SHORT STUDY

Price spikes on the German electricity market

An empirical study of the day-ahead market with regard to capacity shortages and abuse of market power in 2023 and 2024

This is a machine-translated version of a study originally published in German. The original is available at neon.energy/preisspitzen-strommarkt

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On behalf of 50Hertz Transmission GmbH

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SAPB

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This study is available at neon.energy/preisspitzen-strommarkt and on the website of the 50Hertz Scientific Advisory & Project Board.

50Hertz Scientific Advisory & Project Board. This brief study was prepared by the 50Hertz Scientific Advisory and Project Board (SAPB). The SAPB is an interdisciplinary group of professors who support 50Hertz in developing new approaches and solutions and, where appropriate, applying research findings to 50Hertz's practical work. The brief study was supported in particular by experts from TU Berlin, TU Dresden, TU Ilmenau, the Öko-Institut and IKEM.

In the context of the SAPB studies commissioned by 50Hertz, the participating scientists conduct their research freely and without preconceived conclusions. The results of the study and the recommendations for action developed from them are thoroughly reviewed and discussed by 50Hertz, but do not necessarily reflect the positions of 50Hertz.

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Table of contents

Summary

Price spikes. In the winter of 2024, the day-ahead market saw exceptionally high wholesale prices; on December 12, the price reached €936/MWh, higher than during the gas crisis. Against the backdrop of political and public debate, this brief study examines whether the observed price spikes are due to capacity shortages or potential abuse of market power – and what conclusions can be drawn from this for the design of a capacity market.

Definition. Based on a conservatively parameterized merit order approach, we define price spikes as hours in which the day-ahead price exceeds the costs of an open gas turbine, including start-up costs. In the period from 2015 to 2024, there are only 31 such hours, all of them in 2023 and 2024. They occur exclusively in situations of very low wind and PV feed-in combined with high residual load.

Power plant utilization. The plant-specific evaluation shows that a large proportion of fossil fuel power plant and pumped storage capacity was heavily utilized during price peaks. For the majority of plants that did not produce or did not produce at full capacity, there are plausible technical or operational reasons, including reserve commitments, short- and long-term unavailability, and industrial restrictions. Only around 6 GW of capacity remain without a clear explanation. Overall, the pattern points more to actual supply shortages than to systematic strategic volume restraint.

Scarcity prices. Our findings suggest that the price peaks in the winter of 2023/24 can be interpreted economically as scarcity prices, in which rarely operating peak load power plants achieve contribution margins above their variable costs. In comparable supply and demand situations, renewed price peaks are therefore to be expected.

Capacity market. The price peaks clearly show that the actual available generation capacity is significantly below the installed nominal capacity according to publicly available data sources (Federal Network Agency's list of power plants), presumably due to aging, maintenance, or technical malfunctions. A reliable assessment of secured capacity therefore requires a consistent and up-to-date data basis on installed capacity and actual availability. The capacity factors observed during price peaks—around 75% for gas and lignite, around 50% for hard coal, and only 30% for pumped storage—underscore that conventional plants must be taken into account in the capacity market with realistic, in some cases significantly higher, de-rating factors.

1 Introduction

Figure1 shows how exceptional these price peaks were. Prices last winter even exceeded the prices seen during the energy crisis of 2022/23 in some hours. On the one hand, wind and PV power generation was very low. On the other hand, many conventional power plants did not generate electricity at full rated capacity despite the high prices. These observations led to an intense political and public debate about the function and resilience of the German energy system.

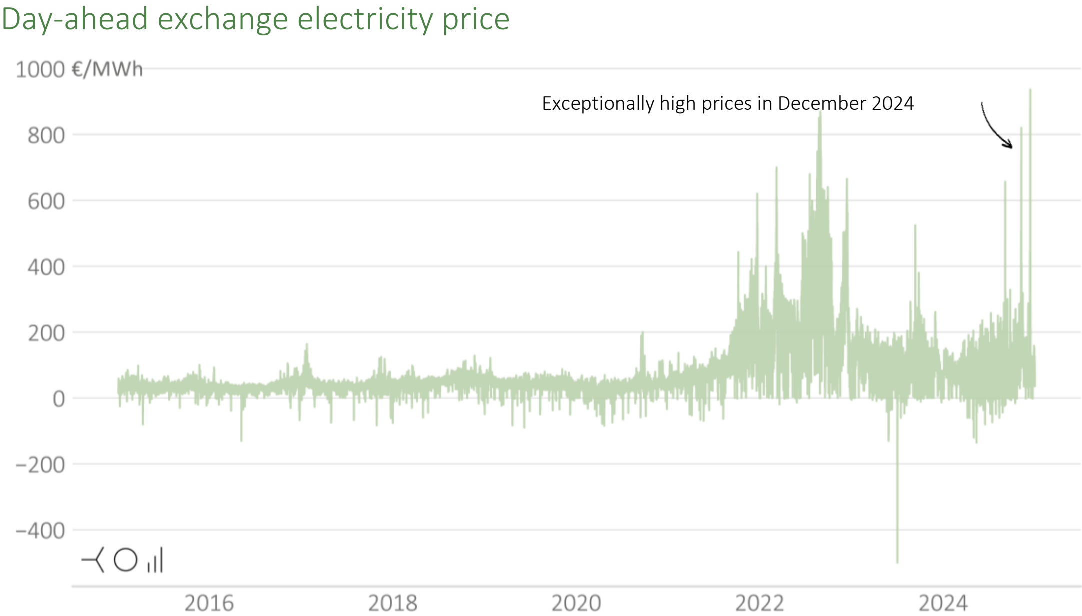

Figure1 : Day-ahead exchange electricity price per hour for the period 2015 to 2024 (Source: Federal Network Agency/SMARD)

Objective. We aim to achieve three objectives with this study. First, we develop a definition of price spikes and identify 31 hours with price spikes within the last 10 years. Second, we discuss theoretically the two main reasons for price spikes: scarcity of generation capacity and abuse of market power. Finally, we empirically examine the behavior of power plants during price spikes in the last year.

Report. Against the backdrop of public debate, the Federal Network Agency and the Federal Cartel Office also investigated the price spikes in December 2024. The recently published report concludes that there were no supply security problems and that no abuse of market power could be proven. Our short study, which was conducted independently of the report, concurs with the findings of the authorities' report, while also going beyond it in important areas, as the report did not examine technology-specific power plant utilization or the economic causes of the price spikes. This study thus deepens our understanding of price formation in the German electricity market in the mid-2020s and provides important impetus for a possible reform towards a capacity market.

2 Identification of price spikes

In this section, we explain when we refer to the hourly day-ahead price as a "price spike": namely, whenever prices can no longer be explained by generation costs alone. Based on this definition, we identify a total of 31 hours with price spikes in the last 10 years, the majority of which occurred at the end of 2024.

2.1 Definition of price spikes

High electricity prices. Not every high price is a price spike. Electricity prices fluctuate greatly – sometimes within a matter of hours. These short-term price fluctuations distinguish electricity markets from other commodity markets. The reason for this lies in a key characteristic of electricity: its lack of storability. As a result, changes in supply have an immediate impact on prices – for example, when available generation is low, as in the case of a dark doldrums, or in the future in the event of a general energy shortage. Similarly, high fuel prices, as during the energy crisis, lead to significantly higher electricity prices. Finally, large short-term load changes can also require power plants to ramp up and down rapidly, causing very high prices for a short period of time.

Merit order model. In order to distinguish between high prices on the electricity market and price spikes, we first need to consider the basic mechanisms of short-term price formation. The merit order model describes how the price of electricity is formed on the basis of variable generation costs. In short-term economic equilibrium, the installed generation capacity is fixed and cannot be changed. Because investment and fixed costs are irreversible ("*sunk* costs"), they do not play a role in production decisions. A power plant produces electricity as long as the market price covers its variable costs – and stops production as soon as the price falls below this level. Sorting the power plants according to their variable costs results in a supply curve whose intersection with demand (which is largely price-inelastic in the short term) determines the market price (Figure 2). The power plant at this point—the marginal power plant—sets the price. The merit order model thus explains why the price of electricity generally corresponds to the variable costs of the most expensive power plant needed to meet demand.

Price formation in the merit order model

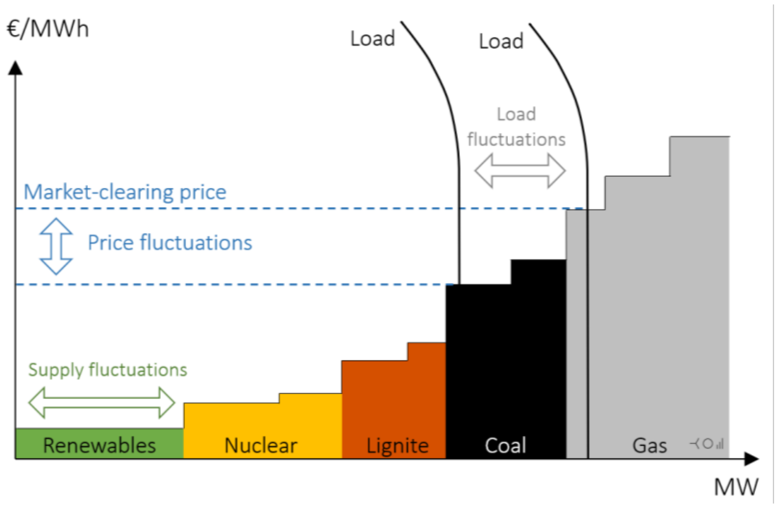

Figure 2 : The merit order model conceptually describes how prices are formed on short-term wholesale markets for electricity. The merit order represents the power plants in the electricity market, arranged in ascending order according to their production costs, i.e., without taking investment costs into account.

Start-up costs. In its simplest form, the merit order model describes an electricity market in which power plants are completely flexible and each hour is considered independently of the others. In reality, however, this is only true to a limited extent: the start-up and shutdown of large thermal power plants incurs considerable start-up costs – both in terms of additional fuel consumption and wear and tear and maintenance costs. In addition, many plants need several hours, sometimes days, to become operational. These technical and economic constraints mean that producers cannot make new decisions about their deployment every hour. Instead, they must determine in advance which plants will participate in the market ("unit commitment"). As a result, the short-term price in individual hours may exceed the pure variable costs. We explicitly take such effects into account in our definition of price spikes by including start-up costs in the calculation of the cost threshold.

Cost threshold. We define "price spikes" on the day-ahead market as prices that can no longer be explained solely by the variable costs and start-up costs of even the most expensive power plants. We use the costs of a natural gas-fired open gas turbine as a reference point for the most expensive power plant, because this is typically the most expensive thermal power plant used to cover peak loads. Theoretically, the cost threshold could also be based on even more expensive technologies, such as gas turbines fired with extra light heating oil (HEL). However, HEL-fired gas turbines play only a very minor role in the German electricity market and do not typically participate regularly in the day-ahead market. The marginal costs of an open gas turbine, on the other hand, can be derived in a robust and comprehensible manner on the basis of transparent input variables. With a view to future system development, gas-based peak load technology remains significantly more relevant than HEL-fired plants.

Quantification. According to this definition, a price spike occurs when the observed day-ahead price in one hour exceeds the variable costs of an open gas turbine, taking into account start-up costs. We calculated the marginal costs resulting from the natural gas price, CO_2 costs, technology-specific efficiency, and operating and start-up costs using the formula shown inFigure2 . Start-up costs are only taken into account in the hour in which the actual electricity price exceeds the cost threshold for the first time during the day.

$$\text{Kosten einer offenen Gasturbine (€/MWh)} = \frac{(\text{Erdgaspreis} + \text{Gasspeicherumlage}) + (CO_2\text{-Preis} \cdot \text{Emissionsfaktor})}{\text{Wirkungsgrad}} + \text{Betriebskosten} + \text{Anfahrtskosten (1x täglich)}$$

Figure2 : Formula for calculating the marginal costs of an open gas turbine.

Parameterization. The parameter values are assumed conservatively. This ensures that we actually determine realistic generation costs for plants at the far right of the merit order, for example, a low efficiency of 30%[1] , operating costs of €2.5/MWh, and high start-up costs of €200/MW incurred once a day. Other parameters included in the calculation are the emission factor of 0.2 t CO2/MWh and the daily gas price (TTF future) and CO2 price (ICE EUA). The sum of these factors results in the total costs, which reflect the rational market offer of the open gas turbine as the price cap in the market. On the day with the most expensive day-ahead hourly price in the last 10 years, December 12, 2024, the observed exchange electricity price exceeds the modeled costs of an open gas turbine continuously for 14 hours (Table1).

Table1 : Day-ahead prices and marginal costs of the open gas turbine in hours with price peaks on December 12, 2024.

Date	Day-ahead Exchange electricity price (€/MWh)	Costs of open gas turbine (€/MWh)
12/12/24 07:00	600	41
12/12/24 08:00	656	218
12/12/24 09:00	647	218
12/12/24 10:00	544	218
12/12/24 11:00	465	218
12/12/24 12:00	405	218
12/12/24 1:00	415	218
12/12/24 2:00	490	218
12/12/24 3:00 p.m.	668	218
12/12/24 4:00 p.m.	819	218
12/12/24 5:00 p.m.	936	218
12/12/24 6:00 p.m.	674	218
12/12/24 7:00 p.m.	551	218
12/12/24 8:00 p.m.	296	218

2.2 IDENTIFICATION OF PRICE SPIKES

A new phenomenon. Over the entire 10-year analysis period, price spikes occurred in only 31 individual hours. They are therefore an extremely rare phenomenon, occurring in only 0.04% of all hours. It is noteworthy that all 31 price spikes occurred in the last two years of the study

[1] Based on the lower heating value Hi for technical efficiency, corresponds to 27% based on the upper heating value Hs, standard market fuel prices

period: in September 2023 and in September and November, and December 2024 (Figure 4). Price spikes are therefore empirically a new phenomenon in the German electricity market. It is also noteworthy that although the price level was high during the energy crisis of 2021/2022, there were no price spikes in our sense of the term. This suggests that the extremely high electricity prices during the crisis can be explained entirely by the massive increase in fuel prices, especially high natural gas prices. The 31 hours identified thus represent price events in which market prices exceeded the pure short-term costs of the most expensive marginal power plant.

Electricity price peaks since 2015

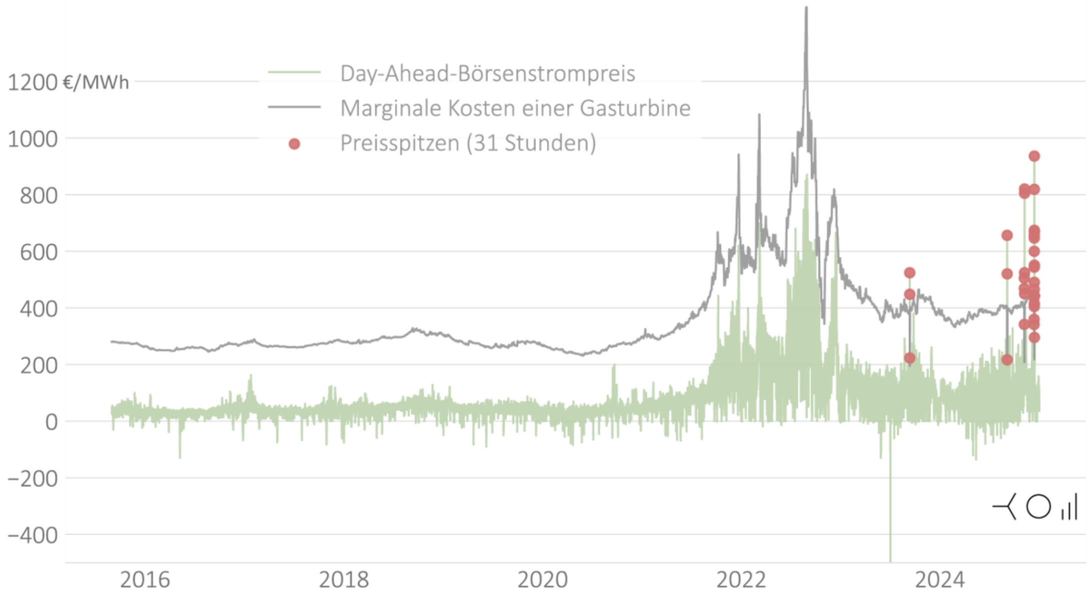

Figure 4 : Day-ahead electricity prices (green, source: Federal Network Agency/SMARD) and the modeled marginal costs of an open gas turbine (gray) in the period from 2015 to 2024. Red dots mark the 31 identified price peaks.

Characteristics of hours with price peaks. In order to classify the identified price peaks, we compared electricity generation and load during the affected hours in September, November, and December 2024 with all other hours in the second half of 2024. This analysis shows that generation from renewable energies was very low during the hours with price peaks (Figure 5 , left). This low generation from renewables coincided with high electricity demand, which was reflected in an above-average residual load (Figure 5 , center). The residual load—the demand that cannot be met by fluctuating renewable generation—was at the upper end of the distribution during these hours, at >60 GW. The high residual load is typical for the early evening hours in autumn and winter, when the hours with price peaks mainly occurred. The residual load is usually covered by imports and generation from fossil fuel power plants. The latter was also high at 30 to 45 GW compared to all other hours, suggesting that the majority of fossil fuel power plants generated electricity during these hours. To find out whether additional fossil fuel capacity could have been mobilized, we examine the activity of individual fossil fuel power plants and their generation during the critical hours in Section 4.

Generation and load in hours with price peaks

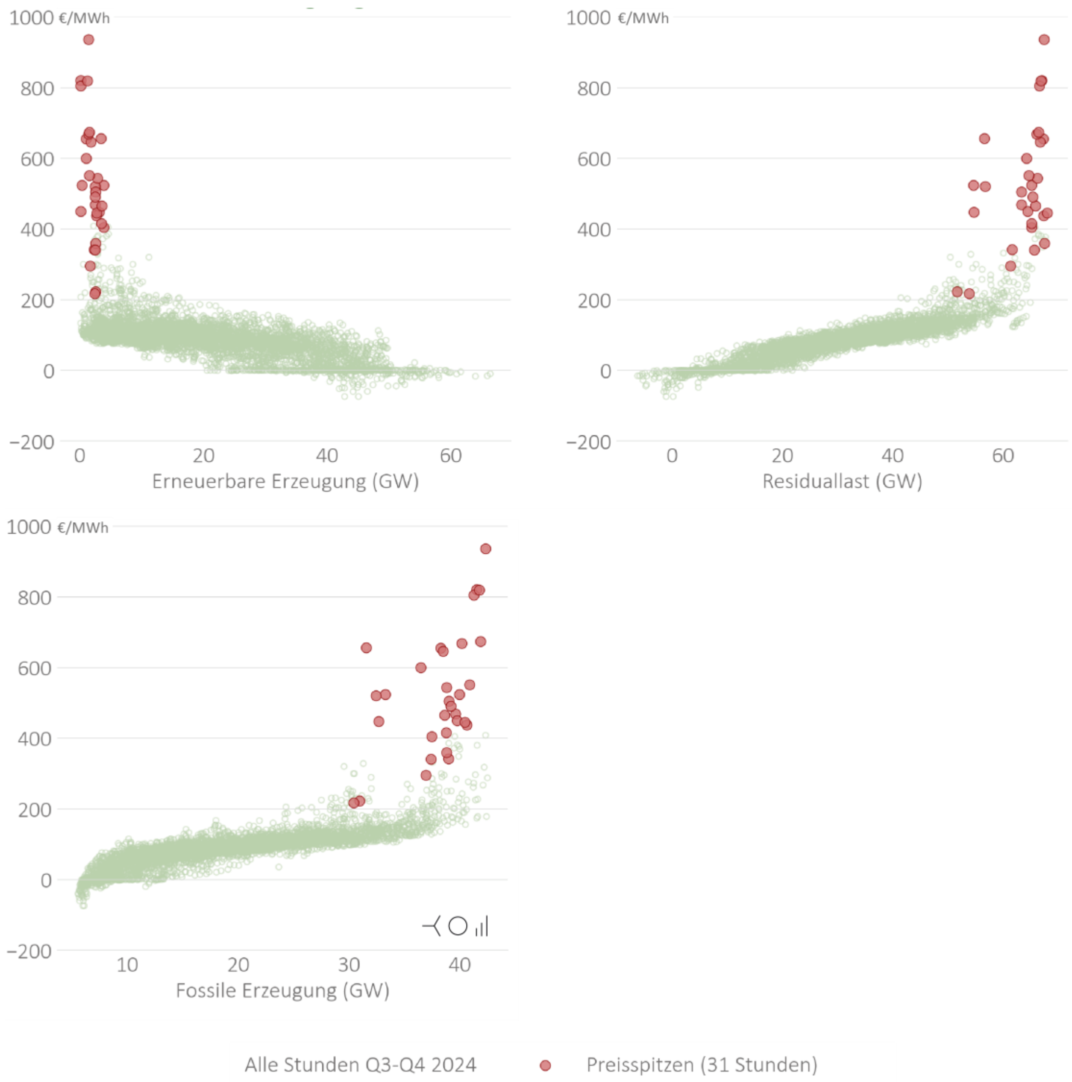

Figure 5 : All hours in Q3-Q4 in 2024 (green) and hours with price peaks (red). Renewable generation: PV, onshore wind, offshore wind. Fossil generation: nuclear, hard coal, lignite, gas, pumped storage, other fossils. Residual load is defined as grid load minus PV and wind generation. The grid load results from net electricity generation minus export transmission capacity plus import transmission capacity minus the storage capacity of pumped storage power plants (source: ENTSO-E via Federal Network Agency/SMARD).

3 Explanations for price spikes

In this chapter, we consider two economic explanations for price spikes: scarcity prices and strategic quantity restraint.

3.1 Scarcity prices

Covering fixed costs. The merit order model presented in the previous chapter describes the electricity market in short-term equilibrium: the price corresponds to the variable costs of the most expensive power plant needed to meet demand. Investment and fixed costs do not play a role here. In the long term, however, such a market mechanism cannot lead to an economically viable power plant fleet. In theory, the last power plant required to meet demand runs for exactly one hour. During this hour, the power plant cannot generate any profit above its variable costs and therefore cannot cover its fixed and investment costs. Inframarginal power plants can generate a contribution margin, but this may not be sufficient to refinance their investment costs.

Scarcity prices. The theory of scarcity pricing ("peak load pricing" or "scarcity pricing") describes how fixed costs can also be refinanced in a long-term market equilibrium. In a highly simplified system with completely price-inelastic demand—i.e., when electricity consumption remains constant regardless of price—the market price continues to correspond to the variable costs of the marginal power plant in almost all hours. Only during a few hours of particularly high demand does the price rise significantly above this level, allowing the fixed costs of the generation plants to be covered. During these hours, available capacity is scarce, and the resulting high price is referred to as the scarcity price.

Literature. This idea is by no means new: the foundations of peak load pricing theory were developed as early as 1949 by Marcel Boiteux (English republication in 1960), an economist and later head of Électricité de France. In the 1950s and 1960s, the concept was further developed by contributions from Houthakker (1951), Steiner (1957), and Hirshleifer (1958) and generalized in various models. Crew et al. (1995) provide an overview of this literature, and Green (2005) offers an accessible presentation.

Screening curve model. The screening curve model shows how these long-term equilibria can be derived. It combines the short-term order of priority for power plants (merit order) with their long-term cost structures and illustrates how both the optimal power plant mix and the level of scarcity prices are determined. Each generation technology is described by a cost line (screening curve) that shows its total costs per MWh—consisting of fixed and variable costs—as a function of the number of full-load hours (seeFigure3). The more frequently a plant runs, the more its fixed costs are distributed across the amount of energy generated. The intersection of the screening curves of different technologies determines which technology is most cost-effective in which load range: base load power plants (e.g., nuclear energy) with high fixed and low variable costs, medium load plants (coal), and peak load power plants (gas, diesel) with increasingly lower fixed costs but higher variable costs. In combination with the load duration curve, it becomes clear that only a few hours per year require very high prices so that even rarely used peak load plants can cover their fixed costs. In order for this "last power plant" to be operated economically despite low operating times, the price must rise so high during these few hours that the fixed costs are refinanced. In the theoretical limit case with completely price-inelastic demand when considering a year, the price can correspond to the annualized fixed costs plus variable costs in exactly one hour of the year (in the example fromFigure3 exactly €130,060/MWh).

Screening Curve Model

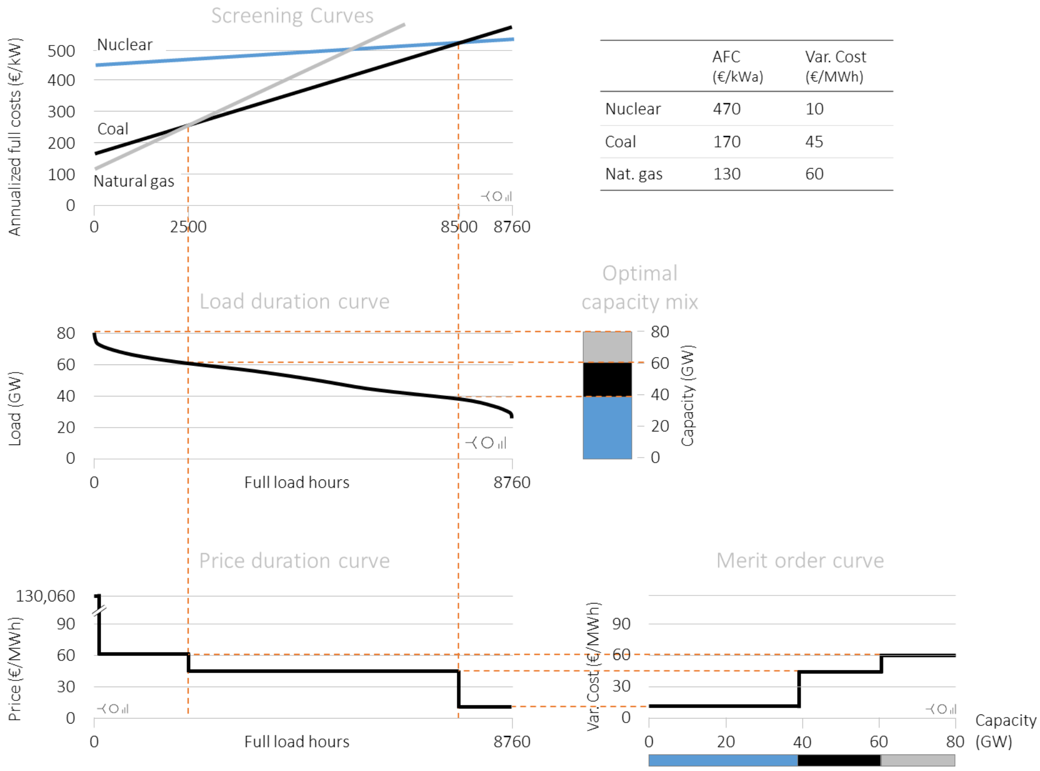

Figure3 : Screening Curve Model. Source: Open Electricity Economics based on *Electricity and Markets* by Richard Green , 2005.

Decommissioning and investment incentives. If scarcity prices do not materialize or are prevented by regulation—for example, if price spikes are mistakenly interpreted as the result of abuse of market power—producers cannot cover their fixed costs and will not invest. If, on the other hand, prices rise permanently above the level required to cover costs, operators will generate excess profits. These excess returns attract new investors, creating additional capacity and increasing competition. As a result, prices fall again. Prices continue to fall until a long-term equilibrium is reached in which all producers cover their costs but do not earn excess profits. These arguments apply to a long-term economic equilibrium in which key parameters (availability of technologies, fuel prices, etc.) remain stable.

Model assumptions and demand behavior. The above description greatly simplifies reality in order to make the mechanisms analytically comprehensible. In reality, the price level in situations of scarcity would be high, but not as extreme as suggested by the theoretical model fromFigure3 . The electricity market encompasses significantly more technologies, including very expensive peak load plants such as older gas or diesel power plants, which provide additional supply during bottleneck phases. In addition, consumers respond at least partially to price signals when prices are very high. If demand decreases as prices rise, scarcity prices do not occur in a single hour, but in several phases with a tight supply situation. A theoretical price limit results from consumers' willingness to pay. Above this value, it would be cheaper for consumers to reduce their consumption than to continue purchasing electricity.

Usefulness. The theory of scarcity prices is not a forecasting model in the strict sense, but describes the economic logic behind high prices. In reality, for the reasons mentioned above, there are no individual hours with extreme price levels, but rather several hours in which electricity prices exceed the variable costs of peak load power plants. Over these hours, the plants generate the necessary contribution margins to refinance their fixed costs – for example, ten hours at around €13,060/MWh instead of a single hour at €130,060/MWh. At the same time, the theory illustrates that the economic value of electricity in situations of scarcity can be many times higher than in normal operation. Compared to these theoretical values, the prices actually observed last year are still very moderate.

Conclusion. Prices that are significantly higher than the variable costs of the most expensive power plant are to be expected because they result from market equilibrium in situations of scarcity. They are also necessary to refinance the fixed and investment costs of generation capacities and are fundamentally compatible with functional competition. Such scarcity prices per se are therefore not a sign of market failure, but a necessary element of a functioning electricity market that secures long-term investment and guarantees security of supply. The fact that they did not occur in the past would therefore merely be a sign that the market did not offer sufficient profits for new investments in peak load power plants. From this perspective, the occurrence of price spikes in the German electricity market can be seen more as a sign of normalization than as a cause for concern.

3.2 STRATEGIC VOLUME RESTRAINT

Strategic volume restraint. Another possible reason for high wholesale prices is strategic volume restraint by producers. This refers to the deliberate withholding of generation capacity by individual market participants in order to artificially increase the market price. This requires market power, i.e., the ability to influence prices through one's own behavior. In most situations, only a few companies in Germany have the necessary size to do this. In situations of scarcity, however, all power plants are needed to meet demand and are known as "pivotal power plants." This also changes the incentives for *all* power plants available in these situations compared to normal situations. In particular, players who would not have market power in other situations could also bid above their variable costs. In practice, however, abusive behavior is difficult to prove, as not every instance of unavailability or high bidding automatically indicates manipulation.

Reasoning: Economically, strategic withholding of supply is rational if the increase in profits due to higher market prices exceeds the lost revenue of the plants that are not operating or not operating at full capacity. The mechanism is similar to classic oligopoly behavior: by reducing the available supply, a company increases the market price for all remaining quantities. This allows a company's overall profits to increase despite lower physical production.

Forms of quantity restraint. In practice, strategic quantity restraint can take various forms:

- Non-marketing of available capacity: Plants are not brought onto the market at all or only partially. Often, plants for which "plausible reasons" such as heat supply obligations can be cited are selected.
- Excessive bids ("economic withholding"): Power plants offer their energy at prices that are significantly above marginal costs, which means they are no longer included in the merit order. The price rises because cheaper capacities appear to be lacking.
- Reporting unavailability ("physical withholding"): Capacities are reported as technically unavailable—for example, due to alleged malfunctions or maintenance. Instead of provoking malfunctions, actual malfunctions can of course also be remedied more slowly than possible. This reduces the available supply on the spot market.

Empirical evidence. Empirical analyses of international electricity markets show that strategic withholding of capacity does occur statistically. A recent study by Xu et al. (2025) finds evidence of strategic withholding of capacity in about 8% of hours on the German market, caused in particular by combined cycle gas and steam power plants (CCGT). According to this study, the probability that a plant will not produce increases by around 1 percentage point for each additional euro of profit per MW that the operator receives due to a higher market price. With a potential additional revenue of €200/MW, the probability that a plant will be shut down increases from around 24% to 71% (Xu et al., 2025).

Hedging. In practice, however, there are strong economic incentives against strategic volume restraint. Many producers have already sold a large portion of their expected electricity production on a long-term basis through forward contracts. Hedging strategies allow producers to secure prices and revenues in advance, thereby reducing the impact of short-term spot market prices on profits. From a risk hedging perspective, this is a rational and common practice for companies. Shortly before delivery, producers have usually hedged a large portion of their production. A high hedge ratio significantly weakens the incentive for strategic restraint: if, for example, a company has already sold 99% of its expected production at fixed prices, a price increase on the spot market would only generate additional profits for the remaining 1%. The economic benefit of an artificial price increase thus falls to almost zero.

Hedging ratios of companies over time

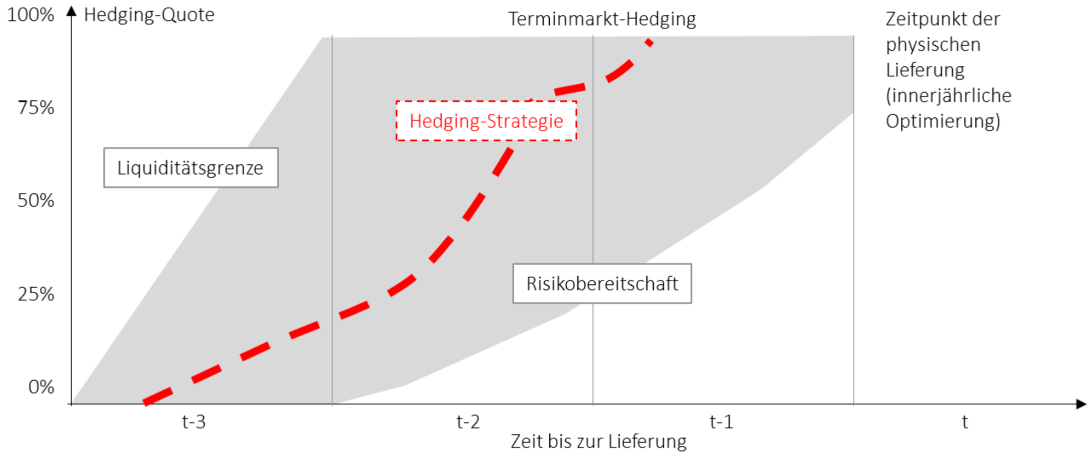

Figure4: Change in the volumes typically hedged by companies over time (source: own representation)

Hedging during price peaks. However, hedging is typically carried out predominantly with peak and base forward contracts. As a result, companies may be 100% hedged *on average* over all hours of a month, but significantly less or more in individual hours. In peak load situations, when above-average amounts of electricity are generated, producers are therefore usually hedged at significantly less than 100% of their generation. During such hours, the potential profit from a price surge increases – and with it the incentive to strategically hold back capacity.

Conclusion. Strategic Withholding supply can lead to price spikes if market participants have sufficient market power and regulatory oversight is ineffective. Withholding supply to exercise market power is illegal, but in practice it is difficult to clearly distinguish this from legitimate technical or economic reasons. In practice, however, strategic quantity restraint requires complex trading strategies and optimization across the entire portfolio. In theory, extensive hedging positions significantly reduce the incentive, but do not offer complete protection. Effective market surveillance should therefore focus not only on company size, but also on hedging profiles and bidding behavior in order to identify risks of manipulation in situations of scarcity at an early stage. In our quantitative analysis, we therefore also examine the availability of individual power plant units, but present results only in aggregate form by technology.

4 Plant-specific power plant analysis

In this section, we examine the generation behavior of conventional power plants during hours with identified price spikes. In particular, we examine whether additional fossil fuel generation capacity would actually have been available during these hours and identify various reasons and operating conditions that provide plausible hypotheses as to why individual power plant units did not deliver their maximum generation output.

Installed capacity. For our analysis, we used the generation data of fossil fuel and hydroelectric power plants reported via the ENTSO-E Transparency Platform. We focus on lignite, hard coal, natural gas, and pumped storage power plants. Since only plants greater than or equal to 100 MW are reported on the ENTSO-E Transparency Platform and feed-ins to industrial, railway, and local networks are not taken into account, the total capacity of these plants is less than the combined installed capacity of these technologies in Germany. This becomes clear when compared with the net installed generation capacity reported by the BNetzA (Figure 8), which shows all plants with at least 1 MW of installed capacity. Coverage is particularly low for natural gas. Here, the power plants reported via the transparency platform add up to just under half of the capacity according to the BNetzA list. The fact that generation data for smaller plants is not available is acceptable for the analysis in this study, as it can be assumed that small players have little market power potential.

Installed capacity in the data set compared to the BNetzA list

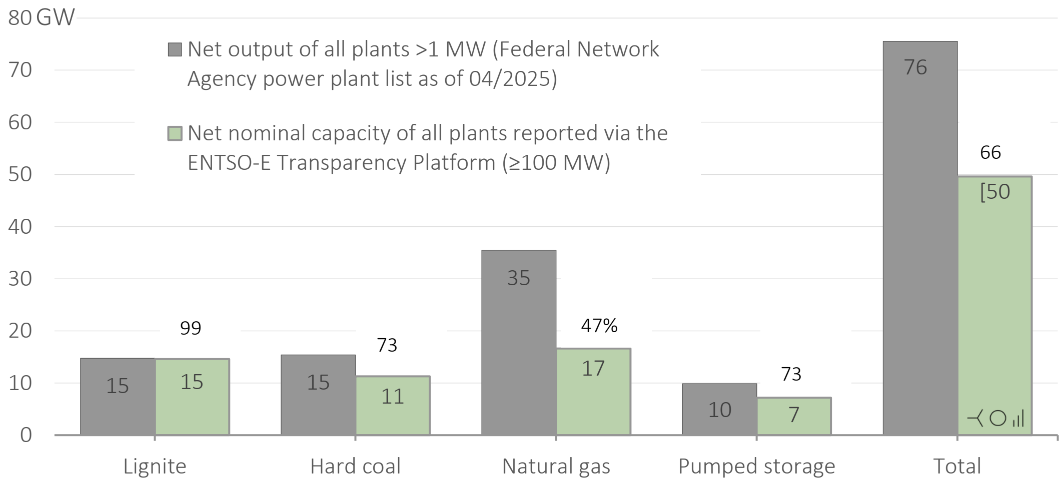

Figure 8 : Net nominal capacity of all plants >1 MW (gray) published by the Federal Network Agency and net nominal capacity of all plants ≥100 MW (green) reported on the ENTSO-E Transparency Platform. Right: Total of the technologies shown.

Data quality. When interpreting the results, it must be taken into account that the quality of the reports—both in terms of generation and planned maintenance and unplanned repairs—is difficult to verify and may not be representative of the entire plant portfolio.

4.1 Hypotheses on the activity of individual power plants

Scarcity prices. Peak prices on the electricity market can be interpreted as economically legitimate scarcity prices if even the marginal fossil fuel power plants are operating at full capacity during price peaks. In this case, the price offered exceeds the variable marginal costs of the most expensive power plant.

Operating at full capacity. Our analysis aims to verify this assumption based on the actual generation behavior of the plants. To do this, we examine for each individual price peak for each individual plant whether it generated electricity and how much. We define a plant as "operating at full capacity" if its generation is close to its maximum generation capacity, i.e., at least 80%. With the threshold value of 80%, we take into account possible operating restrictions, such as reserve power provision or ramp restrictions. For combined heat and power (CHP) plants, we have granted a larger flat-rate discount of 50%, as CHP plants generate electricity and useful heat at the same time and the extraction of heat requires a necessary reduction in the maximum possible electrical output compared to pure condensation operation. The threshold value of 50% has been deliberately chosen to be generous in order to distinguish between technically and economically limited production and the potential strategic withholding of capacity.

Maximum generation capacity. We did not use the theoretical net rated capacity from the Federal Network Agency's list of power plants as the maximum generation capacity, but rather the actual observed maximum generation of the respective plant in the period from September to December 2024. In doing so, we take into account the fact that plants may not be able to achieve their theoretical net rated capacity due to their age, technical condition, or current stage in the maintenance cycle. For most plants, the listed nominal output corresponds to the observed maximum generation. In a few cases, the values differ by up to 20%. In fact, the observed maximum generation capacity for a few plants was even higher than the nominal output listed in the Federal Network Agency's power plant list.

Limited or no generation. In addition to plants operating at full capacity, we identify those units that do not produce at full capacity or do not produce at all during price peaks, but for which there is a plausible hypothesis for this behavior. Such "good reasons" include commitment to the grid or capacity reserve, industrial operating restrictions, permanent inactivity due to decommissioning, or unavailability reported via the ENTSO-E Transparency Platform due to planned maintenance work or unplanned outages. The interpretation of price spikes as legitimate scarcity prices is strengthened if plausible hypotheses can be formulated for the majority of plants that are not producing at full capacity or not producing at all.

Abuse of market power. The possibility of abuse of market power or strategic withholding of generation capacity is an obvious alternative explanation for the observed price spikes when generation plants are not producing or are producing only to a limited extent without a plausible hypothesis. In the absence of these reasons, the unused capacity could indicate a deliberate supply shortage with the aim of driving the price above the level of the pure scarcity price. It should be noted at this point that, although we consider reported unavailability to be a plausible explanation in our analysis, it is conceivable that such reports are used as a strategy to conceal volume restraint.

Categorization. We summarize the criteria for the listed categorization of plants inTable2 . In our analysis, we took a step-by-step approach to categorization in order to identify those plants that did not produce at full capacity without a plausible hypothesis.

Table2 : Plant categorization in hours with price peaks.

Category	Hypothesis	Definition
All reported plants		All plants for which generation data was reported on the ENTSO-E Transparency Platform between September and December 2024.
Full producing		Plants that produced at full capacity on a day with price peaks. This means that generation was not less than 80% of maximum capacity in more than 30%* of the price peak hours of a day. For CHP plants, the capacity criterion is 50%. Maximum capacity is defined as the maximum observed generation capacity between September 1, 2024, and December 31, 2024. * The number of hours with price peaks varies between 3 and 14 hours per day. With the tolerance criterion of 30% of hours, we ensure that normal operational fluctuations and short-term restrictions are not mistakenly interpreted as deliberate volume restraint.
Not producing at full capacity or no production with plausible hypothesis	grid or capacity reserve	Plants in the grid or capacity reserve
	Industrial processes	Only applies to by-product gas plants, i.e., combined cycle power plants with integrated coal gasification. These burn gas from industrial processes and are therefore limited in their electricity generation by the operation of industrial plants and the availability of by-product gas.
	No generation	Plants that did not generate any electricity during the entire period (September 1 to December 31, 2024) but were nevertheless reported on the ENTSO-E Transparency Platform.
	Long-term Unavailable	Plants that were reported as unavailable on the ENTSO-E Transparency Platform, i.e., reports were received more than 5 days before an hour with price peaks.
	Short-term unavailable	Plants that were reported as unavailable on the ENTSO-E Transparency Platform at short notice: 1) Notification within 5 days prior to a peak price hour or 2) Notification only after the peak price hour but for the period of the peak price hour
Not fully producing without hypothesis		Plants that do not meet any of the above criteria.

4.2 IDENTIFICATION OF GENERATION NOT RUNNING AT FULL CAPACITY

Procedure. The analysis of the generation behavior of conventional power plants during price peaks divides the total generation output (dark gray) into three categories (Figure5): the output of plants that produced at full capacity (light gray); 2) the output of plants that did not produce at full capacity or did not produce at all, but for whose behavior there is a plausible hypothesis (light green); 3) the output of plants that produced at full capacity without a plausible hypothesis (dark green).

Categorization of the activity of individual plants during price peaks

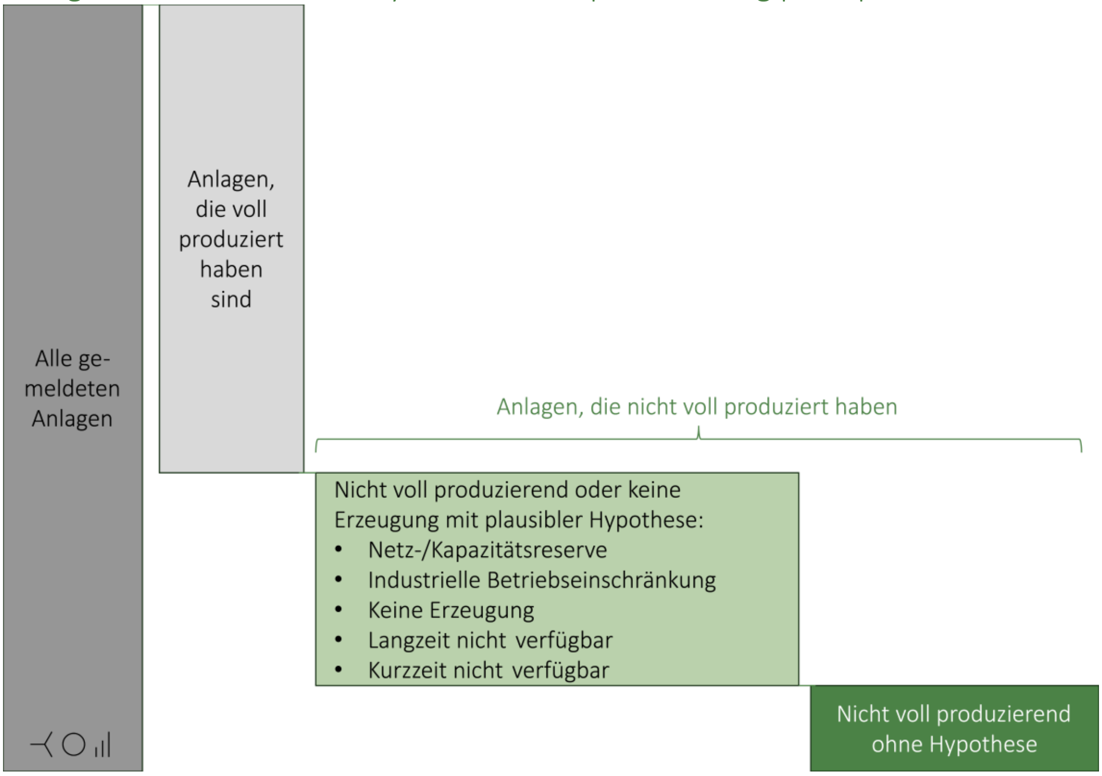

Figure5 : Schematic representation of the categorization of individual plants. The categorization corresponds to the criteria listed in Table 2.

Scarcity.Figure 10 shows the average generation capacity per category in waterfall charts for the six days with price peaks (28 hours) in 2024. The majority of gas, hard coal, and lignite power plants, which account for the bulk of fossil fuel generation capacity, either produced at full capacity during hours with price peaks or there was a plausible hypothesis for the limited production. Crucially, only a very small proportion of gas-fired power plants (less than 2 GW) did not produce at full capacity without a plausible hypothesis. This indicates a high degree of capacity utilization and suggests that the observed price spikes signaled scarcity.

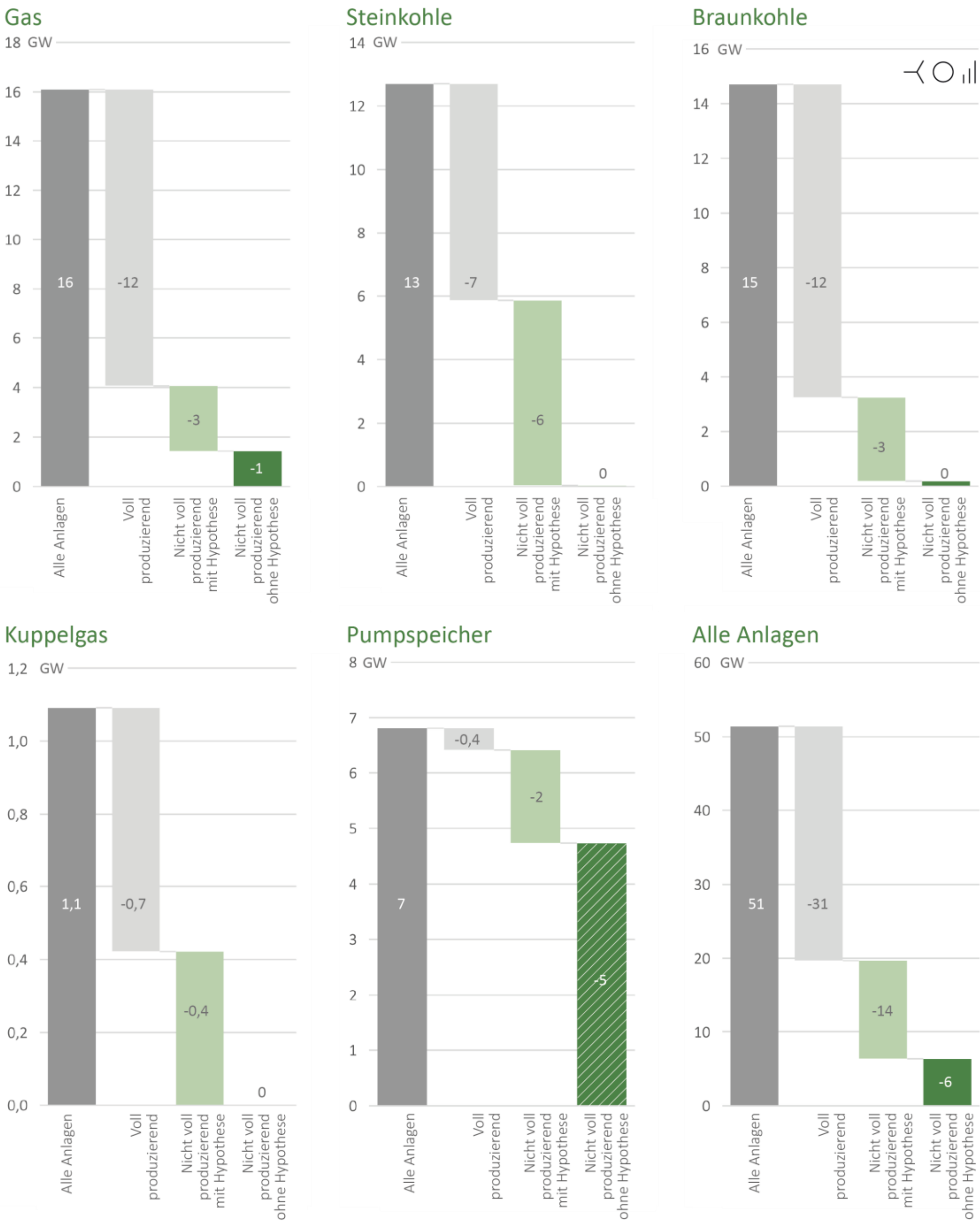

Figure 10 : Average generation capacity per technology in all hours with price peaks in 2024 (28 hours). The categorization of the plants is described inTable2 . The capacity of all plants per technology (dark gray) refers to the maximum observed generation capacity in Q4 2024.

Unavailable output. Analysis of plant activity shows that a significant proportion of fossil fuel generation capacity was not available on the market during peak price hours. Short-term unavailability can be caused by unforeseen technical malfunctions (e.g., component defects), while long-term unavailability is typically due to scheduled, extensive maintenance work and overhauls. In particular, a significant proportion of the reported gas, hard coal, and lignite plants were either unavailable in the short or long term or tied up in the grid or capacity reserve (Figure6). This unavailability was particularly severe in the case of hard coal ( ): here, this category accounted for almost 50% of the capacity reported via the ENTSO-E platform.

However, the most important reason for this is that around a quarter of the capacity is tied up in grid and capacity reserves. Across all the power plants examined, short-term unavailability also plays a major role: in total, more than 10% of generation capacity was reported as unavailable at short notice. This tied-up or unavailable capacity reduced the supply available on the market and thus increased scarcity. In their analysis, the Federal Network Agency and the Federal Cartel Office also intensively examined the plausibility of the reasons reported by power plant operators for unavailability during price peaks. To this end, the authorities compared the information with the results of balancing power auctions, drew on findings from surveys of heat-led power plants, and checked the plausibility of technical parameters such as start-up times. Overall, no anomalies were found.

Pumped storage power plants. One striking aspect is the behavior of pumped storage power plants. Of the nearly 7 GW of installed capacity, less than 1 GW on average generated full power during price peaks. A good two-thirds of the capacity did not produce full power according to our definition. However, unlike other conventional plants, pumped storage power plants are limited in their operation by their variable storage levels or relatively low capacity, which is why technical restrictions cannot be ruled out as "good reasons" here. The current storage level is in turn heavily dependent on how electricity prices have developed in the hours and days prior. Pumped storage power plants may also have been guided by lower intraday prices and therefore not produced any electricity – a hypothesis put forward by the Federal Network Agency and the Federal Cartel Office in their report. Nevertheless, this observation has implications for security of supply and capacity mechanisms: clearly, these power plants cannot be regarded as reliably available capacity.

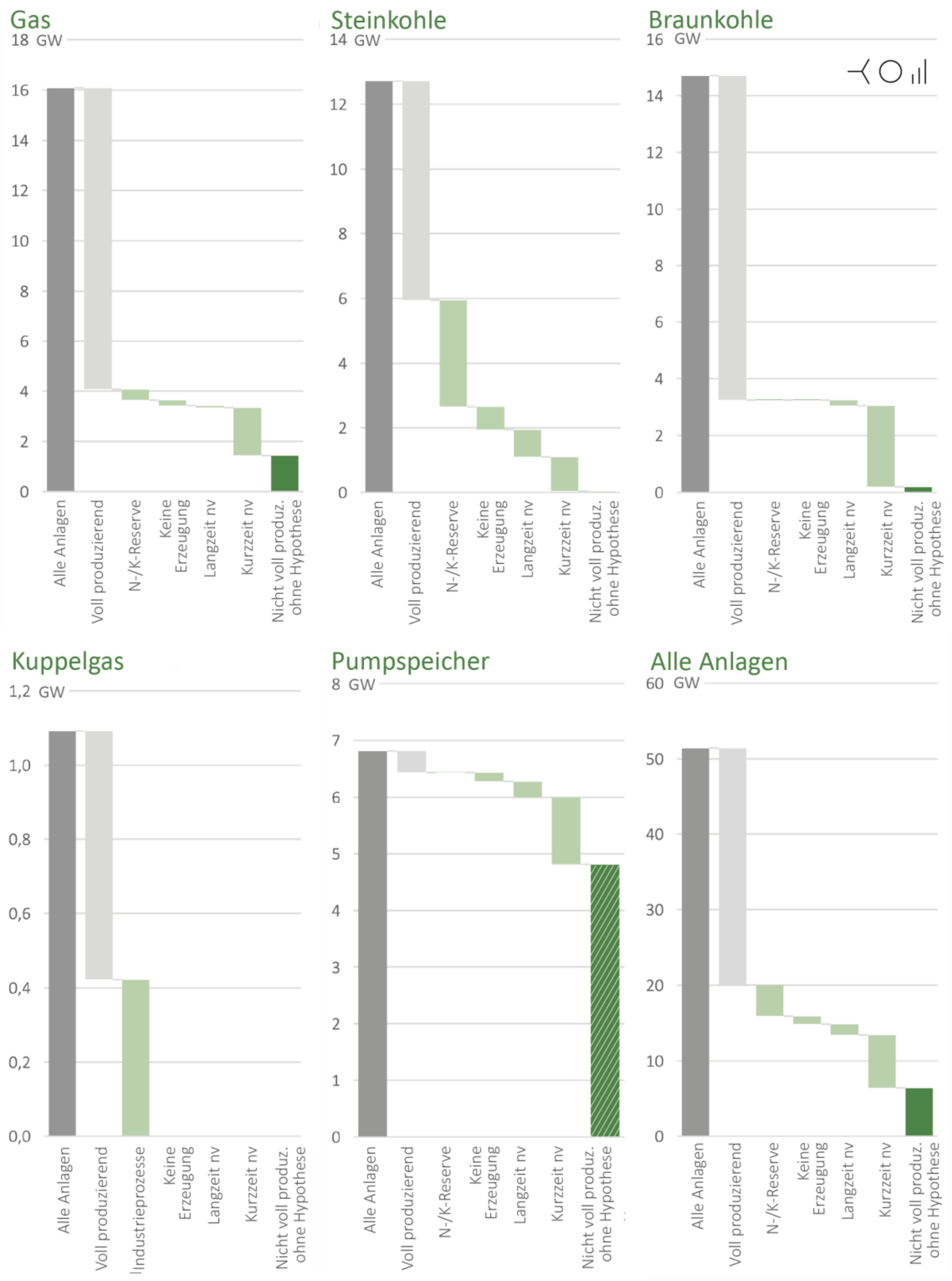

Figure6 : Average generation capacity per technology in all hours with price peaks in 2024 (28 hours), broken down according to the hypothesis for plants that did not achieve their maximum generation capacity. The categorization of the plants is described inTable2 . nv = not available.

4.3 CAPACITY FACTORS

Generation per technology. To further classify our plant-specific analysis, we calculated the capacity factor for each technology (**Fehler! Verweisquelle konnte nicht gefunden werden.**). This shows the average proportion of the nominal rated capacity (master data from the BNetzA power plant list) per technology that was actually produced in hours with price peaks. It represents the ratio between the total energy actually generated by a technology per peak price hour and the total nominal capacity per technology across all individual plants reported to ENTSO-E. These capacity factors confirm that significantly less capacity was available on the market during peak price hours than the nominal capacity would suggest. Specifically, it shows that only lignite and natural gas technologies achieved a capacity factor of around 75%, while hard coal and by-product gas were significantly lower at around 50% and pumped storage at around 30%.

Less available capacity than expected. These results have direct implications for security of supply calculations and considerations regarding the capacity market. If these price spikes are representative of future shortage situations, it must be assumed that the currently installed capacity of fossil fuel power plants and pumped storage power plants, which is often assumed to be "secure capacity," can only be assumed to be actually available capacity with large discounts of 25% to 70%. Of course, it cannot be expected that the entire nominal capacity of a power plant fleet will always be available; however, we were surprised by the extent of the discounts.

Capacity factor per technology

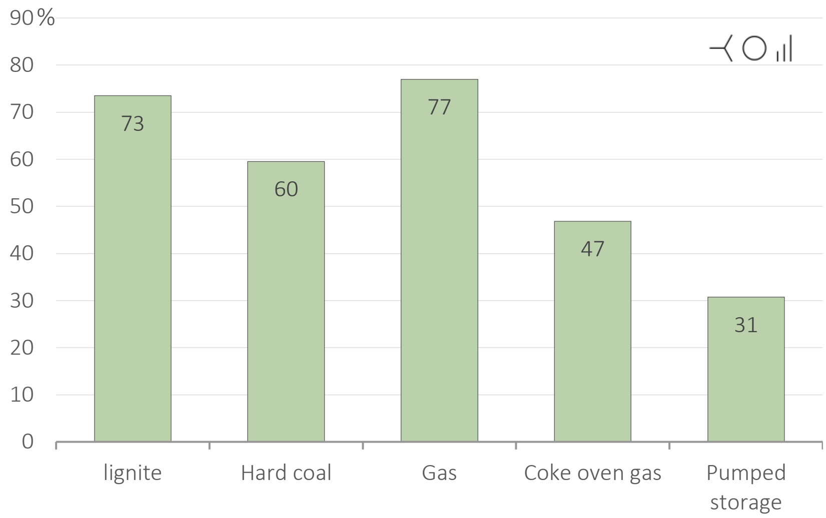

Figure7: Capacity factors per technology for plants registered with ENTSO-E, excluding grid and capacity reserves. To this end, the ratio between the total energy actually generated by all individual plants of a given technology registered with ENTSO-E and the total nominal capacity of that technology was calculated, and then the average was calculated across all peak price hours.

5 Conclusion & recommendations for action

Price peaks. In the winter of 2024, wholesale electricity prices on the day-ahead market rose to historic levels that even exceeded the prices seen during the energy crisis. Against this backdrop, we examined in this study how these exceptionally high prices can be explained. We defined price peaks as those hours in which the variable costs of a typical peak load power plant—an open gas turbine—are below the observed prices. Using this approach, we identified only 31 individual hours with price spikes in the last 10 years, all of which occurred in the fall and winter of 2023 and 2024. This is clearly a new phenomenon in the German electricity market, occurring exclusively during hours when very low generation from renewable energies coincided with high residual load.

Power plant utilization. The plant-specific evaluation shows that although most power plants operated at maximum capacity during hours with price peaks, this was by no means the case for all of them. Overall, around 60% of gas, coal, and PSW capacity was operating at full capacity. The remaining 40% was either not operating or operating at low capacity. In most cases, we were able to identify plausible reasons for plants that either did not generate electricity or only generated limited amounts. These include operational restrictions in the case of cogeneration plants and short- or long-term unavailability. In addition, some plants, particularly hard coal units, are tied up in the grid reserve and are therefore not available to the market. However, there was also 6 GW of generation capacity that did not generate electricity at full capacity during price peaks, for which we could not find plausible explanations.

Scarcity prices. Our analyses suggest that the observed price peaks can be explained by a shortage of available supply. According to the BNetzA power plant list, approximately 6 GW of conventional power plant capacity will be taken off the grid in the course of 2024, and some of the coal-fired power plants that were temporarily available to the market during the energy crisis are now back in full grid reserve. We therefore consider it plausible that the price spikes clearly represent scarcity prices. In this respect, it is also to be expected that they will occur again in comparable situations.

Abuse of market power. Our analyses do not provide any concrete evidence of systematic strategic volume restraint. Nevertheless, abuse of market power cannot be completely ruled out. Despite the conservative approach taken in assessing capacity reductions (e.g., through flat-rate deductions for CHP heat obligations), we find no obvious explanation for a total of 6 GW of capacity, and there is also the possibility that strategic withholding is concealed behind the reduced generation of individual units or short-term unavailability. Nor can we verify whether power plants reported as unavailable at short notice have actually suffered technical failures. We have therefore argued that the hedging profiles of market participants should be taken into account if market power abuse is to be investigated more closely in the future. In addition, the introduction of more granular futures (e.g., for specific hours or load profiles) could make an additional contribution to market efficiency by significantly reducing the economic incentive for manipulation through strategic volume restraint.

Supply shortage. However, as we cannot identify any systematic evidence of withheld volumes, our analysis leads to a key conclusion: the price spikes indicate a genuine supply shortage and are likely to recur in comparable situations. If price spikes are tolerated politically, they could represent genuine investment signals for load flexibility or new secured services.

Missing money. However, the political response to the 2022/23 energy crisis and the discussion surrounding the price spikes in 2024 have shown that politicians, the media, and the public do not seem to be able to tolerate high prices, even if they are only very short-lived. This gives investors legitimate doubts that price spikes will be allowed, and the German government has already committed to introducing a capacity market. In this respect, our final focus is on the question of what consequences our analysis has for the design of a capacity market.

Capacity market. In a situation where price spikes occur on the market, technical and other restrictions become apparent. The analysis reveals three consequences for the design of a capacity market. Firstly, the quantification of currently available power plant capacity should not be based on the nominal output of plants, but must realistically reflect actual availability. This is likely to be significantly lower than power plant lists suggest, for example due to aging effects (comparison of net nominal output with observed maximum generation), maintenance, and technical malfunctions (unavailability). The role that interruptible gas supply contracts already play and could play in the future during periods of scarcity should also be examined. Second, a reliable assessment of secured capacity requires a consistent data basis that transparently shows installed capacities, technical availability, and reserve commitments. This is not currently the case. Thirdly, the aggregate capacity factor for gas and lignite power plants was only around 75% during price peaks, for hard coal only around 60% and for pumped storage as little as 30%. Against this background, it seems all the more relevant to use realistic de-rating factors in security of supply studies and capacity mechanisms, even for capacity that is often assumed to be "secure."