Friedrich-Alexander-Universität Erlangen-Nürnberg

Institut für Wirtschaftswissenschaft • Kochstr. 4 (17) • D-91054 Erlangen

Institut für Wirtschaftswissenschaft
Universität Erlangen-Nürnberg

IWE Working Paper
Nr. 02 2006

THE RISE IN GERMAN WHOLESALE ELECTRICITY PRICES: FUNDAMENTAL FACTORS, EXERCISE OF MARKET POWER, OR BOTH?

von

Hans-Günter Schwarz und Christoph Lang

August 2006

Institut für Wirtschaftswissenschaft
(Institute of Economics)
Kochstr. 4 (17), 91054 Erlangen
Tel.: 09131 85-22381
Fax: 09131 85-22060
Internet: http://www.phil.uni-erlangen.de/economics
E-mail: Hans-Guenter.Schwarz @wiwi.phil.uni-erlangen.de
Christoph.Lang@wiwi.phil.uni-erlangen.de
ISSN: 1862-0787

1. Introduction

The process of liberalisation in most continental European electricity markets commenced in the second half of the 1990s. The EU directive 96/92/EC which determined common rules for the internal electricity market in the European Union proved to be a milestone towards deregulation. Germany arranged deregulation in 1998 when its new 'Energiewirtschaftsgesetz' was passed. As a consequence, the German power exchange in Leipzig came into operation in June 2000. Among other contracts, the exchange trades electricity contracts for every hour of the following day. During the first months, monthly base-load spot market prices (delivery of one MW for every hour of the month) ranged from 15 to 25 Euros per MWh. A first peak with a price of more than 40 Euros was reached in December 2001. In the following months, prices were going down and ranged between 20 and 30 Euros per MWh until June 2003. In July 2003, prices were rising: The prices fluctuated between 25 and 35 Euros until the end of 2004. In 2005, prices were shooting up. In December 2005, a new peak was reached with more than 70 Euros per MWh.

Analogous to the discussion concerning the California crisis (see e.g. Borenstein et al. 1999), there are two competing hypotheses concerning the cause of rising prices. The first hypothesis assumes that rising prices in the German wholesale electricity market are caused by 'fundamental factors' such as rising fuel prices (see e.g. Schiffer 2004), capacity shut down[1] (see e.g. Monopolkommission 2004: 543-545) or (since 2005) the implementation of CO_2 emission trading with high and rising allowance prices (see e.g. Bauer and Zink 2005). The second hypothesis is that an increasing exercise of market power is responsible for rising prices (see e.g. Monopolkommission 2004: 543-545, Richmann 2006).

Indeed, the nature of electricity production and consumption make the power market particularly susceptible to market power. The two most important factors are: The supply response to price changes is relatively inelastic because electricity cannot be stored cheaply (except in hydro facilities) and short run capacity constraints are binding. In addition, demand responsiveness of electricity customers is limited and therefore very inelastic (Twomey et al. 2005: 11). Studies of the British electricity market show that even relatively small suppliers can affect market prices substantially (cf. Monopolkommission 2004: 584).

Despite the intense public debate on rising wholesale electricity market prices, there are only very few papers that quantify the significance of different factors, one of them being market power. In fact, there has been only one attempt to assess the exercise of market power in the

[1] Capacity shut down can be strategic behaviour of power generators, but model calculation of Schwarz and Lang showed that this is negligible for the German electricity market.

German power market so far (see Müsgens 2004). This approach is based on a simulation model and will be discussed in more detail in section 3. The lack of papers on the German power market is partly due to missing data, particularly on hourly power consumption and on hourly international electricity trade. In addition data on individual bidding behaviour of individual generators which would allow the use of the so called direct method is not available. In contrast, there is a great number of papers that quantify the exercise of market power especially for the British and the Californian power market for different periods of time. Von der Fehr and Harbord (1993) used the direct method mentioned above. They analysed bid and marginal cost data for the two large conventional generating companies in the England and Wales pool from May 1990 to April 1991, using the electricity pool bid data and generator cost estimates derived from publicly accessible data on thermal efficiencies and fuel prices. Joskow and Kahn (2001) used an indirect approach and simulated competitive wholesale prices for electricity in California during the summer of 2000. They also compared them with exchange prices, taking account of changes in natural gas prices, electricity demand, and imports from other states during this period of time.

These and other papers (e.g. Short and Swan 2002, Fabra and Toro 2003, Evans and Green 2003) have shown that using simulation models to assess marginal costs and comparing them with exchange prices can be seen as 'best-practice' in order to quantify market power. This holds particularly true for cases like the German market, where it is impossible to study the bidding behaviour of operators directly (Twomey et al. 2005: 27-28). However simulation models tend to underestimate marginal costs by not correctly incorporating the complexities of real electricity markets. Harvey and Hogan (2002) for example remodelled the Californian electricity market to revise the results of the simulation model of Joskow and Kahn (2001) mentioned above. In contrast to Joskow and Kahn, the model of Harvey and Hogan produced no marginal costs substantially below exchange prices due to different assumptions on wind energy production, capacities available and reserves. Both author collectives based their studies on a very short period of several months. A rather simple method to prevent such conflicts of results could be the use of an expanded time frame of several years especially if marginal cost pricing can be assumed for some months and the simulation model can be validated for these months.

It is the objective of this paper to quantify the significance of fundamental factors (like rising fuel costs) and of the increasing exercise of market power on rising prices in the German wholesale electricity market by using an adequate simulation model incorporating the complexities of real electricity markets.

A simulation model of the German wholesale market is developed to assess marginal costs. Then, scenario calculations are made to study the significance of changes in the fundamental factors on marginal costs. In the end, estimated marginal costs are compared with EEX prices. An increasing margin between prices and marginal costs can be interpreted as an increase in the exercise of market power.

The calculations show that, if the whole period from 2000 to 2005 is considered, fundamental factors are the most important causes for the rising prices. The increasing exercise of market power is less important for rising wholesale electricity prices. The average EEX price for one MWh was 49 Euros in 2005. If marginal cost pricing, constant fuel prices of 2000 and no allowance trading are assumed, the average EEX price for 2005 would be approximately 20 Euros according to the model calculation for every day. Rising fuel prices caused a price increase of 6.5 Euros, the EU emissions trading is responsible for additional 14 Euros, the increasing exercise of market power for 8 Euros.

Interestingly, further analysis clarifies that the price-cost-margin widened substantially already in 2003. In 2003, the price-cost-margin was most extensive with almost 30%. The increasing exercise of market power was the single cause for the rising price in 2003. The price-cost-margin eroded in the following two years to 14 and 16% respectively. That means that only fundamental factors were responsible for the sharp rise of prices from 31 Euros in 2004 to 49 Euros in 2005. In 2005, the price-cost-margin was more or less the same as in 2004. But in contrast to 2004, the monthly values were very unstable. There were months when the price-cost-margin was more or less zero or even negative and there were months when the price-cost-margin is very large. One possible reason for the greatly varying price-cost-margin in 2005 is discussed in section 5.

The paper is organised as follows: The specifics of the German electricity market and related methodological issues are discussed in section 2. The simulation model is presented in section 3 and the most important model parameters are described in section 4. The model results follow in section 5. In section 6, the results are summarized.

2. Specifics of the German electricity market and related methodological issues

The German electricity market is the largest in Europe. In 2004 the total net consumption was 542 TWh. The installed net generating capacity amounted to 120 GW in total in 2004 (25% hard coal, 17% nuclear power, 17% lignite, 15% natural gas, 8% hydro power, 15% wind and biomass, 2% oil). When the German electricity market was liberalized in 1998, there were eight major integrated generation companies. The mergers and acquisitions of the years 2000 and 2001 reduced this number to four. The two largest (E.ON, RWE) had a joined share of 55% on total power production in 2004, the four altogether (including Vattenfall Europe and ENBW) came up to 75% (Schwarz and Lang 2005: 867).

The first German power exchange, the Leipzig Power Exchange (LPX), started operations in June 2000. The LPX was the first market place which quoted hourly prices. In the years before, electricity was traded just over the counter. In August 2000, a second power exchange started business, the European Energy Exchange (EEX) in Frankfurt. Both exchanges merged in July 2002 and formed the new European Energy Exchange based in Leipzig. Regarding day-ahead operations, bids and offers have to be sent to the EEX before 12 p.m. of the day before delivery. Market results are published by the EEX until 12:30 p.m. and become binding half an hour later (for further details on day-ahead market see e.g. EEX 2005 and on reserve supplies and balancing markets see e.g. Albers and Stelzner 2001, VDN 2005). The market volumes of the exchange spot markets were low in the beginning but increased steadily over time. In 2005, the hourly spot auction had a share of almost 15% (83 TWh) of the German net consumption. The EEX price is typically seen as the reference price of the German spot market (see e.g. Müsgens 2004: 5 f.) because of the comparatively large share of EEX trade and its repercussion on the OTC (Over the Counter) market.

The trading of electricity with neighbouring countries plays an important role. Electricity imports summed up to 44 TWh in 2004 and electricity exports to 52 TWh. Nevertheless, the German electricity market is only partially integrated into the European market. On the one hand, congestions to and from some of the neighbouring countries are comparatively frequent (to Netherlands, from Denmark [West], the Czech Republic, Poland) while there are (almost) no congestions from and to Austria and France. On the other hand, spot markets are still separated in Central Europe. Market Coupling is intensively discussed (e.g. Consentec and Frontiers Economics Ltd. 2004, EUROPEX and ETSO 2004, Hinüber et al. 2004, Schwarz and Lang 2006) but still far away from realisation. If the law of the one-price criterion (Twomey et al. 2005: 15) is used for defining regional boundaries, Germany can in the short run but not in the long run be seen as a relevant market. The hourly spot market prices can be quite different between Germany and the neighbouring countries because of separated spot markets. This is also true for German prices compared with French and Austrian prices although there are (almost) no congestions. Comparing monthly or annual instead of hourly or daily prices, there are only slight differences between German, French and Austrian prices because of successful counter trading (cf. Schwarz and Lang 2006: 14 f.).

The question of regional boundaries concerning electricity markets is highly critical for studies measuring potential market power by using market shares, the Herfindahl-Hirschman Index (HHI) or the pivotal supplier index as indicators (Twomey et al. 2005: 14 f.). Most existing studies of this type assume that Germany is the relevant market (e.g. European Commission 2003, Schwarz and Lang 2005). For studies (like this) on exercised market power using the price-cost-margin as an indicator, the question of regional boundaries is less important. Because of separated spot markets and the objective to evaluate their outcome, it is advisable to interpret Germany as a relevant market. The influence of foreign demand and supply decisions on the domestic marginal cost estimator can be easily considered by adjusting domestic load for foreign trade. The only alternative would be the use of a model of the complete EU market considering the net transfer capacity figures of ETSO (2004) limiting power exchange (see Müsgens 2004). If the European electricity markets would be coupled, this would be an adequate approach. But in fact, spot markets are separated and international electricity exchanges as well as spot market outcomes are far away from the theoretical model of a market coupling regime (a market coupling regime would lead to equal spot market prices as long as there are no congestions!). Therefore, the marginal cost estimator of such an EU model would be too high if real net imports were larger than assessed in the model run and too low if the real net imports were lower than assessed.

3. The Model

Figure 1 shows the structure of the market model of German electricity generation. The most important model parameters are specific operating and short-run fixed costs (like fuel prices, net efficiencies, specific allowance costs, start up and abrasions costs), power consumption data und power plant capacities. These parameters will be discussed in section 4 in more detail. The model type used for calculating marginal cost estimators is a successive mixed integer linear (MIP) and ordinary linear program (LP). Total electricity production costs are minimised in both successive models under the auxiliary conditions of market clearance, capacity constraints and non-negativity of production quantities. The MIP model optimises costs over one whole day considering start-up and abrasions costs as short-run fixed costs. Start-up and abrasion costs are connected via binary variables with plant capacities. Start-up and abrasion costs are a decisive cost determinant and their non-implementation or a non-adequate implementation in existing market models of electricity generation are often criticized (see e.g. Harvey and Hogan 2002: 6). The MIP is used for assessing the daily hours of operation of power plants. This data is used as input for the LP which has to assume that the daily hours of operation are known. Daily start-up and abrasion costs are divided by assessed daily hours of operation to define specific start-up and abrasion costs which are connected with the production. In contrast to the MIP, hourly (and not daily), electricity production costs are minimised. The Lagrange multiplier connected with the market clearance condition shows the variation of hourly production costs when changing demand for one unit. This Lagrange multiplier can be interpreted as a marginal cost estimator. In the case of LP, the Lagrange multiplier incorporates the start-up and abrasion costs because they are considered as operating costs. In the case of MIP, the same Lagrange multiplier does not incorporate start-up and abrasion costs (they are considered as fixed costs) and therefore neglects a decisive cost component. This is why a successive MIP/LP approach is used.

As already mentioned, the paper of Müsgens (2004) has been the only attempt to quantify the exercise of market power for the German electricity market so far. Table 1 shows the main differences between Müsgens (2004) and the approach presented. Müsgens` objective was to assess the monthly marginal cost estimators which were compared with average monthly EEX prices. The objective of the presented approach is the calculation of hourly marginal cost estimators which are compared with hourly EEX prices. Müsgens analysed every hour of one representative week for every month from June 2000 to June 2003. A representative week consists of a typical working day which is assumed to appear 4.8 times, 1 Saturday and 1.2 Sundays.

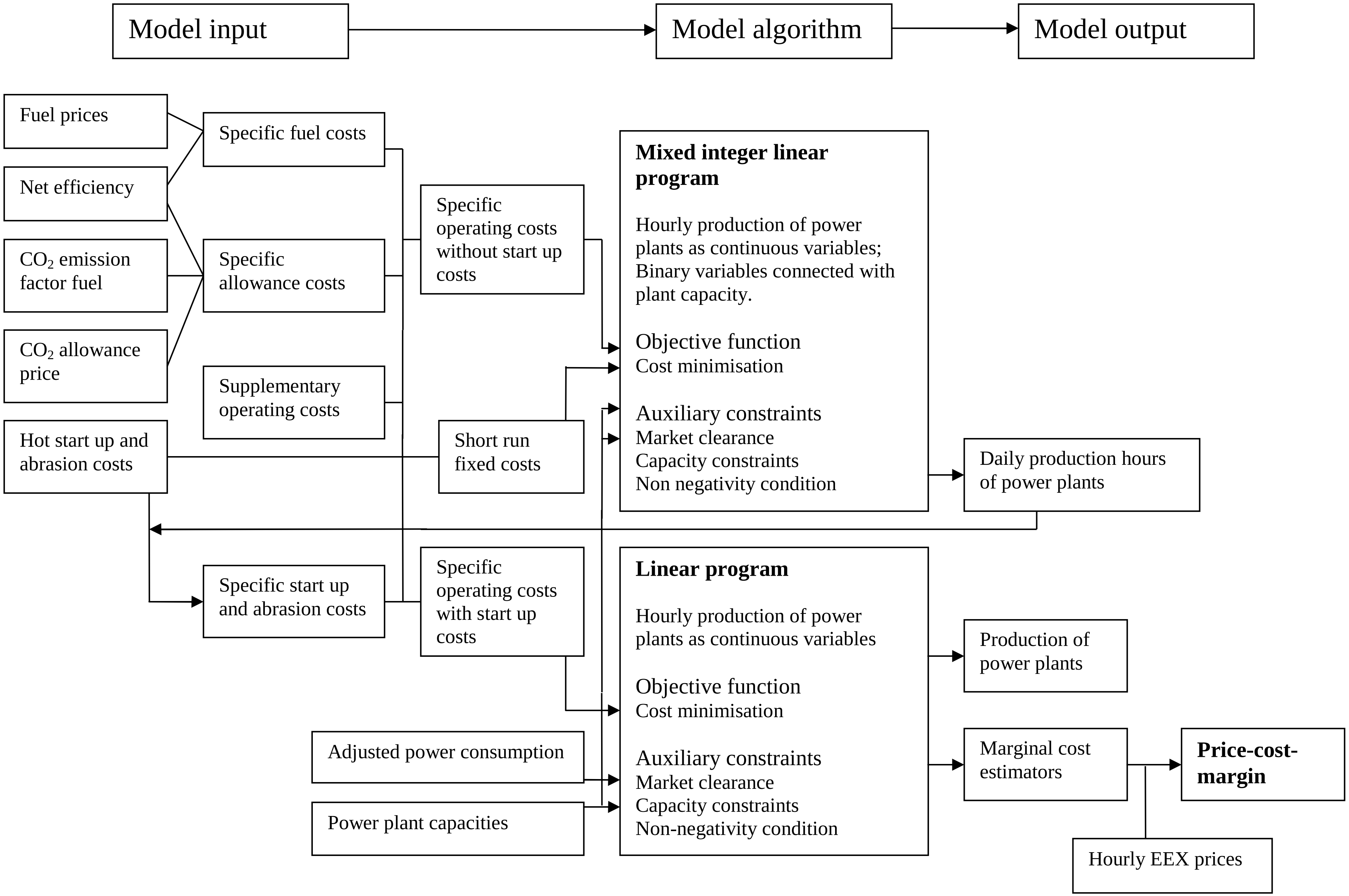


Figure 1: Structure of the market model of German electricity

The reason for using representative days was a lack of demand data. For the period of time analysed, hourly load data (at least for Germany) was only available for every third Wednesday of a month (see UCTE 2006a).

Table 1: Main differences between Müsgens (2004) and the presented approach

	Müsgens (2004)	Presented approach
Objective	Assessment of monthly marginal cost estimators	Assessment of hourly marginal cost estimators
period of time analysed	June 2000 to June 2003 analysing every hour of a representative week for every month; a representative week consists of one typical working day which is assumed to appear 4.8 times, 1 Saturday and 1.2 Sundays.	June 2000 to December 2005 analysing every hour of every third Wednesday of every month; July 2003 to December 2005 analysing every hour and every day.
Regional boundaries	EU	Germany
Model type	LP	Successive MIP/LP

Indeed, there was no possibility to assess ‘exact’ total load figures for Germany until June 2003. Things have changed in July 2003. Since then, German common carriers are obliged to publish the vertical load. The vertical load can, as shown in section 4, be used together with other data to assess the total load. Because of the problems with load data availability every hour of every third Wednesday of every month is analysed from June 2000 to December 2005. In this paper every hour and every day are analysed for the period from July 2003 to December 2005, when vertical load data is available for every day. In the first run the Wednesday-model is used to validate the quality of the every-day-model because existing studies assume that the 2000 EEX prices represent more or less the marginal costs (see Monopolkommission 2004: 449-450, Müsgens 2004: 12).

The regional boundaries of Müsgens (EU) and the presented approach (Germany) are different. In the latter case, domestic demand is adjusted for power exchange. As explained in section 2, this seems to be the more adequate procedure. From a formal point of view, the Müsgens`model and the presented model are very similar. Müsgens used a LP while in this paper a successive MIP/LP is used. The successive MIP/LP approach permits a more adequate consideration of start-up and abrasion costs. On the other hand, power plant reserves are implemented in a well-elaborated way in the Müsgens approach while power plant reserves are considered in a rather simple way in the presented approach.

A model can never incorporate all real world features. One has to decide whether the most important system elements are adequately implemented. The statistical tests in section 5 will show that the quality of the presented approach is satisfactory.

4. Model parameters

Adjusted power consumption, plant capacities and cost parameters are the most important model parameters. They will be discussed in this order.

4.1 Adjusted power consumption

UCTE (2006a) publishes the hourly load data of every third Wednesday of a month. The German public carriers were been obliged to publish the vertical load since July 2003 (RWE 2006, E.ON 2006, ENBW 2006, Vattenfall Europe 2006). The vertical load is defined as the total amount of the power flows out of the transmission network into distribution and large consumer networks. Vertical load does not incorporate most local power production like wind power. In this paper, the total load is assessed by a regression analysis using the UCTE hourly load values of all Wednesdays considered as dependent variable, the vertical load and wind power production of these Wednesdays as independent variables. The model quality is rather high (the adjusted R^2 is 0.97 and all parameters are highly significant). The resulting parameters are used to assess the total load of any day from July 2003 to December 2005.

The total load has to be adjusted for power exchange. UCTE (2006b) publishes hourly international trade data only for two hours (3:00 a.m. and 11:00 a.m.) of every third Wednesday of a month. In addition, monthly power exchange values are available. A regression analysis is carried out using the hourly power exchange as dependent and total load as well as monthly net imports as independent model parameters. The model quality is satisfactory (the adjusted R^2 is 0.63 and all parameters are highly significant). The resulting parameters are used to assess the hourly net imports for every third Wednesday of a month and for every day from July 2003 to December 2005.

Figure 2 shows the hourly vertical load, the hourly total load and the adjusted power consumption for the week from 23/08/2004 to 29/08/2004. The vertical load is lower than the total load because most local power production is missing. Total load and adjusted power consumption differ by the amount of net imports.

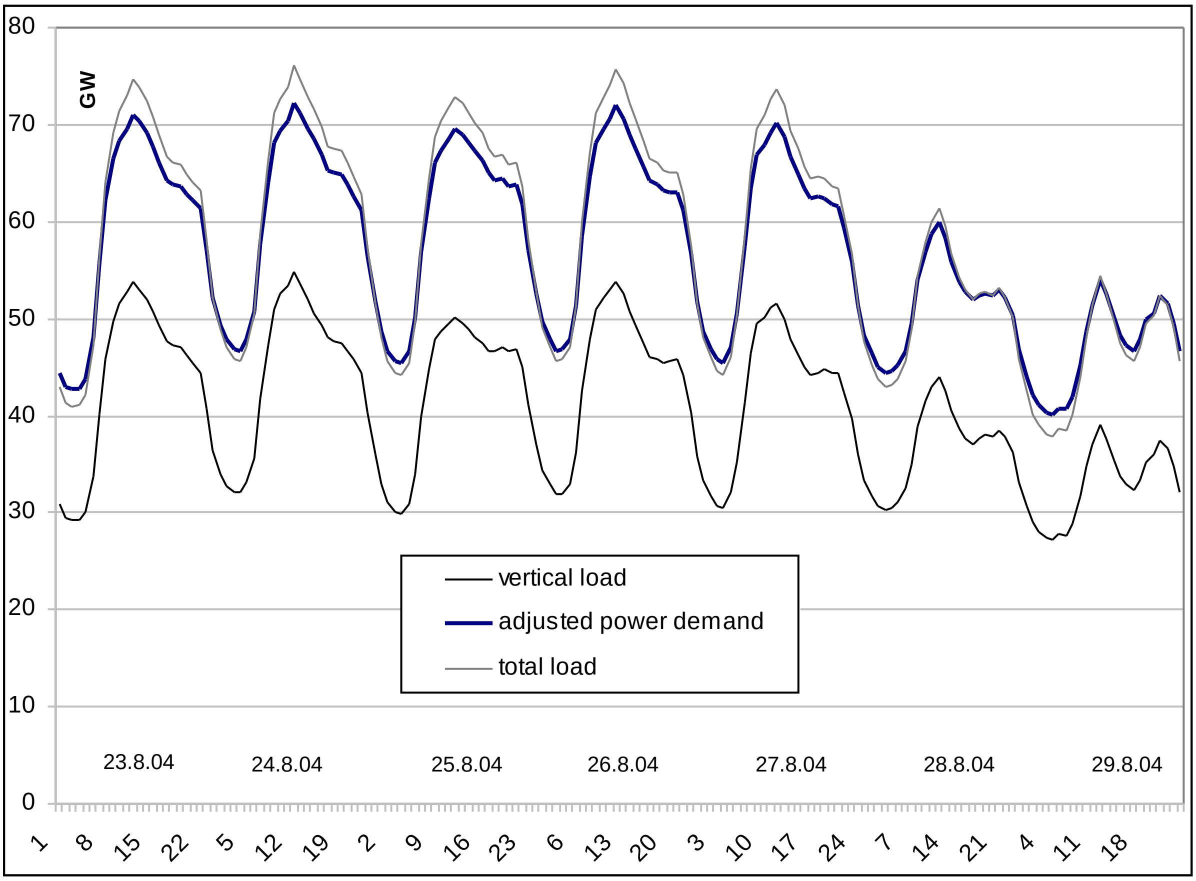


Figure 2: Vertical load, total load and adjusted power demand

4.2 Plant types and capacities

The presented model uses the data of the IWEN power plant data base (2006). All conventional power plants with more than 50 MW (circa 210) are considered. The smaller ones are pooled. The capacity available covers the different plant types; furthermore it depends on data availability (see Table 2).

Table 2: Plant types and coverage of available capacity

Power plant type	Coverage
Must-take	*Coverage of production*
- Bio mass	Annual specific
- Wind power	Hourly specific
- Hydro power	Monthly specific
- Co-generation 1[a]	Monthly specific
Conventional power plants	*Coverage of available capacity*
- Nuclear power	Daily specific
- Lignite	Monthly specific
- Hard coal	Monthly specific
- Natural gas	Monthly specific

- Oil	Monthly specific
- Co-generation 2[b]	Monthly specific
- Pump storage power	Monthly specific

a) Power production connected with heat production

b) Variable power production

With respect to must-take power stations, the hourly specific production is available for wind energy while for hydro power stations and the power production of co-generation power plants connected with heat production only the monthly production can be assessed. Concerning conventional power plants, the data availability is best for nuclear power stations. All revisions of nuclear plants have to be published. The data availability is less detailed for coal, gas or oil fired power plants. The net capacities can only be adjusted for revision cycles which depend on the plant type. In addition, the capacity of conventional power plants has to be adjusted for reserves for system services. This is done by factors depending on the plant type ranging from 1.5% of available capacity for lignite to 50% for pump storage power stations. Figure 3 shows the net capacities of different power plant types from 2000 onwards. The extension of wind power capacity from 6.1 GW in 2000 to 18.3 GW in 2005 is most striking while conventional capacity has slightly decreased.

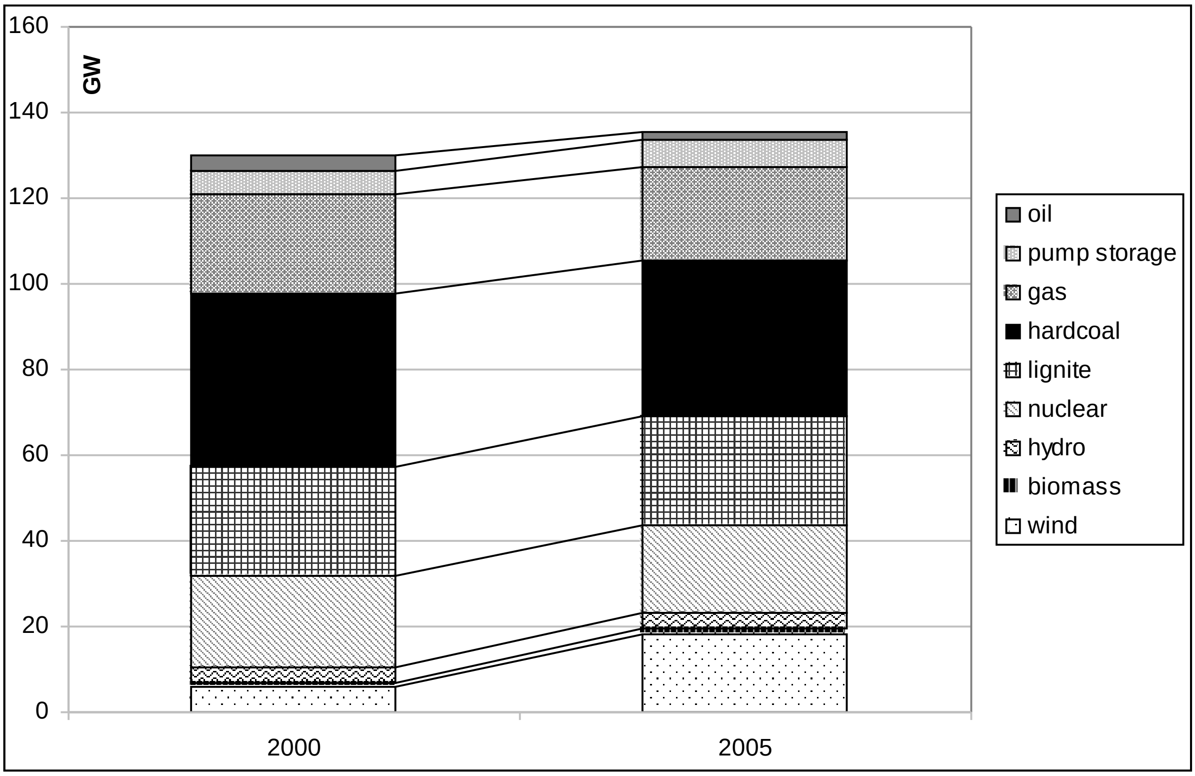


Figure 3: Net power generation capacity, 2000 and 2005

4.3 Cost parameters

There are several components of operating costs i.e. specific fuel costs which are determined by net efficiencies and fuel prices, supplementary operating costs and, since 01 January 2005, specific allowance costs which are determined by the CO_2 emission factor of the fuel and the CO_2 allowance price. Start-up and abrasion costs are treated as short-run fixed costs in the MIP and as operating costs in the LP.

Net efficiencies are available for all power plants (IWEN data base 2006). Fuel price figures are from VIK (2006). They have to be adjusted for transport costs and taxes. The CO_2 emission factors of fuels that are used are the ones of BMU (2003). CO_2 allowance prices are available from EEX (2006).

The standard CO_2 allowance allocation for old plants in trading period 1 (2005-2007) is geared to the emissions of these plants in a defined base period (Grandfathering). But the German national allocation plan provides alternatively a so called option rule for old plants. The allowance allocation depends according to this option rule on the actual power production of a plant and a benchmark for the fuel used (fixed for gas and coal). If a plant has decided for the option rule, the CO_2 allowance costs are only partially priced in depending on the fuel used and the efficiency of the plant. In contrast, if a plant decided for the standard allocation, the total CO_2 allowance costs have to be priced in. Data on how many power plants have decided for the option rule exists (DEHSt 2005), but there is no publicly available data specifying which power plants in particular have decided for it.[2] Because of the fixed benchmarks, it is generally more attractive for gas-fired plants to decide for the option rule. Therefore, the proposed model assumes that all gas-fired power plants have decided for the option rule and all coal-fired power plants for the standard allowance allocation.

The daily start-up and abrasion costs (SC) are modelled analogous to Schröter (2004) as:

$$SC = \left(0.3 \cdot CF_{fuel} \cdot t_{start} \cdot \frac{1}{1 - CF_{abrasion}} \right) MC_{without\ start-up\ costs}$$

The marginal costs without start-up costs ($MC_{without\ start-up\ costs}$) are multiplied by a cost factor for fuels (CF_{fuel}) and the start-up-factor 0.3. In addition, the duration of the start-up process (t_{start}) is a decisive factor as well as the increased abrasion which is represented by the factor $1/(1-CF_{abrasion})$.

Table 3 shows the values of the factors mentioned earlier for hard coal, gas and oil fired power plants. No start-up costs are considered for lignite and nuclear power because they are

[2] The option rule dropped out in the NAP II. Under the assumption of constant CO_2 allowance prices, the electricity price will rise.

(typically) used non-stop at least in a daily perspective. As already explained in section 3, start-up and abrasion costs are considered as operating costs. They have to be adjusted for daily production hours.

Table 3: Fuel specific factors of start-up and abrasion costs

	CF_{fuel}	t_{start}	$CF_{abrasion}$
Hard coal	0.5	8	0.4
Natural gas	0.2	2	0.35
Oil	0.25	2	0.35

(Schröter 2004: 36-39)

Figure 4 shows the development of fuel prices from July 2000 onwards. Compared to July 2000, hard coal, gas and oil prices were 55 to 75% higher by the end of 2005, uranium prices rose by about 40%.

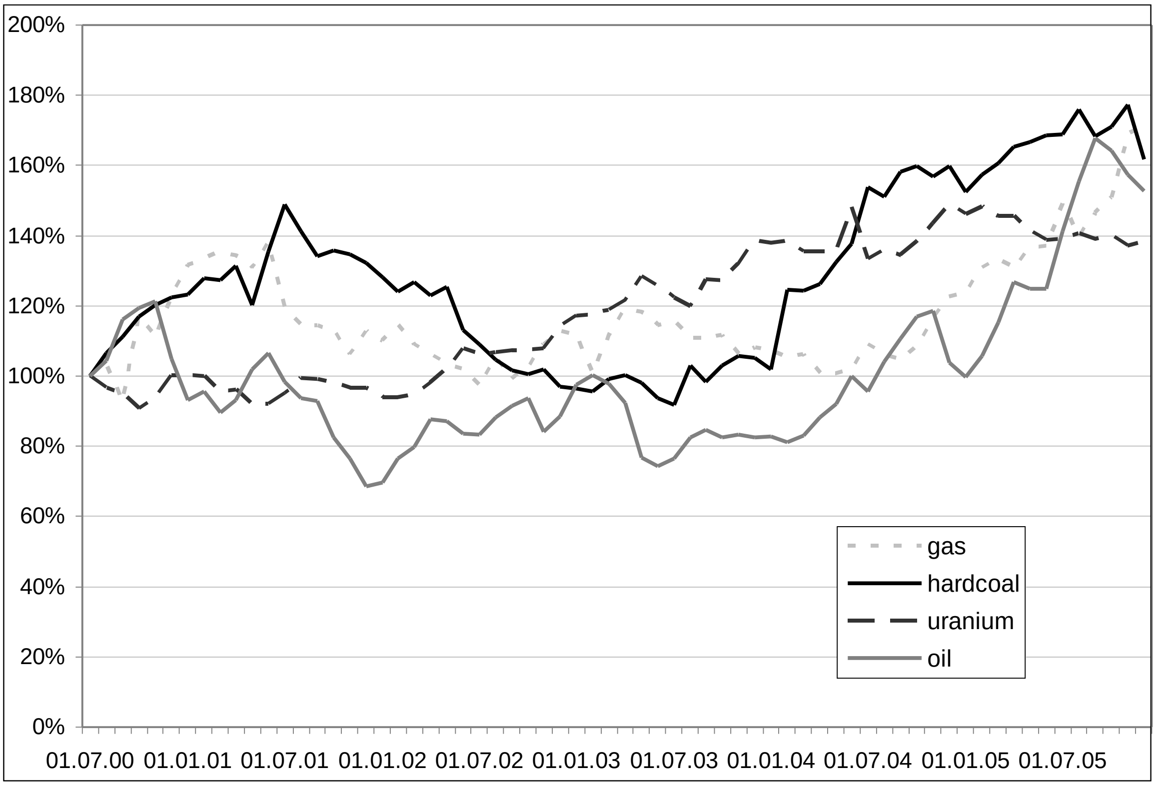


Figure 4: Evolution of fuel prices, July 2000 until December 2005 (Prices July 2000 = 100) (VIK 2006)

5. Model results

Figures 5a and b show the significance of different factors on the evolution of spot market prices using the Wednesday- and the every-day-model. The results for 2003, 2004 and 2005 differ slightly, because the presented annual results of the Wednesday-model are based on 12 Wednesdays each while the annual results of the every-day-model are based on all days of the second half of the year 2003 and on all days of the other years. As already mentioned, the Wednesday-model is in the first run used to validate the every-day-model. Figure 5a shows that the presented models obviously do not overestimate marginal costs. Far from it! In 2000, when marginal cost pricing can be assumed, the price-cost-margin was even slightly negative. It will be pointed out later on that the deviations of the EEX prices from the model results are very small in 2000.

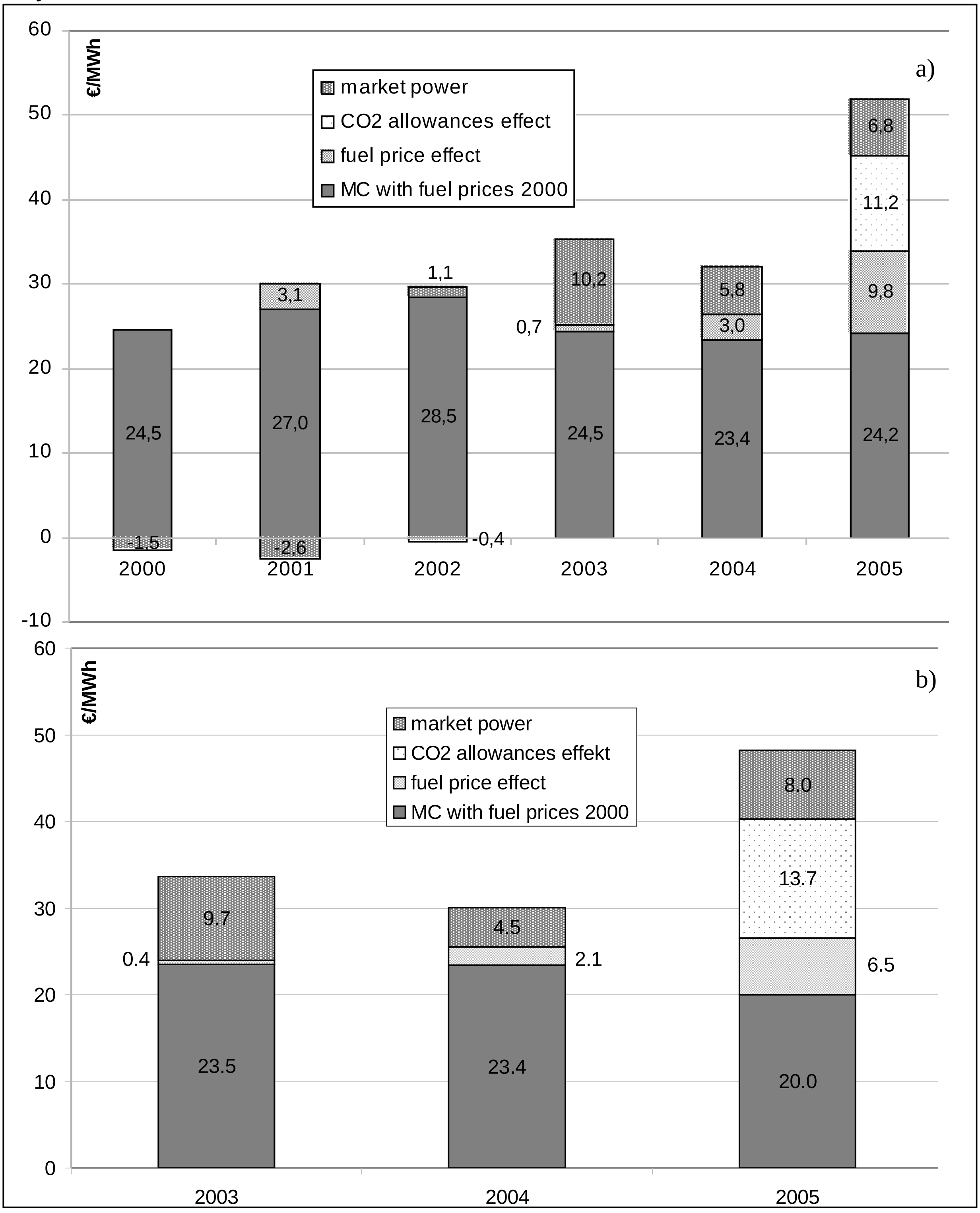


Figure 5: Impact of different factors on spot market prices, a) results of the Wednesday-model, II/2000 until 2005; b) results of the every-day-model, II/2003 until 2005

Figures 5a and b clarify that if the whole period from 2000 to 2005 is considered, fundamental factors are primarily responsible for rising wholesale market electricity prices; an exercise of market power is less important. The average EEX base load price for one MWh was 49 Euros in 2005. If marginal cost pricing, the fuel prices of 2000 and no allowance trading are assumed, the average EEX price for 2005 would be, according to the every-day-model, circa 20 Euros per MWh. Rising fuel prices caused a price increase of 6.5 Euros and the EU emissions trading proves to be responsible for additional 14 Euros. The increasing exercise of market power is responsible for additional 8 Euros.

In contrast, only fundamental factors were responsible for the sharp price increase from 31 Euros in 2004 to 49 Euros in 2005. As Figures 5 and 6 show, the value for exercised market power has changed only very slightly.

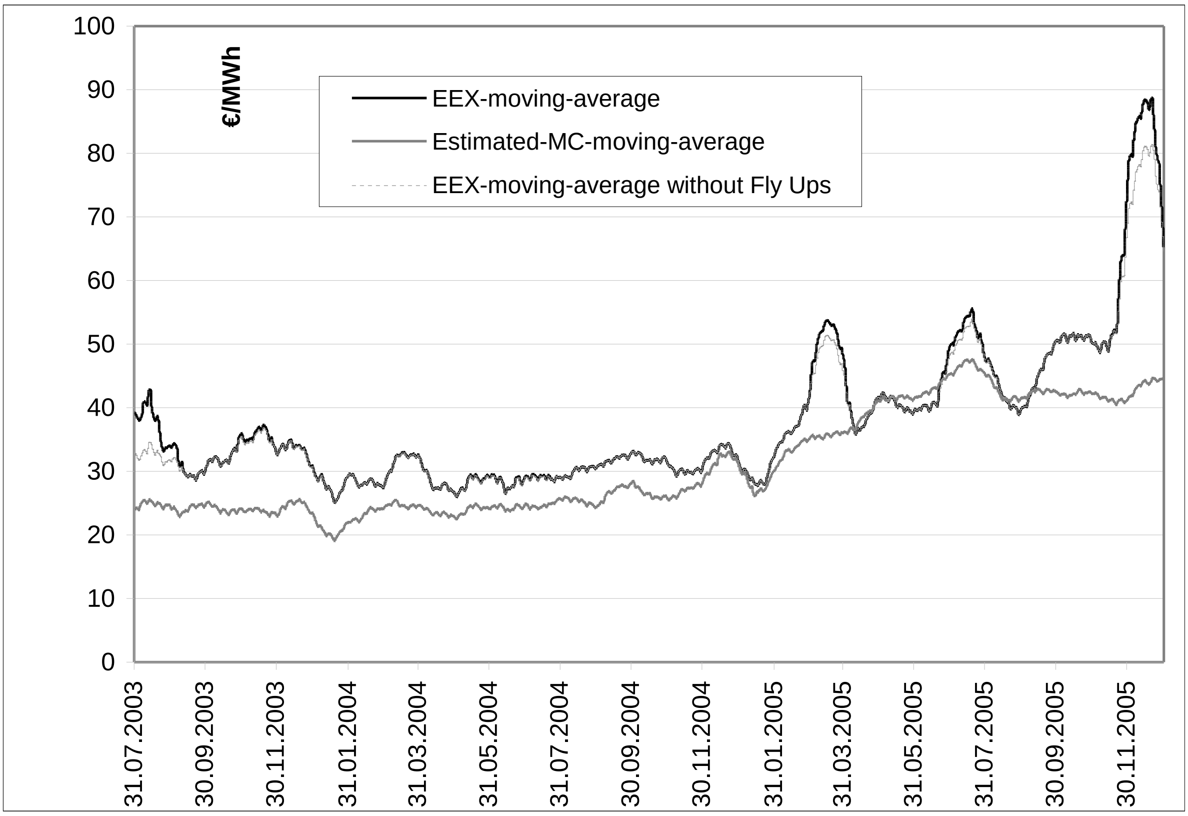
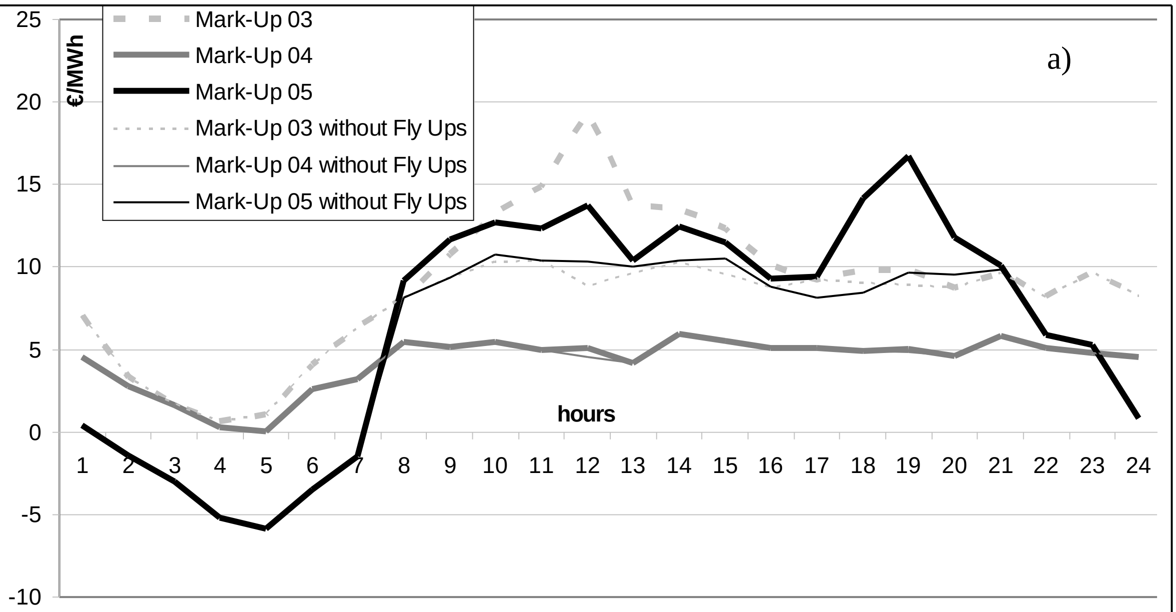


Figure 6: Monthly moving-weighted-average of EEX prices and marginal cost estimators, July 2003 until December 2005

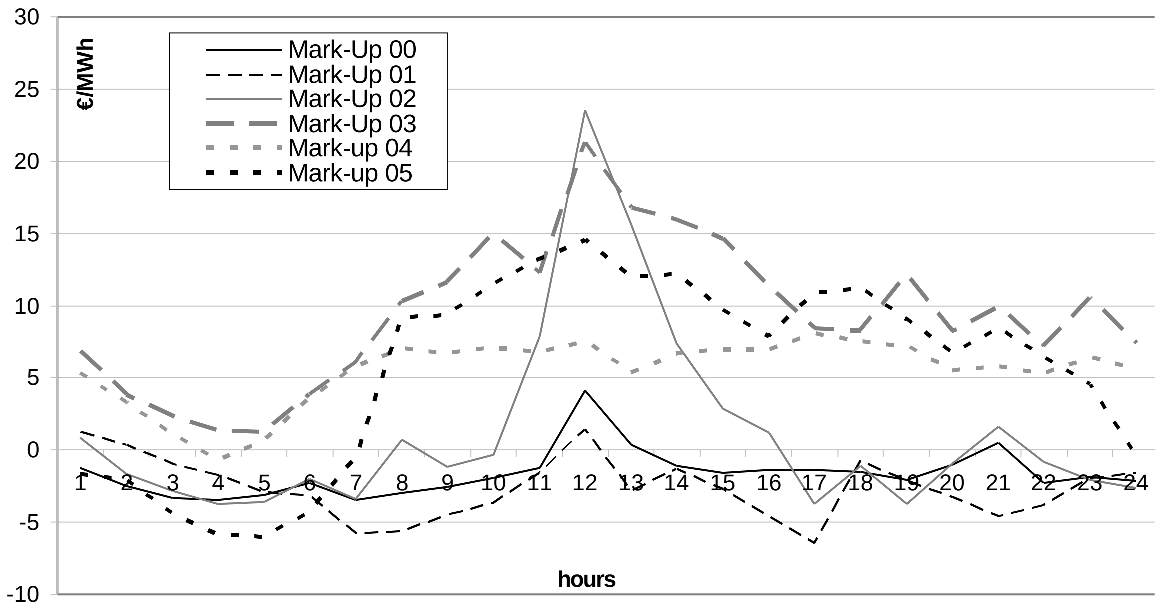
Indeed, the Wednesday-model and the every-day-model show that price-cost-margins were most excessive in 2003 and were eroded in the following years. According to the every-day-model, the price-cost-margin was almost 30% of the total price in 2003, 14% in 2004 and 16% in 2005.

Regarding the annual average, the price-cost-margin was more or less the same in 2004 and 2005. Figure 6 presents the monthly moving-average of the EEX prices and of the marginal cost estimators from July 2003 to December 2005. It shows that in 2004 the margin was quite stable while in 2005 there were months with a large margin (in the extreme more than 50% in December) and months with a very small and even negative margin (e.g. in April 2005). One possible reason for this surprising result might be that the German power producers were in a strategic dilemma in 2005. On the one hand, larger mark-ups in bids mean higher prices and larger profits. Model calculations of Schwarz and Lang show that within a certain range it is profitable for at least the two largest suppliers (E.ON and RWE) to consider mark-ups in bids even if all other suppliers decide on marginal cost pricing. On the other hand, it was speculated that 2005 was going to be the new base year for the CO_2 allowance allocation of trading period 2 (2008-12). Indeed, 2005 is the new base year in the second national allocation plan, passed in mid-2006. That means that there was an incentive for each supplier to increase the production and the emissions. In fact, suppliers were in a kind of prisoners' dilemma with respect to the allocation distribution. If all decided to increase production, none of the suppliers could improve his allowance allocation. If only one of them enlarged his production, he would be able to improve his allowance allocation and his long-run profits. Possibly, the suppliers switched between short and long run optimisation of profits.

The dashed line in Figure 6 shows the moving-monthly-average of the EEX prices without fly-ups. Fly-ups are extreme EEX prices. They can be defined, analogous to Lang et al. (2006), as EEX prices that are higher than the marginal costs of an oil-fired power plant of the 1960s. This power plant type is the one with the highest marginal costs ranging from 100 Euros per MWh in 2000 to more than 150 Euros per MWh in 2005. In contrast to hourly prices discussed in the following, there is no substantial change in the monthly moving-average of the EEX prices if fly-ups are not considered. Figures 7a and b show the hourly mark-ups of the Wednesday-model and of the every-day-model respectively. The hourly mark-ups were quite stable in 2000 and 2001. The model calculations indicate that prices were slightly below marginal costs for almost all hours with the exception of 12:00 a.m., the peak load hour in summer, and of 07:00 p.m., the peak load hour in winter. But the prices exceeded the marginal costs only very slightly for these two hours. In 2002, things changed. Prices were close to the marginal costs from 05:00 p.m. to 10:00 a.m. but there were substantial mark-ups from 11:00 a.m. to 04:00 p.m. with a maximum at 12:00 a.m. These extreme mark-ups can be partly explained by four fly-ups that happened on 19/06/2002 at 11:00 a.m., 12:00 a.m., 01:00 p.m. and 02:00 p.m. In 2003, there were rather high mark-ups in almost all hours with an exception from 03:00 a.m. to 06:00 a.m. The maximum of hourly price cost-margins-and mark-ups was reached at 7:00 p.m. according to the Wednesday-



a)
€/MWh
Mark-Up 03
Mark-Up 04
Mark-Up 05
Mark-Up 03 without Fly Ups
Mark-Up 04 without Fly Ups
Mark-Up 05 without Fly Ups
hours
25
20
15
10
5
0
-5
-10
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24



€/MWh
Mark-Up 00
Mark-Up 01
Mark-Up 02
Mark-Up 03
Mark-up 04
Mark-up 05
hours
30
25
20
15
10
5
0
-5
-10
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24

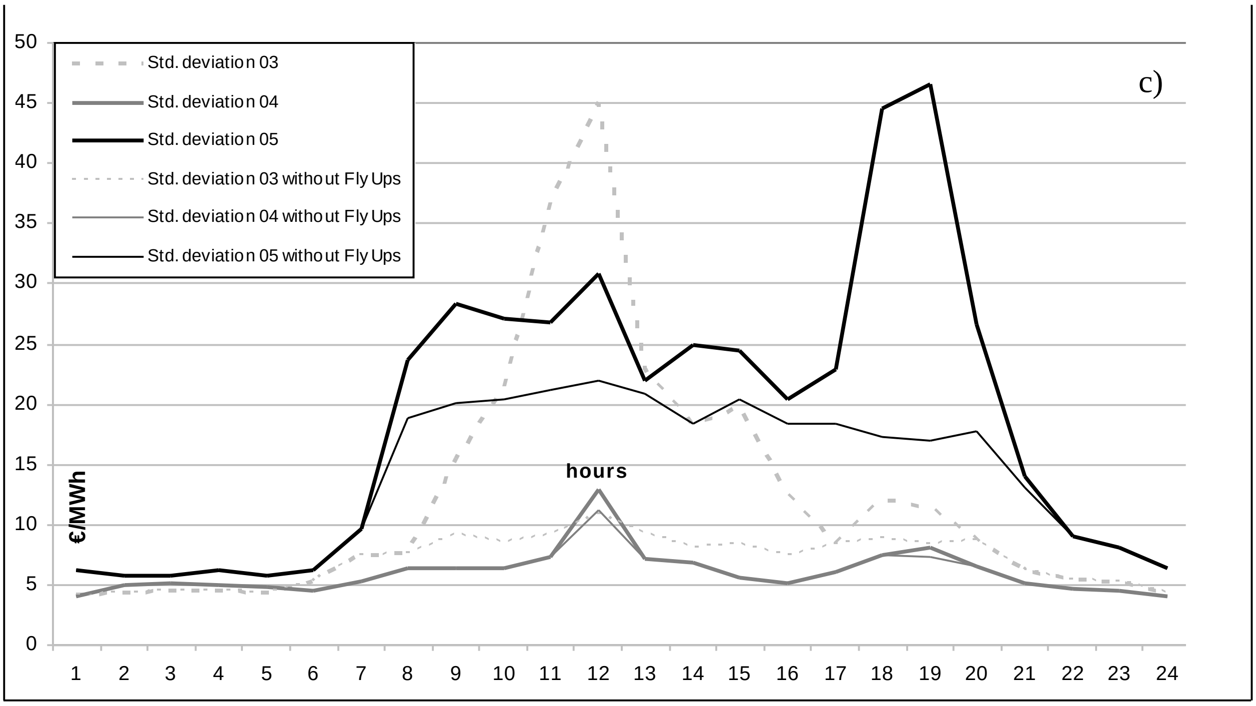


Figure 7: Hourly mark-ups, a) results of the Wednesday-model, II/2000 until 2005; b) results of the every-day-model, II/2003 until 2005; c) connected standard deviation of the every-day-model, II/2003 until 2005

model and at 12:00 a.m. according to the every-day-model. The reason for this difference is the fact that the every-day-model considers only the second half of the year 2003, i.e. the cold winter months of January and February are missing. If fly-ups are not considered in the every-day-model, the mark-ups were quite stable from 08:00 a.m. to 12:00 p.m. They were about 10 Euros per MWh. The mark-ups were surprisingly stable in the year 2004. They ranged from 5 to 7 Euros from 08:00 a.m. to 01:00 p.m. and dropped below 5 Euros for the other hours. Because there were only a few fly-ups in 2004, the non-consideration of the fly-ups has almost no influence on mark-ups. In contrast to 2004, the model calculations indicate negative mark-ups from 02:00 a.m. to 07:00 a.m. for the year 2005. Mark-ups were 10 to 15 Euros from 08:00 a.m. to 09:00 p.m. and below 10 Euros but positive from 10:00 p.m. to 01:00 a.m. Again, if fly-ups are not considered in the every-day-model, the mark-ups were quite stable from 7:00 a.m. to (in this year) 09:00 p.m. As in 2003 they were about 10 Euros per MWh. But the high standard deviations of hourly mark-ups in the year 2005 (see Figure 7c) clarify that hourly mark-ups were very different on a monthly base as discussed above.

The rather stable level of mark-ups for 18 hours in 2004 and, at least if fly-ups are not considered, the quite stable level of mark-ups in 2003 for 18 hours and in 2005 for 14 hours is surprising and conflicts with the typical expectation that mark-ups are larger if the demand is higher and the market tighter (see e.g. Burns et al. 2004). One possible explanation might be that for political reasons suppliers do not exercise all market power when they possess but decide for more or less stable margins on their bids during those hours in which they possess market power. If the approach of Burns et al. of discrete strategies for suppliers is used for the German electricity wholesale market, model calculations show that market suppliers do not exercise all the market power they possess. Wolfram (1999) presents a similar result for the British market for an 18 month period between 1992 and 1993. She found that whilst generators had marked up prices considerably over marginal cost, they had not taken full advantage of their position of market power. She suggested that this might be due to the threat of entry or the implicit threat of regulatory intervention. She found that the mark-ups between price and marginal costs were higher when demand was above the median level while mark-ups in Germany were at least for 2004 almost the same for 18 out of 24 hours although demand was noticeably varying within these 18 hours.

Table 4: Results of the regression analysis of EEX prices and marginal cost estimators

	Constant	Std. error	Slope	Std. error	Adjusted R^2	Constant	Std. error	Slope	Std. error	Adjusted R^2
	Wednesday-model					**Wednesday-model without fly-ups**				
II/2000	-1.89	0.79	1.01	0.03	0.82	-1.89	0.79	1.01	0.03	0.82
2001	0.70	3.27	0.88	0.13	0.54	3.93	1.90	0.76	0.07	0.47
2002	9.96	3.73	0.67	0.15	0.10	9.50	2.83	0.61	0.10	0.39
2003	1.88	5.41	1.31	0.28	0.29	5.12	4.08	1.12	0.20	0.31
2004	1.68	1.99	1.15	0.07	0.76	1.68	1..99	1.15	0.07	0.76
2005	-23.86	8.21	1.66	0.21	0.58	-23.86	8..21	1.66	0.21	0.58
	Every-day-model					**Every-day-model without fly-ups**				
II/2003	-4.30	2.14	1.58	0.11	0.42	1.40	0.94	1.27	0.04	0.66
2004	4.23	0.90	1.00	0.04	0.64	4.36	0.88	0.99	0.04	0.65
2005	-24.37	2.58	1.78	0.07	0.33	-18.55	1.72	1.60	0.05	0.46

Table 4 shows the results of a simple regression analysis with EEX prices as dependent variable and marginal prices estimators as independent variables. In 2000, marginal cost pricing can be assumed. In the ideal case that prices and marginal cost estimators are the same, the constant element is zero and the slope is one. The regression shows that the constant element is almost zero (-1.89) and the slope is almost one (1.01). The adjusted R^2 is quite good (0.82). Because of mark-ups and the appearance of fly-ups the adjusted R^2 is lower in the following years. With exception of 2001, the adjusted R^2 gets better when fly-ups are not considered. In 2004, the adjusted R^2 is quite high because only a few fly-ups appeared and mark-ups were quite stable on a monthly and an hourly base.

6. Summary

It was the objective of this paper to quantify the significance of fundamental factors (like rising fuel costs) and of the increasing exercise of market power on rising prices in the German wholesale electricity market. A successive MIP/LP approach was used for this.

The calculations show that, if the whole period from 2000 to 2005 is considered, fundamental factors explain most of the price movement. The increasing exercise of market power is less important for rising wholesale market electricity prices.

Further analysis clarifies that the price-cost margin widened substantially already in 2003. In this year, the price-cost-margin was most extensive with almost 30%. The increasing exercise of market power was the single cause for the rising price in 2003. The price-cost-margin eroded in the following two years to 14 and 16% respectively. That means that only fundamental factors were responsible for the sharp price rise in 2005. Over the whole year, the price-cost-margin in 2005 was more or less the same as in 2004. But in contrast to 2004, the monthly values were very unstable. There are months when the price-cost-margin is more or less zero or even negative and there are months when the price-cost-margin is very large. As discussed in detail, one possible reason for this surprising result might be that the German power producers were in a strategic dilemma in 2005 because of the discussion that 2005 would probably be the new base year for the CO_2 allowance allocation of trading period 2.

The quite stable level of mark-ups for 18 hours in 2004 and, at least if fly-ups are not considered, the quite stable level of mark-ups in 2003 for 18 hours and in 2005 for 14 hours is surprising and conflicts with the typical expectation that mark-ups are larger if the demand is higher and the market tighter. As clarified, one possible explanation might be that for political reasons suppliers do not exercise all market power they possess but decide to have more or less stable margins on their bids during the hours when they possess market power.

Reference

Albers, K., Stelzner, P. (2001): Regelenergiebeschaffung durch den Übertragungsnetzbetreiber. Energiewirtschaftliche Tagesfragen 51(11): 704-709.

Bauer, C., Zink, F. (2005): Korrelation zwischen Strompreisen und CO_2-Zertifikatpreisen. Energiewirtschaftliche Tagesfragen 55(8): 574-577.

BMU (2003): Bundeseinheitliche Liste der CO_2-Emissionsfaktoren bezogen auf den unteren Heizwert. Berlin.

Borenstein, S., Bushnell, J. (1999): An Empirical Analysis of the Potential for Market Power in California's Electricity Industry. The Journal of Industrial Economics 47(3), 285-323.

Burns, P., Huggins M., Lydon, R. (2004): Generators' Strategies in the England and Wales Electricity Market - A Synthesis of Simulation Modelling and Econometric Analysis. Centre for the Study of Regulated Industries, Technical Paper No. 16.

CONSENTEC und Frontier Economics Limited (2004): Analysis of Cross Border Congestion Management Methods for the EU Internal Electricity Market. Final Report, June.

DEHSt (2005): Emissionshandel in Deutschland: Verteilung der Emissionsberechtigungen für die erste Handelsperiode 2005-2007. Berlin, Februar.
EEX (2005): EEX Spot Market Concept. Leipzig.

EEX (2006): Download Center Marktdaten (http://www.eex.de/index.php?page=25&session=f5851b3ba1b895a33a863b504f7d7301; last access: 02/08/2006).

ENBW (2006): Vertikale Netzlast (http://www.enbw.com/content/de/netznutzer/strom/netzkennzahlen/vertikale_netzlast/index.jsp;jsessionid=1CCB7834FACDB106F5F3419064748AF1.nbw05; last access: 02/08/2006).

E.ON (2006): Vertikale Netzlast (http://www.eon-netz.com/frameset_german/main_frameset_reloader.phtml?top=http://www.eon-netz.com/Ressources/frame_head.jsp&bottom=http://www.eon-netz.com/frameset_german/net/net_netzkennzahlen/net_netzkennzahlen.jsp; last access: 02/08/2006).

European Commission (2003): Competition indicators in the electricity market. EU, Norway and the candidate countries. Luxembourg.

EUROPEX und ETSO (2004): Flow-based Market Coupling. Eleventh meeting of the European Electricity Regulatory Forum, Florence.

Evans, J., Green, R. (2003): Why did British Electricity Prices fall after 1998? Working Paper. Center of Economic Policy. University of Hull.

Fabra, N., Toro, J. (2003): The Fall in British Electricity Prices: Market Rules, Market Structure, or Both? Industrial Organization.

Harvey, S. M., Hogan, W. W. (2002): Market Power and Market Simulations. Center for Business and Government, Harvard University.

Hinüber, G., Egger, H., Neus, H. und H.-J. Haubrich (2004): Market Coupling - ein Verfahren zur Ermittlung des bestmöglichen Marktgleichgewichts. Energiewirtschaftliche Tagsfragen 54(12): 790-793.

IWEN Power Plant Database (2006), Power Plant Database of the Institute of Economics, University of Erlangen-Nürnberg

Joskow, P., Kahn, E. (2001): A Quantitative Analysis of Pricing Behaviour In California's Wholesale Electricity Market During Summer 2000. NBER Working Paper 8157.

Lang, Ch., Schwarz, H.-G., Kähler, J. (2006): Analyse und Prognose von Fly Ups am Spotmarkt der EEX. Energiewirtschaftliche Tagesfragen 56 (7): 46-51.

Monopolkommission (2004): Wettbewerbspolitik im Schatten "Nationaler Champions", Hauptgutachten XV (2002/2003). Bonn.

Müsgens, F. (2004): Market Power in the German Wholesale Electricity Market. EWI Working Paper, Nr 04.03.

Richmann, A. (2006): Die Entwicklung der Energiemärkte und deren Auswirkungen auf die deutsche Wirtschaft. VIK. Remscheid.

RWE (2006): Netzkennzahlen (http://www.rwe-transportnetzstrom.com/generator.aspx/netznutzung/netzdaten/netzkennzahlen/language=de/id=75454/netzkennzahlen-page.html; last access: 02/08/2006).

Schiffer, H.-W. (2004): Die aktuelle Strompreisentwicklung auf der Erzeugerebene. energy weekly: 8-9.

Schröter, J. (2004): Auswirkungen des europäischen Emissionshandelssystems auf den Kraftwerkseinsatz in Deutschland. Berlin.

Schwarz, H.-G., Lang, Ch. (2005): Marktstruktur und Konzentration in der deutschen Stromerzeugung. Energiewirtschaftliche Tagesfragen 55(12): 864-870.

Schwarz, H.-G., Lang, Ch. (2006): Europäische Stromerzeugungsmärkte am Beispiel Zentraleuropas: Stand der Integration und Handlungsbedarf. IWE Working Paper 01-06.

Short, C., Swan, A. (2002): Competition in the Australian National Electricity Market. ABARE Current Issues.

Twomey, P., Green, R., Neuhoff, K., Newbery, D. (2005): A Review of the Monitoring of Market Power. CMI Working Paper 71. Cambridge.

UCTE (2006a): Consumption Data (http://www.ucte.org/statistics/onlinedata/consumption/e_default.asp; last access: 02/08/2006).

UCTE(2006b): Exchange Values (http://www.ucte.org/statistics/onlinedata/exchange/e_default.asp; last access: 02/08/2006).

Vattenfall Europe AG (2006): Vertikale Netzlast (http://transmission.vattenfall.de/index.asp; last access: 02/08/2006).

VDN (2005): Beschaffung von Regelleistung und –energie in Deutschland. Berlin.

VIK (2006): Energiepreise und Notierungen (http://www.vik-online.de/index.php?id=12; last access: 02/08/2006).

Von der Fehr, N. H., Harbord, D. (1993): Spot Market Competition in the UK Electricity Industry. Economic Journal 103: 531-546.

Wolfram, C. D. (1998): Strategic Bidding in a multiunit auction: an empirical analysis of bids to supply electricity in England and Wales. Rand Journal of Economics 29(4): 703-725.

Wolfram, C. D. (1999): Measuring Duopoly power in the British Electricity Spot Market. American Economic Review 89(4): 805-826.