HONEYMOON - A High resOlution Numerical wind EnergY Model for On- and Offshore forecasting using eNsemble predictions

Special Project Final Report

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28th June, 2006

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Contents

1 Introduction

Wind power forecasting is an important tool in the daily operation of today's energy markets, because the wind power today is in many countries traded on a market one day prior to the generation time. Each market participant inclusive the wind power generator must follow a schedule with typically 15 minute intervals for the next period, mostly one day. Any deviation needs to be levelled out between the market participants. Urgency and lack of competition causes the final balance costs to increase towards the time period of generation. To get a fair price on wind generated electricity, the sale of wind power would therefore have to be as close to the actual generation (closing of the market) as possible or better a month after generation when the actual generation has been retrieved and approved. Even the estimated production from selected turbines may lack accuracy. Already produced electricity has no value on a liberalised market even if it is renewable. Thus, the wind power production forecast is what creates value for the wind farm generator, the society and the security of the electrical grid.
The wind power prediction step is the last step in a long production chain, where the output from NWP models is one of the most important input sources. Around year 2000 many studies concluded that the wind power forecast error is due to NWP wind speed forecast errors (e.g. Landberg, 1994, 2001, Thor, 2003, Mönnich, 2000, Martí, 2001). This conclusion has resulted in many studies that investigated the impact of the NWP model's imperfect prediction of wind speeds for wind power predictions (see Giebel, 2003/2006). Modelling experiments, where NWP models were downscaled up to 1km (e.g. Barstad 2001, Bergen, 2003, Moehrlen. 2004) however could not proof that the accuracy of the wind speeds improved significantly enough when applied to wind power to promote higher resolution modelling for wind power prediction purposes. The well known phenomena of double punishment in the high resolution experiments led to the conclusion that other methods have to be developed in order to improve wind power prediction and hence Articles (e.g. Giebel 2003/2006, Jackson, 2003) continue to state that the NWP models are mainly responsible for the prediction error in wind power.

1.1 The Misinterpretation of Weather Forecasts in the Wind Energy Community

The statement that the prediction error of wind power predictions is a result of imperfect weather forecasts came from countries, where there are a large amount of small turbines gathered in small farms with less than 1MW and well dispersed. The view has been that, if the wind speed is correctly forecasted, then the wind power is also correct, even with the most simplistic transformation to wind power. We will refer to this view as the "true-wind belief". It has to be noted, that this is a valid statement for such environments at days, where many turbines produce approximately the same amount of energy. This typically happens, when the isobars are straight lines and the major pressure extremes are far away from the target area and are only slowly moving. Nevertheless, the statement has let to the conclusion that it is enough to have a simplistic conversion of wind to wind power, if the wind speed is computed correct. However, the correctness of this statement only holds, if many dispersed turbines are considered that do not affect each other, because then the effective wind speed over the area can be well predicted from a NWP model. In other situations, or if the wind power capacity is built up upon fewer, larger wind farms with less dispersion, this statement does no longer hold (see also Kariniotakis et al, 2004).

We will discuss here the pit-falls of this “true-wind belief” in order to bring awareness to end users and providers of forecasts, that it is wrong to blame the weather forecast.

Improvements of wind power prediction however have to come from a dialogue between the meteorological and wind energy community. Unfortunately, this has not been achieved in the past.

If we look closer into the statement, then this “true wind” or more correctly expressed, “momentum flux” could be demonstrated by selecting a single wind turbine on a hill. The “momentum flux” is the flow along the blades with increasing weight towards the tip of the blades. The flux integral is dependent on the shape of the blade as the torque increases with the distance from the center where the blade becomes narrower. This flux is a function of the wind speed, if the flow around the blade is constant and laminar. Wind shear, direction changes with height and time among other processes, spoil the efficiency of this process. Only, if the efficiency of the process would be constant, the “true wind belief” would hold. If we in addition assume a linear and weak vertical wind profile, then we can even measure the “true wind” at the center of the rotor.

The next problem is however that it is not trivial to convert raw model output to this particular “true wind speed”. The turbines produce power according to the wind speed in the rotor area on second basis. To compute this wind speed is very difficult and far beyond the purpose of a NWP model’s prediction of the wind speed.

The goal in fact is to compute a 15-min time integral with a power curve of the “true wind speed”. We have an area averaged wind speed from a discrete approximate wind field in maybe steps of one hour. We have a rotor diameter of 100m with a known height above ground. There will be changes to the wind from the diurnal cycle. There might also be inversions within the 100m rotor diameter, which may cause confusion of the effective wind direction. This process calls for a considerable level of parameterisation including a number of subgrid effects. Therefore, we have to question, whether the “true wind belief” has any practical relevance.

The fact, that the wind is not constant and that the power production changes on second basis has never been of interest to NWP model developers until wind energy established as a serious energy source that requires forecasts of meteorological parameters to become a sustainable and predictable source.

The aim of this report is summarise the experiences gained within the past 4 years on this topic and to explain the need for weather forecasts for the wind industry. We will also focus on discussing how weather forecasts should be understood and used. The report is written to the meteorological community with the intention of explaining what the wind power community needs.

Our belief is that each turbine has an identity that should not be hidden via smoothing, but used actively in the predictions. The wind energy community rather prefers to smooth out the identity before computing the power. The smoothing is about taking care if hidden problems that may be of relevance, thus, risking that the predictions may not continue to improve.

We believe that the weather and wind power prediction systems do have to work well together to generate result that are of sufficient quality to ensure that possible future deployment will not be suppressed, because of the wind power’s seemingly “unpredictable nature”.

2 Forecasting error decomposition

The wind energy community has published average wind power forecast errors between 2 and 50%. Both extremes appear unrealistic, knowing the verification scores of near surface NWP model output parameters.

Most of the difference is a result of different computations of the error with different verification standards.

- The error can be measured relative to installed wind power capacity or relative to the delivered wind power. The average load differs from region to region in the range 15% to 50% of peak production. Thus, using the delivered wind power as reference at 15% average load gives an error that is over 6 times higher than the error relative to the installed capacity. Errors relative to the delivered production can produce infinite numbers and hide the events where no energy was produced nor forecasted. Small errors may appear large in periods without much wind.
- The RMS and STDV scores are normally 30% higher than the MAE error. Thus, a factor 1.3 may lie in the choice of the verified parameters.
- The forecast error contains two components: The error that is due to the NWP error growth and a relatively unknown remainder. As the NWP forecasts become better, this remainder also becomes more important to minimise. The NWP service provider is naturally not responsible for the remainder of the error. Part of the source of the error is therefore hidden in today's verification.

Nearly all wind farm projects after year 2005 will have sizes between 20MW and 300MW. The installation costs amounts to about 1 Mio. EUR per installed MW. The payback will be around 1.5 times the investment over 15 years, if the power is sold on liberalised market terms. The payback rate is in fact highly influenced by tax and subsidy rules introduced to accelerate installation of Renewables. The pioneer countries have still many older small turbines installed that are well dispersed. An area integral in these countries is likely to be more accurate than a point measurement, because a single wind farm reacts on one boundary layer eddy, while the reactions from many dispersed turbines is uncorrelated. The error level of one single wind farm is therefore higher than for an area integral, especially compared to the summation over many approximately equally sized, smaller wind farms. There is therefore a tendency that the forecast error is higher for the newly installed larger wind farms than for the older dispersed wind farms.

Part of the wind power forecasting error could in fact be considered as a consequence of the lack of planning, i.e. allowing wind farms to be built without consideration of their output predictability. This pattern is a result of fixed price policy, where the owner is payed proportional to the delivered amount of wind power only without penalties for the noise that may arise from poor predictability of this particular farm.

The brings us back to the fundamental problem of understanding which parts of the error are due to the the initial conditions, the weather forecast and the computation of the wind power generation, respectively.

The serious errors are undoubtedly a function of the weather forecast. At a certain time, a day-ahead forecast can have an error of 50-60%, which was not necessarily present in the short-term forecast. Such errors do happen with prediction errors of 3-4m/s even near an almost stationary high pressure system, if the sea level geostrophic wind is in the range 8-13m/s.

In this range, the error is dramatic in wind energy and harmless in terms of weather. Nevertheless, the official weather forecasters broadcast to the public empirical margins of about 5m/s uncertainty, because of the sensitivity of the wind speed to the cloud cover and the detailed shape of the isobaric field. A major problem in wind power context is that this margin occasionally implies an uncertainty of 100% in wind power. The consequence is that the environmental and economic value of wind power drops and the NWP model output is blamed to be the source of the problem. A reputation that is hard to escape.

The best answer to this problem is to develop tools that can quantify the uncertainty with objective methods and that hour by hour predicts the uncertainty in advance.

Once the uncertainty is known, then it is a matter of market arrangements to prepare for the possibility to exchange schedule deviations at day-ahead traded market prices for reserve instead of a last minute corrections. The ensemble forecasting approach is the natural choice to provide such information, because it is an objective method and it can be constructed to simulate a portion of the uncertainty that causes the day-ahead wind power prediction errors.

Weather ensemble forecasting is approaching it's 15-year anniversary in 2006 and the industry still seems somewhat reluctant in adopting the objective uncertainty estimates from ensembles. The globalised economy may however be able to change this pattern soon, because of the daily trading of energy that has impact on everybody via consumer prices and profits, which nowadays drive the world economies.

We belief, that an ensemble of wind power forecasts will have to be built for the wind industry on top of an ensemble of weather forecasts, because the uncertainty caused by other factors than the weather forecasts need to be incorporated.

2.1 The Error Statistics of Wind Power measurements

An objective quality check of measurements with a maximum threshold error tolerance can hardly work in wind power. The major problem is that the wind speed changes frequently between 5 and 11m/s due to boundary layer eddies, equivalent to. 10-85% of the peak generation. A filter with a maximum error tolerance would therefore exclude many correct observations. The best approach is to accumulate the measurement over an hour or many similar turbines, but with the risk of hiding false measurements. Therefore, we applied a manual control check before and after time accumulation and site accumulation in our investigations.

The engineering and weather forecasting literature has often used the word noise as a synonym for model errors. This wording is somewhat misleading when used for wind power, because noise is something that applies quite pronounced to the measurements. Figure 1 illustrates the noise of wind power measurements at a wind farm, when measured in 15 minute intervals (left picture) and 1 hourly averages (right figure). It can be seen that there is a significant portion of noise in the measurements, whereas the forecasts (white lines) are rather smooth functions. When averaged over one hour, the measurement noise is reduced, even though the variability is still much larger than the forecasts.

The 10min average of a 10m wind speed is hence a much better estimate of the the mean value, because the time scale of eddies in 10m altitude is short enough to ensure that the 10min mean converges. Figure 1 shows that the accuracy of a 15 minute wind power measurement in a height of 60m to 80m above ground does not seem to be as reliable as the 10m wind. This is most likely due to bigger eddies' timescale that are of the same order as the sampling period. An amplitude of 1-2 m/s has however significant impact on the power, if the mean value is in the range of 6-11m/s. A SODAR in front of a solitary turbine would in fact be required to further investigate the relationship between noise and large scale boundary layer eddies.

The small boundary layer eddies might even be another source of uncertainty, because they could have effect on the software control system of the turbine. The turbines search for the optimal direction based on the wind direction near the center of the blades. This is likely to not be optimal in stable conditions, where the bulk of the torque on the blades is above the center with a different mean wind direction than below.

A 30-45 deg. wind direction discontinuity across an inversion is likely to "confuse" a wind turbine, if the controlling device is located in the conditions below the inversion and the blades range above the inversion.

It can be concluded that weather, software and hardware play together and generate a fairly chaotic pattern. To find out, which of the components are responsible for the bulk of the forecasting error, or which combination of components is creating large errors is not a trivial task. A decomposition of the errors is required as much as detailed observational data to find an adequate answer.

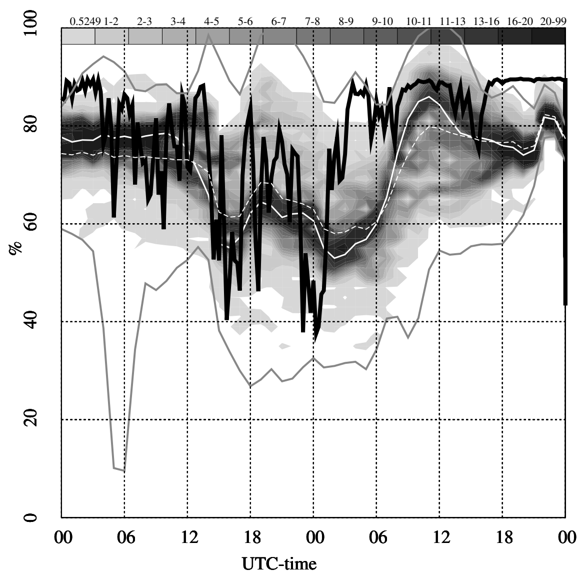

Figure 1: Example of a 48h forecast (white lines) and uncertainty distribution (gray shading) of wind power in % installed capacity and corresponding power measurements at a wind farm. The measurements are at 15 min intervall.

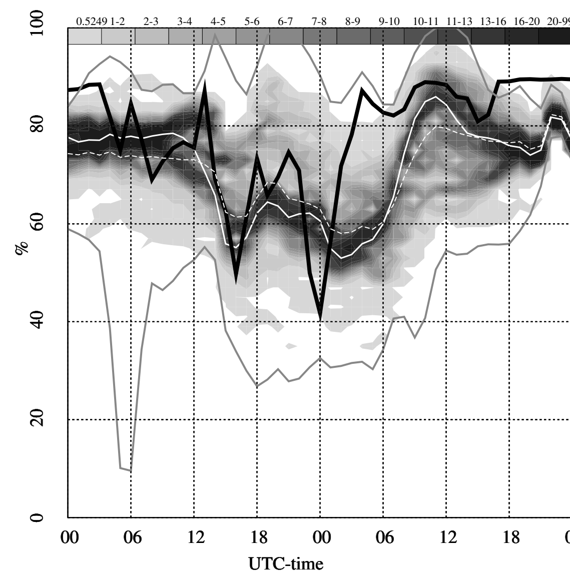

Figure 2: Example of forecasts (white lines) and uncertainty distribution (gray shading) of wind power in % installed capacity and corresponding power measurements at a wind farm. The measurements are at 1 hour intervall.

2.2 Transformations between Model and Observational space

End users need at present only the predicted aggregated production given with equationeq1.

$$MAE_{time} = abs(\sum_{site=1}^{N_{site}} FC_{time,site} - \sum_{site=1}^{N_{site}} OBS_{time,site}) \tag{1}$$

where $FC_{time,site}$ and $OBS_{time,site}$ represent forecasted and observed effect for each of the N_{site} wind farms. This equation illustrate a one dimensional problem in which concurrent positive and negative errors partially cancel each other. The observational coordinate system is however non-uniform in geographical coordinates. Thus, the equation appears simple. However, internal phase errors turn out as additional errors, because of horizontal inhomogeneity. The equation therefore rather represents the economic value of the forecast, but

assumes that there are no transmission bottlenecks and that the balance costs are independent of the forecast error.
The real forecast quality is best described by 2, because this equation measures the predictions at every point and counts also the phase errors.

$$MAE_{time} = \sum_{site=1}^{N_{site}} abs(FC_{time,site} - OBS_{time,site}) \tag{2}$$

The measurement noise and local errors cause the error of 2 to be always greater than those of equation 1. Although the aggregated result is requested, the best performance over longer time is achieved by minimising the error of 2, which implies that predictions should be made for every wind farm.
Thus, the wind power output should be computed on farm basis taking into account:

- Effective rotor height computation in model space
- Wake effect computation including other specific obstacles
- Rotor averaged wind speed computation using a vertical wind profile
- A parametrisation for the deviation between the turbine's direction and the "real" wind direction
- A power curve to transform the effective rotor wind into wind power
- A specific algorithm for the cutoff behaviour etc.
- Scheduled service and maintenance
- Conditional generation constraints
- A time integral using time steps of the order seconds

For confidentiality reasons some of the wind farm specific information will however not be accessible. We are therefore forced to develop parameterisations that may apply for groups of turbines only.
Therefore, it is obvious that the resulting forecasting error is not only due to imperfect weather predictions.
The transformation from model space to physical space is also not trivial:

- The NWP delivers the 1^{st} order mean value of every variable
- The mean represents an area integral at a specific point in time, whereas the measurement is sampled locally in space
- The lower boundary condition used to diagnose the NWP variable is most likely not representing the local conditions well
- A staggered grid causes some in-consistency, because different wind components feel different roughness length with a risk of biased wind directions.
- The orographic difference between the 3D-model and the real terrain should be considered
- The orographic gradient differences and the effective dynamical resolution have to be taken into account
- The impact of fractional handling of the surface types need to be considered
- The discrete vertical resolution with few layers at levels, where the vertical wind profile is steepest requires specific solutions

- Varying height of the model levels

The list of approximations is long, but the results will improve as the raw model output improves, which may not be the case with a pure statistical translation.

2.3 Feedback from Wind Power to the Atmosphere

The western part of Denmark has an average energy drain of 0.1W/m^2 at full wind power production. Certain regions have up to 2.5W/m^2, which is still quite little compared to the average momentum flux. The energy drain will result in a reduced mean wind speed down-steam of the turbines. A 3MW turbine has a rotor radius of 50m and a kinetic energy flux of 13MW at 15m/s. Thus, the efficiency is said to be under 33%. The effect on the mean flow has little meteorological significance, but this might not be the case for the turbulent flow. The mixing length corresponding to the turbulent kinetic energy created by the wind turbine might be longer than the actual mixing length. This means that wind turbines can increase the vertical mixing and thereby suppress the development of a stable boundary layer. This process is not likely to have impact in unstable conditions, where the mixing length of the atmosphere is longer.
A possible way to parameterise this effect is to add a turbulent kinetic energy source in the relevant height by using an empirical fraction of the produced energy.
From this, it can be concluded that wind power measurements are on the one hand robust for studies of the boundary layer, but the feedback process causes some uncertainty in the interpretation of any results.

2.4 Sensitivity to small Wind Speed Errors

The feedback of turbines into the atmosphere is not the only problem, when using wind power measurements. The sensitivity to small errors under normal weather conditions and the insignificance to other errors may cause that the verification score in wind power does not result in the same result as a verification of wind speed.
In the following examples we will bring the attention to the problematic issue of interpretation and evaluation of wind power and weather.

* We consider a day with a relatively harmless wind speed error of 4m/s at say 7.5m/s. In such a situation a stationary high could control the weather on synoptic scale for one day and the forecast would be biased 4 m/s. This could easily result in a wind power error that is close to 50% in a period of 24 hours. Such an error may be caused by a small error in the initial conditions and hence does not express the true quality of the weather forecasts on synoptic scale.

* The same error of 4m/s near 16m/s results in very little wind power error and can easily be accepted, whereas the difference between 16m/s and 20m/s would be an unacceptable synoptic scale error.

* A wind speed error of 2m/s at around 24m/s would be an acceptable synoptic scale result, but an unacceptable error in wind energy, because of the danger of cut-off at around 25 m/s.

This simple example illustrates that “good performance” expressed in wind power context is relative and rather different than a “good performance” on synoptic scale weather forecasts. This discrepancy needs to be acknowledged from both meteorology and wind energy community, if progress in the predictability of wind energy should be achieved.

Another issue is the size of the forecasting error measured in wind power. Periods with 50-100% deviation between forecast and measurement may dominate a 3 monthly verification. One outliers of such size can in fact change the interpretation of a verification to the exact opposite. To generate a robust verification score in wind power, periods of at least one year are therefore required and recommended.

2.5 Ratio between NWP and non-NWP error of wind power forecasts

By showing the linear error growth of wind power forecasts with time, we are able to demonstrate that the bulk of the forecast error is already present in the 0-6 hour forecast, which is adopted to the observational state of the atmosphere as accurate as possible with the constraint that the 3-dimensional state should be in balance for further integration.
The time averaged total wind power forecast error can then be decomposed to:

- a background error present at the start of the forecast
- a linear error growth term increasing with the forecast length

The linear error growth is the contribution from the weather forecast. The background error contain all other sources.
The weather forecast error has two terms:

- incorrect synoptic scale initial conditions
- forecast model error

Only part of this error is directly visible on the background error, because the domain of the dependence for a two day wind power forecast is much larger than the electrical grid (the influence area). Thus a portion of the linear error growth is due to errors outside the domain of influence.
The origin of the initial condition errors can therefore be split on two domains:

- the dependency area with impact on the weather forecast error growth
- the influence area with impact on the accuracy of the short term wind power forecast due to insufficient resolution

A fraction of the error of the initial conditions arise from insufficient resolution, forecast and a component that is related to the effective resolution, which is part of the background error.
Higher spatial resolution and a stronger weight on the observations may reduce the background error and increase the linear error growth.

The verification results for 2005 from three TSO's areas in the Republic of Ireland (496MW), western part of Denmark (1800MW) and the eastern part of Germany (7400MW) indicate that the background error contributes with approximately 70% of the error for a day-ahead prediction. Figure 3 shows the forecast error over the forecast length for 2005 for these three TSO areas.

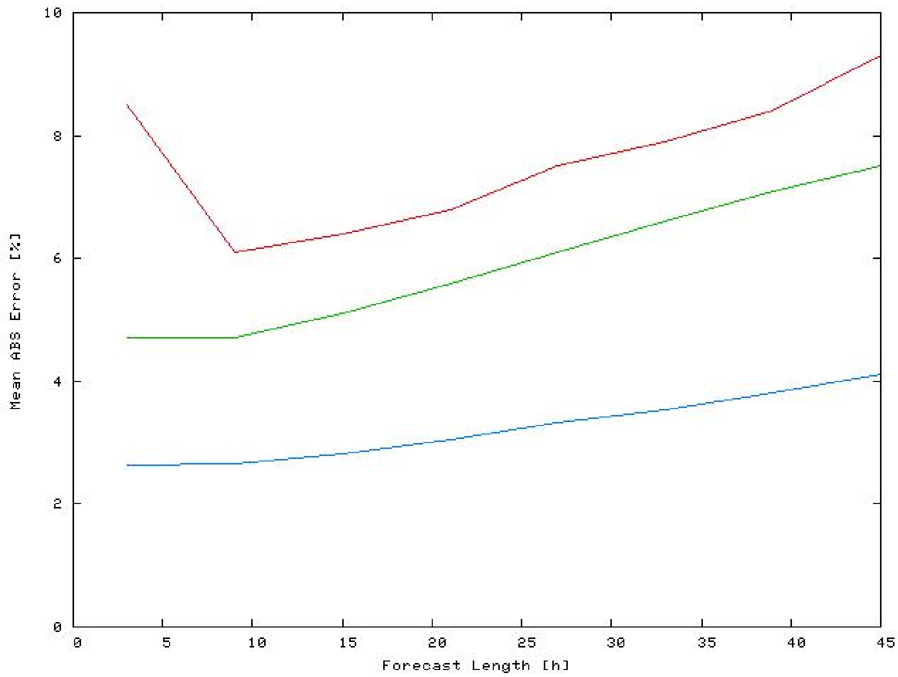

Figure 3: Verification results for 2005 for three TSO areas. The red line shows the result from Ireland covering 496MW, the green line shows the results from Denmark covering 1800MW of installed capacity and the lower blue line is the result from 7500MW of the German wind power capacity.

2.6 Value of verification results of atmospheric parameters

The dominance of the background error as described above is consistent with the experience from objective verification of 2m temperature and 10m wind, where the initial error is usually very high compared to the error in a two day forecast.

Part of the forecast error in an objective verification between SYNOP observations and raw forecasts is therefore not expressing forecast accuracy, but limitations in the localisation step.

Verification of wind, temperature and pressure in the context of wind power forecasting has therefore little value.

A statistical double conversion and correction from model to synop space on first weather parameters and secondly onwards to wind power can be done. However, it is difficult to justify why such an approach should be better than a conversion from weather parameters to wind power, which then is statistically corrected with measurements and not limited to more or less relevant observed variables. There is a complexity in the first approach by applying double corrections that rather confuses the error contribution from the NWP model than helps reducing it, because it in fact would require very detailed meteorological measurement data at the wind farms.

3 Factors other than wind influencing wind power prediction

Wind turbines appear as aerodynamic devices designed with the target of generating the least impact on the flow, but at the same time dragging the maximum amount of energy out of the atmosphere. In the following we have compiled a list of factors that influence the power production of wind turbines and the predictability of wind farms. This can be considered as a summary of the past 3 years of research on the wind power predictability over Europe:

* Wind turbines are mostly located at places with wind resources higher than the average wind speed in the area
* Wind turbine's effective height in the terrain is often direction dependent due to small ridges or valleys with specific local wind directions
* Shadow effects from other turbines within wind farms have been observed for certain wind directions
* Turbulence from obstacles in a specific but rare wind direction is also observed regularly
* In areas, where farm land is used to host wind power, the surface changes characteristics from year to year and over the seasons, which has impact on the diurnal cycle at the sites
* The vertical integral of the momentum flux through the rotor area is what accounts for the production, but the wind profile required to compute the effective flux can only be computed, if the effective turbine height in the terrain is known
* Inversions can have peculiar effects on the performance of wind turbines, if the inversion crosses the upper 60% of the rotor area. The efficiency is in most cases low, because the direction of the flux through the rotor area will be different than of the flow direction below the inversion.
* The time integral required to produce the power in a 15 or 60 min. interval from hourly instant values results in a positive or negative bias dependent on the wind speeds. Turbulent eddies increase the energy generation at the steep part of the power curve until 85-90% load is reached. Above this point additional vertical mixing via turbulence is more a sink than a source of energy
* Any temporary wind direction changes between two time stamps will cause a drop in the energy production.

A number of the above mentioned potential problems require more accuracy than a NWP forecast can effectively be expected to provide. The more turbines, the less significance these items have. This is the background, why it has become common practise that the wind energy community predicts mostly for a subset or group of wind farms than predicting for individual wind farms.

From a meteorological point of view and maybe also from a electricity grid security point of view, it would however always be more natural to predict for all wind farms rather than a subset, because wind extremes might only touch a few wind farms and the accuracy of the up-scaling used to represent all farms is in such events rather poor.

4 Expected Predictability of offshore wind farms

The predictability of wind power should increase with farm size from a theoretical point of view, because the effective power curve flattens out and becomes more linear over a wider wind speed interval when lee turbines are in a shadow effect. This theoretical point of view is confirmed by investigations in Ireland on 51 individual wind farms, where the predictability ca be directly correlated with the wind farm size (Möhrlen and J/orgensen, 2006).

Recent investigations at large wind farms with a capacity of greater than 50MW indicate that efficiency losses exist, known as wake effects (Möhrlen and J/orgensen, 2006). The actual loss can probably reach up to 20% dependent on the distance between the turbines and the weather situation. The efficiency loss is most clearly described by the fact that a single wind turbine might reach full load (peak power) at an average wind speed of 15m/s, whereas a wind farm of size greater than 50MW requires an average wind speed of 18m/s to reach full load, i.e. all turbines producing peak power.

Since offshore wind farms are and will be rather between 100 - 200MW in the future, the predictability should be higher than onshore. Theoretical considerations would suggest that the predictability of the wind over sea is higher than over land, because of softer gradients in the roughness fields. The vertical influence length scale from the sea surface is short, because the average roughness length is at least 3 orders of magnitude smaller than the roughness over land and the temperature difference between air and sea is small and varies slowly. The wind speed at 100m above sea level is therefore a function of the weather and much less dependent on the lower boundary condition in comparison to the wind in the same altitude over land. However, the motion is almost frictionless, which means that weather disturbances on the meso-scale may survive relatively long. Thus, there is a potential danger for small-scale weather systems developing and creating high variability and strong wind gusts.

Such small scale weather can only be captured when considering mesoscale data assimilation in order to resolve such mesoscale systems in the initial conditions and to be able to predict the evolution of such systems up to maybe 12 hours ahead. It is probably unrealistic to expect that the prediction quality will be improved after 12 hours by this technique. In contrary, it will decrease significantly, because the error in the smaller scale will grow.

5 Real Offshore Results

The relatively optimistic expectations towards offshore wind power predictability diminished significantly after samples from the first large offshore wind farm of 160MW installed capacity have been published (e.g. Eltra Systemplan, 2004).

In a recent verification (Lang et al. 2006) we found the mean absolute error (MAE) at this offshore farm to be 14.5% and 20.7% standard deviation (SD) over a 4 month period in the beginning of 2005. Compared with 12.5% MAE and 17.8% SD for a 15MW wind farm in Ireland at complex terrain, this was not a very encouraging result. Especially, the theoretical considerations about the higher predictability of the large offshore wind power in comparison to onshore wind power do not seem to hold.

In the following, we will discuss the single offshore wind farm results and argue why the result is not as poor as it appears at a first glance.

The error statistics is very often dominated by how often the wind farm is either idle or has full load versus varying load in the wind speed range 6-11m/s. The more wind speed hours in the medium range are recorded,

forecast length	persistence forecast
0	0
1	5.7
2	9.0
3	11.2
4	13.2
5	15.1

Table 1: Persistence forecast error at the beginning of the forecast.

the worse the error statistics. This is because there is little structure in the weather.
It takes very little latent heat to trigger disturbances that may give 50% more or less wind power production. The difference between a drop or an increase in the production as a matter of 5-10km displacement of a convective cell. The cyclonic motion in the coordinate system of a convective cell may be approximated by circular flow. There might be full production, where the tangent of the cyclonic motion and the mean flow are parallel, but too little wind to produce wind power in the region, where the tangent and the mean flow are opposite of each other. In the region between the high and low energy area, the wind direction changes and causes a drop in production, although the mean wind speed never drops. On top of the impact on the flow, the convective cell will be responsible for downdrafts with stronger momentum. The outcome in wind power is then very sensitive to how the wind farm is located relative to the core of the cell.
These considerations are not specific for offshore wind power, but relatively more important, because the wind farms are much larger in capacity. It makes a difference, if there is a sudden drop or increase in the production with 80MW. Large wind farms on land have the same negative skills with respect to noise and low predictability. Some examples are shown in (Möhrlen and J/orgensen 2006).
It means, that the mesoscale weather activity is on the one hand important for offshore wind farms, but the required accuracy might not be achievable, because the weather development is not driven by a clearly identifiable source.
Looking on a persistence forecast, as displayed in Table 1, the error increases above the so-called background error after 4-5 hours.
It can be seen in Figure 4 that the short-term forecast error for offshore wind power is nearly as high as the day-ahead error. In Figure 4, the error is given as mean absolute error relative to the installed capacity. The start-up or background error is quite dominant in comparison to the day-ahead error, which is only 2% higher than at the beginning of the forecast.
This result confirms that a major fraction of the error is either noise or mesoscale weather activity, because a synoptic scale weather derived parameter cannot have an 11% average error in the 4-5 hour persistence forecast.
Looking on the forecast noise, it is the numerical solution method used within the model systems that is responsible for the noise. The numerical noise is kept under control via filters and implicit solutions developed with focus on noise control rather than the numerical accuracy. The noise level of the forecast is then also resolution dependent. Even though the horizontal extend of the wind farm itself is comparable in size to one grid point in a high resolution forecast of maybe 5km grid spacing, the noise of the high resolution forecasts cannot be related to the noise in the power production of a wind farm. Figure 5 shows a sample of the power production at an offshore wind farm.

In fact, a synoptic scale forecasting system would only produce the same level of noise as an offshore wind farm during periods with numerical instability. A mesoscale prediction system with similar noise as an offshore farm would also only produce similar noise, if the numerical time step would be too high. The observed noise at offshore farms might be a turbulence phenomena, because measurement noise with nearly constant amplitude that continue for several hours are likely to be due to turbulence generated from an inversion at a critical altitude within the rotor area. Short lasting noise with high amplitude is more likely generated by mesoscale weather activity or changing wind direction. However, more detailed measurements and investigations are required to draw further conclusions from this.

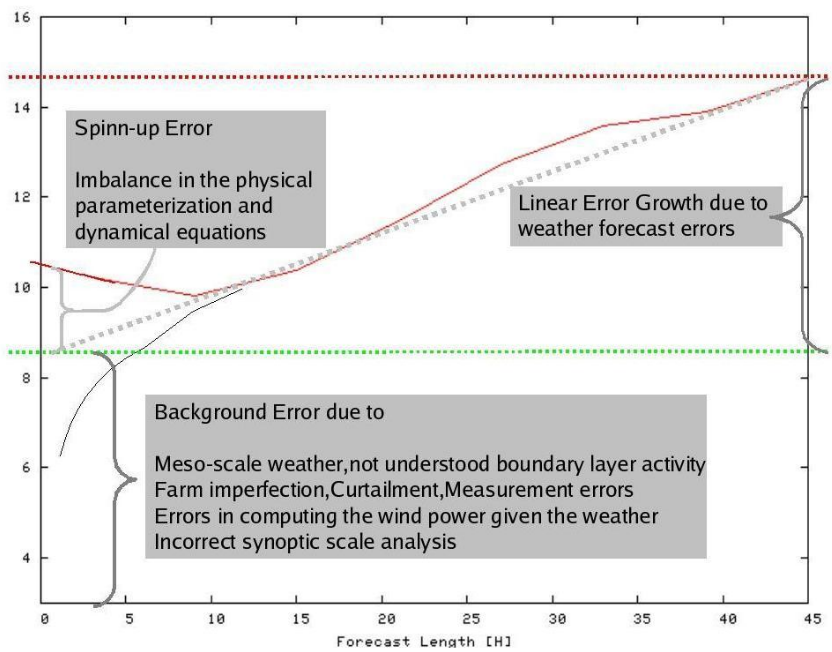

Figure 4: Illustration of the forecast error for an offshore wind farm. The y-axis shows the mean absolute error in % installed capacity.

Since the offshore wind resource is approximately 10% above the resources on land, away from the coast (Naturlig Energi, 2006), and the space on land is limited, offshore wind power will be a major contributor of renewable energy in the future. This means that, even though the error levels are high at present, because of the greater resource, new parameterisations for prediction methods for offshore conditions will have to be developed to reduce the error levels of today. It is known that the diurnal cycle is weaker offshore than on land. The turbines on land "feel" therefore a stronger diurnal cycle than the offshore turbines, especially during periods with few clouds. Integration of more realistic ocean and wave parameterisations and inclusion of wake effects into the prediction, together with a good mixture of on- and offshore wind energy will therefore enable a large integration and a reasonable predictability in the future. Such an energy mix might even produce the same average diurnal cycle as the demand for energy.

The need for area smoothing or dispersion of offshore wind farms became in fact apparent already in 2003. The initial experience with the Horns Reef wind farm in Denmark indicated that the noise in the power output was occasionally stronger than expected (Eltra Systemraport 2004).
Prior to the experience with Hornsrev, there was no feasible way to concurrently study the boundary layer eddy activity over the area, where the wind farm was built. The eddy activity is not a problem, if a large number of similar sized wind farms are interconnected. However, the wind farms need to be gridded to ensure that a number of farms have similar wind speed, otherwise the noise will remain.

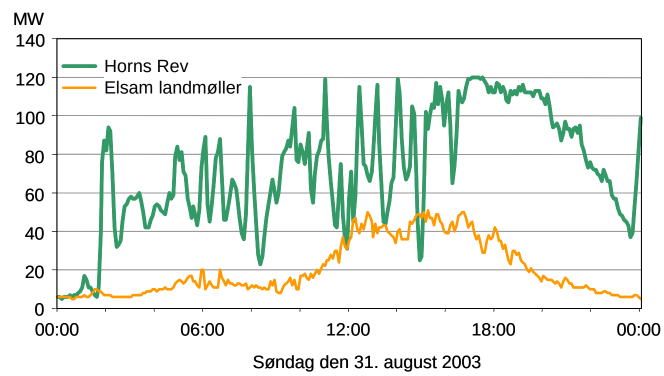

Figure 5: Observed fluctuations in power production at Horns Reef offshore wind farm are larger than expected (Picture: Eltra Systemplan 2004)

6 Conclusions

The predictability of wind power is important from an environmental point of view. It is also known, that the more turbines there are, the higher the predictability, except if there exists a concentration of wind turbines in bigger wind farms. In that case, there is a risk of strong internal turbulences on the wind farms, but also rapid changes in the load from mesoscale weather. As a consequence, a quite high forecast error has to be expected. It is likely that the weather forecasts will continue to be blamed as the source for the wind power prediction error. If this is so, the bulk of the error will either remain or will have to be dealt with in other ways. Accurate day-ahead predictions with 15 minute intervals of convective cells at particular points are at least from a meteorological perspective impossible.

Wind energy projects are expensive and they are paid from the consumers over 10-20 years. The wind farm installation costs grow with dispersion. However,the more wind farms are installed, the better the forecasts. The value of a energy unit is dependent on how well it can be controlled and how constant the power generation is. The bigger wind farms therefore have a plus on a control level and a minus because of their higher variability.

Improvements in the weather forecast will in the first approximation only improve on approximately 2% out of 12-15% mean absolute error for single wind farms per year. If the forecast improvements give a feedback on the data-assimilation process, then there is a possibility that a smaller fraction of the start-up or background error will disappear. It is however likely that most attempts to improve on this background error by stronger weight on measurements will result in a steeper growth of the error with the forecast horizon and hence result in the same total error after one day to two days.

That 70% of the forecast error is not due to the weather forecast step shows that more effort has to be put into better initial conditions and more accurate computations of wind power. It is not likely that the forward integration of the weather can be blamed for the bulk of the wind power forecast error. This does not hold for every forecast. The weather forecasts do sometimes fail and these events might be more important than the daily events with small errors. The poor forecasts occur most likely in periods with low predictability. For this purpose the ensemble approach has been developed to warn the end-user about such events in advance. It is therefore our view that the wording that the wind power forecast error is due to the weather forecast is wrong. It rather looks like the wind energy prediction system needs more detail on the local scale. For this more detailed measurements need to be provided to the wind power forecasters. Wind energy is partly about reducing the greenhouse effect. There have been a number of stones thrown after the meteorological community with respect to the forecasting error (e.g. Jackson, 2003), where it was impossible for the meteorological community to protect themselves or to argue against the postulates, because neither wind power measurements nor forecasts were made available to them.
It took a long time for this project to get enough measurements and to develop a sufficiently accurate power parameterisation to be able to readjust some prejudices by giving some more detailed information about the error sources. We hope that this will help to develop a more constructive dialogue between the two communities in the future.

Acknowledgements

We would like to thank Met Eireann for the continued support of this project.

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