The Value of Wind Energy in the European Electricity Market – Application of a Stochastic Fundamental Model

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Abstract

In this paper a novel stochastic fundamental European electricity market model (E2M2s) is applied to estimate the value of electricity produced by wind turbines. The principle of E2M2s is cost minimisation in the European power network. The model determines the marginal system costs mainly as a function of available generation and transmission capacities, primary energy prices, plant characteristics and electricity demand. Thereby notably reduced efficiencies at part load, start-up costs and reserve power requirements are taken into account. In extension to many other models available in the open literature E2M2s handles investments in new power plants endogenously. Since hydropower is of high relevance in the European power system, also time-coupling hydro storage constraints are considered. To be able to estimate the value of fluctuating RES-E, the fundamental modelling approach is significantly extended by introducing a scenario grid accounting for the uncertainties of wind and hydro power availability. Exemplary results are presented for the stochastic model in comparison with a deterministic version. The results are discussed for a German case study. It is shown that the value of wind is overestimated in a deterministic model. Especially the decreasing capacity credit with increasing installed wind capacities can not sufficiently be modelled. The proposed stochastic model E2M2s, however, can give far more realistic estimates of the value of wind energy in the European system.

Keywords: Energy market modelling, stochastic programming, cost minimisation, value of wind, fluctuating energy sources.

1 Introduction

Within the European Union large amounts of fluctuating renewable energy sources for electricity production (RES-E) and especially wind energy are expected to be integrated in the electricity system in the coming years. By their fluctuating nature these RES-E influence the performance of the whole system and cannot be valued as conventional sources. Yet their value will depend on the system they are embedded in, e.g. by the avoided fuel costs. This leads to a great interest in models for estimating the value of RES-E and especially wind energy in the European electricity system. Thereby fundamental models account well for the impact of power plant characteristics and capacities, for restrictions in transmission capacities and demand variations. Due to uncertainties in predicting fluctuating sources it is necessary to consider a stochastic modelling approach. This will be exemplarily shown in this paper.

In the following, first a stochastic fundamental bottom-up European electricity market model (E2M2s) to analyse the electricity wholesale market is presented and then a case study on estimating the value of wind energy in the German power system until 2020 is discussed. Special focus is given on the importance of the novel inclusion of stochastics in the model, which allows to model the impact of fluctuating RES-E as wind or hydro power. Next to these important enhancements over similar fundamental models, the time and regional resolution, the power plant portfolio, the final energy demand and the reserve power requirements are discussed. The developed approach aims particularly at providing realistic estimates of future electricity prices, which can be used to assess the profitability of investments in RES-E technologies. But at the same time it is an integrated approach, which allows analysing the interaction between the deployment of RES-E technologies and the developments on the conventional electricity market, both with respect to electricity prices and power plant capacities.

2 Methodology

The basic idea of fundamental models is to analyse power markets based on a description of generation, transmission and demand, combining the technical and economical aspects. These models often aim at explaining electricity prices from the marginal generation costs. Examples of such models include Kreuzberg (1999), Müsgen and Kreuzberg (2001), Kramer (2002), Kurihara (2002) and ILEX (2004). Many more fundamental models have been developed by consultants or the utilities themselves and are therefore not published. Fundamental models are often also incorporated in more sophisticated game theoretic (cf. Jebjerg and Riechmann (2001), Ellersdorfer *et al.* (2001), Hobbs (2001)) or stochastic models (cf. Skantze *et al.* (2000), Barlow (2002)).

One fundamental assumption is that the electricity spot market operates efficiently, so that it leads to an efficient system operation with minimal costs, satisfying all customer demands. If customer demand is taken as price inelastic (and there is much evidence of almost price-inelastic demand, cf. Barlow (2002)), prices will equal to the marginal generation costs of the last unit needed to fulfil given demand. Of course, this is only a very basic model, which has to be extended into several directions in order to at least cope to some extent with the reality in European electricity markets. A first extension to be considered is multi-regional modelling. Since transmission capacities between countries and within countries are often limited, those have to be included in an optimisation model, which describes the cost minimal provision of electricity demand. Besides often-focused thermal power plants, hydro power plants also play a considerable role in many electric power systems, including the European one. At least three cases have to be distinguished: Run-of-river plants, Hydro storage plants and Hydro storage plants with pumping facilities (pumped storage plants). Notably, the storage plants require a modelling approach, which encompasses several time steps and possibly stochastic inflows. Furthermore, start-up costs may considerably influence the unit commitment decisions of plant operators. In unit commitment and load dispatch models, they are typically modelled using binary variables for unit operation, start-up and shut down. But this is hardly feasible when modelling a national or regional market. Weber (2004) has, however, provided an approximate approach for dealing with part-load efficiencies and start-up costs. A further point to be considered is the different types of reserves, which have to be provided by the generators. A rather detailed model of the different cases for the German market can be found in Kreuzberg (1999).

For the practical implementation of any such fundamental model, three major challenges arise. The first one is data availability. Depending on the market, more or less information on plant capacities and costs, demand patterns and transmission capacities may be available to construct such a model. A second challenge is the choice of appropriate time resolution. On the one hand, the modelling of seasonal hydro storage necessitates the modelling of a full year. On the other hand, the adequate modelling of start-up costs requires a time resolution of one hour or at most two in order to keep the model manageable. Hence one solution is to model typical days. Another is to use load segments within a seasonally decomposed yearly model, cf. Kreuzberg (1999). In such a framework, the integration of start-up costs is, however, difficult. A final challenge is the incorporation of stochastic fluctuations, e.g., in demand or plant availability. This is particularly relevant, if the model is to be directly used for short-term predictions (time horizon of up to two weeks) or to give an estimate of the value of wind. Within this paper a methodology to include stochastics in a longer term fundamental model is proposed in order to cope adequately with the integration of fluctuating RES-E. The stochastics considered are consequently mainly those related to wind power and hydro power fluctuations. Thus, thorough simulations of the European electricity market will allow to analyse the impact of these stochastic fluctuations.

Within the following subsections key aspects of the E2M2s modelling approach are discussed. The discussion is focussed on general as well as problem specific assumptions. The methodology is first explained with the most relevant equations of a deterministic version of the model. The explanation starts with the objective function, the identity equations and closes with the restrictions. Finally the so far deterministic model is expanded to include wind and hydro power uncertainties using a scenario grid.

2.1 Objective function

The model determines the marginal generation costs (like most other fundamental models) as a function of available generation and transmission capacities, primary energy prices, plant characteristics and actual electricity demand. Additionally (and in difference to other fundamental models) the impact of hydro-storage and start-up costs is accounted for. The principle of the model is cost minimisation in a Europe-wide power network. The deterministic objective function can thus be written:

$$\text{Minimise } C = \sum_{t=1}^{T} f_t d_t \left(\sum_u C_{Op,u,t} + C_{St,u,t} + C_{Fix,u,t} \right) \tag{1}$$

Thereby the overall costs C are minimised and are calculated by the sum of operating costs $C_{Op,u,t}$, corresponding start-up costs $C_{St,u,t}$ and fix costs $C_{Fix,u,t}$ subject to unit type u and time segment in a typical day t. This sum is weighted by the duration of a time segment d_t and its frequency in the planning horizon f_t. The additional sum over the endogenously modelled regions is omitted in this equation and will be omitted in the following equations to maintain a certain degree of readability.

2.2 Identity equations

The most relevant identity equations describe the operating, start-up and investment costs as well as the required balance of supply and demand. The operating costs $C_{Op,u,t}$ are assumed to be an affine function of the plant output $y_{u,t}$. Thereby the decision variable of capacity currently online y_{ONL} is introduced, cf. Weber (2004), which allows describing the difference between part-load and full-load efficiency:

$$C_{Op,u,t} = p_{F,u,t} h_{m,u} y_{u,t} + p_{F,u,t} \left(h_{0,u} - h_{m,u} \right) r_{MLF,u} y_{ONL,u,t} + c_{OP,oth,u} y_{u,t} \tag{2}$$

In this equation $p_{F,u,t}$ gives the fuel price, $h_{m,u}$ the marginal heat rate between minimum and full load and $h_{0,u}$ the heat rate at the minimum load factor $r_{MLF,u}$. The heat rates are assumed to be constant. If $h_{m,u} < h_{0,u}$ the operators have an incentive to reduce the capacity online. Furthermore other variable costs $c_{OP,oth,u}$, e.g. related to desulphurisation of plant exhaust gases, are included.

Start-up costs may influence considerably the unit commitment decisions of plant operators. In unit commitment models, they are typically modelled using binary variables for unit operation, start-up and shut-down. However, this is hardly feasible when modelling a European wide market. Nevertheless, an approximation can be done by using the capacity currently online as an additional decision variable for each plant type, cf. Weber (2004). On the one hand, the capacity online then forms an upper bound to the output and on the other hand, the capacity online multiplied by the minimum load factor for the plant type gives a lower limit to the output. The specific start-up costs $c_{St,u,t}$ then arise, if the capacity online $y_{ONL,u,t}$ is increased, i.e. when the start-up capacity $y_{St,u,t} \geq y_{ONL,u,t} - y_{ONL,u,t-1}$ gets strictly positive. In order to avoid that units are always kept online, the efficiency at part load has to be lower than at full load. The total start-up costs $C_{St,u,t}$ are then described by the relation:

$$C_{St,u,t} = c_{St,u,t} y_{St,u,t} \tag{3}$$

Contrarily to many fundamental market models E2M2s takes investments into new power plants into account. Hence, for calculating the fix costs $C_{Fix,u,t}$ the choice among different available investment alternatives with specific investment costs $c_{Inv,u,t}$ and capacity $K_{Pl,new,u,t}$ is endogenously modelled. The investments are discounted by an annuity factor a defined by the interest rate i and the lifetime l_u. Thereby static expectations on fuel and electricity prices are assumed. Moreover, other specific fix costs $c_{Fix\ oth,u,t}$, e.g. the costs for personnel, are taken into account for the total installed power plant capacity $K_{Pl,u,t}$ in the year considered:

$$C_{Fix,u,t} = a(i, l_u) c_{Inv,u,t} K_{PL,new,u} + c_{Fix,oth,u} K_{PL,u} \tag{4}$$

2.3 Constraints

A key restriction is that supply and demand have to be identical at every time step and in every region. The demand is given by the exogenously given final energy demand $D_{r,t}$ and export flows $e_{r,r',t}$, while supply is given by the supply of the power plants $y_{u,t}$ and import flows $e_{r',r,t}$. As imports from region r' to r and exports from r to r' are allowed, the balance equation has to be formulated for each region and import and export flows have to be added. As also pumped hydro plants are considered the pumping energy for hydro storage $y_{Pump,u,t}$ need to be added, leading to:

$$\sum_{u \in U_r} y_{u,t} + \sum_{r'} \left(e_{r',r,t} - e_{r,r',t} \right) \geq D_{r,t} + \sum_{\substack{u \in U_r \\ u \in U_{PS}}} y_{Pump,u,t} \tag{5}$$

In the equation above, supply needs to be greater or equal to demand. This formulation leads to a faster calculation time and does not alter the expected results.

Moreover, several capacity constraints need to be considered in a fundamental framework. Probably the most important one is the constraint on a plant's output that must not to be greater than the rated capacity of the power plant $K_{PL,U}$ multiplied by an availability factor $\nu_{PL,u,t}$:

$$y_{u,t} \leq K_{PL,u} \cdot \nu_{PL,u,t} \tag{6}$$

Additionally, the pumping energy for pumped hydro plants $y_{Pump,u,t}$ needs to be constrained and not to be greater than the pumping capacity $K_{Pump,U}$ multiplied by an availability factor $\nu_{Pump,u,t}$.

$$y_{Pump,u,t} \leq K_{Pump,u} \cdot \nu_{Pump,u,t} \tag{7}$$

As wind power fluctuations are of special importance to adequately estimate the value of wind, it is necessary to consider reserve power requirements and the corresponding regulating power markets within the model. A detailed discussion of the German market for power systems reserve focussing especially on non-spinning reserve may be found in Swider and Weber (2003b, a), a comparative discussion on the German and Scandinavian markets is in Meibom *et al.* (2003). Following this discussion a formulation distinguishing spinning (primary and secondary) and non-spinning (tertiary or minute) reserve is considered. The positive reserve is included in the capacity balance equation of those plants able to provide them. First the capacity of a plant $K_{PL,u,t}$ may not exceed the current capacity online $y_{ONL,u,t}$ and the reserve capacities. Thereby, positive spinning reserve capacity provided by a single plant is given by $\zeta_{RESsp+,u,t}$ and positive non-spinning reserve by $\zeta_{RESoth+,u,t}$.

$$y_{ONL,u,t} + \varsigma_{RESsp+,u,t} + \varsigma_{RESoth+,u,t} \leq K_{PL,u,t} \tag{8}$$

Second the negative spinning reserve margin $\zeta_{RESsp-,u,t}$ has to be included as a lower margin between the actual and the minimum output.

$$y_{ONL,u,t} \cdot r_{MLF} \leq y_{u,t} - \varsigma_{RESsp-,u,t} \tag{9}$$

Besides these restrictions at the plant level, which may include also maximum levels of reserve power to be provided by different types of plants, of course also overall reserve restrictions have to be satisfied, cf. UCTE (2004).

When considering hydro storage plants, storage constraints need to be considered. It is first necessary to describe the filling and discharging of storage. This may be obtained by constraining the storage level $H_{u,t}$, which is expressed for simplicity in energy units, at time step t not to be greater than the level at time step t-1 minus the production $y_{u,t}$ and plus the inflow $w_{u,t}$ at time step t for all hydro storage plants.

$$H_{u,t} \leq H_{u,t-1} - y_{u,t} + w_{u,t} \qquad \forall u \in \boldsymbol{U}_{STOR} \tag{10}$$

For the pumped storage plants an even further extension of the framework is required. The pumping energy $y_{Pump,u,t}$ and a cycling efficiency η_{PS} is required to formulate the storage level constraints for pumped storage plants. The cycling efficiency is the fraction of the energy recovered when first pumping the water and then propelling it through the turbine again.

$$H_{u,t} \le H_{u,t-1} - y_{u,t} + \eta_{PS} \cdot y_{Pump,u,t} + w_{u,t} \qquad \forall u \in \boldsymbol{U}_{PS} \tag{11}$$

Finally, an adequate terminal condition has to be included for the water reservoirs. One attractive formulation is to require that the final and the initial reservoir level are identical, which can be expressed through the following cyclical condition for time step 1 for the hydro and pumped storage plants.

$$H_{u,1} \le H_{u,T} - y_{u,1} + w_{u,1} \qquad \forall u \in \boldsymbol{U}_{STOR} \tag{12}$$

$$H_{u,1} \le H_{u,T} - y_{u,1} + \eta_{PS} \cdot y_{PUMP,u,1} + w_{u,1} \qquad \forall u \in \boldsymbol{U}_{PS} \tag{13}$$

Last but not least the export flows $e_{r,r',t}$ from region r' to r may not exceed the transmission capacity $K_{TR,r,r'}$ from region r to r' multiplied by the availability of the transmission lines $v_{TR,r,r'}$.

$$e_{r,r',t} \le K_{TR,r,r'} \cdot v_{TR,r,r',t} \tag{14}$$

2.4 Stochastic approach

The aforementioned equations need to be reformulated and extended in order to cope with the stochastics of wind and hydro power. Instead of considering one operation mode of the system at one moment in time, one has to consider different alternative stochastic cases depending on the actual wind power production and other stochastic factors. For the stochastic modelling two types of uncertainties have to be distinguished:

- *Short-term fluctuations*: these comprise mainly the fluctuations in wind power production; but also PV output and electrical load are subject to impredictabilities and fluctuations, which occur in the short-term and where in the longer term a return to the average occurs.
- *Long-term fluctuations***:** especially hydropower also exhibits strong yearly variations, which need to be considered since they have a strong impact on generation possibilities, security of supply and CO_2 emissions. Short-term fluctuations are of lower importance for hydro power, since they may be averaged away through storage.

In the following a day is subdivided in four stochastic stages and for each stage six nodes are distinguished. Thereby two levels for the long-term stochastic variables are combined with three levels describing short-term stochastic fluctuations, cf. Figure 1.

For the long-term stochastic variables it is most important to single out situations with low water inflow and consequently relative energy scarcity. According to Austrian and Swiss inflow statistics, variations of 20 % and more may occur between years. The low water scenario should correspond to about the lower twenty percent of the distribution of yearly water inflows.

For the short-term stochastic variables also the extreme cases have to be modelled separately. Moreover it is necessary to describe adequately the transition between different wind situations. Therefore actual wind speed data have been combined with aggregated power curves, similar to the approaches by Sontow (2000) and Swider (2004). This has been done using weather data from 10 weather stations in Germany and the actual distribution of the wind power plants over the country. So wind power time series for two years are obtained, which are then used to determine clusters of days with similar wind energy production. Thereby summer, winter and intermediate days are distinguished and for each six hour period cluster analyses are carried out for identifying the very high wind, normal wind and low wind cases. The transitions between these cases are determined by analysing the observed transition probabilities between the different wind cases.

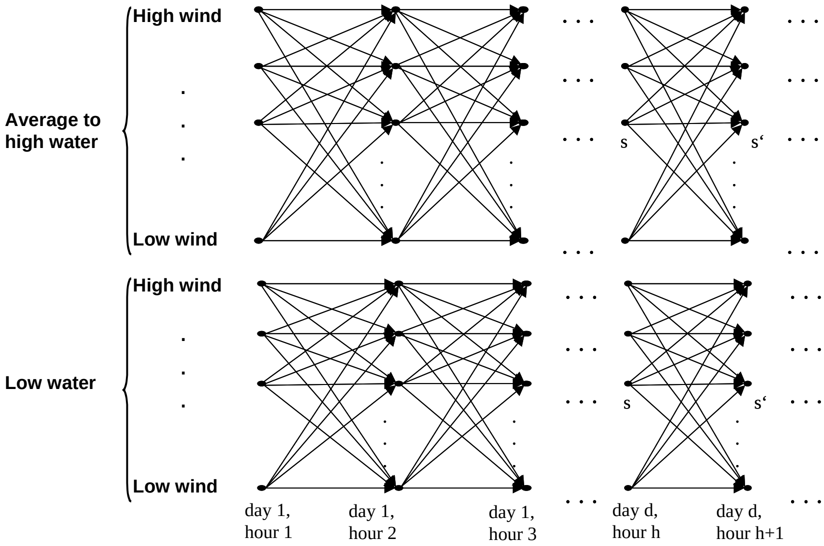

Figure 1 Node structure to include stochastics in the fundamental model

This leads to a grid (or recombining tree) structure for the different wind cases as shown in Figure 1. At the end of each typical day, the transition possibilities to a day of the same type and the possibilities of a weekend/weekday shift are taken into account. Transitions between low and high water scenarios are not considered, since the key point precisely is that reduced water inflow may occur over a longer time period, not allowing for levelling out with other years. For the status variables at the beginning of each node (especially water storage content, thermal capacity online), a weighted average of the values in the preceding nodes is taken. This avoids constructing separate stochastic trees for each possible scenario path.

The objective function for the stochastic market model is a straight-forward extension of the deterministic function. The key point is that now all decision variables are simultaneously indexed over time *t* and node *n* and that the different nodes enter the objective function with their occurrence probability $\psi_{t,n}$:

$$\text{Minimise} \quad C = \sum_{t=1}^{T} \psi_{t,n} f_t d_t \left(\sum_u C_{Op,u,t,n} + C_{St,u,t,n} + C_{Fix,u,t,n} \right) \tag{15}$$

For the other static equations the general approach is to add an index for the different nodes. The capacity, reserve power and transmission equations are examples of such static equations. However, for dynamic equations, which link different time steps, it is important to account for the different transition possibilities. E. g. reservoir fillings at the beginning of a node will be determined by the weighted averages of the filling levels at the end of all predecessors.

3 Application

For applying a fundamental model in the European context the challenges mentioned in introduction are important to cope with. These are mainly the availability of data but most important the degree of detailing. Thereby the time horizon and resolution, the regional resolution and transmission capacities and finally the representation of power plants has to be considered. Solving the problem in a computer-assisted optimisation model always requires a compromise between several aspects. On the one hand a fairly high resolution with a high number of considered time steps, regions and power plant types is recommended for modelling as accurately and realistically as possible. On the other hand a high resolution increases the computing time and hampers the handling of the model without gaining in the models methodology. Hence, the time and regional resolution as well as the considered power plant types have to be reasonably restricted. This is discussed in the following subsections.

3.1 Time horizon and resolution

In this paper a time horizon until 2020 is considered. To represent the different seasonal effects on renewable energy potentials and electricity demand the European conventional electricity market and their interaction with the spot market, a complete description would comprise an hourly time resolution resulting 8760 time periods per year. This would lead to an extremely high computing time. To limit the computing time each year can be divided in typical days and each day in typical hours to take the differences in load and price patterns into account. Furthermore, to capture seasonal effects in load, water inflow, sunshine etc., separate typical days are distinguished for every two months period. In this paper it was decided to have twelve typical days. With this for every two months one typical weekday (Monday to Friday) and weekend (Saturday and Sunday) exists. The days are divided into a two-hourly resolution, as the integration costs of renewable energy especially wind power highly depend on the temporal fluctuations in their supply, which has to be modelled with sufficient accuracy.

3.2 Regional resolution and transmission capacities

In order to model the conventional European electricity market realistically, the interactions between the diverse countries need to be accounted for. Here it was decided to focus on defined regions, cf. Figure 2. The regions are chosen to account for the major grid constraints within Europe, cf. e.g. Auer *et al.* (2002), and are divided in model endogenous and exogenous regions. For the endogenous regions, the full set of equations will be specified. For the exogenous regions only the import and export flows to the endogenous regions will be specified using time series based on historically observed values. The regions endogenously modelled are the most important sub-segments in the European electricity market, cf. e.g. Kramer (2002) or Weber (2004).

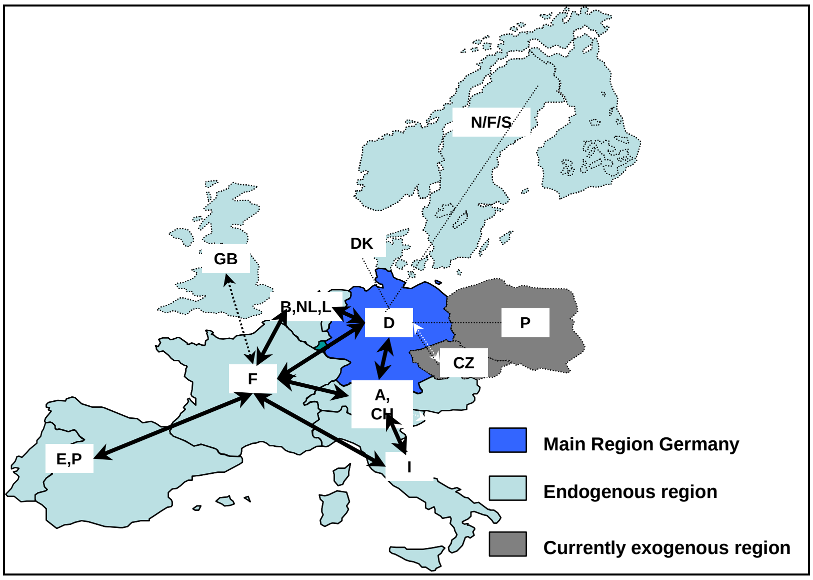

Figure 2 Definition of regions in the fundamental model.

The considered regions are interconnected through defined transmission capacities. In principle an assignment of country specific transmission capacities is hardly possible. This is due to the fact that transmission constraints do not only depend on the transmission capacity but also on the rear local net. In the model the net transfer capacities as reported by ETSO (2004) are taken as basis.

3.3 Power plant portfolio

All fundamental models greatly depend on the representation of the power plant portfolio of the considered system. With respect to the restricted computing time not all power plants can be modelled specifically. This implies that technologies have to be grouped in order to reduce the complexity and the amount of computational work to a level that can be handled by the tools available. Hence a reasonable classification of conventional and RES-E technologies is necessary. Within this paper it was decided to classify power plants according to the main fuel used and the vintage. Thereby, the characteristics of the various types of plants are differentiated by region. The characteristics to be used are availability, efficiency, times and costs.

The (net) efficiency of thermal power plants has improved greatly over the last years. Therefore, a correlation between year of commissioning and efficiency can be taken as proxy if insufficient public data on the efficiency of the classified plants is available. It is furthermore important to distinguish between full-load and part-load efficiencies. In principle, the efficiency greatly depends on load. However, implementing a general function of efficiency depending on the actual load would lead to a non-linear formulation of the problem. This would increase the computing time in an intolerable way, thus an approximation needs to be found. In this paper part-load efficiencies are approximated linearly by a part-load efficiency at minimum plant output and a constant marginal efficiency for any increase between minimum and maximum output (cf. equation 2)

One of the most important characteristics of the power plant classes are the costs of generation. Variable costs are expenses on fuel costs, supply and disposal of materials, operational maintenance, and deterioration of materials. The greatest part of the variable costs is determined by the fuel costs. The fuel costs itself greatly depend on the fuel and the efficiency of the power plant, with the latter being a function of load. However it is unclear, whether observed price differences are only due to regional specificities or also to different times of observation. Furthermore the persistence of these price differences in the future is also unclear. Therefore in the current model version no regionally differentiated fuel prices are considered, cf. Figure 3.

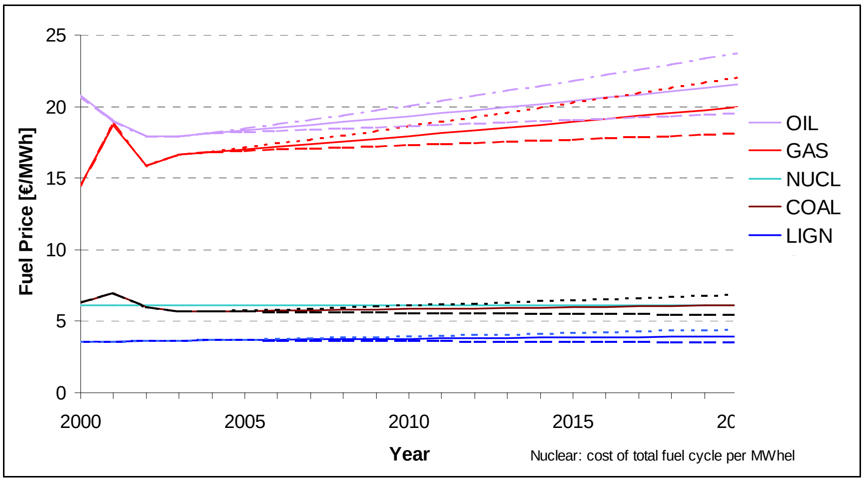

Figure 3 Time path of fuel prices considered in the model.

Besides the thermal power plants focused on so far, hydroelectric power plants also play a considerable role in the continental European system. In difference to the thermal power plants in case of hydroelectric ones the costs of generation do not play such a significant role. In case of run-of-river plants no variable cost need to be considered. In case of hydro storage plants no real variable costs arise, however opportunity costs arising from using the stored capacities now and not later may be interpreted as variable costs. These are determined endogenously in the chosen modelling approach. In case of pumped storage plants the costs for pumping are often interpreted to be variable costs. This is definitely true in case of *ex ante* knowing electricity prices in the future. In reality the prices are not know *ex ante* and hence at the time of commitment these costs may be interpreted as sunk costs. The operator's unit commitment will thus not depend on the criteria of past pumping costs, rather on the actual opportunity costs, which correspond to the minimum of future expected revenues and future expected pumping costs.

4 Exemplary results

The exemplary results are based on a defined base-line scenario with modest fuel price developments, cf. solid lines in Figure 3, low or negligible CO_2 prices and continuation of the current nuclear policies in the considered regions. In the model currently two classes of short-term fluctuating renewables are implemented, namely wind on-shore and wind off-shore with exogenously given installed capacities. Off-shore wind generation is thereby supposed to increasingly gain in importance. Such wind farms are exposed to higher average wind speeds with less variation than on-shore schemes, leading to greater yields. In this paper a business-as-usual (BAU) and a best (BEST) case scenario are considered, based on work by Auer et al. (2004), cf. Figure 4.

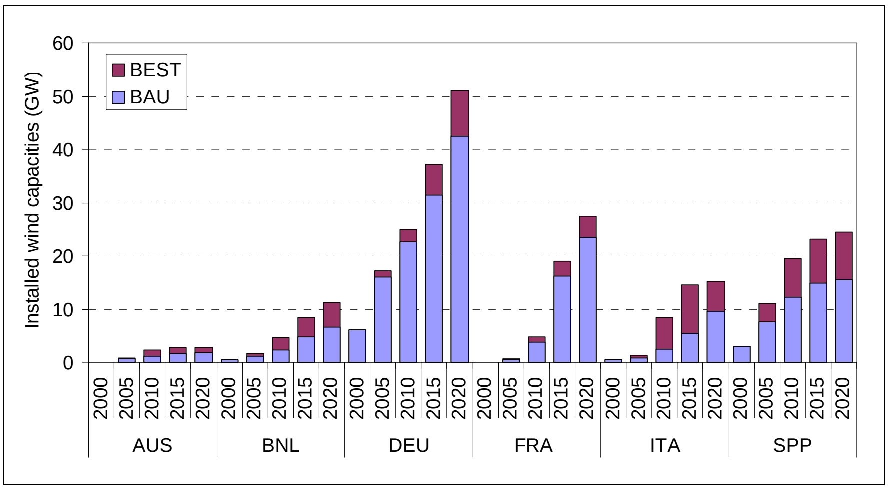

Figure 4 Business-as-usual and best scenario of installed on- and off-shore wind capacities.

Next to the consideration of a BAU and a BEST case scenario of installed wind capacities the stochastic version of the model (the latter constitutes the proposed model E2M2s). This comparative discussion will allow to conclude on the importance for stochastic models to accurately estimate the value of wind in the European electricity market.

One of the major outputs of the model is the development of wholesale electricity prices over a time horizon until 2020. These prices correspond to the marginal generation costs in each regional subsystem in E2M2s and may hence be different from the spot market prices historically observed. For the year 2000 the prices as given in Figure 5 are relatively high compared to available prices on the spot market (prices in 2000 at EEX, Germany about 20 €/MWh). The reason for this may on the one hand be that the German market was not fully developed in 2000 and may therefore not reflect actual prices (the traded volume was less than 5 % of the total consumption). On the other hand the generation companies may have submitted bids below their marginal generation costs in order to achieve a sufficient market share. Notably, the operators, contrarily to the model, may at that time not have included the fixed operational costs (e.g. insurance premiums, staff wages) in the bidding prices. Of course, inaccuracies in the model data may also account for some of the observed deviations. It can be seen that the prices for France are generally lower compared to the prices for the other regions since low cost nuclear power plants dominate electricity production. This is in contrast to Italy, where the generation mix is dominated by low efficiency oil fired power plants.

Figure 5 indicates that the prices level out over time at about 33 €/MWh. This nearly identical price level is due to investment occurring in the model: Investments in new capacities are endogenously modelled and will occur in the places which offer the highest profit and result in levelling out existing price differences between regions in the medium to longer term. Different assumptions on fuel and CO_2 prices and the nuclear policy, however, would greatly impact the future price development. Here medium fuel and CO_2 price paths and a continuing nuclear policy in the considered regions are assumed.

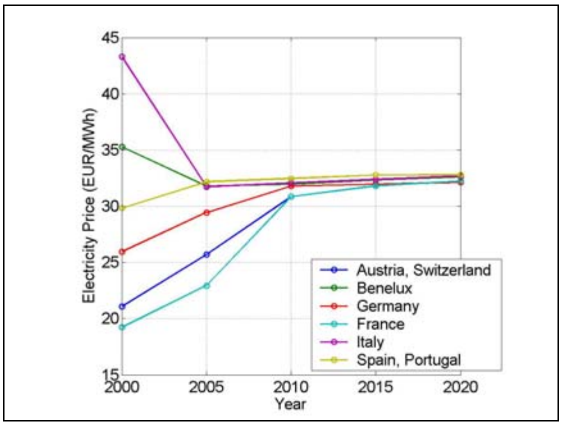

Figure 5 Wholesale electricity prices in the stochastic BAU scenario.

In Figure 5 the prices as calculated with the BAU wind capacity scenario are given, however by considering the BEST wind capacity scenario the results do not alter significantly. This is due to the fact that the prices correspond to the marginal costs of the last unit produced by conventional units. These specific costs do not change much if more wind energy is introduced, albeit the value of the last unit produced from wind energy may change substantially as shown in the following.

In Figure 6 wind shadow prices for the German case for the different scenarios are given in comparison to the base electricity price. The wind shadow price is calculated as a weighted average price of the hourly prices, taking the wind energy production as weighting factor. It can be interpreted as the value of the wind energy produced, including avoided fuel costs, increased start-up cost reduced part-load-efficiency etc. The difference between the base and wind price corresponds then to the system integration costs for wind due to increased balancing costs plus the value decrease due to the fluctuating nature of wind. System integration costs include in this application the joint effects of increased balancing costs, reduced operation hours of conventional power plants, additional reserve capacities and modified investment strategies in the considered electricity supply system.

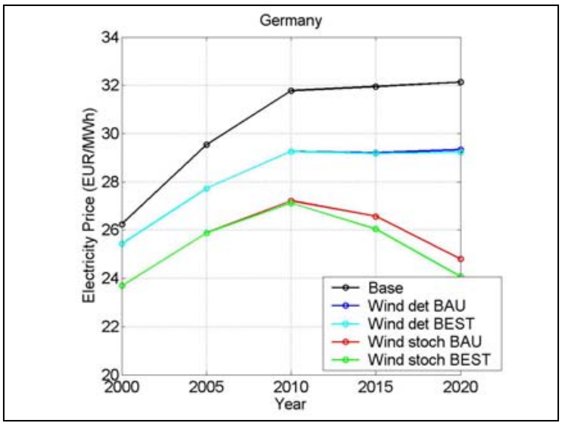

Figure 6 Marginal value of wind in the different scenarios.

With Figure 6 it may be seen that the marginal value of wind as estimated with the stochastic model version decreases over the considered time horizon. This decrease is due to the higher share of wind in the system. An additional wind turbine then reduces the marginal value of wind in the total system. This can be explained by the decreasing capacity credit with an increased share of wind in the system and increased balancing cost. It may also be seen that this effect is not accounted for in a deterministic model version. Hence, a relatively simple deterministic model will systematically overestimate the value of wind.

Next to the prices the utilized generation capacities are a major output of the model and are given for the stochastic BAU case with Figure 7. They are of special importance in the developed model as investments in new capacities are not exogenously given but considered endogenously. It may be seen that the utilized capacities increase due to the assumed increase in demand. In the depicted German case high investments in lignite-fired power plants are observed over time, while in other countries the share of hard coal increases (not depicted in this paper). This is due to the different investment possibilities allowed in the diverse regions. Namely lignite is a relatively cheap technology in Germany but is not available in most of the other regions.

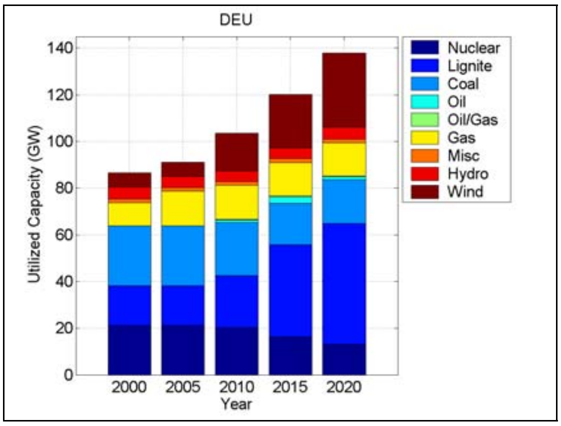

Figure 7 Utilized capacities in the stochastic BAU scenario.

The final aspect of the model results to be discussed is the electricity production. The results for the German case are given in Figure 8. It may be seen that the results are quite similar to the already discussed utilized generation capacities. However, a few particularities may be observed.

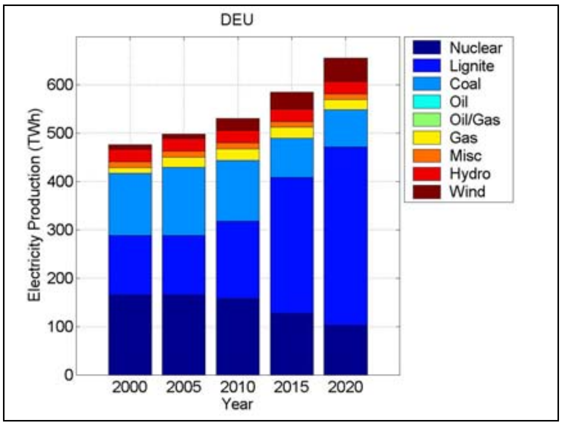

Figure 8 Electricity production in the stochastic BAU scenario.

It can be seen that the share of wind in electricity production is relatively low compared to the share of wind generation in the total generation capacity. This is due to the high fluctuations in the generation and the fairly low full load hours of about 1600 hours (on-shore). Another difference to the share of the utilized generation capacities is the low share of electricity production using gas-fired plants. This difference, however, can easily be explained by the usage of the gas-fired plants. They are characterized by, compared to coal fired plants, high variable costs and are therefore mainly used in peak load times only. However, by comparing the results calculated using the stochastic and the deterministic model may be seen that the share of gas power plants increases in the stochastic model relatively to the deterministic one, mainly due to the necessity of backup.

5 Conclusions

This paper provides a novel methodology for estimating the value of wind using a stochastic fundamental European electricity market model. The results presented show that the value of wind is generally overestimated using a deterministic model. Especially the decreasing capacity credit with increasing installed wind capacities can not sufficiently be modelled. By incorporating a scenario grid in the classic mathematical description of a fundamental model it is shown that the fluctuating nature of wind energy can be much better represented as by using a deterministic model.

The developed approach lends itself to multiple further developments, including notably the extension to further regions and inclusion of further technologies. But also the rules for deriving optimal investments may be developed further, contributing to getting even more realistic pictures of the market developments. All these aspects are subject of currently ongoing research.

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