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The Influence of Spatial Effects on Wind Power Revenues under Direct Marketing Rules

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Abstract

In many countries worldwide, investment in renewable technologies has been accelerated by the introduction of fixed feed-in tariffs for electricity from renewable energy sources (RES). While fixed tariffs accomplish this purpose, they lack incentives to align the RES production with price signals. Today, due to a growing proportion of renewable electricity, the intermittency of most RES increases the volatility of electricity prices and might even prevent market clearing. Therefore, support schemes for RES have to be modified. Recently, Germany launched a market premium model which gives wind power operators the monthly choice to either receive a fixed feed-in tariff or to risk a - subsided - access to the wholesale electricity market. This paper quantifies the revenues of wind turbines under this new model and, in particular, analyzes whether, when and where producers may profit. We find that the position of the wind turbine within the country significantly influences revenues. The results are of interest and importance for wind farm operators deciding whether electricity should be sold in the fixed tariff or in the wholesale market.

Key words: Wind Power, Market Premium Model, Optimal Areas of Production
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1. Introduction

The promotion of electricity generation from renewable energy sources (RES) is a key element of the European energy policy. As of today, without additional subsidies electricity generation from RES cannot economically compete with generation from other sources (especially thermal power plants). Hence, politicians in many European countries, including Germany, decided to subsidize RES-generation with feed-in tariffs.

In Germany, feed-in tariffs are specified in the Renewable Energy Sources Act (RESA). The act was established in 2000 and successfully increased the share of energy generation from RES in Germany. For example, a total of nearly 22.000 wind turbines are currently installed. Electricity generation from all RES amounted to 20 percent of the total electricity consumption in Germany in the first half of 2011. However, increasing shares of RES led to new challenges, especially in terms of integrating RES-generation in the conventional wholesale electricity market. If an increasing share of supply - in addition to large parts of demand - is price inelastic, the remaining part of the market (i.e., mostly thermal generation) has to balance supply and demand. Hence, price volatility increases. During certain hours, the market may not even clear. Various possible solutions for these challenges are currently being discussed. One approach is an improved demand-side management (i.e., increasing the price elasticity of demand). In addition, available storage capacity could be increased. Furthermore, grid extensions could increase the market, thus allowing for more balanced supply and demand profiles. Another interesting approach, from an economic perspective, is to bring RES closer to the wholesale market, with the aim of increasing the price elasticity of supply. These challenges will become even more important in the future, when RES shares increase further. The current political goals for future shares of RES are 35% in 2020, 50% in 2030 and 80% in 2050.[1]

Consequently, the German parliament passed a new version of the Renewable Energy Sources Act (in the following called RESA_{2012}) which addresses these aspects. The act became effective January 1st, 2012. One key aspect of RESA_{2012} is an improved direct marketing approach as an alternative to the feed-in tariff. The goal is to set incentives to sell electricity generation from RES directly in the wholesale electricity market in order to link the produced energy to price signals. In addition to the revenue earned on the wholesale market, a subsidy (market premium) is paid to compensate for the difference between feed-in tariff and wholesale market prices.

While this approach is likely to increase price elasticity for RES technologies with significant variable costs, such as, e.g., biomass, the short-run effect on wind is probably low due to the very low variable generation costs. However, positive effects can be expected in the long run because in addition to the total energy output the payoff profile will be included in the investment decision. More detailed discussions of the general efficiency or the compati-

[1]BMU / BMWi (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety / Federal Ministry of Economics and Technology, ed.) (2010): Energy Concept for an Environmentally Sound, Reliable and Affordable Energy Supply, Berlin. p. 5

bility of the incentives set for investing in renewable energy may be found in a variety of papers, e.g., the recent papers of Fandez (2008), Mulder (2008), Marques et al. (2011), Cansino et al. (2010), Desrochers (2008), Lipp (2007). A historical overview of incentive schemes for renewable energy in Europe is given in, e.g., Haas et al. (2011).

In this paper, we take the subsidy scheme in RESA_{2012} as given and focus on the effects on wind turbines. In particular, we analyze the effect which the location of a wind turbine has on its revenue. As direct marketing in RESA_{2012} subsidizes a turbine's energy in €/MWh based on the nationwide wind feed-in profile, the relation of the turbine's power profile to the nationwide wind feed-in profile is a significant additional revenue component under the new scheme. If a turbine tends to produce energy in times where the nationwide wind energy production is relatively low, revenues will be higher than for a production profile which is in line with the nationwide production because electricity prices and wind generation are negatively correlated. However, the production profile of a wind turbine is determined by the wind speeds at its geographical position. Therefore, the position of a wind turbine is decisive for the revenue potentials of wind energy in RESA_{2012}. In the short term, information on this revenue potentials is valuable for the operators of 22.000 wind turbines currently installed in Germany. In the long run, it can be used as an input to quantify the incentive to build future wind turbines in locations with more valuable pay-off profiles and thus increase efficiency in the system.

To our knowledge, no other publication has analyzed this effect so far. It has been studied for some time, however, that dependencies (e.g., correlations) of wind speeds at distant locations affect the accumulated wind power production of wind turbines. Kahn (1979) systematically analyzed these effects for arrays of Californian wind farms of different sizes. In a recent study based on copula functions, Grothe and Schnieders (2011) analyzed dependencies of wind power positions in Germany. In this study, we go a step further and analyze the effect of the position (and the unit specific production profile) on a wind turbine's revenue under the subsidized direct marketing of RESA_{2012}.

In a first step, we use hourly wind speed data from different locations to calculate the hourly electricity production that a reference wind turbine would have produced in a particular place. Then, we calculate the relative performance for a representative unit at each location based on these electricity production estimates, the nationwide historical total feed-in, and hourly electricity prices for the 12 months period from July 2010 to June 2011.

However, as we are interested in making recommendations for the future, the question remains whether a good performance was achieved by chance or was rather the result of a statistically significant negative dependence of the unit's feed-in with nationwide feed-in. Hence, in a second step, we analyze an extended period of observation from 2001 to 2011. Since no consistent dataset for nationwide feed-in exists (the four German TSOs started reporting nationwide data 2009-10-29), we use our set of hourly wind data for the different locations to estimate the nationwide feed-in for the extended period of observation. Then, again using electricity production estimates for the different locations, the estimated nationwide feed-in and historic hourly wholesale electricity prices, we calculate the relative performance for all locations in the extended time period. We are thus able to estimate at which location (and in which season and month) the new scheme leads to systematically higher or lower revenues when compared to the fixed feed-in tariff.

The remainder of the paper is organized as follows: In section 2 we review the German Renewable Energy Sources Act with special focus on wind energy. In section 3 we introduce the methodology and data used in the paper. Descriptive tables regarding the data are listed in the appendix. Our empirical analysis is presented in section 4. Section 5 concludes.

2. RES promotion under $\mathbf{RESA_{2012}}$

In the $RESA_{2012}$, RES units can choose freely between two subsidy options on a monthly basis: the fixed feed-in tariff (defined in §§ 23 to 33, where §§ 29 and 30 regard onshore wind power) and subsidized direct marketing (§33a to i).

2.1. Fixed feed-in tariff

The oldest and most widely used option for selling the electricity of wind turbines in Germany is RESA's fixed feed-in tariff system. These tariffs were successful in increasing the share of RES in the German electricity market and providing a relatively risk free option for suppliers. However, one immanent problem in pure feed-in tariff models is that RES produce electricity independently from the fundamental situation of supply and demand in the electricity wholesale market. Hence, the elasticity of RES output with respect to wholesale electricity prices is zero. In a fixed feed-in system, a unit produces electricity if two main conditions are met: Firstly, the unit's variable production costs must be below the specific feed-in tariff for that unit. For wind power with variable generation costs close to zero, it seems safe to assume that this is always the case. Secondly, the unit's specific energy source has to be available. This second condition effectively restricts the output of RES generation from wind power.

Every unit has the opportunity to earn a unit specific revenue EV per MWh generation. A wind turbine's profit under the feed-in tariff for any given period $t = 1 \ldots T$ of time (hours) can hence be written as:

$$\pi^{fit} = EV \sum_{t=1}^{T} e_t - FC, \tag{1}$$

where e_t is the produced energy of the turbine at hour t and FC represents fixed costs (calculated for the whole period from 1 to T).

2.2. Direct marketing

Direct marketing is legislated in RESA$_{2012}$, §33a to i. The unit specific payments and the method of calculation are described in RESA$_{2012}$, Appendix 4. The underlying idea is that a RES unit's revenues should depend on the wholesale electricity price in order to increase the price elasticity of the units.[2] Hence, instead of receiving a fixed feed-in tariff, units can decide to sell their output directly on the wholesale electricity market.

However, wholesale electricity prices are below feed-in tariffs for most wind turbines and the revenues would most likely be too low to cover investment costs. Furthermore, existing units profit from guaranteed fixed feed-in tariff for 20 years. Hence, direct marketing is implemented on a voluntary basis. In effect, this means that the expected revenues for direct marketing must exceed the revenues received with the unit specific feed-in tariff. Otherwise, units would stay in the feed-in tariff system. Consequently, a market premium MP was introduced. This market premium is paid in addition to wholesale electricity prices if units give up the feed-in tariff and sell their output in the wholesale market. Furthermore, in comparison to the feed-in tariff, direct marketing shifts additional cost components to the wind plant operators. These are also subsidized.

The MP for onshore wind power is calculated on a monthly basis as follows:[3]

$$MP = EV - MW + PM, \tag{2}$$

[2] See Joskow (2011) for a concise discussion that it is not only important how much but also when RES units provide electricity.

[3] We follow the notation given in RESA_{2012}

where EV is again the revenue the plant would receive (in €/MWh) if it would not opt for direct marketing in a particular month, i.e., the unit specific feed-in tariff. MW is the benchmark market value for electricity from wind power for a certain month in €/MWh and PM is an allowance meant to cover additional costs from direct marketing, such as costs of market access, balancing group management and risk premia. In RESA_{2012}, PM is identical for all onshore wind turbines. It is set at 12 €/MWh in the year 2012, 10 €/MWh in 2013, 8.5 €/MWh in 2014, and 7 €/MWh from the year 2015 onwards. The benchmark market value MW is calculated using the average market price of Germany's nationwide overall onshore wind power production NF_t over all hours $t = 1 \dots T$ of the respective month:

$$MW = \frac{\sum_{t=1}^{T} p_t NF_t}{\sum_t NF_t} \tag{3}$$

In the equation, p_t is the hourly price in the EPEX spot day-ahead auction and NF_t is the nationwide overall wind energy generation in hour t in MWh. Note that NF_t refers to the sum of wind energy from all onshore wind turbines, i.e., wind energy from turbines under direct marketing and wind energy from turbines under classical feed-in tariffs. In other words, MW is the average price an average wind turbine would receive per MWh of output during the respective month if selling on the wholesale market.

Hence, when denoting the costs for direct marketing (e.g., trading and market access etc.) during the respective month by C, the profit of a wind turbine opting for the market premium model can be calculated as:

$$\pi^{MP} = (EV - \frac{\sum_t p_t NF_t}{\sum_t NF_t} + PM)\sum_t e_t + \sum_t p_t e_t - C - FC. \qquad (4)$$

The cost component FC once again denotes the fixed costs (e.g., capital costs, repair and maintenance,...). These costs are assumed to be the same as in equation (1). Additional costs for selling on the wholesale market are subsumed in C.

2.3. Comparison

We have already pointed out that wind turbine operators will decide to sell their output on the wholesale market only if $E(\pi^{MP}) \geq E(\pi^{fit})$. Assuming that wind turbine operators are risk averse and that $var(\pi^{MP}) > var(\pi^{fit})$, the inequality is strict.

Note that the decision to enter direct marketing is not directly influenced by the total energy output per month, as payoffs of both alternatives (equations (1) and (4)) contain the term $\sum_t e_t$. However, regarding the question of which wind turbines should choose the direct marketing approach, the following two points are of interest.

1. The lower the costs associated with direct marketing C are for a turbine, the higher the profit will be. This refers to costs for market access, balancing group management and uncertainty. For example, a better forecast of e_t will enable a better estimate of the unit's revenue and

reduce costs for balancing group management. Generally, it can be expected that operators marketing larger volumes have lower specific costs per MWh output and are more likely to choose direct marketing.

2. The turbine's revenues on the wholesale market are determined by the unit-specific output e_t plus the difference of the average wind turbine's revenue MW and the fixed feed-in tariff's revenue EV. Hence, if a specific wind turbine can earn payments above the average, the unit receives additional payments. Now, the question is when this is the case. One possibility is that the turbine's generation is more centered towards the peak hours. During peak periods, demand is high, which leads to high hourly prices. This effect is mostly independent of the amount of wind turbines in the system. Another effect is the following: the more wind turbines there are, the more their output lowers prices. Hence, having a wind turbine at a location where output is negatively correlated with the output at other locations will increase profits. On the other hand, producing above-average when everybody else also produces a large amount will lower the unit-specific revenue. Thus, the location of a wind turbine may be crucial for the decision to apply the direct marketing approach.

This paper concentrates on the second point and analyzes the effect of the locations of wind turbines on their possible revenue in the direct marketing approach.

3. Data sets and methodology

In order to analyze the effect of the position of a wind turbine on its revenue potential under direct marketing in RESA_{2012}, we need hourly historical data of wind energy produced at different locations, the nationwide feed-in of wind energy produced in Germany and the respective spot price p_t. The spot price data is obtained from the European Power Exchange (EPEX). Our time series lasts from 2001-01-01 to 2011-06-30, on an hourly basis. Hourly spatial and overall wind energy data are discussed in the next two subsections.

3.1. Spatial wind data and conversion to energy data

We need historical wind energy data produced at certain locations within Germany to differentiate between wind turbines at different locations. Therefore, we start with the available historical wind speed data at certain locations and convert them into wind energy data. The conversion takes place in two steps. In the first step, wind speeds are scaled to the hub height of modern wind turbines, and in the second step, the wind to power relationship from a benchmark wind turbine is used to convert the scaled wind speeds to power output.

The wind speed data set was provided by the German weather service. It consists of hourly means of wind speeds measured at 37 German weather stations[4] from 2001-01-01 to 2011-06-30. Table 5 in the appendix shows de-

[4] Aachen, Augsburg, Bamberg, Berlin-Tempelhof, Bremen, Dresden-Klotzsche, Duesseldorf, Emden, Erfurt-Weimar, Fichtelberg, Frankfurt/Main, Goerlitz, Greifswald,

scriptive statistics of the stations as well as the geographical altitude of each station, the wind detector height above ground and the number of annual full-load hours a benchmark turbine at the location would have. The mean values of wind speed at the stations vary from 2 m/s to more than 8 m/s, while full load hours vary from about 200 hours to about 6000 hours per year.

Note that the wind speed is measured at different heights above ground. Following Grothe and Schnieders (2011) and Katzenstein et al. (2010) based on Seinfeld and Pandis (2006) we scale the measurements to the wind speeds at the typical hub height of modern wind turbines ($h_1 = 80$ m) by assuming a vertical logarithmic profile of the wind velocity v leading to

$$v_{h_1} = v_{h_0} \cdot \left(\frac{\log(h_1) - \log(z_0)}{\log(h_0) - \log(z_0)} \right), \tag{5}$$

where h_0 and h_1 are the height of the measurements (see table 5 for the respective values of h_0) and the height of interest, respectively. The parameter z_0 corresponds to a surface roughness length. Within the model it is the height at which the wind speed is zero and is chosen as $z_0 = 0.03$ (see Katzenstein et al. (2010)). The rescaled wind speed data is converted into electrical power output by a GE 1.5 MW benchmark turbine. The energy

Hamburg-Fuhlsbuettel, Hannover, Helgoland, Hof, Hohenpeissenberg, Kahler Asten, Kempten, Konstanz, Leipzig-Halle, Lindenberg, Magdeburg, Meiningen, Neuruppin, Nuernberg, Potsdam, Rostock-Warnemuende, Saarbruecken-Ensheim, Schleswig, Schwerin, Straubing, Stuttgart-Echterdingen, Westermarkelsdorf, Wuerzburg, Zugspitze output of this turbine as a function of the wind speed v_{h_1} is approximated by the following combination of third-order polynomials (see Archer and Jacobson (2007)):

$$P(v_{h_1}) = \begin{cases} 0 & v_{h_1} < 3\,\mathrm{m/s} \\ P_{\mathrm{lower}}(v_{h_1}) & 3\,\mathrm{m/s} \le v_{h_1} \le 8\,\mathrm{m/s} \\ P_{\mathrm{upper}}(v_{h_1}) & 8\,\mathrm{m/s} \le v_{h_1} \le 12\,\mathrm{m/s} \\ 1500 & 12\,\mathrm{m/s} \le v_{h_1} \le 25\,\mathrm{m/s} \\ 0 & 25\,\mathrm{m/s} \le v_{h_1} \end{cases}, \tag{6}$$

where $P_{\mathrm{lower}}(v_{h_1}) = v_{h_1}^3 + 8v_{h_1}^2 - 53v_{h_1} + 60$ and $P_{\mathrm{upper}}(v_{h_1}) = -11.25v_{h_1}^3 + 307.5v_{h_1}^2 - 2520v_{h_1} + 6900$. Figure 1 shows a plot of this function.

The wind data is converted into power data for all the time series of wind speeds from the 37 stations. In the following, the produced amount of energy at location $i = 1 \dots 37$ and hour t will be denoted by $e_t^{(i)}$.

3.2. Nationwide wind energy feed-in data

For the most recent months, i.e., the year from 2010-07-01 to 2011-06-30, we use available historical nationwide hourly feed-in data from all German (on-shore) wind turbines provided by the European Energy Exchange. However, data for one year is not sufficient to make robust assessments for the future. Hence, we extend the period back to 2001-01-01. Since data from the European Energy Exchange is only available back to 2009-10-29, we estimate nationwide wind feed-in by a model based on the hourly data of our

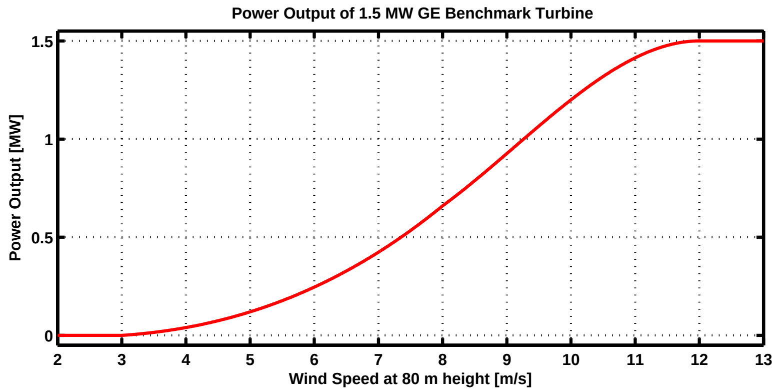

Figure 1: The power output as a function of the wind speed for a GE 1.5 MW turbine. The rated wind speed is 12 m/s. The cut-in and cut-off wind speeds are 3 m/s and 25 m/s, respectively.

37 weather stations. The model is calibrated to the nationwide feed-in for the most recent months, where data is available. The implications of this approach will be discussed in section 3.2.2.

3.2.1. The period 2010-07-01 to 2011-06-30

The average EPEX spot price for the nationwide feed-in data NF_t (i.e., the average price for the wind profile) from 2010-07-01 to 2011-06-30 is

$$\frac{\sum_{t=1}^{T} NF_t \cdot p_t}{\sum_{t=1}^{T} NF_t} = 47.18\,€/\text{MWh},$$

where $t = 1 \ldots T$ denotes the 8760 hours from 2010-07-01 00:00 to 2011-06-30 23:00. The average spot price (flat profile) of this time interval is

$$\frac{1}{T}\sum_{t=1}^{T} p_t = 50.17\,€/\text{MWh}.$$

Table 1 shows the respective averages in monthly subperiods. For all months, the average price for the wind profile lies below the flat average price. This result has been expected because wind energy production and EEX spot prices are negatively correlated. A high supply of wind energy in one hour will reduce the spot price of the same hour and decrease the average price for the wind profile. The difference between the prices is larger in the winter months than in the summer months.

	Month of interest											
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Wind Profile	44.26	44.73	53.26	51.20	54.00	46.89	43.23	39.79	44.58	47.70	44.89	49.37
Flat Profile	50.13	50.86	54.46	51.57	56.85	52.29	45.81	39.80	45.88	50.30	48.53	55.55

Table 1: Comparison of flat average prices and wind profile average prices from 2010-07 to 2011-06 in €/MWh.

3.2.2. The extended period 2001-01-01 to 2011-06-30

We use historical realisations for nationwide total feed-in for only 12 months because the data is only available as far back as 2009-10-29. In addition, the goal of this paper is to help answer the question whether (and which and when) wind power plants should opt for the new market premium subsidy instead of the feed-in tariff - today and in the near future. The further back we go, the less representative the data becomes for the current situation, as the installed wind power capacities increased significantly over time.

As a consequence, the negative dependencies between total nationwide wind feed-in and electricity prices were less pronounced in the past. Hence, generating electricity when the other wind turbines are not generating (much) electricity would also be less important. Applying historic data for wind feed-in and spot prices would underestimate these effects.

To reflect the current situation, both historic prices and historic total generation would have to be adjusted with regard to currently installed capacities. In addition, for a perfect forecast, other factors in the power system (e.g., installed thermal capacities, PV and consumption) would also have to be corrected.

Instead of trying to quantify these effects, we use realised historical hourly electricity prices and combine them with estimates for the total nationwide wind feed-in. The latter are calculated on the basis of historical data for the 37 weather stations. Leaving electricity prices uncorrected means that our results for the extended time period can be seen as a lower estimate in absolute values. In other words, the importance of a good location (and the danger of opting for the market premium from a bad location) is at least as large as our computations in this section suggest.

We calculate the nationwide wind feed-in under the assumption that the relation between our 37 weather stations and the nationwide feed-in is the same in the whole period from 2001-07-01 to 2011-06-30. To be precise, we use a regression model to explain the nationwide total feed-in (NF_t) by the wind energy data $e_t^{(i)}$ of the $i = 1 \dots 37$ locations which are distributed across Germany. The model is estimated in the time interval where both feed-in data and wind energy data is available, i.e., the period from 2010-07 to 2011-06. For the period before 2010-07, the model is used to compute a corresponding total nationwide energy feed-in. Computed overall feed-in at hour t will be denoted by $\widehat{NF}_t$. We use the following model

$$NF_t = \beta_0 + \beta_1 e_t^{(1)} + \cdots + \beta_{37} e_t^{(37)} + \varepsilon_t, \tag{7}$$

where t denotes the hours from 2010-07-01 00:00 to 2011-06-30 23:00 and $e_t^{(i)}$, $i = 1 \ldots 37$ refers to the amount of energy produced by the benchmark turbine mentioned in section 3.1 in hour t at location i. See table 5 for the assignment of the station names to the station numbers. The coefficient of determination of the estimated model is $R^2 = 0.93$. The mean absolute error (MAE) is 795 MW. While the average spot price per MWh for the original feed-in data is 47.2 €/MWh, the average spot price for the reconstructed feed-in data is 47.9 €/MWh, which shows that the model performs quite well. See figure 2 (blue line) for a graphical validation of the model performance in sample and out of sample (blue dashed line) and table 5 for the estimated coefficients. Note that the coefficients β_i may be negative, which makes them difficult to interpret. Alternatively, we estimate the model under the constraints of $\beta_0 = 0$ and $\beta_i \geq 0$, $i = 1 \ldots 37$ (see red line in figure 2). The coefficients of the constrained model are denoted by β_i^c in the following. While these constraints reduce the quality of the model slightly (MAE 817 MW instead of 795 MW), the coefficients of the constrained model may be easily interpreted: β_i^c corresponds to the number of benchmark turbines to be

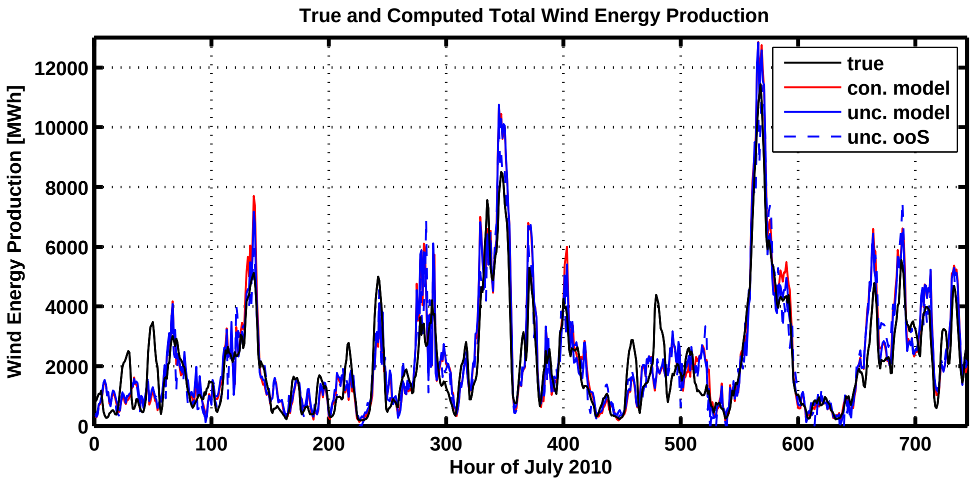

Figure 2: Actual (black) and model based (unconstained model (blue), constraint model (red)) total wind energy production July 2010. The models are calibrated on data from 2010-07-01 to 2011-06-30. Additionally, the blue dashed line depicts out of sample model based wind energy production when calibrated on data from 2010-09-01 to 2010-09-30 (ooS).

installed at location i to replicate the total nationwide wind feed-in profile.

4. Empirical analysis

In this section, we analyze the average energy prices received from wind energy production at 37 different locations. The empirical analysis consists of two parts. Firstly, in section 4.1 we concentrate on the time period from 2010-07 to 2011-06, where all data (i.e., hourly wholesale electricity prices, hourly nationwide feed-in and hourly wind data for all 37 locations) are available. For this period, we assume that historical nationwide feed-in data is compatible with the current allocation of wind turbines and can thus be used to make consistent forecasts for the (near) future. Secondly, we analyze the relative performance of different locations that could have been achieved over the period from 2001 to 2011 if the wind park allocation would have matched the current allocation.

4.1. Results for 2010 to 2011

The key result in this paper is the deviation between the average monthly spot price of wind energy produced at a certain location and the average monthly spot price of the total nationwide wind energy production. This difference is a premia a single unit could earn or lose exclusively based on the location of the plant. It is an important factor for the decision of whether or not a plant should opt for the market premium model.

For each of the locations i and months j from 2010-07 to 2011-06 we therefore calculate the difference of these two prices, denoted by $\widetilde{p}_j^{(i)+}$, as:

$$\widetilde{p}_j^{(i)+} = \frac{\sum_{t=1}^{T} e_t^{(i)} p_t}{\sum_{t=1}^{T} e_t^{(i)}} - \frac{\sum_{t=1}^{T} NF_t p_t}{\sum_{t=1}^{T} NF_t^{(i)}}, \tag{8}$$

where $t = 1 \dots T$ denotes the hours of month j. Thus, the price $\widetilde{p}_j^{(i)+}$ is the premium paid for wind energy produced in location i compared to an average wind profile. Table 2 shows the calculated values of $\widetilde{p}_j^{(i)+}$ (note that the results are not presented in chronological sequence but ordered by month).

The majority of the premia vary between -4 €/MWh and 4 €/MWh. As these premia have no associated costs (as soon as the windmill is erected), they are directly moving the profit contribution. In the context of a rather competitive market where many companies compete for the right to market

RES energy, this order of magnitude seems significant.

There is one extreme value of -17.75 € /MWh for Konstanz in February 2011. The reason for this low premium is that a high percentage of the wind produced at that location was concentrated within a short time period where a high overall wind supply led to low spot prices. One of the insides gained from the extension of the analysis to cover a period of 10 years is that this result is not persistent, i.e., it happened by chance.

While the ratio between positive and negative premia is balanced in the winter months, the summer months show positive premia for most of the stations. This may be counterintuitive as prices should be distributed around the average price. However, note that the average price is not a direct average of the single prices. According to Lemma 1 presented in Appendix A, it may be decomposed as a weighted average, where the weights depend on the coefficients β_i^c of the constrained model in equation 7 and the overall and individual wind energy production at the stations over the period of interest. Table 4 in the appendix shows the resulting weights ω_{ij} for all stations and months.

	Month of interest											
Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Aachen	3.35	-4.80	-1.04	2.13	.84	-1.45	8.24	1.06	-.49	-1.60	-5.10	-1.41
Augsburg	5.45	-5.22	3.23	2.80	3.53	1.67	3.25	5.21	5.83	4.39	-1.02	-.65
Bamberg	5.13	-5.38	2.24	1.84	.66	3.58	4.41	7.04	5.23	1.91	-1.72	-3.97
Berlin-Tempelhof	-2.10	.50	.15	-.25	1.38	4.89	-1.73	4.36	4.27	1.85	3.83	.52
Bremen	-.33	.07	-.07	1.48	1.59	2.27	5.47	2.54	1.59	.34	.82	-1.80
Dresden-Klotzsche	-.90	-.93	-.45	-.23	1.58	2.55	.73	2.28	4.73	-.81	-.85	1.31
Duesseldorf	5.25	-.62	.66	.25	.04	2.01	6.00	2.77	1.14	-.59	-2.22	-1.88
Emden	2.29	2.28	.91	1.32	2.08	1.79	5.88	3.52	1.08	.27	2.58	-.82
Erfurt-Weimar	.69	-2.92	.49	1.54	1.45	1.40	1.92	3.33	2.46	.42	-2.14	.67
Fichtelberg	4.33	5.53	1.17	.08	.74	2.26	-1.55	-.44	.95	1.28	1.74	4.82
Frankfurt/Main	4.85	-6.20	1.27	1.14	1.99	2.36	5.51	2.47	2.39	.87	-.71	-2.45
Goerlitz	-1.58	-1.38	-.87	-.58	2.15	4.19	-.07	2.71	4.07	.44	-.91	1.94
Greifswald	-5.07	3.04	.90	.20	-.09	9.45	.68	4.99	4.66	.29	6.28	-1.46
Hamburg-Fuhlsbuettel	-1.02	2.21	.63	1.41	2.31	1.76	4.13	1.36	.80	.18	-.18	-1.14
Hannover	1.75	-1.57	-.03	1.04	1.68	3.32	4.76	3.19	2.14	-.04	.68	-1.33
Helgoland	3.46	7.12	.93	.39	.49	1.77	1.43	.20	1.00	1.98	3.44	3.64
Hof	2.21	-7.06	1.16	1.52	3.04	2.15	2.20	5.10	2.79	-2.26	-2.66	-2.40
Hohenpeissenberg	2.47	-6.66	1.86	.18	1.67	-3.86	1.50	3.73	-2.03	3.67	-.36	1.80
Kahler Asten	2.02	1.75	.88	-.22	.42	1.74	1.38	.18	-.74	.45	-.32	.35
Kempten	.94	-8.85	2.28	2.43	4.30	1.53	4.26	4.94	4.73	4.15	-3.18	1.28
Konstanz	5.81	-17.75	3.07	1.02	5.41	-2.63	3.04	5.06	3.63	3.32	-1.34	2.02
Leipzig/Halle	-1.25	-.29	-.21	1.25	2.30	1.48	1.48	1.20	2.45	1.37	-.32	1.31
Lindenberg	-4.45	-3.30	-.90	.77	3.27	-.86	-3.33	1.20	1.95	-.28	1.79	-.25
Magdeburg	-7.16	-9.44	-1.11	.82	3.98	-.90	2.83	4.27	2.54	.22	-2.16	-2.13
Meiningen	6.47	-8.54	1.25	-.44	1.99	4.21	2.39	3.54	2.02	2.64	-.46	-1.27
Neuruppin	-2.16	1.02	-1.32	-.74	1.09	3.80	3.42	4.34	4.23	-.05	-.25	1.37
Nuernberg	5.09	-2.17	3.23	3.00	4.43	1.22	4.12	5.92	5.05	1.64	-.84	-3.83
Potsdam	-5.53	-2.94	-.72	.40	.95	-1.16	-3.72	.61	.92	-.64	.69	-.79
Rostock-Warnemuende	-2.82	1.45	.15	.65	1.84	4.19	-2.95	3.08	3.79	2.02	4.76	.23
Saarbruecken-Ensheim	4.62	-5.89	.97	-.46	2.63	2.47	8.02	3.05	1.38	1.20	-2.07	.94
Schleswig	-5.05	1.35	.31	1.16	3.74	6.77	3.78	3.36	2.24	2.48	2.87	-1.74
Schwerin	-6.23	-1.68	-.32	1.52	2.79	1.31	1.82	.96	.86	1.70	.17	-3.04
Straubing	5.26	.82	1.56	.89	6.32	2.06	1.75	5.72	6.07	3.56	-.53	-3.42
Stuttgart-Echterdingen	7.80	1.14	3.02	2.92	3.32	2.17	5.17	5.31	5.16	3.57	-2.51	.42
Westermarkelsdorf	1.96	5.82	.78	.30	1.36	4.39	-.41	1.14	.79	1.79	3.60	2.80
Wuerzburg	5.26	-1.84	2.55	1.43	3.88	1.81	6.63	3.87	1.81	-.70	-.79	-4.60
Zugspitze	4.44	4.73	1.17	1.36	1.63	2.47	.57	-.11	-.11	.51	2.51	6.06

Table 2: Deviations of the individual average price for wind energy from the overall average price for wind energy from 2010-07 to 2011-06 in € /MWh. Positive numbers denote revenues above the average.

4.2. Model based results for 2001 to 2011

While the results in the previous section provide indications which plants should opt for the market premium instead of the fixed feed-in in which month, they contain uncertainty due to the short period of observation. Hence, the results of the previous section may or may not be representative for the future. In this section, we extend the study to a horizon of 10 years beginning from 2001-01 to receive statistically significant statements.

Since no suitable overall feed-in data is available, the overall feed-in data is estimated from the production data $e_t^{(i)}$ of the $i = 1 \ldots 37$ stations by equation 7 (unconstrained model). Using this data in addition to the station data and historical spot prices we can calculate the profit or loss of each month just applying the same methodology as in section 4.1.

The results are averaged for each month and shown in table 3. The table shows the mean premia of the respective month from 10 years of data. The numbers of stars attached to a number denote the level of significance. One, two, or three stars denote that 90%, 95%, or 99% of the probability mass of a fitted normal distribution in the premia lie on the same side from zero. It is thus to be expected with the same probability that the locational effect on the revenue is positive or negative. We see that no location dominates the other locations over the whole year. Therefore, the results are especially useful for the monthly decision of whether to opt for the market premium model or not.

	Month of interest											
Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Aachen	-1.02	-1.22	-1.61	1.13	1.04	3.78	4.17***	3.28	.84	-2.37***	-1.51	-3.55
Augsburg	-.52	.30	.67	2.35*	2.73***	4.60***	5.41	3.99***	3.40	3.87***	1.66	-1.35
Bamberg	.66	-.49	.43	2.29**	2.69***	4.24***	6.04***	5.71***	5.58***	4.34***	-.68	-1.32
Berlin-Tempelhof	-1.22	.23	.51	1.85	1.82	2.82***	2.77	3.36***	3.02	1.73*	.04	-2.38
Bremen	-.81	-.31	.27	1.03	2.22*	3.12	4.04***	3.40***	2.46**	.51	-.49	-2.62
Dresden-Klotzsche	-.56	-.19	.32	1.10	1.54	2.24	1.52	2.27	2.05	.89	-.80	-2.03
Duesseldorf	-.10	-.66	.57	1.49	1.97	3.24	4.70*	3.38	2.98	1.41	.57	-1.40
Emden	-.19	.36	.51	1.39	2.52**	3.31***	4.70	3.02**	2.81	.48	-.59	-1.41
Erfurt-Weimar	-1.26	-.68	-.14	1.00	1.58	1.96	4.39*	2.22***	2.11	-.21	-1.01	-2.00
Fichtelberg	1.98**	.94	1.26	-.23	-.96	-1.60	-2.08**	-.99	-.34	.92	1.47	4.17***
Frankfurt/Main	.23	.09	.84	2.15	2.49***	3.48	4.92	3.61**	3.10**	3.69***	2.18	-1.63
Goerlitz	.20	-.26	.41	2.18	3.12	4.11*	2.95	4.66**	4.16	1.10	-.29	-1.37
Greifswald	-.84***	1.02	.34	2.06	2.80***	5.23	7.85***	3.86*	3.42***	2.99***	.24***	-3.62
Hamburg-Fuhlsbuettel	.17	-.65***	.50	1.63***	2.78	3.61***	5.02	3.29***	3.04	.55	-.21	-2.87***
Hannover	-1.07***	-.37	.26	1.47**	2.68***	3.90	4.03***	3.86***	2.91***	.39	-1.74***	-2.12
Helgoland	1.73	1.26***	1.17	-.35***	-.41	-.61***	-1.41	-.04***	.30	1.76*	1.81	2.41***
Hof	-1.70***	-.69	-.64	1.84	2.63***	3.13	4.33***	4.34***	3.06***	1.22	-1.47***	-1.54
Hohenpeissenberg	-.08	-.42***	-.49	-.98***	-1.35	-1.52***	-2.71	-1.55***	-1.71	-.38	.09	-.55***
Kahler Asten	.33***	-.19	-.02	-.52	-.67***	-1.58	-.91***	-1.13	-.87***	-.40	-.29***	.44
Kempten	-2.69	-.11***	.05	1.68***	4.05	6.76***	4.79	3.72***	4.16	4.96***	-.76	-1.71***
Konstanz	1.13***	.26	-.08	1.68	3.30***	5.66*	4.51***	1.85	2.09***	3.21***	3.54***	-.50
Leipzig/Halle	-.77	-.06***	.28	1.26***	1.66	2.80***	1.57	2.32***	2.52	.19	-.60	-2.00***
Lindenberg	-1.64***	-1.25	-.89	1.35	1.25***	2.16	2.42***	2.46	1.36***	-1.22	-1.08***	-4.47
Magdeburg	-2.80	-1.70***	-1.70*	2.27***	3.57	3.65***	2.60	4.68***	3.49	-.26	-3.42	-6.63***
Meiningen	-1.86***	-.67	.19	1.62	2.52***	3.40	4.13***	3.59***	2.59***	1.01	-.06***	-1.55
Neuruppin	-1.67	-.69***	-.25	1.74***	3.77	6.05***	5.37	5.19***	4.47	1.92*	.44	-3.50***
Nuernberg	.07***	.31	.53	1.96	2.27***	4.49*	5.60***	4.12***	4.74***	3.38***	-.30***	-.37
Potsdam	-2.35	-1.49***	-1.75*	-.34***	-.31	-.52***	-1.51	.01***	-1.13	-2.11**	-2.08	-4.20***
Rostock-Warnemuende	.79***	.56	1.41	1.92	.86***	.51	1.09***	.37	1.29***	.61	.44***	-.15
Saarbruecken-Ensheim	1.08	-.10***	.20	2.32***	2.27**	4.85***	7.74	3.93***	2.16	1.65*	-.51	-.04***
Schleswig	-.42***	-.25	-.60	1.51	2.54***	3.60	5.28***	3.65***	2.85***	-.40	-.09***	-2.40
Schwerin	-1.20	-1.01***	-.81	1.04***	1.56	2.55***	2.85	2.32***	1.96	-1.02	-1.36	-4.83***
Straubing	.18***	-.07	.96	2.09	1.64***	5.42*	6.84***	4.88***	3.54***	3.48***	.67***	-1.22
Stuttgart-Echterdingen	.89	.76***	.84	2.50***	3.07	4.15***	6.48	3.78***	2.97	4.43***	2.54	.46***
Westermarkelsdorf	.88***	.72	1.00	.80	-.09***	.07	1.33***	-.08	.40***	1.19	1.32***	1.14
Wuerzburg	-.95	-.49***	.01	2.44***	2.38**	4.99***	5.09	4.22***	2.99	3.61***	.45	-1.87***
Zugspitze	1.60***	1.30	1.41	.67	-.34***	-1.15	-1.44***	-1.58	.01***	1.45	2.06***	3.40

Table 3: Mean profit or loss by month from 2001-01 to 2011-06 as derived by our model.

5. Conclusion

This paper analyzes the effect of the location of a wind turbine within Germany on its revenue under the new direct marketing scheme introduced by Germany's Renewable Energy Sources Act 2012. Based on RESA_{2012}, wind turbine operators have the free and monthly choice to either sell their electricity generation according to the new direct marketing approach or to receive a fixed feed-in tariff. We find that the position of a turbine affects its expected revenues by up to 5-6 EUR per produced MWh. However, the monthly effect is not constant over a year. For example, turbines at certain locations may receive above-average revenues per MWh in the summer months, whereas their revenues per MWh in winter months may lie below average.

Our study offers monthly calculations for 37 German regions based on hourly wind data from the last 10 years. The operators of 22,000 wind turbines in Germany may use the results in order to decide which subsidy is more profitable for a given plant in a given month. Our results could also be used for risk management purposes. We discuss and quantify the risk associated with a deviation from the nationwide feed-in. Furthermore, together with information on the total amount of electricity expected at a certain location the results can be used to direct investments to more profitable locations. This would at the same time increase efficiency in the system because the overall production of wind energy would then be more aligned with scarcity signals, i.e., prices.

To improve the empirical value of our results, our methodology can be applied to unit specific wind data as well. Given our estimate of total nation-wide historical feed-in, further analyzes do not necessitate a new representative set of data. Instead, individual units (or wind farm locations) could be analyzed. Furthermore, future research could try to estimate how historic wholesale electricity prices would have been influenced by the wind power production given today's wind capacity.

Our study shows, that the patterns of the locations producing the most lucrative wind profiles show yearly seasonalities, i.e., change from month to month, and that there are no *dominating* locations for the whole year. The locational profit of wind turbine operators from the direct marketing approach (not counting the additional allowance PM) is therefore highly driven by the decision in which month to sell the energy directly and in which month not. We therefore doubt that RESA_{2012} is able to push the overall allocation of wind turbines and with it the wind energy production nearer to the demand side.

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A. Decomposition of the average wind price

For each month, the average price of the nationwide wind energy feed-in can be decomposed into a weighted average of the average prices of wind energy produced at the 37 locations and a residual term. This decomposition can be used to check the plausibility of the results of section 4. For each month of a certain year it provides the weights which have to be assigned to the revenues in table 2 so that they net to the residual term. For the time period 2010-07-01 to 2011-06-30 the resulting weights are presented in table 4.

To derive the decomposition let $\widetilde{p}_M$ denote the average selling price per MWh of the total wind energy supply over a time period M, e.g., a month, with hours $t = 1 \dots T$. Furthermore, let $\widetilde{p}_M^{(i)}$ be the average price for wind from station i, $i = 1 \dots n$. Then the following lemma holds.

Lemma 1. *The overall average price for wind energy over a certain time period M ($\widetilde{p}_M$) may be decomposed as a (non-trivial) weighted average of the average prices of local wind energy ($\widetilde{p}_M^{(i)}$, $i = 1 \dots 37$):*

$$\widetilde{p}_M = \sum_{i=1}^{n} \underbrace{\beta_i^c \frac{\sum_{t=1}^{T} e_t^{(i)}}{\sum_{t=1}^{T} NF_t}}_{:=\omega_i} \widetilde{p}_M^{(i)} + R_M$$

The term R_t is a residual term induced by the approximation of NF_t by the regression model.

Note that $\sum_{i=1}^{n} \omega_i = 1$ and that all weights are positive.

Proof:

$$\begin{aligned}
\widetilde{p}_M &= \frac{\text{Total market value of wind energy in period } M \text{ in EUR}}{\text{Total amount of of wind energy in period } M \text{ in EUR}} \\
&= \frac{\sum_{t=1}^{T} NF_t \cdot p_t}{\sum_{t=1}^{T} NF_t} = \frac{\sum_{t=1}^{T} \left(\sum_{i=1}^{n} \beta_i^c e_t^{(i)} + \varepsilon_t \right) \cdot p_t}{\sum_{t=1}^{T} NF_t} \\
&= \frac{\sum_{i=1}^{n} \beta_i^c \left(\sum_{i=t}^{T} e_t^{(i)} \cdot p_t \right) \cdot \frac{\sum_{t=1}^{T} e_t^{(i)}}{\sum_{t=1}^{T} e_t^{(i)}}}{\sum_{t=1}^{T} NF_t} + \frac{\sum \varepsilon_t p_t}{\sum_{t=1}^{T} NF_t} \\
&= \sum_{i=1}^{n} \beta_i^c \frac{\sum_{t=1}^{T} e_t^{(i)}}{\sum_{t=1}^{T} NF_t} \widetilde{p}_M^{(i)} + R_M,
\end{aligned}$$

where $t = 1 \dots T$ denotes the hours of period M. The term R_t corresponds to the deviation of the average price for the true feed-in wind profile in the considered period from the average price for the feed-in profile as calculated in equation 7, i.e.,

$$R_t = \frac{\sum_{t=1}^{T} \varepsilon_t p_t}{\sum_{t=1}^{T} NF_t} = \frac{\sum_{t=1}^{T} \left(NF_t - \sum_{i=1}^{n} \beta_i^c e_t^{(i)} \right) p_t}{\sum_{t=1}^{T} NF_t}.$$

For the year where both historical feed-in data and model data are available, we find $R_M = 47.9 - 47.2 = 0.7$. On subintervals with length of 1 month the values vary between 0.27 and 1.78 with a mean of 0.84.

The weights in table 4 are unequally distributed across the locations. Most of the stations have a low weight, while the stations Fichtelberg, Helgoland, Kahler Asten and Potsdam represent nearly 50% of the overall weight. Since these stations correspond to stations with negative premia in table 2, the weighted sums of the columns fluctuate around zero, i.e., they are balanced again. Note that we do not expect them to be exactly zero, but to coincide with the residual term R_M in the Lemma 1, i.e., to be in the order of magnitude of 1 €/MWh.

	Month of interest											
Station	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Aachen	.10	.07	.06	.03	.05	.05	.05	.06	.04	.04	.09	.05
Augsburg	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Bamberg	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Berlin-Tempelhof	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Bremen	.04	.07	.05	.06	.08	.05	.07	.06	.06	.05	.05	.05
Dresden-Klotzsche	.02	.02	.02	.02	.02	.01	.01	.01	.02	.02	.02	.02
Duesseldorf	.01	.01	.01	.01	.02	.01	.01	.01	.01	.01	.01	.01
Emden	.03	.05	.03	.04	.05	.04	.04	.04	.04	.04	.03	.04
Erfurt-Weimar	.04	.02	.03	.03	.02	.03	.02	.04	.03	.03	.04	.03
Fichtelberg	.08	.04	.08	.07	.07	.08	.07	.10	.08	.07	.05	.08
Frankfurt/Main	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Goerlitz	.01	.01	.01	.01	.01	.01	.00	.01	.01	.01	.01	.02
Greifswald	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Hamburg-Fuhlsbuettel	.03	.06	.04	.06	.07	.05	.06	.04	.05	.05	.04	.03
Hannover	.01	.02	.01	.02	.02	.02	.02	.01	.01	.01	.02	.02
Helgoland	.11	.11	.11	.09	.13	.11	.18	.13	.15	.14	.11	.11
Hof	.01	.01	.00	.01	.00	.01	.00	.01	.01	.01	.01	.01
Hohenpeissenberg	.02	.02	.02	.01	.01	.02	.01	.02	.01	.01	.03	.03
Kahler Asten	.21	.13	.17	.14	.15	.18	.14	.17	.15	.18	.15	.17
Kempten	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Konstanz	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Leipzig/Halle	.02	.02	.02	.02	.02	.02	.01	.02	.02	.02	.02	.03
Lindenberg	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Magdeburg	.01	.01	.01	.01	.01	.01	.00	.01	.01	.01	.01	.01
Meiningen	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Neuruppin	.01	.02	.01	.02	.01	.01	.01	.01	.01	.01	.01	.01
Nuernberg	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Potsdam	.11	.15	.13	.18	.11	.14	.12	.10	.13	.13	.13	.14
Rostock-Warnemuende	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Saarbruecken-Ensheim	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Schleswig	.03	.05	.05	.06	.05	.03	.04	.03	.04	.03	.04	.03
Schwerin	.04	.07	.06	.08	.06	.05	.04	.05	.06	.05	.06	.06
Straubing	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Stuttgart-Echterdingen	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Westermarkelsdorf	.03	.04	.05	.04	.05	.05	.06	.05	.05	.04	.04	.04
Wuerzburg	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00
Zugspitze	.02	.02	.03	.01	.01	.02	.02	.03	.02	.02	.02	.02

Table 4: Weights ω_{ij} of location i and month j as given by lemma 1 from 2010-07 to 2011-06. Although the weights vary over the month, the locations Fichtelberg, Helgoland, Kahler Asten and Potsdam represent nearly 50% of the summed weights. In this sense, the wind profiles at these locations are most representative for the overall profile.

B. Additional tables

Number	Station	f.load	mean	med	std	skew	kurt
1	Aachen [202, 16.0]	875h	3.1	2.6	2.0	1.2	4.6
2	Augsburg [462, 10.0]	984h	2.9	2.4	2.0	1.4	5.9
3	Bamberg [239, 10.0]	356h	2.2	1.9	1.4	1.0	3.9
4	Berlin-Tempelhof [48, 10.0]	1559h	3.8	3.5	1.9	0.9	4.3
5	Bremen [4, 10.0]	1986h	4.1	3.8	2.2	0.9	4.2
6	Dresden-Klotzsche [227, 10.0]	2002h	4.2	3.8	2.2	1.0	4.2
7	Duesseldorf [37, 10.2]	1787h	3.9	3.7	2.1	0.8	4.0
8	Emden [0, 9.7]	2382h	4.4	4.1	2.3	0.8	3.9
9	Erfurt-Weimar [316, 10.0]	2055h	4.2	3.7	2.5	1.2	5.0
10	Fichtelberg [1213, 23.8]	5360h	9.1	8.4	4.8	0.7	3.3
11	Frankfurt/Main [112, 10.0]	1219h	3.3	2.8	2.0	1.2	5.0
12	Goerlitz [238, 13.0]	1723h	3.9	3.4	2.4	0.9	3.8
13	Greifswald [2, 25.0]	1091h	3.8	3.5	2.1	1.0	4.7
14	Hamburg-Fuhlsbuettel [11, 10.0]	1821h	4.0	3.7	2.1	0.7	3.3
15	Hannover [55, 10.0]	1627h	3.8	3.5	2.0	0.8	3.8
16	Helgoland [4, 10.0]	5956h	8.4	8.0	3.9	0.5	3.0
17	Hof [565.1, 16.0]	762h	3.2	2.9	1.7	0.9	4.1
18	Hohenpeissenberg [977, 40.5]	2265h	5.5	4.5	3.7	1.5	5.6
19	Kahler Asten [839, 27.3]	3041h	6.1	5.7	2.5	0.7	3.8
20	Kempten [705, 10.0]	205h	2.0	1.8	1.1	1.2	5.9
21	Konstanz [443, 17.0]	271h	2.1	1.7	1.4	2.0	9.4
22	Leipzig/Halle [144, 10.0]	2078h	4.3	3.9	2.2	1.1	4.8
23	Lindenberg [98, 10.4]	1234h	3.5	3.2	1.9	1.3	5.5
24	Magdeburg [76, 18.0]	476h	2.6	2.3	1.7	1.2	5.4
25	Meiningen [450, 18.0]	818h	3.2	2.9	1.9	0.8	4.0
26	Neuruppin [38, 18.0]	678h	3.0	2.8	1.8	0.8	3.8
27	Nuernberg [314, 10.0]	890h	3.0	2.7	1.8	1.3	5.7
28	Potsdam [81, 37.7]	1092h	4.3	4.1	1.9	0.8	4.5
29	Rostock-Warnemuende [4, 22.0]	2036h	4.8	4.1	2.9	1.4	5.4
30	Saarbruecken-Ensheim [320, 10.0]	1471h	3.6	3.3	2.1	0.9	4.2
31	Schleswig [43, 16.6]	1396h	4.0	3.6	2.0	0.9	4.1
32	Schwerin [59, 22.0]	1123h	3.8	3.4	2.1	1.1	4.7
33	Straubing [350, 10.0]	656h	2.6	2.2	1.7	1.5	6.2
34	Stuttgart-Echterdingen [371, 10.0]	785h	2.6	2.1	1.9	1.3	5.1
35	Westermarkelsdorf [3, 10.0]	4011h	6.1	5.6	3.2	0.8	3.8
36	Wuerzburg [268, 10.0]	1159h	3.1	2.6	2.1	1.3	5.4
37	Zugspitze [2964, 16.0]	4499h	7.3	6.6	4.0	1.0	4.6

Table 5: Descriptive statistics of the wind speeds of all considered weather stations for the time 2001-01-01 to 2011-06-30. The wind speeds are measured on an hourly grid. The brackets behind the names contain the respective absolute altitudes of the stations and wind detector heights in m. The column *f.load* contains the average numbers of full load hours of the modern benchmark turbine considered in section 3.1. As to be expected, the mean values of the stations deviate clearly with values below 2 m/s (Kempten) and over 8 m/s (Fichtelberg, Helgoland). Kempten is located in a shielded valley in southern Germany, while Fichtelberg lies exposed in the forelands of Bavaria and Helgoland lies exposed in the north sea. All wind distributions are skewed to the right and show excess kurtosis, i.e., are heavier tailed than the Gaussian distribution.

		Unconstr. Model	Constr. Model	
β_i	Station		absolute	relative
β_0	–	261401.9	0.0	0.0 %
β_1	Aachen	199.3	283.0	2.1 %
β_2	Augsburg	-117.9	0.0	0.0 %
β_3	Bamberg	-50.3	0.0	0.0 %
β_4	Berlin-Tempelhof	-778.3	0.0	0.0 %
β_5	Bremen	632.0	593.0	4.3 %
β_6	Dresden-Klotzsche	-661.8	0.0	0.0 %
β_7	Duesseldorf	183.0	134.4	1.0 %
β_8	Emden	561.3	461.6	3.4 %
β_9	Erfurt-Weimar	778.0	699.5	5.1 %
β_{10}	Fichtelberg	620.5	456.3	3.3 %
β_{11}	Frankfurt/Main	-197.5	0.0	0.0 %
β_{12}	Goerlitz	-768.3	0.0	0.0 %
β_{13}	Greifswald	61.6	0.0	0.0 %
β_{14}	Hamburg-Fuhlsbuettel	341.1	322.7	2.3 %
β_{15}	Hannover	-56.1	0.0	0.0 %
β_{16}	Helgoland	392.9	521.6	3.8 %
β_{17}	Hof	238.1	0.0	0.0 %
β_{18}	Hohenpeissenberg	939.4	771.8	5.6 %
β_{19}	Kahler Asten	1398.6	1538.6	11.2 %
β_{20}	Kempten	-660.0	10.8	0.1 %
β_{21}	Konstanz	984.7	567.9	4.1 %
β_{22}	Leipzig/Halle	349.0	187.8	1.4 %
β_{23}	Lindenberg	846.9	369.5	2.7 %
β_{24}	Magdeburg	1655.0	2234.9	16.2 %
β_{25}	Meiningen	611.1	295.8	2.2 %
β_{26}	Neuruppin	760.3	262.9	1.9 %
β_{27}	Nuernberg	35.4	0.0	0.0 %
β_{28}	Potsdam	3424.7	2797.8	20.3 %
β_{29}	Rostock-Warnemuende	10.6	0.0	0.0 %
β_{30}	Saarbruecken-Ensheim	16.2	0.0	0.0 %
β_{31}	Schleswig	250.1	306.4	2.2 %
β_{32}	Schwerin	693.0	321.9	2.3 %
β_{33}	Straubing	-340.6	0.0	0.0 %
β_{34}	Stuttgart-Echterdingen	-249.8	0.0	0.0 %
β_{35}	Westermarkelsdorf	149.2	168.9	1.2 %
β_{36}	Wuerzburg	-227.5	0.0	0.0 %
β_{37}	Zugspitze	316.8	447.2	3.3 %

Table 6: Estimated β-coefficients of model (7) predicting the overall wind energy feed-in. The first column shows the results of the unconstrained model, i.e., β-coefficients may be negative. The second and third columns refer to the constrained model with positive coefficients and $\beta_0 = 0$. In the third column, the estimetd values are shown while the fourth column refers to their relative proportion in the sum of all βs. The third column may be interpreted in that way, that the allocation of β_i units of GE 1.5 MW turbines at station i would reproduce the German overall wind energy production (see section 3.2).

ABOUT EWI

EWI is a so called An-Institute annexed to the University of Cologne. The character of such an institute is determined by a complete freedom of research and teaching and it is solely bound to scientific principles. The EWI is supported by the University of Cologne as well as by a benefactors society whose members are of more than forty organizations, federations and companies. The EWI receives financial means and material support on the part of various sides, among others from the German Federal State North Rhine-Westphalia, from the University of Cologne as well as – with less than half of the budget – from the energy companies E.ON and RWE. These funds are granted to the institute EWI for the period from 2009 to 2013 without any further stipulations. Additional funds are generated through research projects and expert reports. The support by E.ON, RWE and the state of North Rhine-Westphalia, which for a start has been fixed for the period of five years, amounts to twelve Million Euros and was arranged on 11th September, 2008 in a framework agreement with the University of Cologne and the benefactors society. In this agreement, the secured independence and the scientific autonomy of the institute plays a crucial part. The agreement guarantees the primacy of the public authorities and in particular of the scientists active at the EWI, regarding the disposition of funds. This special promotion serves the purpose of increasing scientific quality as well as enhancing internationalization of the institute. The funding by the state of North Rhine-Westphalia, E.ON and RWE is being conducted in an entirely transparent manner.