WIND TURBINE POWER CURVE UPDATE BASED ON ATMOSPHERIC CONDITIONS AND STRUCTURAL FATIGUE

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ABSTRACT

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Wind energy is still developing industry and people who work in this industry working hard to accomplish the difficulties. Problems are not arise only by nature of wind but technological developments, methods and even market pressure itself. Wind turbine theoretical power curves are given only for certain conditions and one can easily say that those conditions are not met in real sites. This difference generates a uncertainty in AEP calculations thus financial models become less reliable. Shifting power curve by taking atmospheric effects into account will give more realistic power curve thus more accurate AEP and financial models. In this study, effects of atmospheric conditions and correction methods on NREL 5MW wind turbines power curve have been investigated and importance of corrected power curve has been discussed.

ÖZET

ATMOSFER DURUMUNA VE YAPISAL YORGUNLUĞA BAĞLI GÜÇ EĞRİSİ GÜNCELLEMESİ

Rüzgar enerjisi hala gelişmekte olan bir endüstridir ve bu alanda çalışan insanlar ortaya çıkan zorlukları çözmek için ciddi çalışma içerisindedir. Ortaya çıkan problemler sadece doğanın ortayta çıkardığı problemler değil, teknolojik gelişmeler, kullanılan metodlar ve hatta pazarın yarattığı ticari baskıdan dolayı ortaya çıkmaktadır. Rüzgar türbinlerinin teorik olarak verilen güç eğrileri belirli koşullar için hesaplanmakta ve hemen hiç bir gerçek sahada bu koşullar elde edilememektedir. Ortaya çıkan bu fark ise yıllık enerji üretimi hesaplarında bize bir belirsizlik getirmektedir bundan dolayı yapılan finansal modellerde güvenilirliğini yitirmektedir. Atmosferik etkileri göz önüne alarak güç eğrisinin güncellenmesi, daha gerçekcç bir güç eğrisi elde edilmesine ve daha doğru ve güvenilir yıllık üretim hesabı ve finansal modeller verecektir. Bu çalışmada atmosferik etkiler ve düzeltme metodları, NREL 5MW rüzgar türbini güç eğrisi için incelenmiş ve düzeltilmiş güç eğrisinin önemi tartışılmıştır.

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CHAPTER 1

INTRODUCTION

Power curves are the indicators that shows power output of the wind turbine depending on wind speed. In figure 5.12 theoretical power curve for reference turbine NREL 5MW shown. This is power curve for NREL 5MW wind turbine under $1.225 kg/m^3$, 15° C, 1013.25 hPa. Between 0-3 m/s there is no production, after 3m/s turbine starts to rotate and production. This wind speed called 'cut-in' wind speed. between 3-12 m/s energy production is increases with wind speed and after around 12 m/s energy production is no longer increases with wind speed. This region called 'partial load' and after 12 m/s wind turbine generates maximum energy and this region is called 'full-load' and at 25 m/s wind turbine shutdowns due to security risks and stops producing energy. Maximum allowed wind speed for wind turbine is called ' cut-out' wind speed. Between 12-25 m/s wind turbine produces its nominal power.

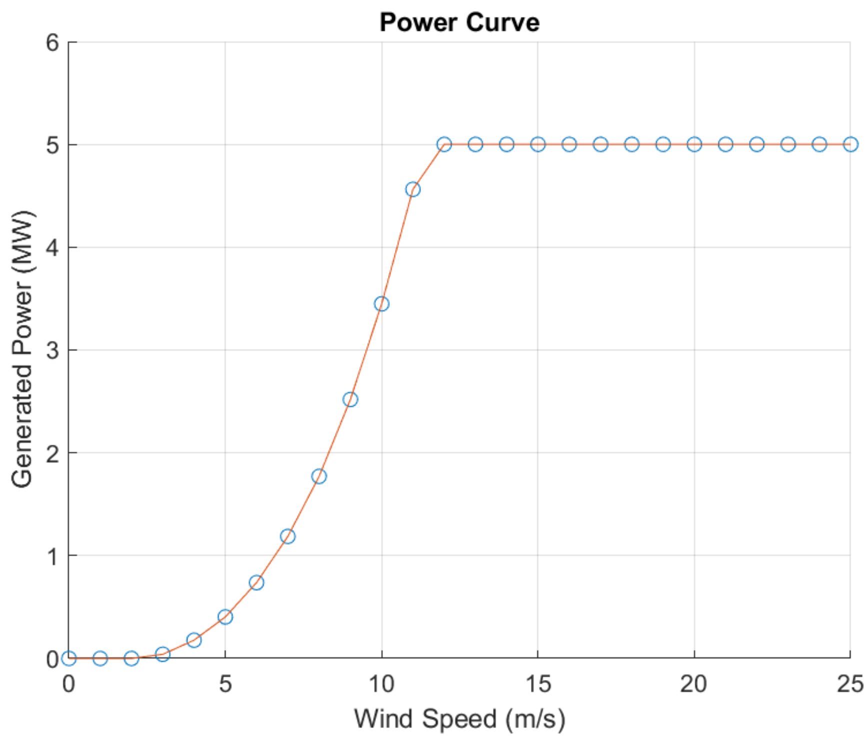


Figure 1.1: NREL Power Curve
[Jonkman et al., 2009]

Predicting and produce a theoretical power curve for a wind turbine is one of the most important part of the design process. During this process rotor, gearbox, control system and generator conditions should be considered. Designing a theoretical power curve is different for variable-speed wind turbine and fixed-speed wind turbine.

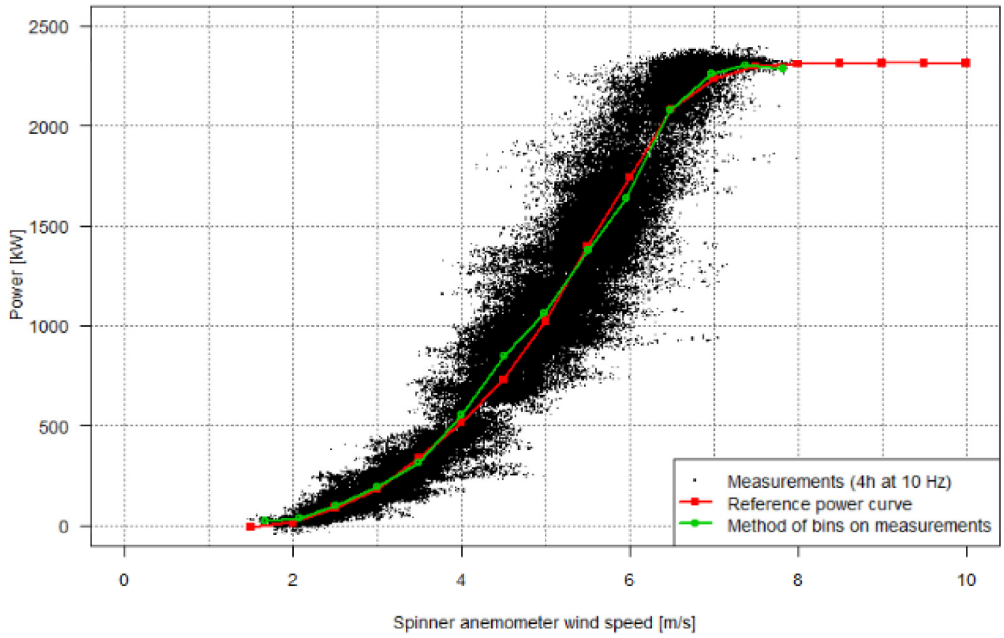


Figure 1.2: Example Wind Turbine Power Curve
(Source:[Pedersen et al., 2016])

Theoretical wind turbine power curves are the initial knowledge about a wind turbine. The producers shares with the customers and related people their standard power curves. The power produced from a wind turbine is calculated as;

$$P = \frac{1}{2}\rho A C_p U^3 \tag{1.1}$$

where P is related to air density; ρ, swept area; A, power coefficient; C_p and cube of the wind speed; U.

The main downside of using such power curve is that the actual working conditions of the turbine is never the same as the theoretical. Several items might be altered. For example, most commonly known one is the air density. Air density changes through out the days and months. An average is used to calculate the yearly production but the real power curve is almost always below than the theoretical one. Besides atmospheric conditions other effects might also alter the power generation. Power coefficient (C_p) might also be changed to lower values for different working conditions.

Several other effective factors of field conditions can also be listed. This uncertainty creates a difficult phenomena for wind turbine siting modeling. Usually, low uncertainty for modeling components are preferred in the feasibility studies because final concatenated uncertainty (P50) is used to calculate higher order production probabilities namely P70 and P90 which are all used as the main decision making statistics for financing the projects. In current generation of wind turbines and wind farms, a total uncertainty of 15% is considered to be low and within this statistical sum wind turbine power curve is calculated with 6% to 7% uncertainty with the highest contributor. Therefore, it is significantly important to to lower this uncertainty to decrease the total uncertainty of a feasibility study. (KEMA DNV Framework...).

Uncertainty calculations are basically square root of the sums of squares of the all uncertainties. Uncertainties can be coming from wind measurements, long-term climate corrections, year to year climate variability, vertical and horizontal extrapolation flow models, power curve, wake loss modeling, turbine availability. A full list of mostly used uncertainty variables are listed in Table 1.1.

An example of uncertainty study is given in table 1.2. It can be seen that biggest uncertainty comes from the power curve. By investigating how atmospheric conditions and structural fatigue effects wind turbine power curve, uncertainties due to power curve is tried to be reduced. By considering all of these uncertainties total uncertainty can be found by:

$$\sigma_{tot} = \sqrt{\sigma_{WM}^2 + \sigma_{LTCC}^2 + \sigma_{YtYCV}^2 + \sigma_{VE}^2 + \sigma_{HE}^2 + \sigma_{PC}^2 + \sigma_{WL}^2 + \sigma_{TA}^2} \tag{1.2}$$

.

The uncertainty of wind speed and AEP estimations, based on our example, can be calculated as

$$\sigma_{WS} = \sqrt{4^2 + 1^2 + 2^2 + 1^2 + 2^2} = 5.10\% \tag{1.3}$$

$$\sigma_{AEP} = \sqrt{6^2 + 3^2 + 1^2} = 6.78\% \tag{1.4}$$

Table 1.1: Uncertainty Classes

Uncertainty Class	Reason
Site Measurement	-Instrument Accuracy -Measurement Interference -Data Quality and Metadata
Historic Wind Resource	- Period of Representative Data - Reference Site - Wind Speed Frequency Distribution - On Site Data Synthesis
Vertical Extrapolation	Extrapolation to Hub Height
Future Wind Variability	-Interannual Variability -Climate Change -Wind Speed Frequency Distribution
Spatial Variation	-Model Inputs -Horizontal Extrapolation -Other Uncertainty
Plant Performance - Losses	-Availability -Wake Effects -Turbine Performance -Electrical Losses -Environmental -Curtailment -Other Losses
Other	Other

Table 1.2: Uncertainties of a Feasibility Study

Uncertainty of Wind Speed	σ [%]
Wind Measurements	4
Long Term Climate Correction	1
Year to Year Climate Variability	2
Vertical Extrapolation by Flow model	1
Horizontal Extrapolation by Flow Model	2
Sub-Total	5.10 %
Uncertainties of AEP Estimations	
Power Curve	6
Wake Loss Modeling	3
Turbine Availability	1
Sub-Total	6.78 %
TOTAL UNCERTAINTY	8.48%

where the total uncertainty is the sum of both;

$$\sigma_{TOTAL} = \sqrt{5.1^2 + 6.78^2} = 8.48\% \tag{1.5}$$

Aim of this study is to reduce uncertainty of AEP estimation by reducing uncertainty that comes from power curve by using site specific power curve. If uncertainty due to power curve managed to be reduced to 3 % new total uncertainty for a feasibility study becomes:

$$\sigma_{AEP} = \sqrt{3^2 + 3^2 + 1^2} = 4.36\% \tag{1.6}$$

$$\sigma_{TOTAL} = \sqrt{4.36^2 + 6.78^2} = 6.71\% \tag{1.7}$$

where the effect of the reduction to the total amount is around 1.77% which is significant difference in P75 and P90 values. Risk assessment is obligatory to quantify all the risks that effects the wind farm financing. It is very critical to estimate and quantify the uncertainties. To be able to do that exceendance probabilities, P50, P75 and P90 are used. Energy yield production is defined as P50 which means that probability to reach that annual energy production is 50 %. It is basically Reducing the wake and other losses from the annual energy production. For P75 it is 75 % probability to reach the defined annual energy production and it 90% for P90. P90 and P75 are usually used by banks and investors to make confident financial decisions about repay the debts. All Pxx values are calculated based on P50 value and P50 is the best estimate and it has an uncertainty associated with it. Uncertainty expressed as standard deviation most of the time and uncertainties for P75, P90 and P99 can be calculated as table 1.3. Standard deviation can be calculated as 68.27% of occurrence.

When uncertainty correctly calculated, Pxx values can be obtained by using the formulas in table 1.4. Uncertainty due to power curve usually taken as 6%. In this thesis uncertainty related to the power curve is aimed to reduce by investigating the effects of atmospheric parameters and structural fatigue. According to this aim if uncertainty due to power curve can be reduced by 3% total uncertainty is reduced from 8.48% to 6.71%. For 200MW, 30% capacity factor wind farm this difference is shown in table 1.5.

Table 1.3: PXX uncertainty calculation from normal probability distribution

	Formula [%]
P75 Uncertainty	0.675 × STDEV
P90 Uncertainty	1.282 × STDEV
P99 Uncertainty	2.326 × STDEV

Table 1.4: PXX exceedance calculation from normal probability distribution

	Probability of exceedance	Formula [%]
P75 Value	75%	P50 Values × (1-P75 uncertainty)
P90 Value	90%	P50 Values × (1-P90 uncertainty)
P99 Value	99%	P50 Values × (1-P99 uncertainty)

Table 1.5: Effect of reduced uncertainty on PXX calculation for 200MW wind farm

Uncertainty [%]	8.48	6.71
P75 Calculation	188.6MW	193.8MW
P90 Calculation	178.2MW	188.3 MW

For annual production and profit calculation following calculation is used;

$$AEP = Installed\ Capacity \times Hours\ in\ year \times Capacity\ Factor \tag{1.8}$$

For scenario-1 which uses 8.48 % uncertainty annual production for P90 is 518.4 GW/h and if MW/h price is 0.07 $ total production revenue becomes 32.3 M$ .For scenario-2 using uncertainty 6.71 % annual production for P90 becomes 488.1GW/h and for same tariff annual revenue becomes 34.17 M$. According to this results decrease the uncertainty by 3% , increase the annual revenue approximately 2M$.

In this study, most of the major factors that plays significant role on alternation of the wind turbine power curve are studied and for each natural or unnatural effect a method of power curve update is suggested. Furthermore, those updates are combined in one single methodology to apply easily to a given theoretical power curve based on the working conditions of the turbines are known. By doing that site specific and more realistic power curve can be obtained. Power curves are one of the most important input in AEP calculations. Below listed effects are considered for the updated power curve:

- Air Density, ρ $[kg/m^3]$
- Altitude
- Fatigue due to mechanical aging
- Icing

CHAPTER 2

LITERATURE SURVEY

[Torres et al., 2003] et al. studies selected model effects on site effectiveness and capacity factor for pitch regulated turbines. In this study keeping cut-out and rated wind speed and varying cut-in speed maximizes the effectiveness. Effectiveness is the maximum energy that can be delivered by wind turbine and it is kinematic parameter that changes with local wind frequency distribution and wind turbine characteristic speed. To be able to determine effectiveness, wind speed and power curve should be considered simultaneously. Curves are different for pitch regulated and stall control turbines. For the section between cut-in and cut-out points of the power curve two models are considered, the quadratic model and the potential model. Potential model includes $(V_i, V_r, V_f \; and \; P_r)$ as well as shape factor and scale parameter from Weibull distribution that represents local wind. Objectives are simplify the expression to use to calculate site effectiveness for pitch regulated turbines, using potential model and wind speed fits into Weibull distribution. According to this study for pitch regulated wind turbines, potential model is used to fit power curve with idealized pitch control, Weibull shape factor is limited with 3. If k is increased capacity factor curve has a tendency to steeper. Maximum effectiveness is differs slightly when potential model and quadratic model is compared but both of the model maximum effectiveness is decreases if scale factor increases. Cut-in speed differs significantly for maximum effectiveness. For the pitch regulated turbines quadratic model should be used if k is below 2.

[Khaled et al., 2004] et al. studied air density power curve correction not as an independent and constant parameter than the wind speed. Khaled et al. uses a cross-correlation coefficient to determine corrected power output by simply adding the mean air density value instead of constant values.

[Albadi and El-Saadany, 2009] et al. presents a new approach to model power curve capacity factor using wind characteristics and power curve parameters which gives more accurate and relatively simpler than previous models.Three main models are used to model power curve which, linear model, cubic model and quadratic model. For quadratic model maximum efficiency achieved at $1.73V_c$. In this study proposed model is based on quadratic model of the power curve. Main difference between cubic and proposed quadratic model is; proposed model has no dependency on (V_c/V_r) ratio and proposed model is a function of mean wind speed and also function of $\Gamma(2/k)$ while previous model is function of $\Gamma(3/k)$ and cubic mean speed. For the real case proposed model increases energy production by 5% compared with the old model.

[Virk et al., 2010] et al. studied rime ice effect on aerodynamic characteristics of turbine blades on four different wind turbines. According to numerical analyses in this study if the blade profile is increases, ice accretion reduces significantly on the leading edge. Also significant change in flow behaviors are observed when iced and clean blades are compared, increase in both lift and drag coefficient is observed. In terms of blade size, icing is more severe for the smaller turbine compared with the larger turbines. Also torque decreases more in the smaller turbines which also supports that larger turbines effected less than the smaller turbines.

[Akdağ and Önder Güler, 2011] et al. uses Weibull distribution model to evaluate turbine power generation and seven different power curve models and their outputs are compared with WAsP results.Weibull distribution given as

$$f(v) = \frac{k}{c}(\frac{v}{c})^(k-1)e^{-}(\frac{v}{c})^k \tag{2.1}$$

where $f(v)$ is the probability of the wind speed, k is shape factor, c is the scale parameter and v is the wind speed. Weibull parameters are calculated by using power density method. Observed and Weibull frequencies are compared. On the other section seven different models are investigated which are;

$$M_1 = P_R * \left(\frac{v - v_1}{v_R - v_1}\right) \quad v_1 \leq v_R \tag{2.2}$$

$$M_2 = P_R * \left(c_1 v^2 + c_2 v + c_3\right), \quad v_1 \leq v_R \tag{2.3}$$

$$M_3 = P_R * \left(\frac{v^2 - v_1^2}{v_R^2 - v_1^2}\right) v_1 \leq v_R \tag{2.4}$$

$$M_4 = P_R * \left(\frac{v^3}{v_R^3}\right) \quad v_1 \leq v_R \tag{2.5}$$

$$M_5 = P_R * \left(\frac{v - v_1}{v_R - v_1}\right)^3 \quad v_1 \leq v_R \tag{2.6}$$

$$M_6 = P_R * \left(a_1 v^3 + a_2 v^2 + a_3 v + a_4\right) \quad v_1 \leq v_R \tag{2.7}$$

$$M_7 = P_R * \left(b_1 v^4 + b_2 v^3 4 + b_3 v^2 + b_4 v + b_5\right) \quad v_1 \leq v_R \tag{2.8}$$

where a_i, b_i, c_i are reggression constants, P_R is rated wind turbine power, v_1 is the cut in speed, v_R is the rated wind speed. In the estimated values M_6 gives the smallest error while M_5 gives the highest error. Also M_6 and M_7 provides the best fit while M_3 is used to find optimum turbine parameters. On the other hand M_2 over estimates in all turbines. Reason of M_2, M_6 and M_7 gives the small error compared to other is these models uses multipoint curve approach while others are uses only cut-in and cut-out wind speeds. This approach leads these models to predict same curve for any turbine which has same cut-in and cut-out speeds. Estimating power curve changes from location to location and turbine to turbine but in all circumstances multipoint curve approach gives errors in acceptable range.

[Stephen et al., 2011] shows joint probability distribution by using data instead of using two variable function. This method can be used to simulate plant operation,compares inner plant performance and also includes uncertainty measurements into performance estimations. Copula model is studied int this study. Copula model gives a relation between marginal densities of the observed values and complex dependency structure of a single function. This generative model allows to use data to obtain parameters. Model changes also reflects physical changes of the turbine, comparisons might also used in to monitor wind farm which is an issue for the operators if wind farm size increases. Wind profiles can be linked with stochastic methods like Gibbs sampling to obtain power generation time series that also shows uncertinities individually and their whole operation of all farm.

[Kubik et al., 2013] et al. studied about the accuracy of a meteorological wind data to estimate wind turbine power curve. In this paper Kubik et al. uses 10m meteorological masts to simulate theoretical wind turbine output by using power law and compare results with the wind farm located in North Rhins, Scotland. In this study it is seen that α wind shear parameter is varying value. Selecting only one α value for whole year gives good estimation because errors cancels each other during the year but for shorter time intervals i.e. in hourly basis gives huge errors. In previous studies α is taken as 1/7 as rule of thumb which represents the neutral atmospheric conditions but several studies shows that α is usually has higher value than 1/7 and 1/7 value underestimates the power output. Applying 1/7 in this study underestimates the true capacity factor by %29.7 and provides no improvement for North Rhins wind farm. Wind shear coefficients derived from one height can not be used to extrapolate another height. Power generation has tendency to overestimate if the true wind speed is low and underestimate for high true wind.

[Paiva et al., 2013] et al. studies wind turbine power curve determination based on statistical methods, , operational data, in situ measurements,computational methods and nacelle anemometry. Determining power curve by those methods can be an alternative to IEC power curve measurement standards. Turbine power output is not only the function of the wind speed, it is also depends on site turbulence intensity, yaw error, atmospheric stability, wind direction, drive train temperature and etc. Power curve that obtained from manufacturer represents the ideal conditions that might show differences on site and there is no available alternative to find the real power curve by experiment. Nacelle anemometry is new and useful technique for a sites that wind turbine is operating and there is no chance to do site assessment other than using SCADA data. Main purpose is to determine wind turbine power curve uncertainty which is around 4-13% for the experimental methods and 5-20% for numerical methods and for the nacelle anemometry it is 5-30%. Acquired SCADA data is not free of errors and needs to be cleaned and filtered. Wind power has cubic relation with the power output thus wind power forecast is very sensitive to small wind speed variations. Forecast accuracy can have a factor of 1.8 to 2.6 of wind speed forecast accuracy. Procedures in this study aims to determine power curve of operational wind turbines using operational data and computational methods to reduce time and costs of the procedures like IEC Method.

[Liu and Liu, 2013] et al. studied effect of the air density on wind turbine output and show that same wind farm gives different output when air density of the site has changes. If air density is lower, power output also smaller. Li et al. studies this theory on a site with mean air density value is $1.07kg/m^3$ where standard air density is $1.225kg/m^3$. According to this study power output is 12.7% smaller than the theoretical output.

[Edwin et al., 2014] et al. reviews the available techniques on modeling wind turbine power curve. Power curves plays important role in wind energy. Power curves are used for wind energy assessments and prediction, wind turbine selection for specific sites, monitoring and troubleshooting of wind turbine and control optimization. Power curves can be obtained from manufacturer and also estimation can be made by using rotor power characteristics, gearbox and other components of the wind turbine. Theoretical wind turbine power output can be found by $P = 0.5 * \rho \pi R^2 C_p u^3$ where ρ is air density, R rotor radius, C_p is power coefficient and u is the wind speed. Power coefficient is a parameter depends on tip speed ratio (λ) and β blade pitch angle. IEC has a methodology to measure wind turbine power curve. Basically simultaneous wind measurement made in the site long enough to include varying atmospheric conditions and by using method of bins power curve can be determined. IEC method power curve gives power curve of the turbine with turbulence effects so that it can not be applied to other sites and also by using 10 min averages IEC method ignores the fluctuations. So site specific wind turbine power curve modeling is significant. Good models helps investors to choose optimum wind turbines for the selected site to improve performance also helps developers to predict future energy production and possible extensions, models also can be used to determine identify faults , detect anomalies. According to Lydia2014 et al. identical power curves can be changes with the array effect, high wind cut out, topographic effects and spatial averaging and availability. Site specific curve adjustments are required to include effects of turbulence, terrain complexity, icings, blade fouls, wind shear anx etc. Wind turbine power curve modeling techniques can be investigated in two categories; parametric and non-parametric techniques. Parametric techniques basically solves mathematical expressions while non-parametric techniques solves the assumption $P = f(u)$. Parametric techniques are;linearized segmented model, polynomial power curve, maximum principle method, dynamical power curve, probabilistic model, ideal power curve, 4- parameter logistic function, 5- parameter logistic function. Non-parametric modeling techniques are; copula power curve, cubic spline interpolation, neural networks, fuzzy methods, data mining algorithms. According to this study non-parametric models that data mining and neural networks gives good results but best results are obtained by 5 or 4 parameter logistic function whose parameters are obtained by using differential evolution.

[Villanueva and Feijóo, 2016] et al. studies about current methods to obtain parameters of logistic function. Current procedures to obtain logistic function parameters are gives meaningless values and needs to be optimized since every turbine have different parameter values. Villaneueva2016 et al. proposes a procedure to obtain 4 parameter logistic function parameters as a function of the power curve that provided by the manufacturer. wind turbine manufacturers obtains power curve by wind speed - power for $0.5m/s$ wind speed interval but for large amount of data it is hard to deal with a graph so that mathematical expressions are used to obtain piece-wise continuous function. Main reason of the inaccuracy for the piece-wise functions are that lack of continuity of the slope that is near rated wind speed. That is not represent the real behavior of the wind turbine. It is very helpful to make available continuous models when electrical analysis is made to derive analytic expressions which can be used as input. Proposed model in this study only valid for wind speed range between $u_ci \ and \ u_co$ power outside of these ranges are 0. Proposed model is;

$$P(u) = a = \frac{1 + me^{-u/\tau}}{1 + ne^{-u/\tau}} \tag{2.9}$$

Where a,m,n τ is the constants that can be obtained by optimization techniques but obtaining by using optimization techniques have no technical meaning and useless if intention of the wind turbine behavior. Using technically meaningful parameters is important if wight of the parameter not only for power curve but also for their derives. If parameters are obtained by only using optimization process this assessments can not be done. Using 4 parameter logistic function with parameters obtained by deterministic method makes the model meaningful. Another approach is 4 parameter logistic function parameters obtained by simplified deterministic method. The difference between those two methods is simply taking $m = 0$ in previous method. Applying this to the model brings some issues like deriving probability density function lower wind speed curve approximation. Another model is 3 parameter deterministic parameter, in this model $2P_ip = P_r$ approximation is made. This model improves the other models while reducing the number of parameters on the other hand compared with other models error is increased in this model but still in acceptable range. All of these three model is assumes the curve as a continuous function which simplifies the curve implementation into computer compared to piece-wise function.

[Yirtici et al., 2016] et al. studies ice accretion prediction on turbine blades and how this degrades the power production. Yirtici et al. showed that icing on wind turbine can cause annual power loss up to 17%. Power loss due to ice loss depends on blade type, control type and amount of ice that accretion on blade. In this study 2D ice accretion model is used to make predictions about ice accretion and Blade Element Momentum (BEM) method is used to determine aerodynamic properties of iced turbine blade. This study shows there is a good agreement with the simulation results, similar studies and experimental results.

CHAPTER 3

SPECIFICATIONS

3.1 NREL 5MW Reference Wind Turbine

NREL 5MW wind turbine is a conceptual wind turbine developed and sponsored by the U.S Department of Energy's (DOE's) National Renewable Energy Laboratory (NREL)over National Wind Technology Center (NWTC). This turbine developed to support studies about off-shore and on-shore with standardized input data. NREL conceptual wind turbines rating is 5MW with upwind 3 blade configuration. Turbine control method is variable speed collective pitch. Drive train is high speed, multiple-stage gearbox. Rotor diameter is 126 m and hub diameter is 3 m where hub height is 90 m. Cut-in wind speed is 3 m/s, cut-in rotor speed is 6.9 rpm. Rated wind speed is 11.4 m/s and rated rotor speed is 12.1 rpm, rated tip speed is 80 m/s. Cut out wind speed is 25 m/s. Overhang is 5 m, shaft is tilted with 5° and precone is 2.5°. Rotor, nacelle and tower masses are 110,000 kg, 240,000 kg and 345,460 kg respectively [Jonkman et al., 2009]. Wind speed and generated power is given at the table 3.1.

By using data in the table 3.1 power curve for NREL 5MW wind turbine is obtained as in figure 3.1. This power curve has used for calculations in this study.

The NREL 5MW wind turbine is 3-blade upwind wind turbine, 61.5 m long LM Glassfiber blades are used in this turbine. Following tables are give information about structural and aerodynamic properties. Blade structure and airfoil positioning is shown in the figure 3.2 .

Table 3.1: NREL 5MW Turbine Data [Jonkman et al., 2009]

NREL 5MW Wind Turbine Power Generation Table	
Wind Speed [m]	Generated Power [kW]
0	0
1	0
2	0
3	40
4	177
5	403
6	737
7	1187
8	1771
9	2518
10	3448
11	4562
12	5000
13	5000
14	5000
15	5000
16	5000
17	5000
18	5000
19	5000
20	5000
21	5000
22	5000
23	5000
24	5000
25	5000

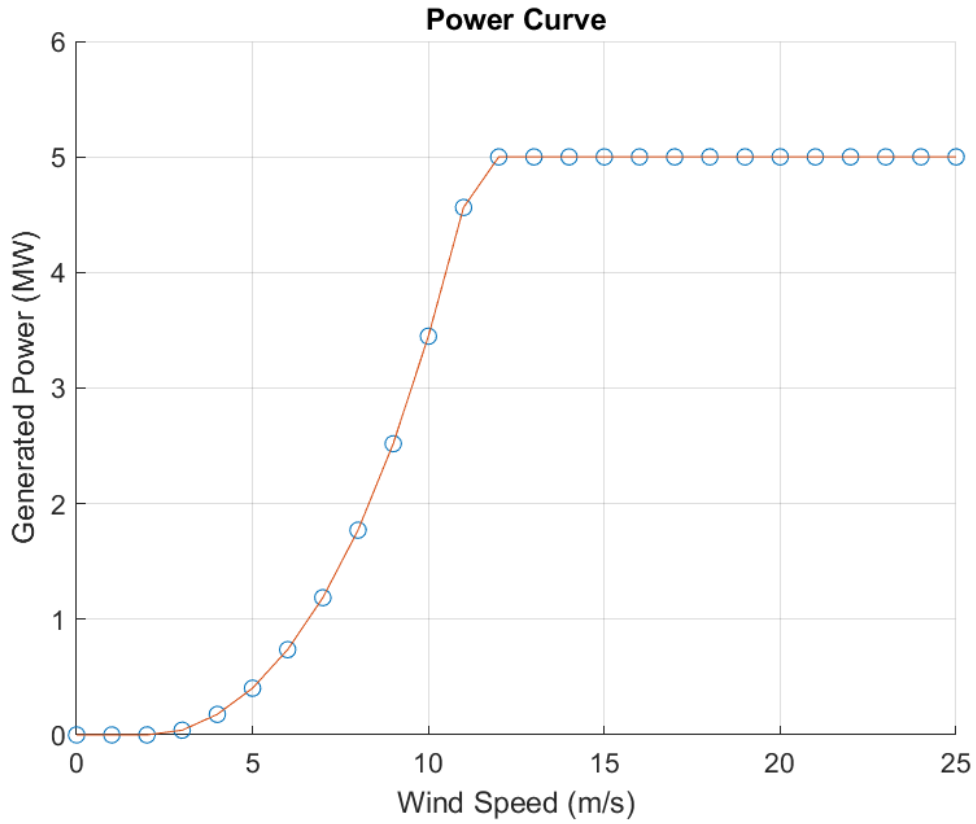


Figure 3.1: NREL 5MW Wind Turbine Power Curve
[Jonkman et al., 2009]

Table 3.2: NREL 5MW Turbine Blade[Jonkman et al., 2009]

Radial Position [m]	Chord [m]	Twist [°]	Airfoil Name
0	3.2	13.08	Circular Foil 0.5
1.36	3.54	13.08	Circular Foil 0.5
4.10	3.85	13.08	Circular Foil 0.5
6.83	4.167	13.08	Circular Foil 0.35
10.25	4.55	13.08	DU99W405LM
14.35	4.652	11.48	DU99W350LM
18.45	4.458	10.16	DU99W350LM
22.55	4.249	9.011	DU97300LM
26.65	4.007	7.795	DU91W2250LM
30.75	3.748	6.544	DU91W2250LM
34.85	3.502	5.361	DU93W210LM
38.95	3.256	4.188	DU93W210LM
43.05	3.01	3.125	NACA64618
47.15	2.764	2.319	NACA64618
51.25	2.518	1.526	NACA64618
54.67	2.313	0.863	NACA64618
57.4	2.086	0.37	NACA64618
60.13	1.4	0.16	NACA64618
61.50	0.7	0	NACA64618

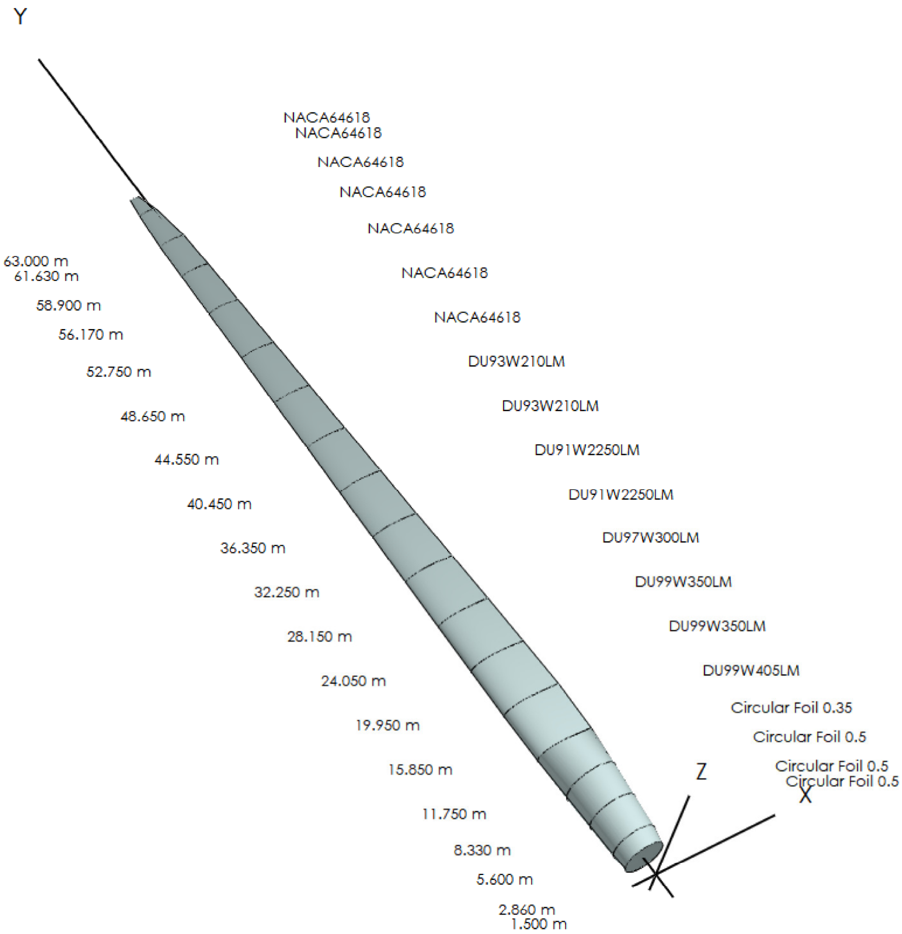


Figure 3.2: NREL 5MW Blade Profile
[Jonkman et al., 2009]

Airfoil profiles of the blade sections are shown below;

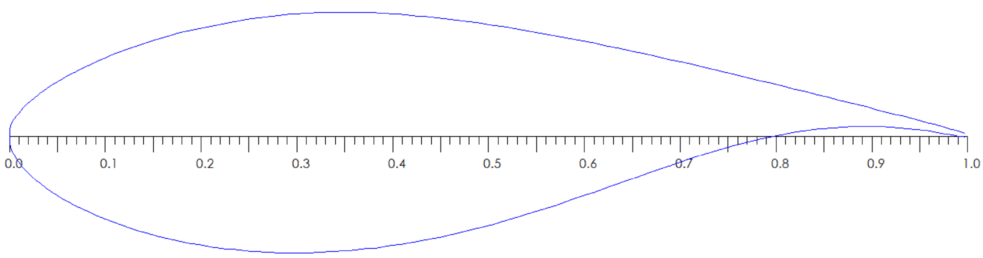


Figure 3.3: DU91W2250LM Blade Profile
[Jonkman et al., 2009]

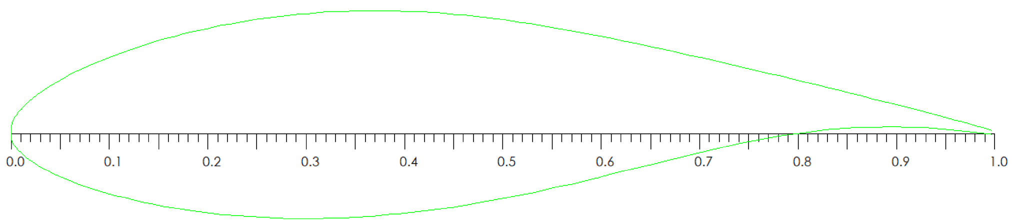


Figure 3.4: DU93W210LM Blade Profile
[Jonkman et al., 2009]

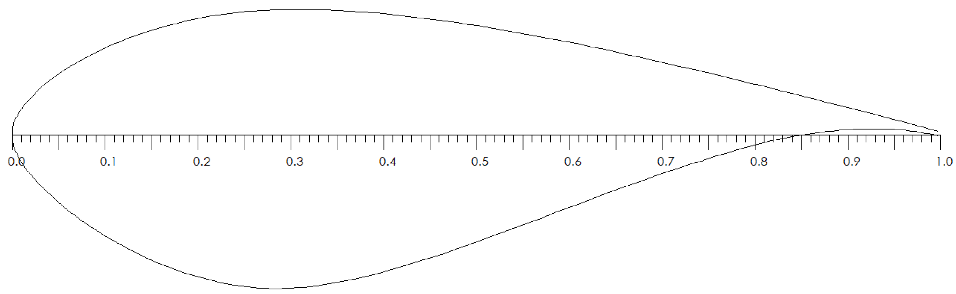


Figure 3.5: DU97W300LM Blade Profile
[Jonkman et al., 2009]

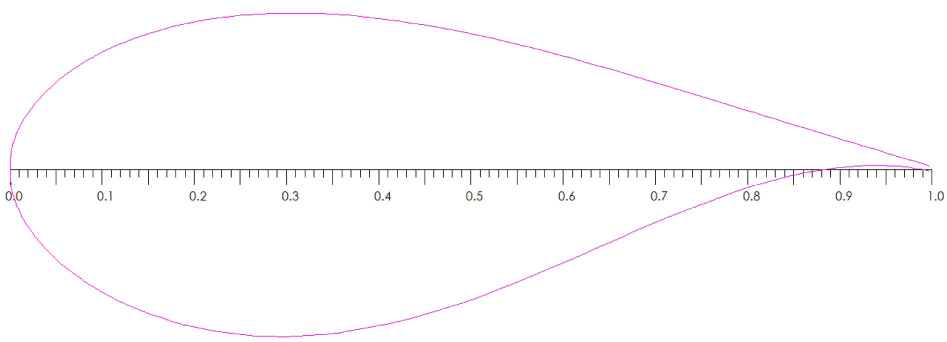


Figure 3.6: DU99W350LM Blade Profile
[Jonkman et al., 2009]

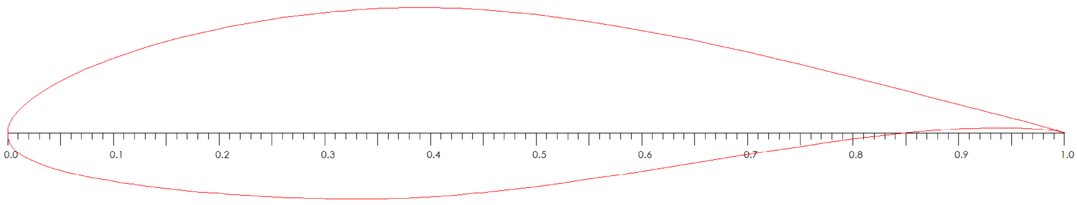


Figure 3.7: NACA64618 Blade Profile
[Jonkman et al., 2009]

3.2 Measurement Site

Measurement site is belongs to Izmir Institute of Technology Energy Engineering Department. Site is located at İzmir Urla Gülbahçe region, inside IZTEC's campus. Site elevation is 52m. Site is complex site, ridges up to 500m surrounds the site starting from NW to SE, campus buildings are located at approximately 1.5km South of the site. Two operational wind farms located at 3km and 6km SW of the site. Sea with 4km width bay is surrounds the site North to SE. Panaromic view of the site shown in the figures below. Site map shown in the figure 3.8. Mast general view shown in 3.10 and sketch is shown in 3.9. IZTECH mast has highest measurement at 101m and for NREL 5MW wind turbine, IZTECH mast classified as "hub height" measurement mast.

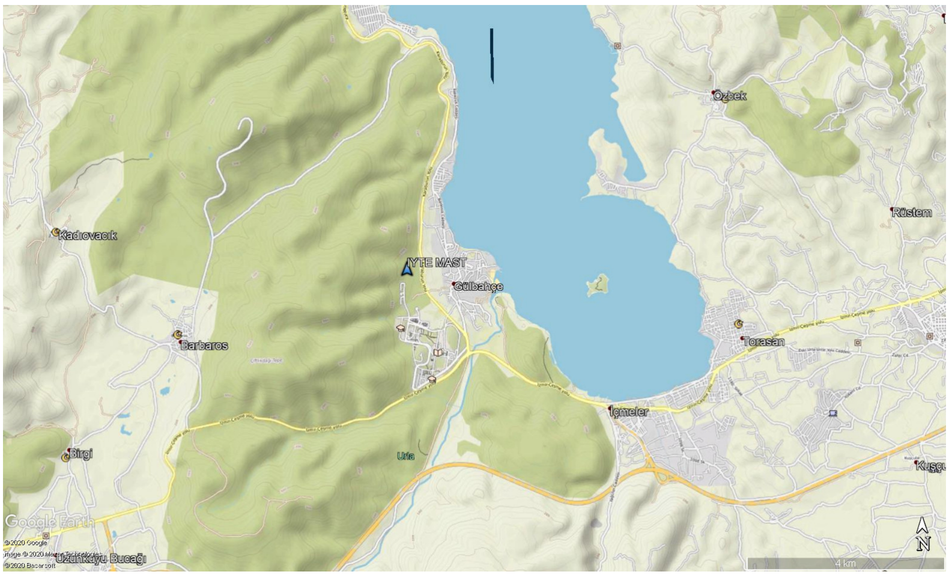


Figure 3.8: Site Overview

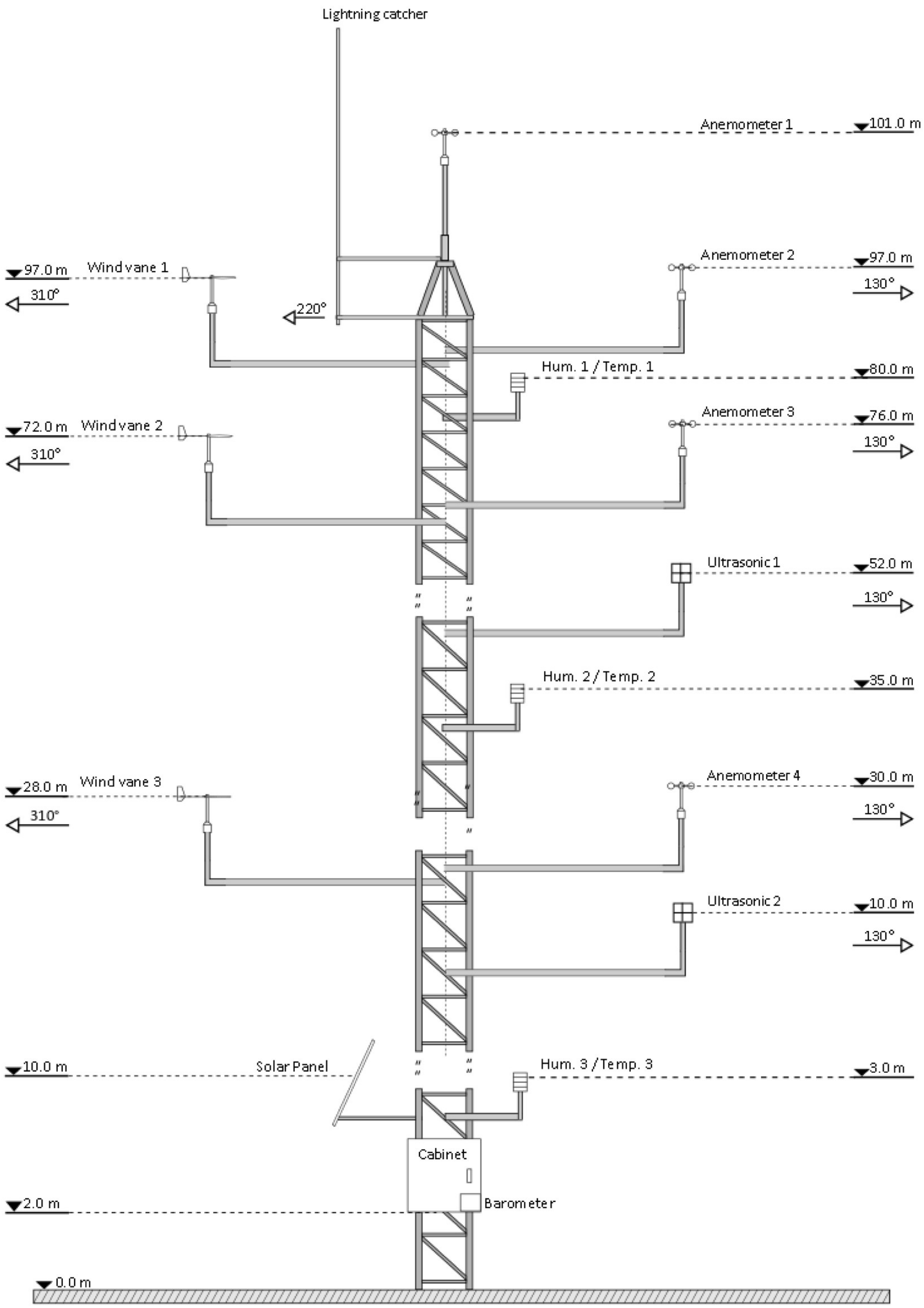


Figure 3.9: Mast Sketch (Not to Scale)

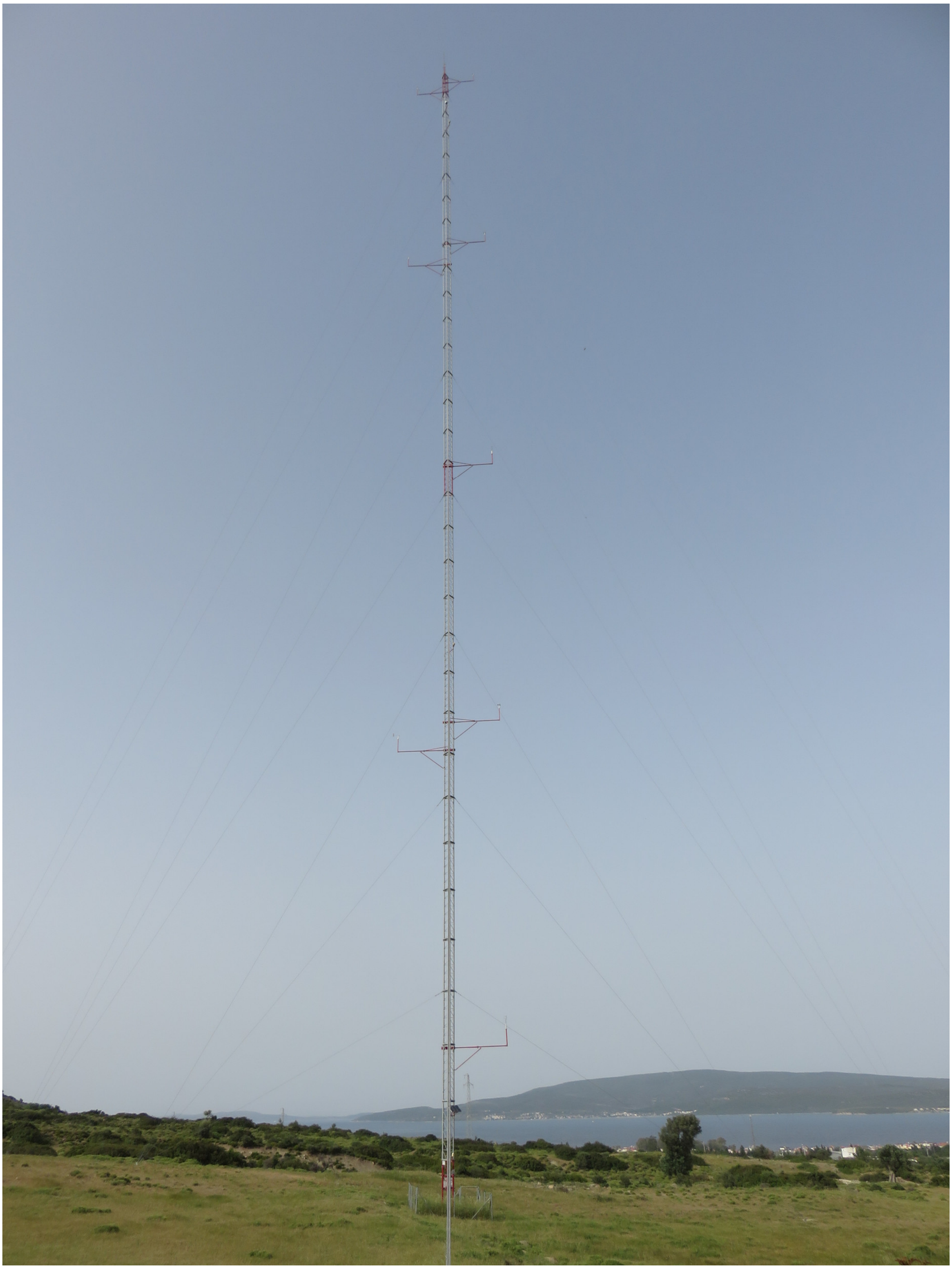


Figure 3.10: Mast General View

(a) North

(b) North-East - Main Wind Direction

(c) East

(d) South-East

(e) South

(f) South-West

(g) West

(h) North-West

Figure 3.11: Panaromic View of the Site

3.3 Site Data

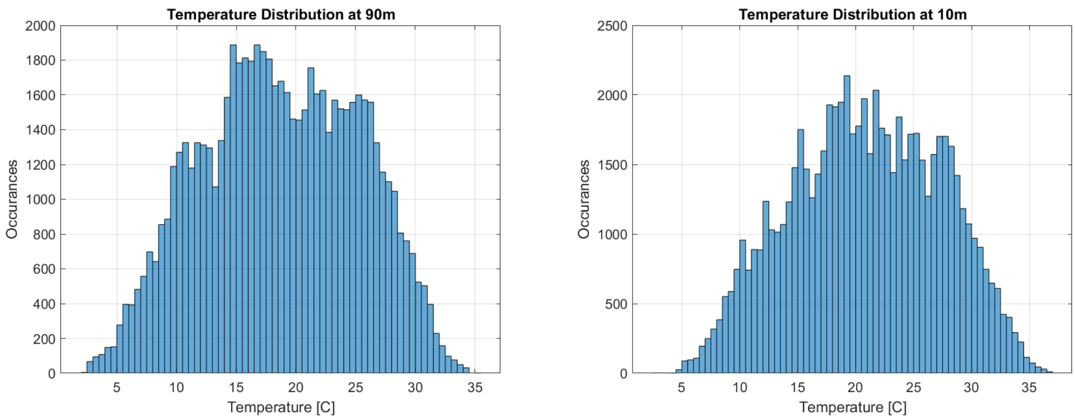
Measurement period is starting from August 2017 to December 2018. Data recovery is 96.21% for wind speed at 101m and wind direction at 98m. Mean wind speed for 101m is 6.068m/s for this period. Mean temperature for the site is 18.72 C° C at 90m and relative humidity is 60.8. Mean pressure for the is 1.007 mbar. Data summary is shown in the table 3.3 .

Table 3.3: Data Summary

Data	Unit	Height [m]	DRR [%]	Mean	Min	Max	Std. Dev
Wind Speed	m/s	101	96.21	6.068	0.219	23.625	3.947
Wind Speed	m/s	76	96.21	5.805	0.239	23.125	3.782
Wind Speed	m/s	52	95.56	5.373	0.094	21.797	3.514
Wind Speed	m/s	30	96.21	4.939	0.230	19.746	3.183
Wind Speed	m/s	10	96.21	4.010	0.098	14.769	2.471
Wind Direction	°	98	96.21	66.9	0.0	360.0	80.0
Wind Direction	°	74	96.21	71.8	0.0	360.0	81.7
Wind Direction	°	52	95.56	46.0	0.0	360.0	75.1
Wind Direction	°	28	96.21	68.8	0.0	360.0	86.0
Wind Direction	°	10	96.21	41.0	0	360.0	76.5
Pressure	mbar	2	94.07	1007.3	988.4	1026.3	5.7
Relative Humidity	%	90	94.07	60.8	16.6	94.7	14.6
Relative Humidity	%	35	94.07	63.4	17.8	96.9	14.7
Relative Humidity	%	3	94.07	66.8	16.8	100.0	15.9
Temperature	° C	90	93.89	18.72	2.37	35.30	6.55
Temperature	° C	52	95.56	20.84	2.37	35.35	6.37
Temperature	° C	35	96.21	18.86	2.66	35.30	6.62
Temperature	° C	10	96.21	18.86	2.66	36.91	6.46
Temperature	° C	3	94.07	19.29	3.00	36.75	6.97

3.3.1 Temperature Distribution

Temperature values in this site varies between 2.3° and 35.3° no icing events are observed during the measurement period. Temperature distribution at 90 m is shown on figure 3.12a and temperature distribution at 10 m is shown on figure 3.12b. As is seen in the figures temperature distribution is focused around 14 ° C and 26 ° C at 90m.



(a) Temperature Distribution at 90m (b) Temperature Distribution at 10m

Figure 3.12: Temperature Distribution

3.3.2 Wind Speed Distribution

Wind speed distribution is created by using wind speed data at 101m shown in figure 3.13. According to the weibull fit, parameters as A = 6.696m/s and k=1.495 have obtained. In weibull distribution A is the scale parameter of the graph which is proportional to the mean wind speed and unit is in m/s. On the other hand k is the shape parameter and it varies between 1-3 Shape parameter is unit-less and k characterize the variability of the wind. Larger k means constant wind speed while lower k means highly variable wind speed.

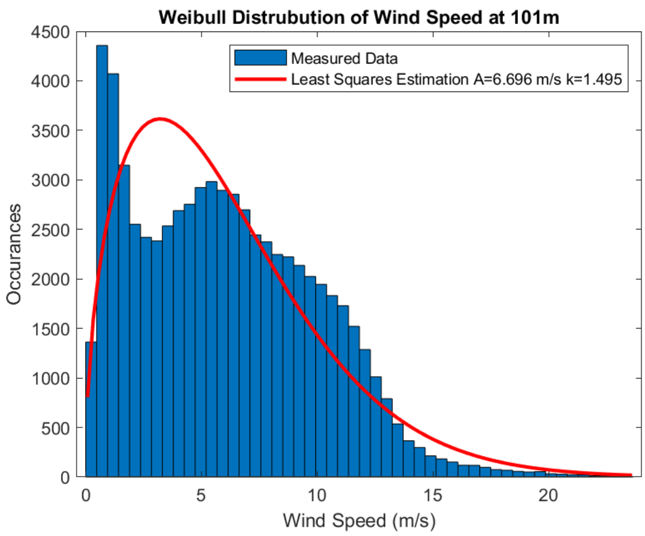


Figure 3.13: Weibull Distribution at 101m

3.3.3 Wind Rose

Wind rose has made for wind speed at 101m for this site. Wind rose made for 16 sectors and can be seen in the figure 3.14 below.

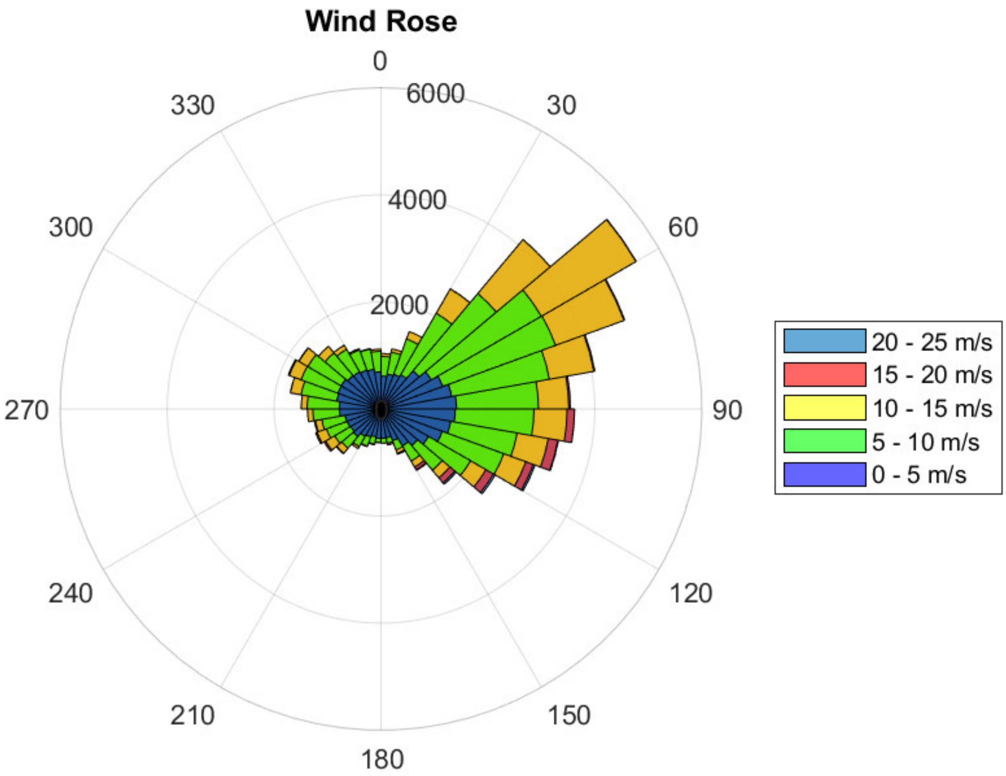


Figure 3.14: Wind Rose at 101m

According to the wind rose, main wind direction is from NNE. Which is also expected wind rose from modeled wind data.

Mean wind speed per wind direction is also shown in figure 3.15. From figure it is also seen that highest wind speed is inline with main wind direction.

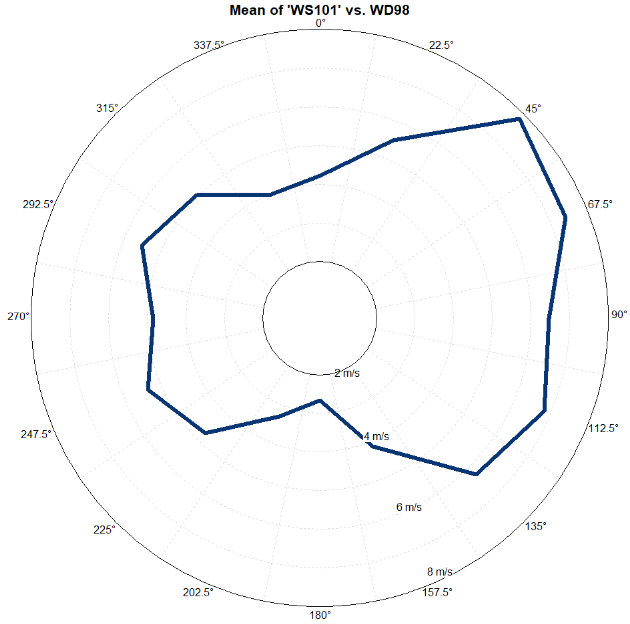


Figure 3.15: Mean Wind Speed per Direction at 101m

3.3.4 Pressure Distribution

Site is nearly at sea level thus there will be no pressure drop due to altitude but still pressure change has effect on air density, it is important to consider. Air density depends on pressure thus pressure has effect on power curve shifting. In figure 3.16, pressure distribution of the site has shown. Maximum and minimum values for the pressure is 1026.3 mbar and 988.4 mbar respectively. Mean pressure for the site is 1007.3 mbar.

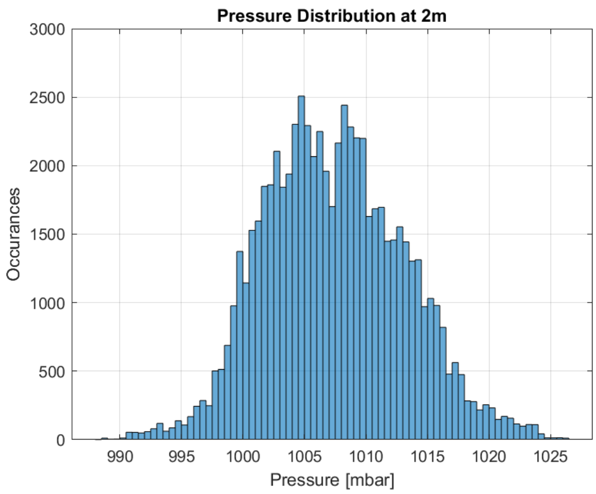


Figure 3.16: Pressure Distribution at 2m

3.3.5 Time Series

Time series for the mast data given in the figures below.

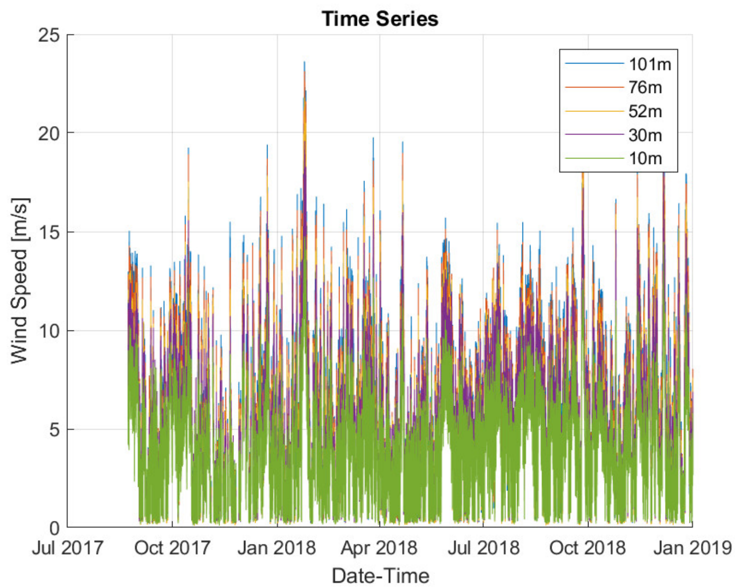


Figure 3.17: Wind Speed Time Series

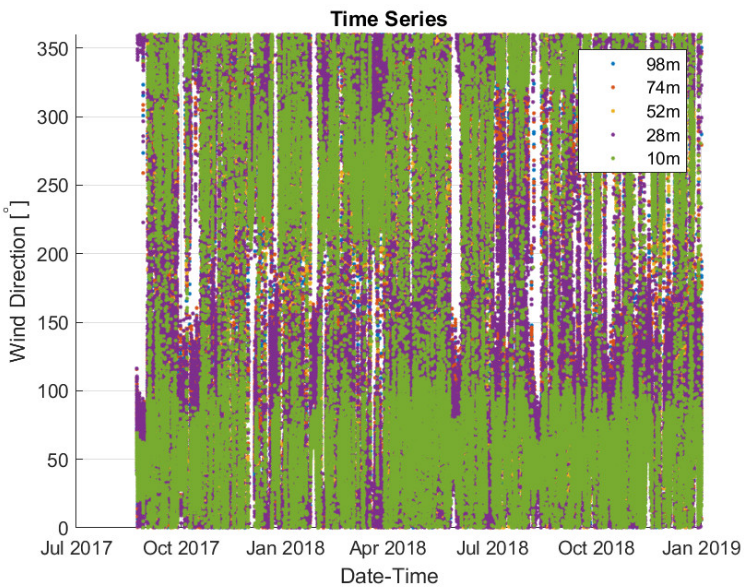


Figure 3.18: Wind Direction Time Series

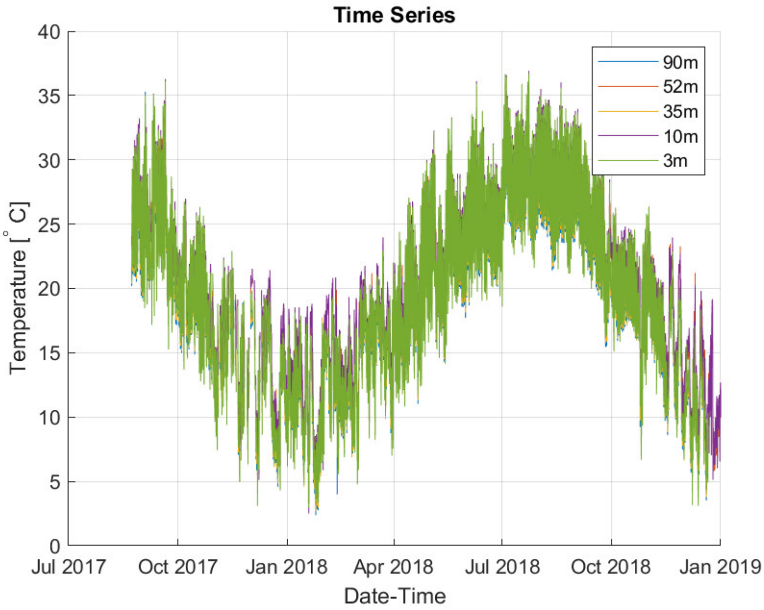


Figure 3.19: Temperature Time Series

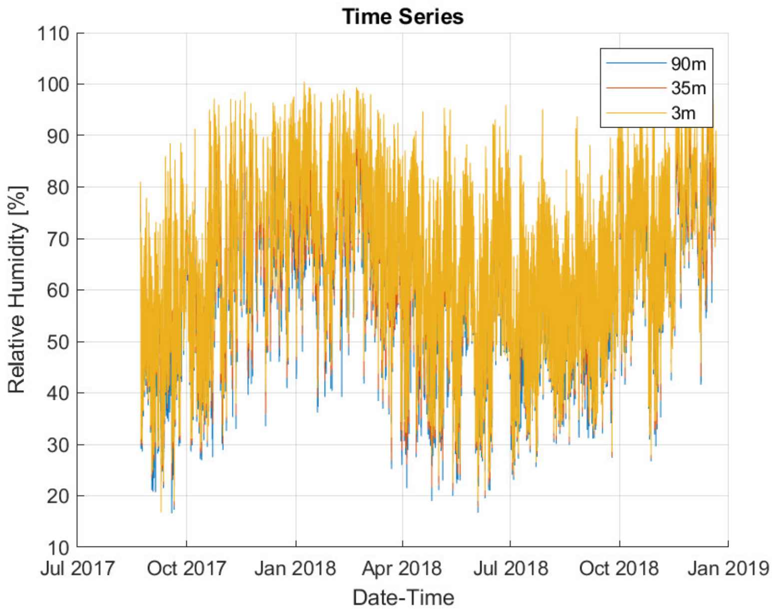


Figure 3.20: Relative Humidity Time Series

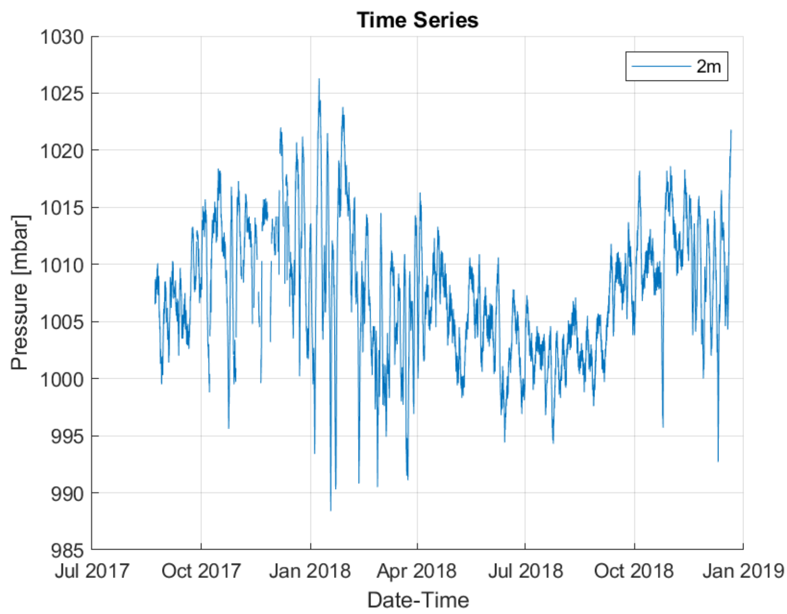


Figure 3.21: Pressure Time Series

CHAPTER 4

THEORY AND METHODS

4.1 Air Density

Air density basically unit mass per unit volume of air. Air density changes with height(pressure), temperature and humidity. Standard atmosphere air density is the air density at 15 ° C, 1013.25 hPa and at dry air and equals to 1.225 kg/m^3. Air density changes with temperature and altitude is given in table 4.1 and 4.2 .

Table 4.1: Effect of Temperature on Air Density
[Atmosphere, 1976]

Temperature - Air Density	
Temperature [°C]	Air Density ρ [(kg/m^3)]
35	1.1455
30	1.1644
25	1.1839
20	1.2041
15	1.2250
10	1.2466
5	1.2690
0	1.2922
-5	1.3163
-10	1.3413
-15	1.3673
-20	1.3943
-25	1.4224

Table 4.2: Air Density Altitude Relation (15° C,1013.25 Pa at Sea Level, Dry Air) [Atmosphere, 1976]

Altitude/Pressure - Air Density		
Altitude [m]	Pressure [hPa]	Air Density ρ [(kg/m^3)]
0	1013.25	1.225
1000	899.97	1.1120
2000	799.35	1.007
3000	709.98	0.9093

Currently, there are five main methods to update [Villanueva and Feijóo, 2016] the power curve of a wind turbine for air density and one of these is suggested by the IEC 61400-1-12 standard. Nevertheless, it is known that the IEC method is not validated in many places, therefore in this study 3 wind turbines with long term production data has been used to check firstly on their performance in different air densities and thereafter long term statistics are compared with above mentioned method results.

Air density for the site is usually determined by taking average air density through the year [Bingöl, 2018]. This averaged density is used by the modeling software. Effect of air density to production is done by applying updating estimated production or power curve at every turbine location. In engineering approaches generally one air density value is used for whole farm for calculations but new approaches enables to use different air density values at every potential turbine location. Standard power curves that given by the manufacturers are usually calculated for 15°C, 0% relative humidity and 1.225 kg/m^3. Air density can be effected by altitude, pressure and relative humidity. According to (1.1) if air density decreases wind speed must increase in order to compensate the power loss. But wind speed and air density has no proportional relation with altitude. Air density is a function of three atmospheric parameters which are temperature (t), pressure (p) and relative humidity (h) according to Committee of International Weights and Measures calculation method. Air density with CIWM method can be found by following;

$$\rho(t, p, h) = \frac{pM_a}{ZRt}\left[1 - X_v\left(1 - \frac{M_v}{M_a}\right)\right] \tag{4.1}$$

where R=8.314472 J/molK, dry air mass $M_a = 28,96546 \times 10^-3 kg/mol$, x_v is steam mole fraction, Z is comprehensibility coefficient. On the other hand engineering approach for air density can be found by;

$$p(z) = p_0[(1 - Lz/t_0)]^{\frac{gM_a}{RL}} \tag{4.2}$$

by using pressure height relation air density depends on only altitude and temperature. where vertical temperature gradient L=0.0065 K/m, $t_0 = 288.15K$ sea level standard temperature, $p_0 = 101325Pa$ sea level standard pressure and gravitational constant g=9.80665 m/s^2. Using engineering method reduces unknown parameters to two and can be used if there is no humidity and pressure measurements. According to Bingöl [2018] for annual calculations difference between CIWM method and Engineering approach effect on power production estimation is negligible but for monthly calculations this difference between 0.2% and 2% thus for shorter periods effects of methods of air density calculation on production estimation should be taken into account.

4.1.1 IEC Method

In IEC method 10 minute avarage air density can be found by using temperature, pressure and relative humidity as in the following equation;

$$\rho_{10min} = \frac{1}{T_{10min}} \left(\frac{B_{10min}}{R_0} - \phi P_w \left(\frac{1}{R_0} - \frac{1}{Rw} \right) \right) \tag{4.3}$$

Where; T_{10min} is the measured absolute air temperature, B_{10min} corrected air pressure to hub height, R_0 is the dry air gas constant (287.05 [J/kgK]), ϕ is relative humidity at hub height, R_w is the water vapour gas constant (461.5 [J/kgK]), P_w is the vapour pressure which equals to 0.0000205exp(0.0631846T_{10min}) [Pa].

In IEC method first of all data sets should be normalized with one, at least, reference air density. Average air density of the valid measured data from the site can be used as reference air density as well as pre-defined air density for the site. Data normalization for the stall-regulated with constant pitch and speed wind turbine should be applied to measured power curve. Data normalization done according to:

$$P_n = P_{10min}\left(\frac{\rho_{10min}}{\rho_0}\right) \tag{4.4}$$

where P_n is the normalized power output, P_{10min} 10 min average measured power output, ρ_0 reference air density, ρ_{10min} is the derived 10 min averaged air density. If these normalization applied to the wind speed following equation can be obtained.

$$V_n = V_{10min}\left(\frac{\rho_{10min}}{\rho_0}\right)^{1/3} \tag{4.5}$$

where V_n is the normalized wind speed and V_{10min} is the 10 min averaged wind speed.

4.1.2 EMD-WindPRO Method

4.1.2.1 WindPRO Air Density Correction

WindPRO's model is simply based on IEC 61400-12 air density correction. Shortcomings of the IEC model is improved in this model. In new WindPro model air density correction method done in two steps which is same as IEC method. Compared to IEC method WindPRO model difference is the exponent in equation below is not constant to $1/3$ for all wind speeds.

$$u_{site} = u_{std}(\rho_{std}/\rho_{site})^{1/3} \tag{4.6}$$

WindPRO method exponent is a function of the wind speed. For wind speeds below $7-8m/s$ exponent is constant and equals to $1/3$. For the IEC method exponent is always equals to $1/3$ regardless of wind speed. For wind speed levels between $7-8m/s \ and \ 12-13m/s$ exponent is smooth step up function from $1/3 \ to \ 2/3$ and after this wind speed levels exponent is constant and equals to $2/3$. Exponent values calibrated by using density specific power curves which obtained from turbine manufacturers. So that in real case WindPRO not uses exact values of $1/3$ and $2/3$ because of the calibration but exponents that are used in model is close to them. Errors on annual energy production levels IEC made over-predictions up to +5% but it is generally less than ±1% for calibration with density specific power curves even for large corrections.

4.1.2.2 Old WindPRO Air Density Correction

Old WindPRO model is uses rate of site to standard density ratio to scale power values. This approach is usually used for stall regulated turbines. If this scaling is applied to all wind speed levels, it is also changes the rated power of the turbine. Scaling in this case stops before rated power level is reached to be able to avoid to change rated power level. In this case smooth empirical transition is made to real rated power of the wind turbine. It is problematic when considering large corrections because smooth transition to the real rated power cannot be smooth enough and does not represents the real behavior of the pitch regulated wind turbines.

4.1.3 Air Density Correction Coefficient Model

In China according to Liu2013 et al. [Liu and Liu, 2013] power curve of the wind turbines in China's inland areas shows significant differences than the theoretical power curve output due to high altitude low air density than the rated turbine power density. In standard conditions wind power can be calculated with following equation;

$$w = \frac{1}{2}\rho F v^3 \tag{4.7}$$

where w is the wind energy, ρ air density, F swept area of the turbine blades and v is the wind speed. In this equation ρ and v ρ_0 are the actual wind speed and air density and v_0 is the standard air density and wind speed. If wind power wanted to be equal for both actual and standard air density and wind speed, it can be written as $w = \frac{1}{2}\rho v^3 = \frac{1}{2}\rho_0 v_0^3$ then

we can find that $v = a * v_0$ where $a = \sqrt[3]{\frac{\rho_0}{\rho}}$. From here it can be seen that if air density decreases wind energy output also decreases.
Measured wind speed in series $V_{rd,i}(i = 1, ...n)$ with a mean value of $\overline{v_{re}}$, that is dependent on two parameter Weibull distribution, from here power density can be found as:

$$\overline{W} = \frac{1}{2}\overline{\rho}C^3\Gamma(\frac{3}{k} + 1) \tag{4.8}$$

where $\overline{W}$ average power density, $\overline{\rho}$ average air density, k Weibull shape factor, C Weibull scale factor. Weibull expectation can be found as;

$$\mu = C\Gamma(1 + \frac{1}{k}) \tag{4.9}$$

By using equation above mean wind power density equation can be found as;

$$\overline{W} = \frac{1}{2}\overline{\rho}C^3\Gamma\left(\frac{3}{k} + 1\right) = \frac{1}{2}\overline{\rho}\mu^3\frac{\Gamma\left(1 + \frac{3}{k}\right)}{\Gamma\left(1 + \frac{1}{k}\right)^3} \tag{4.10}$$

When shape factor $k = 2$ mean wind power density becomes;

$$\overline{W} = \left[\frac{1}{2}\frac{\Gamma(2.5)}{\Gamma(1.5)^3}\right]\overline{\rho}v^3 = 0.955\overline{\rho}v^3 \tag{4.11}$$

According to Liu2013 et al. [Liu and Liu, 2013] in China air density correction done by multiplying the wind turbine power curve with a coefficient to find actual wind turbine power curve. When standard wind farm power output is $x_0(v_0)$ and actual production is $x(v)$, air density correction can be applied as $x(v) = k * x_0(v_0)$ where $k = \rho/\rho_0$ that can be rearranged as

$$x(v) = x_0 \left(\frac{v}{a}\right) \quad 0 \leq v \leq \infty \tag{4.12}$$

where $a = \sqrt[3]{\frac{\rho_0}{\rho}}$. From here it can be observed that if air density decreases wind speed needs to increase to reach rated power output. In that case cut-in, cut-out and rated wind speeds also shifted if air density is changes. Corrected cut-in speed v_s , cut-out speed v_f and rated speed v_r can be found by multiply standard cut-in,cut-out and rated wind speeds with correction coefficient as shown below

$$\begin{aligned} v_s &= a * v_{0s} \\ v_f &= a * v_{0f} \\ v_r &= a * v_{0r} \end{aligned} \tag{4.13}$$

For a constant correction coefficient actual wind turbine power curve can be found by correcting the standard wind turbine power curve.

4.1.4 Random Wind Energy Potential Model

Cross random properties of the wind speed and air density is accounted in new approach of wind energy calculation in Khaled2004 et. al [Khaled et al., 2004] . Wind energy potential can be written as

$$P = \frac{1}{2}\rho V^3 \tag{4.14}$$

where P is the energy potential, ρ air density and V wind speed. Most of the time when calculating wind energy output, air density is assumed constant value of the average air density and wind speed varies by time. In that case air density and wind speed are becomes independent variables. In actual situations these assumptions are not valid. Both of the wind speed and air density changes with time and 4.14 is not applicable for finite time series and need to be rewritten as following in order to applicable for finite time series;

$$P = \frac{1}{2}\overline{\rho}\overline{V^3} \tag{4.15}$$

where $\overline{\rho}$ and $\overline{V^3}$ are arithmetic averages of the air density and cube of the wind speed. Expectation of the potential can be rewritten statistically by $E()$ operator which represents the expectation of the argument. Rewriting the equation 4.15 in terms of expectation;

$$E(P) = \frac{1}{2}E(\rho)E(V^3) \tag{4.16}$$

According to Khaled2004 et. al [Khaled et al., 2004] at high altitudes wind turbine power output overestimated approximately by 30%. Density correction factor needs to be applied to estimate high altitude sites. Khaled et al. also points that correction factor depended on both altitude and monthly temperature annual cycle.

4.1.5 Correction Factor

If air density and wind speed assumed as dependent variables than equation 4.15 can be written as;

$$E(P) = \frac{1}{2}E(\rho V^3) \tag{4.17}$$

Multiplications of two dependent variables expectations can be written as expectation of multiplication and covariance of expectation of multiplication of individuals and multiplication can be written as;

$$Cov(\rho, V^3) = E(\rho V^3) - E(\rho)E(V^3) \tag{4.18}$$

and cross correlation coefficient of air density and cube of wind speed is

$$r = \frac{Cov(\rho, V^3)}{S_p S_{V^3}} \tag{4.19}$$

Where $S_p\ an\ dS_{V^3}$ standard deviations, if $Cov(\rho, V^3)$ eliminated $E(\rho V^3)$ can be written as

$$E(\rho V^3) = E(\rho)E(V^3) + rS_p S_{V^3} \tag{4.20}$$

and inserted in to equation 4.16 $E(P)$ found as

$$E(P) = \frac{1}{2}\left[E(\rho)E(V^3) + rS_p S_{V^3}\right] \tag{4.21}$$

Since there is no cross relation between air density and wind speed thus equation 4.14 is valid. On the other hand r in equation above is important depending on its value between +1 to -1. Air density and wind speed is inversely proportional thus cross correlation between air density and wind speed is should be negative value. By using this information equation 4.21 can be rewritten as

$$E(P) = \frac{1}{2}E(\rho)E(V^3)\left[1 + r\frac{S - pS_{V^3}}{E(\rho)E(V^3)}\right] \tag{4.22}$$

and α can be defined as the square bracket part of the equation above

$$\alpha = \left[1 + r\frac{S - pS_{V^3}}{E(\rho)E(V^3)}\right] \tag{4.23}$$

Variation coefficient C is ratio of standard deviation to average thus α can be rewritten by using variation coefficient

$$\alpha = 1 + rC_p C_{V^3} \tag{4.24}$$

In that case if right side of the sum is below one it can be neglected but if it is big enough than it means that current formula is over estimates the wind turbine power output and when $r = 0$ relative error becomes zero. If expectation value of ρ is evaluated, expectation formula of the universal gas law can be used as following

$$E(\rho) = \frac{E(p)}{R.E(T)} \tag{4.25}$$

where p(Pascal) pressure , T(Kelvin) air temperature and R universal gas constant$R = 287.04 J.K^{-1}Kg^{-1}$

4.2 Vertical Wind Shear

Since turbines becomes larger it is important to extrapolate wind speed correctly up to turbine hub height. There are several models are used to this such as power law, logarithmic wind shear profile. According to Wagenaar2011 et al. two vertical wind shear profile that based on power law are examined and both give nearly same results. According to this study [Wagenaar and Eecen, 2011] after this correction standard deviation of the power is decreased and power itself is increased. Also wind shear correction for multiple heights are used too. To be able to determine wind shear, power law is used (Equ-4.26).

$$U(z) = U(z_r).\left(\frac{z}{z_r}\right)^{\alpha} \tag{4.26}$$

where $U(z)$ is the wind speed at height z, $U(z_r)$ wind speed at reference height, α is the wind shear coefficient and dimensionless constant. Difference between the power curves of various α values are relatively small but difference of the standard deviation of the power for various α values can be differs up to 30% . Also it is observed that different values of α at same wind speed values, standard deviation for low α values larger than the higher α values.

To make the correction for wind shear two approaches are used in [Wagenaar and Eecen, 2011]. First one is using power law directly to hub height and correct the wind speeds according to this wind profile. Other method is using measurements at different heights to redefine wind speed.

Another used method for calculating wind shear is using Logarithmic Law or Log Law. Log law originated from boundary layer in fluid mechanics an give good results up to 200m. Log law based on terrain parameters to estimate wind speed at required height. Log law can be defined as follows;

$$U(z) = \frac{u^*}{k} ln\left(\frac{z}{z_0}\right) \tag{4.27}$$

where z_0 is the roughness length, k is Von Karman constant and equals to 0.4, u^* is friction velocity which can be defined with square root vertical flux of the horizontal momentum divided by air density in equation 4.28.

$$u^* = \sqrt{\frac{\tau}{\rho}} \tag{4.28}$$

which u^* is related with the turbulence thus wind shear profile also related with the turbulence if logarithmic law has used.

4.2.1 Wind Shear Corrected Wind Speed

The power law is used to find average horizontal wind speed at a given height by obtaining α corrected wind speed $U(H)$ (Equ-4.29). Another approach is to average the wind speed over the rotor plane (Equ-4.30):

$$U_{ave,vert} = \frac{1}{2R}\int_{H-D/2}^{H+D/2} U(z)dz = U(H).\frac{1}{\alpha+1}\left(\left(\frac{3}{2}\right)^{\alpha+1} - \left(\frac{1}{2}\right)^{\alpha+1}\right) \tag{4.29}$$

$$U_{ave,rot} = \frac{1}{A}\int_{H-D/2}^{H+D/2} U(z)dA = U(H).\frac{2}{\pi}.\int_{-1}^{1}\sqrt{1-y^2}.\left(\frac{1}{2}.y+1\right)^{\alpha} dy \tag{4.30}$$

where y is a dummy integration value. It is also α corrected wind speed at hub height as before. Both of the correction has same effect on power curve but difference between corrected and uncorrected power can be goes up to 12 % (REF) . For all cases corrected power gives larger results when compared with the uncorrected version. As a result of correction standard deviation decreases by 10 % (REF) .

4.2.2 Rotor Averaged Wind Speed

Kinetic energy flux through to the wind turbine is the total energy flux rotor swept area. By calculating rotor equivalent wind speed, one can find the corresponding wind speed for the kinetic energy flux through to rotor swept area. Considering the wind shear, wind speed is not constant in rotor swept area, lower wind speeds are expected at low tip and higher wind speeds are expected at high tip if site has positive wind shear. As a result of the wind shear, high energy flux is expected above hub height relatively to the below hub height. Most of the energy calculations and wind measurements are designed according to the hub height. By using wind speed at hub height in wind turbine power output it is expected to underestimate power output of the wind turbine. To be able to use rotor equivalent wind speed, at least three wind measurement height is required. Rotor equivalent wind speed calculation according to IEC 61400-12-1 Ed.2 can be expressed as following equation 4.31 .

$$U_{rot,ave} = \left(\sum_{i=1}^{n_h} U_i^3 \frac{A_i}{A} \right)^{\frac{1}{3}} \tag{4.31}$$

where n_h is the number of measurement heights, U_i is the wind speed at the i^th height, A rotor swept area, A_i derived area of the i^th segment of the wind speed U_i.

Area of the divided segment can be found by using following equation 4.32,

$$A_i = \int_{z_i}^{z_{i+1}} c(z)dz = g(z_{i+1}) - g(z_i) \tag{4.32}$$

where z_i is the height of the corresponding i^th segment (H-R<z_i< H+R). Rotor width at height can be found by using equation 4.33;

$$c(z) = 2\sqrt{R^2 - (z-H)^2} \tag{4.33}$$

where H is hub height, R is the rotor radius (63 m for NREL 5MW Wind Turbine [Jonkman et al., 2009])

After using 4.32 and 4.33 integrated function can be found as equation 4.34

$$g(z) = (z-H)\sqrt{R^2 - (z-h)^2} + R^2 arctan\left(\frac{z-H}{\sqrt{R^2 - (z-H)^2}} \right) \tag{4.34}$$

In figure 4.1, swept area of the wind turbine is divided into 5 sections horizontally. In all cases of wind shear corrections, corrected power is larger compared with the uncorrected power values.[Wagenaar and Eecen, 2011] Also for x values larger than 50m,decease of standard deviation of the power is very small. Correction for x=60m corresponds a 3% decrease in standard deviation so that effect of this correction relatively small. Both wind shear correction methods based on α are gives nearly same results. It is seen that standard deviation is reduced up to 10 % but for some wind speed ranges it is increased. [Wagenaar and Eecen, 2011] . Rotor averaged wind speed correction method is only valid for heights above 50m and effects the standard deviation only by 3 % and can be considered small. For all of these correction methods leads the result of higher power for corrected wind speed than uncorrected wind speeds and difference less than 4 % most of

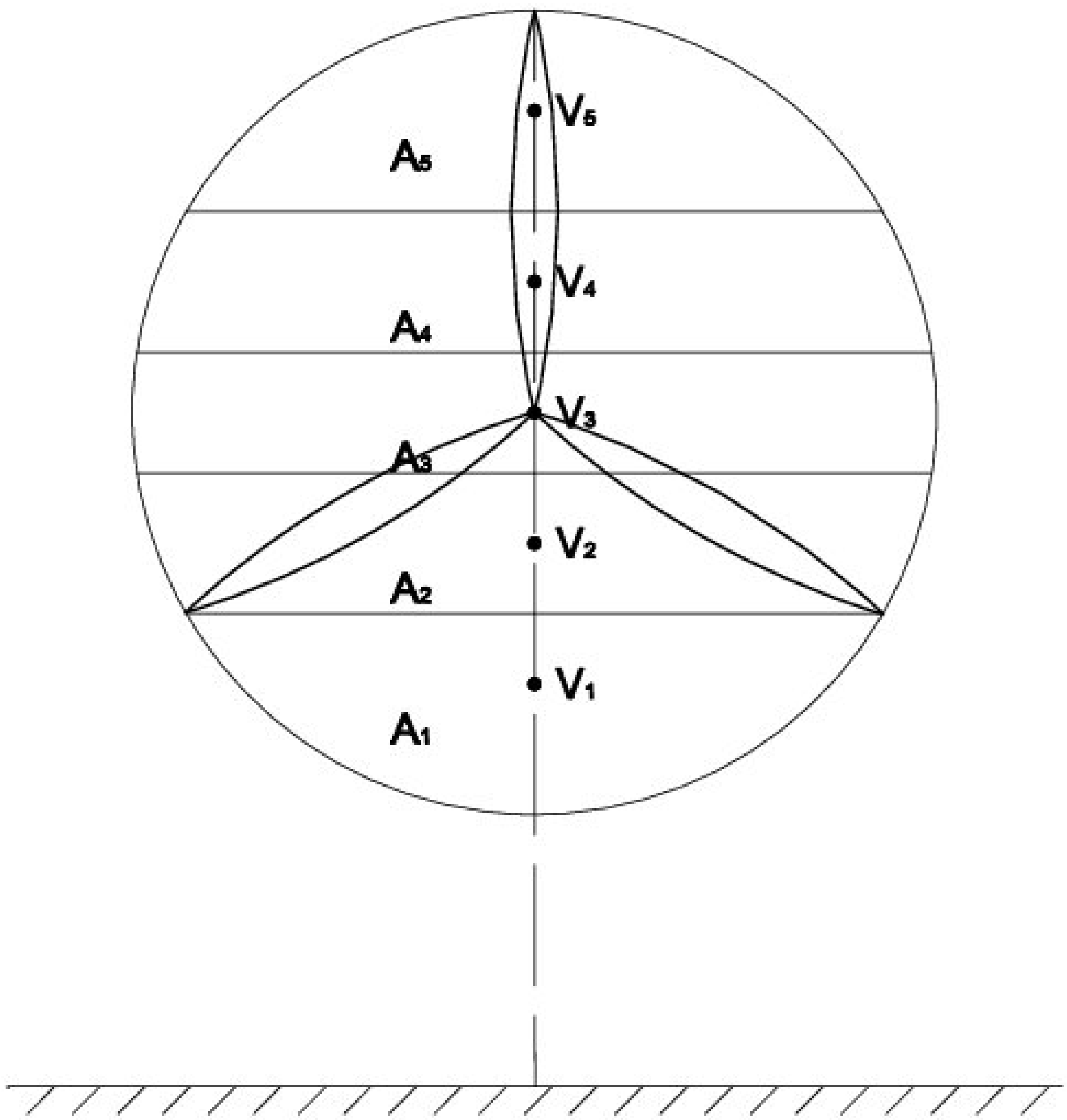


Figure 4.1: Swept rotor area divided into 5 sections(Source:[Wagner et al., 2009])

the time.[Wagenaar and Eecen, 2011]. Since the rotor diameters increasing wind speed and wind direction measurements on hub height becomes less representative because changes in wind speed may not be described with only one wind shear profile [Van Sark et al., 2019]. Since it becomes problem for big rotor wind turbines, measurement at multiple height within the rotor area and by using these measurements,more representative rotor averaged wind speed can be obtained. For large wind turbines that have big swept area, rotor averaged wind speed is more reliable. Especially in cases which constant wind shear coefficient is insufficient to describe wind shear profile, rotor average wind speed becomes significant [Van Sark et al., 2019].

Wagner et al. [Wagner et al., 2009] also studies effect of wind speed profile on wind turbine performance. Wagner et al. investigates different wind shear profiles and turbulence by using a simulation on flat terrain with wind speed up to 160m. High wind shear to no wind shear and local maxima are observed in this study. In this study 3.6MW Siemens turbine with 90m hub height and 107m rotor diameter is used for Blade Element Momentum model simulation. [Wagner et al., 2009]. According to their work, even on flat terrain wind profile shows large variations and both of the logarithmic and power law profiles do not made good estimation. Instead of those profiles, on flat terrain profile depends on the atmospheric condition.[Wagner et al., 2009]. Profiles are used to make an sensitivity analysis between weighted wind speed power production and one wind speed at hub height. Mesauring wind speed from several points in rotor swept area gives better results for correlating wind speed and power production. [Wagner et al., 2009] According to Van et al. [Van Sark et al., 2019] rotor averaged wind speed is not needed always but it is recommended for large wind turbines. In off-shore cases effect of the non-constant wind shear effect is about 1%. It is very limited to use non-constant wind shear coefficient but it is recommended to use rotor equvalent wind speed method for wind shear coefficient values -0.05 $< \alpha < 0.4$. These values indicates that rotor averaged wind speed is suitable for complex or highly vegetable sites and also it is suitable to use non-constant wind shear coefficient in these sites [Van Sark et al., 2019] . When considering offshore wind farms it is not necessary to use rotor averaged wind speed since wind shear is usually about -0.1 . But it is still much reliable to use LIDAR to validate wind shear profile at various locations to reduce uncertainty.

4.3 Aging and Structural Fatigue

Environmental effects wind turbine performance and those effects are degrades performance by mostly changing surface roughness of the wind turbine blade. Wind farms are operated in variety of different environmental conditions and climates. In nordic climates ice accretion degrades the power production, in humid and warm climates insect accumulation degrades the power production and in dry and dessert like climates dust is degrades the power production of the wind turbine.

4.3.1 Leading Edge Erosion

Wind turbines are located in various environments thus wind turbines also exposes to different environmental conditions those conditions, such as abrasive airborne particles, insects, precipitation and other particles can cause significant erosion damage on the blade surface.Erosion mostly occurs on the leading edge and it starts with small pits then it grows to chord wise delamination [Sareen et al., 2014]. According the severity of the erosion, drag coefficient can be increased up to 500%, which causes annual energy loss up to 17.68% in heavy erosion cases [Sareen et al., 2014].

Figure 4.2: Leading Edge Erosion at Several Levels
(Source:[van der Mijlemeijer])

4.3.2 Dust Accumulation

Wind turbines that are operated in dessert like climates faces dust accumulation on the blades leading edge. Accumulated dust on the blade can cause severe aerodynamic changes by changing roughness of the blade surface in time. Accumulated dust increases the drag coefficient of the blade and reduces lift coefficient. This changes on the aerodynamic characteristics causes early stalls due to early flow separation. Dust accumulation increases with time thus, power degradation of the wind turbine also increases in time. If blade cleaning periods are extends, power degradation levels become more severe[Khalfallah and Koliub, 2007].

Another parameter in dust accumulation is the dust size. Khalfallah et al. [Khalfallah and Koliub, 2007] studied the effect of the dust size on power loss and their study showed that if dust size is 0.3mm diameter, dust accumulation can cause power loss up to 38% if dust size is 0.05mm diameter mean power loss only reaches 6.5%. Khalfallah et al. [Khalfallah and Koliub, 2007] also studies degradation of the power curve in time under dust accumulation. Study shows that in different operation periods wind turbine blades are not cleaned for 9 months. Without cleaning the blades power loss due to dust accumulation reaches up to 50%. In figure 4.3 power curve degradation of a wind turbine with dust accumulation is shown and in figure 4.4 mean power loss due to dust accumulation can be seen.

Cleaning of the turbine blades in dusty, desert like climates where heavy dust accumulation occurs is really important in order to avoid power degradation.

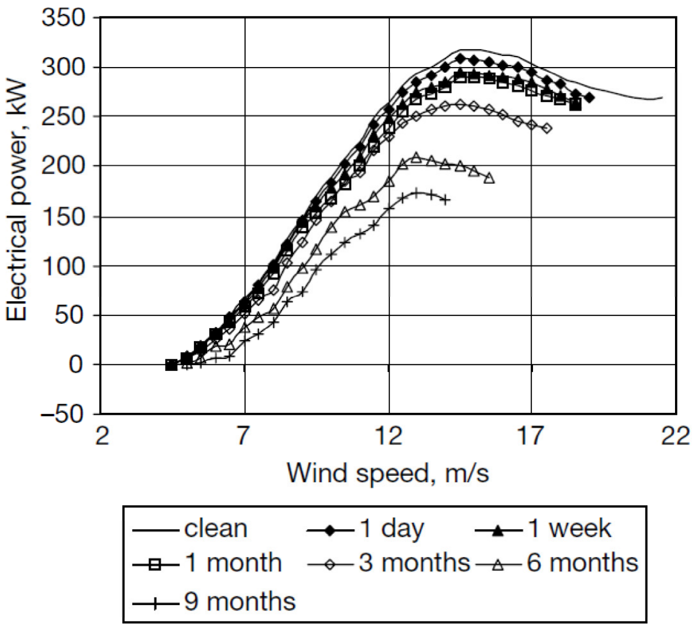


Figure 4.3: Dust Accumulation Effect on Power Curve
(Source:[Khalfallah and Koliub, 2007])

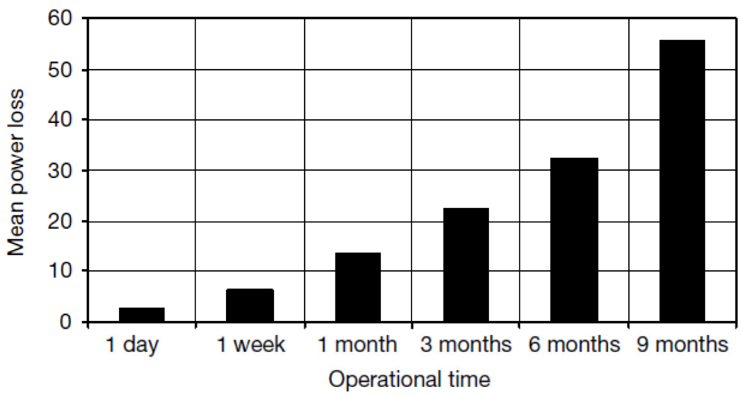


Figure 4.4: Mean Power Loss due to Dust Accumulation
(Source:[Khalfallah and Koliub, 2007])

4.3.3 Insects effects

Power loss due to insect accumulation was not considered as a significant power loss factor until late times. Turbines shows double stall effect on their power curves when insect contamination is significant.

Insects hit and sticks to blade at stagnation point of the turbine blade. In figure 4.5 insects at the leading edge, at stagnation point can be seen.

Figure 4.5: Insect Accumulation on Wind Turbine Blade
(Source:[Wilkinson, 2014])

At low wind speeds it has no significant effect but when wind speed increases and at high angle of attack, suction points shifts to near stagnation point through to highly contaminated area. Flow speed is high around the suction peak and contaminated area creates high frictional drag in the boundary layer thus flow destabilizes due to positive pressure gradient beyond the suction peak. As a result of this effect flow separation occurs early. This effect can be seen as a double stall in measured power curve. In figure 4.6 double stall mechanism has shown. Early occurred flow separation reduces the maximum lift coefficient and power output of the wind turbine also reduces[Soltani et al., 2011]. Insect contamination can reduces design power output by 8% in low contamination and up to 55% if contamination is level is high [Dalili et al., 2009] . Double stall effect due to insect accumulation vanishes after rainfall or blade cleaning. Power curve for insect contamined wind turbine can be seen in figure

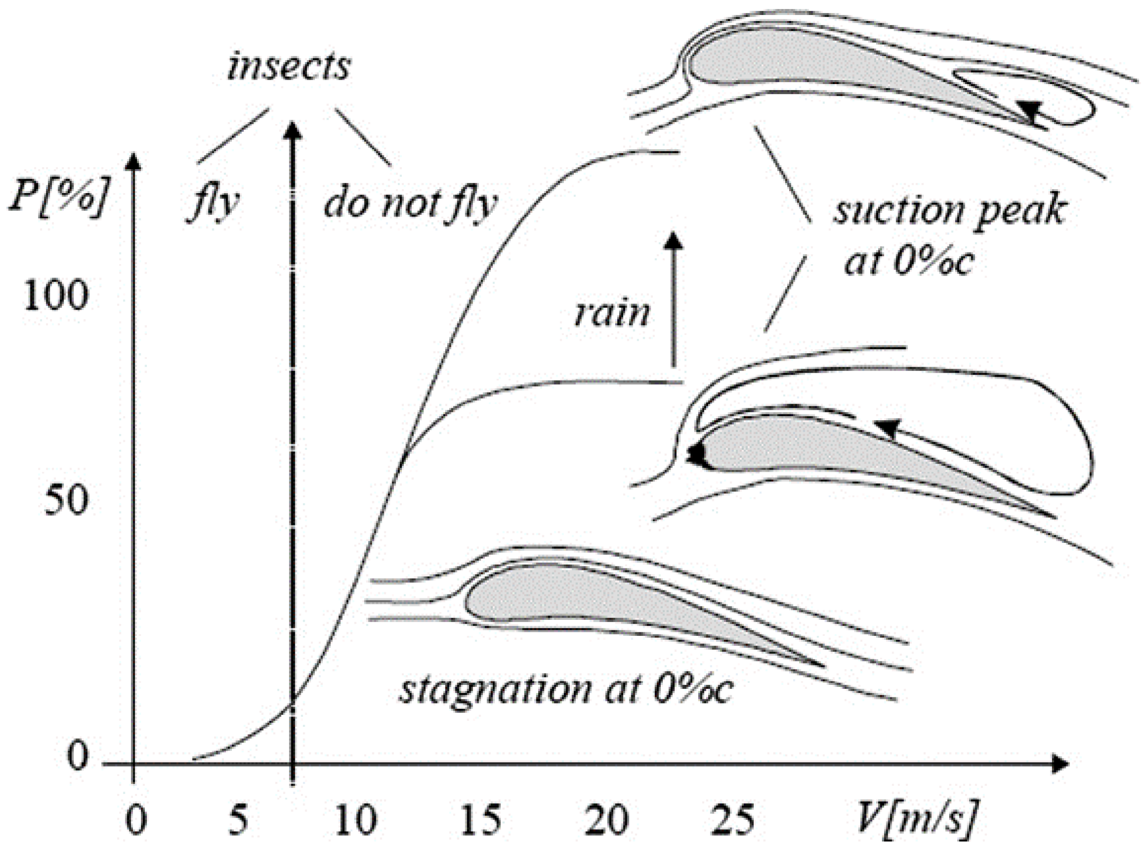


Figure 4.6: Insect Accumulation and Double Stall Effect
(Source:[Sagol et al., 2013])

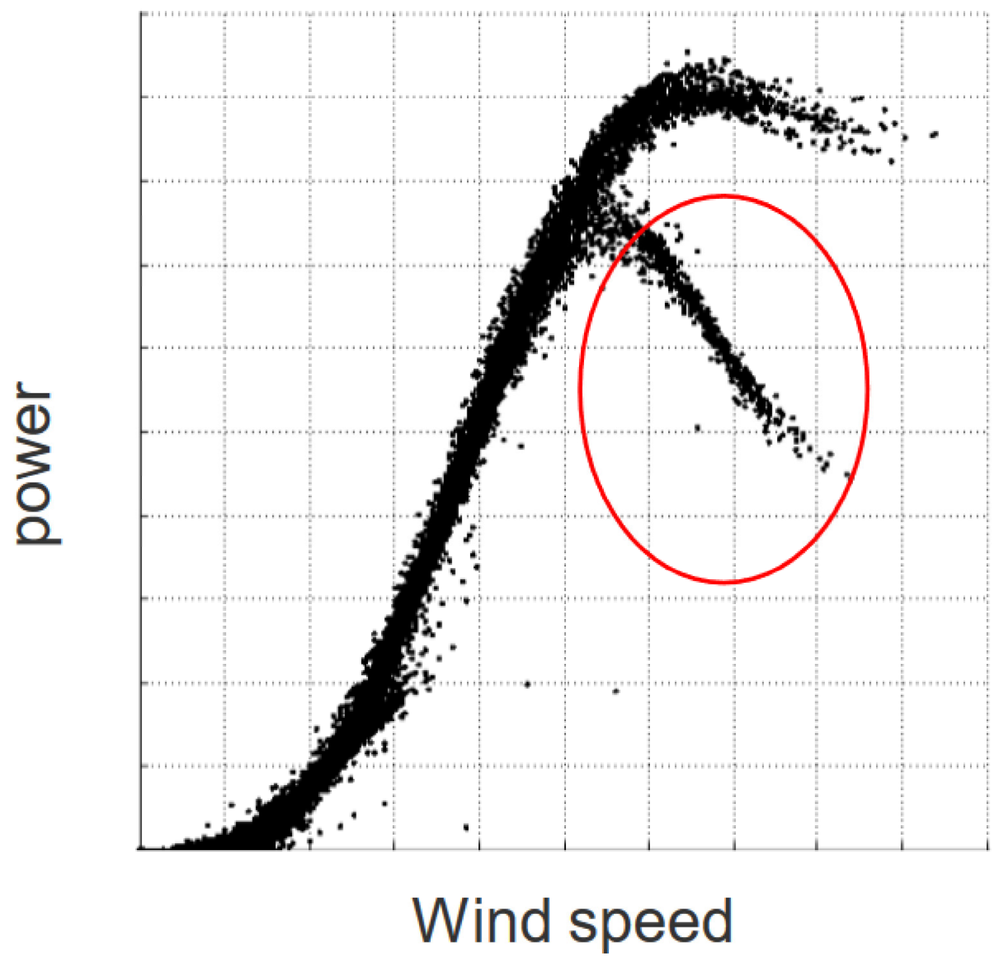


Figure 4.7: Insect Contaminated Wind Turbine, Double Stalled Power Curve (Source:[Wilkinson, 2014])

4.4 Icing

Icing on wind turbines can be effect the turbines production capacity by several different ways. In the places where severe icing events are observed, complete turbine shutdown is one of the option to prevent structural damage to wind turbine and it causes complete loss on power production. Power production is also reduces by the aerodynamic disruption, overload caused by stall delay and imbalance on blades due ice accumulation causes early structural fatigue [Virk et al., 2010].

Icing on wind turbine causes wind turbine power loss due to change in aerodynamics properties,instrument errors or control errors. This power loss can go up to 17 % on AEP and 20% to 50% on power coefficient. [Yirtici et al., 2016] These power losses are depend on the level of icing accumulation.

Atmospheric icing occurs on cold climates which can be described as the temperatures below wind turbines minimum operating temperature for a long term. It is hard to give an exact example for cold climate. At some sites there is no atmospheric icing event is observed although low temperatures. On the other hand mild annual temperature average sites can have heavy icing events regularly. Definitions are described by the IEA Wind Task 19 Wind Energy in Cold Climates for Low Temperature Climate (LTC) and Icing Climate (IC). Low temperature climate is the climate which has temperatures below wind turbines operation limit for a period. Icing climate is the climate where the icing events are observed. [Baring-Gould, 2011]

Wind turbines are affected by two different types of icing during operation, in cloud icing and precipitation icing. In cloud icing is defined as rime icing, glaze icing and mixed icing. Precipitation icing is defined as freezing rain, wet snow and etc.
When air temperature is below zero and cloud base is on site elevation in cloud type icing accumulation occurs. Type of icing is depends on the atmospheric parameters like air temperature, relative humidity, wind speed, pressure, air density, liquid water content and median volume diameter. Icing has three stages; collision, collection and accretion. Water droplets can freeze on impact on the surface,stand, evaporate, shed or rush aft. These properties are depending on the local thermal properties and fluid dynamic conditions. Ice accretion is a time dependent event.

4.4.1 Rime Ice

Rime ice occurs between the temperatures from $0°$ C to $-40°$ C. Super cooled water droplets are freeze when they impact on the surface and accumulates opaque, milky white, tendency to growing into the streamline. Usually occurs on low wind speed, temperature and liquid water content and happens when there is strati form clouds. [Hudecz et al., 2014] Rime ice is easy to remove by using de-icing techniques.[Yirtici et al., 2016]

4.4.2 Glaze Ice

Glaze icing occurs when high wind speed, relatively higher temperatures and high water content causes glaze icing, happens when there is cumulu-form clouds. Rather than like in rime icing, water droplets are not freeze on impact and they freeze through the trailing edge. Glaze icing is hard to remove by using de-icing techniques because have higher adhesion pressure and inherent physical properties.

4.4.3 Mixed Ice

Mixed icing is basically both rime icing and glaze icing happens same time. Mixed icing occurs because of the variation in the sectional differences on velocity, angle of attack.

Wind turbine installation is limited in cold regions because of the ice formation on both on blades and instrumentation . Theoretical power curve degrades greatly by the environmental effects such as icing. Icing on aircraft wings are studied well both experimentally and numerically. These studies shows that ice accretion on an airfoil can be reduce the lift coefficient by 30% and increase the drag coefficient by 50%. According to these studies four different icing formation is classified those are; horn ice, stream wise ice, roughness and span wise ridge ice [Barber et al., 2011]. Type of icing and the severity of the icing depends on the atmospheric parameter liquid water content. Ice accretion changes the aerodynamic properties of the wind turbine blade also causes erroneous behavior on instruments or controllers. These effects causes performance degradation that can result losses up to 17% on annual energy production [Yirtici et al., 2016]. Loss on the power production due to icing events depends on how much ice accumulates, type of blade and turbine control.

The ice shapes that accredited on wind turbine blades are approximately defined by analyzing the photographs of the real iced wind turbines and numerical methods that uses accretion codes. Photo analysis are used to validate accretion code. Accretion code is used to determine 2D icing profile on blade and combination of the code and photographs 3D ice shapes on the blade can be obtained. After getting 3D profile CFD calculations are used to determine the aerodynamic properties of the blade [Barber et al., 2011] . Studies show that ice shape increases with the decreasing angle of attack(α), increasing blade length due to increasing angular velocity(r_w) but still due to uncertainty of the meteorological conditions, although accurate ice accretion prediction simulations icing estimation is still quite big challenge for the wind farms. These simulation tools are used to predict icing and aerodynamic behavior of the rotor after icing events. For different control type turbines, icing shows different effects to degrade power production. For example on stall regulated wind turbines, icing causes early stall than clean blade. For variable speed pitch regulated wind turbines, power curve is designed for the clean blade and controller units adjust the blade pitch angle according to this to reduce the thrust load on the rotor. Since icing changes the aerodynamic properties of the blade pitch angles are not regulated correctly thus power production is reduced. Addition to that additional mass due to ice accretion on the blade adds extra inertia force and alters the natural frequency of the blade and causes early fatigue on wind turbine components [Etemaddar et al., 2014] .

Studies shows that icing on the blade causes significant change in velocity and pressure distribution on the blades. High velocity zones are occurs on the upper surface near leading edge at positive angle of attack. Re-circulation zones are also observed near trailing edge on upper surface for positive angle of attack but for negative angle attack it is seen that re-circulation zones are moved through the lower surface. Turbulence intesity is also increases near the leading edge because of the irregular shape of ice accretion on leading edge[Virk et al., 2010].According to Virk et al. numerical results shows that lift coefficient is also increases for positive angle of attack because effective chord length and the camber of blade also increases. This is also increases the range of the stall range but negative angle of attack early flow separation is occurs due to irregular shape of the upper surface [Virk et al., 2010].

Different parameters has different effect on accredited ice geometry. These parameters are angle of attack, relative wind speed, chord length, airfoil profile and thickness, temperature, liquid water content, median volumetric diameter and relative humidity.

Angle of attack mainly changes the position of the icing profile and it slightly reduces the thickness of the ice profile when angle of attack differs from zero. Peak of the icing profile always occurs at the stagnation point of the airfoil at given angle of attack.

Wind speed is also another parameter that changes the icing profile. When wind speed is low, icing profile becomes parabolic shape with one peak but when wind speed increases, icing profile changes to two peak profile and also thickness of the profile increases with the wind speed.

Chord length is an another parameter that effects the icing profile. When chord length is reduces, thickness of the ice profile relative to the chord length is increases additional to that ratio of the airfoil thickness and chord length changes the thickness of the ice profile like when the ratio increases, thickness of ice profile reduces. Larger chord airfoils are collect less droplet compared with the smaller ones. Thick profiles are collect less droplet because larger chord length usually has larger leading edge radius profile and more droplet follows the stream-line of the blade profile and this makes thick profiles collect less droplet compared with the thinner airfoil profiles. Virk et al. [Virk et al., 2010] shows that if chord length increases, ice accretion on the blade is relatively reduces because collision efficiency of droplets are reduces . If gravity and buoyancy are neglected, droplets are effected by drag and inertia [Mortensen, 2008]. If particle dominated by the drag, it follows the streamline vise versa if inertia is dominant then particle hits the blade. Ratio of the drag to inertia depends on the objects dimension, blade in here, velocity of the air and droplet size [Virk et al., 2010]. In this consequences, rime icing is less severe compared to small turbine blades in terms of accretion and thickness of ice because local collision is less efficient on larger blades. Also torque reduction is much more for small wind turbines compared with the larger ones that also proves that rime ice effects large wind turbines less.

Temperature is also one of the important parameters on icing because temperature effects speed of heat balance directly thus effect on icing geometry is expected. Studies show that temperatures from $0°C$ to $-2°C$ icing profile has two peaks but when temperatures goes below $-2°C$ icing profile becomes parabolic [Etemaddar et al., 2014] but according to Li et al. between $-6°C$ and $-14°C$ horn icing shape occurs and stream line icing shape observed at $-20°C$ and between $-16°C$ and $-18°C$ icing shape has characteristics of both types. Two peak icing shape observed between $-6°C$ and $-14°C$. Two peak shape develops because when water film spreads to sides of the stagnation point when it hits the blade and this makes a concave shape icing which results a two peak icing. This phenomena is can not observed when temperature goes $-20°C$ because water freezes immediately on impact and streamline icing shape observed and thickness of stream line icing increases with time [Li et al., 2018].

Icing area is also increases with decreasing temperature. Ice profile becomes parabolic for any liquid water content value, liquid water content value have only effect on ice profile thickness, when liquid water content increases ice profile becomes thicker and for median volume diameter same conditions are applies as liquid water content.

For relative humidity, that can be said that ice profile is independent from relative humidity [Etemaddar et al., 2014]. When it comes to ice load, it is increases when liquid water content, median volumetric density and relative wind speed increases. It decreases with airfoil thickness. Studies show that ice load is nearly independent from all other parameters [Etemaddar et al., 2014]. When icing studied inner part of the wind turbine blade it is seen that icing is very small and can be neglected compared with the outer part of the blade. It is get thinner because low relative wind speed and thicker airfoil shape compared to outer part of the blade. Thus calculations are made for only outer part of the blade.

CHAPTER 5

RESULTS AND DISCUSSION

5.1 Air Density and Altitude

Wind turbines theoretical power curves are estimated for sea level and taken as 1.225 kg/m^3 at 15°C and 1013.25 hPa. Thus any change in air density will affect the power curve of the wind turbine. Air density decreases with altitude, if wind turbines sited on high altitudes, their power curves will affected accordingly. NREL 5MW wind turbine power curve corrected for 1000m and 2000m altitude by using IEC Method. In figure 5.1 NREL 5MW wind turbine power curves for 0m, 1000m and 2000m plotted.

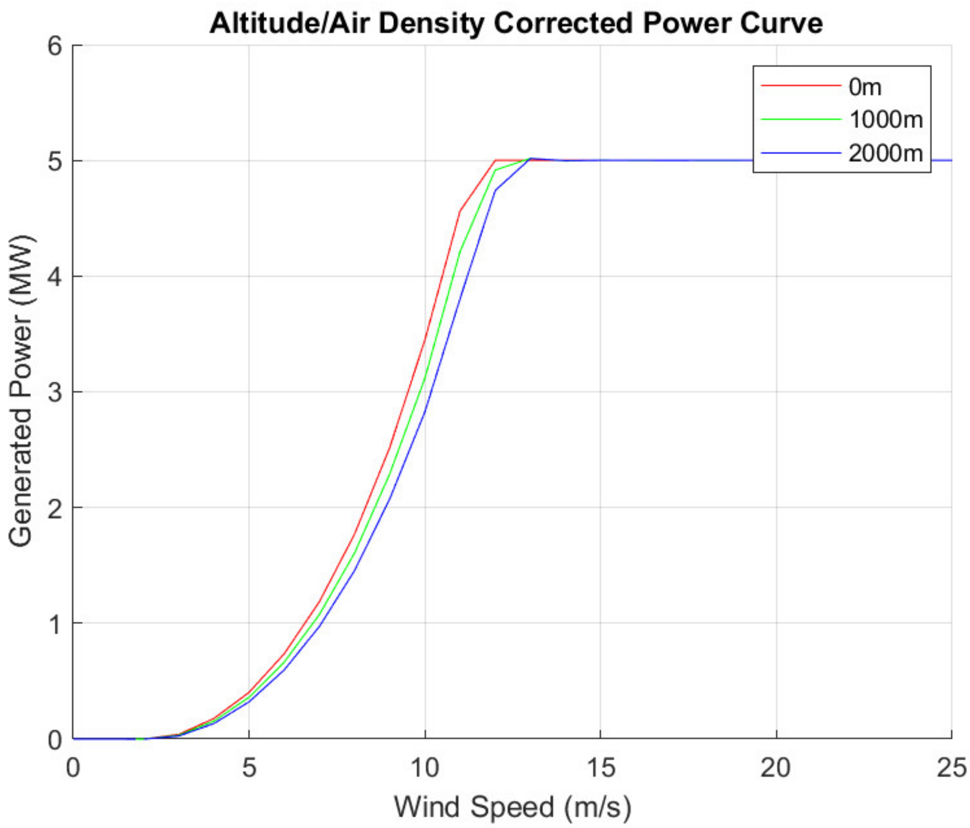


Figure 5.1: Power Curves at Different Altitudes

According to IEC correction, due to altitude only, power production at 1000m decreases about 9.5% at 11 m/s while at 2000m power production decreases about 18% at 11 m/s. In table 5.1 differences of power production in rated power production section of the power curve has given in percentage.

Table 5.1: NREL 5MW Turbine Power Output at Different Altitudes

Power Production Differences in Percentage		
	Altitude [m]	
Wind Speed [m/s]	1000	2000
4	18.78	34.97
5	12.66	24.48
6	10.53	20.30
7	9.80	18.98
8	9.29	18.01
9	9.24	17.79
10	9.04	17.60
11	9.59	18.01
12	7.68	16.60

Regardless of change in any atmospheric condition to differ air density, altitude is important factor for air density change. From table 5.1 there is a significant power production decrease between 0m to 2000m. Since wind turbines are moving up through to mountains, it is really important to put altitude effect on power curve in order to avoid over-estimations in annual energy calculations.

Altitude effect is studied by using pressure change with altitude, then this pressure change applied to air density formula and air density vs altitude values are obtained. After getting air density vs altitude values, IEC air density correction method applied to NREL 5MW wind turbine power curve. Calculations for sea level, 1000m and 2000m are made. According to these calculations, for 1000m calculated change is observed up to 9.5% while for 2000m up to 18% change in power curve has observed in rated wind speed ranges. Such a big difference between power curves of same turbine sited at different altitudes will cause completely different AEP results and result false calculations in financial models. Yet it is known that at high altitudes, high wind speeds are also available so power loss due to air density can be compensated with high wind speeds. According to equation (1.1), in order to provide same power output at 11 m/s wind speed, wind speed must be 11.74 m/s at 2000m. If high wind speeds are expected in high altitudes, power output loss due air density can be compensated with wind speed. Another problem with high altitudes are low air temperatures. Air temperature is also reduces with altitude. When air temperature at sea level is 15 °C, air temperature at 2000m reduces to 2.00 °C [Atmosphere, 1976]. Low temperatures are leads wind turbines to icing during winter times for extended periods. Icing on wind turbines will reduce the power output of the wind turbine up to 17% on AEP [Yirtici et al., 2016] and even causes complete shutdown of wind turbine.

Icing events should be expected at high altitudes at cold regions and loss due to effects of icing should be included in AEP. At that point there is no certain or preferred way to calculate loss due to icing and icing will add additional uncertainty to financial models due to unpredictable occurrences and effects. Also due to icing especially with heavy icing sites, early life-time completion and high O&M costs should be considered. Investors and consultants should evaluate wind farms in high altitude with precaution and use their know-how experiences during the AEP calculations also high uncertainties can be expected in such a sites. Wind farms at high altitudes are come to light recently thus there is many unknown and unpredictable issues can arise during the operation but starting from altitude correction, will reduce the uncertainty compared to uncorrected power curve.

5.2 Air Density Correction IEC Method and EMD-WindPRO Method

IEC and EMD methods are applied to NREL 5MW wind turbine using IZTECH Mast data in order to understand change and correction effects to real measurement. Corrected power curves and uncorrected power curve for NREL 5MW wind turbine plotted in figure 5.3. From the plot it can be seen easily, even at the near sea-level altitude, power curve shifts only by air density change.

Power production decreases by 2.9% by applying IEC Method and decreases by 5.7% by applying EMD-WindPRO method at 11 m/s wind speed. Table 5.2 shows the differences of power production calculated by using IEC method and EMD-WindPRO method in rated power production section of the power curve.

Air density dependent on variables such as temperature, air pressure and etc. Those variables are site specific values thus applying corrections will give different results for different sites. By using this information site specific power curves should be considered when calculation energy production of the wind farm.

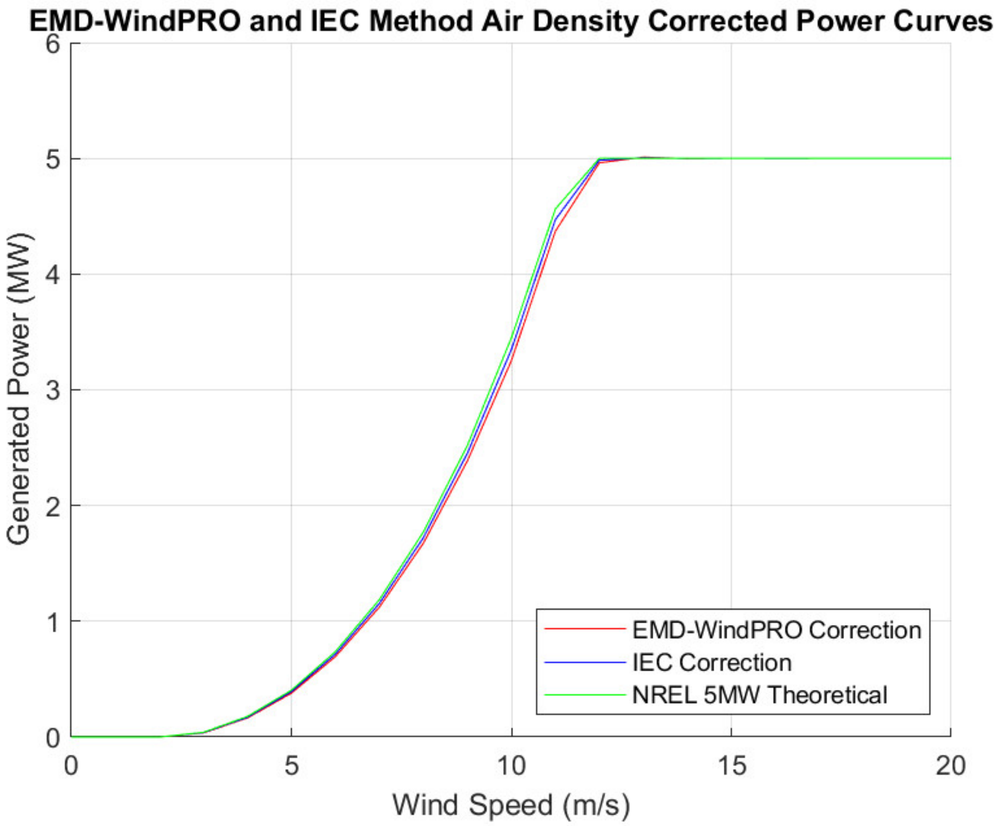


Figure 5.2: Power Curves Corrections with Different Methods

Table 5.2: NREL 5MW Turbine Power Output at Different Altitudes

Power Production Differences in Percentage		
	Method	
Wind Speed [m/s]	IEC	EMD
4	5.74	11.22
5	3.77	7.44
6	3.14	6.20
7	2.92	5.77
8	2.77	5.47
9	2.77	5.45
10	2.67	5.30
11	2.94	5.73
12	2.00	4.22

Two different air density correction method studied in this study. IEC air density correction method and EMD-WindPRO air density correction method. When comparing both method with theoretical power curve, corrected power output reduces in both methods. In figure 5.3 all power curves are shown. Power output is highest in theoretical power curve and when air density corrections are applied, in both corrected power curve power production reduces.

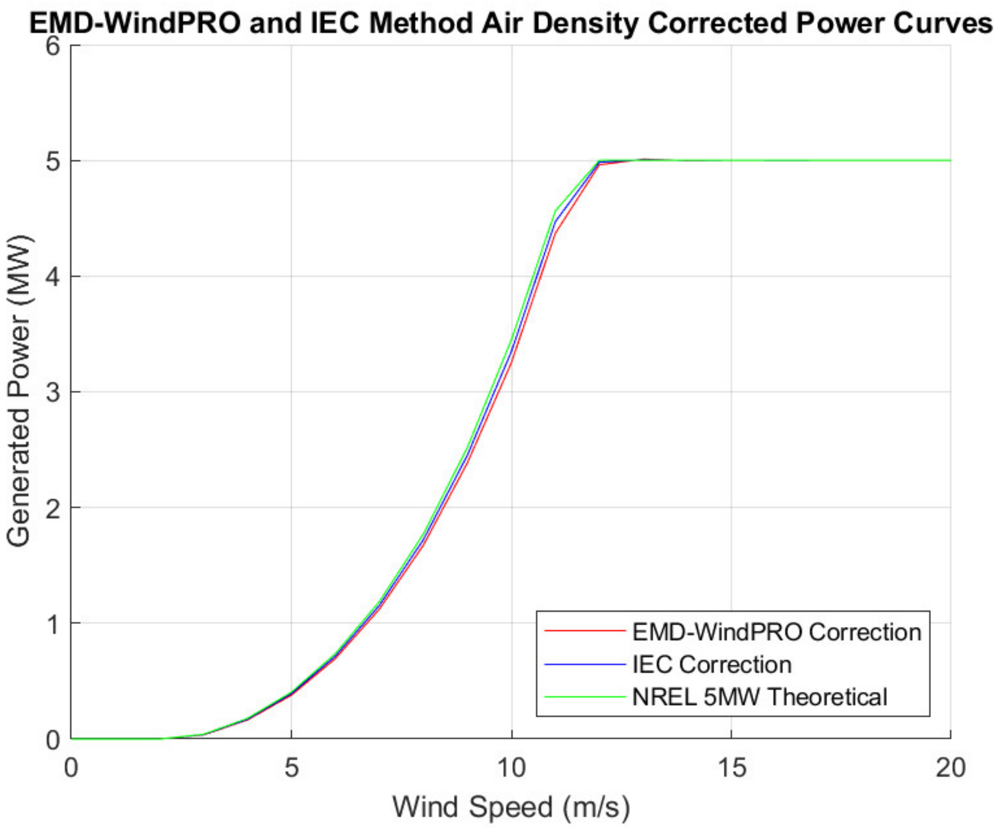


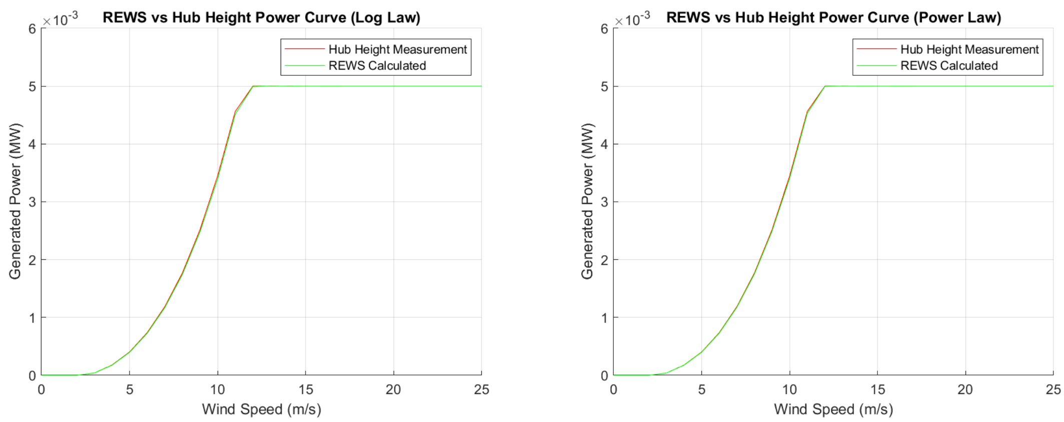
Figure 5.3: Power Curves Corrections with Different Methods

According to calculations, power output is highest in theoretical power curve and when air density corrections are applied, in both corrected power curve power production reduces.In overall IEC air density correction method reduces power generation with 2.9% while EMD-WindPRO method reduces with 5.7%. EMD-WindPROs step-up function changes air density correction between 7 m/s and 13 m/s, that is the reason why EMD-WindPRO method correction reduces power generation more than IEC method. Yet, since there is no real production data available, it is not possible to say which correction method gave more realistic results. But it is known that air density have huge impact on power production thus in both correction methods, it can be assumed that resultant power curve is more realistic than theoretical power curve. Since realistic power curve have less standard deviation, uncertainty comes from power curve should be less then the uncorrected power curve. This results give better PXX calculations and more reliable financial models.

Other methods that mentioned in Theory and Methods section is not included in the calculations in this study.

5.3 Rotor Averaged Wind Speed Correction

In order to calculate rotor average wind speed, 5 measurement heights are used in this study.Since IZTECH Mast is not tall mast and no LIDAR measurements are available, measurements above hub heights are not available. Measurements above hub heights are calculated by using vertical extrapolation of hub height measurement to required measurement heights by using both power law and logarithmic law. Using extrapolation methods, wind speeds at 39 m, 64 m, 89 m, 114 m, and 140 m are calculated in this study. Calculated rotor equivalent wind speeds are shown in table 5.3. By using those calculated wind speeds rotor equivalent wind speed corrected power curves are plotted in 5.4a and 5.4b.



(a) REWS Corrected Power Curve (Log Law) (b) REWS Corrected Power Curve (Power Law)

Figure 5.4: REWS Corrected Power Curves

According to Wagenaar et al. [Wagenaar and Eecen, 2011] power output is larger in REWS corrected power curves compared with the uncorrected power curve. But in this study both calculated rotor equivalent wind speeds and REWS corrected power curve is less than the uncorrected power curve. As an example at 11 m/s wind speed, power output for logarithmic law calculated REWS correction is less than uncorrected power output with 1.64% while it is 1.15% with power law calculated REWS correction. Reduction in power

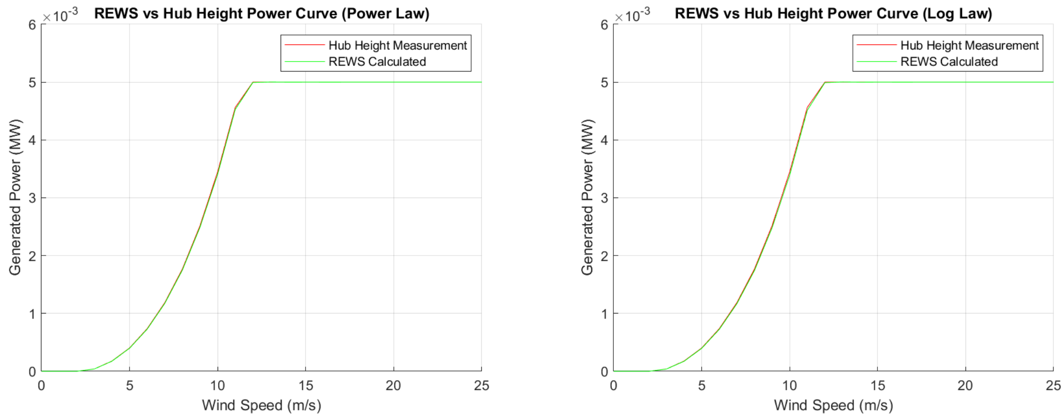
Table 5.3: Calculated Wind Speeds Above Hub Height

Calculated Wind Speeds Above Hub Height		
	Method	
Wind Speed [m/s]	Power Law [m/s]	Logarithmic Law [m/s]
1	0.99	0.99
2	1.99	1.99
3	2.99	2.98
4	3.99	3.98
5	4.98	4.97
6	5.98	5.97
7	6.97	6.96
8	7.97	7.96
9	8.97	8.95
10	9.96	9.95
11	10.96	10.94
12	11.96	11.94
13	12.95	12.93
14	13.95	13.93
15	14.95	14.92
16	15.94	15.92
17	16.94	16.91
18	17.94	17.91
19	18.93	18.90
20	19.93	19.90
21	20.92	20.89
22	21.92	21.89
23	22.92	22.88
24	23.91	23.88
25	24.91	24.87

output might occurs due to using calculated wind speeds by using vertical extrapolation instead of real measurements. Using different vertical wind shear profiles gives different results, thus reliability for calculated wind speeds above hub height reduces. In these consequences, REWS correction is not representative for this site and should be validated by using LIDAR or tall tower measurements in further studies.

Rotor equivalent wind speed aims to find representative wind speed for whole rotor swept area. Due to wind shear, wind speed is not constant on rotor swept area thus wind speed measurements at hub heights is not representative for power generation. In order to make wind shear correction rotor equivalent wind speed measurements must available. To do that RSD or tall-masts are required to measure above hub height. IZTECH mast has highest measurement at 101m thus it is not suitable to calculate REWS for 90m hub height NREL 5MW wind turbine. Although mast height is not enough and no RSD support, vertical wind speed extrapolation used to calculate wind speeds above hub height and make REWS correction to NREL 5MW wind turbine.

Logarithmic law and power law used to extrapolate wind speed. After using REWS correction, updated power curves are obtained as in figures 5.5a and 5.5b .



(a) REWS Correction Power Law

(b) REWS Correction Log Law

Figure 5.5: REWS Corrections

Without RSD and tall mast, only using vertical extrapolation, REWS correction made 1.64% difference for logarithmic law and 1.15% for power law. Difference in power output is relatively small and according to Wagenaar et al. [Wagenaar and Eecen, 2011], wind shear correction with REWS increases power output while in this study REWS results lower power output. After REWS correction, corrected power curve expected to shift to the left side in order to increase power output at rated wind speed ranges. In this study power curve shifted to right after correction, thus after REWS correction power output of wind turbine reduces.

Considering using vertical extrapolation to get wind speeds above hub height, this results may accepted and can be ignored because shear profiles are not well fit with measured data. Also additional uncertainty should be added if REWS correction is made by using vertical extrapolation using power law or logarithmic law. Wind shear affected by many different parameters such as site complexity, roughness, atmospheric stability and etc. thus REWS correction also effected by those parameters, it is also shown in Wagenaar et al. [Wagner et al., 2009] that even in flat terrain power law and logarithmic law wind profiles are not made good estimations. If REWS correction to power curve is applied, it is important to have RSD support or tall masts in order to get reliable results. Also REWS should be applied to large wind turbines, that wind speed difference between tip and top is relatively high. Also according to Van Sark et al. [Van Sark et al., 2019] using REWS is significant where the sites have no sufficient constant wind shear to represent wind profile.

On the other hand in off-shore wind farms, although wind turbines are relatively larger than the on-shore wind turbines, since wind shear is constant most of the times. Still using RSD to validate wind shear profile will provide reliable information about wind profile, especially using at off-shore sites near shore that internal boundary layer might observed. By using validated wind profile to calculate REWS will reduce the uncertainty.

5.4 Aging and Structural Fatigue

After years of production, it is unavoidable to have structural fatigue. Structural fatigue depends on many properties of turbine itself, to site even, quality of O&M management. Since there is no data available for this section, literature data has been used for this study.

Site properties should be determined very well in order to use correct material and expected power curve during the operation lifetime. It is also important to make correct or early diagnoses of failures of wind turbine during the operation only by checking power curve. In this study dust accumulation, insect accumulation and leading edge erosion is studied. Since all of those factors effects the aerodynamic properties of the wind turbine, it is expected to alter power curve thus causes a difference between AEP and actual power generation.

Leading edge erosion can increase the drag coefficient by 500% and causes loss up to 17.68% according to Sareen et al. [Sareen et al., 2014] in heavy erosion cases. Altough dust accumulation can be avoided by cleaning the blades, if those periods are extended, dust accumulation can cause power loss up to 38% with 0.3mm dust particles according to Khalfallah et al. [Khalfallah and Koliub, 2007]. In that case blade cleaning has crucial importance in the sites with dust accumulation is expected, such as deserts. Since dust accumulation is increases with time, longer cleaning periods will lead more power loss. Insect accumulation on the other hand, will not cause significant power loss until late times. When accumulation too much, at high wind speeds double stall effect can be observed at the power curve. Power loss due to insects is around 8% at low accumulation and 55% if contamination is high. Predicting these effects is quite hard prior wind farm becomes operational thus correction for those effects are hard to achieve during AEP. Yet, except leading edge erosion, insect and dust accumulation can be avoided by blade washing. At that point quality of O&M management is important to be able avoid power loss due to those effects. If signs of those effects ignored, even severe results can be arise. In order to do that power curves should be realistic so any turbine failure or power loss can be diagnosed from power curve.

5.5 Icing Effect

Although icing is not expected on IZTECH site, small icing effect on power curve studied in this study. NREL 5 MW is used to determine icing effect on power curve by using Turbine BEM Simulation. Only temperature effect is investigated in this simulation. First normal working conditions are simulated then icing for stream line icing shape [Li et al., 2018] at $-20°C$ is investigated. In table below blade properties for NREL 5MW can be found. Under same conditions but for $-20°C$ temperature levels, icing is modelled for NREL 5MW wind turbine also show in the table below;

Table 5.4: NREL 5MW Turbine Blade with icing

	Airfoil Name	
Radial Position [m]	No Icing	Icing
0	Circular Foil 0.5	Circular Foil 0.5
1.36	Circular Foil 0.5	Circular Foil 0.5
4.10	Circular Foil 0.5	Circular Foil 0.5
6.83	Circular Foil 0.35	Circular Foil 0.35
10.25	DU99W405LM	DU99W405LM
14.35	DU99W350LM	DU99W350LM
18.45	DU99W350LM	DU99W350LM
22.55	DU97300LM	DU97300LM
26.65	DU91W2250LM	DU91W2250LM
30.75	DU91W2250LM	DU91W2250LM
34.85	DU93W210LM	DU93W210LM
38.95	DU93W210LM	DU93W210LM
43.05	NACA64618	NACA64618
47.15	NACA64618	NACA64618
51.25	NACA64618	NACA64618ICE
54.67	NACA64618	NACA64618ICE
57.4	NACA64618	NACA64618ICE
60.13	NACA64618	NACA64618ICE
61.50	NACA64618	NACA64618ICE

Airfoil profiles of the NREL 5MW wind turbine blade sections are shown below;

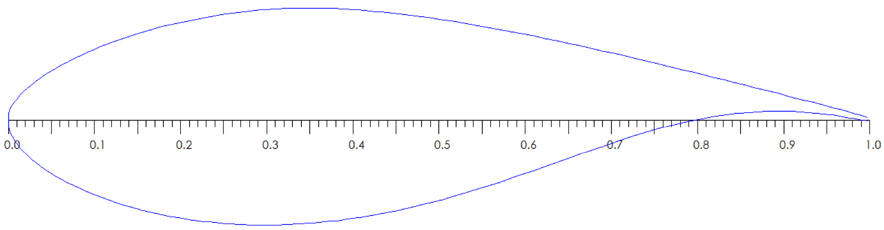


Figure 5.6: DU91W2250LM Blade Profile
[Jonkman et al., 2009]

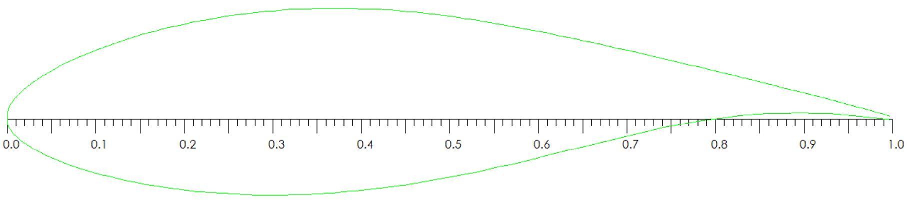


Figure 5.7: DU93W210LM Blade Profile
[Jonkman et al., 2009]

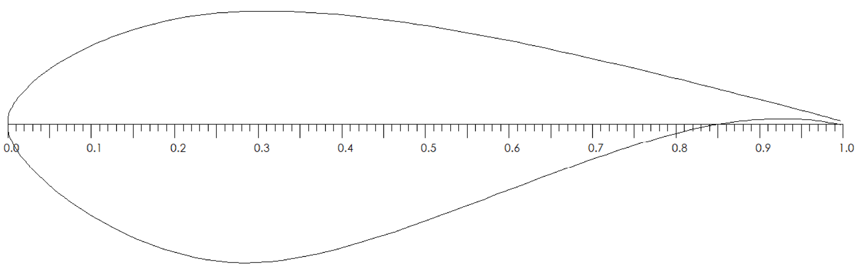


Figure 5.8: DU97W300LM Blade Profile
[Jonkman et al., 2009]

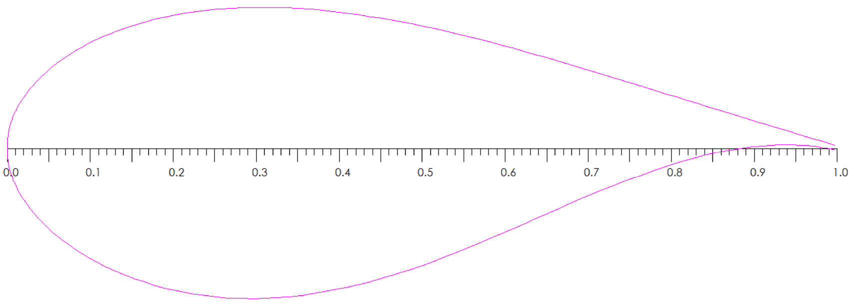


Figure 5.9: DU99W350LM Blade Profile
[Jonkman et al., 2009]

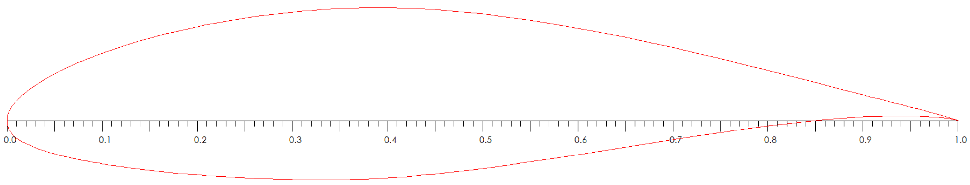


Figure 5.10: NACA64618 Blade Profile
[Jonkman et al., 2009]

In this simulation icing on NACA64618 profile has used. For ice accretion, temperature between -10° and -20° has used to determine ice accretion shape [Etemaddar et al., 2014].

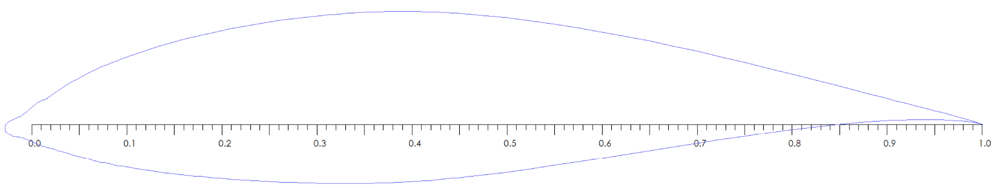


Figure 5.11: NACA64618 Blade Profile Under Icing Conditions

BEM simulation is used to determine and compare the power curves between normal condition and under icing condition. It can be seen in the figure 5.12 ice accretion on the blades, effects

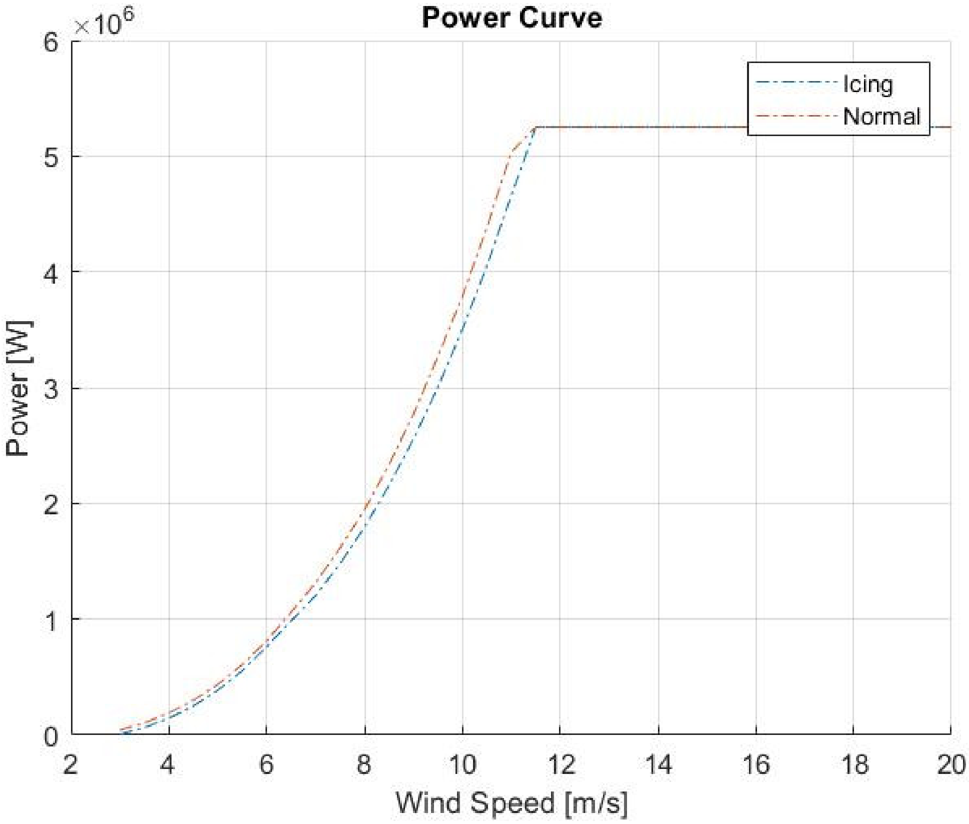


Figure 5.12: Power Curves

As it seen in the figure 5.12 power production of the wind turbine reduced due to changes in the aerodynamic characteristics of the blade. In this simulation icing accretion is only considered between 51.25m and 61.50m and only one icing profile has used. Even though considering little ice accretion, turbine performance changes significantly. In severe icing conditions turbine power production will effected more and also structural fatigue will be increased. To avoid extra fatigue, ice shredding and damaging the turbine, complete shutdown of the wind turbine can be decidable. In complete shut down events, wind turbine produces no energy during these periods. Considering complete loss of energy production for some periods, annual production of the wind farm decreases significantly and this should be taken into account as an uncertainty in energy yield assessments. But to do so, icing and it's effect on power curve should be studied in depth and specified with different parameters to adopt different scenarios and create a standard for power-loss due to icing. By doing that it may become also possible to determine icing from power curve.

Since wind turbines are started to sited to high altitudes and Nordic climates, icing becomes unavoidable. Icing is time dependent event thus predicting, modeling icing is challenging. Resulting from these properties of icing, there is still no accepted icing model is available for wind turbines. Most of the models to define and study icing is taken from aviation and adopted to wind turbines. Icing can occur many different shapes and different severity. In this study, beginning of horn type icing is modeled and only icing at the tip of the blades assumed. BEM method used to calculate after icing power curve. Obtained power curve after icing modeled shown in the figure 5.12 .

As it seen easily, even small amount of ice accretion has huge impact on power output of the wind turbine. Thus if any icing risk is available for the site, it should be taken into account for AEP because according to Yırtıcı et al. [Yirtici et al., 2016], power loss due to icing can reduced by up to 17% and currently there is no accepted de-icing or anti-icing technique available.

Icing alters the aerodynamic shape of the turbine blade and this change leads reduction in power output. Also in severe icing events complete turbine shut down is another result of icing which no power output at all. Operation under icing conditions also causes early fatigue on wind turbine and reduces expected life-time or increases O&M costs.

Studying on icing during the wind farm development is important in several different ways. One of them is getting realistic AEP for sure. But also knowing icing periods and length of those periods are important during the operation. Icing expectancy will alert the technicians during the icing periods and early icing detection and taken correct actions in time will extends wind turbines life and integrity, reduces O&M costs and even increases health and safety quality.

Since there is no accepted model available for icing, there is also no accepted correction is available, effect of icing to uncertainty can be reduced by taken icing periods into account during the development stage and reduce potential power loss due to icing from AEP. Yet there is no model for icing those reduction can not go further from rough estimations.

CHAPTER 6

CONCLUSION

Wind turbine power curve update based on atmospheric conditions are studied in this thesis. Findings in this study proves that power curve is dependent on atmospheric conditions. Theoretical power curve can be obtained by using theoretical values of aerodynamic and electrical components. Atmospheric conditions are usually set to 15 ° C, 1013.25 hPa, 1.225 kg/m^3 when obtaining theoretical power curve, which those parameters are not met all the time in wind farm sites along with many other parameters and site conditions. This situation causes an extra uncertainty from power curve thus AEP calculations and financial models created according to AEP calculations are became unrealistic.

Air density, altitude, rotor averaged wind speed and icing effects are investigated by using IZTECH masts data and applied to NREL 5MW wind turbine. For dust and insect accumulation and leading edge erosion, literature data has been used to discussed in this thesis.

Theoretical power curve is highly dependent on site conditions. At high altitudes, power curve shifts significantly and if theoretical power curve used in AEP, over-estimated results can be obtained. On the other hand high altitudes have more wind potential to produce more power. Another issue with the high altitude is low temperatures. Icing also expected in these sites. Due to these unpredictable behaviors, without any correction, sites at high altitudes will receive more uncertainty thus feasibility of the site will reduce or bad investment decisions can be made.

Air density is one the biggest parameter in power curve. Two methods have been studied and in both methods, power curve changed and power production has reduced. Air density correction to power curve should be applied during the AEP calculations, by applying air density correction, uncertainty will reduce because power curve after correction becomes more realistic and more representative for the site.

REWS has studied with calculated data in this study. Although, in literature, power production increases, in our study power production reduces. This result was not expected but considering using extrapolated data, it can be accepted and ignored. Because, atmospheric stability is not studied and logarithmic law is not representative for this site. Also there was no good correlation with power law too. According to these information, this REWS study for this site is not representative and should be ignored or supported with tall mast or RSD measurements above hub height.

Literature data has been reviewed for the dust and insect accumulation and leading edge erosion. During the planning phase dust accumulation might be considered if the site is located around desert but it is really hard to do that for insect accumulation. In both cases O&M strategies are really important because both effect can be avoided by blade cleaning. On the other hand leading edge erosion is expected in years. Preventive actions can be taken during the operations but if erosion has observed, it is unavoidable. It is important to have good O&M management in order to keep production level stable during the operation. Yet, it is hard to implement those effects to power curve during the AEP calculations to reduce the uncertainty but signs of those effects can be tracked to avoid power loss and even severe results.

Icing is relatively new subject for the wind farms. Currently there is no accepted icing model, icing correction, de-icing or anti icing method is available. Most of the studies are adopted from aviation studies. That's why it is not possible to make any correction to reduce uncertainty in AEP but if icing periods and severity can be known, than it can be taken into account in AEP. By studying icing mechanisms and characteristics well in the site, uncertainty can be reduced.

Wind energy is still under development and there are still much way to accomplish the difficulties. Those problems are not only arise due to nature itself but also new technological developments, new methods and even due to market pressure. Turbine manufacturers provides power curves and developers calculates AEP to make feasible investment. Yet, due to high pressure on the market, power curve has many definitions. Such as theoretical power curve, guaranteed power curve, site specific power curve, measured power curve, actual power curve and etc. and each power curve gives different result in AEP that's why uncertainty due to power curve contributes more than any other parameter. In this study site specific power curve and uncertainty due to power curve in AEP and possible methods to reduce the uncertainty is studied. By using several methods to NREL 5MW wind turbines power curve, shifting effects are observed on power curve. Shifting in power curve effects AEP results and more realistic power curves reduces the uncertainty comes from the power curve. By validating those models with real wind turbine output, more realistic models can be obtained and applied to theoretical power curve to reduce uncertainty and get more realistic AEPs with better P90 statistical results. Main purpose is to obtain realistic power curve with using models for the properties that have effect on power curve and reduce the standard deviation between model and real power curve. If a model can be validated to use for determine site specific power curve than standard deviation of the power curve between real power curve and modeled power curve will reduce and if standard deviation of the power curve reduces, uncertainty that comes to AEP from power curve will also reduce. As a result of it more realistic and reliable AEPs and financial models can be used for the wind farm investments. By doing that both investors and financial resources will be protected. Also having realistic power curve helps to early diagnose any fault in the wind turbine.In this study, air density effect, rotor equivalent wind speed, aging and structural fatigue and icing has studied. Our theoretical findings shows that atmospheric parameters have significant effect on power curve and thus on to AEP. Those shifting effects have to be considered during the modeling phase. Since there is no available turbine power output data with corresponding measurement data, standard deviation for updated power curves can not evaluated in this study but for further studies validating acquired results with real wind turbine output will reduces the uncertainty in AEPs that comes from wind turbine power curve. Finally, it is important to update power curve to get realistic power curve during the modeling phase because even slight reduction in uncertainty in AEP calculations will have significant effect on P75 or P90 calculations and this calculations will determine the financial models. Having a realistic financial model means profitable and sustainable wind power plants, better future for us all.

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