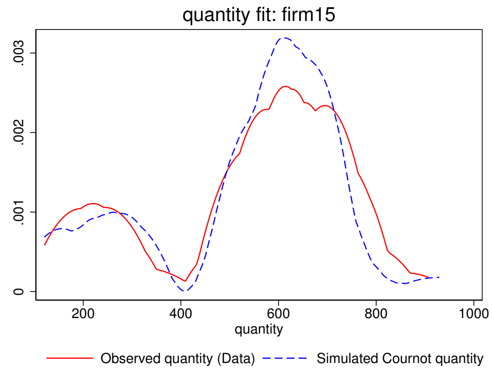
(a) t = 97: gp = $ 9.4/MMBtu

(b) t =436: gp = $ 22.5/MMBtu

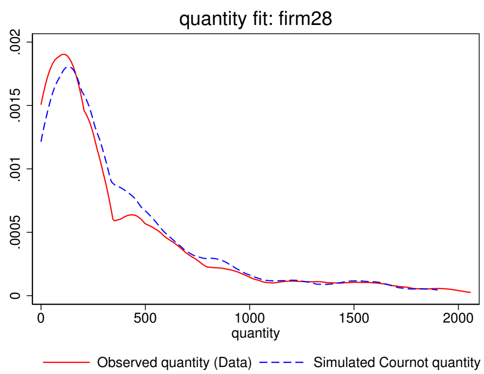
Figure H.6: Residual demand curve: original vs. after adding fringe suppliers



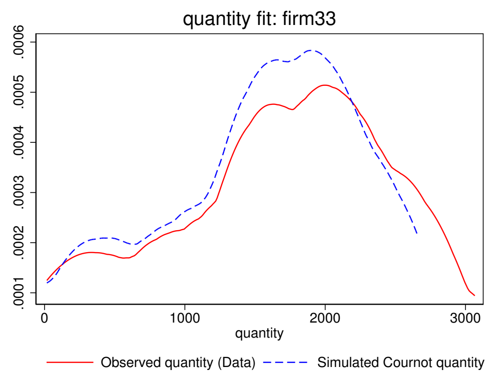
(a) firm 14



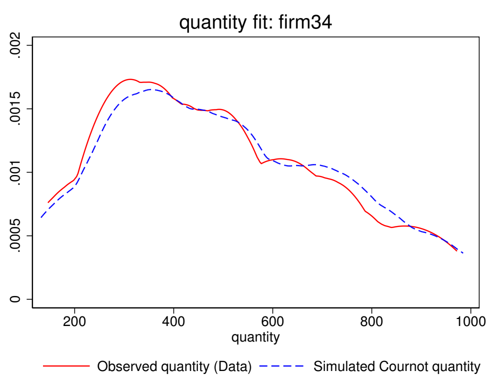
(b) firm 15



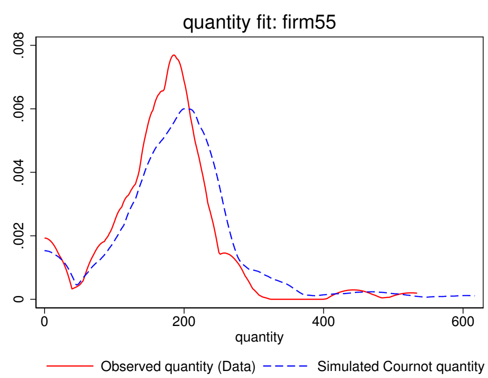
(c) firm 28



(d) firm 33

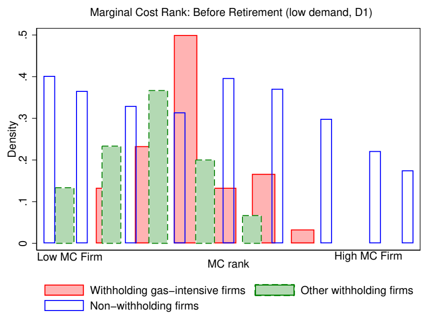


(e) firm 34

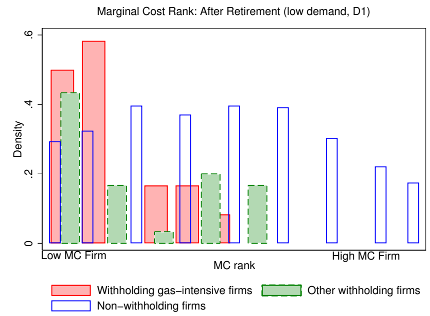


(f) firm 55

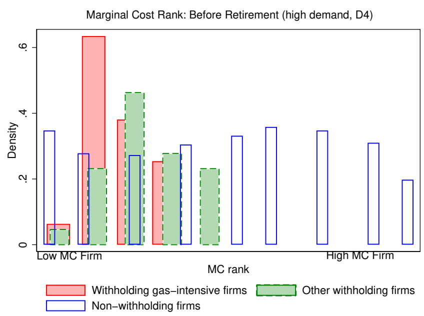
Figure H.7: Fit of the firm-specific quantities simulated using selected firm set to the actual quantity (data): pre-retirement sample



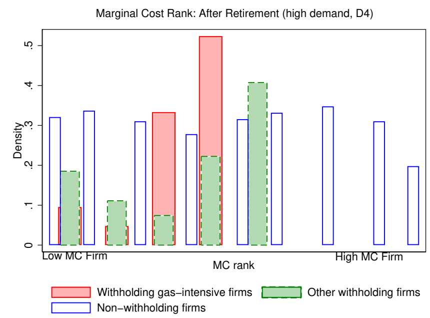
(a) Low D (D1): Before Retirement



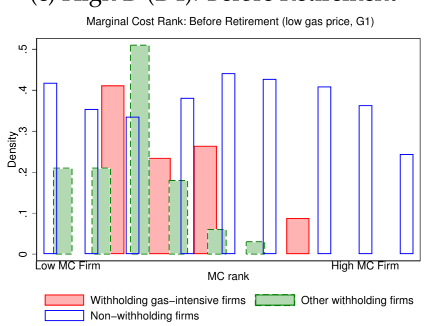
(b) Low D (D1): After Retirement



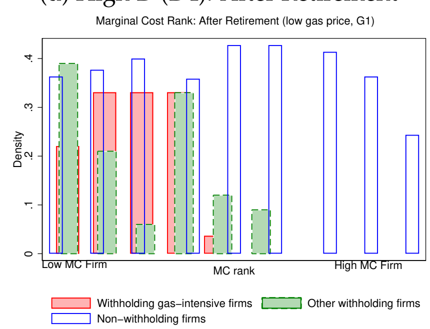
(c) High D (D4): Before Retirement



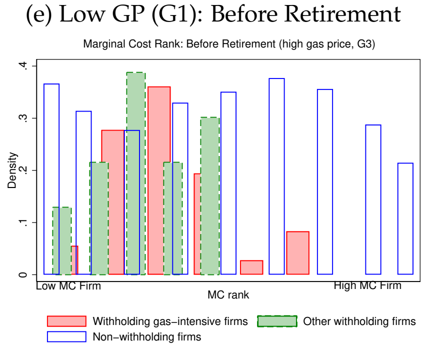
(d) High D (D4): After Retirement



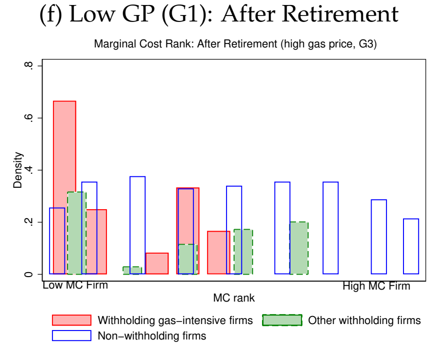
(e) Low GP (G1): Before Retirement



(f) Low GP (G1): After Retirement



(g) High GP (G3): Before Retirement



(h) High GP (G3): After Retirement

Figure H.8: MC rank: before and after the transition: by demand and gas price