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Parameters influencing the market value of wind power – a model-based analysis of the Central European power market

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SUMMARY

In leading European wind power countries wind power generation affects wholesale power prices already today. First investigations indicate that the respective wind power-price relation lowers the market value of wind power relative to the baseload price with increasing penetration. The aim of this paper is to identify parameters that determine this effect based on simulations for the Central European Power Market (CEPM). We model wind power-price interactions and investigate the sensitivity of the market value on a number of wind power and system related parameters. The market value of wind power is sensitive to changes in wind share and variability, wind-demand correlation and the supply characteristics. Results further indicate that for expected wind capacities in 2020 the market value in the CEPM is significantly lower than the baseload price. The market value reducing effect varies among countries and is comparably low for wind power portfolios whose generation is weakly correlated with the overall wind power generation in the respective power market. Hence with rising wind shares it will become increasingly important to take this effect into account when assessing the economics of wind power projects. Future trends in the CEPM that may positively influence the market value are increasing electricity demand, fuel and CO2 prices, a better geographic distribution of onshore wind within the CEPM and an increasing utilization of offshore wind. Copyright © 2010 John Wiley & Sons, Ltd.

KEY WORDS: wind power; power markets; market value

1. INTRODUCTION

In leading European wind power countries like Germany, Spain and Denmark wind power generation affects power prices already today. As marginal cost of wind power is almost zero, rising amounts of wind power *ceteris paribus* have a dampening effect on electricity prices for a given power system. This so-called merit order effect has already been studied for selected power markets (cf. [1–3]).[a]

From the power producers point of view the merit order effect lowers the market value of power generation, i.e. the average price for selling power on the wholesale power market. In contrast to a baseload generation technology, i.e. a technology that produces a fixed quantity constantly, for a variable generation technology like wind power there is a correlation between power generation and electricity prices which is inherent to the system: for a power system that is specified by a certain supply structure and a fixed demand we might observe 'low' electricity prices when wind power generation is high because residual demand can be met with less costly conventional generation and *vice versa*.

While the effect of wind power on power prices has already been analysed, studies investigating implications of the above-mentioned system immanent wind power–price correlation on the market value of wind power are rare. Within an investigation of the long-term system value of intermittent power generation technologies [4] finds that the market value of wind power decreases

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[a] It is important to note that this effect is not wind power specific but might be observed for any power generation technology with low marginal cost of generation that is pushed into the market. In the long term, however, increasing wind shares will influence the investment decision for conventional power plants which has to be taken into account to get a complete picture of the influence of wind power on power prices.

with increasing wind shares relative to the average system baseload price and explains this effect by the decrease in covariance between wind power generation and power price.

This paper aims to go one step further and investigates in more detail the impact of fundamental wind- and system-related parameters on the market value of wind power based on simulations. We model wind power–price interactions using a simplistic representation of the Central European Power Market (CEPM)[b] and analyse the sensitivity of the market value of wind power on parameter variations. Both implications on market as well as country level are looked at. Finally, based on simulation results, a qualitative assessment of impacts of future trends in the CEPM on the market value of wind power is realized.

To get insight in mechanisms affecting the market value of wind power is of importance for both investors and policy-makers. For the first the market value determines the economics of their investment unless wind power support is uncoupled from power markets.[c] Knowledge about the market value helps latter to optimize support schemes and estimate support needs. From an international perspective the market value (together with the quality of wind sites) determines where most cost-efficient potentials can be realized.

The paper is organized as follows. In Section 2, the principle of wind power–price interactions in liberalized power markets is explained and main parameters influencing the market value of wind power are discussed. Section 3 explains the modelling and simulation framework. Simulation results on both CEPM and country level are presented in Section 4. Section 5 discusses future trends in the CEPM and their qualitative impact on the market value of wind power. Section 6 concludes and gives an outlook for future work.

2. WIND POWER IN THE LIBERALIZED POWER MARKET

2.1. Wind power–price interactions

With the liberalization of the European electricity sector and the introduction of competition, a transition from a cost-based price regulation towards a market-orientated price formation took place. In a competitive power market, the wholesale price is determined by the generation costs of the marginal technology, i.e. the variable cost of the most expensive plant which is needed to satisfy demand.

The interaction of wind power and the power price in such a setting is illustrated in Figure 1. The supply curve represents the merit order of marginal cost and corresponding quantities of available generation technologies except for wind power. In the case of no wind and under the assumption of perfect competition, the price results from the intersection of supply and total demand. Wind power is interpreted as negative load and reduces the residual demand that has to be met by other generation. Let us assume that the wind power generation varies between a low and a high level. The average price then refers to the level of average wind power generation under the assumption of a symmetric distribution of wind power variations. The dampening effect on the average price is referred to as the merit order effect. The average price for wind power – the market value – is, however, even lower than the baseload price as a large quantity is sold at comparably low prices and a smaller amount is sold at comparably higher prices. The latter effect will be analysed in this paper in detail.

2.2. Market value – What's that?

We define the market value of wind power as the sum of revenues by unit of energy if all wind power production were sold in the power exchange. Hence it is not the value wind power provides to the system but the market value from a generator's perspective.

When assessing the market value as interpreted within this paper for a specific generation technology it is important to note that there is no single but a broad range of market values depending on the supposed trading strategy. For instance, wind power might be sold on the long-term market, i.e. bilaterally or in the form of baseload futures and additionally short-term deviations based on wind power forecasts may be settled on the day-ahead market. Finally deviations between trading schedules and actual generation are

[b] The CEPM includes Austria, Czech Republic, France, Germany and Switzerland. After the introduction of market coupling between France, Belgium and the Netherlands wholesale power prices in the two Benelux countries tend to converge towards the price level in above-mentioned countries (see Reference [5]).

[c] In Europe we can observe a trend from the classical feed-in tariff schemes which remunerate renewable electricity at a fixed tariff (independent of the wholesale price) to feed-in premium schemes that provide a premium on top of revenues from selling power on the markets. Currently an according adoption of the regulation is discussed in Germany.

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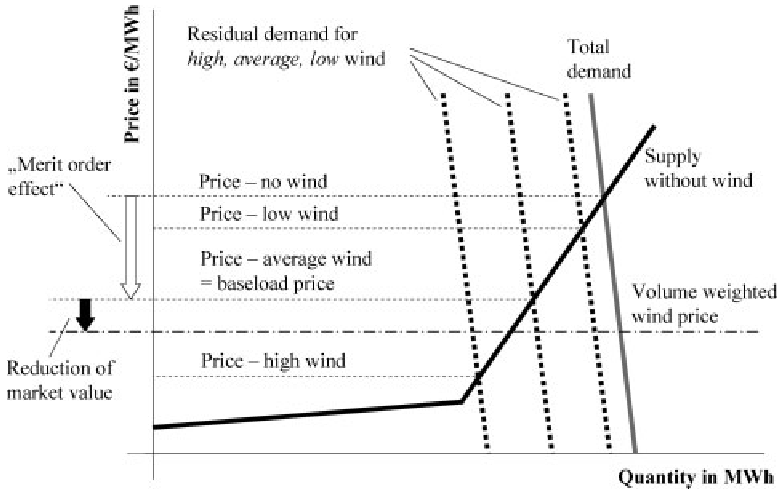

Figure 1. Illustration of wind power–price interactions in the liberalized power market.

settled with imbalance clearing prices within the balancing mechanism. The market value finally results in the sum of revenues (and cost) from several trading activities as illustrated in Reference [6]. As it is not the aim of this paper to analyse trading strategies and imbalance cost, forecast uncertainties are neglected and a single stage of market clearing is assumed when modelling the CEPM.

2.3. Main parameters influencing the market value of wind power

The aim of this section is to identify main parameters influencing the market value of wind power. The starting point for the identification of influencing parameters is the key analytical finding of Reference [4] that the market value of wind power can be split up in two components: (i) a 'baseload' power price component and (ii) a component related to the covariance between power price and wind power production:

$$\mathrm{MV_W} = \frac{\sum_{h=1}^{H} \pi_{\mathrm{PX},h} Q_{\mathrm{W},h}}{\sum_{h=1}^{H} Q_{\mathrm{W},h}} = \overline{\pi}_{\mathrm{PX}} + \frac{\mathrm{cov}(\pi_{\mathrm{PX}}, Q_{\mathrm{W}})}{\overline{Q}_{\mathrm{W}}} \tag{1}$$

where $\mathrm{MV_W}$ is the market value of wind power, $\pi_{\mathrm{PX},h}$ is the power price at the power exchange in hour h, $Q_{\mathrm{W},h}$ is the wind power generation in hour h, π_{PX} is the power price vector, $\overline{\pi}_{\mathrm{PX}}$ is the average baseload price and $\mathrm{Q}_{\mathbf{W}}$ is the wind power generation vector.

Thus the market value of wind power is determined by both parameters influencing the baseload price and those affecting the covariance between wind power and power price. As this paper specifically aims to investigate the relation between market value and baseload price, the analysis focusses on latter parameters.

In a competitive power market, the wholesale price[d] is determined by the generation costs of the marginal technology, i.e. the short run marginal cost of the most expensive unit which is needed to satisfy demand. Therefore power price variations may originate from variations in generation costs of the marginal technologies, from variations in the availability of power generation and from variations in demand. In a non-competitive setting, prices may additionally be affected by strategic behaviour of market actors.

As gas and coal power plants represent the marginal technologies in the CEPM, variations in generation cost are mainly related to the evolution of the gas, coal and CO_2-certificate prices. Depending on the correlation with wind power generation fuel and CO_2 price shocks might significantly influence the market value of wind power relative to the baseload price in a specific period of

[d]Wholesale electricity markets are mainly composed by organized (day-ahead) power market transactions and over the counter (OTC) transactions. Theoretically, the presence of traders that arbitrage opportunities between these two marketplaces ensures that power exchange prices should be equivalent to OTC prices. Supposing that this free arbitrage assumption holds in reality, only power exchange prices are considered in this paper.

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consideration. However, if the observed period is long enough, we expect no significant impact, as there is no evidence for a long-term correlation of these shocks with wind power generation.

Wind power, supply and demand variations are translated into price variations. The resulting wind power–price correlation depends on the shape of the supply curve and on the correlation of corresponding parameters with wind generation. The correlation between wind power and demand as well as other variable renewable generation is mainly determined by meteorological interactions. A correlation between wind generation and the availability of thermal capacities might result from weather depending cooling restrictions and a maintenance planning that takes into account the seasonal availability of wind power. The wind power–price correlation further depends on the wind share as found in Reference [4] and may also be affected by the variability of wind power.

Effects of strategic behaviour on the market value of wind power are investigated in Reference [7]. They conclude that intermittent generation benefits less from abuse of market power than conventional generation.

Within this paper we analyse the following above-mentioned parameters affecting the wind power–price covariance: wind power share and variance, wind–demand correlation and the supply characteristics.

3. MODELLING WIND POWER–PRICE INTERACTIONS

3.1. The power system model

The characteristics of power supply in the CEPM is represented by a function s – the supply curve – that describes the relation between the quantity of supply Q_{S} and the marginal cost MC at which this quantity may be produced:

$$\mathrm{MC} = s(Q_{\mathrm{S}}) \tag{2}$$

The CEPM is modelled as an isolated market, i.e. exchanges with neighbouring systems are not reflected.

In order to account for the variability of wind power the model has a time resolution of 1 hour. Wind power generation $Q_{\mathrm{W},h}$ in hour h is reflected within the residual system demand $Q_{\mathrm{D,res},h}$ which has to be met by remaining power generation technologies in the form:

$$Q_{\mathrm{D,res},h} = Q_{\mathrm{D},h} - Q_{\mathrm{W},h} \tag{3}$$

where $Q_{\mathrm{D},h}$ represents system gross demand in hour h, i.e. electricity demand including power losses.

Note that supply and residual demand curves corresponding to each country are aggregated to a unique curve representing the integrated CEPM. This implies the assumption of perfect (copper plate) integration of national electricity markets.

Then, if we assume perfect competition, the power price π_h results as:

$$\pi_h = s(Q_{\mathrm{D,res},h}) \tag{4}$$

Note that if wind power generation exceeds demand in a certain hour, the price is set to zero.[e]

The baseload price[f] π_{base} is calculated as the average of elements π_h of the resulting price vector:

$$\pi_{\mathrm{base}} = \frac{1}{H}\sum_{h=1}^{H} \pi_h \tag{5}$$

[e]This assumption reflects a framework without support or solely support in the form of investment subsidies. Prices will then not become negative as wind producers are willing to reduce their output when the price is below zero. In markets with significant wind shares like, e.g. Germany we already today see prices of zero or even below zero on the day-ahead market even if wind power generation does not exceed total demand. This is because of start-up costs and dynamic constraints of thermal power plants. Negative prices are a direct consequence of the fact that in a feed-in tariff scheme the producers do not receive any price signal from the market.

[f]Baseload price represents the revenue per unit of energy if power is produced in a constant manner over the studied period.

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Table I. Assumptions for investigated price scenarios.

	Gas (€/MWh)	Oil (€/MWh)	CO_2 (€/tCO_2)
2006 Prices	21.4	32.5	17
High fuel	27.9	41.3	17
High CO_2	21.4	32.5	50
High fuel and CO_2	27.9	41.3	50

Sources: BAFA (2006 prices for gas and oil), EEX (CO_2 certificates), [13] (high fuel prices).

while the market value of wind power MV_W is calculated as the volume weighted average price:

$$MV_W = \frac{\sum_{h=1}^{H} Q_{W,h}\pi_h}{\sum_{h=1}^{H} Q_{W,h}} \tag{6}$$

It is important to note that the model neglects imbalance cost that will in reality lower the resulting market value of wind power.[g]

3.2. Data base

The supply curve represents the average available capacity of all generation technologies in the CEPM except from wind power and is assumed to be fixed. Marginal costs of generation are calculated assuming average prices for fossil fuels and CO_2 certificates and efficiencies differentiated by fuel type and decade of commissioning. All parameters refer to the year 2006 (see below Table I for price assumptions). Hourly demand time series also refer to the year 2006 and stem from UCTE. Hourly wind power time series comprise both simulated and measured data. Simulated data from the TradeWind project are covering all countries of the CEPM. These data base on numerical weather data and cover the years 2000–2006 (cf. [8,9]). Further measured wind power data for the year 2006 were available for Austria, Germany and France.[h]

3.3. Implementation of parameter variations

In order to derive the sensitivity of the market value of wind power we vary single above-mentioned parameters within simulations while several other parameters are kept constant.

Parameter variations are implemented as follows:

Increased *wind shares* are modelled by simply scaling wind power time series for 2006. We investigate different deployment scenarios for 2020 based on simulations with the Green-X model (cf. [10]) for countries of the CEPM: (i) current support policies are retained in the future (2020 BAU), (ii) strengthened national policies in line with 20% target (2020-20%), (iii) a case with wind deployment on CEPM level according to the 2020-20% scenario and distribution among countries as in 2006. Figure 2 illustrates these scenarios in terms of annual wind generation for the single countries and the CEPM as a whole.

Wind power demand correlation: We use copulas to generate random samples with distributions equal to historic wind power and demand in the CEPM but varying correlation. For a detailed description of the methodology, see Reference [11]. Please note that we use the linear correlation as the measure to describe the relation between wind power and demand and not the rank correlation as recommended in Reference [11], because model results in this case fit much better those of real data.

Historic wind power time series represent a certain distribution and variability and are therefore not suited to reflect different scenarios of wind power variability. We simulate a set of samples with varying *wind power variance* and representative distributions according to the following procedure:

[g]In fact interactions on the ‘balancing market’ are similar to those in the wholesale market. When the wind share increases the wind power imbalance will increasingly correlate with the overall system imbalance. As a consequence wind power is expected to face increasing specific imbalance cost.
[h]German wind power data were offered by the Department of Energy Systems of Berlin University of Technology. The French distribution grid operator ERDF and the single buyer for supported electricity from renewables in Austria OeMAG provided wind power data for France and Austria, respectively.

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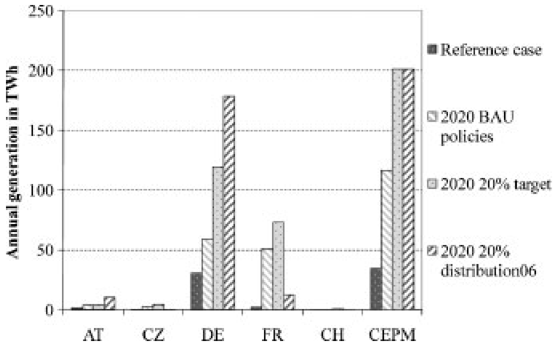

Figure 2. Investigated wind deployment scenarios.

(1) Generation of uncorrelated Rayleigh distributed samples for wind speed with defined mean.
(2) Application of samples to a normalized power curve.[i]
(3) Summing up of different numbers of uncorrelated wind power samples.
(4) Scaling of resulting samples to the reference mean wind power generation.
(5) Again copulas are used to simulate corresponding samples of wind power and gross demand with reference correlation observed for 2006 data (for details, see Reference [12]).

Varying *supply characteristics* are represented by scenarios for fuel prices for gas and oil and the CO_2-certificate price as indicated in Table I. Price scenarios translate in corresponding supply curves as illustrated in Figure 3.

It is important to note, that in contrast to Reference [4], we do not model the optimal energy mix for given wind shares but focus on sensitivities for given system configurations. Our simulations are 'static' meaning that changes in parameters are not endogenous. We do not study the impact of the future development of the supply structure.

4. SIMULATION RESULTS

4.1. Sensitivity analysis for the CEPM

In this section, simulation results on the sensitivity of the relative price difference between market value and baseload price on changes of aforementioned parameters are presented.[j]

As sensitivities depend on the point of reference, two wind deployment scenarios are investigated: (i) the reference case (2006 wind deployment), (ii) the 2020-20% wind scenario.

For the reference case, that reflects wind power and system characteristics of the year 2006, the baseload price is 51.4 €/MWh in the CEPM while the market value of the overall wind power portfolio is 51.2 €/MWh.[k] For a wind share of 2.8% of gross demand the relative price difference is therefore still minor with −0.4% of the baseload price.

The sensitivity of the price difference is significant for all indicated parameters (see Figure 4). While an increase of wind share and variance reduces the market value of wind power *ceteris paribus* an increased wind–demand correlation is beneficial for the economics of wind power. It can be seen that for specific parameter settings the market value can even exceed the baseload price.

[i]The used power curves have been developed within the TradeWind project and reflect the characteristics of regionally distributed wind farms in lowland areas (cf. [9]).
[j]It is important to note that the market values indicated here refer to total wind power generation on country and CEPM level, respectively, and therefore represent the revenue for a single actor managing the whole portfolio. A particular wind farm, however, will have a specific market value that will depend on the specific correlation between its production and market price.
[k]In 2006 wind power generation in the CEPM is highly dominated by German wind (89%) while in the 2020-20% scenario wind power is dominated by both German (59%) and French (36%) wind power resulting in a lower variability of overall wind power.

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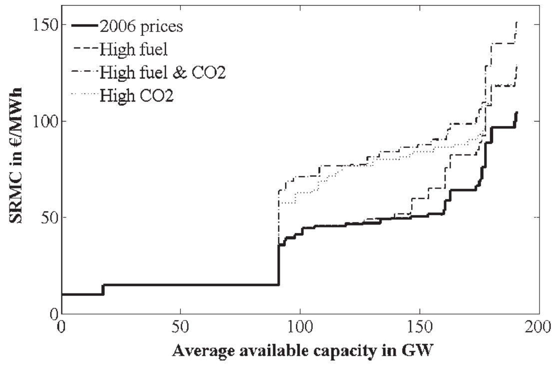

Figure 3. Supply curves representing the power plant mix in the Central European power market for price scenarios indicated in Table I.

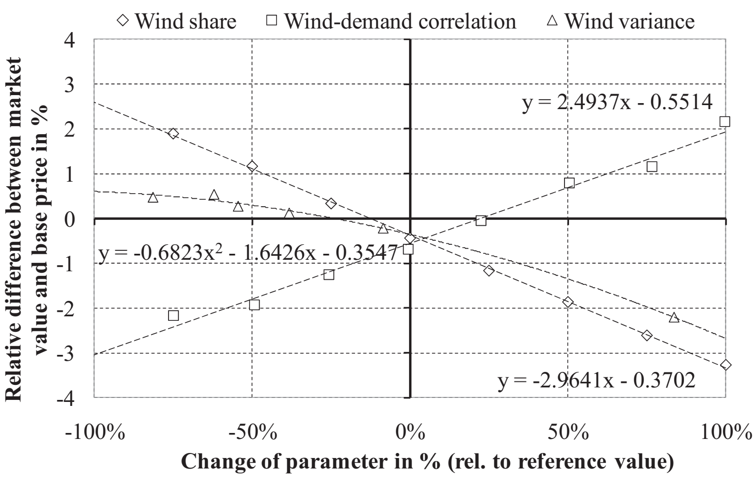

Figure 4. Reference scenario – sensitivity of the relative price difference between market value and baseload price on selected parameters. Assumptions: CEPM, supply, demand and wind power data from 2006.

The highest sensitivity is observed for variations of the wind power share. A doubling results in a price difference of −3.3% while for a reduction to half of the generation the market value is 1.2% higher than the baseload price. The market value equals the baseload price when reducing the variance of wind power by 25% of the reference value or when increasing the wind–demand correlation by 25%.

For a wind generation scenario which is in line with the 20% renewables target in 2020, sensitivities show the same qualitative behaviour. As a result of the increased wind share of 16.3% the baseload price is reduced to 41.7 €/MWh (*ceteris paribus*). For this level of penetration the relative price difference is already considerable with 10.8%. The sensitivity of the price difference on wind share variation is still highest. A 10% increase of wind share results in a 1.3% decrease of market value. The sensitivity on the variance of wind power is in a comparable range. It can be seen that for the investigated level of wind penetration the price difference diminishes only in the case of smooth wind power production. The sensitivity on wind–demand correlation variations is comparable low. An increase of 10% results in an increase of the market value of about 0.2% of baseload price (see Figure 5).

Analyses for stylized, continuous supply curves in Reference [12] indicate that the market value of wind power declines with increasing convexities. The interpretation of this finding for changes in the supply characteristics of real systems is not clear given the complex structure of real supply curves including both linear and convex sections as well as jump discontinuities.

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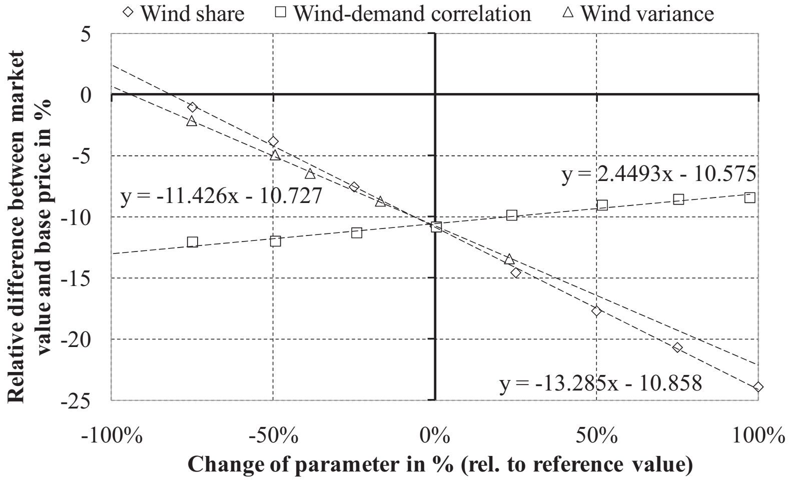

Figure 5. 2020-20% target scenario – sensitivity of the relative price difference between market value and baseload price on selected parameters. Assumptions: CEPM, supply and demand from 2006, wind power generation according to 2020-20% scenario.

For our supply representation of the CEPM we do not observe remarkable changes of the relative price difference for investigated fuel and CO_2 price scenarios compared to the reference case for 2006 wind generation. However, for the 2020-20% wind scenario all alternative price scenarios result in a higher price difference (12.4%) than in the reference case (10.6%). As a consequence of differing baseload prices the difference between market value and base price varies between 5.5 €/MWh in the high fuel price scenario and 8.5 €/MWh in the high fuel and CO_2 price scenario (see Figure 6).

4.2. The price difference on country level

The difference between the market value of wind power and the baseload price on country level is assessed for wind deployment scenarios indicated in Section 3.2 using TradeWind data for Czech Republic and Switzerland and measured data for all other countries for the year 2006.

As illustrated in Figure 7, the price difference becomes significant for increased wind shares.[l] Interestingly, the effect is quite different on country level – for the 2020-20% scenario the price difference varies between 4% in Austria and 16% in Germany. This might be explained by differing resulting correlations between wind generations on country level and overall residual demand in the CEPM. Another remarkable fact is that the increase of the price difference for Austria is significantly lower than for other countries. Austrian wind power obviously profits from comparable low correlation with overall wind power generation in the CEPM (see Table II). When comparing the 2020-20% scenario with the case of wind power distribution of 2006 we can identify a significant benefit of the better geographical distribution of wind capacities on CEPM level.[m] Austrian, German and Czech wind power profit

[l]Potential drivers for the increasing price difference can be identified when further analysing the respective component in (1):

$$MV_W - \overline{\pi}_{PX} = \frac{\mathrm{cov}(\pi_{PX}, Q_W)}{\overline{Q}_W} = \mathrm{cor}(\pi_{PX}, Q_W)\sigma(\pi_{PX})\frac{\sigma(Q_W)}{\overline{Q}_W} \tag{7}$$

Determinants of the price difference are the correlation coefficient between power price and wind power, the power price standard deviation and the ratio between wind power standard deviation and expected value.The relevance of these drivers will be exemplarily worked out by confronting results and parameters for the 2006 and the 2020-20% target scenario. The difference between baseload price and market value of overall wind power in the CEPM is −0.2 and −4.5 €/MWh, respectively. The correlation between power price and wind power increases (in absolute terms) significantly from −0.02 to −0.42 while the standard deviation of the power price increases moderately from 13.3 to 14.7 €/MWh. The third term, the ratio between wind power standard deviation and expected value, decreases moderately from 0.85 to 0.73 due to an improved geographical distribution of wind power.

[m]In 2006 wind power generation in the CEPM is highly dominated by German wind (89%) while in the 2020-20% scenario wind power is dominated by both German (59%) and French (36%) wind power resulting in a lower variability of overall wind power.

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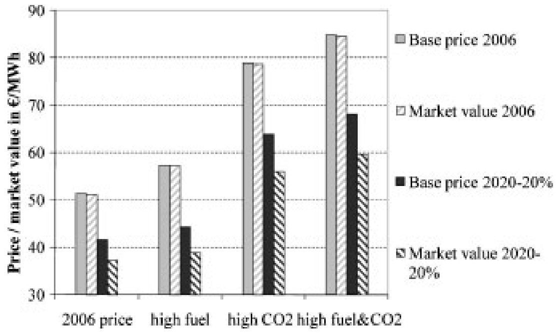

Figure 6. Comparison of baseload price and market value of wind power for investigated price and wind scenarios. Assumptions: fuel and CO_2 prices according to Table I.

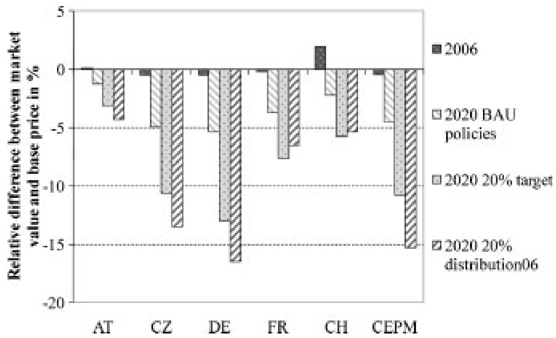

Figure 7. Relative difference between market value und baseload price for investigated wind penetration scenarios.

Table II. Correlation between wind power generations in countries of the CEPM.

	AT	CZ	DE	FR	CH	CEPM
AT	1.00	0.44	0.20	0.12	0.18	*0.23*
CZ	0.44	1.00	0.73	0.32	0.39	*0.69*
DE	*0.20*	*0.73*	*1.00*	*0.51*	*0.38*	*0.95*
FR	*0.12*	*0.32*	*0.51*	*1.00*	*0.57*	*0.75*
CH	0.18	0.39	0.38	0.57	1.00	*0.51*
CEPM	0.23	0.69	0.95	0.75	0.51	*1.00*

Assumption: 2020-20% wind scenario.

from the increased share of French wind power while the market value is reduced in France and Switzerland. This might be again explained by the wind–wind correlation coefficients drawn in Table II. For first countries wind power generation is more correlated with German than with French wind power while for the latter the situation is inverse.

In order to test the sensitivity of results on underlying wind power data we perform simulations using TradeWind data for all available wind years. Figure 8 illustrates exemplary results for the 2020-20% target scenario. Bars draw results for the wind year 2006 while error bars represent the bandwidth for all available wind years. Price differences vary considerably depending on the input data set. Interestingly results for the wind year 2006 are extreme in the sense that the price difference is highest for most of the countries and the CEPM as a whole even though when comparing with other available years, the year 2006 is an average wind year in terms of full load hours. This fact indicates that 2006 is an extreme wind year in terms of correlation between wind generations in the CEPM.

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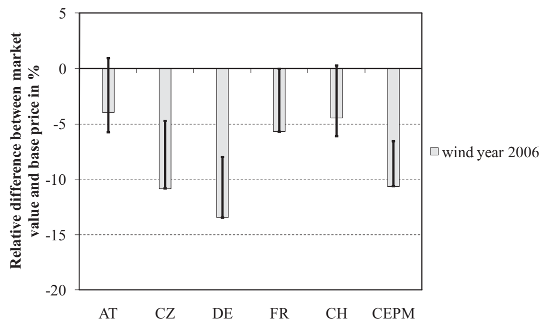

Figure 8. Relative difference between market value und baseload price for different wind years (bars: wind year 2006, error bars: bandwidth for other available wind years).

5. FUTURE TRENDS AND THEIR IMPLICATIONS ON THE MARKET VALUE OF WIND POWER

In this section we firstly discuss how investigated parameters may evolve in the CEPM in the future and then assess the qualitative impact of future trends based on presented simulation results.

5.1. Wind share

Wind deployment scenarios investigated in Reference [10] indicate an increase of overall wind power generation from 34 TWh in 2006 to 196 TWh for the CEPM in 2020 for a 20% renewables target on EU-level. Remarkable trends are an increased share of French wind power (from 6 to 36%) and offshore wind (from 0 to 48%). The wind share obviously also depends on the development of demand. A constant increase of 2% annually up to 2020 would result in demand increase compared to 2006 of more than 30%. Depending on the development of fundamental parameters and the effectiveness of energy efficiency measures this increase might also be considerably lower.

5.2. Wind power variability

The major parameter affecting the variability of wind power is the geographic distribution of wind sites as correlation between wind power generation decreases with increasing distance between sites (cf. [14]). While we can expect that the distribution of onshore wind will not change dramatically within investigated countries, onshore wind in future will be better distributed within the CEPM according to the scenario cited above, resulting in a lower overall variability. Besides that an increased utilization of offshore wind will further dampen the variability of resulting wind power generation as shown in Reference [15] for the case of Germany.

5.3. Wind–demand correlation

In 2006 wind and demand in the CEPM are weekly positive correlated (0.13). Among countries correlation with CEPM demand varies between 0.05 and 0.14. For the 2020-20% scenario there is no significant change in correlation. It is not clear if and in which direction a higher wind offshore share will influence this parameter. A positive influence on the wind–demand correlation might result from an adoption of patterns of flexible demand to the availability of wind power in the long term. Similarly, any other form of electricity storage might influence this parameter indirectly, when it is operated in a way to arbitrage wind power induced price variations.

5.4. Supply characteristics

In the short to medium-term fuel and CO_2 price shocks influence the supply characteristics. In a longer-term perspective the supply mix changes depending on expectations of the future development of these parameters. Further influencing parameters include the development of demand and renewable electricity of which most important wind power. Volatile prices and policy uncertainty involve a broad bandwidth of future supply scenarios.

Table III. Qualitative assessment of the impact of parameter changes in the CEPM on the market value of wind power.

Effect of parameter increase on	Baseload price	Price difference base – MV	MV of wind power
Demand	+	↓	++
Demand side management	–[a]	↓	o[b]
Wind capacity	–	↑	– –
Wind offshore share	o	↓	+
Geographic wind power distribution in CEPM	o	↓	+
Fuel price	++	↑	+
CO_2-certificate price	++	↑	+

[a]Under assumption of a convex supply curve.
[b]Simulation results indicate a slight decrease for both base price and price difference.

5.5. *Qualitative assessment*

Finally based on simulation results presented in Section 4 the implication of discussed future trends in the CEPM on the market value of wind power and its difference to the baseload price are assessed qualitatively (see Table III). All indications follow the logic of a ceteris paribus consideration, i.e. all parameters except for the investigated parameter are kept constant.

This approach will be explained based on an exemplary parameter: an increase in demand (+) leads ceteris paribus to a higher baseload price (+). At the same time an increasing demand results in a lower wind share. From our simulations we know, that a lower wind share means a decrease of the difference between market value and baseload price (↓). These two effects finally result in a significant increase of the market value of wind power (++). The impact of all other parameters is assessed following this logic.

6. CONCLUSIONS

This paper identifies parameters affecting the wind power–price correlation and analyses their impact on the market value of wind power for the case of the CEPM. Future trends for parameter developments are investigated and their qualitative impact on the market value is assessed.

Results indicate that the impact of the system immanent wind power–price correlation on the market value of wind power in the CEPM is negligible in 2006 but will become significant for expected wind capacities in 2020. The baseload price then does not constitute any longer a reliable indicator for the market value of wind power. Simulations further show that the market value will vary considerably among countries even if the CEPM is fully integrated.

The increase of wind capacity will have a dampening effect, while other expected trends like an increase of electricity demand and fuel as well as CO_2-certificate prices, a better geographic distribution of onshore wind within the CEPM and an increasing utilization of offshore wind will influence the market value positively.

Our results have several important implications. First, the effect of market value reduction has to be considered for longer-term forecasts of support cost (net transfers from consumers to producers) when significant wind shares are expected. The same recommendation can be given for forecasts on when wind power will become competitive. Second, when wind power is supported via a variable feed-in premium (or in a quota system) it is crucial to adapt the premium (or the penalty) to the (average) market value of wind power and not to the baseload price. Third, when support reflects the market value of wind power, investors face increasing incentives to utilize second best potentials that are less correlated with overall generation in the relevant market.

For a robust quantification of the analysed effect a corresponding data base representing the long-term patterns of wind power and demand as well as their correlation is essential.

Quantitative results have to be interpreted with care because of the simplified representation of the CEPM. Our model underestimates the reduction of the market value as it neglects operational constraints and imbalance cost. The qualitative effect of other simplifications (neglect of interconnections with other markets and internal congestions) is, however, difficult to assess. We also lack a consistent data set for an according time period.

Further research should therefore focus on both an improved data base and representation of the CEPM in order to derive more reliable qualitative results that may then be confronted with empirical analysis.

7. LIST OF SYMBOLS AND ABBREVIATIONS

AT	Austria
BAFA	Bundesamt für Wirtschaft und Ausfuhrkontrolle
CEPM	Central European power market
CH	Switzerland
CZ	Czech Republic
DE	Germany
EEX	European Energy Exchange
ERDF	Electricité Réseau Distribution France
FR	France
GW	Gigawatt
MC	marginal cost
MWh	Megawatt hour
MV	market value
OeMAG	Ökostromabwicklungsstelle
OTC	over the counter
PX	power exchange
SRMC	short-run marginal cost
TWh	Terawatt hour
UCTE	Union for the Co-ordination of Transmission of Electricity

base	baseload
D	demand
D,res	residual demand
h	time interval (hour)
H	total number of time intervals (hours)
π	price
Q	quantity (generation, demand)
S	supply
s	supply function
σ	standard deviation
W	wind

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