Extension of Wind Power –
Effects on Markets and Costs of Integration

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Abstract

A fast growth of the installation of wind turbines has been experienced in several European countries. The introduction of substantial amounts of wind power in a liberalized electricity system will have serious impacts on the markets: market prices will change since the marginal production costs of wind power are very low, and larger amounts of frequency-responding spinning as well as supplemental power reserve will be needed to maintain the stability of the power system. Moreover transmission bottlenecks may occur between various regions.

Modelling explicitly the stochastic behaviour of wind generation and taking into account the prediction error is crucial for an evaluation of the costs of the integration of wind power. In this paper, a stochastic linear programming model is described for the efficient power market operation using the principle of rolling planning on an hourly basis. The model includes four markets: i) a day-ahead market for physical delivery of electricity, ii) an intraday-market, iii) a day-ahead market for automatically activated reserve power and iv) a market for district heating and process heat. Time series for the wind power production rely on time series for wind speed data and for the prediction error for wind speed. Aggregation of wind power generation reflects the spatial distribution of the wind power stations in each region. Market restrictions, capacity restrictions, restrictions for down regulation, minimum operation and shut down times and hydro storages are included in this model.

The model is applied to the German market which is decomposed in three regions in the year 2020. The results clearly indicate that the integration costs strongly depend on the specific system configuration and that the transmission capacities play an important role. By tripling the transmission capacities the savings per MWh produced by wind can be increased in some cases by 70 %.

Keywords: wind power, stochastic optimization, day-ahead market, regulatory market, integration costs

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 (Molly, 2004).

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 power stability. As substantial amounts of wind power will require increased reserves, the prices on the regulating power markets are furthermore expected to increase. Yet this is not primarily due to the fluctuations of wind power itself but rather to the (partial) unpredictability of wind power. If wind power were fluctuating but perfectly predictable, the conventional power plants would have to operate also in a more variable way, but this operation could be scheduled on a day-ahead basis and settled on conventional day-ahead spot markets. It is the unpredictability of wind power which requires an increased use of reserves with corresponding price implications.

In order to analyse adequately the market impacts and the integration costs of wind power it is therefore essential to model explicitly the stochastic behaviour of wind generation and to take the forecast errors into account. In an ideal, efficient market setting, all power plant operators will take into account the prediction uncertainty when deciding on the unit commitment and dispatch. This will lead to changes in the power plant operation compared to an operation scheduling based on deterministic expectations, since the cost functions for power production are usually non-linear and not separable in time.

The model presented in the following describes an efficient market operation by using a stochastic linear programming model. The commitment and dispatch of the generating units in the electricity system are governed by two main markets: (i) a day-ahead market for physical delivery of electricity and (ii) an intraday market or balancing power market, where the transmission system operators buy balancing power offered by flexible generating units and flexible electricity consumers in the system. As an efficient market is assumed, i.e. without market power, the results will correspond to the outcomes of a system-wide optimization as described in the following.

This paper is organized as follows: Section 2 presents a stochastic linear multi-stage model to study the effect of wind power on market prices in the different European markets (day-ahead, and intraday). Section 3 discusses the methodology to create scenarios for the wind power production, which are needed as input for the stochastic model. Section 4 illustrates the applicability of the model to the German market. Section 5 provides some conclusions.

2 Model

The model analyses power markets based on a description of generation, transmission and demand, combining the technical and economical aspects and derives the 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 four different types of 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. The stochastic part is presented by a scenario tree for possible wind power generation for the different hours.

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. 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. 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, recourse actions are necessary in most cases when the delivery period is in the near future.

In a liberalized market environment it is often possible not only to change the unit commitment and dispatch, but even to trade electricity at the hour-ahead market. In this extended model three electricity markets and one market 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.

2. An *intra-day market* for handling deviations between expected production and consumption agreed upon on the day-ahead market and the realized values of production and consumption in the actual operation hour. Regulating power can be traded up to one hour before delivery at the intra-day market. 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.

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

Nomenclature

The standard indices i, r, s, t refer to unit, region, scenario and time step, respectively.

Sets:

t, T : Index /set of time steps
T^{OPTIM_PERIOD} : Number of time steps
s, S : Index/ set of scenarios
i, I : Index/ set of units
r, R : Index/ set of regions
$R_r^{NEIGHBOUR}$: Set of regions, which are the neighbour regions
I^{ELEC}, I_r^{ELEC} : Set of power producing units, set of power producing units in region r
I^{ELEC_ONLY} : Set of units producing only power
I^{CHP} : Set of combined heat and power producing units
I^{HEAT}, I_a^{HEAT} : Set of heat producing units, set of heat producing units in area a
$I^{EXTRACTION}$: Set of units with extraction-condensing turbines
$I^{BACKPRESSURE}$: Set of units with backpressure turbines
I^{HYDRO}, I_r^{HYDRO} : Set of hydro storages, set of hydro storages

Parameters:

$d_{r,t}^{ELEC}$: Nominal load demand forecast
$d_{a,t}^{HEAT}$: Heat demand forecast
$d_{r,t}^{ANC,UP}, d_{r,t}^{ANC,DOWN}$: Demand for spinning reserve (up-regulation/down regulation)
$p_{r,t}^{EXPECTED\_WIND}$: Expected wind power production
$p_{r,s,t}^{ACTUAL\_WIND}$: actual wind power production capacity
$c_i^{OPERATION}$: operation cost function
s_i : start-up cost function

$p_i^{MAX\_PROD}$: Maximum output of power
$p_i^{MIN\_PROD}$: Minimum output of power
$q_i^{MAX\_PROD}$: Maximum output of heat
$t_i^{MIN\_OP}$: Minimum operation time
$t_i^{MIN\_SD}$: Minimum shut down times
δ_i^{CB} : Heat ratio of CHP turbine i
γ_{i} : Reduction of electric power production due to heat production of CHP turbine i
w_i^{MAX} : maximum capacity of the pump of hydro-storage i
v_i^{MAX} : maximum capability of hydro-storage (reservoir) i
$p_{r,t}^{WATERVALUE}$: value of water in hydro-storages
$i_{i,t}^{INFLOW}$: inflow into hydro-reservoir i

Decision variables:

$P_{i,s,t}, Q_{i,s,t}$: Power / Heat Output
$P_{i,t}^{DAY\_AHEAD}$: Power sold to day-ahead market
$P_{i,s,t}^{+}, P_{i,s,t}^{-}$: Down / up-regulation for balancing market
$P_{i,t}^{ANC,+}, P_{i,t}^{ANC,-}$: Contribution to spinning reserve (down/up-regulation)
$P_{i,s,t}^{ONLINE}$: Online Capacity
$P_{r,\bar{r},s,t}$: Transmission of power from region r to region $\bar{r}$
$P_{r,\bar{r},t}^{TRANS,DAY-AHEAD}$: Planned transmission when bidding on the day-ahead market
$P_{r,\bar{r},s,t}^{TRANS,+}, P_{r,\bar{r},s,t}^{TRANS,-}$: Contribution to up-regulation/down-regulation at balancing market in region $\bar{r}$ by increased/decreased transmission of power from region r to region $\bar{r}$
$W_{i,s,t}$: Pumping capacity of hydro-storage i
$W_{i,t}^{DAY-AHEAD}$: Fixed pumping capacity of hydro-storage i
$W_{i,s,t}^{+}, W_{i,s,t}^{-}$: Down/up-regulation for balancing market of pump of hydro-storage i
$W_{i,t}^{ANC,+}, W_{i,t}^{ANC,-}$: Contribution of pump of hydro-storage i to spinning reserve (down/up-regulation)
$V_{i,s,t}$: Content of Hydro-Storage i

Objective Functions and Restrictions:

The model is formulated as a general stochastic unit commitment model. 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: one part describes the different quantities at the day-ahead market (thus they are fixed and do not vary for different scenarios). The other part describes contributions at the intraday-market both for up- and down-regulation. The latter consequently depends on the scenarios. So for the power output of the units i at time t in scenario s $P_{i,s,t} = P_{i,t}^{DAY\_AHEAD} + P_{i,s,t}^{+} - P_{i,s,t}^{-}$ is defined. The variable $P_{i,t}^{FIXED}$ 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. $P_{i,s,t}^{+}$ and $P_{i,s,t}^{-}$ denote the positive and negative contributions to the regulating power. Analogously 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.

$$
\min\left\{
\begin{aligned}
&\sum_{s=1}^{S}\pi_s\sum_{t=1}^{T}\sum_{i\in I^{ELEC\_ONLY}}\left(c_i^{OPERATION}(P_{i,s,t},P_{i,s,t}^{ONLINE})+s_i(P_{i,s,t}^{ONLINE},P_{i,s,t-1}^{ONLINE})\right)\\
&+\sum_{s=1}^{S}\pi_s\sum_{t=1}^{T}\sum_{i\in I^{CHP}}\left(c_i^{OPERATION}(P_{i,s,t},Q_{i,s,t},P_{i,s,t}^{ONLINE})+s_i(P_{i,s,t}^{ONLINE},P_{i,s,t-1}^{ONLINE})\right)\\
&+\sum_{s=1}^{S}\pi_s\sum_{t=1}^{T}\sum_{i\in I^{HEAT\_ONLY}}c_i^{OPERATION}(Q_{i,s,t})\\
&-\sum_{s=1}^{S}\pi_s\sum_{t=1}^{T}\sum_{i\in I^{HYDRO}}P_{i,s,t}\,p_{i,t}^{WATERVALUE}
\end{aligned}
\right\} \tag{1}
$$

The first two sums in (1) describe the operation and start-up costs of condensing turbines, of CHP turbines like backpressure turbines, gas 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 models through water values, which are calculated with the help of a long-term model developed by Hans Ravn (Dueholm, Ravn 2004).

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 intraday market. The constraint for the time steps, where the day-ahead market is not fixed yet, is defined in (2).

$$
\sum_{i\in I_r^{ELEC}}P_{i,s,t}-\sum_{i\in I_r^{HYDRO}}W_{i,s,t}+\sum_{\bar{r}\in R_r^{NEIGHBOUR}}(P_{\bar{r},r,t}^{TRANS}-P_{r,\bar{r},t}^{TRANS})+p_r^{EXPECTED\_WIND}=d_{r,t}^{ELEC} \tag{2}
$$

$$
\forall t\in T^{NOT\_FIXED},\forall r\in R
$$

The equation requires that all the power produced by the units in one region minus the power the hydro storages need for the pumping plus the import-export balance plus the expected wind power production has to be equal to the demand in that region.

The balance equation for the balancing market is described by the following equation:

$$
\begin{aligned}
&\sum_{i\in I_r^{ELEC}}(P_{i,s,t}^{+}-P_{i,s,t}^{-})+\sum_{i\in I_r^{HYDRO}}(W_{i,s,t}^{+}-W_{i,s,t}^{-})+\sum_{\bar{r}\in R_r^{NEIGHBOUR}}(P_{\bar{r},r,t}^{TRANS,+}-P_{\bar{r},r,t}^{TRANS,-})\\
&+\sum_{\bar{r}\in R_r^{NEIGHBOUR}}(P_{\bar{r},r,t}^{TRANS,-}-P_{\bar{r},r,t}^{TRANS,+})-P_{r,s,t}^{WIND,-}=p_{r,t}^{WIND\_EXPECTED}-p_{r,s,t}^{WIND\_ACTUAL}
\end{aligned} \tag{3}
$$

$$
\forall r\in R,\ \forall s\in S,\ \forall t\in T
$$

When trading on the balancing market, it is assumed that then the real wind production is known at the actual time steps. So the difference between the expected and actual wind has to be balanced. This can be done by reduced/ increased electricity production of the power producing units or by increased/decreased pumping or by increased/decreased export or by decreased/increase import from other regions or by wind shedding

Equation (3) 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. As the model allows wind shedding, the term $P_{r,s,t}^{WIND,-}$ is added to the equation. If the expected wind power production is higher than the actual wind power production, a demand for up regulation exists. Conversely, there exists a demand for down regulation if the expected wind power production is lower than the actual one. The heat market is represented in form of an exogenously given demand for each area (4):

$$\sum_{i \in I_r^{HEAT}} Q_{\mathrm{i,s},t} = \quad d_{r,t}^{HEAT} \qquad \forall r \in R, \forall s \in S, \forall t \in T \tag{4}$$

In order to avoid , that only the cheap units will run when aggregating the heat units of different district heating areas, a minimum heat output is derived for expensive units. How these lower bounds are calculated can be read in (Weber; Barth, 2004)

Similiar to the heat market, the market for ancillary services is described by two exogenously given demand restrictions for up (5) and down regulation (6). The demand for up regulation, can be supplied either by increased power production of the power producing units, or by reduced pumping of the hydrostorages, whereas the demand for down regulation can be meet by decreasing the power production or by increasing the pumping of the hydro storages..

$$\sum_{i \in I_r^{ELEC}} P_{i,t}^{ANC,+} + \sum_{i \in I_r^{HYDRO}} W_{i,t}^{ANC,+} = \quad d_{r,t}^{ANC,UP} \qquad \forall r \in R, \ \forall t \in T \tag{5}$$

$$\sum_{i \in I_r^{ELEC}} P_{i,t}^{ANC,-} + \sum_{i \in I_r^{HYDRO}} W_{i,t}^{ANC,-} = \quad d_{r,t}^{ANC,DOWN} \qquad \forall r \in R, \ \forall t \in T \tag{6}$$

Capacity restrictions

As the model is defined as a multi-regional model, the capacity restrictions of the transmission lines are defined in (7).

$$P_{\bar{r},r,t}^{TRANS} + P_{\bar{r},r,s,t}^{TRANS,+} \quad \leq \quad l_{r,\bar{r}}^{TRANSMISSION} \qquad \forall r, \bar{r} \in R, \ \forall t \in T \tag{7}$$

The capacity restrictions for the electricity producing units are defined in the following equations for maximum (8) and minimum electric power output (9).

$$P_{i,t}^{DAY\_AHEAD} + P_{i,s,t}^{+} + P_{i,t}^{ANC,+} \quad \leq \quad P_{i,s,t}^{ONLINE} \leq p_{i,t}^{MAX} \qquad \forall i \in I^{ELEC}, \ \forall s \in S, \forall t \in T \tag{8}$$

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 has to be lower than the capacity currently online of that unit at time step t. $P_{i,s,t}^{ONLINE}$ is an additional variable introduced in order to describe start-up costs, reduced part-load efficiency and the restrictions for minimum shut down and minimum operation time in a linear programming model. In the typical unit commitment models the restrictions for the minimum operation time and minimum down time include integer variables. However, this is hardly feasible for a model representing a national market. Therefore Weber (Weber, 2004) proposed an approximation to model the restrictions in a linear way, which makes it necessary to introduce this additional decision variable. On the one hand this capacity online forms an upper bound (8) to the output and on the other hand the capacity multiplied with the quotient of maximum and minimum output forms an lower bound to the possible power output within the model (9).

$$P_{i,t}^{DAY\_AHEAD} - P_{i,s,t}^{-} - P_{i,t}^{ANC,-} \geq (p_i^{MIN\_PROD} / p_i^{MAX\_PROD}) * P_{i,s,t}^{ONLINE} \quad \forall i \in I_R^{ELEC},\ \forall s \in S, \forall t \in T \qquad (9)$$

The idea is illustrated in Figure 1.

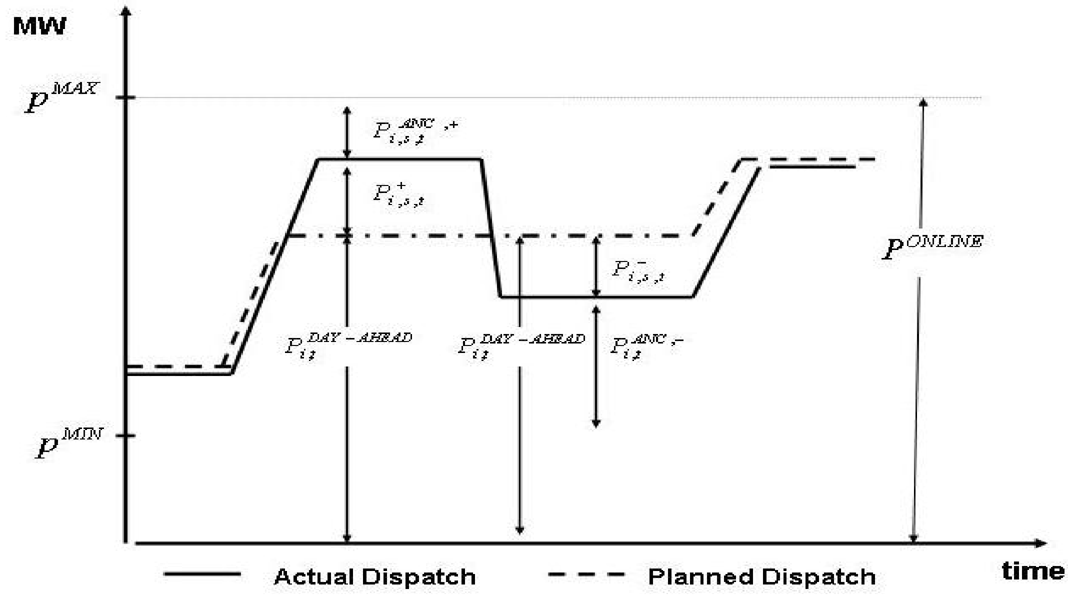

Figure 1: Illustration of the contribution of a power generating turbine to the different markets

For CHP units the model distinguishes between extraction condensing units and backpressure units. The detailed equations restricting their operation modes can be found in (Brand et. al, 2004)

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 (10).

$$P_{i,s,t}^{WIND,-} \leq p_{r,s,t}^{WIND\_ACTUAL} \qquad \forall r \in R, s \in S, \forall t \in T \qquad (9)$$

The down regulation for electricity producing units can not be larger than the committed production (11).

$$P_{i,s,t}^{-} + P_{i,s,t}^{ANC,-} \leq P_{r,t} \qquad \forall i \in I^{ELEC}, s \in S, \forall t \in T \qquad (10)$$

And also the contribution for the down regulation by the transmission lines has to be lower than the planned commission (12).

$$P_{r,\bar{r},s,t}^{TRANS,-} \leq P_{r,\bar{r},t}^{TRANS} \qquad \forall r, \bar{r} \in R, s \in S, \forall t \in T \qquad (11)$$

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 (Weber, 2004) for modelling the start-up costs is used in the model. The function of the start-up costs is defined in the following way (13).

$$s_i\left(P_{i,s,t}^{ONLINE}, P_{i,s,t-1}^{ONLINE}\right) = \begin{cases} c_i^{START\_UP} * \left(P_{i,s,t-1}^{ONLINE} - P_{i,s,t}^{ONLINE}\right) & \text{if} \quad P_{i,s,t-1}^{ONLINE} > P_{i,s,t}^{ONLINE} \\ 0 & \text{else} \end{cases} \qquad (12)$$

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. In the linear approximation the requirement is, that the reduction in the capacity online of unit I between time step t and time step t-1 cannot exceed the minimum of the capacity online during the last $t_i^{MIN\_OP}$ time steps (14). These time steps correspond to the minimum operation hours of the corresponding plant.

$$P_{i,s,t-1}^{ONLINE} - P_{i,s,t}^{ONLINE} \le P_{i,s,\tau}^{ONLINE} \;\forall \tau \quad \text{with} \quad t - t_i^{MIN\_OP} \le \tau \le t-1. \qquad (13)$$

$$\forall i \in I^{ELEC}, s \in S, \forall t \in [t_i^{MIN\_OP},..., T^{OPTIM\_PERIOD}]$$

Conversely the maximum start-up capacity is limited be the minimum of the capacity shut-down during the last $t_i^{MIN\_SD}$ time steps (15).

$$P_{i,s,t-1}^{ONLINE} - P_{i,s,t}^{ONLINE} \le c_i^{MAX\_OUTPUT} - P_{i,s,\tau}^{ONLINE} \;\forall \tau \quad \text{with} \quad t - t_i^{MIN\_SD} \le \tau \le t-1 \qquad (14)$$

$$\forall i \in I^{ELEC}, s \in S, \forall t \in [t_i^{MIN\_SD},..., T^{OPTIM\_PERIOD}]$$

Hydro storages

The equations for the hydro reservoirs are summarized in the following four equations. Equation (16) represents the maximum reservoir capacity, the balance equation (17) represents the content of the reservoir capacity taking into account the power production and the energy inflow by the pump process as well as natural water inflow. Equation (18) restricts the capacity of the pumping process and limits the contribution of the pumping process to the down regulating for the balancing market and ancillary services by increasing the pumping process. Conversely the contribution to the up-regulation by decreasing the pumping process is restricted in (19).

$$V_{i,s,t} \le v_i^{MAX} \qquad \forall i \in I^{HYDRO}, s \in S, t \in T \qquad (16)$$

$$V_{i,s,t} = V_{i,s,t-1} - (P_{i,t} + P_{i,s,t}^{+} - P_{i,s,t}^{-})(1-\varepsilon_i) + (W_{i,s,t} - W_{i,s,t}^{+} + W_{i,s,t}^{-}) + i_{s,t}^{INFLOW} \qquad (17)$$

$$\forall i \in I^{HYDRO}, s \in S, t \in T$$

$$W_{i,t} + W_{i,s,t}^{-} + W_{i,t}^{ANC,-} \le w_i^{MAX} \qquad \forall i \in I^{HYDRO}, s \in S, t \in T \qquad (18)$$

$$0 \le W_{i,t} - W_{i,s,t}^{+} - W_{i,t}^{ANC,+} \qquad \forall i \in I^{HYDRO}, s \in S, t \in T \qquad (19)$$

Data aggregation

To reduce the computation time of the model, several district heat areas are summarized. For areas defined as rural areas, it is required that the heat output is proportional to all units.

Non-ancipativity constraints

As a multi-stage scenario tree to model uncertainty instead of single scenarios is used, it has to be enforced 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 Takriti et. al (2002).

3 Scenario creation and scenario reduction

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:

A. Modelling of the wind power generation data process and the simulation of the independently, identically distributed scenarios, whose first values at the root node are identical

B. Reduction of the scenario tree

Modelling the wind power generation data process

The wind power generation model is based on data of wind speed which can be obtained in two different ways: either directly from a database of meteorological data or as output of the Power-to-Speed Model (Norgard et. al., 2004). The latter reconstructs the wind speed from given regional wind power data. Depending on the region, one of these two alternatives is possible.

A second important source of data is a database containing historical forecast errors of wind speed forecasts. The errors between the wind speed forecasts and the real wind speed can be quite large. So it is of crucial importance to include prediction errors in the model. Since the errors increase with the length of the forecast period, the so called “Wind Speed Forecast Error Module” (Söder, 2004) assumes a multidimensional ARMA time series for this forecast error for each wind speed measurement station additionally taking into account the correlation between different stations. For example, data analysis from Sweden (see Fig. 2) shows that the closer the stations, the higher is the correlation between forecast errors and that the correlation between different station increases with forecast lengths.

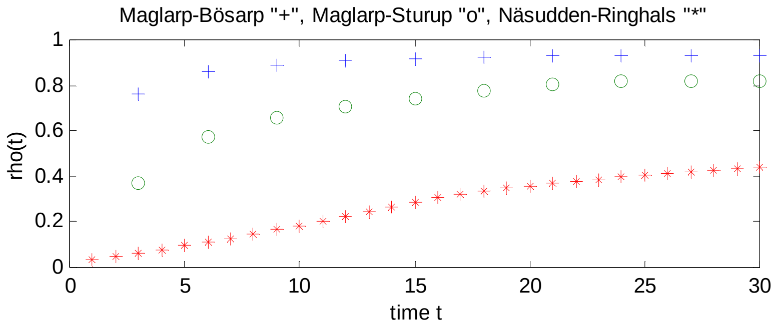

Figure 2: Correlation between forecast errors for different pairs of stations (Source: Söder 2004)

The ARMA time series contain the usual error terms. These are simulated by Monte Carlo Simulations resulting in a large number of scenarios for the forecast error. In order to obtain for each region the forecast of 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 yielding an aggregation of the power generation in each region (see Fig. 3).

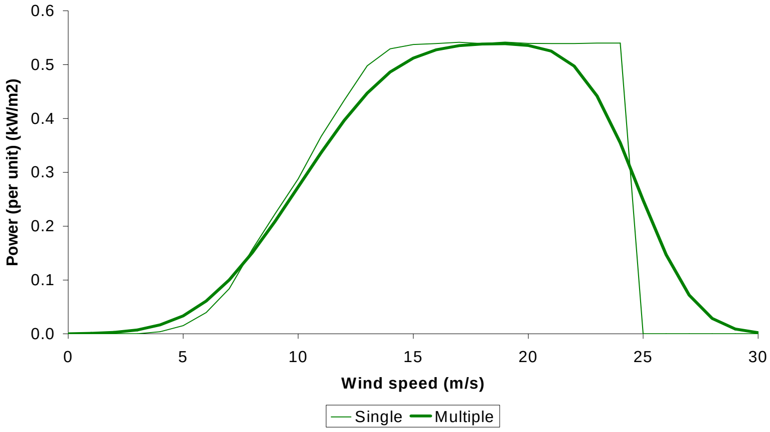

Figure 3: A standard normalised power curve ('Single') and the corresponding smoothed power curve ('Multiple'). (Source: Norgard et al. (2004))

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 can be used. Therefore we use a stepwise backward scenario reduction algorithm based on the approach of Dupacova et al. (2003): the original scenario tree is modified through bundling scenarios or part of scenarios.

As a measure for the similarity of different scenarios, the Kantorovich distance between two scenarios 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.

An overview of the different modules and the data flow can be found in Figure 4. All modules are implemented within Matlab®. For each loop of the model we get a scenario tree describing the wind power production in the different regions.

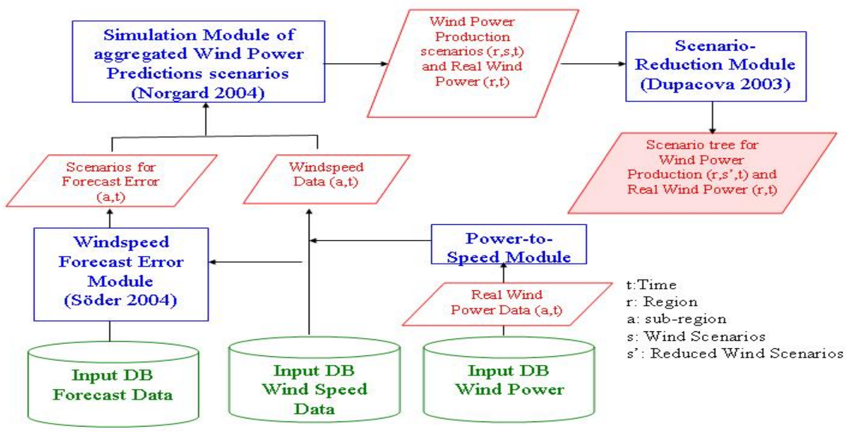

Figure 4: Data flow of the sub-module of the scenario tree creation model

4 Application

The methodology proposed above has been applied to the German market. The market for balancing power is assumed to function as an hour-ahead market in Germany – although such a market is - in contrast to the Nordic countries – not yet established in Germany.

For the case study 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) (see Fig. 2). 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. 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.

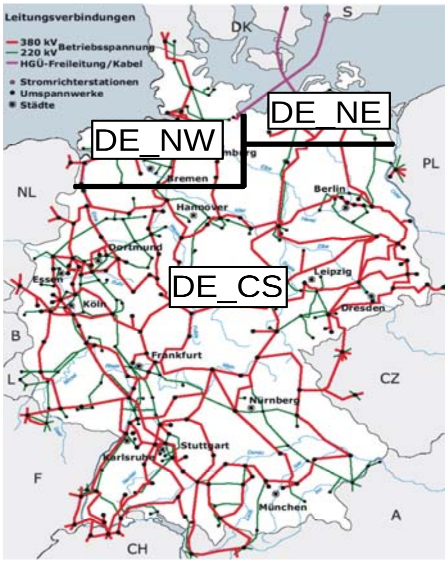

Fig. 5: Subdivision of Germany into 3 regions

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 (see Fig. 3). 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. 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.

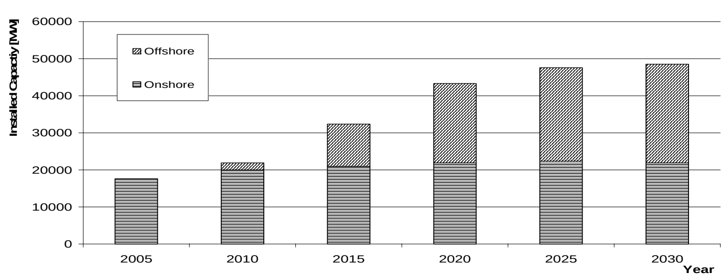

Figure 6: Prognosis of the installed wind power capacity in Germany up to 2030 (Molly, 2004)

In the actual WILMAR Model the installed capacities of the different power plant units are given exogenously. To determine the installed capacities in the year 2020 the results from the European Electricity Market Model E2M2s (Swider, Weber 2004). Thereby the scenario market-mix as dfiened by (Swider, Weber 2004) is taken as basis. It is characterised by moderate fuel price developments, a continuation of current nuclear policies and no severe CO_2 restrictions. The values of the installed capacity of the CHP units were taken from the year 2002. Figure 7 shows the installed capacities in the different regions.

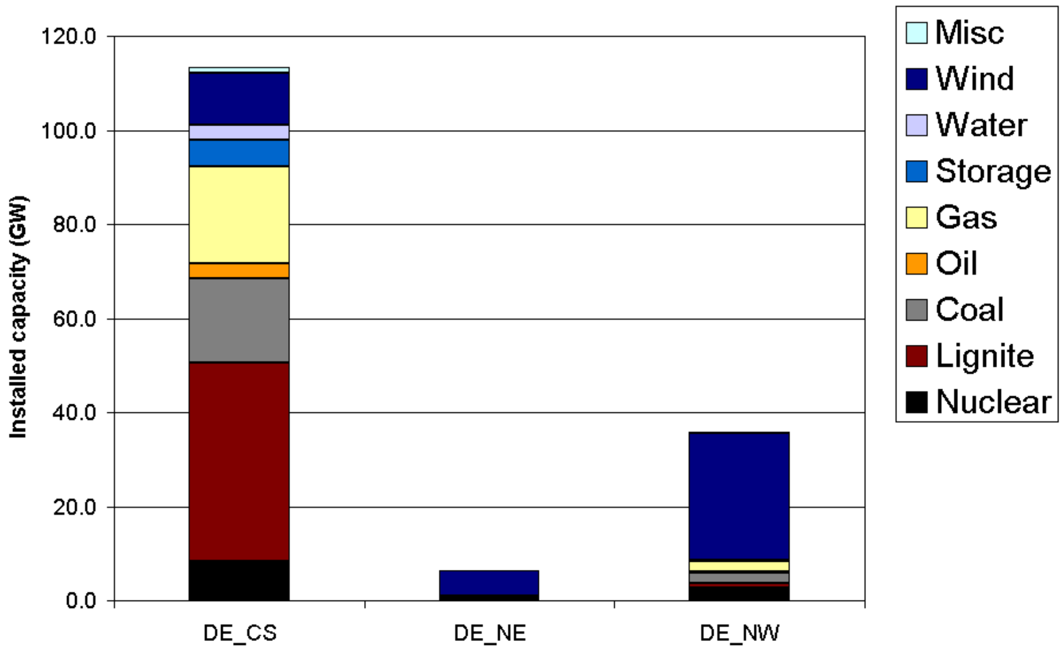

Figure 7: Installed capacities for the case study in GW

Evtl. Stein- und Braunkohle nicht trennen – außerdem Farben in Schwarz-Weiß nicht unterscheidbar

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, etc. as well as forecasts and updated information about day-ahead market and regulating power market prices. Thus, an hourly basis for updating information would be most adequate. However, an increasing scenario number can quickly make stochastic optimisation models become intractable. For representing the impact of the uncertainty of wind power production on the trading activities on the different markets, it is therefore necessary to simplify the information arrival and decision structure in the stochastic model

In the current version a three stage model is implemented. The model steps forward in time using rolling planning with a 6 hour step. For more details about the decision structure of the model see Brand et al., 2004.

Calculations for one year

The WILMAR model is defined on an hourly basis, and for each day 4 loops are required. Thus solving this model for a whole year using standard hardware is impossible. Therefore 5 typical weeks have been determined, applying the scenario reduction algorithm. Each week of the years 2001-2003 has been defined as one scenario including the data of electrical demand, wind production and heat demand. The five typical weeks resulting from scenario reduction applied to the electrical load and the actual wind production and their probability of occurrence are as follows (see also Fig. 8):

i) winter week with low wind (occurrence 18,0.%),
ii) winter week with strong wind (occurrence 7.1%),
iii) spring week with average wind power production (occurrence 21.5%),
iv) summer with average wind power production (occurrence 51.2%),
v) week with 4 working days and 1 holiday day (occurrence 2,6%)

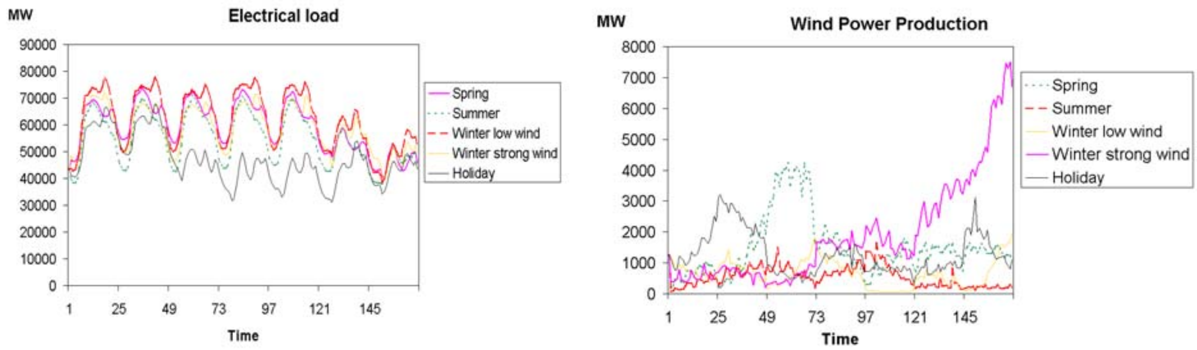

Figure 8: Electrical load and Wind Power production for typical weeks

The day-ahead market prices during a winter week with strong wind are given in Figure 9a for the case of current transmission capacities and in Fig. 9b in the case of tripled transmission capacities between the model regions. In both cases, the prices in the regions DE_CS and DE_NE are very similar but deviate significantly from the prices in DE_NW, where much wind power is produced. As expected, the prices in DE_NW are much lower and become zero for the most time in the case of current transmission capacities.

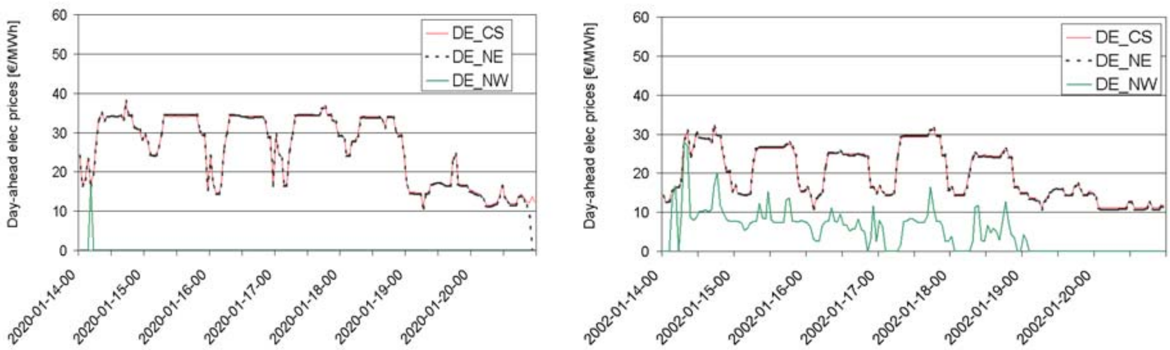

Figure 9: Day-ahead market prices for one week in winter with strong wind, a) current transmission capacities, b) tripled transmission capacities

Obviously, in the case of tripled transmission capacities, much of the wind power produced in DE_NW is transmitted to DE_NE and DE_CS where the demand is higher. Consequently, the prices in DE_NE and DE_CS are lower and the prices in DE_NW are higher than in the case with current transmission capacities. Yet some price-spikes occur in DE_NW, which correspond to start-up of conventional units to meet peak demands. Further analysis of influences of transmission bottlenecks on electricity prices is described in (Barth et al, 2004).

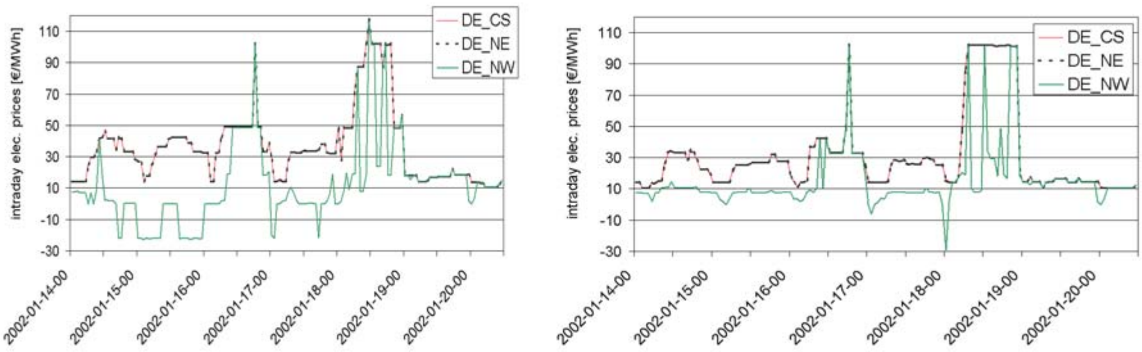

Figure 10: Intraday market prices for one week in winter with strong wind, a) single transmission capacities, b) tripled transmission capacities

In Figs. 10a), b) the intraday market prices are shown for the two cases as above. Different peaks can be seen since the actual wind was lower than expected. Comparing again the cases for different transmission capacities, the prices in DE_CS and DE_NE in the case of tripled transmission capacities are lower during long time periods. Power is transmitted even from DE_CS and/or DE_NE to DE_NW during a day when the actual wind was very much lower than expected, resulting in a decrease of the intraday price in DE_NE.

In Fig. 11 the electricity production aggregated by fuels is shown for the regions DE_CS and DE_NW. in the case of current transmission capacities for one winter week with strong wind. Clearly, the wind production in DE_NW covers practically the whole demand except for some short times during which the wind is less than expected causing other units to be used. In contrast, wind can be practically neglected in DE_CS.

In Fig. 12 the corresponding results are shown in case of tripled transmission capacities. Obviously, the total production in DE_CS is lowered due to transmission of more wind power. The gas units therefore contribute less to the production. In the region DE_NW, still the wind dominates the electricity production, but other units produce also more electricity since more power is exported.

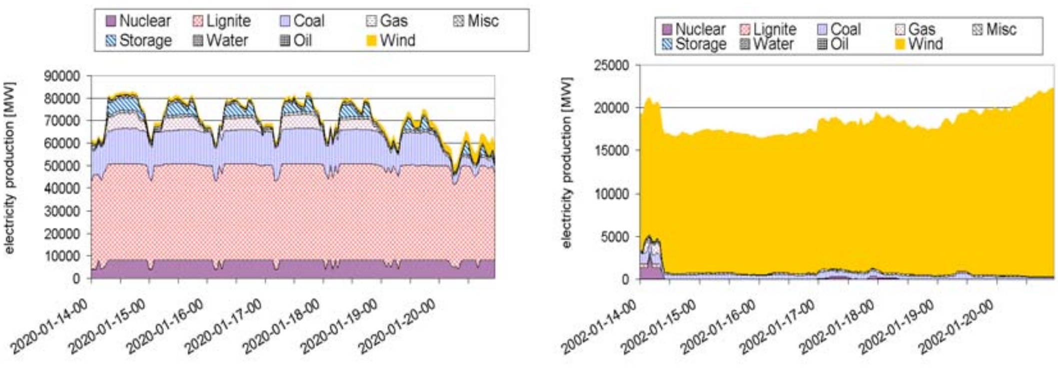

Figure 11: Electricity production aggregated for different fuels for current transmission capacities in the region DE_CS (a)) and DE_NW (b))

For the different typical weeks defined above, Fig. 13 shows a comparison of the system operating cost for the system with current and tripled transmission capacities and without the integration of wind power. By system operating costs we understand fuel costs, start-up and shut down costs and further operation costs. Obviously, the operating costs decrease by integrating wind power whatever type of week is considered. As expected, the decrease is different for the different types of weeks and depends also on the transmission capacities. It can firstly be stated, that the decrease is the lowest within the holiday weeks and in this case almost independent of the precise value of the transmission capacities. The reason is that during such weeks the total demand is significantly lower and is mostly covered by base load plants with cheap operating costs. For all other weeks tripling the transmission capacities leads to a decrease in the system operating costs.

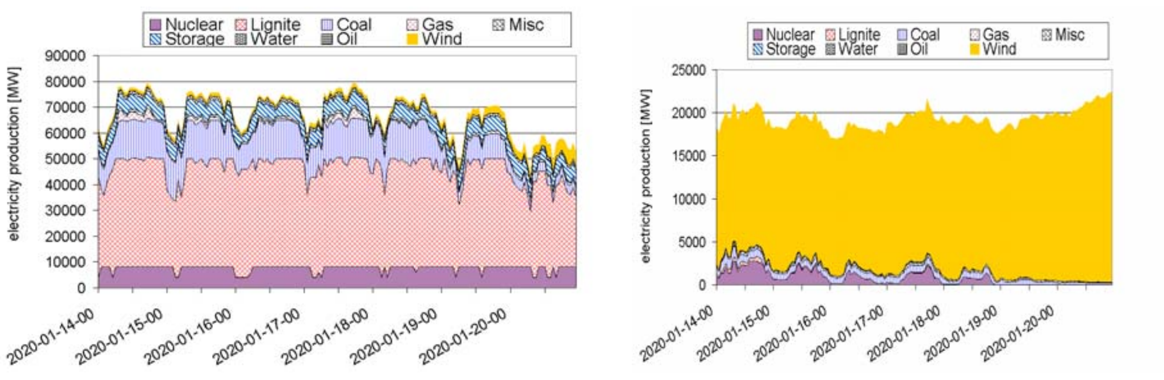

Figure 12: Electricity production aggregated for different fuels for tripled transmission capacities in the region DE_CS (a)) and DE_NW (b))

Comparing the system in the case of current transmission capacity with the system without wind integration, the reduction of the system operating costs for weeks with low and with strong wind is almost equal. It can be concluded that during the weeks with low wind, the wind power is almost completely used. Comparing additionally the system with tripled transmission capacities, the system operating costs during weeks with strong wind is now lower then during weeks with low wind due to the increased amount of transmitted wind power.

The system operations costs for one year are 7.75 bill. EUR for the case study with wind, 7.36 bill. EUR for the system with wind and tripled transmission capacities and 9.18 bill. EUR for the system without wind. So the savings in the case with wind are 1.43 bill. EUR compared to the system without wind and in the case of tripled transmissions the savings through the 42 GW installed wind capacities are 1.81 bill. EUR. Investing in the tripling of the critical transmission capacities provides hence according to these results annual net benefits of about 0.38 bill. EUR – besides improving system stability, an issue which has not been analysed here.

Finally, the savings of the system operating costs for each MWh of wind power produced for the different types of weeks and for the system with current and tripled transmission capacities are given in Fig. 14. As could be concluded from the results from Fig. 11, for holiday weeks the savings of the two systems do not differ too much. In spring weeks, the additional savings per MWh of produced wind only due to tripling the transmission capacities is about 25 %, and for winter weeks with strong wind even up to 70 %. Overall the savings per MWh are rather low, compared to current prices at the German wholesale market. This reflects certainly partly the cost for reserve power and reduced efficiency at part load operation induced by wind power. Moreover prices tend to be low when the wind is blowing, reducing further the market value of the wind energy produced. Yet on the other hand the average cost savings derived here do not take into account that with increased wind power production also changes in the conventional power plant – towards a higher share of flexible middle and peak load units may be advantageous.

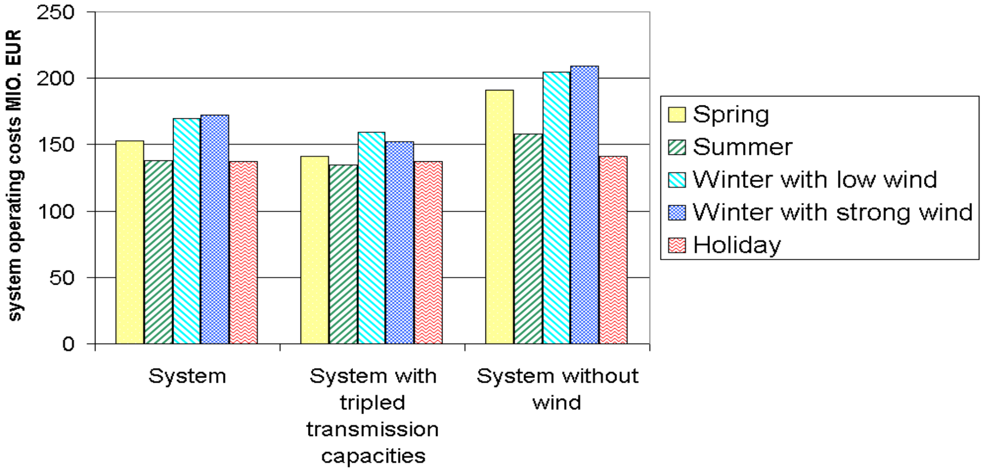

Figure 13: Comparison of operating costs for the typical weeks

Summarizing these results it can be stated that the monetary assessment of the integration of wind power - as could have been estimated – strongly depends on the specific system under consideration. Moreover, the results show that transmission capacities are a key bottleneck and optimizing the system configurations including transmission capacities is an urgent task if the installation of wind turbines is to continue as assumed here.

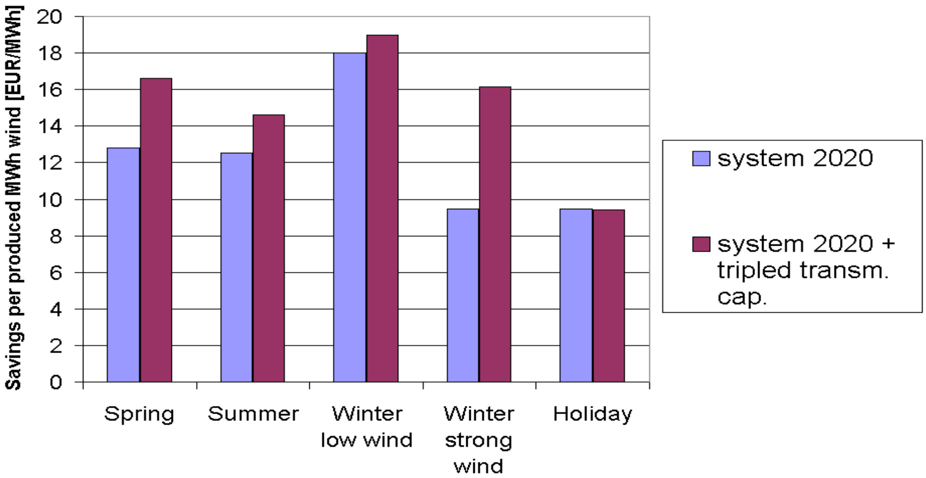

Figure 14: Comparison of savings per produced MWh of wind for different week types

5 Final remarks

In this paper a new approach is presented for a monetary quantification of the integration of wind power into a given system. Since it is crucial to explicitly take into account the stochastic nature of wind power generation, the methodology relies on a stochastic market energy model optimizing the unit commitment while considering technical restrictions as well as the trading activities of the utilities on a day-ahead electricity market, on an intraday-market, on a day-ahead market for reserve power and on a market for district heating and heat power. A detailed evaluation of spot market prices and the costs of integration as well as the impact of wind uncertainty on the system operation could be performed due to the use of special time series models both for the wind speed data and the forecast error of the wind speed.

The new methodology has been applied to the German market (decomposed in three regions) for the year 2020 where the installed capacities were exogenously given. Based on the definition of typical weeks yearly costs could be calculated. The results firstly indicate that the costs of wind power integration clearly depend on the specific system under consideration. Moreover, for Germany the transmission capacities will become important since the wind power is produced mainly in north west, far away from the main consumption area in the middle or southern part. Changing the system by tripling the transmission capacities leads for winter weeks with strong wind to a further increase of savings per MWh produced by wind by more than 70 %. The analysis shows that in such cases wind power substitutes the gas units for electricity production in the middle or southern part in Germany.

So far CO_2 emission reductions and the corresponding certificate values have not been considered - yet their value should not be neglected in considering the costs of integration of renewables in existing energy producing systems. A further interesting aspect, which can be evaluated using the model, is the monetary value of improved wind power forecasts.

Acknowledgements

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