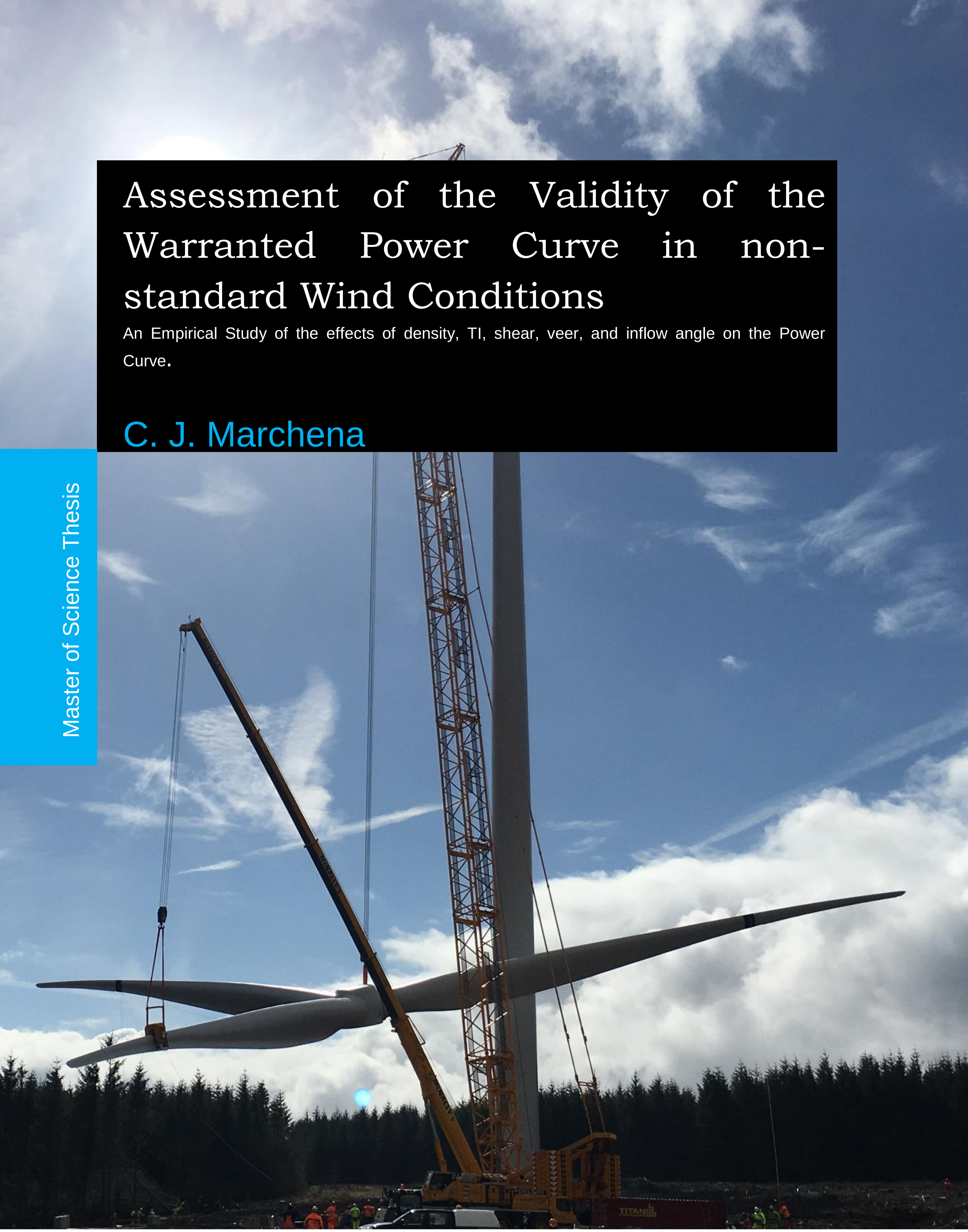

Assessment of the Validity of the Warranted Power Curve in non-standard Wind Conditions

An Empirical Study of the effects of density, TI, shear, veer, and inflow angle on the Power Curve.

C. J. Marchena

Master of Science Thesis

Delft University of Technology

Faculty of Aerospace Engineering (AE)

Challenge the future

Cover photo: Wind Park XYZ – First Turbine Installed - © Vattenfall.

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An Empirical Study of the effects of density, turbulence intensity, wind shear, wind veer, and inflow angle on the Power Curve.

By

C.J. Marchena

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Delft University Of Technology
Department Of
Wind Energy

The undersigned hereby certify that they have read and recommend to the Faculty of Aerospace Engineering for acceptance a thesis entitled "Assessment of the Validity of the Warranted Power Curve in non-standard Wind Conditions" by **C. Marchena** in partial fulfillment of the requirements for the degree of **Master of Science**.

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Disclaimer

Some parties and identifying details have been modified to ensure confidentiality in the research.

Abstract

This research aims to investigate the validity of the standard power curve (i.e. measured power curve M-PC) in non-standard wind conditions and the integration of those results into recommended practices for future warranty negotiations. The Power Performance Testing (PPT) is carried out on a ABC1 with rotor diameter between 105-110m and rated power between 3-3.5MW at a hub height 89-92m for two scenarios: i) PPT based on the IEC 61400-12-1:2005 standard (International Electrotechnical Commission - 2005) [1], where the terrain complexity (elevation differences, forestry, etc.) results in requirement for site calibration, and ii) PPT based on non-standard wind conditions.

The onshore wind farm considered in this study is the XYZ in UK. Five locations within the wind farm were studied: WTG1, WTG2, WTG3, WTG4, and WTG5. Each location had one met-mast pair, one being the reference position met-mast (RM) and the other being a temporary mast located where the wind turbine will be installed, called site calibration mast (SM). Three months of data from 10 met-mats were obtained from the site calibration test. The result of the site calibration is a table of flow correction factors for all wind directions in the measurement sector. The data collected allowed as well, a detailed analysis of the influence of air density, turbulence intensity (TI), wind shear, wind veer, and inflow angle as the main site parameters. These factors influence the wind turbine power performance.

For the air density, constant values were measured in the wind farm despite the distance between locations and particular characteristics of the complex terrain. Due to the complexity of the terrain, high TI and wind shear was found. As expected, high TI is observed at low wind speeds. The wind shear exponent shows a mean higher value during the night hours. During the night, the surface area cools down which enables stable conditions. When the stable boundary layer is lower than the met-mast, then the wind regimen at the upper measuring level (hub height) decouples from the regime at the lower measuring level. This inversion layer discourages vertical air movement but allows two different wind regimes to coexist, leading to a higher wind shear during the night. As well, relatively high wind veer was found. Meanwhile, the inflow angles showed to be small in all locations (i.e. WTG1, WTG2, WTG3, WTG4, and WTG5).

For site calibration results, there is a visible tendency for all sites (i.e. WTG1, WTG2, WTG3, WTG4, and WTG5). As expected, the slope between the wind speed RM and wind speed SM is approximately 1. In addition, a high R^2 ($R^2 \geq 0.96$) is observed for all valid bins in all locations, indicating a good relationship between RM wind speed and SM wind speed. The effects of the filters presented a significant reduction on the data available for the site calibration; an average of 21% of the original data remained available after the filters. Finally, the site calibration could not be avoided from a contract perspective, but the benefits of the site calibration are unseen. This is because the wind speed with site calibration always lies within the wind speed uncertainty of the wind speed without site calibration, implying that both values are correct.

After the site calibration is completed, the SM are removed, the wind turbines are installed and the PPT takes place. For the PPT, an additional three months of data was collected and only two locations were studied (i.e. WTG4 and WTG5), corresponding to ABC1. Here, there was a significant reduction of datasets due to the filters, leaving less than 20% of the available data to perform the study. The measured power curve (PC) is valid only from 4 -16 m/s due to the site calibration and a correction of the air density was not necessary. The warranted power curve is higher than the measured power curve (WTG4 PC and WTG5 PC combined). Consequently, the Warranted Annual Energy Production (W-AEP) 11.3 GWh is higher than the Measured Annual Energy Production (M-AEP) 11.2 ± 0.2 GWh. Nevertheless, due to the uncertainty calculated, the W-AEP is within the M-AEP acceptable range.

For the non-standard power curve, air density, turbulence intensity, wind shear, wind veer, and inflow angle are treated separately. However, it is likely that these factors are not independent of each other. No additional filters are considered necessary, excluding the filter for the free wind sector. Instead, a normalization of the wind conditions has shown to be ascertained for a ‘site specific’ power curve. Corrections with respect to air density, turbulence intensity and wind shear were studied. The results of analyzing air density show that the power expected is lower when the wind speed is normalized to a reference density that is lower than the measured air density. The turbulence intensity shows that the power expected is slightly lower from the TI correction. The overall reduction on the AEP of 2% and 4% are obtained for air density and TI normalization respectively, compared to the M-AEP without corrections. Meanwhile, the wind shear correction led to a higher power, showing an overall increase of approximately 3% in the AEP, compared to the M-AEP without correction. The effects of wind veer and inflow angle were less clear in the power curve, hampered by a lack of data above hub height. Even though that all wind conditions are treated separately, it may be expected that these factors are correlated.

To conclude, it was shown that the main drivers influencing the power curve results, and consequently M-AEP are: air density, turbulence intensity and wind shear. Normalization of these wind conditions (instead of filters) is a recommended practice that can be utilized for future power curve warranty negotiations as well as different warranted power curves for different wind conditions.

Keywords: Power Performance Test, Wind Conditions, Wind Speed, Air Density, Turbulence Intensity, Wind Shear, Wind Veer, Wind Turbines, Inflow Angle, Power Curve, Complex Terrain, IEC 61400-12-1, Supplier Warranties, Contract.

Preface

Nine months ago, I found myself reminiscing about my lectures at the university and enthusiastically looking forward to this new adventure, this compulsory adventure called Master Thesis. While reflecting on the experience of writing my final project, I realized that this has not only value as a TU Delft research thesis but goes beyond that. This thesis targets everyone who has an interested in sharpening their skills and knowledge in power curve verification of wind turbines.

I can now look back and realize that this experience has enhanced my commitment to long projects. I would therefore firstly like to thank my head supervisor W. Bierbooms, who has not only been there to give me valuable and constant input but likewise playing an important part in the 2nd year of my master program. The year when I became a TU Delft student as well.

Furthermore, I would like to thank the alliance created during my studies, my peers from "*Unidos venceremos* (united we stand)" for their big help and support when I needed the most.

My overall experience has been extremely positive. For this, I have to thank Vattenfall as a team. Especially my supervisor J. Coelingh for giving me the opportunity to do my graduation internship in the company and S. Koutoulakos for being my unofficial mentor in this project. I would like to extend my gratitude to all my colleagues from Wind & Site for giving me answers and for making me part of the team from Day 1.

Finally, I would like to thank my family and friends for being always supportive during my studies.

C.J. Marchena
Amsterdam, April 2017

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Chapter 1

Introduction

Every energy company whether profit making or non-profit making has specific requirements when purchasing equipment and services. Procurement rules exist for all new onshore wind farms in European countries. These rules aim at encouraging true and open competition in tendering and contract awarding [2].

As part of the preparation work and before a tender is advertised, the buyer (e.g. Vattenfall) is required to create a business case. The business case includes a technical evaluation and a financial assessment. The realistic estimate of the cost of the project must remain strictly confidential and there should be no relation between stakeholders having this knowledge and the bidders.

When the tender is open, the suppliers have the opportunity to submit their proposal (bidding process). One of the requirements is to provide a detailed description of the wind turbine. For this, and unless otherwise requested by the buyer, a supplier provides a standard power curve as a reference, which is warranted for the specific project. The warranted power curve of a turbine can be validated under a very specific methodology as described in the contract and is mostly based on the IEC 61400-12-1:2005 standard. This standard is broadly accepted and base of almost any power curve warranty of the past years [3].

Subsequently, an evaluation is made by the buyer (e.g. Vattenfall). The bids received are analyzed and questions should be raised on the validity of the bids if it varies greatly from the estimate [2]. For this, decision-making criteria at all stages must be clear, admissible and objective, especially in the assessment and comparison of the bids.

Once the final ranking has been established, the supplier with the highest total is awarded the tender. In this project, ABC was selected as the supplier with the highest ranking. Then, the final negotiation process starts. Particular attention is paid to the Annual Energy Production (AEP) variations, since AEP is fundamental parameter influencing the profitability of a project. A major concern for the AEP are the power curve warranties. Due to their dependency on a variety of environmental conditions they bear a high level of uncertainty.

The IEC 61400-12-1:2005 standard describes a general measurement methodology for testing a power curve, but it does not (and cannot due to the unique site issues) cover adequately all possible sites. In most of the cases, an agreement on site specific topics between buyer and supplier are made, defining individual measurement conditions of additional requirements in the warranty. The additional requirements are addressed in this research (e.g. for XYZ, “Vattenfall PC Warranty Specification for Power Curve Measurement Procedure”). After the agreement between the two parties is established, the contract is settled. Continuous monitoring and auditing are required to supervise the contract and in order to ensure compliance and to cost-effectiveness [2]. This can be carried out by the buyer, government agencies or a third-party consultant.

The IEC 61400-12-1:2005 standard [1] exhibits some gaps, namely regarding the standard wind conditions categorization. For this reason, wind turbine warranties of many turbine supplies became subject to increasing limitations over recent years [4].The influence of the outside standard wind conditions is not considered by default and commonly filtered in the supplier power curve. Which often leads to a warranted power curve not covering the most frequently conditions expected at the wind farm site [4].

Therefore, depending on the site, the warranted range could be limited to less than 10% of the complete measured data [5]. In reality, the wind turbines are mostly operating outside this window, in outside standard range-conditions. Therefore, it remains unclear how different wind conditions affect the real power performance. Now, there is a need for transparency on the warranted power curve since the standards do not cover all the site-specific conditions. For this reason, this research intends to deal in detail with warranties and power curve parameters simultaneously.

1-1 Previous Work

Considerable attention has been given to wind conditions in the last years and many studies have agreed that the real-world power production diverges from the one expected due to non-standard conditions. These observations come from both measurements and simulations. Most attention has been given to uncertainties related to the AEP, others have focused critically on the power curve and on the standard deviation of the power. However, the connection between real wind conditions and power production remains unclear.

The literature that links warranty and power curve is noteworthy but limited, in comparison with the literature on these two topics in separate. Reviewing previous research papers on both warranty and power curves, reveals a gap integrating both topics. The following section provides an overview of the three papers found on the topic between 2001 and 2016.

Title | Author: *Power Consistency Warranty: Closing the Gap between Availability and Power Curve Warranty* **|** A. Albers (Deutsche WindGuard GmbH).
Overview: Production losses are not always covered by availability warranties or power curve warranties. Albers [6] proposes a new type of warranty (called: "Power Consistency Warranty") in the frame of advice and negotiations. He proposed an optimal criterion where the combined losses due to extraordinary power reduction and turbine unavailability should not exceed a certain value. Consequently, compensation rules should be applied. Albers claims that the "Power Consistency Warranty" closes the gap between availability and power curves warranties.
Remark: The generalization of Albers' criteria leads to not accounting for the source of the losses in production. Moreover, for complex systems, as wind turbines are, the losses sources could be very different. A realistic modeling would require grouping the causes into different categories based on wind site conditions and the wind turbine, which implies modeling and analyzing at the cause level rather than a global level.

Title | Author: *Whole Wind Farm Warranty Verification Procedure* **|** J. Matos et al.(INEGI).
Overview: Matos et al. [7] analyze the features that may affect the wind farm behavior in a complex topography. They proposed an alternative scheme (called "Whole Wind Farm Warranty" - WWFW) for power curve and availability performance verification. The WWFW verification aims to determine the difference between the wind farm's Annual Measured Energy, and the Warranted Energy. The production differential should result in monetary compensation. They concluded that the methodology is feasible but with limitations especially when predicting wind speed at each turbine.
Remark: The study on the whole wind farm warranties consider the effect of warranties on the Annual Energy Production. However, in practice, wind farms are also influenced by external factors like wind turbine failures, grid unavailability, scheduled maintenance, among others. In other words, WWFW

verification may be influenced by many other several external aspects on a single turbine level that could complicate the model.

Title | Author: *Development of Power Curve Measurement Standards* | H. Mellinghoff (DEWI GmbH).
Overview: A good reference for optimizing the power curve reference standard is the Mellinghoff research [5] He developed a general overview of the major warranty conditions observed in sales contracts of wind turbines. In addition, an analysis of the IEC 61400-12-1:2012 draft is assessed. Topics as turbulence filters, wind shear filters, limitation of titled inflow and site calibrations are addressed. He concluded that the demands to take site effects more into account are reflected by the recent warranty formulation, and those requirements are being reviewed by the IEC standards.
Remark: Due to the significance of the IEC standards in warranty applications, Mellinghoff proposes a good starting point to evaluate different wind conditions that are compiled in his study. This overview allows considering external IEC practices for future studies.

1.2 Research Question

To support the further integration of the impact of wind conditions into the power curve warranty, this project focuses on Power Performance Testing (PPT). Therefore, the following research question is proposed:

Main research question
Does the inclusion of non-standard wind conditions in the power curve warranty result in better prediction of turbine performance in real conditions?

1-3 Objectives

This study is part of the XYZ Wind Energy Project. The aim of this study is to assess the validity of the Warranted Power Curve in non-standard wind conditions (i.e. turbulence intensity, wind shear, wind veer, and inflow angle). Therefore, to ensure alignment with all known theoretical, technical and operational requirements a list of deliverables is presented below.

- ✓ Analysis of the measurements to verify the validity of the warranted power curve (ABC1).
- ✓ Analysis of the AEP based in the standard and outside standard PC results, observing their differences, and propose recommendations to account for them.
- ✓ Practical aspects of power curves warranties and a proposal to include recommended practices for future contracts (related to power curve warranty).

The contract warranty analysis of this project is focused on power performance test of individual turbines. As part of the agreement between Vattenfall-ABC, the verification will be based on IEC 61400-12-1:2005 standard. However, the IEC 61400-12-1:2005 standard do not describe how the turbine performs outside the window that the power curve is valid for. For this reason, the warranted Power Performance Testing (PPT) is extended to the outside standard wind conditions, data which are normally filtered out and not considered, in order to assess the *actual* power curve, and its implications in the warranty.

1-4 Thesis Overview

In this chapter, a review of other non-standard power curves studies and contracts relevant for the current study has been presented. Chapter two presents the theoretical background of the Power Curve (PC) and the status of warranty contracts. Chapter three summarizes the IEC 61400-12-1:2005 standard for power performance measurement. Chapter four gives a description of the site, including the layout, measurement system, the topographic data, and the XYZ measuring campaign. A Site Calibration of the site is presented in Chapter five. Chapter six includes the measurement setup and

PC analysis following the IEC 61400-12-1:2005 standard. Chapter seven contains an individual study of non-standard conditions of the PC. Chapter eight explains the warranted power curve limitations in detail and proposes the inclusion of recommended adjustments of the Vattenfall Employer's Requirements. The thesis ends with conclusions and recommendations for further work in Chapter ten.

Chapter 2

Power Curve & Warranty Contracts

Before venturing into the factors that influence the power curve and how these are affecting the warranty contracts, the difference between a warranted power curve and a measured power curve needs to be understood. The **Warranted Power Curve (W-PC)** is provided by the wind turbine manufacturer and it shows the expected power production per wind speed bin. The W-PC is the starting point for selecting a specific turbine for a wind project and is also part of the final contract. Throughout the warranty period (typically 5 years after the takeover of the wind farm by the owner/operator), an accredited power measurement campaign can be performed. The result is the **Measured Power Curve (M-PC)**. The measured power curve proves whether the turbine conforms to the W-PC issued by the turbine manufacturer or not.

This chapter intends to create a broader perspective to look at warranty contracts and power curve in an integrated and unified manner.

2-1 Power Curve

In wind energy industry, the electric power output versus the wind speed, known as **power curve** (PC), is an important indicator of wind turbine performance [8] but it is difficult to predict. The reason that the turbine performance is difficult to predict is because the PC is simplified; it assumes that power depends only on wind speed (and air density) but in reality, a number of parameters influence the power output. Consequently, a measured power curve (M-PC) is to a certain extent a site-specific performance test [9].

Overall, the power performance influencing factors can be classified into two groups; the first group includes factors which modify the energy available in the wind profile across the rotor, and the second group is related to the factors that modify the conversion efficiency of the turbine [10]. The environmental conditions: air density, turbulence intensity, shear, veer, wind direction, fall under the first group. Meanwhile, factors like blade conditions and the control strategy fall under the second group.

2-1-1 Measuring the Power Curve

Measurement of wind turbine power curves is fundamental in the wind industry. Power Performance Testing (PPT) is also known as *power curve test or power curve verification or power curve validation*. It is used to measure turbine's power curve on any location (thus test sites and real projects) and detect under-performances. According to the IEC standards, an accredited third party is responsible for performing this test.

The power curve test methodology is part of the contractual agreement between the turbine supplier and the buyer. Nevertheless, the measurement of the power curve has its own challenges, which is usually addressed with uncertainty analysis. Traditionally, the contracts refer to the IEC standards. Since the IEC standards comprise a detailed description of the procedures, the preparation for performance test, test equipment, measurement procedure, derived results and finally the reporting format. This is discussed further in Chapter 3.

An outline of the test is shown Figure 2-1 and goes as follows: prior to a PPT, a **site assessment** needs to be performed. The results of the site assessment will result in: i) the selection of the wind turbines to be tested, ii) the position of the met-mast for wind measurements and information if site calibration is needed (based on the terrain and obstacle results) and iii) measurement equipment specifications.

The next step is the procurement, delivery and installation of all the wind farm related equipment. In this project, this step is called **procurement and construction**.

The last step is the **Power Performance Testing** (PPT), the validation is done by simultaneously recording 10 min averages of the wind speed and power. The period that these measurements are carried out will depend on the wind conditions, since the criterion of the IEC standards needs to be fulfilled.

Figure 2-1: Steps in the Power Performance Testing

In most cases, the turbine supply agreement will ask for the wind data to be filtered. The data can be filtered on a lower temperature limit (e.g. icing), wind direction and wind speed; all based on the IEC standards. Then, the remaining data is analyzed and processed, the uncertainties are estimated and the measured power curve (M-PC) is created. The data is presented in both, a diagram and in a table. Additional requirements can be found in contracts, where the M-PC goes beyond the IEC standards in terms of wind filters. With this analysis, the actual annual energy production (M-AEP) can be estimated and compared against the W-AEP.

2-1-2 Uncertainty in Measurements

A **measurement** is a quantification of a dimension, represented as a number and standardized units. Only when a measurement is brought into scientific context, then the measurement results become scientifically relevant. The result of any quantitative measurement has two components [11]:

- A numerical value which gives the best estimate of the quantity being measured (the measurand). This estimate may be a single measurement or the mean value of a series of measurements.
- A measure of the uncertainty associated with this estimated value.

According to Richard Feynman (Physics Nobel Prize winner in 1965), modern science is characterized by uncertainty. He stated that “Scientific knowledge is a body of statements of varying degree of certainty – some most unsure, some nearly sure, but none absolutely certain" [12]. Uncertainty is a statistical measure of data quality and it shows how the numerical value fits the (unknown) true value. This uncertainty assessment is required in order to decide if the result is adequate for its intended purpose and to determine if it is reliable with other similar or previous results.

An exact number has no uncertainty. Therefore, defined values (e.g. 1kg=1000g) and numbers obtained by counting do not have an uncertainty associated. Nevertheless, inexact numbers have uncertainties (uncertainty is indicated by the symbol ±). For example, if a mass is given as a result of weighing, m = 10.000 ± 0.005 g, and if no additional information is given, this indicates that the "true" mass has to lie between 9.995 g and 10.005 g. **Uncertainty** is the range of possible values within which the "true" value of the measurement lies. All scientifically relevant quantities must be assigned an uncertainty. This applies to all results of parameters out of modeling, not only measurement values.

The distinction between uncertainties and **deviations** needs to be pointed out. In deviations (not to be confused with standard deviation) the sign and its magnitude are known. This is referred as an error but it is not an uncertainty. For this, the data value needs to be corrected and for that deviation consequently, no sign of deviation remains on the "true" value. For example, using the same yardstick to measure the length will deteriorate with time, resulting in a deviation for all measurements done with it afterward [12]. The measured results will not be correct (i.e. too short), provided that the correction of the linear dimension loss of the yardstick has not been accounted for. This deviation is known and it should be corrected before considering the uncertainties of the measurement. In this project, the terms error will be avoided to make this misconception less likely. It is assumed that all the data obtained is free from deviations.

To preserve measurement uncertainty during calculations, it is important to recall the concept of significant figures and how to maintain them during mathematical operations. Significant figures are the meaningful digits in a reported number. The number 15.01, for instance, has four valid digits, 10.5 has only three. For this, rounding numbers is indispensable to write a quantitative measurement correctly. If the digit is less than 5, then it is rounded down (equivalent to truncating), and numbers 5 or larger are rounded up (i.e., the last remaining digit is incremented by one) [12]. Noteworthy, data is never rounded and it is in the final result where the rounding takes place. Additionally, for mathematical operations with measured numbers the basic rules apply: i) addition and subtraction: the result has the same uncertainty as the original number with the largest uncertainty; ii) multiplication and division: the result has the same number of significant figures as the original number with the smallest number of significant figures.

When repeated measurements are made of the same quantity (e.g. wind speed), statistical procedures can be used to determine the uncertainties in the measurement process. This type of statistical analysis provides uncertainties which are determined from the data itself [13]. The important variables are: the **mean**, the **standard deviation** *(*denoted by σ) and the **standard uncertainty** *(*denoted by u).

Moreover, the measurement result is presented as the mean value of the replicate measurements. In case that a measurement is performed N times with the same instrument, and the values obtained are X_1, X_2,…X_N. Then, the mean value $\overline{X_m}$ is calculated as follows:

$$\overline{X_m} = \frac{X_1 + X_2 + \cdots + X_N}{N} = \frac{\sum_{i=1}^{N} X_i}{N}$$

The dispersion or spread of values obtained from repeated measurements is known as the standard deviation that is calculated as follows:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{N}(X_i - \overline{X_m})^2}{N-1}}$$

If two random variables are considered (e.g. *X* and *Y)*. Then, the degree of correlation (denoted by ρ). needs to be introduced. The degree of correlation gives information on how these variables are statistically related. For correlated variables ρ equals 1, and for uncorrelated variables ρ equals 0. If the variables *X* and *Y* are random variables (assuming a normal distribution), then *X+Y* is still normally distributed and the mean is the sum of the means. However, the variances (i.e. the square of the standard deviation) are not additive due to the correlation. Correlated and uncorrelated measurements affect the result. For this, the sum of independent random variables is shown:

$$\sigma_{X+Y}^2 = \sigma_X^2 + \sigma_Y^2 + 2\rho\sigma_X\sigma_Y$$

If ρ=1 (correlated variables), then:

$$\sigma_{X+Y}^2 = (\sigma_X + \sigma_Y)^2 \qquad (2\text{-}1)$$

If ρ=0 (uncorrelated variables), then:

$$\sigma_{X+Y}^2 = \sigma_X^2 + \sigma_Y^2 \qquad (2\text{-}2)$$

The standard uncertainty is statistically equivalent to a standard deviation [14]. Usually, the following is assumed for the uncertainty in a measured variable (e.g. X): (i) the value X represents the mean of the normal distribution and (ii) the uncertainty in X is the standard deviation of the normal distribution [15]. For this, any operation that is performed on a measurand with an uncertainty will require propagating the variance associated with the measurements.

As an example, for adding (or subtracting) independent variables, consider that the height of a door (H) is measured as H= 2.00±0.03 m. The door has a knob which the height is h =0.80±0.05 m (from bottom to top). Then, the distance from the doorknob to the top of the door is Q = H − h = 1.20 m [16]. The uncertainty in Q can be calculated with Eq. (2-2) for uncorrelated variables (ρ=0).

$$\mathrm{u_Q^2} = (0.03)^2 + (0.05)^2 \longrightarrow \mathrm{u_Q} = 0.06\ [\mathrm{m}]$$

The result is Q= 1.20 ±0.06 m.

Now, consider a different example for dependent variables. The total mass of a loaded truck is known as M= 4500 ± 5 kg. Unfortunately, the poorly secured load fell off. The load was estimated with a mass of m=100 ± 4 kg. The current mass of the truck can be estimated as M’ = M - m = 4400 kg.

Meanwhile, the uncertainty for correlated variables (ρ=1) can be estimated with the Eq. (2-1):

$$\mathrm{u_{M'}^2} = (5+4)^2 \longrightarrow \mathrm{u_{M'}} = 9\ [\mathrm{kg}]$$

Then, the new mass of the truck is M’= 4400 ± 9 kg.

As mentioned before, the term standard uncertainty has the same numerical value and mathematical form as the standard deviation. However, the statistical meaning of standard deviation is not the identical as standard uncertainty [13]. In statistics, there are some cases where the standard deviation does not imply the presence of an uncertainty. For example, the height of individuals of a particular ethnic and gender. Here, the standard deviation only describes the dispersion of the individual’s height and the mean height. Therefore, it would not be correct to associate this situation with an uncertainty.

The uncertainty of wind resource and energy production estimates is a critical element in wind projects. Uncertainties can come from various sources: the calibration of the instrument, environmental conditions, the technician controlling the measurements, the procedure, the models, among others [17]. This thesis deals mainly with uncertainties of measured data. In general, these measurement uncertainties may be divided into two classes: **systematic** and **random**. Systematic uncertainties are correlated uncertainties, with a degree of correlation of $\rho=1$. Meanwhile, random uncertainties are uncorrelated uncertainties, with a degree of correlation of $\rho=0$.

The fact that the same uncertainty can be uncorrelated if it is only one measurement, but correlated (i.e., systematic) if more than one measurement is taken, shows that both types of uncertainties are of the same nature. Because of the great confusion that this might lead to, the IEC standard presents a different categorization.

Following the ISO guide (International Organization for Standardization), the IEC standard describes two types of uncertainties: Category A and Category B, this classification is based on the method for evaluating uncertainty. An uncertainty of **Category A** is based on the statistical analysis of a series of measurements (e.g. variability of electrical power). An uncertainty of **Category B** has been obtained by non-statistical procedures (e.g. signal transmission). The information obtained from Category A and Category B uncertainty evaluations is identical; they are given different names to emphasize that the uncertainty values have been obtained by different procedures. These categories can apply to either random or systematic errors. In both categories, uncertainties are expressed as standard deviation and are denoted as standard uncertainty [18].

The final result of any measurement procedure should have an associated standard uncertainty obtained by combining the Category A and Category B uncertainties. In general, this combination is the root-sum-square of the Category A and Category B standard uncertainties. While Category A uncertainties are evaluated using statistical methods, once this evaluation is complete, the combined uncertainty becomes Category B from the perspective of subsequent users of the results.

The combined standard uncertainties may be additionally expressed as **expanded uncertainty** (denoted by *U)*. The expanded uncertainty is obtained by multiplying the combined standard uncertainty by a coverage factor*.* An interval that is symmetric on both sides of a data value and has a total length of twice the uncertainty is called the 1σ confidence level (one-sigma confidence level, with sigma the symbol for the standard deviation and 1 the coverage factor). The "*true"* value is expected to lie in this interval with a probability of about 68.27% assuming a normal distribution. Unless otherwise indicated, uncertainties are always these probable uncertainties [12]. In addition, confidence levels that are wider by a factor 2 or 3 can also be found. These are called the 2σ confidence level with 95.45% confidence (2 as coverage factor) that the "true" value lies inside it, or the 3σ confidence level with 99.73% confidence (3 as coverage factor) [12].

In engineering, the maximum uncertainty (tolerance) term is used. For example, in a wind turbine drive train, if the nominal diameter of the main shaft and its bearing were subject to a symmetric 68% confidence level, this would result in rejecting around 50% of the parts produced [12]. From the rejected parts, some of them will be too loose and the others too tight. Therefore, the usual confidence level is 99.73% (instead of the 68.27% confidence width usually used in science) in engineering. This means that 3σ is used instead of the 1σ*.*

2-1-3 Wind Turbine Performance Indicators

A wind turbine supplier provides a warranted power curve (W-PC) as a reference. The *actual power curve* will vary from the warranted curve for a variety of reasons. The Power Curve Working Group has identified that the power production of a wind turbine is dependent on wind speed, air density (i.e. a function of temperature, pressure, and humidity), turbulence intensity, vertical wind shear, vertical wind veer, directional variation and inflow angle [19] [20]. In this section, an overview of theory and scientific research is given. Figure 2-2 presents the influence factors on the power production. The following parameters are expected to affect the performance of wind turbines.

Figure 2-2: Wind Turbine performance indicators. Modified by the author from [21]

Wind Speed

Definition: The movement of air mass in the atmosphere is perceived as wind. Moreover, the radiation from the sun is absorbed by the earth's surface and then returned to the atmosphere above. The variability of insolation (i.e. solar radiation that reaches the earth's surface) creates fluctuations of the atmospheric pressure. Therefore, in hot areas, there is high pressure and in cold areas, there is low pressure. These large-scale differences in air pressure cause a compensatory movement, the wind. [22]. Consequently, wind energy is an indirect form of solar energy.

The wind that is moving over the ground is slowed down by friction. The influence of friction decreases with height. In Figure 2-3 a representation of the boundary layer is presented. At greater altitude, the air moving along lines of isobars (i.e. equal pressure) is known as *geostrophic* wind, where the airflow can be considered free of surface influences. The layer between the ground and geostrophic wind is referred to as atmospheric boundary layer or *boundary layer*, which is dependent on the surface friction, surface roughness and vertical distribution of temperature and pressure [22]. In this layer, there is still a strong gradient of wind speed which is leading to momentum exchange and a turbulent mass exchange in the higher atmospheric layers [23].

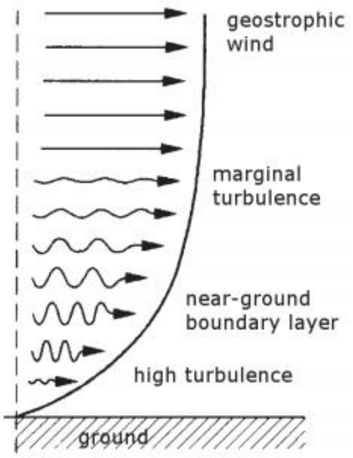

Figure 2-3: Simplified representation of the atmospheric boundary layer. [23]

The height of the boundary layer varies depending on weather conditions. For example, on a cold, clear night the boundary layer can be 100 m high and on a hot summer day with low wind speeds can be more than 2 km high [23]. Wind turbines operate more often in the lowest 10 % of the boundary layer, the near-ground boundary layer and are thus exposed to varying conditions.

The principal effects governing the properties of the boundary layer are the strength of the geostrophic wind and the surface roughness, Coriolis effects and thermal effects. The influences of the thermal effects are classified into three categories: stable, unstable and neutral stratification.

- Unstable stratification occurs when there is significant heat on the ground, causing warm air near the surface to rise. As the air rises, it expands due to reduced pressure and therefore cools adiabatically. If the cooling is not sufficient to bring the air into thermal equilibrium with the surroundings, then it will continue to rise. The result is a thick boundary layer with large-scale turbulent eddies. There is a lot of vertical mixing and transfer of momentum, resulting in a relatively small change of mean wind speed with height [24].
- Stable stratification occurs when the adiabatic cooling effect causes the rising air to become colder than its surrounding, then its vertical motion will be suppressed [24].
- Neutral atmosphere is when adiabatic cooling of the air as it rises is such that it remains in thermal equilibrium with the surroundings. Commonly, this is the case in strong winds, when turbulence caused by the roughness causes sufficient mixing of the boundary layer [24].

For wind energy applications, neutral stability is usually the most important situation to consider, when the turbulence load on the turbine is calculated. Unstable conditions can be important as they result in a sudden gust from low level, and stable conditions can give rise to significant asymmetric load due to high wind shear and wind veer (i.e. change of wind direction with height). The power production diverges from the one expected due to the atmospheric stability. However, the connection between stability and power production remains unclear [10]. After a research among different studies, contradictory results have been found. These results are summarized in Table 2-1.

Table 2-1: Research on influence of atmospheric stability on power output

Title | Author(s)	Data type	Location	Power output effects	Remarks from the authors
Atmospheric Stability Impacts on Power Curves of Tall Wind Turbines | S. Wharton and J. Lundquist. [25]	Cup anemometers and Sodar.	West Coast - US	Power output differences approached 20% between stable and convective regimes. The dependence of stability on power output was apparent only when both turbulence and the shape of the wind speed profile were considered.	Power output at this wind farm is highly correlated with atmospheric stability during the spring and summer months, while atmospheric stability applies little impact on power output during the winter and autumn periods.
Wind turbine power production and annual energy production depend on atmospheric stability and turbulence | Martin C. et. al. [26]	Lidar, cup anemometers and sonic anemometers.	National Wind Technology Center – U.S.	Power curves for different bulk Richardson number (dimensionless ratio between the generation of turbulence kinetic energy and wind shear)- regimes reveal that periods of stable conditions produce more power at wind speeds near rated and periods of unstable conditions produce more power at lower wind speeds.	They suggest implementing an additional step in analyzing power performance data to incorporate effects of atmospheric stability and turbulence across the rotor disk.
The modification of wind turbine performance by statistically distinct atmospheric regimes | B. Vanderwende and J K. Lundquist. [27]	Sonic anemometers.	Central North America – U.S.	Results indicated underperformance during stable regimes and over performance during convective regimes at moderate wind speeds (8–12 m s−1).	[-]

Measurement: Wind speed is measured using a meteorological device known as an anemometer (nowadays other instruments known as remote sensing devices are also used in the field). Operational data can only be obtained by means of measurements over a certain period and recording of the measured values [9]. Usually, it requires anemometers on a mast with a logging device for the data transmission. Additionally, one or more wind vanes are on the mast to measure the wind direction simultaneously.

These measurements are stored in a certain sampling rate. This rate is usually 1 second (1 Hz) for a cup anemometer. For the creation of the power curve; the wind speed and the produced power are stored and summarized in datasets of 10-minutes average each. Then, wind speed bins are created and for every wind speed bin, the average power is calculated. From this set of wind speed bin vs average power, the power curve can be plotted.

Effects: The power curve (PC) is the result of the technical characteristics of the turbine. For a given wind speed, a certain power production is expected.

Nowadays, wind turbines can operate at speeds above the cut-out speed by ramping down the power. Derated operation is the ability of a wind turbine to operate below its maximum capacity during times of high wind speed. This is achieved by intelligently pitching the blades out of the wind and by limiting rotational speed in proportion to the increase in wind speed [28]. This results in a more stable power output at high wind speeds (i.e. a smooth ramp down power output at higher winds rather than stopping the wind turbine abruptly). At the same time, it reduces the wear and tear on components due to fewer stops of the wind turbine [29]. Another benefit is that the wind turbine becomes more grid-friendly, as the amount of energy fed into the grid becomes more stable and predictable, especially in a large wind farm. Some examples of this system can be found today in the market. A modern PC can be seen in Figure 2-4.

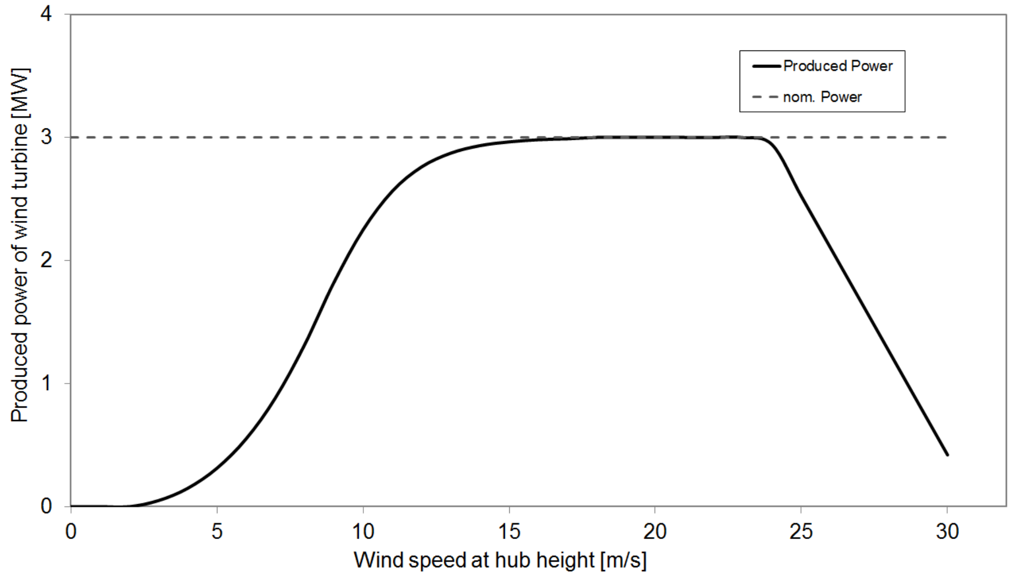

Figure 2-4: Power Curve – Modern wind turbine

Wind power cannot be used completely. The reason is the congestion of the wind behind the rotor. The turbine takes kinetic energy from the wind, slowing down the stream, and this produces an accumulation of air which slows down the complete wind system [23]. The amount of power that a wind turbine can extract from the wind is determined by the following equation

$$P_t = \frac{1}{2} c_p \, \rho \, A \, v^3 \qquad (2\text{-}3)$$

This equation states that the power is equal to one-half, times the power coefficient, times the air density, times the rotor area, times the cube of the wind speed.

Air Density

Definition: Air density is the mass of air per unit of volume it occupies, and it is expressed in kilograms per cubic meter. The power in the air available for conversion by the wind turbine is directly proportional to the density [10]. This can be seen in Eq. (2-3). Noteworthy, the standard air density of the air is taken as 1.225 kg/m^3 at the standard temperature of 15◦C and pressure of 1 atm.

Estimation: Consider a gas mass m with N gas molecules in a closed system, which takes the pressure p, the temperature T and the volume V. In this closed system, the mass and the number of particles remain constant [23]. Thus, the thermal state of the gas mass is determined by volume, pressure, and temperature.

To derive the gas equation, two processes are performed consecutively. First, an isothermal state change with $\{V_1, p_1, T_1\} \rightarrow \{V_x, p_2, T_1\}$, followed by an isobaric change in state with $\{V_x, p_2, T_1\}, \rightarrow \{V_2, p_2, T_2\}$. The relationship of these changes is taken from experimental studies. For isothermal change, the Boyle Mariotte's law is used and for isobaric change Gay-Lussac's law [23]. This leads to the following equation.

$$\frac{p_1 V_1}{T_1} = \frac{p_2 V_2}{T_2} \quad (2\text{-}4)$$

If the system is based on the standard atmosphere with standard pressure p_n, standard temperature T_n and molar volume at standard conditions V_n, the constant is equal to the universal gas constant R. Additionally, the universal gas constant is a product of the specific gas constant R_s and the molar mass m of the gas mass. Consequently, the equation is

$$\frac{p_n V_n}{T_n} = R = R_s\, m \quad (2\text{-}5)$$

and knowing that the density is $\rho = m\,/\,V$, this leads to:

$$\frac{p}{\rho R_s T} = constant \quad (2\text{-}6)$$

From (2-6), it can be seen that the density is a function of pressure and temperature. As well, the temperature is inversely proportional to the pressure. Since the temperature is highly variable in time, in contrast to the pressure, it is assumed to have a more significant impact on the PC.

The amount of water vapor in the air also affects the density. Both the air and water vapor combine to create the overall density, ρ.

$$\rho = \frac{1}{T}\left(\frac{B}{R_o} - \varphi p\left(\frac{1}{R_o} - \frac{1}{R_w}\right)\right) \quad (2\text{-}7)$$

Where, T is the ambient temperature, B is the ambient pressure, $R_o$is the dry air gas constant, φ is the relative humidity, p is the vapor pressure shown in Eq. (2-8) and R_w is water vapor gas constant.

Vapor pressure can then empirically be estimated as follows:

$$p = 0.0000205\, \exp(0.0631846\, T) \quad (2\text{-}8)$$

Effects: The direct relationship between power production and density (Eq. (2-3)) leads to higher performance at a higher density. This can be seen in Figure 2-5. Due to this strong correlation of density and power production, air density correction methods are always needed. For modern pitch controlled wind turbines, normalization of wind speed is foreseen in the IEC standard. This correction is described in Section 3-2 (Air density measurements).

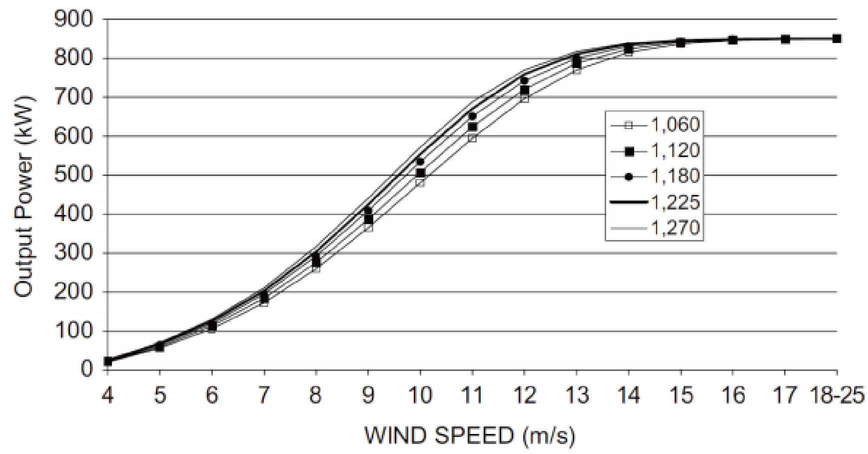

Figure 2-5: Power curve of a selected medium-sized wind turbine for various air density values [23]

Normalization: According to the IEC 61400-12-1:2005 standard, the air density should be accounted for under certain air density conditions. This is addressed in detail in Section 3-4 (Data Normalization). Nevertheless, the latest version of the IEC 61400-12-1:2017 standard states that the data needs to be normalized to at least one reference density. The reference density should be the mean of the average of the measured air density of the collected data during the Power Performance Test (PPT) or a pre-defined nominal air density representative of the site [30]. The difference is that the IEC 61400-12-1:2005 standard has conditions to normalize the measured data and IEC 61400-12-1:2017 standard not. But, the principle is the same for a wind turbine with active power control (this is the case for XYZ). The normalization should be applied to the wind speed according to:

$$V_n = V_m \left(\frac{\rho_m}{\rho_o}\right)^{1/3} \tag{2-9}$$

Where,

V_n Is the normalized wind speed.
V_m Is the measured wind speed.
ρ_m Is the measured air density.
ρ_o Is the reference air density.

On the other hand, for a stall regulated wind turbine with constant pitch and constant rotational speed, the normalization should be applied to the measured power according to:

$$P_n = P_m \left(\frac{\rho_o}{\rho_m}\right)$$

Where,

P_n Is the normalized power output.
P_m Is the measured power output.

Turbulence Intensity

Definition: Atmospheric turbulence is a flow condition. Turbulence can be thought of as fluctuations in the air flow; turbulent flow is chaotic, extending in all directions, has different expansions and is not linear. This is contrary to laminar flow that is ordered and its flow lines do not intersect. This can be seen in Figure 2-6.

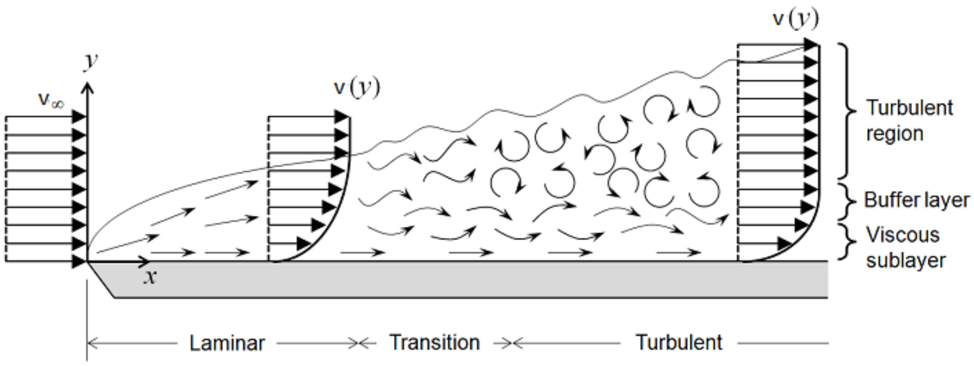

Figure 2-6.: Flow of a fluid over a flat plate. Modified by the author from [31]

A steady flow of air has low turbulence. An unsteady flow of air, in contrast, has higher turbulence. Turbulence Intensity (TI) is a scale characterizing turbulence expressed as a percentage. An idealized flow of air with absolutely no fluctuations in air speed or direction would have a TI value of 0%. Nevertheless, due to how Turbulence Intensity is calculated, values greater than 100% are possible. This can happen when the average wind speed is low and there is large fluctuations present [32].

Calculation: In wind energy applications, turbulence is described by turbulence intensity (TI), the ratio of the standard deviation of the longitudinal wind speed (σ_u) to its average within the same 10 minutes (v_{10min}).

$$TI = \frac{\sigma_u}{v_{10min}} \quad (2\text{-}10)$$

Overall, high TI values represent a strong and quick change of wind speeds, resulting in loads for the turbine. To avoid rapid deterioration of the turbine, the IEC 61400-12-1:2005 standard defined three classes of TI as a reference. This is presented in Figure 2-7.

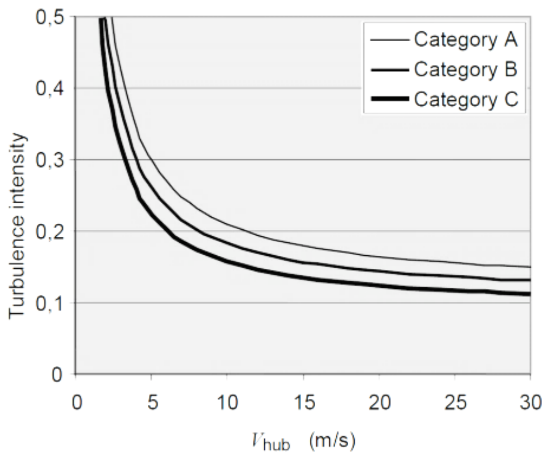

Figure 2-7: Three different turbulence intensity classes from Standard IEC 61400-12-1:2005 standard [23]

Effects: In the PC literature, a significant TI influence on the power curve can be found. The difference in the Measured Power Curve (M-PC) and the Warranted Power Curve (W-PC) can, at least partly, be explained by the temporal averaging of the measured wind speed and power output [23]. In Figure 2-8 the influence of the TI on a PC can be seen. On the left side of the curve, an overestimation occurs; this can be seen for a TI of 16%. Meanwhile, an underestimation occurs at the right curved curve for the same value. This becomes more pronounced as the wind speed increases. This relationship has been described by Albers and Hinsch (1996) as 'Bias of Estimate'. When power values are averaged, the power curve is overestimated at low wind speed and underestimated at higher speeds [23].

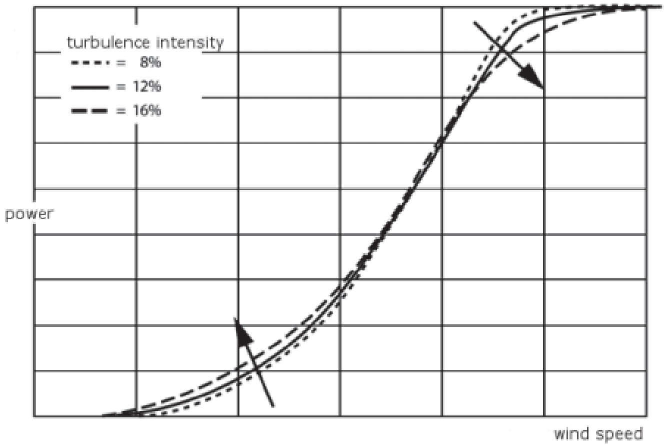

Figure 2-8: Influence of TI on power production. [23]

Normalization: Corrections with respect to Turbulence Intensity (TI) have been suggested in the past [33] [10]. The correction is presented in Eq. (2-11). Even though, that it could be considered too simple [10], this method has shown to effectively account for the TI on some terrain types [33]. In Eq. (2-3) it was shown that the power output depends cubically on the wind speed. The wind speed can be considered the sum of the mean and turbulent parts. Based on this, the cube of the wind speed can be expressed as [10]:

$$v^3 = (\bar{V} + v')^3 = (\bar{V})^3 + 3(\bar{V})^2 v' + 3\bar{V}(v')^2 + (v')^3$$

Where,

v Wind speed.

$\bar{V}$ Mean wind speed.

v' Fluctuating component of the wind speed (i.e. standard deviation of wind speed σ_u).

Then, the mean cube wind speed:

$$\overline{v^3} = (\bar{V})^3 + 3(\bar{V})^2\overline{v'} + 3\bar{V}\overline{(v')^2} + \overline{(v')^3}$$

The second and last terms are equal to zero since the fluctuations are assumed to be symmetrical. It can be simplified to:

$$\overline{v^3} = (\bar{V})^3\left(1 + 3\frac{\overline{(v')^2}}{(\bar{V})^2}\right) = (\bar{V})^3\left(1 + 3\left(\frac{\sigma_u}{\bar{V}}\right)^2\right) = (\bar{V})^3(1 + 3(TI)^2)$$

Finally, the correction can be defined as:

$$V_n = V_m(1 + 3(TI)^2)^{1/3} \qquad (2\text{-}11)$$

Where,

V_n Is the normalized wind speed.
V_m Is the measured wind speed.

Wind shear

Definition: Wind speed varies in space, time, and direction around its mean value due to the effect of turbulence [10]. Both the mean and the instantaneous flow field are shown in Figure 2-9. The change of mean wind speed with height is known as vertical wind shear or simply shear.

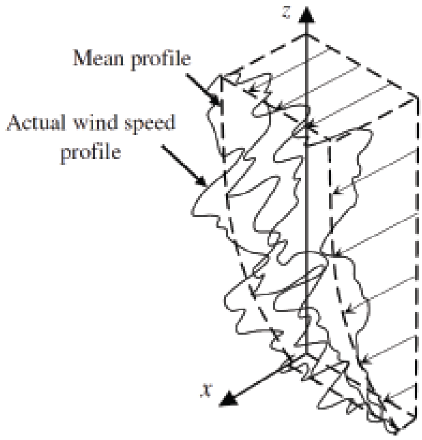

Figure 2-9: Actual wind speed profile [34].

Estimation: As described previously, the wind speed increases with the height in the boundary layer. Two models are usually used to determine wind speed at a given height, the logarithmic law and the power law. Both approaches are subject to uncertainty caused by the variable, complex nature of turbulent flows [35].

In this research, special attention is given to the power law. The power law is a simple, empirical model for the vertical wind profile. The power law is stated in equation (2-12). Nevertheless, using only two points can also lead to ambiguity for certain wind speeds, especially in complex terrain. The most commonly used profile characterization is using the power law with a reasonable number of measurement points. This is the method employed in this research.

$$v_2 = v_1 \left(\frac{z_2}{z_1}\right)^{\alpha} \quad (2\text{-}12)$$

Where, v_1 is the wind speed at known height z_1, wind shear exponent α and the wind speed v_2 at known height z_2. The variable α is known as the power law exponent or shear exponent. Slightly different values of α may be given by different authors. Nonetheless, typical values can be found in Table 2-2. Here, different coefficients are presented as a function of the surface roughness over which the wind blows. However, the shear exponent is highly variable and depends on several parameters: elevation, time of day, season, nature of the terrain, wind speed, temperature, and various thermal and mechanical mixing parameters [11].

Table 2-2: Power law exponent for different terrains [36].

Terrain Description	Power law exponent, α [-]
Smooth, hard ground, lake or ocean	0.10
Short grass on untilled ground	0.14

Level country with foot-high grass, occasional tree	0.16
Tall row crops, hedges, a few trees	0.20
Many trees and occasional buildings	0.22-0.24
Wooded country - small towns and suburbs	0.28-0.30
Urban areas with tall buildings	0.40

As terrain complexities increase, the wind shear also increases, and as wind shear increases, friction between the wind and the ground becomes greater [36].

Effects: Wind shear generates asymmetric loads on the wind turbine components and consequently, affects the aerodynamics behavior. The larger the difference with height is, the larger the wind shear exponent and the greater these loads. As identified before, the wind varies with obstacles (e.g. ground slope, near standing turbines) and atmospheric stability. It is visible in Figure 2-10 that the wind shear changes the wind speed in hub height. In addition, the wind shear leads to a cyclically increasing and decreasing aerodynamic load distribution over the rotor blades that influence the power curve.

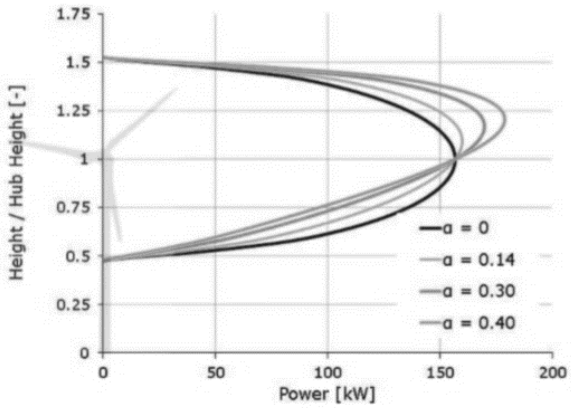

Figure 2-10: Power available in the rotor's area for different shear exponents. Modified by the author from [10]

In a complex terrain, the wind shear could lead to different effects. For example, if the turbine is on a hill, as shown in Figure 2-11a, the wind is accelerated at low altitude over ground creating relatively high wind speeds [23]. This creates a negative effect on the vertical wind profile at hub-height. If a wind turbine is in a forest, as shown in Figure 2-11b the wind is slowed down at the lower tip. This creates a deceleration in the wind speed and will depend on the distance and the height of the obstacle.

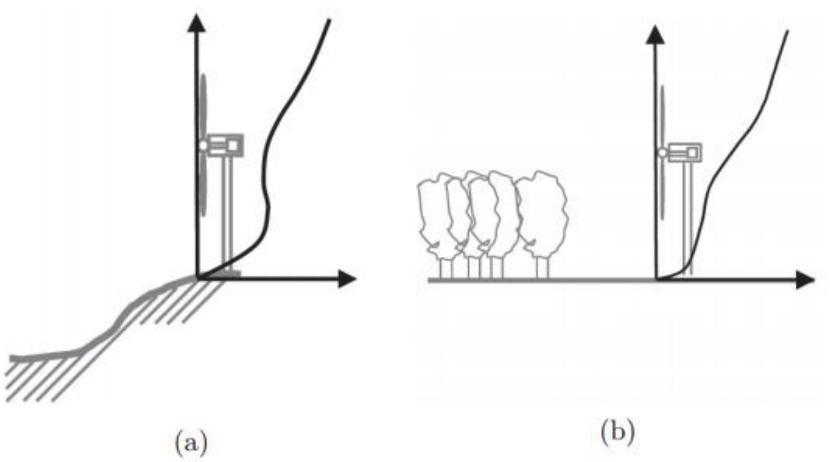

Figure 2-11: Vertical wind profile with (a) large ground slope and (b) with obstacles. [23]

Normalization: If the wind speed over the wind turbine rotor area will be constant, the wind speed at hub height would be representative of the wind speed over the wind turbine rotor and the use of the hub height will be reasonable [30]. This is not the case, especially for big turbines, since different wind speeds can be measured on the rotor for different heights at the same 10-minute average. A new approach is used in this thesis. This was originally proposed by [37] and it is based on the rotor equivalent wind speed measurement. The wind speed could be expressed as the weighted arithmetic mean of their contribution of all wind speed at different height (measured data or estimated with the power law Eq. (2-12)). The method consists of weighing the wind speed recorded at several heights over the rotor swept area according to the area covered by each measurement point [37]. In Figure 2-12 is observed a wind turbine rotor with segmented areas and wind speed.

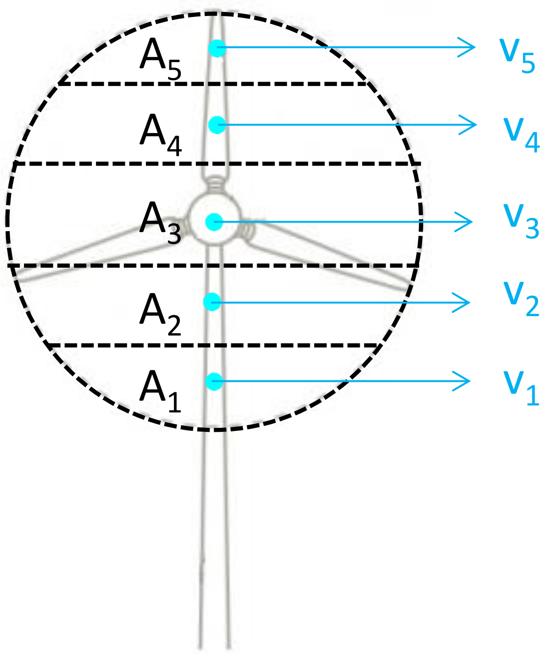

Figure 2-12: Swept rotor area divided into segments.

To calculate the individual areas, geometry can be used [30]:

$$A_i = \int_{Zi}^{Zi+1} c(z)dz = g(z_{i+1}) - g(z_i)$$

$$c(z) = 2\sqrt{R^2 - (z-H)^2}$$

Where:

A_i Is the area of the segment ith.

z_i Is the height of the ith segment separation line (H-R<z_i < H+R).

H Is the hub height.

R Is the rotor radius.

$c(z)$ Is the rotor width at height z.

Then, the integrated function becomes:

$$g(z) = (z-H)\sqrt{R^2-(z-H)^2} + R^2 \tan^{-1}\left(\frac{z-H}{\sqrt{R^2-(z-H)^2}}\right) \quad (2\text{-}13)$$

For the equivalent wind speed, the following equation is given:

$$Vn = \sum_{i=1}^{n} V_i \left(\frac{A_i}{A}\right) \tag{2-14}$$

Where,

V_n Is the normalized wind speed.
V_i Is the measured wind speed in segment i.
A Is the complete area swept by the rotor (i.e. πR^2).
n is the number of available measurement heights ($n \geq 3$).

Moreover, it is suggested [30], that at least three measurements need to be available and the segments (with areas A_i) should be chosen in the way that the horizontal separation line between two segments lies in the middle of two measurement points [30]. This method is implemented in Section 7-3 (Wind Shear Analysis).

Wind veer

Definition: the difference in wind direction with height is known as wind veer or wind direction shear. Positive values indicate a clockwise change with increasing height and negative values indicate a counterclockwise change with increasing height [38].

Estimation: To calculate the wind veer, the minimum angle distance between two wind vanes measurements at different height are calculated, the result is the mean wind veer. As shown in Figure 2-13.

Where,
WD Wind Direction
veer mean wind veer

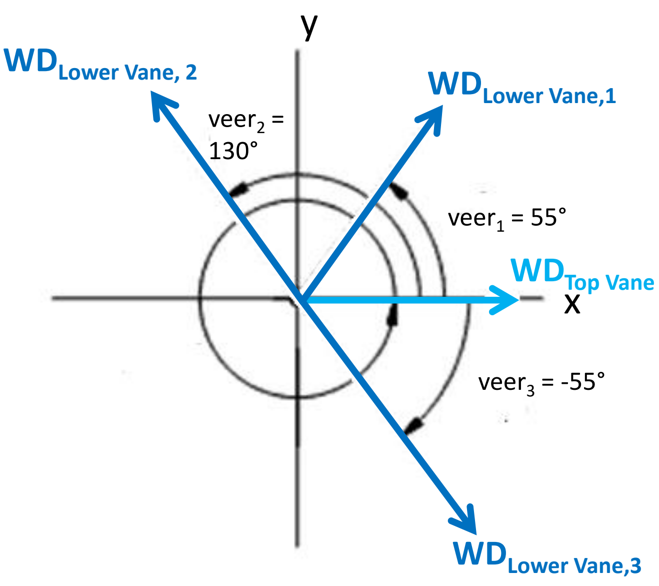

Figure 2-13: Examples of mean wind veer estimation.

Alike the shear, the wind veer rate tends to depend on the character of the surrounding terrain and the stability of the atmosphere. In Figure 2-14 shows a classic representation of wind veer. Here, the wind veer rate is indicated by degrees per 100 vertical meters.

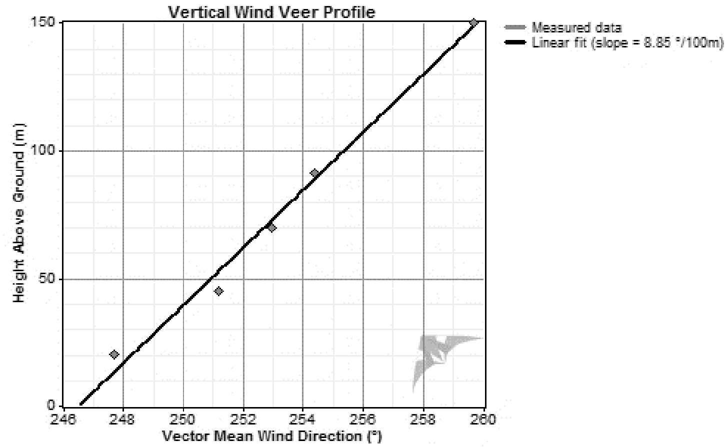

Figure 2-14: Wind veer profile [39]

Effects: Wind not perpendicular to the rotor will translate into lower power output, this could be the case especially with bigger rotors. The yaw drive can follow the wind variations only with a considerable time delay. Thus, the incident air exhibits a yaw angle with respect to the rotor axis. Asymmetric inflow conditions for the rotor can be caused by diverted wind streams in the case of topographically complex terrain or also due to the rotor design in the case of an inclined rotor axis [9].

Despite the unfamiliarity on the implication of the veer effects on the PPT, it is known that wind veer is highly correlated with wind shear. It may be challenging to separate the effects of wind veer and wind shear on performance [38].

Normalization: When accounting for veer, the extended rotor equivalent wind speed corresponding to the kinetic energy flux through the swept rotor area should be used. Similar to shear, at least three height measurements should be available [30]. The extended rotor equivalent wind speed equation is given by:

$$Vn = \left(\sum_{i=1}^{n} (V_i \cos(\varphi_i))^3 \frac{A_i}{A}\right)^{1/3} \quad (2\text{-}15)$$

Where,

V_n	Is the normalized wind speed.
V_i	Is the measured wind speed in segment i.
A	Is the complete area swept by the rotor (i.e. πR^2).
A_i	Is the area of the segment ith.
φ_i	Is the angle difference between the wind direction at hub height and segment i.
n	Is the number of available measurement heights ($n \geq 3$).

Inflow angle

Definition: The inflow angle is the angle that the wind speed vector makes with the horizontal plane. Figure 2-15 shows the inflow angle. Generally, high inflow angles are expected in complex terrains with steep slopes.

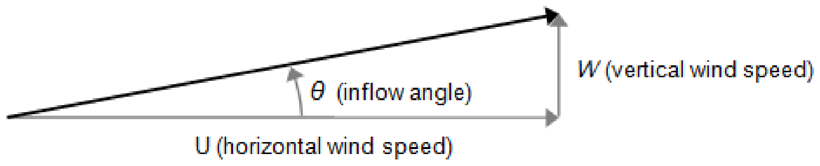

Figure 2-15: Inflow Angle [39]

Evaluation: To measure wind speed in all directions a 3D ultrasonic anemometer can be used. This device can measure the wind direction and the wind velocity in 3 dimensions X, Y, Z with high precision and in real-time. With this information, the angle at which the wind would flow into a wind turbine can be calculated. The Eq. (2-16) is used to calculate the inflow angle. Here, a positive vertical wind speed results in a positive inflow angle.

$$\theta = \arctan\left(\frac{W}{U}\right) \qquad (2\text{-}16)$$

Where U is the horizontal wind speed and W is the vertical wind speed.

Effects: Wind turbines are certified for inflow angles usually within ±8° as required by the IEC 61400-12-1:2005 standard [1]. It is important that the turbine locations comply with this requirement. This will ensure that the turbines will be affected by reasonable wear and tear during their expected lifetime (20-25 years). The effects of the inflow angle on the power output are related to yaw misalignment (See wind veer effects).

Normalization: In addition to the extended rotor equivalent wind speed a new proposal has been studied [40]. Here, the inclusion of the inflow angle is considered:

$$V_n = \sqrt[3]{\frac{1}{A}\sum_{i=1}^{n}\left(v_i \cos\varphi \frac{\cos(\theta + \theta_{tilt})}{\cos\theta}\right)^3 A_i} \qquad (2\text{-}17)$$

Where,

θ_{tilt} Is the tilt angle (positive= head backwards – see Figure 2-16).

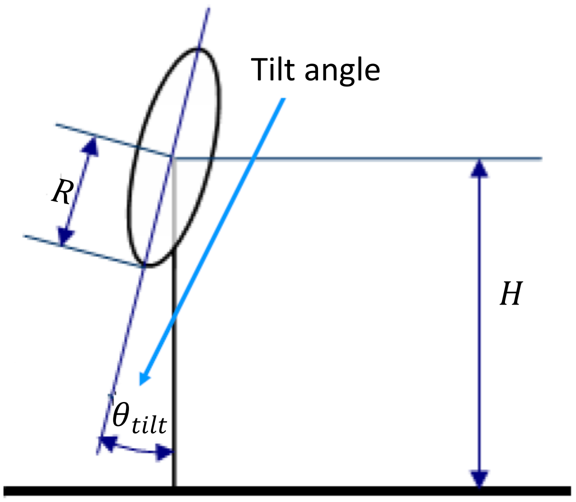

Figure 2-16: Tilt angle representation. Modified by the author from [40]

2-2 Warranty Contract Formulation

Warranties are legally binding assurance that turbines are free from defective material and meet the standards. As described by Murthy et al. [41] warranties play two important roles: (i) promotional, since there is a need for differentiation, especially when the competing products are nearly indistinguishable, and (ii) protection, for complex and expensive products where consumers need an assurance.

Among various type of contracts; a typical Power Curve warranty will read as follows [42] "Subject to the conditions set out herein the contractor warrants that, the Measured Annual Energy Production (M-AEP) of the wind turbine calculated as the product of the Measured Power Curve (M-PC) multiplied by the Nominal Wind distribution (NWD) shall be equal to or greater than the Warranted Annual Energy (W-AEP) Production calculated as the product of the Warranted Power curve (W-PC) multiplied with the Nominal Wind Distribution (NWD) and multiplied by the Uncertainty Adjustment factors". Moreover, the Nominal Wind Distribution (NWD) of the project represents the average hub-height wind speed distribution at the individual Wind Turbine location, this is discussed further in Chapter 4. The equation for AEP (Measured and Warranted) used exclusively in this project are [43]:

$$\text{M-AEP} = \text{M-PC} * \text{NWD} \tag{2-18}$$

$$\text{W-AEP} = \text{W-PC} * \text{NWD} * (1 - u_{AEP}) \tag{2-19}$$

Where, u_{AEP} is the uncertainty in the AEP address in Section 3-4 (Evaluation of Uncertainties in Measurements).

Therefore, the contract stipulates the warranty condition. Within the contract warranty, the warranted power curve is found, this is the indicator of the turbine performance and when it is not met, the compensation rules apply. An outline of the verification procedure is presented in Figure 2-17. In this section, the power curve (PC) warranty contracts are addressed in a universal matter.

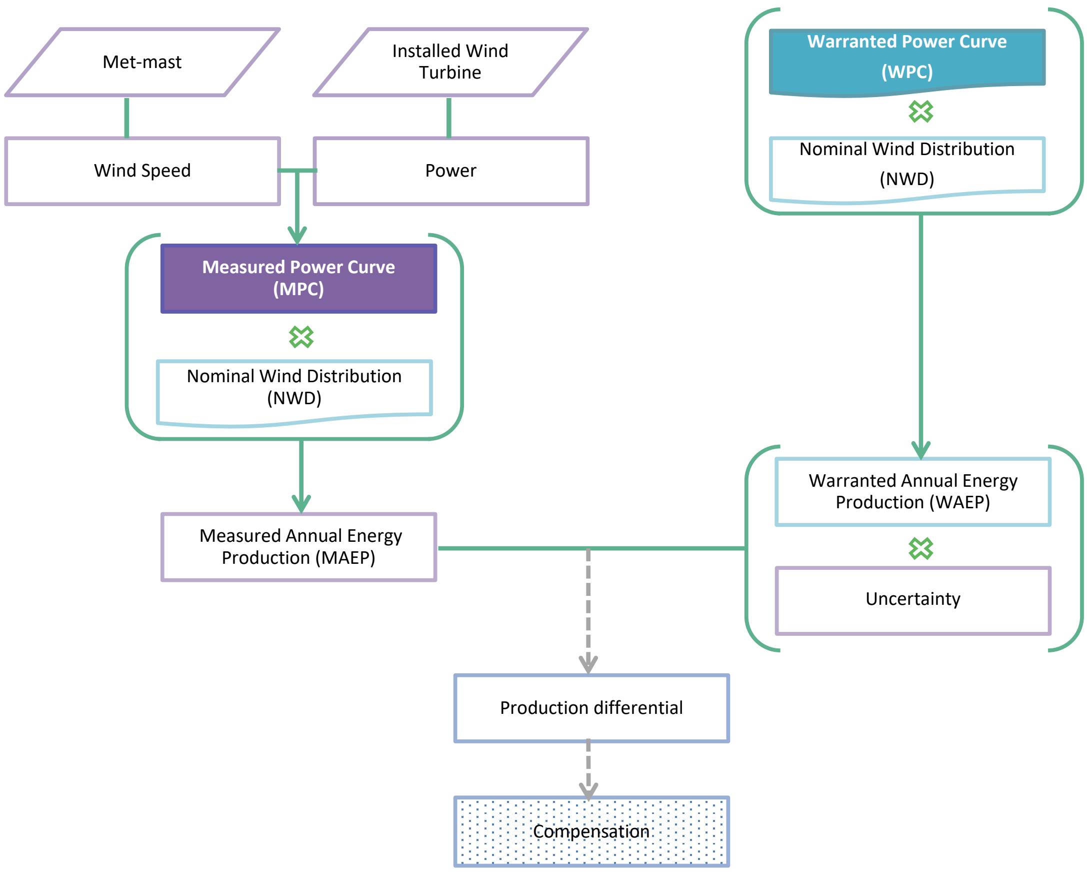

Figure 2-17: Verification procedure based on a warranty contract (without uncertainties).

Type of Warranty Contracts

In the wind industry, the warranty contracts can be broadly divided into three groups [44]: (1) power performance testing of individual turbines, following IEC 61400-12-1:2005 standard [1]; (2) combined power curve/availability warranty and (3) warranty of the energy production of the wind farm. The warranty analysis of this project is focused on P*rocedure 1*: power performance testing (PPT) of individual turbines. Moreover, since the XYZ contract is based on the IEC 61400-12-1:2005 standard, the general procedure of PPT is based on the 2005 version and it is covered in Chapter 3.

In general, the causes for unsatisfying energy production are various: insufficient wind resource assessment, yearly variation on the annual energy production (AEP) or lower than expected technical availability to give a few examples. Moreover, the differences between the warranted power curve (W-PC) and measured power curve (M-PC) is the main cause that this project is focused on.

Current Warranty Procedures

Contracts define the individual measurement conditions of additional requirements.

- Turbulence filter: As explained earlier in this chapter, depending on the wind speed range, topography, thermal stability, the turbulence can increase or decrease the measured power curve (M-PC). Filters aim at reducing the accepted range to conditions which can be seen in an open, flat terrain [5].
- Wind shear filters: The wind speed changes with height could have a significant impact on the M-PC, this impact is believed to increase with the size of the rotor [5].
- Inflow filters: In complex terrain, higher inflow angles are expected. Therefore, the measurement of the vertical wind component has become necessary.

- Site calibration uses advanced correlation schemes for wind speed at hub height but also wind shear and turbulence. The IEC 61400-12-1:2005 standard assumes a linear correlation between the wind speed at hub height of the met-mast pair depending only on the wind direction, not taking into consideration other parameters like wind shear, wind veer, time of the day, to mention a few. This could have a higher impact in complex terrain.

The uncertainty of AEP: Depending on the site, the uncertainty on the M-PC can exceed 5% in the measured AEP [5]. This is specified in the contract as compensation conditions. This will be discussed later in this chapter.

Overall, the applied filters and the correlation schemes mentioned above can limit the evaluated wind data to a small fraction. This seems justified from the point of view of the supplier, who may intend to warrant the power curve only under well-defined environmental conditions. As consequence, the power curve tested may not be representative of the wind farm site anymore and at the same time lead to too optimistic business cases.

2-2-1 Limitation on General Verification Procedure

Most power curve warranties requirements are based on the IEC standards. This is because of IEC is the only international standard on PPT. The procedure outlined there is accepted worldwide.

However, the IEC 61400-12-1:2005 standard has requirements that limit its applicability. Two limitations are identified: (i) a met-mast is needed to verify the power curve; if a site calibration is required then an extra met-mast has to be added. The met masts are expensive, since they are required to reach the hub-height. This could lead to an economic constraint for the project. Additionally, (ii) only turbines at the border of wind farms can be tested to avoid wake effects.

Nowadays, alternative technologies are in place to solve these limitations. In many cases, advanced nacelle anemometry and the application of lidars can be a solution. These alternatives are partly addressed in the draft IEC:2013 standard and IEC:2017 standard, where a met-mast is still required. Nonetheless, all the alternative Power Performance Testing (PPT) procedures are still linked to higher uncertainties [4]. This investigation addresses only the procedure stated in IEC 61400-12-1:2005 standard, but this should not be a reason for the supplier or the buyer to reject these alternative methods in the future.

In an ideal case, a verification of the W-PC should be possible at each turbine of the wind farm, where a PPT should be possible during the entire warranty period. In addition, a repetition of the power curve test should be as well accepted in case of doubts on the M-PC, even if the first test has passed. However, this is not the case in the standard warranties as presented by many turbine suppliers [4].

Currently, the buyer has the right to test the PC within the **defect notification period** is often limited to a short period after commissioning (e.g. five years), and sometimes the PPT is allowed only once [4]. Consequently, the warranty gets unusable in the case that the power performance decreases with time. The **test turbines** can be contractually fixed with no possibility to change them in case that a specific turbine rises doubt. In some cases, warranty contracts (e.g. XYZ contract) offer warranty only on the mean measured power curve on the set tested exemplary, meaning that this average will be representative for all turbines of the same type within the wind farm.

Another limitation is the **test announcement**, here the *buyer* is bound to inform the turbine supplier about his intention to carry out the PPT. In some cases, the supplier has the right and time to optimize the power curve before the PPT starts. This condition makes it difficult to prove a gap between the W-PC and the M-PC, which could have been present before such an optimization.

2-2-2 Limitation on Special Test Conditions

A general direction in which warranty contracts are developing is to define special test conditions, often beyond the IEC requirements and in some cases in contradiction. As mentioned earlier in this section, many warranties require **wind condition filters** (e.g. turbulence intensity, wind shear, vertical flow inclination). Additional to these filters, the following can also be added to the filters: air density and air temperature.

Other special testing conditions are related to curtailed operations (e.g. **noise reduced operation or automatic load reduction** for specific wind direction sectors). This might be considered as a turbine condition representative for the wind farm site and should thus not be excluded from power curve tests [4].

In general, the integration of a wind farm into the grid presents some challenges. Challenges such as system operation and control, system stability, and power quality need to be considered. In addition to these challenges, the technical constraints of the power generation integration (e.g. thermal limits) must be addressed as well. For all these reasons, grid codes are set up to specify the relevant requirements and the wind farms must meet in order to be connected to the grid [45]. An example of special **grid conditions** is the frequency and voltage control. This is done by continuously balance the active power and reactive power. There are also requirements associated with voltage fluctuation (e.g. fluctuation in the system voltage might cause perceptive light flicker depending on the magnitude and frequency of the fluctuation). and harmonics (i.e. distortion of fundamental sine waves).

A series of special grid conditions have been set and the wind turbines must meet these conditions accordingly before they can be connected into the power system [45]. Noteworthy is that the power curve is only valid for the active power (i.e. referring to The Power Triangle - Figure 2-18). Therefore, these special grid conditions should not be included on power curve tests.

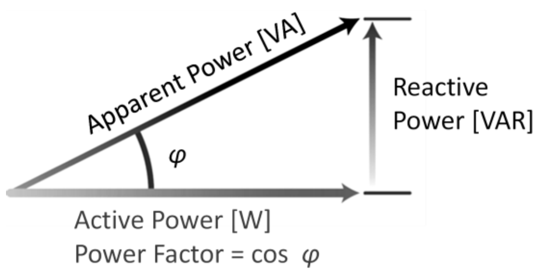

Figure 2-18: The Power Triangle. Modified by the author from [46]

In most cases, a wind turbine will shut down when the wind speed exceeds a certain limit (called cut-out wind speed). High wind speed shutdown events can cause significant fatigue loads. Therefore, to prevent repeated start-up and shut down of the turbine, hysteresis is commonly introduced into the turbine control algorithm [47]. Some contracts exclude the **cut-out hysteresis** from power curve tests, as often not much wind data points are measured during the test period, in the range where the high wind hysteresis takes place, leading to arbitrary measurement results. On the other hand, some warranties require even the **cut-in hysteresis** to be excluded from PPT. Excluding the cut-in hysteresis leads to a systematic improvement of measured power curves in favor of turbine suppliers [4].

Other power curve warranties include special conditions on the **terrain at the test site**, which surpass the requirements defined in the standard. Additional special conditions can be found on the **positioning of met masts**, for example positioning the mast upwind of the turbine in the main wind direction or in short distances to the turbine [4]. This is intended to increase the correlation of wind speeds measurements.

2-2-3 Limitations on Compensation

In some cases, a power curve warranty stipulates compensation in case of underperformance only for the warranty period. This can be critical for the buyer since the expected lifetime of the turbines are between 20 to 25 years and the warranty period can easily be in the range of 2 to 5 years.

Another limitation in the compensation rules is that it will be paid only after unsuccessful trials of optimization of the power curve by the turbine manufacturer. The key issue of this regulation is that the optimization of the power curve and the re-measurement to prove the optimization can take very long.

Another aspect is the low maximum liability, for example, 5 % of the turbine purchase price [4]. Under this low liability, the warranty cannot be expected to compensate significant underperformance in terms of the AEP.

Chapter 3

IEC Wind Turbine Power Performance Measurements

The Power Curve is a key concept for understanding the efficiency of wind turbines. Performance measurements are covered by agreed international standards. To summarize the high-quality requirements, the International Electro-Technical Commission (IEC) developed IEC 61400-12-1 Wind-turbines, *Part 12-1: Power performance measurements of electricity producing wind turbines* [1]. Nowadays, sales contracts define additional individual requirements, but they still refer to the international standards. For this, special attention is given to IEC 61400-12-1:2005 standard as the underlying foundation from which this project is built. An overview of this chapter is presented in Figure 3-1. If the reader is familiar with the standards, it is recommended skip to Chapter 4.

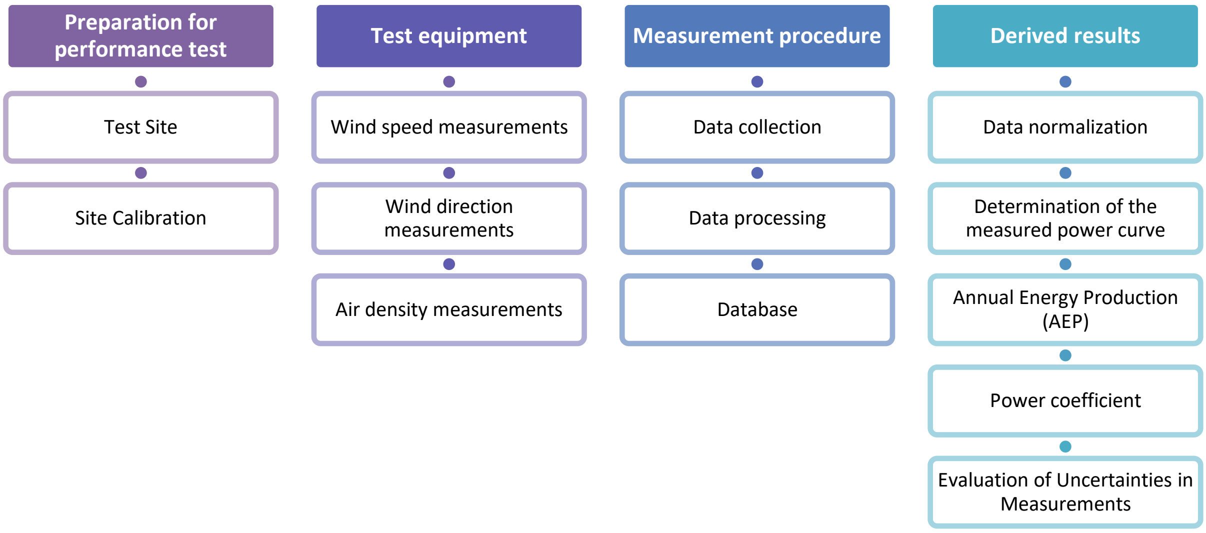

Figure 3-1: Reviewed IEC 61400-12-1 Sections.

3-1 Preparation for Performance Test

Test Site

This section describes a procedure to determine one or more measurement sectors which are not suitable for the test. The reason is because the flow at the wind turbine under test and/or the flow at the position of the met-mast might be affected by an operating wind turbine or by an obstacle. In addition, this section addresses the assessment of terrain. When the terrain does not comply with these requirements then a site calibration is needed.

Requirements regarding neighboring and operating wind turbines:

The wind turbine under test and the met-mast shall not be influenced by neighboring turbines. If a neighboring turbine is operating during the test, then its wake should be accounted for in the calculation. If the neighboring turbine is stopped, it should be considered as an obstacle.

The minimum distance from the wind turbine under test and the met-mast to neighboring and operating wind turbine shall be two rotor diameters of the neighboring wind turbine or two rotor diameters of the wind turbine under test if it has a larger diameter.

Requirements regarding obstacles:

No significant obstacles (e.g. buildings, trees, parked wind turbines) shall exist in the measurement sector within a reasonable distance from the wind turbine and the met-mast. Only small buildings, connected to the wind turbine operation or the measurement equipment are acceptable.

Method for calculation of sectors to exclude:

An obstacle model is used to predict the influence of obstacles upon the mast and the turbine position at hub-height. The criteria for determining a significant obstacle is that the flow is affected by 1% or more. The influence of an obstacle on the met-mast or turbine position at the height *z* is estimated by

$$\Delta {}^{U_z}/_{U_h} = -9.75(1 - P_o)\frac{h}{x}\eta\exp(-0.67\eta^{1.5})$$

$$\eta = \frac{H}{h}\left(K\frac{x}{h}\right)^{\frac{-1}{n+2}}$$

$$K = \frac{2\kappa^2}{ln\frac{h}{z_o}}$$

Where

x Distance downstream obstacle to met-mast or wind turbine [m].

h Height of obstacle [m].

U_h Free wind speed at height h of obstacle [m/s].

n Velocity profile exponent ($n = 0.14$).

P_o Porosity of obstacle (0: solid, 1: no obstacle).

H Hub height [m].

z_o Roughness length [m].

κ Von Karma constant 0.4.

Sectors with significant obstacles shall be excluded with reference to Figure 3-2. The dimensions to be considered are the actual distance L_e and an equivalent rotor diameter D_e of the obstacle. The equivalent rotor diameter of the obstacle is defined as:

$$D_e = \frac{2l_h l_w}{l_h + l_w} \quad (3\text{-}1)$$

Where,

D_e Is the equivalent rotor diameter.

l_h Is the height of obstacle.

l_w Is the width of the obstacle.

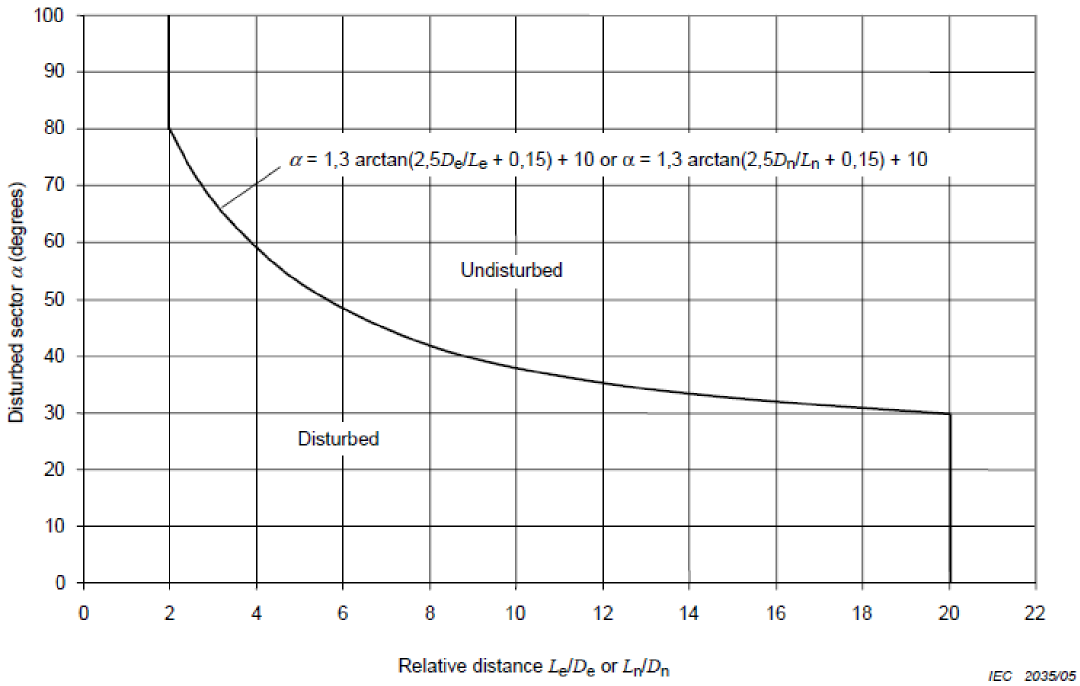

Figure 3-2: Sectors to exclude due to wakes of neighboring and operating wind turbines and significant obstacles [1]

Overall, the sectors shall be excluded when:

- The meteorological mast is in the wake of the wind turbine under test;
- The meteorological mast is in the wake of the neighboring and operating wind turbine;
- The wind turbine is in the wake of the neighboring and operating wind turbine;
- The meteorological mast is in the wake of the significant obstacle;
- The wind turbine is in the wake of the significant obstacle
- All the above effects.

Assessment of terrain at the test site:
The test site should show only minor topographical variations from a plane and should be free from larger obstacles (e.g. buildings, trees). The wind turbine under test and the wind measuring mast shall not be influenced by other wind turbines. If the test site shows significant obstacles and local topographic features a *site calibration* is recommended to quantify the flow distortions for all wind directions. Table 3-1 quantifies the required conditions for a test site if the criterion is not met then, a site calibration is needed. The variables presented are: *L* being the distance between the wind turbine and the meteorological mast; *H is* the hub height and; *D* the diameter of the rotor.

Table 3-1: Site requirements: topographical variation. Modified by the author from [1]

Distance	Sector	Max. Slope (%)	Max. terrain variation from the plain
< 2L	360	<3%	<0.04(H+D)
≥ 2L and < 4L	Measurement	<5%	<0.08 (H+D)
≥ 2L and < 4L	Outside Measurement	<10%	Not applicable
≥ 4L and < 8L	Measurement	<10%	<0.13 (H+D)

If the terrain characteristics are within an additional 50% of the limits of the maximum slopes (Table 3-1), then a flow model can be used to determine if a site calibration can be avoided. If the flow model shows a difference in wind speed between the anemometer position and the turbine's hub less than 1% at 10 m/s for the measurement sectors, then the site calibration can be avoided. The measurement sectors are presented in Figure 3-3.

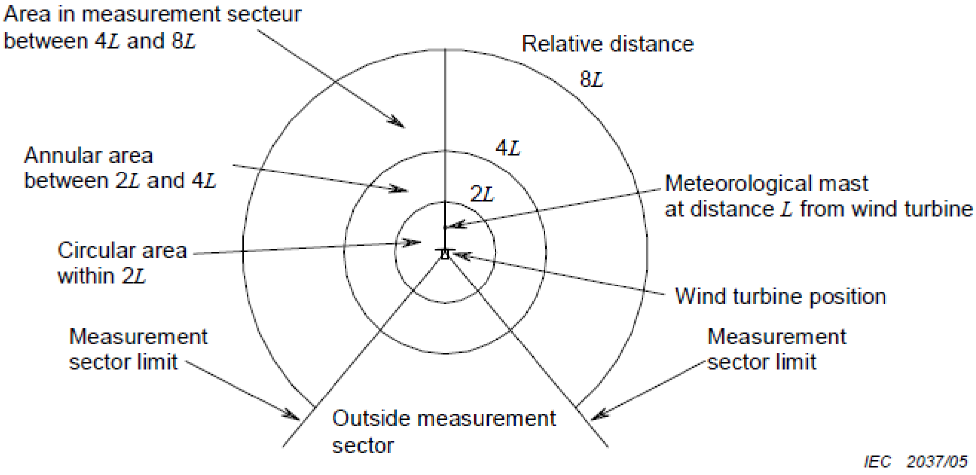

Figure 3-3: Illustration of area to be assessed, top view [1]

Site Calibration

Accurate wind assessment is essential where topography and obstacles may cause a systematic difference in wind speed. A site calibration quantifies and potentially reduces those effects on the power performance measurement. The result of a site calibration test is a table of flow correction factors for all wind directions. Another result is an estimate of the uncertainty of the correction factors.

Before the installation of the wind turbine, two meteorological masts are erected. One mast is the reference position met- mast to be used also for the power performance test. The second mast is the turbine position mast. The test set-up is addressed further in Section 4-4 (Meteorological Mast and Measurement systems). In addition, the anemometers should be the same type and with the same operating characteristics. The met-mast instrumentation should be the same for the power curve measurement as for the site calibration.
The data acquisition should include storing a continuous measurement of the mean, standard deviation, minimum and maximum wind speed for each 10-minute period. In addition, the data should be rejected under the following circumstances [1]:

- Failure or degradation (e.g. due to icing) of test equipment;
- Wind direction outside the measurement sectors;
- Mean wind speed less than 4 m/s or greater than 16 m/s;
- Any other special atmospheric conditions that will also be used as rejection criteria during the PPT.

The rejection criterion of the IEC guideline is supplemented by MEASNET as follows, the data rejection is measured at the reference mast. For this, only the data of the reference mast can be used for filtering, as this is the information available during the power curve measurement.

The data sets should be sorted into wind direction bins. Each bin should not be larger than 10° and each bin needs to have a minimum of 24h data (equivalent to 144 data points). Of these, each bin should have at least 6h data (equivalent to 36 data points) where the wind speed is above 8m/s and at least 6h data (equivalent to 36 data points) where wind is below 8m/s.

Measurement uncertainty of flow correction factors is addressed in Section 3-4 (Evaluation of Uncertainties in Measurements), where the evaluation of uncertainty in measurements is described.

3-2 Test Equipment

A meteorological mast (met-mast) is required for measuring the wind speed that drives the wind turbine. For this purpose, the first task is to find a suitable location for the met-mast. The correlation of power and wind speed can only be carried out correctly with a *"true"* wind speed measurement representative of the generated power. However, due to the necessary spatial distance between the rotor and the met-mast, there is a time delay between the instantaneous wind speed measurement and the power output of the wind turbine. In addition, the disturbed sectors to be excluded due to the met mast being in the wake of the wind turbine are also to be considered. A met mast should have a mean distance equivalent to 2-4 times the rotor diameter. But, a distance of 2.5 times is recommended. The distance, L, should not be too far as for the correlation between wind speed and electric power output to fall, and not too close as for the wind speed to be affected by the wind turbine [10].

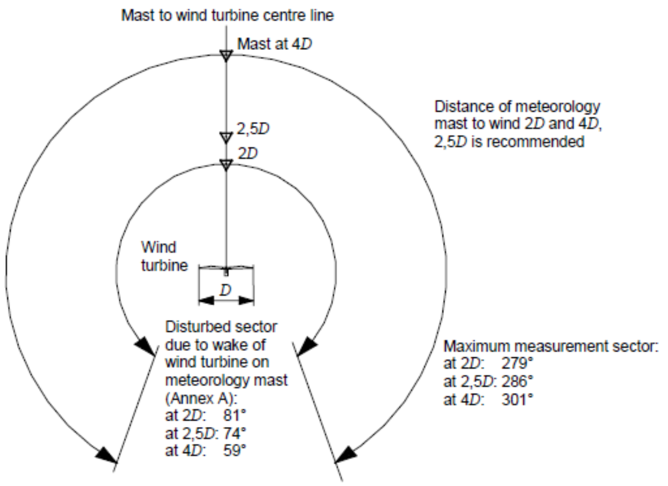

Figure 3-4: Maximum allowed measurement sectors [1]

Wind Speed Measurement

Wind speed measurements should be made with a cup anemometer. This needs to be calibrated before and recalibrated after the measurement campaign. Moreover, the anemometer is placed at a height within ±2.5% of the hub height preferably on a vertical tube configuration. The difference between the regression lines of these calibrations shall be within ±0.1 m/s in the range 6-12 m/s, and only the calibration before the measurements are to be used for the PPT. The uncertainty is derived from three different sources: the calibration of the instrument, the operational characteristics of the anemometer and the flow distortions due to the mounting effects (Section 3-4 (Evaluation of Uncertainties in Measurements)).

Wind Direction Measurement

The wind direction is measured with a wind vane. This should be located at a minimum of 1,5 m below the primary anemometer but within 10% of the hub height. The uncertainty in calibration, operation and orientation should not be higher than 5° combined.

Air Density Measurements

Based on the air temperature and air pressure measurements, Eq. (3-1) is used to derive the air density. The air temperature sensor should be mounted within 10 m of the hub height, this will represent the temperature at the wind turbine rotor center. The air pressure sensor should be located on the met-mast close to the hub height, the measurement will represent the air pressure at the wind turbine rotor center. The accuracy of these measurements should ensure a precision of ±5%.

3-3 Measurement Procedure

Data Collection

A digital data acquisition system with a sampling rate per channel of at least 1 Hz should be used to collect data. The uncertainty of the system should be negligible when compared to the uncertainty of the sensors. The system should store either sample data or statistics of the data sets: mean value, standard deviation, minimum value and, maximum value.
The data collected should be continuous and based on 10 min averaging time.

Data Processing

To guarantee that only data obtained during normal wind turbine operation are used. The database under the following circumstances need to be excluded:

- Wind speed that is out of the wind turbine operating range;
- When the wind turbine is not operating (i.e. mal-function, manually shut down, test or maintenance);
- Failure or degradation (e.g. icing);
- Wind direction outside the measurement sector, as defined in Section 3-1 (Test Site);
- Wind direction outside valid site calibration sectors.

As mentioned previously, the selected data should be corrected for flow distortion and air pressure should be correlated if measured at a height different than close to hub height.

Database

Subsequently to the data normalization (Section 3-4), the selected datasets should be sorted using the “method of bins”. Meaning that the data sets are distributed into bins according to wind speed and then the ensemble mean values in each bin.
Moreover, the data set should cover at least a wind speed range from 1 m/s below cut-in to 1.5 times the wind speed at 85% of the rated power. The size of the bins should be 0.5 m/s, being these contiguous bins centered on multiples of 0.5 m/s. A data set can only be considered complete when it has met the following criteria:

- Each bin includes at least 30 min of sampled data (3 data point);
- The database includes at least 180 h of sampled data.

If a single incomplete bin is preventing the completion of the test, then the bin value can be estimated by linear interpolation from two adjacent complete bins.

3-4 Derived Results

Data Normalization

The measured data should be normalized to two reference air densities. One of them should be the sea level air density, referring to ISO standard atmosphere. The standard conditions at sea level are defined as 15 °C and 1013.3 mbar; which for dried air leads to a standard density ρ_o, of 1.225 kg/m³.

The other reference should be the average of the measured air density data at the test site during periods of valid data collection.
The derived 10 min averaged air density, $\rho_{10\ min}$, is determined from measured air temperature $T_{10\ min}$, measured air pressure $B_{10\ min}$ and the dry air gas constant, R_o = 287,05 J/(kg K). The equation is presented below:

$$\rho_{10\ min} = \frac{B_{10\ min}}{R_o T_{10\ min}} \quad (3\text{-}2)$$

Noteworthy, no air density normalization is needed when the average measured air density of the site is within 1.225 ± 0.05 kg/m^3 .
For a wind turbine with active power control, the wind speed normalization should be applied. Where V_n is the normalized wind speed and V_{10min} is the measured wind speed averaged over 10 min.

$$V_n = V_{10min}\left(\frac{\rho_{10min}}{\rho_o}\right)^{1/3} \quad (3\text{-}3)$$

Determination of the Measured Power Curve

The net power is measured using a power transducer. It is located between the turbine and the electrical connection. Often the electrical output is three-phase 50/60 Hz voltage in the range of 380-415 V. A 3 watt meter method is suggested as it accounts for the load imbalance between the phases. The transducer should be class 0.5 at least, which implies a maximum uncertainty of 0.5%.

The measured power curve is determined by applying the “method of bins” for the normalized data sets, using 0.5 m/s bins and the calculation of the mean values of the normalized wind speed and normalized power output for each wind speed bin. The equations are the following:

$$V_i = \frac{1}{N_i}\sum_{j=1}^{N_i} V_{n,ij} \quad (3\text{-}4)$$

$$P_i = \frac{1}{N_i}\sum_{j=1}^{N_i} P_{n,ij} \quad (3\text{-}5)$$

Where,

V_i Normalized and averaged wind speed in bin *i.*
$V_{n,ij}$ Normalized wind speed of data set *j* in bin *i.*
P_i Averaged power output in bin *i.*
$P_{n,ij}$ Power output of data set *j* in bin *i.*
N_i Number of 10 min data sets in bin *i.*

The power values are the ten-minute means in each bin of wind speed. The result is, the *normalized and averaged power curve.* As explained in Chapter 2 this curve represents the foundation for the calculation of the annual energy yield, which can be expected on a site with a normal wind regime.

Annual Energy Production (AEP)

The AEP is estimated by applying the measured power curve to different reference wind speed frequency distributions. A Rayleigh distribution should be used as the reference wind speed frequency distribution. The Rayleigh distribution is identical to a Weibull distribution with a shape factor of 2. AEP estimations should be made at hub height for an annual average wind speed of 4, 5, 6, 7, 8, 9, 10 and 11 m/s using the following equation:

$$AEP = N_h \sum_{i=1}^{N} [F(V_i) - F(V_{i-1})]\left(\frac{P_{i-1} + P_i}{2}\right) \quad (3\text{-}6)$$

Where,

AEP Annual energy production.
N_h Number of hours in one year (≈ 8760h).
N Number of bins.
V_i Normalized and averaged wind speed in bin i.
P_i Averaged power output in bin i.

And

$$F(V) = 1 - exp\left(-\frac{\pi}{4}\left(\frac{V}{V_{ave}}\right)^2\right) \quad (3\text{-}7)$$

Where
$F(V)$ Is the Rayleigh cumulative probability distribution function for wind speed.
V_{ave} Is the annual average wind speed at hub height.
V Is the wind speed.

The summation starts by setting V_{i-1} equal to V_i – 0.5 m/s and P_{i-1} equal to 0.0 kW.

The AEP should be calculated in two ways: the *AEP-measured* and *AEP-extrapolated*. If the measured power curve does not include data up to cut-out wind speed, the power curve needs to be extrapolated from the maximum complete measured wind speed up to cut-out wind speed.

AEP-measured should be obtained from the measured power curve by assuming zero power for all wind speeds above and below the range of the measured power curve. The extrapolated AEP should be obtained from the measured power curve by assuming zero power for all wind speeds below the lowest wind speed in the measured power curve and constant power for wind between the highest wind speed and the cut-out wind speed.
For all AEP calculations, the availability of the wind turbine has to be set to 100%. For given annual average wind speeds, estimations of AEP-measured needs to be labeled as “incomplete” if the results show that the AEP-measured is less than 85% of the AEP-extrapolated.

Moreover, the uncertainties in AEP only take into consideration the uncertainties originating from the PPT and do not account for uncertainties related to actual energy production for a given installation.

Power Coefficient

The power coefficient C_p of the wind turbine should be added to the test results and presented as a curve vs. wind speed at hub height and as a table. The *cp* will be derived from the normalized and averaged power curve P_i following this equation

$$C_{p,i} = \frac{P_i}{\frac{1}{2}\rho_o A V_i^3} \quad (3\text{-}8)$$

Where
$C_{P,i}$ Power coefficient in bin i.
V_i Normalized and averaged wind speed in bin i.
P_i Averaged power output in bin i.
A Swept area of the wind turbine rotor.
ρ_o Reference density.

Evaluation of Uncertainties in Measurements

This section addresses the requirements for the determination of uncertainty in measurements. Following the ISO Guide (International Organization for Standardization), there are two types of uncertainties, Category A, the magnitude of which can be deduced from measurements, and Category

B, these are estimated by other means. This categorization is explained in detail in Section 2-1-2 (Uncertainty in Measurements).

The measured power curve and the estimated annual energy production should be complemented with an estimate of the uncertainty of the measurement. Table 3-2 provides a minimum list of uncertainty parameters that should be included in the uncertainty analysis.

Table 3-2: List of uncertainty components [1]

Measured parameter	Uncertainty component	Uncertainty category
Electrical power	Current transformers	B
	Voltage transformers	B
	Power transducer	B
	Data acquisition system	B
	Variability of electric power	A
Wind Speed	Anemometer calibration	B
	Operational characteristics	B
	Mounting effects	B
	Data acquisition system	B
	Flow distortion due to terrain	B
Air temperature	Temperature sensor	B
	Radiation shielding	B
	Mounting effects	B
	Data acquisition system	B
Air pressure	Pressure sensor	B
	Mounting effects	B
	Data acquisition system	B
Data acquisition system	Signal transmission	B
	System accuracy	B
	Signal conditioning	B

As presented in Table 3-2, all these are effects related to the instrumentation, the data acquisition system and the terrain surroundings of the test site. In category A variations of the electric power output are included, since it cannot be assessed systematically. Other influencing parameters can be found in Category B, for example, specific wind conditions of the site. In both categories, uncertainties are expressed as standard deviations and are denoted **standard uncertainties.**

The combined standard uncertainty of the power in bin i, $u_{c,i}$, can be expressed by:

$$u_{c,i}^2 = \sum_{k=1}^{M} \sum_{l=1}^{M} c_{k,i} u_{k,i} c_{l,i} u_{l,i} \rho_{k,l,i,j}$$

Where,

$c_{k,i}$ Is the sensitivity factor of the component k in bin i.

$u_{k,i}$ Is the standard uncertainty of the component k in bin i.

M Is the number of uncertainty components in each bin i.

$\rho_{k,l,i,j}$ Is the correlation coefficient between uncertainty component k in bin i and uncertainty component l in bin j(in the expression the components k and l are both in bin i).

The uncertainty component is the individual input quantity to the uncertainty of each measured parameter.

The combined standard uncertainty in the estimated annual energy production, u_{AEP} , can be expressed by:

$$u_{AEP}^2 = N_h^2 \sum_{i=1}^{N} \sum_{j=1}^{N} \sum_{k=1}^{M} \sum_{l=1}^{M} c_{k,i} u_{k,i} f_i c_{l,j} u_{l,j} \rho_{k,l,i,j}$$

Where,

f_i Relative occurrence of wind speed between V_{i-1} and V_i: $F(V_i) - F(V_{i-1})$ within bin i.

$F(V)$ Rayleigh cumulative probability distribution function for wind speed.

N Number of bins.

N_h Number of hours in one year (≈ 8760h).

To allow the above expressions of combined uncertainties to be simplified to a practical level, the following assumptions are considered:

- If the uncertainty components are fully correlated (ρ=1), then a linear summation should be performed, using the same approach as presented in Eq. (2-1). Alternatively, for the uncertain components that are independent of each other (ρ=0), the combined standard uncertainty is a quadratic summation. This method is shown in Eq. (2-2). The combined standard uncertainty is the square root of sum squares of uncertainty components.
- Category A and Category B are independent categories. In addition, all Category A uncertainty components are independent. All Category B uncertainty components are mutually fully correlated.

Using these assumptions, the **combined standard uncertainty of the power** in bin i, $u_{c,i}$, can be expressed by:

$$u_{c,i}^2 = \sum_{k=1}^{M_A} c_{k,i}^2 s_{k,i}^2 + \sum_{k=1}^{M_B} c_{k,i}^2 u_{k,i}^2 = s_i^2 + u_i^2 \qquad (3\text{-}9)$$

Where,

M_A Number of category A uncertainty components.

M_B Number of category B uncertainty components.

$s_{k,i}$ Category A standard uncertainty of components k in bin i.

s_i Are the combined category A uncertainties in bin i.

u_i Are the combined category B uncertainties in bin i.

The same assumptions apply to the AEP uncertainty. For this, the **combined standard uncertainty in the estimated annual energy production**, u_{AEP} , can be expressed by:

$$u_{AEP}^2 = N_h^2 \sum_{i=1}^{N} f_i^2 \sum_{k=1}^{M_A} c_{k,i}^2 s_{k,i}^2 + N_h^2 \left(\sum_{i=1}^{N} f_i \sqrt{\sum_{k=1}^{MB} c_{k,i}^2 u_{k,i}^2} \right)^2 = N_h^2 \sum_{i=1}^{N} f_i^2 s_i^2 + N_h^2 \left(\sum_{i=1}^{N} f_i u_i \right)^2 \qquad (3\text{-}10)$$

In Section 2-1-2 the expanded uncertainty was introduced. Furthermore, the combined standard uncertainties of the power curve and the AEP may additionally be expressed by standard uncertainties. Table 3-3 shows the expanded uncertainties assuming a normal distribution.

Table 3-3: Expanded uncertainty

Level of confidence [%]	Coverage factor [-]
68.27	1
90	1.645
95	1.960
95.45	2
99	2.576
99.73	3

In Table 3-4 all the uncertainty components, sensitivity factors, expressions to calculate the standard deviation and standard uncertainty are listed.

Table 3-4: List of Category A and Category B. Modified by the author from [1] [30]

Description	Uncertainty	Magnitude [30]	Sensitivity	Standard deviation	Standard Uncertainty
Category A: Statistical					
Electric power	$s_{P,i}$	-------	$c_{P,i} = 1$	$\sigma_{P,i} = \sqrt{\frac{1}{N_i - 1}\sum_{j=1}^{N}(P_i - P_{n,i,j})^2}$	$s_i = s_{P,i} = \frac{\sigma_{P,i}}{\sqrt{N_i}}$
Climatic variation *	s_w	-------	-------	a) Subdividing the data record into segments, b) Estimate annual energy production for each of the derived power curves c) Calculate the standard deviation of the annual energy production estimates.	-------
Category B: Instruments					
Power output	$u_{P,i}$				
Current transformers	$u_{P1,i}$	0.75%			
Voltage transformers	$u_{P2,i}$	0.5%	$c_{P,i} = 1$	-------	$u_{P,i} = \sqrt{u_{P1,i}^2 + u_{P2,i}^2 + u_{P3,i}^2 + u_{dP,i}^2}$
Power transducer or	$u_{P3,i}$	0.5%			
Power measurement device	$u_{P4,i}$	0.5%			
Wind Speed	$u_{V,i}$				
Anemometer	$u_{V1,i}$	-------			
Operational characteristics	$u_{V2,i}$	-------	$c_{V,i} \approx \left\|\frac{P_i - P_{i-1}}{V_i - V_{i-1}}\right\|$	-------	$u_{V,i} = \sqrt{u_{V1,i}^2 + u_{V2,i}^2 + u_{V3,i}^2 + u_{V4,i}^2 + u_{dV,i}^2}$
Mounting effects	$u_{V3,i}$	0.5% to 1.5%			
Air density					
<u>Temperature</u>	$u_{T,i}$	-------			
Temperature sensor	$u_{T1,i}$	0.4 K to 0.6 K			
Radiation shielding	$u_{T2,i}$	1.5 K to 2.5 K	$c_{T,i} \approx \frac{P_i}{288.15[K]}$	-------	$u_{T,i} = \sqrt{u_{T1,i}^2 + u_{T2,i}^2 + u_{T3,i}^2 + u_{dT,i}^2}$
Mounting effects	$u_{T3,i}$	0.25 K to 0.4K			
<u>Air pressure</u>	$u_{B,i}$	-------			
Pressure sensor	$u_{B1,i}$	2hPa to 4hPa			
Mounting effects	$u_{B2,i}$	10% of correction	$c_{B,i} \approx \frac{P_i}{1013[hPa]}$	-------	$u_{B,i} = \sqrt{u_{B1,i}^2 + u_{B2,i}^2 + u_{dB,i}^2}$

Data acquisition system	$u_{d,i}$				
Signal transmission	$u_{d1,i}$	-------	Sensitivity factor is derived from actual uncertainty parameter	-------	$u_{d,i} = \sqrt{u_{d1,i}^2 + u_{d2,i}^2 + u_{d3,i}^2}$
System accuracy	$u_{d2,i}$	-------			
Signal conditioning	$u_{d3,i}$	-------			
Category B: Terrain					
Flow distortion due to terrain	$u_{V4,i}$	From site calibration	$c_{v,i}$ (see above)	-------	Discussed in this Chapter. Eq. (3-13)
Category B: Method	$u_{m,i}$				
Air density correction	$u_{m1,i}$	-------	$c_{T,i}$ and $c_{B,i}$	-------	Not elaborated on the IEC 61400-12-1:2005 standard
** parameter not required for uncertainty analysis*					

NOTE: the subscript defined the type of uncertainty (e.g. $u_{dV,i}$ is the uncertainty in the data acquisition system for the wind speed in bin i).

Clarification: Category B - standard uncertainties

If the uncertainties are expressed as uncertainty limits (i.e. ±U) or a non-unity coverage factors is implicitly mentioned. Then, the standard uncertainty must be estimated or they must be converted into standard uncertainties using the following equations:

For an uncertainty expressed as an uncertainty limit ±U:

- When a rectangular probability distribution is assumed, the standard uncertainty is:

$$\sigma = \frac{U}{\sqrt{3}}$$

- When a triangular probability distribution is assumed, the standard uncertainty is:

$$\sigma = \frac{U}{\sqrt{6}}$$

Following the ISO guide, uncertainties are expressed as standard deviation and are denoted standard uncertainty [18]. This is addressed as well in Section 2-1-2.

Category B - uncertainties in Flow distortion (Site Calibration)

The uncertainty from the site calibration shall be included as the uncertainty of the flow distortion due to the terrain $u_{V4,i}$. The category A uncertainty of the flow correction factors of each wind direction bin is determined from the distribution of the measured flow correction factors (ratio of wind speed at wind turbine and wind speed at met-mast. The standard deviation of the distribution in each bin is $s_{\alpha,j}$. Calibration uncertainty is the same as for the power curve measurement. Operational uncertainties of the two cup-anemometers in site calibration may be neglected if both anemometers are of the same type. The site calibration uncertainty (ratio of wind speeds for each wind direction bin j) is expressed as:

$$u_{\alpha i,j} = \sqrt{\frac{2u_{V1,i}^2}{V_j^2} + \frac{2u_{dV,i}^2}{V_j^2} + \frac{s_{\alpha,j}^2}{N_j}} \qquad (3\text{-}11)$$

Where

$u_{\alpha,ij}$ Is the uncertainty of site calibration in wind speed bin i and wind direction bin j [-].

$u_{V1,i}$ Is the uncertainty of anemometer calibration in bin i [m/s].

$u_{dV,i}$ Is the uncertainty in data acquisition system for the wind speed bin i [m/s].

$s_{\alpha,j}$ Is the standard deviation of wind speed ratios in the wind direction bin j [-].

N_j Is the number of wind speed ratios in wind direction bin j [-].

In Eq.(3-11) it can be seen two times the uncertainty of anemometer calibration (comparable to two times the uncertainty in data acquisition system). The factor 2 can be explained by the fact that uncertainties of two cup-anemometers in site calibration may be considered correlated if the two anemometers are of the same type. For this reason, both uncertainties have to be added, following the same principle shown in the Eq. (2-1). The derivation presented below is not in the IEC 61400-12-1:2005 standard, but is shown for clarification purposes.

Assuming two cup anemometers of the same type (ρ=1), denoted X and Y. Then, for an arbitrary wind speed bin:

$$u_{V,(X+Y)}^2 = \left(u_{V,X} + u_{V,Y}\right)^2$$

Noticed that $u_{V,x}$= $u_{V,Y}$. Then,

$$u_{V,(X+Y)}^2 = \left(2u_{V,X}\right)^2 \longrightarrow u_{V,(X+Y)} = 2u_{V,X}^2$$

This shows how the uncertainty of two identical cup anemometers are related in the site calibration.

Moreover, the site calibration uncertainty is dependent on the wind speed. It is recommended to present the uncertainty of the site calibration for three wind speeds. When the site calibration uncertainty is included in the wind speed uncertainty, the site calibration uncertainty is multiplied by the sensitivity factor, which is equal to the wind speed of each bin:

$$u_{V4i,j} = \sqrt{2u_{V1,j}^2 + 2u_{dV,j}^2 + \frac{s_{\alpha j}^2 V_j^2}{N_j}} \quad (3\text{-}12)$$

The uncertainty of each wind speed bin of the power curve shall be weighted with the number of data in that wind speed bin for each wind direction bin of the site calibration:

$$u_{V4,j} = \frac{\sum_j u_{V4,i,j} N_{i,j}}{\sum_j N_{i,j}} \quad (3\text{-}13)$$

Where $N_{i,j}$ is the number of power curve data sets for wind speed bin i and wind direction bin j.

3-5 Remarks of the IEC Standards

The IEC standard presets some gaps or multiple interpretations may exist within the Power performance measurements (61400-12-1:2005). This is addressed accordingly in the following chapters. Nevertheless, to close those gaps, MEASNET [48] provides a uniform interpretation of standards and recommendations. For this, the MEASNET publications will be used as an additional guideline within this project.

Chapter 4

Site and Data Analysis

The IEC 61400-12-1:2005 standard [1] has a power curve test procedure and recommended equipment checklist that can be used to test the ambient condition before the turbines are installed. This process is a once-in-a-project opportunity to understand the initial meteorological conditions happening at a test turbine and fits in a small window of time. Doing this, potentially saves substantial ambiguity and lengthy litigation.

The first step in a wind resource assessment is to conduct a desktop study estimating the resource [49]. The wind resource assessment usually considers the predominant wind direction and mean annual wind speed across the project area. This was performed by the Vattenfall production assessment team in 2013 [50]. In this chapter, an overview of the site is presented, as well as the main power production influencing factors addressed in this project (i.e. wind speed, density, shear, veer, turbulence intensity and inflow angle). The data analyzed are from the meteorological masts on the site during the development period and each data point corresponds to 10- minute average measurements.

4-1 Site Description

The site is located in UK. The location is shown in Figure 4-1. The site is situated in complex terrain, covering a range of hills separated by steep valleys, and contains extensive commercial forestry [51]. The elevation of the turbines ranges from 100 m to 600 m approximately above mean sea level. In addition, due to the complexity of the site, a site calibration is required, thus apart from the 5 reference mast, 5 additional meteorological masts were placed: one pair per test turbine. In Section 4-4 (Meteorological Mast and Measurement systems) the met-masts are discussed in detail.

Figure 4-1: Location of Wind Farm

The general site specifications at hub height are found in Table 4-1. The table is the result of 3 years' wind data and after long-term correction; completed by the Vattenfall production assessment team in 2013 [50].

Table 4-1: Site specific conditions at hub height [43]

Site-specific conditions	Area1	Area2	Area3	Area4
Air density [kg/m^3]	1.183	1.186	1.175	1.183
Mean Wind Speed [m/s]	6.58	7.39	8.13	8.19
Weibull A [m/s]	7.44	8.34	9.17	9.25
Weibull k	1.97	2.11	2.13	2.1
TI @13m/s [%]	23%	23%	22%	24%
TI @14m/s [%]	22%	22%	21%	23%
TI @15m/s [%]	21%	21%	21%	21%
Inflow angle [°]	4.10	1.73	2.16	3.11
Wind Shear	0.29	0.23	0.27	0.33

4-2 Wind Farm Layout

To create the layout [52], a geographic information system (GIS) are typically used. With the GIS, the mapping of the terrain and the constraints are identified. In general, the constraints can be houses, neighboring wind farms, watercourses and roads, for example. After this step is completed, the 'available' useable area for wind turbines is obtained. In Appendix A: XYZ Site and Data, the final layout of this project is presented.

The wind farm consists of 50 ABC2 turbines and 30 ABC1 turbines. In total 80 turbines in total with park installed capacity of 240-280MW.

4-3 Proximity to Electricity Lines

The transmission infrastructure includes two new substations connected by 9.2km of underground cables. The electricity produced is increased from 33kV to 132kV by the XYZ substation. The second substation at SUB further increases the voltage to 400kV for export to the new National Grid substation through overhead lines [53].

4-4 Meteorological Masts and Measurement Systems

The data recorded comes from a total of 10 Meteorological Mast (MM). Here, a distinction is made between site calibration mast and reference mast: **i. Site Calibration Mast** (or Turbine mast) is a temporary mast on the top of the turbine foundation that is replaced by the turbine after the site calibration measurements are completed; and **ii. Reference Mast** is used as a reference at a distance of 2-4 rotor diameters from the corresponding test wind turbine, and can be either temporary or permanent in the lifetime of the wind farm. Each MM pair data (i.e. Site Calibration Mast- Reference Mast) are gathered by a specific location. For this project and according to the contract, the preferred distance between test turbine and Reference Mast is 2.5D [43]. Although all mast distances between 2.0D and 2.5D are allowed, the obstacles assessment was performed using a mast distance of 2.25D as a representative average for all locations.

In Figure 4-2, WTG1 met-mast pair location (i.e. Site Calibration Mast – Reference Mast) is shown, other locations can be found in Appendix A: XYZ Site and Data.

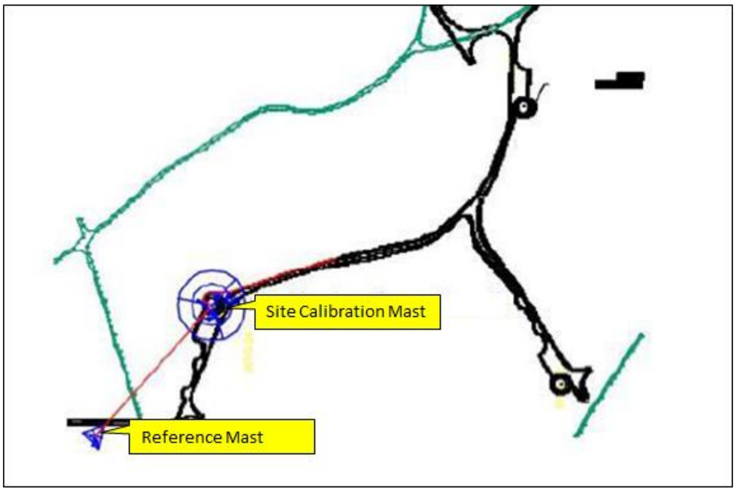

Figure 4-2: WTG1 - Site Calibration Mast and Reference Mast. Modified by the author from [51]

The instruments and positions are shown in Table 4-2 and Table 4-3 for each turbine type (i.e. ABC2 and ABC1). All meteorological masts and all their instruments are IEC standard compliant.

Table 4-2: Instruments on Reference Mast and Site Calibration Mast-corresponding to ABC2

Location: WTG1- WTG2- WTG3				
Reference Mas (RM)t	**[m]**	**[m]**	**[m]**	**m]**
Anemometer	88.000	83.725	59.750	31.500
Wind Vane	83.725	27.500	[-]	[-]
Ultrasonic 3D	81.008	[-]	[-]	[-]
Pressure Sensor	81.800	[-]	[-]	[-]
Temp/Hum - Sensor	81.800	[-]	[-]	[-]
Site Calibration Mast (SM)	**[m]**	**[m]**	**[m]**	**[m]**
Anemometer	88.000	83.725	59.750	31.500
Wind Vane	83.725	27.500	[-]	[-]
Ultrasonic 3D	81.008	[-]	[-]	[-]

Table 4-3: Instruments on Reference Mast and Site Calibration Mast –corresponding to ABC1

Location: WTG4-WTG5

Reference Mast (RM)	**[m]**	**[m]**	**[m]**	**[m]**
Anemometer	89.500	85.225	62.500	35.500
Wind Vane	85.225	31.5	[-]	[-]
Ultrasonic 3D	82.509	[-]	[-]	[-]
Pressure Sensor	83.300	[-]	[-]	[-]
Temp/Hum - Sensor	83.300	[-]	[-]	[-]
Site Calibration Mast (SM)	**[m]**	**[m]**	**[m]**	**[m]**
Anemometer	89.500	85.225	62.500	35.500
Wind Vane	85.225	31.500	[-]	[-]
Ultrasonic 3D	82.509	[-]	[-]	[-]

4-5 Terrain and Obstacle Assessment

For the Power Performance Testing, five locations were selected by the independent party previous to this work WTG1, WTG2, WTG3, WTG4, and WTG5. The locations are shown in Figure 4-3.

Figure 4-3: Studied location (Site Calibration Mast- Reference Mast pair per location). Modified by the author from [54]

Following the procedure described in Section 3-1 (Test Site), the assessment of terrain and obstacles are presented.

Terrain Assessment:

For the terrain assessment, the data is obtained from a 30 meters' terrain grid provided by Vattenfall [55]. According to the IEC 61400-12-1:2005 standard [1], if the slope is <3% and terrain variation <0.04 (H+D) for a distance of 0L to 2L (L=2.25D) around the evaluated turbine, then a site calibration can be avoided. Using Table 3-1 the assessment of the terrain is calculated for this project. The results can be seen in Table 4-4. Here the results are not within the limits and thus, a site calibration is required for all turbine locations.

Table 4-4: Results of terrain assessment at the site

Location	Data slope [%]	Data Variation from the plane [-]	IEC Slope max <	IEC Max. Terrain Variation from the plane < [-]	Within limits?
WTG1	**4.2%**	**0.25**	3%	8.04	**no**
WTG2	**5.5%**	**0.27**	3%	8.04	**no**
WTG3	**7.9%**	**0.39**	3%	8.04	**no**
WTG4	**7.0%**	**0.16**	3%	7.90	**no**
WTG5	**6.6%**	**0.21**	3%	7.90	**no**

A comparison of the terrains for the 5 mast pairs can be found in Appendix A: XYZ Site and Data.

Obstacle Assessment

As established before, site calibration measurements are required at this site and therefore forestry is not considered during the obstacles assessment. It is assumed that the wake influence of the forests will be captured by the site calibration. In addition, at this site, there are no significant obstacles. Only the following cases are considered:

- Met-mast in the wake of test turbine
- Met-mast in the wake of other turbines
- Test turbine in the wake of other turbines

The International IEC 61400-12-1:2005 standard has a clear methodology to determine measurement sectors (i.e. unperturbed and un-waked sectors). This is found in Section 3-1 (Test Site). Due to the complexity of the site, only a few scenarios are shown as an example of the methodology used for the obstacle analysis. Based on the Eq. (3-1) and Figure 3-2 the preliminary results are shown.

Table 4-5: Excluded sectors due to obstacles assessment (Preliminary Results)

WT	Case	Distance [m]	Le/De or L/D	Disturbed sector [°]	Angle [°]	Excl. Start [°]	Excl. End [°]
WTG1	From RM-->WT	248.67	**2.20**	**77.77**	**40.81**	**1.92**	**79.70**
	From RM-->WT2	1632.00	**14.44**	**33.28**	**39.09**	**22.45**	**55.73**
	From WT-->RM	248.67	**63.58**	**N/A**	**220.81**	**[-]**	**[-]**
WTG2	From RM -->WT	251.96	**2.23**	**77.35**	**98.68**	**60.00**	**137.36**
	From WT-->RM	251.96	**64.42**	**N/A**	**278.68**	**[-]**	**[-]**
WTG3	From RM -->WT	235.08	**2.08**	**79.56**	**70.94**	**31.16**	**110.72**
	From WT-->RM	235.08	**60.11**	**N/A**	**250.94**	**[-]**	**[-]**
WTG4	From RM -->WT	243.11	**2.25**	**77.05**	**78.50**	**39.98**	**117.02**
	From WT-->RM	243.11	**62.14**	**N/A**	**258.50**	**[-]**	**[-]**
	From RM-->WT2	415.29	**15.11**	**32.76**	**143.36**	**126.98**	**159.74**
	From WT--> WT2	374.67	**3.47**	**63.36**	**178.89**	**147.21**	**210.57**
WTG5	From RM -->WT	230.00	**2.13**	**78.82**	**67.80**	**28.39**	**107.21**
	From WT-->RM	230.00	**58.78**	**N/A**	**247.80**	**[-]**	**[-]**
	From RM-->WT2	510.66	**15.11**	**32.76**	**22.99**	**6.61**	**39.37**
	From WWTG4--> WT	374.67	**3.47**	**63.36**	**358.28**	**326.60**	**389.96**

The excluded measurements are part of the added contribution of the final measurement sector, an example of this is shown in Figure 4-4. For the not valid cases (color red - Table 4-5), these go outside of the valid region defined by the IEC (Figure 3-2). For this reason, they are not part of the final excluded sector. These results will vary with time and the measurements are carried high uncertainty, because, the distances were self-taken from Google Earth (the data was no longer available at the moment of writing this project). These factors lead to a high uncertainty, and this model will never be able to reach an exactly reproducible definition of the terrain that is valid over time.

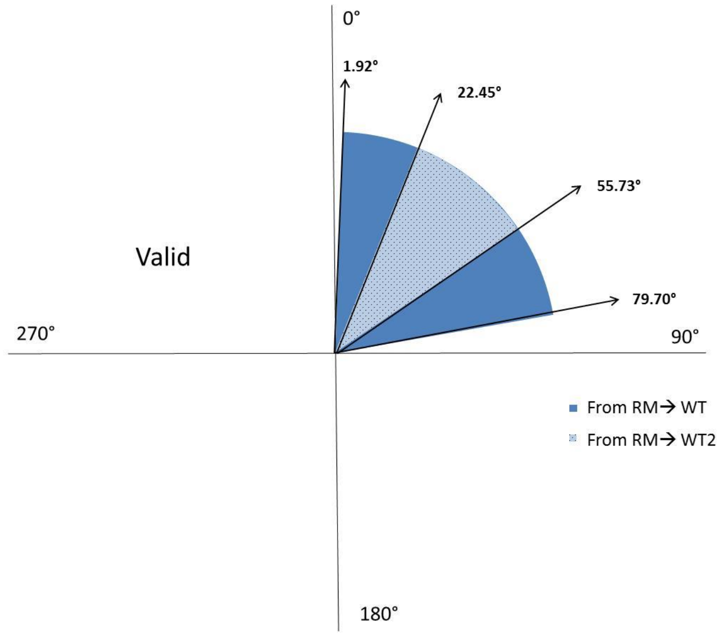

Figure 4-4: Example of WTG1 sectors to exclude due to wakes of the wind turbine under test, and neighboring and operating wind turbine.

Consequently, the free wind sectors are taken as known parameters from a previous study [55] (as mentioned before, the data was not available). This accounts for the test turbine in the wake of other turbines and wake effect on the mast. The preliminary results shown in Table 4-5 are complemented with the previous study. It is believed that in this study a better approach was used, with a detailed flow model. Overall, the results are exhibited in Table 4-6, as well as additional information of data collection period and turbine type.

Table 4-6: Valid Measuring Locations and Turbine Description

Location	Wind direction Sector	Turbine Type
WTG1	192.3° to 252.3°	ABC2
WTG2	250° to 310°	ABC2
WTG3	222.7° to 282.7°	ABC2
WTG4	230° to 290°	ABC1
WTG5	218.7° to 278.7°	ABC1

Figure 4-5 shows the WTG1 valid sector (referred as *free wind sector*) in detail, other locations can be found in Appendix A: XYZ Site and Data. In addition, in some chapters, the whole sector will be studied (360° this is referred as *all wind sectors)*.

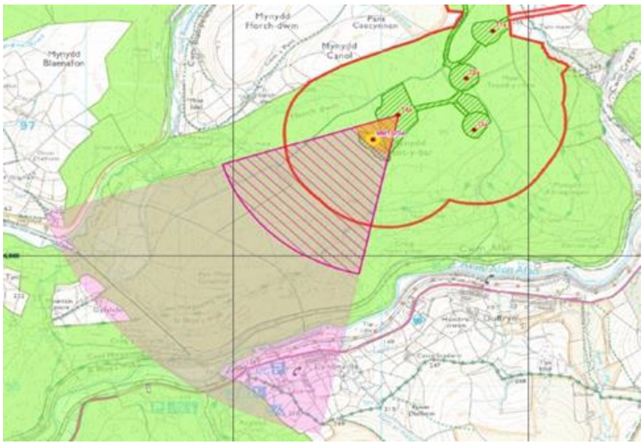

Figure 4-5: WTG1 free wind sector [51]

4-6 Wind Speed and Direction

The predominant direction of the entire site is South-West. The yearly mean wind speed of the site is 7.56m/s based on an average of 3 years of data, after long-term correction [50, 43]. In this chapter, the data used is from WTG1 site calibration period (i.e. 23.03.2016-04.05.2016 – Ref. Table 4-6). Moreover, Figure 4-6 shows WTG1 wind rose. The analysis was carried at hub height and the wind velocity represented in the wind rose is the mean velocity of the site calibration mast (SM) and reference mast (RM). Other wind rose locations can be found in Appendix A: XYZ Site and Data.

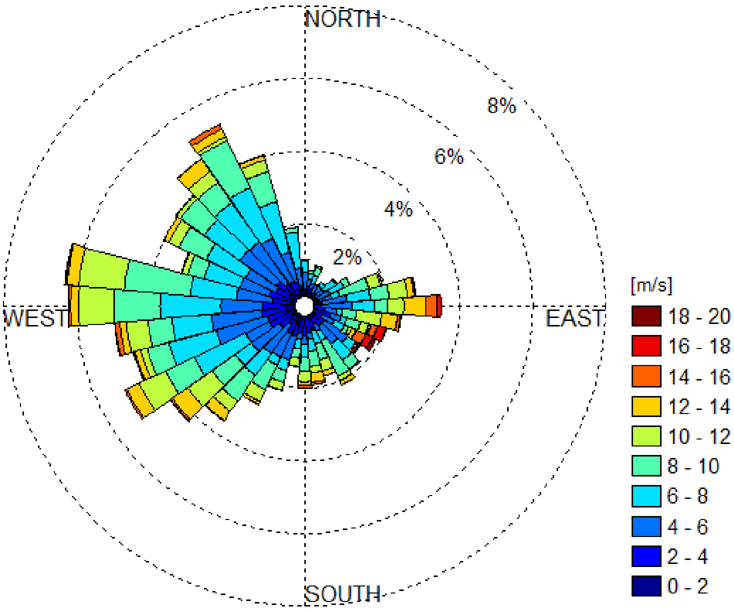

Figure 4-6: Wind Rose WTG1 at hub height, mean wind speed - Reference Mast and Site Calibration Mast.

The Nominal Wind Distribution (NWD) was introduced in Chapter 2. NWD represents the mean hub-height wind speed distribution at the individual wind turbine location. It is further used to calculate the Warranted Annual Energy Production (W-AEP) and the Measured Annual Energy Production (M-AEP). The NWD is stated in the contract, as agreed by both parties (Vattenfall and ABC). Table 4-7 shows the NWD valid for the whole wind farm.

Table 4-7: Nominal Wind Distribution (NWD) valid for ABC1 and ABC2 [42]

Wind Speed (WS)	Min WS Interval	Max WS Interval	NWD
[m/s]	[m/s]	[m/s]	Hours/year
1	0	1.5	172
2	1.5	2.5	345
3	2.5	3.5	531
4	3.5	4.5	692
5	4.5	5.5	812
6	5.5	6.5	880
7	6.5	7.5	895
8	7.5	8.5	861
9	8.5	9.5	786
10	9.5	10.5	685
11	10.5	11.5	570
12	11.5	12.5	453
13	12.5	13.5	345
14	13.5	14.5	252
15	14.5	15.5	177
16	15.5	16.5	119
17	16.5	17.5	76
18	17.5	18.5	47
19	18.5	19.5	28
20	19.5	20.5	16
21	20.5	21.5	9
22	21.5	22.5	5
23	22.5	23.5	2
24	23.5	24.5	1
25	24.5	25.5	1
26	25.5	26.5	0
27	26.5	27.5	0
28	27.5	28.5	0
29	28.5	29.5	0
30	29.5	30.5	0

4-7 Density

Following the power equation, the influence of air density on power output is linear, as presented in Eq. (2-7), the change in power is directly proportional to air density. In addition, the air density varies with elevation because of changing temperature/pressure/humidity.

In this section, the density of humid air has been calculated as a mixture of ideal gasses. The density of humid air is calculated as the sum of the density of the dry air component plus the density of the saturated component of the mixture (Eq. (2-7)). Using 10-min averages for temperature, pressure, and humidity levels; the density for WTG1 is calculated and shown in Figure 4-7. Due to technicians on the reference mast, the figure presents some gaps, this is considered in the evaluation period data.

For WTG5 the temperature data was not available (error with the instrument). For this, WTG4 and WTG5 are assumed to have the same density due to the proximity between these two locations. The density for all locations can be found in Appendix A: XYZ Site and Data.

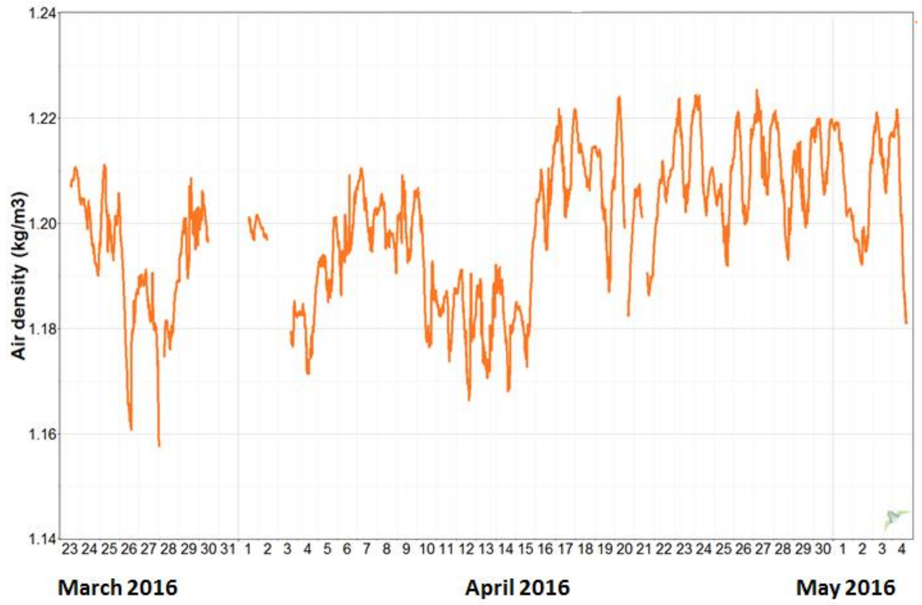

Figure 4-7: WTG1 Air Density– Reference Mast (all wind sectors)

4-8 Turbulence Intensity

The power curve is affected by turbulence, which is related to the topography where the wind turbine is located [56]. The Turbulence Intensity is calculated by dividing the standard deviation of 10-minute wind speed series by its mean wind speed Eq. (2-10). For the turbulence intensity, high levels are observed when the wind speed is low, as shown in Figure 4-8. As expected, when the wind fluctuates rapidly, then the turbulence intensity is high, this is normally at low heights. Conversely, steady winds have a lower turbulence intensity.

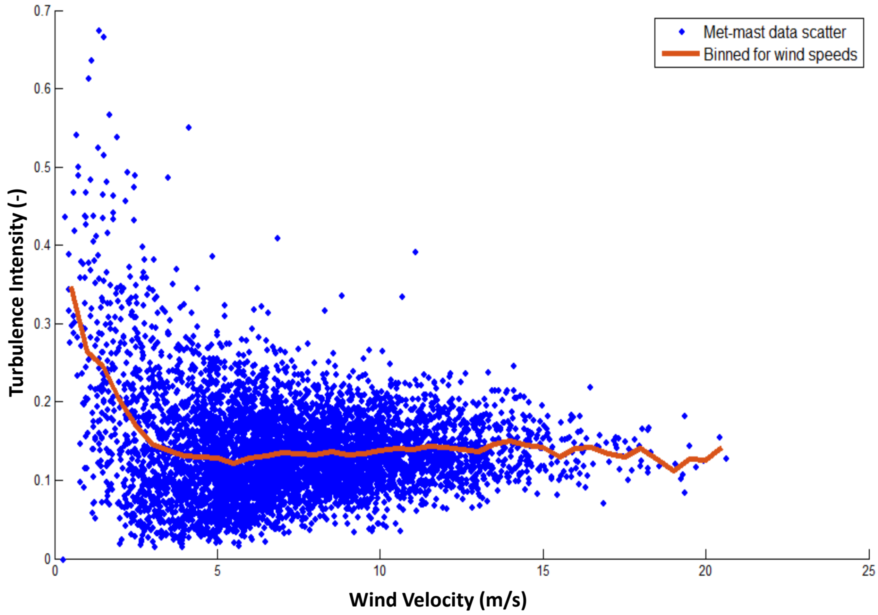

Figure 4-8: Turbulence Intensity WTG1 - Reference Mast at hub-height - (all wind Sectors)

Due to the complexity of the terrain, some of the sectors are being exposed to turbulence levels above Class A. An example of this is location WTG1; in Figure 4-9 is shown the TI IEC categories against the RM and SM wind speeds. The RM and SM showed below are a “screenshot” of that specific period (e.g. March-May 2016)

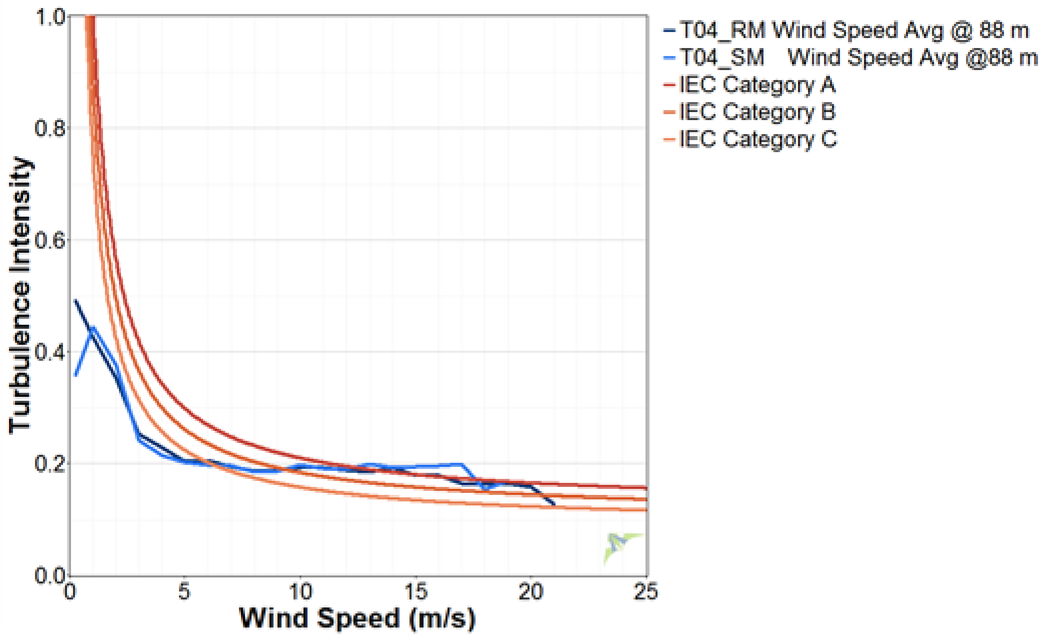

Figure 4-9: TI- Representative TI vs Wind speed Reference Mast and Site Calibration Mast. Comparison with IEC turbulence categories - (all wind Sectors).

4-9 Wind Shear

Using the power law, the wind shear coefficient was calculated using the RM wind speed data. The RM top and lower anemometers are used in this calculation. Based on Eq.(2-12) the wind shear exponent is calculated per data point and then averaged, the result obtained is α=0.402 for WTG1.

Figure 4-10 shows exemplary for WTG1 the RM power law exponent daily profile. It illustrates a marked drop in exponent value during the daytime hours. This trend has been described by other researchers, the power law exponent varies significantly between day and night [57]. The wind shear exponent shows a mean higher value between 10 p.m. (22h) to 5 a.m. (05h). This is because during the night the surface area cools down which enables stable conditions to prevail and the opposite applies for the daytime. When the stable boundary layer is lower than the met-mast at hub height, then the wind regime at the upper measuring level (hub height) is decoupled from the regime at the lower measuring level (near the ground), leading to two different wind regimes and different wind speed magnitudes.

In most locations, the average power law exponent is between 0.3-0.4. The power law exponent probability distribution can be found for all sites in Appendix A: XYZ Site and Data. High shear can have effects on availability, production, and lifetime of the wind farm. But, like the turbulence intensity, this project only considers the possible effect on power production.

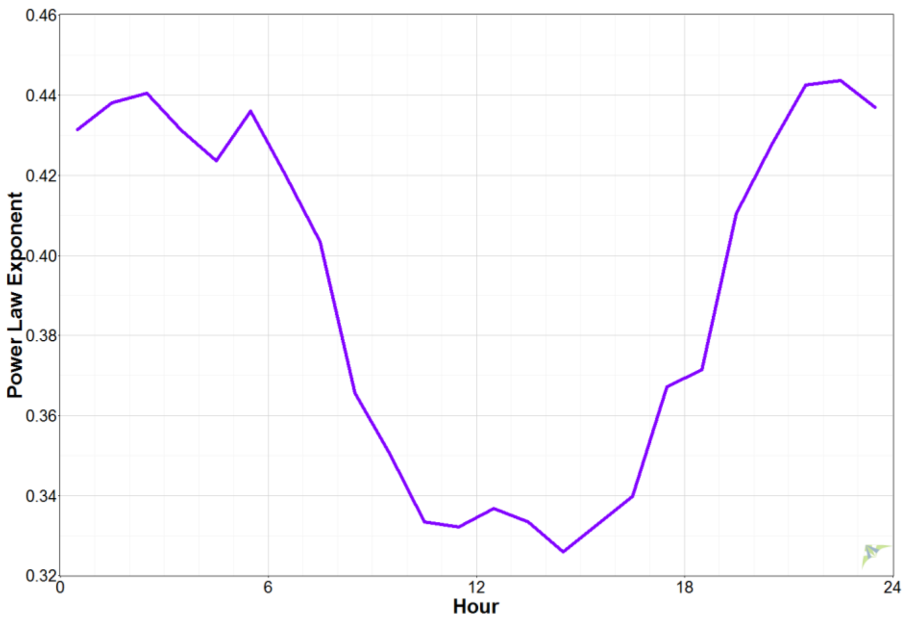

Figure 4-10: WTG1 Mean Daily Power Law Exponent -Reference Mast - (all wind Sectors)

4-10 Wind Veer

As explained in Chapter 2, the wind veer is the change of wind direction with height. The wind flow that is not perpendicular to the rotor disc will translate into a lower output. The mean veer rate value found for the WTG1 location was 4.9 ° /100m. In addition, Figure 4-11 shows the veer rate per direction sector. Positive and negative wind veer can be observed. A small clockwise veer will increase the performance of the turbine [58], as is the case for most of the wind directions shown in the graph, whereas an anticlockwise veer is expected to decrease the performance. Other locations can be found in Appendix A: XYZ Site and Data.

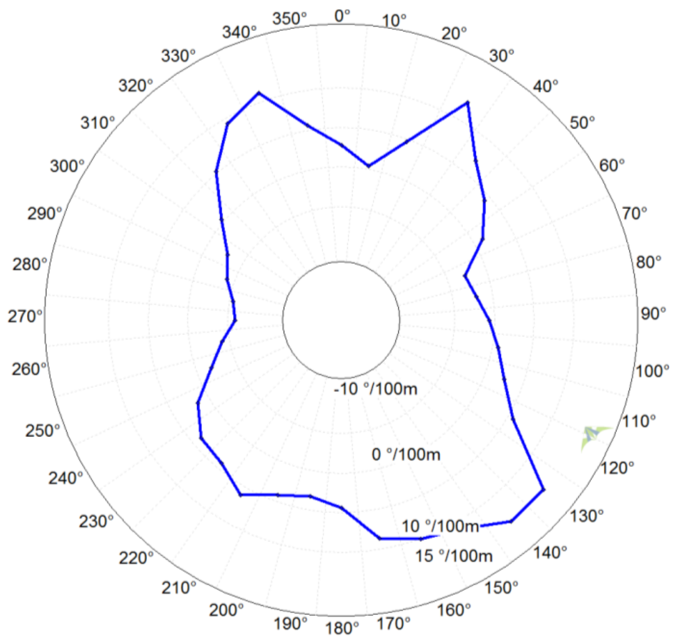

Figure 4-11: WTG1 RM Average Wind Veer Rate per Wind direction bin (10°)- (all wind Sectors)

4-11 Inflow Angle

The angle of the horizontal plane at which the wind flow comes into the rotor is defined as inflow angle. In complex terrain, non-horizontal wind flows are prevalent, driven both by terrain and thermal effects [59]. The inflow angle was calculated based on Eq. (2-16). In Figure 4-12, WTG1 reference mast mean inflow angles are represented in degrees.

The IEC 61400-12-1:2005 standard states that wind turbines are certified for inflow angles within ±8° [60]. Nonetheless, the evaluation period data contains some inflow angles higher than ±8°. High inflow angles are generally found in complex terrains with steep slopes and may affect the production and lifetime of wind turbines. Different inflow angles can be found in Appendix A: XYZ Site and Data. for all locations.

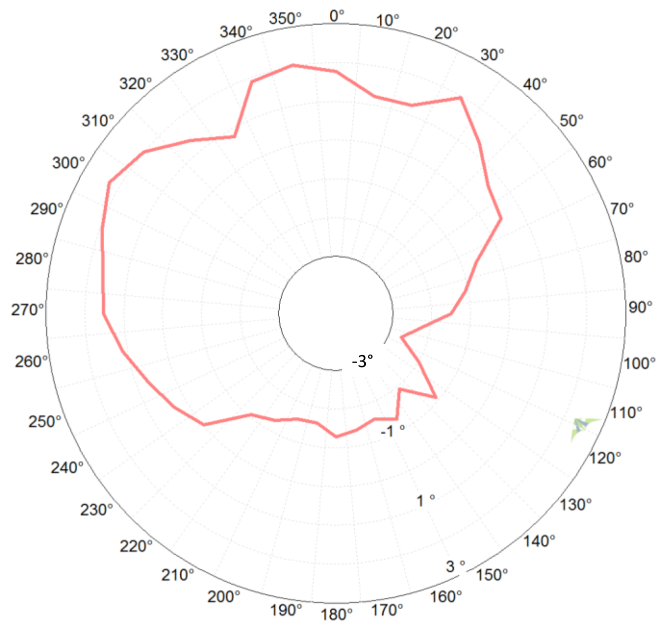

Figure 4-12: Inflow Angle WTG1. Reference Mast -(all wind Sectors)

4-12 Remarks on the Site and Data Description

Based on an average of 3 months' measurement period, some site-specific indicators were studied to understand the power curve dependence on site conditions. Therefore, the analysis of a complex terrain has led to different outcomes depending on the studied location (i.e. WTG1, WTG2, WTG3, WTG4, and WTG5). The impact of the variables studied in this chapter can be related to the period during which the site calibration took place. Though the seasonal variation is not studied in this research, it is reasonable to expect that the tested wind turbines may get different power curves during different seasons as the wind speed, density, turbulence intensity, wind shear, and wind veer differ.
The terrain assessment according to the IEC 61400-12-1:2005 standard resulted in the need of a site calibration. Meanwhile, the obstacle assessment gave the valid measuring sectors of undisturbed flow. The distance between met masts and wind turbines has implications on the wind condition measurements. For this, other wind turbines adjacent to the test wind turbines were analyzed. The forestry was not considered during this obstacles assessment, since it is assumed that the wake influence of the forests is captured by the site calibration.

Chapter 5

Site Calibration

Given the complexity of the wind farm site in terms of topography, site calibration measurements are required prior to turbine installation. This involves the installation of met masts in the location of the proposed turbine (i.e. Site Calibration Mast - SM) and a reference location (i.e. Reference Mast - RM); the distance between the met-mast pair is 2.25 rotor diameter as the average representative for all locations.

The aim of this chapter is to enable a calibration by correlation. The results will be used for the Power Performance Testing (PPT). In the site calibration phase, the correlation coefficients of wind speeds between the two meteorological masts pair are calculated. The correlation equation is derived by linear regression analysis. Linear Regression is a statistical tool and the most common method for fitting a regression line is the method of least-squares. This method calculates the best-fitting line for the observed data points by minimizing the sum of the squares of the vertical deviations from each data point to the line [61].

The result of a site calibration test consists on a table of flow correction factors for all wind directions studied per location and as well the uncertainty related to these correction factors [1].

5-1 Linear Regression: Least squares method.

Regression analysis is a method for investigating the functional relationship among variables. These are commonly referred to as *simple linear regression* or straight-line regression [62]. Site calibration considers the relationship of two variables, RM wind speed and SM wind speed at hub height.

When the data is collected in pairs, the standard notation is:

$$(x_1, y_1), (x_2, y_2), \ldots, (x_n, y_n)$$

Where x_1 denotes the first value of the X-variable and y_1 denotes the first value of the Y-variable. The X-variable is called independent variable, in site calibration, this is RM wind speed values. Whereas the Y-variable is called the dependent variable, referring to SM wind speed values.

As mentioned before, simple linear regression is typically used to model the relationship between Y and X, so that given a specific value of X (i.e. X=*x*); the Y value can be predicted. Mathematically, the regression of two random variables is:

$$E(Y \mid X = x)$$

That represents the expected value of Y when X takes the specific value x. When the regression is linear:

$$E(Y \mid X = x) = b_o + b_1 x$$

Where the unknown parameters b_o b_1 determine the offset and the slope of the straight line respectively. Then, for a set of variables i= 1,2,…,n

$$Y_i = E(Y \mid X = x) + e_i = b_o + b_1 x_i + e_i$$

Where e_i is the random uncertainty in Y_i and complies with E(e|X)=0. In practice, the difference between the actual value y (y_i) and the predicted value of y ($\hat{y}_i$) should be minimal. This difference is called residual, $\hat{e}_i$.

$$\hat{e}_i = y_i - \hat{y}_i$$

A method of selecting b_0 and b_1 is called the *method of least squares*. As the name suggest b_0 and b_1 are selected to minimize the residual sum of squares (RSS). [62]

$$RSS = \sum_{i=1}^{n} \hat{e}_i^2 = \sum_{i=1}^{n} (y_i - \hat{y}_i)^2 = \sum_{i=1}^{n} (y_i - b_0 - b_1 x_i)^2$$

For RSS to be a minimum with respect to b_0 and b_1 is needed

$$\frac{\partial RSS}{\partial b_0} = -2 \sum_{i=1}^{n} (y_i - b_0 - b_1 x_i) = 0$$

And

$$\frac{\partial RSS}{\partial b_1} = -2 \sum_{i=1}^{n} x_i (y_i - b_0 - b_1 x_i) = 0$$

Rearranging terms

$$\sum_{i=1}^{n} y_i = b_0 n + b_1 \sum_{i=1}^{n} x_i$$

And

$$\sum_{i=1}^{n} x_i y_i = b_0 \sum_{i=1}^{n} x_i + b_1 \sum_{i=1}^{n} x_i^2$$

The last two equations are known as normal equations. Solving these equations for b_0 and b_1 give the least squares estimates of the offset:

$$b_0 = \bar{y} - b_1 \bar{x} \qquad (5\text{-}1)$$

And the slope:

$$b_1 = \frac{\sum_{i=1}^{n} x_1 y_1 - n\,\overline{xy}}{\sum_{i=1}^{n} x_i^2} = \frac{\sum_{i=1}^{n} (x_i - \bar{x})(y_i - \bar{y})}{\sum_{i=1}^{n} (x_i - \bar{x})^2} \qquad (5\text{-}2)$$

Vertical least squares fitting proceeds by finding the coefficient of determination or *R-squared value* denoted R^2. This is the regression sum of squares divided by the total sum of squares.

$$R^2 = \frac{\sum_{i=1}^{n}(\hat{y}_i - \bar{y})^2}{\sum_{i=1}^{n}(y_i - \bar{y})^2} \tag{5-3}$$

If R^2=1, all the data points fall perfectly on the regression line, then the predictor RM accounts for all the variation in SM wind speed. If R^2=0, the estimated regression line is perfectly horizontal. The predictor RM wind speed accounts for none of the values in the SM wind speed.

5-2 Evaluation of the Measured Data

A distinction is made between database read period and evaluation period. The database read period (or raw data) specifies the period in which the measuring systems (partially or completely) are working and collecting information to the database. Meanwhile, the evaluation period specifies the period over which data collection is specified in the warranty contract, after revision that all the measuring systems are working correctly. The evaluation period is within the database read period.

In this project, some raw data originally obtained from the met-masts had erroneous data in certain measurements. These errors are a result of incorrect measurements (measuring device or data logger) or technicians on the mast. Therefore, these errors were removed in the evaluation period. The evaluation period is the starting point of this data analysis and it is named in this project as an unfiltered data. After this, all the filters and analysis were done using a code written by the author in MATLAB R2014a.

As mentioned in Chapter 3 the data should be rejected under the following circumstances [1]:

- Failure or degradation (e.g. due to icing) of test equipment;
- Wind direction outside the measurement sectors (free wind sector);
- Mean wind speed less than 4 m/s or greater than 16 m/s;

To avoid failure or degradation due to icing, a temperature filter is applied. Detection of ice is not easy, for this project, a simple temperature filter has been agreed; only temperatures above 2°C are accepted.

In addition to the above-mentioned IEC requirements, the XYZ contract stated the following added requirements to be filtered [43]:

- Absolute wind veer above 15°, as defined by the wind direction difference measured near hub height and near lower tip height (i.e. the rotor radius).
- Wind flow inclination exceeding 8°, measured at the reference mast location.
- Turbulence intensity (TI) outside the limits presented in Figure 5-1, as well as described below:
    - Lower limit: 5%
    - Upper limit for wind speed up to 13 m/s: $TI(v) = 3.0 \times v^{-1}$
    - Upper limit for wind speeds above 13 m/s: $TI(v) = TI_{PCref}(13m/s) + 3\%$, where TI_{PCref} is the TI value specified in Table 4-1. Where the value of TI_{PCref} for each measuring position are indicated: Area1: 23% (WTG1), Area2: 23%(WTG2), Area3: 22%(WTG3), Area4: 24% (WTG4 and WTG5).

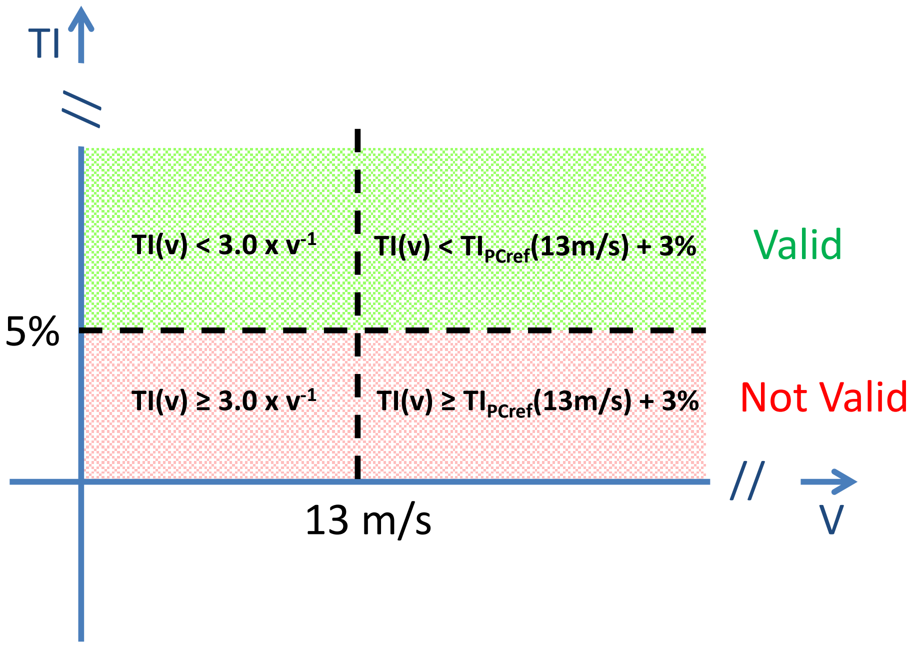

Figure 5-1: Simplification TI filters.

The effect of the applied filters on WTG1 data is shown in Table 5-1. The filtered data represents 16% of the total evaluation period data.

Table 5-1: Effect of applied filters WTG1 – Site Calibration

WTG1			
Steps	**Filter Event**	**remaining hierarchy**	**affected hierarchy**
1	Database read period	8453	0
2	Evaluation period	5496	2957
3	Wind direction sector 192.3° to 252.3°	1203	4293
4	Wind speed 4…16 m/s	991	212
5	Only abs (wind veer <15°)	980	11
6	Only abs (wind flow inclination) < 8°	978	2
7	Turbulence filter	960	18
8	Only temperatures above 2°C	903	75

The first estimation for site calibration (based on WTG1 filtered and unfiltered data) is presented in Figure 5-2.

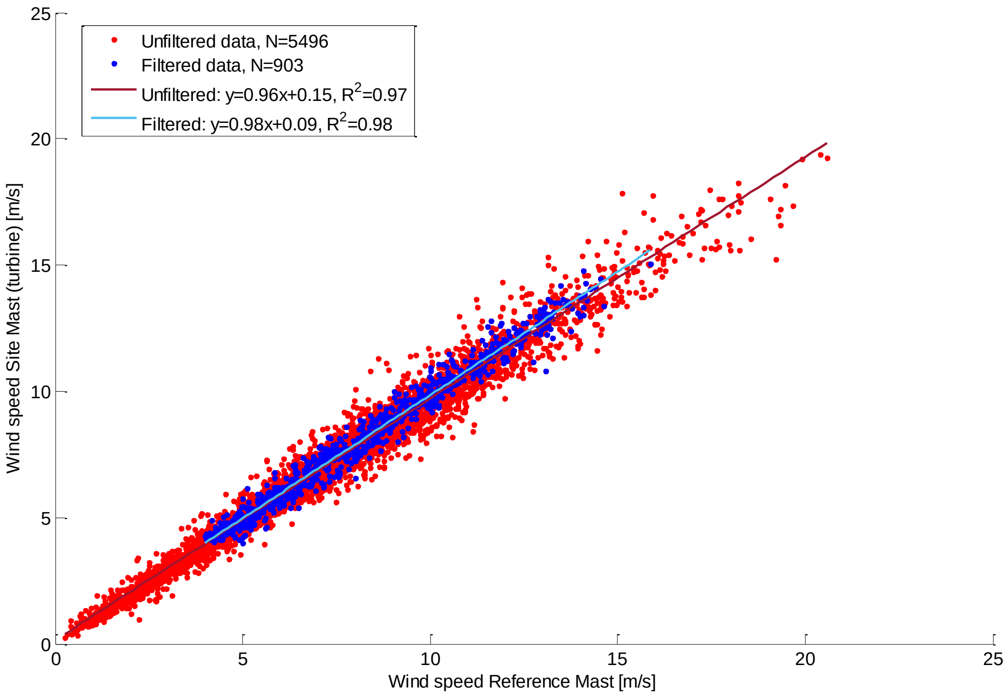

Figure 5-2: Overview site calibration WTG1. Evaluation period data and filtered data – (Unfiltered data: all wind sectors | Filtered data free wind sector)

The effect of the applied filters on WTG2 data is shown in Table 5-2. Where the filtered data is 11% of the total evaluation period data.

Table 5-2: Effect of applied filters WTG2 – Site Calibration

WTG2			
Steps	**Filter Event**	**remaining hierarchy**	**affected hierarchy**
1	Database read period	14250	0
2	Evaluation period	6422	7828
3	Wind direction sector 250° to 310°	1672	4750
4	Wind speed 4…16 m/s	1205	467
5	Only abs (wind veer <15°)	1171	34
6	Only abs (wind flow inclination) < 8°	1120	51
7	Turbulence filter	1048	72
8	Only temperatures above 2°C	694	426

The first estimation for site calibration (based on WTG2 data filtered and unfiltered) is presented in Figure 5-3.

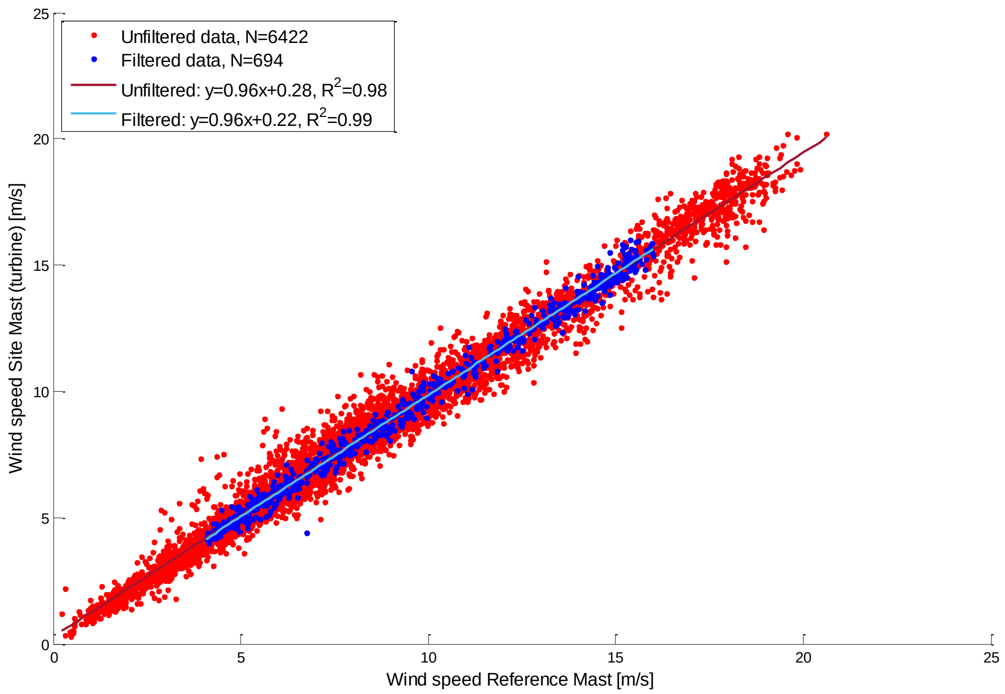

Figure 5-3: Overview site calibration WTG2. Evaluation period data and filtered data – (Unfiltered data: all wind sectors | Filtered data free wind sectors).

The effect of the applied filters on WTG3 data is shown in Table 5-3. The filtered data represents 15% of the total evaluation period data.

Table 5-3: Effect of applied filters WTG3 – Site Calibration

WTG3			
Steps	**Filter Event**	**remaining hierarchy**	**affected hierarchy**
1	Database read period	10226	0
2	Evaluation period	9495	731
3	Wind direction sector 222.7° to 282.7°	3033	6462
4	Wind speed 4…16 m/s	2526	507
5	Only abs (wind veer <15°)	2339	187
6	Only abs (wind flow inclination) < 8°	2325	14
7	Turbulence filter	2313	12
8	Only temperatures above 2°C	1457	868

The first estimation for site calibration (based on WTG3 data filtered and unfiltered) is presented in Figure 5-4.

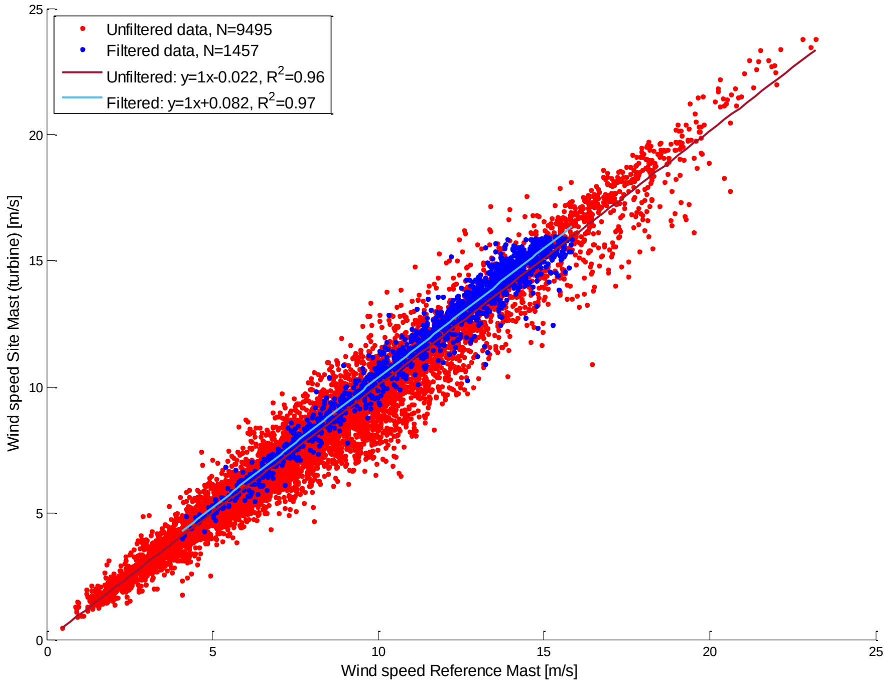

Figure 5-4: Overview site calibration WTG3. Evaluation period data and filtered data – (Unfiltered data: all wind sectors | Filtered data free wind sectors).

The effect of the applied filters on WTG4 data is shown in Table 5-4 where the filtered data represents 21% of the total evaluation period data.

Table 5-4: Effect of applied filters WTG4 – Site Calibration

WTG4			
Steps	**Filter Event**	**remaining hierarchy**	**affected hierarchy**
1	Database read period	16271	0
2	Evaluation period	13136	3135
3	Wind direction sector 222.7° to 282.7°	5641	7495
4	Wind speed 4...16 m/s	4003	1638
5	Only abs (wind veer <15°)	3992	11
6	Only abs (wind flow inclination) < 8°	3968	24
7	Turbulence filter	3910	58
8	Only temperatures above 2°C	2791	1119

The first estimation for site calibration (based on WTG4 data filtered and unfiltered) is presented in Figure 5-5.

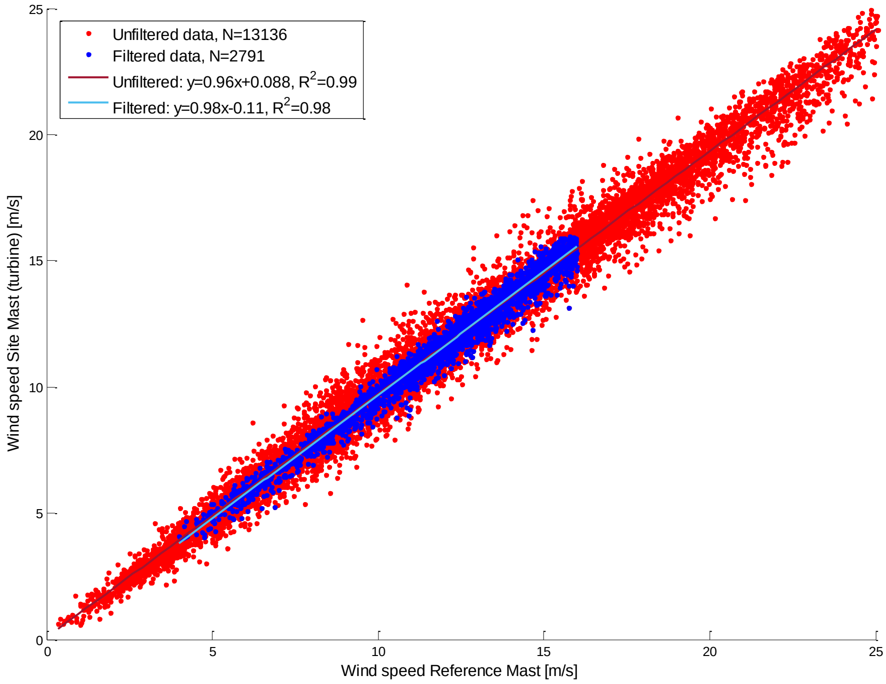

Figure 5-5: Overview site calibration WTG4. Evaluation period data and filtered data – (Unfiltered data: all wind sectors | Filtered data free wind sectors).

The effect of the applied filters on WTG5 data is shown in Table 5-5. Where the filtered data is 28% of the total evaluation period data. Noteworthy, it was not possible to apply the temperature filter, since the temperature/ humidity sensor had a malfunction during the site calibration period.

Table 5-5: Effect of applied filters WTG5 – Site Calibration

	WTG5		
Steps	**Filter Event**	**remaining hierarchy**	**affected hierarchy**
1	Database read period	15984	0
2	Evaluation period	6560	9424
3	Wind direction sector 222.7° to 282.7°	3193	3367
4	Wind speed 4…16 m/s	3115	78
5	Only abs (wind veer <15°)	3103	12
6	Only abs (wind flow inclination) < 8°	3102	1
7	Turbulence filter	1813	1289
8	Only temperatures above 2°C	[-]	[-]

The first estimation for site calibration (based on WTG5 data filtered and unfiltered) is presented in Figure 5-6

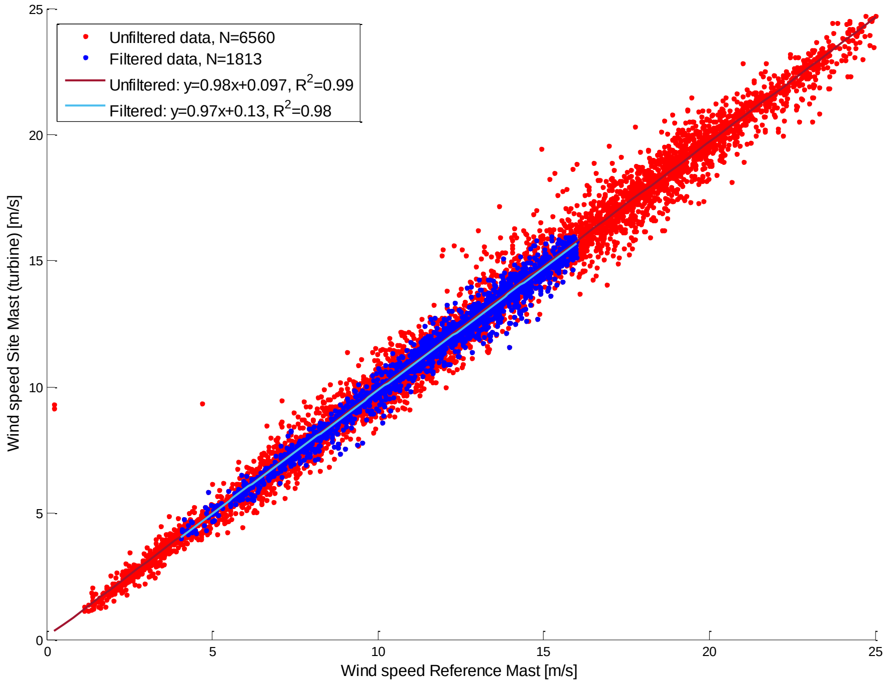

Figure 5-6: Overview site calibration WTG5. Evaluation period data and filtered data – (Unfiltered data: all wind sectors | Filtered data free wind sectors).

The **data filtering** was necessary to eliminate data that could have been compromised as result of an obstruction near the site (valid sectors); this topic is discussed in Section 4-5 (Terrain and Obstacle Assessment). After applying the wind profile filters on the evaluation period data, the reduction was higher than expected, leaving available an average of 19% of the data for all sites (WTG1, WTG2, WTG3, WTG4, WTG5). This can be observed in the effects of the applied filters (Table 5-1, Table 5-2, Table 5-3, Table 5-4, Table 5-5).

The statistics for each 10-minutes period are calculated with 1 s sampling data (i.e. 600 samples for each 10 minutes). The IEC 61400-12-1:2005 standard states the following: A digital data acquisition system having a sampling rate per channel of at least 1Hz shall be used to collect measurements [1]. Nevertheless, it does not indicate a minimum of sampling points to take as valid. This filter (i.e. 600 samples for each 10 minutes) can reduce the data and consequently the final valid bins. For this reason, in the evaluation period, the data with less than 600-sample points is not filtered. Neither the contract nor the IEC address this topic. But, it is noted as an improvement for future contracts.

5-3 Site Calibration Results

The previous section addressed the filters to apply to start a site calibration. As explained in Section 3-1 (Site Calibration) to perform a site calibration the data sets should be sorted into wind direction bins. Each bin should not be larger than 10° and each bin needs to have a minimum of 24h data (equivalent to 144 data points) [1]. Of these, each bin should have at least 6h data (equivalent to 36 data points) where the wind speed is above 8m/s and at least 6h data (equivalent to 36 data points) where the wind is below 8m/s.

A clear example of how the linear regression analysis was performed can be found in Appendix B: Regression Analysis- Site Calibration for WTG1 location. In this statistical process, the relationship between wind speed reference mast (x-axis) and wind speed site calibration mast (y-axis) is calculated. This calculation is based on the Eq. (5-1), (5-2), (5-3) per bin direction, and the results are known as slope, offset, and R-squared respectively.

In Section 3-4 (Evaluation of Uncertainties in Measurements) the uncertainties were stated. The two types of uncertainty to be considered when an experimental site calibration is undertaken are: (i) the combined standard uncertainty derived from the site calibration ($u_{\alpha,i,j}$ - Eq.(3-11)); and (ii) the uncertainty from the wind speed related to flow distortion due to terrain ($u_{v4,i,j}$ - Eq. (3-12)).

The site calibration uncertainties are dependent on the wind speed. As per the IEC 61400-12-1:2005 standard, it is recommended to present the uncertainty of the site calibration for a specific wind speed. In addition, the uncertainty shall be calculated for three wind speeds [1]. In this study, the wind speeds used were 6 m/s,10 m/s and 14 m/s as arbitrary values.

Moreover, the uncertainty calculation of the Site Calibration is calculated based on the uncertainty section of the IEC as shown in Section 3-4, with the known uncertainty components shown in Table 5-6. The uncertainty is expected to increase with increasing complexity of topography.

Table 5-6: Known Uncertainty of components. [55]

Uncertainty source	**Component**	**Value**
Calibration	$u_{V1,i}$	0.07 [m/s]
Data acquisition system	$u_{dV,i}$	0 – negligible with respect to the 10-minute average
Standard deviation of wind speed ration	$S_{\alpha,j}$	depending on wind direction

According to the IEC 61400-12-1:2005 standard [1], the following information should be reflected on the tables for each wind direction bin.

- Minimum and maximum wind direction limits;
- The bin-averaged wind direction;
- The bin-averaged ratio of wind speed;
- Number of hours of data;
- Combined standard uncertainty of the wind speed ratio for 6, 10 and 14 m/s.

The site calibration results are presented in the next tables.

Table 5-7: Site Calibration Results WTG1

bin num	bin from	bin to	WD avg	no Set	no Set	no Set	ratio (SM/RM)	WS SM	WS RM	slope	offset
				4 to 16 m/s	*4 to 8 m/s*	*8 to 16 m/s*	*ws avg -bin*	*avg -bin*	*avg -bin*		
[-]	[°]	[°]	[°]	[-]	[-]	[-]	[-]	[m/s]	[m/s]	[-]	[m/s]
1	190	200	196.4	**55**	**28**	**27**	1.01	8.1	8.0	0.959	0.349
2	200	210	205.1	**106**	**53**	**53**	1.01	7.5	7.4	0.983	0.203
3	210	220	215.7	**140**	**70**	**70**	0.98	8.1	8.2	0.972	0.055
4	220	230	225.4	**165**	**71**	**94**	0.99	8.4	8.5	0.990	-0.024
5	230	240	235.4	**208**	**82**	**126**	0.98	9.0	9.1	0.994	-0.124
6	240	250	244.8	**189**	**131**	**58**	0.99	7.7	7.8	0.964	0.202
7	250	260	251.1	**40**	**29**	**11**	0.98	7.0	7.1	1.005	-0.191

Complete bin	**set>=144**	**set>36**	**set>=36**
Incomplete bin	**set<144**	**set<36**	**set<36**

Table 5-8: Results of uncertainty calculation WTG1

bin num	WD avg	slope	offset	R^2	uα,6,j	uα,10,j	uα,14,j	uv4,6,j	uv4,10,j	uv4,14,j
[-]	[°]	[-]	[m/s]	[-]	[-]	[-]	[-]	[m/s]	[m/s]	[m/s]
4	225.4	0.990	-0.024	0.9905	0.02	0.01	0.01	0.1	0.1	0.1
5	235.4	0.994	-0.124	0.9743	0.02	0.01	0.01	0.1	0.1	0.1
6	244.8	0.964	0.202	0.9591	0.02	0.01	0.01	0.1	0.1	0.1

Table 5-9: Site Calibration Results WTG2

bin num	bin from	bin to	WD avg	no Set	no Set	no Set	ratio (SM/RM)	WS SM	WS RM	slope	offset
				4 to 16 m/s	*4 to 8 m/s*	*8 to 16 m/s*	*ws avg -bin*	*avg -bin*	*avg -bin*		
[-]	[°]	[°]	[°]	[-]	[-]	[-]	[-]	[m/s]	[m/s]	[-]	[m/s]
1	250	260	255.3	**92**	**40**	**52**	0.97	9.0	9.2	1.002	-0.235
2	260	270	265.2	**230**	**74**	**156**	0.98	10.9	11.1	0.974	0.061
3	270	280	274.5	**143**	**45**	**98**	0.99	9.9	10.1	0.954	0.280
4	280	290	284.5	**49**	**21**	**28**	1.01	8.6	8.5	0.969	0.282
5	290	300	295.5	**63**	**30**	**33**	1.01	8.0	7.9	0.976	0.261
6	300	310	304.7	**117**	**76**	**41**	1.01	7.3	7.3	0.944	0.429

Complete bin	**set>=144**	**set>36**	**set>=36**
Incomplete bin	**set<144**	**set<36**	**set<36**

Table 5-10: Results of uncertainty calculation WTG2

bin num	WD avg	slope	offset	R^2	uα,6,j	uα,10,j	uα,14,j	uv4,6,j	uv4,10,j	uv4,14,j
[-]	[°]	[-]	[m/s]	[-]	[-]	[-]	[-]	[m/s]	[m/s]	[m/s]
2	265.2	0.974	0.061	0.9936	0.02	0.01	0.01	0.1	0.1	0.1

Table 5-11: Site Calibration Results WTG3

bin num	bin from	bin to	WD avg	no Set	no Set	no Set	ratio (SM/RM)	WS SM	WS RM	slope	offset
				4 to 16 m/s	*4 to 8 m/s*	*8 to 16 m/s*	*ws avg - bin*	*avg -bin*	*avg -bin*		
[-]	[°]	[°]	[°]	[-]	[-]	[-]	[-]	[m/s]	[m/s]	[-]	[m/s]
1	220	230	226.3	**120**	**28**	**92**	0.99	10.9	11.1	0.934	0.584
2	230	240	235.2	**227**	**53**	**174**	1.04	10.7	10.3	1.044	-0.023
3	240	250	244.8	**331**	**63**	**268**	1.04	11.4	11.0	1.022	0.145
4	250	260	254.7	**380**	**26**	**354**	1.06	12.8	12.0	1.070	-0.110
5	260	270	264.5	**251**	**13**	**238**	1.02	12.8	12.5	1.002	0.255
6	270	280	274.2	**114**	**26**	**88**	1.02	10.8	10.5	1.029	-0.087
7	280	290	281.6	**34**	**13**	**21**	0.99	9.9	9.9	1.004	-0.095

Complete bin	**set>=144**	**set>36**	**set>=36**
Incomplete bin	**set<144**	**set<36**	**set<36**

Table 5-12: Results of uncertainty calculation WTG3

bin num	WD avg	slope	offset	R^2	uα,6,j	uα,10,j	uα,14,j	uv4,6,j	uv4,10,j	uv4,14,j
[-]	[°]	[-]	[m/s]	[-]	[-]	[-]	[-]	[m/s]	[m/s]	[m/s]
2	235.2	1.044	-0.023	0.960	0.02	0.01	0.01	0.1	0.1	0.1
3	244.8	1.022	0.145	0.990	0.02	0.01	0.01	0.1	0.1	0.1

Table 5-13: Site Calibration Results WTG4

bin num	bin from	bin to	WD avg	no Set	no Set	no Set	ratio (SM/RM)	WS SM	WS RM	slope	offset
				4 to 16 m/s	*4 to 8 m/s*	*8 to 16 m/s*	*ws avg - bin*	*avg -bin*	*avg -bin*		
[-]	[°]	[°]	[°]	[-]	[-]	[-]	[-]	[m/s]	[m/s]	[-]	[m/s]
1	230	240	235.7	**741**	**78**	**663**	0.97	12.2	12.6	0.984	-0.203
2	240	250	244.5	**602**	**70**	**532**	0.95	11.3	11.8	0.969	-0.172
3	250	260	254.9	**620**	**62**	**558**	0.98	11.8	12.0	0.982	0.015
4	260	270	264.1	**361**	**52**	**309**	0.98	11.4	11.6	0.989	-0.112
5	270	280	275.3	**188**	**46**	**142**	0.97	10.3	10.6	0.967	0.002
6	280	290	284.6	**279**	**71**	**208**	0.97	10.6	10.9	0.978	-0.098

Complete bin		**set>=144**	**set>36**	**set>=36**
Incomplete bin		**set<144**	**set<36**	**set<36**

Table 5-14: Results of uncertainty calculation WTG4

bin num	WD avg	slope	offset	R^2	uα,6,j	uα,10,j	uα,14,j	uv4,6,j	uv4,10,j	uv4,14,j
[-]	[°]	[-]	[m/s]	[-]	[-]	[-]	[-]	[m/s]	[m/s]	[m/s]
1	235.7	0.984	-0.203	0.976	0.02	0.01	0.01	0.1	0.1	0.1
2	244.5	0.969	-0.172	0.976	0.02	0.01	0.01	0.1	0.1	0.1
3	254.9	0.982	0.015	0.991	0.02	0.01	0.01	0.1	0.1	0.1
4	264.1	0.989	-0.112	0.990	0.02	0.01	0.01	0.1	0.1	0.1
5	275.3	0.967	0.002	0.982	0.02	0.01	0.01	0.1	0.1	0.1
6	284.6	0.978	-0.098	0.977	0.02	0.01	0.01	0.1	0.1	0.1

Table 5-15: Site Calibration Results WTG5 (without temperature filter)

bin num	bin from	bin to	WD avg	no Set	no Set	no Set	ratio (SM/RM)	WS SM	WS RM	slope	offset
				4 to 16 m/s	*4 to 8 m/s*	*8 to 16 m/s*	*ws avg - bin*	*avg -bin*	*avg -bin*		
[-]	[°]	[°]	[°]	[-]	[-]	[-]	[-]	[m/s]	[m/s]	[-]	[m/s]
1	210	220	219.3	**43**	**7**	**36**	0.99	11.3	11.2	1.012	-0.213
2	220	230	225.4	**247**	**36**	**211**	0.97	11.2	11.6	0.939	0.347
3	230	240	235.1	**320**	**55**	**211**	0.98	11.4	11.7	0.973	0.084
4	240	250	244.6	**287**	**54**	**233**	0.99	10.8	10.9	0.983	0.066
5	250	260	255.0	**402**	**80**	**322**	0.98	11.6	11.8	0.971	0.121
6	260	270	265.0	**299**	**41**	**258**	1.00	11.4	11.4	1.005	-0.028
7	270	280	273.9	**215**	**22**	**193**	0.97	11.5	11.8	0.963	0.124

Complete bin	**set>=144**	**set>36**	**set>=36**
Incomplete bin	**set<144**	**set<36**	**set<36**

Table 5-16: Results of uncertainty calculation WTG5

bin num	WD avg	slope	offset	R^2	uα,6,j	uα,10,j	uα,14,j	uv4,6,j	uv4,10,j	uv4,14,j
[-]	[°]	[-]	[m/s]		[-]	[-]	[-]	[m/s]	[m/s]	[m/s]
2	225.4	0.939	0.347	0.958	0.02	0.01	0.01	0.1	0.1	0.1
3	235.1	0.973	0.084	0.991	0.02	0.01	0.01	0.1	0.1	0.1
4	244.6	0.983	0.066	0.996	0.02	0.01	0.01	0.1	0.1	0.1
5	255.0	0.971	0.121	0.993	0.02	0.01	0.01	0.1	0.1	0.1
6	265.0	1.005	-0.028	0.975	0.02	0.01	0.01	0.1	0.1	0.1

5-4 Discussion

For **Site calibration results**, there is a visible tendency for all locations. As expected, the slope is approximately 1. In addition, a high R^2 of $R^2 \geq 0.96$ is observed for all valid bins in all locations, indicating a good relationship between RM and SM wind speed. However, differences have been noticed as well. One critical difference is the quantity of final bins observed. For the special cases, WTG1 and WTG2 (Table 5-7 and Table 5-9) the total final bins were minimum. This is due to the sum of the data points available per bin. 144 data sets are required to complete a wind direction bin according to IEC, but the number of some bins were between 90-130 data sets instead of 144. This is an issue, since some wind direction bins could not be completed because of this. The incomplete bins are considered invalid bins. It is proposed for future contracts, the reduction valid data set (e.g. more than 90 data sets) per bin for the site calibration.

For the uncertainty of flow distortion due to the terrain in bin i ($u_{V4,i}$), it was observed that for all sites, all bin wind directions, and all wind speed studied, the result was $u_{V4,i}$=0.1. Meanwhile, the uncertainty of the site calibration in wind speed bin i and wind direction bin j ($u_{\alpha,ij}$) varies depending on the wind speed: the results were $u_{\alpha,ij}$ =0.02 and $u_{\alpha,ij}$ =0.01 (Table 5-8, Table 5-10, Table 5-12, Table 5-14, Table 5-16). These results indicate an increase in the final uncertainty for the PPT since added uncertainty will be considered due to the site calibration.

The **influence of different site conditions** is investigated as the primary topic of this research. This is done for the main parameters: density, TI, wind shear, wind veer and inflow angle. However, it is worth mentioning that possible seasonal influences could not be investigated because the measuring period at most of the sites lasted between two to three months only.

In Figure 5-7, WTG1 air density can be seen (filtered wind speed data). The range is between 1.180 kg/m^3 – 1.220 kg/m^3. The mean air density obtained at WTG1 was 1.193 kg/m^3 on the site calibration period. According to MEASNET [48], if the difference between the site average density and the standard density (1.225 kg/m3) exceeds ± 0.15 kg/m3, the average density results should be considered as more relevant, due to the additional uncertainty which is introduced in case of normalization to standard density. The difference between standard and calculated density is 0.032 kg/m^3. In upcoming chapters, this will be analyzed to identify whether credible density dependencies can be identified and thereafter used for normalization. It is known that the density correction has an effect on the PC. Since the air density correction can only be compared having the power output, this is performed later, when the power output is analyzed.

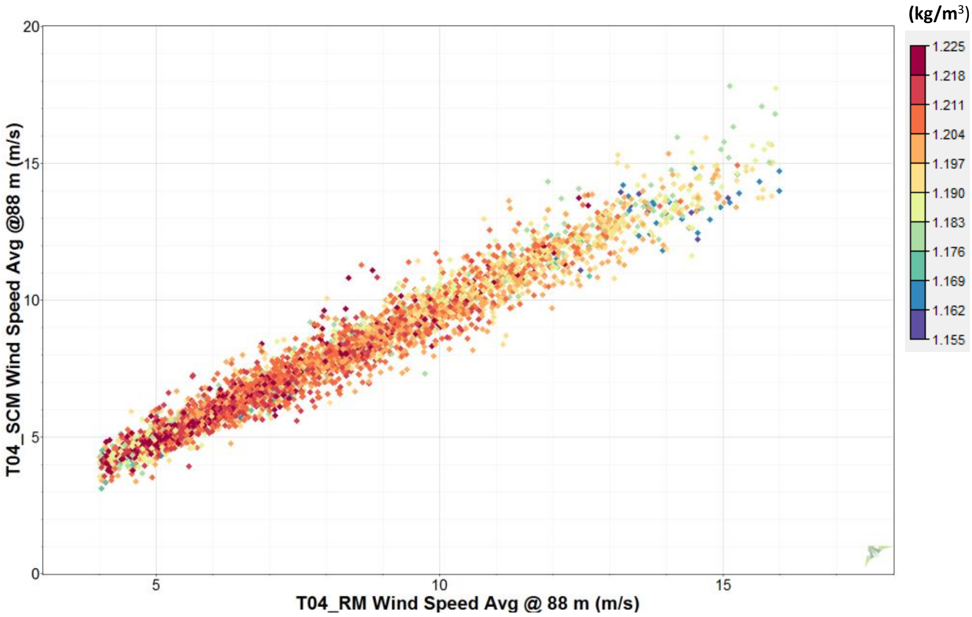

Figure 5-7: Air Density (indicated by color) – Wind Speed Site Calibration Mast vs. Wind Speed Reference Mast - filtered wind speed 4 - 16 m/s. – (all wind sectors)

Average turbulence intensities between 12.6 % and 14.8 % were observed for the top mounted anemometer on the ref-mast at the five sites. A simplified version of the WTG1 TI results can be seen in Figure 5-8, showing the range of TI after filtering. Additionally, a regression analysis for the TI was performed. However, there is not a strong correlation between TI SM and TI RM, an average of $R^2 \approx 0.53$ is obtained for WTG1. The TI data was plotted (after filters) for each location studied. The results can be found in Appendix C: Turbulence Intensity Analysis. This analysis is conducted to show that even high-variability data can have a trend. The trend indicates that the TI Reference mast still provides information about the correlation with TI Site calibration mast. Nonetheless, the data points fall further from the regression line. For this, the TI linear regression analysis shows low R-squared values. These values are problematic when precise predictions are needed. In this case, a turbulence correction based on the site calibration is not recommended.

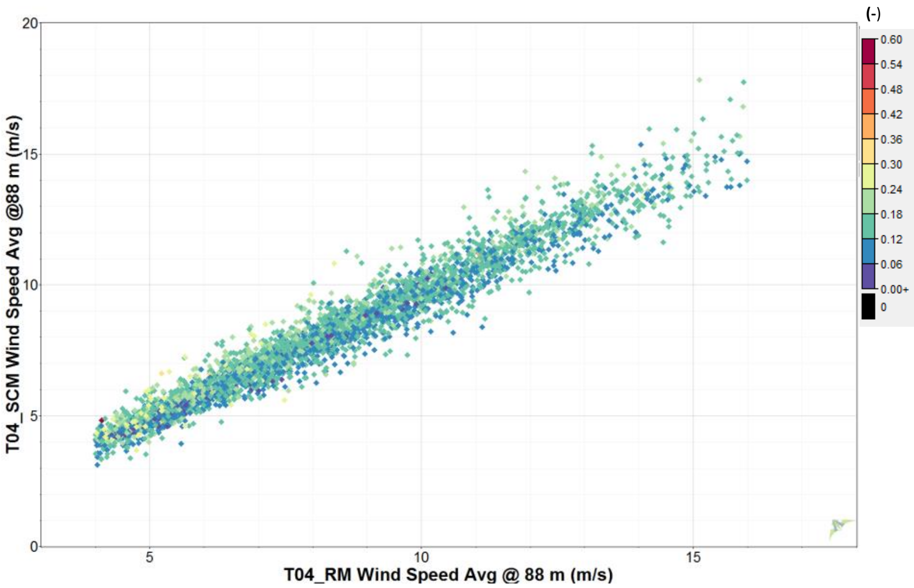

Figure 5-8: Turbulence Intensity (indicated by color) - WTG1 RM Wind Speed Average at huh height- filtered wind speed 4 - 16 m/s – (all wind sectors)

The power law exponent after filtering can be seen in Figure 5-9. By applying the wind profile filters, the *unusual* wind profiles for the free wind sector disappear. Nevertheless, this does not lead to an approximation to ideal flat terrain. As seen, the power law exponent is still between 0.32- 0.45 (for the studied wind direction sector 192.3° to 252.3°) indicating complex terrain as studied in Section 2-1-3 (Wind Shear). Further parameters like wind veer at the site did not show major variation compared to Figure 4-11.

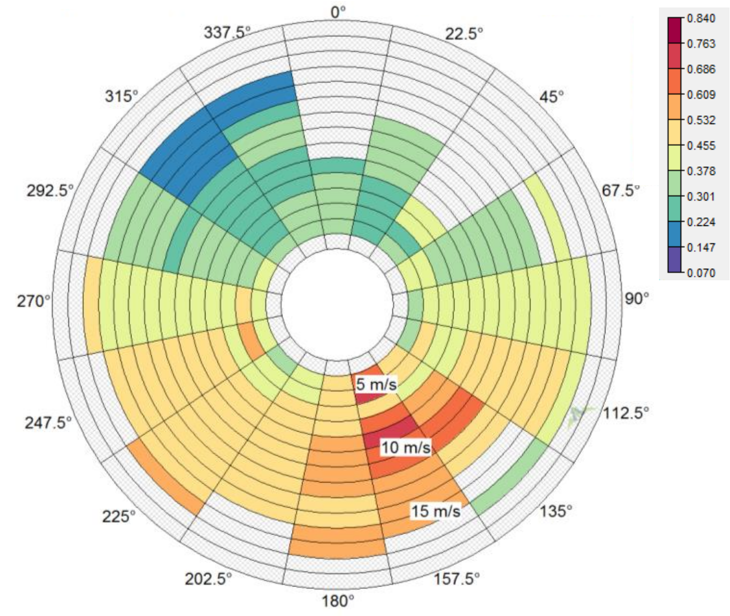

Figure 5-9: Power Law Exponent (indicated by color)- WTG1 RM Wind Speed Average at hub height- filtered wind speed 4 - 16 m/s – (all wind sectors)

The inflow angle was one of the filters applied. As per IEC, the turbine manufacturers' design requirement for inflow angles is +/- 8 degrees (from the horizontal). When the RM mean wind speed is equal and above 12 m/s for WTG1, the mean inflow angle is negative at hub-height. For WTG2 the opposite can be seen, shown in Figure 5-10. As addressed before, these inflow angles depend on the terrain. For WTG2 lower wind speeds indicate a negative angle. In practice, the more critical inflow angle is positive (coming up into the rotor), and this is usually the only one calculated by the turbine manufacturer [63]. The reason for this is predominantly due to the rotor tilt being positive, and therefore a slight negative inflow angle (coming down into the rotor) can sometimes be beneficial for fatigue loads [63]. Although the behavior of the turbine is an interesting topic, the aero-elastics of the turbine is out-of-scope for this project. The focus is directly on how the inflow angle will influence the power curve. Other locations can be found in Appendix A: XYZ Site and Data.

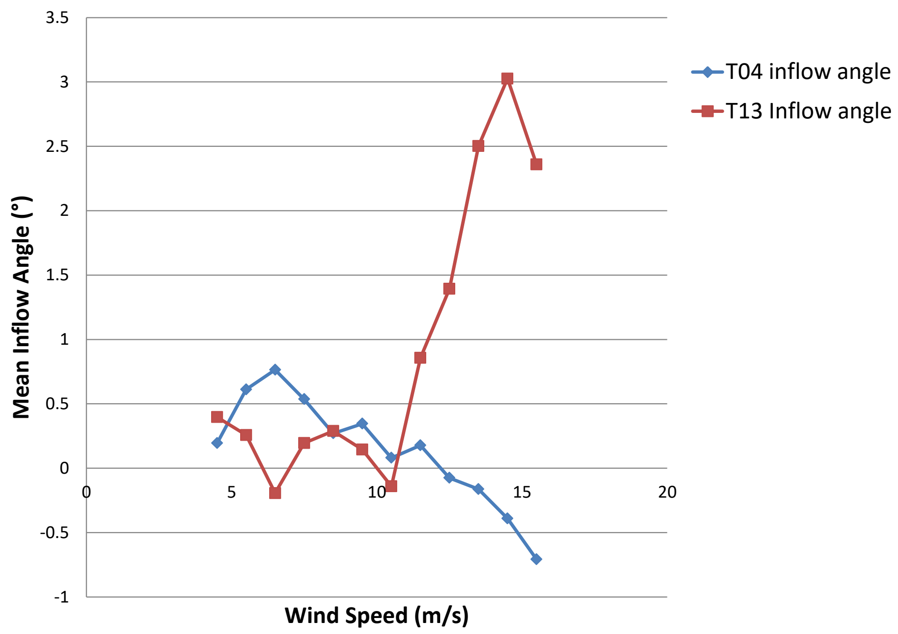

Figure 5-10: RM Mean Inflow angle WTG1 and WTG2 filtered wind speed 4 - 16 m/s - – (all wind sectors)

5-5 Importance of Site Calibration

The accurate wind speed information at the hub height of a wind turbine is essential for the estimation of the wind turbine power performance testing. For this, the ratio between wind speed reference mast and wind speed site calibration mast were studied for WTG4. In addition, the flow distortion uncertainty found for WTG4 is $u_{V4,i}$=0.1 m/s (Table 5-14). The results are shown in Figure 5-11. Here it can be seen that the free wind sector wind speed (without any additional filters) is within the flow distortion uncertainty of the calibrated wind speed. Other locations can be found in Appendix D: Importance of Site Calibration. Taken into consideration the cut-in and cut-out speed of this wind turbine (i.e. 4m/s and 32 m/s respectively), it suggests that site calibration is not improving the wind speed measurements, since the values are within the uncertainty bars.

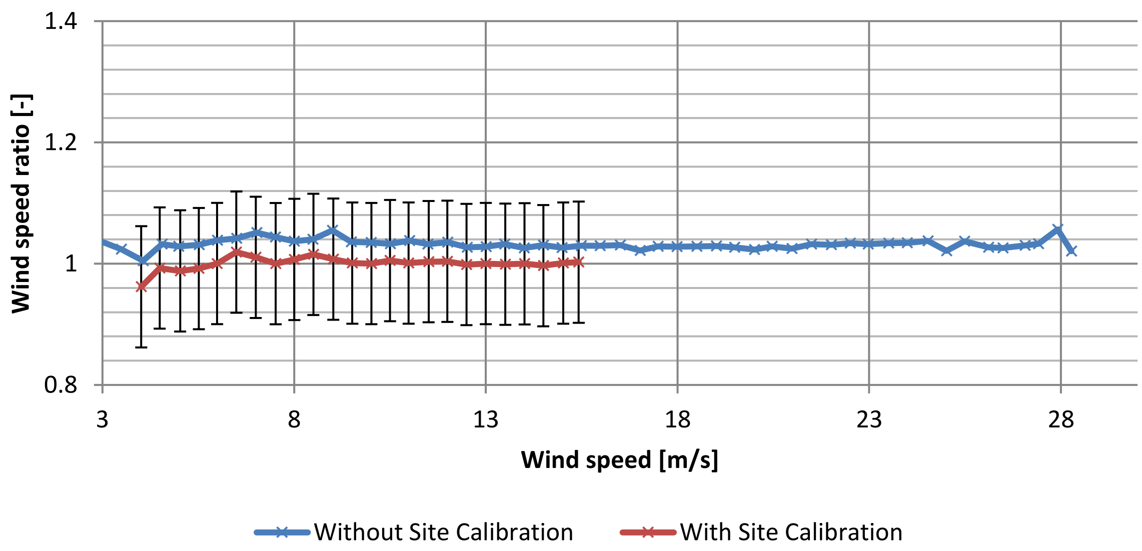

Figure 5-11: WTG4 Wind speed ratio (Free wind sector) | With and without Site Calibration

The overall uncertainty of the wind speed without site calibration is u_V =0.07 m/s per wind speed bin, slightly lower than the wind speed uncertainty with site calibration u_V =0.1 m/s per wind speed bin. To illustrate how the uncertainties could affect the validity of the results, the mean wind speed per bin with and without site calibration is analyzed. In Table 5-17 it can be seen that the absolute difference is not higher than 0.07 m/s per wind speed bin. Therefore, the “true” wind speed value is always between the wind speed uncertainty range as explained in Section 2-1-2 (Uncertainty in Measurements).

Table 5-17: WTG4 Comparison between Wind Speed (WS) with and without site calibration (Free wind sector)

WS without site calibration [m/s]	WS Site Calibration [m/s]	Absolute difference [m/s]
4.06	4.01	0.05
4.55	4.49	0.06
4.99	5.03	0.04
5.52	5.51	0.01
6.00	5.99	0.01
6.50	6.49	0.00
7.03	7.00	0.03
7.51	7.52	0.01
8.00	8.01	0.00
8.48	8.50	0.02
9.00	9.02	0.02
9.49	9.52	0.03
10.01	10.01	0.01
10.51	10.50	0.00
11.01	10.99	0.03
11.49	11.51	0.02
12.00	12.00	0.00
12.51	12.49	0.02
13.00	13.00	0.00
13.49	13.51	0.02
14.00	14.01	0.01
14.50	14.50	0.00
14.98	15.02	0.04
15.49	15.42	0.07

XYZ site is a complex terrain, and according to the IEC the site calibration is needed. Moreover, the uncertainty found for the site calibration has a significant contribution to the total wind uncertainty per wind speed bin $u_{V,i}$ (i.e. by squaring numbers, larger numbers have more weight). Even though, that the site calibration campaign could not be avoided from a contract perspective, the benefits of the site calibration are unseen. The data obtained for wind speed shows a high correlation between RM and SM, implying that the reference mast is well located in relation to the site calibration mast (for all locations). The location of the RM and as suggested by the IEC 61400-12-1:2005 standard is upwind of the turbine and in the direction from which most valid wind is expected.

5-6 Remarks on the Site Calibration

The power curves are influenced by the topographical and climatic conditions where they were measured [10]. For this, a site calibration was performed to quantify the effects of terrain on the wind measurements. This procedure allowed obtaining a correlation between wind speed reference mast and wind speed site mast for each bin direction. In addition, an average added uncertainty of ≈ 1% due to site calibration was identified.

In the linear regression, all data values have the same weight (i.e., all have an uncorrelated uncertainty of the same size).

Specific filters were applied to have a range of data under certain conditions. The potential influences of the wind condition filters have been studied and are verified in Chapter 8 where the effects will be analyzed in terms power production and energy yield.

It was found that in some cases, the IEC 61400-12-1:2005 standard is open for interpretation. Mainly regarding the correct mast to take the measured data for the site calibration, icing filter, quantity of sample points per 10-minute average, the reason for 144 points valid per bin, and density consideration in the site calibration.

Having smaller valid sectors lead to a longer runtime of the power curve test until completion. For the site calibration wind direction bins are used. This could lead to only one valid wind direction bin as result of the site calibration (e.g. WTG2 in Table 5-9). This implies a longer time for the PPT, since all the wind speed bins (at least 3 data points per wind speed bin) must be filled in for this particular wind direction range (i.e. 260° -270°).

As a last remark, it is important to notice that the site calibration is within the free wind sector, but in most of the cases is not the complete free wind sector. For the free wind sector Table 4-6 is referred.

Chapter 6

Power Performance Testing, IEC Method

Power performance testing is used to prove that the installed turbines are meeting the manufacturers warranted power curves [49]. The power curve warranty of the specific project (i.e. XYZ PC warranty) states that at least 2 (two) turbines ABC1 and 3 (three) turbines ABC2 must be tested. Then, the M-PC should be averaged per turbine type and should be compared to the warranted power curve (W-PC) of the relevant type. At the moment of writing this thesis, only the data for WTG4 and WTG5 were available, since the other areas were still under construction or commissioning phase. Whereas in the past chapters, the examples presented are from WTG1, from this chapter on the examples are mainly based on WTG4.

6-1 Evaluation of the Measured Data

As addressed in Section 3-3 (Data Processing) the IEC 61400-12-1:2005 standard stated that the data should be rejected under the following circumstances [1]:

- Wind speed that is out of the wind turbine operating range;
- When the wind turbine is not operating (i.e. mal-function, manual shut down, test or maintenance);
- Failure or degradation;
- Wind direction outside the measurement sector, as defined in Section 4-5;
- Wind direction outside valid site calibration sectors, as defined in Section 5-3.

In the PPT (Power Performance Testing), the availability of the turbine is considered. For this, the filters applied prior to the analysis comply with the IEC rejection criteria (Wind speed that is out of the wind turbine operating range). These filters are power reduction (i.e. wind power curtailment is not considered), turbine grid connection and fail free.

To avoid failure or degradation due to icing, a temperature filter is applied. Only temperatures above 2°C are accepted.

In addition to the above-mentioned IEC requirements, the XYZ contract states the following added requirements [43]. These requirements are the same applied for the Site calibration in Chapter 5:

- Absolute wind veer above 15°, as defined as the wind direction difference measured near hub height and near lower tip height (i.e. the rotor radius).
- Wind flow inclination exceeding 8°, measured at the reference mast location.

- Turbulence intensity (TI) outside the valid limits, presented in Figure 5-1, as well as described below:
  - Lower limit: 5%
  - Upper limit for wind speed up to 13 m/s: $TI(v) = 3.0 \times v^{-1}$
  - Upper limit for wind speeds above 13 m/s: $TI(v) = TI_{PCref}(13m/s) + 3\%$, where TI_{PCref} is the TI value for each measuring position. This values are found in Table 4-1. For WTG4 and WTG5 corresponds the Area4 value: $TI_{PCref}(13m/s) = 24\%$.

The reference mast used in the side calibration continued in the same position during the PPT. The new wind speed data obtained in the PPT phase was corrected with the slopes and offsets (for each 10 degrees' sector) found in the Site Calibration phase, using a code created in MATLAB R2014a by the author.

The effect of the applied filters on WTG4 data is shown in Table 6-1.The filtered data represents 14% of the total evaluation period data.

Table 6-1: Effect of applied filters WTG4 – Power Performance

WTG4			
Steps	Filter Event	remaining hierarchy	affected hierarchy
1	Database read period	9788	
2	Availability Turbine (power Reduction, Grid Conditions, Fail free)	5752	4036
3	Wind direction sector 230° to 290° - In this step, the Site Calibration Results were added)	1042	4710
4	Only abs (wind veer <15°)	1037	5
5	Only abs (wind flow inclination) < 8°	1012	25
6	Turbulence filter	1003	9
7	Only temperatures above 2°C	791	212

The effect of the applied filters on WTG5 data is shown in Table 6-2. The filtered data represents 17% of the total evaluation period data.

Table 6-2: Effect of applied filters WTG5 – Power Performance

WTG5			
Steps	Filter Event	remaining hierarchy	affected hierarchy
1	Database read period	18737	
2	Availability Turbine (power Reduction, Grid Conditions, Fail free)	8305	10432
3	Wind direction sector 220° to 270° - In this step, the Site Calibration Results were added)	1827	6478
4	Only abs (wind veer <15°)	1824	3
5	Only abs (wind flow inclination) < 8°	1805	19
6	Turbulence filter	1794	11
7	Only temperatures above 2°C	1378	416

6-2 Power Curve Results

To perform a PPT the data sets are sorted into wind speed bins. This is known as the “method of bins”, as explained in Section 3-3 (Database). Each bin contains 0.5 m/s, being these continuous bins centered on multiples of 0.5 m/s [1]. In addition, each bin should have at least 30 min of sample data (equivalent to 3 data points) and the database should have at least 180 hours of sampled data (equivalent to 10.800 data points).

The power curves for the test turbines are not corrected to the reference air density. For this site, the air density is 1.195 kg/m^3. Moreover, according to the IEC 61400-12-1:2005 standard, this step is not necessary, since the range to avoid air density correction is 1.225 ± 0.05 kg/m^3 (actual average). The density of the site during the PPV is within the allowed range.

Under consideration of the result of the site calibration, the results obtained are presented in Figure 6-1 and Table 6-3 for WTG4 and Figure 6-2 and Table 6-4 for WTG5 (the incomplete data bins Dataset<3 are indicated in red color).

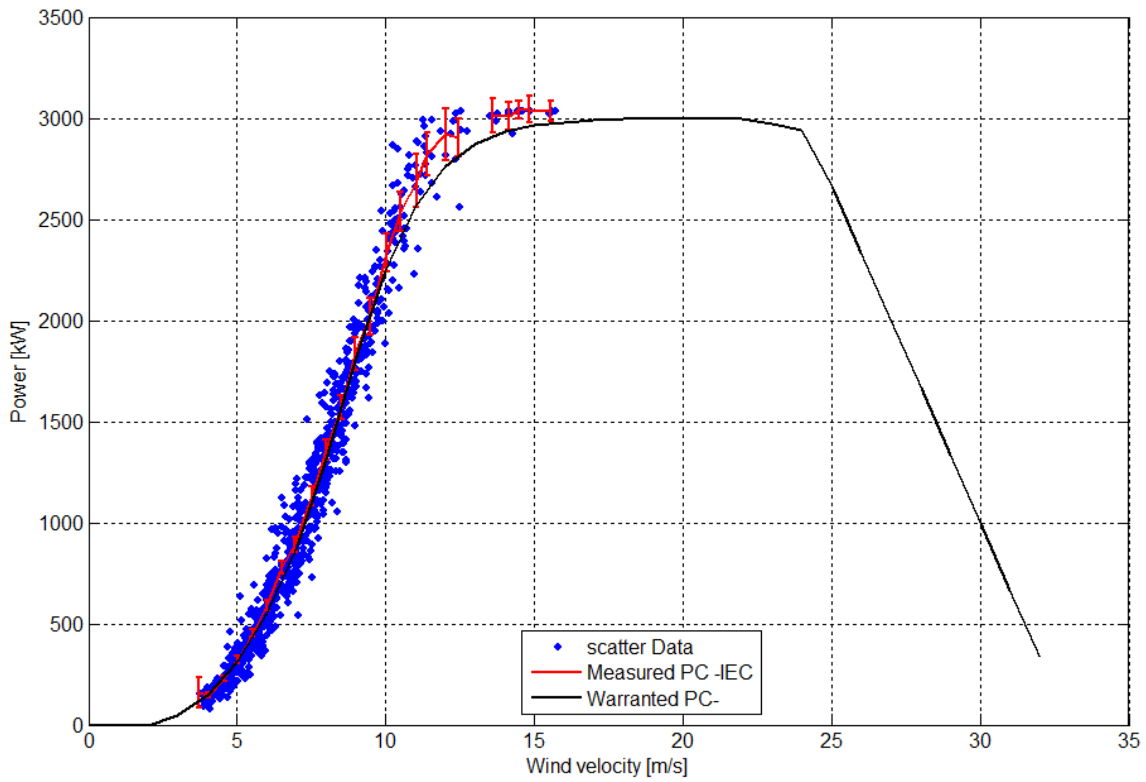

Figure 6-1: WTG4 Measured Power Curve and Warranted Power Curve.

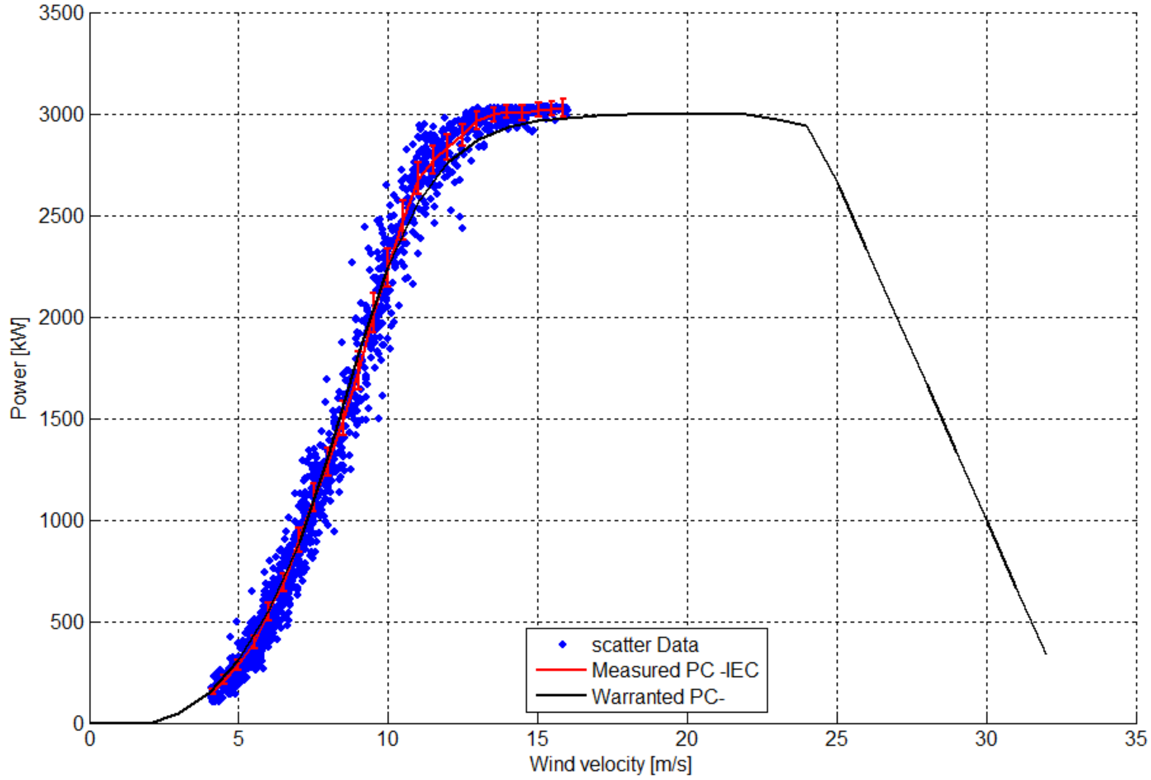

Figure 6-2: WTG5 Measured Power Curve and Warranted Power Curve.

Table 6-3: WTG4 Power Performance Testing results

WS from (≥)	WS to (<)	Dataset (10 min Avg.)	WS mean	Power Mean	Cp	Category A: Std. Uncertainty *si*	Category B: Std. Uncertainty *ui*	Combined uncertainty *uci*
[m/s]		[-]	[m/s]	[kW]	[-]	[kW]	[kW]	[kW]
3.75	4.25	34	4.03	145	0.39	6.55	11.1	12.9
4.25	4.75	42	4.55	228	0.43	11.86	21.9	24.9
4.75	5.25	60	5.01	321	0.46	14.98	26.7	30.6
5.25	5.75	72	5.52	453	0.48	17.22	33.0	37.3
5.75	6.25	73	6.02	591	0.48	22.28	35.5	41.9
6.25	6.75	60	6.49	779	0.51	29.74	49.9	58.1
6.75	7.25	69	6.95	890	0.47	33.55	31.8	46.2
7.25	7.75	56	7.51	1131	0.48	47.71	54.3	72.3
7.75	8.25	80	7.99	1362	0.48	48.69	60.9	78.0
8.25	8.75	67	8.50	1567	0.45	58.46	51.4	77.8
8.75	9.25	43	8.98	1834	0.45	80.75	70.6	107.2
9.25	9.75	36	9.47	2019	0.42	88.23	49.8	101.3
9.75	10.25	27	10.03	2333	0.41	92.04	72.8	117.4
10.25	10.75	25	10.49	2535	0.39	94.08	58.1	110.6
10.75	11.25	10	11.03	2689	0.36	127.93	42.1	134.7
11.25	11.75	10	11.40	2820	0.34	102.84	49.7	114.2
11.75	12.25	4	12.04	2920	0.30	124.42	32.1	128.5
12.25	12.75	7	12.44	2903	0.27	87.68	26.0	91.4
13.25	13.75	3	13.62	3012	0.21	81.27	26.3	85.4
13.75	14.25	4	14.15	3009	0.19	61.41	26.2	66.8
14.25	14.75	3	14.50	3041	0.18	30.97	28.7	42.2
14.75	15.25	1	14.85	3043	0.17	58.21	26.5	64.0
15.25	15.75	4	15.56	3036	0.14	43.83	26.5	51.2
15.75	16.25	0	-	-	-	-	-	-

Table 6-4: WTG5 Power Performance Testing results

WS from (≥)	WS to (<)	Dataset (10 min Avg.)	WS mean	Power Mean	Cp	Category A: Std. Uncertainty *si*	Category B: Std. Uncertainty *ui*	Combined uncertainty *uci*
[m/s]		[-]	[m/s]	[kW]	[-]	[kW]	[kW]	[kW]
3.75	4.25	**29**	4.14	151	0.38	7.25	9.5	12.0
4.25	4.75	**54**	4.52	211	0.41	9.34	21.3	23.3
4.75	5.25	**75**	4.98	285	0.41	10.26	21.9	24.1
5.25	5.75	**106**	5.53	398	0.42	11.95	27.4	29.9
5.75	6.25	**103**	6.01	546	0.45	17.23	39.0	42.7
6.25	6.75	**104**	6.51	691	0.45	21.67	36.6	42.5
6.75	7.25	**89**	7.03	902	0.46	29.17	51.3	59.1
7.25	7.75	**73**	7.51	1110	0.47	39.41	54.7	67.4
7.75	8.25	**73**	8.00	1283	0.45	50.72	45.6	68.2
8.25	8.75	**59**	8.50	1499	0.43	61.86	54.7	82.6
8.75	9.25	**49**	9.01	1736	0.42	73.17	59.9	94.6
9.25	9.75	**63**	9.51	2019	0.42	66.69	71.5	97.8
9.75	10.25	**56**	9.98	2241	0.40	72.30	61.1	94.7
10.25	10.75	**43**	10.50	2475	0.38	78.57	59.1	98.3
10.75	11.25	**53**	11.01	2681	0.36	55.27	54.9	77.9
11.25	11.75	**40**	11.50	2769	0.32	59.79	33.0	68.3
11.75	12.25	**36**	11.98	2834	0.29	55.18	30.1	62.8
12.25	12.75	**35**	12.50	2896	0.26	44.63	29.2	53.3
12.75	13.25	**44**	12.98	2964	0.24	28.90	31.2	42.6
13.25	13.75	**48**	13.53	2994	0.22	22.49	27.0	35.1
13.75	14.25	**49**	13.96	3007	0.20	18.37	26.5	32.3
14.25	14.75	**32**	14.49	3003	0.18	25.85	26.2	36.8
14.75	15.25	**28**	15.03	3019	0.16	20.74	26.5	33.7
15.25	15.75	**28**	15.48	3025	0.15	17.83	26.4	31.9
15.75	16.25	**9**	15.86	3027	0.14	34.62	26.4	43.5

According to the XYZ contract [43], the results of WTG4 and WTG5 need to be averaged to be able to compare it with the W-PC. For the Nominal Wind Distribution (NWD) Table 4-7 is used. The parameters of the Weibull distribution are shape factor of k=2.10 and scale factor of A=9.25 m/s characteristic of the Area4 part of XYZ (Table 4-1). This is represented in Figure 6-3 (green color).

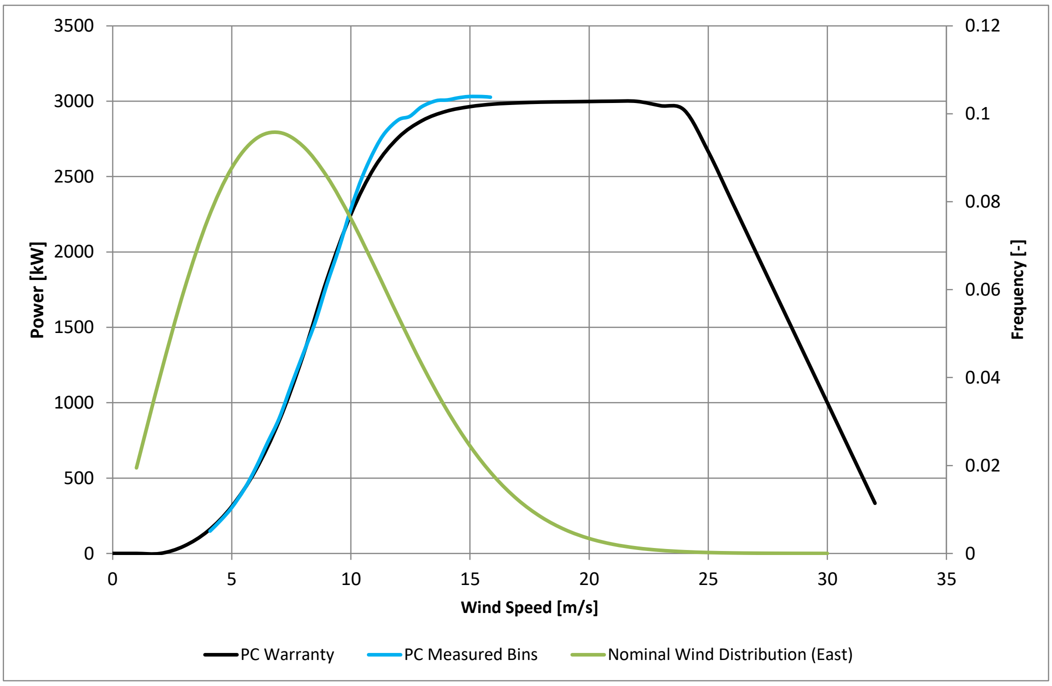

Figure 6-3: Power Curve Warranted and Measured – without uncertainty | Nominal wind distribution (free wind sectors)

The same results are presented in Table 6-5. In this case, the warranted power curve and the AEP (Warranted and Measured) is added for ease the comparison. The incomplete bins are colored red (less than 3 datasets per bin).

Table 6-5: Final Results PPT. Difference between W-AEP and M-AEP is indicated by color.

Wind speed [m/s]	Warranted Power [kW]	WTG4 Measured Power [kW]	WTG5 Measured Power [kW]	Mean Measured Power (WTG4-WTG5) [kW] (without u_{PC})	NWD (Area4)	W-AEP [kWh]	M-AEP [kWh] (without u_{AEP})	Difference W-AEP and M-AEP
4	149	145	151	148	0.0760	99219	98682	-0.54%
5	312	275	248	261	0.0877	239621	200721	-16.23%
6	551	608	472	540	0.0943	454943	446055	-1.95%
7	883	890	797	843	0.0957	740489	707309	-4.48%
8	1315	1246	1196	1221	0.0926	1066557	990620	-7.12%
9	1820	1807	1617	1712	0.0857	1366320	1285342	-5.93%
10	2249	2434	2130	2282	0.0762	1500607	1522621	1.47%
11	2563	2755	2578	2666	0.0652	1462868	1521826	4.03%
12	2760	2912	2802	2857	0.0537	1299125	1344669	3.51%
13	2872	**[]-**	2930	**2930**	0.0428	1076092	1097799	2.02%
14	2933	3021	3001	3011	0.0329	845151	867629	2.66%
15	2964	**3043**	3022	**3032**	0.0245	635028	649654	2.30%
16	2981	**3036**	3027	**3031**	0.0176	459343	467095	1.69%

In addition, the AEP result according to the IEC is presented in Table 6-6. This is calculated with Eq. (3-6) and Eq. (3-7) and AEP uncertainty of ± 0.2 GWh using Eq. (3-10). Moreover, the AEP was calculated as well according to the contract. Using the Eq. (2-18) and Eq. (2-19) leads to the results found in Table 6-7

Table 6-6: Warranted AEP (W-AEP) and Measured AEP (M-AEP) ABC1. IEC 2005

MAEP (IEC) measured [GWh]	10.9 ± 0.2
MAEP (IEC) extrapolated[GWh]	12.3

Table 6-7: Warranted AEP (W-AEP) and Measured AEP (M-AEP) ABC1. Contract

W-AEP	[kWh]	11245363
	[GWh]	**11.3**
M-AEP (contract)	[kWh]	11200021
	[GWh]	**11.2**

6-3 Discussion

The **influence of the applied filters** is presented in Table 6-1 and Table 6-2. The maximum loss of data points was observed in the filter for the free wind sector (i.e. WTG4: 220° to 270° | WTG5: 220° to 270°) in both cases. Moreover, between the turbine availability and the wind direction sector (and wind speed 4m/s to 16 m/s) 82% and 78% of the data points were lost for WTG4 and WTG5 respectively. By studying the prevailing wind patterns for these locations (Appendix A: XYZ Site and Data) winds from South –West direction and between 5 – 20 m/s are expected the most common. The prevalent wind direction coincides approximately with the free wind sector for WTG4 and WTG5. The wind direction filter was not expected to reduce the data so significantly. This led to a longer time to complete the wind speed bins.

The measured power curve is valid only from 4 -16 m/s due to the site calibration (Section 3-1). Moreover, based on the **power performance results (**Table 6-3 and Table 6-4**)** a combined M-PC result is presented in Figure 6-4. Here, it can be seen that the WTG4 and WTG5 power curves are almost indistinguishable. Nevertheless, WTG4 (green line) seems to be above WTG5 PC (light blue line). This difference is more apparent when the **power Coefficient, Cp** is analyzed. Cp is used to estimate the efficiency of the turbines in the wind farm. Cp is calculated with Eq. (3-8) and measures how efficiently the wind turbine converts the energy in the wind into electricity. In Figure 6-4it can be seen that Cp for WTG4 is slightly higher than Cp for WTG5 for a wind speed up to 9 m/s. For higher wind speeds both turbines performance is similar.

Some differences in the power coefficient of WTG4 compared to WTG5 are expected, since they are two different turbines. Cp is a measure of the overall turbine efficiency and this involves the efficiencies of the mechanical and the electrical systems in the turbine.

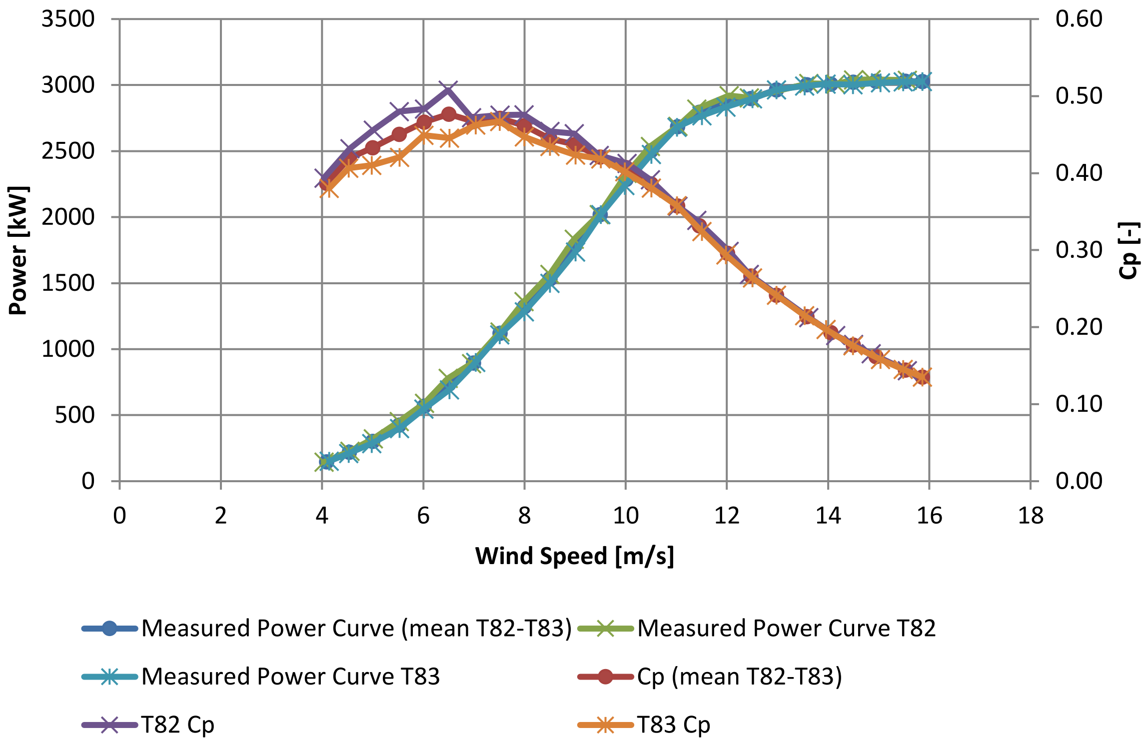

Figure 6-4: Measured Power Curve and Power coefficient Cp, WTG4 WTG5 and Mean (Free wind speed)

The uncertainty bars included in Figure 6-1 and Figure 6-2 are the **standard uncertainty** of the data in each 0.5 m/s bin, these are calculated with Table 3-4. It can be seen in Table 6-5, that the M-PC (mean of WTG4 and WTG5) is above the W-PC indicating clearly an over-performance for wind speed bins above 10 m/s and an underperformance for wind speed bins below 10 m/s. Moreover, it can be seen that the W- PC lays on the uncertainty bars of the measured PC. This is what was expected, since the warranted power values need to be within the uncertainty of the M- PC.

Differences were found in the **W-AEP and M-AEP**. Table 6-5 gives the differences in percentage per wind speed bin, here a lower than expected AEP can be seen for wind speeds equal and below 10 m/s, and an over power production for wind speeds above 10 m/s, this was calculated according to the contract.

Moreover, the contract states that the AEP should be calculated as mentioned in Eq. (2-18) and (2-19). Nevertheless, this is not the IEC method. As addressed in Section 3-4 (Annual Energy Production), the AEP needs to be calculated in two ways: the *AEP-measured* and *AEP-extrapolated*. The extrapolation is done from rated power until cut-out wind speed. This is not the case for this warranted power curve since it has a *Extended smooth cut-out.* For this reason, to be able to get an extrapolation until the last wind speed bin 32 m/s (cut-out wind speed bin) and the first wind speed bin 3 m/s (cut-in wind speed bin). The results in Table 6-5 are used as follow: For the first bin the difference of -0.54% was multiplied by the warranted power at that bin given 48.7 kW, the same procedure was applied for wind bins between 17 m/s – 32 m/s. In this case, 1.69 % was multiplied for the warranted power in that bin. The complete warranted power curve (Area4) can be found in Appendix E: Warranted power curve .

Table 6-7 shows that the M-AEP according to the contract method gives an M-AEP of 11.2 GWh. Meanwhile the M-AEP according to the IEC 61400-12-1:2005 standard gives an M-AEP of 10.9 GWh. The main difference is, that the IEC considers the Rayleigh distribution, meanwhile the contract considers the Weibull distribution.

Both Rayleigh and Weibull are probability density functions. The difference between these two functions is shape parameter k. The Rayleigh distribution is a special case of the Weibull distribution with a shape factor of 2. The shape parameter used for the Weibull distribution is k=2.10 (Area4) which is different than the Rayleigh distribution shape parameter k=2. Literature has found that the Weibull model predicts the actual value better than the Rayleigh model [64].

The contract does not consider the AEP uncertainty calculation with Weibull distribution. Instead, it refers to the IEC 61400-12-1:2005 standard to base this calculation, even though the Weibull distribution shape factor does not match the Rayleigh distribution shape factor. However, in this project, the contract method and results (Table 6-7) for the AEP are considered valid and representative of the site, with the added uncertainty of the IEC.

6-4 Remarks on the Power Performance Testing – IEC Method

The overall calculation of the PPT according to the IEC 61400-12-1:2005 standard is a straightforward procedure. Discrepancy was noticed in the M-AEP. For this M-AEP according to the contract will be taken as representative of this turbine type.

The IEC considers an extrapolated AEP. This could have advantages since there are expected wind speed above 16 m/s on this site according to NWD. But turbines that were up-to-date in 2005 are not the same as now (2017). The *Extended smooth cut-out* is a new feature. Neither the IEC 61400-12-1:2005 standard, nor the contract state a proper approach on this case. In this chapter, a solution was presented (Section 6-3).

Chapter 7

Non-Standard Power Curve Estimation

The dependency of the power curve on air density, turbulence intensity and wind shear, wind veer and inflow angle has been addressed in Chapter 2. This chapter shows that all mentioned conditions influence the power curve and consequently the AEP. State-of-art equations are used in this chapter to account for them. The purpose of these normalizations is to improve the accuracy of the results by means of concrete formulations for each variable [30].

To quantify the effects of so-called "complex" wind conditions (i.e. high shear, high turbulence and high vertical wind speed) on turbine power performance, the "method of bins" is once again applied. In addition, corrections on the power curve are addressed by wind speed normalization.

The analysis for WTG4 (i.e. - ABC1) is presented. It is based on a self-made code created in MATLAB R2014a to study all wind conditions in the free wind sector individually.

7-1 Density Analysis

The air density is calculated with Eq. (2-7) per dataset (10 minutes). The air density encountered in the site (i.e WTG4) is between 1.163 kg/m^3 and 1.213 kg/m^3. The mean value of the site is 1.194 kg/m^3. This can be seen in Figure 7-1.

According to the IEC 61400-12-1:2005 standard, no correction is needed as discussed in Section 3-2 (Air density Measurements). Nevertheless, the IEC 61400-12-1:2017 standard suggests that a correction needs to be made using Eq. (2-9), where the reference air density is taken from the W-PC as the warranted air density of 1.183 kg/m^3. Figure 7-2 shows the W-PC, the M-PC without air density correction (ρ=1.194 kg/m^3) and the M-PC with air density correction (ρ=1.183 kg/m^3) in the free wind sector.

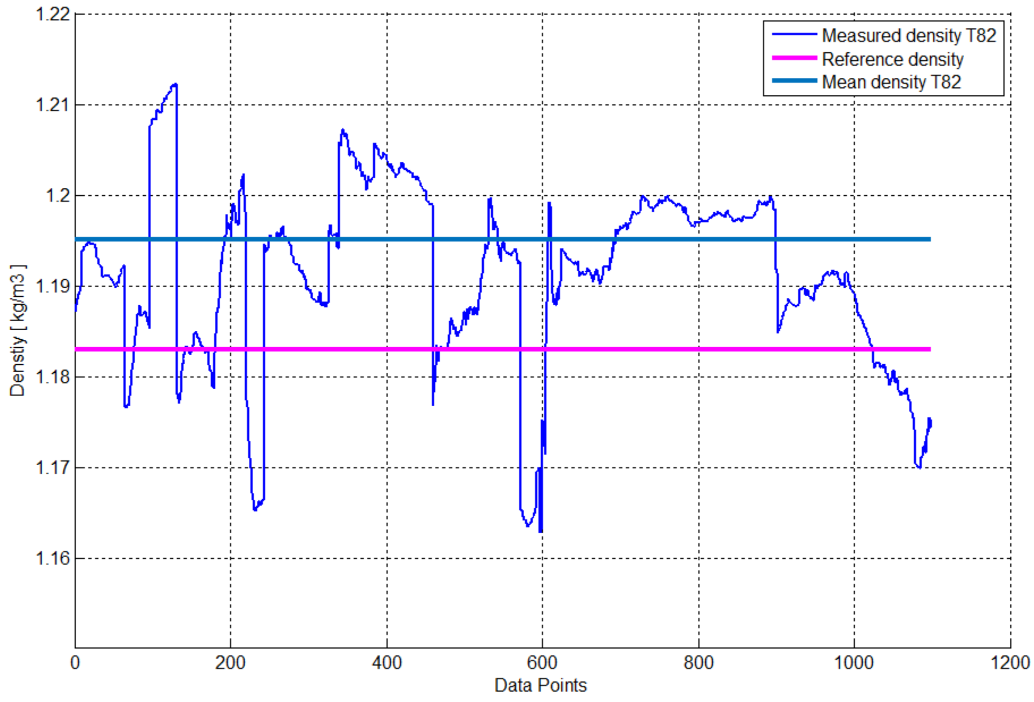

Figure 7-1: WTG4 Measured Air Density

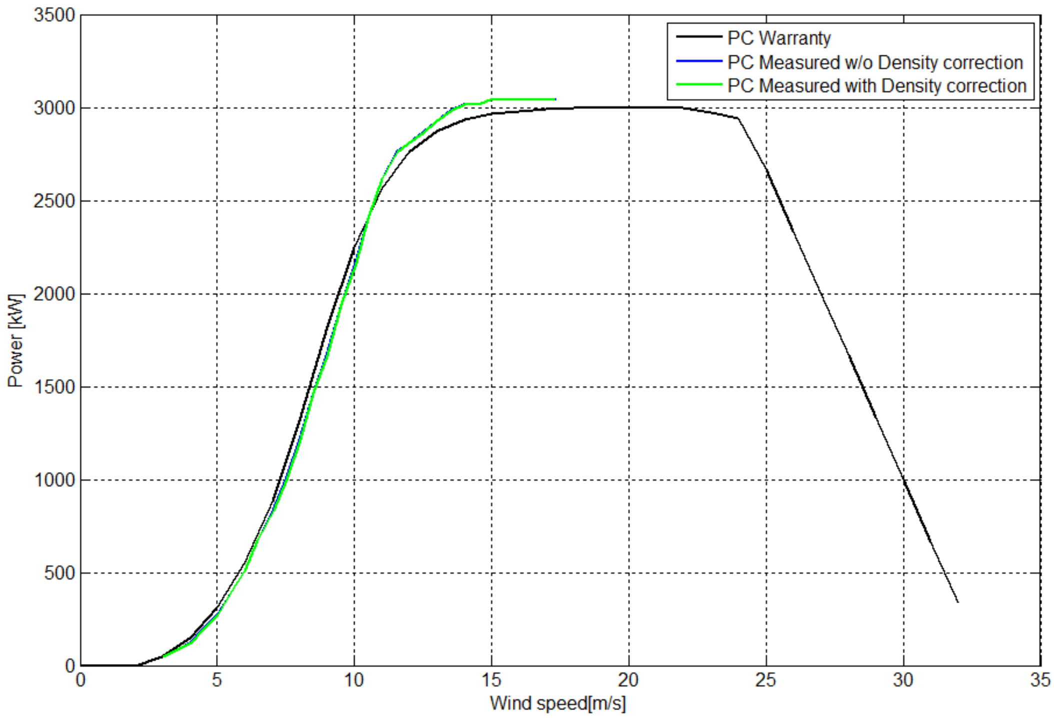

Figure 7-2: WTG4 Warranted Power Curve | Measured Power Curve without corrections | Measured Power curve with normalized wind speed (free wind sectors) - Accounting for air density

The measured power curves are very similar as seen in Figure 7-2. The same results can be seen in detail in Figure 7-3. Nevertheless, the major difference comes when the power per wind speed bin is analyzed. The wind speed bins between 4m/s to 9 m/s showed a mean decrease in the power output of 8.5% when the air density correction is applied. For wind speed bins between 10 m/s to 16 m/s, no difference in power output is found. These relative differences can be seen in detailed in Figure 7-4. It is concluded that the power expected is slightly higher derived from the air density correction accounting for heavier air in a complex terrain.

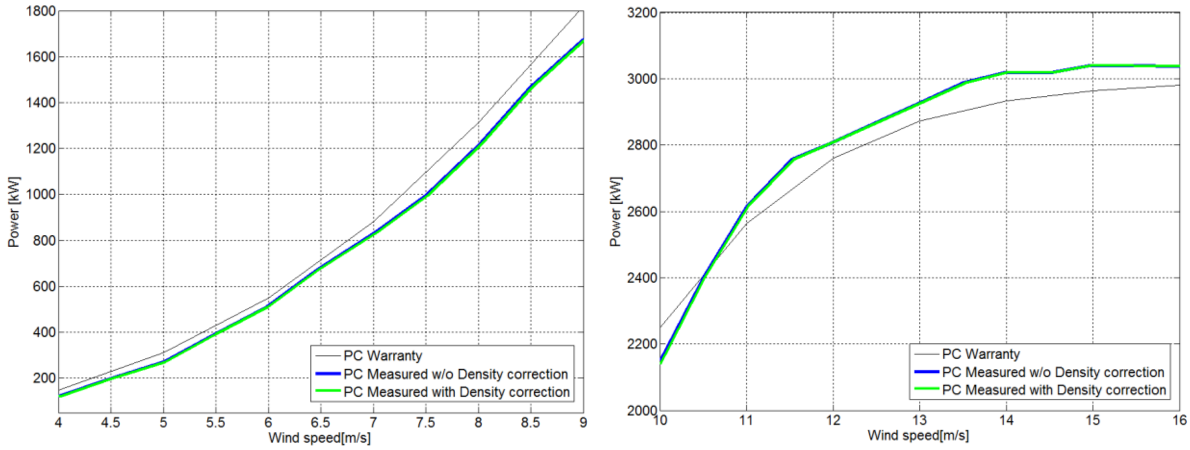

Figure 7-3: WTG4 Detailed M- Power Curve - Accounting for air density

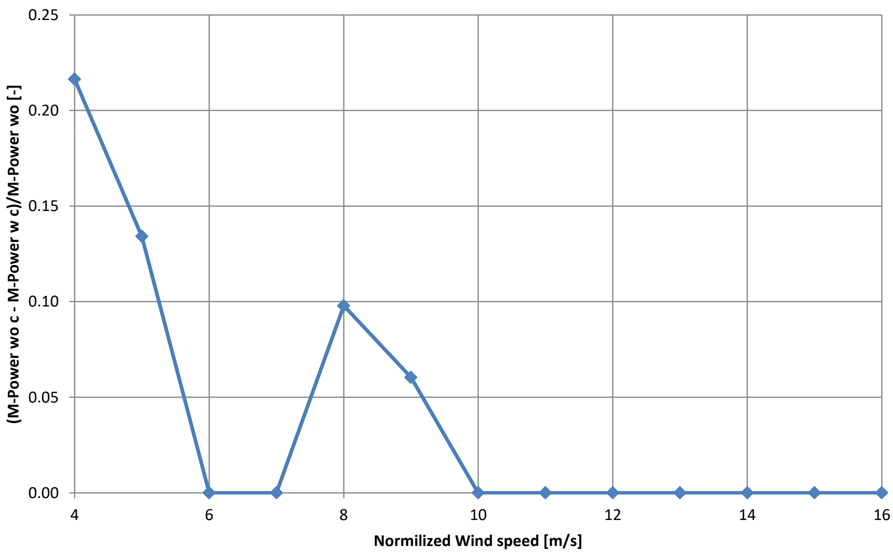

Figure 7-4: WTG4 Relative difference in measured and normalized power- Accounting for air density

The differences between the W-PC and both measured power curves could be explained from the influence of the terrain, since site calibration was not considered in this chapter. For this, the W-PC is only shown for comparison purposes, not for analysis.

As known, air density depends on temperature, humidity, pressure. So, their variations affect the density (as correlated values) that reflect on the power curve. By correcting the density, the temperature is corrected as well, so this could imply a solution for the temperature filter (IEC 61400-12-1:2005 standard: Failure or degradation due to icing).

The normalized wind speed has a small variation in the PC. Now, compared to the M-AEP, the difference becomes more evident (Table 7-1). Since the power variation occurs in the wind speed bins that a higher probability density distribution of wind speed is expected during the year. The M-AEP with air density correction of 1.183 kg/m^3 is lower than the M-AEP without air density correction, since the air reference density is lower than the measured at the WTG4 location in the free wind sector.

Table 7-1: Measured AEP (air density Analysis) – wind speed between 4 m/s-16m/s (Free wind sector)

	[kWh]	[GWh]
M-AEP Measured without air density correction (ρ=1.194 kg/m³)	10960345.12	10.96
M-AEP with air density correction (ρ=1.183 kg/m³)	10733561.58	10.73

7-2 Turbulence Intensity Analysis

The turbulence intensity is calculated with Eq. (2-10). For this site, the TI values are between 2.40% and 35.66% and the average is 14.87% for the free wind sector. This variation can be seen in Figure 7-5.

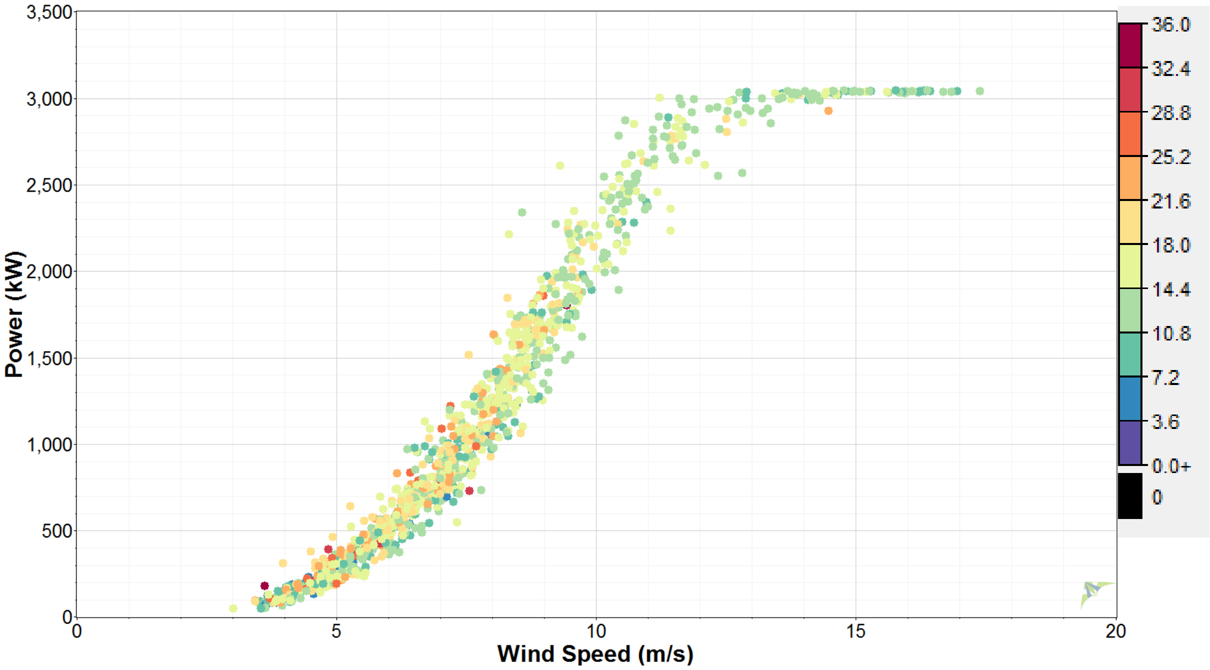

Figure 7-5: Power Curve WTG4 (free wind sectors) - Turbulence Intensity (indicated by color)

Figure 7-6, shows different turbulence intensity classes compared to the M-PC without filters. Here for wind speed between 4m/s to 10 m/s high TI classes produce more power than low classes. At the knee of the power curve changes; low TI classes produce more power. After this, the remaining classes go along the M-PC (without filters) implying that after 14 m/s, only TI between 10% to 15% can be found in this location.

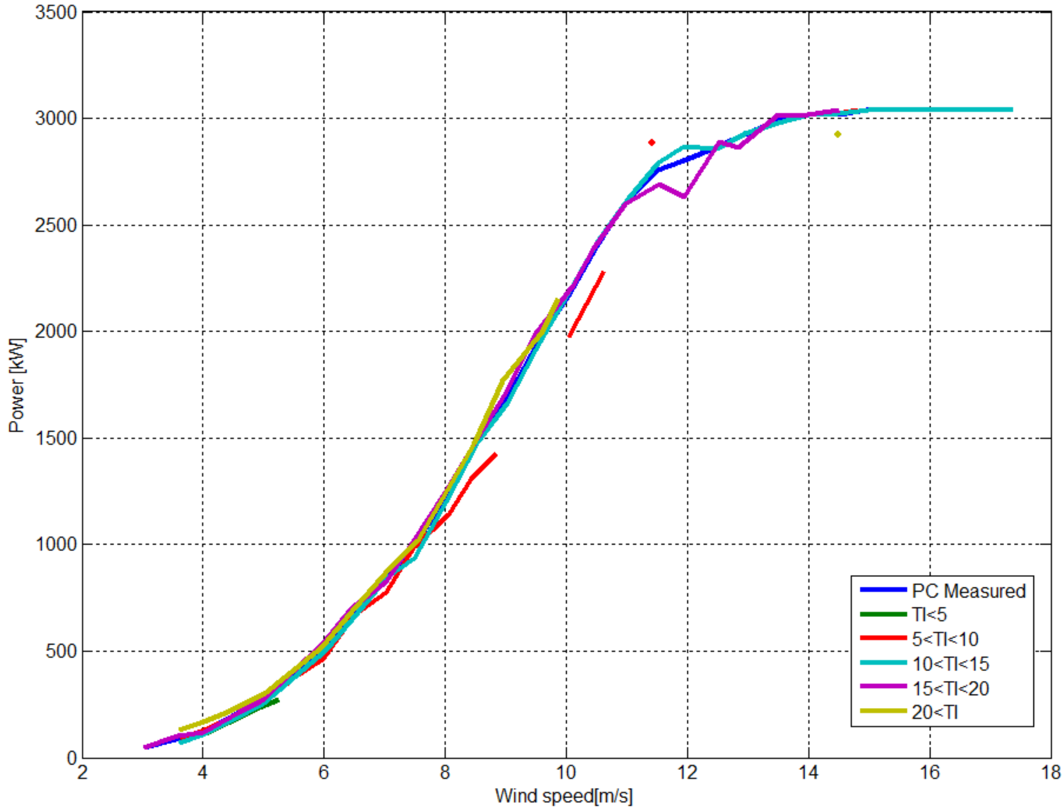

Figure 7-6: WTG4 Power curve for different TI classes (indicated by color) - (free wind sector)

To account for TI in the wind speed normalization, Eq. (2-11) is used. The TI corrected power curve is shown in Figure 7-7. The same results can be seen in detail in Figure 7-8. Here, an almost identical PC can be seen:

- When the M-PC without filters is compared to the M-PC with TI contract filter, a 1% of power increase (due to the TI filters) is observed between 4 m/s and 5 m/s per wind bins. For winds speeds between 6 m/s until 16 m/s, no variation of power was observed.
- When analyzing the M-PC without filters compared to the M-PC with TI corrected, the power with TI correction decreases 17% for wind speed bins from 4 m/s to 9 m/s. From 10 m/s to 16 m/s no differences are found in the power yield.

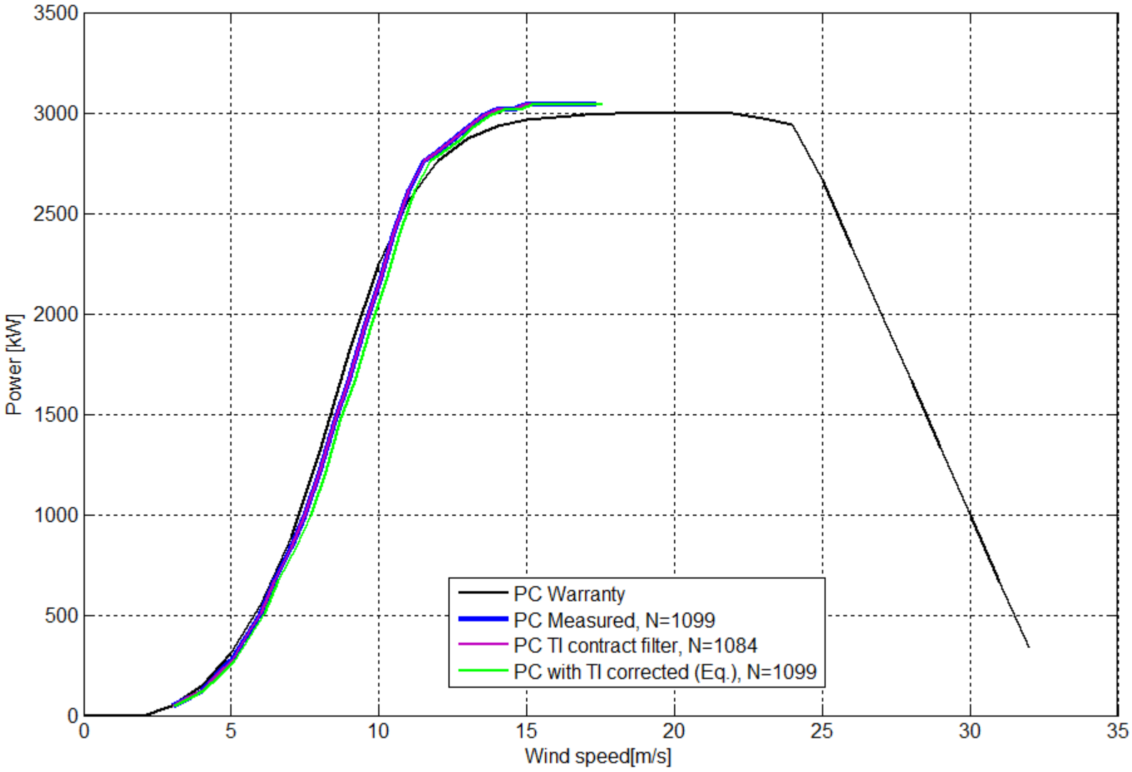

Figure 7-7: Warranted Power Curve | Measured Power Curve without filters | Measured Power Curve with filters | Measured Power curve without filters and normalized wind speed (free wind sectors)- Accounting for TI

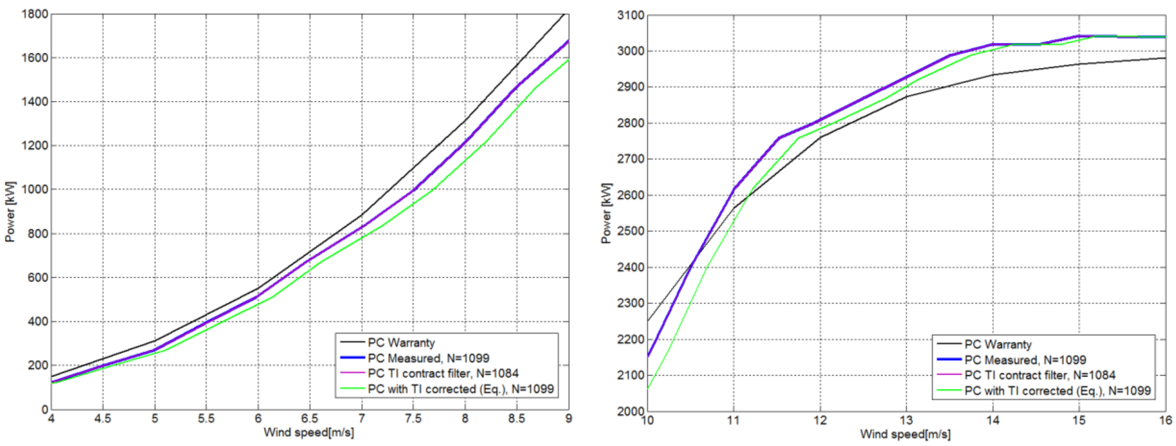

Figure 7-8: WTG4 Detailed M- Power Curve - Accounting for TI

To estimate the reduction in terms of AEP, Table 7-2 is presented. For the wind speed range discussed (4 m/s to 9 m/s) the corrected power is lower than the uncorrected power in accordance with the concept of Section 2-1-3 (Turbulence Intensity - Effects). Consequently, the M-AEP is lower for the normalized wind speed when accounting for TI in this complex terrain. An overall reduction of 4% can be seen for bins between 4-16 m/s.

Table 7-2: Measured AEP (Turbulence Intensity Analysis) – wind speed between 4 m/s-16m/s (Free wind sector)

	[kWh]	[GWh]
M-AEP without filters and without correction	10960345.12	10.96
M-AEP with TI contract filters and without correction	10964020.90	10.96
M-AEP without filters and TI corrected with Eq (2-11)	10507291.96	10.51

7-3 Wind Shear Analysis

For the wind shear coefficient (α), it was observed that most values lie between 0.1 and 0.56, meanwhile, the mean value is 0.31 on the free wind sector. This is shown in Figure 7-9, where Alpha (α) is calculated with the power law equation (Eq. (2-12)).

The differences between the power curve for various α is seen in Figure 7-10. Here, for wind speed between 4 m/s and 9 m/s and a low α, the power curve is higher than the M-PC without filters, and the contrary occurs for high α. This matches the theory explained in Section 2-1-3 (Wind Shear - Effects). At the knee of the power curve, the tendency seems to reverse, similar to the TI. After 15m/s all α follow the measured power curves. Additionally, for this complex terrain, the shear exponent is independent of the wind speed bin (i.e. different α for the whole range of wind speed).

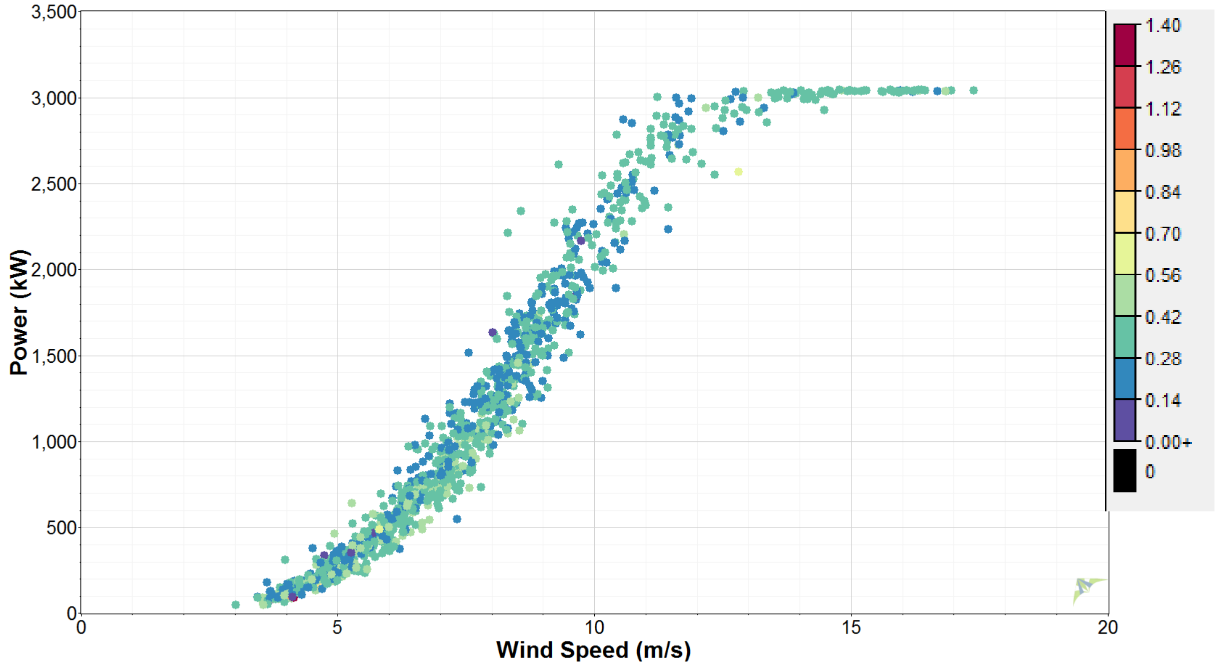

Figure 7-9: Power Curve WTG4 (free wind sectors) – Wind shear exponent (indicated by color)

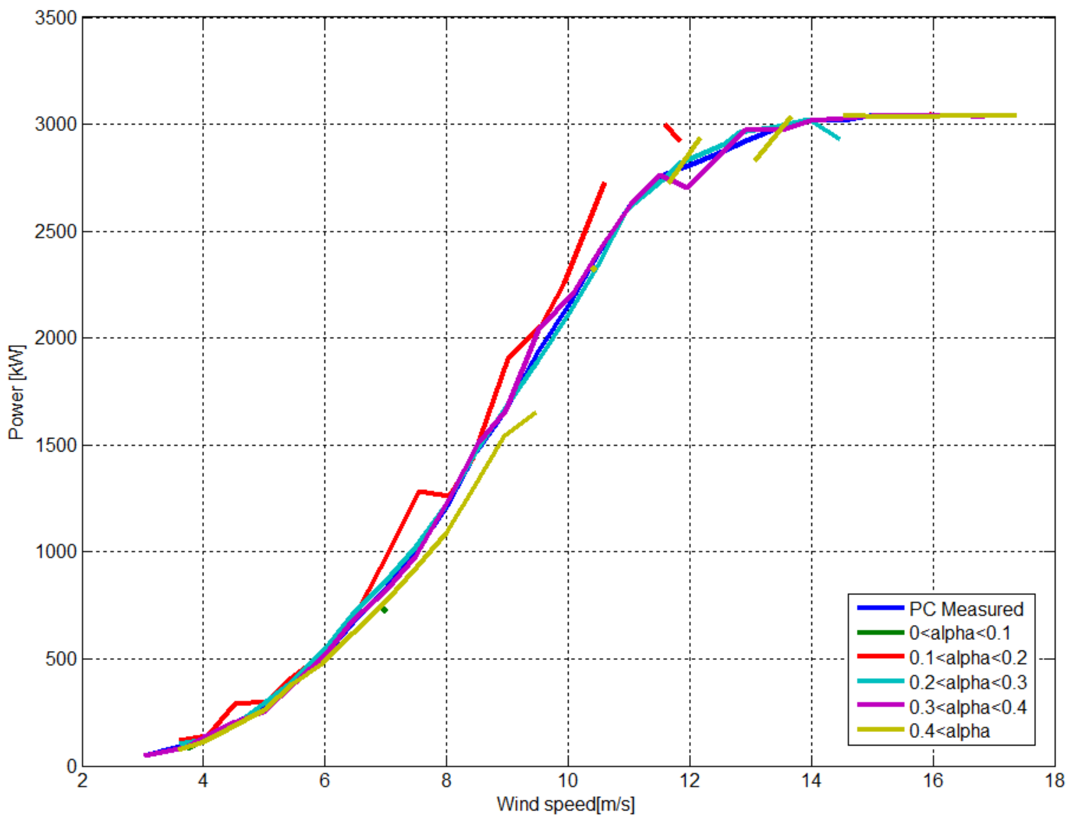

Figure 7-10: WTG4 Power curve for different shear exponent (indicated by color) - (Free wind sector)

The assumption that the hub height wind speed effectively describes the profiles introduces thus a bias [10]. For this reason, the shear correction (Eq. (2-14)) is applied. In Figure 7-11 the segmented area for this analysis can be seen.
The positions of the anemometers do not allow measures above hub height. For this reason, v_3 has been extrapolated with the power law. For v_1, the position of the anemometers did not match the center of A_1, and v_1 was interpolated.

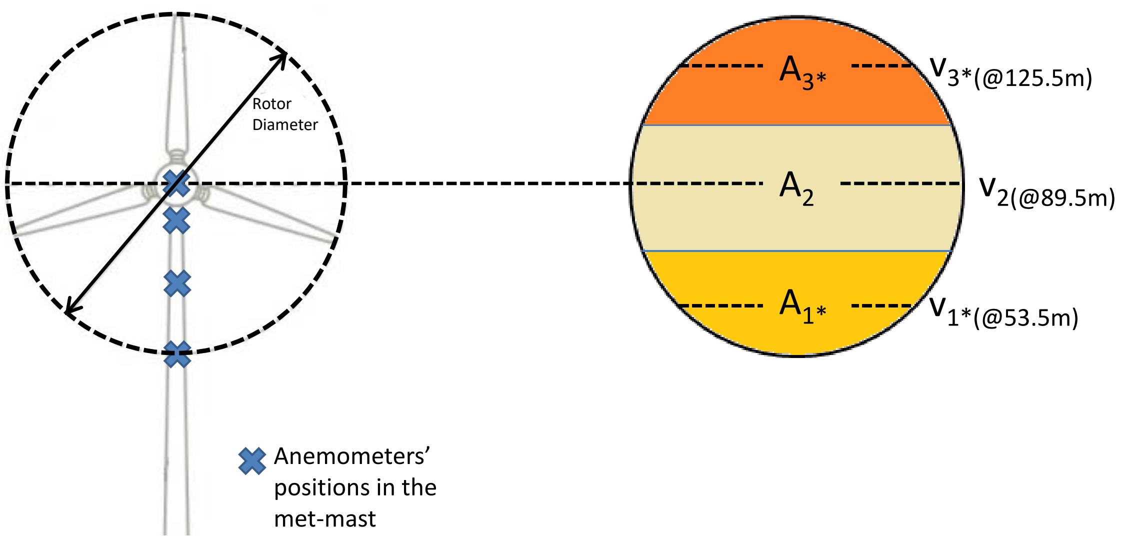

Figure 7-11: Anemometers position and segmented area for shear correction

Using Eq. (2-13) the segmented area was calculated, where the segment weighing is defined as the ratio between the segment area and the total swept rotor area (the total is 100%). The results are presented in Table 7-3.

Table 7-3: Results for normalized wind speed (accounting for wind shear)

subscript (i)	Measurement Heights [m]	Mean Wind speed [m/s]	Area [m^2]	Segment weighting [%]*	Segment inferior limit height (zi) [m]	Segment superior limit height (zi+1) [m]	Segment height [m]
3*	125.5	8.72	**2673**	29%	107.5	143.5	36
2	89.5	7.52	**3815**	42%	71.5	107.5	36
1*	53.5	6.61	**2673**	29%	35.5	71.5	36
				100%			

* estimated with power law

Using Eq. (2-14) the mean normalized velocity is 7.73 m/s, in contrast to the mean wind speed at hub height of 7.52 m/s. Figure 7-12 shows the difference between the corrected and uncorrected power curve. The same results can be seen in detail in Figure 7-13. For wind speeds bins between 4 m/s until 8 m/s the measured power with shear correction decreases around 6%. Between 9m/s until 14 m/s the measured power corrected for shear increases around 5%. For wind speed bins between 15 m/s and 16 m/s, no differences are found in the power. Overall, the corrected power is larger than the uncorrected, since the 5% increase is more significant that the loss on the low wind speed in terms of power. Consequently, this difference can be also noticed in the M-AEP in Table 7-4.

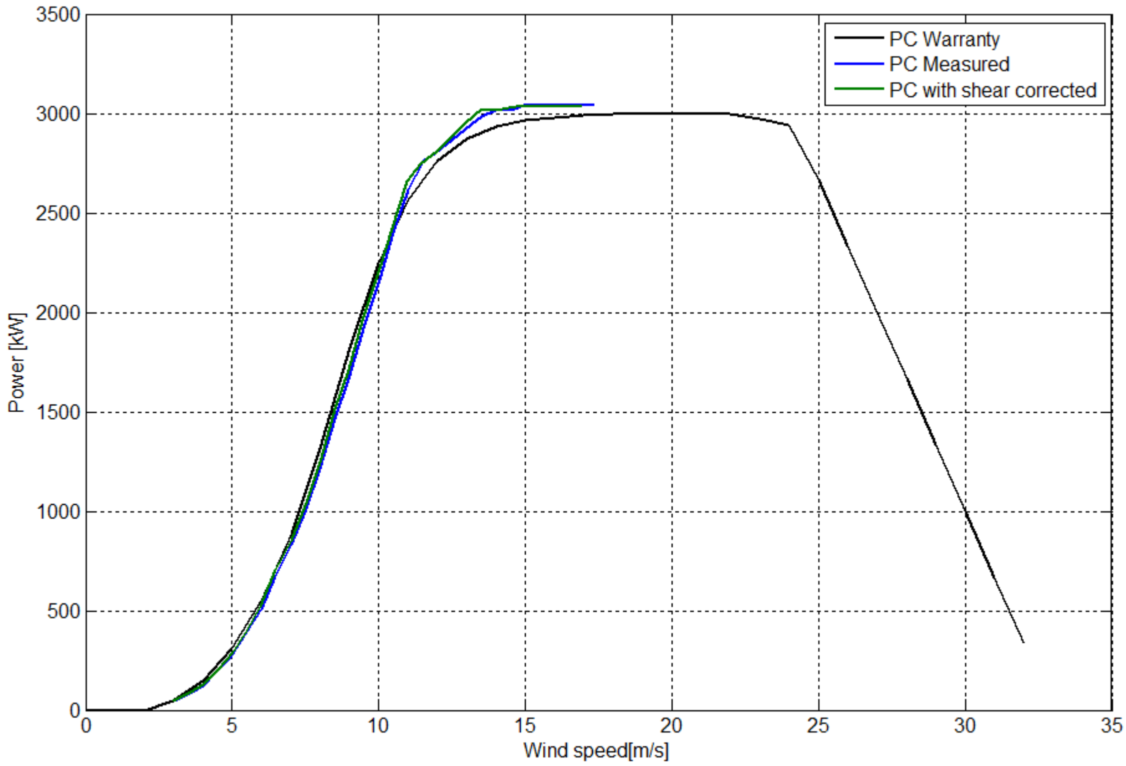

Figure 7-12: Warranted Power Curve | Measured Power Curve without filters | Measured Power curve without filters and normalized wind speed (free wind sectors) – Accounting for shear

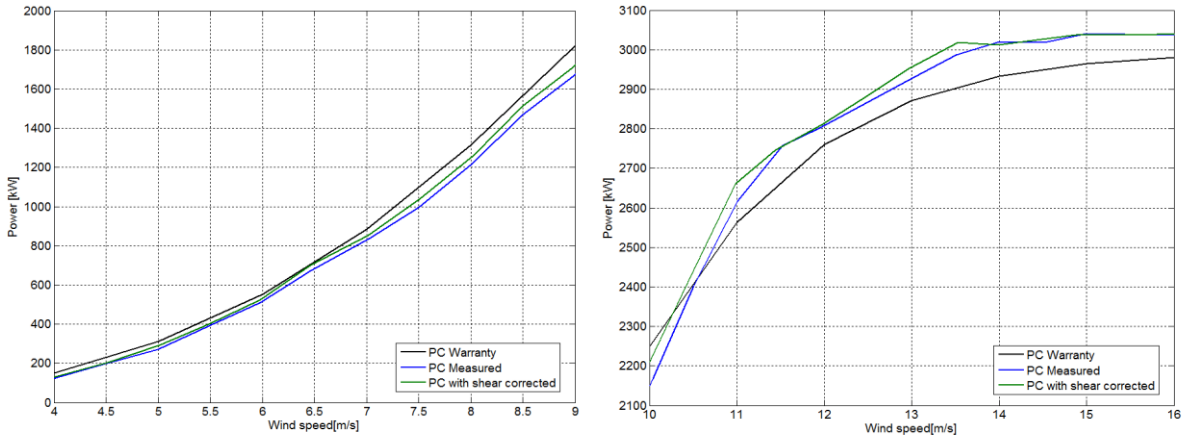

Figure 7-13: WTG4 Detailed M- Power Curve - Accounting for wind shear

Table 7-4: Measured AEP (Wind shear Analysis) – wind speed between 4 m/s-16m/s (Free wind sector).

	[kWh]	[GWh]
M-AEP without filters and without correction	10960345.12	10.96
M-AEP without filters and shear corrected with Eq. (2-14))	11256403.13	11.26

7-4 Wind Veer Analysis

In Figure 7-14 shows that most values lie between 0.1° and 16°, meanwhile, the mean value is 5.6° in the free wind sector. The effects of wind veer are less clear, hampered by a lack of veer data above hub height. It can be seen in Figure 7-15 that all different veers follow the M-PC without filters. In this section, it was not possible to apply the extended definition of equivalent wind speed including veer (Eq. (2-15)), since there are not at least three measurements of wind direction.

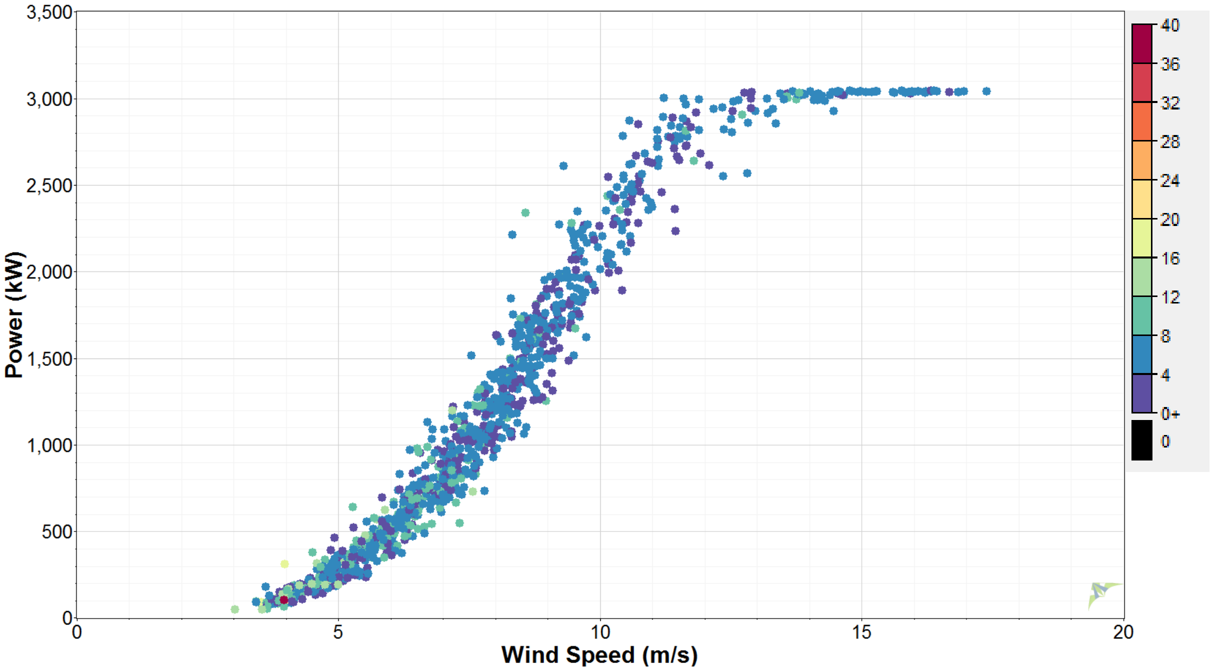

Figure 7-14: Power Curve WTG4 (free wind sectors) – Wind veer (indicated by color)

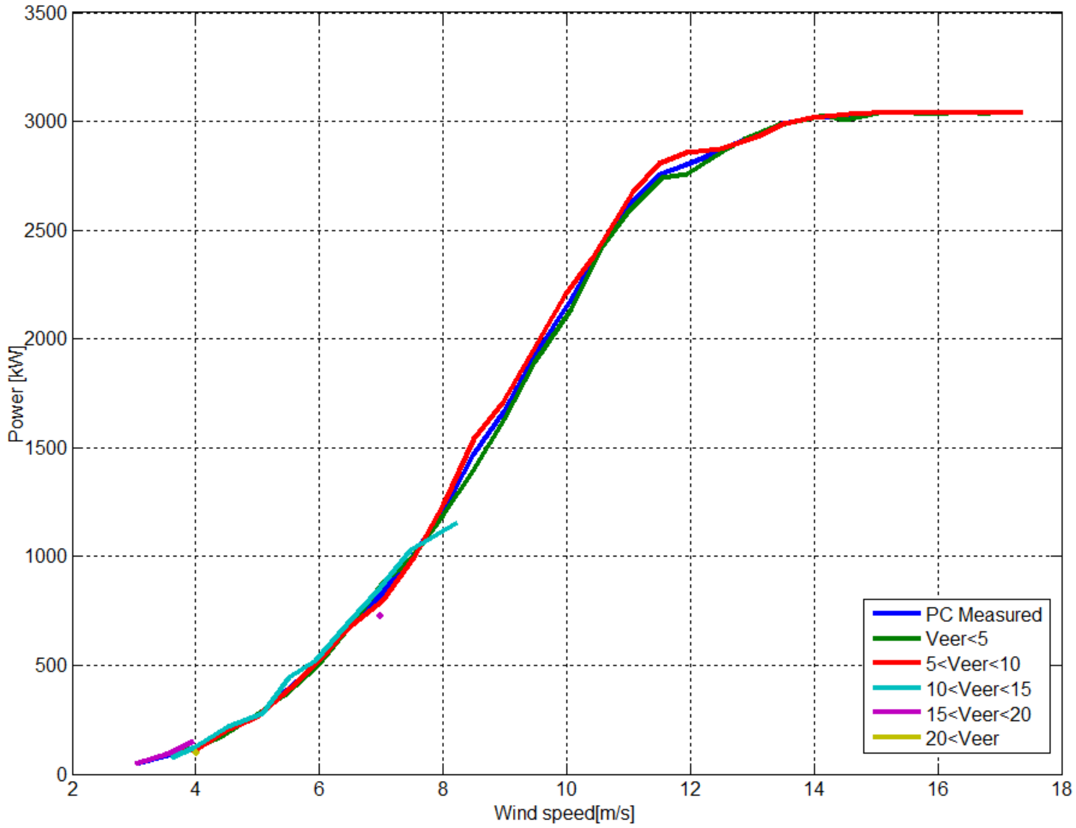

Figure 7-15: WTG4 Power curve for different Veer (indicated by color) - (Free wind sector)

7-5 Inflow Angle Analysis

It can be seen in Figure 7-16 that most values lie between 0.0° and 7.2°, meanwhile, the mean value is 1.87° calculated with Eq. (2-16) in the free wind sector. The effect of the inflow angle is less clear. Probably because the power curve is correlated with the tilt angle of the wind turbine, as suggested in Eq. (2-17). For this reason, in Figure 7-17 a clear tendency for different inflow angles cannot be seen. The information of the tilt angle is not available, consequently, the normalization of the wind speed cannot be completed.

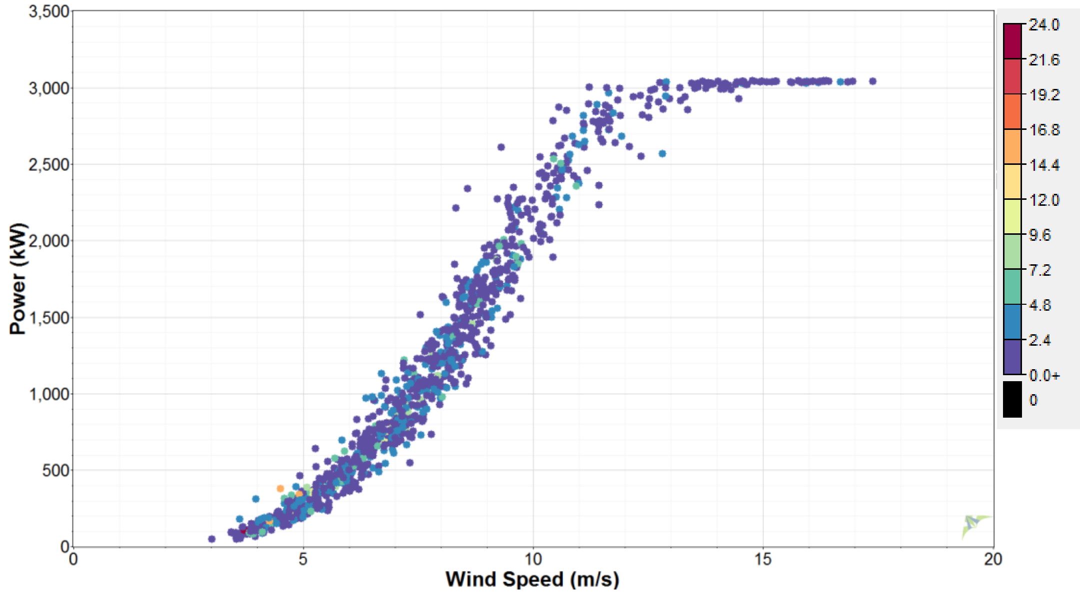

Figure 7-16: Power Curve WTG4 (free wind sectors) – Inflow angle (indicated by color)

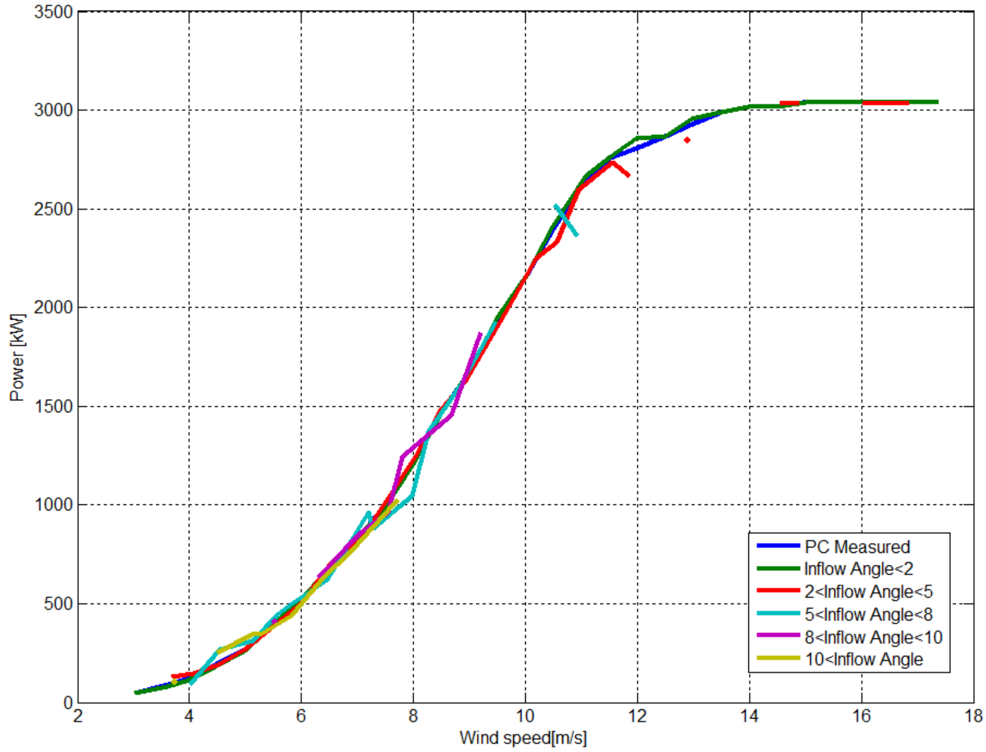

Figure 7-17: WTG4 Power curve for different Inflow angle (indicated by color) - (Free wind sector)

7-6 Remarks on Non-Standard Power Curve Estimation

No filters are considered necessary. Instead, a normalization of the wind conditions has shown to be ascertained for a 'site specific' power curve. Although all wind conditions are treated separately, it may be expected that these phenomena are correlated [33]. To combine these, several normalizations are proposed in the IEC 61400-12-1:2017 standard [30], as shown in Figure 7-18.

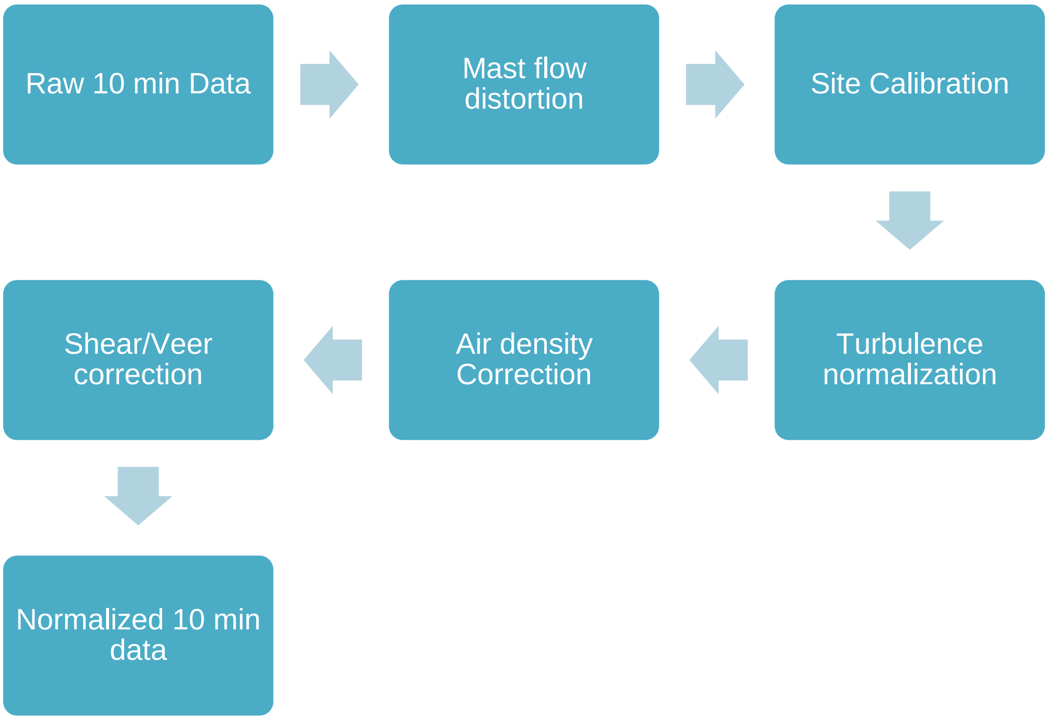

Figure 7-18: Process of application of the various normalizations. Modified by the author from [30].

A further study is recommended for non-linear interactions between inflow angle and power curve, as well as the mast flow distortion effect, since this is out of the scope of this project.

Chapter 8

XYZ Power Curve Warranty

The economy of a wind farm relies mainly on the available wind potential and the wind turbines' power performance and technical availability [65]. Of particular importance is the validity of the warranted power curve to certain environmental conditions and turbine conditions. As discussed in previous chapters, without the Power Performance Testing (PPT), the reason for dropping energy production remains unclear. Therefore, it is common practice among companies (i.e. energy agency and manufacturer) to include PPT in the contract. Wind Turbines with unsatisfying performance can be identified and optimized. Nevertheless, some of the technical risks linked to the limitations remain hidden for non-experts. This chapter uncovers these limitations and suggests possible solutions for shortcomings.

8-1 XYZ Contract terms and Risk sharing

This section presents the main points of the XYZ power curve contract [42]. For confidentiality reasons, the following list has been modified and summarized from the original. Moreover, the points listed below are the ones addressed in this project.

- The PPT shall be carried out in accordance to the IEC 61400-12-1, First Edition 2005-12.
- The air flow must be undisturbed (e.g. not influenced by wake from neighboring turbines).
- The Power Curve test shall be performed by an independent organization. This should be approved by the turbine *supplier* prior to the *buyer* employing the organization.
- The PPT can be performed at any time within the Warranty Period, but no later than six months before the ending of the Warranty Period.
- All cost related to such first PPT shall be paid by the *buyer*. If the turbine failed the test, a compensation rule should apply.
- When more than one Test turbine is measured, the Measured Annual Energy Production (M-AEP) shall be calculated as the arithmetic average.
- If the wind conditions during the PPT are significantly different to the Site-Specific Conditions specified in the contract. The two parties (i.e. supplier and buyer) need to agree on the retest or adopt other solution.
- If the turbine (s) failed the first power curve test, the supplier shall be allowed an 180-day period to modify the test turbines.
- If the *buyer* requires a second PPT the procedure shall be repeated. If the turbines passed (after modifications), then the warranted power curve has been verified, and the modifications to the test turbine shall be implemented to all wind turbines in the project.
- If at the end of the Production Period the M-AEP is less than the Warranted Annual Energy Production (W-AEP), then the *supplier* shall be liable to pay compensation to the *buyer.* In this

case, another PPT can be performed and the supplier is entailed to perform further turbine modifications.

- At least two/three test turbines must be measured (per turbine type).
- The test turbine locations must be selected jointly by the supplier and the buyer.
- A met mast for each of the power curve test shall be erected 2.0 – 2.5 rotor diameters upwind of the turbine location relative to the prevailing wind direction.
- Wind speed measurements shall be made in three heights: at hub-height, at lower tip height and midway between hub-height and lower tip height.
- A site calibration shall be carried out by the *buyer* at the Test Turbines using a temporary met mast.
- The data analysis and reporting of the Power Curve Test shall be based on the IEC 61400-12-1:2005 standard.
- If the database does not include data up to cut-out wind speed, the M-PC shall be established by considering the measurement results with extrapolated power values from the maximum completed wind speed bin.

8-2 Limitations and Recommendations

Bridging the warranty gap is of interest to both researchers and practitioners. PC warranty contracts were converted in a general matter in Chapter 2. Based on the literature studied, this review of PC warranty contracts allows to draw several implications for contract-makers from a technical view and to present suggestions and recommendations for improving future Vattenfall agreements.

One of the contract conditions is, that the air flow must be undisturbed (as well mentioned in the IEC 61400-12-1:2005 standard). The relevant production losses are assessed in an undisturbed environment. This is justified, since the turbine must be tested in the free wind sector. All the turbines that are affected by wake have been already considered in the business case. This is a reasonable consideration, taking all the wind sector (instead of only the free wind speed), will create a measured PC that is not accurate, since the wind speed data could have been compromised by external factors (e.g. wake).

One critical aspect of most standard power curve warranties is that the criterion of fulfillment is defined as the mean of the measured power curves [4]. This is the case in this contract as well, the warranty provides a W-PC per wind turbine type. In practice for XYZ, two / three turbines are being tested, and the results are averaged per turbine type to create the M-PC. As known, a single turbine has a higher uncertainty on the power curve tests compared to the uncertainty of a mean power curve set, because some uncertainty components are independent between the single measurements (e.g. uncertainty of site effects) [4]. Nevertheless, taken the average M-PC do not increase or decrease the validity of the PC in general, but gives an overview of the performance expected for the wind farm

The power performance test (PPT) is covered by the *buyer*. Including mast, mast installation, site calibration and repetition of the PPT. Consequently, the risk is not allocated correctly nor is effective monitoring ensured. Compensation payments if the turbines failed the power curve test should be covered by the *supplier*, including all the previous expenses for the PPT until that point. As well, as compensation payments for losses due to power reductions during the wind farm life until the turbines improvements are done (all turbine of the same type).

To avoid extraordinary data reductions, the following site conditions are to be included in the contract. As shown in Chapter 7, the main atmospheric drivers on the power curve results, and consequently M-AEP are: air density, turbulence intensity and shear. For this, correction of these conditions are a recommended alternative (instead of filters). The new version of the standard IEC 61400-12-1:2017 provides methodologies to account for different wind conditions and the process of application of each correction. This is shown briefly in Figure 7-18. The shortcomings of this method are covered by the added uncertainty, that at the same time will impact the M-PC.

As the uncertainties of Power Performance Testing are considerable, the treatment of the uncertainties is defined in the IEC 61400-12-1:2005 and additional requirements based on the standards are found in the XYZ contract. Here, the method to calculate the cumulative uncertainties of the PC and AEP is considered as being challenging and reduces the warranty level systematically [4].

Furthermore, the uncertainty of including a high wind cut-out is expressed by a higher statistical uncertainty of the measurement, since the contract states that this should be extrapolated to have the power information. This is described by the general law of uncertainty propagation. Within the IEC 61400-12-1:2005 the wind speed analysis is conducted until 16 m/s. This is lower than the cut-out wind speed expected for these turbines. This uncertainty reduces the warranty level. A wind resource analysis based on historical data of high wind speed should be done and added to the Power Performance Testing, in case of missing/incomplete wind speed bins. The result should be accepted by the turbine *supplier* and by the *buyer.* In case that historical data of high wind speed is not available, Section 6-3 (Discussion) address an alternative.

In some cases, for complex terrain, positioning the mast upwind the test turbine can be an improper choice (or not possible) leading to systematic uncertainties of the site calibration and Power Performance Testing. Furthermore, lowering the distance between mast and turbine is sometimes not possible. Therefore, the feasibility of these additional requirements must be decided for each wind farm site, especially for complex terrain.

8-3 Remarks on Warranty Contracts

Overall, to overcome the measured power curve for well-defined conditions, the warranted power curves should be defined for different wind conditions in the free wind sector rather than applying filters. Considering different power curves (in the free wind sector) for:

- Different wind conditions (e.g. Power curve with different TI class)
- Corrected power curve for air density, turbulence intensity and shear as the main atmospheric drivers.

The IEC 61400-12-1:2005 states an extrapolation of the rated power. This cannot be applied to all modern turbines due to the *Extended smooth cut-out*. After all, the *Extended smooth cut-out* is difficult to prove, since: i) there might not be enough high wind speed during the PPT to complete the bins and/or ii) it is outside of the wind speed site calibration limits. The recommendation presented in Section 6-3. is a useful tool to extrapolated AEP and to encourage the supplier to present an accurate warranted power curve. At the same time, this will assure proper turbine settings on higher wind speeds that might not be recorded on the PPT.

A simulated measured power curve which considers the change of wind speed and wind direction in time can be an option for operational wind turbines for comparison and data collection.

As a general recommendation, the special turbine conditions should be excluded from the warranty contract when the supplier cannot be held responsible (e.g. grid conditions, noise reduced operation and automatic load reduction).

Chapter 9

Conclusions and Recommendations

9-1 Site Conditions

By using three months of available data from the met-masts in XYZ site calibration campaign, the site conditions were investigated for this complex terrain. Five locations within the wind farm were studied (i.e. WTG1, WTG2, WTG3, WTG4, and WTG5). A high similarity of wind conditions among these is found despite the distances between them.

For the air density, constant values were measured in the wind farm, meaning no variation from location to location. In general, due to the complexity of the terrain high TI and shear is experienced. As expected, high TI is observed at low wind speeds and relatively high wind veer when studying all wind sectors. Additionally, the wind shear exponent shows a higher mean value during the night hours. This is because during the night the surface area cools down which enables stable conditions to prevail. The stable boundary layer is lower than the met-mast at hub height, causing the wind regimen at the upper measuring level (hub height) to be decoupled from the regime at the lower measuring level (near the ground), leading to two different wind regimes with different wind speeds.

Lastly, inflow angles in most of the locations are relatively small. It is known, that large inflow angles may affect the production and lifetime of wind turbines

The impact of the wind conditions studied is related to the period during which the site calibration took place. Though the seasonal variation is not studied in this research (only 3 months of data), it is reasonable to expect that the tested wind turbines may get different power curves during different seasons as the wind speed, density, wind shear, wind veer, turbulence intensity, and inflow angle differ.

9-2 Site Calibration

The effects of the filters presented a significant reduction of the data available for the site calibration (less than 21% for the locations studied). For this reason, a longer time in measurements was needed in order to complete the wind bins (direction and speed).

For Site calibration results, there is a visible tendency for all sites. As expected the slope is approximately 1. In addition, a high R^2 ($R^2 \geq 0.96$) is observed for all valid bins in all locations, indicating a good relationship between reference mast wind speed and site calibration mast wind speed.

An additional linear regression analysis for TI was performed. The results show low R-squared values. These values are problematic when precise predictions are needed. In this case, a turbulence correction based on the site calibration is not recommended.

Even though, that the site calibration campaign (for wind speed) could not be avoided from a contract perspective, the benefits of the site calibration are unseen. The reason is because the wind speed with site calibration is always within wind speed uncertainty of the wind speed without site calibration. This is valid for the free wind sectors and wind speed between 4 m/s to 16 m/s.

It was found that in some cases, the IEC 61400-12-1:2005 is open for interpretation. Mainly regarding:

- Selecting the correct met-mast or wind condition analysis,
- Temperature filter value of icing,
- The quantity of sample points per 10-minute average.

Recommendation: It is advised to use the MEASNET guide to fill the IEC gaps. Gathering more data during the year will provide a seasonal site calibration and the differences can be studied.

9-3 Power Curve Test (IEC 61400-12-1:2005)

The two locations studied (i.e. WTG4 and WTG5) corresponding to ABC1 were combined. As mentioned before, there was a significant reduction of datasets due to the filters, leaving standard wind conditions of less than 20% of all expected wind conditions for this site.

The measured power curve (PC) is valid only from 4 -16 m/s due to the site calibration and a correction of the air density was not necessary. The warranted power curve is higher than the measured power curve (WTG4 PC and WTG5 PC combined). Consequently, the Warranted Annual Energy Production (11.3 GWh) is higher than the Measured Annual Energy Production (11.2 ± 0.2 GWh). Nevertheless, due to the uncertainty calculated, the W-AEP is within the M-AEP acceptable range.

Different results were found in the M-AEP. This difference is due to the fact that the IEC considers the Rayleigh distribution meanwhile the contract considers the Weibull distribution for the energy calculation. Literature has found that the Weibull model predicts the actual value better than the Rayleigh model [64]. For this reason, the M-AEP according to the contract is considered as representative of this turbine type.

The *Extended smooth cut-out* is a new feature. Neither the IEC nor the contract state a proper approach on this case. In this project, a suggested method is proposed to account for it.

Recommendation: A clear description of uncertainty calculations using the Weibull distribution as well as how to account for the *Extended smooth cut-out* in extrapolated power curve results is needed.

9-4 Non-Standard Power Curve Estimation

No additional filters are considered necessary (except for the free wind sector). Instead, a normalization of the wind conditions has shown to be ascertained for a ‘site specific’ power curve. Corrections with respect to air density, turbulence intensity and wind shear are studied with state-of-art methods. These corrections have shown to be effective in this complex terrain.

The results of analyzing air density show that the power expected is lower when the wind speed is normalized to a reference density that is lower than the measured air density. The turbulence intensity shows that the power expected is slightly lower derived from the TI correction in this complex terrain. The overall reduction on the AEP of 2% and 4% are obtained for air density and TI normalization respectively, compared to the M-AEP without corrections. Meanwhile, the power is higher when accounting for wind shear in this complex terrain, leading to an AEP increase of approximately 3%. The effects of wind veer and inflow angle were less clear in the power curve, hampered by a lack of data above hub height. Even though that all wind conditions are treated separately, it may be expected that these factors are correlated.

Recommendation: Acquire data from a remote sensing device (e.g. Lidar) to get measurements above hub-height to analyze the wind veer and inflow angle contribution. Investigate the contribution of various normalizations combined (i.e. accounting for air density, TI, wind shear, wind veer and inflow angle combined), this could change or improve the results on the Measured Power curve according to the IEC 61400-12-1:2005.

9-5 Power Curve Warranties

To avoid extraordinary data reductions, the site conditions are to be included in the contract. It was shown that the main atmospheric drivers on the power curve results and consequently M-AEP are: air density, turbulence intensity and wind shear. For this, considering different warranted power curves (in the free wind sector) for:

- Different wind conditions (e.g. warranted power curve with different TI class).
- Corrected power curve for air density, turbulence intensity and wind shear as the main atmospheric drivers (instead of filters). The potential shortcomings of normalizations should be covered by an added uncertainty, that at the same time will impact the M-PC.

The uncertainty of including a high wind cut-out is expressed by a higher statistical uncertainty of the measurement, since the contract states that this should be extrapolated to have the power information. This is described by the general law of uncertainty propagation. Within the IEC 61400-12-1:2005 the wind speed analysis is until 16 m/s, which is lower than the cut-out wind speed expected for these turbines. A wind resource analysis based on historical data of high wind speed should be done and this analysis should be done parallel to the Power Performance Testing.

A simulated power curve which considers the change of wind speed and wind direction in time can be an option for operational wind turbines for comparison and data collection.

The recommendations presented are a useful tool to estimate the power curve in non- standard wind conditions. At the same time, it encourages the supplier and buyer to present a power curve valid for most of the site conditions found in a wind park.

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Appendix A

XYZ Site and Data

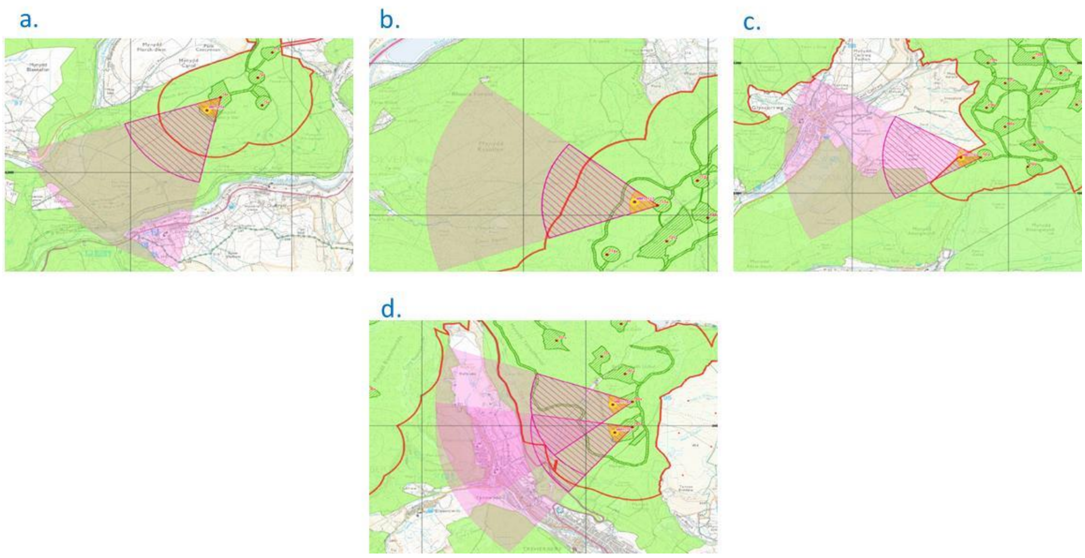

Figure A-1: Free wind sector: a. WTG1 , b. WTG2 , c. WTG3 , d. WTG4 and WTG5 [51].

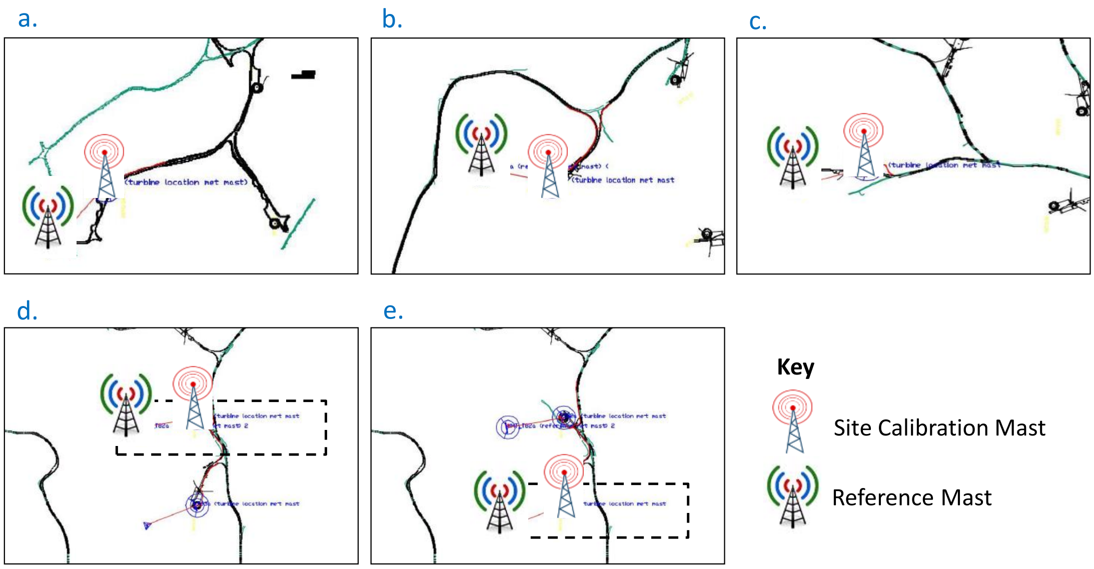

Figure A-2: Locations and orientations of met-mast (detail). a. WTG1 , b. WTG2 , c. WTG3 , d. WTG4 , e. WTG5. Modified by the author from [51].

Table A-1: Comparison of the terrain (5 mast pairs)- Google Earth Pro.

WTG1				
RM	SM	Distance [m]	Elevation RM [m]	Elevation SM [m]
51.658712° , -3.693578°	51.660428° , -3.691170°	248.67	361	362
WTG2				
RM	SM	Distance [m]	Elevation RM [m]	Elevation SM [m]
51.706956, -3.633767	51.706664 , -3.630196	251.96	472	482
WTG3				
RM	SM	Distance [m]	Elevation RM [m]	Elevation SM [m]
51.674179, -3.600567	51.674850°, -3.597352°	235.08	464	470
WTG4				
RM	SM	Distance [m]	Elevation RM [m]	Elevation SM [m]
51.691645°, -3.530159°	51.691743°,-3.527079°	243.11	514	507
WTG5				
RM	SM	Distance [m]	Elevation RM [m]	Elevation SM [m]
51.687893°, -3.529642 °	51.688676°, -3.526573°	230	514	506

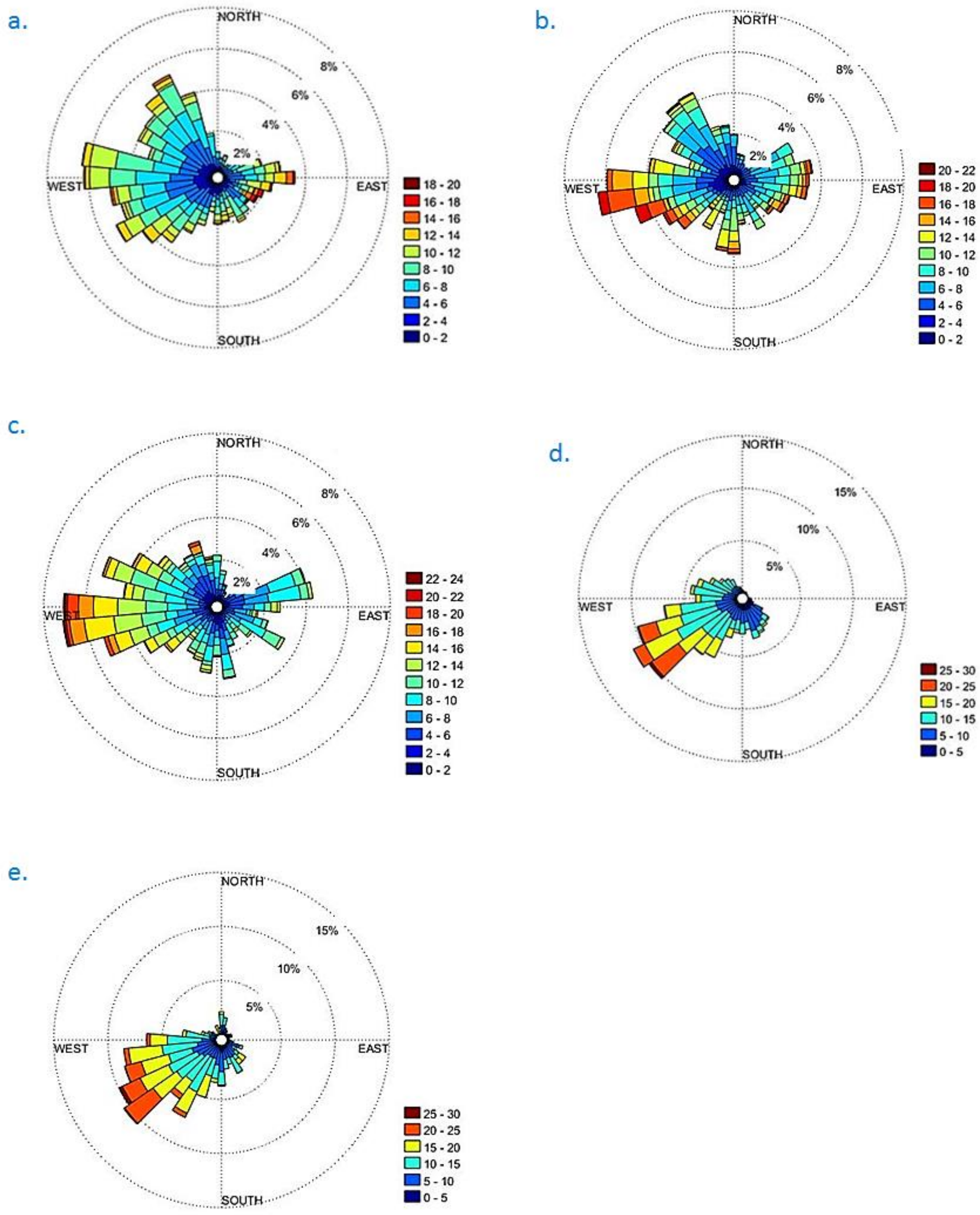

Figure A-3: Wind Rose. a. WTG1 (Data: 23.03.2016 – 04.05.2016) ; b. WTG2(Data: 18.02.2016-03.05,2016) ; c. WTG3(Data:07.01.2016-04.04.2016) ; d. WTG4(Data: 22.10.2015-09.02-2016) ;e. WTG5 (Data: 16.12.2015-13.04.2016).

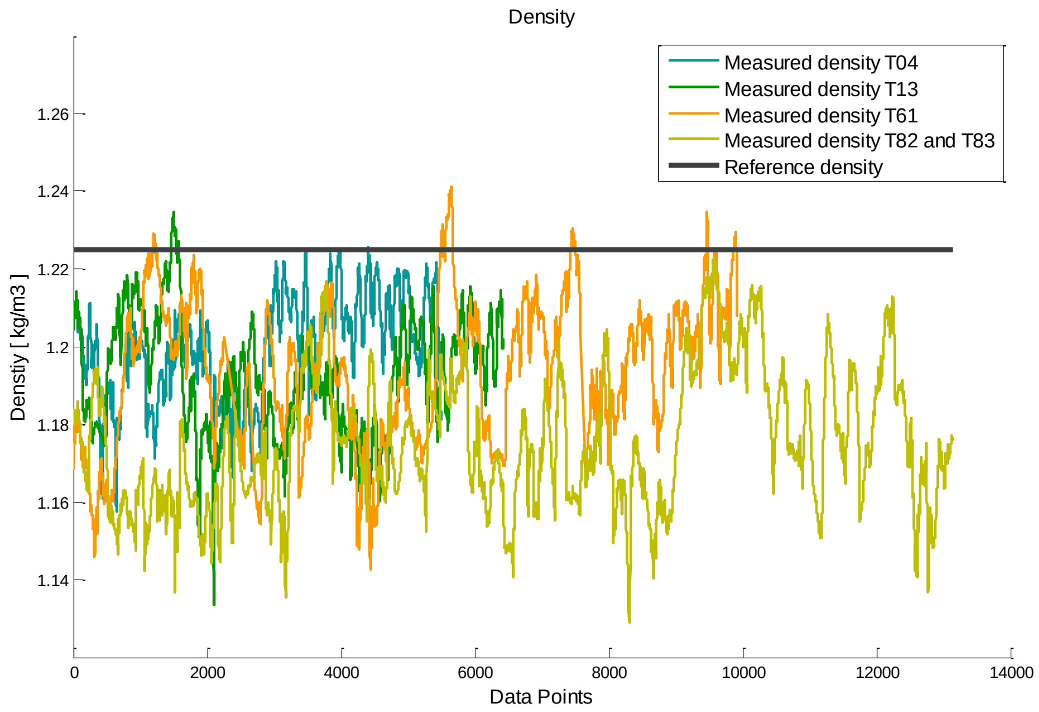

Figure A-4: Density all locations– Reference Mast Data (all wind sectors).

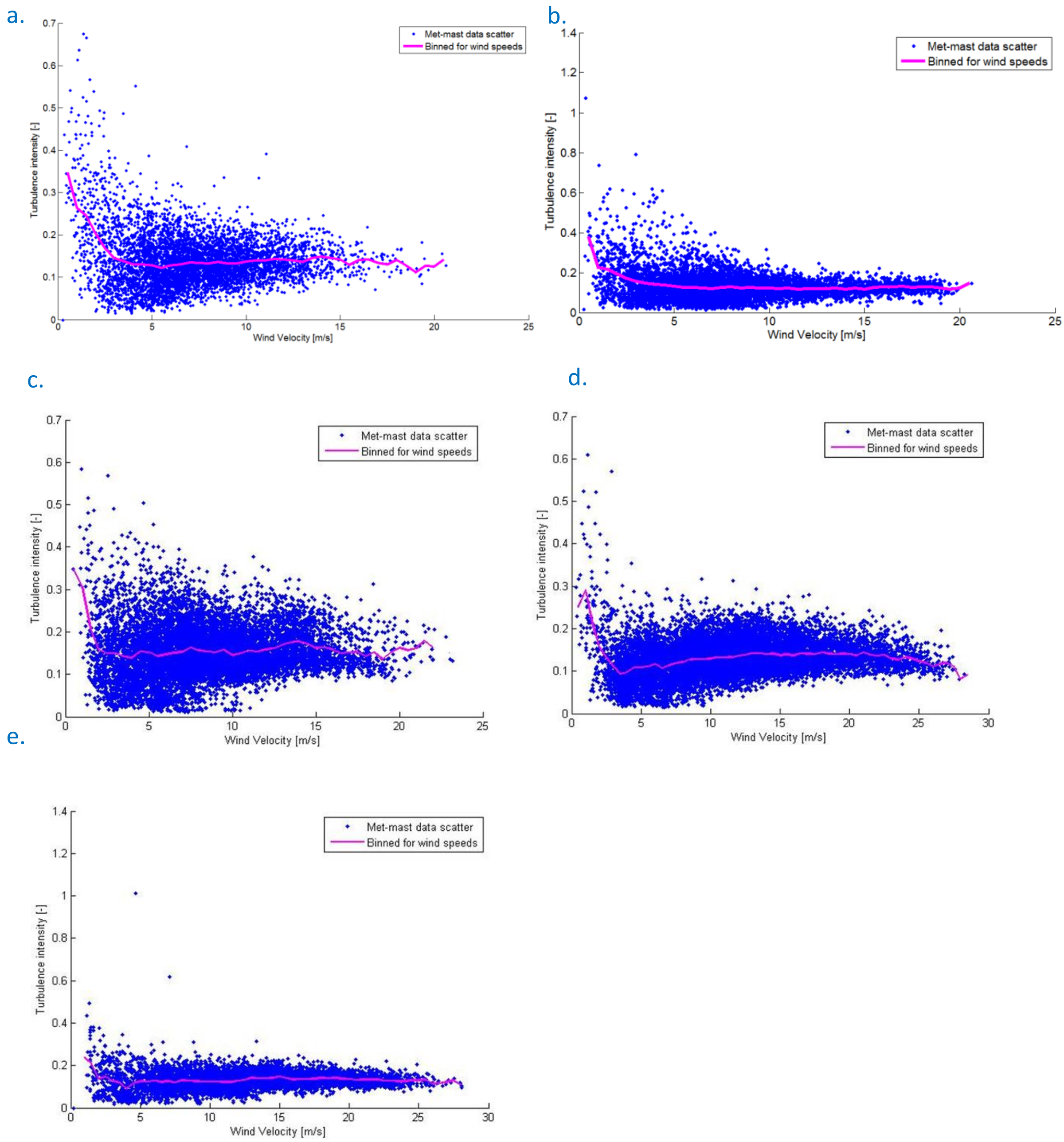

Figure A-5: Turbulence Intensity– Reference Mast Data. a. WTG1 , b. WTG2 , c. WTG3 , d. WTG4 , e. WTG5 (all wind sectors).

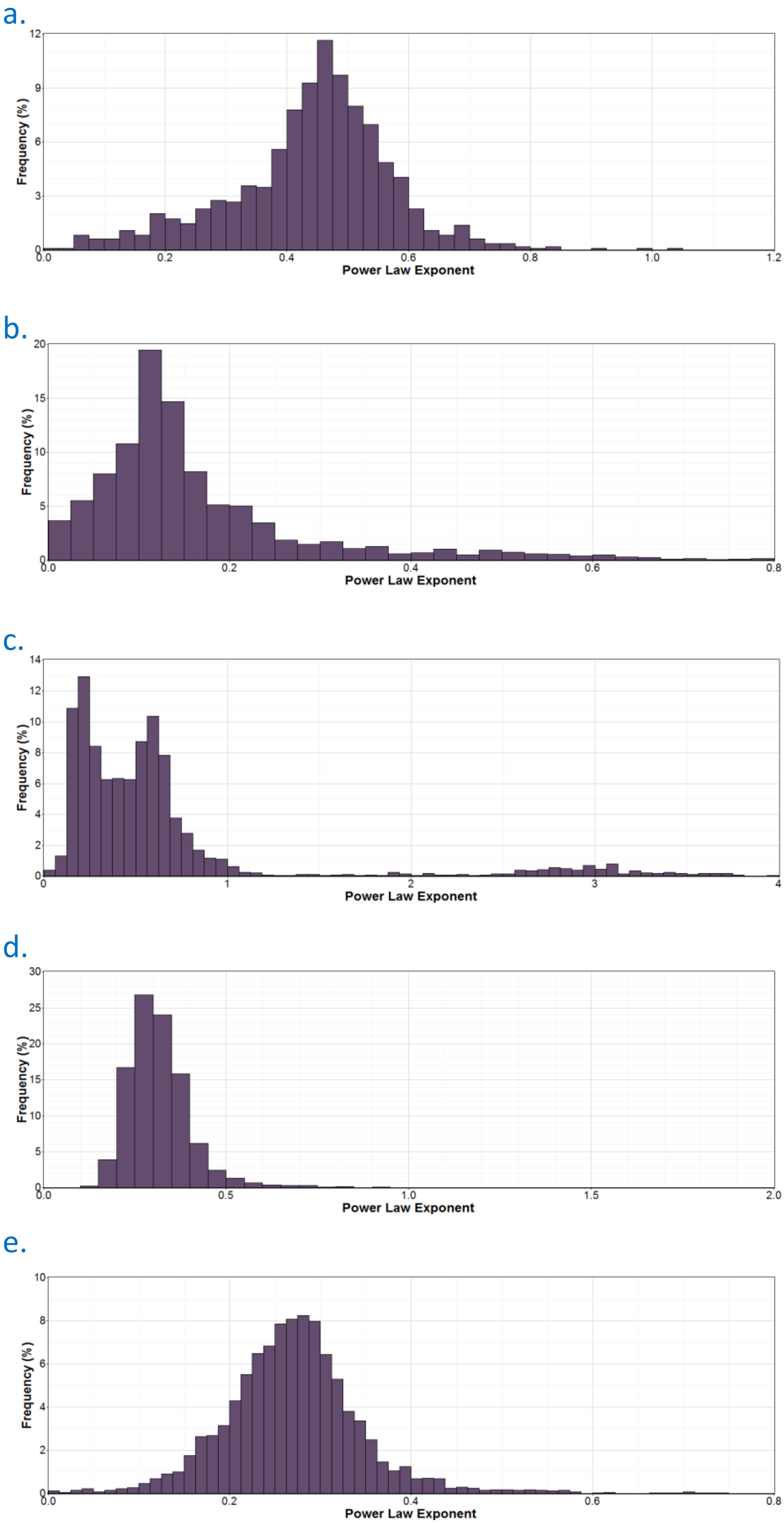

Figure A-6: Power law exponent Probability Distribution. a. WTG1 , b. WTG2 , c. WTG3 , d. WTG4 , e. WTG5 (Free wind sector).

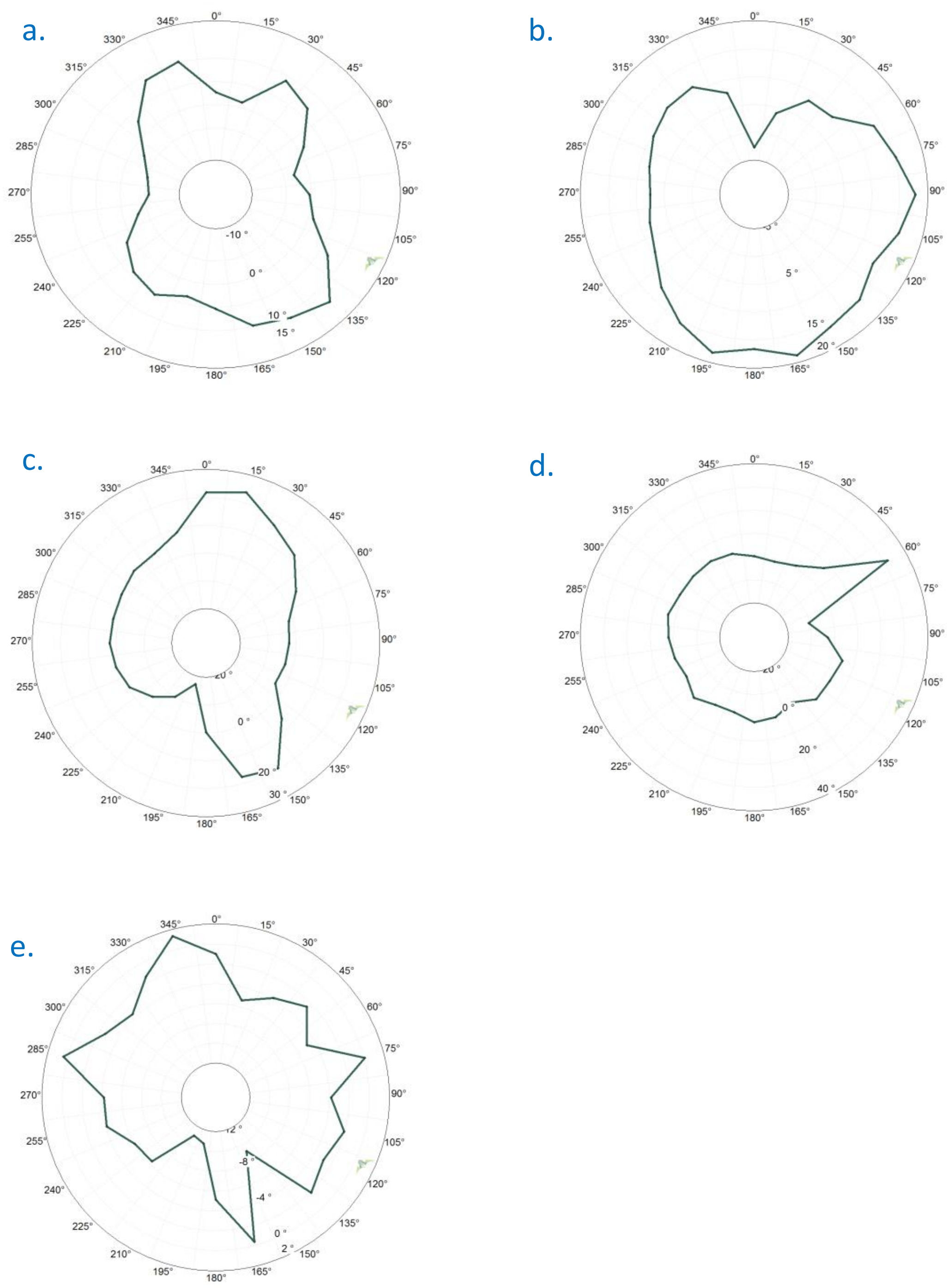

Figure A-7: Wind Veer Rate [°/100m] . a. WTG1 , b. WTG2 , c. WTG3 , d. WTG4 , e. WTG5.

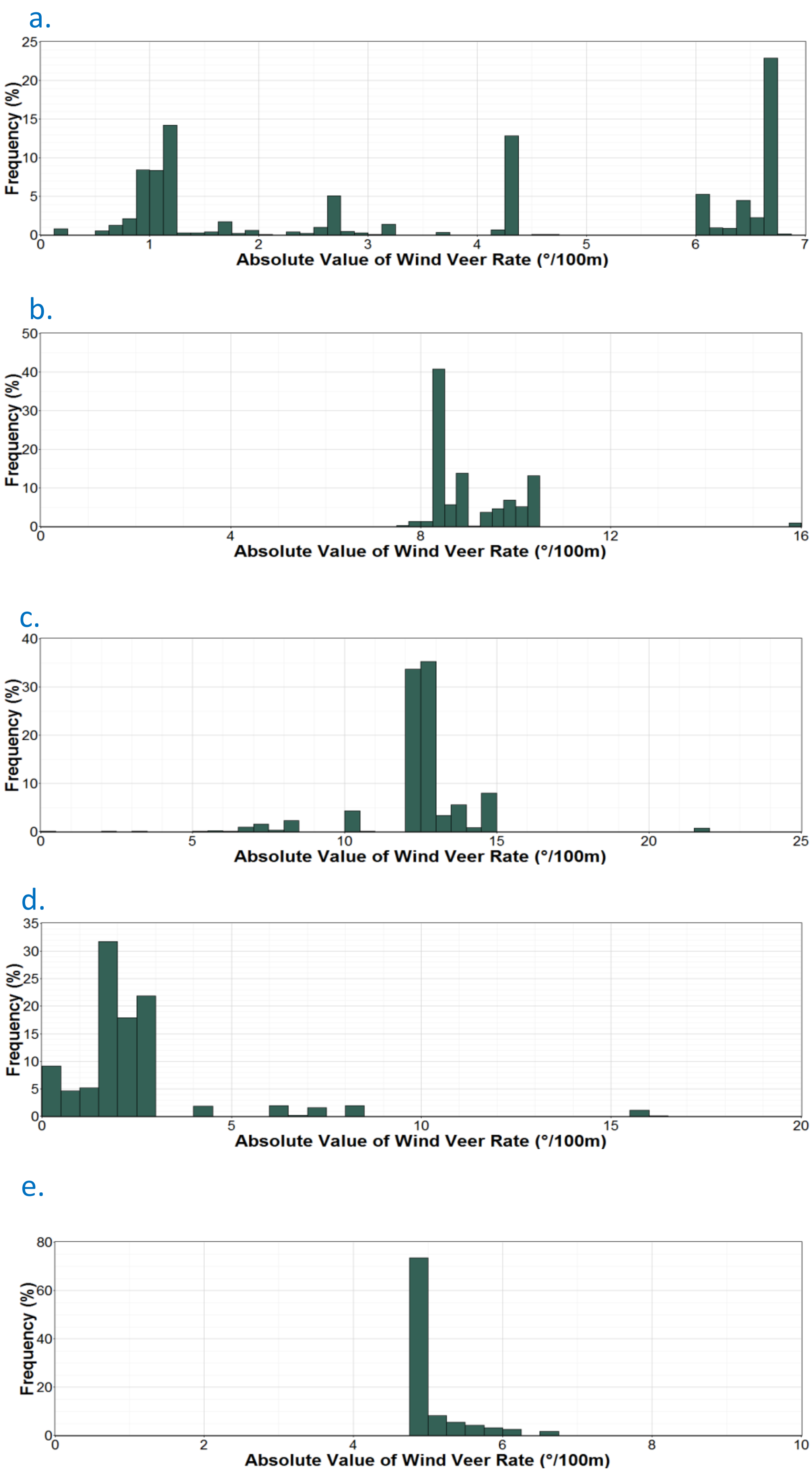
a.
Frequency (%)
Absolute Value of Wind Veer Rate (°/100m)
b.
Frequency (%)
Absolute Value of Wind Veer Rate (°/100m)
c.
Frequency (%)
Absolute Value of Wind Veer Rate (°/100m)
d.
Frequency (%)
Absolute Value of Wind Veer Rate (°/100m)
e.
Frequency (%)
Absolute Value of Wind Veer Rate (°/100m)

Figure A-8: Absolute Wind Veer Rate Probability Distribution. a. WTG1 , b. WTG2 , c. WTG3 , d. WTG4 , e. WTG5 (Free wind sector).

Figure A-9: Inflow angle - RM. a. WTG1 , b. WTG2 , c. WTG3 , d. WTG4 , e. WTG5.

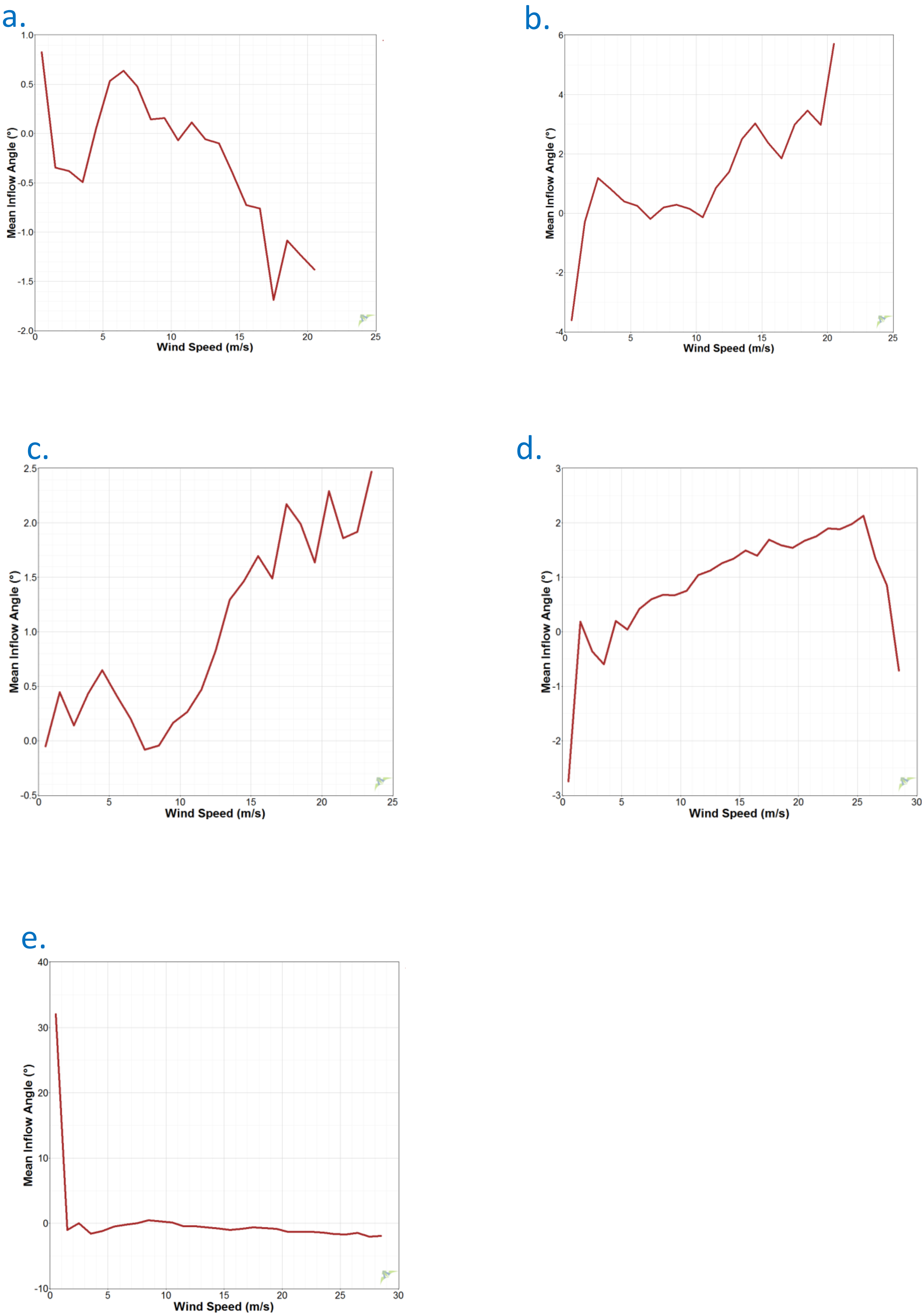

Figure A-10: Mean Inflow angle vs wind speed – RM. a. WTG1 , b. WTG2 , c. WTG3 , d. WTG4 , e. WTG5 (All wind sectors).

Figure A-11: XYZ Wind Farm Layout [52].

Appendix B

Regression Analysis – Site Calibration for WTG1 Location

WTG1: Regression analysis

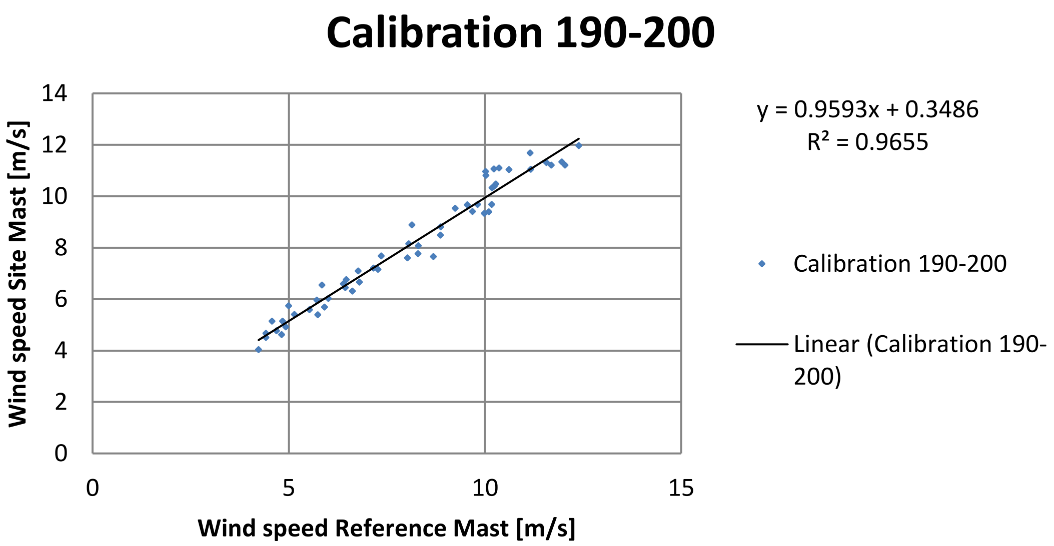

Figure B-1: WTG1- Calibration 190-200.

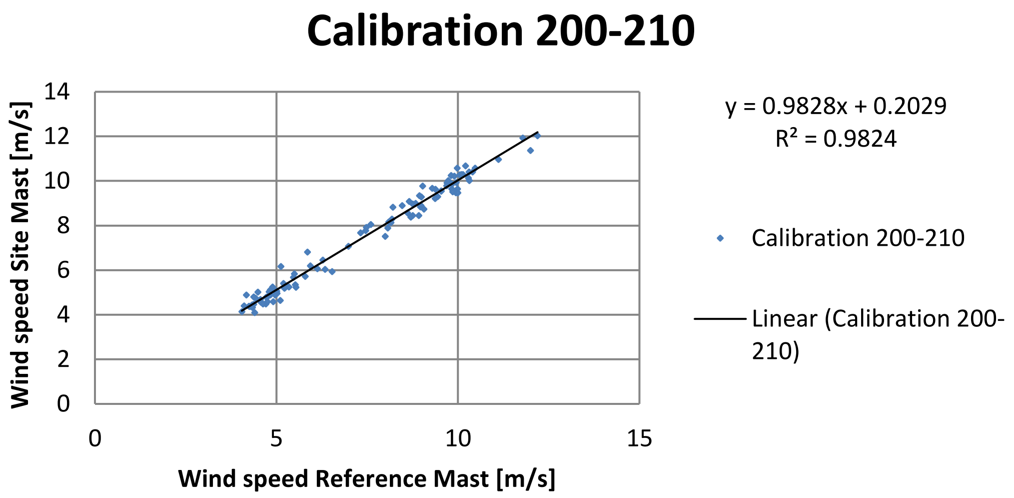

Figure B-2: WTG1- Calibration 200-210.

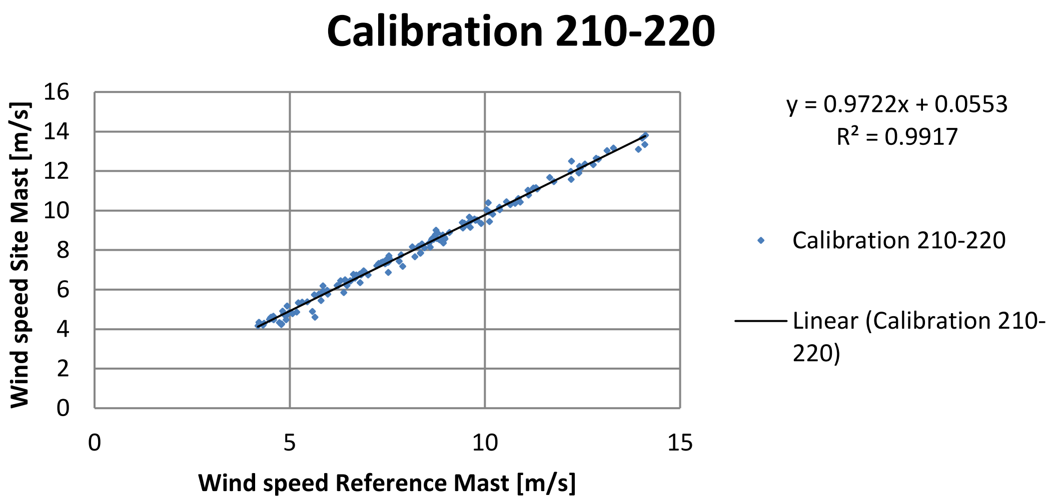

Figure B-3: WTG1- Calibration 210-220.

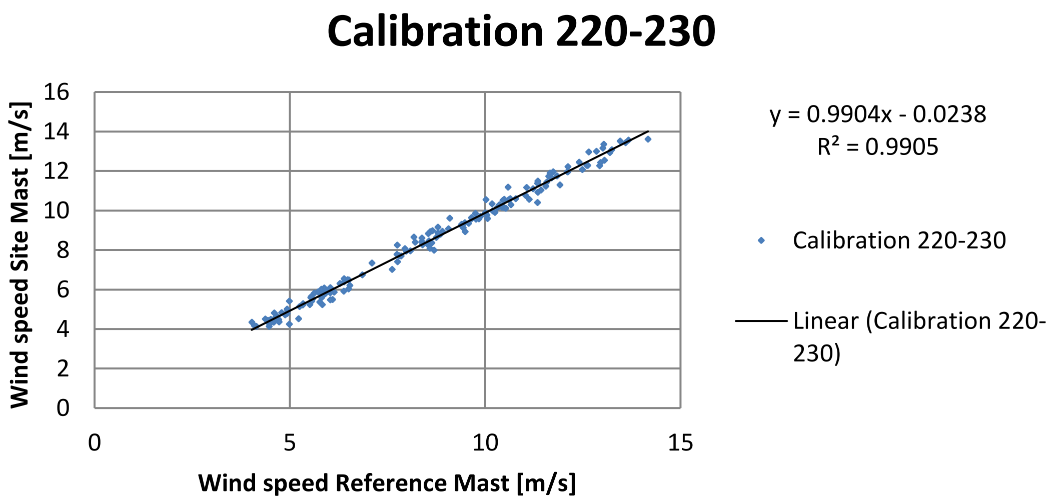

Figure B-4: WTG1- Calibration 220-230.

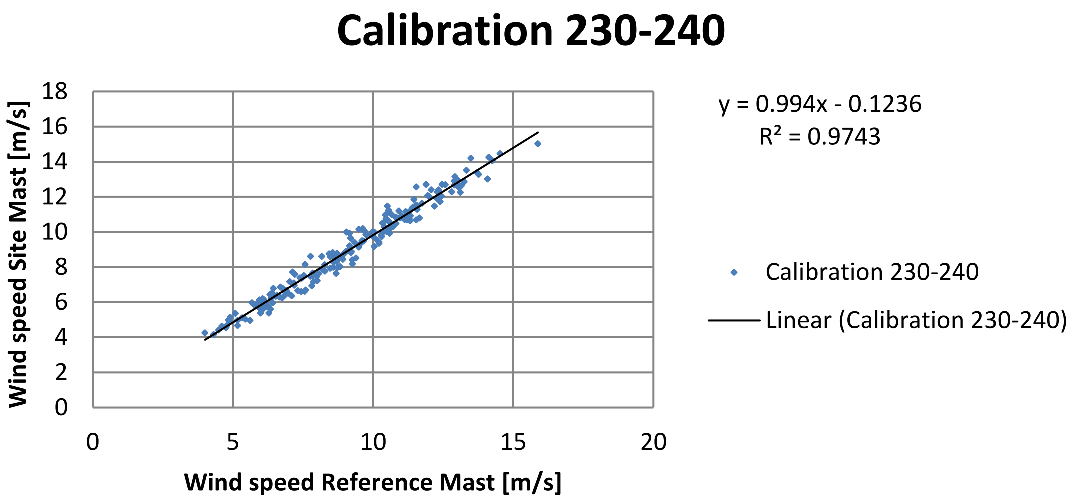

Figure B-5: WTG1- Calibration 230-240.

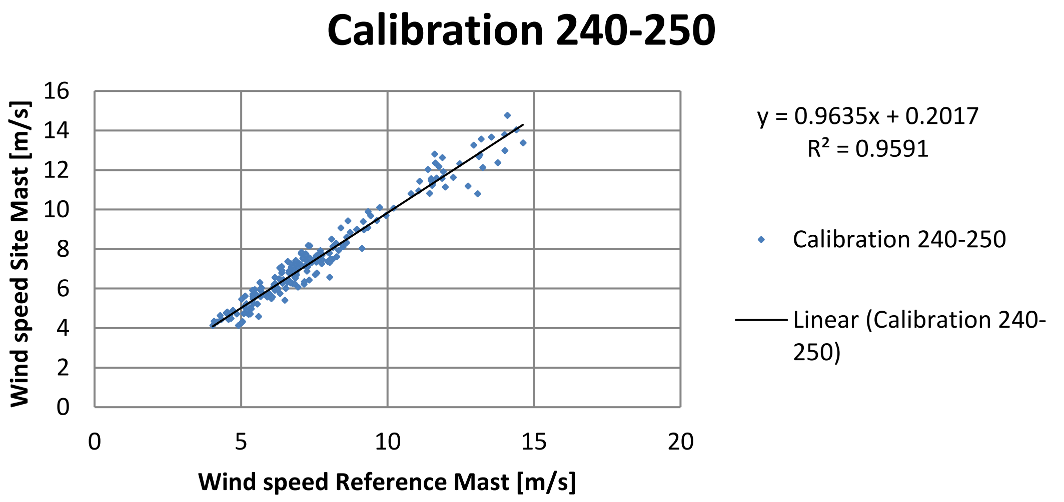

Figure B-6: WTG1- Calibration 240-250.

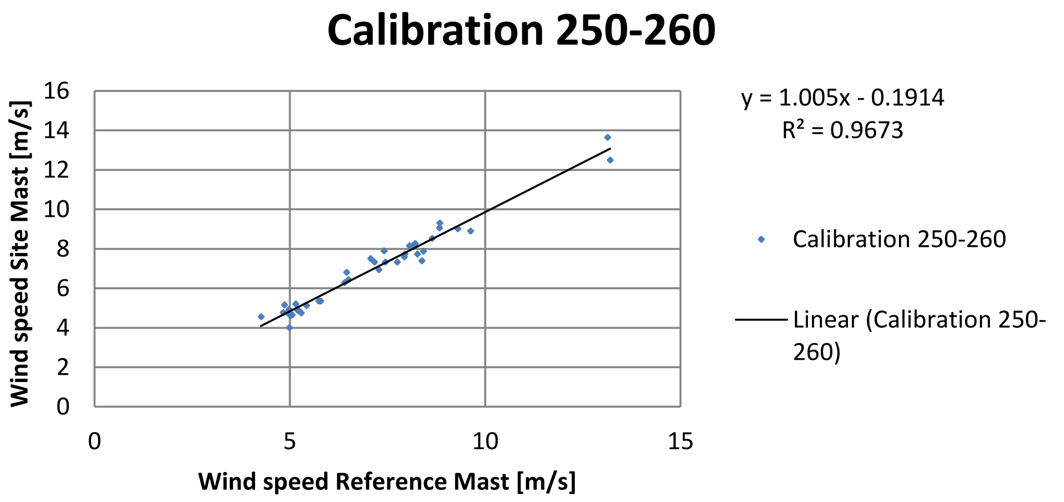

Figure B-7: WTG1- Calibration 250-260.

Appendix C

Turbulence Intensity Analysis

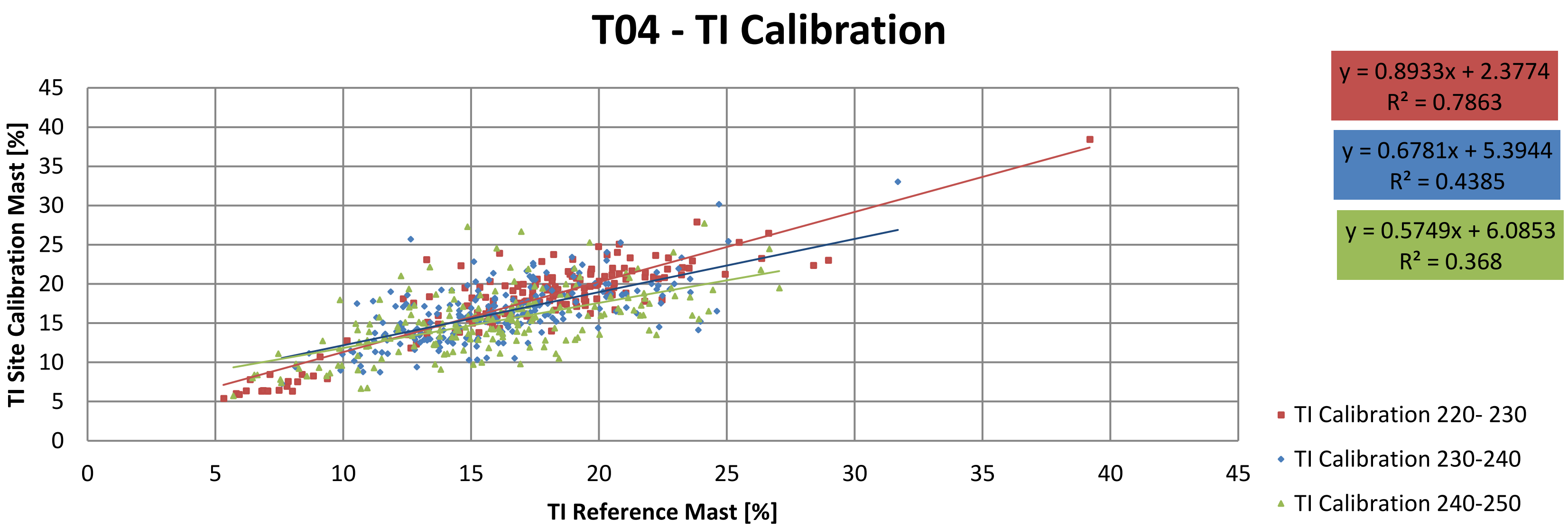

Figure C-1: WTG1- TI Regression Analysis.

Table C-1: WTG1 - TI Calibration Results.

WTG1								
bin #	**bin from**	**bin to**	**WD Avg**	**TI SM**	**TI RM**	**TI slope**	**TI offset**	**R^2**
[-]	[°]	[°]	[°]	[%]	[%]	[-]	[%]	[-]
4	220	230	225.4	17.8	17.3	0.8933	2.3774	0.7863
5	230	240	235.4	16.4	16.2	0.6781	5.3944	0.4385
6	240	250	244.8	15.1	15.7	0.5749	6.0853	0.3680

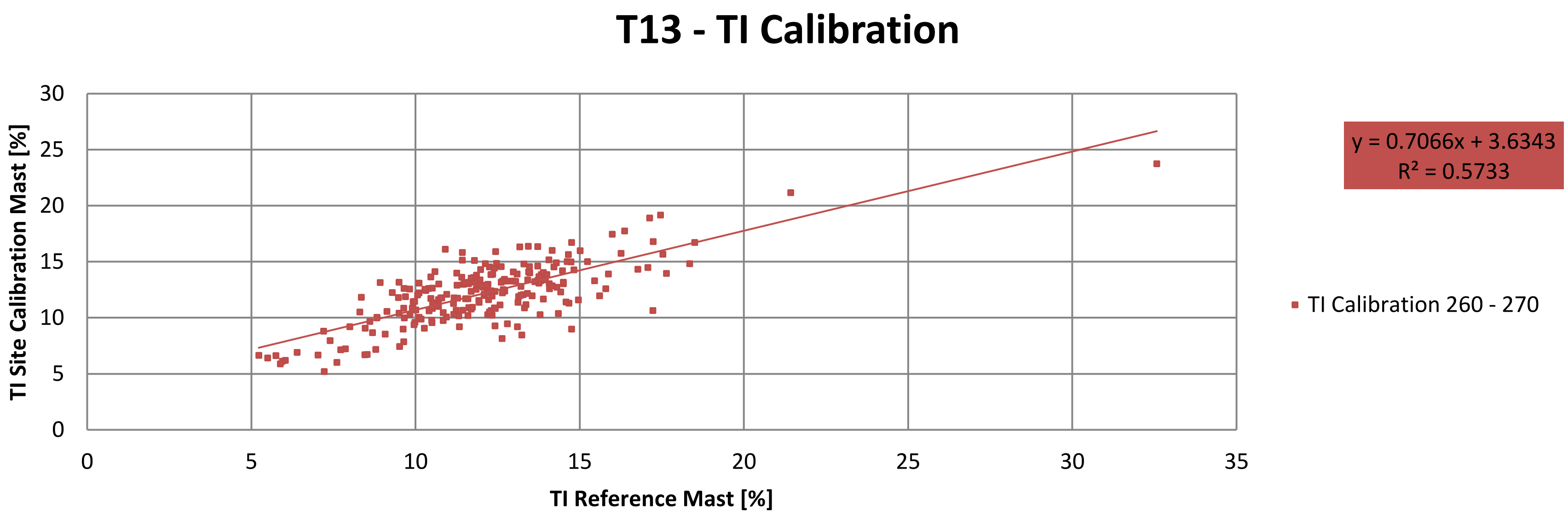

Figure C-2: WTG2 TI Regression Analysis.

Table C-2: WTG2 - TI Calibration Results.

WTG2								
bin #	bin from	bin to	WD Avg	TI SM	TI RM	TI slope	TI offset	R^2
[-]	[°]	[°]	[°]	[%]	[%]	[-]	[%]	[-]
2	260	270	265.2	12.2	12.1	0.7066	3.6343	0.5733

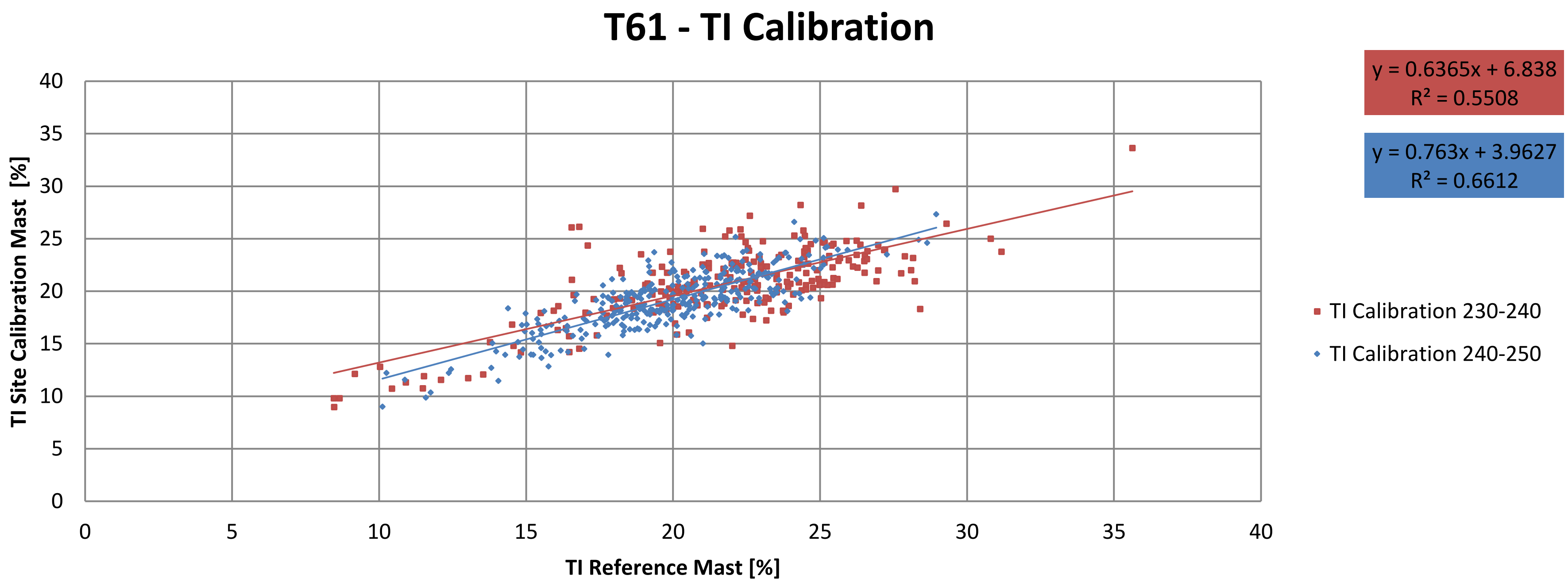

Figure C-3: WTG3- TI Regression Analysis.

Table C-3: WTG3 - TI Calibration Results.

WTG3								
bin #	bin from	bin to	WD Avg	TI SM	TI RM	TI slope	TI offset	R^2
[-]	[°]	[°]	[°]	[%]	[%]	[-]	[%]	[-]
2	230	240	235.2	20.7	21.7	0.6365	6.8380	0.5508
3	240	250	244.8	19.2	19.9	0.7630	3.9627	0.6612

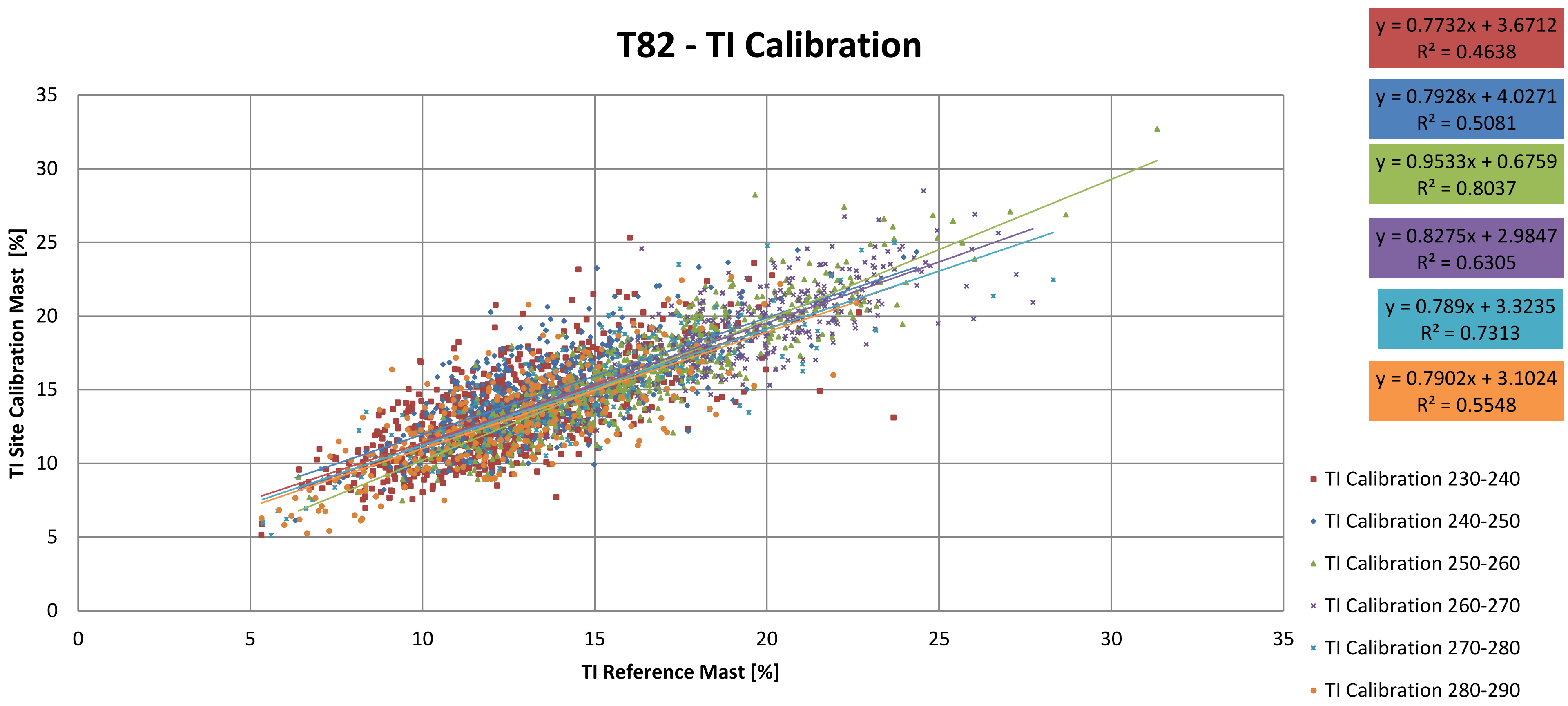

Figure C-4: WTG4- TI Regression Analysis.

Table C-4: WTG4 - TI Calibration Results.

WTG4								
bin #	**bin from**	**bin to**	**WD Avg**	**TI SM**	**TI RM**	**TI slope**	**TI offset**	**R^2**
[-]	[°]	[°]	[°]	[%]	[%]	[-]	[%]	[-]
1	230	240	235.7	13.3	12.4	0.7732	3.6712	0.4638
2	240	250	244.5	14.9	13.8	0.7928	4.0271	0.5081

3	250	260	254.9	16.2	16.3	0.9533	0.6759	0.8037
4	260	270	264.1	19.1	19.5	0.8275	2.9847	0.6305
5	270	280	275.3	14.8	14.5	0.7890	3.3235	0.7313
6	280	290	284.6	13.0	12.5	0.7902	3.1024	0.5548

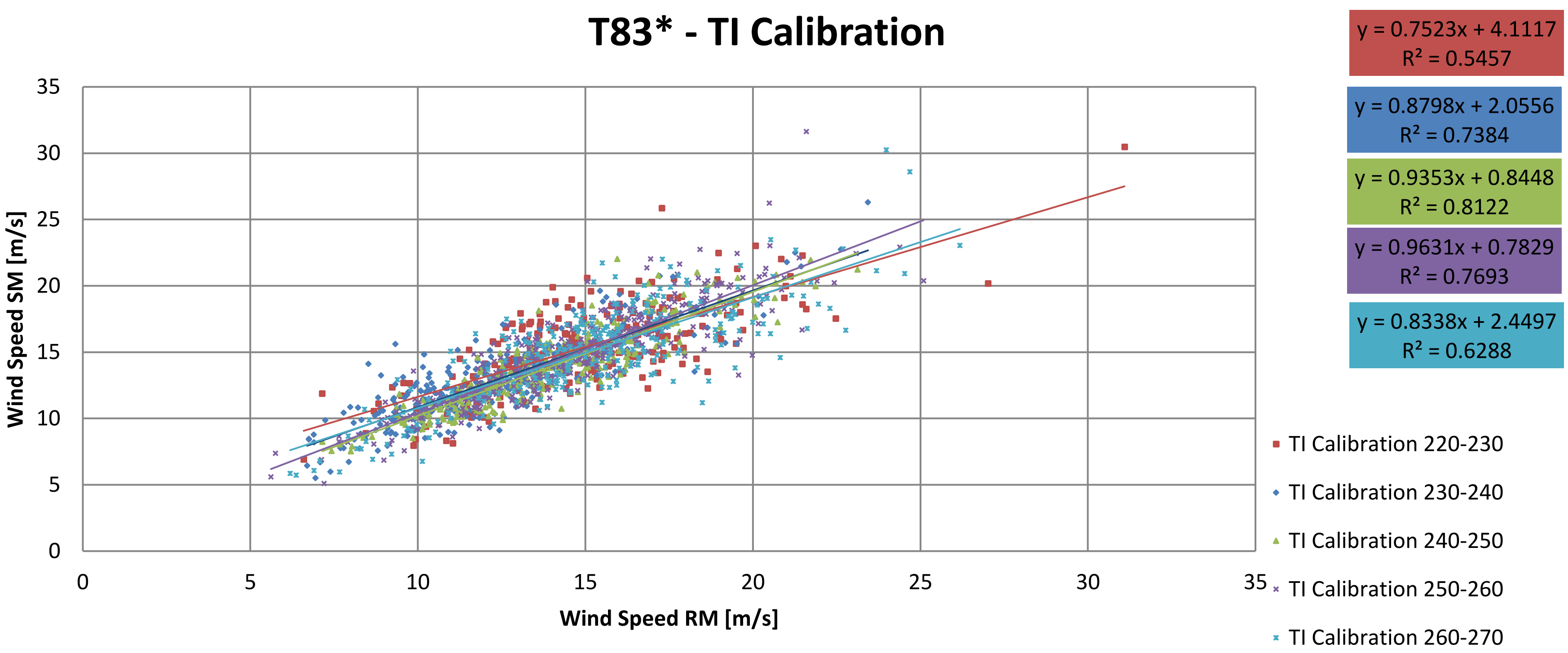

Figure C-5: WTG5- TI Regression Analysis.

Table C-5: WTG5 - TI Calibration Results.

WTG5								
bin #	bin from	bin to	WD Avg	TI SM	TI RM	TI slope	TI offset	R^2
[-]	[°]	[°]	[°]	[%]	[%]	[-]	[%]	[-]
2	220	230	225.4	15.3	14.9	0.7523	4.1117	0.5457
3	230	240	235.1	12.8	12.2	0.8798	2.0556	0.7384
4	240	250	244.6	13.9	14.0	0.9353	0.8448	0.8122
5	250	260	255.0	14.8	14.6	0.9631	0.7829	0.7693
6	260	270	265.0	15.2	15.3	0.8338	2.4497	0.6288

Appendix D

Importance of Site Calibration

For WTG1:

- Free wind sector in 192.3º – 252.3º → Total of data points: 1180 (Without Site Calibration)
- Site Calibration filter: Wind speed: 4m/s – 16 m/s and Wind direction: 220º – 250º → Total of data points: 619 (With Site Calibration).

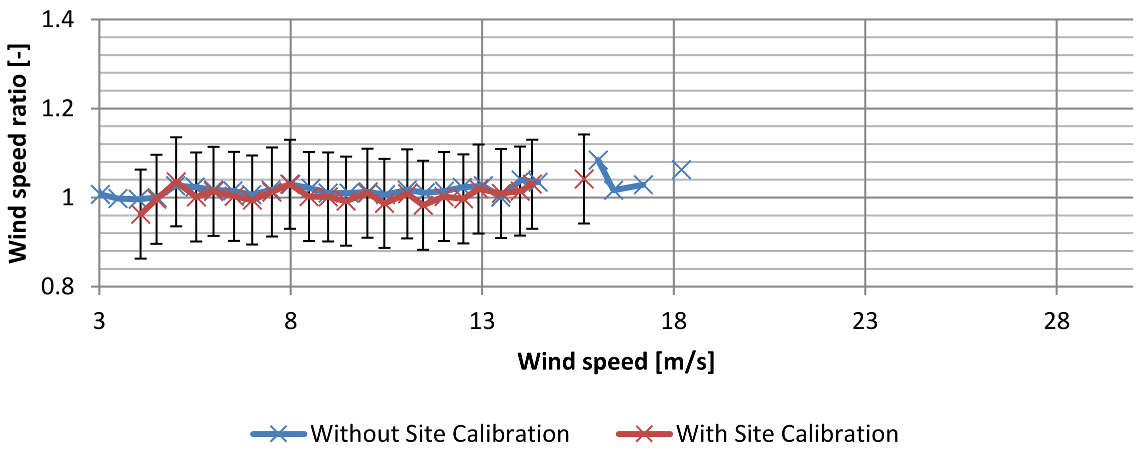

Figure D-1: WTG1 Binned Wind speed ratio with uncertainty bars | Without Site Calibration (Free wind sector) | With Site Calibration (Site Calibration filter).

For WTG2:

- Free wind sector in 250º – 310º → Total of data points: 1690 (Without Site Calibration)
- Site Calibration filter: Wind speed: 4m/s – 16 m/s and Wind direction: 260º – 270º → Total of data points: 322 (With Site Calibration).

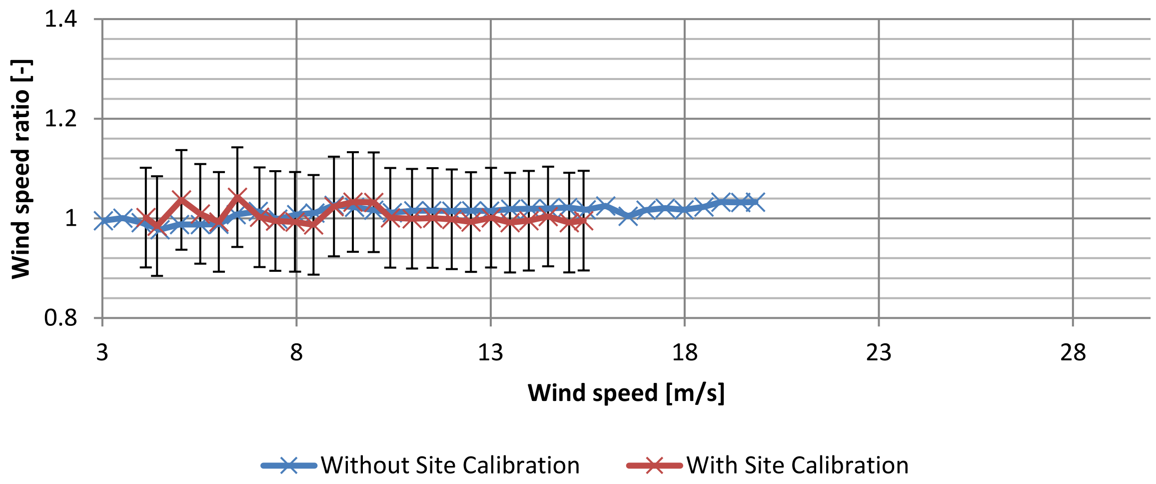

Figure D-2: WTG2 Binned Wind speed ratio with uncertainty bars | Without Site Calibration (Free wind sector) | With Site Calibration (Site Calibration filter).

For WTG3:

- Free wind sector in 222.7º – 282.7º → Total of data points: 2804 (Without Site Calibration)
- Site Calibration filter: Wind speed: 4m/s – 16 m/s and Wind direction: 230º – 250º → Total of data points: 666 (With Site Calibration).

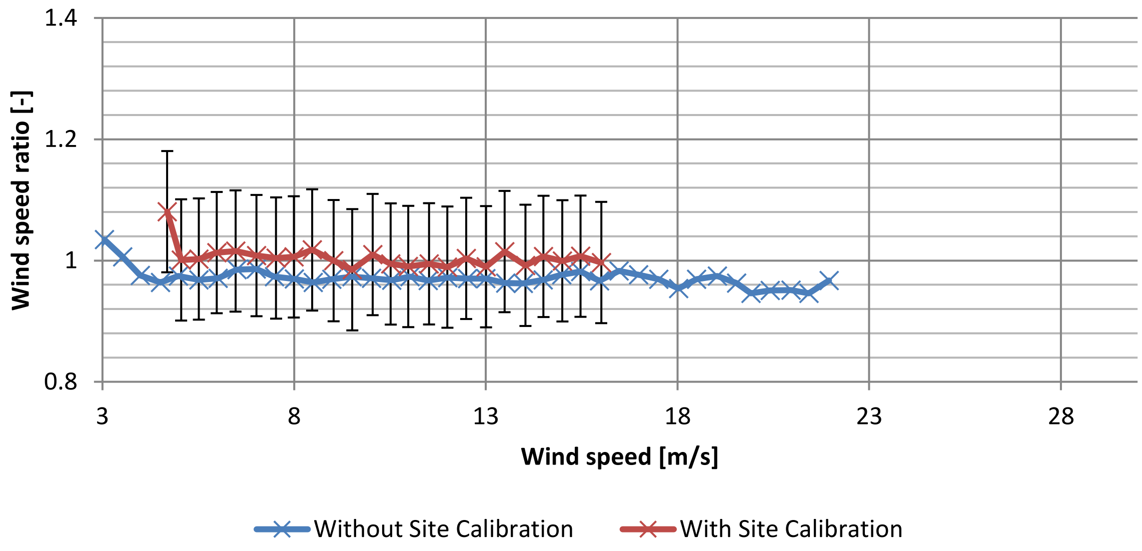

Figure D-3: WTG3 Binned Wind speed ratio with uncertainty bars | Without Site Calibration (Free wind sector) | With Site Calibration (Site Calibration filter).

For WTG4:

- Free wind sector in 230º – 290º → Total of data points: 5704 (Without Site Calibration)
- Site Calibration filter: Wind speed: 4m/s – 16 m/s and Wind direction: 230º – 290º → Total of data points: 4059 (With Site Calibration).

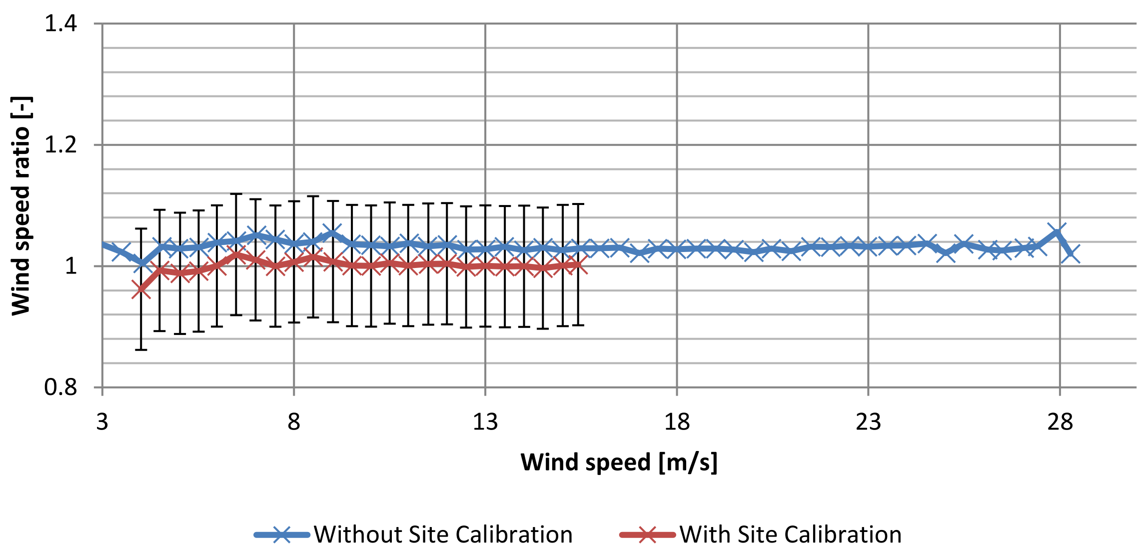

Figure D-4: WTG4 Binned Wind speed ratio with uncertainty bars | Without Site Calibration (Free wind sector) | With Site Calibration (Site Calibration filter).

For WTG5:

- Free wind sector in 218.7º – 278.7º → Total of data points: 3225 (Without Site Calibration)
- Site Calibration filter: Wind speed: 4m/s – 16 m/s and Wind direction: 220º – 270º → Total of data points: 1620 (With Site Calibration).

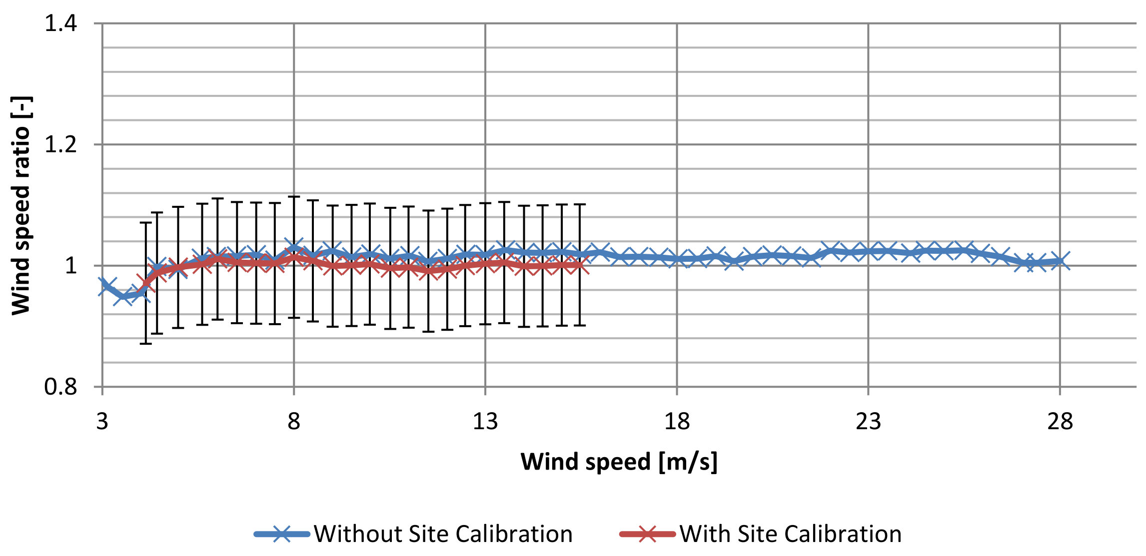

Figure D-5: WTG5 Binned Wind speed ratio with uncertainty bars | Without Site Calibration (Free wind sector) | With Site Calibration (Site Calibration filter).

Appendix E

Warranted Power Curve

Table E-1: Warranted Power Curve WTG4 and WTG5 (Area4) [42].

Wind [m/s]	Power [kW]
0	0
1	0
2	0
3	49
4	149
5	312
6	551
7	883
8	1315
9	1820
10	2249
11	2563
12	2760
13	2872
14	2933
15	2964
16	2981
17	2989
18	2994
19	2996
20	2998
21	3000
22	2999
23	2970
24	2940
25	2666
26	2333
27	1999
28	1666

29	1333
30	1000
31	666
32	333

Glossary

Abbreviation or Term	Definition
AEP	Annual energy production
Avg.	Average
IEC	International electrotechnical commission
ISO	International Organization for Standardization
M-AEP	Measured annual energy production
MEASNET	Measuring Network of Wind Energy Institutes
met	Meteorological
MM	Meteorological mast
M-PC	Measured power curve
NWD	Nominal wind distribution
PC	Power curve
PPT	Power Performance Testing or Power Curve test
REWS	Rotor equivalent wind speed
RM	Reference mast
SM	Site calibration mast
WTG1	Location mast- pair WTG1
WTG2	Location mast- pair WTG2
WTG3	Location mast- pair WTG3
WTG4	Location mast- pair WTG4
WTG5	Location mast- pair WTG5
TI	Turbulence intensity
W-AEP	Warranted annual energy production
WD	Wind direction
W-PC	Warranted power curve
WS	Wind speed

Nomenclature

Latin Symbols	
B	Ambient pressure
Cp	Power coefficient
D	Diameter of the rotor
De	Is the equivalent rotor diameter;
H	Hub height
h	Height of obstacle [m]
L	Distance between the wind turbine and the meteorological mast
lh	Is the height of obstacle;
lw	Is the width of the obstacle.
N	Number of 10 min data sets
n	Number of moles
n	Velocity profile exponent (n=0.14)
P	Normalized and averaged power output
Po	Porosity of obstacle (0: solid, 1: no obstacle)
psat	Saturation vapor pressure
pv	Vapor pressure of water [hpa]
R^2	R-squared (statistical measure)
Ro	Dry air gas constant (287.058 J/kgk)
Ru	Universal gas constant (8.314 $J \cdot K^{-1} \cdot mol^{-1}$)
Rw	Water vapor gas constant (461.5 J/kgk)
T	Ambient temperature [K]
TI	Turbulence intensity
Uh	Free wind speed at height h of obstacle [m/s]
V	Normalized and averaged wind speed
x	Distance downstream obstacle to met-mast or wind turbine [m]
zo	Roughness length [m]

Greek Symbols	
K	Von Karma constant 0.4
ρ	Averaged air density
σ	Standard deviation
ϕ	Relative humidity (pv/psat)

Subscripts	
i	Ith wind speed bin
j	Data set jth 10 min average
u	Longitudinal
v	Transversal
w	Vertical