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Price formation and market power in the German wholesale electricity market in 2006

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ABSTRACT

From 2002 to 2006, German wholesale electricity prices more than doubled. The purpose of this paper is to estimate the price components in 2006 in order to identify the factors responsible for the increase. We develop a competitive benchmark model, taking into account power plant characteristics, fuel and CO_2-allowance prices, wind generation, cross-border flows, unit commitment, and startup conditions, to estimate the difference between generation costs and observed market prices for every hour in 2006. We find that prices at the German wholesale market (European Energy Exchange—EEX) are above competitive levels for a large fraction of the observations. We verify the robustness of the results by carrying out sensitivity analyses. We also address the issue of revenue adequacy.

1. Introduction

Market power is a significant issue for restructured electricity markets around the world. At the same time, questions about resource adequacy of investments in generation have resurged both in the US and in Europe, driven by concerns about supply security. The German electricity market has undergone significant changes in the last decade; yet the scientific discussion about the appropriate market design is still in its infancy. Since the first EU liberalization directive 96/92/EC was promulgated, Germany has taken almost a decade to address critical issues such as network tariff regulation and market monitoring. Since 2006, the newly established regulator ("Bundesnetzagentur") has published cost-based revisions of transmission and distribution network tariffs, and is now considering alternative instruments of congestion management, cross-border trading, etc.; incentive regulation should be operational by 2009. Current political discussion has begun to focus on the generation sector, especially since average spot prices at the European Energy Exchange (EEX) rose by almost 125% from 2002 to 2006. However, a price increase is no proof of malfunctioning markets or market power abuse; during the same period fuel prices rose significantly and Europe's emissions allowance trading scheme was implemented. On the other hand, the oligopolistic structure of Germany's generation market particularly lends itself to abuse, with a duopoly controlling over 55% of market share, and the largest four firms owning almost 85%.

This paper analyzes the level of competition in the country's wholesale electricity markets, by comparing the observed prices with estimated costs and market clearing prices under the hypothesis of perfect competition. We develop a competitive benchmark model testing the observed EEX market prices for 2006. We hypothesize that the oligopolistic structure of electricity generation leads to significant price mark-ups when compared to short-term marginal costs.

In the next section, a survey of market power analysis in other countries (mainly the US. and the UK) and the most recent studies on Germany are provided. Section 3 presents the competitive benchmark model and introduces the data. The analysis is based on publicly available data on electricity prices, generation capacities and costs, wind input, and cross-border flows for 2006. We find that the observed prices exceed marginal costs, especially in peak load situations. We also present the earned revenues of generators in 2006 based on the model's spot market structure. The results are confirmed by sensitivity analyses that account for plant availability and price uncertainty. We conclude that market power is an influential feature of Germany's electricity markets, and should be addressed by more competition-oriented market design.

2. Literature review on market power

2.1. International literature

Market power normally is defined as the ability to profitably alter prices away from competitive levels (Mas-Colell et al., 1995,

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p. 383). Thus one of the main questions of estimating market power abuse is to determine the "right" approximation of competitive levels. The modeling approach used is generally referred to as competitive benchmark. Complex approaches like Cournot or Supply Function Equilibria often use it as a starting point or as additional information to classify the model results.[2]

The chief goal of the benchmarking approach is to estimate a competitive supply function in terms of marginal costs. In a fully competitive market no player can influence the clearing price; thus the simulated supply function in combination with a given demand level yields the competitive benchmark. Arranging the plants according to increasing marginal costs yields the competitive supply curve and the difference between simulated and observed market prices allows quantifying the extent of market power. Stoft (2002, p. 129) shows that marginal cost pricing suffices to cover the capital cost of investment, because price spikes will occur in periods of shortages. An in-depth discussion of the issue is provided by Hogan (2007), Crampton and Stoft (2006), and Joskow (2007). At this point, we note that the marginal costs should set the competitive prices when the market is characterized by overcapacity.

When monopolistic, oftentimes vertically integrated electricity companies predominated, there was neither room nor need for market power analysis. The restructuring of the North American and British electricity markets opened the way to rigorous market power analysis. Wolfram (1999) was among the first to apply a competitive benchmark analysis to the electricity market of England and Wales. She found significant mark-ups during the observed period covering 18 months in 1992, 1993, and 1994, although the generators were not taking full advantage of the inelastic demand as oligopoly models predict. Borenstein et al., (2002) and Joskow and Kahn (2002) used the competitive benchmark approach to analyze the California market. Both found that in summer 2000, observed prices differed from the competitive benchmark price levels, which could not be explained by load, imports, gas prices, or NO_x-allowance prices. Mansur (2001) undertook an analysis of the PJM market calculating a demand-weighted Lerner index of 0.293, an indicator of significant market power abuse.

A drawback of competitive benchmark analysis is the necessary simplification when estimating the supply curve. Electricity markets are highly complex and access to information is generally sparse; therefore, models make assumptions that may influence the outcome. Typically the simulation is static, neglecting startup and shut-down costs or minimum-load constraints. Missing information about plant outages may compound the outcome. Also, the grid is not generally considered a market component. Thus, network congestion, which can lead to market prices above marginal costs, is ignored. Harvey and Hogan (2002) undertook a sensitivity test of competitive benchmark analysis by reproducing the results and estimating the impact of varying assumptions, and concluded that the differences obtained by simulation could result from the real-world constraints that were omitted from the model.

2.2. *German quantitative literature*

The wholesale electricity market in Germany is dominated by four companies owning about 85% of conventional power plant capacity. The German Cartel Office assumes a dominant duopoly consisting of E.ON and RWE owning about 60% of generation (Bundeskartellamt, 2006). Given this oligopolistic structure, the question arises whether the observed market outcomes represent competitive behavior or whether market power is applied.

Müsgens (2006) first simulated a comprehensive marginal cost model of the German market for the period of June 2000–June 2003. He used a linear optimization model to estimate the competitive market prices. Starting in 2000 the observed and modeled market prices coincided until fall 2001, followed by a break leading to a divergence between them that lasted until the end of the observation period. He assumed that strategic company behavior and learning effects were the main reasons for the observed differences. Next, Ellersdorfer (2005) used a two-period Cournot model to study the impact of long-term contracts on the oligopolistic model. A competitive benchmark used as well also concluded that a significant difference between modeled and observed market prices existed.

In a more recent study, Schwarz and Lang (2006) analyzed German electricity prices by estimating the impact of fundamental price components such as fuel price development and allowance prices. They found that from 2000 until 2005, rising fuel prices and in 2005, allowance prices were the major price influencers. However, starting in 2003, the impact of market power increased and therefore influenced prices. Our paper follows Schwarz and Lang (2006) by extending the analysis to 2006.

The Sector Inquiry issued by the European Commission (2007) adds a political view to the market power debate. Most of its conclusions are applicable to Germany: wholesale markets show a high degree of supplier concentration; vertical integration is a dominant factor in many markets; international trade is insufficient to provide pressure on domestic producers; there is a high degree of intransparency; price formation on electricity markets is complex; and consumers have little confidence in the competitiveness of these markets.

Based on the Sector Inquiry, London Economics (2007) carried out an in-depth analysis using real-world data and confirmed that the German wholesale electricity market faced mark-ups of up to 50% in the past few years. Furthermore, an analysis of earned revenues revealed that the two largest German companies would have earned 7 bn. € from 2003 till 2005, which is considered sufficient for covering investment and startup costs by London Economics.

Other studies of Germany's competitiveness have employed strategic or econometric approaches. Zachmann (2006) compared the German and British electricity markets using Markov Switching, concluding that the British market had a closer relation to marginal costs. Traber and Kemfert (2007) applied a strategic model of the European electricity sector to combine oligopolistic company behavior and the German support for renewable energy to estimate the impacts on electricity prices, emissions, and company profits. They show that consumer prices slightly increase, producer prices go down, and the company profits are significantly reduced by the support mechanism. Hirschhausen and Zachmann (2007) tested the impact of emission allowance pricing on electricity wholesale prices in Germany. Based on an error correction model and an autoregressive distributed lag model they found that the price for emission allowances is passed through asymmetrically: allowance price increases are translated into electricity price increases more rapidly than decreases.

However, the impact of market power on price formation is not unilaterally accepted. General electricity market analyses of Germany with respect to market power are presented by Weber and Vogel (2007) and Ockenfels (2007a). These and other authors agree that the lack of full information in the empirical model approaches is viewed as a source of unreliability. Due to a steep merit order close to peak capacity, the impacts of incorrect

[2] For a comprehensive overview about different approaches of measuring and modeling market power see Twomey et al. (2004).

availability or price assumptions can produce large, absolute errors. In addition the non-linear complexity of electricity markets with many external impact factors (wind speed, temperature, and technical restrictions) contribute to the difficulty of designing a fully realistic model. Swider et al. (2007) show these issues exemplary for existing model approaches and specific time periods. Like Harvey and Hogan (2002) they show that every model has some level of uncertainty and thus produces a range of possible outcomes.

Melzian and Ehlers (2007) studied the pricing mechanism at the EEX, and concluded that the structure of the German market makes EEX prices an improper benchmark. They argue that since price formation at the EEX is mainly driven by missing or excess capacity of forward contracts, the price cannot be considered as system marginal price. Ehlers and Erdmann (2007) also analyzed the EEX pricing formation and concluded that the traded volumes and supply and demand curves do not allow a significant price manipulation. We assume that EEX prices act as the benchmark for most bilateral and long-term trades in Germany's electricity market because it is the only transparent price available.

The problem of fixed cost covering and short-term marginal costs has been addressed by Müller (2007) and Ockenfels (2007b). Müller simulated a simplified electricity market with base, mid, and peak load units to estimate the revenues each plant type earns in a competitive market based on short-term marginal costs. He concluded that in an optimal market segmentation with respect to installed capacity, even base load plants will not cover their fixed costs. Ockenfels (2007b) argues that under competitive conditions, market prices above marginal costs are possible and necessary to cover fixed costs. Whenever demand exceeds available capacities, the market price is set according to consumers' willingness to pay. Due to the low elasticity in electricity markets this can lead to significant mark-ups on marginal costs. We note, however, that this situation did not prevail in 2006 since the German electricity market was subject to overcapacities.[3] Section 4.3 of our paper discusses fixed cost covering in more detail.

3. Model and data

This section describes the approach of the competitive benchmark analysis and the data used, the objective being to derive estimates for the true marginal cost, which are then compared with the prices at Germany's wholesale electricity market EEX. The model simulates a wholesale market in which all demand is cleared via a single market process. However, only about 20% of total consumption is traded via the EEX. Since the EEX is the only public source available, we assume the EEX spot market acts as benchmark and as a marker price for OTC trading. Demand (load) data are provided by UCTE for each hour in 2006. We assume that trading is a competitive activity, so that only generators exercise market power.

3.1. Model formulation

The model is designed as a cost-minimizing approach subject to technical characteristics of electricity generation:

$$\min \text{costs} = \sum_{t,p}(c_p^t g_p^t) + \sum_{t,p} startup_p^t \quad \text{objective} \tag{1}$$

where c_p^t are the marginal generation costs of plant p in hour t, g_p^t is the actual output of that plant in hour t, and $startup_p^t$ are the occurring startup costs in the case the plant has to go online. The considered overall timeframe is 2006 divided into 12 model runs, one for each month. The output of a plant is restricted by lower and upper boundaries due to the thermal capabilities of the generation process:

$$on_p^t g_p^{min} \leqslant g_p^t \leqslant on_p^t g_p^{max} \quad \text{capacity constraint} \tag{2}$$

with g_p^{max} as the maximal available power output, g_p^{min} as the minimal necessary generation output to operate a plant, and on_p^t as the binary condition variable stating if a plant is online (1) or offline (0). The resulting startup costs are calculated as a cost block in the hour the plant goes online:

$$startup_p^t = sc_p^t g_p^t (on_p^t - on_p^{t-1}) \quad \text{startup costs} \tag{3}$$

where sc_p^t are the startup fuel cost necessary to heat up the power plant p. These are mainly driven by fuel prices, which vary for the time t. If a plant remains on- or offline the condition difference $(on_p^t - on_p^{t-1})$ is zero and thus there are no costs. In the case of a shut-down the difference becomes -1 but the actual output g_p^t of the plant p in t is zero. Only in the case of a startup the condition difference is 1 and the output is positive, resulting in a positive startup cost block. According to the type of plant, startup can take from a few minutes (small gas turbines) up to several days (nuclear); thus a constraint on the plants condition variables is introduced as follows Takriti et al. (1998):

$$on_p^{t-1} - on_p^t \leqslant 1 - on_p^\tau, \quad \tau = t+1, \ldots, t+l_p \quad \text{startup constraint} \tag{4}$$

with l_p as the required startup time of a plant p. In the case a plant goes offline in t the left hand side of Eq. (4) becomes 1. In order to fulfill the inequality the condition variables of the following τ hours have to remain 0, thus restricting the startup possibilities of the plant.

As the model is an ex-post analysis, demand d in hour t is known and has to be satisfied:

$$PSP_{up}^t + d^t = \sum_p g_p^t + PSP_{down}^t \quad \text{energy balance} \tag{5}$$

with PSP_{up}^t as the stored energy in pump storage facilities in t and PSP_{down}^t as the withdrawn energy from that facilities in t. In order to satisfy the demand in electricity markets the only possibility besides power generation is to use pump storage facilities. The storage process is considered as additional demand, increasing the necessary power generation, whereas the withdrawal is equal to conventional generation increasing the energy output. Typically pump storage facilities use cheap generation during nighttimes to fill their storage and use the stored water during peak times to allow for a better control of the transmission grid. Network constraints are not considered and thus losses are not taken into account.

The pump storage process is an inter-temporal condition:

$$PSP_{storage}^{t+1} = 0.75\, PSP_{up}^t - PSP_{down}^t + PSP_{storage}^t \quad \text{storage equation} \tag{6}$$

where $PSP_{storage}^t$ is the stored amount of energy in hour t. If it runs in pump mode (PSP_{up}), 75%[4] of the consumed energy will be added to the storage for the next period and if it runs in generation mode (PSP_{down}), the appropriate amount of energy is taken from the storage. The initial storage level for each model run is assumed to be zero. The storage and withdrawal processes are

[3] In 2006, overall public available conventional capacity was 103 GW, with a system peak load of 86.2 GW. At this peak, the market had surplus capacities of 8.4 GW in addition to 7.9 GW system reserves and an export surplus of 2.1 GW (VDN, 2006).

[4] Following Müller (2001), modern PSPs have an average efficiency between 70% and 80%.

furthermore subject to capacity restrictions:

$$PSP^t_{up} + PSP^t_{down} \leqslant PSP^{max} \quad \text{1st PSP capacity constraint} \tag{7}$$

with PSP^{max} as the maximum capacity of pump storage plants in Germany. The total sum of storage and withdrawal cannot exceed the installed pump capacity. The withdrawal is further limited by the amount of energy stored, which may be lower than the installed pump capacity:

$$PSP^t_{down} \leqslant P^t_{storage} \quad \text{2nd PSP capacity constraint} \tag{8}$$

The model is implemented in GAMS as a combination of a mixed integer problem for the unit commitment and an optimization problem with fixed binary plant condition variables for the actual dispatch. The dual variable on the energy balance constraint is considered to represent the hourly market price.

3.2. Data

The hourly demand level for Germany (UCTE, 2007) ranges between 75 GW at peak and 35 GW at off-peak times. The German electricity market is a winter-peaking market with significantly less demand in the summer months. Generation capacity is characterized by overcapacity. Total generation capacity is about 120 GW, including renewable energy sources (VDN, 2005). The basic plant list we obtained from VGE (2005, 2006) includes all conventional facilities in Germany with more than 100 MW generation capacities by plant and fuel types. Available and installed capacity may differ according to weather conditions, maintenance, or outages, requiring adjustments to prevent an overestimation of available plant capacity and an underestimation of prices in our simulation. To account for these effects, seasonal availability factors for each plant type are used according to Hoster (1996) with the highest level of availability in winter months.[5] Since our analysis is based on single hours, the generalization can lead to divergences in specific cases (e.g., a plant outage of a large coal block).

Part of the available capacity may be sold abroad and therefore cannot be used to cover the German demand. Lack of publicly available information restricts the possibility to deal with this issue directly within the plant list. Therefore, we calculated the total trading balance based on actual cross-border power flows (ETSOVista, 2007).[6] The resulting net flow into or out of Germany is considered in the total demand level d^t. Thus when energy is imported, a portion of Germany's demand is covered by foreign plants, reducing the necessary amount of domestic generation and vice versa. However, the modeled prices represent the upper bound in cases of net exports, since plants above market price can be used for exports, and a lower bound in cases of net imports since a foreign generator can set the market price in Germany.

Germany has a large amount of renewable energy, in particular wind (19 GW in 2006) and the actual demand level to be satisfied by conventional plants varies considerably. Therefore, we reduced demand by calculating the hourly wind input for the analyzed days.[7] We neglected other renewable sources like solar and biomass due to their relatively small installed capacities.

To estimate the marginal cost curve ("merit order") for electricity generation, fuel type and fuel prices are needed. The efficiency of each plant is estimated using the age as a proxy: for coal, lignite, oil/gas-fired steam plants, CCGT plants, and gas turbines, the link between the age and the efficiency are taken from Schröter (2004). Nuclear plants are assumed to have an average efficiency of 33% (Müller, 2001) and hydro plants have 100% efficiency.

Fuel prices for coal, oil, and natural gas are based on wholesale price levels of reference markets; thus we do not consider transportation costs or transmission fees.[8] The price for steam coal is based on prices for internationally traded coal at ARA, daily natural gas prices are taken from the Dutch market TTF, and oil prices are daily Brent prices. For nuclear plants, fuel costs of 3 €/MWh are assumed, leading to generation costs of 9 €/MWh.[9] As there exists no global market for lignite, extraction costs of 1.76 €/GJ as shown in the high-price scenario in Schneider (1998) are used; this figure over- rather than underestimates the real costs. Hydro plants are assumed to have no fuel costs. Hydro plants act as price takers like every other plant type. PSPs are modelled as either demand or generators and thus have no external marginal costs. The resulting impact on the price level is obtained by optimizing pumped storage usage and accounting for the generation costs needed to replenish the storage (see Section 3.1). In addition to fuel costs an uplift payment for variable operating expenses is used for each plant type (EWI, 2005): coal plants have additional expenses of 2 €/MWh, nuclear 3 €/MWh, gas-fired 0.5 €/MWh, and hydro plants 1 €/MWh.

With the introduction of Europe's emission allowance trading scheme in 2005 an additional cost element has to be considered when estimating electricity prices. Allowance prices can be accounted for as opportunity costs of production. Therefore, we calculated plant-specific CO_2 emissions based on efficiency and plant type following Gampe (2004). The emissions are valued with the allowance price taken from EEX (2007b) and added to the fuel and operation costs.

The marginal generation costs c^t_p of a plant p in any considered hour t consist of the fuel costs based on plant efficiency η and fuel price, operating costs, and opportunity costs for emissions based on plant-specific CO_2 emissions and the allowance price at the EEX:

$$\begin{aligned} c^t_p = {} & \frac{1}{\eta_p}\, fuelprice^t + operation\ costs_p \\ & + emissions_p\ \mathrm{CO_2}price^t \\ & \quad \text{marginal costs of generation} \end{aligned} \tag{9}$$

The minimum capacity restrictions as well as the necessary startup fuel consumption are differentiated according to plant type and taken from DENA (2005, p. 280). Within the model, nuclear plants are assumed to supply base load. Therefore, they are must-run plants that cannot be shut down; thus their condition variable on^t_p is fixed to one. Coal, steam, and CCGT plants are modeled with specific startup times l_p according to Schröter (2004, p. 39). Gas turbines and hydro plants are assumed to be able to go online in less than an hour; thus Eq. (4) is not binding for them.

As Germany has a large fraction of combined heat- and power-producing (CHP) plants particularly in the industry sector, these plants are treated as must-run plants with a specific minimum output level. We assume that CHP plants must run at least 50% of their maximum electrical capacity in winter, 30% in spring and fall, and 20% in summer. A detailed hourly heat profile is not used.

[5] December, January, and February are considered as winter months; June, July, and August as summer months; the remaining months as transition period.

[6] The values for cross-border flows have been completed using publicly available information from the four TSOs and Nordel.

[7] The actual energy input depends on wind speeds and is published on an hourly basis by the four German TSOs.

[8] Due to the volatility of wholesale prices, particularly for oil and natural gas, generators are expected to sign contracts for their fuel supply. The pricing details of these contracts are not publicly available. We assume that wholesale prices are sufficient to reflect the average price level. However, this can lead to divergences for specific plants.

[9] Nuclear is not the marginal supplier in the relevant periods, so that the estimate of its marginal costs does not change the resulting prices.

4. Results and sensitivity analysis

We compare the modeled market prices with observed priced at the EEX for all hours of 2006, obtaining mark-ups, withheld capacity, and earned revenues for fixed costs coverage. To testify the results, two sensitivity analyses are carried out. First the uncertainty regarding exact fuel prices is considered by increasing gas and oil prices (which mainly influence peak units). Second, plant availability is reduced to estimate the impact of uncertainty about technical and external restrictions on generation structures.

4.1. Market power and price mark-ups

The basic model approach uses 12 runs (one for each month) to simulate the wholesale market in 2006 and find the competitive market outcomes. The simulated prices and the EEX prices behave similarly with a clear segmentation between off-peak and peak prices. However, in off-peak periods, EEX prices often drop below marginal generation costs and sometimes even reach zero, whereas the model prices reach a level, representing coal- and lignite-fired base load plants. In general, prices below marginal costs are explained by startup conditions since the temporary shut-down of a base load plant can become more expensive than maintaining operations without revenues. Because our model is based on perfect knowledge, we note that the price difference may be due to asymmetric information (e.g., bidders' "wrong" expectations about market conditions). Furthermore the model includes emission allowance prices as opportunity costs whereas bidders may vary between full, partial, and no cost past through.

Model prices in peak-price periods were generally below the observed prices at the EEX. Fig. 1 shows the model prices and the observed prices ordered from highest to lowest EEX price. The results clearly show that high EEX prices generally do not have an equivalent high competitive price counterpart. In the off-peak segment, EEX prices and model prices are between 30 and 40 €/MWh. However, EEX prices decrease towards zero while modeled prices tend towards a coal plant equivalent. In the mid-price segment the EEX prices increase from 40 to about 60 €/MWh while the model prices exhibit volatility ranging from 28 to 65 €/MWh with a high number of price combinations that diverge strongly from each other. This trend continues for peak-price situations, where EEX prices increase towards their yearly peak of more than 2000 €/MWh while model prices remain between 40 and 95 €/MWh.

However, in peak periods, the competitive prices in the model tended to be lower than EEX prices. The average price in 2006 at the EEX is 50.79 €/MWh whereas the model average is about 11% lower with 45.28 €/MWh. For the peak segment (weekdays 8 am–8 pm), the difference is more striking with a model average price of 52.31 €/MWh (about 30% below the observed average of 74.48 €/MWh). For off-peak hours, including holidays and weekends, the observed prices are lower with an average of 38.23 €/MWh compared to 41.54 €/MWh in the model. Focusing only on weekdays, this divergence is reduced to 1.4 €/MWh or 3%. Using the underlying demand, the total expenses at the EEX price level are 3.6 bn € higher than in the model.

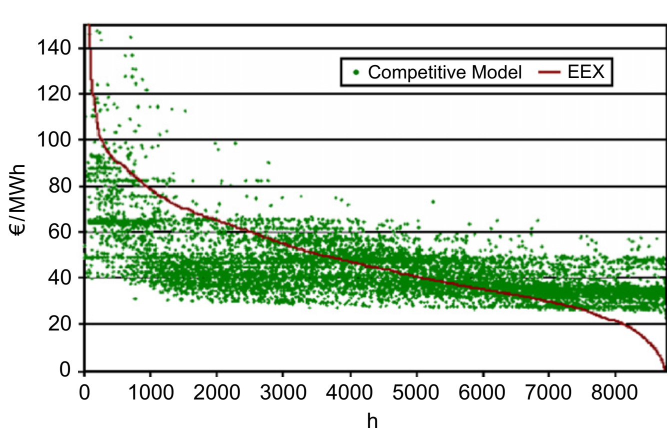

Fig. 1. Price comparison model and EEX.

4.2. Capacity withheld

To estimate the difference in quantities between the model and the EEX, we calculated the capacity withheld for weekday hours 8 am–8 pm (off-peak and weekend hours show a high degree of prices below marginal generation costs). Furthermore, market power abuse is expected to occur mainly when demand is close to the capacity limit. To obtain the withheld capacity all available plant capacities with marginal costs below the EEX price but not operating in the corresponding modeled solution for each hour are summed up.

In 2006, the average amount of capacity withheld during peak hours is about 8 GW, but it varies throughout the year. Fig. 2 shows that the average values in the first 2 months of around 9 GW, the gap then narrows significantly from March until June, even reaching an average of −2 GW in April. After July, the capacity withheld again increases, with average values between 8.5 and 14 GW. The high number of values above 10 GW indicates the existence of strategic company behavior.

4.3. Fixed cost coverage

One further point of interest is how competitive market outcomes translate into revenues for fixed cost covering. Pricing is based on short-term marginal costs; therefore, companies are expected to cover their investment costs when generators with higher costs set the market price or capacity is lower than demand, and both situations can result in price spikes that allow companies to "earn" rents above their generation costs. As mentioned, the German market is frequently subject to overcapacities. Thus, the price level is expected to give no signal for new investments. The earned revenues do not take into account forward trading. Thus, the values represent spot-market-based results.

Table 1 shows the calculated rents generators earned according to the model. As noted above, the European-wide emission allowance trading scheme includes a grandfathering mechanism that allows the revenues from opportunity pricing of allowances to be included in fixed cost covering. Hence, our model must incorporate both revenues for each plant type: one that includes allowance prices as marginal generation costs and one that excludes them. We use average investment costs as the benchmark. We can calculate an annuity assuming average overnight costs per MW, an interest rate of 7%, 40 years' duration for base, and 25 years for peak units.

Only the values including allowance costs are relevant for estimating market competitiveness. They reveal that under modeled competitive conditions, only nuclear plants can cover their fixed costs, under EEX price calculations, both nuclear and coal plants can cover their costs, and in both scenarios, peak load plants cannot cover their costs.[10] The results indicate that no

[10] The possible rents for peak units may increase since other market segments (e.g., reserve markets) are not considered.

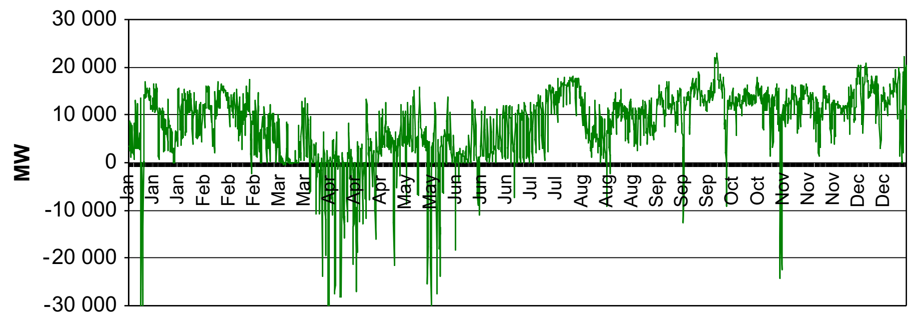

Fig. 2. Capacity withheld during workday peak hours (8 am–8 pm).

Table 1
Annually earned revenues for fixed-cost covering per installed MW in 2006

Plant type	Competitive model		EEX price based		Annuity of investment cost[a] (€)
	Including allowance costs (€)	Excluding allowance cost (€)	Including allowance costs (€)	Excluding allowance cost (€)	
Nuclear	234 100	234 100	271 800	271 800	187 500
(surplus)	(+46 600)	(+46 600)	(+84 300)	(+84 300)	
Lignite	64 900	167 100	114 500	216 600	112 500
(surplus)	(−47 600)	(+54 600)	(+2 000)	(+104 100)	
Hard coal	60 300	147 700	110 200	197 600	90 000
(surplus)	(−29 700)	(+57 700)	(+20 200)	(+107 600)	
Steam	600	2200	1700	3300	85 800
(surplus)	(−85 200)	(−83 600)	(−84 100)	(−82 500)	
CCGT	5000	11 000	14 400	20 400	47 200
(surplus)	(42 200)	(−36 200)	(−32 800)	(−26 800)	
Gas turbine	160	320	70	230	21 450
(surplus)	(21 300)	(−21 100)	(−21 400)	(21 200)	

[a] Nuclear plants are assumed to have overnight cots of 2500 €/kW, lignite 1500 €/kW, coal 1200 €/kW, steam 1000 €/kW, CCGT 550 €/kW, and gas turbines 250 €/kW.

additional capacities are needed in the postulated overcapacity of the German market.[11]

However, the results do not permit us to conclude which empirical mechanism (competitive system or the EEX market) is adequate for fixed costs covering. Due to the long-term investment character of power plants, importance of forward contracts, fuel price variations, existence of optional markets like reserve markets, and the uncertain further development of the emission allowance system in Europe, consistent results regarding the issue of capacity financing can only be answered with long-term analyses.

4.4. Sensitivity analysis

All model approaches are subject to simplifications, assumptions, and mathematical restrictions. Further, empirical analyses are affected by missing information and possible data errors. We undertook two sensitivity analyses to test the robustness of the obtained results. First, the fuel price level is varied by increasing prices for gas and oil by 10%. This should lead to an increase in peak prices when CCGT, gas turbines, and oil- or gas-fired steam plants set the market price, while off-peak prices are unaffected. Second, we varied power plant availability. Due to a lack of hourly availability values only seasonal factors are used, which may misinterpret the real availability due to high temperatures, low water levels, or plant outages.[12] The basic availability values from Hoster (1996) are altered by reducing the winter availability by 2%, the intermediate values by 3%, and summer values by 4%. Table 2 shows the available capacities in each season compared to the corresponding values at monthly peak load of 2004 (VDN, 2005).

The impact of the changed fuel prices is evident only during peak load situations when the according plant capacities are needed. During these times the price level slightly increases. The average market price increases to 46.54 €/MWh (about 8% below EEX prices); average peak prices are 2.5 € above the base case and thus still 26% below the observed ones. The impact of reduced plant availability is more distinctive. During off-peak and mid-load periods, the difference is rather small because the remaining capacity is still sufficient to keep a moderate price level. During peak situations the prices are above the basic model results, particularly in winter and summer months. This effect can be explained by the steep slope of the merit order close to maximum

[11] Another issue is the impact of the allowance trading mechanism on investment signals. The political intent is to foster investment in emission reduction mechanisms or power plants with low emission values like CCGT. However, the results to date point to an absence of investment activity. Due to the base load character of most coal plants and the grandfathering mechanism giving the largest bulk of allowances for free, the current market prices set a high incentive to invest in coal technology rather than gas-fired units. Based on the values for 2006, the current system fails to fulfill the expected political objectives.

[12] Ockenfels (2007a, b) discusses this topic in detail. Other potential model limitations like stochasticity, asymmetric information, and opportunity pricing of cross-border transactions and hydro plants are not considered in our sensitivity analysis.

Table 2
Available capacities

	Winter (MW)	Intermediate (MW)	Summer (MW)
Basic model			
Fossil plants	83 350	77 850	74 170
Pump storage	3900	3650	4150
Reduced capacity			
Fossil plants	81 430	74 960	70 320
Pump storage	3770	3460	3900
Values at peak load (VDN, 2005)			
Reliably available capacity	83 130	79 500	74 370

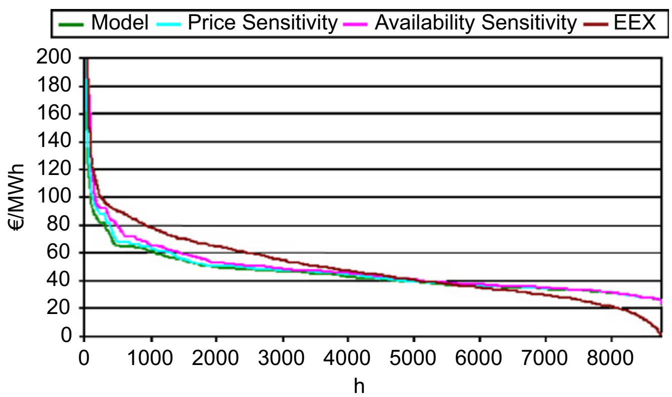

Fig. 3. Price duration curves.

capacity in combination with startup conditions that lead to prices above marginal costs. On average a market price of 48.74 €/MWh (4% below EEX prices) can be observed. Average peak prices increase to 59.55 €/MWh (20% below observed prices). In both sensitivities the off-peak prices are little affected.

However, even the reduced capacity is still sufficient to satisfy demand; thus no capacity rent for peak units can be expected. The average quantity gap in peak hours is reduced to 6.7 GW in the fuel price variation scenario and to 5.8 GW in the availability variation scenario. The monthly pattern remains similar to the base case with average values above 10 GW in the second half of 2006 for both sensitivities. The adjustments do not alter the obtained results of the revenue analysis since the revenues of peak and coal units are still below fixed costs.

Comparing the basic model with the sensitivity analyses and EEX prices shows that the observed price duration curve has higher prices in about 4500 h in 2006 (Fig. 3). On the other hand, EEX prices are lower than the modeled prices in 3000 h.[13] All model variations have price spikes of more than 200 €/MWh (in cases of the availability analysis also 500 €/WMh), which are comparable but generally still lower than the maximum prices at the EEX. The mid- to peak-price region (between 50 and 100 €/MWh) also produces interesting results: a general price divergence of about 10 €/WMh is observed for more than 2000 h. This difference is only slightly affected by the changed parameters of the sensitivity analyses. Since these differences are observed in price regions that do not indicate capacity shortages, the question to raise is weather missing information and model simplification are solely responsible for the divergence.

[13] These values correspond to the price duration curves and not to actual model/EEX price combinations.

5. Conclusion

This paper analyzes the intensity of competition in the German wholesale electricity market in 2006. We test the hypothesis of previous literature for 2000–2005 that finds significant market power abuse. Based on a competitive benchmark model taking into account plant efficiencies, fuel prices, emission allowance prices, cross-border flows, startup conditions, and pumped storage, we estimate competitive market outcomes. These are below EEX prices for a large fraction of the observations, leading to an average market price in 2006 of 45.28 €/MWh that is 11% below the average price at the EEX and about 30% lower during peak times. These differences add to the additional expenses of about 3.6 bn € at the 2006 EEX price level compared to the model results. To estimate the resulting quantity distortion, we calculate the capacity withheld in peak hours and find that on average about 8 GW of capacity are not running in the model, although the generators have marginal generation costs below EEX prices. These values vary for the different months with average values above 10 GW in the second half of 2006.

We verify the robustness of the results by carrying out two sensitivity analyses: first, fuel prices for peak units (oil and gas) are increased by 10%, and second, plant availability is reduced. The latter has a significant impact on the obtained results, increasing the average market price to 48.74 €/MWh. However, the price duration curve still shows more than 2000 h with prices about 10 €/MWh below EEX prices. The models share an inability to reproduce the decrease of the EEX price duration curve to zero since the modeled prices are still at marginal generation cost level even in low demand off-peak hours. The average quantity gap is reduced to 6.7 and 5.8 GW, respectively. However, in the second half of 2006 these values constantly remain above 10 GW.

We also calculate the revenues for generators based on the modeled and observed spot market prices. The results show that under competitive conditions, the existing market structure and overcapacity of the German market do not lead to full-cost coverage, an expected result. Factoring in emission allowance prices as part of the fixed costs covering shifts the results in favor of coal plants, contrary to the desired political outcome.

While we acknowledge the conceptual data limitations of our model, the large number of significant price differentials and the corresponding quantity gaps indicate that the market is not yet sufficiently competitive to overcome market abuse.

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