Wind energy potential assessment & cost analysis of a wind power generation system at Búrfell.

Birgir Freyr Ragnarsson

Faculty of Industrial Engineering, Mechanical Engineering and Computer Science.
University of Iceland
2014

WIND ENERGY POTENTIAL ASSESSMENT & COST ANALYSIS OF A WIND POWER GENERATION SYSTEM AT BÚRFELL.

Birgir Freyr Ragnarsson

30 ECTS thesis submitted in partial fulfillment of a
Magister Scientiarum degree in Industrial Engineering

Advisors
Rúnar Unnþórsson
Guðmundur Valur Oddsson
Birgir Hrafnkelsson

Faculty Representative

M.Sc. committee

Faculty of Industrial Engineering, Mechanical Engineering and Computer Science.
School of Engineering and Natural Sciences
University of Iceland
Reykjavik, June 2014

Wind energy potential assessment & cost analysis of a wind power generation system at Búrfell.
Wind energy potential at Búrfell
30 ECTS thesis submitted in partial fulfillment of a M.Sc. degree in Industrial Engineering

Faculty of Industrial Engineering, Mechanical Engineering and Computer Science.
School of Engineering and Natural Sciences
University of Iceland
Hjardarhagi 2-6
101, Reykjavik, Reykjavik
Iceland

Telephone: 525 4000

Bibliographic information:
Birgir Freyr Ragnarsson, 2014, Wind energy potential assessment & cost analysis of a wind power generation system at Búrfell., M.Sc. thesis, Faculty of Industrial Engineering, Mechanical Engineering and Computer Science., University of Iceland.

Printing: Háskólaprent, Fálkagata 2, 107 Reykjavík
Reykjavik, Iceland, June 2014

Abstract

Wind energy harnessing is a new energy production alternative in Iceland, current installed wind power in Iceland sums up to 1.8 MW which in contrast is 0.1 % of the countries total electricity production. This thesis is dedicated to researching the potential cost of wind energy production in Búrfell (Iceland). A Levelized Cost of Energy (LCOE) approach was applied when estimating the potential cost and the wind energy potential at the site was assessed using a new wind Monte Carlo simulation approach based on historical wind data and autocorrelation effects in wind distribution. Wind energy potential assessment revealed that capacity factor at Búrfell is 40.13 % on average and that E44 wind turbines from Enercon produced significantly more energy at Búrfell on average than estimated by power curves. Key results were that the LCOE for wind energy at Búrfell was estimated 0.0756-0.0857 USD/kWh (assuming 10% WACC), which classifies Búrfell among the lowest LCOE sites for wind energy in Europe. As a conclusion the decision stands whether the estimated LCOE is low enough for wind energy harnessing to be profitable at Búrfell. This conclusion is considered to be an introduction to a further research.

Útdráttur

Vindorka er talin sem nýr möguleiki til orkuframleiðslu á Íslandi, uppsett vindafl á Íslandi í dag er samanlagt 1.8 MW sem samsvarar 0.1 % af orkuframleiðslu landsins. Þessi meistararitgerð er tileinkuð rannsókn á mögulegum kostnaði á framleiddu rafmagni með vindorku í Búrfelli. Notuð var LCOE aðferðafræði við mat á mögulegum kostnaði, mat á framleiðslumöguleikum vindafls í Búrfelli var gert með því að notast við nýja Monte Carlo hermunaraðferð sem byggir á gögnum yfir vindhraða og einnig fylgni í vindi á svæðinu. Rannsókn á mögulegri framleiðslu með vindorku á svæðinu leiddi í ljós að nýtnihlutfall E44 vindmylla í Búrfelli er 40.13 % að meðaltali. Einnig kom í ljós að E44 vindmyllur í Búrfelli framleiddu umtalsvert meiri orku en gefið var út af framleiðanda. Lykilniðurstöður voru að LCOE fyrir vindorku í Búrfelli var metinn á 0.0756-0.0857 USD/kWh (gert ráð fyrir 10 % WACC), sem setur Búrfell á meðal lægstu framleiðslustaða fyrir vindorku í Evrópu. Niðurstaða ritgerðarinnar setur fram kostnað í USD á kWh, þessa niðurstöðu þarf í framhaldi að meta frá því sjónarhorni hvort vindorka sé arðbær í Búrfelli. Kostnaðurinn liggur fyrir og mat á arðbærni vindorku í Búrfelli er sett fram sem tillaga að frekari rannsókn.

Contents

List of Figures

List of Tables

Acknowledgments

I would like to thank everyone who assisted me in the process of writing this thesis. Special thanks go to my advisors Rúnar Unnþórsson, Guðmundur Valur Oddsson and Birgir Hrafnkelsson who helped me define and develop this thesis, Birgir Hrafnkelsson especially for his guidance in the field of statistics. I would also like to thank Sascha Thorsten Schröder from the faculty of DTU and Margrét Arnardóttir at Landsvirkjun for their informative help.

All data used in this thesis is gathered from Landsvirkjun and the Icelandic Meteorological Office. I am grateful for their assistance, without their help the making of this thesis would not have been possible. The thesis was sponsored by Orkurannsóknarsjóður Landsvirkjunar, for their financial support I am truly grateful.

Last but not least I would like to thank my fiancée for her unlimited support during the writing of this thesis.

1. Introduction

Iceland can be ranked within the highest wind power class in Western Europe. This fact was published by the Icelandic Meteorological Office in 2013 and shows that wind resources in Iceland are among the highest available in Europe. The objective of this thesis is to conduct a wind energy potential assessment, followed by a levelized cost of energy (LCOE) analysis for a wind power generation system located at Búrfell in south Iceland.

Despite the fact that Iceland has high wind resources, wind energy harnessing has not been seriously considered in Iceland until recently Landsvirkjun energy company set up two wind turbines for testing located at Búrfell in the end of January 2013. With technological improvements and experience of wind energy production in conditions comparable to Iceland, wind energy has become a serious energy option for Iceland. Arguably the Faroe Islands have a similar climate to Iceland, 4 % of their total electricity is produced with wind, according to the Faroe Islands Wind Energy Association (FIWEA). Currently Iceland produces 71.8 % of its electricity with hydro power, 24 % with geothermal power, 4.1 % from fossil fuels and 0.1 % from wind energy. Icelandic electricity consumption is thus almost entirely powered by renewable energy (Orkustofnun, 2014).

Development of wind energy

Technological improvements in wind energy over the years are mirrored by the global growth in installed capacity. The global annual installed wind capacity experienced an exponential growth from the year 1996 to 2009. After 2009 the growth stabilized to a linear growth until the year 2012. USA and China are leading countries in new installed wind power capacity outside of Europe. In Europe, Germany, Spain and the UK were leading in new installed capacity in 2012 (GWEC, 2012).

Motivation and objectives

This thesis will be set up to answer two research questions.

1. What is the wind energy potential at Búrfell?
2. What is the levelized cost of energy (LCOE) produced by wind at the specific site?

The research motive is to analyze the potential and cost of harnessing wind energy at Búrfell. The final output of the research will be in the form of LCOE presented in USD/kWh which can be compared to LCOE of other wind energy sites in Europe.

Contributions

The thesis is a contribution to the research of wind energy in Iceland, more specifically the Búrfell site. The main contributions are listed in the bullets here below.

- The wind shear factor at Búrfell will be calculated using the power law equation. The power law describes the relation between wind speed in different heights. New wind speed data from Búrfell measured at 55 m height will be used to verify the power law at the Búrfell location.
- When estimating wind speed distribution at Búrfell, a new simulation approach will be applied and compared to a established approach used in the wind energy industry. The new simulation approach is referred as the wind Monte Carlo (MC) simulation.
- Estimated annual energy production (AEP) will be calculated for the Búrfell site and compared to actual measured AEP from the test wind turbines at Búrfell.
- New experienced cost data for wind power in Iceland will be used to estimate the LCOE for wind energy at Búrfell.

Scope of the research

The scope of the research is restricted to wind energy potential assessment and levelized cost of energy (LCOE) analysis. Within the scope is creating a capacity scenario for a wind farm at Búrfell. The assumption is made that the location Búrfell is the optimal location in Iceland for wind energy. Based on knowledge and research done by Landsvirkjun, Búrfell has been selected as the location for wind energy development in Iceland. Environmental rules and regulations are assumed to be approved by the government of Iceland and should thus not constrain the development of a wind generation system at the specific site. Soil stability and foundation requirements for wind turbines are out of scope of this study. Technical analysis of a wind farms electrical system are considered out of scope. Market analysis and power prices are not to be researched, but should be considered for further research. Profit is as known calculated by subtracting cost from sales price, this thesis has the aim of calculating the cost. Knowing the cost, one can state that the project will not be economically feasible unless sales price is higher than the cost. Thus in conclusion the LCOE will be presented as a break even price for the wind energy production. This study is considered to be a part of a complete wind feasibility study, and should not be considered as a full wind feasibility or integration study.

Methodology and data sources

The methodology applied to answer the research questions is acquired from two sources. The fundamental method follows recommended best practices for wind integration studies presented by the International Energy Agency for Wind (IEA Wind). On a more detailed level a method of analyzing wind farm feasibility presented by Wang et. al. will be used as guide to acquire the desired result of LCOE. For the wind energy potential assessment, two different methods will be applied. Firstly the Weibull distribution will be used to represent the distribution of wind at the site, this is a commonly used method in the wind energy industry. Secondly a simulation method will be applied to assess the distribution of wind at the site, this method relies solely on historical data at the site and creates a representative distribution of the wind at the site. This representative distribution of wind at the site is then used to calculate the potential wind energy production. Wind energy potential assessment is a crucial factor in evaluating the feasibility of wind energy projects, since the profitability is highly correlated with energy production output.

Data from Landsvirkjun and the Icelandic Meteorological Office will be used for the wind energy potential assessment. Landsvirkjun will also provide operational data that has been gathered from the beginning of 2013, from two test wind turbines located at Búrfell. The operational data will be used for reference in estimating potential power production as well as operation and maintenance cost (OPEX). The data used for potential wind energy production calculations in this thesis is new data that can not be presented in the thesis directly due to protection rights from Landsvirkjun. Cost data is provided partly from experience data gathered from Landsvirkjun and partly by data from international constitutions like IRENA and IEA Wind.

Structure of the thesis

In the next chapter a literature research is done on wind energy methodologies and status of knowledge in Iceland and Europe. The chapter that follows the literature research is about the methodology used as structure for this thesis. Followed by the method chapter is a chapter on theory applied in the wind energy industry, the most important equations and abbreviations are explained in that chapter. After the theory chapter there is a chapter about the design scope of the wind farm. This chapter includes explanation of selected location for the wind farm, including a wind data analysis and selection of the wind turbine to be used for the wind generation system at Búrfell. Chapter six is dedicated to wind energy potential assessment where two simulation methods are applied to estimate wind speed distribution at Búrfell. The resulting estimated wind speed at Búrfell is then used to calculate the estimated AEP and capacity factor at Búrfell, which represents the wind energy potential at the site. The final chapter is reserved for the cost analysis where the desired final output of the thesis, the LCOE of wind energy at Búrfell, is calculated based on estimated AEP at the site. The results and main contributions from the thesis are presented in the discussion and conclusion chapters at the end of the thesis.

2. Literature Research

A research of literature on the status and knowledge in the wind energy field in Europe and also within Iceland is presented in this section. Researches of wind resources and wind energy in Iceland are reviewed with the purpose of getting knowledge of the status of wind energy development in Iceland. European research about wind energy are also reviewed to gain knowledge of wind energy research methods. Experience data from Landsvikjun and Europe about cost of wind energy projects is reviewed at the end of this section, including a introduction to the standards used in wind energy.

To ensure robustness of the literature research, the following paragraph will explain the methods and search criteria used.

Search of documents for the literature research was conducted by using search engines such as the "Web of knowledge" and "leitir.is" which is operated by the consortium of Icelandic libraries. The search criteria was set to have "wind power" and "wind energy" included in the topic of the literature. Searching for the title of the literature was more complicated because of the fact that the phrase "feasibility study" of wind energy, apparently is defined in different ways in the academic world. Feasibility studies can be conducted on specific topics or sectors within wind energy projects, and thus they are not a "complete" feasibility study for wind energy projects as defined by IEA wind (see section 3.1) (Holttinen, 2013). In example several articles with "feasibility study" in the title were found that performed a study on wind resource feasibility at a specific site/s, disregarding cost of energy and other parts that are to be included in a feasibility study according to IEA Wind (Holttinen, 2013). More explanation on wind energy research and the IEA Wind feasibility study methodology can be found in the method chapter.

The search criteria for the literature title was in conclusion set to "feasibility study" or "cost analysis" or "break even analysis". These title topics were the most describing titles for what is to be researched in this thesis and gave sufficient literature data. The search disregarded articles published from the year 2000 and older, because of technological improvements in the field of study.

2.1. Wind energy research in Iceland

The Icelandic Meteorological Office published a report in 2013 about wind energy potential in Iceland (Nawri, Petersen, Björnsson, & Jónasson., 2013). The result showed that Iceland can be ranked within the highest wind power class in Western Europe. The wind power classes are defined by the European Wind Atlas published by Risø National Laboratory (Troen & Petersen, 1989). Wind power classes are listed by wind power density (W/m^2) over different types of terrain. The research also included an analysis of wind energy potential at several specific sites in Iceland, one of them being Búrfell. It is presented in the paper that one Enercon E44 wind turbine installed at Búrfell could produce 0.540 MW annually on average, which adds up to approximately 4730.4 MWh. These results were acquired using the Weibull distribution function as estimation of the wind energy potential (Nawri et al., 2013).

In May 2012 Kristbjörn Helgason published his master thesis with the title "Selecting optimum location and type of wind turbines in Iceland" (Helgason, 2012). The research presented the top ten optimal sites in Iceland for wind energy harnessing, Búrfell being on the list and Garðskagaviti in the southwest corner of Iceland being number one. The decision making criteria between sites was expected annual energy output in GWh, capacity factor, and cost of energy. The Weibull distribution function was used to generate a representative year for each site from historical wind data. The sites investigated were 48 in total and a total of 47 wind turbine power curves were researched. In general the result of this research concluded that wind resources were feasible for wind energy in Iceland, but the cost per kWh was too high at Garðskagaviti to be competitive with other renewable energy sources in Iceland. This conclusion was based on a cost analysis using a certain 3 MW turbine at Garðskagaviti, this combination of site and turbine type was according to the research economically optimal. Several cost assumptions were included, as well as a sensitivity analysis was not conducted since it was out scope of the thesis . The cost data was from the European Wind Energy Association (EWEA), no experience cost data from wind power in Iceland was available at the time.

The potential in combining hydro and wind power has been noticed in Iceland. The trend of a typical hydro-logical and meteorological year for water discharge and wind speed noticeably balances each other out in terms of power generation potential. The wind has at maximum power generation potential at winter time while hyro at summer time. This was presented in 2011 when Karol Strak published a research which was a part of a pre-feasibility study of combined wind and hydro system in Iceland. The research was done for hypothetical hydropower plant facilities at Hólmsá River with reservoir at Atley and a hypothetical wind farm at Vatnsfell both located in south Iceland. Results showed positive implications in the combination of hydro and wind but insisted that further research was needed on the matter (Strak, 2011).

The option of a wind pumped storage system has also been researched in Iceland. A system where wind power is used to pump water from lower reservoir to an upper one, with the purpose of increasing the electricity production in a hydropower plant. This research was presented in 2010 by Árni Vignir Pálmason. The main conclusion of the research was that the wind pumped storage system was not considered economically feasible (Pálmason, 2010).

2.2. Wind energy in Europe

Literature research revealed that the word "feasibility study" is used in some cases with different methodological approaches when assessing wind energy, as mentioned before. Therefore a literature research was done on wind energy projects in Europe, with the motive to research what methods and approaches are used in European wind energy projects.

The development of wind energy has been rapid in recent years, Denmark is one of the leading wind energy developers in Europe. The wind power generation related to net power generation in Denmark has increased from 20 % in 2008 to 35 % in 2012. The danish government has set the goal to increase the share of wind power to 50 % by the end of 2020 (Nielsen, Thyregod, & Glar, 2012). Thus encouraging wind energy development even more. Recently improvements have also occurred in the development of wind energy in cold climates. In 2012 the International Energy Agency (IEA) for Wind, published a report about the state of the art wind energy in cold climates, where knowledge on technical solutions and operational experience of wind turbines in cold climates was presented among other topics. Currently a selection of wind turbines that can operate under cold climate conditions are available, these turbines can include anti- or de-icing systems if conditions require (Peltola, 2012).

Wang et. al performed a feasibility study of a wind power generation system located at the Arctic Valley in Anchorage Alaska in 2010. The feasibility study was set up with three main goals. The first goal, was to perform a wind resource analysis and thus determine whether there was enough wind at the specific site. Second goal, to perform a economic analysis of the wind generation system. In this study a After Tax algorithm was used. Additionally the third goal, to determine sensitive factors in the analysis, hence a sensitivity analysis (Wang et al., 2010). A flow chart of the research process was presented in the paper. This flow chart (see Figure 3.2) is used as a part of a methodological structure for the wind power generation system resource and cost analysis. Further explanations on the method can be found in section 3.2.

Another paper on wind energy also published in 2010, written by Akdağ and Güler was about wind energy investment interest and electricity generation cost analysis for Turkey. Wind resources were analyzed in several sites in Turkey, as well as a economic cost analysis for electricity produced by wind power. This paper was not set up specifically as a feasibility study, but performed two of the main topics of interest, wind energy potential and cost analysis. The paper, concluded that the average wind power capacity factor for the top sites in Turkey was 41.9%. Compared to an average of below 21% in other European countries from 2003 to 2008. The capacity factor is explained as the ratio between average power output and the rated power output of a wind turbine. For wind energy potential assessment, the Weibull distribution function was used to describe the behavior of the wind at the specific sites (Akdağ & Güler, 2010).

A good example of a wind energy potential research was published by Saeidi et al. in 2011 (Saeidi, Mirhosseini, Sedaghat, & Mostafaeipour, 2011). The article is about analyzing the wind energy potential at two sites in Iran, north and south Khorasan. In the study wind speed measurements were done at 10 m, 30 m, and 40 m heights. The wind direction was also measured in order to be able to find the optimal positioning of a wind farm at given sites. Wind rose analysis was used to show the prevailing wind directions. Turbulence at the site was analyzed because of the fact that existence of turbulence decreases the potential power production of wind turbines. Moreover it causes fatigue stress in wind turbines which effects OPEX cost and lifetime of them. Again the Weibull distribution was used to estimate the wind speed distribution at the sites. Power and energy density calculations were as a conclusion used to determine the wind power potential at the sites. Wind power density (W/m^2) demonstrates how much energy is available at a specific site for conversion to electricity by a wind turbine (Saeidi et al., 2011).

Because of an uncertainty in the meaning of a "feasibility study" it is considered essential to describe in detail the methodology conducted in this thesis. This thesis will conduct a wind energy potential assessment at the specific site Búrfell in Iceland, followed by a cost analysis of wind power generated by a wind farm at the site. This research can be considered as a part of a feasibility study, not a complete feasibility study. The methodology of the study is described in the method section.

2.3. Cost of wind energy in Europe vs. Iceland

The International Renewable Energy Agency (IRENA) published a report in 2012 on cost of wind power. It explains that wind energy like other renewable energy options is capital intensive. The main parameters in cost calculations for wind power were presented as: Investment cost (CAPEX), Operation and Maintenance cost (OPEX), Capacity Factor (CF), Economic Lifetime and Weighted Average Cost Of Capital (WACC). The key findings in the report showed that wind turbines account for 64-84 % of total installed costs of onshore wind farms. The rest of the cost is covered by grid connection cost, construction cost and other cost. The OPEX cost was presented as 11-30 % of wind farms levelised cost of electricity (LCOE), which can be explained in simple terms as present value of total costs divided by the lifetime energy production of the wind farm. The LCOE for wind power is dependent on the wind resource at each site and the wind project cost. The typical onshore wind power system and turbine was broken down in the report (IRENA, 2012). Capital cost breakdown is shown on Figure 2.1, it shall be noted that source data is gathered from 2009 (Blanco, 2009).

Capital investment cost (CAPEX) per kW and the operation and maintenance cost (OPEX) per kWh, for onshore wind power systems in European countries assessed by IRENA in 2012, is presented in table 2.1.

Table 2.1.: Table over wind power cost data gathered from IRENA.

IRENA cost data	Onshore	Offshore
CAPEX [USD/kW]	1700 - 2450	3300 - 5000
OPEX [USD/kWh]	0.013 - 0.025	0.027 - 0.048

Experience cost data from Landsvirkjun was available due to the test project launched in the beginning of 2013. This test project included two Enercon E44 wind turbines installed at Búrfell. The total capital cost (CAPEX) of the project was 4.012 million USD and the operation and maintenance cost (OPEX) was 0.015 USD per kWh. The CAPEX per kW is shown in table 2.2, notice that the cost for the Landsvirkjun test project is within the cost interval for onshore wind projects assessed by IRENA in table 2.1. The OPEX was also within the European interval close to the lower limit, which can be explained by the fact that the E44 is gearless and thus they have low OPEX. The capital cost breakdown can be seen on Figure 2.2. Notice that the percentage breakdown is also very comparable to the European experience data from IRENA shown in Figure 2.1.

Table 2.2.: Table over wind power cost data gathered from Landsvikjun.

LV cost data	Onshore
CAPEX [USD/kW]	2229
OPEX [USD/kWh]	0.015

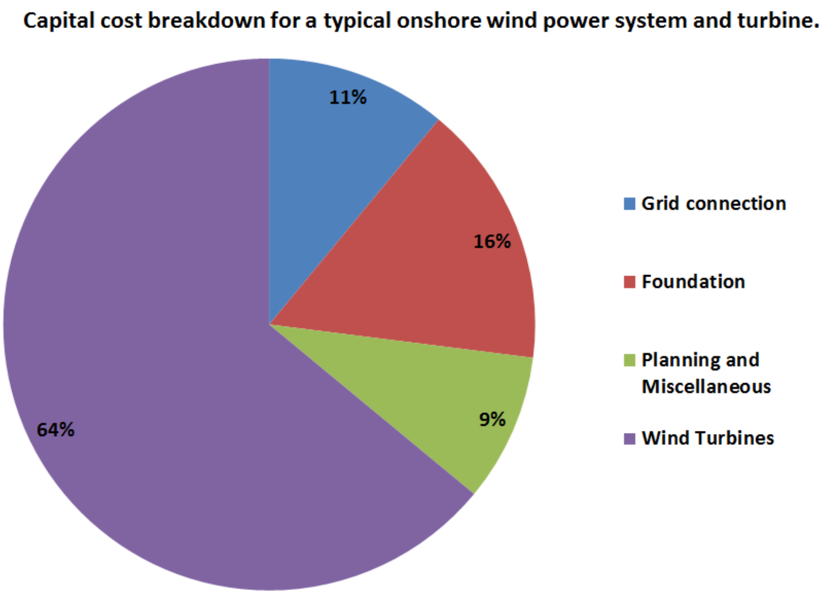


Figure 2.1.: Capital cost breakdown for wind power projects experienced in Europe (Blanco, 2009).

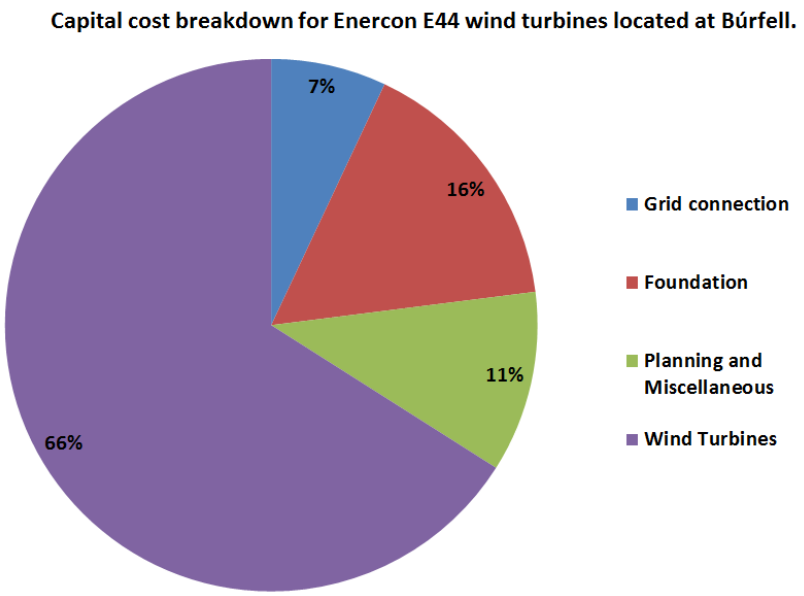


Figure 2.2.: Capital cost breakdown of the wind power test project at Búrfell (Landsvirkjun data).

Considerable economic of scale trend in wind projects in the United States from 2009 to 2010 was identified in the report. Projects under the size of 5 MW systems had considerably higher total installed cost than larger systems. However it is explained that there was not a linear trend identified. Findings showed that systems of the size of 5 MW or higher did not experience linearly decreasing costs with more installed power. The total installed cost per MW was similar for project in the 5-20 MW range as projects with 100-200 MW installed power (IRENA, 2012).

The Landsvirkjun test project had a total of 1.8 MW installed, the cost data from that project thus falls into the category of projects of size lower than 5 MW. The cost of 2229 USD per kW may thus be considered as a conservative estimate since research has shown that projects under 5 MW experience higher cost per kW than project with over 5 MW installed.

2.3.1. Levelized cost of energy (LCOE)

Levelized cost of energy (LCOE) is widely used as a cost reference in the wind energy industry. The LCOE is the price of electricity required for a wind energy project to break even, that is, setting revenues equal cost. The LCOE takes into account the weighted average cost of capital (WACC), thus does the LCOE include return on capital invested equal to specific WACC (sometimes referred as discount rate). The LCOE method is used in the cost analysis of this thesis, it is adapted from IRENA. The LCOE method uses a relatively simple cost estimation approach which has the advantage of being transparent and easy to understand. Because of the transparency and simplicity this LCOE approach can be used to compare LCOE of individual wind projects and other energy projects across countries. The difference in LCOE between projects should be reflected in the technological performance and resources at sites, not difference in methods (IRENA, 2012). More detailed explanation of the LCOE equation is found in section 4.9.

Cost of wind power is highly correlated to the respective capacity factor at production sites. The capacity factor is dependent to the characteristics of each production site, that is the quality of the wind resource and the technical qualifications of the wind turbine. The estimated LCOE of onshore wind in Europe was 0.08 - 0.14 USD/kWh in 2010 (see Table 2.3), this LCOE was estimated with the assumption of 10% WACC (IRENA, 2012).

Table 2.3.: LCOE in Europe assuming 10% WACC.

Europe	Onshore
LCOE [USD/kWh]	0.08-0.14

2.4. Standards in wind energy

Standards are important tools for engineering and management. This fact is symbolized nicely with a quote from the fictional retired Toyota manager in the book Andy & me, "...how can one manage without a standard" (Dennis, 2010).

The wind engineering standards represent widely accepted best practice methods regarding wind energy. The standard presents method for wind energy research and also, it include rules and regulation to be followed in wind energy production. For turbine manufacturers it is considered a business advantage to have standard certified wind turbines. When it comes to business decision making in wind energy projects, standards can provide certifications that are more easily understood than lengthy design reports. The rules presented in standards are deliberately simplified, they reflect reality but often they are conservative estimations of the reality (Berg, Mann, & Nielsen, 2013).

The standard that will be focused on in this research is from the International Electrotechnical Commission (IEC). It is a standard for wind turbine safety called the IEC 61400-1 standard. The standard covers structural, electric and control aspects, in this research the focus will be on the wind related aspects. The standard is set up so that wind turbines are classified to tolerate certain limits of which the manufacturer has the responsibility. It is however the responsibility of the project developer to research his site specific limits and match them by selecting the correct wind turbine class (Berg et al., 2013).

The IEC 61400-1 standard has three turbine classes for maximum wind speed tolerance. Those classes are defined by the so called reference maximum wind, V_{ref}. The classes are set as class I with 50 m/s reference wind, class II with 42.5 m/s and class III set to 37.5 m/s as the reference maximum wind speed at the specific site. This maximum wind speed should represent the maximum wind over 50 year period, if measurements are not available the standard provides approximation methods. The wind turbines are also classified after reference turbulence intensities (I_{ref}). These classes are named A, B and C, with turbulence intensity set to 16 %, 14 % and 12 % respectively. The standard sets the rule that measured turbulence should be the mean turbulence over a random 10-min period with a mean wind speed of 15 m/s. These two classes define the wind turbine, manufacturers use them as quality measures to promote their products.

2.5. Summary

Wind energy research in Iceland has increased noticeably over the past years. Wind resources have mostly been analyzed by the Icelandic Meteorological Office. Wind energy potential research has been performed at the Búrfell site, but without comparison to measured data or LCOE analysis. The Weibull distribution is the most widely used distribution in Europe to describe wind speed distribution at wind energy project sites. Cost distribution of installed wind capacity in Iceland proved to be highly comparable to cost distribution in Europe. LCOE analysis approach is recommended the best practice by IRENA for cost analysis of wind energy projects because of its transparent simplicity, and because it is comparable between countries and technologies.

3. Wind energy research methodology

In this chapter the methodology used for the structure of the research will be described. The methodology used, consists of a combination of recommended best practices for wind integration studies (Holttinen, 2013) from the International Energy Agency for Wind (IEA Wind), and a research method used for wind farm feasibility analysis in Alaska, published by the University of Alaska (Wang et al., 2010).

3.1. IEA Wind methodology

The IEA has a department devoted to wind energy, all material published on wind energy is therefore referred as IEA Wind material. Founded in 1974, this organization which includes 20 member countries (including DK, GER and USA for e.g) is a forum for international discussion of research and development issues regarding wind energy. In the annual IEA Wind report from 2012, there are recommendations of best practices and instructions on how to perform a wind integration study. A wind integration study is a reference to a research performed with the purpose of investigating the potential in setting up a wind energy generation system at a specific site. Complete wind integration studies include several researches and analysis, usually including an iteration process. Wind research studies therefore often only include one or few parts of the complete study. The best practice method for a complete wind integration study is described with a flow chart displayed on Figure 3.1 (Holttinen, 2013).

The flow chart shows necessary inputs, simulations and iteration loops recommended to perform in a wind integration study. This method is built on the experience from previous studies done by IEA member countries. The starting point of a wind integration study is with a set of input data. This data includes the location of the wind generation system, wind resources and the general situation of the power system that is to be examined. These objectives are defined in the blue boxes in Figure 3.1, this is where the scope of the study is determined.

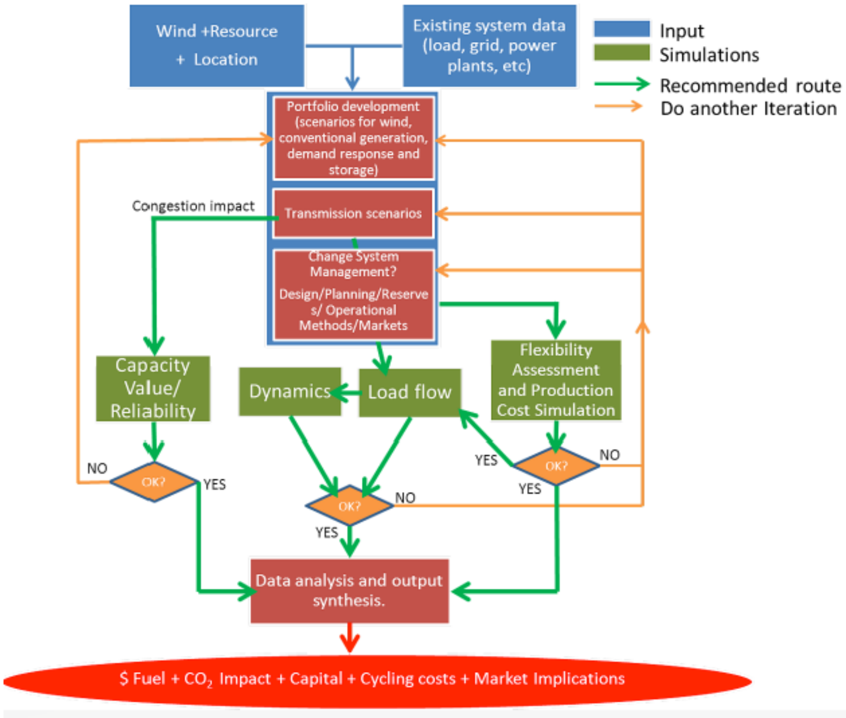


Figure 3.1.: Flow chart of a complete wind integration study according to IEA Wind (Holttinen, 2013).

Next steps are portfolio development, transmission scenarios and system management. The portfolio development is a detail setup of the system to be studied, present or future. Here demand and flexibility in the power system is analyzed, as well as interconnection options to neighboring areas. The objective is to answer the question of how wind power is added to the general power system, whether it is replacing some other energy source or adding to the energy generation. System management and transmission scenarios are to be checked as well as the flexibility available in the system. Check if the system is ready to accommodate large amounts of wind power for example. This part of the study also includes profitability analysis of the wind generation system design.

The complete wind integration study also includes detailed investigation of transmission capabilities of the power system involved. Referring to the green boxes in Figure 3.1 this includes simulation of operating power plants in the system as well as calculations of the capacity adequacy to peak load situations. If the wind generation system has high capacity, then dynamic simulations and flexibility assessments are also to be made. This is done for the purpose to check if changes are necessary on the transmission grid or operational methods.

Interpretation and analysis of the results from a wind integration study is a complex task. According to IEA Wind, data analysis and output synthesis should include: fuel cost, CO_2 impact analysis, Capital, cycling cost and market implication analysis (circled red in Fig. 3.1).

The cost calculation of a wind integration study has a level of complexity on its own. First there is the investment cost of wind turbines and other cost related to the actual wind farm. Secondly there are other costs like transmission grid cost, costs of grid upgrades if needed, and other incremental power system costs. This cost is difficult to derive because of the fact that upgrades to power systems benefit other users than wind energy as well. Additionally there is the operational cost which excludes investment cost of power plants. Operational cost can be divided to market cost and technical cost, market cost includes transfer of money from one to another while technical cost is associated with the cost of integrating wind to the power system. Most studies have been done on the technical cost of wind integration. Another option is to assess the benefit of adding wind power to the power system which can be assessed with the reduction of operating cost and emissions due to replacement of fossil fuels. The fuel cost and CO_2 emission analysis has the goal of explaining the cost savings of wind replacing fossil fuels and the emissions from them. This description is the international approach, which does not apply for Iceland for the reason that no electricity in the power system is generated using fossil fuels.

The focus in this study will firstly be on part of the inputs for a wind integration study, which are wind, resource and location. Secondly a cost analysis of the wind generation system exclusively. This data will be analyzed with the prospective output of levelized cost of energy (LCOE) per kWh produced by wind power at Búrfell. The cost analysis will be a technical analysis according to IEA Wind, disregarding market costs and fuel cost including a CO_2 emission analysis.

As a conclusion it can be seen that this study only includes the wind, resource, location and levelized cost of energy (LCOE) analysis parts of the whole IEA Wind integration study. This study is therefore not considered as a full wind integration study or a full feasibility study. The study is conducted as a part of a wind integration study or a feasibility study, that can be used as input for a complete study.

3.2. Decision making methodology

The process from selecting a location and conducting a wind data assessment to calculating the estimated cost of energy per MWh, will be conducted according to the methodology presented in Wang et al. thesis, see Figure 3.2 (Wang et al., 2010). The process is described from designing the scope of a wind farm to a final decision based on economical analysis criteria of the wind farm.

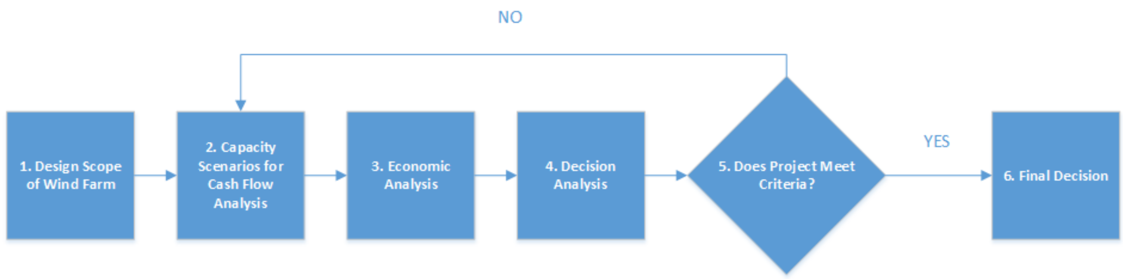


Figure 3.2.: Research methodology (Wang et al., 2010).

The first step in the analysis was set to define the scope of the wind farm. This includes selecting a location, wind data analysis, prevailing wind direction analysis, wind turbine selection and calculation of capacity factor at the specific site. The second step is to set up a scenario for the wind farms capacity for a cash flow analysis. This is followed by the economical analysis, including the economic criteria in the Wang et. al. case of study. A After Tax model was used and life cycle costs were calculated. After economical calculations a decision analysis can be performed including a sensitivity analysis. In this thesis however a LCOE approach will be used for the economical analysis. The fifth step is to conduct if the project meets economic criteria, if not, capacity scenarios should be reconsidered in step two and calculations iterated. If the project meets economic criteria a final decision can be made (Wang et al., 2010). The final two steps are not included in the scope of this thesis and are considered as a future research.

The research methodology presented by Wang et al. (2010) will be followed in this thesis except for one alteration. The economical analysis will be performed with an LCOE analysis approach presented by IRENA. See section 4.9 for further detail on the LCOE approach.

3.3. Summary

The IEA Wind organization presents best practice instructions of what is to be included in a wind integration study. This study is conducted as a part of a wind integration study or a feasibility study, that can be used as input for a complete study. On a more detailed level a research methodology presented by Wang et al. (2010) will be used as structure of the analysis done to get answers to objectives, except for one alteration when it comes to the economical analysis. This thesis will use a LCOE analysis approach instead of the cost analysis methods presented by Wang et al (2010). In the next chapter the theory applied in the thesis will be illustrated.

4. Theory in wind energy

In this section the theory applied in the thesis will be presented. Theories in wind speed distribution will be explained and two methods for wind speed estimation will be introduced. One being the Weibull distribution method and the other a simulation method based on historical data. The Weibull method is an established method in the wind energy industry, the other method is new and may be considered as a contribution to the research of wind energy. The theory applied when calculating the wind shear factor, AEP and capacity factor including explanations of availability of wind turbines, is illustrated in this chapter.

4.1. Wind speed distribution analysis

Estimation of wind speed distribution will be done with statistical methods and simulation. One year of measured wind speed is not enough to represent the wind speed distribution at a specific site. Wind speed can differ from year to year and it is known that wind speed has seasonality, that is, higher wind speeds are measured in winter than in summer for example (Petersen, Birgisson, Björnsson, Jónasson, & Nína, 2011). Therefore the use of statistical distributions or simulation methods is more efficient for a representative wind resource assessment at the specific site. Literature research revealed that the Weibull distribution function was used in many cases of wind speed distribution assessments (Akdağ & Güler, 2010; Mostafaeipour, 2010; Pantaleo, Pellerano, Ruggiero, & Trovato, 2005; Saeidi et al., 2011). The Weibull distribution was also used when generating the European Wind Atlas, which contains a collection of the Weibull shape and scale parameters for different sites all over Europe (Troen & Petersen, 1989). Moreover is the Weibull distribution function considered as a key tool in wind resource assessment, where the main goal is to estimate the mean annual energy production (AEP) (Berg et al., 2013).

In this research two methods will be applied when estimating wind resources at the specific site. Firstly the Weibull distribution method will be applied, an established method in the wind energy industry. Secondly a simulation method will be used where the data is analyzed and a representative distribution of the wind resource at the site is generated, based solely on historical data at the site. This method was developed in collaboration with Birgir Hrafnkelsson and will be referred as the wind Monte Carlo (MC) simulation method in this thesis.

The reason for applying two different methods for the wind resource assessment is for the fact that the cost of energy analysis (LCOE) is based fundamentally on the wind energy potential assessment. The cost of energy is highly dependent on energy production, which is essentially based on wind resources in the case of wind energy. To generate a good cost of energy assessment for the Búrfell site, the wind energy potential assessment is key. Applying two methods and comparing them to measured data at the site will show which of the two gives better estimate of potential energy production. One method is established in the wind energy industry and the other method is based on statistical experience of professor Birgir Hrafnkelsson.

4.1.1. Weibull simulation method

The probability density function of the Weibull distribution is given by (Gelman, Carlin, Stern, & Rubin, 2004),

$$p(\theta) = \frac{A}{k^A}\theta^{A-1}\exp\left(-\left(\frac{\theta}{k}^A\right)\right) \tag{4.1}$$

where A is the shape parameter and k is the scale parameter ($A > 0, k > 0$). The mean and variance of the Weibull distribution function is given by (Gelman et al., 2004),

$$\mu = k\Gamma\left(1 + \frac{1}{A}\right) \tag{4.2}$$

$$\sigma^2 = k^2\left[\Gamma(1 + \frac{2}{A}) - (\Gamma(1 + \frac{1}{A}))^2\right]. \tag{4.3}$$

Different methods can be used to determine the shape and scale parameters of the Weibull distribution function. There are analytic and empirical methods available used to find the Weibull parameters, they are often referred to as classical methods. Other methods match the average wind power density and the occurrences above average wind speed to the Weibull distribution (Nawri et al., 2013). Discrepancies can appear between measured and statistical distributions. However because of measurement errors, under sampling or lack of data the statistical distribution may be considered as a more representative for the long term compared to a sample of measured data (Nawri et al., 2013). In this research the built in Matlab function $wblfit$ will be used to estimate the Weibull shape and scale parameters.

4.1.2. Wind Monte Carlo (MC) simulation method

The wind MC simulation method applied in this thesis was introduced by professor Birgir Hrafnkelsson. The method is based on his experience in Bayesian inference. Essentially the method is fairly simple and its foundation is historical data. The minimum amount of historical data for this method is 10 years data. In stead of fitting the wind speed data to a known distribution like the Weibull distribution i.e, the method creates a distribution of wind speed at the specific site using solely historical data. This method assumes that history is likely to repeat it self, therefore i.e for one future year of wind speed data, a representative distribution can be created based on previous 10 year data or more. The method is described in more detail, with probability equations and the distribution generation in section 6.3.

4.2. Turbulence

Turbulence in wind can be explained as random wind speed fluctuations imposed to the mean wind speed. These fluctuations can occur in all tree directions, in the direction of the wind (longitudinal), perpendicular to the average wind (lateral) and vertical direction. Turbulence is generated with two different mechanisms, wind shear and heat convection. When high wind speeds occur, atmospheric conditions are called *neutral*, which means that thermally driven turbulence is negligible compared to wind shear. Therefore is turbulence generated by wind shear is primarily of interest in wind energy. Wind which includes turbulence may be constant over a period of an hour, but recorded in minutes it may be quite variable. Measurements of wind speeds are usually averaged over 10-min periods (Berg et al., 2013; Saeidi et al., 2011).

Turbulence intensity is defined by the ratio of standard deviation of the wind speed and the mean wind speed. In calculations short term fluctuations are usually ignored since mean wind speed is normally averaged over ten minute period (Saeidi et al., 2011). The turbulence intensity is defined as follows,

$$I_u(z) = \frac{\sigma_u}{U(z)} \tag{4.4}$$

where σ_u is the standard deviation of the wind and $U(z)$ is the mean wind speed at height z. Wind turbines are chosen according to site specific turbulence intensity I_u when following the International Electrotechnical Commission (IEC) standard (Berg et al., 2013).

4.3. Wake turbulence

Wake turbulence occurs from wakes from other neighbor wind turbines. The equation suggested by the IEC standard is a simplified version of Frandsens wake model (Berg et al., 2013; Frandsen, 2007),

$$I_{wake} = \sqrt{I_{added}^2 + I_u^2} \tag{4.5}$$

where I_u is the ambient turbulence and I_{added} is the added turbulence modeled by Frandsen. The added turbulence is given by (Frandsen, 2007),

$$I_{added} = \frac{1}{\left(1.5 + 0.8d/\sqrt{C_T(u)}\right)^2} \tag{4.6}$$

where, C_T is the wind thrust coefficient also modeled by Frandsen as (Frandsen, 2007),

$$C_T \approx \frac{3.5(2U - 3.5)}{U^2} \approx \frac{7m/s}{U} \tag{4.7}$$

and U is the wind speed and d is the distance to a neighbor turbine normalized by the rotor diameter (Frandsen, 2007).

4.4. Wind profile

In the wind energy industry, situations often occur where limited measurement data is available. In some cases the only wind speed data available for a specific site is measured several kilometers away. For those situations the Geostrophic Drag Law (GDL) can be used, if the site is within tens of kilometers that is. The GDL method was used when creating the European Wind Atlas (Berg et al., 2013; Troen & Petersen, 1989). Since measurements for Búrfell, the specific site under research are available, the use of the GDL will not be needed. The power law will be used to extrapolate the measured wind speed to the wind speed at the wind turbine hub height.

4.5. Power Law

Wind speed measured by typical weather stations are normally measured at 10 m height or lower. The problem with that is that within wind energy the wind speed measurements of interest are usually at 40 m heights or higher. To solve this problem wind engineering applications and the IEC Standard use the power-law. The power-law can be used when measurements at one height (usually called reference height) are available but measurements and wind turbine hub height are unavailable. In these situations the power-law is considered as a good approximation. The power law equation is given by,

$$U(z) = U_{ref} \left(\frac{z}{z_{ref}} \right)^{\alpha} \tag{4.8}$$

where U_{ref} is the measurement available at reference height, z is the turbine hub height, z_{ref} is the reference height and α is the wind shear exponent (normally between 0.1 and 0.2). According to the IEC standard the wind shear exponent can not exceed 0.2 and has to be positive. The standard sets these requirements to avoid enhanced fatigue damage and the risk of blade-tower interaction which can occur with negative shear (Berg et al., 2013).

The accuracy of the power law will be tested at the Búrfell site by comparing measured wind speed at 55 m height to extrapolated wind speed to 55 m height using the power law. This accuracy test of the power law is performed in section 6.1.1.

4.6. Annual Energy Production (AEP)

In wind energy potential assessments, the estimation of the mean annual energy production (AEP) is the main goal. To reach that goal, methods are used to estimate a representative year in wind resources at the research site, in this case, Búrfell. These are statistical methods that estimate from historical data the distribution of wind at the site. As mentioned above, this research will apply two different methods for wind potential assessment. These methods are the Weibull distribution method and a simulation method, both methods are explained here above.

The AEP is given by,

$$E = T \cdot f \int_0^\infty p(U)P(U)dU \tag{4.9}$$

where T is the time length of one year, f is the frequency, p(U) is the probability density function (pdf) of the wind speed, and P(U) is the power curve of the selected turbine for the site (Berg et al., 2013).

When calculating the AEP, losses have to be taken into account, losses are deducted from the net AEP. The fundamental losses that need to be considered occur during production and transportation, they are called wake loss, availability loss and transmission line losses (Djamai & Merzouk, 2011). Wake loss is from wake turbulence, that is turbulence from wakes of neighbor turbines (Frandsen, 2007). Availability loss is explained by the time the turbine is available for energy production, transmission line losses occur when energy is transmitted.

4.7. Capacity factor

The capacity factor (CF) is a ratio of actual energy produced by a wind turbine versus the energy that could potentially be produced by the wind turbine under constant perfect conditions. The capacity factor can be calculated according to equation 4.10,

$$CF = \frac{AEP}{P_N \times t} \tag{4.10}$$

where P_N is the nominal power of the wind turbine and t is the time length of one year typically measured in hours. The capacity factor is a good measure of the wind energy production potential (Wang et al., 2010). As a reference, the mean capacity factor for wind power plants in Europe from 2003 to 2007 was measured 21% (Akdağ & Güler, 2010). Because of technological improvements in the wind energy industry, this number is expected to have increased.

Full load hours (FLH) are also often used for quality measure of wind energy sites, along side the capacity factor. The full load hours are calculated as follows (Djamai

& Merzouk, 2011),

$$FLH = \frac{AEP}{P_N}. \tag{4.11}$$

4.8. Wind turbine availability

Availability of wind turbines is defined as the time which the wind turbine is available for power production, sometimes also called up-time. Wind turbines are always unavailable for a small fraction of the year because of mandatory maintenance. This fraction can however be increased because of unexpected malfunction. If no availability has been recorded for a specific site, the fraction is usually set to 3%, therefore it is assumed that the wind turbine is available 97% of the year (Djamai & Merzouk, 2011). If availability data has been recorded at the site under examination, recorded data should be used as reference.

4.9. LCOE equation

The LCOE method presented by IRENA is as mentioned a widely used measure of energy technologies. The LCOE approach uses simple discounted cash flow (DCF) analysis, thus taking into account the time value of money. In words the equation can be explained as present value of all costs divided by present value of all energy produced over project lifetime. Symbolically the equation is explained as follows,

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{4.12}$$

where n is the lifetime of the project in years, r is the WACC, E_t is the AEP in year t, F_t is fuel expenditure in year t, M_t is OPEX in year t and I_t is investment expenditures in year t or CAPEX (IRENA, 2012). Renewable energy project are in most cased capital intensive and fuel expenditure are low or zero, the WACC thus has critical effect on the LCOE assessment. The WACC is decided by project developer or the business behind the project. Landsvirkjun energy company uses WACC of 6 % for their energy projects for example.

4.10. Summary

The AEP calculation is the main goal of the wind energy potential assessment, the AEP is then used to calculate the LCOE of wind energy at Búrfell. The AEP at Búrfell however can not be calculated without estimating wind speed distribution at Búrfell. The estimated wind speed at Búrfell is simulated using two methods the Weibull and wind MC. AEP is calculated using simulated wind speed and the estimated power curve for selected wind turbine. Wind speed measurements can be extrapolated to desired turbine hub height using the power law. One year of measured wind speed at 55 m height has been recorded at Búrfell. This data will be compared to power law extrapolated wind speed from 10 m high measurements in the chapter 6 which is followed by a simulation of the wind speed at Búrfell. Next chapter will define the design scope of the wind farm at Búrfell including a statistical analysis of the wind at the specific site.

5. Design scope of the wind farm

In this chapter the steps of the wind research methodology retrieved from Wang et al. (2010) are followed. The methodology states that first of all the location of the wind generation system needs be selected. Next step is to analyze the wind speed measured at the specific site, this is done with a statistical analysis of the wind speed data. At the end of the chapter the wind turbine type for the wind farm is select including calculations of the prevailing wind direction and measured capacity factor at Búrfell.

5.1. Select location

According to the research methodology for wind farms presented in section 3.2 the first objective is to select the location for the wind farm. In the case of this thesis the wind farm location has been selected to be Búrfell, located in south of Iceland (see Figure 5.1). The selection is made based on the assumption that Búrfell is the optimal location for wind energy harnessing in Iceland. This assumption is made based on knowledge and researches made by Landsvirkjun and because of the fact that at Búrfell two 900 kW wind turbines have been set up for testing. The two test wind turbines are owned by Landsvirkjun and they are currently assessing the profitability of setting up a wind generation system at the site. This thesis is done as a contribution to the research of wind energy harnessing at Búrfell.

Figure 5.1.: Location of Búrfell in south Iceland (Maps, 2014).

5.2. Wind data analysis

The data needed for the wind energy potential assessment is wind speed and wind direction data gathered from Landsvikjun energy company and the Icelandic Meteorological Office. Landsvirkjun has recorded data from the two test turbines since the end of January 2013, this data includes wind speed and wind direction measurements at turbine hub height (55 m). The test wind turbines also provide availability (up-time) data from their energy production time, including their power production statistics from the end of January 2013. Due to copyright claims from Landsvirkjun, no raw data from Landsvirkjun will be published in the thesis.

Data from the Icelandic Meteorological Office is measured from a weather station in Búrfell located approximately 1 km from the test turbine site (see Figure 5.2). The assumption is made that the data from the two locations is comparable because they are fairly close to each other and the terrain does not change dramatically between them. Since the terrain does not change between the locations, factors that effect wind speed like surface roughness is arguably the same for both locations. The data from the weather station is measured at 10 m height and is recorded in 10-min average values. The measurements done at the weather station are wind speed, wind direction and temperature. Wind speed and direction data is available in 10-min average values from the year 2004 to 2014. Temperature data at the site is available from the year 1997 to 2013 and is recorded in hourly averages.

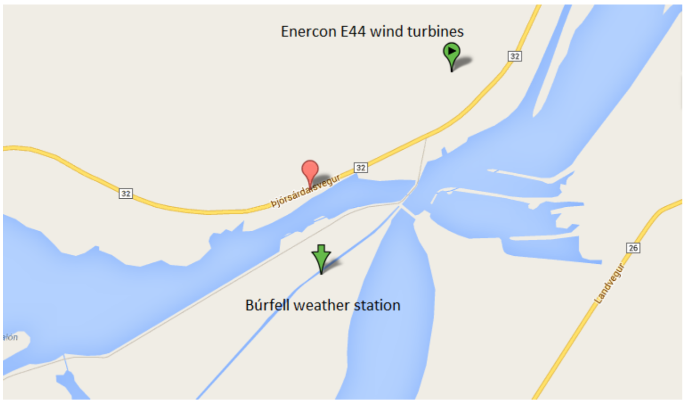


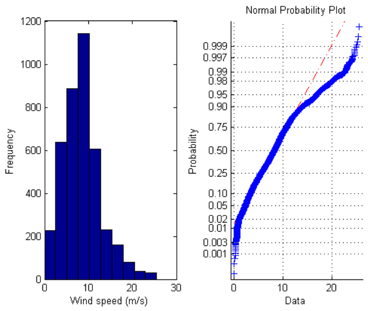
Figure 5.2.: Map of the Búrfell site, showing the weather station and the test turbines locations (Maps, 2014).

Missing data

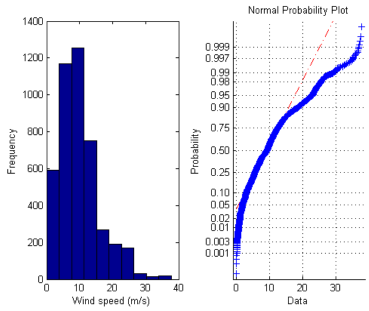
The data from Landsvirkjun did not include any missing data points or gaps. The data from the Icelandic Meteorological office however included some missing data due to malfunction in measurement devices. The amount of missing data points were however just a fraction of the total measured data. Missing data was linearly extrapolated when there was gap in data. For computational simplification, leap year days were eliminated from data thus setting all year with equal lengths.

5.2.1. Statistical behavior of wind speed data from Búrfell

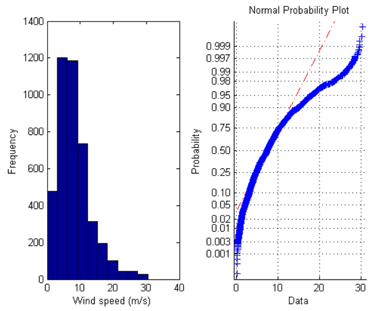
To examine the statistical behavior of wind speed data, data from 55 m height gathered from Landsvirkjun was used. The wind speed was measured at hub height of the E44 wind turbines and is recorded in 10-min average values. The distribution of the wind speed data is presented by histogram plots on Figure 5.3. Histogram of wind speed data from each month of the year from February 2013 to January 2014 at Búrfell is displayed, months are dived from a) to l). Along side the histogram plot is a normal probability plot, which shows clearly that the data is not normally distributed. Notice that the histogram plots show that the distribution is in basis similar for every month but not exactly the same. The distribution shows resemblance to the Weibull distribution with the high peak and a long tail. However it shall be mentioned that fitting one Weibull distribution for a whole year would seem unreasonable, hence the difference in histogram plot between months. The difference in wind speed distribution between months is an unsurprising result since it has been pointed out that seasonality occurs in wind speed data. Higher winds occur in the winter compared to the summer, this can be seen in data and was also confirmed in a research from the Icelandic Meteorological Office (Petersen et al., 2011).



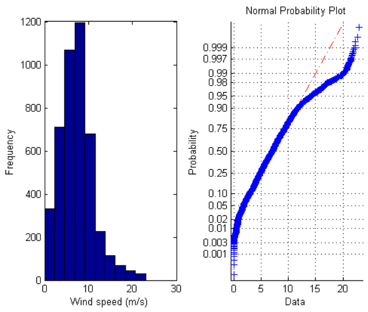
a: Histogram and normal plot of February 2013.



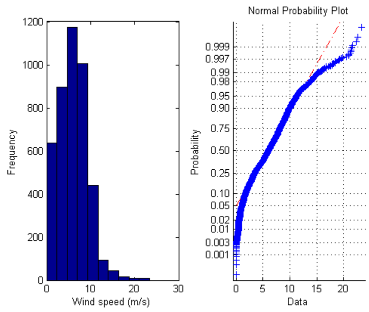
b: Histogram and normal plot of March 2013.



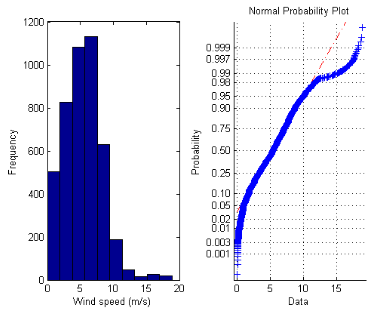
c: Histogram and normal plot of April 2013.



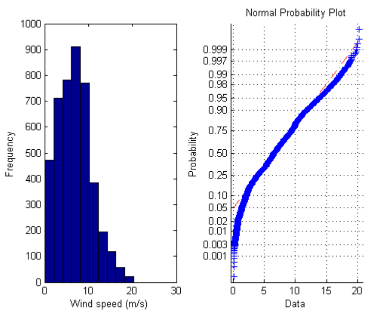
d: Histogram and normal plot of May 2013.



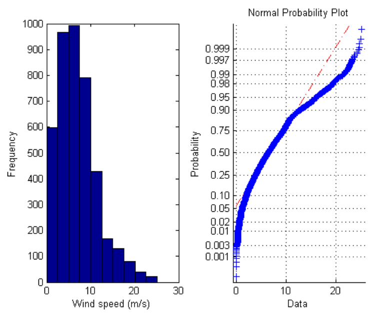
e: Histogram and normal plot of June 2013.



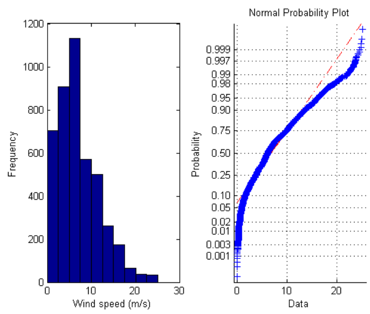
f: Histogram and normal plot of July 2013.



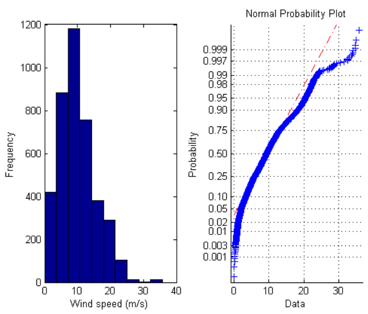
g: Histogram and normal plot of August 2013.



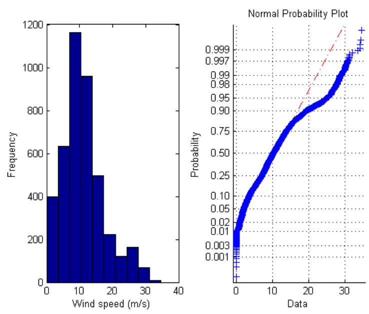
h: Histogram and normal plot of September 2013.



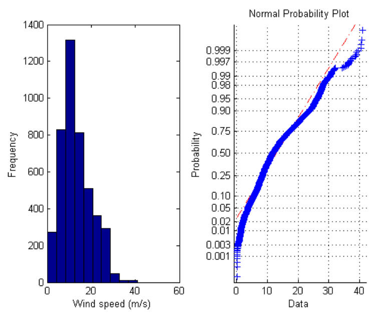
i: Histogram and normal plot of October 2013.



j: Histogram and normal plot of November 2013.



k: Histogram and normal plot of December 2013.



l: Histogram and normal plot of January 2014.

Figure 5.3.: Histogram and normal probability plot of wind speed data measured at 55 m height for each month from February 2013 to January 2014.

5.2.2. Autocorrelation in wind data

Autocorrelation in wind data was checked in each month for one year at Búrfell and is presented in Figure 5.5, months are divided from a) to l). The same data is used as in the previous section. One year of data was considered sufficient to conclude on autocorrelation in the wind at the specific site. Figure 5.5 presents autocorrelation in wind data from each month of the year, starting in February 2013, with 2 week time lag which adds up to 2016 lags. Rejection lines for autocorrelation are calculated as $\pm\frac{2}{\sqrt{N}}$, where N is the number of data points. This rejection criteria is set with the assumption that the data is normally distributed. From Figure 5.3 it can be seen that the data is not normally distributed. However, the calculated autocorrelation which is based on dividing sums of the data is heading towards normal distribution according to the central limit theorem (Brosamler, 1988). Therefore the assumption for rejection line criteria holds.

The autocorrelation function (ACF) is defined by,

$$\rho_{XX}(\tau) = \frac{\gamma_{XX}(\tau)}{\sigma_X^2} \tag{5.1}$$

with the assumption that the process is stationary $\rho_{XX}(\tau)$ is the ACF with τ defined as time difference $t_2 - t_1$. The γ_{XX} is the autocovariance function and σ_X^2 is the variance of the process (Madsen, 2008). However from Figure 5.4 it can be seen that the data is not a strictly stationary process. It is hard to notice in Figure 5.4 but there is a seasonality wave in the data. This seasonality could be removed from data by calculation manipulations like fitting sinus curves or using averaging method. In this thesis however a rough cut analysis on the autocorrelation is considered sufficient and thus the data will be used as it is.

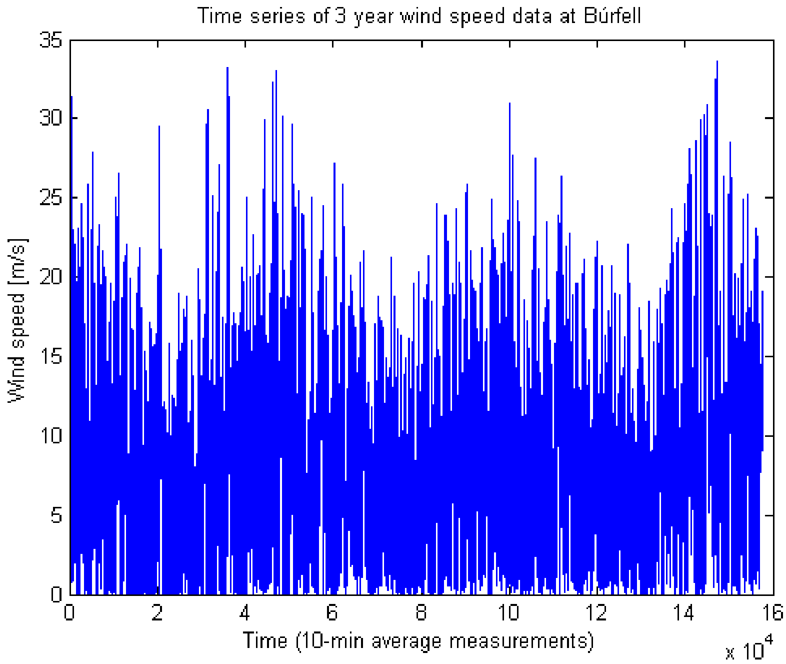
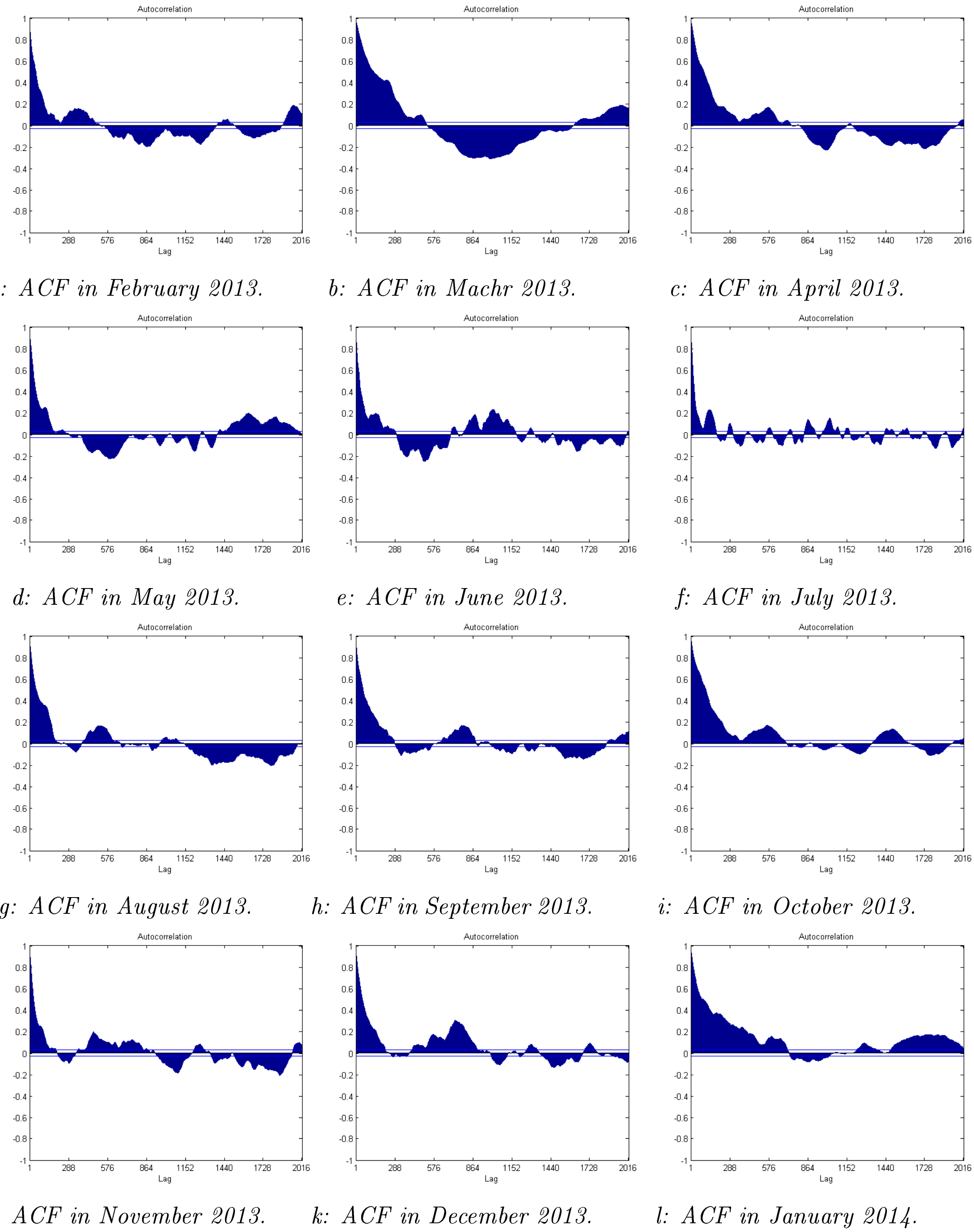


Figure 5.4.: Time series of three year wind speed data at Búrfell.

From Figure 5.5 it can be concluded that autocorrelation in wind data fades out on the time interval from just over one day to approximately 5 days. The shortest time for autocorrelation in data occurs in July where autocorrelation fades out after just approximately one day, that is 144 lags. The longest sustained autocorrelation in wind data occurs in January where autocorrelation first fades out after approximately 5 days, that is 720 lags. The small correlation that occurs after 1-5 days has negligible effects and is assumed not to affect further data analysis. Note that this is a rough cut analysis which means that the maximum autocorrelation value is roughly 5 days.



a: ACF in February 2013. *b: ACF in Machr 2013.* *c: ACF in April 2013.*

d: ACF in May 2013. *e: ACF in June 2013.* *f: ACF in July 2013.*

g: ACF in August 2013. *h: ACF in September 2013.* *i: ACF in October 2013.*

j: ACF in November 2013. *k: ACF in December 2013.* *l: ACF in January 2014.*

Figure 5.5.: Autocorrelation (ACF) in wind speed data at Búrfell for each month from February 2013 to January 2014.

5.2.3. Prevailing wind direction at Búrfell

The wind direction at Búrfell was analyzed using a wind rose diagram, the objective was to find the prevailing wind direction at Búrfell. Knowledge of the prevailing wind direction is used when decisions are made for the orientation of the wind turbines in a wind farm, i.e.

Wind direction data from 10 m height (10 year data) and 55 m height (1 year data) is presented with a wind rose diagram in Figures 5.6 and 5.7. The wind rose diagram shows wind direction and the relative frequency of the wind, a color scale is used to show the wind speed. The wind rose diagram was generated using computer code in Matlab developed by Marta-Almeida (Marta-Almeida, 2010).

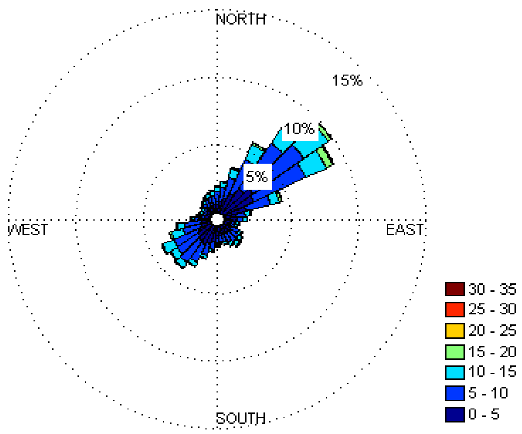


Figure 5.6.: Wind rose diagram of the measured 10 m wind at Búrfell.

From Figure 5.6 it can be concluded that the prevailing wind direction at the site is from northeast (NE). Noticeably there is also some wind coming from southwest (SW) direction, but NE appears to be the dominating direction however.

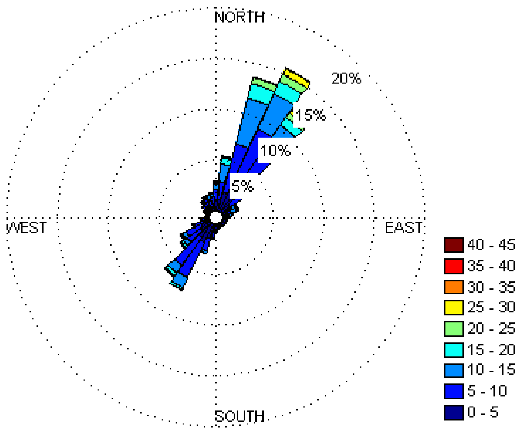


Figure 5.7.: Wind rose diagram of the measured 55 m wind at Búrfell.

Similar results are presented in the 55 m wind measurements. The prevailing wind direction is also NE but it appears to be drawn slightly more to the north compared to the 10 m wind measurements. Predictably there are also higher wind speeds measured at 55 m height, as shown on the color scale on Figure 5.7. The relation between increasing wind speed with increasing height is shown in section 6.1 which shows the power law calculations.

5.2.4. Temperature at Búrfell

The temperature at the specific site needs to be examined in the purpose of checking climate conditions. Since the wind energy project researched in this thesis is located in Iceland a temperature site classification is considered reasonable. According to IEA study on wind energy projects in cold climates (Peltola, 2012) a site is classified as Low Temperature Climate (LTC) site if minimum temperature of -20°C has been observed nine times or often per year. The long term average air temperature of the site has also to be below 0°C for the site to be classified as LTC site. Figure 5.8 shows temperature time series for Búrfell site from the year 1997 to 2013. The Icelandic Meteorological office provided the data.

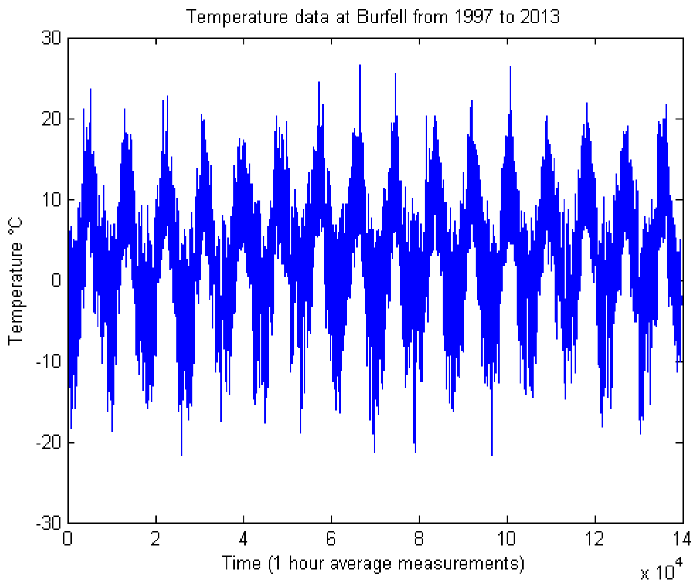


Figure 5.8.: Time series of temperature data at Búrfell from 1997 to 2013.

The average temperature at the site for this time series was measured 3.21 °C and the temperature went below -20 °C, 20 times in total in the measurement period. This concludes that the site does not qualify as a LTC site according to IEA. Icing is a proposed threat to wind turbines, those threats are mirrored in production losses and increased maintenance cost. Modern wind turbine manufacturers can provide anti-icing and de-icing devices and other solutions for icing conditions. Although Búrfell is not a cold climate site, anti-icing technology should be considered because of the fact that the Búrfell climate is very close to being a LTC site.

5.2.5. Wind turbine selection

The wind turbines used for testing at Búrfell were as mentioned before, wind turbines from Enercon of type E44 with rated power of 900 kW and 55 m hub height. The E44 wind turbine has the wind class of IA, defined by the IEC-61400 standard. The IA wind class means that the turbine is guaranteed by the manufacturer to withstand at least 50 m/s wind speed and turbulence level of 16 %. For comparison and verification of wind energy simulation methods the E44 turbine will be used, because of the fact that all measured data from a E44 wind turbine, provided by Landsvirkjun.

The E44 wind turbines were set up for testing, Landsvirkjun is currently assessing the profitability of a wind generation system at Búrfell. The E44 wind turbine is a relatively small wind turbine and Landsvirkjun have implied that if a wind farm will be set up at Búrfell, larger wind turbines will be used. A meeting with Margrét Arnardóttir the project manager of the wind energy project at Landsvirkjun revealed that Landsvirkjun are focusing on 3000 kW wind turbines for the possible wind farm at Búrfell. Since it is out of this thesis scope to research and analyze which wind turbine would be optimal at Búrfell, the expert opinion from Landsvirkjun is used when selecting the size of the wind turbines used for the wind farm.

The size of each wind turbine rated power is 3000 kW, and since the E44 has showed good performance in Icelandic conditions. It is advised that the 3000 kW turbine should have the same wind class as the E44 turbine. Therefore the 3000 kW wind turbine will have wind class of IA and for simplification it will also be selected from the Enercon wind turbine manufacturer. The turbine selected for the wind generation system at Búrfell is the E82 3000 kW wind turbine. The stats over the E44 and E82 wind turbines can be seen in Table 5.1.

Table 5.1.: Stats table over the Enercon E44 and E82 wind turbines.

Wind turbine	Rotor diameter $[m]$	Hub height $[m]$	Swept area $[m^2]$	Wind class
E44 900 kW	44	55	1521	IEC IA
E82 3000 kW	82	78	5281	IEC IA

5.3. Capacity factor and wind turbine availability at Búrfell

The two Enercon E44 wind turbines set up by Landsvirkjun in the end of January 2013 measured an average capacity factor of 40.51%. The measured capacity factor was calculated according to equation 4.10, using one year data from February 2013 to January 2014 acquired from Landsvirkjun. The capacity factor, full load hours and the availability for each turbine is shown separately in Table 7.2.

Table 5.2.: Stats over the two Enercon E44 test turbines at Búrfell.

Búrfell	Capacity factor	Full load hours	Availability
Enercon E44 turbine 1	41.92%	3538.63	98.65%
Enercon E44 turbine 2	39.11%	3266.02	89.16%

5.4. Summary

Wind data analysis confirmed the seasonality in wind speed distribution, the histogram plots of wind speed on Figure 5.3 show resemblance to Weibull distribution. Autocorrelation analysis concluded that wind speed autocorrelation fades out after 5 days. Thus it can be stated that wind speed measured at day one does not effect the wind speed measured at day 6 and that wind speed is correlated for up to 5 consecutive days. This conclusion is used in the wind MC simulation in next chapter. The Enercon E82 wind turbine was selected for the wind farm based on expert opinion from Landsvirkjun and the capacity factor at Búrfell was calculated to be just over 40 % on average, based on measured data. This shows that measured capacity factor at Búrfell is quite high. In comparison the literature research revealed that the capacity factor of wind projects in Europe averaged around 21 % (Akdağ & Güler, 2010).

In the next section the wind energy potential at Búrfell will be estimated using Weibull simulation and a new approach based on historical data and autocorrelation in wind, referred as the wind MC simulation. Next section also illustrates the calculated wind shear factor at Búrfell. All estimations in the next chapter are compared to measured data for valuation of their credibility.

6. Wind energy potential assessment

In this section the wind energy potential at Búrfell is assessed. Recorded wind speed measurements are available from the past 10 years at Búrfell. These measurements are measured at 10 m height, the power law is used to calculate the wind shear exponent which can be used to extrapolate the measured data to the hub height of the E44 test turbines and the E82 turbine selected for the potential wind farm at Búrfell. The calculation of the wind shear factor using the power law is considered a contribution to the wind energy research there. The calculation of the wind shear factor verifies if the power law applies at Búrfell. The Weibull and wind MC simulation methods are used in this chapter to simulate the wind speed distribution at Búrfell. The MC simulation method is a new approach to estimating wind speed distribution and may be considered as a contribution to wind energy research. The validity of the method will be proven in this chapter by comparing the method to the established Weibull method. Power law extrapolated data is used as input for both methods. The results from the simulation methods is then used along side with the E44 power curve to calculate the simulated AEP for the E44 test turbines at Búrfell. The simulated AEP of the E44 turbine, using both Weibull and the wind MC simulation is compared to the measured AEP of the E44 turbine. The method that gives better result will be used in next chapter to simulate the AEP for the E82 turbine and estimate the LCOE of wind energy at Búrfell.

6.1. Power law extrapolation

Wind speed increases with increased height above ground, this relation can be described by the power law, see equation 4.8. The wind speed of interest in this research is at 55 m height and 78 m height, as the data from wind turbines with hub height 55 m is available at Búrfell and that the selected turbine for the wind farm, the Enercon E82 turbine has hub height of 78 m. Since wind speed data from the desired 55 m height is limited to one year, data from 10 m height measured by the Icelandic Meteorological Office from 2004-2013 will be extrapolated for the AEP estimation, from 10 m to 55 m and from 10 m to 78 m using the power law. First measured data at 10 m height from one year will be extrapolated to 55 m height and compared to measured data at 55 m height from the same time period. This will show the accuracy of the power law extrapolation.

The wind shear constant will be derived from equation 4.8 as follows,

$$\alpha_i = \frac{log(U_i(z)) - log(U_{ref})}{log(\frac{z}{z_{ref}})}, \quad i = 1, 2, 3, ..., N. \tag{6.1}$$

This equation gives a vector of α_i values, essentially it includes the median of α_i which is presented in equation 6.2 as α plus the error of α which is presented as e_i and has median zero.

$$\alpha_i = \alpha + e_i \tag{6.2}$$

The α_i vector is plotted on Figure 6.1, it can be seen that most of the calculated values are close to zero. Large and small α values reach however up to plus four and minus three. Therefore it was decided to use the median value for the wind shear factor to avoid skewed mean value. The calculated median wind shear factor was,

$$\alpha = 0.1309.$$

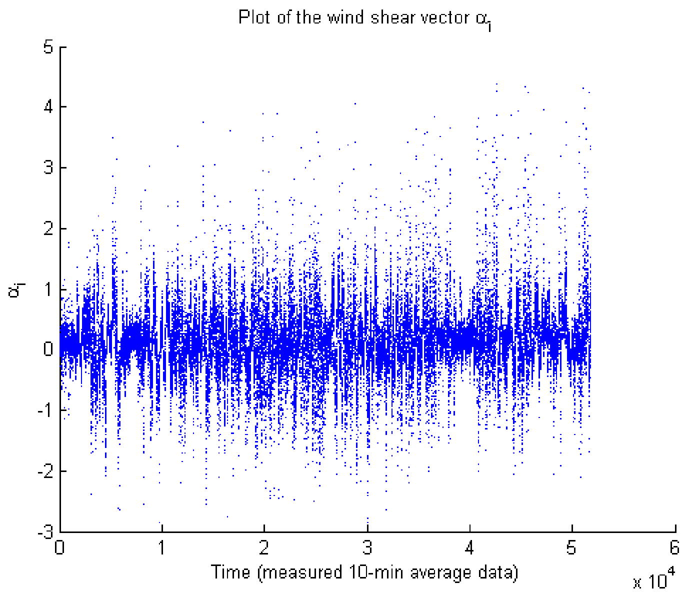


Figure 6.1.: Plot of the calculated wind shear factor α_i using the power law.

The confidence interval for α was calculated using the 95 % Bootstrap confidence interval method. The built in Matlab function *bootci* was used to compute the interval which is displayed in Table 6.1.

Table 6.1.: Table of α and its 95 % Bootstrap confidence interval.

α	Lower α value	Upper α value
0.1309	0.1270	0.1354

From Table 6.1 we can see that the confidence interval is relatively small which indicates a precise point estimate of the wind shear factor α. The length of the confidence interval or the difference between the two endpoints of the interval is an indication of the precision of the parameter estimated from sample data (Tong, Chang, Jin, & Saminathan, 2012). The Bootstrap method is a data based simulation method which means that it does not rely on distributional assumptions. Therefore it suits well for estimates of the sample median distribution in example. In Table 6.1 however the sample median is estimated. Bootstrap sampling is considered to be comparable to sampling with replacement from the empirical probability distribution function (Tong et al., 2012).

The confidence limit was calculated again with the reduced α vector to ensure robustness of the result. The alpha vector is reduced to remove autocorrelation effects in the alpha estimate. Figure 6.2 shows that autocorrelation fades out after six data points, thus the alpha vector is reduced to every sixth value.

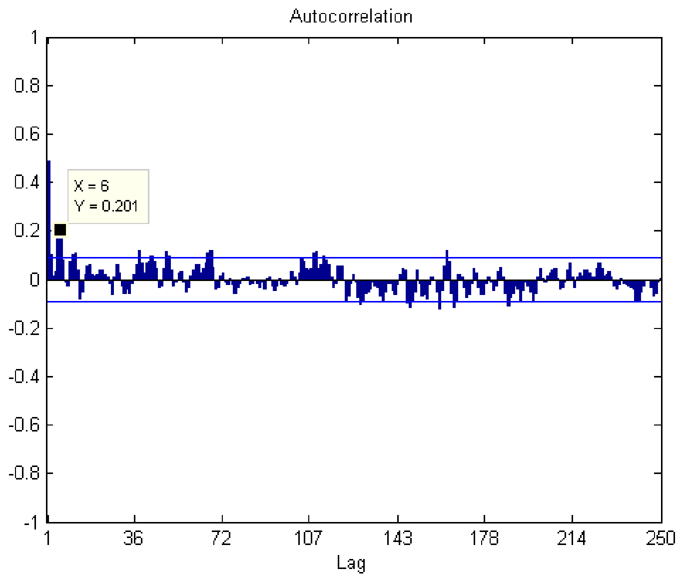


Figure 6.2.: Autocorrelation in estimated α_i vector.

The reduced α Bootstrap confidence limits are presented in Table 6.2.

Table 6.2.: Table of α and its 95 % Bootstrap confidence interval.

α	Lower α value	Upper α value
0.1309	0.1192	0.1399

From Table 6.2 we conclude that the wind shear constant α is estimated as 0.1309 with a 95 % Bootstrap confidence interval from 0.1192 to 0.1399. This estimation fits into the IEC 61400-1 standard which states that the wind shear factor for a wind production site should not exceed 0.2 and should always be positive (see section 4.5).

6.1.1. Extrapolated data compared to measured data

As a measure of the accuracy of the power law extrapolation, the wind shear factor was used to extrapolate wind data from Búrfell measured at 10 m height to 55 m height and then compared to measured data at 55 m height. The data used for the comparison is from February 2013 to January 2014. The comparison of the extrapolated data vs. measured is shown in Figure 6.3. The figure presents the probability density function (pdf) generated with the built in Matlab function *ksdensity*. The estimate is based on a normal kernel function.

The estimated distribution appears to be slightly off at the peak compared to the measured data distribution. The indication is however that the power law gives a quite good estimate judging by Figure 6.3.

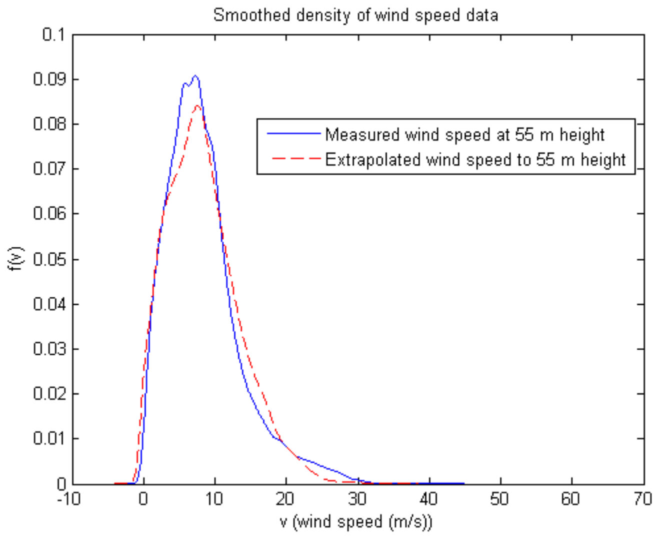


Figure 6.3.: Pdf of measured data at 55 m vs. extrapolated data to 55 m height.

The empirical cumulative distribution function (cdf) was also plotted for both measured and extrapolated data. The result is presented in Figure 6.4, where it can be seen that the estimate fits the measured data not perfectly but does however give a quite good estimate.

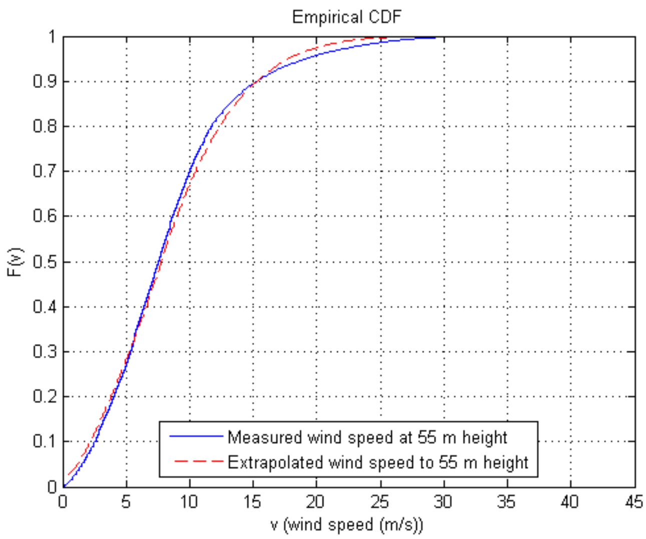


Figure 6.4.: Cdf plot of measured data at 55 m vs. extrapolated data to 55 m height.

A quantile-quantile plot was made to determine whether the wind speed extrapolated to 55 m height came from the same distribution as measured wind speed at 55 m height. If they do the plotted points will be linear, red reference line is drawn on the plot to help judge linearity. The plot was conducted using the built in Matlab function *qqplot*. It can be seen on Figure 6.5, where an example of measured wind speed at 55 m height vs. extrapolated with power law is shown, that the points appear to be approximately linear up to wind speed above 20 m/s. At wind speed above 20 m/s the power law appears to underestimate the acceleration of the wind, this will be noted in power production forecasting.

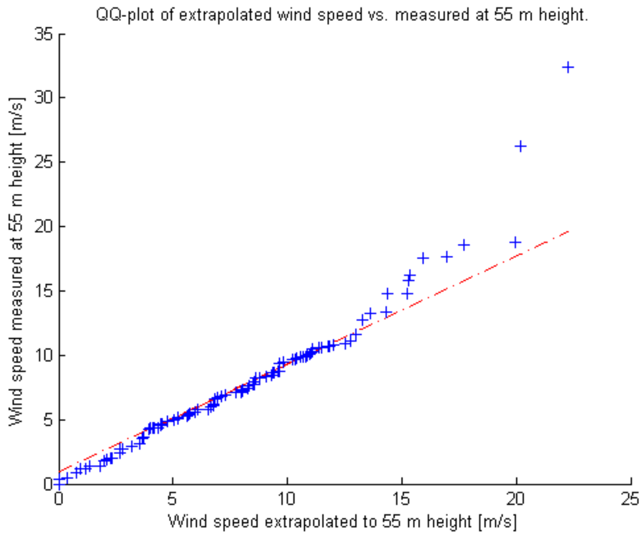


Figure 6.5.: QQ-plot of measured data at 55 m vs. extrapolated data to 55 m height.

Based on these calculations it has been shown that the wind shear factor α of 0.1309 can be used to extrapolate the wind speed data measured at 10 m height up to the desired wind turbine height. This verifies that the power law is applicable at Búrfell, the deviation in the power law approximation has however been noted at wind speeds above 20 m/s.

6.2. Weibull simulation of wind speed at Búrfell

The method of using the Weibull probability distribution function to represent wind speed distribution is dominant in the wind energy industry as literature research revealed. The method in practice has the motive to set up a representative distribution of the wind speed at a specific site by fitting Weibull distribution to the data based on historical data from the site.

6.2.1. Weibull parameter fit

First the Weibull distribution was fitted to all recorded wind speed data as a whole (10 year data), that is, fitting one A and k parameter to all data. The built in Matlab function *wblfit* is used to acquire the parameters. The values of the parameters were calculated to be 9.27 for A and 1.35 for k. They were assessed using wind speed data from 2004 to 2013 recorded at Búrfell. The data was measured at 10 m height and extrapolated using the power law to 55 m height. The result of the Weibull fit to all data can be seen on Figure 6.6.

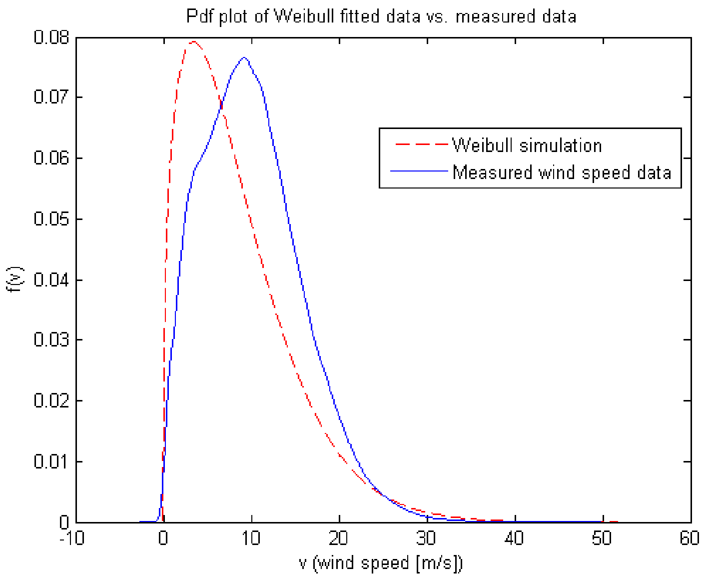


Figure 6.6.: Pdf of Weibull distribution and measured wind speed data.

It can be seen that the Weibull fit is skewed to the left. This is not surprising since it is unreasonable to fit one Weibull distribution to all data, because of the fact that wind distribution is different between yearly seasons (Petersen et al., 2011).

Because of this misfit when fitting one Weibull distribution to all data there have been developed improved methods, Weibull fit methods, that divide the data into wind directional sectors and fit a Weibull distribution to each sector separately. Because of the fact that wind direction tends to be dependent to yearly seasons. Dividing the data into directional sectors should give a better Weibull distribution fit, since dominant wind direction tends to change according to seasons. This method of dividing the wind data into directional sectors is presented in a paper on characterization of wind speed data according to wind direction (Torres, García, Prieto, & Francisco, 1999).

The wind direction was divided into eight directional sectors, north (N), northeast

(NE), east (E), southeast (SE), south (S), southwest (SW), west (W) and northwest (NW). The N direction is set to 0 degrees and the N sector extends from -22.5 degrees to +22.5 degrees, the NE sector is set from +22.5 to +67.5 degrees and so on (Torres et al., 1999). A Weibull distribution was fitted to each sector using $wblfit$. When fitting Weibull parameters to each directional sector, it was noticed that the Weibull distribution function was having trouble fitting sectors that included high amount of zero values. One particular sector, the N sector experienced this problem. Thus it was decided to remove all zero values from the sectors and fit a Weibull distribution to the non-zero data. The frequency of zeros in each sector was stored and simulated separately.

The results of the new Weibull fit parameters within directional sectors are presented in table 6.3. Two sectors are dominant in the wind direction at Búrfell, they are the NE and SW sector, this can also be seen clearly on Figure 5.7 in the previous chapter. The frequency of data within each sector was calculated over the whole data set, spanning 10 years.

Table 6.3.: Stats table of the Weibull fit for wind speed at Búrfell in 55 m height.

Sector	A	Mean wind speed [m/s]	k	Frequency [%]	zero values [%]
N	9.27	7.72	1.47	0.0907	0.0825
NE	10.72	9.53	1.92	0.3617	0.0011
E	9.84	8.84	1.66	0.0946	0.0014
SE	9.15	8.27	1.53	0.0492	0.0020
S	10.27	9.19	1.72	0.0816	0.0015
SW	9.41	8.37	1.93	0.1652	0.0007
W	7.47	6.75	1.46	0.0777	0.0015
NW	9.55	8.60	1.55	0.0793	0.0023

6.2.2. Weibull simulation

Weibull distributed wind years were simulated according to the statistics in table 6.3. The built in function *wblrnd* in Matlab was used to generate each simulated year, this function takes in the Weibull parameters from each sector and the amount of data desired to generate in each sector. All sectors are consequently added together generating one simulated year, this was repeated 2000 times in the simulation.

The number of generated points in each sector is decided by the frequency of data from each sector. Wind speed distribution in every sector is however not always perfectly identical from year to year. Thus in stead of setting the frequency fixed, the frequency was allowed to vary slightly by using multinomial distribution, the frequency ratio in Table 6.3 sets the probability for data points in each sector. The multinomial distribution generates years with variate number of data points in each sector, but is always limited to a total of 52560 data points since that is the number of data points in one measured wind speed year (10-min average data).

Since the Weibull distribution had troubles simulating the zero values, the number of zero values within each sector was simulated using binomial distribution. Thus the mulitnomial distribution was used to decided the number of data points for each sector and the binomial distribution was used to generated the number of zero's within each sector. Both distributions utilize the percentage distribution of data and zero's in each directional sector shown in table 6.3. The multinomial and binomial distributions are appropriate to use when generating random values based on certain probability, the built in functions *mnrnd* and *binornd* in Matlab were used for the calculation. Further detailed explanation of calculations can be seen in Appendix XX.

The result and comparison of the Weibull fit simulation vs. measured data at Búrfell is presented in Figure 6.7 and 6.4. It can be seen clearly on Figure 6.7 that the division of sectors and assigning Weibull distribution to each sector has improved the estimated wind speed distribution. The Weibull fitted wind speed distribution is now very comparable to measured data, there is however a slight deviation at the top of the curve. The mean wind speed for the Weibull simulation and measured data at Búrfell is very similar and the same goes for the standard deviation (std), see Table 6.4.

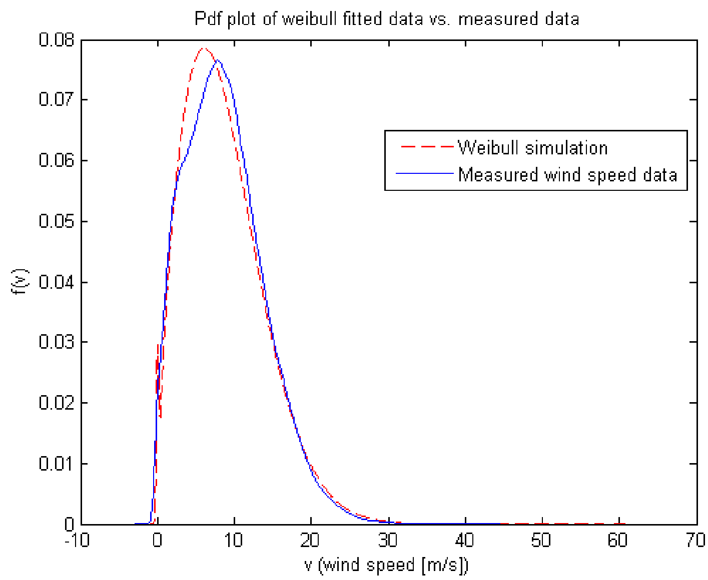


Figure 6.7.: Pdf of Weibull simulated wind speed and measured wind speed data.

Table 6.4.: Measured data vs. Weibull fit for wind speed at Búrfell in 55 m height.

Búrfell	Mean [m/s]	Median [m/s]	Std [m/s]
Weibull simulation	8.70	7.93	5.29
Measured wind speed	8.73	8.24	5.18

6.3. MC simulation of wind speed at Búrfell

A simulation method presented by professor Birgir Hrafnkelsson was used to simulate the distribution of wind speed at Búrfell. The method relies solely on historical wind data at the site, accommodated with simple probability calculations. The method was developed in cooperation with Birgir Hrafnkelsson and is based on his experience in Bayesian inference. The purpose of this simulation is to generate a representative distribution of wind speed at Búrfell, which ultimately will be used to calculate the potential annual power production (AEP) at the site.

The method is as mentioned based on historical data, the simulation is essentially based on manipulation of historical data and is described as follows:

All measured data is divided into five day blocks of data, including 720 data points since data is measured in 10-min averages. The five day blocks division was created due to the fact that autocorrelation in data was proved to fade out after five days (see section 5.2.2). This means that wind speed can be correlated for up to 5 consecutive days. This fact is taken into consideration in the wind MC simulation by dividing data into five day blocks, thus taking blocks of correlated wind speeds into the simulation. In terms of the wind MC simulation, the 5 day correlation in the wind data is used as a foundation for the simulation. Instead of simulation each 10-min average data point independently, the wind MC simulation, simulates blocks of correlated wind speed data points.

As mentioned, all measured years are divided into five day blocks, there are 73 blocks of 5 days in each year and the total amount of data includes 10 years. This historical data matrix is thus a 10×73 matrix (see Table 6.5) with the years lined up from one to ten, year one being the last recorded year (2013) and year ten being the last (2004). This historical matrix is set up for the simulation structure. The simulation was done in Matlab, the matrix was stored as a cell matrix with each five day block including 720 data points. The simulation draws from the matrix 73 times (there are 73, five day blocks in one year) with the probability of,

$$P(Y = y) = \frac{1}{10}, \quad y \in [1, 2, 3, ..., 10] \, . \tag{6.3}$$

Table 6.5.: Example of a historical matrix, the first 5 of 73, five day blocks in all years are illustrated.

	5 day blocks				
Year	1	2	3	4	5
1	720x1	720x1	720x1	720x1	720x1
2	720x1	720x1	720x1	720x1	720x1
3	720x1	720x1	720x1	720x1	720x1
4	720x1	720x1	720x1	720x1	720x1
5	720x1	720x1	720x1	720x1	720x1
6	720x1	720x1	720x1	720x1	720x1
7	720x1	720x1	720x1	720x1	720x1
8	720x1	720x1	720x1	720x1	720x1
9	720x1	720x1	720x1	720x1	720x1
10	720x1	720x1	720x1	720x1	720x1

This creates one simulated year from the 10 year data with 73 blocks drawn by the probability shown in equation 6.3. The five day blocks in the historical matrix are arranged in ascending date order, so that each simulated year is built correctly. For example one year is built by drawing the first five days of the year from 10 possible first five days in data with equal probability, see equation 6.3.

The procedure is repeated 73 times to generate one simulated year. Starting by drawing from the 10 available first five day block, next the second 10 available five day blocks, ending with the last five day block of the year. This creates a complete simulated year, built from the past 10 year measured data. This procedure is repeated 1000 times, thus creating a 1000×52560 matrix containing 1000 years of simulated 10-min average wind speed data. This simulation can be done for more than 1000 years but because of computational limitations, 1000 year simulation was considered enough for this case. Example of a vector used to draw from the historical matrix is shown in Table 6.6. This simulated year would for example draw the first five days from historical year number nine, which would be 2005 and the next five days from year five (2008) and so on.

Table 6.6.: Example of a vector used to select years to draw from historical matrix

Vector	Number of year							
P(Y = y)	9	5	2	10	7	1	5	6

The method has the assumption that history will repeat it self and the future years of wind will be similar to the previous 10 years of wind. To verify that wind speed has not been increasing or decreasing the last 10 years, the sum of wind speed for the previous 10 years was plotted, see Figure 6.8. The result shows that it can not be said that wind speed is clearly increasing or clearly decreasing at the Búrfell site. Thus holds the assumption for the simulation method in that relation.

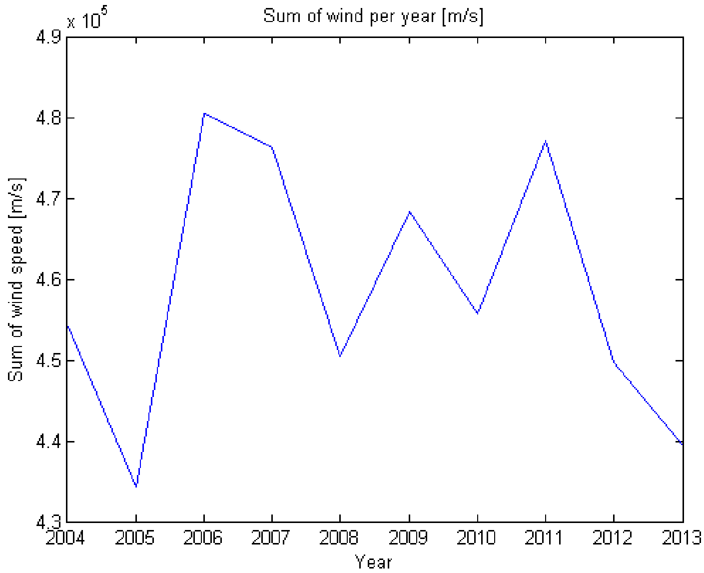


Figure 6.8.: Sum of wind speed per year from 2004 to 2013.

The simulated data matrix should represent the wind conditions at Búrfell better than using the past measured year (2013) data i.e. Because of the fact that wind speed changes between years and usually it can not be known if last year was a bad wind year or a good one. This can lead to over or under estimation in production capabilities of a wind generation system at the site. Notice also from Figure 6.8 that the sum of wind in year 2013 appears to be slightly below average.

The result and comparison of the MC simulation method vs. the measured data at Búrfell is presented in Figure 6.9 and 6.7. From Figure 6.9 it can be seen that the probability density of the simulation gives a good fit to measured data, which is not surprising since the distribution is solely based on previous data. The simulation however appears to have overestimated slightly the amount of zero values, hence the deviation from the measured pdf on Figure 6.9. The stats from table 6.7 verify that the simulation method gives a good fit to the data.

The biggest edge that this method gives however is the fact that when calculating the AEP for the site, the 1000 simulated years give a representative distribution of the power production of the site. A forecast of future 25 years (typical lifetime of a wind park) of wind speed can be drawn from this distribution that represents wind speed at Búrfell. This type of forecasting could not be performed using solely 10 years of historical data and no simulation. The MC simulation method also takes into account autocorrelation effects in wind speed distribution, which is ignored in the Weibull simulation method in example.

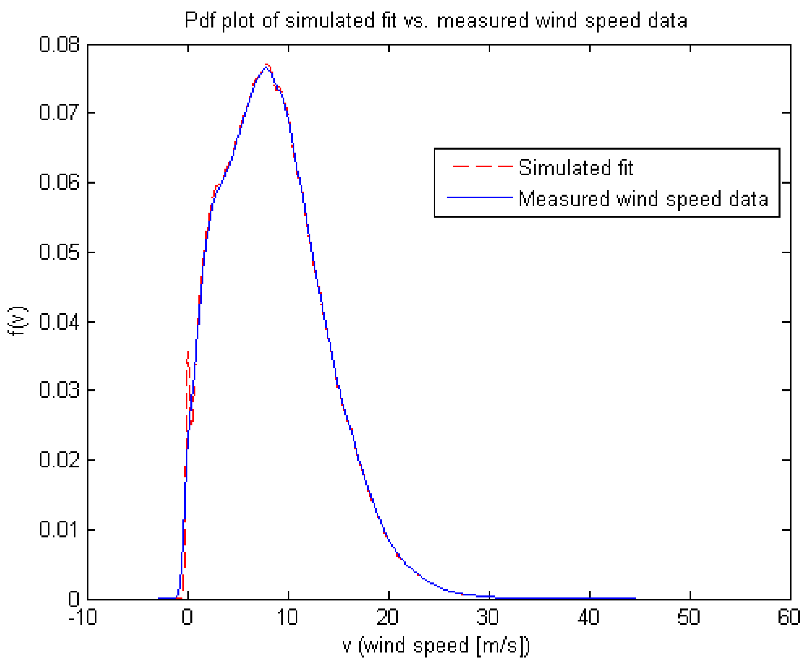


Figure 6.9.: Pdf plot of each simulated wind year at Búrfell (55 m height).

Table 6.7.: Stats table of simulated wind speed at Búrfell in 55 m height.

Búrfell	Mean [m/s]	Median [m/s]	Std [m/s]
Simulated wind speed	8.71	8.20	5.19
Measured wind speed	8.73	8.24	5.18

6.4. Annual Energy Production (AEP) Analysis

In this section the measured and estimated AEP at Búrfell will be analyzed. The measured AEP is from the two Enercon E44 wind turbines set up by Landsvirkjun at Búrfell. The two wind speed distribution fitting methods presented in the section above will be compared to the measured AEP from the Enercon E44 wind turbines. The comparison will be performed by using the power curve for the Enercon E44 wind turbine. The power curve is published by Enercon and is an estimation of the power production output of the Enercon E44 wind turbine. The method that gives result closest to measured data will be used for the cost analysis of a wind generation system at Búrfell.

6.4.1. Enercon E44 power curve

Enercon is a German wind turbine manufacturer which produces the E44 wind turbine among many others. A specific power curve is published by Enercon for each of their wind turbines, this power curve presents the power output in kW for a given wind speed measured in meters per second. The Enercon power curve gives the power output for wind speed in whole number, thus the interval of wind speed between the whole numbers needs to be estimated.

All power curves published by Enercon have the assumption of average standard air density of 1.225 kg/m^3 and average turbulence intensity of 12 %. They are also based on realistic assumptions concerning anemometer behavior. All Enercon wind turbines include a special patented storm control feature which enables power production at high wind speeds without shutdown. The calculated Enercon power curves are estimated with regard of this feature. Measurements however showed that the E44 wind turbine was capable of producing more power than the power curve displays. This is explained graphically on Figure 6.11 (Enercon, 2012).

The estimated power curve for the Enercon E44 wind turbine is shown on Figure 6.10.

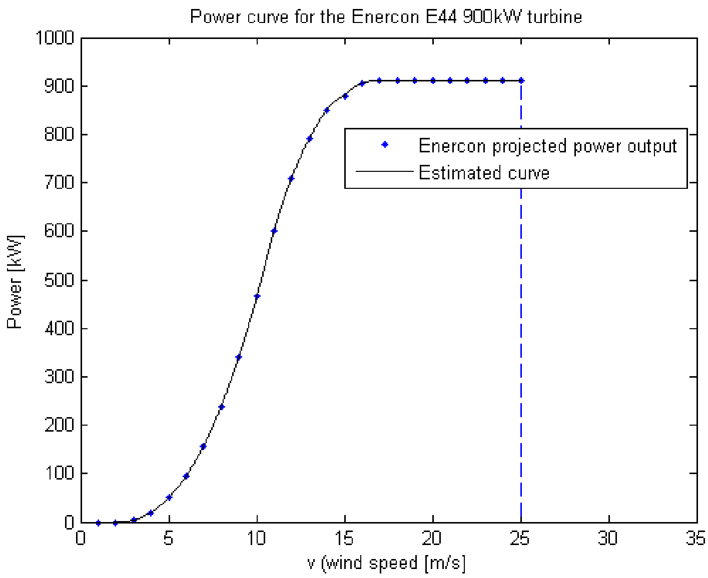


Figure 6.10.: Power curve for the Enercon E44 wind turbine (55 m hub height).

The blue dotes represent the given power output for wind speed in whole numbers from 0 to 25 m/s. The so called cut-in wind speed for this turbine is 3 m/s, that is when the turbine starts to produce power. The so called cut-out wind speed for this turbine is set at 25 m/s, but with the Enercon storm control feature the turbine can produce power at higher wind speeds than 25 m/s. The Enercon E44 wind turbine shuts down all production at wind speeds of 34 m/s or higher.

The functionality of the storm control feature can be seen evidently when measured production data gathered from Landsvirkjun for the E44 900 kW turbine is plotted vs. the wind speed at the site. Figure 6.11 shows the measured power curve for E44 turbine number one at Búrfell.

The storm control feature is evident when comparing Figure 6.10 vs. 6.11. The storm control feature clearly enables extra power production capabilities above wind speed of 25 m/s. The estimated power curve from Enercon tries to implement that into their estimation by setting the maximum power output slightly higher than rated power output. For example the power curve for the E44 900 kW turbine has maximum estimated power output set to 910 kW. The zero power data points on Figure 6.11 at wind speeds higher than 3 m/s up to 34 m/s occur because of downtime due to maintenance or turbine malfunction. Measurements at Búrfell site from the two E44 wind turbines showed that the two turbines produced approximately 21.5 % more on average than the power curve assumed. This extensive underestimation of power produced by the E44 turbine and Figure 6.11 which appears to show two different power curves, is discussed in further detail in Chapter 8.

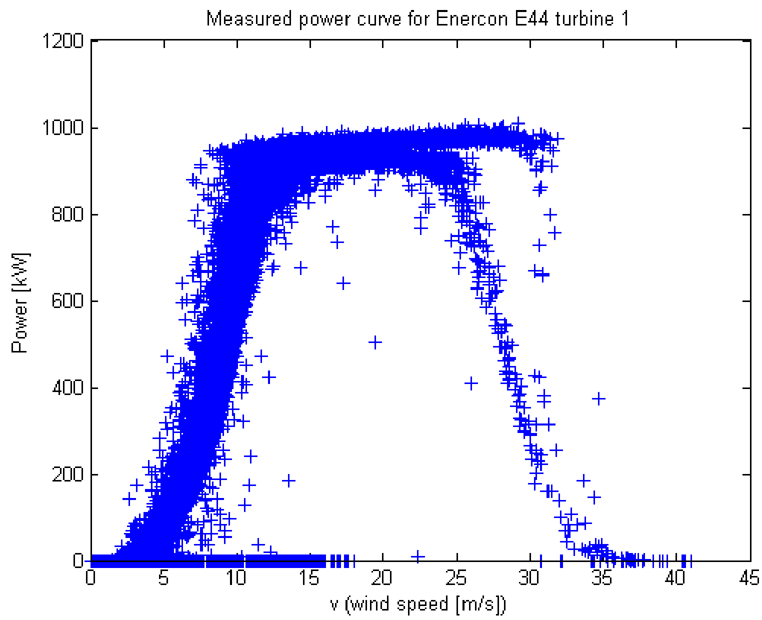


Figure 6.11.: Measured power curve for the E44 wind turbine number 1 at Búrfell.

The measured 12 hour power production from E44 wind turbine number one can be seen on Figure 6.12. It can be seen that the estimated power curve gives a quite good fit to the measured data. However because of slight underestimation in the power curve and the storm control feature the measured power output is almost always higher.

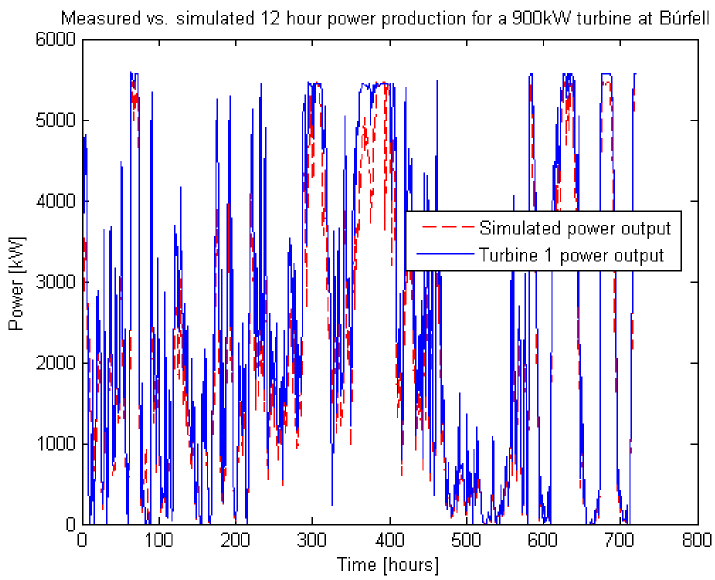


Figure 6.12.: Measured vs. simulated 12 hour power production for the E44 900kW turbine at Búrfell.

For simulation of AEP for the Enercon E44 wind turbines at Búrfell, their power curves will be used without scaling. It is noticed that the storm control feature enables more produced power than the power curve estimates, but since Enercon state that their power curves provide highly reliable and realistic calculations for expected energy production based on wind conditions at respective sites, their power curves will be used un-scaled in AEP estimations. It is though regarded that the estimate acquired from their power curves is considered a conservative estimate.

6.5. AEP calculations

For the calculation of AEP using the two wind speed simulation methods, the power curve for the E44 turbine shown in Figure 6.10 was used. The AEP can be calculated for each simulated year k, using equation 6.4,

$$AEP_k = T \cdot \frac{1}{n} \sum_{t=1}^{n} P(U_t) \tag{6.4}$$

which is derived from equation 4.9. The sum in equation 6.4 is an approximation of the integer in equation 4.9. The $P(U_t)$ parameter represents the power output from the wind turbines power curve at wind speed U_t. The U_t parameter is simulated 10-min average wind speed, which is drawn from simulated years generated by the two different simulation methods. The simulated years are equivalent to a distribution of wind speed at Búrfell. The number of data points in year k is presented with n.

6.5.1. AEP calculated from Weibull distribution method

For each Weibull simulated wind year the AEP is calculated using equation 6.4. The mean AEP and the 95 % prediction interval is presented in Table 6.8 and with Figures 6.13 and 6.14. Notice that the prediction interval for the Weibull simulated AEP is quite narrow. This is also evident in Figures 6.13 and 6.14 which show the probability density and cumulative density of the simulated AEP. The Weibull distribution simulates wind speed values independently, meaning that one simulated 10-min average wind speed is not correlated to the next. This type of simulation gives a quite good estimate of the mean, but it however does not manage to replicate the variation in wind between years, hence the narrow 95 % prediction interval.

Table 6.8.: Weibull simulated AEP for E44 900kW wind turbine (55 m hub height).

Búrfell	Mean	95 % prediction interval	
AEP [MWh]	3063.67	3042.42	3084.46

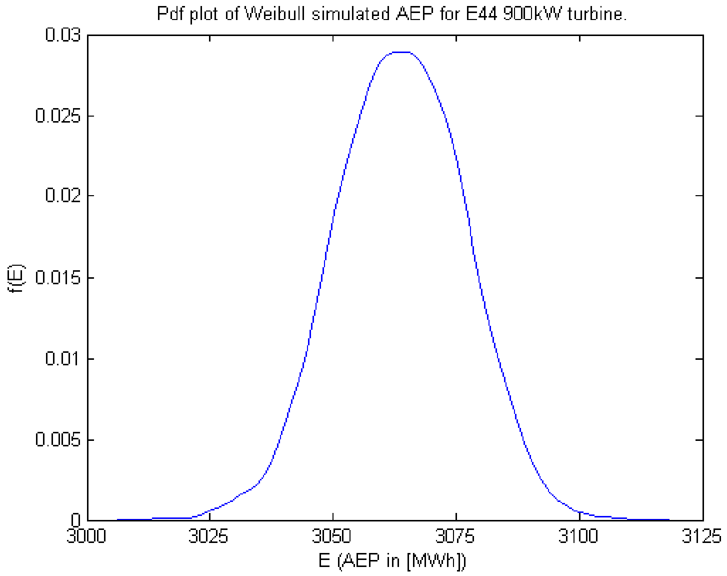


Figure 6.13.: Pdf of Weibull simulated AEP for the E44 wind turbine at Búrfell.

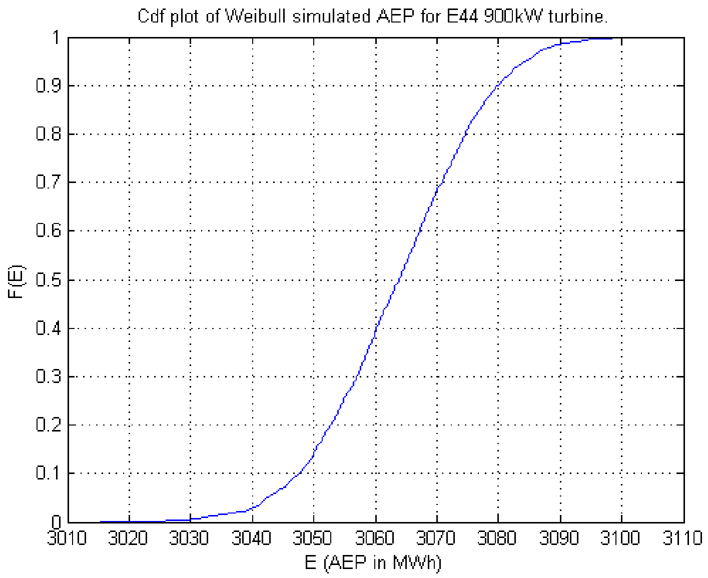


Figure 6.14.: Cdf of Weibull simulated AEP for the E44 wind turbine at Búrfell.

6.5.2. AEP calculated from MC simulation method

The result of the MC simulation method is presented in Table 6.9 and with Figures 6.15 and 6.16. The prediction interval presented in Table 6.9 is larger compared to the Weibull simulated interval. The mean AEP is also slightly higher compared to the Weibull simulated AEP mean. The wind MC simulation takes into account autocorrelation in wind, by simulating blocks of wind speed instead of independent values. The results show that the mean AEP calculated from the MC simulation is quite comparable to the Weibull simulation mean, but the 95 % prediction interval is significantly wider. This result shows that by taking into account the autocorrelation in wind speed distribution, the variation in wind distribution can be replicated better, compared to an independent simulation approach, hence the wider 95 % prediction interval in Table 6.9.

Table 6.9.: Simulated AEP for the E44 900kW wind turbine.

Búrfell	Mean	95 % prediction interval	
AEP [MWh]	3169.80	2926.20	3402.70

Figure 6.15 and 6.16 show the pdf and cdf of simulated AEP for a 900 kW wind turbine at Búrfell. The pdf is a bell shaped curve around the mean AEP, and it can also be seen that the prediction interval presented in table 6.9 is reflected by the area under the pdf and the stretch of the cdf.

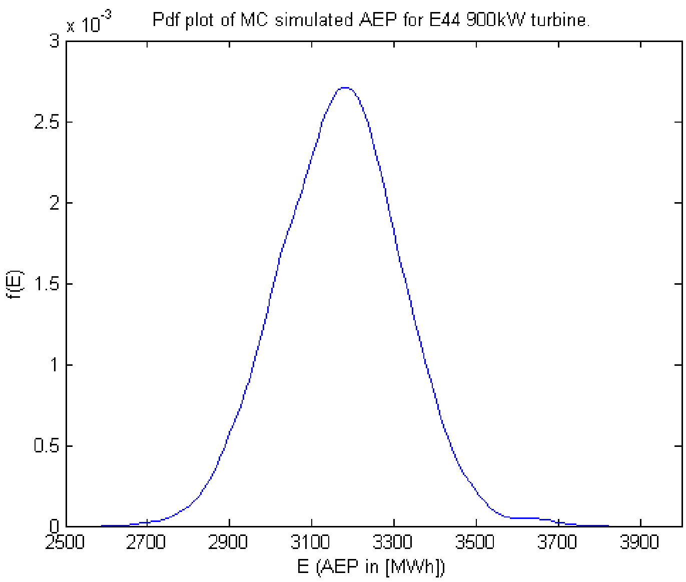


Figure 6.15.: Pdf of MC simulated AEP for the E44 wind turbine at Búrfell.

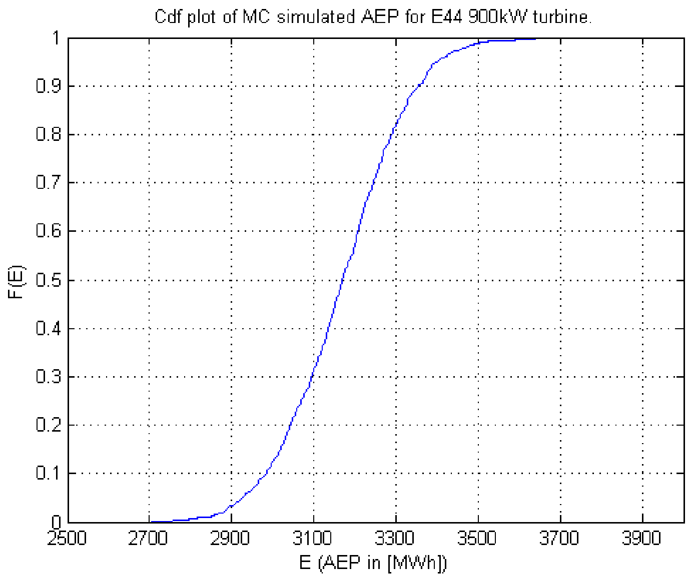


Figure 6.16.: Cdf of MC simulated AEP for the E44 wind turbine at Búrfell.

6.5.3. Comparison of simulated AEP to measured AEP

The AEP for the E44 900 kW turbine at Búrfell was calculated for each simulated year k for both Weibull and MC simulation method. The E44 wind turbine is the same as the two installed test turbines at Búrfell. Thus calculated results can be compared to measured AEP data verifying the simulation result. Measured power production output data from the two 900 kW test turbines at Búrfell is available from the end of January 2013 until present. The AEP in MWh of turbine 1 and 2 from February 2013 to January 2014 is presented in table 6.10, the data was provided by Landsvirkjun.

Table 6.10.: Measured AEP for both E44 900kW wind turbines at Búrfell.

Búrfell	E44 turbine 1	E44 turbine 2
AEP [MWh]	3184.8	2939.4

It is noticeable from table 6.10 that the AEP for each wind turbine is slightly different. This difference is caused by different availability between the two turbines. Each turbine experienced different amount of downtime caused by malfunction.

The measured data from Table 6.10 has to be scaled according to availability data for the two E44 turbines presented in Table 7.2 in order to be comparable with simulated AEP. The scaling makes sure that measured and calculated results are being compared with the same amount of production hours in the year. The scaled data for the measured AEP is presented in Table 6.11. This is done because simulated AEP assumes that the wind turbines are producing power throughout every hour of the year.

Table 6.11.: Scaled measured AEP for both 900kW wind turbines at Búrfell.

Búrfell	E44 turbine 1	E44 turbine 2
AEP [MWh]	3228.24	3296.91

The two E44 turbines are placed side by side and thus they should produce almost exactly the same amount of energy. After scaling the measured AEP by the availability data for each turbine the AEP values are very similar in comparison. Table 6.11 can consequently be used to compare measured vs. simulated AEP.

Weibull simulated AEP comparison

By comparing Table 6.8 and 6.11 it can be seen that the Weibull simulated mean AEP is lower than the measured particular year. Moreover the 95 % prediction interval for the Weibull simulated AEP does not include the measured AEP. This shows that the Weibull simulation method does not replicate the variations that can occur in wind years and consequently the AEP. However by referring to section 6.4.1 we notice that the simulated AEP is done using a conservative estimate of the E44 power curve, mostly because of excess energy produced by the storm control feature in the E44 turbine. Having that in mind the Weibull simulation method does present a quite good estimate of the potential mean AEP at Búrfell.

MC simulated AEP comparison

By comparing table 6.11 and 6.9 it can be verified that the measured AEP from the two test turbines is within the 95 % prediction limits of the MC simulated AEP for the same type of turbine, Enercon E44. The prediction limits from the MC simulation method catch the variety between years in wind distribution and hence the AEP variation between years. Wind speed distribution varies between each year and the MC simulation does reflect that, this can be seen by looking at the stats from Table 6.9 and Figures 6.15 and 6.16. The mean AEP from the MC simulation is higher compared to the Weibull simulation and also closer to the measured AEP, comparing Tables 6.9 and 6.11. This confirms that taking into account autocorrelation in wind distribution results with a better estimate of the AEP.

In conclusion the MC simulation method will be used for AEP calculations in the cost analysis for the wind generation system at Búrfell. This conclusion is based on the comparison of the two AEP simulation methods here above. Both methods showed good fit of the mean AEP to measured AEP data. For future research it would be recommended that the Weibull simulation method should be used for sites that have less than 10 years of recorded wind speed data, the MC simulation method is recommended for sites with 10 year or more recorded wind speed data.

6.6. Summary

Based on these calculations it has been shown that the wind shear factor α of 0.1309 can be used to extrapolate the wind speed data measured at 10 m height up to the desired wind turbine height. This result is considered a contribution to wind energy research at Búrfell. Wind energy potential assessment concluded that the 95 % prediction interval of AEP produced with a E44 wind turbine is from 2926.2 MWh to 3402.7 MWh. This prediction interval includes the measured AEP for the same type of turbine, see table 6.11. The estimated capacity factor from 37.11 % to 43.16 % at Búrfell, this prediction interval also includes the measured capacity factor at Búrfell which was 40.51 % on average, see section 5.3.

The MC simulation of wind speed was selected as the more appropriate method for AEP calculations, it was preferred instead of the Weibull method when forecasting wind speed at Búrfell. This decision was made based on comparison of measured AEP of the E44 turbine at Búrfell vs. simulated AEP for the same turbine using Weibull simulated wind speed or MC simulated wind speed. Results showed that MC simulated wind speed replicated the variation of wind between years better than the Weibull method and the MC simulated mean AEP was closer to the measured AEP at Búrfell. It was concluded that the main reason for the difference between the methods was because of autocorrelation effects were taken into account in the MC simulation while the Weibull method simulated wind independently.

The benefit of choosing to simulate wind speed at Búrfell based on historical data instead of just using the raw historical data for AEP estimation, is that by using the MC simulation method, a distribution of estimated AEP can be created which consequently can be used to draw from a representative forecast of future years of AEP at Búrfell. The MC simulation of wind speed may be considered as a contribution to wind energy research at Búrfell.

In the next chapter the MC simulated method will be used to estimate the AEP for the Enercon E82 wind turbine select for the wind generation system. Consequently the LCOE of wind energy at Búrfell will be calculated.

7. Cost analysis

In this chapter the cost of wind energy at Búrfell will be estimated. The purpose is to calculate LCOE of wind energy at Búrfell. To perform the LCOE calculation, a capacity scenario needs to be created for the wind generation system. The MC simulation method is used to simulate wind at Búrfell and the power curve for the E82 wind turbine is used in combination to simulated wind speed to calculate estimated AEP for the E82 turbine. The economical analysis consequently uses the result of the MC simulated AEP estimation to calculate the LCOE for wind energy at Búrfell. The LCOE calculation is regarded as contribution to wind energy research at Búrfell since new data and methods were applied in the estimation process. At the end of the chapter the decision analysis procedure is presented. Landsvirkjun needs to make a decision whether or not to start harnessing wind energy at Búrfell, this decision can be based on the estimated LCOE among other important factors which are out of scope in this thesis.

7.1. Wind farm capacity scenario

In section 5.2.5 it was decided that the Enercon E82 3000 kW wind turbine should be the turbine used for the wind generation system. After consulting with Margrét Arnardóttir, project manager of the wind energy project at Landsvirkjun it was decided that the total capacity of the wind farm should be 100 MW. Margrét also mentioned that the Búrfell site has potential to carry larger capacities than 100 MW. But according to Landsvirkjun this is a reasonable size for a wind generation system at Búrfell. There can be installed 99 MW with 33 E82 wind turbines, this is the closest capacity to 100 MW that adds up by using the E82 3 MW turbine. Note if desired, the size of the wind farm or the wind turbine selected can be changed. All calculations are the same, except the size of the wind farm and the power curve for the wind turbine. This shows that estimated calculations are highly flexible.

The power curve for the E82 wind turbine is acquired from Enercon (see Figure 7.1) and was used together with the MC simulation method of wind speed to calculate the potential AEP for the E82 turbine at Búrfell. Data used for the simulation is extrapolated data from 10 m height to 78 m (turbine hub height) using the power law, the data is gathered from the Búrfell weather station. The lifetime of the wind farm is set to 25 years, thus a forecast of next 25 year of wind is drawn from the MC simulation and used to calculate the AEP for the E82 wind turbine. The 25 years are drawn randomly from the MC simulated wind years using the built in Matlab function *randsample*. The results are presented in Table 7.1 and Figures 7.2 and 7.3.

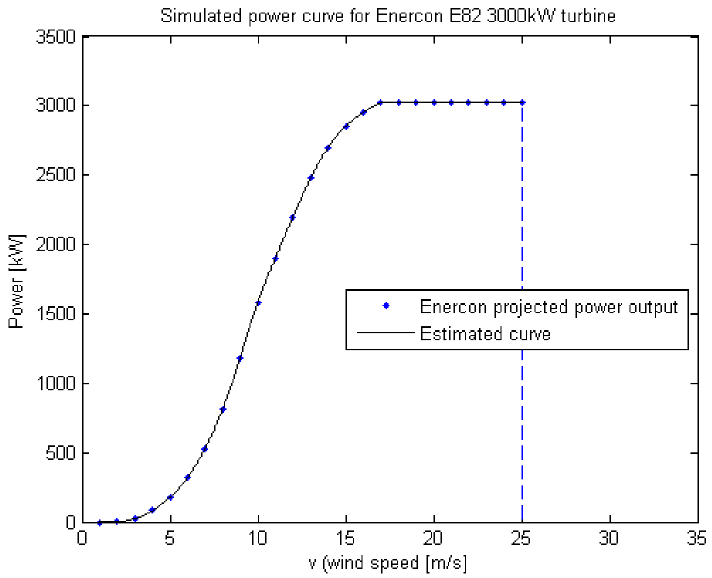


Figure 7.1.: Power curve for the Enercon E82 wind turbine (78 m hub height).

Table 7.1.: MC simulated AEP for the E82 3000kW wind turbine at Búrfell.

Búrfell	Mean	95 % prediction interval	
AEP [MWh]	10987.65	10195.46	11909.04

The availability of the E82 wind turbine is set fixed at 93.90%, this is explained by mandatory downtime due to maintenance and unexpected malfunction. The measured availability for the E44 wind turbines at Búrfell ranged from 89% to 98%, the average of those two values was taken and used for availability of the E82 wind turbine simulation at Búrfell.

Table 7.2.: MC simulated stats for the Enercon E82 wind turbine at Búrfell (scaled according to availability).

Búrfell	Mean CF	Mean FLH [hours]	Availability
Enercon E82 turbine	39.25%	3439.13	93.90%

The mean capacity factor and full load hours were calculated for the E82 wind turbine at Búrfell from the results of the MC simulation method. Note that the capacity factor and full load hours were both adjusted according to the fixed 93.90% availability set for the E82 wind turbine.

For the cost analysis, downtime of the E82 wind turbine needs to be taken into account. Therefor the results from the MC simulation of the AEP at Búrfell was scaled according to availability factor in Table 7.2.

Table 7.3.: MC Simulated AEP for the E82 3000kW wind turbine (scaled).

Búrfell	Mean	95 % prediction interval	
AEP [MWh]	10317.40	9573.52	11182.59

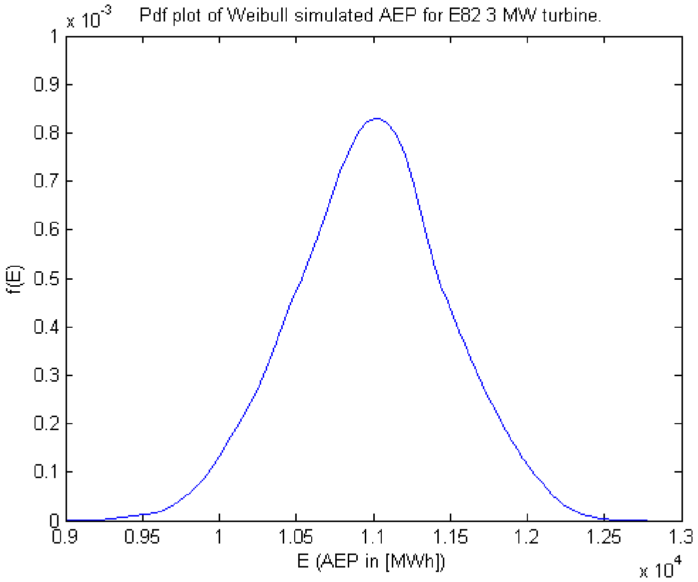


Figure 7.2.: Pdf of MC simulated AEP for the E82 wind turbine at Búrfell.

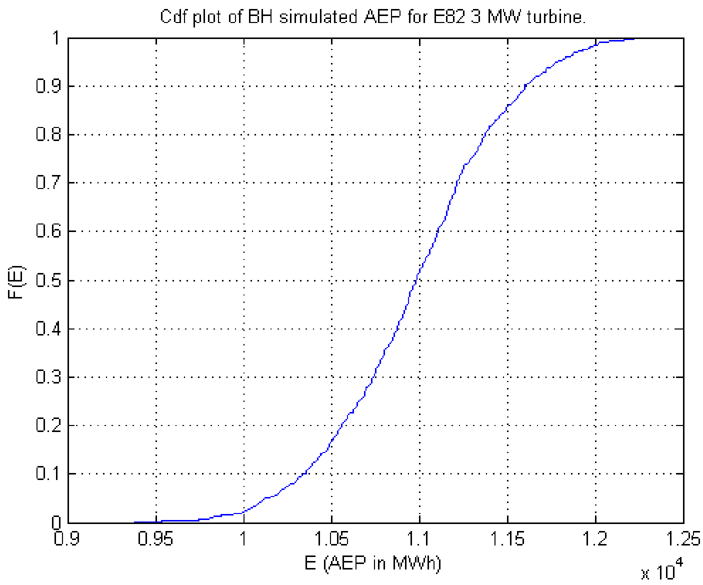


Figure 7.3.: Cdf of MC simulated AEP for the E82 wind turbine at Búrfell.

Setting the wind farm size at Búrfell to 100 MW, equals to installing 33 or 34 E82 wind turbines at the site. Installing 33 E82 turbines would be equal to 99 MW wind farm, 33 turbines will be used as reference in cost calculations. The wind farm including 33 E82 wind turbines would generate 340474.20 MWh annually according the AEP calculations. To set this number into perspective, that would provide approximately 40% of Iceland's home electricity demand or just over 2% of Iceland's industrial electricity demand (Hagstofa, 2012).

7.2. Economical Analysis

Cost data is gathered from Landsvirkjun and literature from international constitutions such as International Renewable Energy Agency (IRENA) and the European Wind Energy Association (EWEA). Experience data from the two test turbines tested at Búrfell is available through Landsvirkjun, this data is used in combination when assessing the levelized cost of energy (LCOE) at Búrfell.

7.2.1. LCOE estimation

The LCOE for Búrfell was assessed using equation 4.12, the inputs in the equation were simulated AEP required from the MC simulation method. Cost data was acquired from Landsvirkjun and IRENA, presented in Tables 2.1 and 2.2. The energy production lifetime of the project was assumed to be 25 years. CAPEX is calculated with the value of 2229 USD/kW and the OPEX is set to 0.015 USD/kWh according to data from Landsvirkjun. CAPEX is assumed to be invested in 2014 and one year is assumed for building the wind farm, first energy production year is thus set to year 2016. OPEX cost was inflated yearly with fixed 2.20 % inflation and WACC was set to 10 % in general LCOE calculation for European comparison and 6 % for Landsvikjun case. Inflation rate estimate was acquired from Hagstofa Íslands. The results of the LCOE estimation is presented in Table 7.4.

Table 7.4.: LCOE estimation for a 99 MW wind generation system at Búrfell

WACC (10%)	Mean	95 % prediction interval	
LCOE [USD/kWh]	0.0807	0.0756	0.0857

The results from the estimated LCOE at Búrfell for a WACC of 10 % shows that compared to LCOE of wind energy project in Europe, the LCOE for wind energy at Búrfell is among the lowest in Europe. This can be seen by comparing results from Table 7.4 and 2.3. To compare the OPEX cost assumed to the values presented in Europe, the 0.015 USD/kWh is approximately 19 % of the LCOE, which is comparable OPEX to data from European projects stating that OPEX was from 11 % to 30 % of LCOE.

7.3. Decision Analysis

For the case of Landsvirkjun the WACC was set to 6%. The results of the LCOE estimation for the Landsvirkjun case is presented in table 7.5. The results conclude that the estimated mean LCOE is 0.0653 USD/kWh. Landsvirkjun has stands before the decision of whether or not to launch the project and build a wind generation system at Búrfell. The decision will rely on the question whether Landsvirkjun can, or can not get a higher price than 0.0616-0.0691 USD per kWh for the wind energy.

Table 7.5.: LCOE estimation for a 99 MW wind generation system at Búrfell

WACC (6%)	Mean	95 % prediction interval	
LCOE [USD/kWh]	0.0653	0.0616	0.0691

7.4. Summary

The wind farm capacity was decided to be 99 MW, this was decided after expert consultancy from Landsvirkjun. Estimated LCOE for the wind generation system at Búrfell was from 0.0756-0.0857 USD per kWh, assuming 10% WACC. This result showed that cost of wind energy harnessing in Búrfell is estimated among the lowest in Europe, see table 2.3. The decision that needs to be faced is whether the cost of 0.0756-0.0857 USD per kWh is profitable for energy harnessing at Búrfell. The answer to that question is out of scope of this thesis and is as a conclusion recommended for further research.

8. Discussion

Wind energy potential assessment and cost analysis of wind energy production at Búrfell revealed that wind energy production cost there is among the lowest production cost in Europe. The reason for this low cost estimation is mainly because of high capacity factor (40.13 % on average) performance from wind turbines at Búrfell. This high capacity factor is obtained because of the steady wind resources available. This was revealed by the wind energy potential assessment.

The wind energy potential assessment also revealed that the E44 wind turbines that were being tested by Landsvirjun at Búrfell were producing significantly more energy than expected. The E44 wind turbine manufacturer Enercon, publishes a power curve for all their wind turbines that can be used to estimate the potential power production of their wind turbines. Calculations showed that measured power production exceeded estimated power production by 21.5 % on average for the two E44 turbines.

This extensive "over" production experienced from the two E44 wind turbines is explained essentially by two factors. Firstly, because Enercon is seemingly on purpose underestimating the potential power production of their wind turbines in their published power curves. Enercon publishes a power curve which reflects the power production Enercon can guarantee from their wind turbines. Secondly, because of surprisingly good performance in Icelandic conditions form the storm control feature installed in the Enercon wind turbines. The storm control feature enables the Enercon turbines to keep producing energy at wind speeds from 25-34 m/s. Even though referenced cut-out wind speed for their wind turbine estimated power curves is set at 25 m/s. Icelandic conditions perhaps include more wind speed values from 25-34 m/s than normally experienced by Enercon, because Enercon states that the storm control feature is taken into consideration in their estimated power curves.

The normalized wind distribution in % for approximately one year measured at the E44 hub height (55 m) is presented in Figure 8.1. It can be seen that not a lot of the mass is above 25 m/s, but note that power production at high wind speed is high. Thus do few values at high wind speeds account for high power production values.

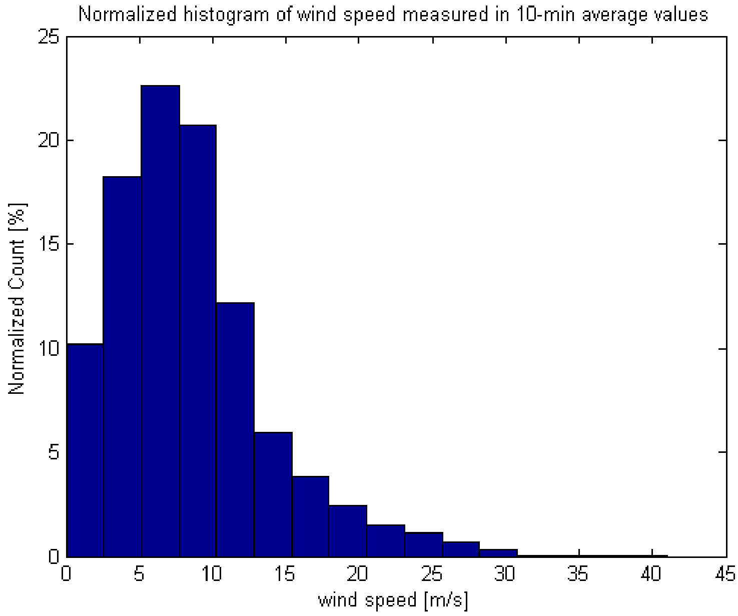


Figure 8.1.: Normalized wind distribution (in %) measured at 55 m height at Búrfell

As a check, the estimated power production for approximately one year was calculated by using wind speeds measured by the wind turbine at its hub height (55 m) and the power curve published by Enercon. In the perfect world the estimated power produced would match the measured power produced because the exact same wind speed values are used in both situations.

The difference plot of measured power vs. estimated on Figure 8.2 however shows that measured power is in most cases slightly higher than the estimated power produced. The points are measured in 10-min average values, there are total of 52560 points in a whole year. A trend seems to be at the beginning of the year or from point 0 to approximately point 43200 (colored blue on Fig. 8.2). On this period the system appears to be stable apart from few high and low peaks which are explained by the wind turbine sometimes shutting off slightly after the cut-out wind speed of 25 m/s and sometimes slightly before. The low peaks can also be explained by unexpected malfunction in the turbine and thus it produces 0 kW at wind speeds where it is estimated to produce power. This explains the peaks in the difference between measured and estimated power production.

After 43200 data points however the system appears to change dramatically and the estimated power production is significantly lower than measured. See for example the data point showing power output of 1009 kW, which exceeds the rated power of the E44 turbine which is 900 kW. But more importantly, analysis revealed that after approximately 43200 data points or in the latter part of the year (colored red on Fig.

8.2), the wind turbine clearly appears to be producing power at wind speeds above 25 m/s. It is evident on Figure 8.2 that in the beginning of the year the estimated power output and the measured power output was in balance but something had changed at the end of the year.

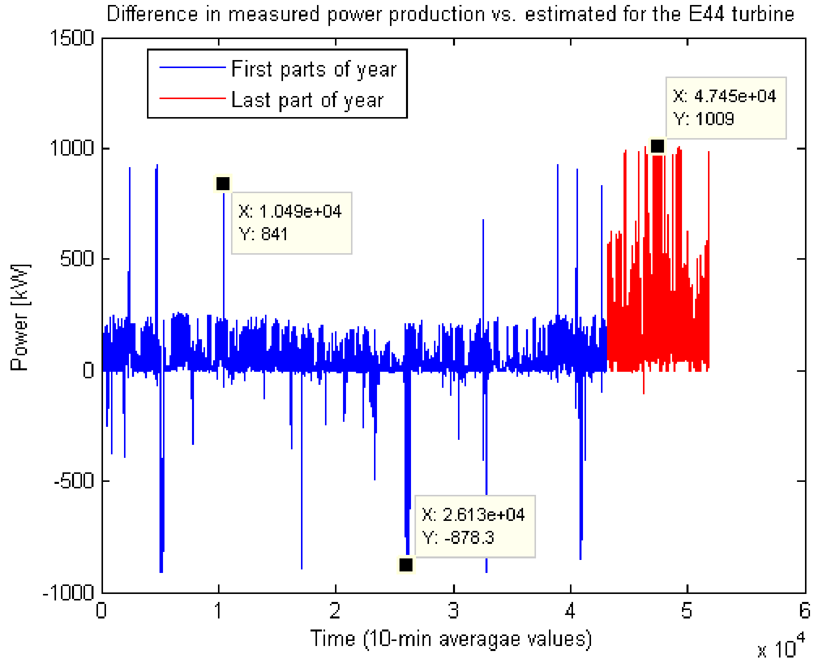


Figure 8.2.: Difference in measured power produced vs. estimated for the E44 turbine.

The conclusion is made that the storm control feature in the E44 turbine at Búrfell was either turned off at first and was turned on for the last part of the year, or re-calibrated for the last part of the year. This could explain the extensive difference in measured power produced vs. estimated in the latter stages of the year. These theories can perhaps also be used to explain the offset in Figure 8.3, which appears to show two different power curves. The first parts of the year is presented by blue scatter points and the last part of the year is colored with red scatter points. Clearly the color plot on Figure 8.3 shows two different power curves which confirms that something was changed in regard to the wind turbine performance capabilities.

For cost calculations it was decided that the AEP would be calculated using an non-scaled power curve from Enercon. Results in section 6.4.1 and Figure 8.4 show that the power curve gives a conservative estimate of the potential AEP at Búrfell. On Figure 8.4 the estimated power curve for the E44 turbine is plotted on top of measured power curve. Notice that the estimated power curve lies within the lower scatter points of the measured curve. A new power curve could have been estimated from measured data, but for this thesis the conservative power curve estimate was used, as recommended by the Enercon wind turbine manufacturer.

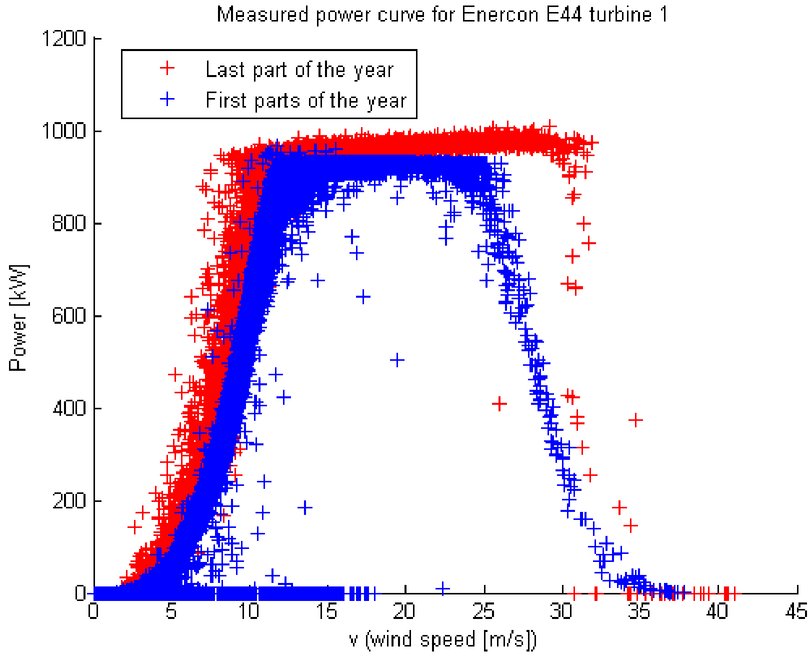


Figure 8.3.: Measured power curve for the E44 wind turbine number 1 at Búrfell at different times of year.

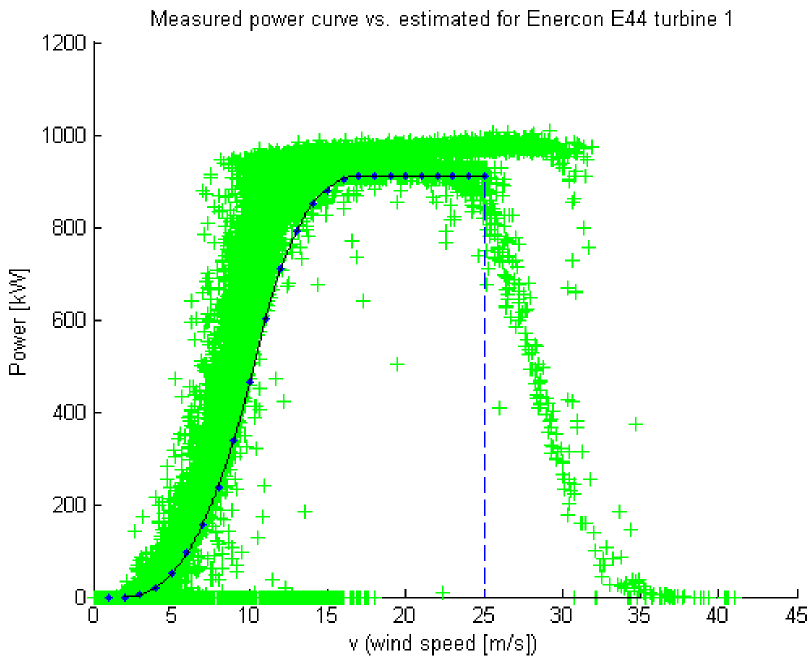


Figure 8.4.: Measured power curve vs. estimated curve for the E44 turbine.

9. Conclusions

This thesis has presented a proposed scenario for a wind generation system at Búrfell, with the capacity of 99 MW using the Enercon E82 3 MW type of wind turbine. The research was set up with the objective to answer two research questions, which were, what is the wind energy potential at Búrfell and what is the LCOE of wind energy at Búrfell?

The answer to the first research question was obtained by wind energy potential assessment in chapter 6 and is presented here below.

1. The wind energy potential assessment revealed that the estimated capacity factor at Búrfell is from 37.11 % to 43.16 %. Which means that wind turbines at Búrfell are estimated to have 40.13 % power produced on average of their rated power production capabilities. The result was obtained using the E44 wind turbine as reference turbine and the MC simulation was used for wind speed simulation. This places the Búrfell site among the highest capacity factor rated sites in Europe and shows high potential for wind energy production.

In contrast to the result from research question number one, harnessing a E82 3 MW wind turbine at Búrfell gives estimated AEP from 9573.52-11182.59 MWh. This estimated AEP result was used to calculate the LCOE of wind energy at Búrfell. Note that this AEP estimation was scaled with fixed wind turbine availability of 93.9 %.

The answer to the second research question was revealed in chapter 7, where the cost analysis was performed. The answer is presented here below.

2. The LCOE of wind energy at Búrfell was estimated from 0.0756-0.0857 USD/kWh, assuming 10% WACC. This places wind energy harnessing at Búrfell in the same category as lowest LCOE for wind energy in Europe. Landsvirkjun sets 6% WACC for their energy projects, the LCOE for Landsvirkjun is thus lower or estimated at 0.0616-0.0691 USD/kWh.

Contributions and key findings

The contributions made to the research of wind energy at Búrfell are listed in the bullet points here below.

- New data was used to calculate the wind shear factor at Búrfell and the result showed that the wind shear factor α is estimated on the interval from 0.1192 to 0.1399, with median value of 0.1309. Comparison of extrapolated wind speed data from 10 m height to 55 m heigt vs. measured wind speed at 55 m height, showed that using the power law with the median wind shear factor of 0.1309 gives a good estimation of how wind speed increases with rising height at Búrfell.

- New simulation method for wind speed distribution at Búrfell, referred as the MC simulation method was selected for wind speed simulation ahead of the established Weibull method. Based on comparison of calculated AEP at Búrfell using simulated AEP vs. measured AEP data from the E44 test turbines at Búrfell. Comparison showed that the mean of MC simulated AEP was closer to measured AEP than Weibull simulated AEP. The prediction interval for the MC simulation was also wider and replicated fluctuations in wind years better than the Weibull simulation. One of the reasons for better estimate of the MC simulation was that the MC simulation simulated blocks of wind speed and thus took into account the autocorrelation in wind, while the Weibull method simulated wind speed independently.

The Weibull simulation showed good result nonetheless, with the mean Weibull simulated AEP being not far from measured AEP. Significant improvement was shown on the Weibull distribution fit to wind speed at Búrfell when dividing the historical data into directional sectors which got fitted each with their own Weibull parameters.

As a conclusion the Weibull method is recommended for wind project sites which experience limited amount of historical data. The MC simulation method is on the other hand recommended for sites which have access to 10 years of historical wind speed data or more. The MC simulation method has the limitation of minimum requirement of 10 years of historical wind speed data.

The analysis of the power production capabilities of the two E44 wind turbines at Búrfell is considered as a contribution to the wind energy research at Búrfell. The results from the analysis is presented here below.

- Estimated calculations of AEP from E44 wind turbines at Búrfell were compared to measured AEP from the E44 turbines. Results showed that calculations of AEP by using power curves provided by the turbine manufacturer, Enercon, underestimated the AEP of the E44 wind turbine by approximately 21.5 %. This significant difference in calculated AEP compared to measured AEP of the E44 turbine can be explained by a storm control feature installed to the wind turbine which enables it to produce power at high wind speeds. The Enercon power curve for the E44 turbine assumes that the wind turbine power production cuts out at 25 m/s. But in real time, the turbine keeps producing power from 25 m/s to 34 m/s with the help of the storm control feature. This storm control feature seemed to work surprisingly well in Icelandic conditions. The extensive power production of the E44 wind turbines at Búrfell has been surprising for Landsvirkjun and even Enercon as it seems. Further details can be found in Chapter 6, section 6.4.1 and the discussion chapter.

This significant underestimation of the Enercon power curves is explained with the theory that Enercon sets a conservative estimation to their wind turbine power production capabilities. The conservative estimation is what Enercon can guarantee that their wind turbines will produce. Enercon recommends the use of their power curves to their buyers when estimating potential AEP. Calculations and analysis for the turbines at Búrfell showed however that the estimated power curves by Enercon may be scaled up because of conservative estimations.

Further research

Suggested further research is to research the potential power price available for the wind energy produced at Búrfell. The LCOE estimation has been done in this research and it would be interesting to see if wind energy is profitable in Iceland. A decision which Landsvirkjun stands up against today.

Several other topics have not been researched yet regarding wind energy at Búrfell such as load flow and dynamics of a wind generation system at Búrfell. Since wind energy is unstable it would be interesting to research the impact of wind energy to the grid in Iceland. Flexibility assessment of wind energy in Iceland is also interesting in the contrast of the potential combination of hydro and wind power, that is, can hydro power be used to balance out peaks in power production from wind? A combination of these researches and more would add up to a complete wind integration study or feasibility study at Búrfell.

References

Akdağ, S. A., & Güler, n. (2010). Evaluation of wind energy investment interest and electricity generation cost analysis for turkey. *Applied Energy*, *87*(8), 2574-2580. doi: http://dx.doi.org/10.1016/j.apenergy.2010.03.015

Berg, J., Mann, J., & Nielsen, M. (2013). *Introduction to micro meteorology for wind energy.* Denmarks Tekniske Universitet (DTU).

Blanco, M. I. (2009). The economics of wind energy. *Renewable and Sustainable Energy Reviews*, *13*(6–7), 1372-1382. doi: http://dx.doi.org/10.1016/j.rser.2008.09.004

Brosamler, G. A. (1988). An almost everywhere central limit theorem. *Mathematical Proceedings of the Cambridge Philosophical Society*, *104*, 561–574. doi: 10.1017/S0305004100065750

Dennis, P. (2010). *Andy & me: Crisis & transformation on the lean journey.* New York: CRC Press.

Djamai, M., & Merzouk, N. K. (2011). Wind farm feasibility study and site selection in adrar, algeria. *Energy Procedia*, *6*(0), 136-142. doi: http://dx.doi.org/10.1016/j.egypro.2011.05.016

Enercon. (2012). *Enercon product overview.* Germany: Enercon wind turbine manufacturer.

Frandsen, S. T. (2007). *Turbulence and turbulencegenerated structural loading in wind turbine clusters.* Denmark: Risø-R-1188(EN).

Gelman, A., Carlin, J. B., Stern, H. S., & Rubin, D. B. (2004). *Bayesian data analysis* (Second ed.). USA: Chapman and Hall/CRC.

GWEC. (2012). *Global wind statistics.* Belgium: Global Wind Energy Council (GWEC).

Hagstofa. (2012). *Raforkunotkun.* Retrieved from `http://www.hagstofa.is/?PageID=2597&src=https://rannsokn.hagstofa.is/pxis/Dialog/varval.asp?ma=IDN02104%26ti=Raforkunotkun+1998-2012+%26path=../Database/idnadur/orkumal/%26lang=3%26units=Megavattstundir`

Helgason, K. (2012). *Selecting optimum location and type of wind turbines in iceland* (MSc thesis). University of Reykjavík, Reykjavik, Iceland.

Holttinen, H. (Ed.). (2013). *Iea wind 2012 annual report.* International Energy Association for Wind.

IRENA. (2012). *Renewable energy technologies: Cost analysis series.* Germany: International Renewable Energy Agency (IRENA).

Madsen, H. (2008). *Time series analysis.* USA: Chapman & Hall/CRC.

Maps, G. (2014). *Map of burfell location in iceland.* Google maps. Retrieved from https://www.google.com/maps/place/64%C2%B007'00.5%22N+19%C2%B044'41.6%22W/@64.1168,-19.7449,6z/data=!4m2!3m1!1s0x0:0x0

Marta-Almeida, M. (2010). *Wind rose of direction and intensity.* Retrieved from http://www.mathworks.com/matlabcentral/fileexchange/17748-wind-rose

Mostafaeipour, A. (2010). Feasibility study of harnessing wind energy for turbine installation in province of yazd in iran. *Renewable and Sustainable Energy Reviews*, *14*(1), 93-111. doi: http://dx.doi.org/10.1016/j.rser.2009.05.009

Nawri, N., Petersen, G. N., Björnsson, H., & Jónasson., K. (2013). *The wind energy potential of iceland.* Reykjavik, Iceland: Icelandic Meteorological Office.

Nielsen, P. s. A., Thyregod, T., & Glar, T. (2012). *Consolidated annual report 2012.* Energinet.dk.

Orkustofnun. (2014). *Orkutölur 2013.* Reykjavík, Iceland. Retrieved from http://os.is/gogn/os-onnur-rit/orkutolur_2013-islenska.pdf

Pantaleo, A., Pellerano, A., Ruggiero, F., & Trovato, M. (2005). Feasibility study of off-shore wind farms: an application to puglia region. *Solar Energy*, *79*(3), 321-331. doi: http://dx.doi.org/10.1016/j.solener.2004.08.030

Peltola, E. (2012). *Wind energy projects in cold climates.* USA: International Energy Association for Wind.

Petersen, J. B., Birgisson, T., Björnsson, H., Jónasson, K., & Nína, G. (2011). *Vindhraðamælingar og sambreytni vinds.* Reykjavik, Iceland: Icelandic Meteorological Office.

Pálmason, A. V. (2010). *Wind power pumped storage system for hydropower plants* (MSc thesis). University of Iceland, Reykjavik, Iceland.

Saeidi, D., Mirhosseini, M., Sedaghat, A., & Mostafaeipour, A. (2011). Feasibility study of wind energy potential in two provinces of iran: North and south khorasan. *Renewable and Sustainable Energy Reviews*, *15*(8), 3558-3569. doi: http://dx.doi.org/10.1016/j.rser.2011.05.011

Strak, K. (2011). *Hep together with wind farm wep : simulation of energy generation and water level in the reservoir* (MSc thesis). University of Akureyri, Akureyri, Iceland.

Tong, L.-I., Chang, C.-W., Jin, S.-E., & Saminathan, R. (2012). Quantifying uncertainty of emission estimates in national greenhouse gas inventories using bootstrap confidence intervals. *Atmospheric Environment*, *56*(0), 80-87. doi: http://dx.doi.org/10.1016/j.atmosenv.2012.03.063

Torres, J. L., García, A., Prieto, E., & Francisco, A. d. (1999). Characterization of wind speed data according to wind direction. *Solar Energy*, *66*(1), 57-64. doi: http://dx.doi.org/10.1016/S0038-092X(99)00007-9

Troen, I., & Petersen, E. (1989). *European wind atlas.* Denmark: Risø National Laboratory.

Wang, H. M. S., Spohn, K. M., Piccard, L., & Yao, L. (2010). Feasibility study of wind power generation system at arctic valley. *Emj-Engineering Management Journal*, *22*(3), 21-33.

A. Appendix - Matlab codes

A.1. Autocorrelation in wind

```matlab
function autocorrelation = acorr(data,lag)

global yhat
global N
N = length(data); % Number of data points
yhat = median(data); %Use median value instead of mean
autocorrelation = zeros(lag,1);

% Autocorrelation at each lag
for i = 1:lag
    autocorrelation(i) = acorr_lag(data,i) ;
end

% Plotting of results

% Assuming that data is normal distributed, we have the rejection lines
% of autocorrelation at +/- 2/sqrt(N).
bar(autocorrelation)
line([0 lag], (2/sqrt(N))*ones(1,2))
line([0 lag], (-2/sqrt(N))*ones(1,2))


title('Autocorrelation')
xlabel('Lag')
set(gca,'YTick',[-1:.20:1])
set(gca,'XTick',floor(linspace(1,lag,8))) % lags ticks shown

% Set axis limits
axis([0 lag -1 1])

%% Calculations of autocorrelation
```

```
function calc = acorr_lag(data,t)

% Calculate autocorrelation at lag t

global yhat
global N
co_sum = zeros(N-t,1) ;

% Covariance
for i = (t+1):N
    co_sum(i) = (data(i)-yhat)*(data(i-t)-yhat) ;
end

% Variance
yvar = (data-yhat)'*(data-yhat) ;

% Autocorrelation function
calc = sum(co_sum) / sum(yvar) ;
```

A.2. Power law

```
% Power law extrapolation from 10 m to 55 m.
close all
clear all
clc

global m_alpha
global F10
global F55

data = xlsread('test_powerlaw.xlsx'); %feb 2013 to feb 2014
    data,
F10 = data(:,2); % Wind speed at 10m height
F55 = data(:,1); % Wind speed at 55m height

T = length(F10);
alpha = zeros(1,T);
for i = 1:T
alpha(i) = [log(F55(i)) - log(F10(i))] / [log(55/10)];
end
alpha(isnan(alpha)) = 0;
m_alpha = median(alpha)
figure, scatter((1:T),alpha,2), xlabel('Time (measured 10-
    min average data)'), ylabel('\alpha_i'), title('Plot of
    the wind shear vector \alpha_i')
figure, plot(F10,F55,'b+'), xlabel('Wind speed at 10 m
    height (m/s)'), ylabel('Wind speed at 55 m height (m/s)')
    , title('Plot of wind speed in 55 m height vs 10 m height
    ')
F_mod_10 = F10(1:80:T);
F_mod_55 = F55(1:80:T);
figure, scatter(F_mod_10,F_mod_55,5,[1 0 1]), xlabel('F10 (m
    /s)'), ylabel('F55 (m/s)')
figure, plot(F_mod_10,'+'), hold, plot(F_mod_55,'+r'),hold
    off, xlabel('F10 (m/s)'), ylabel('F55 (m/s)'), legend('
    Wind speed in 10 m','Wind speed in 55 m','Location','Best
    ')
figure, plot(F_mod_10,F_mod_55,'+'), xlabel('F10 (m/s)'),
    ylabel('F55 (m/s)')

% Bootstrap confidence interval for alpha
median1 = @(x) median(x);
```

```
%boot_int = bootci(2000,median1, alpha) % Bootstrap conf.
    int. with 2000 bootstrap data samples

% Reduced alpha vector because of autocorrelation
r_alpha = alpha(1:6:end);
%r_boot_int = bootci(2000,median1, r_alpha)


%% F10 wind at 10m height extrapolated to 55m height for
    power law check
for c = 1:T
    U_10(c) = F10(c)*(55/10)^(m_alpha);
end


%% Wind speed at 79.5 meters height
for k = 1:T
    U_z(k) = F55(k)*(79.5/55)^(m_alpha);
end
figure,plot((1:T),U_z,'+',(1:T),F55,'r+',(1:T),F10,'y+'),
    legend('Wind speed in 79.5 m','Wind speed in 55 m','Wind
    speed in 10 m','Location','NorthEastOutside'), xlabel('N'
    ), ylabel('Wind speed (m/s)')


%%
data2 = xlsread('6430_2004_2013_full_years'); % data from
    jan 2004 to dec 2013

dir = data2(:,1);
u_10 = data2(:,2);

w = length(u_10);
% Wind speed extrapolated to 55m height.
for s = 1:w
    u_55(s) = u_10(s)*(55/10)^(m_alpha);
end

med_u55_hat = median(u_55) % Estimated 55 m height median
med_F55 = median(F55) % Measured 55 m height median
med_u_10 = median(u_10) % Measured 10 m height median


mean_u55_hat = mean(u_55) % Estimated 55 m height median
```

```
mean_F55 = mean(F55) % Measured 55 m height median
mean_u_10 = mean(u_10) % Measured 10 m height median

% Wind speed extrapolated to 79.5m height.
for s = 1:w
    u_79(s) = u_10(s)*(79.5/10)^(m_alpha);
end

med_u79_hat = median(u_79) % Estimated 55 m height median
med_F55 = median(F55) % Measured 55 m height median
med_u_10 = median(u_10) % Measured 10 m height median


mean_u79_hat = mean(u_79) % Estimated 55 m height median
mean_F55 = mean(F55) % Measured 55 m height median
mean_u_10 = mean(u_10) % Measured 10 m height median

%% Figures

yi = [(min(F55) - 10):0.05:(max(F55) + 20)];
k = ksdensity(u_10,yi);
k_star=ksdensity(u_55,yi);
kk = ksdensity(u_79,yi);
figure, plot(k),hold on, plot(k_star,'--r'), plot(kk,'--g'),
    legend('Measured wind speed at 10 m height', '
    Extrapolated wind speed to 55 m height','Extrapolated
    wind speed to  m height','Location','Best')


%% Turbulence intencity

sigma_55 = std(u_10);
mean_u_55 = mean(u_55);
I_55 = sigma_55./u_10;
I_55_med = median(I_55);
%figure,plot(1:length(u_55),I_55)

test = sigma_55/(mean(u_55));

G = length(u_55);

% 1 hour
l = 6; % Number of 10-min values in 1 hour.
w = length(u_55);
```

```
d = zeros(l,w/l);
d(:,1) = u_55(1:l);
t = 0:l:w;
for i =2:length(d)
    d(:,i) = [u_55(t(i):(t(i)+l-1))];
end

for x = 1:(G/6)
sigma_u(x) = std(d(:,x));
end

for x = 1:(G/6)
mean_u(x) = mean(d(:,x));
end

for x = 1:(G/6)
    turbulence(x) = sigma_u(x)/mean_u(x);
end
turbulence(isnan(turbulence)) = 0;
figure,plot(turbulence), xlabel('Time (measurement periods
    of one hour)'), ylabel('I_u(55)'),title('Turbulence
    intencity')
disp('average turbulence')
mean_turb = mean(turbulence)
disp('median turbulence')
med_turb = median(turbulence)
```

A.3. Enercon estimated power curves

E44 power curve

```
% E-44 900 kW turbine estimated power curve
function P = powercurve_1(v)
v = roundn(v,-2); % round input to two decimals

% Power curve data from source:
u = [1  2     3     4     5     6     7     8
        9     10    11    12    13    14    15
        16    17    18    19    20    21    22
        23    24    25
];
p = [0  0     4     20    50    96    156   238
        340   466   600   710   790   850   880
        905   910   910   910   910   910   910
        910   910   910
];
u = u';
p = p';
% Find parameter for the approximate power curve
% Interval u in (2,11: assume P(u) = a*(u - 2)^b
% Estimate a and b from data
ufit = u(3:11);
pfit = p(3:11);
y = log(pfit);
x = log(ufit-2);
nf = length(x);
X = [ones(nf,1) x];
abhat = inv(X'*X)*X'*y;
a = exp(abhat(1));
b = abhat(2);

% Interval u in (11,13): P(u) = c1*u^2 + c2*u + c3
ivec = [11 12 13];
uvec = u(ivec);
pvec = p(ivec);
A = [uvec.^2  uvec uvec.^0];
c1 = A\pvec;

% Interval u in (13,15): P(u) = c1*u^2 + c2*u + c3
ivec = [13 14 15];
```

```
uvec = u(ivec);
pvec = p(ivec);
A = [uvec.^2  uvec uvec.^0];
c2 = A\pvec;

% Interval u in (15,17): P(u) = c1*u^2 + c2*u + c3
ivec = [15 16 17];
uvec = u(ivec);
pvec = p(ivec);
A = [uvec.^2  uvec uvec.^0];
c3 = A\pvec;

% Interval u in (17,25): P(u) = P(17) = 910
pmax = p(17);

% Interval u in (25,infty): P(u) = 0
pcutout = 0;

up1 = 2:0.01:11;
up1 = roundn(up1,-2);
up2 = 11:0.01:13;
up2 = roundn(up2,-2);
up3 = 13:0.01:15;
up3 = roundn(up3,-2);
up4 = 15:0.01:17;
up4 = roundn(up4,-2);
up5 = 17:0.01:25;
up5 = roundn(up5,-2);
up6 = 25:0.01:35;
up6 = roundn(up6,-2);

p1 = a*(up1 - 2).^b;
p2 = c1(1)*up2.^2 + c1(2)*up2 + c1(3);
p3 = c2(1)*up3.^2 + c2(2)*up3 + c2(3);
p4 = c3(1)*up4.^2 + c3(2)*up4 + c3(3);
p5 = pmax*ones(size(up5));
p6 = pcutout*ones(size(up6));

% Ploting of power curve
% figure,
% plot(u,p,'.')
% hold on
% plot(up1,p1,'k-')
% plot(up2,p2,'k-')
```

```
% plot(up3,p3,'k-')
% plot(up4,p4,'k-')
% plot(up5,p5,'k-')
% plot(up6,p6,'k-')
% plot([up6(1) up6(1)],[pmax pcutout],'--')
%
% hold,title('Simulated power curve for Enercon E44 900kW turbine'), xlabel('v (wind speed [m/s]'), ylabel('Power [kW]')...
%       ,legend('Enercon projected power output','Estimated curve','Location','Best')

% Set up if sentences to release the correct power output in contrast to
% wind speed input v.

    if  v<2
        P = 0;
    elseif v>=2 && v<=11
        P = p1(find(up1==v));
    elseif v>11 && v<=13
        P = p2(find(up2==v));
    elseif v>13 && v<=15
        P = p3(find(up3==v));
    elseif v>15 && v<=17
        P = p4(find(up4==v));
    elseif v>17 && v<=25
        P = 910; % Max energy output from turbine is 910 kW
    elseif v>25
        P = 0;
    end


end
```

E82 power curve

```
% ENERCON E-82 3 MW turbine estimated power curve
function P = powercurve_3020kW(v)
v = roundn(v,-2); % round input to two decimals

% Power curve data from source:
u = [1  2       3       4       5       6       7       8
```

```
            9          10          11          12          13          14          15
           16          17          18          19          20          21          22
           23          24          25
];
p = [0.00         3.00      25.00     82.00     174.00   321.00
    532.00   815.00   1180.00  1580.00  1900.00  2200.00  2480.00
    2700.00  2850.00  2950.00  3020.00  3020.00  3020.00  3020.00
    3020.00  3020.00  3020.00  3020.00  3020.00
];
u = u';
p = p';
% Find parameter for the approximate power curve
% Interval u in (2,5: assume P(u) = a*(u - 2)^b
% Estimate a and b from data
ufit = u(2:5);
pfit = p(2:5);
y = log(pfit);
x = log(ufit -1);
nf = length(x);
X = [ones(nf,1) x];
abhat = inv(X'*X)*X'*y;
a = exp(abhat(1));
b = abhat(2);

% Interval u in (5,7): P(u) = c1*u^2 + c2*u + c3
ivec = [5 6 7];
uvec = u(ivec);
pvec = p(ivec);
A = [uvec.^2  uvec uvec.^0];
c1 = A\pvec;

% Interval u in (7,9): P(u) = c1*u^2 + c2*u + c3
ivec = [7 8 9];
uvec = u(ivec);
pvec = p(ivec);
A = [uvec.^2  uvec uvec.^0];
c2 = A\pvec;

% Interval u in (9,11): P(u) = c1*u^2 + c2*u + c3
ivec = [9 10 11];
uvec = u(ivec);
pvec = p(ivec);
A = [uvec.^2  uvec uvec.^0];
c3 = A\pvec;
```

```

% Interval u in (11,13): P(u) = c1*u^2 + c2*u + c3
ivec = [11 12 13];
uvec = u(ivec);
pvec = p(ivec);
A = [uvec.^2  uvec uvec.^0];
c4 = A\pvec;

% Interval u in (13,15): P(u) = c1*u^2 + c2*u + c3
ivec = [13 14 15];
uvec = u(ivec);
pvec = p(ivec);
A = [uvec.^2  uvec uvec.^0];
c5 = A\pvec;

% Interval u in (15,17): P(u) = c1*u^2 + c2*u + c3
ivec = [15 16 17];
uvec = u(ivec);
pvec = p(ivec);
A = [uvec.^2  uvec uvec.^0];
c6 = A\pvec;

% Interval u in (13,25): P(u) = P(13) = 3050
pmax = p(17);

% Interval u in (25,infty): P(u) = 0
pcutout = 0;

up1 = 1:0.01:5;
up1 = roundn(up1,-2);
up2 = 5:0.01:7;
up2 = roundn(up2,-2);
up3 = 7:0.01:9;
up3 = roundn(up3,-2);
up4 = 9:0.01:11;
up4 = roundn(up4,-2);
up5 = 11:0.01:13;
up5 = roundn(up5,-2);
up6 = 13:0.01:15;
up6 = roundn(up6,-2);
up7 = 15:0.01:17;
up7 = roundn(up7,-2);
up8 = 17:0.01:25;
up8 = roundn(up8,-2);
```

```
up9 = 25:0.01:35;
up9 = roundn(up9,-2);

p1 = a*(up1 - 1).^b;
p2 = c1(1)*up2.^2 + c1(2)*up2 + c1(3);
p3 = c2(1)*up3.^2 + c2(2)*up3 + c2(3);
p4 = c3(1)*up4.^2 + c3(2)*up4 + c3(3);
p5 = c4(1)*up5.^2 + c4(2)*up5 + c4(3);
p6 = c5(1)*up6.^2 + c5(2)*up6 + c5(3);
p7 = c6(1)*up7.^2 + c6(2)*up7 + c6(3);
p8 = pmax*ones(size(up8));
p9 = pcutout*ones(size(up9));

%%Ploting of 3 MW power curve
%figure,
%
% plot(u,p,'.')
% hold on
% plot(up1,p1,'k-')
% plot(up2,p2,'k-')
% plot(up3,p3,'k-')
% plot(up4,p4,'k-')
% plot(up5,p5,'k-')
% plot(up6,p6,'k-')
% plot(up7,p7,'k-')
% plot(up8,p8,'k-')
% plot(up9,p9,'k-')
% plot([up9(1) up9(1)],[pmax pcutout],'--')
%
% hold,title('Simulated power curve for Enercon E82 3000kW
    turbine'), xlabel('v (wind speed [m/s]'), ylabel('Power [
   kW]')...
%      ,legend('Enercon projected power output','Estimated
    curve','Location','Best')

% Set up if sentences to release the correct power output in
     contrast to
% wind speed input v.

      if  v<2
           P = 0;
      elseif v>=2 && v<=5
           P = p1(find(up1==v));
      elseif v>5 && v<=7
```

```
            P = p2(find(up2==v));
        elseif v>7 && v<=9
            P = p3(find(up3==v));
        elseif v>9 && v<=11
            P = p4(find(up4==v));
        elseif v>11 && v<=13
            P = p5(find(up5==v));
        elseif v>13 && v<=15
            P = p6(find(up6==v));
        elseif v>15 && v<=17
            P = p7(find(up7==v));
        elseif v>17 && v<=25
            P = 3020; % Max energy output from turbine is 910 kW
        elseif v>25
            P = 0;
        end


end
```

A.4. Weibull simulation method

```
% Weibull simulation of wind data
clear all
close all
clc

%% Data reading

d = xlsread('simulation_data.xlsx'); % data from february
    2004 to february 2014.

v_10 = d(:,7); % wind speed data (10-min average data) 10
    years of data
d_10 = d(:,6); % direction of the wind speed

%% Extrapolte data using wind shear factor alpha from power
    law calculations
% v_10 wind at 10m height extrapolated to 55m height for
    power law check

m_alpha = 0.1309; %median alpha value from power law calc.
T = length(v_10);

% Wind speed at 55 meters height
for i = 1:T
    v_55(i) = v_10(i)*(55/10)^(m_alpha);
end


%% Weibull fit method using built in weibull functions

% Data fix for weibull
v_55(find(v_55==0)) = 0.00000000001; % the vector can not
    contain zero value data for weibull fit

% First we fit one weibull distribution to all data:

[PARMHAT,PARMCI] = wblfit(v_55); % First param. is the scale
     param., A and second is the shape param., B

A = PARMHAT(1);
kpar1 = PARMHAT(2);
```

```

yi = linspace(min(v_55)-5,max(v_55) +10,1000);

Y = wblpdf(yi,A,kpar1);
P = wblcdf(yi,A,kpar1);

ks = ksdensity(v_55,yi);
figure, plot(yi,Y,'r--'), hold, plot(yi,ks), title('Pdf plot of Weibull fitted data vs. measured data'), xlabel('v (wind speed [m/s])'), ylabel('f(v)'), legend('Weibull simulation', 'Measured wind speed data', 'Location', 'Best')
figure, plot(yi,P, 'r--'), hold, cdfplot(v_55), title('Cdf plot of Weibull fitted data vs. measured data'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'),legend('Weibull fit', 'Measured data', 'Location', 'Best')


%% Secondly we fit a weibull distribution to each directional sector


% Divide data into 8 sectors
sec1_half1 = v_55(find(d_10>337.5 & d_10<=360)); % North, N, first half
sec1_half2 = v_55(find(d_10>=0 & d_10<=22.5)); % North, N, second half
sec1 = [sec1_half1 sec1_half2]; % North, N full section
sec2= v_55(find(d_10>22.5 & d_10<=67.5)); % North East, NE
sec3= v_55(find(d_10>67.5 & d_10<=112.5)); % East, E
sec4= v_55(find(d_10>112.5 & d_10<=157.5)); % South East, SE
sec5= v_55(find(d_10>157.5 & d_10<=202.5)); % South, S
sec6= v_55(find(d_10>202.5 & d_10<=247.5)); % South West, SW
sec7= v_55(find(d_10>247.5 & d_10<=292.5)); % West, W
sec8= v_55(find(d_10>292.5 & d_10<=337.5)); % North West, NW


check = [sec1 sec2 sec3 sec4 sec5 sec6 sec7 sec8];
sc = size(check) % check if the sections include all data, sc should have same length as v_55.

%% Calculate frequncy in each sector

ff = length(v_55);
```

```
f1 = length(sec1)/ff;
f2 = length(sec2)/ff;
f3 = length(sec3)/ff;
f4 = length(sec4)/ff;
f5 = length(sec5)/ff;
f6 = length(sec6)/ff;
f7 = length(sec7)/ff;
f8 = length(sec8)/ff;

freq = [f1 f2 f3 f4 f5 f6 f7 f8];
total = f1+f2+f3+f4+f5+f6+f7+f8 % shold add up to one

% Calc for wblrnd generation

N = 1000*52560; % number of generated wind data points (same
    as in simulation method)
fn1 = f1*N;
fn2 = f2*N;
fn3 = f3*N;
fn4 = f4*N;
fn5 = f5*N;
fn6 = f6*N;
fn7 = f7*N;
fn8 = f8*N;

f = [fn1 fn2 fn3 fn4 fn5 fn6 fn7 fn8];
% Sectors f2 and f6 have the highest freq. this is verified
   in wind rose
% diagram

% Mean wind speed in each sector

m1 = mean(sec1);
m2 = mean(sec2);
m3 = mean(sec3);
m4 = mean(sec4);
m5 = mean(sec5);
m6 = mean(sec6);
m7 = mean(sec7);
m8 = mean(sec8);

m_sec = [m1 m2 m3 m4 m5 m6 m7 m8];
```

```
%% Zero values

% set zero values from data aside - they are effecting the Weibull estimate in
% a negative matter.
% Use weibull to estimate non-zero wind speeds

% Count zero values from data

z1 = find(sec1 == 1e-11);
c1 = length(z1)/length(sec1); % calculate the frequency of zero values in sector
sec1(z1) = []; % remove zero values from sector

z2 = find(sec2 == 1e-11);
c2 = length(z2)/length(sec2); % calculate the frequency of zero values in sector
sec2(z2) = []; % remove zero values from sector

z3 = find(sec3 == 1e-11);
c3 = length(z3)/length(sec3); % calculate the frequency of zero values in sector
sec3(z3) = []; % remove zero values from sector

z4 = find(sec4 == 1e-11);
c4 = length(z4)/length(sec4); % calculate the frequency of zero values in sector
sec4(z4) = []; % remove zero values from sector

z5 = find(sec5 == 1e-11);
c5 = length(z5)/length(sec5); % calculate the frequency of zero values in sector
sec5(z5) = []; % remove zero values from sector

z6 = find(sec6 == 1e-11);
c6 = length(z6)/length(sec6); % calculate the frequency of zero values in sector
sec6(z6) = []; % remove zero values from sector

z7 = find(sec7 == 1e-11);
c7 = length(z7)/length(sec7); % calculate the frequency of zero values in sector
```

```
sec7(z7) = []; % remove zero values from sector

z8 = find(sec8 == 1e-11);
c8 = length(z8)/length(sec8); % calculate the frequency of
    zero values in sector
sec8(z8) = []; % remove zero values from sector

c = [c1 c2 c3 c4 c5 c6 c7 c8];

%% Weibull parameters for each section
[PARMHAT,PARMCI] = wblfit(sec1); % First param. is the scale
     param., A and second is the shape param., B

A1 = PARMHAT(1);
B1 = PARMHAT(2);

yi = linspace(min(sec1)-5,max(sec1) +10,1000);

Y1 = wblpdf(yi,A1,B1);
P1 = wblcdf(yi,A1,B1);

ks = ksdensity(sec1,yi);
figure, plot(yi,Y1,'r--'), hold, plot(yi,ks),title('Pdf plot
     of weibull estimate of N sector vs. measured N sector'),
     xlabel('v (wind speed [m/s])'), ylabel('f(v)'),legend('
    Weibull estimate of N sector','Measured N sector','
    Location','Best')
figure, plot(yi,P1, 'r--'), hold, cdfplot(sec1),title('Cdf
    plot of weibull estimate of N sector vs. measured N
    sector'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'),
    legend('Weibull estimate of N sector','Measured N sector'
    ,'Location','Best')


[PARMHAT,PARMCI] = wblfit(sec2); % First param. is the scale
     param., A and second is the shape param., B

A2 = PARMHAT(1);
B2 = PARMHAT(2);

yi = linspace(min(sec2)-5,max(sec2) +10,1000);

Y1 = wblpdf(yi,A2,B2);
P1 = wblcdf(yi,A2,B2);
```

```

ks = ksdensity(sec2,yi);
figure, plot(yi,Y1,'r--'), hold, plot(yi,ks),title('Pdf plot of weibull estimate of NE sector vs. measured NE sector'), xlabel('v (wind speed [m/s])'), ylabel('f(v)'),legend('Weibull estimate of NE sector','Measured NE sector','Location','Best')
figure, plot(yi,P1, 'r--'), hold, cdfplot(sec2),title('Cdf plot of weibull estimate of NE sector vs. measured NE sector'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'), legend('Weibull estimate of NE sector','Measured NE sector','Location','Best')


[PARMHAT,PARMCI] = wblfit(sec3); % First param. is the scale param., A and second is the shape param., B

A3 = PARMHAT(1);
B3 = PARMHAT(2);

yi = linspace(min(sec3)-5,max(sec3) +10,1000);

Y2 = wblpdf(yi,A3,B3);
P2 = wblcdf(yi,A3,B3);

ks = ksdensity(sec3,yi);
figure, plot(yi,Y2,'r--'), hold, plot(yi,ks),title('Pdf plot of weibull estimate of E sector vs. measured E sector'), xlabel('v (wind speed [m/s])'), ylabel('f(v)'),legend('Weibull estimate of E sector','Measured E sector','Location','Best')
figure, plot(yi,P2, 'r--'), hold, cdfplot(sec3),title('Cdf plot of weibull estimate of E sector vs. measured E sector'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'), legend('Weibull estimate of E sector','Measured E sector','Location','Best')


[PARMHAT,PARMCI] = wblfit(sec4); % First param. is the scale param., A and second is the shape param., B

A4 = PARMHAT(1);
B4 = PARMHAT(2);

```

```
yi = linspace(min(sec4)-5,max(sec4) +10,1000);

Y1 = wblpdf(yi,A4,B4);
P1 = wblcdf(yi,A4,B4);

ks = ksdensity(sec4,yi);
figure, plot(yi,Y1,'r--'), hold, plot(yi,ks),title('Pdf plot of weibull estimate of SE sector vs. measured SE sector'), xlabel('v (wind speed [m/s])'), ylabel('f(v)'),legend('Weibull estimate of SE sector','Measured SE sector','Location','Best')
figure, plot(yi,P1, 'r--'), hold, cdfplot(sec4),title('Cdf plot of weibull estimate of SE sector vs. measured SE sector'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'), legend('Weibull estimate of SE sector','Measured SE sector','Location','Best')


[PARMHAT,PARMCI] = wblfit(sec5); % First param. is the scale param., A and second is the shape param., B

A5 = PARMHAT(1);
B5 = PARMHAT(2);

yi = linspace(min(sec5)-5,max(sec5) +10,1000);

Y1 = wblpdf(yi,A5,B5);
P1 = wblcdf(yi,A5,B5);

ks = ksdensity(sec5,yi);
figure, plot(yi,Y1,'r--'), hold, plot(yi,ks),title('Pdf plot of weibull estimate of S sector vs. measured S sector'), xlabel('v (wind speed [m/s])'), ylabel('f(v)'),legend('Weibull estimate of S sector','Measured S sector','Location','Best')
figure, plot(yi,P1, 'r--'), hold, cdfplot(sec5),title('Cdf plot of weibull estimate of S sector vs. measured S sector'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'), legend('Weibull estimate of S sector','Measured S sector','Location','Best')

[PARMHAT,PARMCI] = wblfit(sec6); % First param. is the scale param., A and second is the shape param., B

```

```
A6 = PARMHAT(1);
B6 = PARMHAT(2);

yi = linspace(min(sec6)-5,max(sec6) +10,1000);

Y6 = wblpdf(yi,A6,B6);
P6 = wblcdf(yi,A6,B6);

ks = ksdensity(sec6,yi);
figure, plot(yi,Y6,'r--'), hold, plot(yi,ks),title('Pdf plot
    of weibull estimate of SW sector vs. measured SW sector'
   ), xlabel('v (wind speed [m/s])'), ylabel('f(v)'),legend(
   'Weibull estimate of SW sector','Measured SW sector','
   Location','Best')
figure, plot(yi,P6, 'r--'), hold, cdfplot(sec6),title('Cdf
   plot of weibull estimate of SW sector vs. measured SW
   sector'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'),
   legend('Weibull estimate of SW sector','Measured SW
   sector','Location','Best')

[PARMHAT,PARMCI] = wblfit(sec7); % First param. is the scale
    param., A and second is the shape param., B

A7 = PARMHAT(1);
B7 = PARMHAT(2);

yi = linspace(min(sec7)-5,max(sec7) +10,1000);

Y1 = wblpdf(yi,A7,B7);
P1 = wblcdf(yi,A7,B7);

ks = ksdensity(sec7,yi);
figure, plot(yi,Y1,'r--'), hold, plot(yi,ks),title('Pdf plot
    of weibull estimate of W sector vs. measured W sector'),
    xlabel('v (wind speed [m/s])'), ylabel('f(v)'),legend('
   Weibull estimate of W sector','Measured W sector','
   Location','Best')
figure, plot(yi,P1, 'r--'), hold, cdfplot(sec7),title('Cdf
   plot of weibull estimate of W sector vs. measured W
   sector'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'),
   legend('Weibull estimate of W sector','Measured W sector'
   ,'Location','Best')

[PARMHAT,PARMCI] = wblfit(sec8); % First param. is the scale
```

```
param., A and second is the shape param., B

A8 = PARMHAT(1);
B8 = PARMHAT(2);

yi = linspace(min(sec8)-5,max(sec8) +10,1000);

Y1 = wblpdf(yi,A8,B8);
P1 = wblcdf(yi,A8,B8);

ks = ksdensity(sec8,yi);
figure, plot(yi,Y1,'r--'), hold, plot(yi,ks),title('Pdf plot of weibull estimate of NW sector vs. measured NW sector'), xlabel('v (wind speed [m/s])'), ylabel('f(v)'),legend('Weibull estimate of NW sector','Measured NW sector','Location','Best')
figure, plot(yi,P1, 'r--'), hold, cdfplot(sec8),title('Cdf plot of weibull estimate of NW sector vs. measured NW sector'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'), legend('Weibull estimate of NW sector','Measured NW sector','Location','Best')

% setup vectors for A and k parameters

Apar = [A1 A2 A3 A4 A5 A6 A7 A8];
kpar = [B1 B2 B3 B4 B5 B6 B7 B8];

%% Weibull simulation

%
% Constants in simulation. Gathered from measured data.
p_geirar = freq; %ratio of each sector in whole year
p_null = c; % ratio of zero's in each sector, simulated separately
N_year = 52560;

% Weibull parameters
wpar = zeros(2,8);
wpar(1,:) = Apar;
wpar(2,:) = kpar;

% for loop starts
D = 2000;
wind_sim = zeros(D,N_year);
```

```
for k = 1:D
% Grunn thaettir i hermun
% Frequency simulation
N_geirar_sim = mnrnd(N_year,p_geirar); %set variation on the
    ratio of amount of data in each sector
N_01 = zeros(2,8);
N_01(1,:) = binornd(N_geirar_sim,p_null); % set variation on
    how many zero values are in each sector
N_01(2,:) = N_geirar_sim - N_01(1,:);
Nref1 = sum(N_01(1,:));
Ncump = Nref1 + cumsum(N_01(2,:));
Ncumm(1) = Nref1 + 1;
Ncumm(2:8) = Ncump(1:7) + 1;

% Weibull simulation
wind_temp = zeros(1,N_year);
for j = 1:8
    wind_temp(Ncumm(j):Ncump(j)) = wblrnd(wpar(1,j),wpar(2,j
        ),1,N_01(2,j));
end
wind_sim(k,:) = wind_temp;
end

% for loop ends

% Plot results and compare to measured data
wbl_wind = reshape(wind_sim,1,2000*52560);
wbl_wind(find(wbl_wind==0)) = 1e-11;
yi = linspace(min(wbl_wind)-5,max(wbl_wind) +10,1000);

[PARMHAT,PARMCI] = wblfit(wbl_wind); % First param. is the
    scale param., A and second is the shape param., B

A_sim = PARMHAT(1);
k_sim = PARMHAT(2);

yi = linspace(min(v_55)-5,max(v_55) +10,1000);

Psim = wblcdf(yi,A_sim,k_sim);


% ks_mea = ksdensity(v_55,yi);
% ks_wbl = ksdensity(wbl_wind,yi);
% figure, plot(yi,ks_wbl,'r--'),hold, plot(yi,ks_mea),title
```

```
('Pdf plot of weibull fitted data vs. measured data'), legend('Weibull simulation','Measured wind speed data','Location','Best'),xlabel('v (wind speed [m/s])'), ylabel('f(v)')
% figure, plot(yi,Psim, 'r--'), hold, cdfplot(v_55), title('Cdf plot of Weibull fitted data vs. measured data'), xlabel('v (wind speed [m/s])'), ylabel('F(v)'),legend('Weibull simulation', 'Measured wind speed data', 'Location', 'Best')
%

%% Two highest freq. sectors plotted together with total measured pdf

% yi = linspace(min(sec2)-5,max(sec2) +10,1000);
%
% ks = ksdensity(v_55,yi);
% figure, plot(yi,Y2,'r--'),hold, plot(yi,Y6,'r--'), hold on, plot(yi,ks), title('Pdf plot of weibull fitted data vs. measured data')
% figure, plot(yi,P2, 'r--'),hold, plot(yi,P6,'r--'), hold on, cdfplot(v_55), legend('NE sector','SW sector','Total measured data','Location','Best')

%% Calculate AEP with Weibull fit
n = 52560; % number of 10-min average data points in 1 year

for q = 1:2000 % q is number of simulated years

y = wind_sim(q,:);

for t = 1:n
        [P] = powercurve_3050kW(y(t)); % Calculate power output from turbine at each 10-min simulated data point
        power(t) = P; % Collect power output values to a vector
end
 %pp(:,q) = power;   % store power output each year [kW]
 AEP(q) = sum(power); % sum of power output in kW

% AEP for each simulated year

AEP_k(q) = 365*24*1*(1/n)*AEP(q); % AEP in kWh at simulated
```

```
year k.

end

figure, plot(AEP_k), title('AEP for one turbine each simulated year'), xlabel('Number of simulated year'), ylabel('AEP [MWh]')
figure,ksdensity(AEP_k),xlabel('E (AEP in [MWh])'), ylabel('f(E)'), title('Pdf plot of simulated AEP for one 900kW (55 m hub height) turbine at Burfell.'), set(gca,'XTick',[2.5*10^6:2e6:4*10^6]),set(gca,'XLim',[2.5*10^6 4*10^6])
figure, cdfplot(AEP_k), xlabel('E (AEP in MWh)'), ylabel('F(E)'),title('Cdf of AEP for simulation')
```

A.5. Wind MC simulation method

```
% MC Simulation of wind data
clear all
close all
clc

%% Data reading

d = xlsread('simulation_data.xlsx'); % data from february
    2004 to february 2014.

v_10 = d(:,7); % wind speed data (10-min average data) 10
    years of data

%% Extrapolte data using wind shear factor alpha from power
    law calculations
% v_10 wind at 10m height extrapolated to 55m height for
    power law check

m_alpha = 0.1309; %median alpha value from power law calc.
T = length(v_10);

% Wind speed at 55 meter height - for the E44 wind turbine
for i = 1:T
    v_55(i) = v_10(i)*(55/10)^(m_alpha);
end


% Wind speed at 78 meter height - for the E82 wind turbine
for k = 1:T
    v_78(k) = v_10(k)*(78/10)^(m_alpha);
end


%% Simulation preface

% First we set the blocks up in the year according to acf
    results
% The result was that acf fades out after 5 days

blocks = (365*10)/5; % Number of 5-day blocks in 10 years
n = 6*24*5; % Number of data points in 5 days
```

```

% Cut years into 5 day blocks
h = 1:blocks;
upper = h*n; % upper block limit
lower = (h*n - (n-1)); %lower block limit


T = 24*6*365; % number of data points in one year
v_78_1 = v_78(1:T*10); % 10 year data fix
N = length(v_78_1);

% build matrix
day_blocks = zeros(n,blocks);

for h = 1:blocks
    day_blocks(:,h) = v_78_1(lower(h):upper(h));
end

% create matrix to store blocks

c = cell(10,73);
% Assign blocks to its year
lower1 = 1:73:730;
upper1 = 73:73:730;

for g1 = lower1(1):upper1(1)
        c{1,g1} = day_blocks(:,g1);
end

g2 = lower1(2):upper1(2);
for f =1:73

        c{2,f} = day_blocks(:,g2(f));
end

g3 = lower1(3):upper1(3);
for f =1:73

        c{3,f} = day_blocks(:,g3(f));
end

g4 = lower1(4):upper1(4);
for f =1:73

```

```
        c{4,f} = day_blocks(:,g4(f));
end

g5 = lower1(5):upper1(5);
for f =1:73

        c{5,f} = day_blocks(:,g5(f));
end

g6 = lower1(6):upper1(6);
for f =1:73

        c{6,f} = day_blocks(:,g6(f));
end

g7 = lower1(7):upper1(7);
for f =1:73

        c{7,f} = day_blocks(:,g7(f));
end

g8 = lower1(8):upper1(8);
for f =1:73

        c{8,f} = day_blocks(:,g8(f));
end

g9 = lower1(9):upper1(9);
for f =1:73

        c{9,f} = day_blocks(:,g9(f));
end

g10 = lower1(10):upper1(10);
for f =1:73

        c{10,f} = day_blocks(:,g10(f));
end

%% Simulate wind years
B = zeros(1000,52560);
for q = 1:1000


```

```
p = unidrnd(10,1,73); % set equal probability to all years
%b = zeros(720,73);
%b(:,1) = c{p(1),1};
for s = 1:73
    b(:,s) = [c{p(s),s}]; % One year of data drawn with 1/10
        probability
end

b_vector = reshape(b,1,T);
B(q,:) = b_vector;
end

B_vec = reshape(B,1,1000*52560); % one vector with all
    simulated data.



% plot comparison of simulation and measured data
% yi = linspace(min(v_78)-5,max(v_78) +10,1000);
% ks = ksdensity(v_78,yi);
% ks_sim = ksdensity(B_vec,yi);
% figure, plot(yi,ks_sim,'r--'), hold, plot(yi,ks), title('
    Pdf plot of simulated fit vs. measured data'), xlabel('v
    (wind speed [m/s])'), ylabel('f(v)'), legend('Simulated
    fit', 'Measured wind speed data', 'Location', 'Best')
% %figure, plot(yi,P, 'r--'), hold, cdfplot(v_78), title('
    Cdf plot of Weibull fitted data vs. measured data'),
    xlabel('v (wind speed [m/s])'), ylabel('F(v)'),legend('
    Weibull fit', 'Measured data', 'Location', 'Best')


%% Plots of simulation
%
% for e = 1:1000
% ksdensity(B(e,:),yi),hold on, plot(yi,ks,'k')
% end
%

% for e = 1:1000
% cdfplot(B(e,:)),hold on
% end
%% Calculating the AEP
%
% real_prod_turb2 = 3096487-157066 % 1 year production in
```

```
kWh, data from LV (1/2/2013−1/2/2014)
% real_prod_turb1 = 3358726−173959 % 1 year production in
    kWh, data from LV (1/2/2013−1/2/2014)
%
% % power = zeros(1,52560);
% % AEP = zeros(1,1);
% for q = 1:1000
% y = B(q,:);
%     for t = 1:T
%         [P] = powercurve_3020kW(y(t)); % Calculate power
    output from turbine at each 10−min simulated data point
%         power(t) = P; % Collect power output values to a
    vector
%     end
% AEP(q) = sum(power); % sum of power output in kW
% end
%
% % AEP for each simulated year
% for k = 1:q
%     AEP_k(k) = 365*24*1*(1/T)*AEP(k); % AEP in kWh at
    simulated year k.
% end
%
% AEP_k = AEP_k/1000; %Change unit to MWh
% figure, plot(AEP_k), title('AEP for one turbine each
    simulated year'), xlabel('Number of simulated year'),
    ylabel('AEP [MWh]')
% figure,ksdensity(AEP_k), xlabel('E (AEP in [MWh])'),
    ylabel('f(E)'), title('Pdf plot of Weibull simulated AEP
    for E44 900kW turbine.'), set(gca,'XTick
    ',[3*10^3:25:3.125*10^3]),set(gca,'XLim',[3*10^3
    3.125*10^3])
% figure, cdfplot(AEP_k), xlabel('E (AEP in MWh)'), ylabel('
    F(E)'),title('Cdf plot of Weibull simulated AEP for E44
    900kW turbine.')

%% sum of total wind per year

% To check if wind speed is increasing by each year.
winc = zeros(1,10);
for j = 1:10
r=sum(cell2mat(c(j,:)));
tot(j) = sum(r);
winc(j) = tot(j);
```

```
end
years = 2004:1:2013;
figure, plot(years, winc),title('Sum of wind per year [m/s]'), xlabel('Year'), ylabel('Sum of wind speed [m/s]')

m_winc = mean(winc);
std_winc = std(winc);

diff = zeros(1,5);
diff(1) = winc(1)-winc(2);
for d = 2:9
diff(d) = winc(d)-winc(d+1);
end

% Use t-test to check if the difference comes from a distribution with mean
% zero.
ttest(diff);
%Test shows that mean of diff is zero, with 5% significance level


%% AEP for the year 1/2/2013 - 1/2/2014 measured vs. simulated with power curve
winddata = xlsread('vindmyllur_feb2013_feb2014.xlsx');

v_1 = winddata(:,1); % wind speed measured from turbine 1 hub height
v_2 = winddata(:,5); % wind speed measured from turbine 2 hub height
AEP_meas_turb1 = winddata(:,4);
AEP_meas_turb2 = winddata(:,8);
AEP_meas_turb1kw = winddata(:,3); % Production in kW for turbine 1
AEP_meas_turb2kw = winddata(:,7); % Production in kW for turbine 2
v_2013_14 = winddata(:,1);
power = zeros(1,52560);
yt = v_2013_14;
yt2 = v_2;

% Real power curves
figure,plot(v_1,AEP_meas_turb1kw,'+'),title('Measured power curve for Enercon E44 turbine 1'), xlabel('v (wind speed
```

```
[m/s]'), ylabel('Power [kW]') % Turbine 1
figure,plot(v_2,AEP_meas_turb2kw,'+'),title('Measured power curve for Enercon E44 turbine 2'), xlabel('v (wind speed [m/s]'), ylabel('Power [kW]')  % Turbine 2

% Two color plot
figure,plot(v_1(1:43200),AEP_meas_turb1kw(1:43200),'+'),hold on, plot(v_1(43200:end),AEP_meas_turb1kw(43200:end),'r+'),title('Measured power curve for Enercon E44 turbine 1'), xlabel('v (wind speed [m/s])'), ylabel('Power [kW]'), legend('First parts of year','Last part of year','Location','Best') % Turbine 1

% Measured power production data
for t = 1:length(yt)
        [P] = powercurve_1(yt(t)); % Calculate power output from turbine 2 at each 10-min simulated data point
        power1(t) = P; % Collect power output values to a vector
end

for t = 1:length(yt2)
        [P2] = powercurve_1(yt2(t)); % Calculate power output from turbine 2 at each 10-min simulated data point
        power2(t) = P2; % Collect power output values to a vector
end


% AEP_13 = sum(power); % sum of power output in kW
%
% % AEP for 2013
%
% AEP_k13 = 365*24*1*(1/T)*AEP_13; % AEP in kWh at simulated year k.

% Measured power

N1 = length(AEP_meas_turb1kw);
blocks_h = N1/6; % Number of hours in 1 year
nh = 6; % Number of data points in 1 hour

```

```
% Cut years into hourly block data
h_h = 1:blocks_h;
upperh = h_h*nh; % upper block limit
lowerh = (h_h*nh - (nh-1)); %lower block limit

% Turbine 1
real_power = zeros(1,blocks_h);
for tt12 = 1:blocks_h
        real_power(tt12) = sum(AEP_meas_turb1kw(lowerh(tt12):
           upperh(tt12)));
end


real_power12 = zeros(1,blocks_h/12);
for tt12 = 1:blocks_h/12
        real_power12(tt12) = sum(AEP_meas_turb1kw(lowerh(tt12
           ):upperh(tt12)));
end

real_power24 = zeros(1,blocks_h/24);
for tt12 = 1:blocks_h/24
        real_power24(tt12) = sum(AEP_meas_turb1kw(lowerh(tt12
           ):upperh(tt12)));
end

% Turbine 2
real_power2 = zeros(1,blocks_h);
for tt12 = 1:blocks_h
        real_power2(tt12) = sum(AEP_meas_turb2kw(lowerh(tt12)
           :upperh(tt12)));
end

real_power12_2 = zeros(1,blocks_h/12);
for tt12 = 1:blocks_h/12
        real_power12_2(tt12) = sum(AEP_meas_turb2kw(lowerh(
           tt12):upperh(tt12)));
end

real_power24_2 = zeros(1,blocks_h/24);
for tt12 = 1:blocks_h/24
        real_power24_2(tt12) = sum(AEP_meas_turb2kw(lowerh(
           tt12):upperh(tt12)));
end

```

```
% Simulated power turbine 1
h_power = zeros(1,blocks_h);
for tt12 = 1:blocks_h
        h_power(tt12) = sum(power1(lowerh(tt12):upperh(tt12)));
end


h_power12 = zeros(1,blocks_h/12);
for tt12 = 1:blocks_h/12
        h_power12(tt12) = sum(power1(lowerh(tt12):upperh(tt12)));
end

h_power24 = zeros(1,blocks_h/24);
for tt24 = 1:blocks_h/24
        h_power24(tt24) = sum(power1(lowerh(tt24):upperh(tt24)));
end

% Simulated power turbine 2
h_power_2 = zeros(1,blocks_h);
for tt12 = 1:blocks_h
        h_power_2(tt12) = sum(power2(lowerh(tt12):upperh(tt12)));
end


h_power12_2 = zeros(1,blocks_h/12);
for tt12 = 1:blocks_h/12
        h_power12_2(tt12) = sum(power2(lowerh(tt12):upperh(tt12)));
end

h_power24_2 = zeros(1,blocks_h/24);
for tt24 = 1:blocks_h/24
        h_power24_2(tt24) = sum(power2(lowerh(tt24):upperh(tt24)));
end

% simulated power vs. turb 1 and 2
figure,plot(1:blocks_h,h_power, 'r--'),title('Measured vs. simulated 1 hour power production for a 900kW turbine at Burfell '), xlabel('Time [hours]'), ylabel('Power [kW]')
```

```
    ,...
    hold, plot(1:blocks_h,real_power), hold on, plot(1:blocks_h,real_power2,'k'), legend('Simulated power output','Turbine 1 power output','Turbine 2 power output','Location','Best')

figure,plot(1:blocks_h/12,h_power12, 'r--'),title('Measured vs. simulated 12 hour power production for a 900kW turbine at Burfell '), xlabel('Time [hours]'), ylabel('Power [kW]'),...
    hold, plot(1:blocks_h/12,real_power12), hold on, plot(1:blocks_h/12,real_power12_2,'k'), legend('Simulated power output','Turbine 1 power output','Turbine 2 power output','Location','Best')

figure,plot(1:blocks_h/24,h_power24, 'r--'),title('Measured vs. simulated 24 hour power production for a 900kW turbine at Burfell '), xlabel('Time [hours]'), ylabel('Power [kW]'),...
    hold, plot(1:blocks_h/24,real_power24), hold on, plot(1:blocks_h/24,real_power24_2,'k'),legend('Simulated power output','Turbine 1 power output','Turbine 2 power output','Location','Best')

% simulated power vs. turb 1
figure,plot(1:blocks_h,h_power, 'r'),title('Measured vs. simulated 1 hour power production for a 900kW turbine at Burfell '), xlabel('Time [hours]'), ylabel('Power [kW]'),...
    hold, plot(1:blocks_h,real_power, '--'), legend('Simulated power output','Turbine 1 power output','Turbine 2 power output','Location','Best')

figure,plot(1:blocks_h/12,h_power12, 'r--'),title('Measured vs. simulated 12 hour power production for a 900kW turbine at Burfell '), xlabel('Time [hours]'), ylabel('Power [kW]'),...
    hold, plot(1:blocks_h/12,real_power12), legend('Simulated power output','Turbine 1 power output','Turbine 2 power output','Location','Best')

figure,plot(1:blocks_h/24,h_power24, 'r--'),title('Measured vs. simulated 24 hour power production for a 900kW turbine at Burfell '), xlabel('Time [hours]'), ylabel('
```

```
Power [kW]'),...
    hold, plot(1:blocks_h/24,real_power24), legend('Simulated power output','Turbine 1 power output','Turbine 2 power output','Location','Best')

% simulated power vs. turb 2
figure,plot(1:blocks_h,h_power_2, 'r--'),title('Measured vs. simulated 1 hour power production for a 900kW turbine at Burfell '), xlabel('Time [hours]'), ylabel('Power [kW]'),...
    hold, plot(1:blocks_h,real_power2,'k'), legend('Simulated power output','Turbine 2 power output','Location','Best')

figure,plot(1:blocks_h/12,h_power12_2, 'r--'),title('Measured vs. simulated 12 hour power production for a 900 kW turbine at Burfell '), xlabel('Time [hours]'), ylabel('Power [kW]'),...
    hold on, plot(1:blocks_h/12,real_power12_2,'k'),legend('Simulated power output','Turbine 2 power output','Location','Best')

figure,plot(1:blocks_h/24,h_power24_2, 'r--'),title('Measured vs. simulated 24 hour power production for a 900 kW turbine at Burfell '), xlabel('Time [hours]'), ylabel('Power [kW]'),...
    hold on, plot(1:blocks_h/24,real_power24_2,'k'), legend('Simulated power output','Turbine 2 power output','Location','Best')



figure,plot(AEP_meas_turb1kw),hold,plot(AEP_meas_turb2kw,'k'), hold on, plot(power,'r--'), legend('Turbine 1 power output','Turbine 2 power output','Simulated power output','Location','Best')

% Difference in real production vs. simulated production with power curve
ppt = zeros(1,length(power1));
for s = 1:length(power1)
ppt(s) = AEP_meas_turb1kw(s) - power1(s);
end

```

```
pp1 = real_power - h_power;
pp2 = real_power2 - h_power_2;
figure, plot(pp1)
figure, plot(pp2)
figure, plot(ppt)
figure, plot(T(1:43200),ppt(1:43200)), hold on, plot(T
    (43200:end),ppt(43200:end),'r'), title('Difference in
    measured power production vs. estimated for the E44
    turbine'), xlabel('Time (10-min averagae values)'),
    ylabel('Power [kW]'), legend('First parts of year', 'Last
     part of year','Location','Best')

over_prod_ratio1 = (sum(AEP_meas_turb1kw)/sum(power1))
over_prod_ratio2 = (sum(AEP_meas_turb2kw)/sum(power2))
%% Real production data

% figure,plot(AEP_meas_turb1kw), hold, plot(power,'r--')
% % figure, plot(AEP_k), title('AEP for one turbine each
    simulated year'), xlabel('Number of simulated year'),
    ylabel('AEP [MWh]')
% % figure,ksdensity(AEP_k), , xlabel('AEP [MWh]'), ylabel('
    f(AEP)'), title('Pdf plot of simulated AEP for one 900kW
    (55 m hub height) turbine at Burfell.'), set(gca,'XTick
    ',[2.5*10^6:2e6:4*10^6]),set(gca,'XLim',[2.5*10^6
    4*10^6])
% % figure, cdfplot(AEP_k), xlabel('E (AEP in MWh)'), ylabel
    ('F(E)'),title('Cdf of AEP for simulation')
%
%



%% Real power produced vs. calculated power for E44 turbines
T = length(v_2);
power = zeros(1,T);
%AEP = zeros(1,1);

y = v_2;
    for t = 1:T
        [P] = powercurve_1(y(t)); % Calculate power output
            from turbine at each 10-min simulated data point
        power(t) = P; % Collect power output values to a
            vector
    end
```

```
AEP = sum(power); % sum of power output in kW


% AEP for each simulated year

    AEP_k = 365*24*1*(1/T)*AEP; % AEP in kWh at simulated year k.

% Over production ratio due to storm control featue
over_prod_ratio2 = (sum(AEP_meas_turb2kw)/AEP)

figure, plot(AEP_k), title('AEP for one turbine each simulated year'), xlabel('Number of simulated year'), ylabel('AEP [MWh]')
figure,ksdensity(AEP_k), xlabel('E (AEP in [MWh])'), ylabel('f(E)'), title('Pdf plot of simulated AEP for one 900kW (55 m hub height) turbine at Burfell.')%, set(gca,'XTick',[2.5*10^6:2e6:4*10^6]),set(gca,'XLim',[2.5*10^6 4*10^6])
figure, cdfplot(AEP_k), xlabel('E (AEP in MWh)'), ylabel('F(E)'),title('Cdf of AEP for simulation')
```