TRANSMISSION RESTRICTIONS AND WIND POWER EXTENSION – CASE STUDIES FOR GERMANY USING STOCHASTIC MODELLING

Rüdiger BARTH[+#], Heike BRAND[+], Christoph WEBER°,

[+]Institute of Energy Economics and the Rational Use of Energy (IER), University of Stuttgart, Hessbruehlstr. 49a, 70565 Stuttgart, Germany

°Chair of Energy Economics, University of Duisburg and Essen, Universitätsstr. 12, 45117 Essen, Germany

[#] Dipl.-Ing. Rüdiger Barth. Tel.: +49-711-78061-39; Fax: +49-711-780-3953. E-Mail: Rüdiger.Barth@ier.uni-stuttgart.de.

Abstract

In the German power system there is notably a high concentration of installed wind power capacity in the north . To increase the share of wind power in the German electricity system further extensions are planned in the North Sea as off-shore wind farms. By contrast the main consumption areas are in the midland of Germany. This requires large transmissions capacities to transfer the power from north to south. It is unclear whether the German transmission grid in its actual design can meet the future requirements and how the electricity prices are affected by possible transmission restrictions.

Case studies to evaluate the restrictions of the actual German transmission grid and the impacts on electricity prices and the unit commitment are presented. Wind power extensions as they are envisaged for the years 2010 and 2020 are studied and compared to the year 2001. The effect of the installation of further transmission capacities from North to South is also analysed. The behaviour of wind generation is thereby modelled with a stochastic linear programming model where the dispatch of the conventional generating units in the electricity system is governed by trade on a day-ahead electricity market, an hour-ahead regulatory power dispatch as well as district and process heat requirements.

The results of the case studies show that the transmission capacities from North-West to the midlands are not sufficient to cover the future wind power extensions. The day-ahead prices and the unit commitment of all model regions are strongly affected by the impossibility to transmit wind energy from the North to the midland.

Keywords: wind power, off-shore wind power, transmission restriction, stochastic optimization, day-ahead market, electricity prices, unit commitment

1 Introduction

In recent years a number of European countries have simultaneously experienced a fast growth in the installation of wind turbines, e.g. Germany, Spain and Denmark. It is very probable that these fast growth rates of wind power will continue in the years to come, which is also reflected in a 72,000 MW prognosis for wind power in 2010 in the European Countries [1].

The introduction of substantial amounts of wind power in a liberalized electricity system will impact both the technical operation of the electricity system and the electricity market. In order to cope with the fluctuations in the wind power production in a certain system area, other units of the power system have to be operated more flexibly to maintain the stability of the power system. Increased wind power generation may also lead to bottlenecks in the transmission and distribution networks, if wind power is concentrated in certain (mostly coastal) regions. In the case of insufficient transmission capacities electricity system areas could be isolated from the entire transmission network and the system stability has to be secured only by reserve power capacity disposable in this isolated area. The transmission of balancing power from plants opposite of the bottleneck is then impossible. Therefore the occurrence of transmission bottlenecks could cause system stability problems in the local system areas and moreover the changes in system operation of the conventional power plants have certainly cost and consequently price implications.

The German power system shows notably a high concentration of installed wind power in the coastal regions in the North. By contrast the electricity demand in these regions is rather low compared to the consumption in the midland and the south. Thus the wind power generated has to be transmitted to areas with higher electricity demand. Furthermore the future extension of wind power will primarily take place in the North Sea by installing large off-shore wind power plants. The existent transmission grid was originally not designed to accomplish this challenge. Consequently the the question arises whether the German transmission grid in its actual design can meet these future requirements.

In order to analyse adequately the restrictions of the German transmission grid and the market impacts case studies with future wind power scenarios of 2010 and 2020 are carried out by a stochastic linear multi-stage electricity model. The developed model simulates explicitly the stochastic behaviour of wind generation and takes the forecast errors into account.

The main purpose of this model is to derive the unit commitment and dispatch in an electricity system with power trade at different markets on an hourly basis. Time series for the wind power production rely on time series for wind speed data and on simulations of the prediction error for wind speed. Aggregation of wind power generation reflects the spatial distribution of the wind power stations in each region. Moreover, capacity restrictions, market restrictions, restrictions for down regulation, minimum operation and shut down times and hydro storages are included in this model.

This paper is organized as follows: Section 2 presents the stochastic linear multi-stage model to study the effect of wind power on power dispatch and market prices in the different electricity markets. Section 3 discusses the methodology to create scenarios for the wind power production and the rolling planning, which are needed as input for the stochastic model. Section 4 describes the case studies of the model to the German transmission system underlying the estimated wind power extensions in the forthcoming decades. Section 5 provides some conclusions and an outlook for further research.

2 Model

The model analyses power systems based on a description of generation, transmission and demand, combining the technical and economical aspects and it derives electricity market prices from marginal system operation costs. The model optimizes the unit commitment and dispatch taking into account the trading activities of the different actors on the different energy markets. Additionally different restrictions such as transmission constraints or capacity constraints of the power and heat generating units are taken into account. An approximation for modelling minimum operation times and minimum shut down times in a linear way is included into the model definition. The proposed market model is defined as a stochastic linear programming model. In a liberalized market environment it is often possible not only to change the unit commitment and dispatch, but even to trade electricity at power markets. In this extended model three electricity exchanges and one dispatch for heat are included in the planning model:

1. A day-ahead market for physical delivery of electricity where the EEX market at Leipzig, Germany, is taken as the starting point. In the following, this market is called the day-ahead market.

2. An intra-day power regulation for handling deviations between expected production and consumption agreed upon the day-ahead market and the realized values of production and consumption in the actual operation hour. Regulating power can be committed until the time of delivery . Both flexible producers and flexible consumers offer regulating power at this market. In our model the demand for regulating power is caused by the forecast errors connected to the wind power production.

3. A day-ahead market for automatically activated reserve power (frequency activated or load-flow activated). The demand for these ancillary services is determined exogenously to the model. This market will be called the ancillary services market.

4. Due to the interactions of CHP plants with the day-ahead and intra-day market, the dispatch for district heating and process heat is included in model.

A more detailed description of the model is given in [2].

2.1 Parameters and decision variables:

<u>Sets:</u>

t, T	: Index /set of time steps
s, S	: Index/ set of scenarios
i, I	: Index/ set of units
r, R	: Index/ set of regions
k	: Index set of price-elastic intervals

<u>Parameters:</u>

$c_i^{OPERATION}$	: cost function of unit i for operation costs
$t_i^{MIN\_OP}$	: Minimum operation time of unit i
$p_{r,t}^{WATERVALUE}$	: value of water in hydro-storages in region r at time step t

Decision variables:

$P_{i,s,t}, Q_{i,s,t}$: Power / Heat Output of unit i in scenario s, at time step t

$P_{i,t}^{DAY\_AHEAD}$: Power of turbine i sold to day-ahead market , at time step t

$P_{i,s,t}^{+INTRA\_DAY}$, $P_{i,s,t}^{-INTRA\_DAY}$: Down / up-regulation for balancing market of turbine i in scenario s

$P_{i,s,t}^{ONLINE}$: Online Capacity of unit i at time step t

$V_{i,s,t}$: Content of Hydro-Storage i in scenario s

$D_{r,k,t}^{FLEX\_DAY-AHEAD}$: Amount of increased/decrease demand (price-elastic)in region r

2.2 Objective Function and Restrictions

The model is formulated as a general stochastic unit commitment model considering more than one model region. The technical consequences of the consideration of the stochastic behaviour of the wind power generation is the partitioning of the decision variables for power output as well for the electricity consumption and for the transmissions power: For the power output of the units i at time t in scenario s we find $P_{i,s,t} = P_{i,t}^{DAY\_AHEAD} + P_{i,s,t}^{+INTRA\_DAY} - P_{i,s,t}^{-INTRA\_DAY}$. The variable $P_{i,t}^{DAY\_AHEAD}$ denotes the energy sold at the day-ahead market and has to be fixed the day before. Therefore it does not vary for different scenarios. $P_{i,s,t}^{+INTRADAY}$ and $P_{i,s,t}^{-INTRADAY}$ denote the positive and negative contributions to the regulating power varying for different scenarios. The decision variables for the electricity consumption and for the transmissions power are defined accordingly.

The objective function (1) tries to minimize the costs in the whole system, which corresponds to the maximization of producers' and consumers' surplus:

$$\min \left\{ \begin{array}{l} \sum_{s=1}^{S} \pi_s \sum_{t=1}^{T} \sum_{i \in I^{ELEC\_ONLY}} \left(c_i^{OPERATION} (P_{i,s,t}, P_{i,s,t}^{ONLINE}) + s_i (P_{i,s,t}^{ONLINE}, P_{i,s,t-1}^{ONLINE}) \right) \\ + \sum_{s=1}^{S} \pi_s \sum_{t=1}^{T} \sum_{i \in I^{CHP}} \left(c_i^{OPERATION} (P_{i,s,t}, Q_{i,s,t}, P_{i,s,t}^{ONLINE}) + s_i (P_{i,s,t}^{ONLINE}, P_{i,s,t-1}^{ONLINE}) \right) \\ + \sum_{s=1}^{S} \pi_s \sum_{t=1}^{T} \sum_{i \in I^{HEAT\_ONLY}} c_i^{OPERATION} (Q_{i,s,t}) \\ - \sum_{s=1}^{S} \pi_s \sum_{t=1}^{T} \sum_{i \in I^{HYDRO}} V_{i,s,t}\, p_{i,t}^{WATERVALUE} \\ + \sum_{t=1}^{T} \sum_{r \in R} \sum_{k \in K^{UP}} D_{r,k,t}^{FLEX\_DAY-AHEAD}\, p_{r,k,t}^{FLEXIBLE\_PRICE} \\ - \sum_{t=1}^{T} \sum_{r \in R} \sum_{k \in K^{DOWN}} D_{r,k,t}^{FLEX\_DAY-AHEAD}\, p_{r,k,t}^{FLEXIBLE\_PRICE} \end{array} \right\} \tag{1}$$

The first two sums in (1) describe the operation and start-up costs of condensing turbines, of CHP turbines like backpressure turbines and extraction-condensing turbines. The third sum models the operation costs of heat boilers. The hydro-reservoirs are included into the model and their power production costs are modelled through water values, which are calculated with the help of a long-term model developed by [3]. The model includes price-elastic consumer demand, which is done by defining a step-wise demand function. The change of the customers' utility relative to the change of their demand is represented through the last two sums in (1).

A. Market restrictions for the balance of supply and demand

The demand constraint is split up into two constraints: one balance equation for the power sold at the day-ahead market and one balance equation for the power sold at the balancing market. The price-elastic demand consists of two parts: the nominal value at time t in region r and an elasticity function which specifies the relationship between quantity and the price for the deviation from the nominal profile.

The balance equation for the balancing operation says that the up and down regulation of the different turbines and the up and down regulation of the different pumps as well as the up and down regulation by increased /decreased import or decreased / increased export has to be equal to the difference between the expected wind power production and the actual wind power production. Thereby the model allows wind shedding.

B. Capacity restrictions

The capacity restrictions for the electricity producing units are defined for maximum and minimum electric power output. The power, which is committed to the day-ahead market, plus the energy sold at the balancing market for up-regulation plus the contribution to the spinning reserve have to be lower than the capacity currently online of that unit at time step t.

As the model is defined as a multi-regional model, the capacity restrictions of the transmission lines are defined as follows:

$$P^{TRANS}_{\bar{r},r,t} + P^{TRANS,+}_{\bar{r},r,s,t} \leq l^{TRANSMISSION}_{r,\bar{r}} \qquad \forall r,\bar{r} \in R,\ \forall t \in T \qquad (2)$$

Transmission loss is considered to be proportional to the amount of electricity transmitted, furthermore a cost is assigned to the transmitted energy.

C. Restrictions for down regulation

For the fluctuating units for which wind shedding is taken into account, the amount of wind shedding has to be lower than the possible wind power production. The down regulation for electricity producing units can not be larger than the committed production and also the down regulation by the transmission lines has to be lower than the planned utilization.

D. Start-up costs

Start-up costs may influence considerably 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. As the size of the power systems require the definition of the model as a linear optimization model, the approximated formulation proposed by Weber [4] for modelling the start-up costs is used in the model. In order to avoid that units are always kept online, one has to account for the fact that the efficiency at part load is usually lower than at full load. The cost function is defined as fuel consumption function multiplied with the fuel costs.

E. Minimum operation and shut down times

Like start-up costs, minimum operation times and minimum shut down times influence the unit commitment decisions of plant operators. The typical formulation of the minimum operation times restrictions says, that a unit can be shut down, only if it was on during the last $t_i^{MIN\_OP}$ time steps corresponding to the minimum operation hours of the power plant.

F. Non-ancipativity constraints

As we use a multi-stage scenario tree to model uncertainty instead of single scenarios, we have to enforce that the decisions taken at time t must be the same if two scenarios are indistinguishable until time t. These sets of restrictions are known as non-anticipativity constraints. The detailed formulation of the restrictions can be found e.g. in [5].

3 The stochastic approach of the model

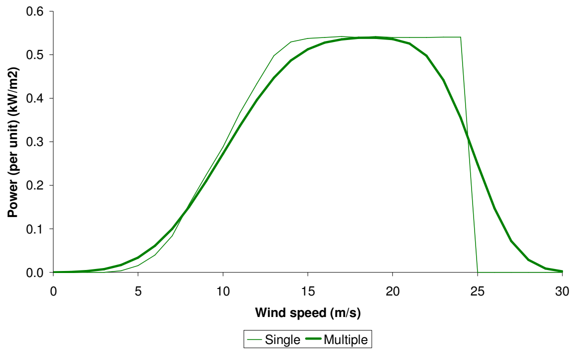
The inclusion of the uncertainty about the wind power production in the optimization model is considered by using a scenario tree. The construction of this scenario tree is carried out in two steps described in the following:

1. Modelling the wind power generation data

The wind power generation model is based on data of wind speed and of historical forecast errors for the forecasted wind speed horizon. The deviations between the wind speed forecasts and the real wind speed can be quite large. Since the errors increase with the length of the forecast period, the so called “Wind Speed Forecast Error Module” [6] assumes a multidimensional ARMA time series for this forecast error for each station additionally taking into account the correlation between the forecast errors at different stations. The ARMA time series contain the usual error terms. These are simulated by Monte Carlo simulations resulting in a predefined large number of scenarios for the forecast error.

In order to obtain for each region the forecast for the wind power from the wind speed forecast, technological aspects of the wind power stations located in the considered region are needed. Additionally, their spatial distribution within each region has to be taken into account. This yields an aggregation of the power generation in each region by smoothing the wind power curves (see Figure 1).

Figure 1: A standard normalised power curve ('Single') and the corresponding smoothed power curve ('Multiple').



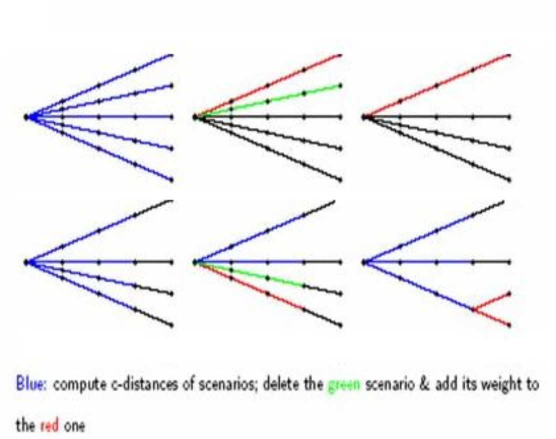
Source: [7]

2. Scenario reduction

In order to keep computation times small for models representing a national market with a huge number of generating units, only significantly less scenarios than the scenarios created by Monte Carlo simulations before can be used. Therefore a stepwise backward scenario reduction algorithm based on the approach of [8] is used: the original scenario tree is modified through bundling scenarios or part of scenarios.

As a measure for the similarity of different scenario trees the Kantorovich distance between two probability distributions is used. The reduction algorithm proceeds backwards: in the first iteration, the calculation of the distance between two scenarios includes all stages, in the second iteration, all stages except the last one are considered, etc. Merging two scenarios or parts of scenarios means deleting the one (or the part of the scenario) with the lower probability and adding its probabilities to the remaining one (see Figure 2). Note that merging scenarios in the second or any following iteration changes the successors of nodes in the scenario tree.

Figure 2 : Example for the backward scenario reduction heuristic



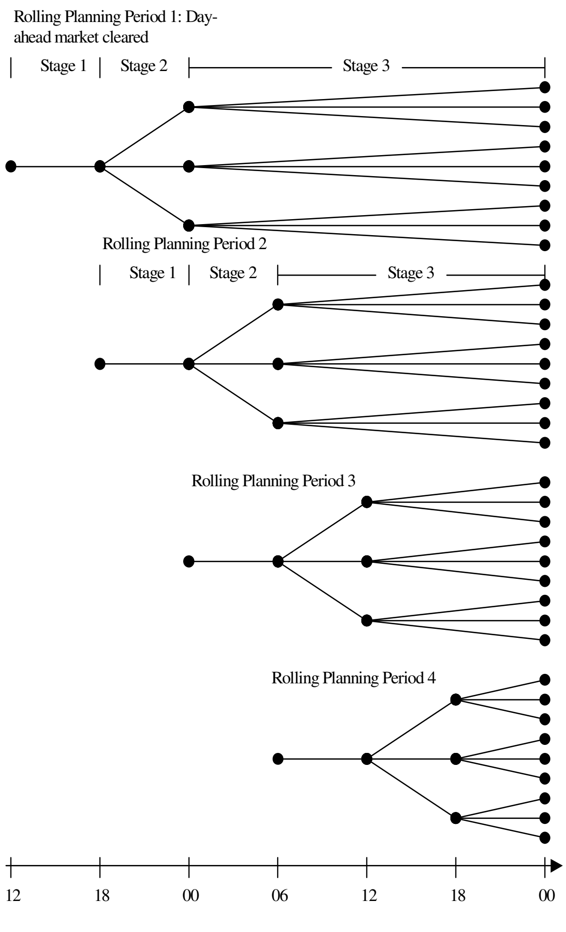
Source: modified figure from [9]

As it is not possible to cover the whole simulated time period with only a two-stage planning tree, the model is formulated by introducing a multi-stage recursion using rolling planning. In stochastic multi-stage linear recourse models, there exist two types of decisions: decisions that have to be taken immediately and decisions that can be postponed. The first kind of decisions are called "root" decisions, as they have to be decided "here and now" and before the uncertain future is known. The second kind of decisions is called “recourse decisions”. They are taken after some of the uncertain parameters are known. With these “recourse decisions” actions can be started which might possibly revise the first decisions. In the case of a power system with wind power, the power generators have to decide on the amount of electricity they want to sell at the spot market before the precise wind power production is known (root decision). In most European countries this decision has to be taken at least 12-36 hours before the delivery period. And as the wind power prediction is not very accurate, regulating power activiation is necessary in most cases, when the delivery period is in the near future (recourse decisions).

In general, new information arrives on a continuous basis and provides updated information about wind power production and forecasts, the operational status of other production and storage units, the operational status of the transmission and distribution grid, heat and electricity demand as well as updated information about market prices. Thus, an hourly basis for updating information would be most adequate. However, stochastic optimisation models quickly become intractable, since the total number of scenarios has a double exponential dependency in the sense that a model with $k+1$ stages, m stochastic parameters, and n scenarios for each parameter (at each stage) leads to a scenario tree with a total of $s = n^{mk}$ scenarios. It is therefore necessary to simplify the information arrival and decision structure in the stochastic model.

In the current version of the model a three stage model is implemented. The model steps forward in time using rolling planning with a 6 hour step. This decision structure is illustrated in Figure 3 showing the scenario tree for four planning periods covering one day. For each planning period a three-stage, stochastic optimisation problem is solved having a deterministic first stage covering 6 hours, a stochastic second stage with three scenarios covering 6 hours, and a stochastic third stage with 9 scenarios covering a variable number of hours according to the rolling planning period in question. In the planning period 1 the amount of power sold or bought from the day-ahead market is determined. In the subsequent replanning periods the variables for the amounts of power sold or bought on the day-ahead market are fixed to the values found in planning period 1, such that the obligations on the day-ahead market are taking into account when the optimisation of the intraday trading takes place.

Figure 3: Illustration of the rolling planning and the decision structure in each planning period within a day.

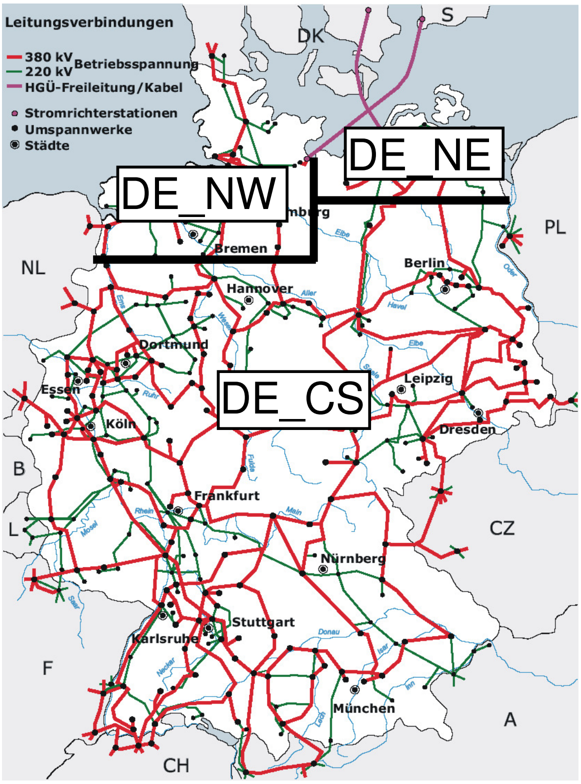


4 Application

The model proposed above has been applied to the German electricity system to analyse the impact of future wind power extensions on transmission constraints unit commitment and electricity markets.

For the case studies, Germany is divided into three model regions: one for the costal areas in the north-west (model region titled DE_NW) and the north-east (DE_NE) respectively and a third, larger one for the central and southern part (DE_CS). This subdivision reflects the concentration of installed wind power capacities in the coastal areas where the demand is low (especially in DE_NE) in comparison to the central part. Furthermore the borders of the model regions are reflecting the expected bottlenecks in the German power transmission grid from north to south (see Figure 4).

Figure 4: Subdivision of the German electricity system into three model regions and the power transmission grid [10]



The power generating units in Germany are represented by 40 different types of unit groups. The conventional and hydro power plants have a total installed electrical capacity of 9.8 GW in DE_NW, 0.5 GW in DE_NE and 81.9 GW in DE_CS. Their capacity and the level of the nominal electricity demand are not varied in the case studies. The assumed transmission capacities between the model regions are given in Table 1. Between the two coastal regions DE_NW and DE_NE no transmission capacity is installed so that surplus energy of the off-shore wind power farms can only be transmitted to the model region DE_CS directly.

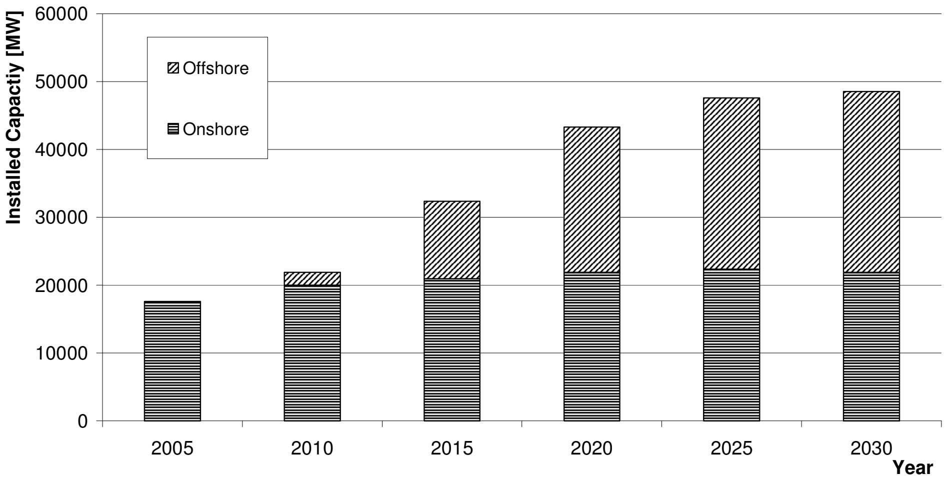
Table 1: Assumed transmission capacities between the model regions in [MW]

	DE_NW	**DE_NE**	**DE_CS**
DE_NW	-	0	3330
DE_NE	0	-	3060
DE_CS	3330	3060	-

The analysed wind power extension in the forthcoming years is based on a prognosis of the installed wind power capacity in Germany up to the year 2030 [11] (see Figure 5). The wind power extensions show a small growth concerning on-shore capacities especially from the year 2020 onwards. In 2005 no off-shore wind power will be installed, from 2010 onwards the off-shore capacity will rise up to 26.6 GW. As wind power extension decreases considerably after 2020, the prognosis of installed wind power in the years 2010 and 2020 are treated in the case study and compared to 2001. Scenarios for the further development of conventional power plant capacities are not considered in the calculations.

The simulated wind power production is based on hourly wind speed data from 11 wind speed measurement stations reflecting the wind power capacity distribution in Germany. The wind speed time-series describing the off-shore production in the North-Sea has been taken from a measurement station on Helgoland. For the Baltic Sea, a wind speed time-series measured on an island at the Eastern coast was chosen.

Figure 5: Prognosis of the installed wind power capacity in Germany up to 2030 [11]

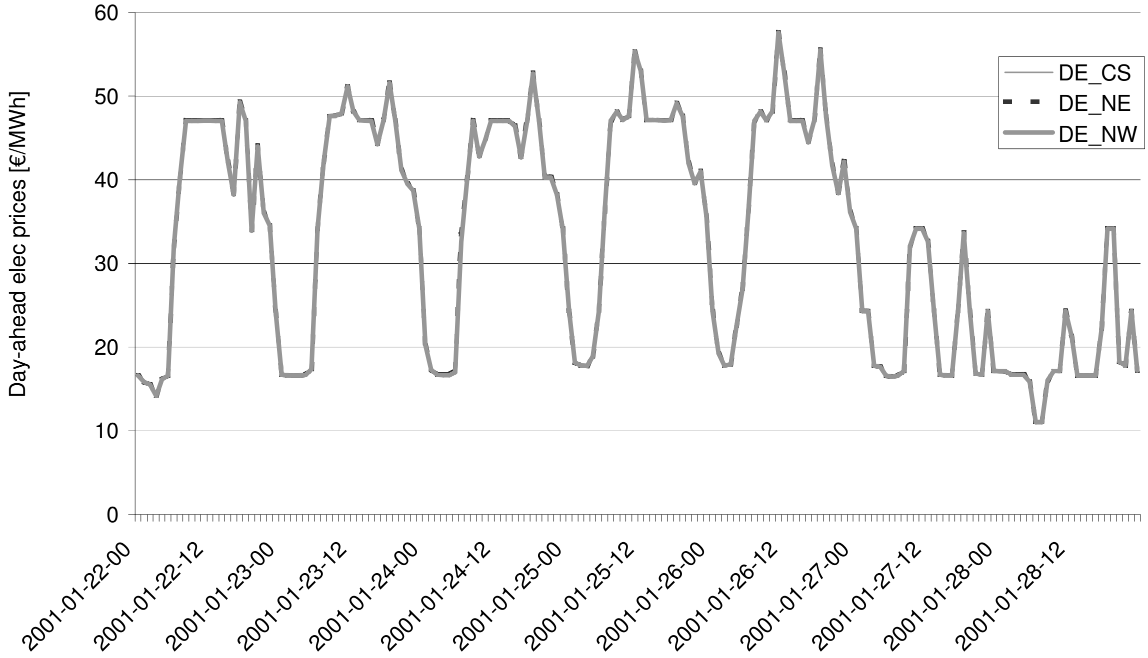


4.1 Results for the year 2001

A week in September 2001 (Monday 10th September to Sunday 16th September) was chosen for investigation in the case study. This week is characterised by periods with high and low wind power feed-in in correlation to a relatively low electricity demand. The installed wind power capacity in 2001 is taken as up to 4.1 GW in the model region DE_NW, 0.8 GW in DE_NE and 7 GW in DE_CS.

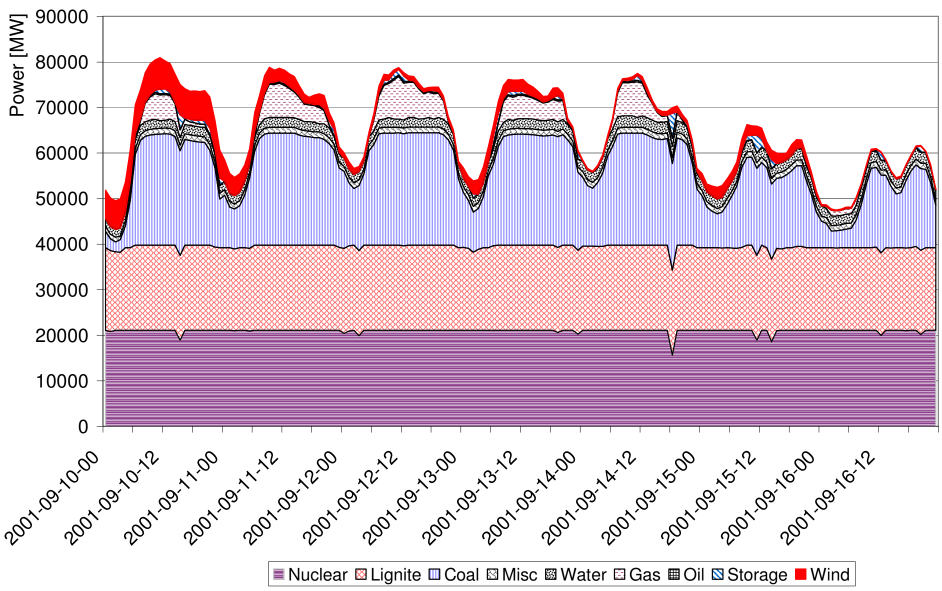
Figure 6 shows the resulting day-ahead electricity prices for the three model regions in this week. The prices in the individual model regions show very similar values. This means that no transmission restrictions occur and sufficient electricity can be transmitted between the regions to level out the electricity prices. .

Figure 6: Resulting day-ahead electricity prices for the three German model regions in the considered week in 2001



The electricity production differentiated by fuel used in Germany is shown with Figure 7. The sum of the generated electricity is equal to the total electricity demand. Power plants with low variable costs (e. g. nuclear and lignite power plants) run most of the time with their maximal capacities whereas the output of power plants using more expensive fuels (e. g. coal and gas) is varied. Wind power is high at the beginning of the week with a maximum of 13.5 % of the total load.

Figure 7: Electricity production differentiated by the use of fuel in Germany in the considered week in 2001



4.2 Results for wind power in 2010

2010 is the first year with additional off-shore wind power. Additional 10 GW of wind power capacity is installed within Germany in comparison to 2001. The total installed wind power capacity is assumed to be divided into 8.3 GW for the model region DE_NW, 3.3 GW for DE_NE and 10.3 GW for DE_CS.

Figure 8 shows the resulting day-ahead electricity prices for the basis week with the forecasted wind power extension in the year 2010. The prices in the model regions DE_CS and DE_NE are equal so that the transmission capacities between these two regions remain sufficient. By contrast the transmission capacities between the model regions DE_CS and

DE_NW with an installed off-shore wind power capacity of ca. 1.8 GW are temporarily binding. As a consequence the electricity prices in DE_NW decline below the prices in DE_CS and DE_NE during approximately the half of the considered week. Because of the surplus of generating power the peaks of the electricity prices in all three regions are lower, too.

Figure 9 shows the electricity production differentiated by fuel in Germany in the considered week with the wind power scenario of 2010. Wind power has a maximum share of 24 % of the total generated power. No wind shedding occurs. Contrary to the use of fuels in 2001, even the power generation of technologies with cheap fuels is observably reduced in the hours from 0 to 6 o'clock on 9thand 11th September. Furthermore, the use of expensive gas units is reduced to cover the electricity load. The slope of the total electricity production has somewhat changed because of the price flexible demand function included in the model.

Figure 8: Resulting day-ahead electricity prices for the three German model regions in the considered week with the wind power scenario of 2010

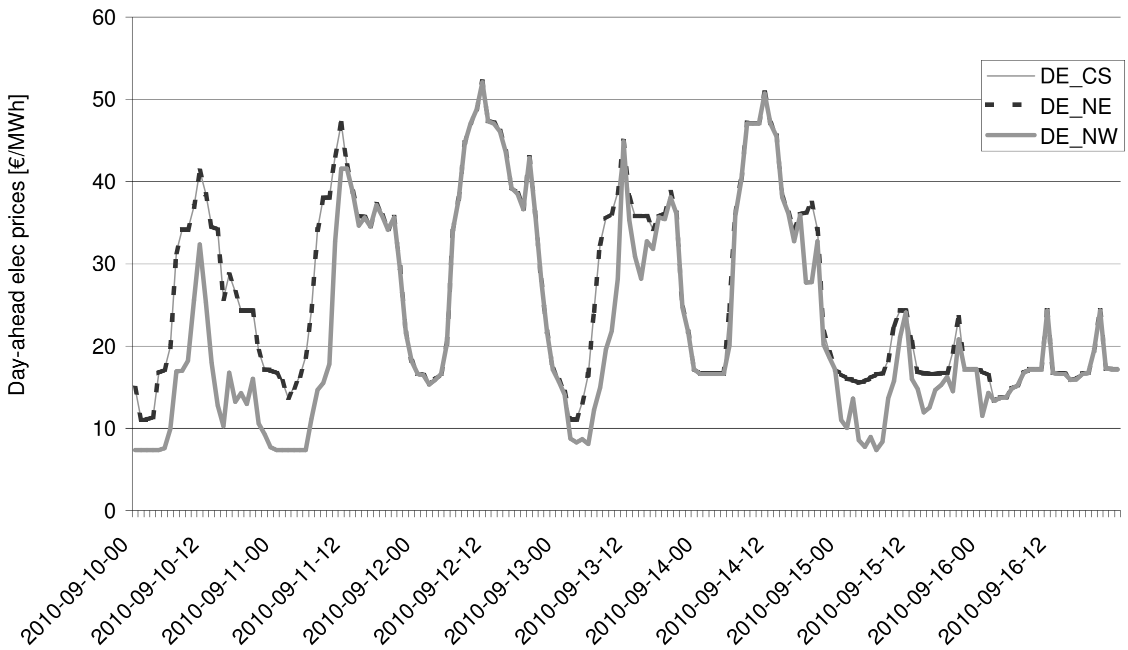
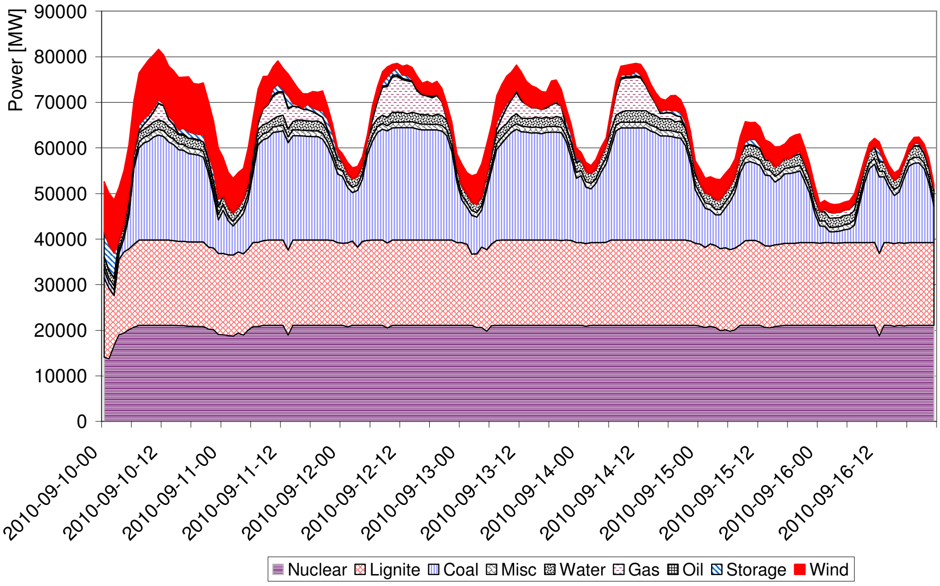


Figure 9: Electricity production differentiated by the use of fuel in Germany in the considered week with the wind power scenario of 2010



4.3 Results for wind power in 2020

For the year 2020 an additional wind power capacity of 31.5 GW compared to the base year 2001 is assumed. Thereby the extension is concentrated in the northern model regions and mainly based on off-shore wind power in DE_NW. So the total installed wind power capacity is divided into 26.9 GW for the model region DE_NW, 5.3 GW for DE_NE and 11 GW for DE_CS.

Figure 10 shows the resulting day-ahead prices for the basis week with the wind power scenario for 2020. Beside the afternoon hours of the 10th September the prices in the model regions DE_NE and DE_CS are equal. Besides this time period, the transmission capacities between these two model regions are still sufficient to transmit wind energy into the midlands. The prices of the region DE_NW are remarkably lower except the time period from the afternoon hours of 11th September to the morning hours of 12th September where the wind power feed-in is rather low. Furthermore the prices are equal to 0 for several time steps. In these time periods it is expected at the day-ahead market that the electricity demand can be totally covered with wind power and other regenerative energy sources. The price peaks reach only once the value of 50 €/MWh.

Figure 11 shows the electricity production differentiated by fuel used in Germany in the considered week with the wind power scenario of 2020. Wind power generation has a remarkable share in the total electricity production of up to 36 %. The maximum wind shedding does not exceed 0.5 GW. It is obvious that the unit dispatch of the conventional power plants is highly influenced by the wind power. The output of power generation technologies with cheap fuels varies within a broad range and these base-load power plants are running in inefficient part-load mode. As the electricity price becomes lower the demand rises due to the price flexible demand function. The last two week-days show load peaks with 85 and 82.6 GW respectively.

Figure 10: Resulting day-ahead electricity prices for the three German model regions in the considered week with the wind power scenario of 2020

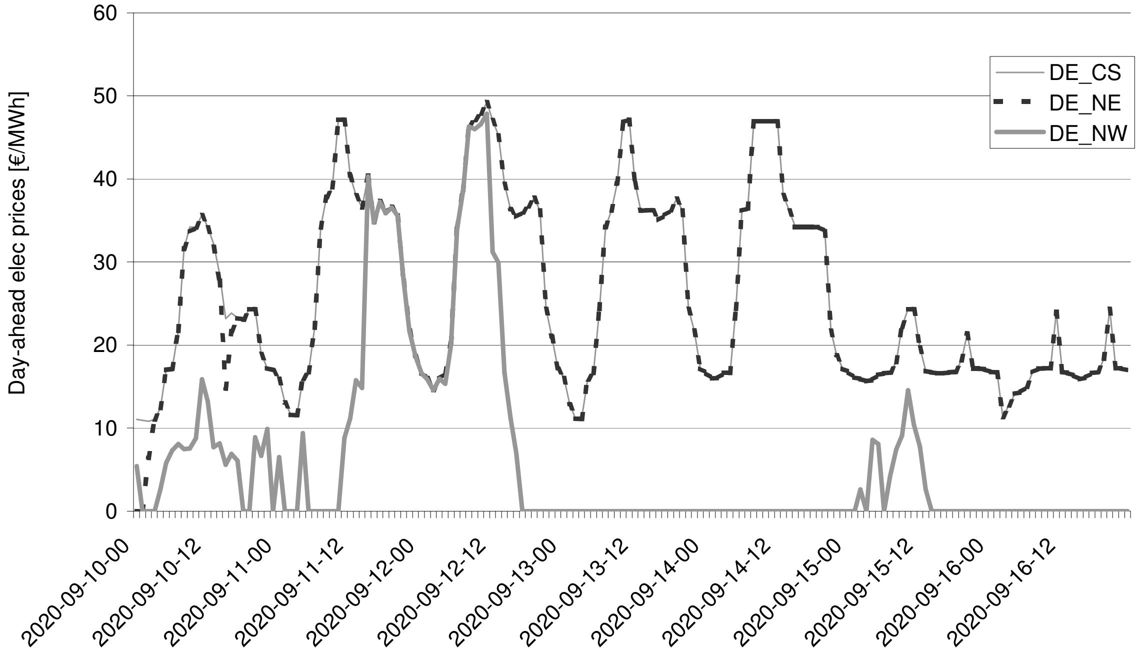
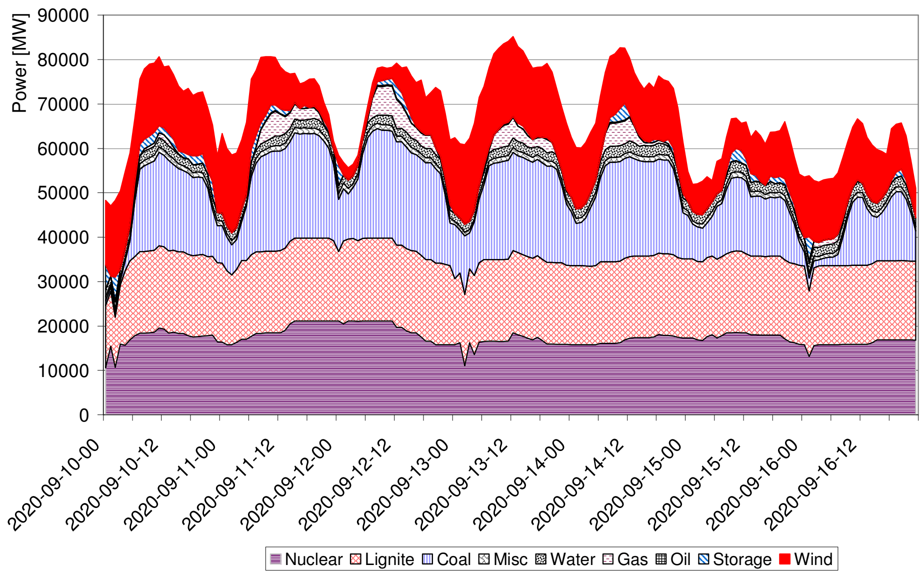


Figure 11: Electricity production differentiated by the use of fuel in Germany in the considered week with the wind power scenario of 2020



A detailed analysis of the capacity online of the different three regions (see Figs. 12, 13 and 14) shows that in the year 2020 the wind power in the region DE_NW and DE_NE (Figs. 12 and 13) is so much that it can meet the demand in that region during different time intervals completely alone or in combination with other regenerative fuels. Especially in the region DE_NW, due to the high amount of 26.9 GW of wind power installed in 2020, over long periods significant amount of wind power are available. It is worth mentioning that sometimes the nuclear power plants are shut down in the region DE_NW.

In the region DE_NE, coal plants guarantee the basic supply. The variations in wind power are balanced by changing capacities of gas turbines.

The situation is different for the region DE_CS (see Fig. 14); here the wind power can only yield relatively small contributions to the whole capacity online and the analysis looks qualitatively similar to the situation in whole Germany (see Fig. 11)

Figure 12: Available capacity online differentiated by the use of fuel in the wind power scenario of 2020 for North-West Germany (DE_NW)

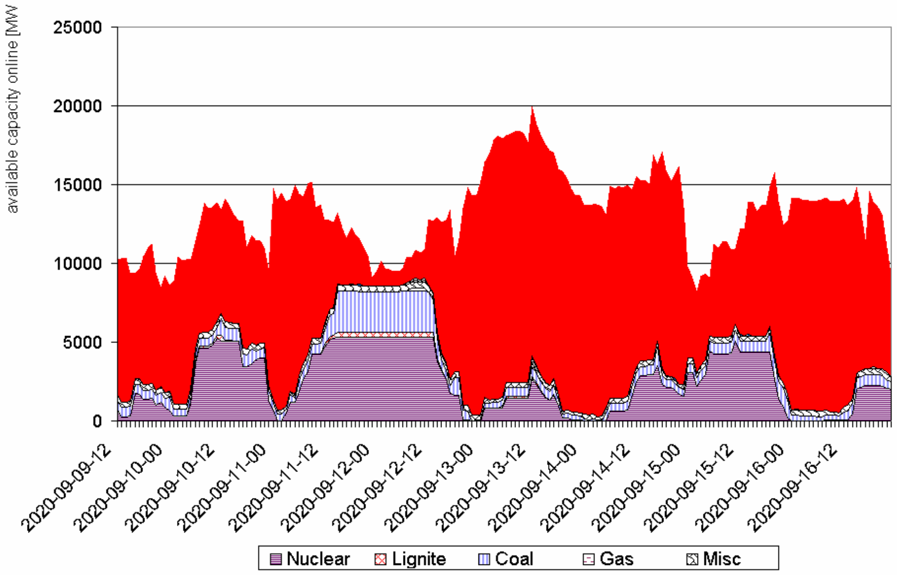


Figure 13: Available capacity online differentiated by the use of fuel with the wind power scenario of 2020 for North-East Germany (DE_NE)

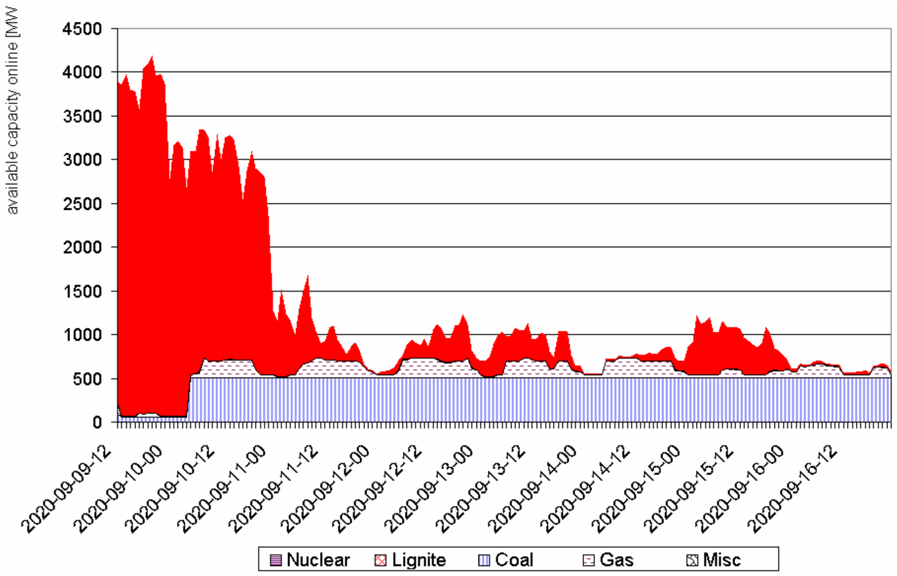
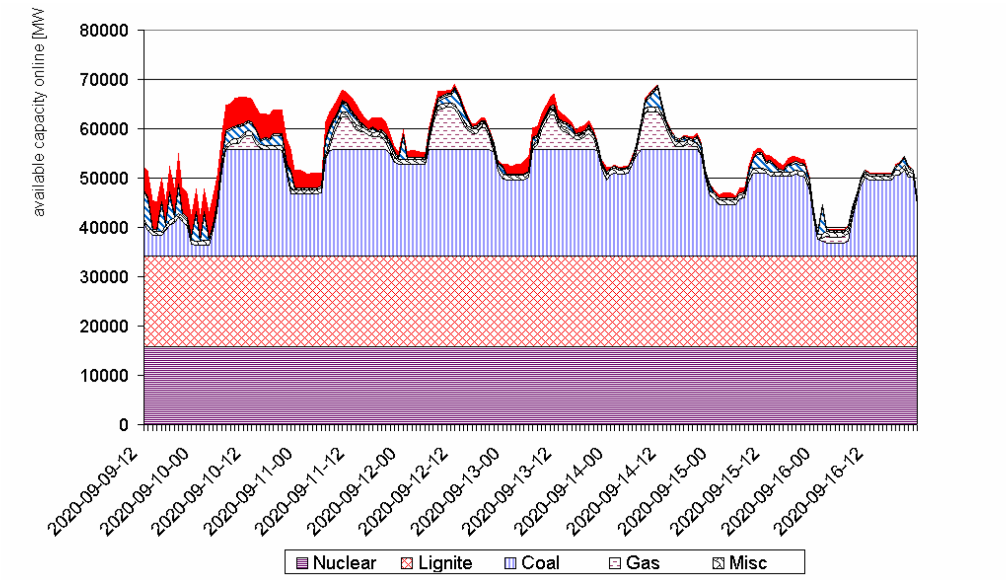


Figure 14: Available capacity online differentiated by the use of fuel in with the wind power scenario of 2020 for central and south Germany (DE_CS)



In the following a transmission capacity extension between the model regions DE_NW and DE_CS is assumed. Therefore the transmission capacity between these two model regions is tripled to 9990 MW. The transmission capacity between DE_NE and DE_CS is left unchanged because the correspondent prices are equal except for a short time sequence (see Figure 10). As the demand in DE_NE is rather low and it is not expected that additional wind power can be used there, a possible further transmission line between the two coastal regions DE_NW and DE_NE is not included.

Figure 15: Resulting day-ahead electricity prices for the three German model regions in the considered week with the wind power scenario of 2020 and with trebled transmission capacity between DE_NW and DE_CS

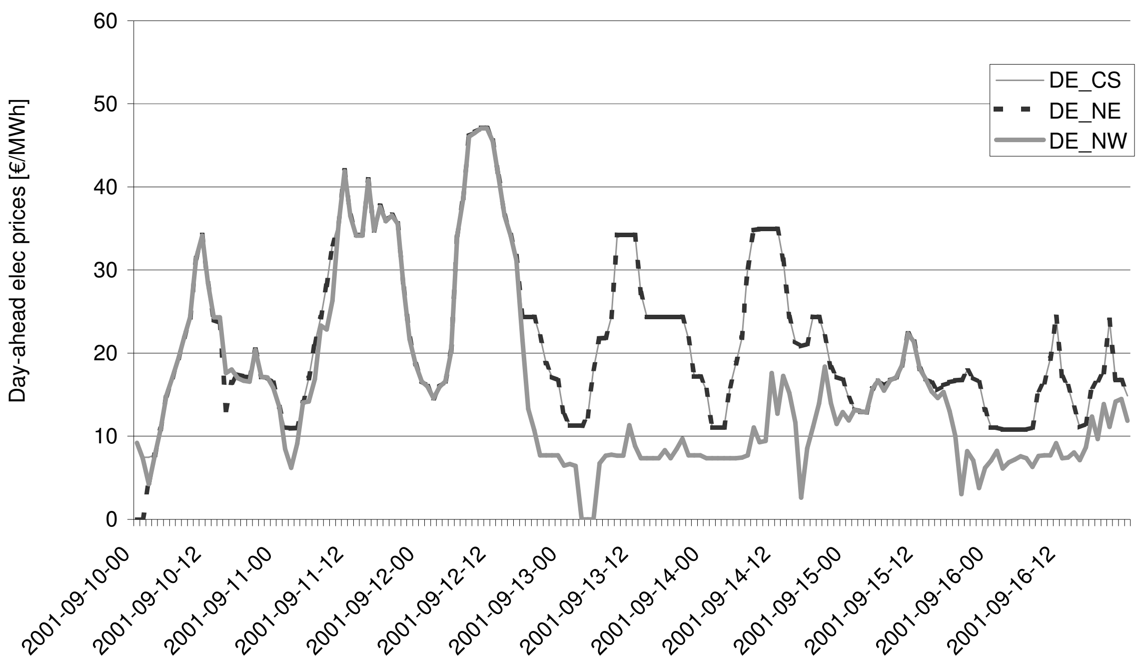
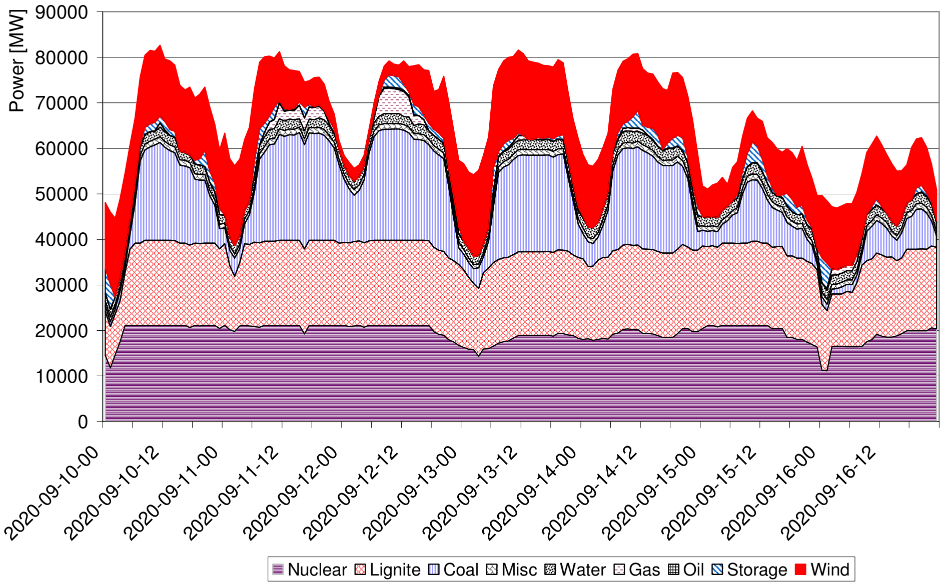


Figure shows the day-ahead prices for the modelled basis week with the forecasted wind power extension with the wind power scenario of 2020 and tripled transmission capacity between DE_NW and DE_CS. The envisaged transmission capacity extension is not sufficient to equal the prices in all model regions over the complete time frame. Especially in the second half of the considered week the day-ahead prices in DE_NW remain lower than in the other regions. In some morning hours of 13th September the prices are still equal to zero. As more energy can be transmitted to the regions DE_CS and DE_NE the prices in general decline in these regions.

Figure shows the electricity production differentiated by fuel in Germany for this case. The amount of energy produced by wind power remains the same. Also the wind energy that is shed stays equal, but the peak shedding decreases to 380 MW. In the first half of the week it is nearly possible to run base load units constantly at their maximum capacity. The use of power plants using more expensive fuel like coal, gas and oil is reduced, the production of the latter two fuels is even halved. The peak load value is decreased to 82.6 GW.

Figure 16: Electricity production differentiated by the use of fuel in Germany in the considered week with the and wind power scenario of 2020 with trebled transmission capacity between DE_NW and DE_CS



5 Conclusion and outlook

In this paper a stochastic linear programming model for evaluating the impact of wind power integration has been applied to analyse the transmission restrictions in Germany caused by wind power extensions. The model describes efficient, optimized decision making in the unit commitment by trading at several power markets using rolling planning. By using detailed time-series for wind speed data and modelling the forecast error of wind speed, the impact of wind uncertainty on system operation and prices can be evaluated in detail.

Germany was subdivided into three appropriate model regions to determine the transmission restrictions and their impact on day-ahead electricity prices and on the unit commitment. Case studies with the forecasted wind power extension in the years 2010 and 2020 are simulated and the resulting day-ahead prices and the unit commitment are analysed. Especially the case study for the year 2020 shows insufficient transmission capacities and the electricity prices in the model region describing the north-west coast with a large amount of installed off-shore wind power differ a lot from the prices of the other model regions. The unit commitment is changed remarkably. For the year 2020 a further case study with extended transmission capacity has been carried out. A triplication of the transmission capacities is not sufficient for levelling out the electricity prices within the considered model regions in Germany.

The reduction in electricity prices observed in the scenarios with increased wind power should not be understood as cost reductions, since neither the investment costs for conventional nor for wind power plants have been included in this model. The prices are mostly given as an economic indicator for the occurrence of bottlenecks in the transmission system.

For further research the input data need to be improved to allow a more detailed analysis of the case studies. The future nominal electricity demand has to be transformed to the level of the considered years. Furthermore the subdivision of the capacity of conventional power generating units has to be adopted to the future years by considering different scenarios of extension and removal of the individual power generating technologies.

6 Acknowledgements

This work was carried out within the WILMAR (Wind Power Integration in Liberalised Electricity Markets) project which is supported by the European Community under Contract No. ENK5-CT-2002-00663.

7 References

1. Molly JP. Market Prognosis 2008, 2012 and 2030. DEWI. Wilhelmshaven, 2004
2. Brand H, Weber C, Meibom P, Barth R, Swider DJ. A stochastic energy market model for evaluating the integration of wind energy. *6 th IAEE European Conference;* Zurich , 2004
3. Dueholm L, Ravn HF. Modelling of short term electricity prices, hydro inflow and water values in the Norwegian hydro system. *6th IAEE European Conference;* Zurich, 2004
4. Weber C. *Uncertainties in the electric power industry: methods and models for decision support.* Springer: Berlin, at al. 2004
5. Takriti S, Supatgiat C, Wu LSY. Coordinating Fuel Inventory and Electric Power Generation under uncertainty. *IEEE Transactions on Power Systems* 2002; 17: 13-18
6. Söder L. Simulation of wind speed forecast errors for operation planning of multi-area power systems. *8th International Conference on Probabilistic Methods Applied to Power Systems;* Iowa, 2004
7. Norgard P, Giebel G, Holttinen H, Söder L, Petterteig A. Fluctuations and predictability of wind and hydro power. *WILMAR Deliverable 3.2;* www.wilmar.risoe.dk at 05 November 2004
8. Dupacova J, Gröwe-Kuska N, Römisch W. Scenario reduction in stochastic programming - an approach using probability metrics. *Math. Program., Ser. A 95;* 3: 493-511
9. Gröwe-Kuska N, Heitsch H. Römisch W. Scenario Reduction and Scenario Tree Construction for Power Management Problems. *IEEE Bologna Power Tech Proceedings*; http://www.mathematik.hu-berlin.de/~heitsch/ieee03ghr.pdf at 05 November 2004
10. Verband der Netzbetreiber beim VDEW. Deutsches Höchstspannungsnetz. www.vdn-berlin.de at 05 November 2004
11. Deutsches Windenergie-Institut GmbH. Molly P. Technische Entwicklung und Anwendung der Windenergie. *OGE-Fachtagung*; Salzburg, 2003