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Wake Effects on Middelgrund Windfarm

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Abstract

This report describes the data analysis of the Middelgrund Wind Farm online collected data with the purpose of calculating the wake effects and turbulence intensities within the wind farm when maximum wake effects are present. The data are compared to the most commonly used wake model PARK implemented in Wasp 8.

In the analysis we have focused on the winds coming from North based on a Waspengineering analysis of the Middelgrund Wind Farm:

The analysis shows that the directional change of the turbines with respect to the direction of turbine no 1 is nearly identical for the individual wind situations within a sector of 20 along the turbine array. The alignment of turbine no. 16 differs significantly from the others. In this analysis we cannot conclude whether this is a misalignment in the yaw angle measuring system or a real flow effect as calibration of the yaw angle system is only approximate.

The data analysis have been compared to a PARK calculation performed in Wasp 8. The PARK calculations have been converted from power to wind speed deficits and there is as substantial difference between the calculated deficits in wind speed between the data and the PARK model. However, it shall be noted that it is a very crude comparison since the lowest directional sector interval in the PARK/Wasp mode is 10° , and all events are assumed uniformly distributed over this sector. Furthermore, the model does not include the changing direction of the wind flow through the turbine array caused by the interaction between the turbines and the flow. Finally the turbines are spaced by 2.6 rotor diameters, which is in the limit of the park model assumptions where the spacing is assumed to be higher than 5 rotor diameters.

Taking all this assumptions and model constraints into account the Park model overestimates the wind speed deficits with up to 30 % ,with an ever decreasing wind speed through the array when the wind is coming from north whereas a the data shows a tendency to a recovery of the wind through the array.

The turbulence intensity is enhanced up to 0.3 due to the wake effects. The analysis has shown that this enhancement is nearly independent of the number of turbines involved in the wake creation.

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Contents

Preface

This report is based on the online measurement on middelgrund windfarm collected over the period of two years. The data consist of a variety of parameters from the turbines, and we have here used focused on the power production data with the aim of extracting wind data and directional data based on the power curve of the turbines. The aim have been to investigate the wake effects based on these measurements and create a reliable dataset for testing different types of wake models.

1 Introduction

Based on observed data from the Middelgrund Wind Farm we have evaluated the PARK model for the purpose of calculating the wake effects. The data on which the report has been build originate from the monitoring system of the wind farm. These data have been supplied by BONUS and Københavns Miljø og Energikontor and consist of all available measured parameters on the turbines.

1.1 Middelgrund Wind Farm

Middelgrund Wind farm consists of twenty 2 MW BONUS wind turbines with a hub height of 64m and a rotor diameter of 76m. The turbine array is located in Øresund outside of Copenhagen and the turbines are equally spaced on a circle with a diameter of approximately. 12 km. The spacing is 2.4 rotor diameters, se table 1. Figure 1 show the location of Middelgrund Wind Farm together with the met-mast (which was sailed down in 1999). The map is shown with topographical contours and roughness lines and is output from Wasp 8 program.

Table 1 Shows the positions of the twenty 2MW Bonus turbines in UTM coordinates.

Turbine_No.	North	East
1	6179564.99	730458.93
2	6179386.19	730498.59
3	6179206.96	730534.82
4	6179027.04	730567.71
5	6178846.51	730597.40
6	6178665.47	730623.63
7	6178484.06	730646.62
8	6178302.19	730666.30
9	6178119.86	730682.87
10	6177937.44	730695.70
11	6177754.84	730705.46
12	6177571.92	730711.71
13	6177389.07	730714.74
14	6177206.12	730714.45
15	6177023.25	730710.62
16	6176840.44	730703.70
17	6176657.73	730693.34
18	6176475.28	730679.50
19	6176293.10	730662.60
20	6176111.30	730642.20

The circular siting results in a stepwise different alignment with respect to North for the turbine array, illustrated in Figure 2. This of course results in a different wake effect along the line of wind turbines, which makes the data analysis more cumbersome.

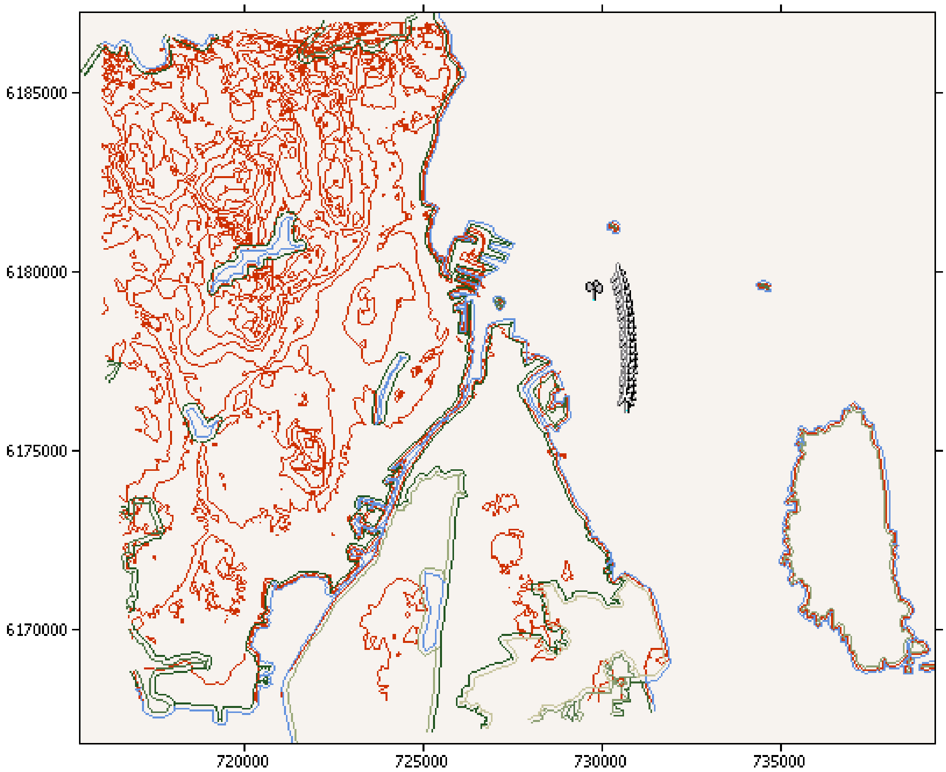

Figure 1 The location of Middelgrund Wind Farm and the previous met-mast. The map is shown with contours and roughness lines and is output from Wasp 8.

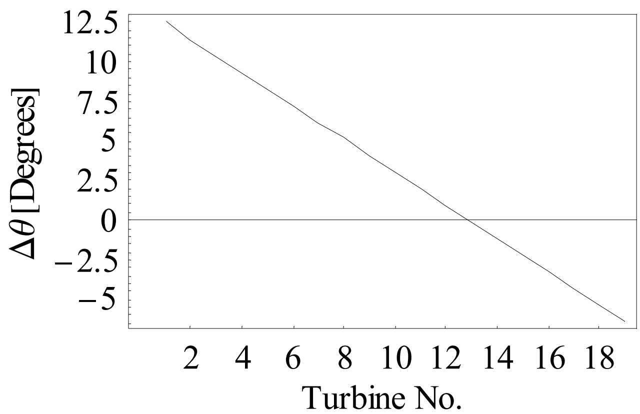

Figure 2 Deviation of the individual turbines in the wind farm array with respect to North. The first and second turbines are here aligned in the direction of 360-12.5 = 357.5 Degrees, whereas the turbine 19 and 20 is aligned 5 degrees from North.

The measured data consist of active power and wind speeds obtained from the nacelle cup anemometer. These wind speeds are known to have a considerable bias with respect to the true wind speed. Therefore, we have chosen to convert the measured power data to wind speed by means of the approved power curve (shown in Figure 3).

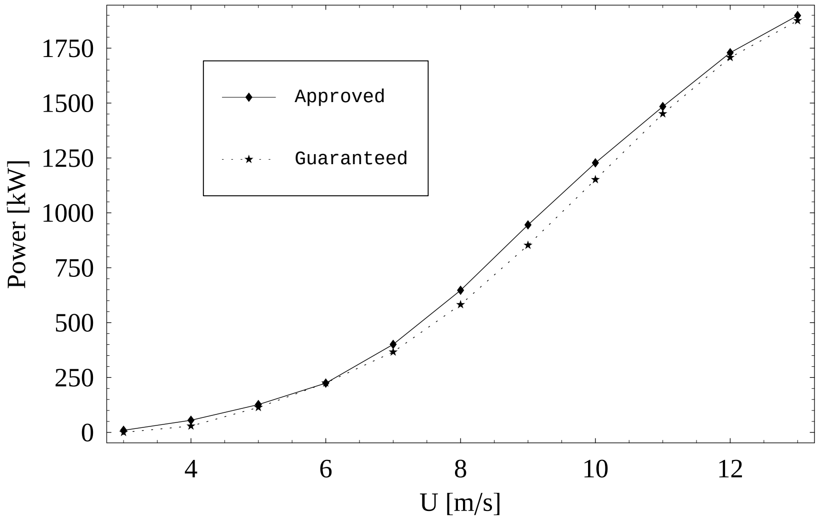

Figure 3 Power curve for the Bonus 2MW turbine, the approved and guaranteed curves are shown, but only the approved values are used in the further analysis.

The power curve is inverted and an interpolation function is generated and use of data has been restricted to where power is larger than 50 kW and less than 1950 kW to limit the uncertainty in the conversion. The used inversion function is shown Figure 4.

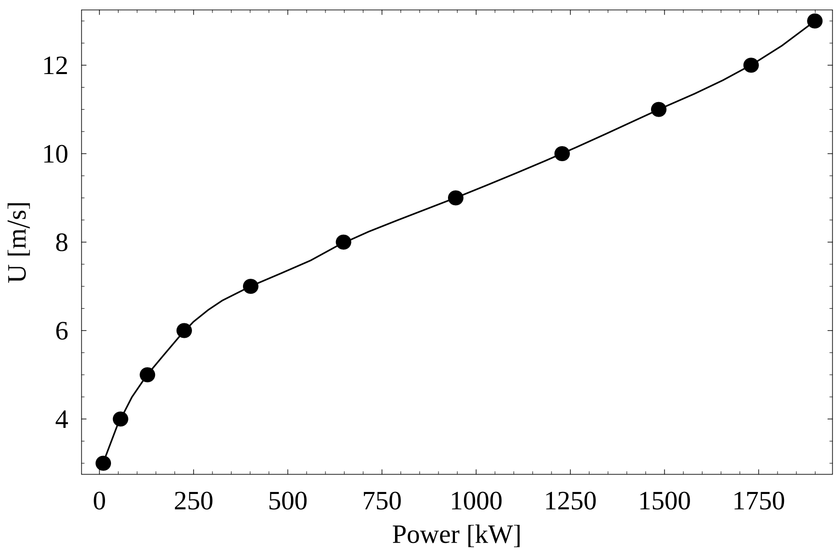

Figure 4 The inverse power curve for the Bonus 2MW turbine. The points represent the measured power curve and the full line represents the corresponding interpolation function.

The thrust curve for the turbine is shown in Figure 5, and a table of data is given in the appendix

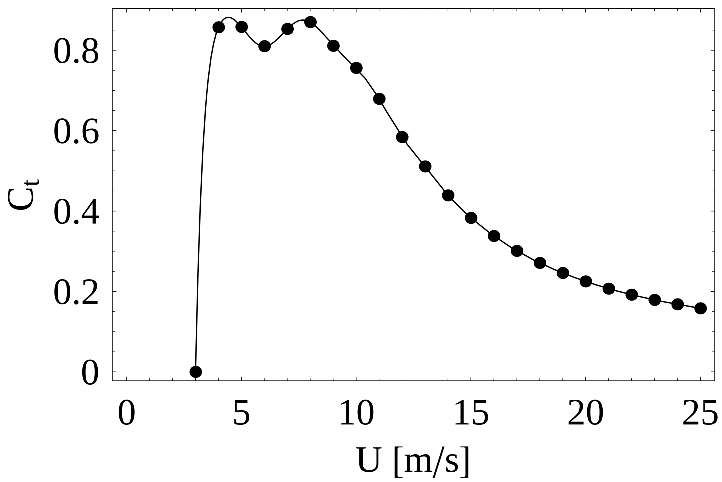

Figure 5 shows the thrust coefficient C_t as function of wind speed for the 2 MW Bonus turbines. The dots show the data given by BONUS, and the line is the interpolation function based on the dots.

2 Data selection

The data from the turbines are stored as Access database files and a range of parameters from the turbines are available as 10-minute statistics. The data are stored in two different databases, one called the standard database which essential consists of mean values from the turbines, and the scientific database which consist of mean values and other statistics such as standard deviations and minimum and maximum. In the analysis of the wind deficit the standard database was used and the scientific database was used for the analysis of the turbulence intensities.

In the analysis we have focused on the following measured parameters:

1) Timestamp here used as a key parameter to select events that fulfill the criteria that have been specified in the query. Together with the turbine number this is the basic search parameter.
2) ActivePowerMean and the standard deviation ActivePowerSD. The power from the turbine is used to generate the "true wind speed"[1] based on the power curve. The standard deviation ActivePowerSD is used to generate the standard deviations of the wind speed.
3) NacellewindspeedMean or WindSpeed is the wind speed from the Nacelle cup anemometer and used to select the wind speed interval in which the specified analyses are performed. This wind speed is typical slightly lower than the true wind speed.

1 By true is meant the hub height wind speed which under non-wake conditions would generate the corresponding power. Under wake conditions the true wind speed is to be interpreted as a rotor average of wind speed

4) GeneratorRPM or ShaftSpeedMean which is the rotation speed of the generator, here used to determine whether the turbine is grid-conected. It is assumed that the turbine is grid-connected for values of the parametersbetween 1000 and 1500.
5) Yawangle or NacelleorientationMean is assumed to be equal to the wind direction. The analyses have been performed in intervals of 2 degrees from 340° degree azimuth to 15°.

The analysis has been limited to the Northern sector as this is the sector with wake effects and where there are no major influencing obstacles. The southern sector has a smaller fetch over water, and therefore also a larger speed-up over the water through the array turbines as the water fetch is increased, see also Figure 6. The map shows the roughness of the area including the turbines and it is seen that North is expected to be the undistributed sector.

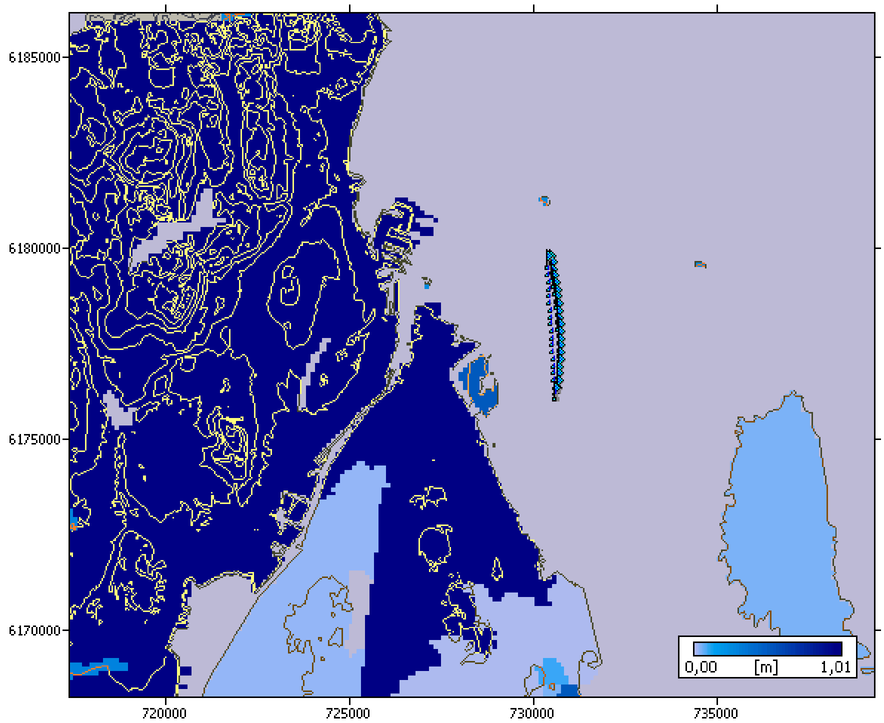

Figure 6 The roughness map used in the analysis of wind speed increase through the array of wind turbines. The turbines are indicated as flags. To simplify the calculations a straight line between turbine 1 and 20 is used as the point for calculation.

By running WaspEngineering on the area it is found that the speed deficit through the turbine array due to the water fetch is neglible see Figure 7 and Figure 8.

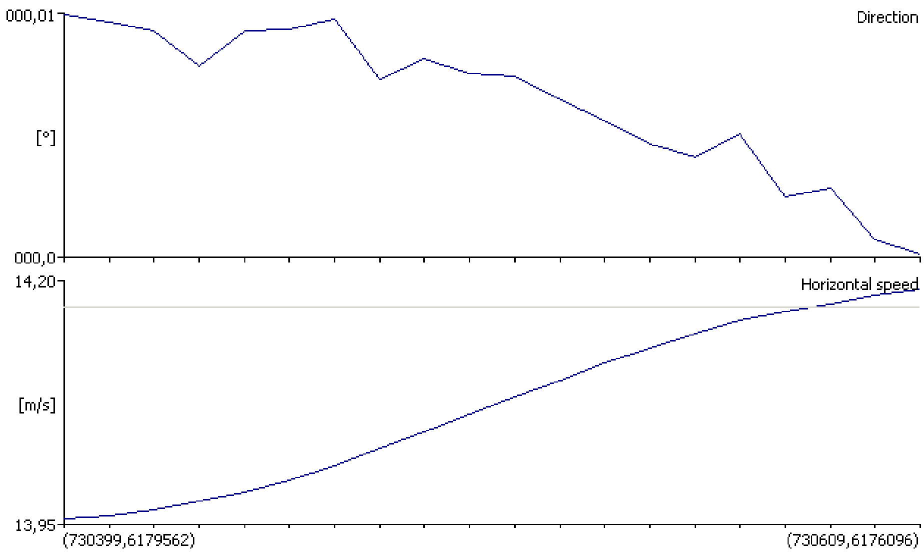

Figure 7 Tthe wind directional change and wind speed through the array of wind turbines with a wind coming from North. The directional change is identical to a zero turning of the wind and the wind speed is increasing with 0.25 m/s through the array. The modeling is performed with Waspengineering.

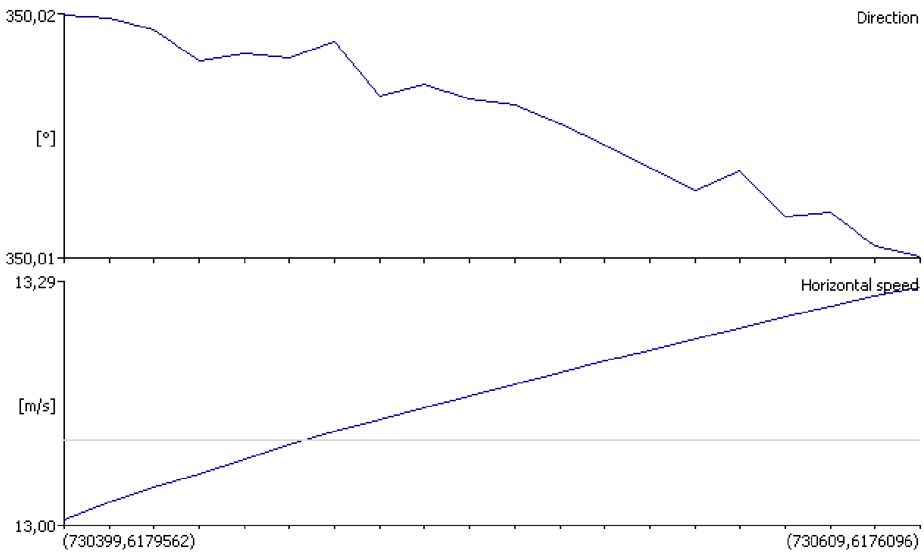

Figure 8 The wind directional change and wind speed through the array of wind turbines with a wind coming from 350^o. The directional change is identical to a zero turning of the wind and the wind speed is increasing with 0.3 m/s through the array. The modeling is performed with Waspengineering.

2.1 Wind speed deficits

The data have been analyzed as follows:

1) Based on the measured power combined with the power curve the true wind speed for each turbine is calculated.
2) The analysis of the wind speed deficit is performed for wind speed bins of approximately 1 m/s .
3) The applied wind direction sector bins are 2 degrees ranging from 345 to13 degrees.
4) The individual yaw angles compared to turbine no. one (the most northern one) are shown for each sector. The directions are not precise in absolute sense but it is seen that relatively the direction are reasonably precise.

Examples of the individual 10 min wind speed deficits through the turbine array are show in Figure 9. The data are shown for each of the 2 degrees sectors and for wind speed data with 7 and 8 m/s.

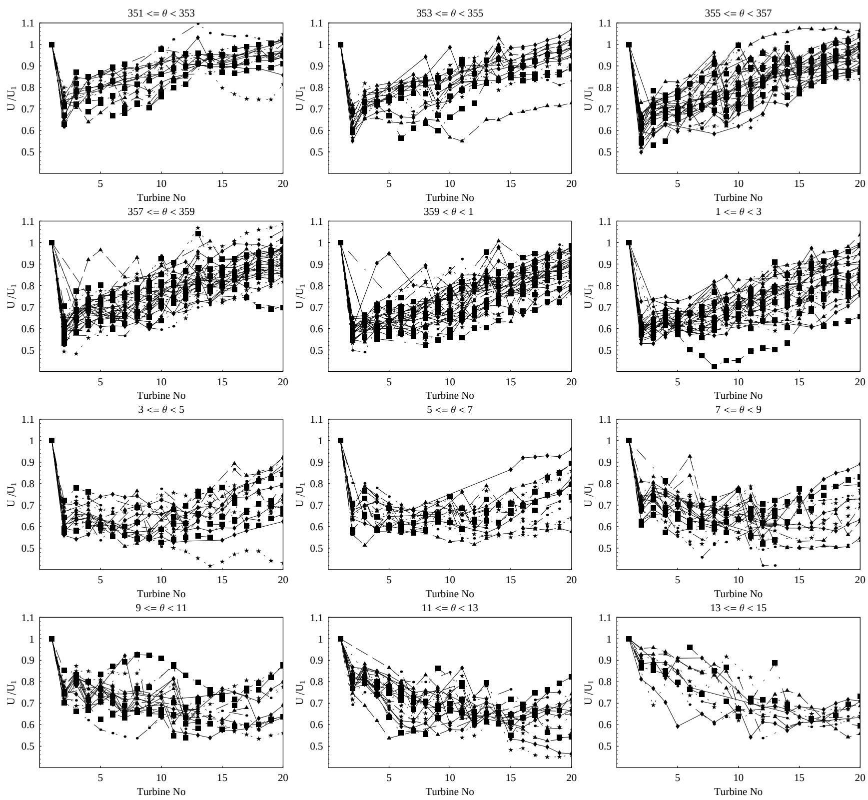

Figure 9 Normalized wind speed calculated on the basis of the measured power and power curve. The winds are normalized with the wind speed at turbine one.

Based on the data of Figure 9 the mean wind speed is calculated. This is done only when all of the 20 turbines are running i.e. the values of GeneratorRPM are 1000 or 1500. An example of the mean wind speed deficit is shown in Figure 10

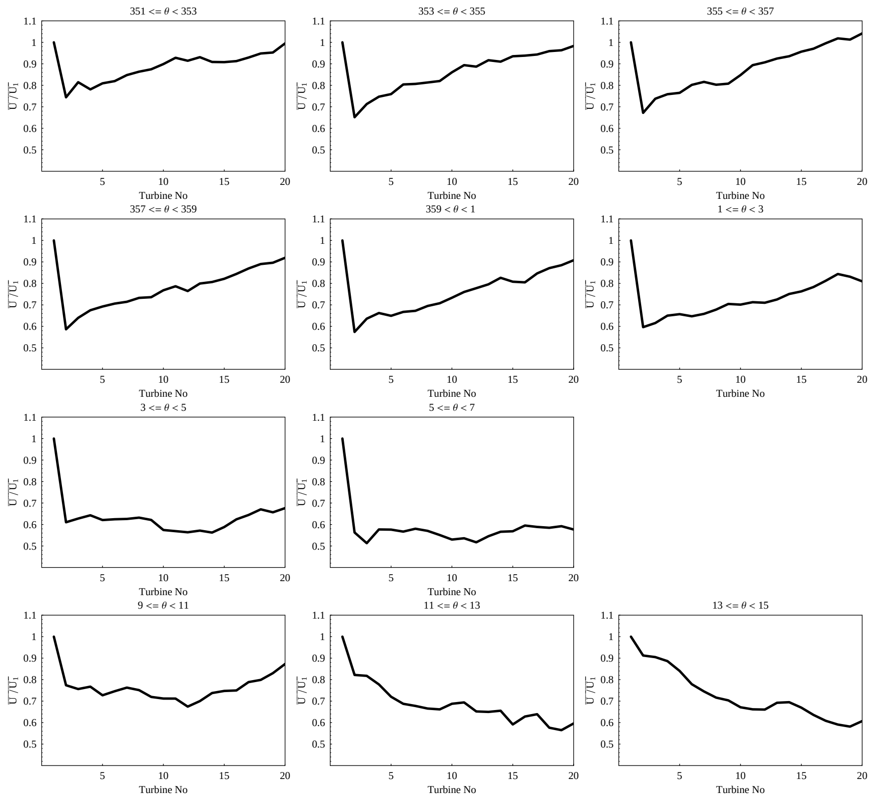

Figure 10 The average normalized wind speed in front of the turbines based on the data from the previous figure.

All analyzed data are shown in appendix for the intervals 5-6-7-8-9-10-11-12-13 m/s including mean values and directional changes through the array.

2.2 Turbulence intensities in the wake

The turbulence intensities in the wake is here estimated based on the work of Kenneth Thomsen and Søren Markilde (1992) where the relation between standard deviation of the electrical power and wind speed standard deviation is found to be represented as :

$$\sigma_p = B\,\sigma_u \left(\frac{dP}{dU}\right)_U \tag{1.1}$$

where σ_p is the stdev of power and σ_u is stdev of wind, B is a constant which is in the range of 0.8-0.9, and P is power and U is wind speed.

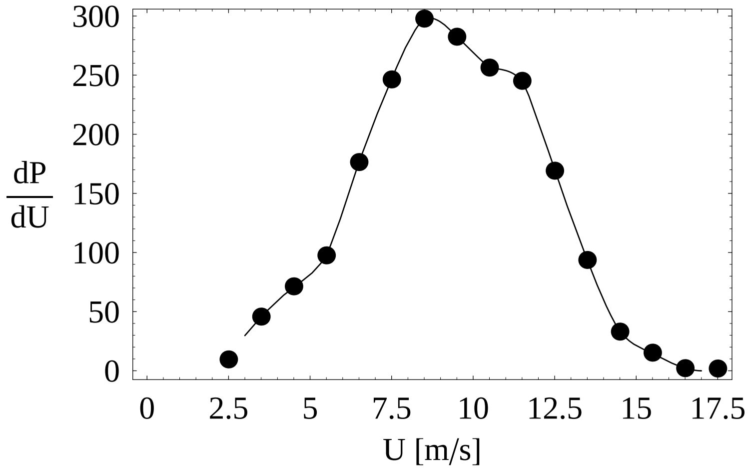

Figure 11 The derivative of the power curve with respect to the wind speed U. The dots show the measured points and the thin line is the interpolation function used in the following.

The estimated turbulence intensities are calculated based on the measured powers of the turbines through eq. (1.1).

The free stream water fetch turbulence intensity i.e. the estimated turbulence intensity from turbine one with the wind directions coming from North (in the sector from 355 to 360) is shown in Figure 12. The intensities is compared to the theoretical expression for the turbulence intensities based on the following equations:

$$\begin{aligned} z_0 &= c\frac{u_*^2}{g} \\ U(z) &= \frac{u_*}{\kappa} Ln\left(z / z_0\right) \\ \frac{\sigma_u}{u_*} &= A \end{aligned} \qquad (1.2)$$

Here c and A are constants and the roughness z_0 is described by the charnok relation. The normalized turbulence in the last equation appears from surface layer scaling and A is in the order of 1.2.

The comparisons between the estimated and modeled intensities are different under low and high wind speeds. Here the difference for low wind speeds can be explained by convection, which is not included in the theoretical expression. In the high wind speed regime the estimated turbulence is likely to be wrong due to the method of using the gradient of the power curve. We therefore conclude that the method does not work for wind speeds over 13 m/s.

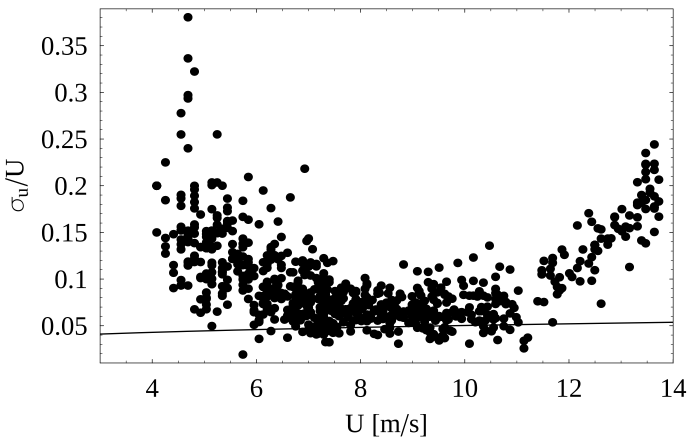

Figure 12 shows estimated turbulence intensities for different wind speeds compared to the theoretical intensities derived from the Charnok relation and surface layer scaling. Data are here shown as dots and the model as a thin line.

Examples of the calculated intensities through the turbine array for the different 2° sectors and a wind speed interval of 8-9 m/s are shown in Figure 13

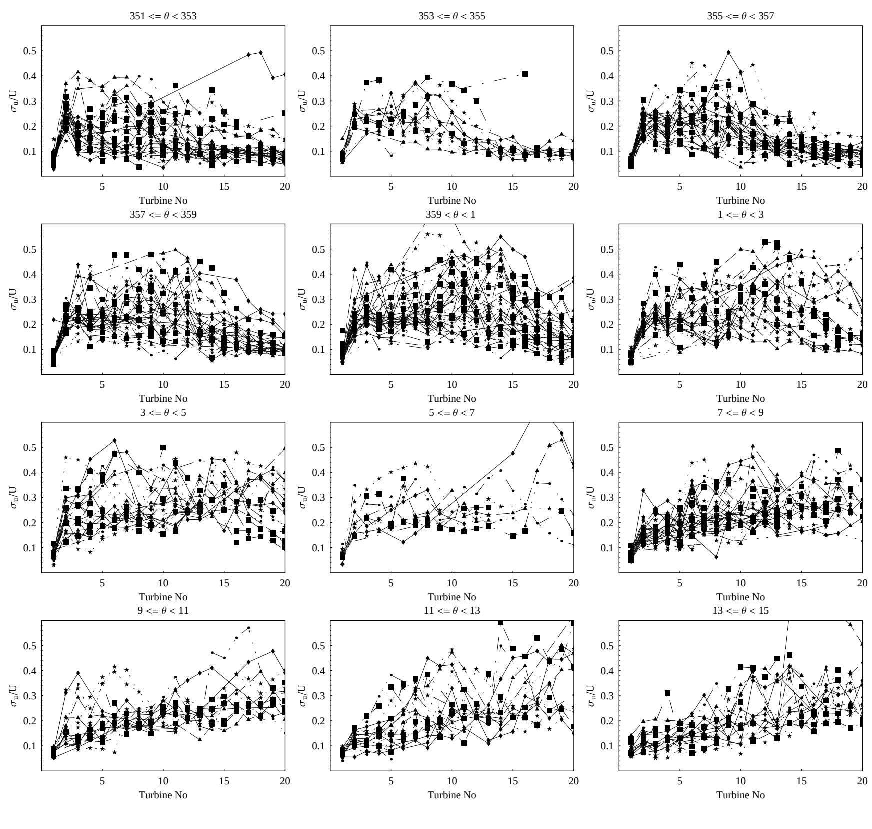

Figure 13 Turbulence intensities for the different sectors.

The corresponding mean values are shown in the appendix.

The mean turbulence intensity as function of wind direction is shown in Figure 14 and Figure 62 calculated on the basis of winds in the interval of 8 to 10 m/s measured at turbine no. 1. Data from turbine one represents the undisturbed measurement and Copenhagen can be identified due to a slightly higher background turbulence. The enhancement on the turbines 2 to 19 is due to the wakes which increase the values to approximately 0.3

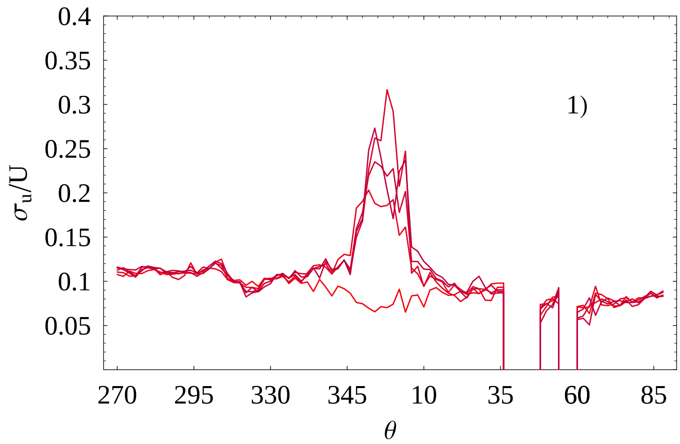

Figure 14 show the turbulence intensity as function of direction for the first 5 turbines.

The measurements have been compared to the model of Sten Frandsen (2003) and show a reasonable good agreement, see Figure 15.

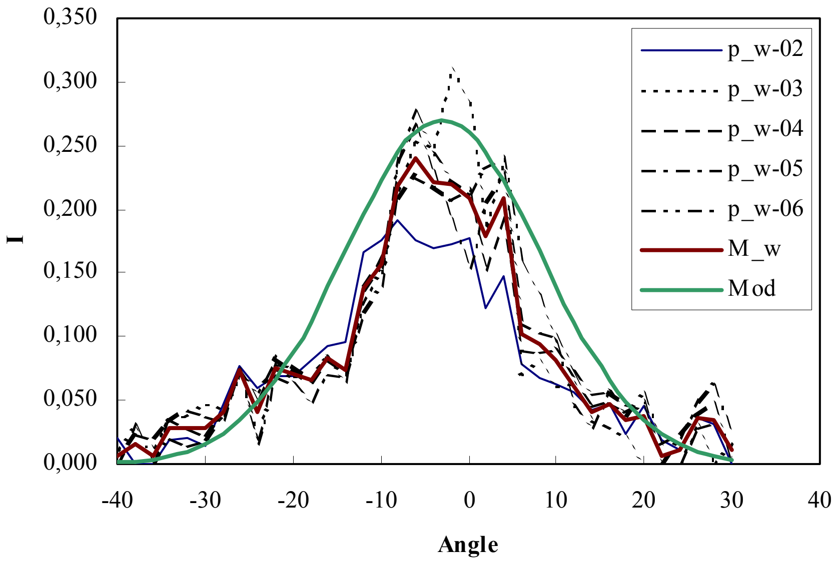

Figure 15 shows measured fluctuation intensities I as function from angle (around North) The data are shown for the 5 turbines after no 1 compared to the mean value and a model from Steen Frandsen 2003.

2.3 Wind speed deficit as function of turbulence intensity.

Based on all the estimated wind speeds and turbulence intensities have we tried to estimate the deficit in the wakes as a function of the turbulence intensity. We have here extracted data within the northern sector (355-360 degrees) within the free wind speed interval from 7 to 10 m/s. The data have further been divided into bins of turbulence intensities I in the interval of 0.03, 0.05, 0.07, 0.09 and 0,11. The resulting deficits are shown in Figure 16.

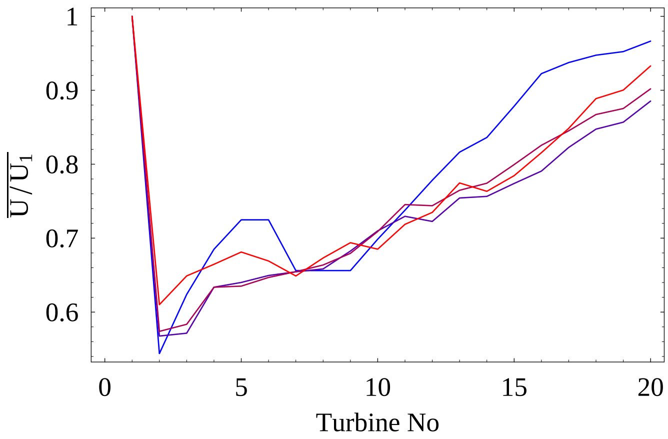

Figure 16 Wind speed deficits through the turbine array as function of the I, where the blue lines are 0,03 to 0,05 and the red line are 0,09 to 0.11

As seen from the figure there is a tendency to a increasing wind speed deficit as function of a decreasing background turbulence intensity on the turbine behind turbine no 1. The dependency vanishes fast trough the turbine array as the increasing amounts of wakes are included. Figure 17 show the deficit dependency on turbulence intensity for the first wake.

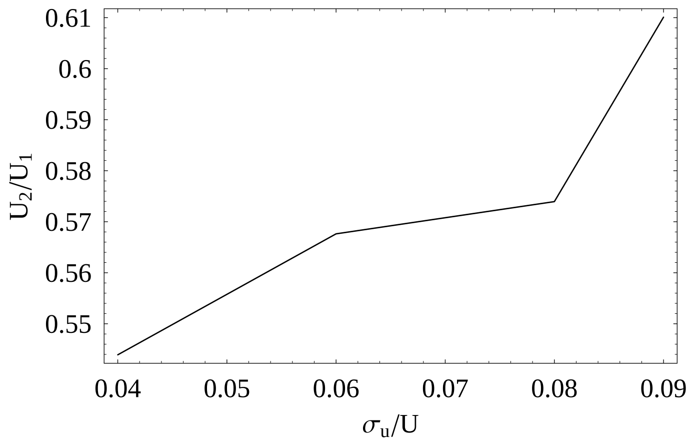

Figure 17 shows the deficit between the first and second turbine as function of turbulence intensity

3 PARK modeling

3.1 Measured data

Based on Wasp 8 the production losses of the Middelgrund Wind Farm have been calculated with the PARK model. The losses can only be calculated within a 10° sector. We have here extracted data around 8 to 9 m/s and around north in two 10° sectors shown in Figure 18 and Figure 19.

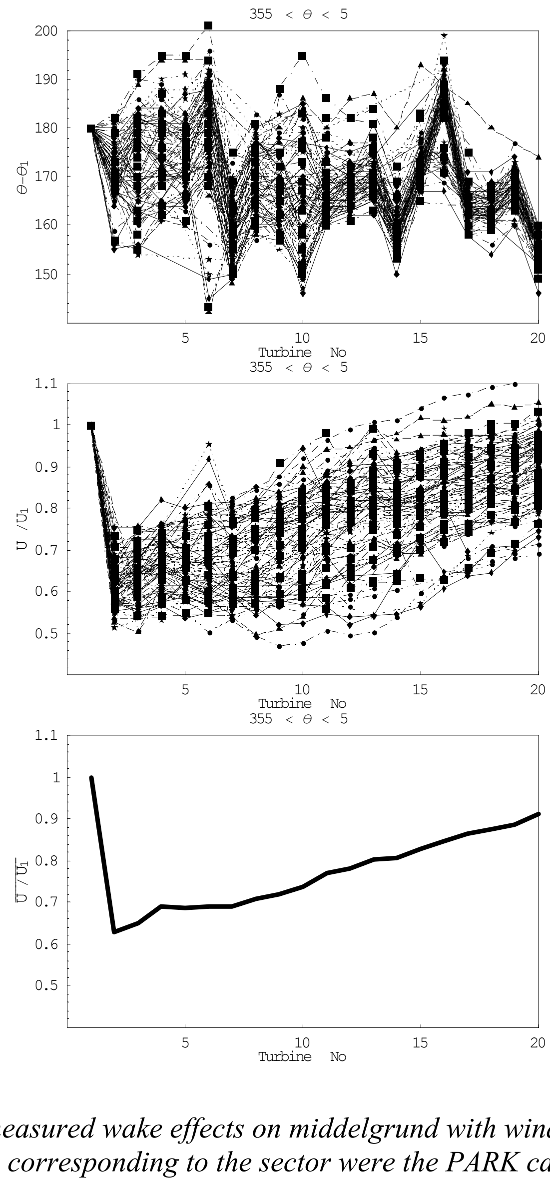

Figure 18 The measured wake effects on middelgrund with winds coming from 355 to 5 degrees corresponding to the sector were the PARK calculation have been performed. Only situations with winds between approx 8 and 9 m/s (wind speed taken from the nacelle anemometer) on turbine no. one have been included. The first figure shows the directional change of the individual turbines compared to turbine one and with an offset of 180 degrees to avoid the jump from 360 to 0. Second figure shows the wind speed in front of the turbines normalized with the wind speed at turbine one. Third figure shows the average of the second figure when all 20 turbines are in operation

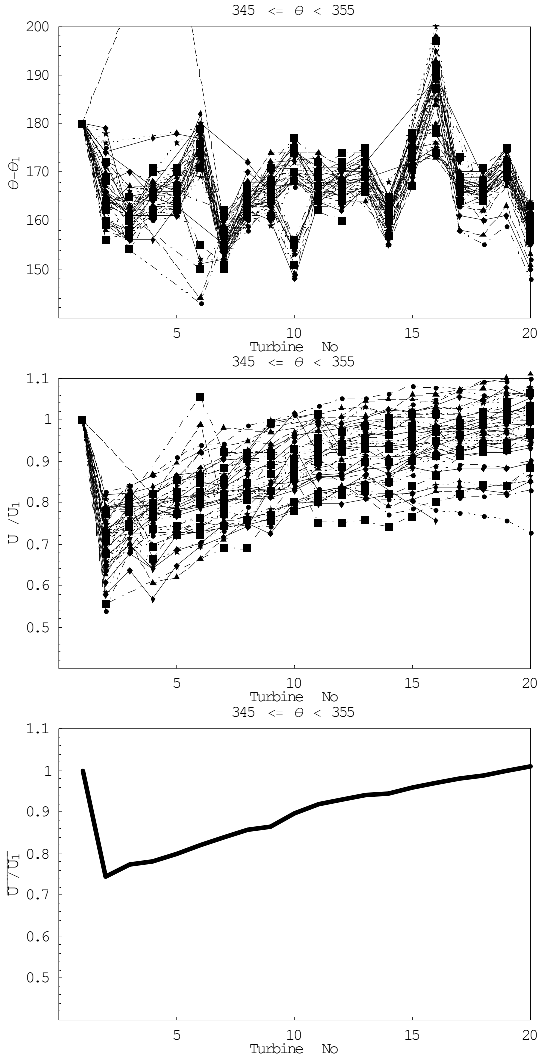

Figure 19 The measured wake effects on middelgrund with winds coming from 345° to 355° corresponding to the sector were the PARK calculation have been performed. Only situations winds between approx 8 and 9 m/s (speed from the nacelle anemometer) on turbine one have been included. The first figure shows the directional change of the individual turbines compared to turbine one and with an offset of 180 degrees to avoid the jump from 360 to 0. Second figure shows the wind speed in front of the turbines normalized with the wind speed at turbine one. Third figure shows the average of the second figure when all 20 turbines are in operation

3.2 Modeled data

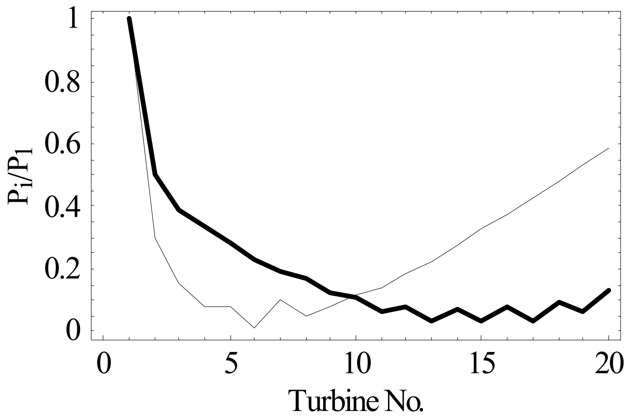

Figure 20. Calculated wake effects by the PARK module in WasP 8, shown as normalized power in two case where the winds are coming from two different sectors. The thin line shows the sector fro 345 to 355, and the thick line shows the sector from 355 to 5.

The winds are simulated with a random Weibull distribution with a (high) shape parameter of 19 and a scale parameter of 8 to ensure a narrow peak distribution around 8 m/s. Furthermore is the wind simulated with a preferred wind direction of 360 degrees. Figure 20 shows the result of the Wasp analysis of the energy decreasing down in the array of turbines.

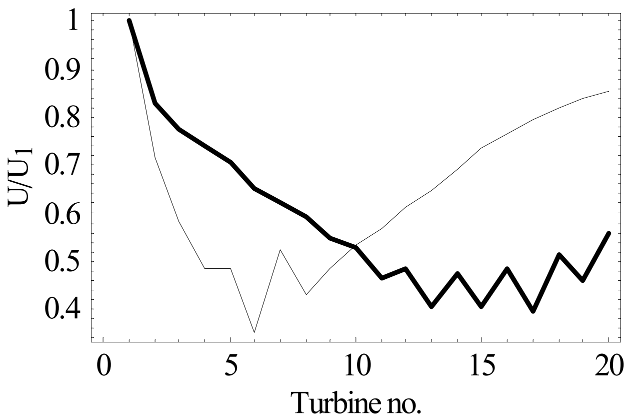

Figure 21 . Calculated wake effects by the PARK module in WasP 8. as in Figure 20 but shown as the calculated winds with use of the power curves. The thin line shows the sector from 345° to 355°, and the thick line shows the sector from 355° to 5°.

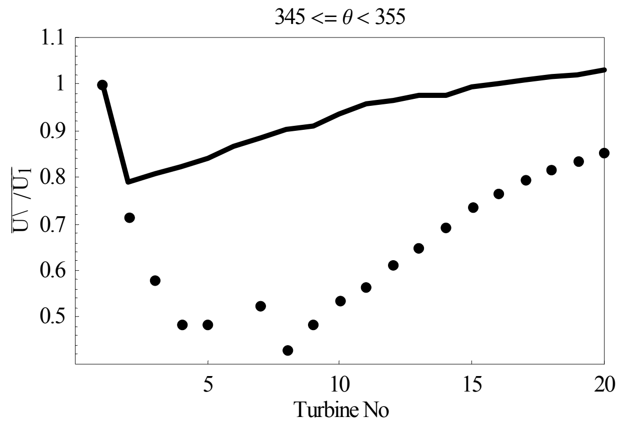

Figure 22 The measured wake effects on Middelgrund with winds coming from 345 to 355 degrees (the full line). The corresponding Park calculation is shown as dots.

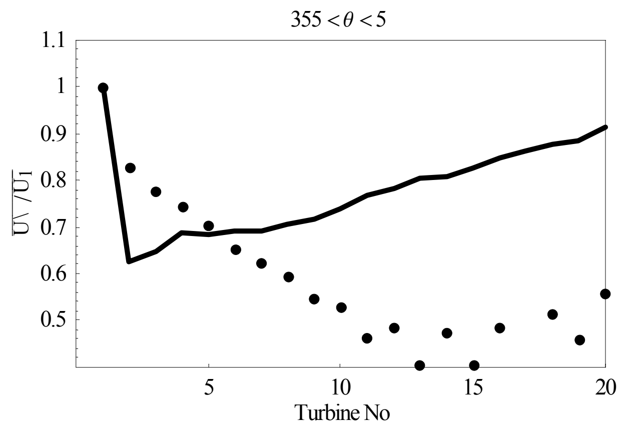

Figure 23 The measured wake effects on Middelgrund with winds coming from 355 to 0 degrees (the full line). The corresponding Park calculation is shown as dots.

4 Conclusion

In the analysis we have focused on the winds coming from North for the following reasons and based on a Waspengineering analysis of the Middelgrund Wind Farm:

1) The undisturbed fetch is largest when the winds are coming from Northern sector
2) The speed up and directional changes are neglible when the winds are coming from the Northern sector.
3) The array of turbines is aligned with a direction of 348^0 for the first two turbines, a direction of 0^0 at turbine no. 15 and 6^0 at turbine 19 and 20.

The analysis shows that the directional change of the turbines with respect to the direction of turbine no 1 is nearly identical for the individual wind situations within a sector of 20 along the turbine array. The alignment of turbine no. 16 differs significantly from the others. In this analysis we cannot conclude whether this is a misalignment in the yaw angle measuring system or a real flow effect as calibration of the yaw angle system is only approximate.

The data analysis have been compared to a PARK calculation performed in Wasp 8. The PARK calculations have been converted from power to wind speed deficits and there is as substantial difference between the calculated deficits in wind speed between the data and the PARK model. However, it shall noted that it is a very crude comparison since the lowest directional sector interval in the PARK/Wasp mode is 10° , and all events are assumed uniformly distributed over this sector. Furthermore, the model does not include the changing direction of the wind flow through the turbine array caused by the interaction between the turbines and the flow. Finally the turbines are spaced by 2.4 rotor diameters, which is in the limit of the park model assumptions where the spacing is assumed to be higher than 5 rotor diameters.

Taking all this assumptions and model constrains into account the Park model overestimates the wind speed deficits with up to 30 % with an ever decreasing wind speed through the array when the wind is coming from north whereas a the data shows a tendency to a recovery of the wind through the array.

The data also confirms that there is a wake deficit depending on the turbulence intensity although this is only valid for the first wake behind turbine 1.

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Appendix 1

Thrust coefficient data

The thrust coefficient C_t is used for the calculation of the wind speed deficit in the wake of a wind turbine. C_t is defined by the following expression:

$$C_t = \frac{F}{(0.5\,\rho U^2 \mathrm{A})} \tag{1.3}$$

where F is the rotor force [kN], and U is the wind speed , A is the Swept area of the rotor [m^2]. The calculated C_t-data are valid for the air density of 1.225, clean rotor blades, and horizontal, undisturbed flow. It is known that rotor thrust forces are predicted with some uncertainty, particularly in the stall range. Consequently, the Ct data should be taken as indicative only.

Table 2. Calculated thrust data for the 2MW Bonus machine.

Wind [m/s]	C_t
0,0	0,000
1,0	0,000
2,0	0,000
3,0	0,000
4,0	0,857
5,0	0,858
6,0	0,810
7,0	0,853
8,0	0,870
9,0	0,811
10,0	0,756
11,0	0,679
12,0	0,584
13,0	0,511
14,0	0,439
15,0	0,383
16,0	0,338
17,0	0,301
18,0	0,271
19,0	0,246
20,0	0,225
21,0	0,207
22,0	0,192
23,0	0,179
24,0	0,168
25,0	0,158

Wind speeds between 5-6 m/s

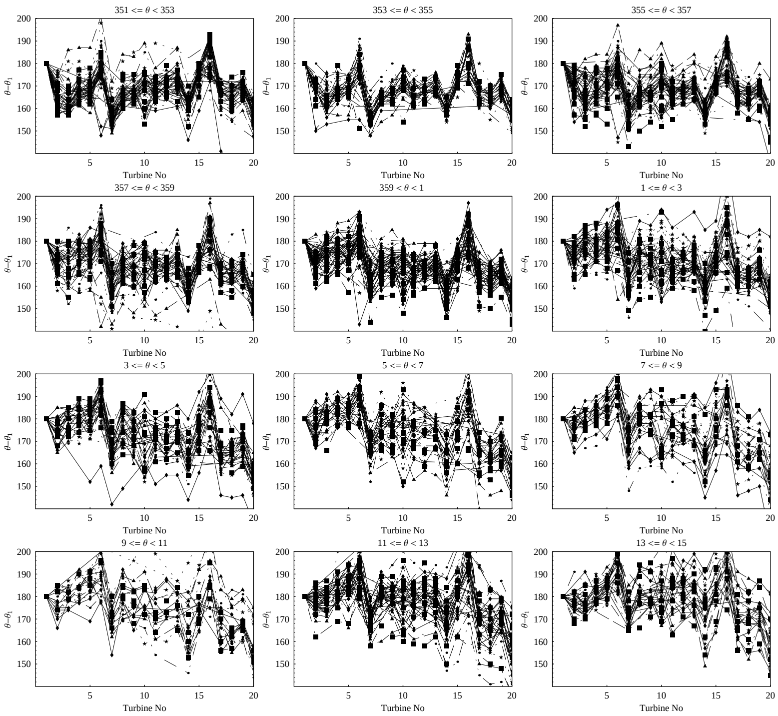

Figure 24 shows the directional change of the individual turbines compared to turbine 1 with an offset of 180 degrees to avoid the jump from 360 to 0.

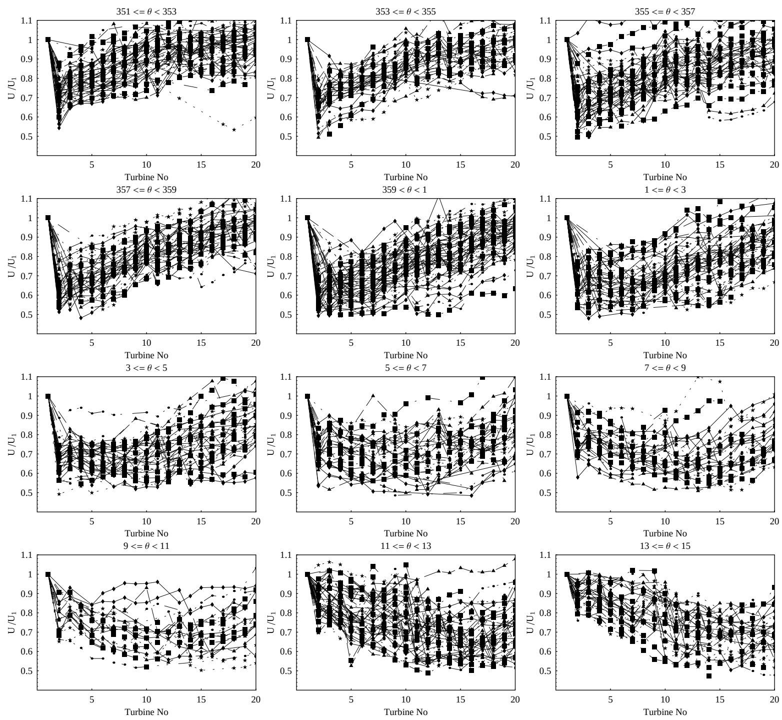

Figure 25 shows a normalized wind speed calculated on the basis of the measured power and power curve in front of the turbines. The winds are normalized with the wind speed at turbine one.

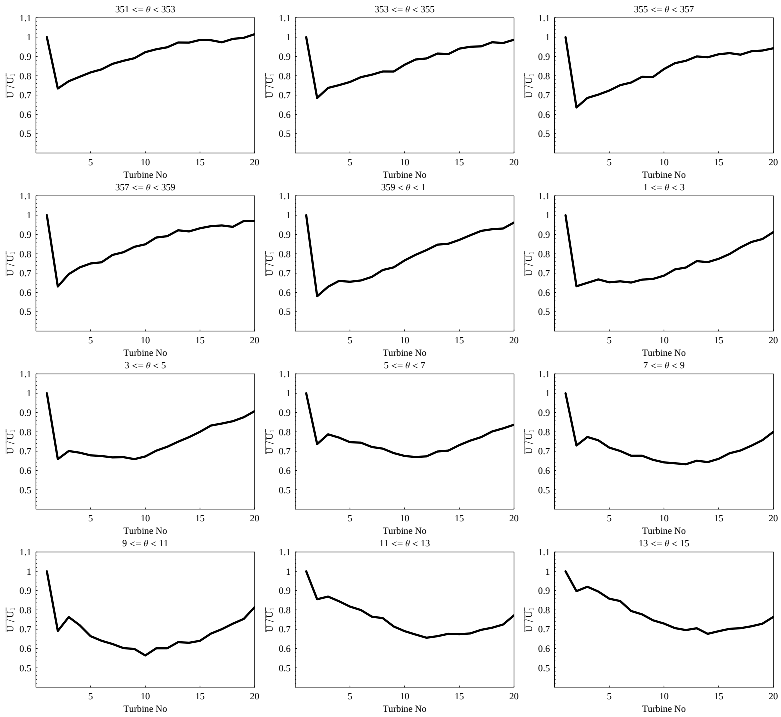

Figure 26 Shows the average normalized wind speed in front of the turbines based on the data from the previous figure.

Wind speeds between 6-7 m/s

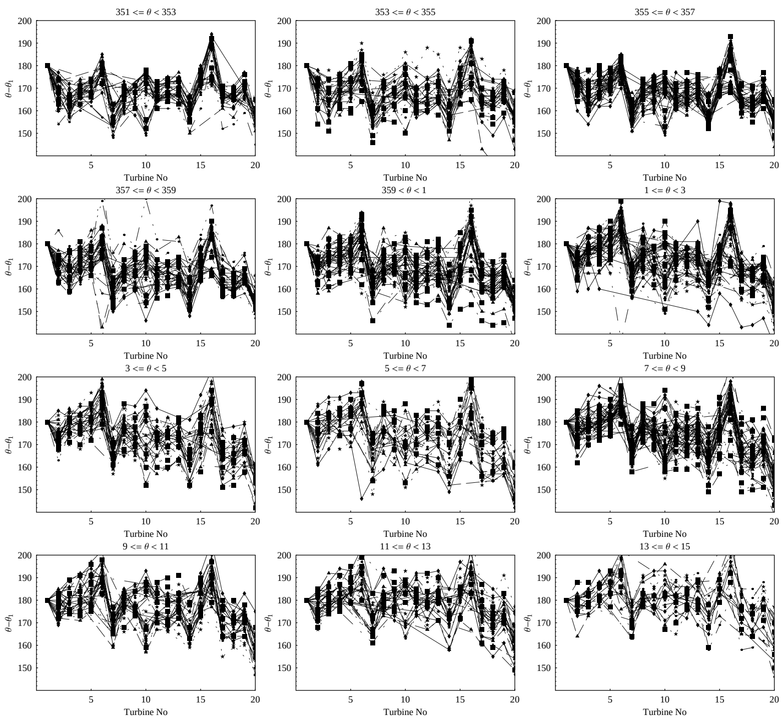

Figure 27 shows the directional change of the individual turbines compared to turbine 1 with an offset of 180 degrees to avoid the jump from 360 to 0.

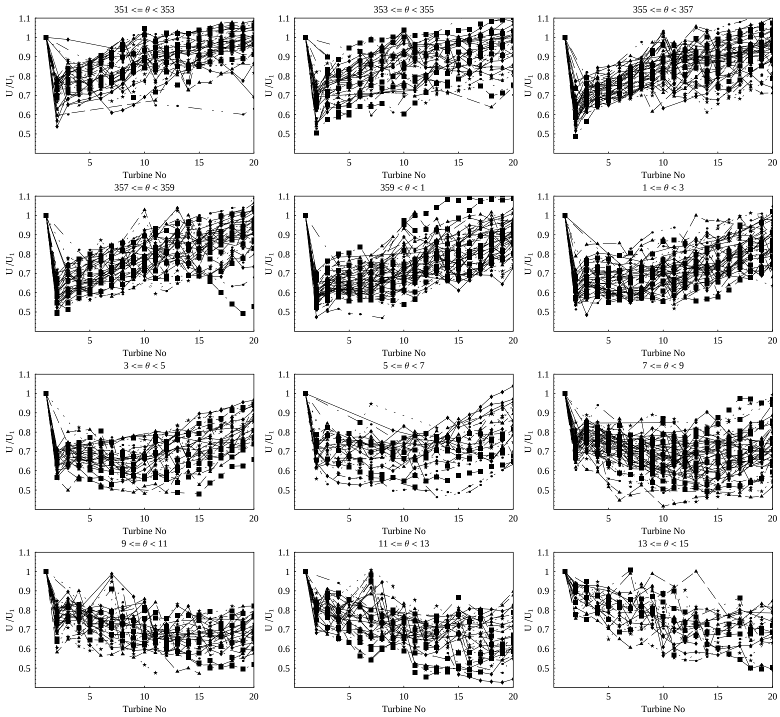

Figure 28 shows a normalized wind speed calculated on the basis of the measured power and power curve in front of the turbines. The winds are normalized with the wind speed at turbine one.

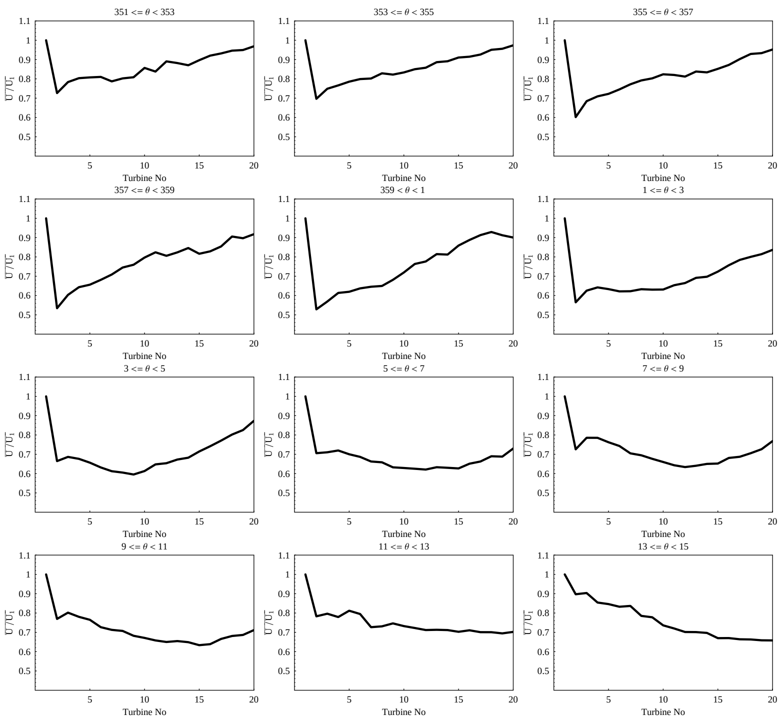

Figure 29 Shows the average normalized wind speed in front of the turbines based on the data from the previous figure.

Wind speeds between 7-8 m/s

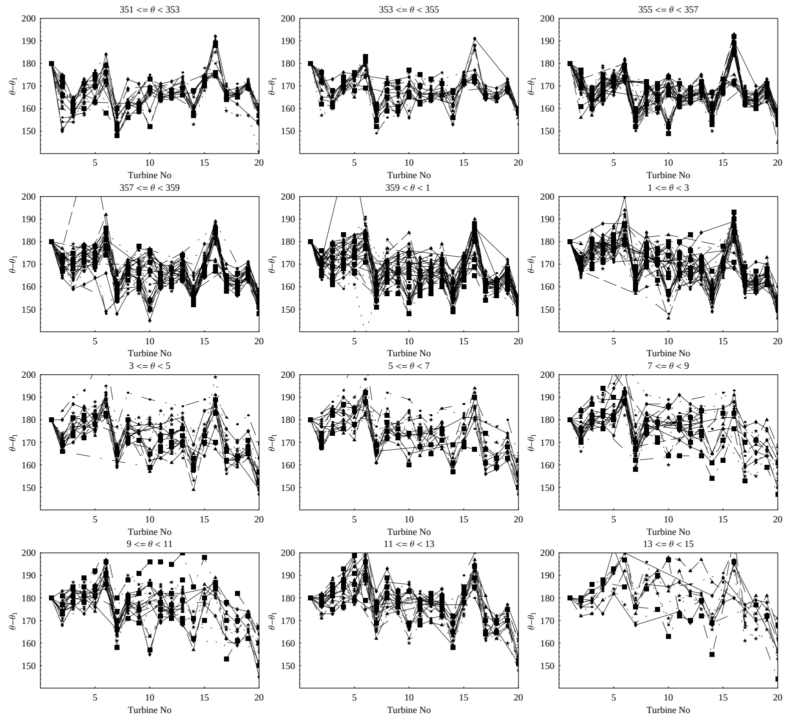

Figure 30 shows the directional change of the individual turbines compared to turbine 1 with an offset of 180 degrees to avoid the jump from 360 to 0.

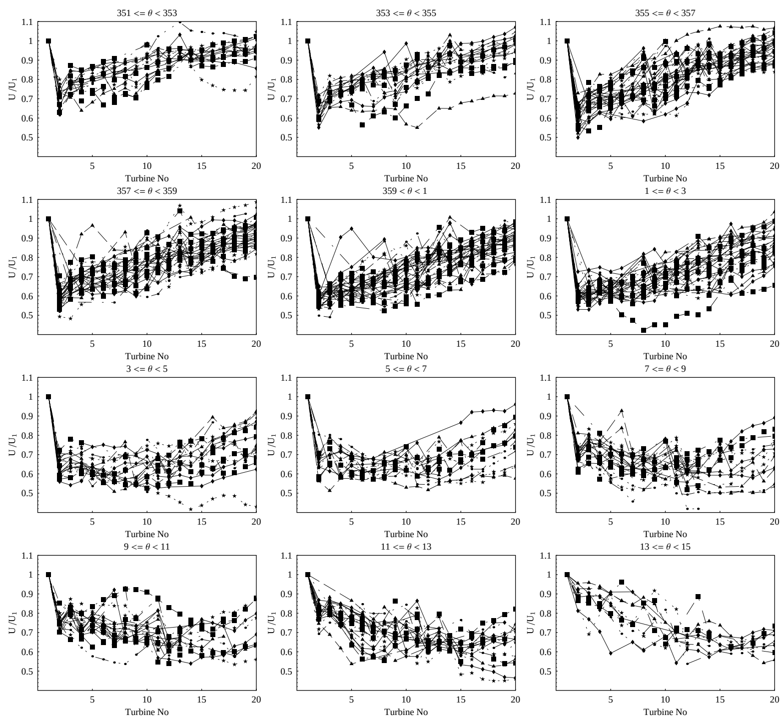

Figure 31 shows a normalized wind speed calculated on the basis of the measured power and power curve in front of the turbines. The winds are normalized with the wind speed at turbine one.

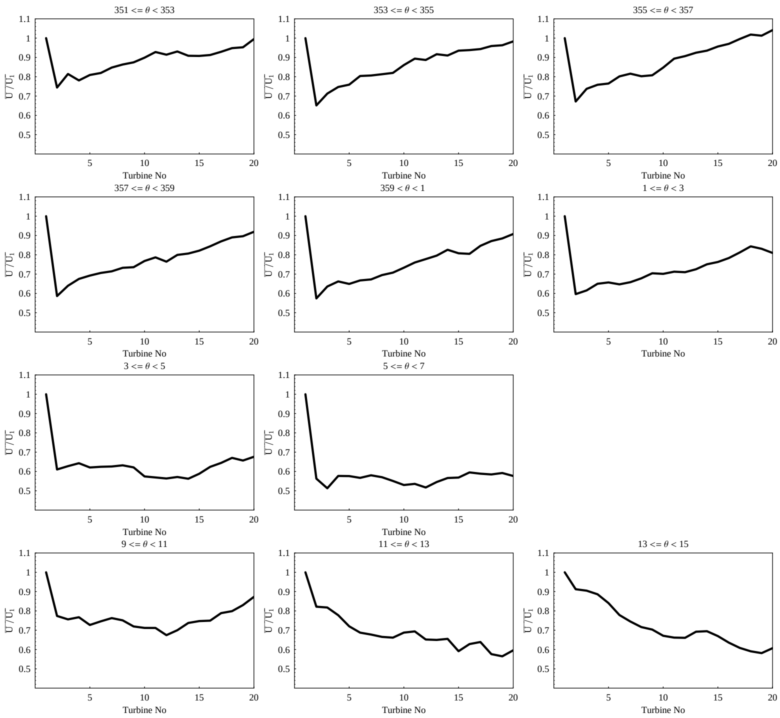

Figure 32 Shows the average normalized wind speed in the front of the turbines based on the data from the previous figure.

Wind speeds between 8-9 m/s

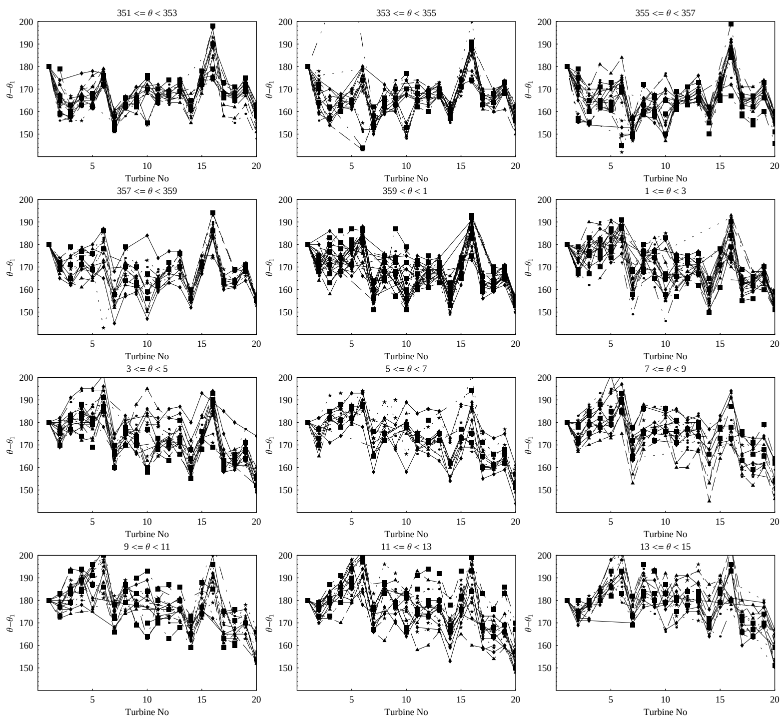

Figure 33 shows the directional change of the individual turbines compared to turbine 1 with an offset of 180 degrees to avoid the jump from 360 to 0.

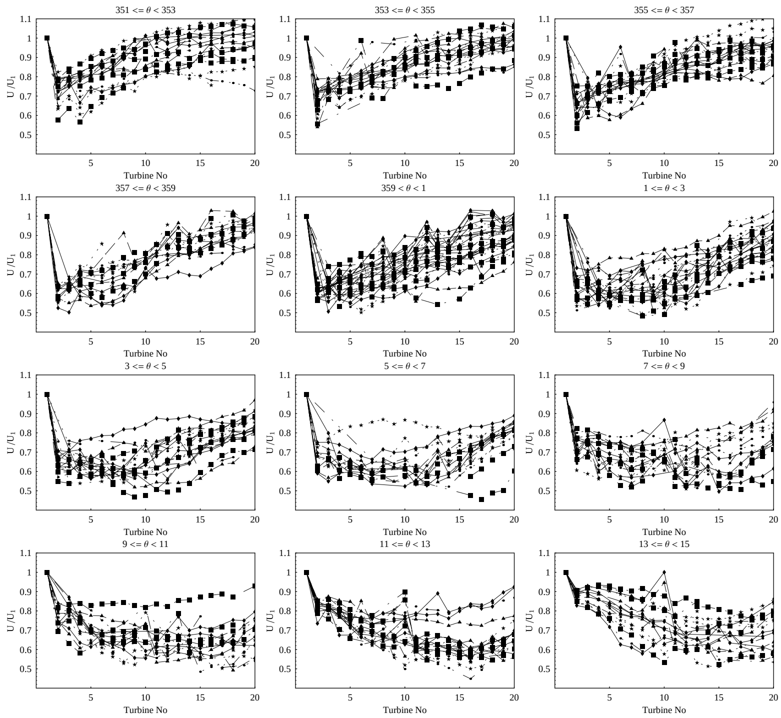

Figure 34 shows a normalized wind speed calculated on the basis of the measured power and power curve in front of the turbines. The winds are normalized with the wind speed at turbine one.

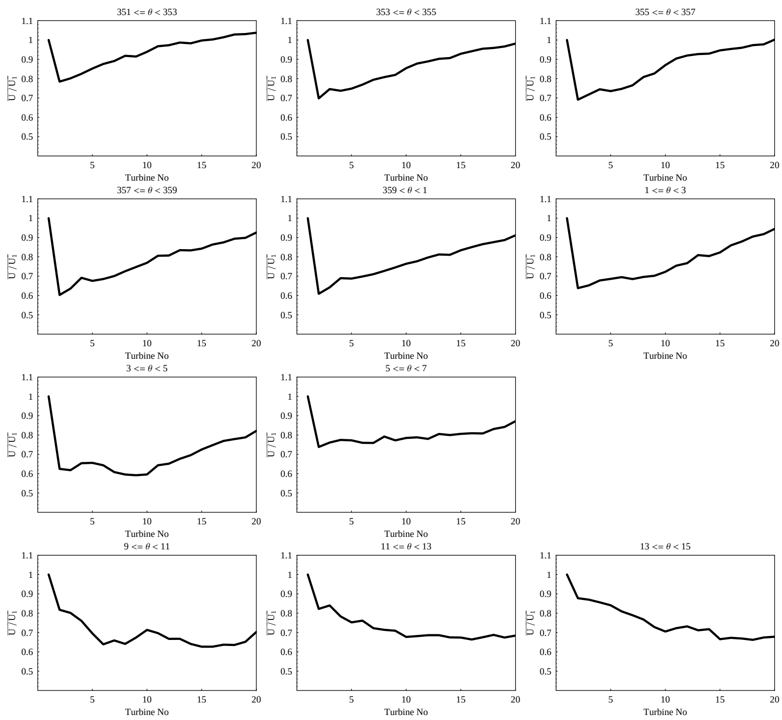

Figure 35 Shows the average normalized wind speed in the front of the turbines based on the data from the previous figure.

Wind speeds between 9-10 m/s

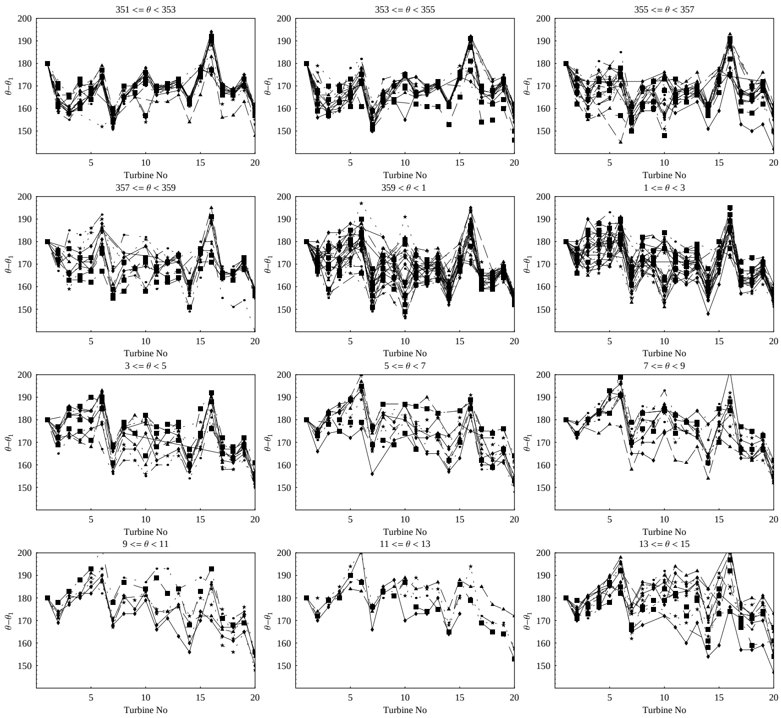

Figure 36 shows the directional change of the individual turbines compared to turbine 1 with an offset of 180 degrees to avoid the jump from 360 to 0.

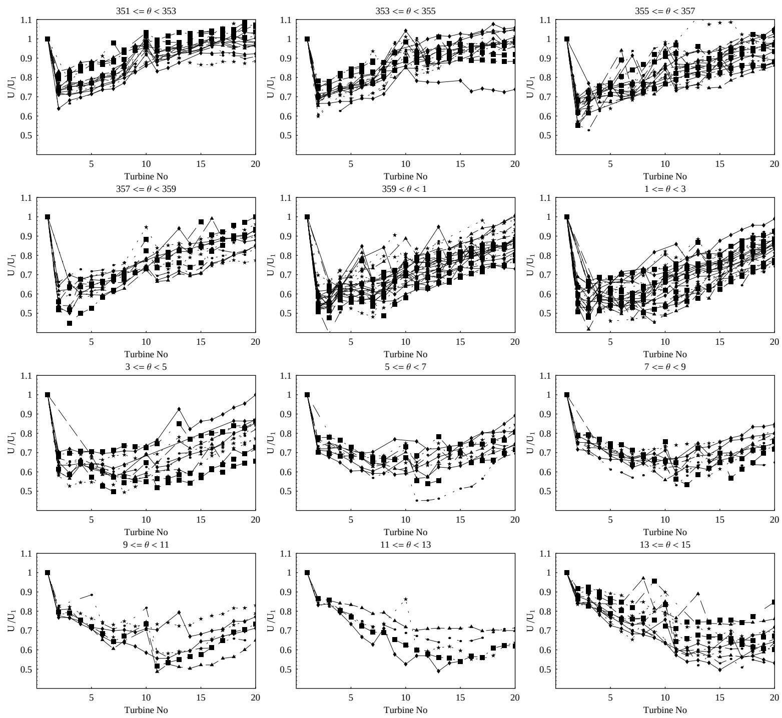

Figure 37 shows a normalized wind speed calculated on the basis of the measured power and power curve in front of the turbines. The winds are normalized with the wind speed at turbine one.

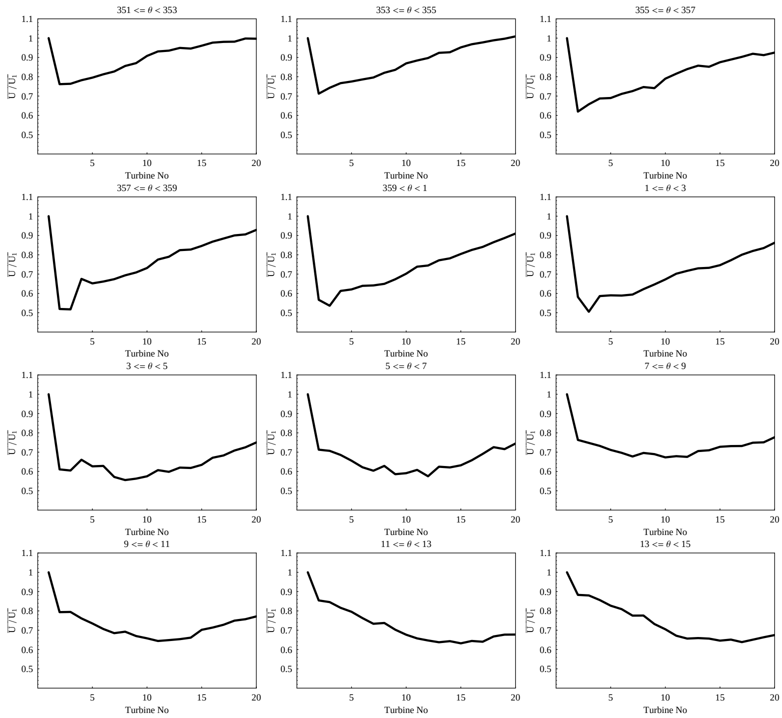

Figure 38 Shows the average normalized wind speed in front of the turbines based on the data from the previous figure.

Wind speeds between 10-11 m/s

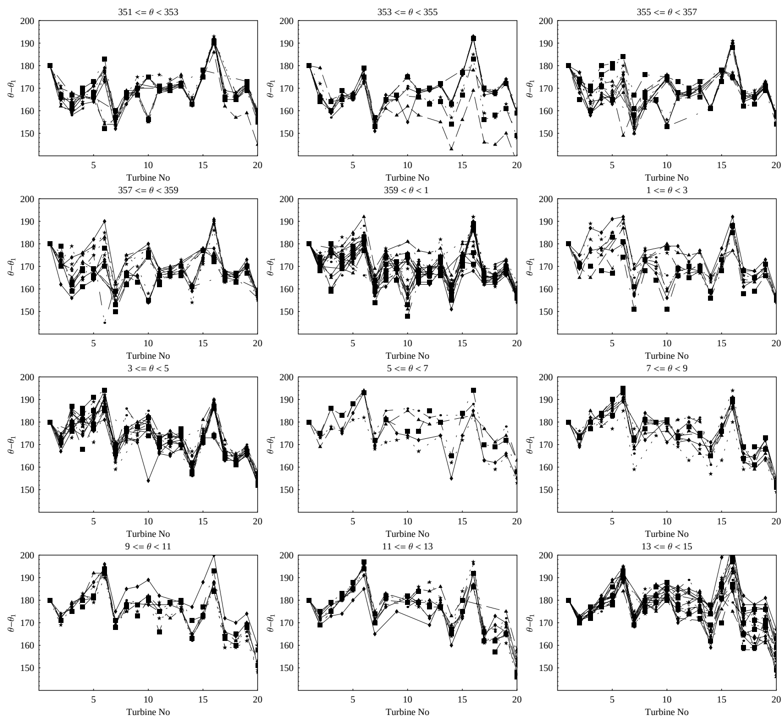

Figure 39 shows the directional change of the individual turbines compared to turbine 1 with an offset of 180 degrees to avoid the jump from 360 to 0.

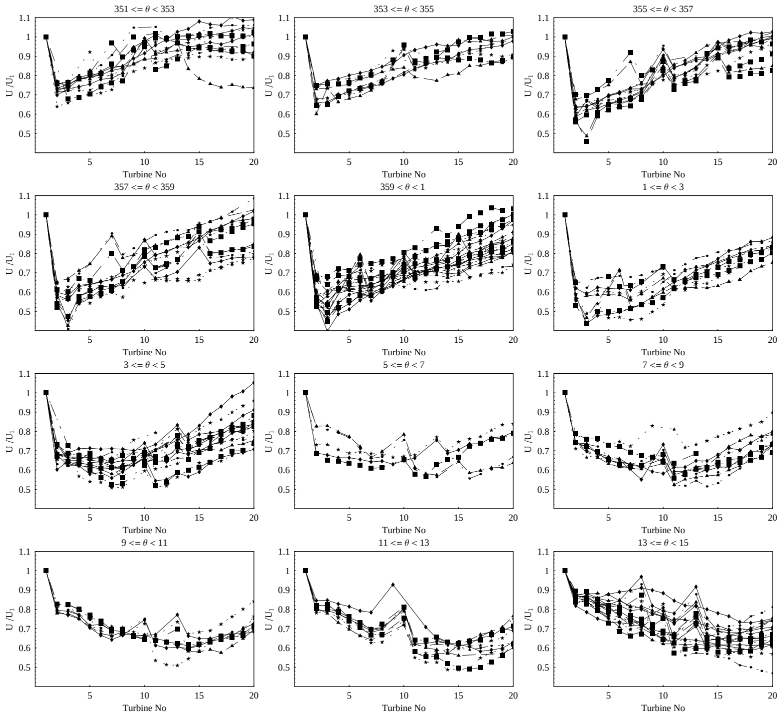

Figure 40 shows a normalized wind speed calculated on the basis of the measured power and power curve in front of the turbines. The winds are normalized with the wind speed at turbine one.

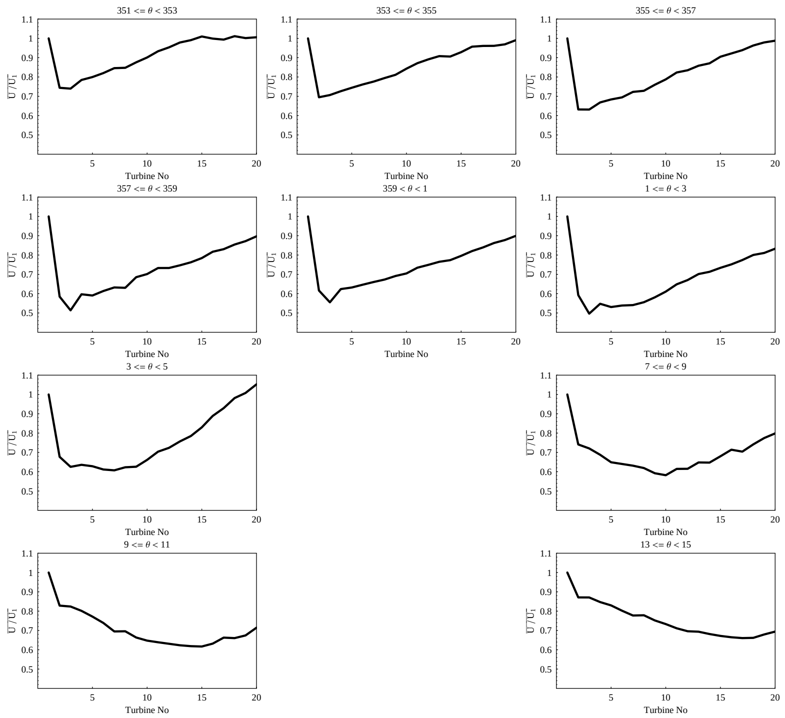

Figure 41 Shows the average normalized wind speed in the front of the turbines based on the data from the previous figure.

Wind speeds between 11-12 m/s

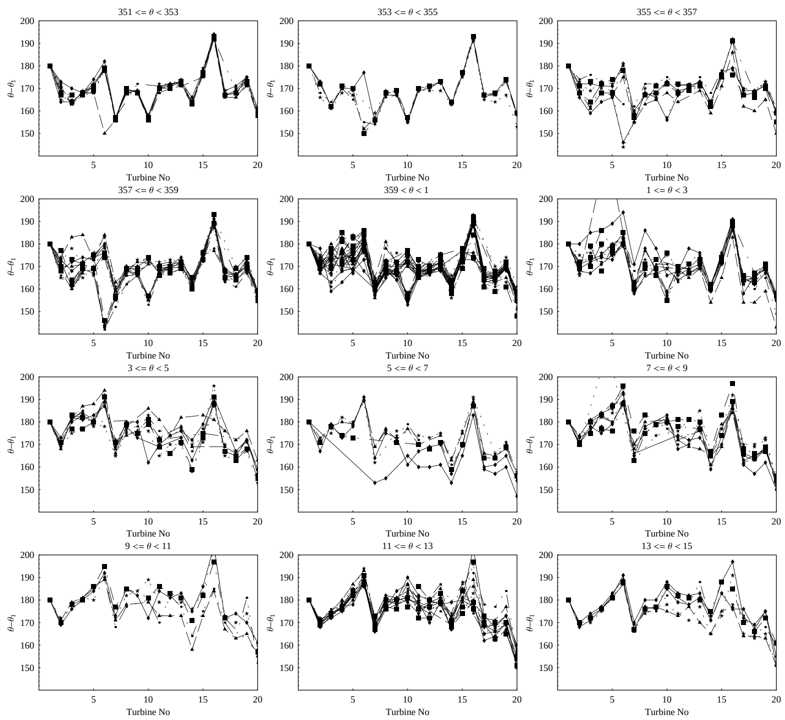

Figure 42 shows the directional change of the individual turbines compared to turbine 1 with an offset of 180 degrees to avoid the jump from 360 to 0.

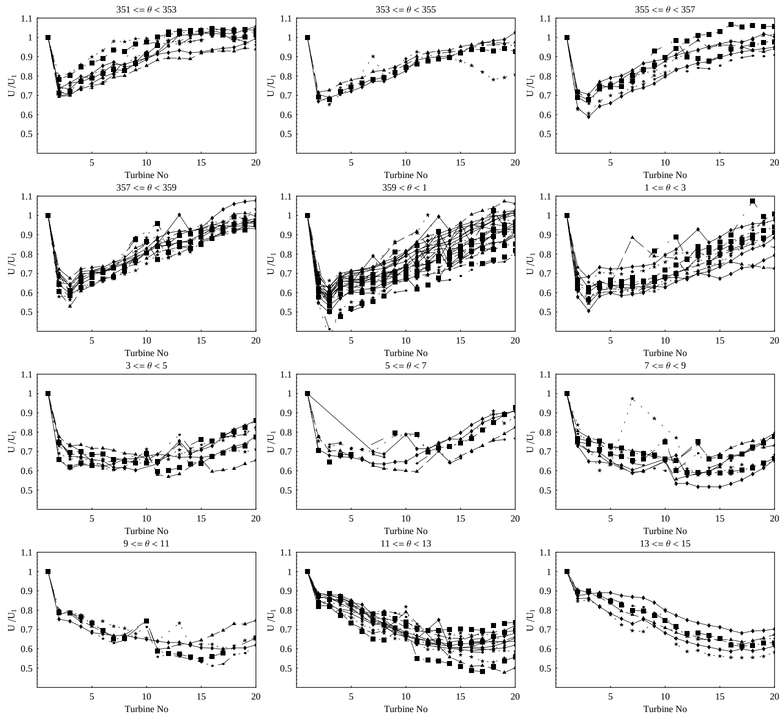

Figure 43 shows a normalized wind speed calculated on the basis of the measured power and power curve in front of the turbines. The winds are normalized with the wind speed at turbine one.

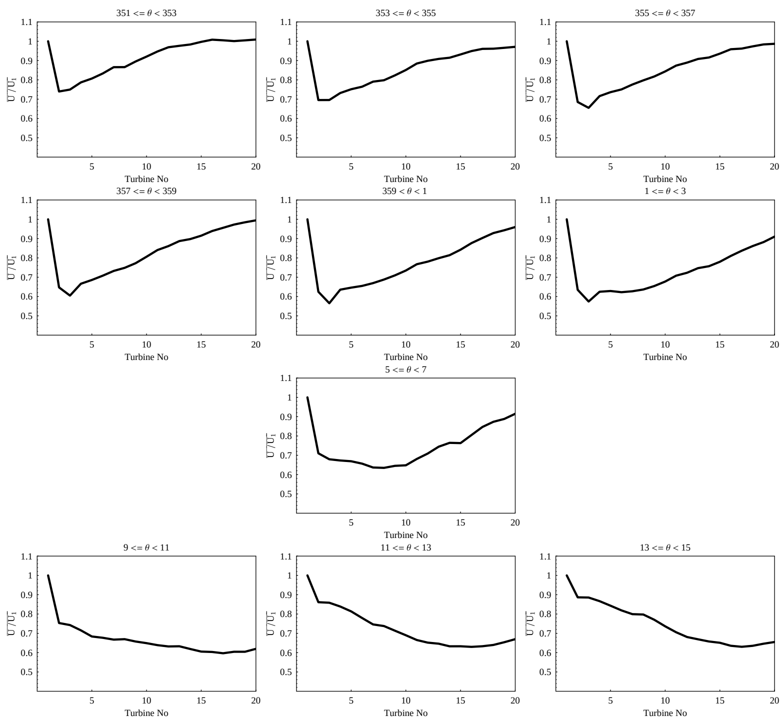

Figure 44 Shows the average normalized wind speed in front of the turbines based on the data from the previous figure.

Wind speeds between 12-13 m/s

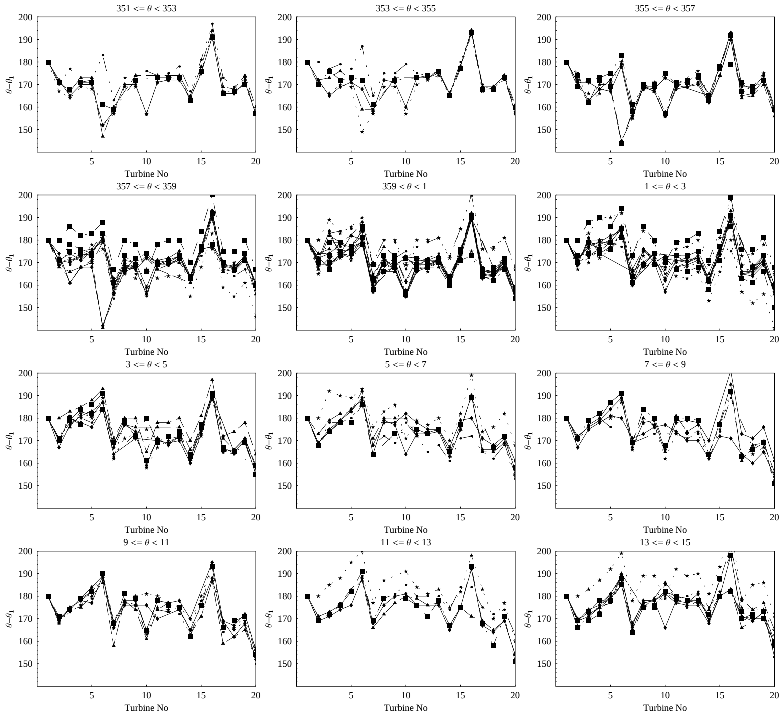

Figure 45 shows the directional change of the individual turbines compared to turbine 1 with an offset of 180 degrees to avoid the jump from 360 to 0.

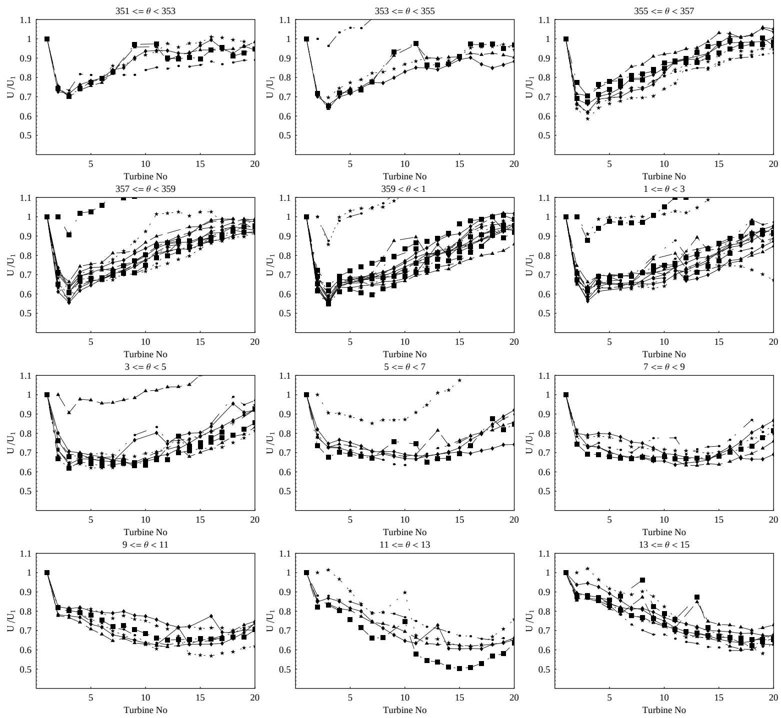

Figure 46 shows a normalized wind speed calculated on the basis of the measured power and power curve in front of the turbines. The winds are normalized with the wind speed at turbine one.

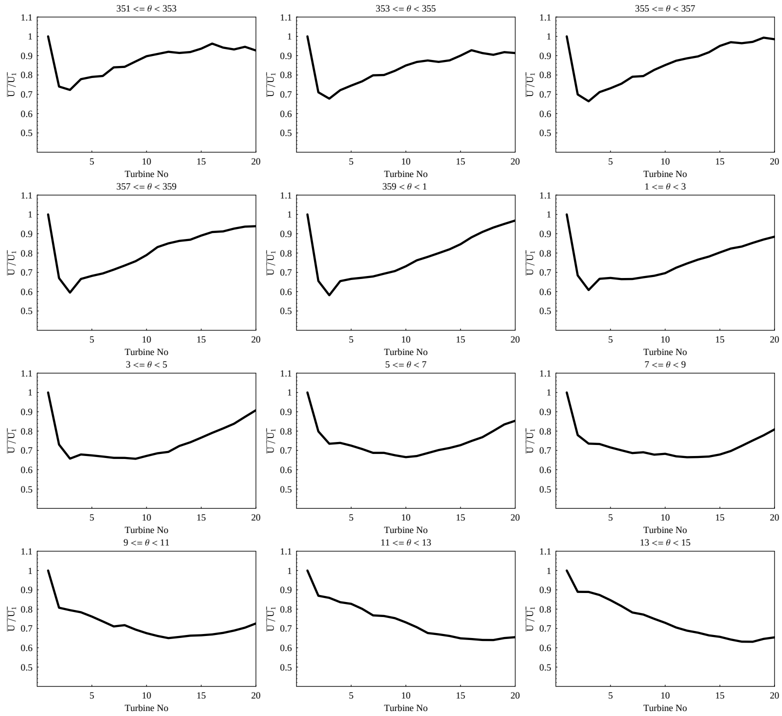

Figure 47 Shows the average normalized wind speed in front of the turbines based on the data from the previous figure.

Appendix 2

Turbulence intensities between 6-7 m/s

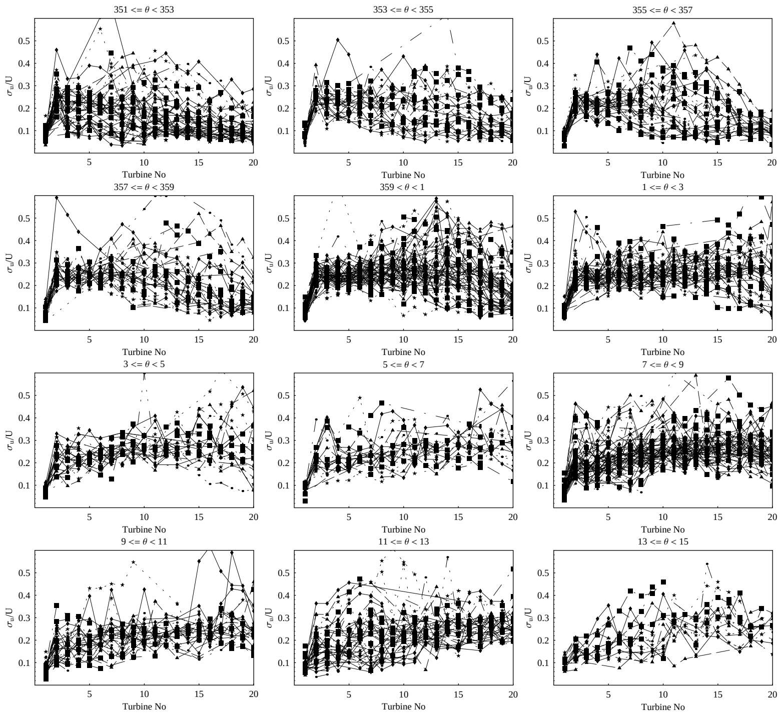

Figure 48 show the individual 10 min averaged turbulence intensities for the different sectors.

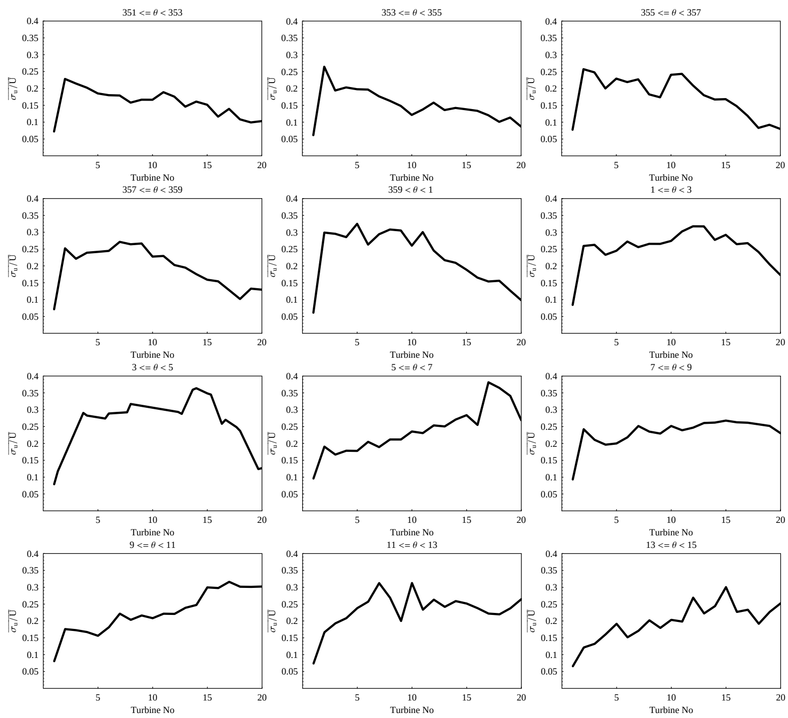

Figure 49 shows the average turbulence intensities for each sector.

Turbulence intensities between 7-8 m/s

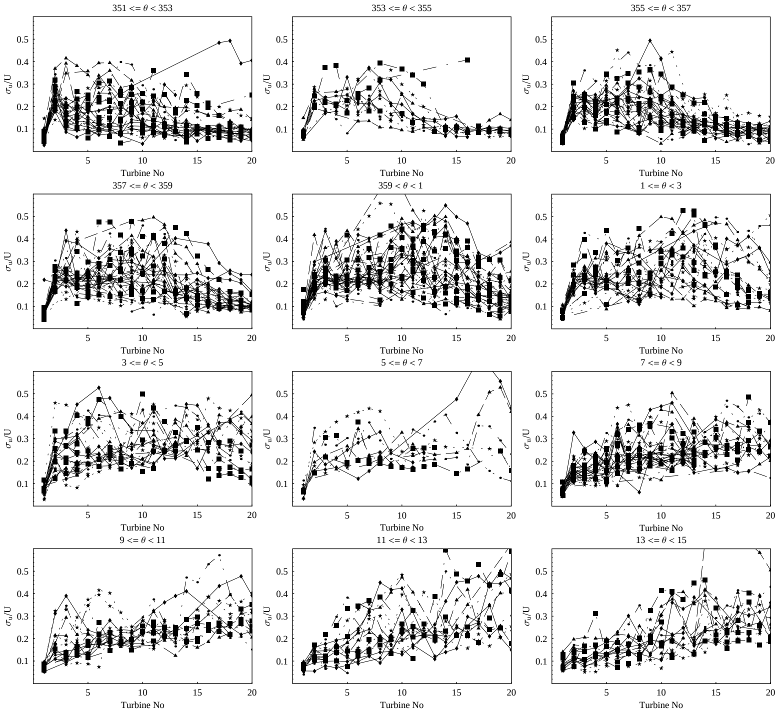

Figure 50 show the individual 10 min averaged turbulence intensities for the different sectors.

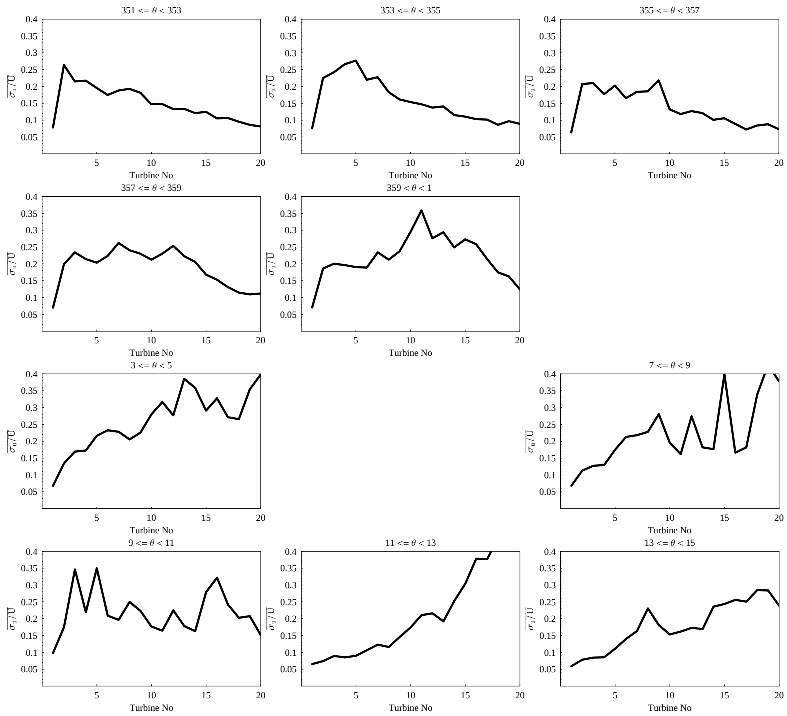

Figure 51 shows the average turbulence intensities for each sector.

Turbulence intensities between 8-9 m/s

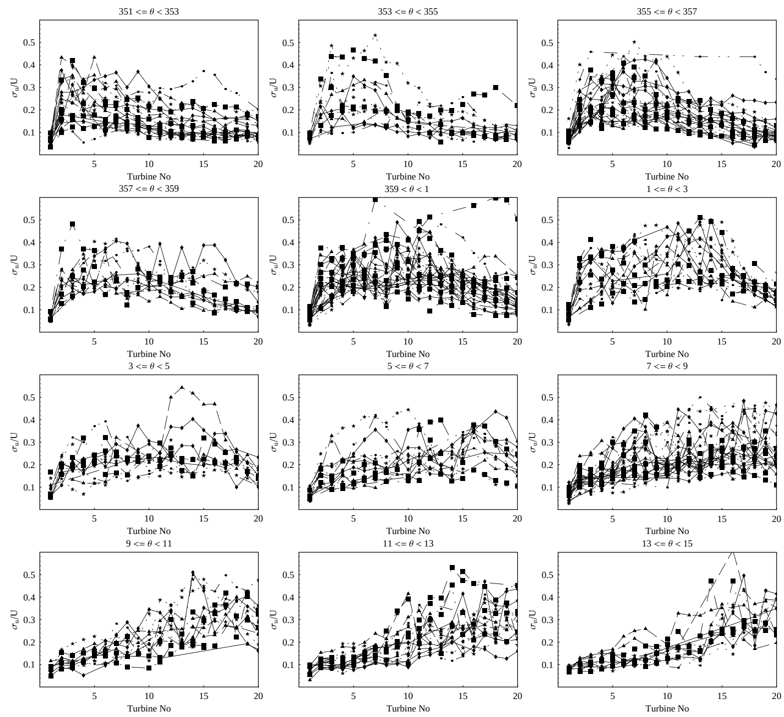

Figure 52 show the individual 10 min averaged turbulence intensities for the different sectors.

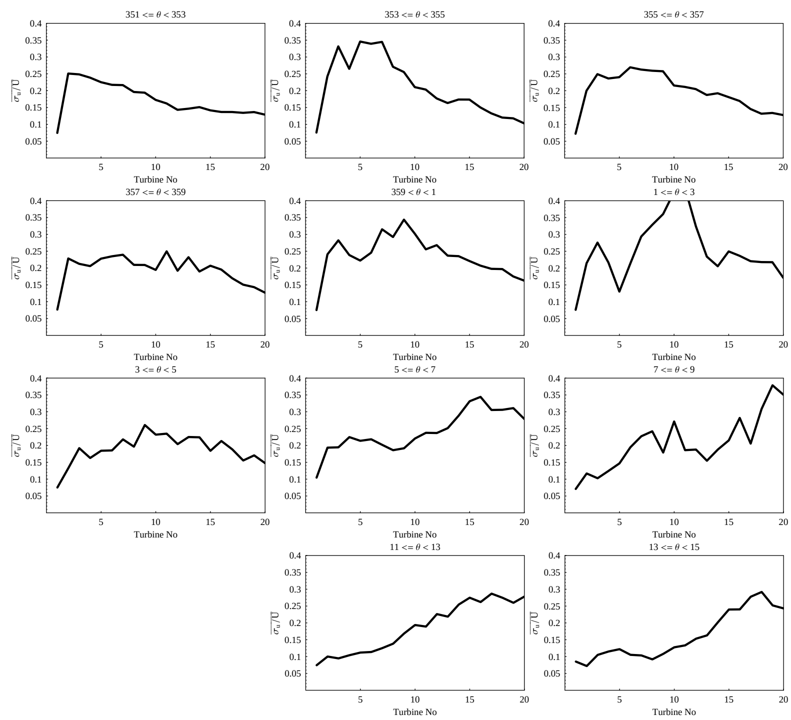

Figure 53 shows the average turbulence intensities for each sector.

Turbulence intensities between 9-10 m/s

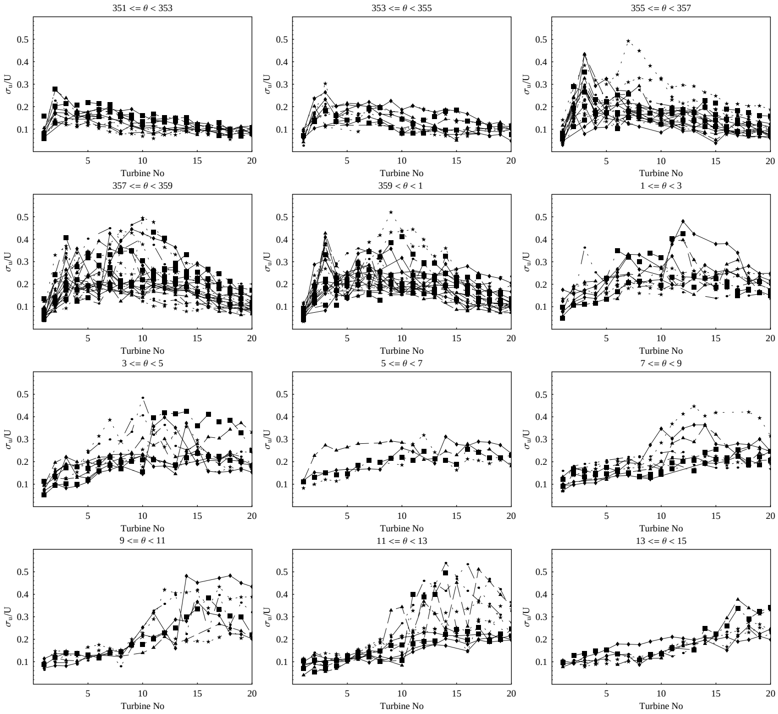

Figure 54 show the individual 10 min averaged turbulence intensities for the different sectors.

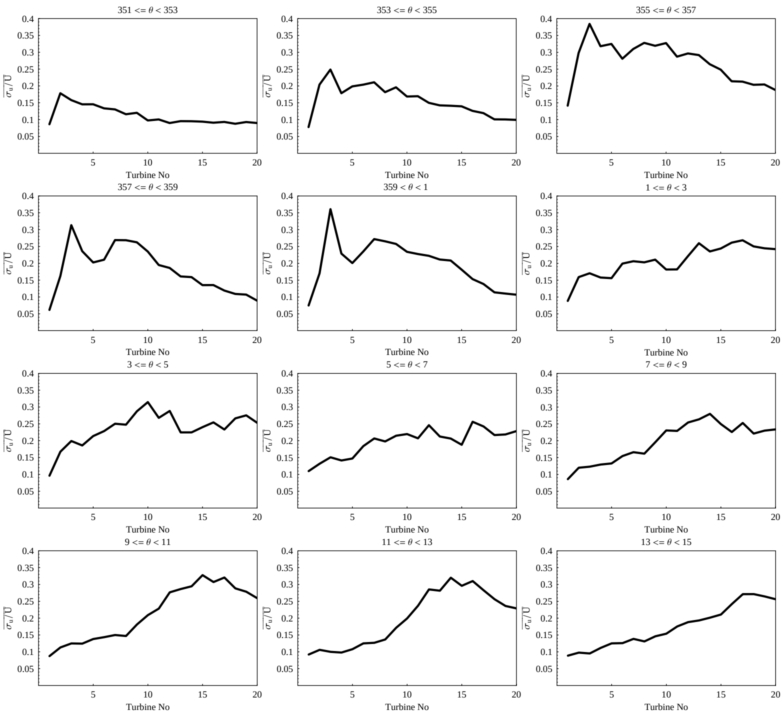

Figure 55 shows the average turbulence intensities for each sector.

Turbulence intensities between 10-11 m/s

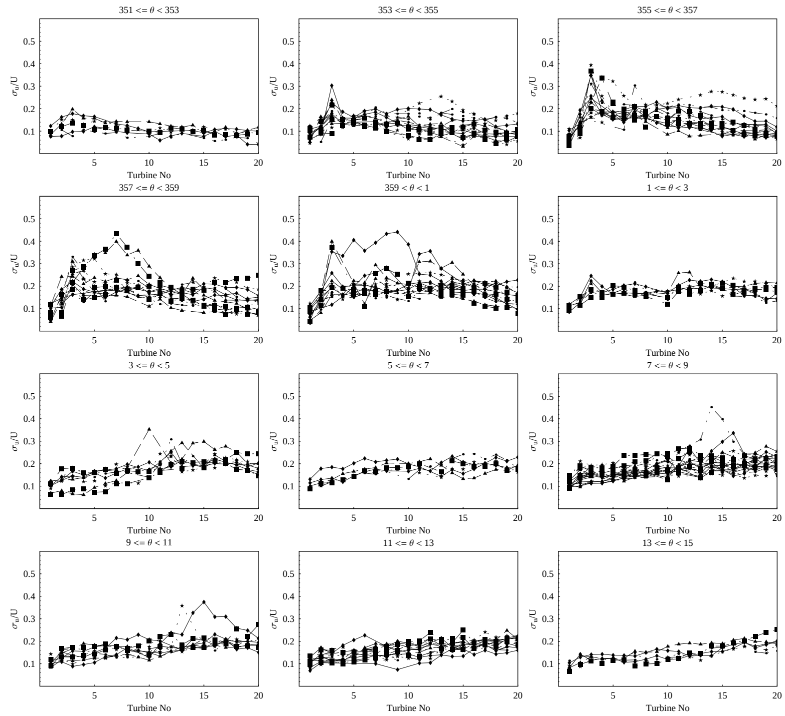

Figure 56 show the individual 10 min averaged turbulence intensities for the different sectors.

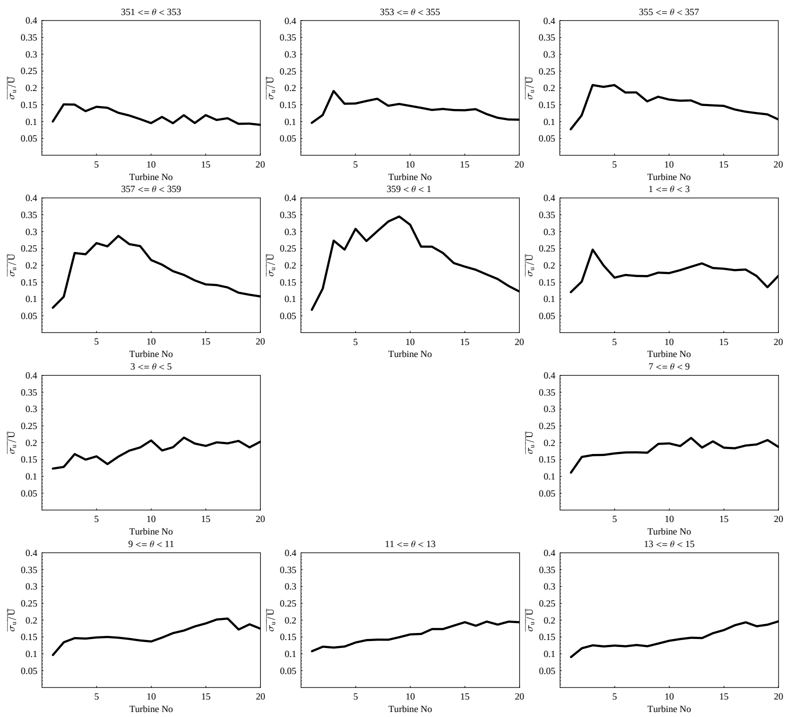

Figure 57 shows the average turbulence intensities for each sector.

Turbulence intensities between 11-12 m/s

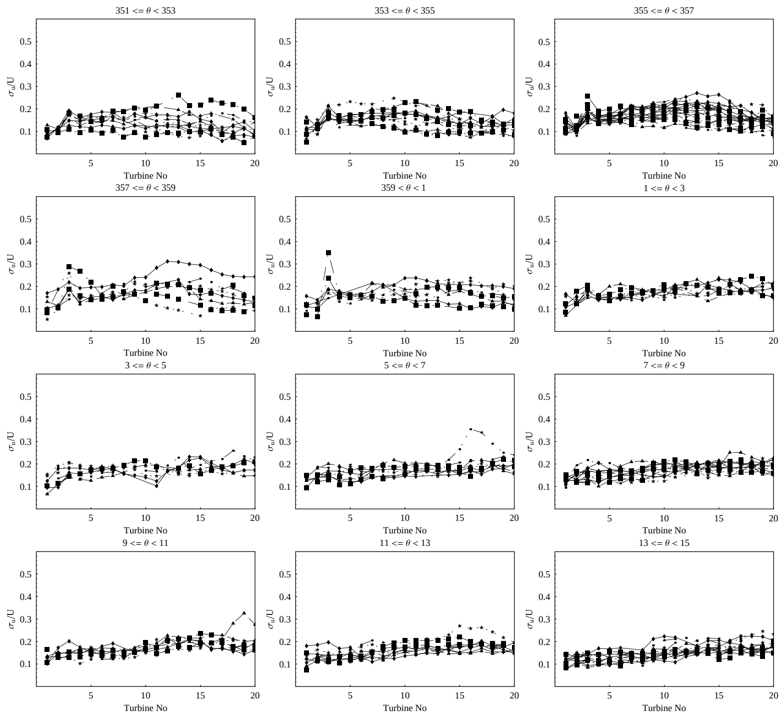

Figure 58 show the individual 10 min averaged turbulence intensities for the different sectors.

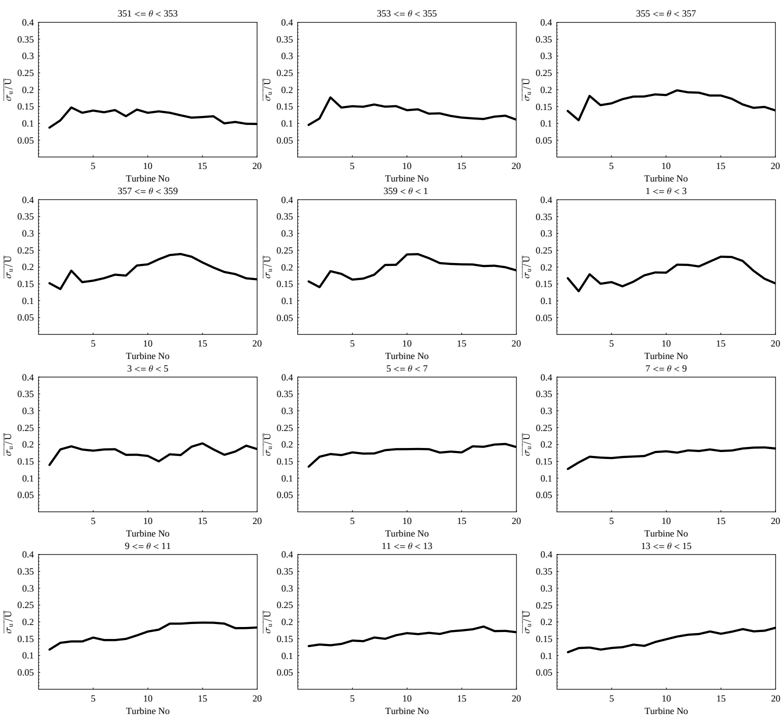

Figure 59 shows the average turbulence intensities for each sector.

Turbulence intensities between 12-13 m/s

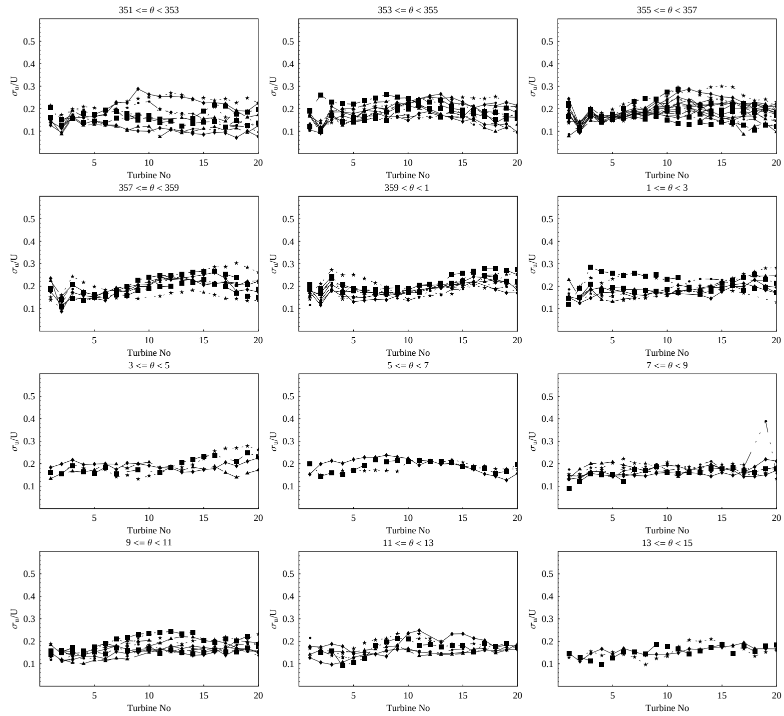

Figure 60 show the individual 10 min averaged turbulence intensities for the different sectors.

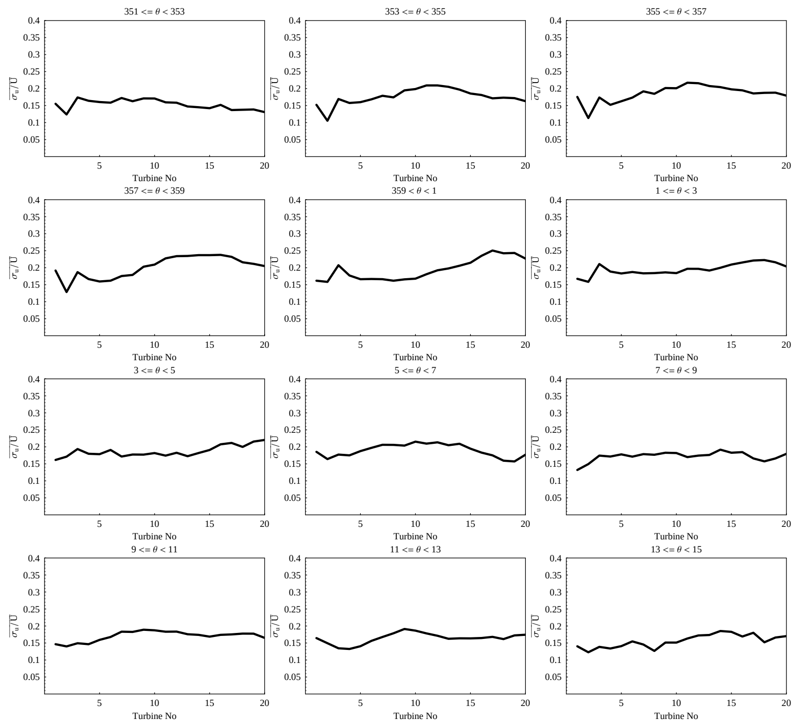

Figure 61 shows the average turbulence intensities for each sector.

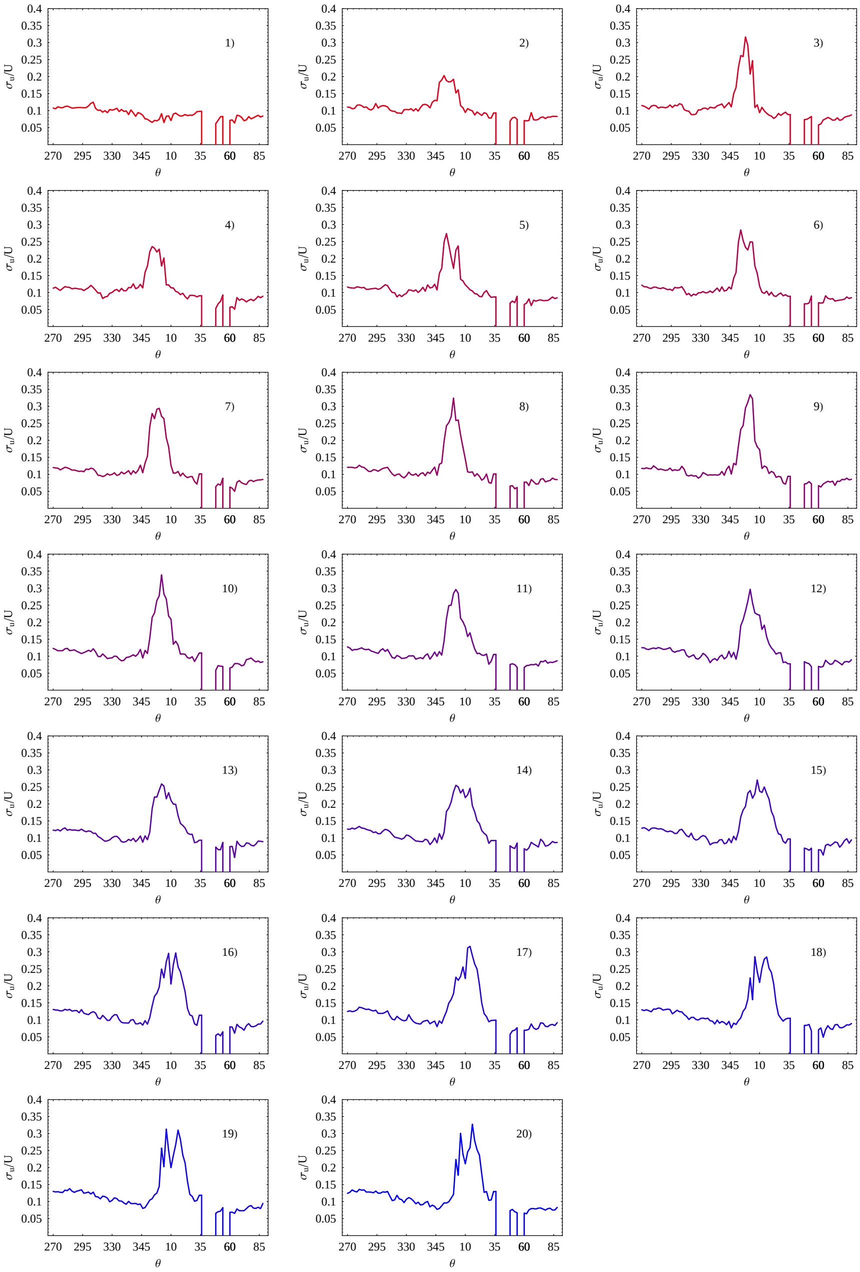

Figure 62 Show the turbulence intensity for all 20 turbines as function of flow direction. The winds selected are in the range of 8 and 10 m/s.

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Title and authors

Wake effects on Middelgrund Windfarm

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Abstract (max. 2000 characters)

This report describes the data analysis of the Middelgrund Wind Farm online collected data with the purpose of calculating the wake effects and turbulence intensities within the wind farm when maximum wake effects are present. The data are compared to the most commonly used wake model PARK implemented in Wasp 8. The PARK calculations have been converted from power to wind speed deficits and there is as substantial difference between the calculated deficits in wind speed between the data and the PARK model. However, it shall noted that it is a very crude comparison since the lowest directional sector interval in the PARK/Wasp mode is 10° , and all events are assumed uniformly distributed over this sector. Furthermore, the model does not include the changing direction of the wind flow through the turbine array caused by the interaction between the turbines and the flow. Finally the turbines are spaced by 2.6 rotor diameters, which is in the limit of the park model assumptions where the spacing is assumed to be higher than 5 rotor diameters. Taking all this assumptions and model constrains into account the Park model overestimates the wind speed deficits with up to 30 % and with an ever decreasing wind speed through the array when the wind is coming from north

The turbulence intensity is enhanced up to 0.3 due to the wake effects. The analysis has shown that this enhancement is nearly independent of the number of turbines involved in the wake creation

Descriptors INIS/EDB

DATA ANALYSIS; OFFSHORE SITES; TURBULENCE; VELOCITY; WIND;WIND TURBINE ARRAYS