Forecast of Regional Power Output of Wind Turbines

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A method for predicting the power output of wind turbines connected to the public electricity grid will be introduced. Using this procedure it is possible to forecast – over a time horizon of 6 - 48 hours – the wind power to be expected. Base of the method are the operational, large scale wind field predictions of the numerical *Deutschlandmodell* of the german weather service DWD. For wind power forecast, these predictions have to be spatially refined. The local roughness and orography conditions have to be taken into consideration for this. The procedure has been used for wind and power prediction for several sites distributed over the northern part of Germany. The quality of the predictions will be discussed in comparison to measured values of a one-year database.
Keywords: Forecasting Methods, Utility-Integration, Meteorology, Models(Physical)

1 Introduction

The development of wind energy use has led to a noticable contribution to the energy supply in Denmark and Northern Germany. At the moment, the installed capacity of wind turbines is in the order of magnitude of the minimal load of the corresponding utility (approx. 30 % of max. load). The feed in of electricity by wind energy comes out as a negative load leading to an increase in fluctuations of net load patterns. The insecurity of the development of wind speed has consequences for the operation of conventional power plants or the load management respectively (Figure 1). For a time scale of some hours to two days additional reserves have to be kept ready to replace the wind energy share in case of decreasing wind speeds.

In this paper we introduce our investigations of predicting the power gained from wind energy on base of a numerical weather prediction model covering a prediction time range from 6 to 48 hours.

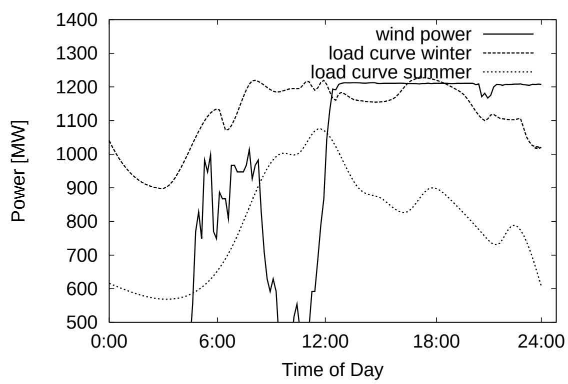

Figure 1: Typical curve of load of a north germany utility (summer and winter). One can see the fluctuations of the power output of a wind turbine as well, scaled up to the installed power of all turbines in the supply region of the utility. Balancing effects smoothing this curve, have not been considered here.

2 Model approach

In principle the general numerical weather prediction models of the national or european weather services provide information on the temporal development of meteorological values including wind speed and direction. In Germany the weather service DWD uses the numerical *Deutschlandmodell* with a – internal – temporal resolution of one hour and a spatial grid of approx. $14 \times 14\,\mathrm{km}^2$. Due to this given horizontal resolution the local wind conditions at the wind turbine site are only described very coarse or not at all. Furthermore, the height level of model levels differ from the hub heights of the wind turbines in general. For an application for wind energy forecasting, these predictions have to be refined spatially to gain a local prediction which in the end leads to an overall forecast of wind power.

The first approach in this direction has been developed at Risø National Laboratory in Denmark. On base of the numerical weather prediction model HIRLAM a 36-hour-forecast of windpower was developed and used for scheduling conventional power plants [1]. The procedure presented here for Germany is analogous to the danish one. The wind field predicted from the *Deutschlandmodell* will be transformed to the height of the wind mast or the wind turbines hubheight respectively under consideration of the roughness given in the direct surrounding of the turbine (Figure 2).

Numerical Weather Prediction
Deutschlandmodell
Wind speed
$t_0 + 6\text{h}, +12\text{h}, \ldots, +48\text{h}$
Resolution $14 \times 14\,\text{km}^2$

$\Downarrow$

Horizontal Refinement
to local Site
(Roughness,Stability,Orography)

$\Downarrow$

Model Output Statistics
for Correction of
systematic Errors

$\Downarrow$

Wind Turbine
Power Characteristic
Wind Farm Effects

$\Downarrow$

Local Prediction of
Power Output

Figure 2: Principle of the spatial refinement of the Deuschlandmodell*-prediction, leading to a local prediction of wind conditions.*

3 Prediction refinements

Starting point of the refinement is the predicted wind speed and direction of the *Deutschlandmodell*. This is transformed into the regional geostrophic wind using a mesoscale roughness length given by DWD and the geostrophic drag law

$$G = \frac{u_*}{\kappa}\sqrt{\left(\ln\left(\frac{u_*}{f\,z_0}\right) - A\right)^2 + B^2}$$

Here, G denotes the geostrophic wind speed, u_* the friction velocity, z_0 the roughness length, f the Coriolis parameter, A, B are constants.

Data at the four surrounding grid points of the *Deutschlandmodell* have been transformed to the site of the wind turbine using a distance weighting.

In the next step the wind has to be transformed to the hubheight of the wind turbine, which is done analogous under account of a detailed description of the local roughness conditions using the logarithmic wind profile and a correction term Ψ describing the thermal stratification of the atmosphere:

$$u(z) = \frac{u_*}{\kappa}\left(\ln\left(\frac{z}{z_0}\right) - \Psi\left(\frac{z}{L}\right)\right)$$

Here, $u(z)$ denotes the horizontal wind speed at height z, κ the von Kármán constant, u_* the friction velocity, Ψ the thermal stability correction function depending on the Monin Obukhov length L.

Roughness changes are also considered in the model. The used methods are analogous to the approach in the European Wind Atlas. Connecting this local wind speed with the power curves of wind turbines, the power output to be expected is predicted.

4 Comparing predictions and measured data

For the application we used prediction data of the *Deutschlandmodell* from January 1996 to December 1996. These have been the 6, 12, 18, 24, 36 and 48 hour predictions at the initialisation time 00:00 UTC with a spatial horizontal resolution of 0.125 degree, which is approx. $14 \times 14\,\text{km}^2$. The measured data needed for comparison covers the same time period and has been taken from the german WMEP-program[1]. The refined results of the prediction model have been compared with measurement data from 6 sites distributed over Northern Germany (Figure 3).

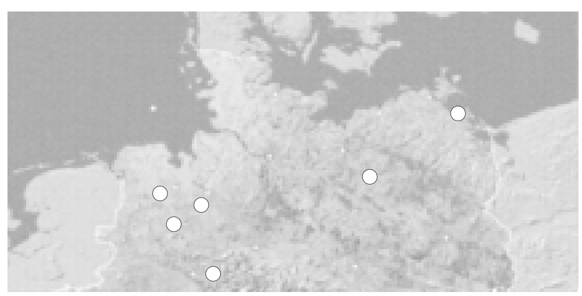

Figure 3: Sites under investigation.

But even though it is a relatively long period for measured data, there still is a lack of data for deeper statistical investigations, especially for higher wind speeds. Mainly two reasons are the cause for this: The available time resolution of 6 hours is too coarse and high wind speeds do not occur very often over a longer period of time in Northern Germany.

[1]Wissenschaftliches Meß- und Evaluierungsprogramm (Scientific measurement and evaluation program) of the german ministry BMBF, managed by ISET, Kassel.

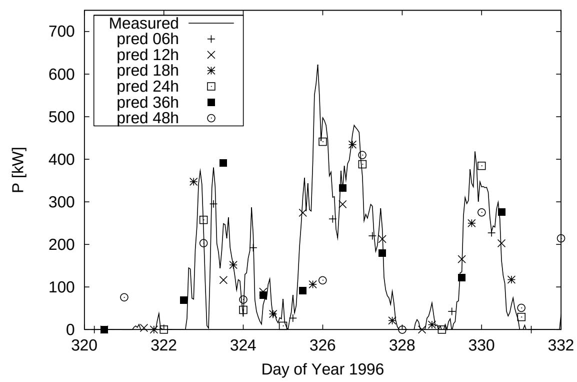

Figure 4: Time series of a predicted and measured power output for a site near the coastline.

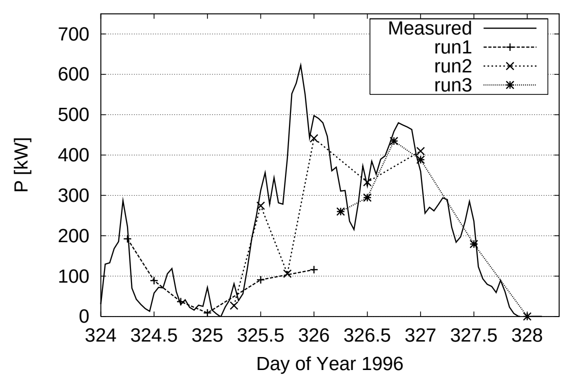

Figure 5: Part of the time series of Figure 4, showing the prediction of three model runs. The one at day 325/326 does not recognize the increasing wind speed.

First comparisons with measured data show a good general agreement. Figure 4 shows a typical time series of measured and predicted wind power for one turbine. The two storm events are predicted quite well, especially as far as it concerns a prediction time up to 24 hours. Nevertheless for the 36 and 48 hour forecast the differences to measured values are larger – especially on day 325/326 (Figure 5).

Table 4 shows the RMS error of measurements and forecasts for different forecast times. The error was gained by comparing one year of predictions and an according data set of six measuring stations. The error is normalized to the maximum power output of the turbines. For the regional power output (here: the sum of all 6 turbines), the forecast insecurity is significantly smaller (see also Table 4).

For prediction times up to 24 hours the RMS-deviation is nearly constant, but raises for the 36 and 48 hour forecasts. On a first view the normalization on maximal power output does not seem to be very conservative. Nevertheless this makes sense because in practice – as a tool for supporting conventional

Site	6 h	12 h	18 h	24 h	36 h	48 h
1	11	12	12	14	15	15
2	12	15	14	14	18	19
3	11	11	13	14	17	18
4	11	11	12	11	17	16
5	9	10	11	12	15	15
6	12	14	15	13	19	17
Mean	11	12	13	13	17	17
Regional	7	8	9	9	13	13

Table 1: Comparison of predicted and measured power output of wind turbines, normalized on the respective maximal power output. Shown are the RMS error values for 6 sites for different prediction times. The mean value of all stations can be seen as well as the error for the lumped power output of all turbines.

power plant scheduling – not the relative deviations between prediction and real power output are of interest but the absolute deviations. For example, often occuring deviations at absolute small power outputs lead to a high RMS error, but have no meaning for the operation of a conventional power plant, whereas at high absolute power outputs with a high meaning for scheduling conventional power plants, the deviations are over-estimated.

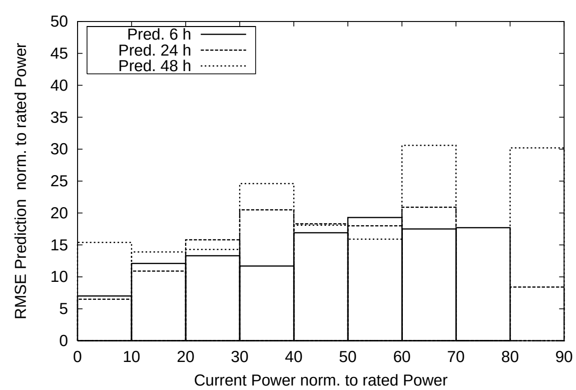

Figure 6: Normalized RMS-error between prediction and measurement, classified after power output.

Figure 6 shows the deviation for one site classified after the measured power output. Values range between 12 and 20 %. They do nearly not raise for higher mid-range power outputs. Only the 48-hour-forecast shows up with a very high deviation at rated power output. The reason for this is probably the very low number of data pairs in this power range, leading to a high insecurity of statistical values.

5 Spatial correlation of deviations

Regarding the spatial correlation of the prediction deviations (see Figure 7 for 12 h and 48 h forecast) one can see the correlation decreasing with growing distance. This means, the standard deviation declines when regarding regions covering a hundred kilometres and more. Furthermore, the deviations for longer prediction times are more correlated than for short ones. This is due to the increased systematic error of the prediction for longer times.

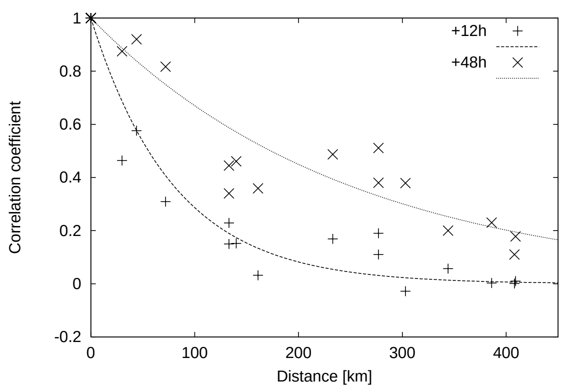

Figure 7: Spatial correlation of prediction deviations.

6 Regional balancing effects

Regarding the lumped power output of all turbines in a region, it is possible that the local deviations at the sites are compensating each other. The magnitude of this effect is depending on the correlation of the deviations for the different turbines. Figure 8 shows a comparison between the RMS errors for single sites and the lumped power output, regarding different prediction times. The deviation for the total power output is reduced significantly. As expected, the relative improvement decreases for the longer prediction times (see Table 4 as well). The reason for this is the increase of the systematic error at higher forecast times.

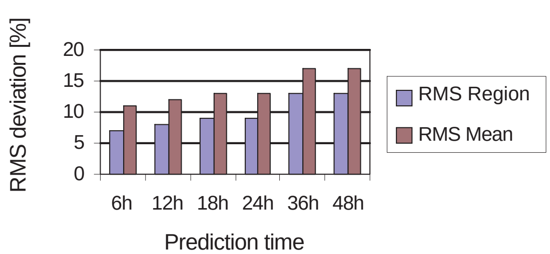

Figure 8: Comparison of regional RMS errors with the mean value of RMS errors of the single sites. A look at the power output of all turbines in a region leads to a clear decrease of deviation between measurement and prediction at all prediction times compared to single sites.

Figure 9 shows a comparison between predicted and measured normalized power output for a single site and for the lumped power output. The reduction of scattering can clearly be seen.

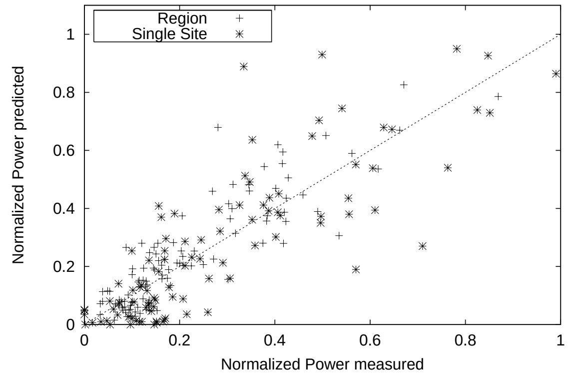

Figure 9: Comparison between measured and predicted power output for a single site and the sum of all 6 sites in the region, normalized to the maximal power output respectively.

7 Résumé

As a conclusion, it can be stated that the shown approach for a wind energy weather forecast is quite encouraging.

We have shown that a prediction of the power output of wind turbines on base of the numerical *Deutschlandmodell* is possible and leads to reasonable results. The forecasts of the *Deutschlandmodell* have been refined with a model that takes local surface conditions into account.

At low power outputs high deviations between measurement and prediction have been gained. Higher power outputs resulted in good predictions. When regarding the regional lumped power output, uncertanties of the prediction could be reduced compared to the prediction for single sites.

Inclusion of measured power data into the prediction model is one possibility to improve the procedure, because measured power curves often differ drastically from manufacturers data.

8 Words of Thanks

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9 References

[1] Lars Landberg: *Predicting the power output from wind farms.* Proceedings of the EWEC 1997, Dublin.