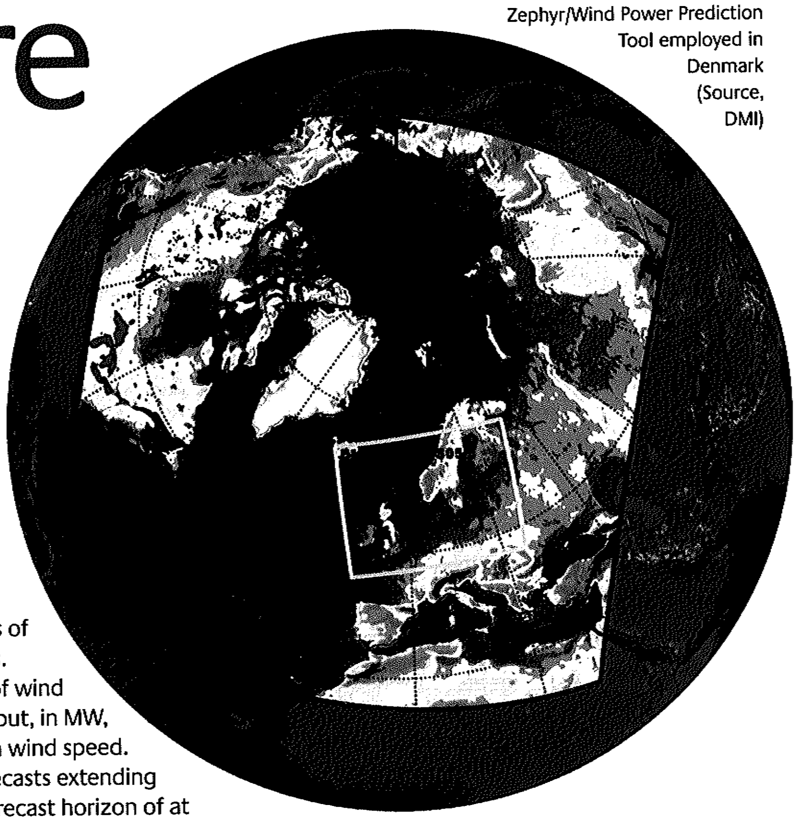
The future of wind

Investment in wind prediction should pay back for both the wind farm and the grid operator



Two domains of the Danish NWP HIRLAM (High Resolution Limited Area Model), used as input by the Zephyr/Wind Power Prediction Tool employed in Denmark (Source, DMI)

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One of the biggest problems posed by wind power is the variability of the wind. Two time scales are most important: for turbine control (from milliseconds to seconds), and for integration in the electrical grid (from minutes to weeks). For example, the 27% yearly proportion of wind power in western Denmark means over 100% wind power in the grid at certain hours. This would not be possible without the forecasting models employed [in Denmark] since 1994.

Short term wind prediction has three applications:

- Optimising the scheduling of power plants by functions such as economic dispatch etc. Prediction horizons are 3-10 hours.
- Optimising the value of electricity in the market. Such predictions are required by different types of end-users (utilities, TSOs, ESPs, IPPs, energy traders etc) and for different functions such as unit commitment, economic dispatch or participation in the electricity market.
- Longer time scales, eg for maintenance planning and construction planning. However, the accuracy of weather predictions decreases strongly 5-7 days in advance, and such systems are only just appearing. For example, Vestas had dedicated weather forecasts from Danish private weather company Vejr2 during the construction phase of Horns Rev.

When polled, schedulers, research planners, dispatchers and energy planners at utilities gave the following list of requirements for wind prediction:

- Forecasts for individual windfarms and groups of wind farms.
- Forecasts of wind power output, in MW, rather than wind speed.
- Hourly forecasts extending out to a forecast horizon of at least 48 hours.
- Accurate forecasts with an associated confidence level.
- Reliable forecasts of likely changes in wind power production.
- Better understanding of what meteorological conditions tend to lead to poor forecasts.
- Use of historical data to improve accuracy of forecasts over time.
- Forecasts available early in the morning (before 08:00) in order to prepare for trading at noon.
- Updated forecasts in the afternoon based on production data.
- Forecasts several days ahead for maintenance planning.

Few analyses that have looked in detail into the economic benefits of forecasting for a utility.

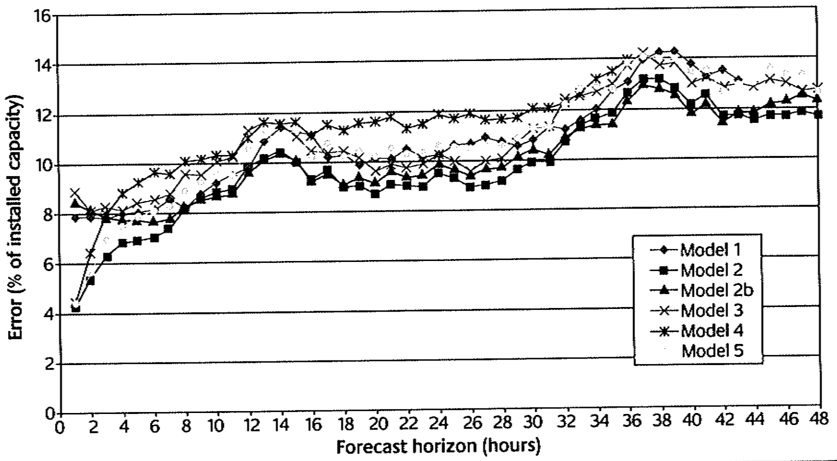
In the mid 1990s one study analysed the relative merit of over and underpredicting and found that while underpredicting was cheaper for one utility, the opposite held true for the other. The cost penalty depended on the plant mix and the power exchange contracts.

Generally speaking, a utility with a relatively large percentage of slow-start units benefits more from accuracy gains.

Analysing the proposed structure of the Dutch electricity exchange in 1999, Hutting and Cleijne found that 1500 MW of offshore

The Normalised Mean Absolute Error for the ANEMOS test case of the Klim wind farm, Denmark.

The error is shown as percentage of installed capacity over the prediction horizon. The Mean Absolute Error is shown as this relates to the actual payments the utility has to make for erroneous predictions



wind power could achieve an average price of 3.5€c/kWh, when coupled with back-up conventional plant. This assumes that 75% of the output can be predicted well enough for the market. Perfect prediction would raise the price to 4€c/kWh.

However, building 6000 MW of wind power would decrease the price to 2.9€c/kWh. Reducing the specific power of the rotor from 500 to 300 W/m² would decrease the overall power output, but increase the capacity factor, thereby increasing the predictability and therefore enhancing the value by an extra 0.05€c/kWh. This would actually improve the price performance ratio by about 10%, just by installing larger blades on the turbines. Spreading out the wind farms along the coast would increase the reliability of the generation and therefore lead to another 0.15€c/kWh.

Some prediction systems in use

- Denmark West, Eltra and Elsam: Zephyr/WPPT of Technical University of Denmark (since 1994)
- Denmark East, Elkraft System, E2 and SEAS: first Zephyr/Prediktor of Risø National Laboratory (since 1993), now also Zephyr/WPPT of DTU (since 1999)
- Germany, E.On Netz, Vattenfall Europe, RWE: Wind Power Management System of ISET (since 1999)
- Germany, EWE (Energieversorgung Weser-Ems) and EnBW (Energieversorgung Baden-Wuerttemberg): Previento, by energy & meteo systems
- Spain, Red Electrica: Sipreólico, by University Carlos III (since 2002)
- Spain, prediction for a number of wind farms: LocalPred, by CENER (from 2005)
- Ireland, ESB National Grid (TSO): AWPPS (Advanced Wind Power Prediction System) as part of MORE-CARE, by Armines (since 2002)
- Crete, PPC (Public Power Corporation): AWPPS, by Armines (since 2002)
- Madeira, EEM (Electricidade da Madeira): AWPPS, by Armines (since 2003)
- Azores: AWPPS, by Armines (2003)

Modelling the wind

Some models are based on a numerical weather prediction model (NWP). 'Persistence' (ie setting the forecast for all times ahead to the current measured value, also known as the "naive predictor") beats the NWP-based model easily for short prediction horizons (less than 3-6 hours). However, after about 4 hours the quality of even "raw" NWP model output is better than persistence and beyond 15 hours, even forecasting with the climatological mean is better, so all the utilities' models use NWP.

Most of the errors in wind power forecasting stem from the NWP model. A level error misjudges the severity of the storm, while a phase error misplaces the onset and peak of the storm in time. While the level error is easy to get hold of using standard time series error measures, the phase error is harder to quantify.

Weak points for NWP are data collection and the assessment of the current state of the atmosphere. One reason NWP models deliver inadequate accuracy of surface wind speeds is that, for existing customers (eg shipping or storm warnings), the accuracy is good enough. This is changing: Spain now mandates short-term forecasting, for example, and a large market for STP is developing there.

Accurate predictions require high resolution and large area, but running both is numerically too expensive. However, calculating the power directly in the NWP model allows major physical properties like direction dependent roughness, actual density, and stratification of the atmospheric boundary layer to be used in the calculations.

Phase errors have a much larger influence on the error scores (and eventual payments) than level errors. One remedy would be to use free-standing turbine data as input for the NWP, thereby increasing the observational meteorological network. However, due to the size of weather phenomena, this can only be helpful for the first few hours.

Among the most important forecasts are the forecasts of sudden and pronounced changes, like a storm front passing the utility's area. To develop a measure for the quality of these forecasts is very difficult, and the best way to get a feeling for the quality of the forecasts is visual inspection of the data set.

Spot predictions of wind are a primary requirement for end-users, but to make the most of the prediction the user also needs tools to assess the prediction risk.

Confidence intervals provide an estimation of the error linked to power predictions. In wind power prediction error distributions may exhibit some skewness, while the confidence intervals are not symmetric around the spot prediction due to the form of the wind farm power curve. The level of predicted wind speed introduces some non-linearity to the estimation of the intervals; eg at the cut-out speed, the lower power interval may suddenly switch to zero.

Since the correlation between forecast errors and distance is weak, the forecasts for a region are much more accurate than the forecast for single wind farms. This means that only a certain number of wind farms is needed to predict the power production in a region 'well enough'. For regions, the error autocorrelation is also stronger on a time scale of days than for single wind farms.

Available computer power is increasing. But instead of just using it to up the resolution more and more, the processing cycles might be better used in reducing the other errors. This can be done using ensembles of forecasts, either as a multi-model ensemble or by varying the input data and calculating an ensemble of different input values.

A number of groups in the field are currently investigating the benefits of ensemble forecasts. More advanced wind flow models are coming into play, like meso-scale models and CFD. One demonstration project has predicted quantiles of the forecast running for all of Jutland/Fyn and for the Nysted offshore plant.

The ANEMOS project

The ANEMOS project (anemos.cma.fr) is a four-year R&D project that started in October 2002 funded by the European Commission. Some 22 partners participate from seven countries.

The aim of the project is to develop advanced forecasting models that will substantially outperform current methods. The prediction models are implemented in a software platform and installed for online operation at onshore and offshore wind farms by the end-users participating in the project.

Research on physical models emphasises techniques for use in complex terrain and the development of prediction tools based on CFD techniques or meso-scale modelling, or high resolution meteorological information. Statistical models are developed for downscaling, power curve representation, upscaling for prediction at regional or national level. A benchmarking process has been set up to evaluate the performance of the developed models and to compare them with existing ones using a number of case studies.

A next generation forecasting software, ANEMOS, is being developed to integrate the various models. The tool is enhanced by advanced ICT functionality and can operate both in stand alone, or remote mode, or can be interfaced with standard EMS/DMS systems. The software will be installed for on-line operation at a number of onshore and offshore wind farms. Finally, the benefits from wind prediction will be evaluated during on-line operation, while guidelines will be produced for the optimal use of wind forecasting systems.