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Electricity Prices during the Energy Crisis in Germany: The Role of Market Power¹

Till Fladung^{*}, Anna Saile^{†‡}

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Abstract

During the energy crisis in 2022, electricity prices in Germany soared to unprecedented levels. To explore the drivers of the high electricity prices, we develop an electricity dispatch model that simulates hourly equilibrium prices under the assumption of perfect competition. We then extend this model to account for firms exercising market power. By comparing the outcomes of the perfect competition and Cournot competition models with actual market data, we demonstrate that market power may have contributed to higher prices during the crisis, elevating them beyond what rising input costs alone would justify.

Keywords: Energy Economics, Market Power, Energy Crisis, Electricity Prices, Cournot Competition

JEL Codes:: Q41, Q43, L13, D43, L94

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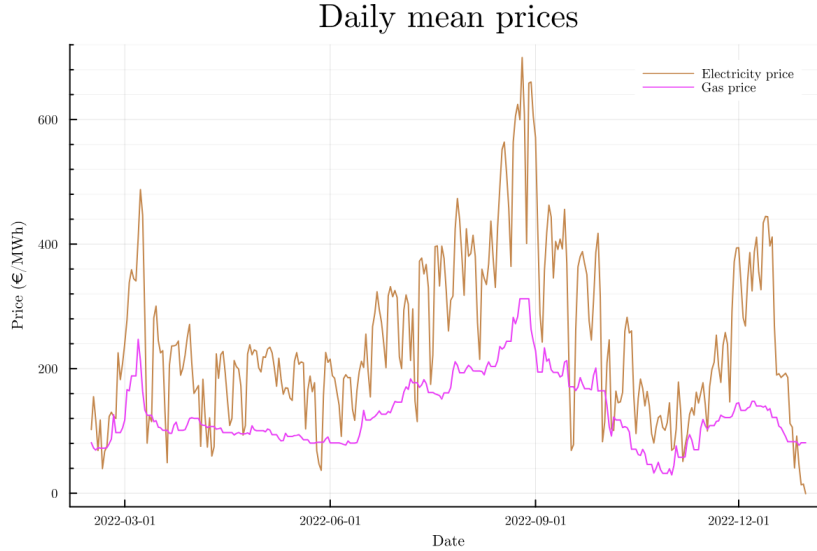


Figure 1: Daily mean electricity and gas prices from 02/14/2022 to 12/31/2022

1 Introduction

Europe experienced a period of exceptionally high gas prices in 2022. These were caused by rising demand after many economies recovered from the Covid-19 pandemic, as well as supply disruptions that occurred through the political backlash following Russia’s invasion of Ukraine in February 2022. These extraordinary increases in gas prices were accompanied by unprecedented price spikes in the German electricity market, placing a burden on consumers struggling to pay high electricity prices (see Figure 1). In the following paper we analyze whether the high electricity prices can be justified conclusively through the rise of input costs. Comparing model predictions of competitive benchmark prices with actual market outcomes, we find that the predictions follow the same trends as actual market outcomes, i.e. increase with the gas price, but are unable to explain the exceptional electricity price spikes observed in 2022. Reasons for this could be modeling limitations as well as the abuse of market power, which we will explore in the following.

Electricity markets exhibit several characteristics that make them prone to the exercise of market power, enabling large companies to charge prices above their marginal cost of generation (Borenstein (2000), Brown et al. (2023), Von Hirschhausen et al. (2007), Bushnell

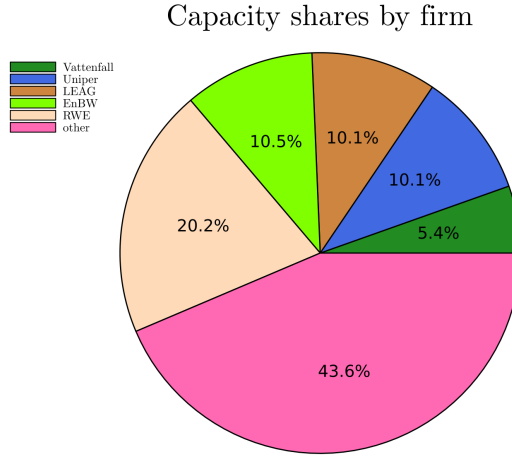


Figure 2: Shares of total capacity owned by five largest firms and fringe firms

et al. (2008)). The German electricity market is concentrated around five big players (RWE, EnBW, LEAG, Vattenfall and Uniper) who own around 56 % of the installed capacities, with the remaining 44 % being shared among numerous smaller actors (see Figure 2). The German competition authority notices a concerning trend of market concentration specifically in the thermal power plant sector (Bundeskartellamt, 2023), which is dominated by the five big players. This lead to RWE, EnBW and LEAG being indispensable for many hours during the year 2022, providing them with a favorable environment for strategic interaction and the exercise of market power (Bundeskartellamt, 2023).

On top of this unexpectedly increased marginal costs for gas powered thermal plants give room for large companies that own different generation technologies to allocate their modules strategically in order to maximize their profits (Adelowo & Bohland, 2024). In their latest market report, the German competition authority raised concerns about the abuse of market power in the electricity market during the year 2022 (Bundeskartellamt, 2023), implying that prices might have been increased more than necessary to cover the rising production costs.

Addressing concerns of the Bundeskartellamt (2023) and Fabra (2023) we develop the hypothesis that market power could be a reason for divergence between the competitive bench-

mark and observed prices. To validate this hypothesis, we follow Bushnell et al. (2008) and run a model specification allowing for markups consistent with strategic interaction resembling Cournot competition and compare the outcomes to observed prices. We contribute to the existing methodology by introducing a conjectural variation parameter θ to the Cournot model which allows to assess market conduct more flexibly. In line with our hypothesis, the model with market power provides a better fit of predicted market outcomes on observed prices than the competitive benchmark model, even after accounting for model limitations through robustness checks. The value of θ that we find for the German market during the observed period is 0.266, indicating the presence of markups in between competitive pricing ($\theta = 0$) and symmetric Cournot pricing ($\theta = 1$). We calculate a mean price-cost margin of 17.45 % in our baseline specification, placing an additional burden on consumers during a time of high electricity prices. This would correspond to extra profits of 11.5 bn € for electricity generating companies during the year 2022.

The remainder of the paper is organized as follows. In Section 2 we give a brief overview of the relevant literature on market power in electricity markets. Section 3 introduces the theoretical framework of the two models under the assumptions of perfect and Cournot competition. Section 4 explains the input data and model calibration to the German market. The results are presented in Section 5, followed by a discussion of our findings (Section 5.5) and resulting policy implications (Section 5.6). The final conclusions are summarized in Section 6.

2 Literature review

The exercise of market power has been a steady concern in the context of wholesale electricity markets. They exhibit several characteristics that favor the exercise of collusion and market power. Those characteristics include concentrated production, frequent interaction, multi-market contact, a high degree of information transparency, and limited storability of

the traded product (Brown et al., 2023, Von Hirschhausen et al., 2007, Borenstein, 2000, Adelowo and Bohland, 2024).

The microeconomic framework indicates that the exercise of market power raises prices within the market (Mas-Colell et al., 1995), since under perfect competition prices will be pushed down to the level of marginal costs. However, it is difficult to prove that firms exercise market power since marginal costs, corresponding to prices under perfect competition, are unobserved. Since the components that make up marginal costs in the electricity sector are well understood, it is a common approach in the literature to infer electricity producer’s marginal costs and predict competitive benchmark prices based on marginal cost estimations. The first influential study on market power in electricity markets was published by Wolfram (1999) who implemented a competitive benchmark model in the British electricity industry. This approach was followed by Borenstein et al. (2002) who studied the Californian electricity market from 1998 to 2000. They decompose cost increases into production costs, inframarginal competitive rents, and costs resulting from the exercise of market power.

Both studies claim that large parts of high electricity prices, especially during peak demand hours, cannot be explained by the competitive benchmark and are therefore due to the exercise of market power (Wolfram, 1999, Borenstein et al., 2002).

Bushnell et al. (2008) extend this method by not only simulating a competitive market equilibrium but also providing a model of Cournot competition. By simulating a model specification where firms act as strategic market participants in an oligopoly and withhold capacities to artificially raise prices, they create a second counterfactual to bound the space of possible static, non-cooperative outcomes. The counterfactual Cournot prices explain the actual market prices well during high demand hours, lending credibility to previous studies attributing price differences between actual and competitive prices to market power. Investigating the underlying market power dynamics at play in the Californian electricity market between 1998 and 2000, Puller (2007) finds that price-cost margins were consistent with

Cournot interaction rather than tacit collusion in the market, varying with more or less inelastic demand and production costs rather than the degree to which firms exercised market power. In the following paper we extend and apply the methodology proposed by Bushnell et al. (2008) to the German electricity market for the year 2022 during the energy crisis.

In the context of Germany, Von Hirschhausen et al. (2007) use various methods to assess market conduct in the German electricity market and conclusively find that prices seem to follow oligopoly characteristics rather than a competitive benchmark. This creates a loss in overall welfare on top of shifting surplus from consumers to producers (Von Hirschhausen et al., 2007). Further econometric literature points out mixed results regarding market conduct in Germany. Graf and Wozabal (2013) use a conjectural variations approach, allowing for flexible interaction in between competitive and monopoly price formation and can not reject the hypothesis that there was no market power at play determining prices on the European wholesale electricity market. On the other hand, from an empirical analysis of intraday electricity prices, Hagemann (2015) supports the hypothesis that price spikes can be caused by owners of flexible generation technologies exercising market power during hours of high demand.

Following the approach of Borenstein et al. (2002), several studies implemented a competitive benchmark model in order to quantify the extent of market power as the difference between simulated competitive and observed market outcomes in Germany (Weigt and Von Hirschhausen (2008), Müsgens (2006), Pham (2016)). All studies find differences of 12 to 25 % between their competitive benchmark model and observed market prices. However, they do not run a model with Cournot competition as proposed by Bushnell et al. (2008) to assess if price deviations can be conclusively explained through market power.

Our paper aims to apply the methodology proposed by Bushnell et al. (2008) to address the concerns raised by Fabra (2023) and Bundeskartellamt (2023), pointing out the possibility of abuse of market power during the energy crisis in 2022. This topic is also investigated

in parallel work by Krzywnicka and Barner (unpublished), whose results are in line with our findings. Our paper is the first to investigate the effect of market power in the German market through a counterfactual model of Cournot competition over price setting. We also contribute to the existing methodology by introducing the conjectural variation parameter θ to the Cournot model. This allows future research to adapt the framework more flexibly to the specific market conduct. We provide an estimate and calibration method for θ in the German market in 2022, indicating the extent to which market power was used to artificially raise prices.

3 The Model

To simulate market outcomes under different assumptions of market conduct, we construct a stylized electricity dispatch model, which solves for the partial equilibrium of hourly prices and quantities in the day-ahead wholesale electricity market. Supply curves in the model are constructed in two specifications. Under the assumption that firms bid at their marginal costs when there is perfect competition, or assuming that large companies bid above their marginal cost according to a markup derived from the Cournot competition framework.

3.1 Demand

Since Germany was a net exporter of electricity in 2022, we model demand as the sum of domestic and foreign demand (net exports). Each demand type is defined as

$$Q_{o,t,h}^{observed}(p_{t,h}^{observed}) = a_{o,t,h} - b_{o,t,h}p_{t,h}^{observed} \quad \forall o \in \{foreign, domestic\} \quad (1)$$

where t and h refer to day and hour, respectively. We calibrate the slope of the demand curve $b_{o,t,h}$ and the intercept $a_{o,t,h}$ to match the observed market price $p_{t,h}^{observed}$ and total quantity $Q_{o,h,t}^{observed}$ in each hour, assuming different elasticities η_o for domestic and foreign

demand as described in section 4.1, such that

$$b_{o,t,h} = \eta_o \frac{Q_{o,t,h}^{observed}}{p_{t,h}^{observed}} \quad (2)$$

The resulting total demand is equated to supply in every hour.

3.2 Supply

On the supply side, we differentiate between must-run technologies with low or zero marginal costs and thermal power plants. Given the relatively short-term focus of our model, we do not model investment and abstract from operation and maintenance costs. We also do not model start-up costs.

3.2.1 Must-runs

Considering the focus of our model on market power dynamics, we do not explicitly model generation sources with low or zero marginal costs such as solar, wind, hydro, nuclear and biomass but take their observed or forecasted (in the case of solar and wind) generation as given:

$$m_{s,t,h} = m_{s,t,h}^{observed} \quad \forall s \in \{hydro, nuclear, biomass, solar, wind\} \quad (3)$$

$m_{s,t,h}$ directly enters as the quantity produced from these sources in each hour, as we assign all of the above technologies zero marginal costs and thus model them as must-runs. We abstract from additional cost components for marginal costs of these technologies, as they will not represent the price setting technology in the merit order curve during peak demand hours.

3.2.2 Thermal power plants

To account for the market structure and different cost structures among firms, we aggregate the power plants owned by each firm on the technology level so that firms have a portfolio of single representative power plants for each technology they own.

Marginal costs of firm specific representative thermal power plants depend on their efficiency, input costs and the carbon price:

$$MC_{f,i,t,h}(q_{f,i,t,h}) = (c_{f,i} + \tilde{c}_{f,i} q_{f,i,t,h}) p_{i,t}^{input} + e_i p_t^{CO_2} \quad (4)$$

$$\forall i \in \{hardcoal, lignite, natural\ gas, oil, waste\}$$

where f refers to firm and i to technology. c and \tilde{c} refer to the amount of input needed to produce one unit of electricity. Marginal costs for representative plants increase with the generated quantity $q_{f,i,t,h}$, since less efficient plants will be called to produce with higher demand (see estimation of c and \tilde{c} in section 4). $p_{i,t}^{input}$ refers to the daily cost for the production input used by the technology, i.e. the fuel price. e_i refers to the emissions generated per unit of electricity, for each of which the daily carbon price $p_t^{CO_2}$ has to be paid. Thus, marginal costs vary depending on the prices of inputs and CO_2 and with the quantity produced by each firm and technology $q_{f,i,t,h}$.

Under perfect competition, thermal power plants produce up to the point where the equilibrium wholesale price equals their marginal costs or they reach their capacity limit at $K_{f,i}$:

$$q_{f,i,t,h}(p_{t,h}) = \begin{cases} 0 & \text{if } p_{t,h} \leq MC_{f,i,t,h}(q_{f,i,t,h}) \\ [0, K_{f,i}] & \text{if } p_{t,h} = MC_{f,i,t,h}(q_{f,i,t,h}) \\ K_{f,i} & \text{if } p_{t,h} > MC_{f,i,t,h}(q_{f,i,t,h}) \end{cases} \quad (5)$$

The price equals marginal costs for the price setting plant, while plants with marginal costs below the price earn the difference as the shadow value.

3.2.3 Cournot competition

We now extend the model to simulate market outcomes under the assumption that large firms do not bid competitively, but instead strategically reduce quantities to increase the

wholesale price and profits. This is modeled as economic capacity withholding where firms bid their marginal costs plus a markup term derived from the Cournot oligopoly model. The markup applies to the total quantity of each firm as the sum of the quantities supplied by each of their representative plants. The Cournot profit maximization setup yields the following set of first order conditions, which are to be simultaneously satisfied in equilibrium (see Cournot setup in the appendix A.1):

$$p_{t,h} = MC_{f,i,t,h} + \frac{q_{f,t,h}}{\sum_o b_{o,t,h}} \quad (6)$$

The markup term $\frac{q_{f,t,h}}{\sum_o b_{o,t,h}}$ increases with the quantity provided by the respective firm, and decreases in the demand elasticity as quantity reductions following higher prices limit extra profits.

The general markup term is derived from the symmetric Cournot oligopoly model. However, since we model a market where large firms additionally face the competition of fringe firms, we generalize the first order conditions to allow the markup to be more flexible depending on market conduct:

$$p_{t,h} = MC_{f,i,t,h} + \theta \frac{q_{f,t,h}}{\sum_o b_{o,t,h}} \quad (7)$$

where θ allows for flexibility in the degree of market power through the size of markups in the market. $\theta = 1$ yields the markup in the standard Cournot framework as in (eq. (6)), while $\theta = 0$ characterizes the case of perfect competition (see structural interpretation of θ in the appendix A.1).

Since many fringe suppliers do not own enough quantity to exercise market power, we let the markup be bigger than zero only for the five largest firms. Fringe suppliers keep bidding competitively as in (eq. (5)). Firms with market power in the Cournot framework now submit bids equal to their marginal costs plus the markup allowed for through θ . This effectively reduces the quantities supplied by the respective firms, as they now only produce up to the point where the price equals their higher bids:

$$q_{f,i,t,h}(p_{t,h}) = \begin{cases} 0 & \text{if } p_{t,h} \leq MC_{f,i,t,h}(q_{f,i,t,h}) + \theta \frac{q_{f,t,h}}{\sum_o b_{o,t,h}} \\ [0, K_{f,i}] & \text{if } p_{t,h} = MC_{f,i,t,h}(q_{f,i,t,h}) + \theta \frac{q_{f,t,h}}{\sum_o b_{o,t,h}} \\ K_{f,i} & \text{if } p_{t,h} > MC_{f,i,t,h}(q_{f,i,t,h}) + \theta \frac{q_{f,t,h}}{\sum_o b_{o,t,h}} \end{cases} \quad (8)$$

with $\theta = 0$ for fringe suppliers

Allowing some firms to have positive markups leads to higher equilibrium prices and lower quantities in all hours where plants that are owned by the largest firms set the price.

3.3 Equilibrium

In equilibrium, demand equals the supply of must-runs and thermal power plants. The model is solved by finding the combination of production inputs so that supply equals demand for each hour of the day, taking into account the different price bidding structures under the assumption of perfect competition or Cournot competition. The equilibrium price will be the price that satisfies:

$$\sum_o Q_{o,t,h}(p_{t,h}) = \sum_s m_{s,t,h} + \sum_f \sum_i q_{f,i,t,h}(p_{t,h}) \quad (9)$$

The solution of the model yields the hourly equilibrium price $p_{t,h}$ and the hourly equilibrium quantities for each firm and technology $q_{f,i,t,h}$.

4 Data and Model Calibration

We calibrate the model to reflect the characteristics of the German day-ahead wholesale electricity market during the energy crisis. We model market outcomes from 02/14/2022 to 12/31/2022 using mainly publicly available data.

4.1 Demand

To calibrate demand curves reflecting the sum of domestic and foreign demand, we use market data on quantities, prices and exports for the joint day-ahead wholesale electricity market of Germany and Luxembourg. This data is available in hourly resolution at the SMARD Portal (Bundesnetzagentur (2024)).

For domestic demand, we assume an elasticity of -0.05 as estimated by Hirth et al. (2023) for the German market. For foreign demand, we follow the approach of Reguant (2019) and Bushnell et al. (2008) to estimate the export elasticity in our sample. For that purpose we regress the logarithm of electricity exports to neighbouring countries on the logarithm of electricity prices. To avoid the endogeneity issue as prices and exports are determined simultaneously, the price of gas and predicted demand can be used as instruments for electricity prices. Fluctuations in the price of gas during the observed period can mainly be attributed to exogenous political decisions following the Russian attack on Ukraine. We also include controls for different times of the day (γ) and generation from wind, solar and the sources which are treated as must-runs in our model (X):

$$\ln(exports_t) = \eta \ln(price_t) + \beta\gamma + \beta_n X + \epsilon \quad (10)$$

This yields an estimate for the export elasticity of -0.55, which is by 0.2 higher than the estimate by Reguant (2019) for California. This might be due to the greater interconnection and flexibility of the European electricity market. With the elasticities and the market data on prices and quantities we calibrate the demand functions as described in section 3.1.

4.2 Supply

On the supply side, we gather data to reconstruct firm-specific marginal cost functions in the thermal power plant sector and data on actual electricity generation for must-run technologies.

4.2.1 Thermal power plants

Open-Power-Systems database (Open Power System Data (2020)) provides a dataset with capacity, efficiency and operating company for each power plant in Germany as of 2020. In July 2020, the German parliament passed the Act to Reduce and End Coal-Fired Power Generation (Press and Information Office of the Federal Government (2020)), requiring the total capacity of hard coal and lignite plants to be reduced to around 15 GW by 2022. Since this reduction is not reflected in the dataset, we limit the capacity of hard coal and lignite plants to 72 % and 83 % of the reported capacities respectively, in line with the 15 GW limit.

To account for firm structure, we assign firm ownership to each plant using publicly available data on company structures and subsidiaries of the five largest firms RWE, EnBW, LEAG, Uniper and Vattenfall. All remaining plants are gathered as a representative fringe firm "other". For each firm, we accumulate plants on the technology level to make the model less computationally demanding.

The efficiency of each representative plant decreases with the produced quantity, as the units that make up each representative plant get called to produce in order of their efficiency. To reflect that, we accumulate the capacity of power plants of the same technology within each firm from the most efficient to least efficient plant and perform linear regressions of efficiency on accumulated capacity. The slope of the regression yields the model parameter \tilde{c} , the rate at which marginal costs increase with quantity as described in eq. (4). The intercept, approximating the efficiency of the most efficient plant, is taken as the starting value (see illustration of c and \tilde{c} calibration in appendix A.2).

As described in eq. (4), the efficiency estimates are multiplied by the price of the resource to obtain the marginal costs for each hour of the day and depending on the quantity. Resource prices for oil, lignite and hard coal are taken from a report of the German Federal Statistical Office (Destatis, 2023). Among input prices, the largest price fluctuations are observed for

the price of gas. To model gas prices, we requested data of the daily spot market price of gas from the European Energy Exchange (EEX).

Emissions are calculated based on the efficiency of the plant together with the emission factor estimate of the fossil fuel used for generation, corresponding to the amount of CO_2 emitted from producing one unit of electricity. The emission factor is extracted from a report of the German Environment Agency (Umweltbundesamt, 2016). Power plants have to pay the EU-ETS carbon price for each ton of carbon they emit. Data for daily average EU-ETS prices is also obtained from EEX.

4.2.2 Must runs

For hydro, nuclear and biomass, we obtain data on the actual hourly generation amounts from the SMARD Portal (Bundesnetzagentur (2024)). For solar and wind, we include the amount predicted to be generated one day in advance as the generated quantity in our model which is also available at SMARD Portal (Bundesnetzagentur (2024)). We use data of the generation forecast instead of actual generation since we model the day-ahead wholesale electricity market where the expectation of generation from renewables is crucial for bidding behavior. Additionally, generation from renewables is often affected by curtailment due to their low start-up costs, which does not affect the wholesale price but would be reflected in the data on actual generation from renewables.

An overview of calibrated supply side model inputs can be found in the appendix A.2. Codes for our model and datacleaning are linked in appendix A.3.

5 Results

We run the proposed model in two variations. The competitive benchmark model simulates firms bidding their prices equal to marginal costs. We also simulate the results allowing for

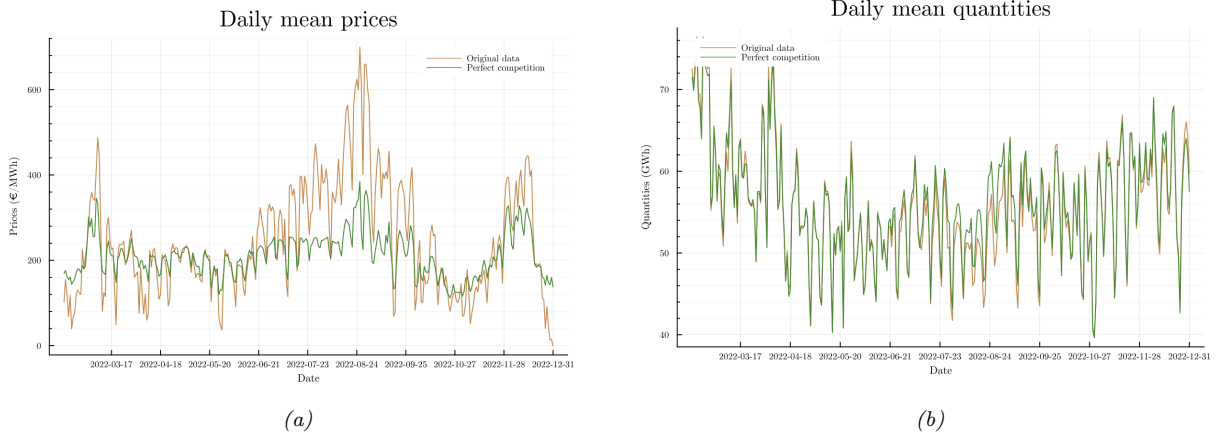


Figure 3: Daily mean prices and quantities predicted under perfect competition vs. actual prices and quantities

firms exercising market power using Cournot competition, as proposed in ???. The results of the model runs will be compared to the observed prices and quantities of the German day ahead wholesale electricity market.

5.1 Competitive Benchmark Model

Figure 3 shows the daily means of hourly equilibrium prices and quantities from our competitive benchmark model of the German electricity market in 2022 alongside the observed market outcomes. Daily mean quantities are predicted fairly well (Figure 3b). As seen in Figure 3a, the modeled prices also follow the same trend as the original prices. Periods with lower average prices and low variation, as in April and May, seem to be well approximated by the model with perfect competition. However, the rise in input prices is not able to explain the large price increases as observed e.g. during the summer months, where competitive prices remain far below observed prices. This leads us to conclude that the exceptionally high prices during the energy crisis can not be sufficiently explained by the change in resource prices, as accounted for in our model.

Reasons for divergence of the model from the original data could be modeling limitations like startup costs or unobserved high fuel prices. Such factors and their potential influences

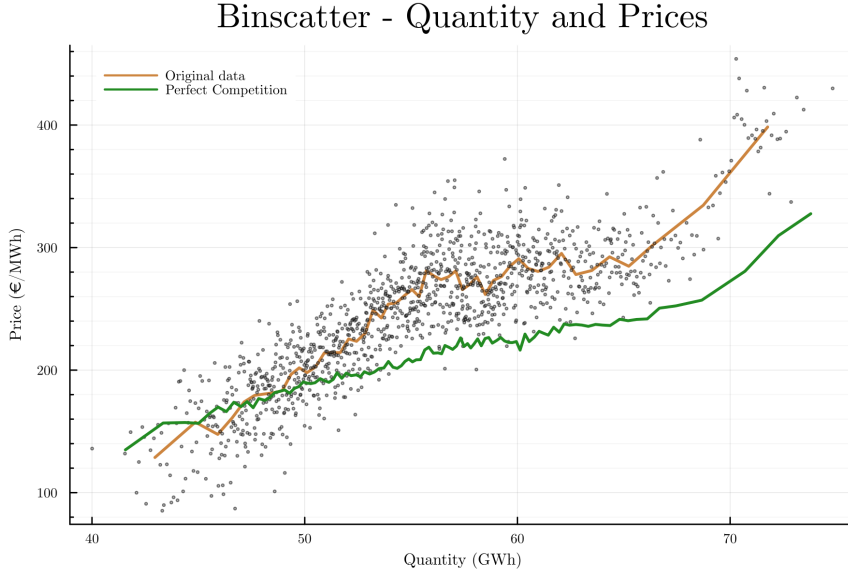


Figure 4: Binscatter of original data and the model of perfect competition controlling for the price of gas and the quantity of must runs. The grey dots represent the residualized values of the original market outcomes.

are discussed in more detail in section 5.4. Apart from model inaccuracies, prices above the ones predicted under the assumption that firms bid at their marginal cost point towards the exercise of market power (Wolfram (1999), Borenstein et al. (2002), Weigt and Von Hirschhausen (2008), Alpino et al. (2023), Reguant (2014)). After controlling for important price determinants, such as the availability of renewables and the gas price through a binscatter regression, Figure 4 shows that price divergence increases during high-quantity hours. This supports the hypothesis that market power might be a contributing factor to price differences for two reasons: First, the market gets less competitive at higher demand hours when most fringe suppliers have already maxed out their capacity (Bushnell et al., 2008). This gives room for owners of large capacities to raise prices above competitive levels (Von Hirschhausen et al., 2007). Second, given that firms behave strategically, the potential markup from Cournot competition, as derived in Section 3, grows proportionally with the total quantity provided by the respective firm.

5.2 Calibrating optimal θ

To investigate the potential impact of market power on prices, we explicitly model market outcomes under the assumption that a number of large firms behave as in a Cournot oligopoly. The model allows for different forms of conduct by varying the conjectural variation parameter θ , resulting in markups closer to perfect competition (no markup) or Cournot competition.

In order to calibrate θ , we first reduce the dimensionality of our dataset by applying the k-means method to cluster the dataset that is used for the binscatter regressions to 500 representative hours. We then iteratively solve the model for different values of θ and obtain the sum of squared residuals between the modeled and observed market outcomes during hours with quantities > 62 GWh. The optimal θ is the value associated with the minimal deviations.

In our setting, the optimal θ is reached at 0.266 when applying the calibration method to the whole period. A constant θ is in line with Puller (2007), finding that firms seem to behave as in a stable Cournot oligopoly. Since θ indicates the degree of deviation from perfect competition outcomes ($\theta = 0$) towards Cournot interactions where firms' decisions are determined by profit maximization through choice of quantities in strategic interaction ($\theta = 1$, see also appendix A.1). $\theta = 0.266$ indicates that firms are not able to behave as in a pure oligopoly framework. This is consistent with the fact that they face the competition of not only other strategic firms, but also fringe suppliers, especially during low to medium demand hours. Additionally, markups below the ones predicted by the oligopoly framework might simply indicate fairly effective regulatory mechanisms in the market. Firms might not use their market power to the full extent, in order not to alarm regulatory authorities and potentially face penalties. However, $\theta = 0.266$ clearly indicates a deviation of market conduct from perfect competition outcomes.

5.3 Model with Cournot Competition

We now run the competitive benchmark and the Cournot competition model for the unclustered dataset from 02/14/2022 until 12/31/2022, setting θ equal to 0.266.

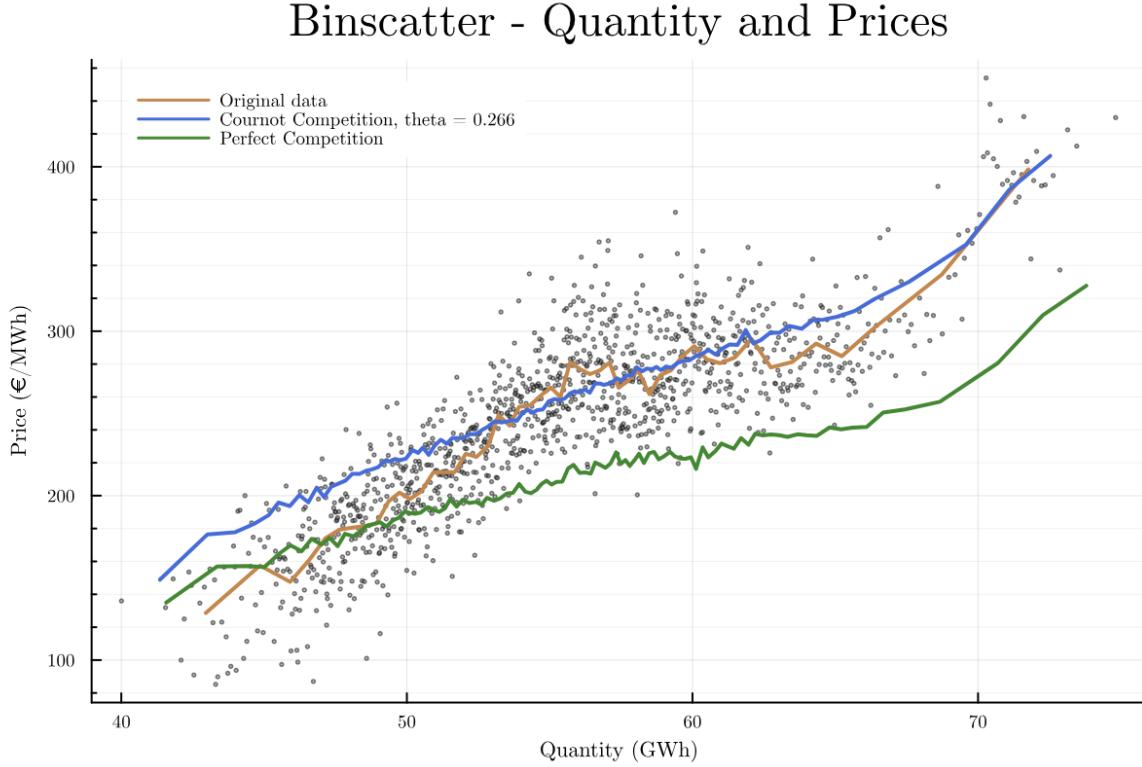


Figure 5: Binscatter of original data and the model of perfect competition controlling for the price of gas and the quantity of must runs. A model of Cournot competition is added to control for market power determining price setting. The grey dots represent the residualized values of the original market outcomes.

Figure 5 shows the market outcomes of the perfect competition model (green), the market power model (blue) and the original data (brown, individual data points in gray) after controlling for the gas price and quantity of must-runs. Below quantities of 50 GWh, the original data is fairly well characterized by the competitive outcomes. However, for quantities above 55 GWh, the Cournot model best describes the price setting behavior. This is strongly aligned with the results of Bushnell et al. (2008) and Puller (2007), who find larger price-cost margins during high demand hours in the Californian electricity market.

Deviations of observed prices from marginal costs (as indicated by the competitive bench-

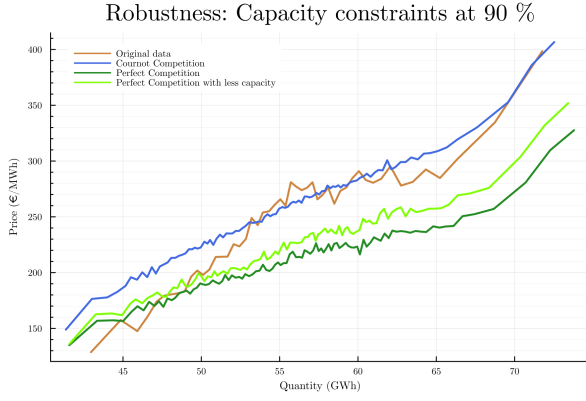
mark prices) point towards the existence of markups through the exercise of market power in the market (Cowling & Waterson, 1976). Assessing the impact of market power through measures like the price-cost margin, studies typically compare observed prices to the ones estimated in a perfectly competitive benchmark model. We calculate the potential impact of market power by comparing the benchmark model with the counterfactual market power prices during hours with quantities above 55 GWh, where the Cournot model explains actual prices better. This smooths out variations in prices that stem from dynamics in prices that are not due to market power and which are captured by neither of our models.

Compared to the competitive benchmark prices, we find an average mark-up of 17.45 % during high demand hours. This difference between prices and costs corresponds to extra profits of 11.5 bn € for the electricity generating firms in Germany. These extra profits would coincide with additional costs for consumers, since surplus is transferred from consumers to producers when prices are raised above the competitive equilibrium through market power. These costs average at 140 € per capita for the modeled period from 02/14/2022 until the 12/31/2022 if distributed evenly across the German population. These results do not account for the dead weight loss resulting from deviations from the efficient perfect competition equilibrium, which could raise the costs per capita even further (Von Hirschhausen et al., 2007).

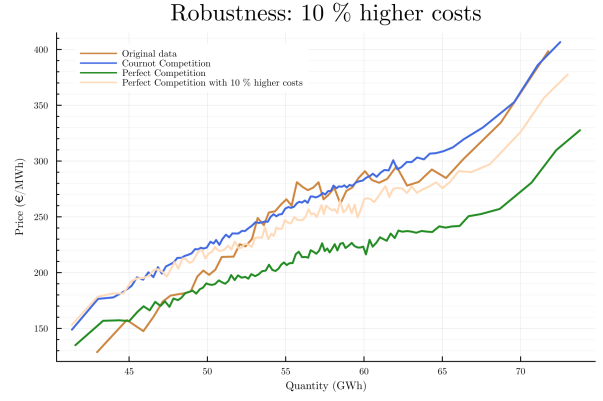
Our results indicate that high prices during the energy crisis could be explained by the increase in resource prices and the exercise of market power through RWE, EnBW, LEAG, Uniper and Vattenfall.

5.4 Robustness Checks

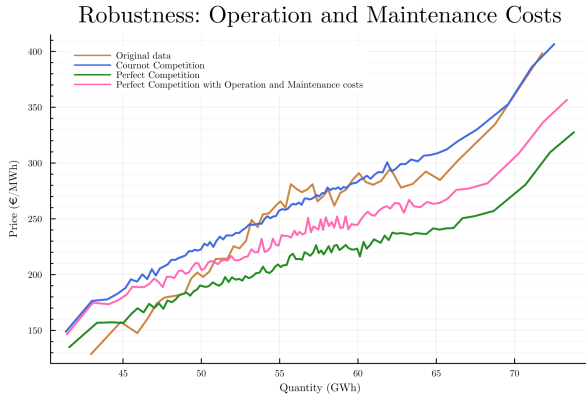
As mentioned, competitive benchmark prices could also differ from actual prices due to reasons other than market power, i.e. factors that are not accounted for in our model. To control for some of the modeling limitations and enhance the validity of our results we perform three robustness checks.



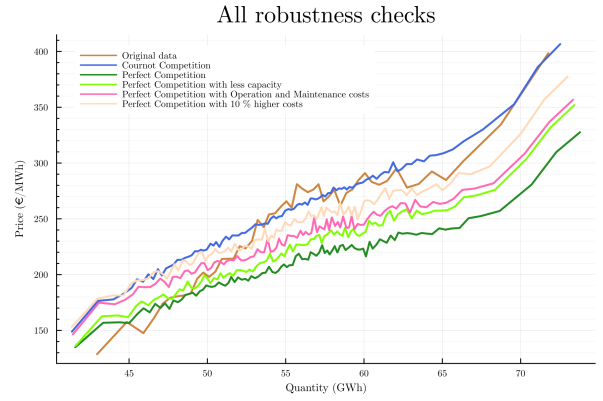
(a) Capacities of thermal power plants are limited to 90 % of their capacity in our dataset.



(b) The percentage markup on costs is modelled as a 10 % markup on marginal costs for each power plant.



(c) Operation and Maintenance costs are modelled as a 10 € markup on marginal costs for each power plant.



(d) Comparison of all robustness checks, simulated outcomes of both models and original data.

Figure 6: Robustness checks on competitive benchmark prices

The dataset on power plant characteristics taken from Open Power System Database reports plant data as sourced in 2020. Power plants might not be able to operate up to their full reported capacity of 2020. We thus follow Weigt and Von Hirschhausen (2008) and run the model while restricting the capacity of all power plants to 90 % of the reported value. This restriction only marginally raises the competitive benchmark prices (see Figure 6a). Therefore, adjusting the benchmark model for potential capacity losses does not help in explaining the high observed prices.

Furthermore, the benchmark results strongly rely on our marginal cost specification. Firm's true marginal costs could diverge for different reasons. Firms might face different input prices than the spot price, which we use in our model. In reality, large shares of fuel are

traded via long-term contracts. Whether plants face higher or lower costs in the presence of long term contracts depends on the expectations of price developments at the time of setting up the contract. In our case, it is likely that especially gas plants faced lower prices than on the spot market, since price spikes were unexpected. Nevertheless the spot market price influences bidding behavior since it represents the opportunity cost of the given input. This assumption seems to be supported by Figure 1 where gas prices are correlated with electricity prices without a lag. Even under the assumption that generators pay the spot price, the actual fuel cost might be higher than the spot price due to e.g. transportation costs and transmission fees. To account for potential underestimations of fuel costs, Weigt and Von Hirschhausen (2008) proceed by increasing fuel costs by 5 %. Since another reason for higher marginal costs could be that plants have also gotten less efficient over time, we go one step further and increase all marginal costs by 10 %. Even after increasing all marginal costs in the benchmark estimation by 10 %, the prices during high quantity hours are still better explained by the model accounting for market power (see Figure 6b).

We extend the robustness checks performed by Weigt and Von Hirschhausen (2008) by including an approximation for operation and maintenance costs (OMC) in our model. We do not include them into our original model since they are (a) subject to private information of the generators (Alpino et al., 2023) and (b) almost impossible to map exactly as marginal costs for the corresponding unit. As a robustness check and approximation we added OMC of 10 € per unit to the marginal costs of generation, overstating the published OMC by the U.S. Energy Information Administration (2023). This exercise aims to show the sensitivity of our baseline results to the inclusion of OMC. Including OMC raises the level of the competitive benchmark model (Figure 6c), but as with the other robustness checks, our model with Cournot competition still best describes the original data.

Even though the model with market power still best describes observed prices, Figure 6d shows that the resulting price-cost margin varies between scenarios. Table 1 summarizes the lower bound (referring to the baseline model) and upper bound (referring to the robustness

check with 10 % higher marginal costs) estimates for price-cost margins, corresponding profits and costs per capita. Average refers to the mean of the estimates across all scenarios.

	Lower bound	Upper bound	Average
Mean Price-Cost Margin	5.08 %	17.45 %	11.28 %
Extra profits of firms	3.3 bn €	11.5 bn €	7.45 bn €
Costs per Capita	40.52 €	140.5 €	90.92 €

Table 1: Lower bound refers to the difference to the robustness check with 10 % cost increase, the upper bound refers to the difference to the competitive benchmark model and average is the mean over all calculated scenarios

5.5 Discussion

Figure 7a shows the daily mean prices and quantities predicted by the perfect competition model and the Cournot model as well as the observed market outcomes over the full sample period. Quantities are described fairly well, with on average higher quantities predicted by the perfect competition model due to lower prices. As mentioned in Section 5.1, competitive prices as predicted by our model are lower than actual prices for most days of the year. The average price of the year in the perfect competition model is 210.88 €, while the actual prices averaged at 246.05 €. The Cournot model with $\theta = 0.266$ approximates the average price better with 255.99 €. The higher average in the Cournot model is mainly due to the overstatement of prices for quantities less than 55 GWh (see Figure 5).

One reason that the competitive benchmark prices lie above the actual prices during some hours could be that we do not include start-up costs or minimum output constraints. Electricity prices can be low or even negative in some hours, as inflexible generation technologies like nuclear power plants face large start-up costs and bid negative prices during hours of low demand with sufficient availability of low-cost generation like renewables, to avoid getting shut down. This omission results in actual prices below our competitive estimates especially in hours with low quantities (see Figure 5). Negative hours are not explicitly depicted in

Figure 7a, since these are daily averages, but certainly influence the low average prices on such days. Including start-up costs of power plants with higher marginal costs like coal or gas plants, however, would increase competitive benchmark prices during those hours where these plants need to ramp up or down. We do not model this explicitly, but account for potentially higher marginal costs in our robustness checks (Figure 6b).

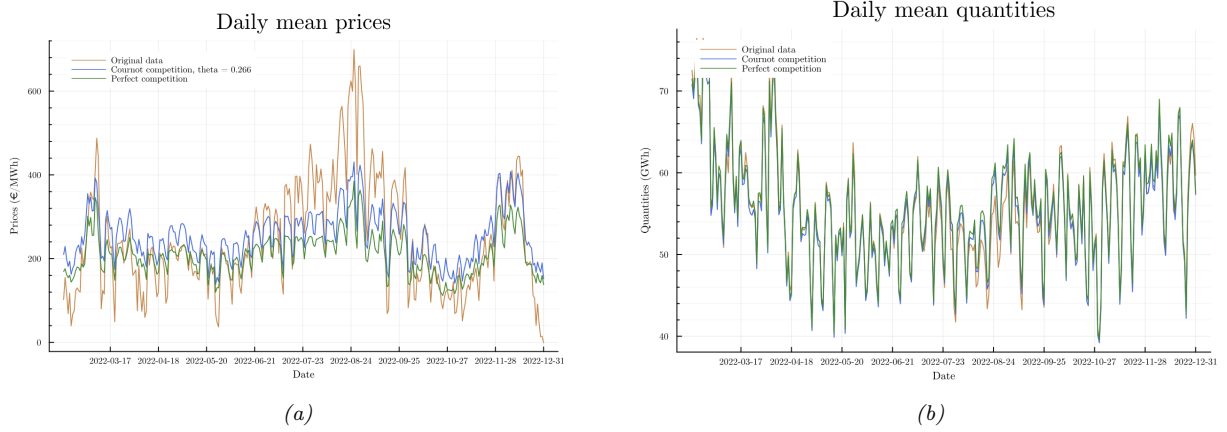
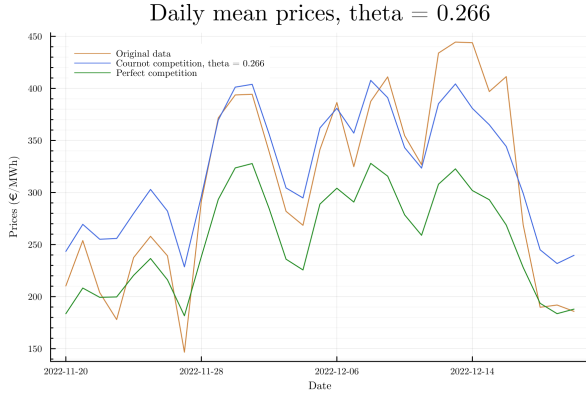
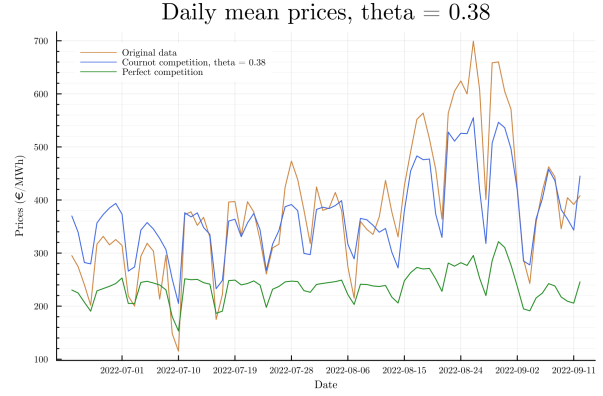


Figure 7: Daily mean prices and quantities over time with original data, perfect competition, and Cournot competition ($\theta = 0.266$).

Figures 7a and 8a show that Cournot prices follow the observed prices well, especially during high price periods in the first and last months of our sample. However, the summer months of 2022 exhibited exceptionally high prices, which go beyond the outcomes predicted by our model with θ to best match the whole sample (see Figure 7a). In the public debate, the large price spikes were attributed to the increase of the gas price. Looking back at Figure 1, gas prices were merely above the level already observed during the first price spikes in March. However, Figure 7a shows that competitive prices, accounting for the increase of the gas price, remain far below the observed prices.



(a) Daily mean prices (original, competitive and with Cournot competition) for November and December 2022 with $\theta = 0.266$



(b) Daily mean prices in summer months with $\theta = 0.38$

Figure 8: Market power over time: Seasonal trends in daily mean prices with different θ values.

Another factor that these exceptional price spikes were attributed to are increasing electricity exports to e.g. France and Austria due to maintenance issues of nuclear plants in France and plunges in domestic generation in Austria due to weather conditions. The direct price effect of higher export demand is already accounted for in our model specification and would thus be reflected in competitive prices. However, from a market power perspective, less import availability also coincides with lower competition from abroad, setting a more favorable environment for domestic companies to exercise market power (Lise et al., 2006). Building on the hypothesis that the conditions during the summer months might have given more room for large companies to exercise market power, we run the model for only the summer months and find that the optimal fit is reached for $\theta = 0.38$. Figure 8b shows that with a higher θ , the Cournot model provides a good fit for high prices during the summer months. This leads to the hypothesis that firms' ability to exercise market power may not be constant over time. Further research could explore the possibility of a dynamic θ over time depending on additional market characteristics shaping the environment for exercising market power, which could increase the fit of the model.

5.6 Policy Implications

In the long run, the further implementation of renewables will decrease overall market concentration (Brunekreeft et al., 2016). However, due to the limited number of companies still participating in the thermal power plant sector, the German competition authority raises concerns that this sector is becoming even less competitive in the future (Bundeskartellamt, 2023). Therefore, tracking the impact of market power, specifically in the thermal power plant sector, as we do in our model is becoming increasingly important.

The concern about adverse impacts of market power in the German electricity market during the energy crisis has been raised by the German competition authority in their market report for 2022 (Bundeskartellamt, 2023). In our study we address and validate this concern quantitatively. We propose a novel method of quantifying the impact of market power on price formation by introducing the conjectural variation parameter θ to the Cournot model and providing a calibration method. This modeling approach can be useful for competition authorities to quantitatively evaluate the extent of market power in their area of concern.

Apart from finding ways to measure the impact of market power, it is important to think of possible ways of reducing market power ex-ante. One way could be to reform the structure of the electricity market, e.g. as proposed by Fabra (2023), who suggests to structure part of the market based on regulator backed long-term contracts. This would introduce competition in the bidding process for contracts and thus limit the opportunities for large companies to exercise market power. Further research should investigate alternative market designs mitigating the abuse of market power and quantify their impact from a scientific standpoint.

Other common policies to mitigate the impact of market power on electricity prices include regulatory measures and antitrust policies. Taking it one step further, some US electricity markets apply automated mitigation policies (AMP), where benchmarking algorithms are used to screen all bids in real time and alleviate offers where undue deviation from the

underlying costs is detected. Adelowo and Bohland (2024) show that a clustering based approach performs quite well in screening offers where bids deviate from the underlying cost in the Iberian electricity market. A wider application of AMP mechanisms in electricity markets could be discussed to limit the impact of market power on electricity prices.

6 Conclusion

Analysing possible drivers behind the record high electricity prices in Germany during the energy crisis in 2022, we show that price increases cannot be sufficiently explained by higher input costs. We extend existing literature on market power in the German wholesale electricity market by explicitly modeling market power in addition to competitive benchmark pricing and introducing the conjectural variation parameter θ to this methodology. This shows that additionally to higher input costs, market power could have been a decisive factor for price increases. Our results substantiate concerns about the potential abuse of market power through RWE, EnBW, LEAG, Uniper and Vattenfall (Bundeskartellamt, 2023) and may give rise to policy discussions on how to prevent additional price increases through the exercise of market power in order to avoid adverse effects on consumers and overall welfare losses.

Comparing the competitive prices during high demand hours to the corresponding prices of the model with market power, we find that prices were 17.45 % higher than they would have been if firms did not exercise market power. Being aware of our model's limitations, we conduct robustness checks to account for factors not included in our model. We find that price-cost margins average at 11.45 % across all simulations and robustness checks. In our model, firms benefited from the higher prices through extra profits of 11.5 bn € (or 7.45 bn € averaging over robustness checks) during the observed period. The value of θ that we find for the observed period is 0.266, where 0 would indicate a competitive market and 1 would correspond to symmetric Cournot competition.

Refining the model e.g. by including start-up costs is left for future research. Additionally, the possibility of a dynamic conjectural variation parameter θ over time could be explored, reflecting changes in the market regarding the opportunity to exercise market power. Alternative market designs or screening mechanisms that limit the possibility of exercising market power should be investigated further.

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A Appendix

A.1 Cournot Setup

Building on economic theory, we assume that, when markets are not perfectly competitive, firms exercise market power by choosing quantities in order to maximize profits as in the Cournot oligopoly framework (Cowling and Waterson (1976), Bushnell et al. (2008)). In this section, we show a static Cournot set-up assuming identical firms in order to illustrate the interpretation of θ .

From (1) we derive the inverse demand function where Q refers to the total quantity:

$$p(Q) = \frac{a - Q}{b}$$

Firm's maximize their profits by choosing quantities as in:

$$\max_{q_i} \pi_i = \frac{a - Q(q_i)}{b} q_i - C(q_i)$$

where the total quantity Q varies with the quantity supplied by the individual firm i .

Taking first order conditions:

$$\frac{\partial \pi_i}{\partial q_i} : p(Q) - \frac{1}{b} \frac{\partial Q}{\partial q_i} q_i - \frac{\partial C(q_i)}{\partial q_i} \geq 0$$

In order to define the markup term, we need to define how the total quantity changes with the supply of firm i . In the symmetric Cournot model, all firms have equal best response functions, so $Q = \sum_i q_i$ and $\frac{\partial Q}{\partial q_i} = 1$, leaving the markup term as $\frac{1}{b} q_i$. In a monopoly, $Q = q^M$, thus $\frac{\partial Q}{\partial q_i} = 1$ and the markup equals $\frac{1}{b} Q$. Under perfect competition, $\frac{\partial Q}{\partial q_i} = 0$, so there is no markup. However, making market conduct more flexible, we follow Graf and Wozabal (2013) and assume that firms choose quantities depending on their beliefs about the best responses of other firms, described by the reaction function R_{-i} :

$$Q(q_i) = R_{-i}(q_i) + q_i$$

This lets us rewrite the markup term as $\frac{1}{b} (R'_{-i} + 1) q_i$. Setting $(R'_{-i} + 1) = \theta$ we can rewrite the FOC as:

$$\frac{\partial \pi_i}{\partial q_i} : p(Q) - \theta \frac{1}{b} q_i - \frac{\partial C(q_i)}{\partial q_i} \geq 0$$

which defines the markup as we incorporate it in our model. The conjectural variation parameter θ thus describes the companies beliefs (conjecture) about how the quantity supplied by rivals reacts to changes in their own quantity, i.e. how much total quantity changes with q_i . $\theta = 1$ recovers the markup under static Cournot competition. If the market is not a monopoly, so $q_i < Q$, but the markup is higher than the one expected under Cournot competition and tends towards the monopoly markup $\frac{1}{b}Q$, θ can be larger than 1. Under perfect competition, total quantity is unaffected by the supply of firm i , so $Q = R_{-i} + q_i = -q_i + q_i$ resulting in $\theta = 0$. Higher values of θ indicate the belief that rival's quantities are more affected by variations in the own quantity, indicating a less competitive market.

A.2 Model Calibration

Firm	Energy Source	Capacity	Emission Factor	MWhin to GWhout	c1	c2
EnBW	Hard coal	3.996	987.532	2308.09	2025.37	116.866
EnBW	Lignite	0.875	1170.06	2515.09	2515.09	0.0
EnBW	Natural gas	1.46155	589.776	2658.73	287.904	2098.82
EnBW	Oil	0.718	770.191	2905.46	2379.06	1192.37
EnBW	Waste	0.0732	0.0	3030.3	3030.3	0.0
LEAG	Lignite	6.662	1170.06	2532.47	2398.17	33.1848
LEAG	Natural gas	0.1835	589.776	2879.95	2854.07	234.213
RWE	Hard coal	0.7637	987.532	2173.91	2173.91	0.0
RWE	Lignite	8.981	1170.06	2990.23	1830.82	191.618
RWE	Natural gas	3.836	589.776	2401.3	1652.4	281.959
RWE	Waste	0.065	0.0	3030.3	3030.3	0.0
Uniper	Hard coal	2.902	987.532	2685.59	2320.97	198.504
Uniper	Lignite	0.9	1170.06	2561.48	2561.48	0.0
Uniper	Natural gas	1.614	589.776	2238.39	1231.11	1023.15
Uniper	Oil	1.418	770.191	2881.98	2676.04	192.227
Vattenfall	Hard coal	2.253	987.532	2380.75	1891.98	293.977
Vattenfall	Natural gas	1.041	589.776	2413.41	1335.77	1383.82
Vattenfall	Oil	0.319	770.191	3229.11	2954.63	1073.76
Vattenfall	Waste	0.053	0.0	3030.3	3030.3	0.0
other	Hard coal	10.9911	987.532	2515.09	1911.93	95.828
other	Lignite	0.63102	1170.06	2712.92	2123.12	1809.05
other	Natural gas	15.2112	589.776	2385.69	1279.75	101.567
other	Oil	1.1979	770.191	2760.51	2398.48	531.792
other	Other fossils	0.0754	0.0	2635.73	1248.8	23627.4
other	Waste	1.36881	0.0	3030.3	3030.3	0.0

Table 2: Firm portfolios with data on thermal energy sources and their properties. Firm "other" represents the aggregate of fringe suppliers

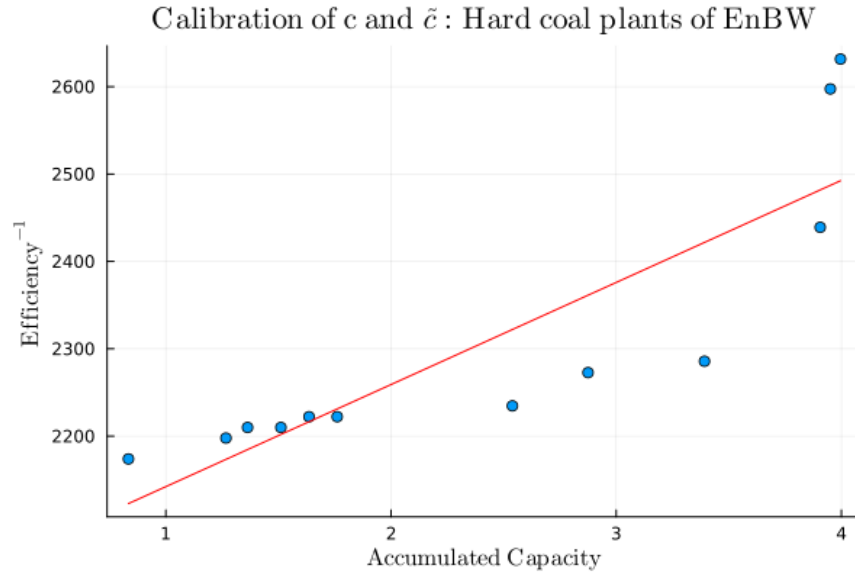


Figure 9: Linear fit of the inverse efficiency on accumulated capacity to calibrate c and \tilde{c} representing increasing marginal costs for each firm and technology. c is the intercept, \tilde{c} the slope.

A.3 Model Codes

HTML files of our datacleaning and model codes are available under this link:

Fladung_Saile_Codes

A.4 List of Abbreviations

Abbreviation	Full Term
RWE	Rheinisch-Westfälisches Elektrizitätswerk AG
EnBW	Energie Baden-Württemberg AG
LEAG	Lausitz Energie Verwaltungs GmbH
GW	Gigawatt
GWh	Gigawatt hour
MWh	Megawatt hour
CO ₂	Carbondioxide
p.c.	per capita
SMARD	"Strommarktdaten für Deutschland" from Bundesnetzagentur
OMC	Operation and Maintenance Costs
EEX	European Energy Exchange
bn	Billion
€	Euros
θ	Conjectural variation parameter
t	Day
h	Hour
f	Firm
Q	Quantity demanded
q	Quantity produced
a	Intercept of demand curve
b	Slope of demand curve
p	Price
η	Price elasticity of demand
m	Quantity of must-run plant
MC	Marginal Costs
c	Costs
\tilde{c}	Slope of costs
e	Emissions
K	Capacity
γ	Time-controls
X	Matrix of controls for must runs