Challenges in Detecting Wind Turbine Power Loss: The Effects of Blade Erosion, Turbulence and Time Averaging

Tahir H. Malik[1] and Christian Bak[2]

[1]Vattenfall, Amerigo-Vespucci-Platz 2, 20457, Hamburg, Germany
[2]DTU Wind and Energy Systems, Frederiksborgvej 399, 4000 Roskilde, Denmark

Correspondence: Tahir H. Malik (tahir.malik@vattenfall.de)

Abstract. The complex interplay of factors affecting full-scale wind turbine performance challenges the establishment of a clear correlation between blade leading edge erosion (LEE) and operational turbine performance and obscures the underlying reasons. To better understand and enhance the analysis of real wind turbine measurements, this study employs aeroelastic simulations to investigate the combined effects of LEE and turbulence intensity (TI) as well as time-interval averaging as a data processing technique. An offshore original equipment manufacturer (OEM) provided aeroelastic model was used to simulate various scenarios. Turbulence intensity was varied for a range of wind speeds and the aerofoil characteristics for the blade were modified to simulate different degrees of erosion, represented by varying levels of roughness. For a given site, findings reveal that even mild simulated erosion can reduce the annual energy production (AEP) by 0.82% at 6% TI, while more severe erosion leads to a 1.46% decrease. Furthermore, increasing TI exacerbates these losses, with a 15% TI causing up to a 2.14% AEP reduction for eroded blades, making it increasingly difficult to distinguish the effects of blade erosion and turbulence intensity (TI) on turbine performance. These effects were most pronounced at sites with lower average wind speeds. Moreover, the interaction between TI levels and longer time-averaging intervals, which varies with wind speed, can obscure the true magnitude of LEE's impact on short-term power fluctuations. This study also showed that 10-minutes time-average intervals could mask the performance significantly and that analysis of unsteady data on the rotor can benefit from shorter time intervals. The work emphasises the importance of considering blade condition's impact in the context of various influencing factors for accurate AEP assessments, performance monitoring and improved wind turbine design for operational wind turbines.

1 Introduction

The performance of wind turbines is a multifaceted subject of research, being intricately affected by a multitude of environmental (Wharton and Lundquist (2012)) and operational factors. Wind turbine manufacturers and owners place great focus on this aspect due to its implications for revenue as well as operations and maintenance (O&M). However, accurately identifying and validating performance within operation wind turbines using Supervisory Control and Data Acquisition (SCADA) data remains a major challenge (Ding et al. (2022)). This challenge stems from the complex interplay of factors affecting the turbine's performance (Barthelmie and Jensen (2010)), making it difficult to isolate the effects of individual causes amidst the numerous

variables and uncertainties. Consequently, extensive efforts are invested in analysing SCADA data, with the default approach involving the analysis of 10-minute average values of wind speed and power, focusing particularly on power degradation over time. In industry practice, wind turbine operators typically calculate power curve loss contributions using static components, employing static tables that include factors such as the thrust coefficient, C_t, temperature, wind shear, transformer losses and component friction. However, quantifying the impact of blade leading edge erosion (LEE) on the power curve for operating turbines remains a challenge. Nevertheless, it is acknowledged that significant uncertainties exist within this 10-minute averaging analysis (Yang et al. (2014)).

This study specifically investigates the degradation of power due to LEE. The detrimental effects of LEE or leading edge roughness (LER) on aerofoil characteristics have been extensively documented in wind tunnel experiments (Hansen (2008); Maniaci et al. (2016); Gaudern (2014); Krog Kruse et al. (2021); Bak et al. (2023)). Furthermore, these effects have also been the subject of numerous studies on the impact of erosion on wind turbine annual energy production (AEP) (Bak et al. (2016); Ehrmann et al. (2017); Kruse (2019); Han et al. (2018); Castorrini et al. (2023)). These studies indicate potentially significant AEP losses of up to 7%. While the impact of blade erosion on AEP is generally smaller than that of wake deficits and some controllers can compensate for degraded lift through pitch adjustments, its subtle effects are nonetheless crucial to quantify. Where, currently, a 1% variance in AEP for Vattenfall, an energy utility, equates to an average daily approximately 380 MWh loss. Although easily measurable in controlled environments such as wind tunnels, the question is not whether losses occur, but why these effects are obscured within the scattered sensor signals of operational wind turbines and how to detect them when a rotor operates in a turbulent flow field with significant wind fluctuations.

Analysis of extensive measurement data from wind farms revealed difficulties in obtaining sufficient insight into the influencing mechanisms, a finding supported by studies from Badihi et al. (2022) and Gonzalez et al. (2019). Consequently, simulations of a wind turbine within a wind farm environment were considered more valuable than solely studying SCADA data. The analysis of the simulated data, again, revealed that understanding how turbulence intensity (TI) and the effect of averaging unsteady data influenced the results and was crucial for interpreting both measured and simulated data. Furthermore, turbulence is a well-known atmospheric condition that significantly impacts wind turbine performance (St. Martin et al. (2016); Saint-Drenan et al. (2020); Kim et al. (2021); Cappugi et al. (2021)).

Therefore, this study aims to address the following question: "What makes power losses due to erosion so challenging to detect in operational wind turbines and how can these challenges be more effectively addressed?". The current work addresses this by incorporating a certified model of an operational turbine's controller in the full aero-servo-elastic simulation loop. This approach ensures that the response to degraded blades, including pitch adjustments utilising aerodynamic reserves, is captured accurately. The study also investigates and compares significant effects, such as turbulence intensity, alongside the impact of degraded aerofoil polar coefficients (C_l and C_d), in an effort to reveal the reasons behind the obscurity of erosion's effects on performance in SCADA data. The influence of turbulence intensity shall be investigated at the rotor level, expanding upon existing knowledge that primarily focuses on performance at the aerofoil level (e.g., Bak et al. (2008) and Cappugi et al. (2021)). Additionally, the effects of time interval averaging, traditionally performed using 10-minute intervals, shall be examined.

This study thus aims to improve the understanding and analysis of wind turbine performance measurements, rather than focusing on aerodynamic computations. The goal is to develop more reliable methods for detecting degradation in real-world wind turbine performance.

2 Method

This study aims to conduct a fundamental investigation into the impact of turbulence intensity on the aerodynamic performance of wind turbine rotors, focusing on the effects of leading-edge erosion. This is achieved through the use of an aeroelastic code that incorporates structural dynamics. Also, the effects of wind shear are briefly investigated. Additionally, the study examines the potential impact of different time-averaging intervals used in operational data analysis on the ability to detect and quantify the effects of leading-edge erosion.

2.1 Wind turbine and aeroelastic code

The investigation utilises the Blade Element Momentum (BEM) based multi-body aero-servo-elastic tool HAWC2, developed by DTU Wind Denmark. A comprehensive description, usage and implementation of HAWC2 are well-documented in the literature Larsen and Hansen (2007). The multibody model used in this study, provided by an OEM, represents a currently operational offshore wind turbine. It is a three-bladed, multi-megawatt, horizontal axis wind turbine with variable speed, pitch regulation and yaw control. Due to intellectual property considerations, specific details about the turbine, such as structural properties and control philosophy, are not disclosed; hence, the power is presented as *normalised power* and is expressed as power relative to the rated power.

A reference wind turbine such as the NREL 5 MW (Jonkman et al. (2009)) or the DTU 10 MW (Bak et al. (2013)) could have been employed; however, since this study is closely connected to measurements from a wind farm, a study incorporating a controller from an actual wind turbine is essential to investigate the unsteady effects. Furthermore, since relative changes in performance are more critical than absolute performance, it is considered key that a model of a real wind turbine is investigated. Numerous parameters affect potential degradation, such as the severity and radial position of the damages, the specific power of the turbine, etc. Therefore, it is expected that the results from this study indicate general trends, with specific numerical results varying slightly depending on the actual wind turbine design.

2.2 Representing leading edge erosion

Blade leading edge erosion was modelled as varying levels of surface roughness, a quantifiable measure of damage severity directly impacting aerodynamic performance and representing a precursor to more significant aerofoil deterioration where voids or cavities may begin to form. The multibody model's blade aerofoil polars for the outer 15% of blade length were modified applying factors to reflect the effects of erosion. The length and location of this applied degradation correspond to field observations of similar blades after approximately two years of operation. Wind tunnel test data from Krog Kruse et al. (2021), which utilised P400 and P40 sandpaper to simulate different erosion levels on a NACA 63_3-418 aerofoil, served as the

empirical basis for deriving factors for these modifications. These textures represent the roughness induced by rain droplets impacting the leading edge at high velocities. While the sandpaper provides a simplified model of erosion, it is important to acknowledge that real-world erosion on turbine blades can be influenced by a multitude of factors.
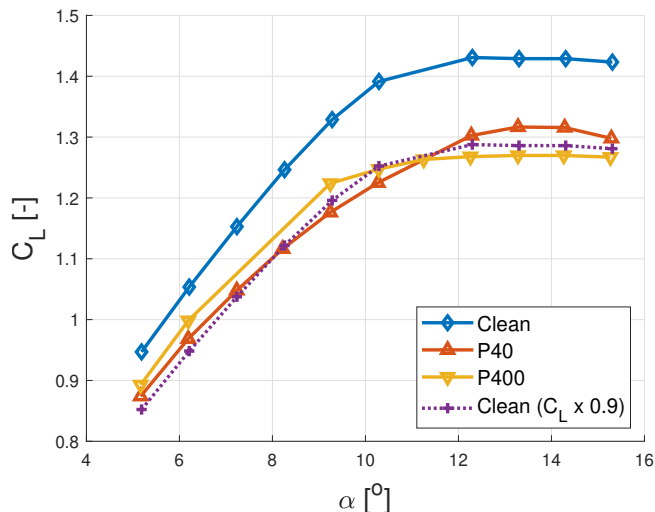
Figure 1. Effect of leading-edge erosion on lift coefficient (C_L) as a function of angle of attack (α). Compares Clean, P40 and P400 blade conditions, demonstrating decreased C_L with increased roughness (measurement data from Krog Kruse et al. (2021))
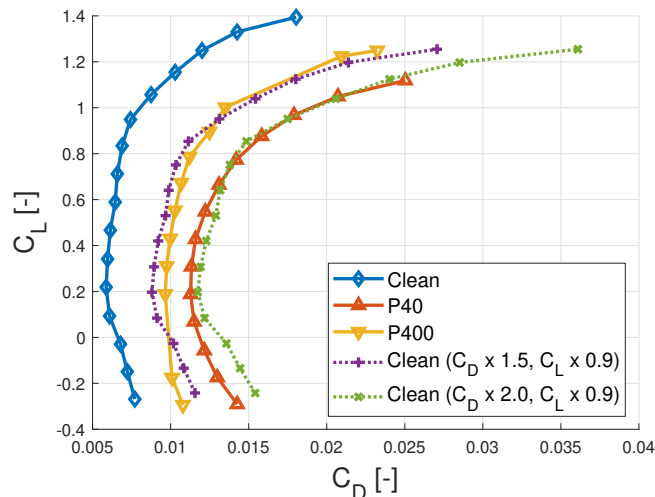
Figure 2. Effect of leading-edge erosion on drag coefficient (C_D) as a function of lift coefficient C_L). Compares Clean, P40 and P400 blade conditions, demonstrating increased C_D with increased roughness (measurement data from Krog Kruse et al. (2021))

A challenge in this work is the lack of access to the aerofoil geometry. Although the aerofoil characteristics are available, they cannot be presented due to intellectual property rights. Therefore, the degradation of the aerofoil characteristics was modelled based on observations from an alternative aerofoil, relying on relative changes. While Skrzypinski et al. (2014) have proposed a model for altering aerofoil characteristics, this study employs a simplified approach. Therefore, although the tested aerofoil is not an identical match to that in the multibody model, this approach is deemed a suitable approximation for representing the outboard region of eroded turbine blades.

Wind tunnel tests on the alternative aerofoil were conducted at a Reynolds number of 5 x 10^6. Results for the Clean (no sandpaper), P400 (fine, with an average roughness value of 0.035 mm) and P40 (coarse, with an average roughness value of 0.415 mm) sandpapers were used. The P40 sandpaper, which has a larger grain size, was chosen to represent a more severe erosion state. Figures 1 and 2 illustrate that for both P400 and P40 sandpaper roughnesses, the $C_L max$ is reduced by approximately 10% within a specific range of α before deep stall. Similarly, the C_D increases by approximately 50% for P400 roughness and 100% for P40 roughness, compared to a clean aerofoil surface. To represent the effects seen in the wind tunnel experiments on the simulation model's aerofoil, these derived percentages were used to approximate the degradation of the the proprietary aerofoil polars. For simplicity, the original proprietary model blade's last 15% blade section's lift polars

representing the clean aerofoil were scaled by a factor of 0.9. Similarly, two artificial drag polars were created by scaling the model's original drag polar representing the clean aerofoil by applying factors of 1.5 and 2.0 to it.

This approach was deemed acceptable as the multibody simulations were performed over a limited range of angle of attacks, which is relevant for cases of normal turbine operation, detailed in Section 2.5. These factors were applied between the aerofoil's minimum and maximum lift angles of attack. Beyond this range, at high angles of attack (30 degrees), the adjusted characteristics were smoothly blended into the original data. The assumption is that at high angles of attack the performance is dominated by the flow separation and the resulting pressure distribution, resembling that of a flat plate, thus being less dependent on the specific surface characteristics. Due to confidentiality, the final modified aerofoil characteristics cannot be shown.

2.3 Representing Wind Farm turbulence

The simulations reproduce turbulence conditions typical of operational offshore wind farms. Turbulence data was sourced from a meteorological mast located adjacent to an operational offshore wind farm which utilises the same turbine type as the multibody model.

The turbulence intensity profile at the site, corrected to the turbine's hub height using WindPro EMD International A/S (2023), is shown in Figure 3. This comprehensive dataset was derived from six years of 10-minute averaged data and includes all wind speeds without directional filtering. It incorporates the effects of wakes from adjacent turbines as well as a wind farm, offering a realistic depiction of the first row in a wind farm environment.

The mean TI is 7.3% for the entire period and 6.7% when limited to turbine operational wind speeds - between 4 and 25 m/s. The TI distribution is depicted in Figure 4 and together, these figures reveal that although higher turbulence intensities do occur, they are relatively rare and primarily occur at lower wind speeds. For sake of convenience in the simulation environment, a turbulence intensity of 6% was used to represent mean annual wind farm turbulence with wake free directional filters applied. Specific location details of the wind farm and the met mast are omitted due to confidentiality.

2.4 Data Time Averaging

To better understand the potential impact of different data processing techniques on wind and power measurements, this study investigates the effects of varying time-averaging intervals on the detection and quantification of erosion-related power losses. The analysis of wind and power measurements often involves binning and time-averaging. Binning and time-averaging data are forms of data filtering that can both clarify and potentially complicate the interpretation of results. Careful selection of bin sizes is crucial to avoid information loss and potential misinterpretation.

Time averaging, traditionally over a 10-minute period, is used to smooth turbine signals such as wind speed, power and behaviours such as pitch or torque. These responses are slightly delayed to wind speed, that can fluctuate rapidly. Time averaging can provide a more representative overview of turbine performance and prevailing wind conditions, allowing identification of trends, patterns in data, supported by findings from Abolude and Zhou (2018), Do and Berthaut-Gerentes (2018) and Elliott and Infield that highlight associated benefits and complexities. While longer intervals simplify data processing and reduce
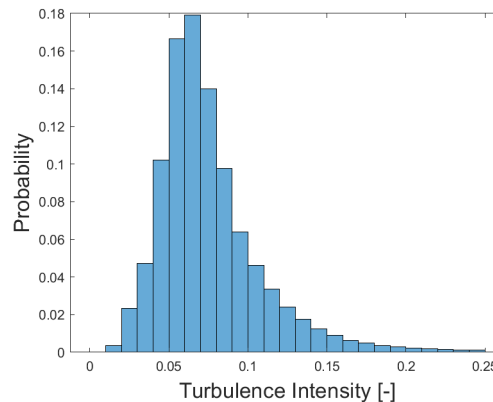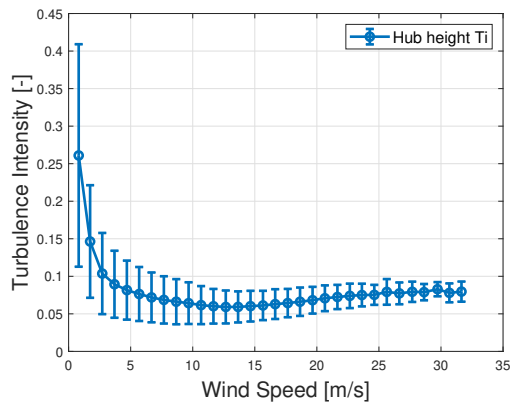
Figure 3. Turbulence intensity at the hub height as a function of wind speed. Data obtained from the wind farm's meteorological mast

Figure 4. Probability density distribution of turbulence intensity (TI) for wind speeds between 4-25 m/s (limited at 25%)

140   data storage needs, they also risk masking changes in performance and the subtle effects of leading-edge erosion on turbine dynamics (Gonzalez et al. (2017); Gonzalez et al. (2019)).

Importantly, time averaging potentially introduces bias into data analysis. For example, smoothing out short-term fluctuations in power output can inadvertently alter the perceived shape of the power curve, such as the location of the the knee in the power curve. A crucial aspect to consider is the balance between the need to reduce noise in the data and the risk of masking important

145   turbine responses. An excessively short time interval may lead to noisy data, while an interval that is too long risks filtering the turbine's behaviour too much.

Furthermore, time averaging affects the perceived inertia of the turbine. When power output is averaged over a longer time interval, short-term fluctuations in power output are suppressed, potentially making the turbine appear less responsive to changes in wind speed. If the time interval used for averaging significantly exceeds the characteristic response time of

150   the turbine, the inertia of the turbine may be underestimated and its ability to respond to changes in wind speed could be overestimated. Conversely, using a time interval that is too short may amplify short-term fluctuations in power output, making data interpretation difficult because the raw data in many cases shall be a swarm of data points. It is therefore important that the specific requirements of the analysis should ultimately dictate the selected averaging time interval.

To investigate these effects, this study explores the use of shorter time-averaging intervals to potentially unravel the nuanced

155   effects of leading-edge erosion on turbine performance, which may be masked in traditional 10-minute averages. The challenge lies in selecting an interval that offers sufficient detail without sacrificing clarity, ensuring that critical information about turbine performance and the impact of blade surface conditions is neither lost nor misrepresented. Data from multibody simulations, with a 0.01 second time step, was collected from all wind speed simulation seeds for a given turbulence intensity and blade profile. Time averaging was then applied to wind speed and turbine sensor variables such as power for time intervals of 0.01, 1,

160   30, 60, 120, 300 and 600 seconds. Subsequently, the data was averaged into 1 m/s wind speed bins and the turbulence intensity of the original simulation seed was applied to time intervals sliced from it.

2.5 Simulation settings and test cases

This study employed a range of simulation cases using HAWC2, a Blade Element Momentum (BEM)-based multi-body aero-servo-elastic tool, to explore the impact of turbulence intensity and blade erosion on wind turbine performance. Simulations were executed for a range of turbulence intensities for the clean and and two eroded blade profiles. Individual cases were run in 1 m/s increments ranging from 4 to 25 m/s, representing the turbine's cut-in and cut-out wind speeds. Each configuration of wind speed, TI and blade condition was represented by six individual simulation runs, or seeds, to ensure statistical robustness International Standard. Wind energy generation systems - Part 1: Design requirements. IEC 61400-1 International Electrotechnical Commission (IEC) (2019).

The turbulence intensity was varied across a broad spectrum including 0%, 4%, 5.5%, 6.0%, 6.5%, 7%, 10%, 15% and 20%, with a focus on values around the observed average annual ambient TI at an offshore site, along with broader values for comparison. Each simulation was run for 900 seconds, with data from the last 600 seconds used for analysis to ensure steady-state conditions were reached. The time step of the simulations is 0.01 seconds. The wind shear was investigated for two conditions, including a zero shear value and a power-law profile with an alpha value of 0.14. The air density was fixed at 1.225 kg/m^3, representative of sea-level conditions at 15°C. The Mann turbulence parameter $\alpha\epsilon^{2/3}$ Mann (1994), energy level was set to its default value of 1.0. For a detailed explanation of specific parameters and settings, refer to the HAWC2 manual Larsen and Hansen (2007) or IEC61400-1 ed. 3 International Electrotechnical Commission (IEC) (2019).

3 Results and Discussion

The simulations conducted in this study have been analysed from multiple perspectives, with the results presented in four distinct sections:

- Effect of shear and blade erosion on power

- Effect of turbulence intensity and blade erosion on power

- Effect on Annual Energy Production

- Effect of erosion, time averaging and turbulence on power curve

3.1 Effect of shear and blade erosion on power

This section investigates the impact of leading edge erosion on wind turbine power curves under different wind shear conditions using multibody simulations. The simulations were executed at a constant turbulence intensity of 0% to isolate the distinct effects of shear and blade condition. Figure 5 presents normalised power curves for clean blades and those exhibiting P400 and P40 roughness levels, under both zero shear and with imposed wind shear conditions of a power-law profile with an alpha value of 0.14 . As expected, the leading-edge roughness reduces the power output across the range of wind speeds.
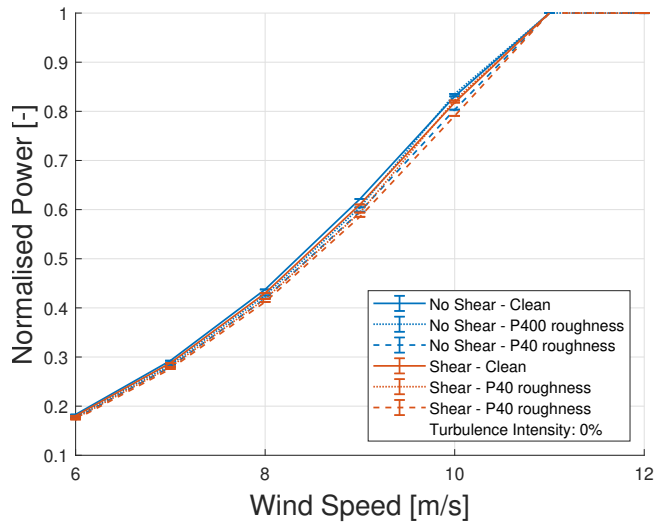
Figure 5. Effect of various blade conditions compared to that of shear and no-shear wind condition on the power curve (0% TI)
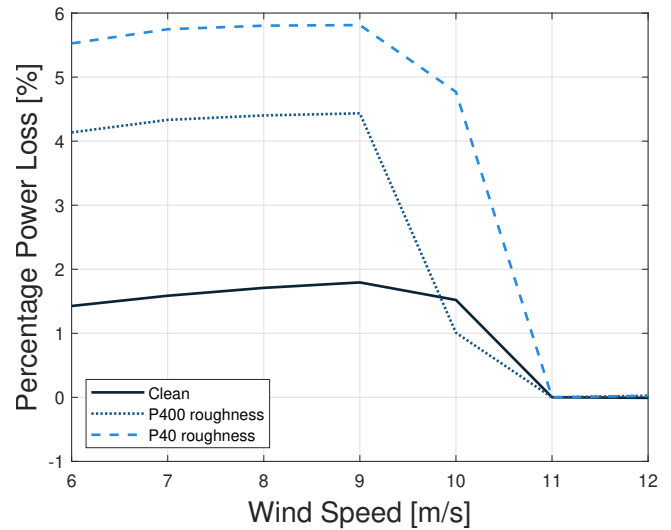
Figure 6. Percentage power loss due to shear, referenced against the baseline clean blade without shear, for various blade conditions (0% TI)

Comparing the no-shear and shear conditions reveals the turbine's sensitivity to shear-induced variations in the wind profile along the rotor span. Under shear conditions, the power curves for both clean and eroded blades exhibit a shift, up to 5.8% for the P40 roughness blade with shear, relative to a clean blade at zero shear conditions, as seen in Figure 6. This demonstrates an adjustment in operational behaviour to account for the velocity gradient imposed by the atmospheric shear and the convoluting effects on power of the factors.

Despite these observed shear effects complicating the isolation of variables and highlighting the difficulty of analysing real-world measurement data, this analysis shall focus on investigating turbulence, as it an atmospheric condition whose impact on performance is typically more substantial than that of wind shear (Saint-Drenan et al. (2020)).

3.2 Effect of turbulence intensity and blade erosion on power

3.2.1 Investigation based on the power curves

The normalised, 10-minute averaged power curve of the turbine for various turbulence intensities is shown in Figure 7. Consistent with previous research Saint-Drenan et al. (2020), Wagner et al. (2010), the turbine's power output is significantly influenced by turbulence intensity (TI), particularly pronounced within the partial load region of the power curve, which is the operational range between the wind speed where maximum rotational speed is achieved and the wind speed where rated power is reached. The plot includes higher turbulence intensities, such as 20%, to demonstrate the trend in their effect on the power curve. This variance highlights the the considerable effect of turbulence intensity on turbine performance.
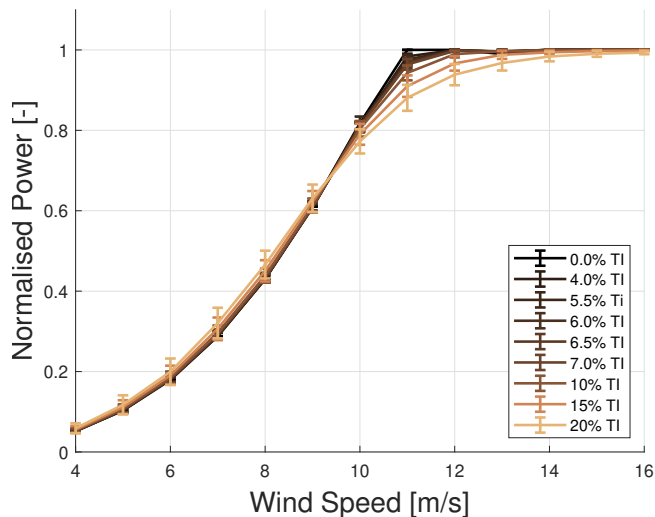
Figure 7. Effect of turbulence intensity on the power curve (Clean blades)
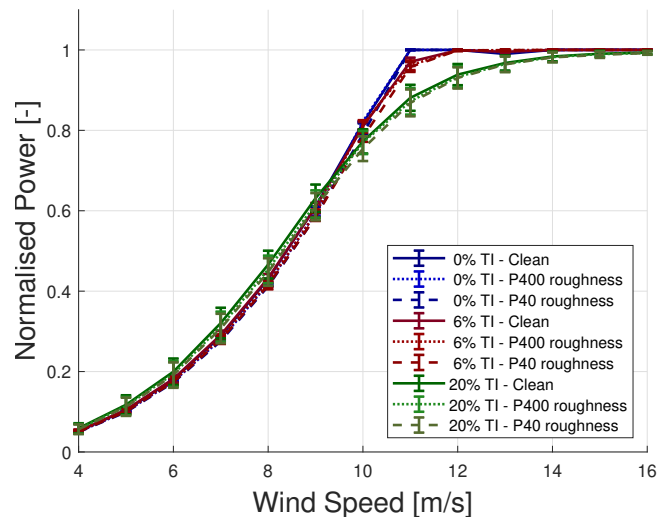
Figure 8. Effect of specific turbulence intensities compared to that of blade conditions on the power curve

Comparative analysis among Clean, P400, and P40 blade conditions, representing varying degrees of erosion applied on the leadinge edge of the last 15% of the blade length, are presented in Figure 8. Results are shown for 6% turbulence intensity, representing a typical mean value for offshore sites. The 0% and 20% plots are included for comparison to more outlying
210 conditions, demonstrating a similar trend in power reduction with increasing blade erosion. Similar effect on omitted power curves affirms the consistent detrimental impact of erosion across various TI conditions.

The figures facilitate a revealing comparison of effects of turbulence relative to erosion. Analysis of the power curve at a specific point, such as the 'knee', reveals that changes in turbulence intensity influence power output are more pronounced than blade erosion. This is evident in Figure 8: for the clean blade at 11 m/s wind speed, power reduces to approximately 97.0%
215 when TI increases from 0% to 6% and further to 88.1% at 20% TI. For eroded blades, these reductions are comparable: 96.2% and 87.2% (P400) and 95.7% and 86.9% (P40).

Considering a wind speed of 11 m/s and 6% TI, erosion causes power losses of approximately 0.9% (P400) and 1.3% (P40) relative to the clean blade. Importantly, the power output's standard deviation at this wind speed is approximately 1.03% (6% TI) and 3.23% (20% TI). This underscores a major challenge: particularly at higher TI, the standard deviation exceeds the
220 power loss due to roughness, making it difficult to isolate and detect the effects of erosion on power output based on the power curve alone. However, the comparability of values at lower TI suggests that erosion effects could potentially be detected more readily under less turbulent conditions.

An interesting observation in Figure 8 is the intersection of power curves around 9.5 m/s. This intersection is caused by a combination of factors. Firstly, the inflection point in the power curve at 9.5 m/s, where the curvature changes, plays a role. Sec-
225 ondly, the averaging effects inherent in calculating power curves from unsteady power output contribute to this phenomenon.

While analysing the changes in power curve shapes provides valuable insights, it offers an incomplete understanding of the true impact of erosion and turbulence. To accurately assess the overall effect, it is crucial to consider the site-specific wind speed distribution and its influence on the turbine's annual energy production. A more comprehensive analysis is presented in Section 3.3.

3.2.2 Investigation relative to a reference power curve

To further investigate how the power curve is influenced by erosion under varying turbulence intensities, this study conducted a comparative analysis. The change in power relative to a reference Clean profile power curve at 6% TI, focusing on "P40" roughness, was investigated. The results are shown in Figure 9 as a function of wind speed across a range of turbulence intensities. The delta power curve exhibits a 'kink', a point characterised by a sudden change in gradient, at around 9.5 m/s attributed to the previously discussed effect of time averaging. The most substantial reduction of power due to roughness were identified between 9 and 13 m/s. At lower turbulence intensities, i.e. 7% and below, roughness was found to have an effect in reducing power. Moreover, for increasing turbulence intensities, the influence of roughness increases dramatically within the same wind speed range.
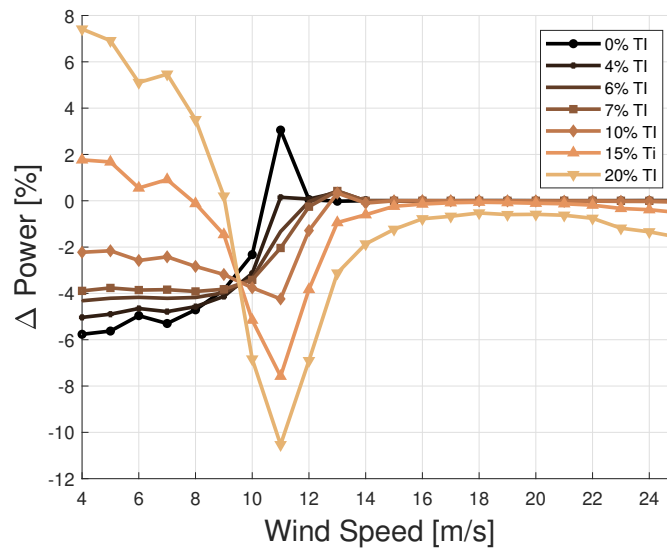
Figure 9. Change in power percentage P40 roughness - Clean (6% TI) for various turbulence intensities as a function of wind speed

These findings highlight the non-linear and interdependent relationship between blade roughness and turbulence intensity in their impact on power output. Furthermore, they suggest that both factors must be considered when assessing wind turbine performance, especially within specific wind speed ranges.

3.2.3 Investigation using power coefficients

The coefficient of power (C_p) represents a key metric for evaluating the performance of wind turbines. This study analysed how C_p varies with wind speed, turbulence intensity and blade roughness. The rationale for investigating C_p is based on the understanding that turbulence intensity does not inherently alter the efficiency of the wind turbine; rather, it is the combination of turbulence intensity and the averaging time period that can lead to erroneous conclusions. Here, C_p is computed based on averaged power and averaged wind speed. This investigation also highlights the contrast between steady-state aerodynamic analysis with zero turbulence intensity and analysis that includes turbulence intensity. Figure 10 shows the C_p as a function of wind speed for various turbulence intensities, employing a clean profile blade. The findings indicate that the greatest variation of C_p is observed at wind speeds below approximately 9 m/s. To evaluate the impact of roughened blade leading edges on C_p, Figure 11 shows the variation of C_p for the profiles at 6% turbulence intensity. These results suggest that the impact of both forms of roughness is less pronounced than that of a certain threshold value of turbulence intensity.
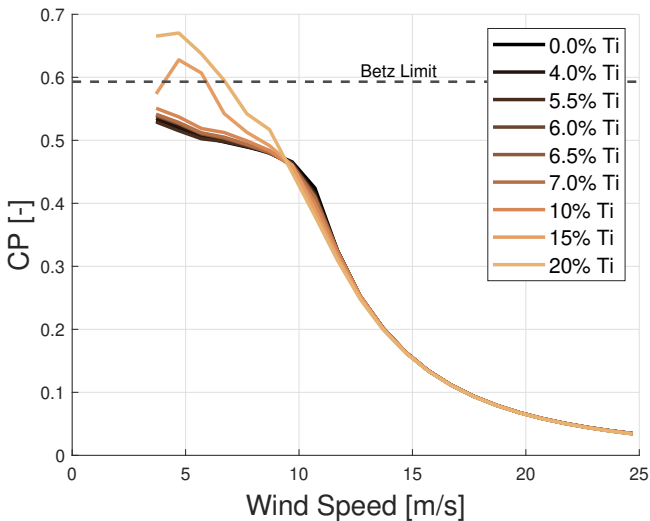
Figure 10. Power coefficient as a function of wind speed for a clean profile blade, with various turbulence intensities
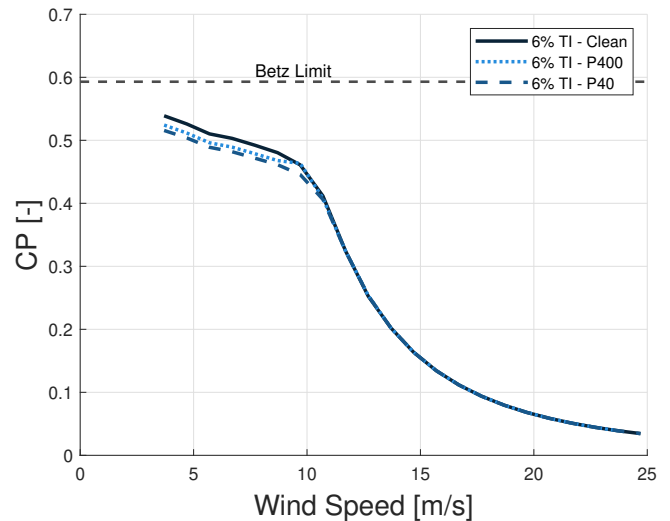
Figure 11. Power coefficient as a function of wind speed for various leading edge roughness profiles (6% TI)

This investigation analysed multibody simulated data, focusing on the last 10 minutes of each simulation to capture steady-state conditions. Instances where the power coefficient (C_p) exceeds or approaches the Betz limit of 0.593 in high turbulence intensity conditions are carefully examined. The exceeding of the Betz limit may be attributed to several factors, including turbine inertia and control dynamics, where the inherent latency in response mechanisms such as pitch and generator torque control results in a temporal mismatch between the turbine's power response and rapid wind speed fluctuations characteristic of turbulent environments. This mismatch, particularly when results are time-averaged over a 10-minute window, can yield simulated C_p values that in some conditions surpass the Betz limit. Thus, it is not believed that C_p values exceeding the

260   Betz limit have any physical meaning, but rather that it is an artefact from the averaging of the the wind speed and the rotor performance. Therefore, the analysis can lead to erroneous conclusions.

      Additionally, the analysis reveals that highly turbulent conditions create localised gusts, temporarily increasing the effective wind speed at segments of the rotor, diverging from steady-state assumptions and causing transient spikes in power output, further exacerbating the mismatch between wind speed and power output. This effect, coupled with the stochastic nature

265   of turbulence that can enhance kinetic energy transfer to the rotor plane and momentarily boost the available wind energy beyond typical averages used in Betz limit calculations. These findings underscore the limitations of steady-state assumptions in accurately capturing the dynamic interactions between wind turbines and complex wind fields. Future efforts should focus on refined simulation models and analysis techniques designed to address these limitations.

      Figure 12 provides further insight on the combined effects of roughness and turbulence intensity. It depicts C_p for a lim-

270   ited range of lower turbulence intensities, along with the three blade profiles at 6% TI for wind speeds up to 11 m/s. The overlap between the C_p's for turbulence intensity and roughness suggests that distinguishing between these two effects may be challenging due to the 'masking' effect, particularly in high turbulence conditions. This complicates the interpretation of aerodynamic performance degradation caused by blade erosion.
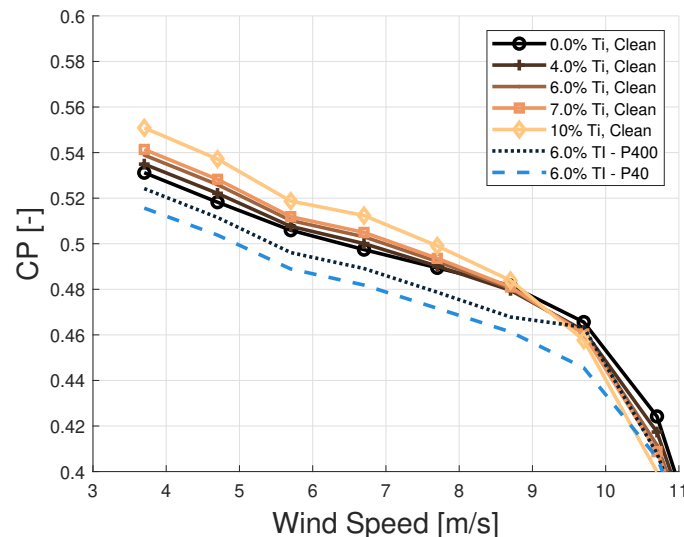
Figure 12. Power coefficient as a function of wind speed for a clean profile blade at various turbulence intensities and various leading edge roughness profiles at 6% TI

3.2.4   Summary of the influence of TI and erosion on power

275   The findings presented herein reinforce the notion that both turbulence and blade erosion exert substantial influences on the wind turbine power output. It has been observed that turbulence profoundly affects the power curve, predominantly in the partial load region. Despite the inherent complexities associated with analysing the performance of the wind turbines under

turbulent conditions, this study emphasises the significance of incorporating TI in performance evaluations. This alignment with preceding studies Wagner et al. (2010) and Saint-Drenan et al. (2020) further validates the critical nature of TI in such analyses.

The examination of delta power highlights the detrimental effects blade roughness on wind turbine power output, with the greatest power reduction due to roughness observed at wind speeds between 9 and 13 m/s. This observation is consistent with prior research Bak et al. (2020), emphasising the significance of considering roughness effects when assessing wind turbine performance. The study also showed that the impact of roughness on power output is further exacerbated at higher turbulence intensities, suggesting that both turbulence and erosion should be considered in performance assessment.

While the analysis focused on the impact of blade erosion on power, it is important to recognise that erosion could also influence other aspects such as loads and sensor output. These potential impacts warrant further investigation.

3.3 Annual Energy Production (AEP) Calculation

This section explores the calculation of annual energy production, investigating the impact of both blade erosion and turbulence on wind turbine performance. Analyses included a real-world operational offshore wind farm and hypothetical scenarios at three fictitious sites.

3.3.1 AEP for an existing site

AEP was calculated for a wind turbine situated in an offshore wind farm operating under mean turbulence intensity of 6%, characterized by a Weibull distribution with a scale parameter $A = 10.72$, a shape parameter of $k = 2.17$. This corresponds to an average wind speed of 9.49 m/s. The computations expressly exclude the wake effects of upstream wind turbines.

The comparative analysis focused on quantifying the impact of blade erosion and turbulence intensity on AEP by comparing the outcomes for three distinct blade profiles. Table 1 shows the AEP variation for each profile relative to the 6% TI power curve of the corresponding profile.

Table 1. Change in AEP as a function of TI. Row 2 shows AEP change relative to "Clean" performance at TI=6%; Row 3 shows AEP change relative to "P400" performance at TI=6%; Row 4 shows AEP change relative to "P40" performance at TI=6% with V_{ave}=9.49 m/s

	TI [%]							
Blade profile	0	4	5.5	6	6.5	7	10	15
Clean delta AEP [%]	0.34	0.11	0.03	0	-0.02	-0.04	-0.23	-0.63
P400 delta AEP [%]	0.44	0.11	0.05	0	-0.04	-0.07	-0.29	-0.78
P40 delta AEP [%]	0.51	0.12	0.05	0	-0.04	-0.06	-0.26	-0.70

Similarly, Table 2 shows the AEP variation for each profile relative to the Clean blade profile's 6% TI power curve. From the results it is clear that even mild simulated erosion, represented by the P400 blade profile, has a significant impact on the turbine's AEP, with a 0.82% decrease. As erosion progresses, the AEP decreases further to 1.46% for the rougher P40

Table 2. Change in AEP as a function of TI and roughness level: AEP change relative to "Clean" performance at TI=6% with V_{ave}=9.49 m/s

Blade profile	TI [%]							
	0	4	5.5	6	6.5	7	10	15
Clean delta AEP [%]	0.34	0.11	0.03	0	-0.02	-0.04	-0.23	-0.63
P400 delta AEP [%]	-0.38	-0.71	-0.77	-0.82	-0.86	-0.89	-1.10	-1.59
P40 delta AEP [%]	-0.96	-1.33	-1.41	-1.46	-1.49	-1.51	-1.71	-2.14

sandpaper, relative to a Clean blade. Moreover, once a blade is rough, its impact on AEP relative to the Clean blade profile is significant.

Table 2 also presents turbulence intensities impact on AEP. As turbulence intensity increases, the AEP decreases for all blade
305 profiles. The impact is more significant for the rougher blade profiles, with the P40 sandpaper profile already showing a high decrease in AEP at 2.14% for 15% turbulence intensity.

3.3.2 AEP for Three Fictitious Sites with Varying Wind Speeds

The investigation extended AEP calculations to three hypothetical sites, each characterised by average wind speeds of 6, 8 and 10 m/s. The subsequent AEP variations for each blade profile, relative to the Clean blade profile's 6% TI power curve, are
310 presented in Table 3 for an average wind speed of 6 m/s, Table 4 for an average wind speed of 8 m/s and Table 5 for an average wind speed of 10 m/s. Three different climates are investigated:

- 6 m/s average wind speed: k = 2, A= 6.8 m/s (Table 3)

- 8 m/s average wind speed: k = 2, A= 9 8 m/s (Table 4)

- 10 m/s average wind speed: k = 2, A= 11.3 m/s (Table 5)

Table 3. Change in AEP as a function of TI and roughness level: AEP change relative to "Clean" performance at TI=6 % with V_{ave}=6 m/s

Blade profile	TI [%]							
	0	4	5.5	6	6.5	7	10	15
Clean delta AEP [%]	0.16	-0.04	-0.20	0	0.02	0.05	0.25	0.86
P400 delta AEP [%]	-1.20	-1.49	-1.65	-1.47	-1.46	-1.44	-1.28	-0.76
P40 delta AEP [%]	-2.51	-2.84	-3.02	-2.83	-2.82	-2.79	-2.60	-2.00

315 From these results it may be concluded that the impact of turbulence intensity on AEP is more pronounced at lower average wind speeds. This observation is evidenced by the more substantial AEP reductions at lower TI levels for the P400 and P40 blade profiles, as well as the higher AEP decrease at higher TI levels for the Clean blade profile, at lower average wind speeds.

Table 4. Change in AEP as a function of TI and roughness level: AEP change relative to "Clean" performance at TI=6 % with V_{ave}=8 m/s

Blade profile	TI [%]							
	0	4	5.5	6	6.5	7	10	15
Clean delta AEP [%]	0.32	0.08	-0.02	0	-0.01	-0.03	-0.13	-0.31
P400 delta AEP [%]	-0.51	-0.85	-0.94	-0.94	-0.97	-1	-1.13	-1.40
P40 delta AEP [%]	-1.39	-1.78	-1.89	-1.88	-1.91	-1.92	-2.03	-2.24

Table 5. Change in AEP as a function of TI and roughness level: AEP change relative to "Clean" performance at TI=6 % with V_{ave}=10 m/s

Blade profile	TI [%]							
	0	4	5.5	6	6.5	7	10	15
Clean delta AEP [%]	0.30	0.10	0.03	0	-0.02	-0.04	-0.21	-0.61
P400 delta AEP [%]	-0.67	-0.96	-1.02	-1.06	-1.10	-1.13	-1.32	-1.80
P40 delta AEP [%]	-0.84	-1.18	-1.25	-1.29	-1.32	-1.34	-1.52	-1.95

Simultaneously it is obvious, that the impact of blade erosion on AEP is more significant for lower average wind speeds. This is evident from the larger AEP decrease due to blade erosion for the P400 and P40 blade profiles, as well as the higher AEP decrease for the Clean blade profile, at higher average wind speeds.

The large loss due to erosion for v_{ave}=6 m/s is due to the fact that much of the energy is produced below rated power and that is where erosion has an impact. Erosion has almost no impact at rated power. Smaller losses due to erosion are seen for v_{ave}=10m/s. The higher the TI, the more gain when most of the production is made at low wind speeds because the power increases below 9.5 m/s due to the averaging. The higher the TI, the more loss when most of the production is made at high wind speeds because the power decreases above 9.5 m/s.

Also a trend emerges, suggesting that the comparative effects of blade erosion and turbulence intensity on AEP vary contingent upon the average wind speed and the specific blade profile under consideration. For instance, at an average wind speed of 6 m/s, blade erosion has a larger impact on AEP than turbulence intensity for all blade profiles. At higher wind speeds, turbulence intensity has a more pronounced impact on AEP, particularly evident in the context of the P40 blade profile.

3.3.3 Summary of the effect of TI and erosion on AEP

The investigation into Annual Energy Production encompassed both:

– A specific actual wind climate

– Three artificial wind climates

For the first AEP calculation the AEP variation for the three blade profiles pertaining to a specific climate with a mean wind speed of 9.49 m/s revealed that even minimal simulated erosion, represented by the P400 blade profile, could precipitate a

notable reduction in AEP by 0.82%. As erosion progresses, the AEP decreases further to 1.46% for the coarser P40 sandpaper, relative to a Clean blade. Furthermore, the effect of a blade's roughness on AEP in comparison to the Clean blade profile is substantial.

The second study additionally examined how three different site specific mean average wind speeds (6, 8 and 10 m/s) affected AEP for the three blade profiles. The findings indicate that at lower wind speeds, the AEP variation caused by turbulence intensity in comparison to a Clean blade profile is more important. This result underlines the importance of considering the level of turbulence intensity there is on AEP in wind farm site selection and design considerations. Notably, the findings from the hypothetical scenario with the highest wind speed at 10 m/s corresponded well to the the first AEP calculation for the specific wind climate.

From the study it was observed that alterations in TI invariably influence AEP. Such variability introduces complexities in accurately attributing changes in AEP solely to erosion, as fluctuations in TI could equally account for observed variations.

3.4 Influence of erosion, time averaging and turbulence intensity on power curve

This section examines the influence of time averaging on power output. Simulations were conducted employing a clean blade profile across a spectrum of turbulence intensities. Figure 13 delineates the power as a function of wind speed for different time averaging intervals at a fixed turbulence intensity of 15%. Both the low speed region and knee of the power curve are presented in this segmented example, illustrating the varied impact of time averaging on the power curve across different wind speeds.

Figure 14 presents the percentage change in power relative to the 0.01-second baseline. This figure highlights the deviations in power output across various averaging intervals, especially at lower wind speeds. The 15% TI example underscores the significant reductions in observed power with longer averaging intervals, with smaller time intervals showing lower deviations. Notably, the 1-second interval exhibits a more neutral impact on power deviation across the range of wind speeds.

To further investigate the effect of time averaging on the power curve, the percentage difference in power from the baseline Clean profile power curve 0.01 second time interval was calculated for various time intervals and turbulence intensities. Firstly, Figure 15 shows the results for a fixed wind speed of 7 m/s, situated in the low speed region of the power curve. The data reveal a trend of power reduction with increasing turbulence intensity, with larger time intervals resulting in greater percentage decreases in power. However, the 1 second time interval shows only a marginal effect.

Contrasting, in second place Figure 16 shows the results for a fixed wind speed of 11 m/s, situated at the knee of the power curve. In this case, different time intervals exhibited both increasing and decreasing effects on power output, with lower time intervals of 30 and 60 seconds pulling the power curve upward, 1 second and 120 seconds having a more neutral effect and larger time intervals of 300 and 600 seconds pulling the power curve downward. Increasing turbulence intensity has a somewhat linear influence on power change.

In both cases the delta power ratios for longer time intervals are generally higher than those for shorter time intervals. However, the magnitude of the delta power ratios for 7 m/s wind speed appear to be larger than those for 11 m/s wind speed, indicating a potentially larger impact of time intervals on power output for lower wind speeds.
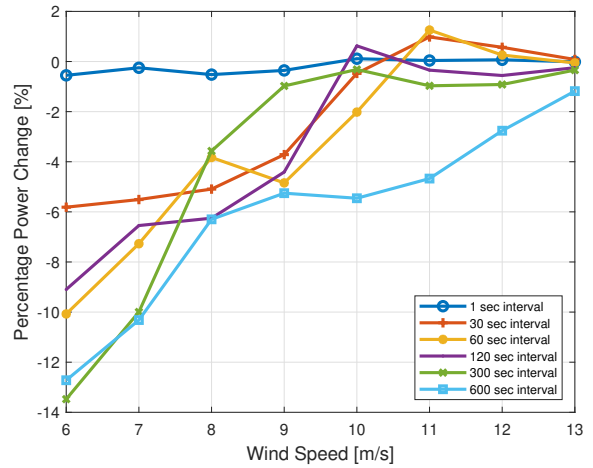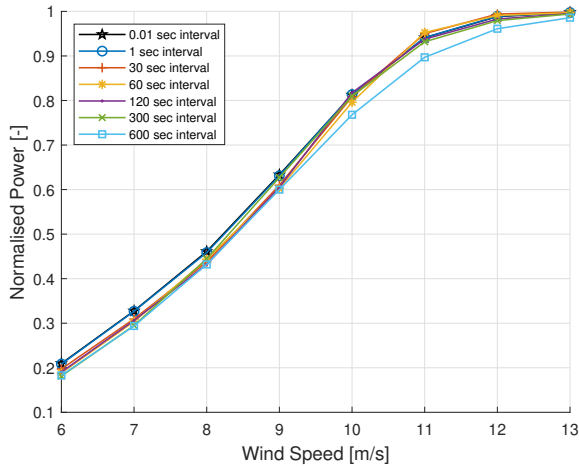
Figure 13. Normalised power as a function of wind speed for a Clean blade profile at various time averaging intervals, highlighting masking effects (TI 15%)

Figure 14. Percentage difference in power as a function of wind speed for a Clean blade profile at various time averaging intervals (TI 15%)
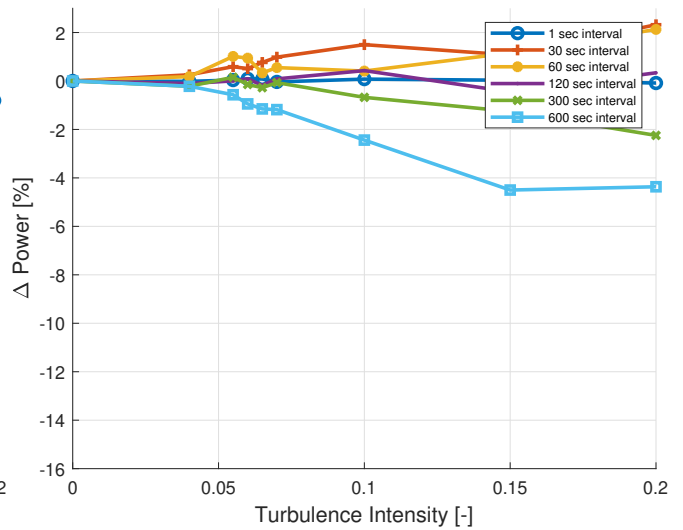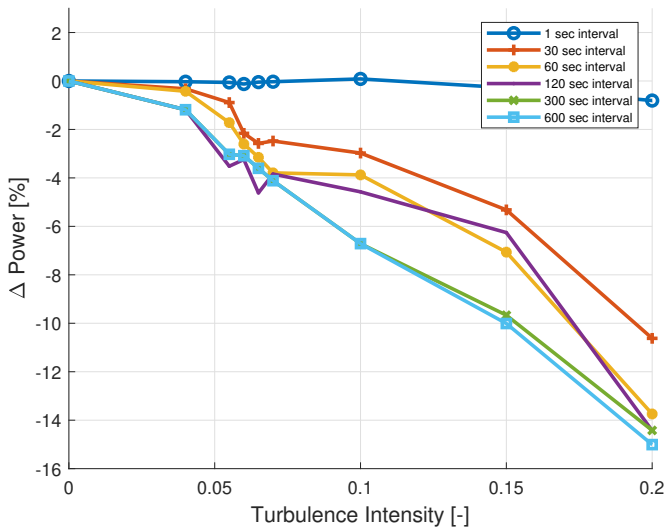
Figure 15. Percentage difference in power from the 0.01 second time interval power value as a function of turbulence intensity at a fixed wind speed of 7 m/s for the Clean blade profile - low speed region of power curve

Figure 16. Percentage difference in power from the 0.01 second time interval power value as a function of turbulence intensity at a fixed wind speed of 11 m/s for the Clean blade profile - knee region of power curve

To further investigate the effect of erosion or roughness combined with time averaging, the percentage difference of a clean and then P40 roughness blade profile in power from the base case of a clean profile power curve with 0.01 second time interval and, in this case at 0% turbulence intensity was calculated for different time intervals and turbulence intensities. This is to provide a comparison between the effects of time interval averaging and blade surface roughness.

Figure 17 and Figure 19 show the results for a fixed wind speed of 7 m/s for the clean and P40 roughness blades, respectively. In contrast, Figure 18 and Figure 20 show the results for a fixed wind speed of 11 m/s for the clean and P40 roughness blades, respectively.

To effectively, correct for the influence of time averaging on power output, it is necessary to consider the time interval employed for data analysis. This requires careful selection of the time interval, since overly short intervals can result in noisy data while overly long intervals can mask important behaviour of the turbine.

Additionally, one may conclude that the effect of time averaging on power output is not uniform and varies depending on the wind speed and turbulence intensity, hence precluding the application of a universal correction to the data. Moreover, it is important to use both a turbine simulation model and meteorological mast data, for accurate TI measurements, to correct for influence of time interval averaging.

3.4.1 Summary of the influence of Time Averaging on Power Curve

In light of the investigation into time averaging effects on power analysis, it becomes evident that the choice of time interval for data analysis can significantly impact the resulting power curve. This accentuates the importance of careful time interval selection for data analysis. The simulation outcomes revealed that larger time intervals, in general, precipitate in a more pronounced decrease in power output with increasing turbulence intensity. The impact of time averaging on power output, however, is not always clear-cut and is contingent upon the wind turbine's operational conditions. At lower wind speeds, situated in the low speed region of the power curve, larger time intervals result in a more pronounced decrease in power output. Conversely, at higher wind speeds, situated at the knee of the power curve, lower timer intervals can result in an increase in power output, while larger time intervals can lead to a decrease in power output. Notably, a 1-second time interval maintained a neutral effect on power across all turbulence intensities.

When comparing the P40 roughness blade to a clean blade at 0% turbulence intensity, the findings demonstrated that the impact of blade surface roughness on power output is less pronounced than the effect of time averaging, with roughness causing a lower reduction in power output. However, the confluence of time averaging and blade roughness can have a significant impact on the power curve. It is vital to consider both factors carefully while analysing power output data.

Time interval averaging impacts the ability to identify or detect changes in wind turbine performance due to subtle modifications of aerodynamic efficiency, potentially arising from phenomena such as blade erosion. This is because changes that occur on a shorted time scale can be harder to detect because time interval averaging can smooth out short-term fluctuations in the turbine's response to changes in wind speed and other variables.

To mitigate this issue, consider selecting an averaging time period that is shorter and better suited to capturing transient variations in turbine performance. While shorter time intervals may produce noisier data that is more challenging to analyse, this
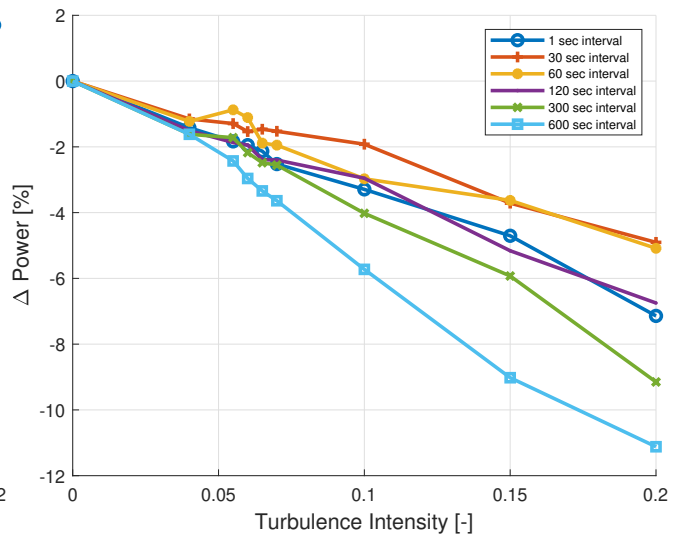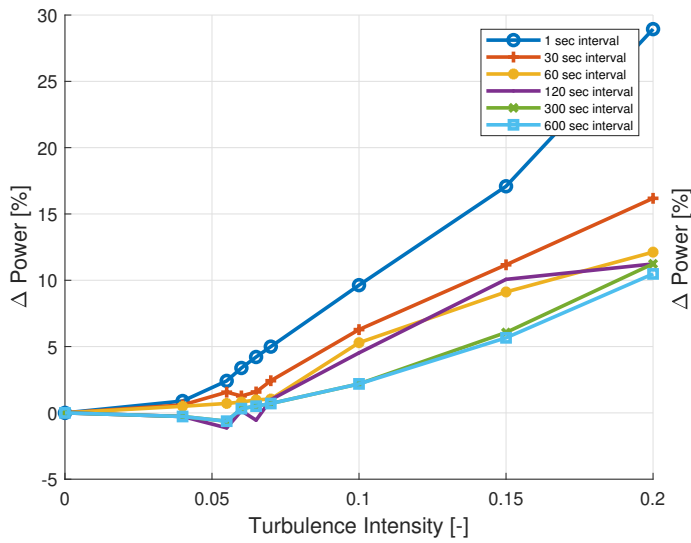
Figure 17. Percentage difference in power from the 0.01 second time interval power value as a function of turbulence intensity at a fixed wind speed of 7 m/s for the Clean blade profile compared to the Clean profile at 0% turbulence intensity

Figure 18. Percentage difference in power from the 0.01 second time interval power value as a function of turbulence intensity at a fixed wind speed of 11 m/s for the Clean blade profile compared to the Clean profile at 0% turbulence intensity
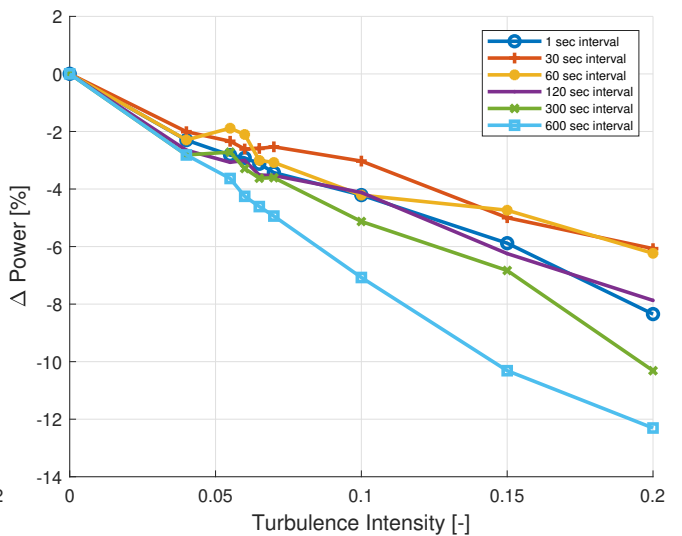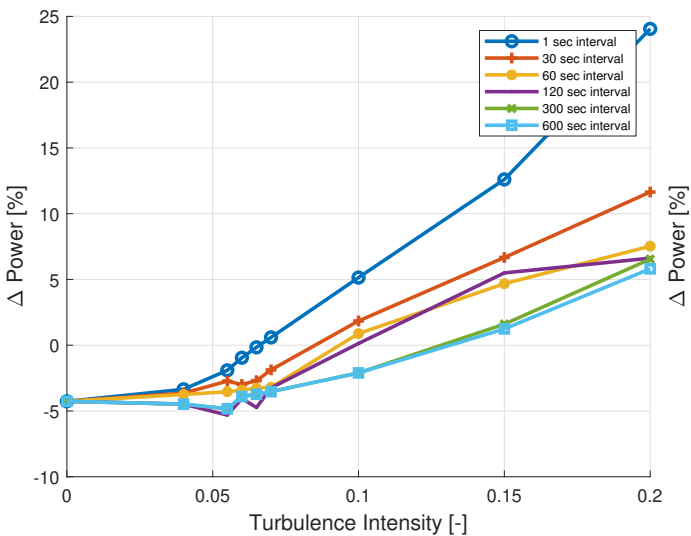
Figure 19. Percentage difference in power from the 0.01 second time interval power value as a function of turbulence intensity at a fixed wind speed of 7 m/s for the P40 roughness blade profile compared to the Clean blade profile at 0% turbulence intensity

Figure 20. Percentage difference in power from the 0.01 second time interval power value as a function of turbulence intensity at a fixed wind speed of 11 m/s for the P40 roughness blade profile compared to the Clean blade profile at 0% turbulence intensity

trade-off between the degree of analysis detail and data noise is often necessary. The study discerned minimal information loss with 1 second values. In general, shorter time averaging periods led to smaller losses. Since this study is based on simulations there is a good control of the signals. Nonetheless, applying short time averaging periods to measured data presents additional challenges due to the greater uncertainties inherent in real-world measurements.

It may be argued that the standard deviation of average values can compensate for the effect of time interval averaging. Indeed, the standard deviation can provide a partial offset. By calculating the standard deviation of the averaged data, it is possible to estimate the degree of short-term variability that has been lost due to the averaging process. The impacts of time interval averaging, however, are not entirely offset by the average values' standard deviation. A significant portion of the sensor response may be lost if the time interval used for averaging is much greater than the typical response time of the sensors and this loss cannot be compensated for by calculating the standard deviation of the averaged data.

Therefore, to ensure accurate and meaningful analysis of wind turbine performance, it is still important to choose an appropriate time interval for averaging sensor data. Even though the standard deviation of the average values can partially compensate for the effect of time interval averaging on the accuracy of the data.

3.5   Influence of other factors

Although the current investigation demonstrates the significant impact of blade surface roughness, turbulence intensity and time interval averaging on wind turbine power output, it is imperative to acknowledge that additional variables also play crucial roles. Among these, atmospheric conditions including shear, that has briefly been demonstrated in this paper to significantly influence the performance, but also temperature, veer, climate change as well as mechanical factors such as, component wear, yaw misalignment, pitch system reliability, ageing, operations and maintenance events and increased friction in the drive train, significantly influence turbine performance. Moreover, reliable measures of wind speed, necessitating regular calibration of wind speed sensor based on turbine output or updates in turbine control software, along with the effects wind speed binning, are pivotal in evaluating turbine performance accurately. Furthermore, the control of the wind turbine such as generator speed and pitch as a function of wind speed or power, potentially influence the outcomes of such analyses.

However, these aspects were outside the purview of the present study, they warrant further exploration to achieve a comprehensively understanding of their individual and combined impacts on turbine power output. Future research should prioritise a holistic approach, systematically investigating the complex interplay between these factors and their implications for the long-term efficiency and sustainability of wind turbines.

4   Conclusion

This study examines the power and energy losses of multi-megawatt wind turbines caused by erosion-induced degradation of blade leading edges and thereby the aerodynamics. A significant aspect of this work is the use of time-dependent aeroelastic computations to investigate the feasibility of observing the power degradation in real-world measurements. To achieve this, not

only were the aerodynamic characteristics degraded, but the influence of turbulence intensity and the time-period for averaging data were investigating due to their suspected influence on the analysis.

The investigation reveals that blade roughness significantly affects wind turbine performance; however, it also demonstrates that turbulence intensity significantly masks this degradation. Based on 10-minute averaging data the impact of turbulence intensity on the power is significant, especially in the partial load region, whereas the impact of blade erosion in this region was less pronounced. Notably, blade roughness can significantly affect power production, particularly at wind speeds between 9 and 13 m/s, i.e. in the transition between the partial load region and rated power.

The study of the power coefficient underscored the critically of considering both blade roughness and turbulence intensity when assessing wind turbine performance. It appeared that turbulence intensities greater than approximately 10% make the analysis very challenging. The analysis to determine the power coefficients and encountering values exceeding the Betz limit illustrates this challenge. Findings of the AEP analysis revealed, for a given site, that even mild simulated erosion can reduce AEP by 0.82% at 6% TI, while more severe erosion leads to a 1.46% decrease. Additionally, the study underscores the variable impacts of erosion and turbulence intensity across different wind climates. In climates characterised by lower average wind speeds, the effects of erosion and turbulence intensity on AEP are accentuated compared to those in wind climates with a higher average wind speed. A key finding from this analysis is that turbulence intensities exceeding 10% may introduce significant uncertainties in power performance analysis. Therefore, when feasible, it is recommended to filter out such high turbulence intensity data to ensure more reliable assessment of wind turbine performance.

Furthermore, the exploration of time averaging's influence on power output through simulations across different turbulence intensities and time intervals provides additional insights. The findings indicated that larger time averaging intervals generally result in greater percentage decreases in power and that rising turbulence intensity show a decrease in power at 7 m/s wind speed. At the 'knee' of the power curve, at 11 m/s, smaller time intervals of 30 and 60 seconds elevated the power curve, where shorter time intervals of 1 second and 120 seconds having a more neutral effect. Longer time intervals of 300 and 600 seconds lowered the power curve. Thus, at 11 m/s, different time intervals can have both increasing and decreasing effects on power output. This analysis showed that 10-minutes (600 seconds) average time periods resulted in values significantly different from those based on smaller average time periods. Notably, analysis based on 1-second time periods seems to be neutral to turbulence intensities. Thus, this study indicates that using short time periods results in less influence from turbulence intensity when analysing measurement data.

This study enables more accurate identification of degradation in operational wind turbine measurement data, however it is important to acknowledge that many uncertainties still exist. Future research should broaden the scope to investigate how leading edge roughness, turbulence intensity, wind shear, yaw misalignment and other factors such as operations and maintenance events collectively influence annual energy production. This research should focus on the long-term implications of these combined effects and could lead to the development of optimised maintenance and operational performance monitoring strategies.

Author contributions. Tahir H. Malik was the primary researcher, responsible for the conception of the study, all experimental work, data collection and analysis and the drafting of the manuscript. Christian Bak, as the PhD supervisor, provided oversight, theoretical support and guidance in refining the research methodology and helped shape the direction of the work.

470 *Competing interests.* The author Tahir H. Malik has received his PhD funding and is employed by Vattenfall.

Acknowledgements. We gratefully acknowledge the support of Vattenfall, particularly for financing this study and providing access to vital wind turbine resources. We acknowledge the use of AI language model by OpenAI (2023) for refining the manuscript.

References

Abolude, A. T. and Zhou, W.: Assessment and Performance Evaluation of a Wind Turbine Power Output, Energies, 11, https://doi.org/10.3390/en11081992, 2018.

Badihi, H., Zhang, Y., Jiang, B., Pillay, P., and Rakheja, S.: A comprehensive review on signal-based and model-based condition monitoring of wind turbines: Fault diagnosis and lifetime prognosis, Proceedings of the IEEE, 110, 754–806, 2022.

Bak, C., Zahle, F., Bitsche, R., Kim, T., Yde, A., Henriksen, L., Hansen, M., Blasques, J., Gaunaa, M., and Natarajan, A.: The DTU 10-MW Reference Wind Turbine, danish Wind Power Research 2013 ; Conference date: 27-05-2013 Through 28-05-2013, 2013.

Bak, C., Skrzypiński, W., Gaunaa, M., Villanueva, H., Brønnum, N. F., and Kruse, E. K.: Full scale wind turbine test of vortex generators mounted on the entire blade, in: Journal of Physics: Conference Series, vol. 753, p. 022001, IOP Publishing, https://doi.org/10.1088/1742-6596/753/2/022001, 2016.

Bak, C., Forsting, A. M., and Sorensen, N. N.: The influence of leading edge roughness, rotor control and wind climate on the loss in energy production, in: Journal of Physics: Conference Series, vol. 1618, p. 052050, IOP Publishing, https://doi.org/10.1088/1742-6596/1618/5/052050, 2020.

Bak, C., Olsen, A., Forsting, A., Bjerge, M., Handberg, M., and Shkalov, H.: Wind tunnel test of airfoil with erosion and leading edge protection, Journal of Physics: Conference Series, 2507, 2023.

Bak, D., Andersen, P., Madsen Aagaard, H., Gaunaa, M., Fuglsang, P., and Bove, S.: Design and verification of airfoils resistant to surface contamination and turbulence intensity, in: Collection of Technical Papers - AIAA Applied Aerodynamics Conference, pp. AIAA 2008–7050, American Institute of Aeronautics and Astronautics, 26th Applied Aerodynamics Conference ; Conference date: 18-08-2008 Through 21-08-2008, 2008.

Barthelmie, R. J. and Jensen, L.: Evaluation of wind farm efficiency and wind turbine wakes at the Nysted offshore wind farm, Wind Energy, 13, 573–586, 2010.

Cappugi, L., Castorrini, A., Bonfiglioli, A., Minisci, E., and Campobasso, M. S.: Machine learning-enabled prediction of wind turbine energy yield losses due to general blade leading edge erosion, Energy Conversion and Management, 245, 114 567, https://doi.org/https://doi.org/10.1016/j.enconman.2021.114567, 2021.

Castorrini, A., Ortolani, A., and Campobasso, M. S.: Assessing the progression of wind turbine energy yield losses due to blade erosion by resolving damage geometries from lab tests and field observations, Renewable Energy, 218, 119 256, https://doi.org/https://doi.org/10.1016/j.renene.2023.119256, 2023.

Ding, Y., Barber, S., and Hammer, F.: Data-Driven wind turbine performance assessment and quantification using SCADA data and field measurements, Frontiers in Energy Research, 10, 1050 342, 2022.

Do, M.-T. and Berthaut-Gerentes, J.: Optimal time step of SCADA data for the power curve of wind turbine, Journal of Physics: Conference Series, 1102, 012 025, https://doi.org/10.1088/1742-6596/1102/1/012025, 2018.

Ehrmann, R. S., Wilcox, B., White, E. B., and Maniaci, D. C.: Effect of surface roughness on wind turbine performance, Tech. rep., Sandia National Lab.(SNL-NM), Albuquerque, NM (United States), 2017.

Elliott, D. and Infield, D.: An assessment of the impact of reduced averaging time on small wind turbine power curves, energy capture predictions and turbulence intensity measurements, Wind Energy, 17, 337–342, https://doi.org/https://doi.org/10.1002/we.1579.

EMD International A/S: WindPRO Software for Wind Energy Analysis, https://www.emd.dk/windpro/, accessed: 2023-06-01, 2023.

Gaudern, N.: A practical study of the aerodynamic impact of wind turbine blade leading edge erosion, in: Journal of Physics: Conference
Series, vol. 524, p. 012031, IOP Publishing, 2014.

Gonzalez, E., Stephen, B., Infield, D., and Melero, J. J.: On the use of high-frequency SCADA data for improved wind turbine performance
monitoring, Journal of Physics: Conference Series, 926, 012 009, https://doi.org/10.1088/1742-6596/926/1/012009, 2017.

Gonzalez, E., Stephen, B., Infield, D., and Melero, J. J.: Using high-frequency SCADA data for wind turbine performance monitoring: A
sensitivity study, Renewable energy, 131, 841–853, 2019.

Han, W., Kim, J., and Kim, B.: Effects of contamination and erosion at the leading edge of blade tip airfoils on the annual energy production
of wind turbines, Renewable energy, 115, 817–823, 2018.

Hansen, M. O.: Aerodynamics of wind turbines. Earthscan, James & James, 8, 14, 2008.

International Electrotechnical Commission (IEC): Wind turbines - Part 1: Wind turbine generators - General requirements, Tech. rep., Geneva,
Switzerland, 2019.

Jonkman, J., Butterfield, S., Musial, W., and Scott, G.: Definition of a 5-MW Reference Wind Turbine for Offshore System Development,
https://doi.org/10.2172/947422, 2009.

Kim, D.-Y., Kim, Y.-H., and Kim, B.-S.: Changes in wind turbine power characteristics and annual energy production due to atmospheric
stability, turbulence intensity, and wind shear, Energy, 214, 119 051, https://doi.org/https://doi.org/10.1016/j.energy.2020.119051, 2021.

Krog Kruse, E., Bak, C., and Olsen, A. S.: Wind tunnel experiments on a NACA 633-418 airfoil with different types of leading edge
roughness, Wind Energy, 24, 1263–1274, 2021.

Kruse, E.: A Method for Quantifying Wind Turbine Leading Edge Roughness and its Influence on Energy Production: LER2AEP, Phd, DTU
Wind Energy, Roskilde, Denmark, (DTU Wind Energy PhD), 2019.

Larsen, T. J. and Hansen, A. M.: How 2 HAWC2, the user's manual, Risø National Laboratory, 2007.

Maniaci, D., White, E., Wilcox, B., Langel, C., van Dam, C., and Paquette, J.: Experimental Measurement and CFD Model Development of
Thick Wind Turbine Airfoils with Leading Edge Erosion, in: Journal of Physics: Conference Series, vol. 753, p. 022013, IOP Publishing,
https://doi.org/10.1088/1742-6596/1618/5/052050, 2016.

Mann, J.: The spatial structure of neutral atmospheric surface-layer turbulence, Journal of fluid mechanics, 273, 141–168, 1994.

OpenAI: ChatGPT: Optimizing Language Models for Dialogue, https://openai.com/chatgpt/, 2023.

Saint-Drenan, Y.-M., Besseau, R., Jansen, M., Staffell, I., Troccoli, A., Dubus, L., Schmidt, J., Gruber, K., Simões, S. G., and Heier, S.: A
parametric model for wind turbine power curves incorporating environmental conditions, Renewable Energy, 157, 754–768, 2020.

Skrzypinski, W., Gaunaa, M., and Bak, C.: The Effect of Mounting Vortex Generators on the DTU 10MW Reference Wind Turbine Blade,
vol. 524, IOP Publishing, ISSN 1742-6596, https://doi.org/10.1088/1742-6596/524/1/012034, content from this work may be used under
the terms of the Creative Commons Attribution 3.0 licence. Any further distribution of this work must maintain attribution to the author(s)
and the title of the work, journal citation and DOI. Published under licence by IOP Publishing Ltd; 5th International Conference on The
Science of Making Torque from Wind 2014, TORQUE 2014 ; Conference date: 10-06-2014 Through 20-06-2014, 2014.

St. Martin, C. M., Lundquist, J. K., Clifton, A., Poulos, G. S., and Schreck, S. J.: Wind turbine power production and annual energy production
depend on atmospheric stability and turbulence, Wind Energy Science, 1, 221–236, https://doi.org/10.5194/wes-1-221-2016, 2016.

Wagner, R., Courtney, M., Larsen, T. J., and Paulsen, U. S.: Simulation of shear and turbulence impact on wind turbine performance,
Danmarks Tekniske Universitet, Risø Nationallaboratoriet for Bæredygtig Energi, 2010.

Wharton, S. and Lundquist, J. K.: Atmospheric stability affects wind turbine power collection, Environmental Research Letters, 7, 014 005,
https://doi.org/10.1088/1748-9326/7/1/014005, 2012.

Yang, W., Tavner, P. J., Crabtree, C. J., Feng, Y., and Qiu, Y.: Wind turbine condition monitoring: technical and commercial challenges, Wind Energy, 17, 673–693, 2014.