TotalControl

*Advanced integrated supervisory and wind turbine control for optimal operation of large Wind Power Plants*

# Reduction in OPEX based on maintaining target reliability levels through control
# Deliverable D2.6

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# 1. EXECUTIVE SUMMARY

For assessing the remaining life of existing wind turbine structures in a wind farm, it is necessary to forecast the damage equivalent moment to the future, based on present measurements of loads or simulated loads using measured inflow conditions. Life consumption in the Lillgrund wind farm is quantified under wake situations to determine the reliability margins for the wind turbine blades under fatigue or determine if the operation is below the design reliability level. The maintenance and repair costs are also projected based on the fatigue margins available. Extrapolation of the damage equivalent load magnitudes is made to determine the safety of wind turbine operation over the next one year period. The procedure to determine an expected annual damage value for remaining life assessment process is presented. Using a continuously updated small sample of measured loads, the expected annual damage equivalent can be continually updated, thus providing a valuable indicator of the potential life consumption of the structure in the next year and longer time. A neural network based algorithm to quantify the inflow wind turbulence for the turbines in Lillgrund is also explained, which can be used as input to the wind farm controller, so that the turbine or the upstream turbine can be de-rated to reduce loads under high detected turbulence.

# 2. INTRODUCTION

Wind turbine blades are exposed to aerodynamic and inertial loads which can possess 1e8 to 1e9 load cycles over its lifetime [1]. As a consequence of these load cycles, fatigue is one of the major factors determining the design lifetime of the rotor blades [2]. Reduction in the blade life due to excessive fatigue loads increases maintenance costs and may cause financial loss [3]. Thus, having an accurate model for prediction of fatigue lifetime of the turbine blades is of great importance. The aim of the present work is to assess the annual reliability level in fatigue of major structures such as blades in a wind farm on a continual basis, using measurements. This will help in quantification of the cost of lowered annual reliability below design levels versus reduction in O&M cost for maintaining target reliability level. It also can be used for finding the right controlling schemes to maintain a target lifetime for the blades within the windfarm.

## 2.1 FATIGUE OF BLADES WITHIN THE WINDFARM

Higher ambient turbulence together with turbulence caused by the wakes causes higher loads/stresses variations and makes the fatigue lifetime shorter [4]. Bustamante et. al [5] showed effects of wakes up to 15 rotor diameters downstream can increase fatigue loads. For offshore wind turbines, loads from waves, ice and current can [6] add to fatigue

There are several studies done on fatigue lifetime estimation of wind turbine blades. Sørensen et al., 2008 [7] investigated the reliability using fatigue limit states of turbines situated in wind farms. Noda et. al. [8] examined the effects of turbulence intensity, mean wind speed, wind shear, vertical wind component, dynamic stall, stall hysteresis, and blade stiffness on blade-root fatigue damage. The results of their study showed that the rate of increase in normalized fatigue damage from an increase in site turbulence intensity was non-linear. Reliability indicies used in partial safety factors can vary in literature such as 2.7 ( [7]), 3.1( [9]), and 3:5 ( [10]). These magnitudes have been calculated from an economic point of view.

## 2.2 FATIGUE DAMAGE MODELS

There are different damage accumulation rules for estimation of fatigue using S-N curves. Some of these methods are stress dependent and some are stress independent. Here Miner's rule [11] is used for accumulation of the fatigue damage/DEL over time. Miner's rule is one of stress independent models, which is widely used for its simplicity. Palmgren-Miner has drawbacks and limitations such as, in some circumstances, the order of stress cycles, such as low stress cycles followed by high stress cycles cause more damage than the rule predicts. It also does not consider the effect of compressive residual stresses that may retard crack growth. However, it is a method used commonlly in the design of wind turbine structures, and as mentioned before its usage is simple and efficient. Therefore, this rule is used herein, and its aspects in terms of load and cycle counts is explained.

Another common categorization of fatigue assessment model includes time-domain analysis method, spectral method, and deterministic approach. The time domain analysis is more accurate, while the simplified time-domain method and frequency domain method have less complicated algorithm and less computational cost [12]. The drawbacks of spectral methods (frequency domain analysis) especially for fatigue analysis of the blades is the challenge to represent simultaneous mechancial loading accurately, as mentioned in [13]. The time domain approach involves repeated fatigue analysis on an ensemble of time histories and using rainflow counting methodology to detremine the stress/load cycles.

## 2.3 LIFETIME ESTIMATION MODEL

The stress-cycle curve or S-N curve gives the failure stress for a given number of cycles. It has several uncertainties such as limited number of tests, geometry variations in the specimen, internal defects etc. Therefore the design SN curve usually has a safety margin imposed on the mean SN curve to account for these uncertainities. Further the Miners damage sum, which theoretically should be unity for failure, has variability, thus fatigue failure could occur when the damage sum is less than one also. Thus life estimation of a structure requires a probabilistic analysis, where the uncertinities in the materials, mechancial loads and the design criteria are included.

The fatigue life of wind turbine blades that are exposed to the random loading environment of atmospheric winds is described using stochastic analysis procedures. For a random load, the computed fatigue damage is a random variable. In the present study, a new probabilistic approach which uses probability distributions such as Weibull, to fit simulated or measured fatigue damage over time and extrapolate the distribution to determine the annual probability of damage is proposed.

## 2.4 LOAD EXTRAPOLATION

Due to the computational cost involved, it is not feasible to simulate the full lifetime of the blade under normal operation. Thus, in case of determining the lifetime it is needed to perform statistical extrapolation on the short-term simulated or measured fatigue damage to determine the probability of the damage over a long period. The IEC 61400-1 standard [14] requires extrapolation of extreme loads obtained from 10 min or longer load simulations using normal wind turbulence sample realizations to a 50-year exceedance probability of 3.8*1e−7. It also suggests, but does not mandate fatigue damage equivalent load extrapolation to determine the long term damage equivalent load. However to account for non-extrapolative methods, the IEC 61400-1 uses a 90% quantile of wind turbulence in loads simulation, which quantile is determined as the effective turbulence quantile that shows the same damage equivalent load as a Monte Carlo simulation over all turbulence values. As assumed in the IEC 61400-1 Ed. 3, the wind turbulence is assumed to follow a lognormal distribution in each mean wind speed bin.

Since the real conditions on the wind farm have a multitude of wind turbulence intensities, it is preferred that the actual measured turbulence is used conditional on the mean wind speed as input to the aeroelastic software. For the calculation of loads, several aeroelastic simulations of the wind turbine under measured wind conditions or realistic turbulent wind conditions are made. The resulting load time series undergoes rainflow counting to determine the the number of cycles of load amplitude levels. A generalized S-N fatigue slope of m = 10 is assumed to determine damage equivalent loads from the rainflow counted amplitudes.  Fatigue curve slope of 10 is a widely used value for unidirectional laminate materials such as glass fiber as in the present case [15]. The resulting damage equivalent load values from different simulation at each mean wind speed can be extrapolated, and the probability of exceeding a damage equivalent load level over a long term period can be determined. This is more accurate and realistic than the conventional process used today of assuming the same load cycles over a set of load simulations for limited time are prevalent for the entire life of the blade.

The following sections explains the effects of wind turbulence on blade fatigue damage along with the mathematical and practical details of the extrapolation methodology for determining fatigue failure as used in this study and applied to the Lillgrund wind farm.

# 3. EFFECT OF WIND TURBULENCE ON BLADE FATIGUE DAMAGE

The design loads of a wind turbine under normal operation, which is also defined as the design load case DLC1.2 in IEC 61400-1 standard, uses the 90% quantile of wind turbulence at each mean wind speed between cut-in to cut-out. The empirical formula for the 90% turbulence intensity is

$$TI = \frac{Reference\ TI.(0.75.(U_{hub}) + 5.6)}{U_{hub}} \qquad 3\text{-}1$$

Where $U_{hub}$ is the mean wind speed at hub height and the reference TI is the mean turbulence intensity at 15 m/s.

It is recommended in the IEC standard to consider six different realizations of 10min simulation (one hour periods) to account for the variability of wind. Results of the research done by Zwick and Muskulus in [16] show that there can be errors of 16-29% following this standard, and the mentioned errors can be reduced by extending the length of the simulations. The extensions can be done by using many realizations of short duration or using longer times. The threshold of simulation duration up to which the accuracy of representing wind turbulence is studies using constant wind turbulence simulations at each mean wind speed up to 200 minutes duration. Figure 3.1 show the results with the wind turbulence levels from six seeds when truncating 10, 20, 40, 70, 100, 130, and 160 durations from the wind output of the 200-minute simulation.

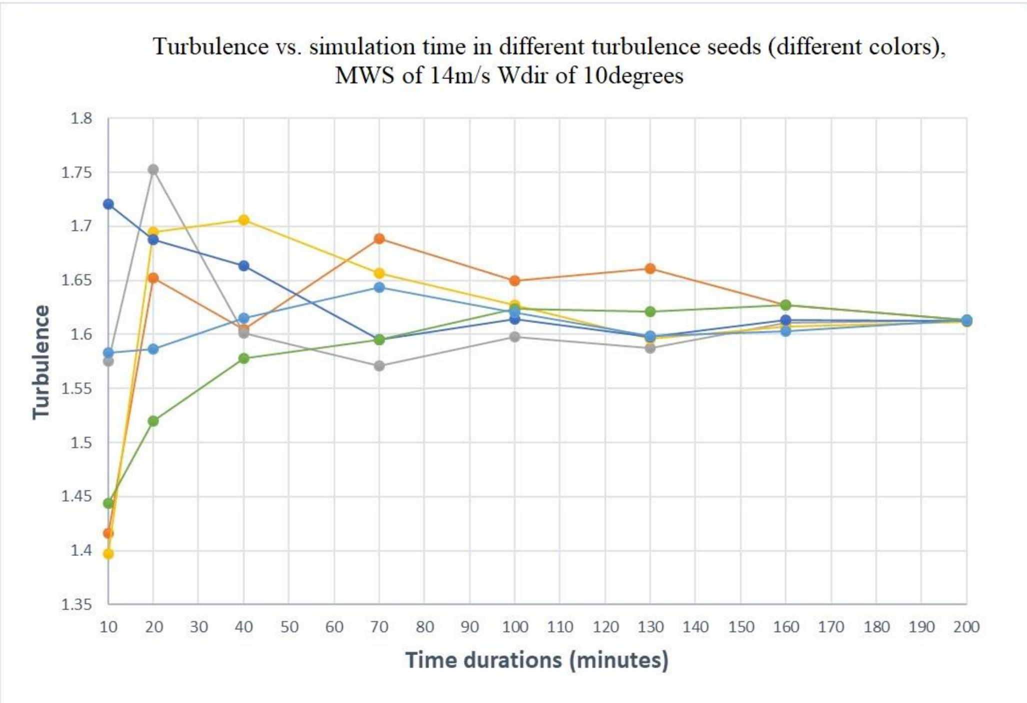


FIGURE 3. 1: ACTUAL TURBULENCE MAGNITUDES IN DIFFERENT REALIZATIONS (TURBULENCE SEEDS) – SHOWN BY DIFFERENT COLORS- IN WIND TIME SERIES WITH A GIVEN TURBULENCE LEVEL INPUT FOR FIXED WIND MEAN WIND SPEED OF 14M/S AND WIND DIRECTION OF 10 DEGS

As shown in Fig.3.1, the turbulence levels within six different wind realizations using Mann turbulence model are simulations from 10 minute up to 200 minute are not showing the same value for the turbulence level within one specific simulation using six realizations. This result can be caused by both the fact that the wind output from the 200 minute simulations is not stationary, and also because longer time duration of the aero elastic simulations bring higher accuracy due to inclusion of lower frequency fluctuations of wind. For determining the extent of the representation of the wind turbulence spectra (whose area is the square of the turbulence), the turbulence level fluctuations between different seeds for one single wind condition using different simulation lengths is investigated. The result of such investigation is shown in Fig. 3.2 is converging to a specified value in 200 minutes. However, the smaller truncations of 200-minutes from 10 minute up to 200 minute are not showing the same turbulence level within one specific simulation using six realizations. This result can be caused by the fact that the wind output from the subdivisions of 200 minute simulations is not stationary and also because longer time duration of the aero elastic simulations bring higher accuracy due to inclusion of lower frequency fluctuations of wind.

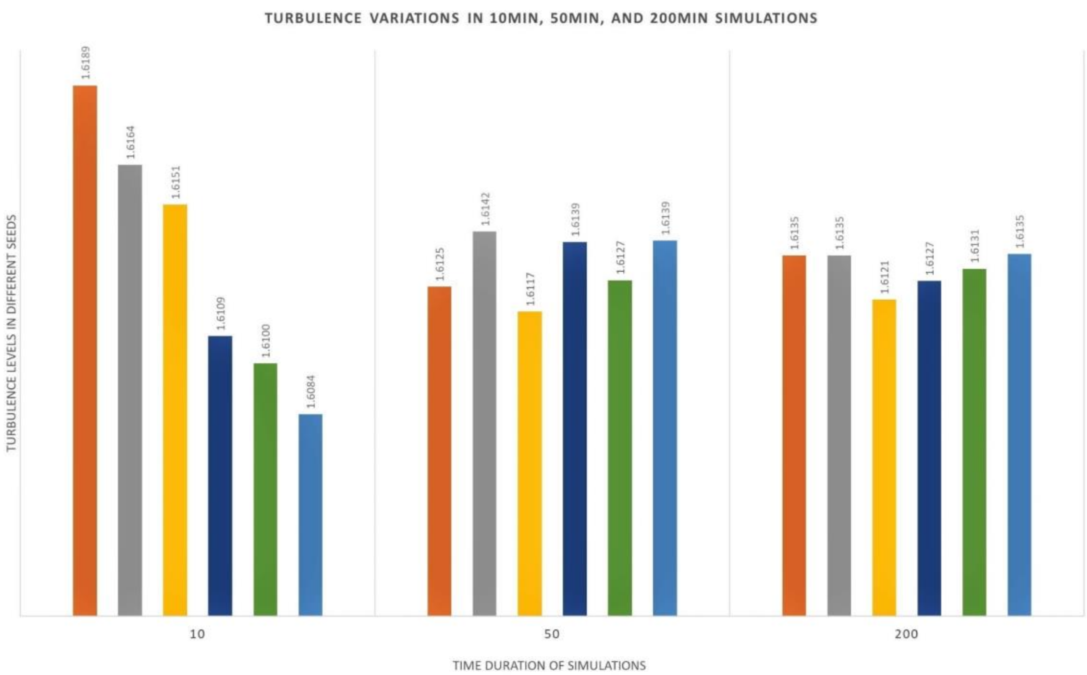


**FIGURE 3. 2: VARIATIONS OF TURBULENCE LEVELS FOR DIFFERENT SIMULATION TIME DURATIONS AT A FIXED MEAN WIND SPEED**

As it can be seen from the above diagrams, the fluctuations of turbulence level between different seeds in independent simulations with similar wind input conditions and seed numbers but with different durations is shown. When using several short-term wind turbulence inputs, it is important that the results from different 10-minute simulation blocks are combined without bias in the estimated cycles and that half cycles are included. This is of higher importance especially when considering fatigue cycle counts, where there is a possibility of having non-continuous cycles between different 10-minute load results.

On the other hand, there is an error due to the loads being non-stationary when using truncations from long time simulations. In other words, when truncating shorter time series from the longer one, they may no longer account for that specific wind condition and a small deflection in mean and standard deviation from those of the full turbulence box is seen, although the mean of mean would be the same as the mean of the longer time duration. In order to minimize such error small intervals of 10-minute duration are taken to account for calculation and fitting of damage. In addition, the number of grid points for Mann box is increased due to the longer time of the simulation in order to maintain the high accuracy.

To produce data for analysis of damage accumulation through time using only 10-min data different time factors of 10-min are produced.

## 3.1 BLADE DAMAGE COMPUTATION

The 1-D bending stress of each blade section is estimated at four points around the airfoil section as:

$$S_z = \left(M_{edg}(4) * \frac{(c/2)}{I_y}\right) + \left(M_{Flap}(4) * \frac{(c/2)}{I_x}\right) \quad \text{3-2}$$

where, *c* is the chord length of the section and *d* is the distance of the edge point in each section to its mid-chord point (origin of the local coordinate system). In this equation, it has been assumed that the maximum moments happen at points along the chord and thickness directions, which have the maximum distance from the local origin.

The number of cycles, *N* vs. stress, *S* in the material fatigue properties are normalized by the ultimate stress using the relation between failure number of cycles and stress range as below.

$$k.logN = 1 - \left(S/S_{ut}\right) \quad \text{3-3}$$

in which for the unidirectional (UD) glass epoxy composite with volume percentage of 55% (as mentioned in the DTU-10MW document), thus the value of *k* equals 0.998 [17]. Ultimate strength is also assumed to be 2013MPa according to [17]. And since:

$$D = \sum m_i = \sum n_i/N_i \quad \text{3-4}$$

where $n_i$ is the number of damage cycles under different stress states. Thus, the overall damage would be as:

$$D = \sum n_i/_{10}(1 - (S/S_{ut}))/\mathrm{k} \quad \text{3-5}$$

The cycles are counted based on rainflow counting [18], and the stress ranges are modified by considering mean stresses in cycles. This procedure is done using the 'rainflow' function in Matlab, which gives a rainflow matrix. In the resulting rainflow matrix the number of cycles for each specific stress range and mean stresses are provided. These informations are used as below to produce the effective stress as the input for calculation of damage:

For the cases with negative mean stress:

$$S_{eff} = |(-(\mathrm{Sa}/2) \ + \mathrm{Sm})| \tag{3-6}$$

For the cases with positive mean stress:

$$S_{eff} = (\mathrm{Sa}/2) \ + \mathrm{Sm} \tag{3-7}$$

where $S_a$ and $S_m$ are the half stress range and mean stress respectively. Different mean load amplitude correction techniques with different degrees of accuracy are available. The accuracy and validity of the different techniques depends, among other, on the magnitude of *R*, which is defined by below equations:

$$\text{If } M_{mean} < 0: \ R = {}^{M_{max}}/_{M_{min}} \tag{3-8}$$

and

$$If \ M_{mean} > 0: \ R = {}^{M_{min}}/_{M_{max}} \tag{3-9}$$

The Goodman correction for considering the non-zero mean stress is as below:

$$M_{ar} = \frac{M_a}{(1 - (M_m/M_u))} \tag{3-10}$$

The above correction is used in the present case. Critical section is found by testing the damage results in the 6-16 m/s mean wind speed regime and testing three conditions of each mean wind speed. Among the fifteen sections (up to mid-span) where the structural loads are the highest, the sections close to the root have the maximum damage, but the damage also increases after the mid-span of the blade towards the tip due to the low sectional inertia at these sections. The below plots show the trend of the change of the damage in different sections and different mean wind speeds. There are total of 26 sections among the blade numbered from root to tip. As can be seen from the below plots, the most critical situation happens at the maximum wind speed.

While the 10-minute damage with or without Goodman correction shows higher damage at sections towards the blade tip, these are not structurally loaded significantly and therefore not considered.

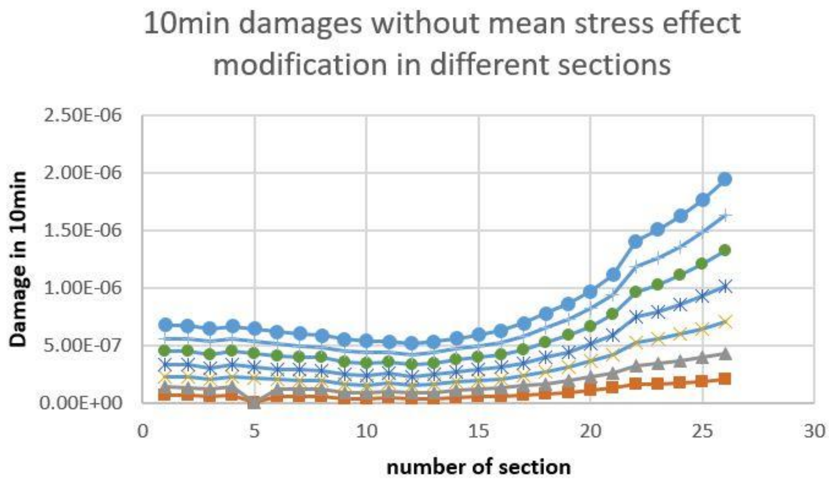


FIGURE 3. 3: 10-MINUTE MAX DAMAGE PER BLADE SECTION ACROSS DIFFERENT SECTIONS (EACH CURVE IS A FOR A DIFFERENT MEAN WIND SPEED)

In Figure 3-3, the different curves correspond to different mean wind speed and the behavior of the damage across the blade section is the same for each mean wind speed.

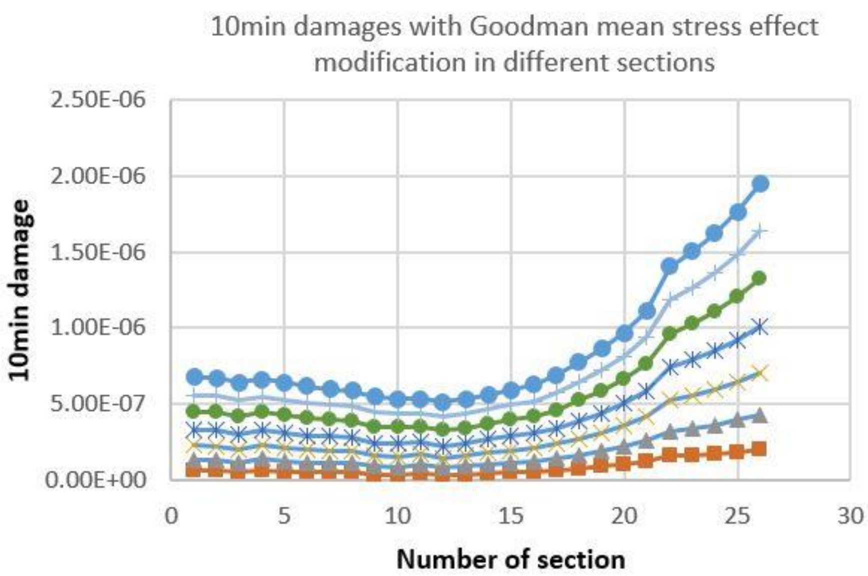


FIGURE 3. 4: 10-MINUTE DAMAGE WITH GOODMAN CORRECTION PER BLADE SECTION

A similar behavior can be seen if damage equivalent load was used instead of damage. For wind farm reliability assessment, since the details of wind turbine blade structures are not known, the damage equivalent loads is usually used instead. The concept of damage equivalent loads and their use in fatigue life monitoring is explained in the next sections.

# 4. DESCRIPTION OF FATIGUE MODEL APPLIED TO LILLGRUND WIND FARM

The fatigue damage can be expressed both in terms of the Miner damage sum or the damage equivalent load. For a fixed geometry, the loads may be used instead of stress, for a given set of cycles to determine damage, from which the load magnitude for a specified equivalent number of cycles may be determined. This is termed as the damage equivalent load. The load case during normal power production (DLC 1.2), as described in the IEC 61400-1 standard [14], has been used as a basis for determination of fatigue damage. The fatigue load calculations for the Lillgrund Siemens 2.3 MW turbine has been performed for different inflow turbulence levels.

Fatigue damage of structural components subjected to wind turbulence is a complex problem. While the most widely used damage model is the Palmgren-Miner linear damage sum, it is a non-physcial model, since the damage stated by the model is a numercial quantity unrelated to actual visual damage in the structure. The Palmgren Miner's rule states that the fatigue damage D shall be less than or equal to unity as per equation (4-1).

$$D = \sum_{i=1} D_i = \sum_{i=1} \frac{n_i}{N_i} \leq 1 \tag{4.1}$$

where $n_i$ is the number of cycles in bin "i", and N_i is the number of cycles on the S-N curve corresponding to the stress amplitude.

Considering fatigue failure based on SN-curves represented by the Basquin's equation, the number of cycles to failure is given as

$$N = K \triangle \sigma^{-m} \tag{4.2}$$

where $\triangle\sigma$ is the stress amplitude, K is a material constant, and m is the slope of the SN curve.

Fatigue cycles can be counted using time histories of the loads instead of stress, assuming the geometry does not vary with time or stress amplitude. Then a quantity termed as damage equivalent load can be defined using Eq. (4.2) for a prescribed $N_{eq}$ number of cycles as the equivalent load that has the same value as the sum of several individual occuring damages for N_eq cycles.

Thus damage equivalent load may be expressed as $L_{eq} = \left(\sum \frac{n_i L_i^m}{N_{eq}}\right)^{1/m}$

## 4.1 CONVENTIONAL PROCESS OF DAMAGE ASSESSMENT

The annual probability of mean wind speed is given by a Weibull distribution, whose cumulative distribution function is denoted as P(v), where v is the mean wind speed. Given 8760 hours in a year, the number of hours of operation of the wind turbine at a given mean wind speed bin is

$N_v = \mathrm{a} * \big(P(v + \Delta v/2) - P(v - \Delta v/2)\big) * 8760$ , where $\Delta v$ is the wind bin size, and $a$ is the availability of the wind turbine expressed from (0 to 1).
The conventional design process and damage assessment process assumes that the same load cycles, that were the result of aeroelastic simulations for a short period (say a few days) at each mean wind speed, are repeated continually over the full expected annual duration at each mean wind speed.

Therefore given the load cycles over 10-minutes, the damage equivalent load at a given mean wind speed for one year is

$$L_{eq|v} = \left( 6N_v \frac{\sum_{i=1}^{N} n_i L^m}{Neq} \right)^{1/m}$$

Now taking the Weibull probability of each mean wind speed from cut-in to cut-out and assuming a lifetime of 25 years for the wind turbine, the lifetime damage equivalent load is

$$L_{eq|life} = \left( 25 * 6 \sum_{v_i=cutin}^{v_i=cutout} \left( N_v \frac{\sum_{i=1}^{N} n_i L^m}{Neq} \right) \right)^{1/m} \quad (4.3)$$

This lifetime damage equivalent load computed using measured operational conditions must be less than the lifetime damage equivalent load computed during the design of the structure of interest for all load components for the structure to survive.

This method, while frequently applied, does not consider the variability of wind turbulence, and a constant conservative 90% quantile of turbulence is used in the fatigue assessment. Many load components are strongly dependent on the degree of wind turbulence at different mean wind speeds, and the load amplitude variation due to the energy content wind turbulence should be considered to obtain an accurate quantification of fatigue lifetime. The turbulence is considered using a Mann model [14] and is considered to represent the turbulence in the free stream and under wake conditions. Further this conventional method uses the mean damage equivalent load from a limited number of 10-minute load simulations with 90% turbulence intensity as the design load level. For life assessment, this approach is not feasible, as the consumed life of the actual structure must be evaluated for a long operating period using the actual inflow conditions.

## 4.2 New approach of lifetime damage assessment using probabilistic approach

The spectrum of wind turbulence implies that considering only 10-minute load simulation duration over a given mean wind speed and turbulence is insufficient to capture its full energy content. Figure 4-1 display a sample Mann model spectrum [14] used in the load simulations to compute blade fatigue damage equivalent loads. Since the area within the turbulence spectrum represents the variance of the wind speed in a given direction, it is necessary that the wind time series input to load simulations also capture the low frequency content in the spectrum; implying longer durations of the time series are necessary. This allows capturing larger amplitudes of wind speed variation and reflects correspondingly load amplitude changes in the simulated output.

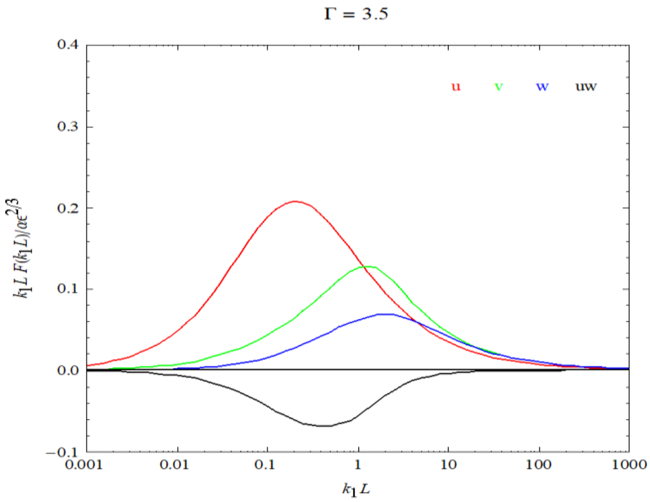


FIGURE 4. 1 DEPICTION OF THE MANN MODEL TURBULENCE SPECTRUM IN THE U,V AND W DIRECTIONS

Successive 10-minute load simulation results cumulate to provide higher fatigue damage, whether the wind turbulence is at a fixed value (such as 90% quantile) or if it varies per simulation. This is also true for the real wind turbine, where longer durations of operation result in larger fatigue damage. The growth of fatigue damage over time is usually nonlinear and hence the linear superposition of constant damage over limited time duration as given in Eq. 3.3 is not an accurate representation of the fatigue damage over long time. A more accurate method also indicated in the IEC 61400-1 is to extrapolate fatigue damage or damage equivalent load using fitted probability distribution functions to the simulated damage over time.

This process of damage equivalent load extrapolation is as follows:

1- Simulate several 10-minute or longer duration at different wind speeds over varying turbulence
2- Determine the damage equivalent loads
3- Determine the short-term cumulative distribution function (CDF) of the damage equivalent loads
4- Extrapolate the fitted CDF to a large damage equivalent load
5- Determine the probability of exceedance of the extrapolated damage equivalent load
6- Select a target probability of exceedance level of acceptance and corresponding extrapolated damage equivalent load level that is a target level of fatigue to ensure not to exceed in a one year period.

The cumulative probability distribution (CDF) of the damage equivalent load or the damage may be fitted to various standard distributions. The extrapolated CDF would allow the determination of the probability of exceedance of damage equivalent load levels that are significantly greater than observed in simulations. As a first step to determine the CDF, the fitting of the median rank of the data to different distributions is done and the probability of the damage is compared over different CDFs fit in Figure 4-2.

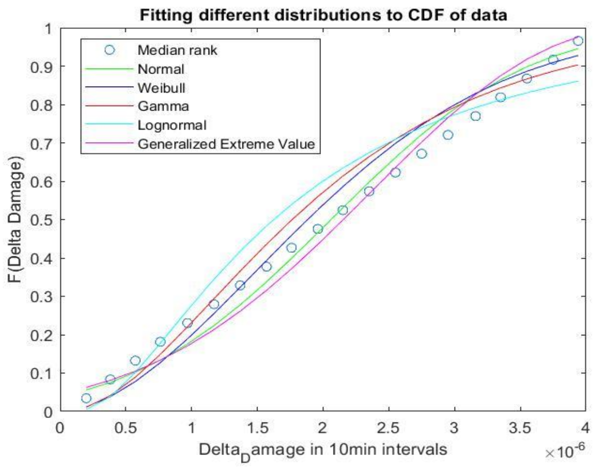


FIGURE 4. 2 PROBABILITY OF BLADE ROOT FLAP DAMAGE MAGNITUDES OVER 10 MINUTES

Both a 3-parameter Weibull distribution and a generalized extreme value distribution were found to depict the tail of the CDF of the damage reasonable well. Herein the 3-parameter Weibull CDF for damage equivalent load (DEL) analysis was used, which for a DEL value of $d$, is given as:

$$F(d) = 1 - e^{-\left(\frac{d-\gamma}{\alpha}\right)^{\beta}} \qquad -(4.4)$$

where $\alpha$ is is the scale parameter, $\beta$ is the slope, $\gamma$ is the position of the Weibull distribution. Further, instead of the damage, which is a very small number over 10-minutes, the damage equivalent load is considered, which is also directly relatable to a physical load quantity.

Considering several samples of simulated damage equivalent load at each mean wind speed, the allowable damage equivalent load at a selected probability of exceedance is computed. The probability of exceedance of the 10-minute damage equivalent load over one-year, at a given mean wind speed, can be determined by considering the number of 10-minutes in the prevalent annual hours at that wind speed. The annual hours at a given mean wind speed is determined from the Weibull probability distribution of the mean wind speed. For example considering that there are about 1000 hours in a year at 10 m/s, the isolated probability of exceedance of the damage equivalent load from one-year load simulations at a given mean wind speed for 10-minute intervals is 1/(6*1000) = $1.67 * 10^{-4}$. The mean of this set of damage equivalent loads over all probabilities of exceedance from near one to the annual probability of exceedance is determined as the expected damage equivalent load level. This is different than the mean of the 3-parameter Weibull distribution, as now the arithmetic mean of the one year damage equivalent load set is directly used. The Weibull distribution is only used to determine the extrapolated damage equivalent loads, but the mean is computed directly from the set of all load values. This allows a realistic one-year expected 10-minute damage equivalent load to be used in Eq. (4.3), instead of the result of a limited number of 10-minute load simulations, whose mean can be exceeded in practise when measurements from operating wind turbines are analysed. This assumes that increasing the number of simulations, or duration of simulations, to compute the damage equivalent load results in generating higher damage equivalent moments with lower probabilities of exceedance along the same fitted CDF.

As an example, Figure 4-3 shows the damage equivalent load extrapolation for an example at 10 m/s a turbine in Lillgrund in the free stream without wake effects. Here the maximum simulated damage equivalent load is determined as 229 kNm over a few 10-minute simulations for a prescribed number of equivalent cycles. These damage equivalent moments are extrapolated to higher damage equivalent moments with lower probabilities.

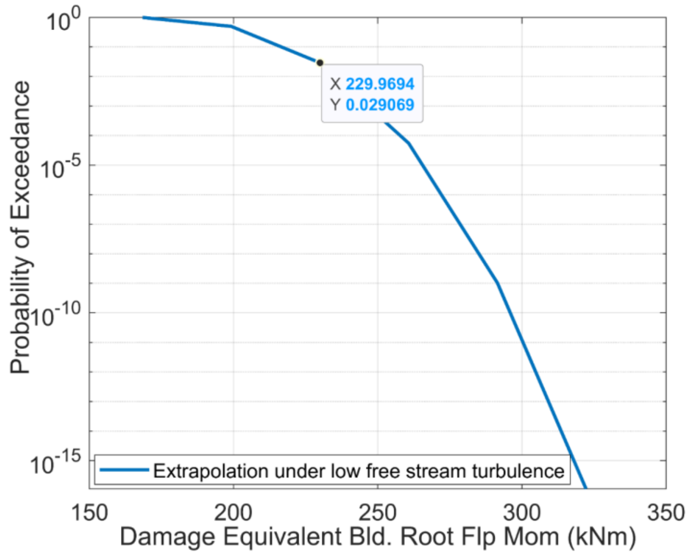


FIGURE 4. 3 BLADE ROOT FLAP DAMAGE EQUIVALENT MOMENT EXTRAPOLATION USING 3-PARAMETER WEIBULL DISTRIBUTION

If we assume that further 10-minute simulations cause the expected damage equivalent moment to move along the curve shown Fig. 4.3, then the annual 10-minute damage equivalent load level at a probability of exceedance of 0.000167 is about 260 kNm. This assumes that all wind turbulence levels have been considered in the simulated damage equivalent moments, and with a prescribed equivalent number of cycles, $N_{eq}$. Now the mean expected damage equivalent load over 10-minutes from a probability of exceedance of 1 to 0.000167 is determined as the mean value and multiplied by the annual Weibull hours and multipled with the number of years as given in Eq. ( 4.3) to determine the lifetime equivalent moment. These moments are not mean corrected, but reflect only the amplitude variation.

## 4.3 MONITORING OF FATIGUE LIFE

Given an aeroelastic model of the commercial wind turbine, measured wind characteristics can be used to compute the damage equivalent load and its probability of exceedance as explained in section 4.2. For structural load components that are dominated by wind turbulence, such as the blade root flap moment, increase in the inflow turbulence due to wake situations will result in increased fatigue damage.

Figure 4.4 displays the extrapolated damage equivalent blade root flap moment at two mean wind speeds, where the turbulence intensity ranges from 8% to 21%. This implies that the turbulence at

10 m/s is higher, and therefore Fig. 4.4 shows a higher probability of exceedance of a given damage level at 10 m/s versus at 8 m/s. The damage equivalent moments are normalized by the mean damage equivalent moment determined from simulations. Figure 4.4 shows that at 8 m/s, the one year damage equivalent load level ( at a probability near $10^{-4}$) is about 5 times the mean damage equivalent moment in simulations, while at 10 m/s, the same load level has a much large probability of exceedance near 0.01. This implies that the probability of exceedance of a load level increases very quickly with increase in the turbulence. Further limited simulations as prescribed in the IEC 61400-1 show a very low damage equivalent load level, which is not useful in ascertaining an annual safe damage equivalent load target. However, by using extrapolation. the probability of exceedance of the damage equivalent moment can be continuously tracked based on aeroelastic simulation results using measured wind characteristics. The effect of extrapolation of the damage equivalent load is usually conservative if all turbulence intensities are considered, since the seed-to-seed load variation with turbulence is not averaged, and an isolated turbulence seed can result in high probability of exceedance. Therefore, the extrapolated curve can be said to be an upper bound for the damage equivalent load at a given probability of exceedance.

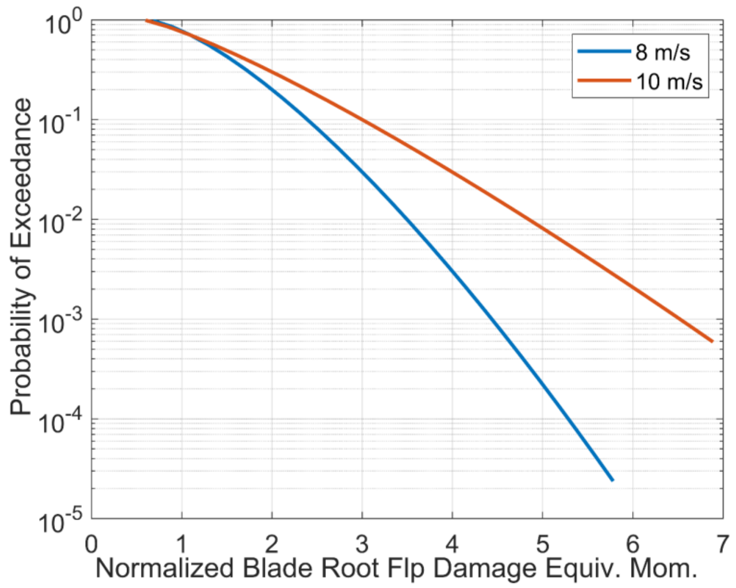


FIGURE 4. 4 EXTRAPOLATED BLADE ROOT FLAP DAMAGE EQUIVALENT MOMENT FOR VARIABLE TURBULENCE INTENSITIES BETWEEN 8% TO 21%

As a verification, if instead of 10-minute simulations, a 200-minute turbulent wind load simulation is made, the resulting damage equivalent blade root flap moment should have the same magnitude as 20 10-minute load simulations with a probability of exceedance of 1/20 or 0.05. A 200 minute HAWC2 simulation at 8m/s reveals the corresponding normalized blade root flap damage equivalent moment of 1.7, which from Figure 4-4 has a probability of exceedance of about 0.2 and not 0.05. The normalized damage equivalent moment at the probability of exceedance of 0.05 from Fig. 4.4 would be about 2.5 at 8 m/s, which then can be considered as an upper bound for the damage equivalent load from 200 minutes of simulation considering all turbulent seed variations. This also establishes that results from single long duration simulations (200 minutes) predicts lower damage equivalent loads than ascertained through extrapolation.

The blade root flap damage equivalent load extrapolation is repeated using the measured turbulence conditions on one of the wind turbines in wake in the Lillgrund wind farm. Using 10 different turbulence levels, one wind direction (zero) and 15 different seeds for each condition of mean wind speed and turbulence levels, 150 aero elastic simulations are performed for each wind bin. The table below shows the turbulence levels, which are used in the simulations. This turbine (C-08) will be studied in the next section with regards to its reliability in fatigue. The measured turbulence approximately covers the IEC turbulence classes A, B and C. Figure 4.5 depicts a slightly larger than one year damage equivalent moment level values at 8 m/s and 10m/s, with significantly higher damage equivalent moment at 10 m/s. Even though the annual 10-minute damage equivalent moment at 10 m/s is significantly higher than at 8 m/s, the mean normalized damage equivalent moment taken over the set of loads for the one-year return period at 8m/s and 10m/s are relatively close to each other at about 2.4.

**TABLE 1- RANDOM TURBULENCE LEVELS IN EACH MEAN WIND SPEED**

| MWS | 4 | 6 | 8 | 10 | 12 | 14 | 16 | 18 | 20 | 22 | 24 | 26 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Random TI levels | 0.339 | 0.208 | 0.183 | 0.174 | 0.177 | 0.161 | 0.161 | 0.140 | 0.138 | 0.112 | 0.128 | 0.147 |
| | 0.266 | 0.243 | 0.231 | 0.172 | 0.178 | 0.153 | 0.146 | 0.166 | 0.106 | 0.125 | 0.105 | 0.110 |
| | 0.230 | 0.254 | 0.163 | 0.153 | 0.171 | 0.167 | 0.145 | 0.147 | 0.108 | 0.124 | 0.157 | 0.139 |
| | 0.336 | 0.204 | 0.242 | 0.170 | 0.131 | 0.164 | 0.170 | 0.156 | 0.130 | 0.101 | 0.113 | 0.119 |
| | 0.347 | 0.194 | 0.225 | 0.179 | 0.140 | 0.174 | 0.153 | 0.136 | 0.109 | 0.112 | 0.110 | 0.126 |
| | 0.267 | 0.212 | 0.203 | 0.183 | 0.145 | 0.173 | 0.153 | 0.135 | 0.144 | 0.116 | 0.124 | 0.131 |
| | 0.219 | 0.214 | 0.211 | 0.164 | 0.165 | 0.144 | 0.167 | 0.158 | 0.144 | 0.112 | 0.115 | 0.148 |
| | 0.241 | 0.225 | 0.181 | 0.162 | 0.133 | 0.163 | 0.164 | 0.115 | 0.140 | 0.120 | 0.131 | 0.125 |
| | 0.263 | 0.233 | 0.201 | 0.204 | 0.167 | 0.137 | 0.151 | 0.118 | 0.111 | 0.119 | 0.123 | 0.149 |
| | 0.290 | 0.190 | 0.245 | 0.140 | 0.131 | 0.129 | 0.128 | 0.120 | 0.137 | 0.109 | 0.156 | 0.120 |

The probability of exceedance of the damage equivalent load under increased turbulence can be monitored to ensure that the annual 10-minute damage equivalent load level is not exceeding an acceptable level. If the extrapolated annual 10-minute damage equivalent load level is higher than acceptable, then either the turbine in question can be de-rated to a lower power level, or the turbine upstream can be de-rated to reduce its wake turbulence. This supervisory control action of de-rating can also be made if the turbulence detected is above a threshold level, since increase turbulence results in increased fatigue damage as shown in Fig. 4.5.

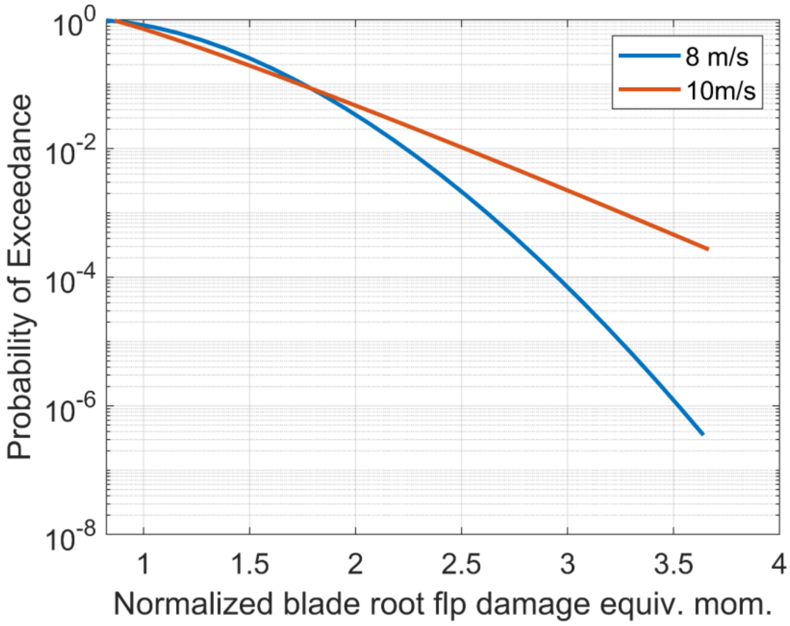


FIGURE 4. 5: COMPARISON OF THE SIMULATED 10-MINUTE DAMAGE EQUIVALENT MOMENT AT 8M/S AND 10 M/S USING THE MEASURED TURBULENCE AT THE C-08 TURBINE ON LILLGRUND WIND FARM

The next sections show the quantification of turbulence in the wake in Lillgrund and the control method used to ensure that the life of the turbine blades or other major structures is not compromised due to high turbulence.

## 4.4 LIFE ASSESSMENT OF LILLGRUND WIND TURBINE BLADES

Figure 4.6 describes the layout of the Lillgrund wind farm with 48 Siemens 2.3 MW wind turbines. It shows that the smallest distance between turbines is 3.3 rotor diameters (3.3D) when the free stream wind is from the south east. The wind direction from the south west where the distance between adjacent wind turbines is 4.4D, is also considered in the analysis herein . Such small distances between wind turbines in a park, result in high wake generated flow variability and thus the potential for high damage equivalent loads.

The Siemens 2.3 MW wind turbine at Lillgrund is assessed for an IEC turbulence class A, which is the highest general class of turbulence in the IEC 61400-1, with a mean turbulence intensity of 16% at 15 m/s mean wind speed. This implies that the wind speed fluctuations due to wake effects as seen by wind turbines within the wind farm must at all times be less than Class A turbulence that the turbine is assumed to be certified for.

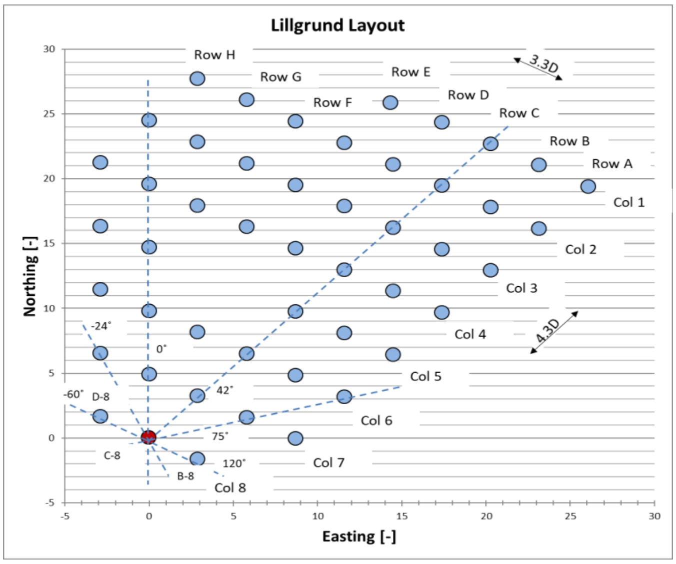


FIGURE 4. 6: LILLGRUND WIND FARM LAYOUT

## 4.5 TURBULENCE MEASUREMENT ACROSS THE WIND FARM

The only source of wind measurements through the multi-year operation of the wind farm are the nacelle anemometer based wind measurements. Since the nacelle top cup-anemometer is installed behind the rotor, it results in increased measured turbulence intensity due to the wake from the flow behind the blades. Thus the nacelle anemometer based measured turbulence is conservative and tends to increase the spread in the standard deviation of wind speed over different mean wind speeds.

To correct the nacelle anemometer measured wind turbulence, the measured 10-minute SCADA signal statistics from the turbine are used, such as the mean pitch angle, mean power, std. deviation of power, mean rotor speed and mean wind speed. At each mean wind speed, several HAWC2 loads simulations are run with normal turbulence (DLC 1.2), and the output simulated pitch angle, power, rotor speed are observed along with the simulated turbulence of wind speed at hub height. Several such HAWC2 simulations are performed at mean wind speeds from cut-in to cut-out and for turbulence intensity variations that encompass all IEC type classes and also go below and above the IEC wind turbulence classes. The results of these HAWC2 simulations are used to train a neural network, such as shown in Figure 4.7, so that given a set of 10-minute SCADA statistics, the neural network can predict the wind turbulence in the longitudinal wind speed at hub height.

The inputs of the neural network are the 10-minute mean pitch angle, mean power, std. deviation of power, mean rotor speed and mean wind speed. The output of the neural network is the 10-minute std. deviation of wind speed or turbulence at hub height. While the neural network was trained using results from HAWC2 simulations of the Siemens 2.3 MW wind turbine, the trained network was applied to the Lillgrund wind farm turbines using the measured 10-minute SCADA signals. The resulting predicted wind turbulence from the neural

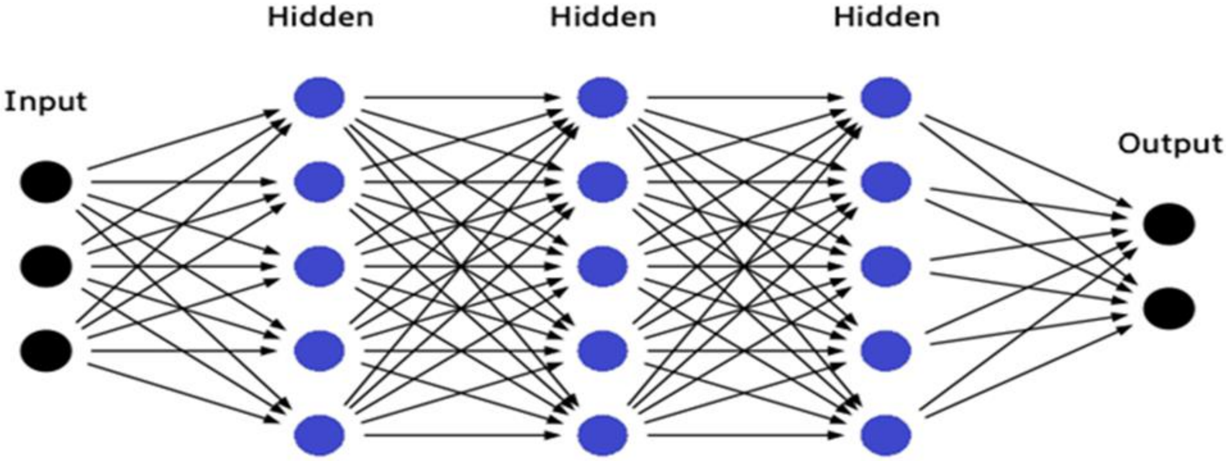


FIGURE 4. 7: REPRESENTATION OFA FEED-FORWARD NEURAL NETWORK WITH 3 HIDDEN LAYERS

network was compared with the measured turbulence from the nacelle anemometer of the corresponding wind turbine, Figure 4.8 displays the result for a turbine in the wake in row E, number 2, that is turbine E02, when the wind directions is from 120 degs or near to the south east sector. As seen from Fig. 4.8, the predicted wind turbulence from the neural network over all the mean wind speeds closely follows the trend shown in the measurements, but the predicted turbulence has lower spread than the measured turbulence, which is the desired correction to reduce the measured uncertainty from the nacelle anemometer.

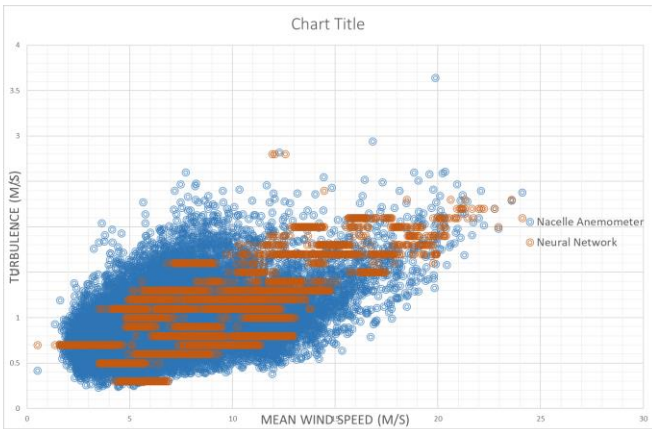


FIGURE 4. 8: COMPARISON OF THE PREIDCTED WIND TURBULENCE FROM THE NEURAL NETWORK USING MEASURED SCADA SIGNALS WITH THE MEASURED WIND TURBULENCE FROM THE NACELLE ANEMOMETER

## 4.6 IDENTIFICATION OF WIND TURBINES OPERATING UNDER LOWERED RELIABILITY

When loads measurements on turbines are not available (as is the usual case), the ability to identify inflow wind turbulence based on measured 10-minute SCADA statistics allows the detection of wind turbines operating under turbulence situations, which are more severe than the turbulence used in the design process. If such cases are found, then it implies that the wind turbine loads and thus the fatigue limit states or ultimate limit states may be exceeded leading to potential failures.

The wind turbulence used in the design of wind turbines is the 90% quantile, which is chosen corresponding to the high fatigue SN curve slope of blades. Thus, using a 90% quantile of wind turbulence implies that all turbulence variations in the wind farm are considered, wherein the turbulence levels above 90% are taken to be a very small fraction, such as in the tail of a log-normal distribution. Therefore using the neural network, wake situations can be detected, wherein the measured turbulence exceeds the 90% turbulence at each mean wind speed, based on which the period of such operation of the wind turbine, can be monitored to determine if it is unreliable. If corrective measures should be taken, then the turbine in question or the upstream turbine is de-rated to a lower power level to reduce the loads on the turbine structures.

Considering the south east wind direction of the free stream, the row of turbines A02-E02 is considered as shown in Fig. 4.6. The predicted turbulence intensities using the neural network, as well as the turbulence intensity from the nacelle anemometer measurements, are plotted over two years of wind turbine operation across all mean wind speeds as shown in Fig. 4.9. The Siemens 2.3 MW is assumed to be certified to class A wind turbulence conditions, implying that the mean wind turbulence at 15 m/s is 0.16 and the design wind turbulence at 90% quantile over wind speeds is as shown in Fig. 4.9. As can be seen the measured wind turbulence is rarely above the design wind turbulence. The neural network is seen to be inaccurate just before rated wind speed (10-11m/s), since the wind turbine pitch control at those mean wind speeds on the

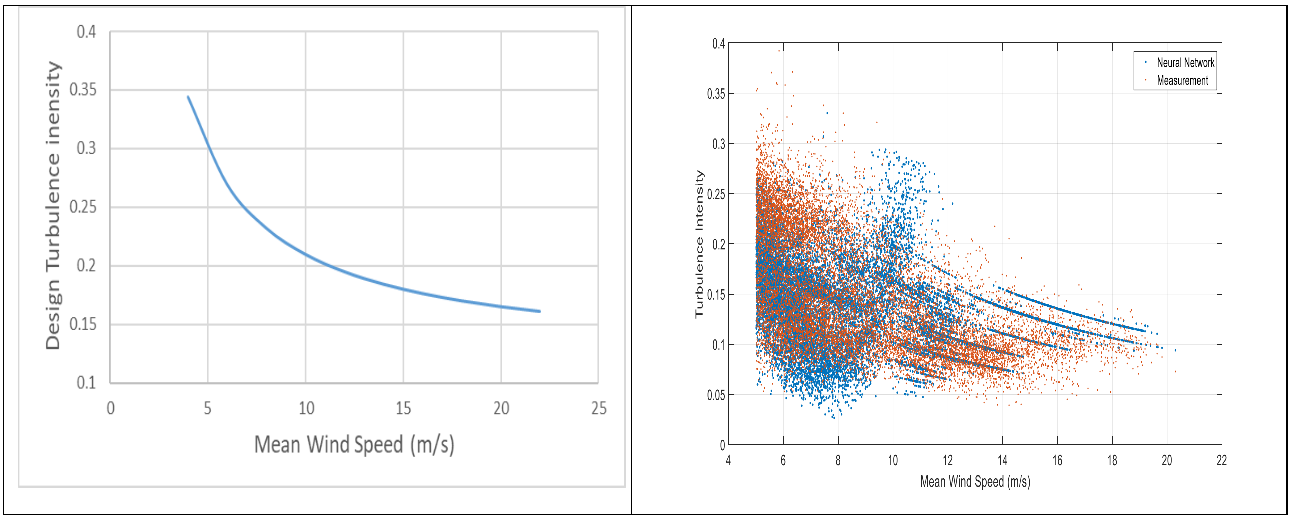


**FIGURE 4. 9: LEFT: THE DESIGN TURBULENCE INTENSITY AT 90% QUANTILE FOR CLASS A, RIGHT: THE PREDICTED AND MEASURED TURBULENCE INTENSITIES ON 5-TURBINES IN A ROW (A02-E02) IN LILLGRUND.**

actual wind turbine behaves differently than in the aeroelastic simulations. However, even the turbulence intensity computed directly from the nacelle anemometer shows only very few points at the lower mean wind speeds that are above the design wind turbulence. Thus we may conclude that these wind turbines do not show operation that is unreliable from a wind turbulence perspective.

## 4.7 PRESENT RELIABILITY MARGINS IN FATIGUE USING EXTRAPOLATION

Since the wind turbines facing south-east did not show that the design wind turbulence was exceeded sufficiently through winds turbulence measurements, the prevalent south-west wind direction is now investigated. One of the turbines in this direction, C-08 has load instrumentation.

Therefore, instead of using only wind turbulence predictions, the measured loads on one of the wind turbines, C-08 is used to track the annual damage equivalent blade moments using the methodology described in previous sub-sections. The 10-minute measured load statistics, include the 10-minute damage equivalent moments on the blade root and tower base are available on turbine C-08 for almost 5 years of operation. This turbine can experience wake from a single wind turbine.

The measured damage equivalent moments were shown to be accurately reproducible in aeroelastic simulations in the TotalControl deliverable report D2.5. Using extrapolation of the probability of exceedance of damage equivalent moments for a limited period of time, the long term or annual probability of exceedance can be forecast, from which the annual mean damage equivalent moment can be computed. This methodology can be used to track the damage equivalent moments over time to understand if the actual damage equivalent moment is showing an increase over time, which is inconsistent with the extrapolated damage equivalent moment. If an increase in the damage equivalent moment beyond the predicted values using extrapolation is found, then the extrapolation could be corrected to use these increase load values in the methodology to follow the measured damage equivalent moment trend. If further passage of time shows an even greater increase in measured damage equivalent moment than shown by the corrected extrapolation, then there is the possibility that the operation of the wind turbine is not reliable due to the constantly increasing damage.

The wind turbine C-08 is seen to experience a wide range of turbulence intensities from the direct anemometer measurements at 8m/s mean wind speed bin as shown in Fig. 4.10. The turbulence is normalized with the 90% design quantile at 8m/s as shown in Fig. 4.10. It can be seen that there are several measurements above the 90% design turbulence level. It should be noted that since these are from the nacelle anemometer readings, there would be a measurement uncertainty, that causes a higher turbulence reading than actually present. But there can still be instances that show the inflow turbulence was higher than the measured design levels. The measured damage equivalent moments need to be used to determine, if such high turbulence is detrimental to the wind turbine fatigue life.

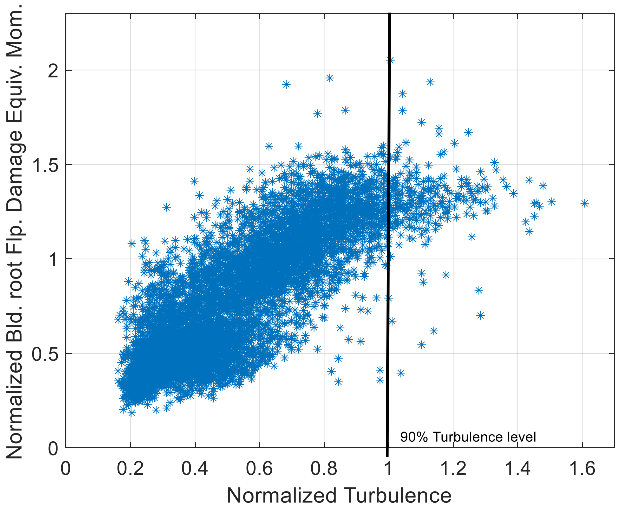


**FIGURE 4. 10. MEASURED WIND TURBULENCE AT C-08 WIND TURBINE USING NACELLE ANEMOMETER**

Figure 4.11 compares the probability of exceedance of the normalized measured damage equivalent moment with the extrapolated damage equivalent moment using a small subset of the measurements at two of the most frequent mean wind speeds, 8 m/ and 10 m/s. Here 20 measured blade root flap damage equivalent moments, taken over all turbulence levels are used to fit a 3-parameter Weibull distribution to their probability of exceedance, which is then extrapolated to cover the full measurement period. As shown in Fig. 4.11, there are several measured damage equivalent moments that show a higher load level at high probability of exceedances than predicted by the fit. However at the lower probabilities of exceedance, the extrapolated fit is seen to be an upper bound to the damage equivalent moment, since all measured damage equivalent moments are lower than the extrapolated curve at the low probabilities of exceedance. This is the needed behaviour of the extrapolated curve to compute a safe damage equivalent moment at the annual exceedance probability. Now the mean damage equivalent load level from the set of extrapolated equivalent loads is computed to determine if the turbine is operating at below reliability levels.

Comparing Fig. 4.11 with Fig. 4.5 where load simulations were run to determine the blade root flap damage equivalent moments with the measured turbulence, one can see that the resulting annual damage equivalent moments in Fig. 4.2 are only about 60%-70% of the levels seen in Fig. 4.5. The mean of this set of normalized damage equivalent moments shown in Fig. 4.11 is about 1.7. The annual mean damage equivalent moment from using a uniform set of turbulence inputs covering IEC classes A,B,C as shown in Fig. 4.5 reported the normalized mean equivalent moment as 2.4, which is about 30% higher than the annual average seen in Fig. 4.11. This specific margin observed will be even higher if the full design turbulence had been used in the results shown in Fig. 4.5, since the design turbulence is IEC class A, which is shown in Fig. 4.9. Thus we can conclude that within the measurement period seen in Fig. 4.10, the damage equivalent moments shown in Fig. 4.11 are well within the fatigue reliability margins of the blade, and there is very little risk of fatigue failure.

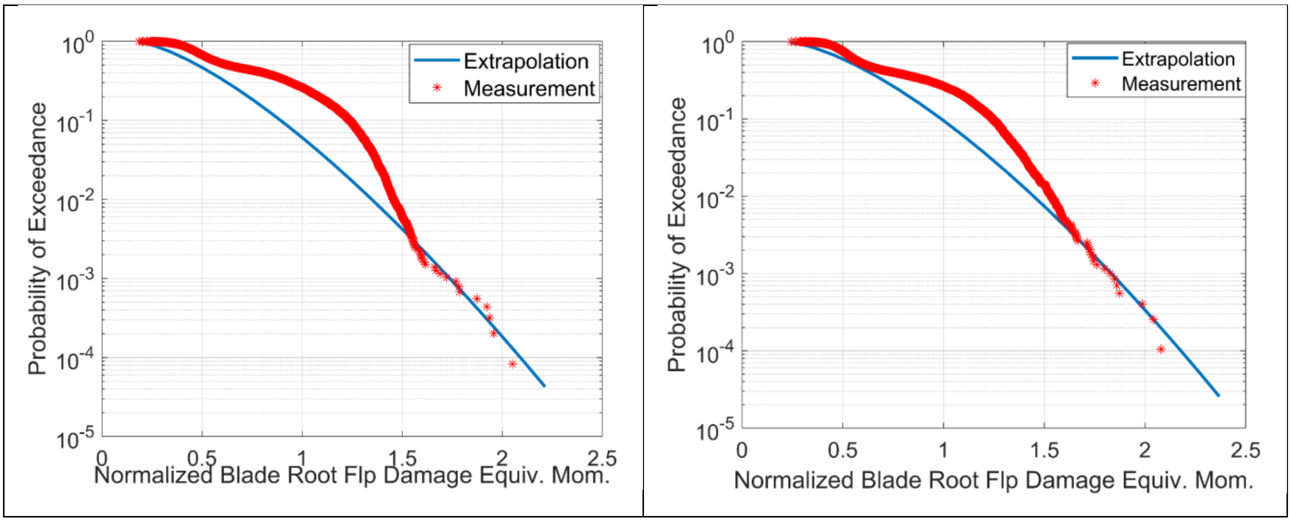


**FIGURE 4. 11: EXTRAPOLATED BLADE ROOT FLAP DAMAGE EQUIVALENT MOMENT COMPARISON WITH MEASUREMENTS FOR 1) LEFT: 8 M/S MEAN WIND SPEED BIN AND 2) RIGHT: 10 M/S MEAN WIND SPEED BIN**

Based on this methodology, one can say that there is no unreliable operation of turbine C-08 as measured by the annual max 10-minute damage equivalent load level or the annual expected 10-minute damage equivalent load level. There is more margin for damage accumulation, and the turbine can be up-rated (increased power production) if needed at certain time durations to produce more power. Had we only utilized only the mean of a small set of 10-minute damage equivalent moments without extrapolation as per conventional practise, then we could not have made this conclusion. This methodology allows us to obtain the annual safety margin in terms of damage equivalent moments.

# 5. OPEX REDUCTION POTENTIAL

## 5.1 REQUIRED RELIABILITY FOR TARGET FATIGUE LIFE

The limit state function g(X) is used to describe the state of the structure given input X. Usually $g(x) = 0$ indicates the failure surface, and g(X)=0 describes the entire failure domain. Solving the reliability problem involves solving the limit state function as follows

$$G(R, S, t) = R(t) - S(t) \quad \text{6-1}$$

where *R(t)* is the material limit or design damage equivalent load, and *S(t)* is the incurred damage or actual damage equivalent load due to wind inflow. The failure happens when:

G <= 0

Deliverable report D2.5 showed how the damage equivalent load level can be used to determine the reliability margins, which is also applicable to the methodology presented here.

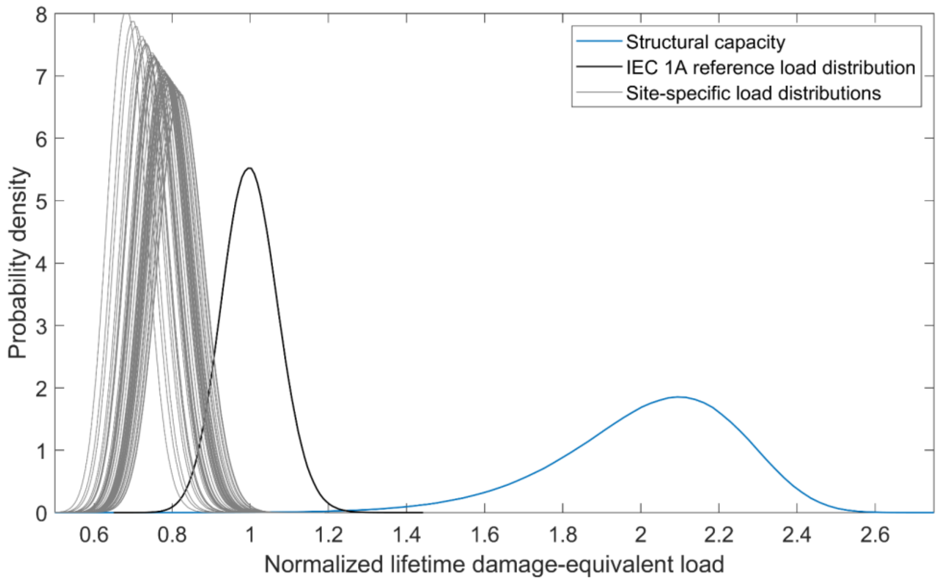


**FIGURE 5. 1: DAMAGE EQUIVALENT LOAD DISTRIBUTIONS FOR INDIVIDUAL TURBINES AT LILLGRUND COMPARED TO IEC 1A DESIGN REFERENCE (TOTALCONTROL DELIVERABLE REPORT 2.5)**

As was seen in Fig. 4.11, there range of the measured damage equivalent blade root flap moments is large, and therefore the conventional damage equivalent moment approach of comparing with the simulated mean of six 10-minute damage equivalent moments at each mean wind speed is not realistic. The normalized measured damage equivalent moments were found to vary between 0.25 to 2 and an appropriate criteria is needed to determine if those damage equivalent moments, that are much larger than the mean of the measured values can cause unreliable wind turbine operation.

In order to assess effectively the reliability of this turbine with such large measured damage equivalent moments over the operational period, the approach explained in section 4 is required, so that the arithmetic mean of all damage equivalent moments using extrapolation to a year at each mean wind speed can be compared with the corresponding values in the design basis. Based on the analysis done in section 4, the wind turbine blades in Lillgrund such as C-08 have a 30%

margin in annual damage equivalent moments at the most common wind speed, which may be extended to the lifetime damage equivalent moments in similar wind conditions. Since the design margins are not being breached when the mean of the one-year load-set is considered, the use of control methods such as by de-rating, need not be analyzed to improve reliability.

## 5.2 CONTROL METHODS NEEDED TO MAINTAIN RELIABILITY MARGINS

The neural network that predicted wind turbulence as shown in Figs 4.6 and 4.7 can be used in a control system that can de-rate the wind turbine upon detection of turbulence levels that exceed the design turbulence level. It is also possible to de-rate the upstream turbine if the downstream turbine detects high turbulence. Figure 5.2 describes the control algorithm that can be used, whereby the neural network based detection of higher turbulence allows the implementation of turbine de-rating to reduce the loads on the wind turbine.

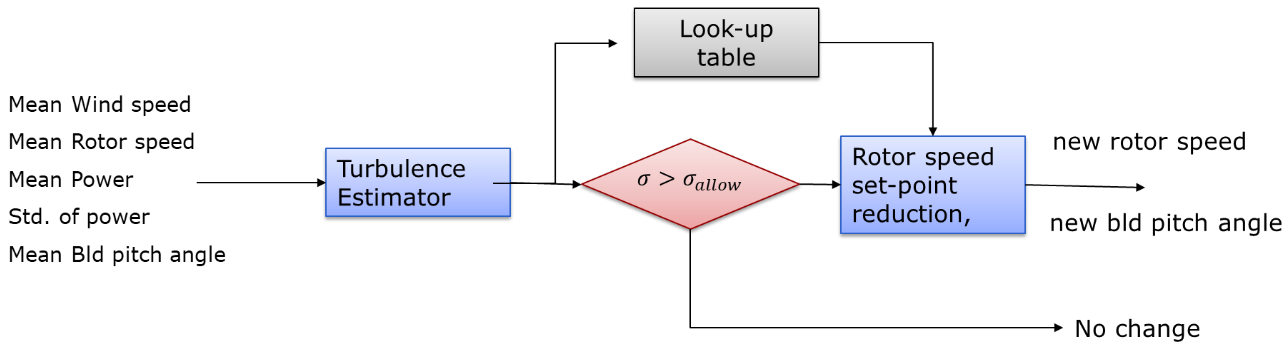


**FIGURE 5. 2 : NEURAL NETWORK BASED CONTROLLED THAT DETECTS INFLOW TURBULENCE BASED ON WHICH THE TURBINE CONTROLLER CAN DE-RATE THE POWER USING THE TURBINE ROTOR SPEED AND BLADE PITCH ANGLE SET POINTS.**

Since the neural network uses the turbine's own SCADA system outputs, no additional inputs are needed, other than a look-up table that provides information to the turbine controller on the rotor speed, blade pitch angle needed at a given detected inflow turbulence level. Such a controller will automatically prevent unreliable operation of the wind turbine, if the allowable turbulence ($\sigma_{allowable}$) is set to be the design turbulence level. If otherwise, as noted in the previous section, the turbine is operating well within the design margins, then the allowable turbulence level can be increased to allow for higher than design turbulence levels for a limited time, thus allowing for unreliable operation of the wind turbine, since we have reserve design margins. Such unreliable operation for shorter durations will not have a cost penalty since sufficient reliability margins are present.

## 5.3 BENEFIT IN OPERATIONAL COSTS

The cost tool explained in deliverable report D2.1 is used to quantify the operational cost benefit due to operating in high reliability levels as determined for some turbines in Lillgrund. The tool represents reliability using the mean time between failures (MTBF). The annual reliability level of wind turbine that blades are designed for 0.0005. Hence two scenarios are considered, on either side of this design reliability: 1) there is unreliable operation and the MTBF of the blades is 0.001 per year and 2) when the operating reliability is much higher, with MTBF of the blades to be 0.0001 per year. A cost analysis can now be made for the upper and lower bounds of blade reliability using the D2.1 cost tool.

1) For the higher annual blade failure frequency of 0.001, using the D2.1 cost sheet, a blade repair cost of €720000 is to be expected in the 20 year lifetime of the wind farm with a loss of production revenue of €100000. This corresponds to unreliable wind farm operation with approximately three blade failures and is the upper cost of blade failures.

2) For the higher reliability wind farm operation with the MTBF of blades equal to 0.0001, these costs reduce by a factor of 10, which implies a €72000 blade repair cost and a small production loss of €10000. This corresponds to the lowest cost of blade repairs, where nearly no blade failure is reported in the farm life.

Based on the safety margins seen on some of the blades in Lillgrund under moderate wakes (such as turbine C-08), it can be concluded that the cost of unreliable operation would be as per point 2 above, that is the expected cost of blade failure would be insignificant. This would also allow life extension of the wind farm, if other components are also found reliable, thus adding to revenue and not adding to repair cost.

# 6. Conclusions

Quantification of potential lowered annual reliability in fatigue below design levels was made for wind turbine blades in the Lillgrund wind farm using an innovative method that was developed herein. The new method used both the results of aeroelastic simulation and direct load measurements on the Lillgrund wind turbine to determine the annual expected fatigue damage equivalent moment at the blade root. The new method was based on extrapolation of the damage equivalent moment from limited measurements or simulations to a one-year return period at each mean wind speed, and subsequently the mean of all damage equivalent loads over the full one-year set was taken as the expected annual damage equivalent load.

The comparison of the damage equivalent moment extrapolation forecast to the next year, using a small sample of measurements on one of the wind turbines in wakes in the wind farm showed that its annual damage equivalent moment was well within design margins, and therefore it had no lowered reliability levels. The assessment of the wake turbulence on other wind turbines and wind directions did not reveal that the wind turbulence including wakes from at least 4 upstream turbines was above that of the design turbulence level.

A neural network was developed to quantify the inflow turbulence with wake effects, based on the measured 10-minute SCADA statistics of the wind turbine. The output of the neural network being the predicted wind turbulence also showed that it reduced the scatter in the turbulence measured using the nacelle anemometer. The neural network can feed into the turbine control system, whereby if it detects that the inflow turbulence is higher than a set allowed limit, then the turbine can be de-rated, or the upstream turbine can be de-rated to lower the mechanical loads.

The cost analysis showed that there is a low impact of unreliable operation on the blade repair cost, since most of the wind turbine blades in Lillgrund appear to be within design margins. Therefore, there is scope for life extension and thus higher revenues, rather than additional cost due to the operational conditions.

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