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

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Abstract

The U.S. wholesale electricity industry is undergoing a major transformation due to increasing retirements of coal-fired power plants which will be replaced mainly by cheaper and cleaner natural gas generation. This paper shows that such an environmentally desirable transition towards cleaner energy could change the competitive nature of the industry, focusing on a specific feature of clean energy: the volatility of its input costs. Unlike coal generation that has a stable generation cost, the cost of gas generation could increase sharply due to the volatile spot gas prices. Thus, the retirement could affect market competition by making proportionally more of the industry's generation susceptible to potential input cost shocks. Using data from the New England wholesale electricity market, we study how strategic competition changes due to retirement, accounting for the volatile gas prices. We also examine the post-retirement industry structure – which depends on how new capacity is installed – that would lessen the exercise of market power. We find that, conditional on having the same industry structure as before, so that the retired coal capacity is replaced by the same amount of gas capacity owned by the same firms, the exercise of market power increases, more so when the gas prices are higher. However, this effect is mitigated when retirement is accompanied by the capacity installation that creates a more fragmented post-retirement industry and suppresses the scale expansion of large gas-intensive incumbent firms.

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1 Introduction

The conventional baseload generation using coal and nuclear power plants is rapidly retiring from the grid, and the cleaner natural gas and renewable energies are emerging as a new source of baseload generation in the U.S. wholesale electricity market. Broadly, two factors are responsible for this transition. The first is the stringent environmental regulation that raises the emission costs of the highly-polluting coal generation.[1] The second and most important factor, is the increasing economic pressure from cheap natural gas generation. Due to a significant drop in the price of natural gas in the past decade, coal power plants are losing their cost advantage over gas power plants. The low gas price makes these coal plants relatively less efficient, thus driving them out of the industry, with the low-cost gas generations replacing them.

While coal plant retirement draws attention regarding the environmental benefits and grid stability issues, this paper focuses on the competition side of this transition. That is, will the changing grid condition – into a heavily gas-concentrated industry – affect the way that firms compete in the wholesale electricity market? This question is particularly relevant when considering a specific feature of clean energy; the volatility of input costs. Unlike coal – the price of which is always low and stable – gas prices are subject to potential shocks as the gas price is sensitive to the condition of the infrastructure (e.g., the pipeline).[2] When the gas prices are at the normal low level, the input cost of gas generation is similar to that of coal generation, but it becomes more expensive than that of coal when gas prices are high.

In this respect, the retirement of coal plants results in replacing a consistently low-cost generation with generation having a lower but more volatile cost, which could increase levels up to several times higher. Therefore, the industry's transition towards cleaner energy sources is making the industry more vulnerable to the input cost shock. For a comprehensive assessment of the true benefit and cost of transitioning to clean energy, it is important to study how different the competition and the market outcome will be when such input cost shocks occur in the transformed industry, compared to when the industry was composed of a relatively balanced generation mix including stable baseload generation.

Our concern for competition arises because the electricity market is characterized by imperfect competition, where firms make strategic decisions facing their own residual demand. The retirement disturbs the distribution of costs among these firms, more so when combined with a higher gas price (under which the input cost difference between the retiring coal plant and the new gas plant replacing it is large). Such disturbance changes the supply response of firms, thereby affecting competition by changing the firms' residual demand. Whether market power increases

[1] About 40 % of carbon dioxide emissions in the U.S. originate from electricity generation (Goulder et al., 2014), therefore the primary goal of the environmental regulation of the energy sector is to reduce the use of highly-polluting fossil fuels such as coal and increase the use of less-polluting natural gas and renewable sources of electricity generation.

[2] Gas must be delivered through pipelines at the time of use, which makes its spot prices sensitive to congestion in the pipeline. Renewable energy, though not explicitly considered in our analysis, is also prone to input cost volatility due to its intermittent nature; the sudden unavailability of renewables causes a high-cost fringe (reserve) generator to replace the zero-cost renewable generation.

or decreases, and under which market conditions it does so more, would be an interesting and policy-relevant question to ask.

In addition, another important aspect of the retirement is that the retirement-induced transition reshapes the industry structure which also critically affects the degree of competition; that is, how and by which firms the new gas generation capacity is installed changes the scale and the number of firms in the industry. For instance, a firm can simply replace its retiring generation with a new gas generation of the same capacity, in which case the industry structure remains unchanged. Or instead, small fringe suppliers could enter with the new capacity, resulting in a more fragmented industry. Also, the size of the installed capacity could exceed that of the retired, increasing the total capacity at the firm and industry levels. Nevertheless, very little attention has so far been given to how the characteristics of firms and the industry are changing as a consequence of the retirement, with most of the discussion centering on whether or not the overall capacity being installed would meet the retiring capacity. Therefore, we investigate several different forms of post-retirement industry structures to show under which case the increase in market power due to retirement would be mitigated the most. This should also offer an acceptable policy suggestion to regulators of the market as to how to properly incentivize the new capacity installation in this industry.

We study this in the context of the New England wholesale electricity market which is one of the several electricity markets in the U.S. that frequently experience a surge in natural gas prices. The local gas prices in New England are volatile, especially during winter, due to the frequently congested pipelines that deliver gas to the region. The congestion results in a sharp increase in the gas price, increasing the input cost of gas-fired generators. Despite having this problem, the New England grid is awaiting retirements of several large coal and nuclear plants, which will be replaced mostly by gas generation.

The empirical approach we take focuses on the impact of the retirement-induced transition in the longer term, instead of the impact of each plant retirement. This is because the actual retirement events are spread over time, with the capacity of each retiring plant too small to have a significant effect on the market outcome.[3] The main idea is to construct the market environment that is likely in the near future; where all of the planned baseload retirements have taken place, and the installations of capacities replacing the retired ones are completed. Every other market condition, such as the demand and marginal cost of generators, are held fixed to the level observed before the retirement, so that the only difference between the counterfactual and the observed environments is whether or not the retirement occurred. We then numerically solve the equilibrium outcomes – firm production, market price – in the post-retirement environment we have constructed, based on the model that describes competition between firms in this market. Then the impact of retire-

[3]For this reason, event study type of analysis is not so attractive in this setting. Also, the retirement of a plant affects the entire industry, thus finding a control group to assess the impact of retirement in a reduced form set up (e.g., dif-in-dif) is challenging. Moreover, predicting a counterfactual generation pattern using the generation regression, as in Davis and Hausman (2016), is not suitable in our case where the merit order and the cost distribution are significantly disturbed in the counterfactual situation.

ment can be identified by comparing the post-retirement equilibrium outcome to that observed before the retirement.

In order to examine how the impact of retirement changes with the increase in input cost resulting from the volatile gas prices, we need to account for the variation in gas prices in our analysis. We do so by selecting the pre-retirement sample days from the actual days during the winters of 2013 and 2014 when gas prices were volatile, from which we construct the counterfactual post-retirement environment. Therefore, comparing the outcome differences (between pre- and post-retirement states) across days that differ in gas prices reveals how the impact of retirement varies with the increase in gas prices.

The additional variation we explore when examining the retirement's impact is the change in industry structures, which depends on how the retired baseload generation is replaced by the new gas generation. We consider several scenarios regarding the capacity installation, starting with a baseline case where the firm that owns the retired generation installs the new gas generation having the same capacity as the retired one. In this case, the industry structure remains unchanged as the scale and the number of firms do not change after the retirement. We then extend the baseline case to three additional cases by varying which type of firms install new gas generation capacity – the new entrant or the incumbents, small or large firms, those who operate (or do not operate) the retired plant – and the size of the capacity being installed. Comparing our results across these different cases show how the impact of the retirement differs according to the post-retirement industry structure.

To compute the equilibrium, we use two different models – Cournot competition and perfect competition – following the literature (Bushnell, Mansur and Saravia, 2008). The Cournot model describes firm competition in wholesale electricity market (Klemperer and Meyer, 1989), and is commonly used to compute the counterfactual equilibrium (Borenstein and Bushnell, 1999; Bushnell et.al., 2008; Ito and Reguant, 2016). We also simulate the competitive equilibrium to obtain the competitive benchmark that will be used to measure the extent of market power. While the change in the Cournot outcome involves strategic consideration, the competitive model captures the outcome change due to disruption in the industry marginal cost distribution, absent of strategic consideration. Therefore, by comparing the outcome difference between the pre- and post-retirement states across two different forms of competition, we can better identify the outcome change attributable to the market power. Based on this idea, we identify the impact of the retirement on (unilateral) market power by measuring the change in Cournot prices relative to the change in competitive prices.

From the baseline case simulation, where the retired coal capacity is replaced by the same amount of gas capacity owned by the same firms, we find that unilateral market power increases due to the retirement, raising the price additionally by about $9/MWh, on average. Examining the pattern across different (aggregate) demand and gas price levels, which vary across the days simulated, two main patterns emerge. First, the market power increases more in low-demand hours than in high-demand hours. While the market power in the electricity market is known to be high during the high-demand (peak) hours and less exercised when the demand is low, what we quantify here is the additional increase in market power on top of the level prior to the retirement, which turns out to be greater in low-demand hours. Second, the market power tends to increase more when the gas prices are higher. For instance, if the gas price again increases above \$15/MMBtu after the industry's transition is completed, the market price is estimated to be about \$16/MWh higher than the price before the retirement under the same conditions.

How can we rationalize our findings? Intuitively, replacing the baseload with gas generation would be more costly when baseload generation is usually the pivotal, which happens during low-demand hours, and when the cost difference between the baseload and gas generation is large, which happens under high gas price. Indeed, the retirement raises the average marginal costs of strategic firms the most during low-demand hours and when the gas price is high, which results in a drop in the quantity supplied by strategic firms. The price would not increase much in this case if the decrease in strategic quantity is met by abundant, price elastic (non-strategic) fringe supply. However, non-strategic fringe supply turns out to be relatively inelastic during low-demand hours, especially when accompanied by higher gas prices, offering a more favorable environment for strategic firms to raise prices. Among the strategic firms, we find that the large gas-intensive firms that do not operate retired baseload generation are those that most actively exercise market power. They become the relatively low-cost suppliers among strategic firms after the retirement, facing lesser competitive pressure from non-strategic fringe suppliers, which gives them an increased ability to exercise market power.

The results from the capacity installation counterfactuals suggest that the well-planned installation of new gas generation capacity can help mitigate the retirement's adverse impact on market power. Among the three cases examined, we find that the most pro-competitive case is when the new capacity is installed by small fringe suppliers, followed by the case where a 50% larger gas generation capacity is installed by the same firm operating the retired baseload plants. In both cases, the market power increases by less than in the baseline case, where the price decreases by \$0.5/MWh in the first case, and increases by approximately \$5/MWh in the second case, on average. Moreover, the market power does not increase much in low-demand hours and when gas prices are high. This implies that new capacity should be installed in such a way as to make the industry more fragmented or to suppress the market power of gas-intensive incumbent firms by making their residual demand to be more price responsive. The worst case is where the large incumbent firms that are gas-intensive in their generation further expand the capacity by adding new gas generation; the market power increases by more than in any other counterfactuals, including the baseline case. This is because letting these firms to expand their capacity is analogous to increasing the scale of a firm that already has a dominant position.

Our findings have important policy implications for the market regulators preparing for the retirement-induced transition. First, the paper provides new insights into the volatile nature of the provision of clean energy and its implications on market competition. Although the gas price is not high all the time, our experience tells us that it happens quite frequently and may have a significant impact on end consumers of electricity. For instance, the residential electricity prices in New England increased nearly 20% in 2015 to cover the increase in wholesale prices caused by the gas price shocks during the previous two winters (EIA, 2018). Once the transition is completed, gas price shocks could become more frequent and severe – making the gas price more volatile – due to increased demand for gas from power generators.[4] This explains why the volatility of the input cost of the clean energy should receive greater attention when looking ahead. Second, it is of concern that at present, the new capacity is mostly installed by the gas-intensive incumbent firms that expand their existing gas generation, with very few installations coming from smaller firms. This emphasizes the need for a careful examination of the incentive schemes in the capacity market.

This paper contributes to several strands of the literature. First, the paper contributes to the literature that studies competition in the wholesale electricity market (Borenstein et. al 2002; Bushnell et. al , 2008, and etc). To the best of my knowledge, this is the first paper to examine the competitive effects of retirements of baseload generation at the market level. While Davis and Hausman (2016) empirically studies the market impacts of the nuclear power plant closure, our paper differs from theirs in that we focus more on strategic competition with counterfactual analysis based on a model. Several papers study how the competition changes upon the entry of the clean energy; in particular, the renewable generation. For instance, Fabra and Llobet (2019) study the strategic interaction between renewable generators which occurs through capacity withholding, and Bahn et. al (2019) show that ownership transfer of renewables from fringe to strategic players affects the price of electricity. This paper is related to these studies as we can extend our analysis to incorporate renewable generation. However, it differs somewhat as we focus explicitly on the cost volatility of the clean energy in the context of market competition, with an emphasis on natural gas generation which is an important bridge to renewable energy. Since the coal plant's retirement is partially driven by environmental regulation, the paper broadly relates to the literature that studies how the industry/market responds to environmental regulation/policy (Ryan, 2012; Fowlie et. al, 2014; Shapiro and Walker, 2018, etc.).

2 Institutional Background

2.1 The retirement of baseload power plants and the changing market environment

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 renewable energy. Coal-fired power plants and nuclear power plants are considered the *baseload* generation, which usually refers to the low-cost power plant that starts generating early on to serve the base of the electricity demand. We will focus on the retirements of baseload generation in general, with an emphasis on coal power plants.

[4]Note that we do not model the gas market's response and the resulting changes in the spot gas prices in our analysis as it is difficult to model the relationship between the pipeline congestion and actual spot gas prices. Our analysis exploits the variation in spot gas prices *observed* in the past.

A large number of baseload power plants have retired from the U.S. wholesale electricity market over the past several years. On the national level, almost 15 % of the coal-fired generation (about 47 GW) has decreased between 2011 and 2016 (EIA, *2017 Annual Energy Outlook*). Nuclear power plants are also rapidly retiring from the grid; almost 25 % of nuclear power generation currently operating is planning to retire.[5] The share of coal and nuclear generation together is continuing to drop as the retired generation is replaced with natural gas and renewable energy.

What have caused the retirements of these baseload power plants? First is the rising environmental costs incurred to meet the stringent environmental regulation.[6] For example, the highest number of coal plant retirements occurred in 2015, the year when the now-repealed *Clean Power Plan* was released by the EPA. While nuclear generation is free of emissions, it faces stringent safety regulations that are burdensome to implement and adhere to.

A more important factor, however, is the economic pressure that coal plants face from the cheaper natural gas power plants and renewable generation. Due to a significant drop in the natural gas prices that started since the shale gas boom, the marginal cost of generating electricity with gas has also declined significantly, to the level comparable to the marginal cost of generating with coal. As a result, coal power plants – which used to be the cheapest energy source – are losing their cost advantage over gas power plants. Similarly, renewable generation that has zero marginal cost of generation puts competitive pressure on the coal generation.[7]

The retired generation will be replaced primarily by the natural gas generation. Despite the rapid growth in renewable generation, the majority of the planned capacity additions are coming from natural gas power plants. For instance, in 2018 alone, 19.2 GW of natural gas generation capacities were added to the grid at the national level, whereas wind and solar generation additions were 6.6 GW and 4.9 GW, respectively. In particular, the share of natural 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. Therefore, the industry's dependence on the natural gas generation will further increase in the near future.

2.2 Baseload power plant retirements in the New England Market

The New England market is one of the regional wholesale electricity markets in the U.S., supplying electricity to six states in the Northeast. There are a total of 85 supply-side firms of different capacities and fuel technologies, and about one-third of them are considered large-scaled firms, the rest being fringe suppliers operating a single, small-scale power plant. These firms together

[5] They 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

[6] EPA regulations such as Mercury and Air Toxics Standards (MATS) and Cross-state Air Pollution Rule (CSAPR) affect coal plants. Clean Power Plan, though repealed in 2019, also contributed to the retirements.

[7] Additionally, because the low-cost gas generation sets the market price most frequently in the daily market, the wholesale price of electricity has decreased substantially, even during peak hours. The revenue that baseload generators make under this low market price is not sufficient to cover the enormous fixed costs that conventional baseload generators incur. Thus, the financially struggling baseload generators are retiring from operation (ISO-NE, 2016; EIA-today in energy). Such profit loss coming from the low electricity price is especially the main driver of the retirement of nuclear power plants (Davis and Hausman, 2016).

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

Table 1: Major Power Plant Retirements in New England

operate a total of 305 generating units (power plants).[8]

The market is undergoing, and expecting retirements of some major baseload power plants which are reported in Table 1. More than 3,700 MW of the market's baseload generation – a size equivalent to almost 15 % of the total capacity as of 2016 – have retired or are expected to retire by 2020. Each retirement – small in size relative to the total market capacity – will not pose a significant threat to the market operation, as the grid is prepared with enough reserve capacity.[9] However, in the longer term, the grid needs more generation capacity to replace the lost capacity from the retired generation to guarantee a reliable supply of electricity.

The retired generation will be replaced primarily by the gas-fired plants and partially by the renewable generation. That is, the total gas-fired generation capacity approved for installation is five times larger than that of renewables, as shown in Table A.5 of Appendix A.4. Once the replacement process is complete, the gas generation will take over the baseload that used to be served by coal and nuclear power generation.

2.3 The volatility of natural gas price and the marginal cost of generation

The marginal cost of electricity generation is sensitive to any change in the spot price of fuel because the fuel cost takes up the largest part of the generation cost. This implies that an increase in both the level and the volatility of the fuel prices will be reflected in the marginal cost.[10]

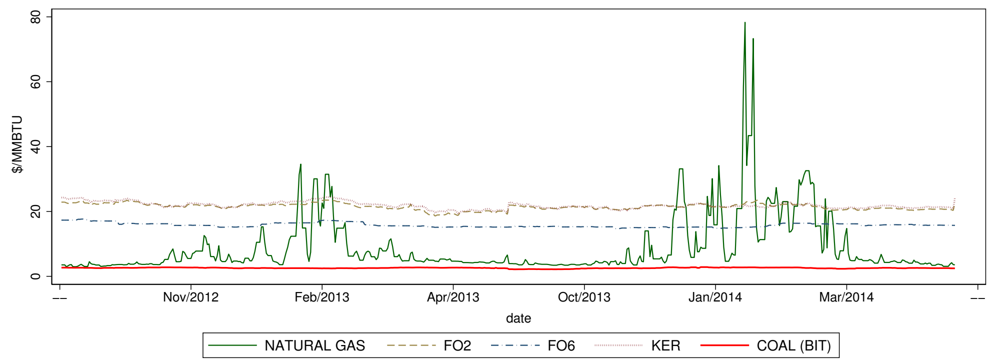
The coal price in the U.S. has always been lower than the price of other fossil fuels, such as natural gas and petroleum products, making coal generation the cheapest means of generating electricity. However, as mentioned earlier, the abundant supply of natural gas has substantially lowered the price of natural gas which had been much expensive in the past. As a result, the price of coal and the price of gas have become similar in the past several years. Once we factor in the emissions cost, the marginal cost of generating electricity with coal is now similar to (or sometimes even higher than) the marginal cost of generating with gas.

However, there is an important difference between natural gas and coal (or other fossil fuels)

[8]More details can be found in Table A.1 of Appendix A.4 where the capacities of power plants in New England are summarized by their fuel type.

[9]Nevertheless, retirement may have some immediate effects on market prices and production efficiency since it leads to an inward shift of the industry supply curve. This was the primary focus of Davis and Hausman (2016), who study the market impact of an abrupt closure of the nuclear power plant in the California wholesale electricity market.

[10]The fuel cost part is represented as heat rate (the physical efficiency of a generator which measures how efficiently a generator can convert the fuel into energy) multiplied by the price of the fuel that a generator uses, i.e. heat rate ·



Notes: Figure shows the spot prices of fossil fuels in the New England region from 2012-2014 (Source: *EIA, SNL Energy, Natural Gas Intelligence*)

Figure 1: Spot prices of fossil fuels in New England

in terms of price *volatility*. That is, the price of gas tends to be volatile, meaning that the gas price may not always be low as observed in the normal period, but could fluctuate between the low and high levels. This is because the *local* gas price, the price at which the power plants purchase gas, is sensitive to the condition of the pipeline that delivers the gas to the region. Unlike other fuels, natural gas cannot be stored and has to be delivered through pipelines at the time of use. When the pipeline becomes congested due to high volume, the spot gas prices surge above the normal level due to this *shock*, increasing proportionally with the degree of congestion.

In other words, while the price of gas is now similar to that of coal, it has a possibility to increase up to a level several times higher overnight, as shown by the fluctuating price paths in Figure 1 where the spot gas prices in New England are plotted together with those of other fossil fuels. This implies that the marginal cost of gas generation is also very volatile, capable of increasing to a much higher level over a short period of time. On the other hand, coal prices have not changed much over time, showing almost no fluctuation in price paths. The cost of generating with coal is, therefore, relatively stable compared to that with gas.

The gas price volatility is most severe in the Northeast, particularly in New England that suffers most from having inadequate pipeline capacity.[11] Then how severe and frequent was this shock? Table 2 summarizes the number of days, and their percentage out of total days when gas prices rose above the normal level of $4/MMBtu in the New England area. In total, almost 30% of days in the sample have experienced mild to extremely severe shocks to the gas prices. Moreover, the impact of these shocks on market outcomes was quite significant; an increase in the wholesale electricity prices during this 30% of abnormal days of high gas prices, in turn, resulted in a 20% increase in the retail electricity prices in the following year (EIA, 2018). Therefore, such an event cannot be disregarded, given its frequent occurrence and the large impact. Also note that the

fuel price.

[11]This happens especially in winter when the substantial increase in the demand for gas from the residential heating sector leads to severe congestion of the pipeline. 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.

	Year	Total	$4 -$10 (MMBtu)	$10-$20	$20-$30	>$30
N	2013	102	59	29	6	8
	2014	112	29	30	37	16
% (N/365)	2013	28 %	16.2 %	8%	1.6 %	2.2 %
	2014	30.7 %	8 %	8.2 %	10.1 %	4.4 %

Notes: Table reports the total number (N) and the percentage (%) of days when gas prices rose above the normal level (shock) in 2013 and 2014. Percentage is taken with respect to the total number of days in a year, not only the days that experienced shock. Also, the last four columns report these values separately by the severity of the shock (level of gas price).

Table 2: Summary of days with above normal gas prices (gas price shock) in New England

congestion in the pipeline – and the gas price shocks – may become more severe and frequent after the baseloads retire, as the demand for natural gas in the power sector is expected to increase as the grid's dependence on gas-fired generation increases.

Renewable energy, though not explicitly considered in our analysis, is also subject to marginal cost volatility due to its intermittent nature. The marginal cost of renewable energy is zero when available. But when renewable energy becomes suddenly unavailable due to external factors (e.g., weather), it has to be substituted with a high-cost reserve (back-up) generator.

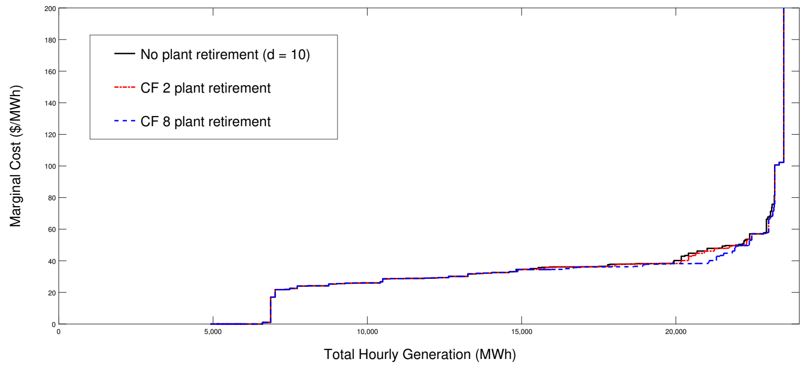
3 The clean energy transition and the market competition

This section discusses the intuition behind why the degree of competition in this market may be affected by the energy transition, focusing on the volatile nature of the marginal cost of the gas generation and the change in the industry structure related to the installation of the new generation capacities. The discussion provided here motivates the design of our empirical strategy. Note that we will be focusing on the complete transition process, including not only the retirements but also the replacements coming from the new gas generation capacities. Also, we explain the intuition with a simple example where only the coal power plants retire, though, in reality, the nuclear power plants retire as well.

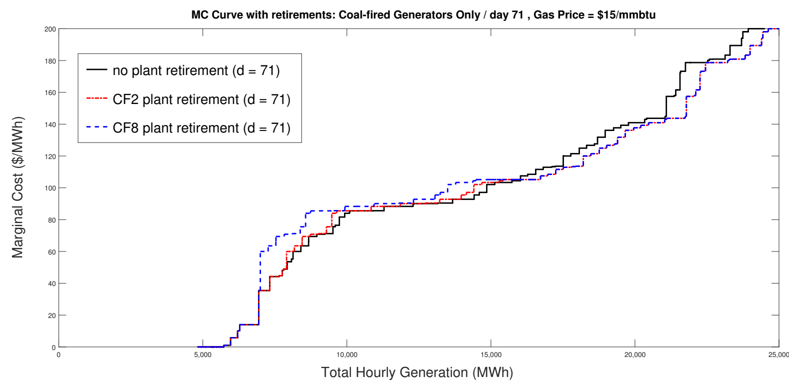
Competition in the wholesale electricity market In the wholesale electricity market, both supply and demand sides participate in an hourly market organized as auctions.[12] The electricity-generating firms compete with each other by submitting a supply schedule (price-quantity pairs) that reflects their marginal costs and strategic positions. A unique feature of this market is that the market demand is (almost) perfectly inelastic, as retail companies demand electricity without specifying the price at which they are willing to purchase.[13] Due to these features, the strategic interactions between suppliers becomes a more important factor in determining market power

[12]Muiti-unit uniform auction is the type of auction commonly used in the wholesale electricity markets in the U.S.

[13]This is because the retail companies are bound to a long-term supply contract with residential customers. As they can pass on the wholesale price to the retail price, their primary goal is to secure the electricity to meet the expected electricity consumption from the households.



(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 estimated for the empirical analysis. For the "plant retiremet" situation, the retired coal power plant is replaced with a hypothetical gas power plant of the same capacity. Details are provided in Section 4. In CF2, we let a total of 1,550 MW coal generation to retire, and more than 4,000 MW in CF8).

Figure 2: The effect of the retirements on the marginal cost curve: coal-fired power plants only

than the demand responses in this market. In particular, large supply-side firms, facing inelastic aggregate demand, are capable of exercising market power.

Volatile gas price and the impact of the retirement on marginal cost distribution The market variable directly affected by the retirement and that has particular relevance to market competition is the distribution of marginal costs. That is, when the distribution of marginal cost among firms changes, the supply responses of firms will change as well, thereby affecting the elasticity of residual demand of a firm. This leads to a change in the degree of competition because a residual demand elasticity of a firm governs its ability to exercise market power (strategic decision).

Therefore, for the coal plant retirement to have an effect on the competition in the market, whether/how the distribution of the marginal cost is affected by the retirement is crucial. And because we consider a complete transition process that involves replacing a retired coal plant with a gas power plant, whether or not the transition would affect the competitive environment depends on how similar the marginal costs of these two types of power plants are. In other words, the impact of retirements on the marginal cost distribution depends on the relative marginal costs of the retiring plant and the replacing plant.

We have demonstrated earlier that volatile gas price makes the marginal cost of gas generation to be volatile as well, while the marginal cost of coal generation does not change. This implies that the relative marginal cost of coal generation versus natural gas generation is not constant and could change. The marginal cost of a gas plant is similar to the marginal cost of a coal plant at the low-gas-price state, but it is much higher than that of a coal plant at the high-gas-price state. Thus, depending on the state we are at, the impact of the retirement and replacement process on the marginal cost distribution may be different.

For instance, if the gas price is low, being at the normal level around $4/MMBtu, the marginal cost of gas power plants in our sample is $45.6/MWh, on average, similar to the marginal cost of coal power plants which is around $45/MWh. In this case, replacing a retired coal power plant with a same-sized gas power plant would not change the distribution of marginal costs much, as these plants are identical from the market point of view. Thus, the retirement would have a minimal impact on the market competition at this low-gas-price state.

On the other hand, when the gas price rises above the normal level due to the shock, the marginal cost of a gas power plant is now different from, and much higher than that of the coal plant which does not change. For example, if the daily gas price increases to $15/MMBtu, the average marginal cost of gas plants in our sample becomes $124/MWh, while that of coal plants stays at $45/MWh. In this case, the transition ends up replacing a low-cost power plant with a high-cost power plant, thereby changing the distribution of marginal cost among firms: which firms are relatively low cost or high-cost suppliers compared to others would change. Therefore, in this higher-gas-price situation, retirement of a coal plant is expected to change the competitive environment even if replaced by a same-sized gas power plant.

To illustrate this, we plot the distribution of marginal costs of all power plants in the industry (i.e., merit order curve) in Figure 2.[14] Each of the panels displays the original distribution before retirements take place, together with the distributions after some coal plants are removed (retired) and replaced with the gas power plants of the same capacity. Panel (a) is for a day when the gas price is at the normal level ($4/MMBtu, low-gas-price state), and Panel (b) is for a day when the gas price was above the normal ($15/MMBtu, high-gas-price state). While the curves before and after the retirement overlap almost perfectly in Panel (a), we observe noticeable shifts and slope changes in the post-retirement curves in Panel (b), which suggests that the retirement affects the distribution of marginal costs considerably in the high-gas-price state, but not in the low-gas-price state.

To summarize, the retirements of coal plants are expected to have a stronger impact on market competition, especially when the marginal cost of gas generation is higher than the normal due to an increase in the gas prices. Hence, we restrict our empirical analysis to the higher-gas-price sample and focus explicitly on examining how such impact varies with increasing gas prices.

[14]Once we have information on the capacity and the marginal cost of a power plant, the distribution of marginal costs is constructed by lining up the capacity-marginal cost pair of power plants in increasing order of marginal cost.

Installation of new generation capacity and the Industry structure In the example above, we have assumed that the same firm that operated the retired coal plant replaces it with a same-sized gas power plant, in which case the production scale of each firm and the total number of firms operating in the industry stay the same as before the retirements take place. However, there could be many different ways in which new gas generation capacities are installed. That is, different types of firms – other incumbent firms or new entrants – could install new generation capacity, and the size of the installed capacity could differ from that of the retired power plant. We may end up having different numbers of firms and the scale of firms – which define the structure of the industry – in each of these different cases.

Because the industry structure is an important determinant of market competition, the impact of energy transition on market competition is dependent on the structure of the post-retirement industry that is probable. While projecting the long-term trajectory of capacity installation is challenging, we will account for the industry structure in our analysis by considering several different scenarios regarding the installation of new capacities, based on the pattern of ongoing installation observed from data. Section 7 provides more details of the capacity installations and the design of post-retirement industry structures.

4 Empirical Strategy

4.1 Counterfactual Analysis

The main methodology we use is a counterfactual analysis based on a structural model that explains how firms compete and optimally produce in the wholesale electricity market. The basic idea is to construct a counterfactual industry that is probable in the near future, once all of the planned retirements of baseload generations have taken place, and new generation capacities added to replace the lost generation. Therefore, the analysis aims to examine the longer-term transition of the industry caused by a series of (planned) retirements, instead of the (short-term) effect of each of the retirement events.

This approach is useful for overcoming the empirical challenge faced when examining the retirement's impact relying exclusively on data (without imposing any structure). That is, plant retirements do not occur all at once, but, are spread over time, and the capacity of each plant retired is too small to have a significant impact on the grid, making the event study type of analysis not attractive in this setting. Moreover, the variation in gas prices observed in the post-retirement sample data is insufficient to identify how the impact of retirement varies with the increasing gas prices. Lastly, the replacement of capacity cannot be accounted for in the analysis if relying exclusively on data because the installation of new generation capacity happens over the long term, and the data at this point is incomplete.

We make adjustments to each day (t) and hour(h) – the unit of *market* observation – of the pre-retirement sample to construct a counterfactual environment. The pre-retirement sample consists of actual days in the winter seasons between 2012 and 2014 (November - February). This period is chosen because major power plant retirements have not yet occurred at this point, but primarily because the spot gas prices in New England were volatile during this winter period.

When constructing the counterfactual environment, we keep the market variables and parameters the same as in the pre-retirement sample, so that the only difference between the pre-retirement and the post-retirement environment is whether or not the retirements occurred. In other words, we are constructing a counterpart of a market (t, h) prior to the retirement by keeping all of the variables, such as the aggregate market demand and the spot price of fuels (all of which are observed from data) to be the same, but letting the baseload power plants to be removed from, and new gas power plants to be added to the firm's generation set. Then the comparison of the equilibrium outcome of the counterfactually created post-retirement situation to the outcome of the pre-retirement situation identifies the impact of retirement.

4.2 Description of counterfactual market environment

This section characterizes the post-retirement counterfactual environment in detail, discussing the three main elements that constitute the environment.

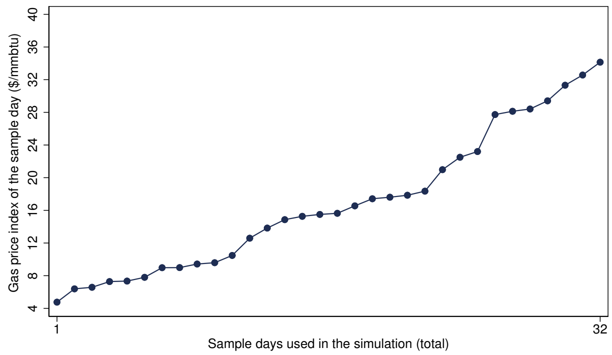
4.2.1 The retirement and the replacement of baseload power plants

We use the actual baseload plant retirements in the New England Wholesale electricity market that were announced as of 2013, which are summarized in Table 1. The list includes both coal power plants and nuclear power plants – with a total capacity of 3,708 MW – operated by four major firms. While the actual timing of these retirements varies, they are grouped and applied at once (removed altogether from the firm's generation set) when forming a counterfactual environment.

It is possible to expand the set of retired plants to include the entire baseload generation in the market (including those that have not yet announced plans to retire), or to focus entirely on the coal plant retirements by excluding nuclear plant retirements from the list. We also examined these different cases, which are summarized in Table A.2 of the Appendix, but found qualitatively similar results.

While the power plants retire from the operation without an immediate replacement in the short term, new generating capacity will be added to the grid in the long term, most of which are gas-fired power plants. Because the plant constructions are yet to be completed, with most of them still in the planning stage, there is substantial uncertainty over which firm will install the new capacity, and by how much. Therefore, we make assumptions on the pattern of new power plant construction, along with the size and the marginal cost of the plant in our analysis.

In our *baseline* analysis, we assume that the retired power plant will be replaced with a hypothetical gas-fired power plant of the same capacity as the retired one, by the same firm that used to operate the retired plant. Note that we generate the marginal cost of the hypothetical gas power plant using the average heat rate of gas power plants with the most up-to-date technology and the daily gas spot price (index). Other confounding factors that are also known to affect the market



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 levels of selected sample days used in the analysis

competition – such as the industry structure and the total industry capacity – remains unchanged under this assumption; only the fuel mix of generation assets and the corresponding marginal cost structure of the firm affected by the retirement change as a result of the adjustment. While the baseline assumption may appear to be strong, the actual pattern of capacity installation (observed in EIA-860 data) confirms that it is indeed quite realistic, as many of the retired coal plant sites are being converted for the use of gas power generation.

However, the data also shows installation patterns that are different from the one assumed in the baseline case. Thus, we will later relax this assumption and consider other scenarios regarding the installation of new capacities, in which case the structure of the industry (firm scale, number of firms, etc.) changes as a result of the retirement. More details will be provided in Section 7.

4.2.2 Accounting for the volatile gas price: selection of sample days

To examine how the impact of retirement varies by the different levels of gas prices, we exploit the variation in gas prices across days, as the pre-retirement sample days are selected from 2012-2014 winters when actual gas prices were volatile. Figure 4 shows the spot gas prices (price index) of the selected days in the pre-retirement sample, which exhibits an increasing pattern across days.[15]

Note that we identify the retirement's impact, for each day-hour market, by examining the outcome difference between the (counterfactual) post-retirement and pre-retirement equilibria, holding fixed the gas price level of the day. In other words, we have identified the impact of the retirement of the market (t, h) at the given gas price level. Since the key parameter associated with the gas price is the marginal cost of gas power plants, holding the gas price level fixed in the counterfactual environment is done by using the daily marginal cost parameters estimated from the pre-retirement sample. Then, comparing the identified impacts across days reveals how the retirement's impact varies with the gas price levels.

[15] We have chosen days having similar average daily demand and the hourly demand pattern to ensure conditions other than the daily gas price level to be homogeneous.

Pre-retirement sample	Plant retirement	Post-retirement sample
(B2) Cournot equilibrium	→	(A2) Cournot equilibrium
Observed equilibrium (SFE)		
(B1) Competitive equilibrium	→	(A1) Competitive equilibrium

Table 3: Description of the equilibrium models to be simulated

4.2.3 Accounting for the equilibrium model: horizontal structures

To compute the counterfactual market equilibrium, we need a model that describes the strategic decision making of electricity-generating firms. Because firms in the wholesale electricity market compete for production in the multi-unit auction, the Supply Function Equilibrium (SFE) model best describes their behavior. However, computing a counterfactual SFE is challenging due to a well-known multiple equilibria problem.

To overcome this challenge, the counterfactual analysis in the wholesale electricity market setting relies on computing the Cournot equilibrium (Bushnell, Mansur, and Saravia, 2008; Ryan, 2014; Ito and Reguant, 2016), leveraging on the findings of Klemperer and Meyer (1989) that multiple supply function equilibria (SFE) are bounded by the Cournot equilibrium and the competitive equilibrium. It is also common to use only the Cournot equilibrium as an approximation of the strategic equilibrium in this market.

Therefore, following the literature, we compute equilibrium based on two different models: the Cournot model and the competitive model. However, instead of providing the bounds of the possible equilibrium, we focus on the insight whereby comparing the outcomes simulated under different horizontal market structures reveals the role of strategic interaction in determining the market outcomes. Unlike the Cournot model, the competitive model does not account for strategic interactions, thus it only reveals the outcome change resulting from the change in the merit order (distribution of marginal cost). Therefore, the difference between equilibrium outcomes computed under two different market structures can be attributed to the competition. Comparison of the Cournot outcome to the competitive outcome also corresponds to the concept of unilateral market power that is represented by how much the market price (or quantity) departs from the competitive level. In this respect, we must control for the natural change in competitive outcome when examining the retirement's impact on competition and market power.

Note that we compute both Cournot and competitive equilibria also for the pre-retirement sample (before making counterfactual adjustments), to keep the form of competition the same when comparing the equilibrium outcomes across pre- and post-retirement samples. That is, the actual equilibrium we observe in the pre-retirement sample data is part of the SFE (see Table 3), thus inconsistency arises when this is compared to either Cournot or competitive equilibrium of the post-retirement sample. In sum, to assess how the retirement affects the competition, we measure the change in strategic Cournot outcomes (A2 - B2), relative to the change in competitive outcomes

(A1-B1), as shown in Table 3.

5 Description of Model, Data and Parameters

5.1 Model

5.1.1 Cournot Model of Competition

To compute the Cournot equilibrium outcomes, a general formulation of how strategic firms compete according to the Cournot assumption is necessary. We adopt the Cournot model specification used in Bushnell, Mansur and Saravia (2008) to compute the equilibrium.

Residual Demand Curve The residual demand is the demand faced by N_{st} strategic firms together. Strategic firms are chosen among those large-scale firms operating multiple power plants. More details of the selection of strategic firms will be provided in Section 6.2.2.

The residual demand, $Q_{s,th}$, must equal the aggregate market demand ($\overline{D}_{th}$) less the electricity generated by non-strategic fringe suppliers together ($Q_{ns,th}$), as shown below.[16] Subscripts s and ns denote *strategic* and *non-strategic*, respectively.

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

While the aggregate demand for electricity in the wholesale market ($\overline{D}_{th}$) is almost perfectly inelastic, the quantity supplied by non-strategic firms ($Q_{ns,th}$) responds to the market price, making the residual demand of strategic firms to be price responsive as well.[17]

To clear the market within the model, a smooth functional form for the residual demand curve is required, thus we adopt a log-linear demand specification used in Bushnell et al., (2008).[18] The functional form of a residual demand curve is specified as follows:

$$Q_{s,th} = \alpha_{th} - \beta_{th}\, ln(p_{th}) \quad \Leftrightarrow \quad p_{th} = \exp((\alpha_{th} - Q_{s,th})/\beta_{th}) \tag{1}$$

Parameter α_{th} and β_{th} must be calculated and estimated before we run a counterfactual simulation. The intercept of the residual demand, α_{th}, is calculated from the price and strategic quantity of the observed equilibrium. That is, exploiting the fact that the actual price and the quantity pair – (P_{th}, $Q_{s,th}$) where $Q_{s,th} = \sum_{i=1}^{N_{st}} q_{ith}$ – lies on the residual demand curve of day t and hour h, the intercept α_{th} can be obtained by plugging this into the specified demand curve. An important part is to

[16]To be precise, $Q_{s,th}$ denotes the quantity level of the residual demand curve of strategic firms.

[17]Because the demand side of the wholesale electricity market – local distribution companies – has obligations to supply electricity to residential customers, they tend to submit price insensitive bids which make the aggregate demand ($\overline{D}_{th}$) to be almost perfectly inelastic.

[18]Although we have complete data on demand side bids which can be used to nonparametrically construct the residual demand curve, it is better to have a more general, smoother demand function for the computation. Also, because I model firms to compete in quantity, it is difficult to obtain market clearing price without a general form of market demand function. The log-linear form fits the actual shape of the residual demand curve (non-linearity) very well.

estimate the slope of the residual demand curve, β_{th}. I will detail the estimation procedure later in Section 5.3.

Firm's problem For each strategic firm $i \in \{1, \dots, N_{st}\}$ and for time $t \in \{1, \dots, T\}$ and hour h, firm i choose to produce electricity q_{ith} that maximizes its profit $\pi_{i,th}$:

$$\max_{q_{ith}} \; \pi_{i,th}(q_{ith} \,, \mathbf{q}_{-ith}) \;=\; p_{th} \; (q_{ith} \,, \mathbf{q}_{-ith}) \; [q_{ith} - q^{f}_{ith}] \; + p^{f}_{ith} \; q^{f}_{ith} \; - \; C(q_{ith}) \tag{2}$$

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

where the firm faces a constraint that the quantity produced cannot exceed its total capacity $q_{i,max}$. The market equilibrium price, p_{th}, is a function of equilibrium quantities of strategic firms including firm i. A common practice among the suppliers is to forward contract a certain amount of their generation with the demand side (residential electricity suppliers), shown as q^{f}_{ith}, at a pre-determined price, shown as p^{f}_{it}. For this reason, the forward contracted quantity and the forward price are assumed to be exogenous at the time of a firm's production decision, and do not affect the firm's strategic decision regarding the quantity produced, q_{ith}.[19]

Cost Functions We need a firm-specific cost function because a firm operates multiple generating units (or power plants) having different marginal costs.[20] We specify the cost curve of each generating unit to be linear so that the marginal cost of a unit is constant over quantity.[21] This allows us to specify the firm-level marginal cost to be a piece-wise linear function; a functional form commonly used in electricity market studies (Bushnell, Mansur, and Saravia, 2008; Ito and Reguant, 2016). If a firm operates a total J number of generating units, we can construct a cost curve $C(q_{it})$ of firm i by arranging the marginal cost values of J units from the smallest to largest. Then, 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

[19]While q^{f}_{ith} appears in the first order condition, p_f disappears from the first order condition in the process of differentiating profit with respect to q_{ith}.

[20]While the power plant is used interchangeably with the generating unit, a power plant can contain multiple generating units. We 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.

[21]Generating units, especially the coal-fired ones, can have a non-linear component in their cost curve, in which case the marginal cost would increase with quantity. Instead of estimating the coefficient of the quadratic term of the cost function, we 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.

bidding model, the estimation procedure of which is detailed in Section 5.2 and the Appendix.[22] We also utilize the data on generating unit's capacity (quantity bids), together with the marginal cost estimates, to construct the marginal cost curve.

While the fixed cost is also an important component of the cost, especially for the baseload generators that usually have high fixed costs, it is challenging to account for the fixed cost in our analysis. That is, estimating and conducting analysis with the fixed cost is more suitable in a dynamic framework, but the model we use is static. Extending the model to a dynamic setting is difficult, and we may lose the tractability of the model by doing so.[23]

Cournot Equilibrium The equilibrium concept used in the simulation is the quantity competition in Cournot setting. Once we have all the data and estimates ready, we can derive the first order condition of a stragic firm i's profit maximization, which is shown below:

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

$$\frac{\partial \mathcal{L}_i}{\partial q_{it}} = \frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it} \leq 0, \qquad q_{it} \geq 0, \qquad \frac{\partial \mathcal{L}_i}{\partial q_{it}}\, q_{it} = 0 \tag{4}$$

$$\frac{\partial \mathcal{L}_i}{\partial \lambda_{it}} = q_{i,max} - q_{it} \geq 0, \qquad \lambda_{it} \geq 0, \qquad \frac{\partial \mathcal{L}_i}{\partial \lambda_{it}}\, \lambda_{it} = 0 \tag{5}$$

We can rewrite equations (4) and (5) by plugging in the actual specifications, which are shown below in equations (4a) and (5a):

$$\frac{\partial p_t}{\partial q_{it}}\, [q_{it} - q_{it}^f] + p_t - C'(q_{it}) - \lambda_{it} \leq 0, \;\; q_{it} \geq 0, \;\; \frac{\partial p_t}{\partial q_{it}}\, [q_{it} - q_{it}^f] + p_t - C'(q_{it}) - \lambda_{it}\; q_{it} = 0 \tag{4a}$$

$$q_{i,max} - q_{it} \geq 0, \quad \lambda_{it} \geq 0 \quad (q_{i,max} - q_{it})\; \lambda_{it} = 0 \tag{5a}$$

[22] Estimating the marginal cost better captures the dispersion of marginal costs that arises when the gas market is affected by a shock (i.e., illiquid gas market). Appendix A.2.2 provides more discussion on the difficulty of measuring the individual generator's marginal cost when the gas market is undergoing a shock.

[23] Omitting the fixed cost could be problematic in very low-demand hours when the market price also becomes very low. Turning off the plant when it is not economical to generate under the low market price is difficult once the plant is online after incurring the high fixed cost. Therefore, in this case, we may observe plants operating at a price below marginal cost, the decision driven mainly by the consideration of fixed cost. We address this issue by dropping the very low-demand hours (12 am to 4 am) from the sample used in the analysis. Also, note that we compare the pre-retirement and the post-retirement outcomes, both computed with the Cournot model that does not account for the fixed cost. Thus, the difference in the strategic outcome we find in the analysis does not result from the differences in the fixed cost.

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

$$
\begin{aligned}
\frac{\partial p_t}{\partial q_{it}}\,[q_{it} - q^f_{it}] \;+\; p_t \;-\; C'(q_{it}) \;-\; \lambda_{it} \leq 0 \quad \perp \quad q_{it} \geq 0 \qquad & \forall i \in \mathcal{F}_s \\
q_{i,max} \;-\; q_{it} \geq 0 \quad \perp \quad \lambda_{it} \geq 0 \qquad & \forall i \in \mathcal{F}_s
\end{aligned}
\tag{6}
$$

These complementarity conditions are similar to those derived in Bushnell, Mansur and Saravia (2008).[24]

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 (6), 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).[25] Once we find the equilibrium quantities, the market price can be obtained by plugging these values into the residual demand curve in Equation (1).

5.1.2 Competitive Equilibrium Outcome

Since the competitive model does not involve strategic considerations, each firm simply starts supplying electricity from their lowest cost generators. They supply the quantity that minimizes the cost of production given the market equilibrium price; that is, $p_t \;-\; C'(q_{it}) \geq 0$.

We then construct the industry-level supply curve with the quantity and marginal cost information of firms' generators, an example of which is shown in Figure 2. The competitive equilibrium price can be found at the intersection of the curve with the aggregate demand which is fixed to the level observed in the data (perfectly inelastic $\overline{D}_t$). Once we have the equilibrium price, firm-level quantities can be calculated as the sum of quantities sold by its infra-marginal generating units.

5.2 Data

We construct the primary dataset for the analysis from the "day-ahead" market (auction) data published by the ISO-New England, which operates the New England wholesale electricity market, for the period between 2012 to 2014.[26] Since electricity generating firms participate in the day-ahead auction held every hour of the day, we have high-frequency bidding data at the generating-

[24] 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 Appendix.

[25] 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.

[26] The day-ahead market (auction) opens a day before the actual generation takes place, whereas the real-time market happens on the day of generation. We chose to focus on the day-ahead market, not only because the majority of the electricity trading occurs in this market, but also because strategic interactions between firms are most active in the day-ahead market.

unit level, which consists of a price bid and a quantity bid.[27] Bidding data is used for estimating parameters required for the counterfactual analysis, the details of which provided in Section 5.3. Also, equilibrium quantities (and capacities) at the generator-level and the firm-level can be measured from the bidding data. The market (auction) clearing prices are also available from the ISO-NE.[28] The maximum (nameplate) capacities of generators ($q_{ij,max}$) and firms ($q_{i,max}$) are obtained from the Seasonal Claimed Capability data (from the forward capacity auction). The information on power plants retiring (or plans to retire) and installed is available from the ISO-New England website and the EIA (U.S. Energy Information Administration).

5.3 Parameter estimation

Broadly, three types of parameters are estimated to be used in the counterfactual analysis: the slope of the residual demand (β_{th}), the marginal cost of generators (mc_{ijt}), and the forward contracted amount of electricity (q^f_{it}). We use the bidding data from the day-ahead auction to estimate these parameters, leveraging the equilibrium properties of the actual equilibrium (supply function equilibrium) from which the bidding data is generated. In other words, the model used for estimating parameters is different from the models used for computing the counterfactual equilibrium. This section describes the basic idea behind the estimation, and more details of the model and the estimation procedure can be found in Appendix A.2.

Residual Demand Slope The slope of the residual demand curve faced by strategic firms together, β, is an important parameter showing how price elastic the non-strategic supplies are in this market. While Bushnell et al. (2008) estimate a single slope parameter for the entire sample, we estimate β separately for each market (t, h) using the bidding data, similar to Ito and Reguant (2016). This is to address the concern that the price responsiveness of the non-strategic (fringe) supply could change under different market conditions.

The residual demand curve of the market (t, h) is constructed directly out of the price and quantity bids submitted by the non-strategic firms, in a non-parametric way. That is, the supply schedule of non-strategic firms ($\sum S_{ns,th}(p_{th})$) is generated from their supply bids, which is then subtracted from the aggregate demand ($\overline{D}_{th}$) to form a residual demand curve. To estimate the slope, we fit a log-linear function, as specified in equation (1), to the residual demand curve.[29] Figure A.1 in the Appendix A.2.1 shows an example of the estimated curve fitted to the original

[27] The bids submitted by each firm consists of a price bid and a quantity bid, $< p_{ijht}, q_{ijht} >$, which specifies the minimum price p_{ijht} at which the unit j is willing to supply q_{ijht}.

[28] Among several prices reported, we use the "energy component (EC) price" that clears the entire system, a single price before factoring in the local congestion costs. As our model cannot account for the transmission congestion (the source of the additional congestion cost) when solving for equilibrium, using the local market price that includes the congestion cost would be misleading.

[29] We have adopted linear-log specification for the residual demand curve because the price elasticity of supply varies with the quantity (non-linear relationship). Since we are dealing with the possibility of having non-local simulation outcomes, we fit the entire curve with a piece-wise linear-log function, and estimate slopes within each bin. We use the spline method with 2 to 1 knots – depending on the shape of the curve – that best fits the residual demand curve generated out of bids.

(A) Summary statistics of β_{th}					
mean	4.18	min	2.52	max	8.30
(B) Correlation of β_{th} with demand and gas price of the market (t, h)					
Demand:	0.05	Gas price:	-0.08		
	(0.02)		(0.01)		

Notes: β_{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 β_{th} on "Demand" and "Gas price" 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-hour h market (*unit*:\$/MMBtu). Standard errors in the parenthesis. N = 287.

Table 4: Summary of the residual demand slope β_{th} and the regression result

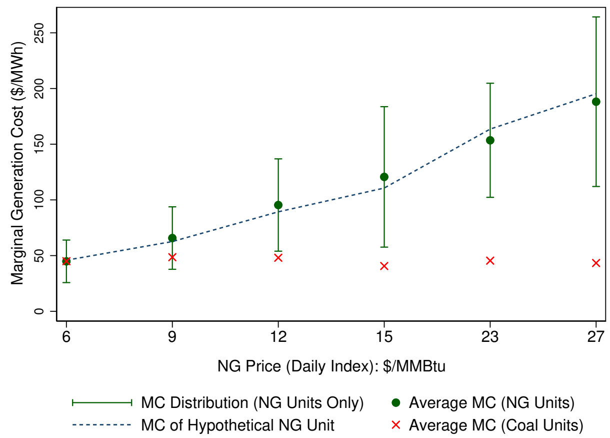
curve. Note that the same residual demand curve estimated from the pre-retirement sample is used in the counterfactual post-retirement situation, as we assume that behavior and the marginal cost of non-strategic suppliers do not change due to retirement.[30]

Marginal Cost We estimate the generator-specific marginal cost parameter (mc_{ijt}) from the bidding data. There are two main ways of obtaining marginal costs of (thermal) electricity generators in the literature. The most widely-used approach is to measure the marginal costs using data on fuel prices (the index data collected by private companies) and the data on heat rate (efficiency) of generators reported by EPA and EIA (Wolfram, 1999; Borenstein et.al, 2002, etc.). Another approach is to estimate the marginal costs that rationalize the bids that firms submit in the electricity auctions, using the estimation techniques developed in the empirical auction literature (Wolak, 2001; Reguant, 2014; Ryan, 2020; Kim, 2020). Although the latter approach requires the modeling of the optimal bidding decision of firms plus additional computation, it performs better in capturing the real opportunity costs of firms, especially when firms are affected by input cost shocks caused by gas price increases. Therefore, we rely on the second approach and use the estimated marginal costs in our empirical analysis. However, marginal cost estimates cannot be obtained for generating units that are far away from the market clearing price (i.e., not marginal), including some small fringe generators and baseload generators like nuclear power plants that submit zero price bids.[31] I use the price bid as a measure of marginal costs for these units, exploiting the fact that firms would submit a bid that equals the marginal cost for its unit with low probability of being marginal.[32] Figure 5 summarizes the estimated marginal costs of gas-fired units, coal-fired units, and the hypothetical gas-fired units used in the counterfactual analysis. More details on

[30]We have omitted import and export bids when calculating the slope of the residual demand curve. More discussion on why omitting these bids will not critically affect our slope estimates to a great extent can be found in Appendix A.2.1

[31]The optimal bidding model enables estimation of marginal cost for units that are close to being marginal, thus having chance of being utilized for a firm's strategic decision.

[32]However, note that marginal costs that matters in our equilibrium computation are those of generating units that are close to marginal (near the equilibrium). Therefore, the use of price bid for non-marginal units does not critically affect our results.



Notes: The distribution and the average of the marginal costs of NG fired generating units are plotted together with the average marginal cost of coal-fired generating units, and the marginal cost of the hypothetical NG fired units used in the counterfactual analysis. These values are plotted across days with different levels of NG prices.

Figure 5: Marginal Cost Summary

the bidding model and the estimation procedure used, and discussion on ramping cost and fixed costs, are further elaborated in the Appendix A.2.

Forward Contracted electricity We estimate forward contract parameters from the bidding data to measure the forward contracted amount of electricity, represented by q_{it}^f in our model. Data does not exist for the forward contracted position as it is determined through confidential bilateral negotiations between electricity generating firms and the demand side (local distribution companies). To overcome the data limitation, we impose a structure on the forward contracted quantity by assuming that it can be represented as a percentage of the firm's actual daily electricity generation, that is $q_{it}^f = \gamma_i q_{it}$. The assumption allows us to estimate the forward contract rate parameter γ_i together with marginal cost parameters, using the bidding data and the optimal bidding model. More details of the estimation will be provided in Appendix A.2.

6 Baseline Results

We have our results for each day-hour market, (t, h), for the selected sample days. This section reports the residual demand slope estimates and the counterfactual equilibrium outcomes.[33] Since the aggregate demand and the gas price levels vary across markets (t, h) we report results – price and market power change – by demand and gas price. We group demand into four different bins (D1 to D4, low to high) and gas prices into three different bins (G1 to G3, low to high), and report the average values taken within each bin.

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

[33]Marginal cost and forward contract rate results can be found in Appendix A.2

differ by the demand level.[34] For example, the baseload generators tend to be marginal (pivotal) with low market demand because firms can produce (dispatch) only with the low-cost generators at the given low-demand, but are far from being marginal under high market demand.

6.1 Residual demand slope estimates

Panel (A) of Table 4 summarizes the estimated slopes of residual demand curves of each day-hour market (t, h); the mean is around 4.18 GWh/$ with some variation across markets.[35] We also examine how the price responsiveness of the market-level residual demand curve differs by the demand and gas price levels of the market. Panel (B) reports the correlation between the estimated slope and the demand and the gas price levels, obtained from a simple OLS regression.

One interesting finding is that the slope of the residual demand is smaller – relatively more inelastic – when the gas price is higher, shown by a negative correlation between beta and the gas price, after controlling for demand. This finding implies that the marginal costs of non-strategic (fringe) suppliers become more dispersed as the gas price further increases. For example, in an extreme case where the marginal cost is the same for all non-strategic firms, the non-strategic supply curve (i.e., the residual demand curve of strategic firms) will be perfectly elastic. This, in turn, implies that the residual demand curve becomes relatively more inelastic as the dispersion in marginal costs among non-strategic suppliers increases. Indeed, the difference in the shape of industry-level marginal cost curves (shown in Figure 2), where the curve of the high-gas-price day was much steeper around the equilibrium than that of the low gas price day, reinforces our finding.[36].

There are several reasons why marginal costs – and the corresponding supply bids of non-strategic firms – become dispersed as the gas price further increases. As gas price increases, the difference in marginal costs among different fuel technologies (baseloads, gas, oil, and dual-fuel technology) increases. Also, note that an increase in gas price is linked to an illiquid gas market, under which the spot gas price becomes volatile even within the same day. Then, the gas prices – and the marginal costs – among gas-fired plants owned by non-strategic firms become very dispersed as well. Lastly, the marginal costs of those purchasing gas at the spot market and through

[34] 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, and (D3) and (D4) to the peak hour demand. Cut-off values for the bins are determined after examining the distribution of demand and gas prices.

[35] Note that β we report here is not the slope evaluated at a certain quantity, so it measures the *relative* elasticity of the curve. We also computed elasticities evaluated at the observed pre-retirement equilibrium, and find that market-level elasticities range between 0.21 and 4.83, with a mean around 0.83. Also, variations in elasticities across demand and gas price levels are similar to those of β.

[36] In Figure 2 Panel (a), which depicts the supply curve of a low-gas-price day, the price bids of suppliers – including both strategic and non-strategic firms – were similar across each other, shown by a relatively flat supply curve. Then, a small price increase would lead to a large quantity response from non-strategic suppliers, implying that the residual demand curve faced by strategic firms is relatively price elastic. On the other hand, when gas prices are high, the price bids of non-strategic supply were sparsely located along the supply curve, resulting in a relatively price inelastic residual demand.

	Competitive Price				
		Low Demand		⇒	High Demand
	Total	(D1)	(D2)	(D3)	(D4)
Before	84.2	74.4	81.4	83.1	100.3
After	83.7	78.4	81.6	81.7	94.1
Further Controlling for the Daily Gas Prices					
(G1) Low Gas Price					
Before	59.1	51.5	54.0	53.6	74.8
After	57.2	51.8	53.7	52.7	68.6
(G2) Med Gas Price					
Before	86.7	77.4	80.1	85.6	112.3
After	85.8	81.7	77.8	83.1	104.4
(G3) High Gas Price					
Before	134.9	116.6	132.6	148.4	152.1
After	138.0	127.5	135.7	148.0	147.9

Notes: *Before* and *After* refer to prices simulated before and after retirements are applied in the counterfactual situation.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 \$10/MMBtu, and (G2) between \$10 and \$15/MMBtu and (G3) gas prices higher than \$15/MMBtu (up to \$27/MMBtu).

Table 5: Competitive Price Result

a long-term contract could become more different as the spot gas price further increases.[37]

6.2 Counterfactual Equilibrium Prices

6.2.1 Competitive Prices

Table 5 summarizes the counterfactual competitive prices simulated for the pre- (*Before*) and post-retirement (*After*) samples. Overall, we find considerable change in the competitive price after the retirement, indicative of a disruption in the merit order of dispatch among generators caused by the retirement. The first two rows of the Table show that the competitive price increases the most in the low-demand sample (D1), and decreases the most in the high-demand sample (D4). In the subsequent panels, from (G1) to (G3), we further control for the differences in gas prices by taking average of competitive prices within each demand(D)-gas price(G) bins. On average, the competitive price decreases after retirement when gas prices are lower, but increases when gas prices are higher, though some variation exists across demand.

[37] For more discussion of this issue, see Kim (2019).

6.2.2 Selection of strategic firms and the model fit

For the Cournot equilibrium computation, we need to determine the set of strategic firms. While it is common to assume that large-scaled firms (with high market share) are strategic players, there are many large firms in this market, making it difficult to pin down several firms that are clearly dominant based on their shares.

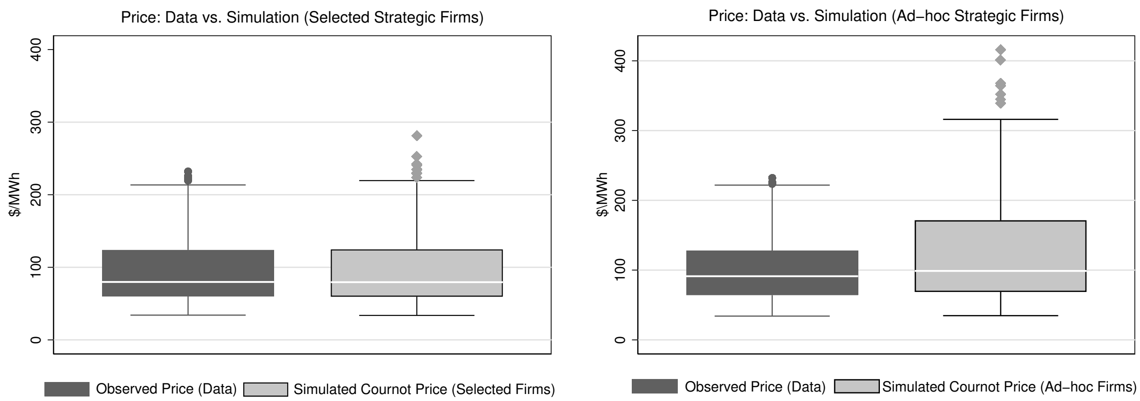
Therefore, we select strategic firms based on what the data and the model predicts, to further restrict the set of strategic players among those large-scaled firms in our sample. This way of selection can also address the concern that even a large-scale firm can behave quite competitively depending on market conditions. Because the market is organized as multi-unit uniform auctions, a firm has an incentive to behave strategically only when its generator is close to being marginal. When the market demand is high, for example, a large-scaled firm that operates only the low-cost generators will not behave strategically as none of its generators is close to being marginal. If so, treating this firm as a strategic player in the Cournot simulation could exaggerate the strategic outcome.

The selection of strategic firms is possible since we can compute the market price and firm-specific quantities for the counterfactual *competitive* equilibrium *before* retirements take place. We select firms that are observed to behave strategically in the actual equilibrium (SFE); whose quantity observed from the data – which is generated from the SFE – is considerably different from its quantity computed under the competitive model.[38] The departure of the actual quantity from the quantity that would have been produced if the firm instead behaved as price taker indicates that the firm is making strategic decisions. The selected firms are modeled as strategic players in the Cournot model, while the rest of the firms are grouped into price taking non-strategic firms; that is, fringe suppliers.[39] Note that the set of strategic firms differs across markets, and a total of 18 strategic firms appear throughout the sample, while the maximum number at the market level not exceeding 10. More details are provided later in Table 8. Figure 6 shows that using the selected firms as strategic players in the Cournot simulation (Panel (a)) yields market outcomes of the pre-retirement sample that are closer to the actual SFE outcomes, compared to when using the strategic firms defined in an ad-hoc way by using a fixed set of firms among those producing more than 1,000MW (Panel (b)).

In addition to that, Panel (a) demonstrates that Cournot model approximates the outcome and the conduct of this market well; the distribution of simulated Cournot prices (of the pre-retirement sample) closely resembles that of the actual prices observed in the data, giving validation to using the Cournot model to predict outcomes in this market. We also find that firm-level quantities computed with Cournot model fits the actual firm-level quantities observed in data very well, shown in Figure A.11 of the Appendix. However, also note that the Cournot prices, in prinicple, could

[38]We select only those with observed quantity smaller than the counterfactual competitive quantity. Quantity difference must be at least 5 to 10 percent of the competitive quantity.

[39]Our categorization of fringe supplier here departs from a conventional definition of fringe suppliers – a firm operating only a single, small-scale power plant – as the fringe supplier may operate more than one power plants and generators.



(a) Selected stategic firms

(b) Ad-hoc strategic firms

Notes: Distribution is generated from the total sample. Simulated Cournot prices are for "pre-retirement" case where the counterfactual adjustments are not yet made. Observed prices (from data) are the Supply Function Equilibrium prices.

Figure 6: Simulated cournot prices vs. actual prices

depart from the prices of the SFE equilibrium.

6.2.3 Strategic Cournot prices

Table 6 reports the simulated Cournot prices, before and after the retirement. As shown in first two rows of the table, strategic price increases more in low-demand hours (D1-D2) than in high-demand hours (D3-D4), regardless of the gas price level. When examining price changes by the gas prices, we find that the strategic price increases more, on average, as the gas price increases (going from G1 to G3, of the column "Total"). While we have shown in Panel (a) of Figure 6 that the Cournot outcome approximates the actual equilibrium outcome well at least in the pre-retirement sample, note again that the post-retirement strategic prices reported here is, in principle, the upper bound for the strategic prices that are likely in the counterfactual situation.

6.3 Measuring the unilateral market power

In order to assess the change in the unilateral market power, a better measure to compare is the extent to which the strategic price departs from the competitive price, as the presence of market power results in quantity and price distortions *relative* to the competitive level. Moreover, because the retirement of plants causes disruption in the marginal cost distribution, even competitive market price is expected change due to retirement, which must be controlled for when assessing the change in market power. Based on this idea, the measure of unilateral market power (or the market-level markup) is computed for each day and hour market, (t, h), as follows:

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

	Strategic Price				
		Low Demand		⇒ High Demand	
	Total	(D1)	(D2)	(D3)	(D4)
Before	90.4	76.8	87.2	88.3	112.8
After	99.1	91.0	98.5	95.5	113.1
Further Controlling for the Daily Gas Prices					
(G1) Low Gas Price					
Before	62.2	52.4	56.7	56.0	80.9
After	67.9	61.2	65.2	58.8	82.6
(G2) Med Gas Price					
Before	94.9	82.4	84.5	92.4	132.0
After	100.2	94.5	87.5	96.3	127.7
(G3) High Gas Price					
Before	145.4	117.8	145.3	156.3	173.4
After	165.0	146.7	167.3	181.6	174.8

Notes: *Before* and *After* refer to prices simulated before and after retirements are applied in the counterfactual situation. 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 \$10/MMBtu, and (G2) between \$10 and \$15/MMBtu and (G3) gas prices higher than \$15/MMBtu (up to \$27/MMBtu).

Table 6: Cournot Price Result

where, T denotes whether the sample is pre-retirement or post- retirement, $P_{\text{strategic}}$ is the Cournot price, and $P_{com,T,th}$ is the competitive price.[40] Because we are interested in measuring the *change* in unilateral market power caused by the retirement, we use $\Delta\Delta P_{th}$, which is a double difference of ΔP_{th}, as our primary measure of interest:

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

The variation in $\Delta\Delta P_{th}$ is driven mainly by the change in the competition between *strategic* firms, since the behavior of non-strategic (fringe) firms and the market variables not directly associated with the baseload plant retirement (e.g., the aggregate demand) do not change across pre- and post-retirement samples.

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 to G3) of the market. Note that a positive $\Delta\Delta P$ indicates an increase in the degree of overall market power, which raises the strategic price more by $\$\Delta\Delta P/\text{MWh}$ relative to the competitive price.

[40]A similar measure was used in Borenstein, Bushnell and Wolak (2002) and Reguant (2014) though they used a percentage measure. In contrast to their empirical setting, our sample involves significant changes in gas prices, making the average price of high-gas price days to be substantially higher than that in low-gas price days. Taking a percentage price change, therefore, will not provide a good comparison of price change across samples.

	$\Delta\Delta P = \Delta P_{\text{post}} - \Delta P_{\text{pre}}$				
		Low Demand	$\Rightarrow$	High Demand	
	Total	(D1)	(D2)	(D3)	(D4)
$\Delta\Delta P$	9.1	10.3	11.2	9.3	5.3
Further Controlling for the Daily Gas Prices					
(G1) Low Gas Price					
$\Delta\Delta P$	5.5	6.9	7.1	2.7	4.9
(G2) Med Gas Price					
$\Delta\Delta P$	9.6	9.5	6.8	14.4	5.8
(G3) High Gas Price					
$\Delta\Delta P$	16.4	18.1	18.9	25.7	5.7

Notes: Average of simulated $\Delta\Delta P$ 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 (with total N = 330). The cut off values for the gas price bins are: (G1) gas prices between \$4 to \$10/MMBtu, and (G2) between \$10 and \$15/MMBtu and (G3) gas prices higher than \$15/MMBtu (up to \$27/mmbtu).

Table 7: unilateral market power change, $\Delta\Delta P$

On average, the market power increases after the retirement, raising the price additionally by \$9.1/MWh relative to the increase in competitive prices (shown in the column named "Total"). However, the extent of market power increase varies considerably by demand and gas price levels. When examining the pattern across different demand levels, $\Delta\Delta P$ tends to be larger when the market demand lower, shown in columns (D1)- (D2), and relatively smaller in high-demand (peak) hours – shown in columns (D3)-(D4).

A more distinctive pattern can be found from the summary across the gas prices, shown in the additional rows from (G1) to (G3), where we find that $\Delta\Delta P$ increases, on average, as the gas price increases. Especially when the gas price exceeds \$15/MMBtu (G3 row), market power drives up the market price additionally by about \$16/MWh, on average, relative to the increase in competitive prices. This implies that if a similar degree of gas price shock again occurs in a transformed industry, the wholesale electricity market would experience a price surge that is higher than before, which mainly results from an increase in market power.

These patterns are also documented from a simple regression of $\Delta\Delta P_{th}$ on demand and gas price levels of the market (t, h). The coefficient estimate for the gas price variable is 0.88 and significant, capturing the positive correlation between the gas price and the $\Delta\Delta P$. The coefficient for the demand variable is negative at -0.174, which also corresponds to the pattern observed from Table 7. However, the estimate is not significant, implying that the relationship between $\Delta\Delta P$ and the demand is not as strong as that with the gas price.

Firm Type	No. of Firms	Total capacity (MW)	Firm capacity (MW)	
			mean	s.d.
Retired firm	4	6,245	1,561	665
Non-retired firm				
Gas-intensive	7	11,660	1,667	1,336
Balanced	7	12,024	1,718	1,033

Notes: Total capacity reports the sum of the capacity of all firms categorized into each firm group. Firm capacity columns report the mean and standard deviation of the firm-specific capacity of each firm group.

Table 8: Summary of strategic firms: by fuel technology composition

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

Overall, three patterns emerge from the baseline case results of $\Delta\Delta P$: first, market power increases more due to the retirement when gas prices are higher; second, low-demand hours suffer the most from the increased market power after the retirement; and third, market power does not increase much in the high-demand hours. To understand these patterns better, we explore how the relevant market variables and firms' strategic behavior are affected by the retirement, accounting for the heterogeneity among firms.

How does the retired firm's production change? We first examine how the production of *retired firms* (i.e., firms that used to operate the retired baseload power plant) changes as their retired plant is replaced with a gas power plant of the same capacity. Figure A.13 of the Appendix shows the average quantity produced by retired firms together, before and after the retirement, plotted separately by demand and gas price levels.

While each of the retired firm's total capacity remains unchanged, the retired firms produce less than before, especially more when the demand is lower (D1 and D2) and gas prices are higher (G1 $\rightarrow$ G3). The drop in the production in low-demand hours is not surprising as the baseload generators are marginal during these hours; the marginal cost of the baseload plant is the firm's marginal cost. Also, because the difference in the generation cost between the retired baseloads and the gas-fired plants is large when the gas price is high, increasingly more production will be shifted away from the retired firms to other firms as the gas price increases.[41]

Which types of firms are active in exercising market power? The strategic firms that appear in our analysis are mostly large-scaled firms that have considerable market share, but are heterogeneous in characteristics, such as the composition of fuel technologies.[42] Therefore, we examine

[41] The quantity reduction we document is not a result of the difference in the fixed costs of the baseload plant and the gas plant. While the production of the baseload plant in the actual observed equilibrium (pre-retirement) is a function of the fixed cost, the quantity comparison presented here is between the pre- and post-retirement quantities both generated under Cournot equilibrium. And we did not account for the fixed cost when computing the Cournot equilibrium. Thus, the quantity reduction we document here for the retired firms does not stem from the difference in fixed costs.

[42] Table 8 in the Appendix summarizes some basic heterogeneity among major firms.

which type of strategic firms more actively exercise market power than others in response to the retirement, and explore the market conditions that enable them to do so.

We exploit the fact that a strategic firm exercising market power would profitably withhold the quantity they produce, and would still be able to raise the market price. In general, strategic withholding is measured by how much the quantity produced by a strategic firm departs from the quantity produced if the firm instead behave as a price taker. Therefore, firm-level withholding – or the net strategic quantity – is measured as a difference between a firm's quantity produced under Cournot equilibrium, $q_{i,st}$, and that produced under competitive equilibrium, $q_{i,com}$. The negative net strategic quantity (i.e., $q^*_{i,st} = q_{i,st} - q_{i,com}$) indicates a withholding of production at the firm level.

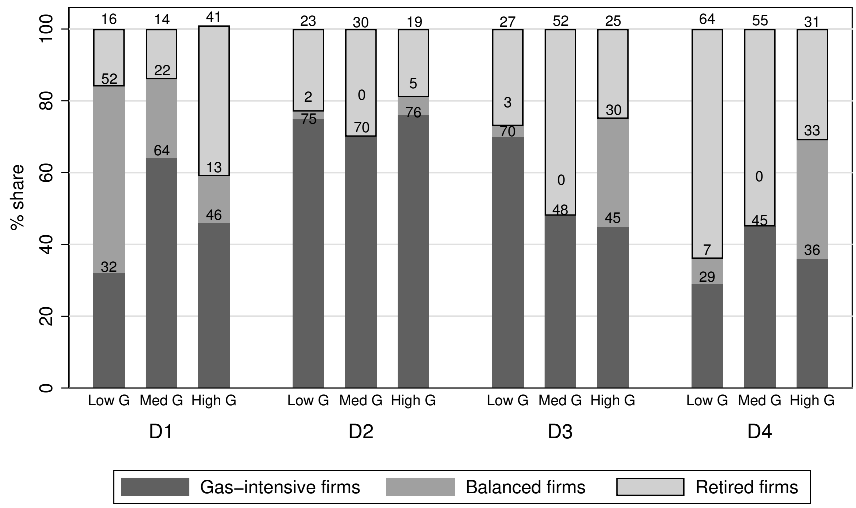
As we are interested in the *change* in the firm's strategic behavior due to retirement, we select firms that *additionally* withhold their net strategic quantity ($q^*_{i,st}$) after the retirement, but enjoy a higher markup by doing so. That is, for each (t,h) market, we find firms whose (i) net strategic 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 ($q^*_{i,st,post} < q^*_{i,st,pre}$) and (iii) markup increases further as a result of withholding ($\text{markup}_{i,post} > \text{markup}_{i,pre} > 0$).[43] Our method allows us to select firms that actively exploit the retirement event to exercise market power, from among those with a reasonably large market share (at least 10% share of total strategic supply).[44]

We categorized strategic firms into three groups that differ in their fuel technology composition. The "Retired" firm refers to firms that used to operate power plants that retired in our counterfactual simulation. Among those not part of the retired firms, if more than 90% of a firm's generation comes from gas power plants, the firm is categorized as a "Gas-intensive" firm. The rest of the "Balanced" firms, therefore, generate electricity using relatively diverse fuel technologies, including coal and nuclear power plants that have not announced plans to retire. Table 8 summarizes the total number of firms and the total capacities by each firm group.

Figure 8 reports the percentage of the *withholding firms* identified as actively exercising market power, by each firm group, summarized over different demand and gas price categories. While some variation exists across the categories, it turns out that, on average, the "Gas-intensive firms that are not directly affected by the retirement – as they do not operate any of the baseload generation – most actively engage in strategic withholding overall. This implies that the market condi-

[43] Condition (iii) is necessary to ensure that the profit loss from withholding quantity is offset by a profit gain 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 = $\Delta markup \times q_{af} + markup_{bf} \times \Delta q$. Note that this is the lower bound of the profit gain since we did not fully account for the piece-wise linear feature of the marginal cost curve, treating the marginal cost to be flat for all infra-marginal quantity. While the profit of all of the selected firms increases after withholding quantities, this is not always the case for other non-selected firms.

[44] The selection method based on quantity comparison is, in principle, similar to selecting high-market power firms based on their firm-specific Lerner index (i.e., firm-specific markup) or the market share. Among the firms selected based on their withholding pattern, about 50% of them have the highest market share and markups, and the rest of them were all included in the top three market share firms.



Notes: D1-D4 denote the demand bins and Low G, Med G and High G each refers to G1, G2, G3 – the gas price bins – that we used in summarizing the results. The percentage of each firm type out of total number of firms selected as exercising greater market power is reported in the graph. For example, 70 % for "Gas-intensive firms" in (D2, med G) indicates that among those firms selected as exercising market power in D2-G2 sample, 70 % of them were gas-intensive firms.

Figure 8: Percentage of selected strategic firm: by firm type

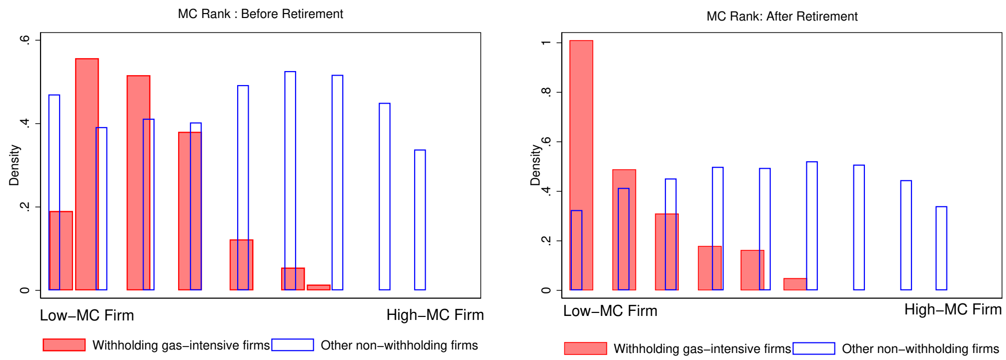
tions altered by the retirement provides increasingly more ability to the incumbent firms that are "gas-intensive" in their generation to exercise market power.

The change in the firm-level cost distribution Now we examine how the distribution of marginal cost among the strategic firms changes due to retirement. The overall shift and order change of the firm-specific marginal costs are related to the shift and rotation of residual demand of a firm, thereby affecting the competition between firms. We focus on the exogenous change to the distribution directly caused by the retirement, excluding the endogenous change resulting from the firm's quantity adjustments due to re-optimization following the retirement.[45] That is, we obtain marginal cost distributions, $C'(\mathbf{q}_{st}) = \{C'(q_1), \ldots, C'(q_{N_{st}})\}$, before ($bf$) and after ($af$) the transition, fixing each firm's quantity to its pre-retirement Cournot quantity, $\mathbf{q}_{st,bf} = \{q_1, \ldots, q_{N_{st}}\}$.[46] While the marginal cost of only the firms that operate retired plants would change, the entire distribution (ordering) of $C'(\mathbf{q}_{st})$ will be affected as a result, shown by the comparison of $C'(\mathbf{q}_{st,bf})_{\text{pre}}$ and $C'(\mathbf{q}_{st,bf})_{\text{post}}$.

We first show that the relative order of firm-specific marginal costs is affected by the retirement. Ranks are assigned to each firm in increasing order of the marginal costs, and are summarized by different firm groups: withholding firms, which are again grouped into firms that are gas-intensive and firms that are not, and the other strategic firms. Panel (a) of Figure 9 plots the ranks for the pre-retirement distribution $C'(\mathbf{q}_{st,bf})_{\text{pre}}$, and Panel (b) is for the post-retirement distribu-

[45]Since we adopt a piece-wise linear cost function, the change in strategic incentives and market power leads to firms re-optimizing quantity, and the marginal cost changes due to a movement along the cost curve.

[46]The cost distribution evaluated at the post-retirement strategic quantity ($\mathbf{q}_{st,af}$), which is the final change incorporating the endogenous quantity reoptimization, is different from this exogenous change.



(a) Full Sample: Before Retirement (b) Full Sample: After Retirement

Notes: Graphs show the distribution of relative rank of the marginal cost of a firm, before and after the industry transition. Relatively higher cost firms are assigned a low rank, thus located towards the left portion of the graph.*Withholding* firm refers to firms identified as exercising greater market power throughout the transition. Panels (a) and (b) shows the (relative) rank of marginal cost of (i) gas-intensive withholding firms, and (ii) other non-withholding firms that are not identifiied as exercising market power much after the retirement.

Figure 9: Marginal cost rank: withholding firms vs. others

tion $C'(\mathbf{q}_{st,bf})_{\text{post}}$. The comparison across panels shows that the withholding firms, especially the gas-intensive ones that are found to be most actively exercising the market power throughout the transition, become the relatively low-cost supplier after the retirements occur. And the extent of the drop in their cost relative to others is larger when demand is lower (D1) and when gas prices are higher (G3), as shown in Figure A.14 of the Appendix. This implies that these gas-intensive firms produce more after retirement as they become the low-cost supplier, but not as much as expected under a fairly competitive market.

The change in the relative order is accompanied by an overall increase in the marginal costs, shown by a comparison of the mean of the marginal cost distributions before and after the retirement. Figure A.5 of the Appendix shows that the mean of marginal cost increases, on average, due to retirement. Moreover, the mean increases especially more in low-demand hours (D1) when retired baseloads are marginal players, and when gas prices are high (G3), in which case the cost difference between the baseload and the gas generation replacing it is large.

The non-strategic (fringe) supply elasticity The supply coming from non-strategic (fringe) firms also influences the decision of strategic firms. While each of these non-strategic firms behaves as price takers, the total quantity supplied together ($Q_{ns,th}$) is responsive to the market price, the extent to which is represented by the slope of the residual demand curve, β_{th}. Note that residual demand curve slopes, β_{th}, were estimated separately for each market (t, h), as summarized in Table 4, to capture the rich pattern in which the shape of the non-strategic supply varies with the market conditions.

The more elastic the non-strategic supply is, the strategic firm's ability to profitably withhold its quantity is more constrained. We show this by examining the correlation between the estimates of β_{th} and the firm-level quantity further withheld after the retirement by those *withholding*

	(1) $\Delta q_{i,wh}$	(2) $\Delta\Delta P_{th}$	(3) $\Delta\Delta P_{th}$
Residual demand slope (β_{th})	-0.08	-1.31	-1.12
	(0.02)	(0.57)	(0.54)
Gas-intensive firm$_i$	0.18		
	(0.05)		
Δ MC mean$_{th}$			1.07
			(0.23)
ΔMC mean$_{th} \times \ \beta_{th}$			-0.20
			(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 (*unit*: GW)."Gas-intensive firm" is a dummy variable assigned to the withholding firms that are categorized into gas-intensive firm group. Columns (2), (3) regressions are at the market level. $\Delta\Delta P_{th}$ is the change in market power (*unit*: \$/MWh). $\Delta MCmean$ is the change in the mean of the distribution of marginal costs of strategic firms (*unit*: \$/MWh). Standard errors in parenthesis. N = 287.

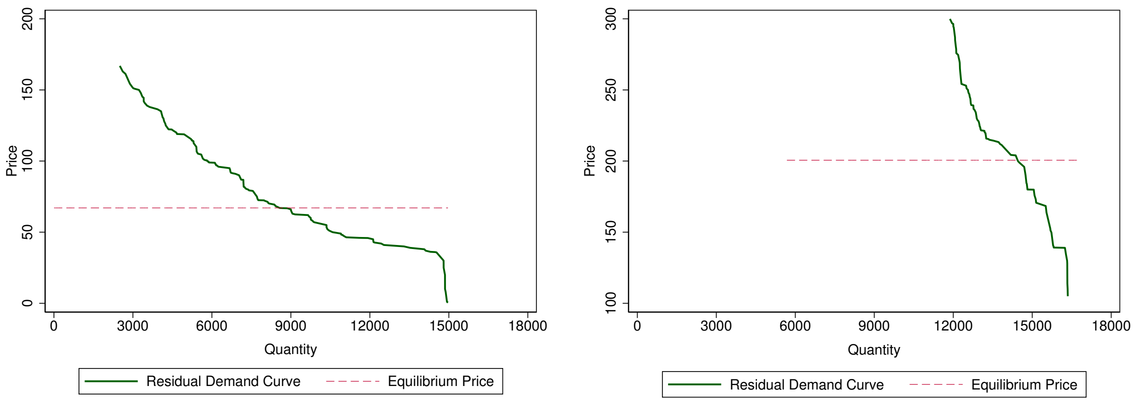
Table 9: Regression of stategic outcomes on firm- and market-level variables

firms (i.e., $\Delta q_{i,wh} = q^*_{i,st,pre} - q^*_{i,st,post}$). Column (1) of Table 9 reports a negative coefficient for β_{th}, indicating that the quantity additionally withheld after the retirement is smaller when the firm faces a more elastic non-strategic supply. This implies that an elastic non-strategic supply works as a competitive constraint to strategic firms. This relationship also holds at the market level, as we find a negative correlation between the change in unilateral market power $\Delta\Delta P_{th}$ and the β_{th}, shown in Column (2) of Table 9.

The link between the non-strategic supply elasticity and the firm's strategic ability can help explain patterns of $\Delta\Delta P_{th}$. That is, we have documented earlier with β_{th} estimates that the residual demand (non-strategic supply) becomes more inelastic especially when the daily gas prices are higher. Figure 10 plots the actual residual demand curves constructed based on bidding data, which shows that the residual demand for a high gas price day is relatively more inelastic than that of a low gas price day. This explains why we find market power to be increasing more due to retirement as the gas prices become higher; the competitive constraint imposed by the non-strategic (fringe) suppliers is reduced as the gas price increases.

Summary: understanding the baseline case result of $\Delta\Delta$ P The examinations of the market- and firm-level variables provide several explanations for our findings from the baseline case analysis.

First, our analysis shows that the retirement and the replacement process causes greater disturbance to the market environment when the aggregate demand is lower and the gas price is higher. For instance, we find that retirement leads to a larger reduction in retired firms' quantity and a greater disturbance and location shift of marginal cost distributions in these situations. The baseload power plants are usually at the margin when the market demand is low, and are far from being marginal when the demand is high. Removing baseload plants will have a greater impact if



(a) Low NG price day ($9/MMBtu)

(b) High NG price day ($22/MMBtu)

Figure 10: Residual Demand Curve: Low vs. High Gas Price Days

they are at the margin, and especially more when gas prices are high, which makes the marginal cost difference between the retiring and the replacing power plants large.

Then why does unilateral market power increase? We can understand this in two steps, first by considering the strategic interaction between the group of strategic firms (treating them as if they are a monopolist) and the non-strategic (fringe) firms. From the analysis of marginal cost distribution, we have shown that the mean of marginal costs of strategic firms increases due to retirement, which would result in a decrease in the quantity produced by these strategic firms together.[47] If such a reduction in strategic quantity is met by an elastic supply coming from the non-strategic firms, strategic firms' ability to exercise market power is restrained. This relationship is documented in Column (3) regression of Table 9. While a positive coefficient for ΔMC mean indicates that an increase in the average of marginal costs is associated with an increase in the extent of market power increase, $\Delta\Delta P$, such an effect is lessened if facing more elastic residual demand, shown by a negative coefficient for the interaction term for ΔMC mean$_{th}$ with the residual demand slope β. However, it turns out that non-strategic supply is more *inelastic* on days with higher gas prices, giving strategic firms increased ability to further withhold the quantity more than what is implied by the marginal cost increase.

At the same time, there are strategic interactions between the strategic firms in this oligopolistic setting. The firm-level analysis shows that the type of firm that exploits the retirement situation the most and behaves more strategically than others is the large gas-intensive firm that did not operate any of the retired power plants. For instance, these type of firms further withholds the quantity more than any other type of firms, as indicated by a positive coefficient for the firm type indicator in Column (1) regression of Table 9. We have shown that gas-intensive firms become the relatively low-cost suppliers after the retirement, which makes their own residual demand to become more inelastic than before. Their strategic ability is increased particularly in low-demand

[47]This was driven mainly by the marginal cost increase of the retired firms, followed by a drop in the quantity they produce.

hours and under higher gas prices, where the large reduction in the retired firms' quantity is expected to increase their own residual demand. Additionally, these large gas-intensive firms face lesser competitive pressure from the non-strategic supply which becomes increasingly more inelastic under higher gas prices.

7 Industry Structure and the Capacity Installation

The assumption imposed on capacity installation until now is that firms that used to operate the retired baseload plant would install the new (hypothetical) gas generation, with the same capacity as the retired one, which would make the industry structure the same as before the retirement. In this section, I show that the effect of retirement on the degree of competition critically depends on the post-retirement industry structure. To show this, we do equilibrium analysis under different counterfactual scenarios regarding the installation of new gas-fired power plants, incorporating some realistic features of the installation pattern observed from the data. 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 industry had conducted transition as planned. The results from the analysis could be useful for market regulators in deciding the most pro-competitive way in which to install cleaner generation capacity.

7.1 Actual installation pattern observed from the data

We first examine the actual capacity installations observed from the EIA-860 data.[48] Table A.4 in the Appendix reports the *proposed* gas power plants in the New England electricity market (ISO-NE), from year 2013 to 2019.

Several patterns emerge from the data. First, the installation of gas-fired generation capacity is proposed mostly by the large-scale firms, and not many firms enter the industry, with almost no entry by the small fringe suppliers.[49]Therefore, most of the capacity addition is completed by large-scale incumbent firms that expand their existing generation facility by adding more gas power plants on their sites. Second, some firms convert the site of the retired coal power plant into a new gas generation facility, implying that re-using the infrastructure (e.g., transmission lines) and the facility of the retired power plant may be economical for firms, and also for the grid. This suggests that our baseline assumption regarding the capacity installation – where the same firm that operated the retired plant replaces it with a new gas power plant – is quite realistic.[50] Third, the capacity of the new gas generation that replaces the retired coal plant is likely to be

[48]EIA-860 form's section 3: Generator, "*proposed*" capacity data is used.

[49]While the small-scale gas plants (with capacity below 50 MW) are proposed as well – though not shown in Table A.4 as very few of them exist, they are planned for commercial use (hospitals, universities, military camps, etc.). Among the large-scale firms that have proposed capacity, three firms are new entrants but only one of them is considered an entirely new entrant (which enters with the smallest capacity). The other two firms are large-scale operators in other markets (e.g., NYISO).

[50]See *PSEG* and *Salem Habor* in Table A.4 in the Appendix, for example.

CF	Which firm installs new gas generation capacity?	Size of the new capacity installed (industry level)	Firm scale
(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, ↓), retired firm (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

larger than that of the retired plant.[51] This can be explained by a substantial difference in the fixed cost and the capital cost between coal and gas power plants.[52]

7.2 Additional Industry Structures to Simulate

We consider three additional counterfactual scenarios that differ in post-retirement capacity installation, and examine how the market impact of the retirement varies across these scenarios. Each case is designed to incorporate important features of the actual capacity installations within the New England market. Since the firm scale, capacity and the number of firms change as we allow for different ways of installing new capacity, the industry structure would also significantly vary across the cases considered here.

Table 10 describes the three additional counterfactual cases. In the first case, CF (1), hypothetical fringe suppliers enter the industry with new gas power plants, the capacity of which is one of the following, $q_{i,\text{fringe}} = \{50, 80, 100\}$ MW.[53] We let the gas generation added by these fringe firms together replace the total capacity of the retired baseload generation, thereby introducing 50 new fringe suppliers to the industry. The marginal cost of these hypothetical 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 we constructed the marginal cost of a hypothetical gas power plant earlier in the baseline case.[54] Note that the scale of firms that used to operate the retired

[51]This is shown by the comparison of the planned capacity and the capacity of the retired plants of *PSEG* and *Salem Habor*, in Table A.4 in the Appendix.

[52]For instance, according to the EIA report, the capital cost spend on kW capacity of the new coal power plant is almost fives times larger than that of a standard combined cycle gas power plant ($5,212/ kW for coal plant and $650/kW for gas plant, *Annual Energy Outlook 2019 (EIA)*). See Table A.3 which reports the Base overnight cost of new central station electricity generating technologies in the Appendix for more detail.

[53]The selection of capacity size is based on the observation of actual capacities of new fringe suppliers that enter.

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

baseload plants would decrease in this case because they do not replace the lost capacity themselves.

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}) and the intercept (α_{th}) of the new residual demand curve, after adding the hypothetical fringe firms to the market, must be re-estimated. As our estimation of residual demand parameters relies on constructing the residual demand curve out of the actual bids submitted in the auction, we first need to create the bids that would have been submitted by hypothetical fringe firms – which do not exist in data – and incorporate these into our new residual demand curve. We construct the hypothetical bids using fringe supplier capacity ($q_{i,fringe}$) and its marginal cost ($mc_{i,fringe}$), exploiting the fact that fringe firms – that are non-strategic price takers – would bid their marginal cost in the auction.[55] Due to the entry of many fringe suppliers, the slope estimate (β_{th}) of a new residual demand curve becomes significantly more price responsive, increasing by \$2.64/GWh, on average.

The second case, CF (2), is similar to the baseline case, as we allow the retired baseload generation to be replaced by the same operating firm. However, it differs in that the capacity of the new gas generation being installed is 50 % larger than that of the retired plant.[56] Therefore, the capacity of firms that used to operate the retired baseloads and of the entire industry increases as a result.

In the last case, CF (3), we let the large-scaled incumbent firms that *do not* operate any of the baseload generation (i.e., not one of the *retired* firms) to expand the capacity of their existing gas generation. That is, approximately 300 MW of additional gas generation is allocated to each of the incumbent strategic firms, starting with the largest firm.[57] The capacity added by these incumbent firms together replaces the capacity of all the retired "nuclear" power plants, but not that of the retired coal plants. Specifically, the retired coal plants are replaced by the same firm operating them, by installing new gas power plant with the same capacity as that of the retired coal plant. As a result, the scale of firms that used to operate the retired nuclear power plant decreases, but the scale of firms that used to operate retired coal plants stays the same. In addition, the scale of incumbent firms that expand capacity will increase.

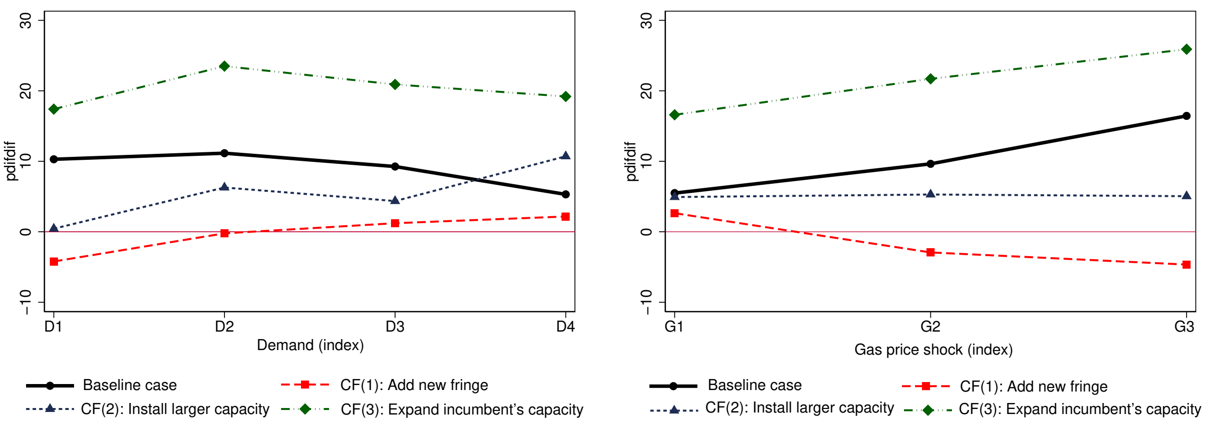
Note that allowing only the coal plants to be replaced by the same firm operating them corresponds to the actual installation pattern observed in the data. While nuclear plant sites are, in general, difficult to reuse for other generation technology due to a significant difference in technical requirements, most of the coal plant sites can be converted to a new gas generation site, supported by the actual installation pattern observed (see Table A.4).[58]

[55]Hypothetical fringe supplier's bid is constructed as $p_{ij} = \rho\ mc_{ij}$ where $\rho \in [0.8, 1.2]$ and $q_{ij} = \{50, 80, 100\}$.

[56]The capacity expansion of 50 % is consistent with the actual rate of expansion observed in the data (EIA-860).

[57]The selection of 300 MW is based on the actual installation size observed in EIA-860 data. The marginal cost was measured similarly as before; using the heat rate of the most advanced CC technology and using the gas price index value.

[58]Moreover, there is a practical reason behind this construction. The number of strategic incumbent firms that we can allocate additional gas generation to is small, compared to the total capacity of the retired plants if both coal and



(a) Average Over Demand (b) Average Over Gas Price Shock

Notes: Original setting (bold line, circle marker) is the result of the baseline case. Add new fringe (square marker) is CF (1), Install larger capacity (triangle marker) is CF(2), and Add capacity to non-retired firms (diamond marker) is CF (3). 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 11: Summary of $\Delta\Delta P$ of capacity counterfactuals

Results Figure 11 summarizes the average values of the change in market power ($\Delta\Delta P$) under each of the counterfactual scenarios. A more detailed summary of the values is presented in Table A.6 in the Appendix. Panel (a) of Figure 11 shows the average value plotted across different demand levels and Panel (b) shows the average plotted across different gas price levels.[59] The results of each counterfactual scenario, along with the baseline results, are overlaid in the graph to see a clearer picture of the change across different cases.

The most pro-competitive scenario is, not surprisingly, the CF (1), where many small-scale fringe suppliers enter the industry to replace the lost generation from the retired baseloads. An overall increase in market power is the least in this case, but also the pattern of market power change differs from that in the baseline case. That is, the market power increases by the least — and even decreases as shown by a negative value of $\Delta\Delta P$ in Panel (a) — in low-demand hours (D1). Most importantly, the market power decreases further as gas prices become higher, as shown by a decreasing path of the CF (1) plot shown in Panel (b).[60]

The result of the CF (1) indicates that having a more fragmented industry after the retirement could lessen the impact of the retirement on market power, even on days when a large gas price shock hits the market. How can we rationalize our findings? From the analysis of the baseline case, we find that the residual demand (or the supply from non-strategic firms) tends to be more

nuclear plant retirements are included. In this case, the capacity added to each of these incumbent firms becomes too large.

[59] Note that in Panel (a), the differences in gas prices are not controlled for within each demand bin, and in Panel (b), the differences in demand are not controlled for within each gas price bin. The plot of the average of $\Delta\Delta P$ controlling for both demand and gas price levels is provided in Table A.4 of the Appendix.

[60] When examining by further controlling for the demand variation within in gas price bin, it turns out that the decrease in $\Delta\Delta P$ in high gas price sample is driven mostly by the significant decrease in value during low-demand hours (D1 and D2), which reaches below $\Delta\Delta P$ = -10, on average.

price inelastic (i.e., β_{th} is larger) when gas prices are higher.[61] The limited response of the residual demand to the price increase was providing the large strategic firms – especially those not operating any retired baseloads – an increased ability to withhold quantity in order to raise the market price further. Indeed, adding small fringe suppliers to the industry as in CF (1) makes the residual demand significantly more elastic (on average) – almost twice as responsive around the equilibrium price – than before, which restricts the strategic firm's ability to increase market power. A decrease in the scale of retired firms (as we do not let these firms replace their own retired baseloads) also contributes to lowering the extent of the market power increase.

In CF (2), where the retired firms add greater gas generation capacity, the overall increase in market power due to retirement is greater than in CF (1), but less than in the baseline case. When examining the pattern across different demands, the market power does not increase much in the lowest-demand hours (D1), but increases more than in the baseline case when the demand is high (D4). Regarding the gas price level, the market power tends to decrease as the gas price increases, a pattern similar to that in CF (1) but not so distinctive as in that case.

Why does market power increase less when we allow retired firms to install larger gas generation capacity than in the baseline case? Expanding the capacity of the gas generation that replaces the retired ones makes the retired firm's supply more price responsive (price elastic) at the given demand range. This makes the "firm-specific" residual demand of firms competing with the retired firms – mostly the large gas-intensive firms who are the large withholders in this market – to be more price elastic, thereby lowering these withholding firms' ability to further exercise market power. [62]

Finally, in CF (3) where the incumbent firms expand their gas generation, the extent of the overall market power increase is higher than in any counterfactual cases, even higher than in the baseline case, consistent across all demand and gas price levels. Moreover, market power increases further as the gas price increases, shown by the increasing path of the CF(3) result in Panel (b). In this case, we let the incumbent firms, particularly the large-scaled gas-intensive firms, to add capacity. As these firms are those that exercise the market power relatively more *after* the retirement than before in the baseline case, allowing these firms to add gas generation capacity is equivalent to expanding the scale of firms that are already dominant, thereby further increasing the market power. At the same time, the scale of retired firms – the competitors of the other incumbent firms – has decreased after the retirement, which further strengthens the large gas-intensive firms' dominant position.

Summary To summarize, the post-retirement industry structures depicted in CF (1) and CF (2) yield outcomes that are better in terms of mitigating the market power increase than our baseline

[61] This can also be inferred from the fact that the industry marginal cost curve becomes steeper and more dispersed as the gas price becomes higher. A steeper curve implies a less price-responsive supply from the non-strategic firms.

[62] Because proportionally more of *retired* firms are large withholding firms in the highest demand hours (D4), the CF (2) scenario that increases the scale of the retired firms yields even larger increase in market power at this demand range, as shown in Panel (a) of Figure 11.

case; market power increases by less (and even decreases in some cases), especially under higher gas prices and during low-demand hours when the increase in market power was most significant in the baseline case. The worst case is CF (3) when we allow for those incumbent firms not directly affected by the retirement to expand their gas generation capacity.

Our results have important policy implications given that the ongoing capacity installations in the New England grid is far from the ideal situation (CF (1)), closer, instead, to increasing the capacity of large-scale firms that could potentially exercise market power (CF (3)). While some of the retired firms seem to replace the retired coal plant with a gas power plant of a larger capacity (CF (2)), a more common form of installation is that other incumbent firms already gas-intensive in their generation to expand the existing gas generation facility. Therefore, our results also highlight the importance of properly designing and incentivizing the replacements of capacity that will follow the retirement. Despite this, surprisingly little attention has been given to this important aspect of the retirement-induced transition; that it reshapes the industry by changing the scale and characteristics of electricity generating firms. How the market authorities could incentivize additional small firms to enter and profit in this market remains an agenda item for future research.

8 Conclusion

An increasing number of baseload coal and nuclear power plants are retiring from the national 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 important feature of cleaner energy; that is, the volatile nature of its input cost. This feature differentiates the clean energy from the traditional baseloads characterized by having low and stable input costs. In other words, the costs associated with generating with gas or renewables are low, but could substantially increase depending on fuel market conditions or the weather. 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. This is especially so, given that the structure of the industry could change depending on how, and by which firms, the clean generation replacing the retired ones is installed. When this occurs, the implications of the retirement on competition becomes more relevant.

We 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, we show that market power increases after the retirement, especially during low demand hours when baseload generation is most pivotal, but increases relatively less during high-demand hours when the exercise of market power is usually most concerned. Moreover, we find that market power tends to increase more due to retirement 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 in their generation.

While our findings have strong policy implications, the results presented here is the upper bound of the likely outcome, and we do not aim to predict the exact price and market power anticipated after the retirement. Also, our equilibrium simulation cannot mimic the complicated clearing process of the market organizers (ISO) that fully accounts for the transmission congestion, thus the actual market outcomes and capacity installations could be different from ours. Nevertheless, 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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A Appendix

A.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:

$$\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it} \leq 0, \quad q_{it} \geq 0, \quad \Big(\frac{\partial \pi_{it}}{\partial q_{it}} - \lambda_{it}\Big) q_{it} = 0 \tag{A.1}$$

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

First, if $q_{it} \in (0, q_{it,max})$, then because q_{it} is positive $\left(\frac{\partial \pi_i}{\partial q_{it}} - \lambda_{it}\right) = 0$ is implied by the third condition of equation (A.1). Also, because $q_{it,max} - q_{it} > 0$, $\lambda_{it} = 0$ is implied by the third condition of equation (A.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 $\lambda_{it} \geq 0$ from the third expression of equation (A.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 (A.1). Therefore, $\frac{\partial \pi_{it}}{\partial q_{it}} = \lambda_{it} \geq 0$ 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 (A.2). And since $\frac{\partial \pi_{it}}{\partial q_{it}} \leq \lambda_{it}$ holds as implied by the first condition of equation (A.1), $\frac{\partial \pi_{it}}{\partial q_{it}} \leq \lambda_{it} = 0$ holds.

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

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

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:[1]

(MCP) Given lower bounds l, upper bounds u and a function $F : R^n \rightarrow R^n$, find $z \in R^n$ such

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

that precisely one of the following holds for each $i \in \{1, \ldots, n\}$:

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

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

A.2 Estimating the Parameters

We estimate the slope of the market-specific residual demand curve, generator-specific marginal cost and the firm-specific forward contract parameters from the high-frequency bidding data which exists for every hourly market auctions. This section explains the specific features of the electricity market and the gas price shock event which make the estimation necessary, along with the empirical methodology that enables estimation.

A.2.1 Residual demand curve

Figure A.1 shows an example of an actual residual demand curve which is nonparametrically constructed out of bids, overlaid with the estimated curve fitted with a log-linear specification. Due to the kinked shape of the original curve, a spline regression with two knots as a default setting is used to estimate the slope of the curve within each bin created. Also, we have adjusted the number of knots to one in some cases where the shape of the curve did not match the two-knot specification. Our codes were designed to read the corresponding slope at the given quantity.

We have omitted the import and export bids when nonparametrically constructing the residual

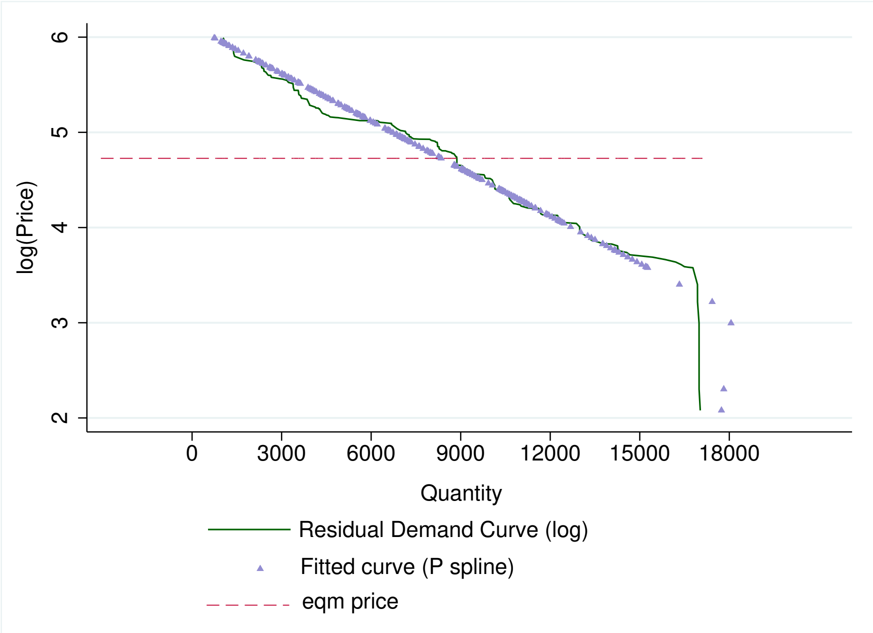
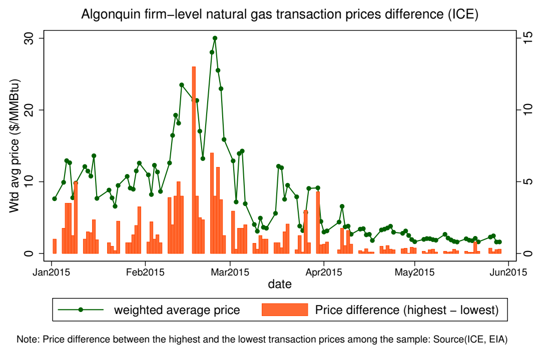
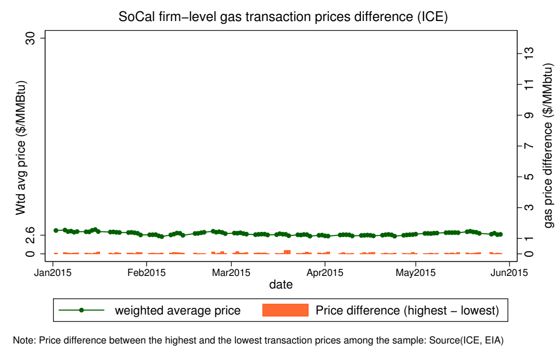


Figure A.1: Actual Residual Demand Curve and the Estimated Curve



(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 A.2: Over-the-Counter Gas Spot Prices: Year 2015

demand curve. Omitting these bids will not critically affect our slope estimates to a great extent, first, because the size of the import quantity is not sensitive to the price in the New England market. That is, very little variation exists within a day for the imported quantity, while the prices vary considerably across hours. Also, a daily variation in import size is very small, almost always importing a fixed amount of electricity, which may be the point where the transmission constraint is binding. All of these indicate that the import size is more bound by the daily transmission condition and capacity, rather than the price. Imports from Canada, which constitute a majority of the imported electricity, flow in irrespective of price, limited by the capacity of transmission lines from Canada to New England. Secondly, omitting export quantity will not affect our estimates to a great extent because the exported amount of electricity is very small compared to the imports.

A.2.2 Marginal Cost Estimation

In studies of the electricity market, the cost of generating electricity using gas is measured with the gas price *index* data, which is a weighted-average value of firm-level spot gas prices. The marginal cost constructed with the index gas price data may not represent the true marginal cost of electricity generators especially when the gas market experiences shock and becomes illiquid.

We first briefly discuss several sources of the measurement error associated with the gas price shock. 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.[2] 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

[2]More than 28 percent of gas generators in New England were dual units (as of 2014).

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 A.2 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.

To overcome this empirical challenge, we utilize the high-frequency data of bids which is available in this electricity market, and estimate the marginal cost that rationalizes the firms' bids, which is the real opportunity cost that is internalized by the firms in their bids.

A.2.3 Model used for estimation

The following model describes the bidding decisions of the firm in a multi-unit uniform auction (Kim, 2019; 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:

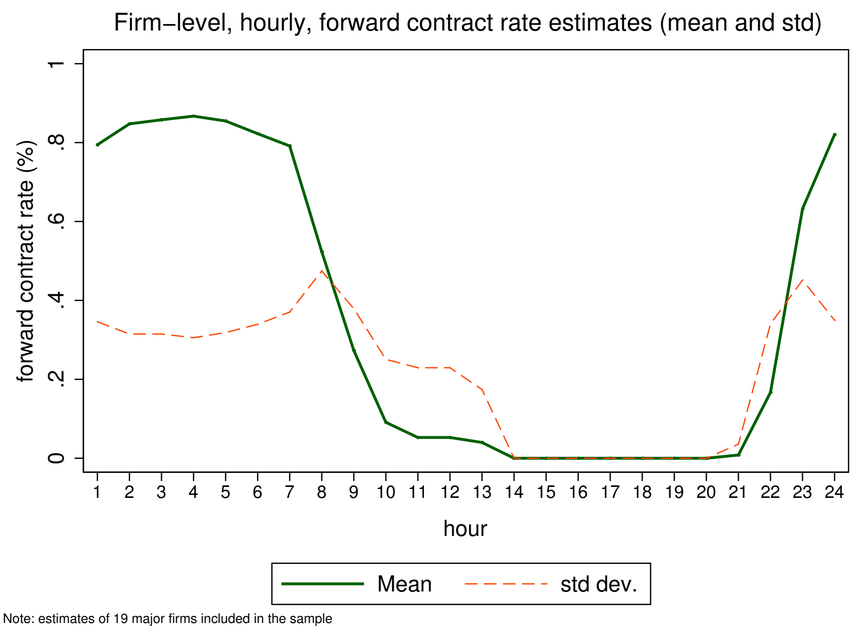
$$\pi_{iht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht}) = P_{ht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht}) \left(Q_{iht}(P_{ht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht})) - \nu_{iht} \right) - \sum_{j=1}^{J_i} C_{ijt}(q_{ijht}(P_{ht}(\mathrm{b}_{iht}, \mathbf{b}_{-iht}))) \tag{A.5}$$

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 (A.7), from which the parameters are estimated.

$$\mathbb{E}_{-it} \left[\frac{\partial P_{ht}}{\partial b_{ijkht}} \left[\left(Q_{iht}(P_{ht}) - \nu_{iht} \right) + \left(b_{ijkht} - C^{'}_{ijt} \right) \frac{\partial RD_{iht}}{\partial P_{ht}} \right] \right] = 0 \tag{A.6}$$

Note that two key parameters we need to estimate from this model is the marginal cost ($C^{'}_{ijt}$) and the forward contracted quantity (ν_{iht}). We assume that the marginal cost of unit j of firm i is constant over quantity, i.e., $C^{'}_{ijt}(q_{ijt}) = mc_{ijt} + \epsilon_{ijkht}$. Assumptions imposed on the forward contracted quantity will be explained in the next subsection. For a more detailed description of other variables in equation (A.5), see Kim (2019).

The empirical analogue of the first-order condition is shown in equation (A.6), which includes an expectation over the bids of other firms ($\mathbf{b}_{-it}$) that are uncertain to firm i. How we deal with



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 A.3: Forward Contract Rates: Summarized Across Firms

the expectation term is explained in Kim (2019).

$$m_{ijkht}(\theta\,;S) = \frac{1}{S}\sum_{s=1}^{S} \frac{\partial \widehat{P^s_{ht}}}{\partial b_{ijkht}} \Big(\,(Q^s_{iht} - \nu_{iht}(\gamma_{ih})\,) \,+\, (b_{ijkht} - mc_{ijt}\,)\, \frac{\partial \widehat{RD^s_{iht}}}{\partial P_{ht}} \Big) \tag{A.7}$$

A.2.4 Forward Contract Parameter

It is common for electricity generating firms to engage in a forward contract where they sell a certain amount of electricity to the demand side at a committed 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}.

We estimate ν_{iht} within the model similar to Reguant (2014), due to the difficulty in obtaining data on the forward contracts.[3] We 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.[4] The

[3]Bushnell, Mansur, and Saravia (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.

[4]The constant forward contract rate assumption is common in the wholesale electricity market studies, as seen in Bushnell, Mansur and Saravia (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. Note that a

specification for the forward contracted quantity of firm i for the hour h of the day t is, therefore, $\nu_{iht} = \gamma_{ih} Q^*_{iht} + \varepsilon_{iht}$, where Q^*_{iht} is the actual quantity of electricity generated by firm i in auction ht, which is observed in the data. Within the model, Q^*_{ht} is treated as exogenous, where the value is fixed for the given hour.[5]

Figure A.3 summarizes the average of firm-specific forward contract rates across hours. Once we have the forward contract rate estimates, we can calculate the forward contracted amount of electricity of firm i in (t, h) market as a fraction of firm's quantity observed in data, $q^f_{it,h} = \nu_{iht} = \gamma_{ih}\ q_{it,h}$, and use in our simulation.

A.3 Plant retirement and the industry-level cost distribution

Different types of retirement and its impact on the marginal cost distribution Retirement of coal plants and nuclear plants have different types of impacts on the marginal cost distribution. A replacement of zero-cost nuclear plants with the gas-fired plant having positive marginal costs would lead to an inward shift of the industry marginal cost curve, with the basic shape of the curve not affected much. Also, such shift is observed regardless of the shock: with and without the cost shock. On the other hand, the effect of coal plant's retirement on marginal cost curve depends on whether or not the gas prices are at the normal level of \$ 4/mmbtu, which is similar to the coal price. That is, when prices of both fuels are similar to each other, replacement of coal plants with gas plants have minimal effect on the distribution of the cost curve. However, retirement significantly disrupts the shape of the curve as well as the ordering of the units when the levels of gas prices increase above the normal level due to the shock.

Figure A.6 illustrates this. As shown in Panel (A.6c), nuclear retirement simply shifts in the distribution, and most significant changes occur at the low-demand region (left portion of the curve) whereas the distribution around the equilibrium (where demand intersects with the marginal cost curve) does not change much after the retirement. On the other hand, as shown in Panel (A.6b), coal plant retirement leads to a significant disruption of the marginal cost distribution; the slope of the distribution curve changes uniformly over all quantity levels. When both types of retirements are combined, which is presented in Panel (A.6a), disruption in the marginal cost distribution (curve) becomes most salient.

Where the market clearing prices will be set, which is determined by the aggregate level of electricity demand, is an important factor since the slope change does not occur uniformly across demand levels. This implies that the retirement's effect on market outcomes and competition would be more salient if the cost distribution is disrupted closer around the market clearing point. Figure A.7 demonstrates this point by presenting cost distributions of two different days. In the first case shown in Panel (A.8a), competitive price is likely to increase because the marginal cost curve around the initial equilibrium – where demand intersects with the marginal cost curve – shifts up. Moreover, we observe in this case that the distribution of costs changes around the equilibrium. On the other hand, in the second case shown in panel (A.8b), the cost curve does not

bias in the forward contract rate estimate will not critically affect our main results because the rate is estimated to be the highest (and positive) during off-peak hours when baseload generation are mostly marginals. The marginal cost of gas-fired units, which is the primary focus of our analysis, is estimated mostly from the peak-hour sample when forward contract is small and close to zero. Therefore, the maginal cost estimates used in the main analysis of this paper are not be sensitive to the bias in forward contract rate estimates.

[5]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.

shift much around the initial equilibrium and the disruption of the marginal cost distribution is also not significant. Consequently, we can expect the changes in both competitive price and the degree of strategic competition due to retirement to be minimal in this case.

A.4 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: Sample day in the winter period of 2012 is used.

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

Retirement Set	Total accumulated capacity of retired plants (MW)	Type of plant retirements applied in the counterfactual simulation
(RT 1: main)	3,708	All of the planned retirements (announced as of 2013, listed in Table 1)◊
(RT 2: extra)	7,132	All coal-fired plants in the market: coal plants used in (1) + remaining coal plants (3,460 MW)
(RT 3: extra)	8,076	All baseload plants (coal + nuclear) in the market

Notes: ◊ includes Salem Harbor, Mt.Tom Station, Vermont Yankee, Brayton Point Station, Pilgrim Nuclear Station. Among retirements included in (RT 1) which sums up to 3,708 MW in total, the coal generation capacity is 2,380 MW, and the nuclear generation is 1,294 MW. *Remaining* coal plants refers to the coal power plants in this industry that have not announced plans to retire as of 2013. All baseload plants categorized into (RT 3) includes both coal and nuclear plants that have not announced plans to retire as of 2013.

Table A.2: Description of counterfactual plant retirements applied in the simulation

Fuel type	Coal	Nuclear	Gas (CC)	adv gas (CC)
Capital cost ($/kW)	5,212	5,224	952	1,963
Average size of a plant (MW)	650	2,234	702	340

Table A.3: Capital cost of power plants by fuel type (2018 EIA)

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	Walligford 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 A.4: Proposed natural gas fired capacity

	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: 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.

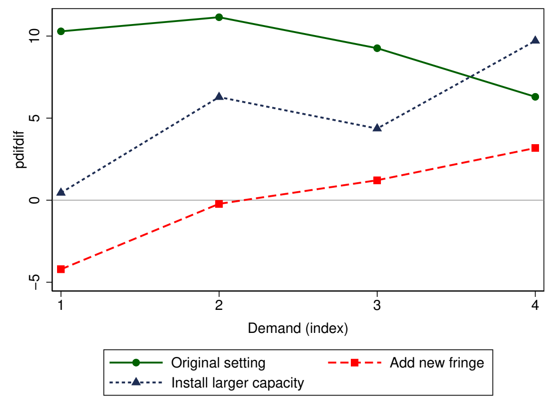
Table A.5: Proposed generation capacity: by fuel type

		$\Delta\Delta P = \Delta P_{af} - \Delta P_{bf}$				
			Low Demand		$\Rightarrow$	High Demand
	CF	Total	(D1)	(D2)	(D3)	(D4)
$\Delta\Delta P$	(*)	9.1	10.3	11.2	9.3	5.3
	(1)	−0.5	−4.2	−0.2	1.2	2.2
	(2)	5.0	0.4	6.3	4.4	10.7
	(3)	19.9	17.4	23.5	20.9	19.2
Further Controlling for the Daily Gas Prices						
(G1) Low Gas Price						
$\Delta\Delta P$	(*)	5.5	6.9	7.1	2.7	4.9
	(1)	2.6	−0.04	2.5	1.3	7.6
	(2)	4.9	3.9	2.7	2.6	10.7
	(3)	16.6	15.3	20.5	16.0	14.2
(G2) Med Gas Price						
$\Delta\Delta P$	(*)	9.6	9.5	6.8	14.4	5.8
	(1)	−2.9	−4.6	1.9	1.5	−6.1
	(2)	5.3	−1.4	8.1	9.6	18.1
	(3)	21.7	17.3	41.6	32.2	11.9
(G3) High Gas Price						
$\Delta\Delta P$	(*)	16.4	18.1	18.9	25.7	5.7
	(1)	−4.7	−12.4	−5.2	0.8	−1.6
	(2)	5.1	−4.8	11.9	5.3	8.1
	(3)	25.9	21.8	26.1	26.4	30.6

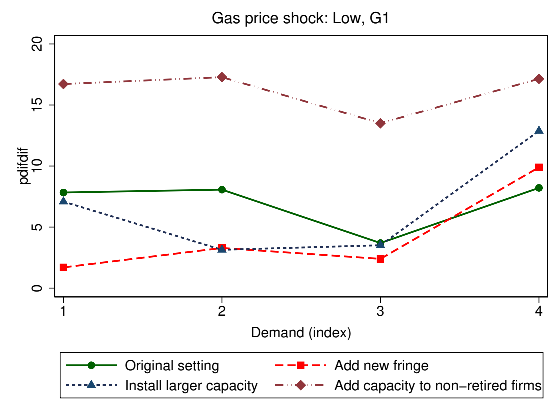
Notes: This is the result based on November 2018 simulation (file 5 mat. retired). Each row presents the results from different capacity installation scenarios: baseline case (*), CF (1): add new fringe, CF(2): larger capacity installed, and CF(3): expand incumbent's capacity. D1 is demand below 14 GW, (D2) is between 14 and 15.5 GW, (D3) is between 15.5 and 17 GW and (D4) is above 17 GW. The frequency of observation of each demand bins are roughly the same. The cut off values for the gas price are: (A) low gas price is gas prices between 4 to 10, and (B) medium is between 10 and 15 and (C) is above 15 up to 27. Cut off values for each gas price bins are determined after examining the pattern of price changes of competitive prices. Average values of simulated Cournot prices are reported in the Table.

Table A.6: Price difference, $\Delta\Delta P$: capacity installation counterfactuals

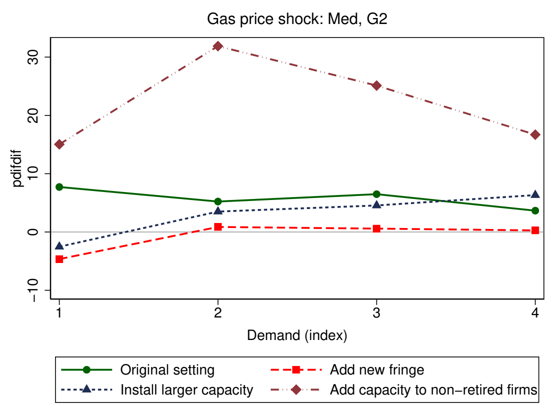
A.5 Additional Graphs



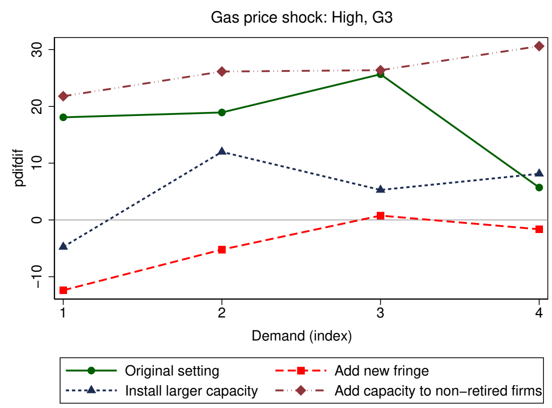
(a) Averaged across D, dropped CF (3)



(b) Averaged across D, G1

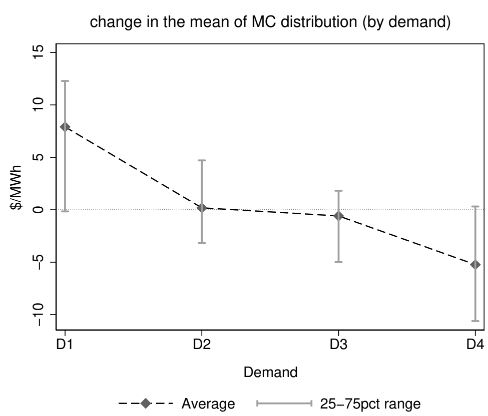


(c) Averaged across D, G2

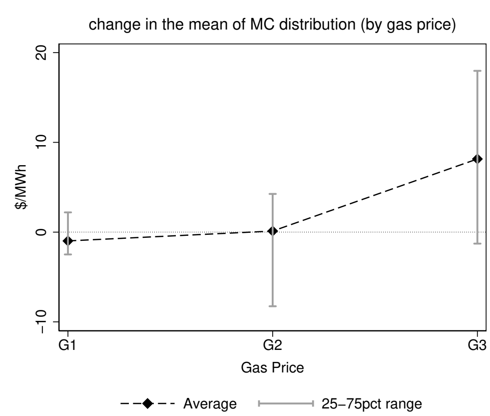


(d) Averaged across D, G3

Figure A.4: Summary of $\Delta\Delta P$ of capacity counterfactuals: controlling for both D and G

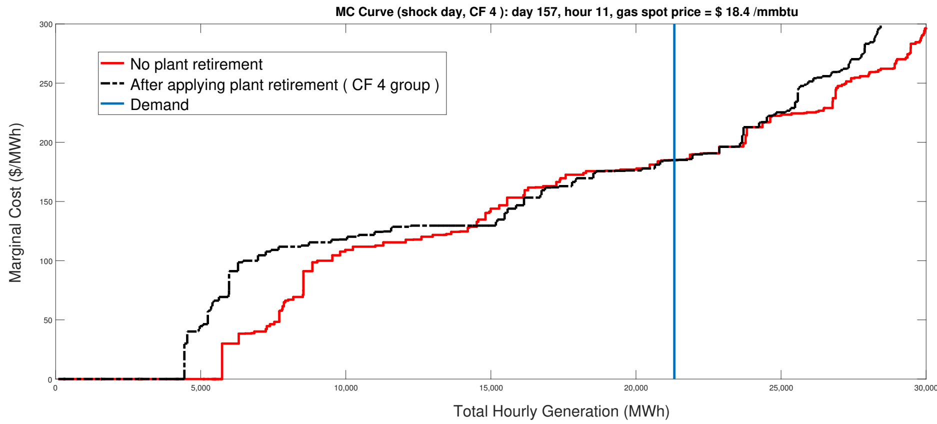


(a) Δ MC mean: by demand

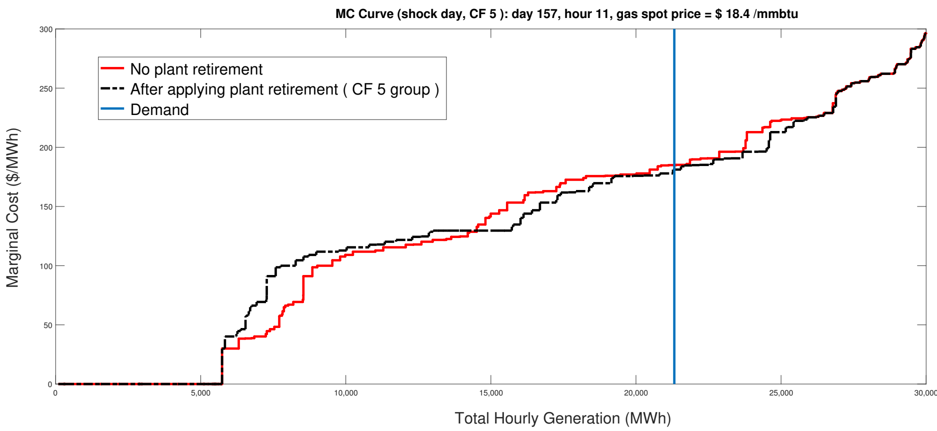


(b) Δ MC mean: by gas price

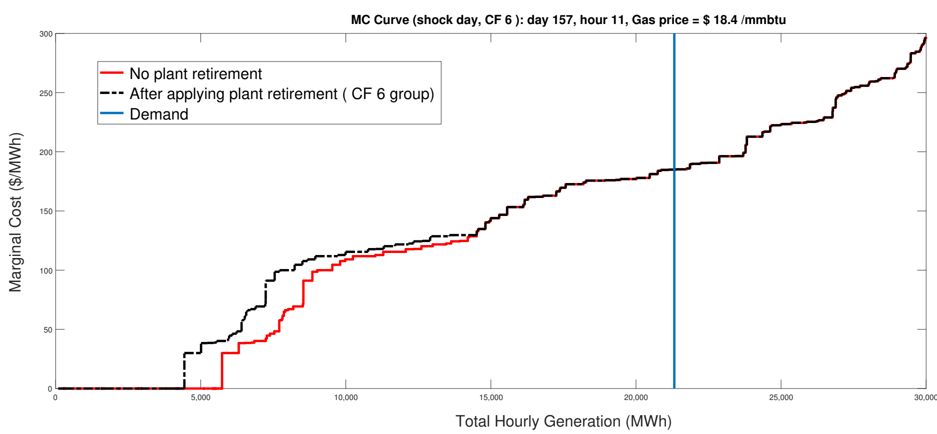
Figure A.5: MC mean change due to retirement



(a) Both Nuclear and Coal Plant Retirements Applied



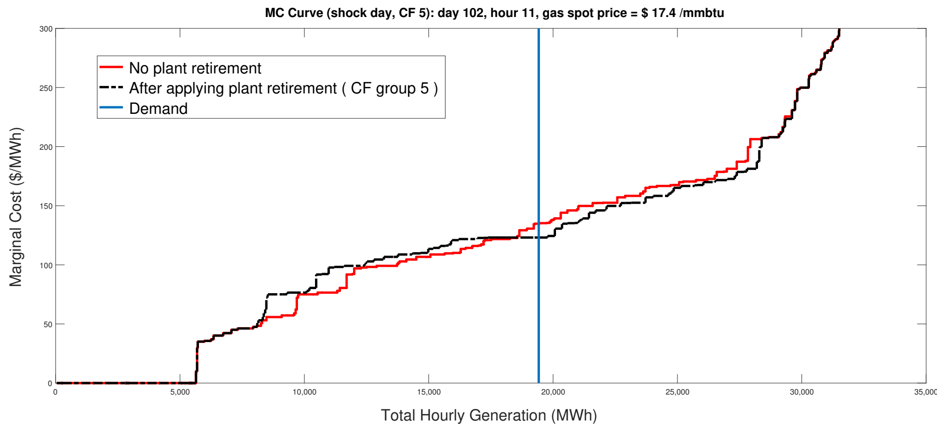
(b) Coal Plant Retirements Applied



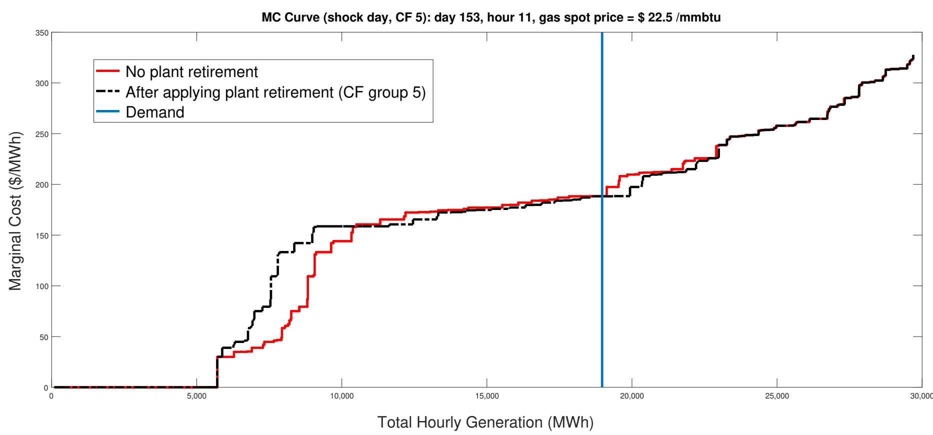
(c) Nuclear Plant Retirements Applied

Figure A.6: Different Impacts on Industry Marginal Cost Curve: Nuclear and Coal Plant Retirements

(a) Example of a significant cost distribution change around the equilibrium due to retirement

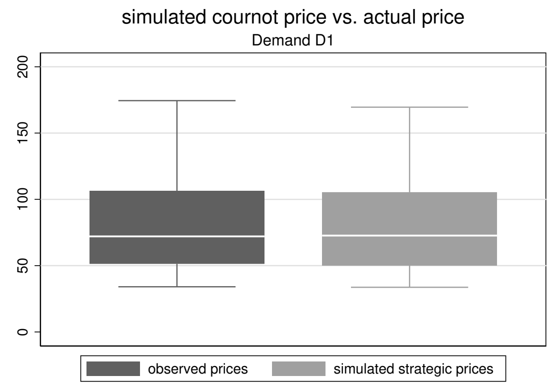


(b) Example of minimal change in slope around the equilibrium due to retirement

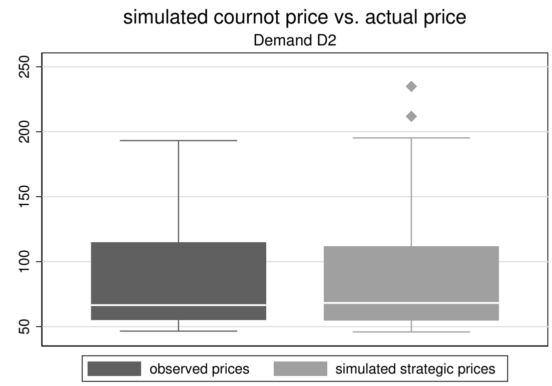


Notes: Only the retirements of coal-fired power plants are applied when plotting graphs shown here.

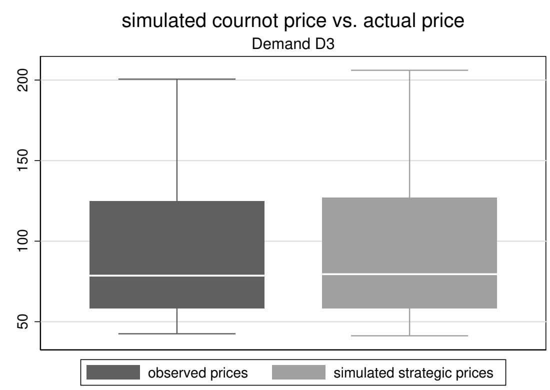
Figure A.7: Different impacts depending on demand and shock intensity



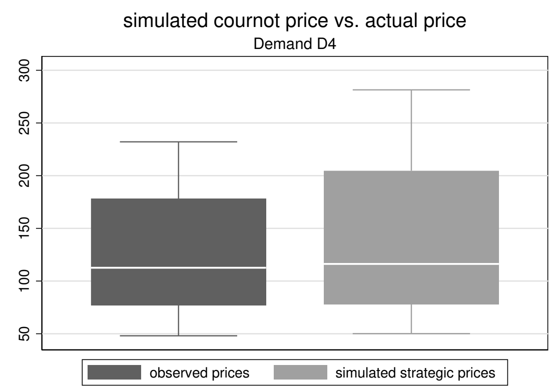
(a) Low demand, D1



(b) Low-mid demand, D2

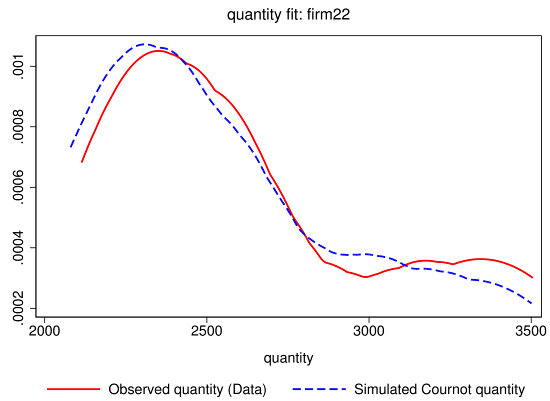


(c) Mid-high demand, D3

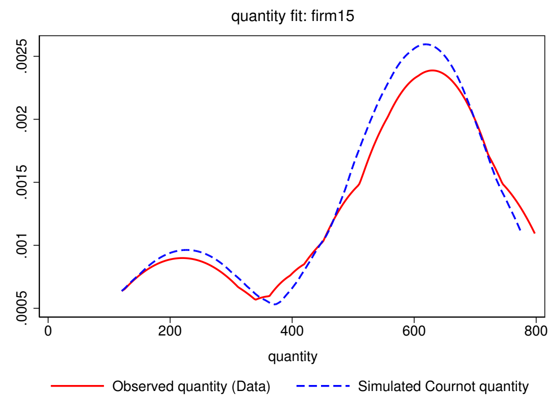


(d) High demand, D4

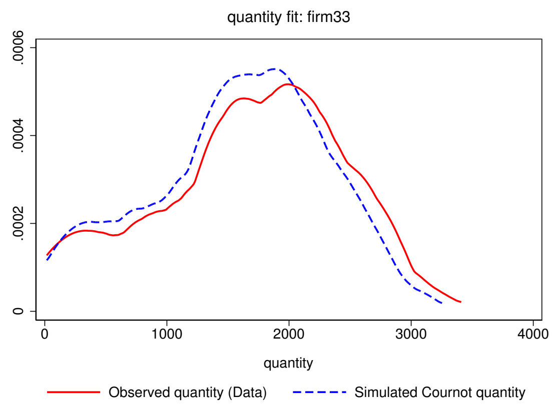
Figure A.9: Simulated cournot prices vs. actual prices (data, one of SFE): across demand



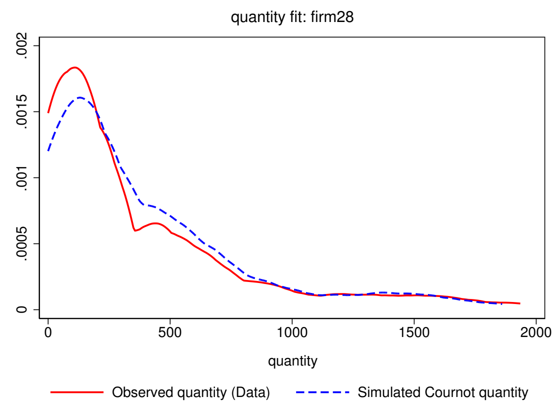
(a) quantity fit: firm 22



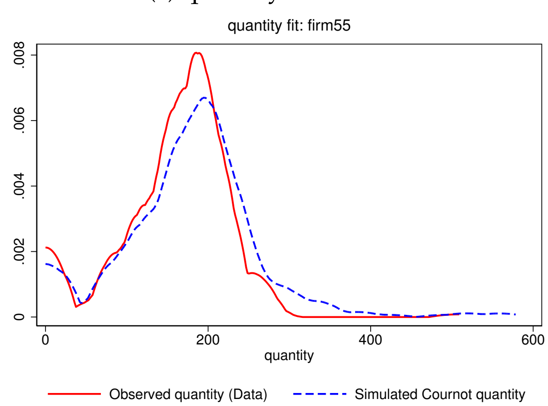
(b) quantity fit: firm 15



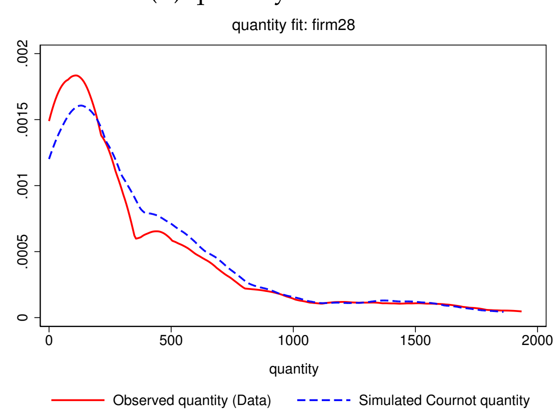
(c) quantity fit: firm 33



(d) quantity fit: firm 28

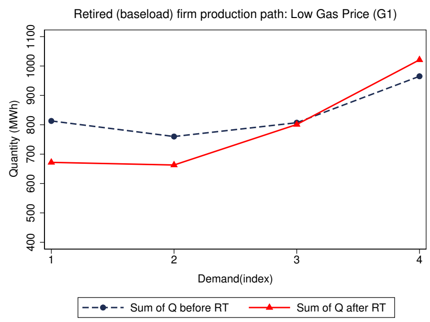


(e) quantity fit: firm 55

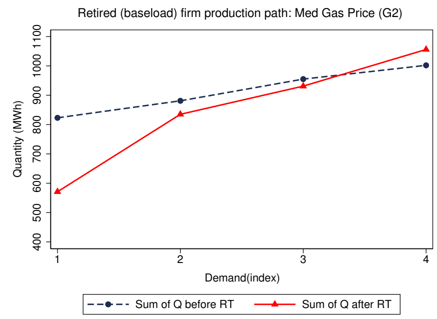


(f) quantity fit: firm 14

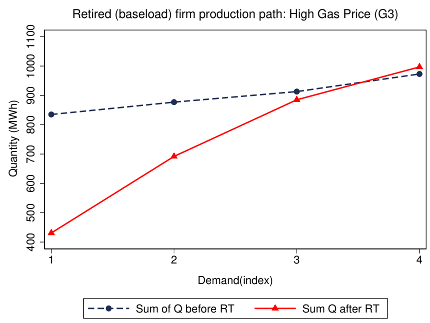
Figure A.11: Fit of the firm-specific quantities: actual quantity vs. simulated (Cournot) of the pre-retirement sample



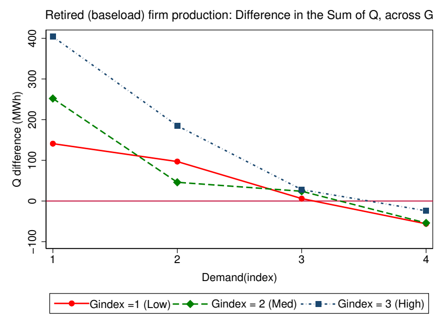
(a) Low gas price (G1)



(b) Med gas price (G2)



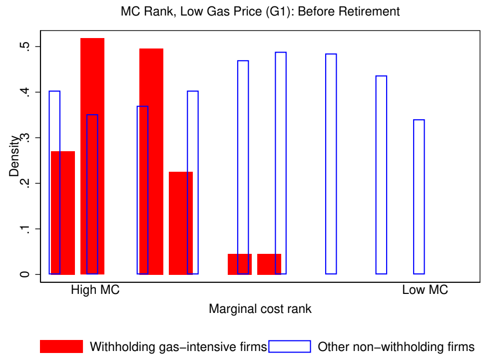
(c) High gas price (G3)



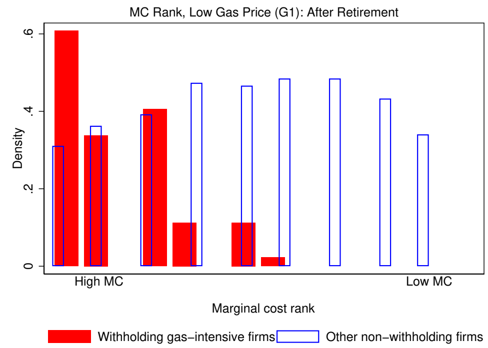
(d) Total quantity difference

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.

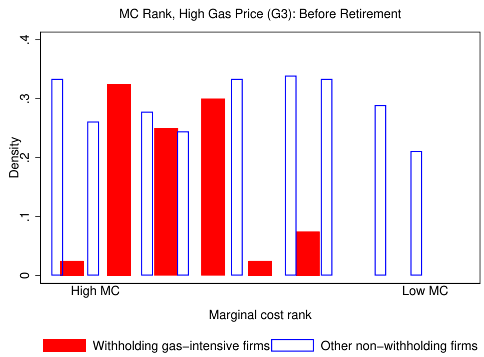
Figure A.13: Retired firm's (average) production paths before vs. after the retirement



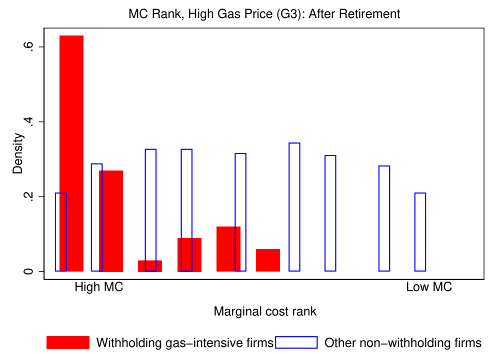
(a) Low gas price, G1: Before Retirement



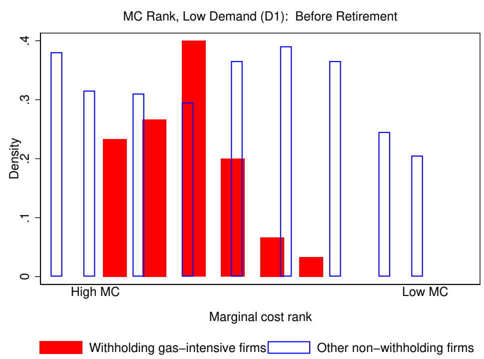
(b) Low gas price, G1: After Retirement



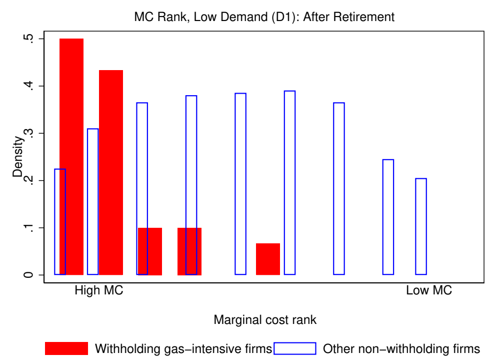
(c) High gas price, G1: Before Retirement



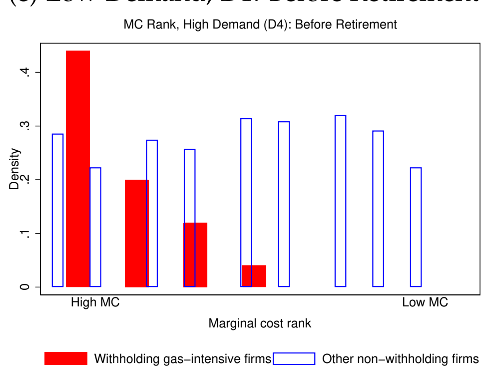
(d) High gas price, G1: After Retirement



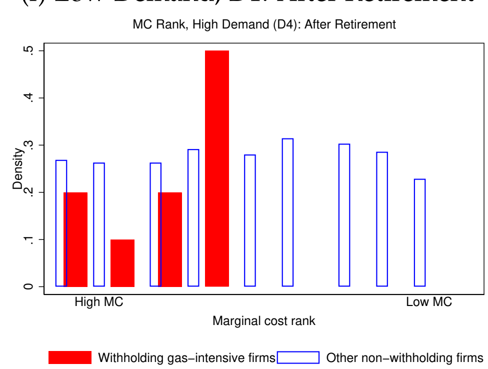
(e) Low Demand, D1: Before Retirement



(f) Low Demand, D1: After Retirement

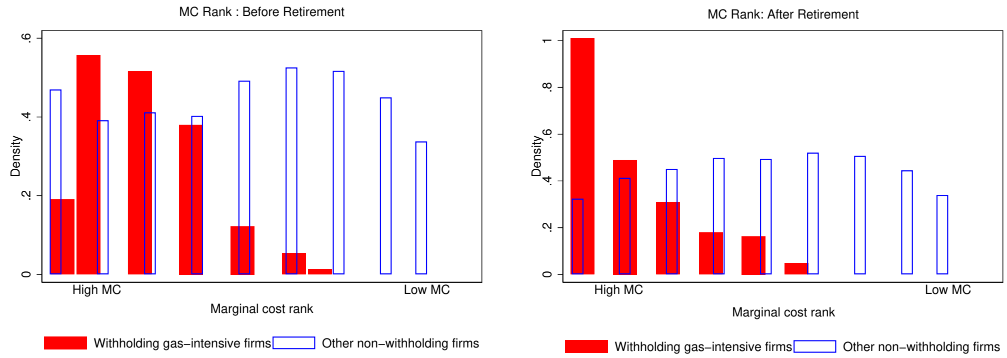


(g) Low Demand, D4: Before Retirement



(h) Low Demand, D4: After Retirement

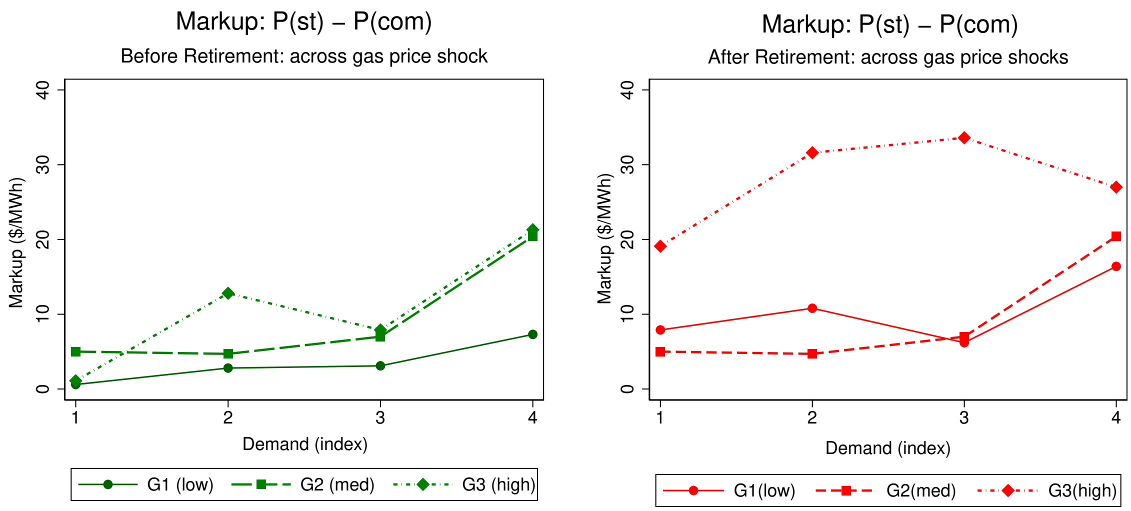
Figure A.14: Marginal cost rank change: by demand and gas price



(a) Full Sample: Before Retirement

(b) Full Sample: After Retirement

Figure A.16: Marginal cost rank change: by three different firm types



(a) Before retirement, total

(b) After retirement, total

Figure A.18: Market-level Markup : ΔP