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Performance test of a 3MW wind turbine – effects of shear and turbulence

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Abstract

In this study a full wind turbine performance test has been performed on a 3MW onshore wind turbine in a coastal location in Norway utilizing a Windcube v2 lidar. The test was performed following the current edition (1. ed) of the IEC 61400-12-1 wind turbine power performance measurement standard with some necessary adaptations for remote sensing anemometry, and was expanded to include wind shear and veer.

10 months of data from a Leosphere windcube v2 pulsed lidar, a 3MW wind turbine and a short met-mast formed the basis for the performance test. This amount of data allows for a more detailed analysis of the influence of shear, veer and turbulence on power production than required by the standard. The coastal location of the turbine also allows us to study wind conditions from sea fetch relevant for offshore turbines.

The study has demonstrated the benefits and disadvantages of using a lidar for wind turbine performance measurements. Differences between hub height wind and rotor equivalent wind speed has been shown, and results show how turbulence, shear and veer influence the power production and the power curve derived from hub height and equivalent wind speed respectively.

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Keywords: Wind power; Power curve; Lidar; Wind shear; Turbulence

1. Introduction

The benefits of using a wind lidar in wind turbine performance testing, site assessment, micrositing and research have made its use widespread in the wind energy field during the last few years. Technical development and increased trust in the technology have also initiated a revision of the IEC power performance measurements standard, expected to be published in 2016, which will include remote sensing wind speed measurement. The introduction of new technology and the process of improving bankability require thorough testing against existing standards under all relevant conditions. The existing lidar technology has now proved to be of comparable

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accuracy with respect to to a conventional mast equipped with cup anemometers in flat terrain. In addition the flexibility of remote sensing anemometry brings along several new possibilities for the assessment of flow parameters relevant for the modern large scale wind turbine structures.

Reliable power performance measurements of wind turbines are important for estimation of annual energy production (AEP) for planned wind farms. The power curve should ideally be independent of local conditions at the test site. The current standard for power performance measurements of wind turbines, IEC 61400-12-1, is based on hub height wind speed and does hence not account for wind shear or veer[1]. Neither does it correct for turbulence intensity. The statistics of these parameters might be site specific and variations will increase the scatter of the power curve. Several previous studies have studied the effect of wind shear and turbulence on the power curve [2-5]. The effect of wind veer causing a partial yaw error over the rotor span is however rarely considered. Such effects become increasingly important as the dimensions of the wind turbine rotors increase. The vertical wind profile is often described by a simple power curve fit:

$$U(z) = U_r \left(\frac{z}{z_r}\right)^{\alpha} \tag{1}$$

where z is height z_r reference height, U_r is wind speed at z_r and α is an empirical shear coefficient.

Figure 1 shows the theoretical influence of different α-values on the ratio between hub-height wind speed and rotor equivalent wind speed (see section 1.1) for a large wind turbine (hub height=92m, rotor diameter=100,6m). In the range of alpha between 0 and ⅓ the hub height wind speed would overestimate the available power over the rotor area while the opposite is true for even higher alpha. Under average shear conditions the difference between wind speed definitions is between 0 and 0,5 percent for a large wind turbine. This is not dramatic, but the instant wind profile often deviates from a power law profile causing higher differences and the deviation will increase for even larger turbines.

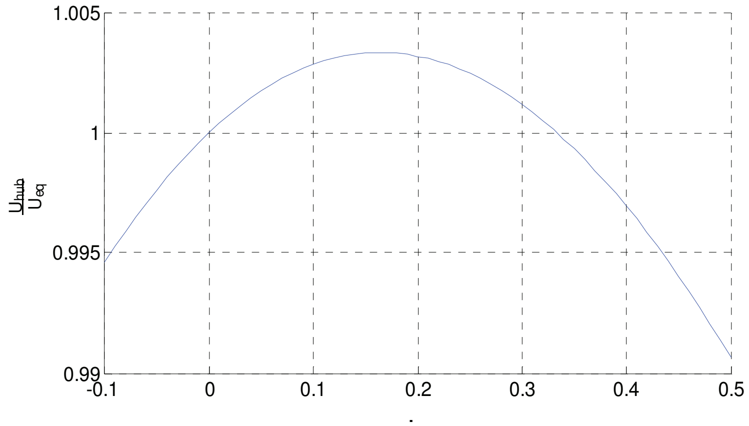

Figure 1 Ratio between hub wind speed equivalent wind speed as a function of power law coefficient alpha

A revision of the IEC standard is in progress and the new edition addresses vertical shear, directional shear and turbulence[6]. Relevant aspects of the development of the new standard is discussed in [7].

1.1. *Wind shear*

Variation of wind speed with height will influence the power output of a wind large turbine. Wind shear in the lower part of the atmospheric boundary layer (ABL), the surface layer, is described by the semi-empirical logarithmic law or by the more simple power law (Eq. 1). The mean wind profile over a 10 minute period will however often deviate from a theoretical profile. Local terrain effects, low level jets and the fact that large wind turbines under some conditions will extend into the Ekman layer of the ABL call for direct measurement of the wind profile.

Wind shear is included in the IEC standard draft by using a rotor equivalent wind speed. This is defined as the wind speed giving the same kinetic energy flux over the rotor area (A) as the sum of contributions from a finite number of horizontal circle segments. The wind speed U_i is measured in N heights, each representing the mean wind of a circle segment of area A_i. The formulation is:

$$U_{eq} = \sqrt[3]{\sum_{i=1}^{N} {U_i}^3 \frac{A_i}{A}} \tag{2}$$

This formulation of equivalent wind speed does not consider change of air density with height. Several studies have reported a reduction of scatter and convergence of binned power curves using this wind speed definition [2, 4, 5]

Wind veering or backing is the change of wind direction with height. This causes the incoming wind to be misaligned with the rotor axis over parts of the rotor swept area. Using a ground lidar allows the wind direction to be measured in multiple segments over the rotor plane. The effect of wind veer can be incorporated into the definition of equivalent wind speed by using the wind component parallel to the rotor axis resulting in the following formulation

$$U_{eq2} = \sqrt[3]{\sum_{i=1}^{N} (U_i \cos\varphi_i)^3 \frac{A_i}{A}} \tag{3}$$

from [6] where ϕ_i is the angle between the wind direction and the rotor axis. However simulations performed by Wagner et al. [8]showed an asymmetric response to directional shear not in agreement with the symmetrical cosine function.

1.2. *Turbulence*

The effect of atmospheric turbulence on power production is complicated to describe and correct for. Turbulence will increase the kinetic energy flux during a ten minute averaging period compared to a steady mean wind. Earlier studies have suggested a simple correction of the wind speed adding the increased kinetic energy associated with turbulence using the turbulence intensity (TI) as the input parameter [9, 10]. This would give a more realistic measure of the efficiency of the wind turbine, but would not reduce the scatter of the power curve. This is because the turbine is not able to utilize all the turbulent energy in the wind. Especially around the rated wind speed TI has a large influence on the power curve causing high scatter. In this region power output is reduced by pitching the blades for gusts higher than the rated wind speed, and hence only the negative wind fluctuations will affect the power output.

The interaction between the wind and the rotor becomes complex when shear and turbulence is introduced and combined in the wind field, and suboptimal aerodynamic performance over parts of the blades will reduce the power output compared to the ideal case for the same kinetic energy potential. In reality the wind parameters are also coupled, meaning that situations with high shear are related to low turbulence and vice versa. This makes it difficult to isolate the effects of a single parameter from field data. Computer simulations of turbine response to various inflow conditions might be helpful, but the complexity introduces high uncertainties for the current modeling tools[8].

In [6] a new method for turbulence normalization is included. This method defines a zero turbulence power curve which is used to simulate power output based on either the measured wind speed distribution or a reference distribution. These values are then used to normalize the power output to the reference conditions. The method is described and evaluated in [11] and [12].

The way a lidar measures wind speed involves substantial spatial and temporal averaging, and it is therefore questionable if the derived turbulence intensity is comparable with cup anemometer measurements, which is the current standard. Mann et al. found errors ranging up to 40%, depending on atmospheric stability and height, for the horizontal velocity variance measured by the WindCube lidar[13]. Canadillas et al. found a systematic overestimation of energy at high frequencies by the lidar for the horizontal velocity spectrum compared to a sonic anemometer [14]. A slight overestimation and high scatter of horizontal velocity standard deviation compared to sonic and cup anemometers was also reported in [15] and [16].

2. Description of test site and measurements

Wind data from a Leosphere Windcube v2 ground lidar and net power output to the grid from a 3MW variable speed wind turbine was collected over a 10 month period from the turbine test site at Valsneset on the coast of Mid-Norway. The IEC 61400-12-1 standard was used as a guideline for the measurement campaign. The lidar was installed on top of a container at a distance 3D and a direction of 290 degrees from the turbine. Meteorological data was also collected from a 33 meter high mast located 350 meters from the turbine. Data from the separate logger systems in the lidar and mast was synchronized using a time server, while the logger clock in the turbine was manually adjusted. Hence some uncertainty is introduced in time synchronization which may introduce additional scatter in the power curve.

An assessment of the surrounding terrain performed following annex B in the IEC standard revealed that the test site fell within the requirements listed, and thereby no site calibration were performed. A small wind farm with 5 turbines is located north-east of the test turbine and will limit the available measurement sector as shown in Figure 1a. Prior to analysis the raw lidar data was filtered by wind direction and data availability. The quality criterion was a data availability $\geq 99\%$ in each 10 minute interval for all heights.

When determining the valid measurement sector, annex of [6] was used. This defines the same angles for the disturbed sectors as the current standard [1] for all types of wind measuring equipment. Depending on the cone angle of the laser, a lidar would have a measurement volume with a diameter extending horizontally around 100 meters at hub height for this turbine. Parts of the lidar's measurement volume could therefore be inside the disturbed sector defined for a met-mast even when the lidar location is within the valid test sector.

2.1. *Valsneset wind climate*

The test site at Valsneset is located on the coastline of mid-Norway with mixed surrounding terrain as shown in Figure 2. The sector from south-west via west to north-east has a sea fetch only disturbed by a group of flat islands 5-13 km west of the test site. These islands have a maximum height of 30 meters asl. Winds from this sector generally have low vertical shear, directional shear and turbulence. The south to east winds are influenced by a small mountain ridge rising 300 to 500 meters asl giving turbulent, high shear winds. This is also the typical case for north-eastern winds having a mixed land and sea fetch. The operating principle of a lidar requires a minimum concentration of aerosols in the atmosphere in order to get a reliable wind vector. At Valsneset this turned out to be a limiting factor for the data collection. As can be seen in Figure 3b, the total availability of the lidar data is highly directional dependent with low availability for winds coming over the mountain ridge in the south-west sector. This implies that the mean statistics of the site will be biased towards the offshore sector and this might be a drawback for using a lidar for site assessment at particular sites. The mean lidar data availability during the measurement campaign was 91% at 90 meters height and 79% at 140 meters height.

a b

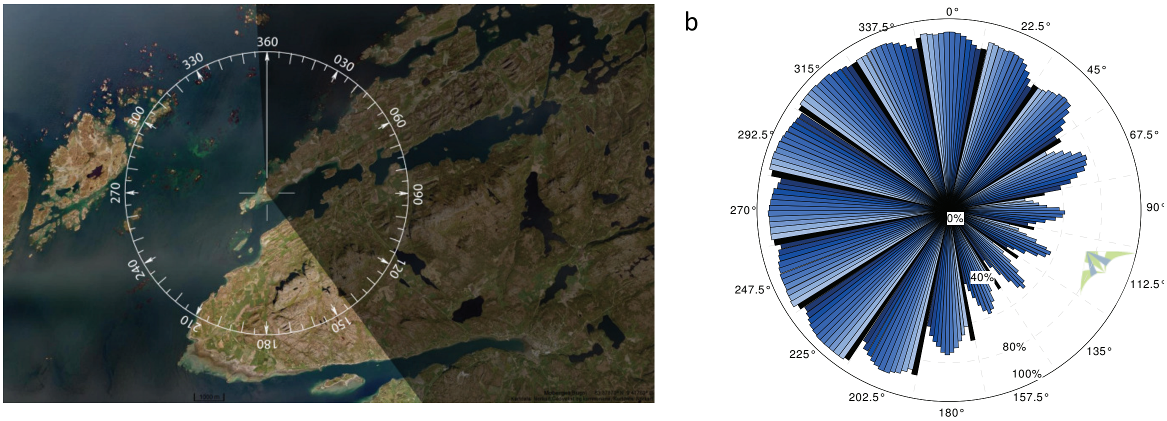

Figure 2 Overview of the test site (a) and lidar data availability by direction for each measurement height (b)

Figure 3 shows the directional dependence of local wind parameters at the test site, showing that the wind conditions are clearly separated between an onshore and an offshore sector. Wind speed shear, directional shear and turbulence intensity are all significantly higher in the onshore sector which means that the turbine operates in varying conditions depending on the incoming wind direction. Note that 5 wind turbines located 10-20 rotor diameters north-east of the lidar may influence the wind from this direction. Also to be noted is the dominant wind direction from south-east which means winds from the small mountain ridge. This direction suffers from low availability, but is not within the measurement sector.

a b c d

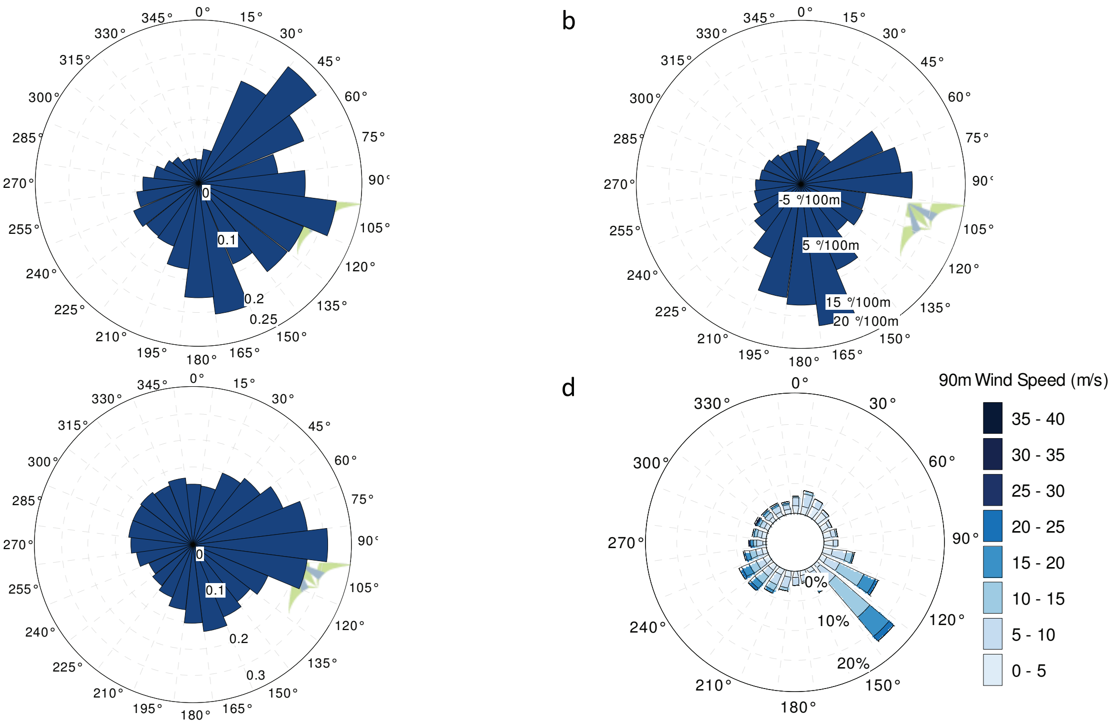

Figure 3 Test site directional statistics based on unfiltered data. Power law coefficient α (a), wind veer over the rotor (b), turbulence intensity (c) and wind rose (d).

2.2. *Annual energy production (AEP)*

Annual energy production is an important measure for the profitability of a wind turbine. It is here calculated by applying the Weibull distribution fitted to 1 year of data from Valsneset to the power curve. The parameter ΔAEP is used as the percentage deviation from the AEP calculated from the mean power curve including all valid measurements and using U_{eq} as the wind speed definition.

3. Results and discussion

3.1. *Effect of shear*

Using the same approach as Wagner et al.[5] the residual sum of squares (RSS) was calculated for each wind profile to classify the profiles by goodness of fit to a power law profile. Compared to the data of Wagner et al. from Høvsøre the wind profiles from Valsneset could in general be better described by a power law with a median RSS of only 0.022. Since only 14% of the profiles had an RSS higher than 0.1 as the threshold used by [5], 0.05 was used as the threshold. 28% of the data points were above this value.

The power curves in Figure 1 show that the “poor-fit” profiles (high RSS) give a lower energy yield in the region from the inflection point of the power curve to the rated wind speed. It appears that use of the equivalent wind speed (Figure 4 b) does not improve the convergence of the two power curves, as opposed to the results from Wagner et al.[5]. This suggests that the turbine efficiency is decreased under such circumstances because of the irregular inflow conditions over the rotor plane.

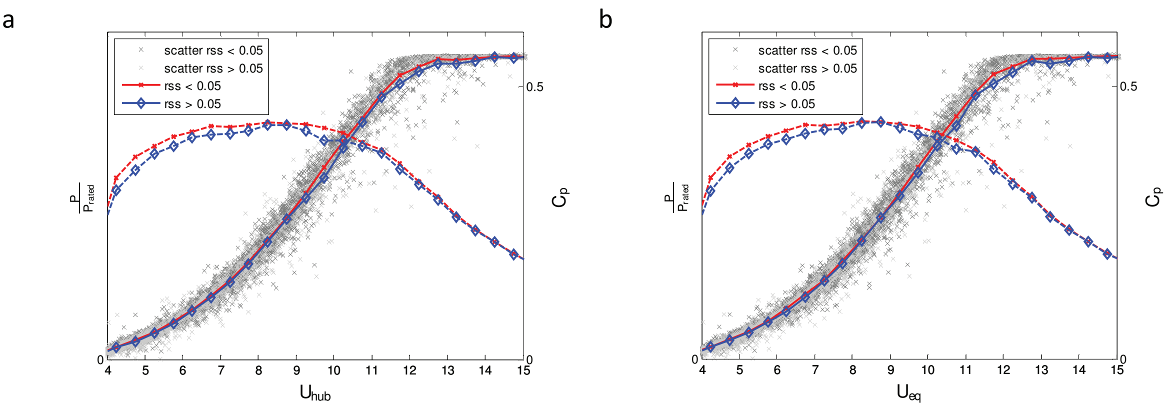

Figure 4 Power curve dependence on wind profile shape for hub wind speed (a) and equivalent wind speed (b)

In Figure 5 power curves are plotted for different ranges of power law coefficient alpha (Eq. 1). Data points with turbulence intensity above 0.08 are filtered out to reduce the influence of correlation with turbulence. Again the scatter is not significantly reduced by the introduction of equivalent wind speed, which indicates that other sources of scatter are dominating our dataset. The effect of wind shear is apparent as a reduction of efficiency for high shear conditions for wind speeds around the inflection point, while the curves converges below rated wind speed. ΔAEP is +1,23% and -0.89% respectively for the low and high shear bins using hub height wind speed, and is reduced to 1,16% and 0,69% when using equivalent wind speed.

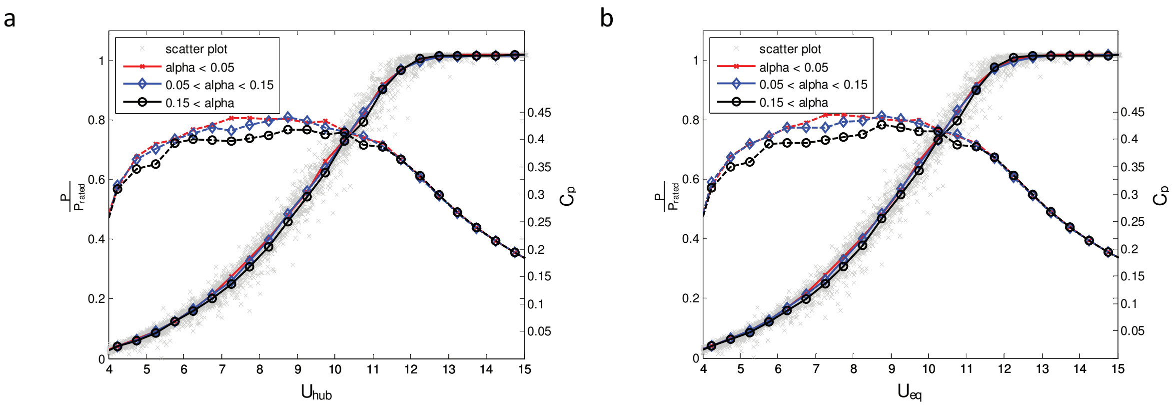

Figure 5 Power curve dependence on shear coefficient alpha plotted with hub wind speed (a) and equivalent wind speed (b)

Mean wind direction shear is less studied than velocity shear, and at Valsneset the mean direction shear is only 6.5 degrees over the rotor area in the measurement sector. However we can still see a small effect of veer in the performance curves shown in Figure 6. The analysis does not distinguish between wind veering and backing. As expected, considering wind veer as a partial yaw error, the power output is reduced in the whole partial load regime under high veer conditions. Using the equivalent wind speed definition from Eq. 3 appears to reduce the separation of the curves at low wind speeds, while around rated wind speeds the low number of high veer occurrences makes results more uncertain.

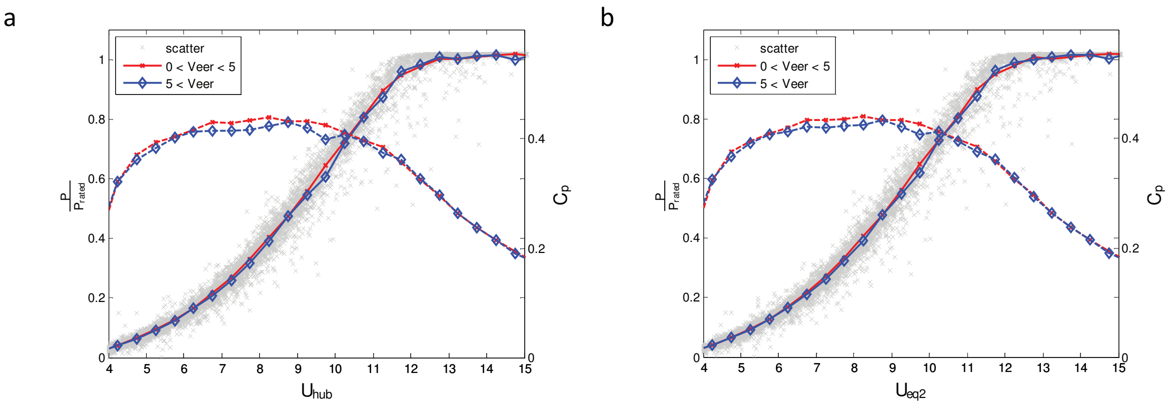

Figure 6 Power curve dependence on wind direction veering/backing plotted with hub wind speed (a) and equivalent wind speed (b)

3.2. *Effect of turbulence*

Because of the offshore fetch the turbulence in the measurement sector is generally low (mean TI=0.088 in measurement sector) the number of samples in the TI > 0.1 bin is low, especially in the higher velocity bins, causing higher uncertainty of these results. The effect of turbulence on the performance curves is as expected an increase of power below and a decrease of power above the inflection point as predicted by the second derivative dependence derived from Taylor expansion[17]. Since the effect of turbulence is opposite in the upper and lower part of the partial load power curve the effect on AEP would tend to cancel out. For the highest turbulence bin ΔAEP is -0,6%, but notice that the number of observation points near rated wind speed is low in this bin. For the low turbulence bin ΔAEP is +1,2%. From the scatter plot in Figure 7 it appears that the scatter is increasing mainly with turbulence intensity in this dataset.

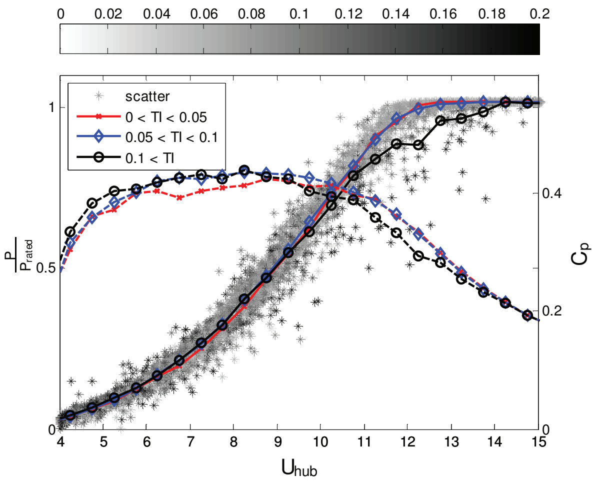

Figure 7 Power curve dependence on turbulence intensity (TI) with color coding of the scatter plot with TI.

4. Conclusion

Using a lidar for power curve measurements has both positive and negative consequences. The obvious benefits of remote sensing equipment compared to a traditional met-mast are ease and flexibility of installation, large range and high vertical resolution. A stand-alone lidar is however still not considered bankable by the new IEC-standard draft, and must hence be validated by a short mast with traditional anemometry at the site. A limiting factor for data collection in some areas might be data availability. This will lead to a longer data collection period. On Valsneset the availability was dependent on wind direction and could thereby give biased results if used for site assessment. Single lidar turbulence measurements must also be considered to be of higher uncertainty due to the measurement principle.

The power curves derived for different, commonly occurring wind shear, and turbulence conditions experienced at Valsneset influences the AEP of the 3MW wind turbine by up to 1,2 % compared to the measured average AEP. The largest influence is found for low shear (α<0,05) and low turbulence conditions (TI<0,05) which both result in a 1,2% increase in AEP compared to the average at this site.

Using an equivalent wind speed definition instead of the hub height wind speed should in theory reduce the scatter and site dependency of the power curve and this is also reported in several studies [2, 4, 5]. In the Valsneset dataset it appears that the scatter is generated also by other variables than wind shear, and introduction of the equivalent wind speed only gives a marginal convergence of the binned power curves.

Acknowledgements

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