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Integrating Intermittent Renewable Wind Generation - A Stochastic Multi-Market Electricity Model for the European Electricity Market*

Jan Abrell[†] Friedrich Kunz[‡]

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In northern Europe wind energy has become a dominating renewable energy source due to natural conditions and national support schemes. However, the uncertainty about wind generation affects existing network infrastructure and power production planning of generators and cannot not be fully diminished by wind forecasts. In this paper we develop a stochastic electricity market model to analyze the impact of uncertain wind generation on the different electricity markets as well as network congestion management. Stochastic programming techniques are used to incorporate uncertain wind generation. The technical characteristics of transporting electrical energy as well as power plants are explicitly taken into account. The consecutive clearing of the electricity markets is incorporated by a rolling planning procedure reflecting the market regime of European markets. The model is applied to the German electricity system covering an exemplary week. Three different cases of considering uncertain wind generation are analyzed. The results reveal that the flexibility of the generation dispatch is increased either by using more flexible generation technologies or by flexibilizing the generation pattern of rather inflexible technologies.

JEL codes: C61, D41, L94

Keywords: Electricity, Unit Commitment, Stochasticity, Renewable Energy

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1 Introduction

Electric power industries in Europe have experienced a major restructuring process towards a competitive market environment in which generators face the fundamental task to determine the optimal dispatch of their thermal power plants. In contrast to former monopolistic times generators now have to recover their costs solely through prices determined in different electricity markets. Furthermore, the concerns on climate change initiated an ongoing transformation of the electricity system towards less carbon intensive generation technologies. Therefore, several European countries have implemented special support schemes for renewable energy sources to reduce firstly domestic carbon dioxide emissions but also import dependency on fossil fuels in the energy sector. In this context, wind energy among others has become a dominating renewable source due to natural conditions, technological progress, and political support. However, the special characteristics of wind energy limit the ability to response to market signals leading to various challenges with respect to the market integration of renewable wind sources.

Firstly, wind generation is characterized by high capital and low operational costs. Thus, wind generation is dispatched first in the short run merit-order curve due to low marginal generation costs.¹ Secondly, wind generation is characterized by a variable and uncertain generation pattern as it directly depends on meteorological conditions and hence cannot be dispatched in a controlled manner like conventional power plants. This results in an increasing variability and uncertainty about the residual load left to conventional generation technologies. However, uncertainty has always been present in electrical power systems in the form of possible unit outages or errors in load prediction. However, electricity generation from wind has increased significantly during the last years and henceforth the corresponding issues regarding uncertainty as well as variability of this generation source. Thus, wind energy and its special characteristics have to be taken into account when planning and operating electricity systems.

To address the complex interactions in electricity systems, unit commitment and economic dispatch approaches are used to achieve a secure and economic generation scheduling as well as grid management. As most electricity systems are dominated by thermal generation capacities, the aim of the short-term planning is to determine the least-cost generation mix of different power plants required to meet a specified electrical load taking operational limitations of thermal generation, such as minimum ontime, minimum offtime, and ramping constraints, into account. In this context, Baldick (1995) provides a generalized formulation of this unit commitment problem. As the approaches are widely used in economic as well as technical research, the approaches itself and their solution techniques are continuously improved and extended to meet newly raised aspects. A review of various contributions to the unit commitment problem is given in Padhy (2004).

The variability and uncertainty associated with renewable wind generation imposes new challenges to the short-term planning. To capture the characteristics of renewable

¹In some European countries (e.g. Germany) the feed-in of renewable energies is additionally prioritized independently of their marginal generation costs.

wind generation, the unit commitment and economic dispatch problem is extended by introducing stochastic optimization. Stochastic models are characterized by uncertainty of at least one input parameter, whereas in deterministic optimization models all input parameters are assumed to be certain. Fundamentals of stochastic optimization can be found in Birge and Louveaux (1997) and Kall and Wallace (1994). With respect to energy, Wallace and Fleten (2003) provide a survey of different stochastic programming models and their application to the energy sector. Herein, stochastic versions of the unit commitment, generation dispatch, as well as optimal power flow are presented and solution methods are discussed. Additionally, an overview of different applications of stochastic programming with focus on power systems is given in Weber (2005), Kallrath et al. (2009), Möst and Keles (2010), and Conejo et al. (2010).

Recent contributions in this field focus on the large-scale integration of wind generation in power systems as installed wind generation capacities increased substantially. For instance, an amount of 75 GW wind capacity has been installed in Europe between 2000 and 2010 resulting in a share of 10% on the European power capacity mix (EWEA, 2011). This leads to new challenges in short-term operation as well as long-term planning of power systems. In the long-term, the appropriate development of transmission as well as generation infrastructure has to ensure a secure and efficient integration of renewable energy sources. In the short-term operation, the variability and uncertainty inherent in wind generation is a dominating aspect affecting the unit commitment of thermal generation units (e.g. Rosen et al., 2007; Bouffard and Galiana, 2008; Wang et al., 2008; Delarue and D'haeseleer, 2008; Bahmani-Firouzi et al., 2013). However, most studies focus on optimal unit commitment strategies within the dayahead market considering stochastic wind generation and thus abstract from the structure of the underlying market regime which is in the European case characterized by a subsequent clearing of daily dayahead and hourly intraday electricity markets with wind generation uncertainty decreasing with the forecast length.

Subsequently, we briefly describe the typical daily market procedure of the German electricity system which is mostly comparable to other European countries. In general, the market approach relies on a decentralized market structure in which market participants are responsible to plan the commitment of their generation and load facilities. Market participants voluntarily interact either on a bilateral basis or standardized market platforms and are thus not obliged to participate in either of them. In the following, we concentrate our analysis on the standardized markets as they can be interpreted as a benchmark for other trading opportunities. The electricity market can be divided into four sub-markets namely the futures or forward market, dayahead or spot market, the intraday market, and the reserve market. We are particularly interested in the latter three markets and therefore abstract from futures and forward markets. In the case of Germany, the dayahead and the intraday markets are organized by the EPEX in Paris, whereas the reserve market is jointly organized by the four German transmission system operators. Contrasting to other market design, the German as well as other European markets account only for international transmission capacity limitations within the markets while the congestion management on national transmission lines is conducted by the corresponding transmission system operators after the last market clearing.

Following Figure 1, the typical daily market procedure proceeds as follows: The day-ahead market is cleared at 12.00 a.m. following the clearing of the market for tertiary reserve. The dayahead market comprises a daily auction for all 24 hours of the following day. Based on the contractual obligations determined in the dayahead market generators have to inform the responsible transmission system operator of their proposed dispatch timetable at 2.30 p.m. dayahead. Subsequently, the intraday market starts at 3.00 p.m. and is closed 45 minutes before real-time or physical delivery. Market participants can trade electricity continuously either standardized through the market platform provided by EPEX or on a bilateral basis. Generators are afterwards obliged to deliver their final dispatch timetables to the corresponding transmission system operator 45 minutes prior to real time at the latest for each 15 minute interval. Based on these dispatch timetables, the transmission system operators are in charge to perform congestion management in case physical network limitations occur. For this purpose, transmission system operators can generally make use of technical and market-based methods. Active loadflow management can be done technically through adjustments of network topology (e.g. switching actions) and network characteristics (e.g. changes of transformer taps). On the other hand, market-based congestion management methods comprise the adjustment of nodal generation or load (e.g. re-dispatch or counter-trading). Finally, close to or at real-time transmission system operators activate precontracted reserve capacities to compensate for deviations between realized load and generation.

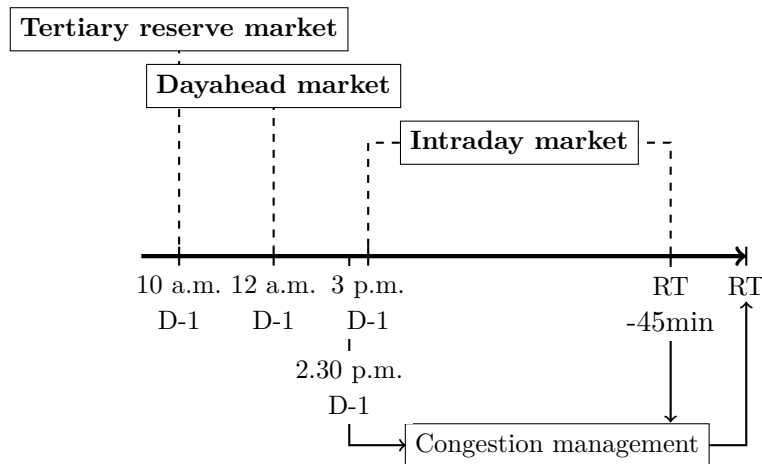


Figure 1: Daily market procedure of the German electricity market

Weber et al. (2009) build on the successive clearing of the dayahead and intraday market and formulate a stochastic programming model to assess the impact of large-scale wind power generation on electricity systems. A rolling planning procedure is implemented to link the different electricity markets. The described model was developed during the Wind Power Integration in Liberalised Electricity Markets (WILMAR) research project². The stochastic behavior of wind generation as well as forecast errors

²<http://www.wilmar.risoe.dk>

on wind generation are explicitly taken into account and the model thus allows to assess the impact of increased wind generation on reserve needs and usage, power plant operation and system cost. Tuohy et al. (2009) present an updated version including a mixed-integer unit commitment model. However, physical characteristics of electricity transmission and hence congestion management are neglected in Weber et al. (2009) and Tuohy et al. (2009) as only transactional transfers between regions are taken into account. In other words, congestion in the physical transmission network which may influence the utilization of thermal as well as renewable capacities is not considered. Leuthold et al. (2012) describe a deterministic techno-economic electricity market model with a detailed representation of the European high voltage network. Physical characteristics of power transmission are represented by a DC-loadflow approach. In various applications, the impact of wind power generation on the power system in particular on the physical transmission network are analyzed (e.g. Leuthold et al., 2009; Weigt et al., 2010). The approach presented in this paper combines the characteristics of the different electricity markets as well as the technical specifics of thermal generation with the characteristics of transmitting electricity. In addition, the intermittency of wind generation is explicitly taken into account by employing stochastic programming techniques.

In this paper we develop the stochastic ELectricty Market MODeL (stELMOD). The model is used to investigate the impact of stochastic wind generation on the unit commitment and dispatch of power plants taking limitations through physical network congestion into account. To do so, a mathematical model is presented which rebuilds the successive clearing process of the dayahead and intraday market given the arrival of improved information on wind generation forecasts. After clearing of the daily dayahead and the subsequent hourly intraday market the final power plant dispatch is determined by the transmission system operator considering congestion in the transmission network. Uncertainty about wind generation is represented by a two-stage multi-period scenario tree and updated for each optimization step within the intraday model. A DC-loadflow approach is used to determine electricity transmission within the interconnected system based on the technical characteristics of the physical transmission network. The model is applied to the German electricity system covering a time frame of 168 hours (one week) in order to investigate the impacts of stochastic wind power availability on the German electricity system.

The remainder of the paper is structured as follows. Based on the German market procedure three distinct models, a dayahead, an intraday market model, and a congestion management, are developed and coupled by a rolling planning procedure to reflect the subsequent clearing of both models. The mathematical model and the coupling procedure are described in Section 2. Section 3 presents the data used including the derivation of wind generation forecasts. In Section 4 indicative results are shown and analyzed given different degrees of uncertainty about wind generation. Section 5 formulates the conclusions.

2 Model

In order to represent daily timing of the German electricity market we use three different models: In the *dayahead model*, the system operator decides about the quantities of electricity and reserve delivered on the next day based on the expected renewable generation supply and the current status of power plants. In the *intraday model*, the operator takes these quantities as given. Based on new information about the renewable supply he has the possibility to correct the pre-contracted electricity quantities by trading in the intraday market. Lastly, flows in the transmission network are determined and arising line overloadings are managed by the transmission system operator in the *congestion management model*. The models are combined in a rolling planning procedure which passes the pre-contracted quantities as well as the plant status between the models. We first describe the three single models in the next subsections. Afterwards we explain the rolling planning approach in detail.

2.1 Dayahead Market Model

In the dayahead model, the system operator decides about the generation and contribution to reserve requirements of thermal power plants $p \in P$, pump storage plants $j \in J$, and renewable sources $w \in W$ in order to minimize the total system operating cost for a specified time horizon T .³ Generation of thermal power plants in period $t \in T$ is denoted by $G_{p,t}$, contribution to reserve market $r \in R$ by $R_{p,r,t}^+$ and $R_{p,r,t}^-$ depending on whether it is upward or downward reserve, and the plant status by $U_{p,t}$ which becomes one if the plant is online and zero else. Thermal power plants are characterized by their marginal generation cost c_p and costs that occur if the plant is started or shut down, c_p^s and c_p^d , respectively. The installed capacity is given by g_p^{max} and the required minimum generation g_p^{min} that has to be committed if the plant is online. Furthermore, power plants have to fulfill technical requirements in the form of minimum offline and online time requirements: After a plant has been started it has to remain online for the next t_p^{on} time periods. Similarly, t_p^{off} denotes the time periods the plant has to be offline if it has been shut down.

Beside thermal power plants, the model includes pump storage facilities. The release or generation of these facilities is denoted by $V_{j,t}$ and pumping or withdrawal from the market by $W_{j,t}$. Both, generation and pumping of the storage facilities are upper bounded by the turbine and pump capacity, v_j^{max} and w_j^{max} , respectively. The pumping process causes losses expressed by $\eta_j \in]0, 1]$. Furthermore, the storage capacity puts a natural bound l_j^{max} on the level of the storage facility $L_{j,t}$. The reserve contribution of storage facilities is denoted by $R_{j,t}^{H+}$ and $R_{j,t}^{H-}$, respectively.

Renewable sources are denoted by $w \in W$. In the dayahead model, there exists a unique forecast $\overline{s_{w,t}}$ for the supply from these sources. The generation of renewable sources $S_{w,t}$ is equal to this forecast reduced by the amount of renewable supply curtailed $C_{w,t}$. The marginal generation costs are assumed to be zero. The curtailment

³A list of the notation used is given in the appendix.

of renewable sources causes a penalty payment c_w^C which can be imposed to reflect the prioritized feed-in of these sources.

The geographical location of load and generation is incorporated by a set of nodes reflecting electrical substations $n \in N$ which belong to a specified country $c \in C$. The relationship of nodes and countries is specified in the set $\Upsilon \subset N \times C$. The exchange of electricity between adjacent countries $T_{c,cc,t}$ is restricted by the net transfer capacity $ntc_{c,cc}$. The locational information of thermal power plants, storage facilities, and renewable sources is expressed using the two-dimensional set $\Psi \subset (P \cup J \cup W) \times N$, meaning that if plant p is located at node n $(p, n) \in \Psi$.

The load at node n in period t is given by $d_{n,t}$. We assume a fixed and thus price-inelastic load which needs to be served by the generation technologies. Additionally, we include the possibility to account for different reserve markets in the model. The reserve markets are denoted by $r \in R$ and are characterized by a country-specific positive and negative reserve load $dr_{c,r,t}^+$ and $dr_{c,r,t}^-$. Depending on the technical pre-qualification requirement of the reserve market, thermal power plants and storage facilities are allowed to contribute to these markets. These pre-qualification requirements are expressed via the two-dimensional set $A \subset (P \cup J) \times R$.

$$\min \sum_{t,p} [c_p G_{p,t} + C S_{p,t} + C D_{p,t}] \quad (1)$$

$$+ \sum_{t,w} c_w^C C_{w,t}$$

$$C S_{p,t} \geq c_p^s (U_{p,t} - U_{p,(t-1)}) \quad \forall p, t \quad (2)$$

$$C D_{p,t} \geq c_p^d (U_{p,(t-1)} - U_{p,t}) \quad \forall p, t \quad (3)$$

$$\sum_n d_{n,t} = \sum_p G_{p,t} + \sum_j (V_{j,t} - W_{j,t}) + \sum_w S_{w,t} \quad \forall t \quad (4)$$

$$\sum_{n \in \Upsilon(c)} d_{n,t} = \sum_{p \in \Psi(\Upsilon(c))} G_{p,t} - T_{c,cc,t} + T_{cc,c,t} + \sum_{j \in \Psi(\Upsilon(c))} (V_{j,t} - W_{j,t}) + \sum_{w \in \Psi(\Upsilon(c))} S_{w,t} \quad \forall c, t \quad (5)$$

$$dr_{c,r,t}^+ = \sum_{p \in (A(r) \cap \Psi(\Upsilon(c)))} R_{p,r,t}^+ + \sum_{j \in (A(r) \cap \Psi(\Upsilon(c)))} R_{j,r,t}^{H+} \quad \forall c, r, t \quad (6)$$

$$dr_{c,r,t}^- = \sum_{p \in (A(r) \cap \Psi(\Upsilon(c)))} R_{p,r,t}^- + \sum_{j \in (A(r) \cap \Psi(\Upsilon(c)))} R_{j,r,t}^{H-} \quad \forall c, r, t \quad (7)$$

$$U_{p,t} g_p^{max} \geq G_{p,t} + \sum_r R_{p,r,t}^+ \quad \forall p, t \quad (8)$$

$$G_{p,t} - \sum_r R_{p,r,t}^- \geq U_{p,t} g_p^{min} \quad \forall p, t \quad (9)$$

$$U_{p,\tilde{t}} \geq U_{p,t} - U_{p,(t-1)} \quad \forall p, t, \tilde{t} \in O_{p,t}^{on} \quad (10)$$

$$1 - U_{p,\tilde{t}} \geq U_{p,(t-1)} - U_{p,t} \quad \forall p, t, \tilde{t} \in O_{p,t}^{off} \quad (11)$$

$$L_{j,t} = L_{j,(t-1)} + \eta_j W_{j,t} - V_{j,t} \quad \forall j, t \quad (12)$$

$$w_j^{max} \geq W_{j,t} + \sum_r R_{j,r,t}^{H-} \quad \forall j, t \quad (13)$$

$$v_j^{max} \geq V_{j,t} + \sum_r R_{j,r,t}^{H+} \quad \forall j, t \quad (14)$$

$$l_j^{max} \geq L_{j,t} + \sum_r R_{j,r,t}^{H-} \quad \forall j, t \quad (15)$$

$$S_{w,t} = \overline{s_{w,t}} - C_{w,t} \quad \forall w, t \quad (16)$$

$$ntc_{c,cc} \geq T_{c,cc,t} \quad \forall c, cc, t \quad (17)$$

$$G_{p,t}, V_{j,t}, W_{j,t}, L_{j,t}, C_{w,t}, T_{c,cc,t}, CS_{p,t}, CD_{p,t}, R_{p,r,t}^+, R_{p,r,t}^-, R_{j,r,t}^{H+}, R_{j,r,t}^{H-} \geq 0 \\ U_{p,t} \in \{0, 1\}$$

The objective function (1) of the dayahead model minimizes the sum of the marginal, startup $CS_{p,t}$, and shutdown $CD_{p,t}$ costs as well as the renewable curtailment penalty payment. The startup and shutdown cost are defined in Equations (2) and (3) in terms of a change of the plant status variable. The market clearing Equation (4) equates the total load and supply in the market. In contrast, the country based market clearing Equation (5) equates load and supply at nodes located in country c . This equation is necessary to define the transfer variable $T_{c,cc,t}$. Equations (6) and (7) ensure the provision of the reserve requirements. Equations (8) and (9) implement the minimum and maximum generation constraints. Equations (10) and (11) are the minimum online and offline time requirements. For the ease of notation we introduced the sets $O_{p,t}^{on} := \{t + 1, \dots, \min[t + t_p^{on}, T]\}$ and $O_{p,t}^{off} := \{t + 1, \dots, \min[t + t_p^{off}, T]\}$ which define the periods in which the plant has to be online and offline. Equation (12) is the law of motion for the reservoir level of storage facilities. The restrictions on the pumping and release processes as well as the reservoir levels are given in Equations (13) to (15). The supply of renewable energy sources $S_{w,t}$ is defined in Equation (16) in terms of the exogenously given supply and the curtailed amount. Equation (17) restricts the commercial transfers between adjacent countries to stay within the transfer limit $ntc_{c,cc}$.

2.2 Intraday Market Model

The intraday model is similar to the dayahead model in terms of technical restrictions for thermal plants and storage facilities. However, in this model the pre-contracted generation quantities and reserve contributions are given from the dayahead model. In order to express the pre-determined character of the given variables we denote them with upper bars, i.e.: $\overline{G_{p,t}}$, $\overline{V_{j,t}}$, $\overline{W_{j,t}}$, and $\overline{C_{w,t}}$ are the fixed generation, pumping, release

and curtailment variables determined in the dayahead market. The reserve quantities are denoted in the same manner, i.e. $\overline{R_{p,r,t}^+}$, $\overline{R_{p,r,t}^-}$, $\overline{R_{j,r,t}^{H+}}$, and $\overline{R_{j,r,t}^{H-}}$ are the reserve contribution contracted in the dayahead market and fixed in subsequent intraday markets. In the intraday market, the system operator has the possibility to correct these quantities by additional trading actions. Due to the corrective character of these variables, they are free in sign, i.e. the operator can in- as well as decrease the amount sold in the dayahead market. We maintain the notation, but denote the intraday variable by a tilde sign. Given these notations, the total generation in the intraday market is defined as the sum of the pre-determined dayahead quantity and the corrective intraday action.

As the second major difference between the dayahead and intraday market model, we explicitly introduce the stochasticity of the renewable sources supply by introducing a scenario tree. This tree represents the underlying stochastic process by a set of nodes $k \in K$ which belong to a certain period. We denote the subset of nodes that belong to period t by $\Omega_t \subset K$. The probability of reaching node k is given by π_k . Except the root node, each node has a unique predecessor node which is denoted by $\gamma(k)$. Furthermore, the set of all nodes in the route from the root node to node k , the path from the root to k , is denoted by the ordered set $\Gamma(k) \subset K$. With this notation at hand, the intraday model becomes:⁴

$$\begin{aligned} \min \sum_{k,t,p} \pi_k [c_p G_{p,k,t} + CS_{p,k,t} + CD_{p,k,t}] \\ + \sum_{k,t,w} \pi_k c_w^C C_{w,k,t} \end{aligned} \quad (18)$$

$$G_{p,k,t} = \overline{G_{p,t}} + \tilde{G}_{p,k,t} \quad \forall p, t, k \in \Omega_t \quad (19)$$

$$V_{j,k,t} = \overline{V_{j,t}} + \tilde{V}_{j,k,t} \quad \forall j, t, k \in \Omega_t \quad (20)$$

$$W_{j,k,t} = \overline{W_{j,t}} + \tilde{W}_{j,k,t} \quad \forall j, t, k \in \Omega_t \quad (21)$$

$$C_{w,k,t} = \overline{C_{w,t}} + \tilde{C}_{w,k,t} \quad \forall w, t, k \in \Omega_t \quad (22)$$

$$CS_{p,k,t} \geq c_p^s (U_{p,k,t} - U_{p,\gamma(k),(t-1)}) \quad \forall p, t, k \in \Omega_t \quad (23)$$

$$CD_{p,k,t} \geq c_p^d (U_{p,\gamma(k),(t-1)} - U_{p,k,t}) \quad \forall p, t, k \in \Omega_t \quad (24)$$

$$\begin{aligned} \sum_n d_{n,k,t} = \sum_p G_{p,k,t} + \sum_w S_{w,k,t} \\ + \sum_j (V_{j,k,t} - W_{j,k,t}) \quad \forall t, k \in \Omega_t \end{aligned} \quad (25)$$

$$\sum_{n \in \Upsilon(c)} d_{n,k,t} = \sum_{p \in \Psi(\Upsilon(c))} G_{p,k,t} + \sum_{w \in \Psi(\Upsilon(c))} S_{w,k,t}$$

⁴In general we continue the notation given above. However, due to stochastic programming approach, the variables are additionally indexed by the set of nodes in the scenario tree.

$$\begin{aligned}
& - \sum_{cc} T_{c,cc,k,t} + \sum_{cc} T_{cc,c,k,t} \\
& + \sum_{j \in \Psi(\Upsilon(c))} (V_{j,k,t} - W_{j,k,t}) \quad \forall c, t, k \in \Omega_t \quad (26)
\end{aligned}$$

$$U_{p,k,t} g_p^{max} \geq G_{p,k,t} + \sum_r \overline{R_{p,r,t}^+} \quad \forall p, t, k \in \Omega_t \quad (27)$$

$$G_{p,k,t} - \sum_r \overline{R_{p,r,t}^-} \geq U_{p,k,t} g_p^{min} \quad \forall p, t, k \in \Omega_t \quad (28)$$

$$U_{p,\tilde{k},\tilde{t}} \geq U_{p,k,t} - U_{p,\gamma(k),(t-1)} \quad \forall p, t, \tilde{t} \in O_{p,t}^{on} \quad (29)$$

$$1 - U_{p,\tilde{k},\tilde{t}} \geq U_{p,\gamma(k),(t-1)} - U_{p,k,t} \quad \forall p, t, \tilde{t} \in O_{p,t}^{off} \quad (30)$$

$$L_{j,k,t} = L_{j,\gamma(k),(t-1)} + \eta_j W_{j,k,t} - V_{j,k,t} \quad \forall j, t, k \in \Omega_t \quad (31)$$

$$w_j^{max} \geq W_{j,k,t} + \sum_r \overline{R_{j,r,t}^{H-}} \quad \forall j, t, k \in \Omega_t \quad (32)$$

$$v_j^{max} \geq V_{j,k,t} + \sum_r \overline{R_{j,r,t}^{H+}} \quad \forall j, t, k \in \Omega_t \quad (33)$$

$$l_j^{max} \geq L_{j,k,t} + \sum_r \overline{R_{j,r,t}^{H-}} \quad \forall j, t, k \in \Omega_t \quad (34)$$

$$S_{w,k,t} = \overline{s_{w,k,t}} - C_{w,k,t} \quad \forall w, t, k \in \Omega_t \quad (35)$$

$$ntc_{c,cc} \geq T_{c,cc,k,t} \quad \forall c, cc, t, k \in \Omega_t \quad (36)$$

$$\begin{aligned}
G_{p,k,t}, V_{j,k,t}, W_{j,k,t}, L_{j,k,t}, C_{w,k,t}, T_{c,cc,k,t}, CS_{p,k,t}, CD_{p,k,t} & \geq 0 \\
\tilde{G}_{p,k,t}, \tilde{V}_{j,k,t}, \tilde{W}_{j,k,t}, \tilde{C}_{w,k,t} & \text{ free} \\
U_{p,k,t} & \in \{0, 1\}
\end{aligned} \quad (37)$$

Equations (19) to (22) define the total quantities as the sum of the pre-determined dayahead quantities and the intraday corrective trading actions. Hereby, $\tilde{G}_{p,k,t}$ is the intraday electricity trading amount which is free in sign and $G_{p,k,t}$ is the total generation of plant p at the node k in the scenario tree in period t . The notation generally follows this reasoning. The remaining Equations (23) to (36) are similar to the corresponding ones in the dayahead model as explained above. Due to the use of the different sets for the expression of the scenario tree we do not need to impose further non-anticipativity constraints. In equations directly related to the previous period we make use of the direct predecessor $\gamma(k)$. Furthermore, in the online and offline time requirements, Equation (29) and (30), we use the set of all predecessors in the path to the root node. The periods before the actual period t are denoted by \tilde{t} and the predecessor nodes by \tilde{k} .

2.3 Congestion Management Model

The congestion management model deals with the management of the physical network constraints and minimizes the costs of generation adjustments in case of overloaded transmission elements. The model bases on the results of the previously described day-ahead and intraday model which are considered as fixed input parameter to the congestion management model. In particular, the congestion management model takes the contracted quantities and the current plant status from the previously solved intraday model. Furthermore, the transmission system operator (TSO) knows the online and offline time restrictions and hence ensures that these are not violated. In this stage of the market procedure we assume that no uncertainty about wind generation left and the TSO faces a deterministic problem. Consequently, the TSO readjusts generation by redispatching operating thermal plants or starting new power plants such that stability of the transmission network is guaranteed. Moreover, the TSO can apply curtailment of renewable sources if necessary. However, the TSO is not allowed to use storage facilities or to completely shut down thermal power plants. Redispatching variables are labeled by hats and pre-contracted day-ahead and intraday quantities are denoted by upper bars, respectively. In general, we follow the notation of the previous model descriptions. However, as the TSO ensures stability for a specific hour we drop the time index.

In contrast to the day-ahead and intraday model which consider only international commercial transfers between adjacent countries, the congestion management model incorporates the physical characteristics of transmission flows and technical limitations. An linearized AC-loadflow approach (or DC-loadflow) is utilized to determine physical flows on transmission lines in an existing network (Leuthold et al., 2012). The electricity network is represented by a set of nodes $n \in N$ and lines $l \in L \subset N \times N$ connecting these nodes. Lines are characterized by their thermal capacity cap_l . The power transmission distribution factors $ptdf_{l,n}$ determine the flow on line l caused by net injection $Y_{n,t}$ at node n . As already introduced in the day-ahead market model, locational information of plants, storage facilities, and renewable sources is expressed using the two-dimensional set $\Psi \subset (P \cup J \cup W) \times N$.

$$\min \sum_p c_p \hat{G}_p + \hat{C} S_p + \sum_w c_w^C \hat{C}_w \quad (38)$$

$$G_p = \overline{G_p} + \widetilde{G_p} + \hat{G}_p \quad \forall p \quad (39)$$

$$C_w = \overline{C_w} + \widetilde{C_w} + \hat{C}_w \quad \forall w \quad (40)$$

$$\hat{C} S_p \geq c_p^s \left(U_p - \widetilde{U_p} \right) \quad \forall p \quad (41)$$

$$\begin{aligned} \sum_n d_n = & \sum_p G_p + \sum_w S_w \\ & + \sum_j \left(\overline{V_j} + \widetilde{V_j} - \overline{W_j} - \widetilde{V_j} \right) \end{aligned} \quad (42)$$

$$d_n + Y_n = \sum_{p \in \Psi(n)} G_p + \sum_{w \in \Psi(n)} S_w + \sum_{j \in \Psi(n)} (\bar{V}_j + \tilde{V}_j - \bar{W}_j - \tilde{V}_j) \quad \forall n \quad (43)$$

$$U_p g_p^{max} \geq G_p + \sum_r \bar{R}_p^+ \quad \forall p \quad (44)$$

$$G_p - \sum_r \bar{R}_p^- \geq U_p g_p^{min} \quad \forall p \quad (45)$$

$$S_w = \bar{s}_w - C_w \quad \forall w \quad (46)$$

$$cap_l \geq \sum_n ptdf_{l,n} Y_n \quad \forall l \quad (47)$$

$$\sum_n ptdf_{l,n} Y_n \geq -cap_l \quad \forall l \quad (48)$$

$$\begin{aligned} G_p, C_w, CS_p &\geq 0 \\ \hat{G}_p, \hat{C}_w &\text{ free} \\ U_p &\in \{0, 1\} \end{aligned}$$

The objective function (38) formally describes the costs that are associated with the redispatch of power plants and which would accrue to the transmission system operator. Thus, given the dayahead and intraday results the model calculates physical line flows and determines cost minimizing redispatch actions if the network is congested. The redispatch costs comprise two parts (Kunz, 2012): power plants which increase their generation ($\hat{G}_p > 0$) get paid their marginal generation costs c_p ; power plants which are asked to decrease their generation level below the contracted market quantities ($\hat{G}_p < 0$) pay their avoided marginal generation costs to the transmission system operator. If the redispatch of thermal generation units is insufficient to ease congestion, the curtailment of wind generation and finally the shedding of load are additional options which are considered in the model. The minimization of the congestion management costs is subject to the constraints (39)-(46) which are comparable to the previous dayahead and intraday market restrictions. Additionally, Equations (47) and (48) limit the physical flows on transmission links to the thermal limit cap_l .

2.4 Rolling Planning Procedure

As described in Section 1 and depicted in Figure 1 the German electricity market is characterized by a sequential clearing of different markets. In the reserve and dayahead markets the commitments regarding reserve contribution and generation quantities are determined for all 24 hours of the next day. After the clearing of the dayahead market, intraday trading is possible for each individual hour of the next day starting at 3.00 p.m. the day before and ending 45 minutes before realtime. During this time frame market participants can trade continuously for a specific hour as for instance new information on

uncertain parameters (e.g. load, renewable generation, unplanned outages of generation units) become available.

The described models are designed to reflect these characteristics, in particular the sequential clearing of markets and the improvement of forecasts on uncertain parameters over time. First, the dayahead market model optimizes the generation and reserve commitments for all hours of the next day given the current information on uncertain parameters. The time horizon of the model covers 36 hours comprising 24 hours of the next day and additional 12 hours to account for terminal conditions. Second, the intraday model reoptimizes the dayahead commitments as the information on uncertain parameters improve. The optimized time frame of the intraday model covers 36 hours. However, the intraday model specification abstracts from the market procedure in two ways: First, the intraday model for a specific hour t is optimized subject to the final realization of uncertain parameters. Thus, the time gap of 45 minutes between the final clearing of the intraday and realtime is neglected. Second, the intraday model abstracts from the continuous trading as the final adjustments of the dayahead commitments for hour t are determined in the intraday optimization of the specific hour t given the improved information on uncertain parameters compared to the dayahead clearing. Furthermore, the future development of uncertain parameters beyond hour t is taken into account by employing a stochastic programming approach. Thus, the continuous trading is substituted by a centralized intraday clearing. Finally, the congestion management model is optimized after the final clearing of the intraday for the hour t , i.e. a single hour is solved.

The sequential clearing of the dayahead and intraday market is achieved by applying a rolling planning procedure. The procedure is initialized by running the dayahead model determining the contracted quantities and reserve contribution for the first 24 hours. Given these values, we run the intraday model for hour one resulting in the realized generation, storage facility actions, and plant status for hour one. Subsequently, the congestion management model is solved using the previously determined dayahead and intraday generation quantities as starting point. If transmission lines are congested, power plants are redispatched. Moving one hour forward, the intraday and congestion management model are solved again. In this second run we use the plant status as well as the level of the storage facilities of the first run as initial values. Furthermore, status variables are fixed if a startup or shutdown occurred within the previous periods depending on the minimum offline and online times. Having solved the model for hour two, we have the necessary information to solve the intraday and subsequently the congestion management model for hour three. This procedure rolls until hour 12. At hour 12, we first solve the intraday and the congestion management model. From this we obtain the expected value for the plant status, generation, and storage values for the next day hour one. Given these expected values as initial conditions, we solve the dayahead model to determine the pre-contracted generation quantities and the reserve contribution for day two hour one to 24. This procedure is repeated until the end of the considered time horizon is reached.

3 Data

In order to apply the described model, a realistic electricity system is chosen comprising Germany as well as its neighboring countries. The underlying data concerning conventional and renewable generation, electrical load, and the transmission network are described in this section. In addition, the applied wind forecast approach is presented. Wind generation is considered as solely source of uncertainty, thus uncertainty resulting from other renewable generation (e.g. solar), electrical load, and unplanned outages of generation units are neglected. The time horizon used for the application covers the time frame from 9th November till 15th November 2010. The week has been chosen due to the a high amount of wind generation and unexpected deviations between expected and final wind generation.

3.1 Conventional Generation

Generation and storage facilities are divided into 12 different technology types reflecting different generation technologies as well as fuel types: run-of-river hydro, nuclear, lignite, coal, gas and oil steam, combined cycle gas (CCGT) and oil turbines plants (CCOT), open cycle gas (OCGT) and oil turbines plants (OCOT), hydro reservoirs and pump storage plants. Installed generation capacities are based on VGE (2008) and include power plants with a capacity above 100 MW. For Germany, we incorporate generation at plant level whereas for neighboring countries we consider generation on an aggregated technology level. The technical characteristics of each technology are given in Table 1. These include the heat efficiency, the minimum generation as percentage of the installed capacity, the emission factors, and the minimum online and offline time restrictions.

	Average Efficiency [%]	Minimum Generation [%]	Emission Factor [t/MWh _{el}]	Ontime [h]	Offtime [h]
Nuclear	30	45	0	12	8
Lignite	37	40	0.98	8	8
Hard Coal	42	38	0.85	8	8
CCGT	54	33	0.37	4	2
OCGT	34	20	0.59	1	0
Gas Steam	39	38	0.52	4	2
CCOT	50	33	0.56	4	2
OCOT	34	20	0.82	1	0
Oil Steam	39	38	0.71	4	2

Table 1: Technical characteristics of thermal generation types. Source: Bagemihl (2003), IPCC (2006), Hundt et al. (2009), and own assumptions

Market prices of fuels and CO₂ certificates for the considered time horizon are used to determine the specific marginal generation costs. The marginal cost are derived from the fuel cost which are given in Table 2 and the carbon cost based on a CO₂ price of

14.89 €/t, both accounted with the power plant specific heat efficiency depending on the commissioning year (Schröter, 2004). Beside the marginal costs, fixed startup cost incurring for each startup of generation unit are considered for each technology type based on DEWI et al. (2005). Shutdown cost are assumed to be zero.

	Fuel Cost [€/MWh]	Marginal Cost [€/MWh]	Startup Cost [€/startup and MW]
Nuclear	3	9.71	60
Lignite	4.39	26.50	87
Hard Coal	11	39.02	73
CCGT	19.63	41.77	79
OCGT	19.63	66.58	32
Gas Steam	19.63	58.04	127
CCOT	37.72	83.74	142
OCOT	37.72	123.14	51
Oil Steam	37.72	107.35	239

Table 2: Economic characteristics of thermal generation types. Source: DEWI et al. (2005) and own assumptions

3.2 Wind Generation

The model uses three different inputs for wind generation: First, the hourly realization of wind generation; second, the daily dayahead forecast of the hourly wind output which enters the dayahead model; finally, a set of wind generation scenarios is considered in the intraday model using a scenario tree. The realized wind power generation as well as dayahead wind power forecast is taken from the EEX Transparency Platform⁵ and depicted in Figure 2. The figure reveals that the forecast has a high quality, i.e. low forecast error, for hours zero up to 120. However, afterwards predicted and realized wind generation show a high deviation.

Uncertainty about wind power generation, considered in the intraday model, is represented by different wind speed scenarios reflecting the increasing wind speed forecast error for future time periods. The simulation approach for wind forecast errors is based on Barth et al. (2006) using an auto regressive moving average (ARMA) approach. The ARMA-series is characterized as follows:

$$W_{ft}^{err} = \alpha W_{ft-1}^{err} + Z_{ft} + \beta Z_{ft-1} \quad (49)$$

where W_{ft}^{err} is the wind speed forecast error for forecast time period ft and Z_{ft} is a random Gaussian variable with a standard deviation of σ . The parameters of the ARMA-series α and β are assumed to be 0.95 and 0.02, respectively (Barth et al., 2006). The standard deviation σ is set to 0.5. For $ft = 0$ the forecast error $W_{ft=0}^{err}$ and the random variable $Z_{ft=0}$ are zero as we already know the final realization. If we

⁵<http://www.transparency.eex.com/en>

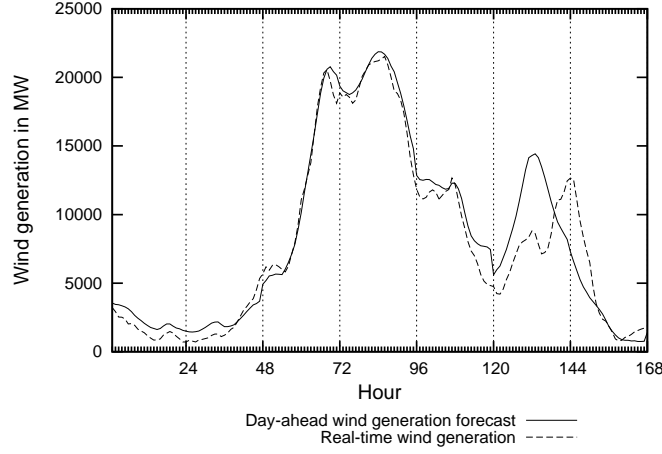


Figure 2: Expected and realized wind generation in Germany from 9th November till 15th November 2010. Source: EEX Transparency Platform

look into the future ($ft > 0$) forecast error depends firstly on the forecast error in the previous period and secondly on a stochastic component. An exemplary set of simulated forecast errors is displayed in Figure 3. As can be seen, the forecast error increases with forecasting length.

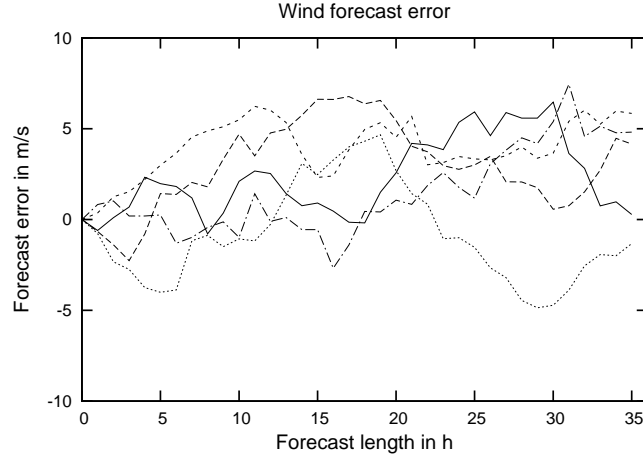


Figure 3: Exemplary set of simulated wind speed forecast errors

Once wind speed errors are simulated, they are added to the realized wind speeds and converted to wind power utilization using mean wind power curves of different wind turbines. In order to incorporate the large amount of simulated wind power series in the stochastic modeling approach a one-stage scenario tree is implemented comprising a reduced number of three representative scenarios or branches. In the literature different algorithms are described to achieve a representative scenario reduction (e.g.

Dupačová et al., 2003; Heitsch and Römisch, 2003). We use the scenario reduction software SCENRED2⁶ to obtain a representative set of scenarios.

In order to derive node-specific wind power supply regional data on wind power installations is taken from 50Hertz Transmission et al. (2011). Node-specific wind power capacities are multiplied with a time-dependent utilization factor to retrieve the wind generation. Hence, we implicitly assume an full correlation of regional wind infeeds.

3.3 Load

Electrical load is assumed as a parameter and elasticity of consumption as well as uncertainty is not considered. Total electrical load and the hourly load profile of the considered countries is based on values derived from ENTSO-E (2011a) for 9th November till 15th November 2010. In order to distribute national load to specific nodes in the transmission network, regional characteristics on gross domestic product (GDP) and population are taken into account. The regional GDP serves as a distribution key for electrical load of industry and services, and regional population for households, respectively. The regional GDP and population are taken from Eurostat (2011) on a NUTS 3 level⁷ corresponding to districts in Germany. The derivation of node-specific load is based on Leuthold et al. (2012).

3.4 Transmission Network

The underlying transmission network of Germany is based on the European high voltage transmission grid (ENTSO-E, 2011b) comprising transmission lines and substations at the 220 kV and 380 kV voltage level. The network topology of the high voltage transmission grid is depicted in Figure 4. Neighbouring countries of Germany (Denmark (West), Poland, Czech Republic, Austria, Switzerland, France, Belgium, and the Netherlands) are additionally considered to account for import from and export to neighbouring countries. In order to reduce computational effort associated with a detailed representation of the transmission network, a zonal transmission model of the German high voltage transmission system is applied. Based on 50Hertz Transmission et al. (2010), existing substations in Germany are assigned to 18 zones and only interzonal transmission lines are considered during the optimization. The zonal aggregation of physical transmission system results in 26 nodes consisting of 18 zones within Germany and 8 neighboring countries, and 159 transmission lines crossing zonal boundaries.

The determination of technical characteristics for the zonal transmission network is based on the detailed physical transmission network and afterwards aggregated to zonal characteristics. Technical characteristics of transmission lines are based on Kießling et al. (2001). For representative voltages of 380 kV and 220 kV specific values for series

⁶<http://www.gams.de/dd/docs/solvers/scenred2.pdf>

⁷NUTS (Nomenclature of Territorial Units for Statistics) is a hierarchical system for geographic division of the European territory. http://epp.eurostat.ec.europa.eu/portal/page/portal/nuts_nomenclature/introduction

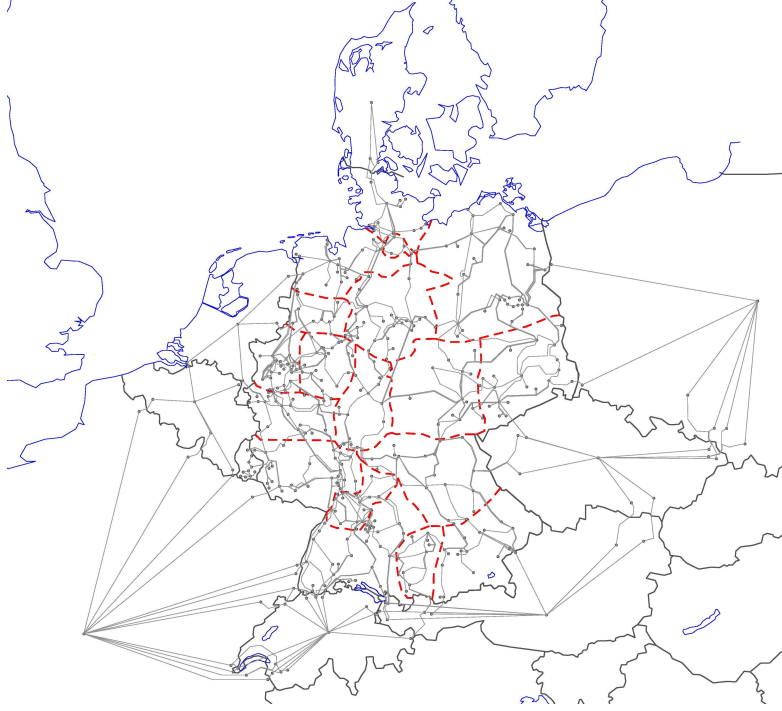


Figure 4: Topology of the high voltage transmission grid and zone definition

reactance and resistance are derived and multiplied with the line length to derive line-specific characteristics (reactance x_l , resistance r_l).

3.5 Cases

In the exemplary application of the model, we consider different kinds of incorporating stochastic wind generation. We compare three cases reflecting different degrees of wind uncertainty considered in the dayahead and intraday markets subject to transmission restrictions of the physical network considered in the congestion management model. The three considered cases of wind uncertainty are as follows.

In the *deterministic* case, wind generation is set to the realized values in both the dayahead and intraday market and thus uncertainty about wind generation is not considered.

In the second case, the impact of a *changing forecast* of wind generation is regarded. Changing forecast means, that in each market clearing, both dayahead and intraday, a single wind generation forecast is considered representing the current status of information on wind generation. Within the intraday market, we use the arithmetic mean of the reduced wind scenario set as single forecast. As the information about wind generation improves with decreasing forecast lengths, the forecast error for a specific hour decreases during the rolling planning procedure. In the final intraday clearing for a specific hour, the wind generation equals the final wind realization.

The third case takes into account the *stochastic* aspects of wind generation. In the intraday market, a scenario tree is introduced and the power plant dispatch is optimized with respect to different possible wind scenarios of the scenario tree. Again, a single wind generation forecast is considered in the dayahead market based on published data and thus stochasticity of wind generation is incorporated solely in the intraday market. We consider a reduced set of three wind generation scenarios accounted by their probability of occurrence.

It is important to note that the three different approaches are distinguished by the treatment of the uncertainty of wind supply. For instance wind supply is known with certainty in the *deterministic* case in both markets, the dayahead and intraday market, respectively. Whereas, in the *changing forecast* case, the system operator has given a unique value of renewable supply in the dayahead market, the dayahead wind generation forecast. In the intraday market this value changes over time as the quality of the forecast is improved with decreasing forecast lengths. In the *stochastic* approach the same unique value is given in the dayahead market. However, in the intraday market, the system operator has given a set of possible wind realizations represented by a scenario tree.

While the approaches differ in the treatment of wind uncertainty, they have an important feature in common: Due to the rolling planning approach each of the employed approaches receives new information on the wind generation and load in each iteration as the time horizon is extended by one hour. As the rolling planning approach moves hourly wise forward, in each iteration a new value for the final model hour for load and wind is given. Consequently, the intraday market serves two functions: First, it enables the system operator to reoptimize the generation portfolio based the additional information about load and wind supply which was not available in the dayahead market. Second, in the cases that incorporate forecast errors on wind generation, the intraday market balances the deviation from the dayahead forecast.

4 Results

The model is optimized for a total time frame of nine days where the first and the last day are introduced to account for initial and terminal model conditions. In particular the first day is characterized by high system operating costs as the entire system has to be initialized and therefore we leave out the first and the last day in the following analysis due to their specifics. In turn, the reported time horizon covers one week of seven days from Tuesday to Monday. The costs analyzed in this section reflect the operating cost of the generation dispatch determined in the final clearing of the congestion management model for each hour of the time horizon.

The aggregated cost as well as the different cost components for the time frame of seven days are given in Table 3. For the *deterministic* case the total system cost amount to 628.98 Mill. €. The main part of the system cost are the fuel cost, 467.53 Mill. €, followed by the carbon cost, 157.74 Mill. €. With 3.71 Mill. €, the startup cost account only for around 0.5% of the total system cost. For the *changing forecast* case the total cost become 630.81 Mill. € consisting of 469.28 Mill. € fuel, 157.79 Mill. € carbon, and

3.74 Mill. € startup cost. Finally, the *stochastic* approach shows 470.25 Mill. € fuel, 157.19 Mill. € carbon, and 3.34 Mill. € startup cost, which sums up to the total system cost of 630.79 Mill. €.

Comparing the cases which incorporate uncertainty about the supply of wind with the *deterministic* case shows higher total system cost. In particular, the sum of marginal cost, defined as the sum of fuel and carbon cost, in the uncertainty cases always exceeds the total marginal cost of the *deterministic* case. The marginal costs are the highest in the *stochastic* case. However, this significant increase is counterbalanced by a decrease of startup cost. Overall, the *deterministic* case shows the lowest cost followed by the *stochastic*, and finally the *changing forecast* approach. However, the differences of the system operating cost between the cases are rather low up to 1.80 Mill. € (0.3% of system operating costs). Among the total system operating costs, costs of managing network congestion sum up to 2.71 Mill. € in the *stochastic*, 1.96 Mill. € on the *changing forecast*, and 1.27 Mill. € in the *deterministic* case.

The ranking of the individual cost component level and their characteristics provide important insights on the impacts of uncertainty. Concerning the fuel cost, the *stochastic* approach shows the highest cost followed by the *changing forecast* and the *deterministic* case. The *stochastic* approach shows the highest fuel but the lowest carbon cost. The carbon cost of *changing forecast* case are lower than for the *deterministic* approach. Finally, the start-up costs are highest in the *changing forecast* case and lowest in the *stochastic case*. Regarding the congestion costs, these are the highest in the *stochastic* case whereas lowest redispatching costs are achieved in the *deterministic* approach.

[Mill. €]	Deterministic	Changing forecast	Stochastic
Fuel costs	467.53	469.28	470.25
Carbon costs	157.74	157.79	157.19
Start-up costs	3.71	3.74	3.34
System operating costs	628.98	630.81	630.79

Table 3: Cost results

The characteristics of the cost results concerning their cost components can be explained by analyzing the aggregated generation and the unit commitment which are depicted in Table 4 and 5. Comparing the different cases, we observe that the generation and the number of plants online are remarkably invariant. Beside a slight change in the use of storage, the approaches differ in the use of lignite, coal, and gas-fired plants. Concerning these technologies it is important to emphasize that the marginal cost of a coal plant are higher than lignite plants, whereas they have the same operational flexibility in terms of minimum online and offline times (see Table 1 and 2). Furthermore, lignite generation is more carbon cost intensive than coal and the same holds true for the comparison of coal to gas-fired generation.

Comparing the *changing forecast* approach with the *deterministic* case, we observe that the introduction of the wind forecast error leads to a decrease of lignite production. The average number of operating lignite plants remains constant implying a decrease

	Deterministic		Changing forecast		Stochastic	
	DA+ID	CM	DA+ID	CM	DA+ID	CM
	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]	[GWh]
Nuclear	14281	-12	14281	-22	14281	-15
Lignite	5159	-48	5135	-72	5121	-107
Coal	5168	60	5200	71	5234	20
Gas	3153	–	3163	23	3135	102
Oil	130	–	130	–	130	–
Hydro	2557	–	2557	–	2557	–
PSP	-200	–	-217	–	-209	–
Wind	1338	–	1338	–	1338	–
Other	29	–	29	–	29	–

Table 4: Contracted generation in the dayahead and intraday market (DA+ID) and congestion-based redispatch (CM)

of average utilization⁸ by 0.9%. The reduction of lignite generation is compensated by a higher generation level of coal and gas-fired plants. The average utilization increases accordingly as the number of operating plants increases only marginally. As in particular lignite generation is replaced by more costly but less carbon intensive gas-fired generation, the fuel cost rise and the carbon cost decline, respectively. However, the change of the generation pattern determined in the dayahead and intraday market causes higher needs for congestion management which impacts system operating costs. Nuclear and lignite generation need to be replaced by more costly coal and gas-fired generation in order to maintain stability of the network. Thus, carbon free nuclear generation is substituted by more carbon intensive alternatives. Finally, it reveals that fuel costs increase and in particular the redispatch of nuclear dominates the carbon costs to rise above the *deterministic* setup (see Table 3). Start-up costs increase as well as the average number of operating plants is slightly reduced at the expense of higher start-up and shut-down processes in order to balance wind forecast errors (see Table 5).

Comparing the *stochastic* case to the *deterministic* case, lignite generation is again reduced but by a larger amount as in the *changing forecast* case. However, the average number of operating plants remains unchanged. Thus, utilization of lignite plants is decreasing by 1.91%. For coal we observe an increase in electricity generation and additionally in the number of plants committed. However, coal plants are used more intensively on average, resulting in an increase of average utilization by 0.49%. This is also true compared to the *changing forecast* approach. Concerning gas-fired plants, generation and average number of operating plants are decreasing. However, the average utilization increases by 3.02%. Hence, by applying the *stochastic* approach the system operator reacts to uncertainty of wind availability mainly by decreasing lignite generation and substituting it by coal-fired generation. Although gas-fired power plants decrease their generation, the results show that the effect of switching away from lignite

⁸Average utilization is defined as the ratio of production to available installed capacity.

generation dominates and thus total fuel cost increase but total carbon cost decrease (see Table 3). As in the *changing forecast* case, lignite and to a smaller extent nuclear generation are replaced in particular by gas-fired generation for congestion management which further increases fuel and decreases carbon costs. Contrasting to the previous cases, the *stochastic* case causes less plants to be in operating mode on average. However, if the installed capacity of the operating plants is taken into account, the *stochastic* case shows the largest amount of online capacity than the other cases which henceforth reduces the need for costly start-up of additional generation units (see Table 5). Thus, the uncertainty about wind generation is mostly captured by unused capacity of operating plants rather than additional start-ups which results in lowest start-up costs among the considered cases.

	Deterministic	Changing forecast	Stochastic
Operating plants (avg.)	326.3	326.4	326.0
Start-ups (total)	45	49	39
Shut-downs (total)	46	50	40

Table 5: Average number of operating plants and total start-up and shutdown processes

Summing up, in both cases with forecast error included, lignite generation is decreased. This decrease is necessary to increase the flexibility of the generation portfolio, in particular increasing the ability to react on changes in the wind forecast in a least cost manner. However, the flexibility is achieved in different ways. The *changing forecast* approach enhances the flexibility by using more flexible generation technologies, i.e. gas-fired plants. In contrast, the *stochastic* approach introduces flexibility by committing plants in particular coal-fired units. As coal plants are not running at their rated capacities, using more coal-fired plants enables reacting to changes in the forecast by varying the generation level instead of starting more expensive gas-fired plants. This more cost efficient behavior of the system operator is caused by the stochastic programming approach: As it takes into account possible deviations of the forecast, coal plants are dispatched at part load which allows for balancing the forecast error in cases of negative and positive deviation. Additionally, the wind forecast error and their impact on the generation portfolio influence flows in the transmission network and requires different redispatching needs. The results reveal that introducing uncertainty about wind generation increases the volume of redispatch and henceforth congestion management costs.

5 Conclusions

In this paper the stochastic electricity market model stELMOD is described which captures the economic and technical characteristics of liberalized electricity markets. First the unit commitment and generation dispatch for the following day is determined in a dayahead market model. Simultaneously capacities providing reserves for system stability are optimized. Afterwards an hourly intraday market model enables to adjust dayahead generation quantities as well as the unit commitment if required. Uncertainty

about wind generation is incorporated and successively updated to reflect the improvement of wind generation forecast over time. Finally network constraints are reflected using a DC-loadflow approach which captures the physical characteristics of transporting electrical energy. Possible applications of the model are to analyze the impact of stochastic renewable generation or the impact of different markets regimes within the rolling planning procedure on electricity market results. Future analysis could also address the issue of the optimal timing of electricity markets within a daily market procedure.

Within this paper, stELMOD is applied to the electricity system of Germany including their neighboring countries. Uncertainty about wind generation is considered in two distinct ways. First, the improving information on wind generation are incorporated by a single wind forecast changing over time, and secondly by a set of possible future wind realizations in a stochastic approach. Both cases are compared to a deterministic case which neglects the uncertain characteristics of wind supply. The consideration of uncertainty induces an adjustment of the generation portfolio towards a more flexible one in order to deal with the forecast errors of wind generation. The changing forecast case achieves the flexibility by the increased use of flexible generation units, whereas the stochastic case balances the forecast error by committing rather inflexible power plants. These characteristics of the generation dispatch impacts the cost components differently but finally leads to an increase of total system operating cost.

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6 Notation

Indices

$\Gamma(k)$	All predecessors of scenario tree node k
$\gamma(k)$	Direct predecessor of scenario tree node k
Ψ	Mapping from power plants to nodes
A	Set of power plants allowed to contribute to reserve r
J, j	Set of pump storage facilities
K, k	Set of nodes in the stochastic tree
L, l	Set of lines
N, n	Set of nodes in electricity network
$O_{p,t}^{off}, O_{p,t}^{on}$	Minimum offline and ontime periods
P, p	Set of power plants
R, r	Set of reserve markets
T, t	Set of time periods
W, w	Set of renewable sources

Parameters

η_j	Pump storage efficiency of pump storage j
$\overline{s_{w,t}}$	Expected renewable supply
ϕ_k	Probability of occurrence of scenario tree node k
$b_{l,n}$	Incidence matrix
$B_{n,nn}$	Nodal susceptance matrix
c_w^c	Curtailment cost of renewable source w
c_p^s, c_p^d	Startup and shutdown cost of power plant p
c_p	Marginal cost of power plant p
cap_l	Line capacity of line l
$d_{n,t}$	Load at node n
$dr_{r,t}^+, dr_{r,t}^-$	Upward and downward reserve load
g_p^{max}, g_p^{min}	Maximum and minimum generation of power plant p
$H_{l,n}$	Branch susceptance matrix
l_j^{max}	Maximum storage level of pump storage j
$ptdf_{l,n}$	Power transfer distribution factor
r_l	Series reactance of line l
t_p^{on}, t_p^{off}	Required online and offline times of power plant p
v_j^{max}	Maximum pump storage release of pump storage j
w_j^{max}	Maximum pump storage pumping of pump storage j
x_l	Series resistance of line l

Variables

	Upper bars denote variables fixed in the respective model. Tilde denotes intraday and hat congestion management variables.
$C_{w,t}$	Curtailment of renewable generation w
$CS_{p,t}, CD_{p,t}$	Startup and shutdown cost of power plant p
$G_{p,t}$	Generation of power plant p
$L_{j,t}$	Storage level of pump storage j
$R_{p,t}^+, R_{p,t}^-$	Provided upward and downward reserve of power plant p
$R_{j,t}^{H+}, R_{j,t}^{H-}$	Provided upward and downward reserve by pump storage j
$S_{w,t}$	Supply of renewable generation w
$T_{n,nn,t}$	Commercial transfer between node n and nn
$U_{p,t}$	Operating status of power plant p (One if plant is on, otherwise zero)
$V_{j,t}$	Generation of pump storage j
$W_{j,t}$	Loading of pump storage j
$Y_{n,t}$	Netinput from the transmission grid at node n