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Cost reduction and stochastic modelling of uncertainties for wind turbine design

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Synopsis

This thesis examines if it is beneficial to up-scale offshore wind turbines in order to make wind energy more cost competitive. Considering the full lifetime cycle, the total cost has been divided into 21 constituents. An up-scaling model has been made for each of the constituents in order to estimate the cost of energy when up-scaling the wind turbines up to 20MW.

Initially it has been found that the optimal wind turbine size is approximately 3MW. However, a reduction in installation and transportation cost, operation and maintenance cost, and electrical connection cost might make it beneficial to design and produce larger wind turbines up to 8MW.

The operation and maintenance cost contribute with more than 30% of the total cost considering the full wind turbine lifetime. It is therefore interesting to examine how the cost can be lowered. It is concluded that the equipment cost has a large percentage share of the total operation and maintenance cost – up to 50%. It is therefore important to design the equipment so it takes the climate into account. The gearbox is one of the components which contribute with the largest operation and maintenance costs. Therefore, direct drive solutions might be beneficial in future offshore wind turbines.

Even though scheduled maintenance is used, sudden failure of the wind turbine components still contribute with more than 60% of the total O&M cost. Finally, it is shown that Bayesian statistics can be used to lower this risk.

Preface

This final thesis “Cost reduction and stochastic modelling of uncertainties for wind turbine design” is a long candidate project written at the 9th and 10th semester at the International M.Sc. Programme in Civil Engineering at Aalborg University. It is written during a period from September 2008 to June 2009.

The thesis is divided into a main document and appendices. The main document outlines the assumptions and main results while the appendices concern general theory, calculations and input parameters to the various cost models. The appendices will be referred to during the main document.

The Harvard method is used to link citations and sources to the references in the end of the main document. The links are written as follows: [Writers surname, year of publishing]. If writers with the same surname are used within the same year, the year of publishing is followed by a letter.

Several models are analysed in MATLAB, by Fortran code, or in Excel. All the files can be found on the CD but some of the files are also referred to in the thesis. References to the files are made by italic letters in parenthesis, e.g. (*OMWindturbine.dsw*). The CD can be found at the last page of the thesis.

Finally, I would like to thank my supervisor John Dalsgaard Sørensen for his support and assistance while writing the thesis.

Kasper Skyum Kjeldsen

Executive summary

The wind turbine technology has been improved significantly during the last decades but, considering cost of energy, fossil fuels are still the most beneficial energy source. Therefore, wind turbine power plants have to be improved even more in order make wind energy cost competitive.

In this thesis it is examined if it is beneficial to up-scale offshore wind turbines with the present technology in order to lower the cost of energy (COE). In general, the energy production depends on the rotor area and therefore the energy production scales with $D^{2+3\alpha}$ while the load, and hereby also the mass/cost of several structural components, scales with $D^{3+2\alpha}$. α is the exponent describing the wind profile and offshore it can be set equal to 0.11. It is therefore obvious that, if up-scaling shall be beneficial, other costs such as installation, transportation, and operation maintenance costs have to result in an up-scaling exponent lower than $2+3\alpha$.

Considering the whole wind turbine lifetime the costs have been divided into 21 cost constituents, whereas 14 represents the technical components such as the rotor, the gearbox, the yaw, and the foundation. The optimal wind turbine size has been found by making an up scaling model for each of the cost constituents. This gives the opportunity to find the COE dependent on the wind turbine size. It is found that the O&M cost contribute with more than 30% of the total cost and therefore the up scaling exponent for the O&M cost is extremely important when determining the optimal wind turbine size. If the up-scaling exponent is equal to 2.33 the optimal wind turbine size is found equal to 3.0MW while it is equal to 8.5MW if the up-scaling exponent is equal to 1.93. The COE is approximately 3.2c€/kWh.

Due to the dependency of the O&M cost model, the O&M costs are examined further. Firstly, the O&M cost for a gearbox is examined in order to find out how the O&M cost can be reduced in order to make wind energy more cost competitive. The model shows that the equipment cost contribute with almost 50% of the total cost and it is therefore important to focus on the requirements when designing new equipment. It is also fund that the optimal O&M strategy is highly affected by several parameters and this has to be taken into account when making the inspection and service plan.

An O&M model is also made for whole wind turbine and it found that the blades, the electrical system, the yaw, the pitch mechanism, the gearbox, and the generator contribute with more than 75% of the total O&M costs. These constituents are therefore extremely important to focus on when designing future offshore wind turbines where the O&M costs are high compared to onshore O&M costs. It might also be advantageous to use a direct drive solution instead of a gearbox in order to lower the costs. Finally, this model is used to re-evaluate if up-scaling is beneficial. By assuming an up-scaling exponent equal to 2.0 for the equipment cost, it is found that the optimal size is a 6.0MW wind turbine.

It is finally examined how reliability updating can be used to decrease the uncertainties concerning the damage accumulation in a component. E.g. by using Bayesian statistics it is possible to change the inspection and service plan continuously in order to increase the detection probability of future errors and hereby lower the O&M cost.

Table of content

1 Introduction

The wind turbine size has increased almost exponentially for more than 20 years but in the last few years the growth has seemed to slow down. It is important to examine if up-scaling the turbines is still beneficial with the present technology. Furthermore, offshore turbines are a relatively new concept which also leads to new challenges concerning e.g. extensive operation and maintenance costs. These costs also have to be minimized if offshore turbines are going to be advantageous. In this introduction the motivation for the thesis is explained. In order to clarify the thesis content, the objectives are afterwards written followed by an overview of the thesis.

1.1 Motivation

For several years the world's energy consumption has increased heavily. Since 1980 the energy consumption has doubled and it is expected to increase almost 50% from now until 2030 [EIA, 2008]. This is shown in fig. 1. Opposite, the fossil energy sources diminish and the focus on CO_2 emission increases, forcing the world society to focus on alternative and sustainable energy sources. In 2020 the European Union has decided that 20% of the energy produced has to be sustainable energy and several countries have even stricter demands. The new US Government has also expressed that sustainable energy will be off high priority. Therefore, it is expected that the demand for sustainable energy such as wind energy will continue to increase in the future.

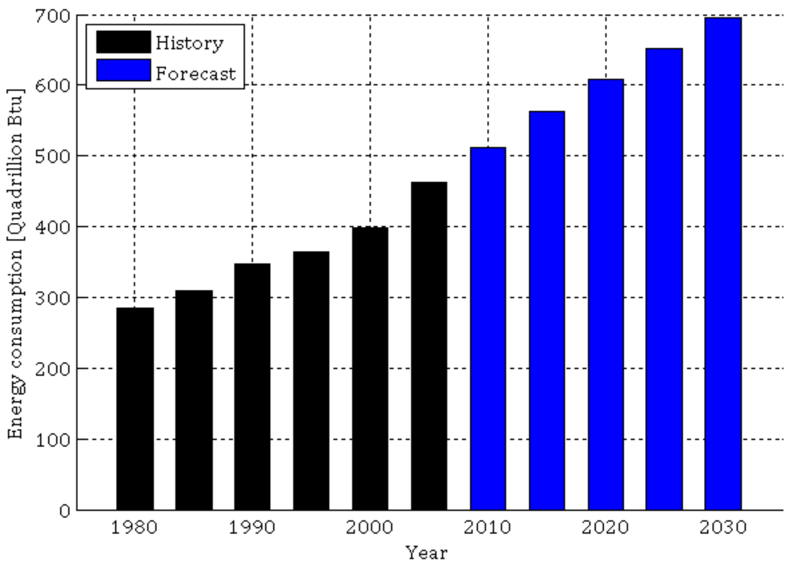

Fig. 1: Forecast concerning the worlds energy consumption [EIA, 2008].

The increased demand for wind energy leads to a need for more efficient and maybe larger wind turbines. Several technical challenges are faced, increasing the turbine size, and the new turbines have to be based on the most advanced research within aerodynamics, aero elasticity, materials, production methods, and monitoring in order to secure a satisfying reliability. Furthermore, when changing the design of a wind turbine, it is often a problem to evaluate the impact of the changes. Improving one thing might have a negative influence on another. In the design process the designer also have to consider the full lifecycle of the wind turbine making the result even more complex. Elements like operation and maintenance (O&M), installation cost, annual energy production (AEP), and transportation cost are as important elements to examine as the turbine capital cost (TCC). Reducing expenses concerning TCC as an example might increase O&M and installation cost, causing the change to be unfavourable over time.

Fig. 2 shows an estimate on the different costs when considering the life cycle of an offshore wind turbine. It can be seen that TCC, which is the wind turbine and tower cost, only apply for approximately 30% of the overall cost. This confirms that other costs such as transportation, installation, and O&M cost also have to be taken into account when designing the wind turbine.

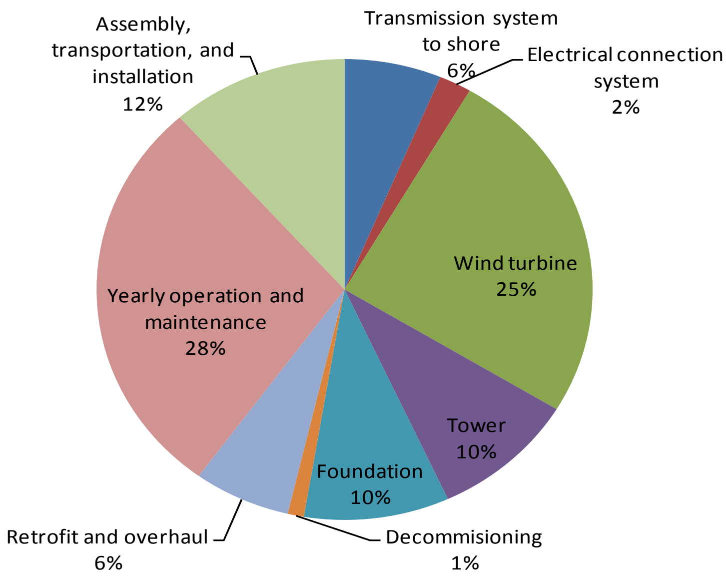

Fig. 2: Offshore generating cost breakdown [Hendriks, 2007].

As explained designing a new and bigger turbine affects all elements of the turbine and the overall benefits and penalties can be very difficult to see clearly. The challenge concerning up-scaling can be explained by looking at some up-scaling laws concerning energy production, blade mass, and O&M cost. As explained in appendix C, up-scaling can be characterized by the change in rotor diameter D. The energy production depends on the rotor area and the size dependency, concerning the rotor diameter, is therefore D^2 without the wind profile effect. Opposite, the size dependency concerning the blade mass is approximately D^3 which is common for many structural wind turbine components. Considering the turbine capital costs, assuming that the blade mass and blade cost are linearly dependent, up-scaling is not beneficial since the exponent concerning the blade mass is larger than the exponent concerning energy production. The penalties have to be off-set by other costs, as the O&M cost, electrical connection cost, or the installation cost, considering the full wind turbine lifecycle. The size dependency of these cost therefore have to be D^X with X<2. In this thesis the impact by up-scaling the wind turbines are examined, creating a model which predicts the AEP and the cost of the various elements when up-scaling. This gives a possibility to examine the overall effect when up-scaling e.g. by finding the cost of energy.

The huge demand for wind energy also leads to a focus on offshore technology which by now only contributes with 1% of the installed wind power capacity [ELFORSK, 2008]. There are several parameters offshore which might make the offshore technology advantageous. As an example the mean wind speed and the acceptable noise level are higher at sea. However, costs concerning installation, transportation, and O&M are significantly higher and more uncertain than for onshore turbines making it even more difficult to predict the economic consequences when up-scaling. This thesis therefore focuses on offshore wind turbines.

1.2 Objectives

As explained there are many challenges concerning the design of future wind turbines but the overall problems analysed in this thesis are restricted to the following questions.

- Is it beneficial to up-scale offshore wind turbines in a wind turbine farm?
- Examining operation and maintenance cost and pre-posterior Bayesian decision theory is it possible to reduce the costs considering the full lifetime of the wind turbine?

A wind turbine is a very complex structure with thousands of components giving the need for well defined limitations concerning the thesis content. The limitations and general assumptions are written in the following.

- Only offshore wind turbines are examined
- The wind turbine is divided into 14 technical components
- The costs concerning the full wind turbine life cycle are divided into 21 constituents
- Only a drive train with a three staged gearbox is examined
- The decommissioning cost is not taken into account

It is assumed that

- the wind turbine farm has a size equal to 500MW
- the cost models are based on the same technology
- the change in component mass can be described only by the change in rotor diameter
- the component mass and cost are linearly dependant
- the tip speed is constant

1.3 Overview of the thesis

The following is made in order to give an overview of the thesis.

C**hapter 2** In this chapter it is examined if it is beneficial to up-scale offshore wind turbines with the present technology. Firstly, it is discussed how to make a proper cost model. Several parameters might have an influence on the component cost when up-scaling and it is therefore important to choose a proper model in order to get a reliable but also simple model. Cost models are afterwards derived for the 21 components and the results are analysed in order to find the optimal wind turbine size. A sensitivity analyses is also made in order to examine the reliability of the model.

Chapter 3 Due to the conclusions in chapter 2 the rest of the thesis focuses on the operation and maintenance cost for an offshore wind turbine. Chapter 3 gives an introduction to the O&M area and it describes the three maintenance strategies which can be used. The cost and downtime constituents are also described in order to be able to analyze the results of the O&M models.

Chapter 4 In this chapter an O&M model is made in order to examine the operation and maintenance costs for a gearbox in an offshore wind turbine. The O&M costs are highly affected by the damage accumulation and therefore two damage models are introduced – a linear and an exponential. This gives the opportunity to examine the operation and maintenance costs dependent on the strategies described in chapter 3 and the type of damage accumulation. The optimal operation and maintenance strategy is also found. Finally, a sensitivity analysis is made in order to find the important parameters concerning the wind turbine, which have to be focused on, if the O&M cost has to be lowered. The change in optimal operation and maintenance strategy is also examined when changing some vital input parameters concerning damage accumulation, quality of inspections, and damage reduction at service visits.

Chapter 5 The O&M model from chapter 4 is expanded in chapter 5 to include all the 14 technical components which represents the main systems in the wind turbine. The optimal O&M strategy is found and the costs and downtime is found for the 14 components. Hereby it is possible to find the components which are most important to focus on when trying to lower the O&M costs during the wind turbine lifetime. In order to update the cost model in chapter 2 and give a new estimate of the optimal wind turbine size, the O&M cost is also found when up-scaling the wind turbine. Finally, a sensitivity analysis is made in order to examine the assumptions used to find the O&M cost when up-scaling.

Chapter 6 Using pre-posterior Bayesian decision theory it is examined in this chapter how it is possible to reduce the O&M costs considering the full lifetime of the wind turbine. The theory is applied on one component which is assumed to have an exponential damage accumulation. It is assumed that one stochastic variable models a significant part of the total uncertainty and it is therefore interesting to use Bayesian statistics to update the statistical model of this variable.

2 Wind turbine cost model

In order to evaluate the optimal design of an offshore wind turbine, it is necessary to make a cost model which includes the main 'components' of the wind turbine. The cost model is based on a full lifetime cycle approach in order to give proper results. To make the cost model simple only a few design parameters are used.

The next section outlines the main turbine components and the relation between the main design parameters. A general description of the cost models is made and a cost model for each component is derived. Finally the costs are compared and evaluated when up-scaling the wind turbine.

2.1 Main components

The following main components are examined to make the cost model.

- Project development
- Rotor
    - Rotor blades
    - Rotor hub
    - Rotor bearings and pitch mechanism
- Nacelle
    - Main shaft
    - Main bearings
    - Gearbox and generator
    - Yaw
    - Main frame and nacelle housing
    - Electronics and hydraulic system
    - Control system
- Tower
- Support structure
    - Foundation
    - Scour protection
- Electrical connection
- Transportation and installation
    - Offshore permits
    - Transportation, port, and staging equipment
    - Installation
    - Offshore personnel access equipment
- Offshore warranty
- O&M and land lease (per year)

A cost model has to be found for the nine components. Since some of the components have individual constituents with a relatively high cost, these are evaluated separately. The decommissioning cost is not taken into account since it is very difficult to make a satisfying cost model.

2.2 Design parameters

Several design parameters have an influence on the design and hereby the cost of the constituents. In order to make the model as simple as possible, it is only possible to change the rotor diameter in the model. Key design parameters such as machine rating, hub height, and wind turbine separation are defined as a function of the rotor diameter. The tip speed is held constant when up-scaling. If the tip speed is changed the relationship between rotor speed and wind speed is changed.

A 5MW wind turbine with a rotor diameter equal to 126m is used as the reference turbine when up-scaling. In tab. 1, corresponding values between rotor diameter, machine rating, tip speed, and hub height are shown. It is assumed that there is a clearance from the mean sea level to the rotor tip equal to 27m.

Tab. 1: The relation between the rotor diameter and the other important design parameters [Chaviaropoulos, 2006].

Rotor diameter, D [m]	126	178	218	252	
Machine rating, MR [MW]	5	10	15	20	$MR(D) = MR(D_0)\left(\frac{D}{D_0}\right)^2$
Torque, Q [kNm]	28.1	56.1	84.1	112.4	$Q(D) = Q(D_0)\left(\frac{D}{D_0}\right)^2$
Tip speed, V_t [m/s]	80	80	80	80	
Hub height, H_{hub} [m]	90	116	136	153	$H(D) = 27m + (D/2)$

2.3 External conditions

To be able to create a satisfying cost model, it is important to focus on a wind turbine farm with realistic characteristics concerning distance to shore, sea climate, wind climate, water depth, etc. In order to do so, this thesis is based on an already erected wind turbine farm; Horns Rev I. The following shows the external conditions which is used throughout the thesis.

- 500MW offshore wind turbine farm
- Same WT in whole wind farm
- Area square
- Separation: 7x7 rotor diameters
- Design lifetime: 20 years
- Wind speed: Measurements from Horns Rev fitted with a Weibull distribution
- Wind shear: Normal wind shear according to IEC61400-3
- Wind rose from Horns Rev
- Water depth: 12m

- Wave height: Horns Rev
- Ice loading: Not included
- Current: Not included
- Soil conditions: Not included
- Distance to shore: 14 km
- Distance to nearest port Esbjerg: 38km from Horns Rev

Further information about the climate can be found in appendix A.

2.4 Generalized cost model

In the following a 'crude' cost model will be introduced. The cost model is based on the reference wind turbine with technology equal to T_0 and with the diameter D_0. The cost model takes into account the technology improvement, the cost per mass at technology T, and the theoretical up-scaling laws as a function of the diameter D. The general cost model is based on [Sørensen, 2008a].

When the rotor diameter is the main design parameter, the cost at technology T can be expressed by (2.1), (2.2), or (2.3).

$$C(D,T)_{comp} = C(D_0,T_0)_{comp} \cdot \frac{c_{comp}(D,T)}{c_{comp}(D_0,T_0)} \cdot \left(\frac{D}{D_0}\right)^{\alpha_{comp}} \cdot r_{comp}(T) \tag{2.1}$$

$$C(D,T)_{comp} = m(D_0,T_0)_{comp} \cdot c_{comp}(D,T) \cdot \left(\frac{D}{D_0}\right)^{\alpha_{comp}} \cdot r_{comp}(T) \tag{2.2}$$

$$C(D,T)_{comp} = m(D_0,T_0)_{comp} \cdot c_{comp}(D,T) \cdot \left(\frac{D}{D_0}\right)^{b_{comp}} \tag{2.3}$$

where

$C(D,T)_{comp}$	is the cost at technology T with the rotor diameter D [€]
$C(D_0,T_0)_{comp}$	is the reference cost at technology T_0 with the rotor diameter D_0 [€]
α_{comp}	is the theoretical scale factor [-]
$r_{comp}(T)$	is the technology improvement concerning the mass at technology T from time T_0 [-]
$m(D_0,T_0)_{comp}$	is the reference mass of the component at technology T_0 with the rotor diameter D_0 [kg]
$c_{comp}(D,T)$	is the cost per mass at technology T with rotor diameter D [€/kg]

(2.3) is different from the other two cost models since it includes the technology improvement in the scaling exponent b_{comp}. b_{comp} is obtained from (2.4).

$$\left(\frac{D}{D_0}\right)^{b_{comp}} = \frac{m(D,T)_{comp}}{m(D_0,T_0)_{comp}} \tag{2.4}$$

In the following (2.3) will be used to create a cost model for each component.

It is difficult to predict how the cost per mass will develop due to a given technology improvement and therefore the cost is set to be linearly dependent on the mass. Instead of using the reference mass and cost per mass at technology *T*, the reference cost can hereby be used in (2.3). According to [Jamieson, 2007a] this is also a satisfying assumption as long as the design is preserved. If also a capitalization factor is included the cost of all components can be written as (2.5).

$$C_I(D,T) = \sum_{comp} C(D_0,T_0)_{comp} \cdot \left(\frac{D}{D_0}\right)^{b_{comp}} \cdot (1+r)^{-(t-t_0)} \tag{2.5}$$

where

r	is the real rate of interest [-]
t	is the time the component is produced [year]
t_0	is the reference time [year]

(2.5) find the cost corresponding to the time t_0. An expression for the operation and maintenance cost can be found the same way. However, where the cost of the structural components can be directly transmitted from a manufacturing time t_0 to the time t, the operation and maintenance and land lease is annual costs and therefore these costs at time t have to be calculated for each year and afterwards summarized. This is shown in (2.6).

$$C_{OM,L}(D,e,T_0) = \sum_{t=t_0}^{t_0+T_L} \left(\left(C_{M,t}(D,e) + C_{F,t}(D,e) \right) \cdot \left(\frac{D}{D_0}\right)^{b_{OM}} + C_{L,t}(D) \cdot \left(\frac{D}{D_0}\right)^{\alpha_L} \right) \cdot \frac{1}{(1+r)^{t-t_0}} \tag{2.6}$$

Where

$C_{M,t}(D,e)$	is the maintenance cost at year t with the rotor diameter D and maintenance strategy e [€]
$C_{F,t}(D,e)$	is the expected failure/repair costs at year t with design D and maintenance strategy e [€]
b_{OM}	is the up-scaling exponent for operation and maintenance taking the technology improvement into account [-]
$C_{L,t}$	is the land lease cost at year t with the rotor diameter D [m]
α_L	is the up-scaling exponent for land lease [-]

In the next section the reference cost $C(D_0,T_0)_{comp}$ and the scaling exponents b_{comp} will be found in order to establish the cost models for each component.

2.5 Component cost models

In the following section the cost models for the main components and constituents will be derived. The section is mainly based on two cost models [Fingersh et al., 2006] and [Bulder, 2008]. Furthermore, the cost models are compared to theoretical similarity rules when up-scaling wind turbines [Chaviaropoulos, 2006] and [Jamieson, 2007a]. The theoretical similarity rules are also explained in appendix C.

In [Fingersh et al., 2006] the currency is dollar while in the report [Bulder, 2008] the costs are in euro. The currencies have been compared in order to compare the two reports. In 2006 the dollar rate was 600 while the euro has been very stabile around 743 since 2006 until now [ECB, 2008]. Furthermore, the general inflation has to be taken into account. From 2006 to 2008 the average price for steel structures increased from index 145.73 to 175.67 [DST, 2008]. Knowing that it is a crude assumption, it is assumed that all the costs concerning wind turbines have increased similarly. Hereby the costs from [Fingersh et al., 2006] have to be multiplied with the following constant in order to change the costs to 2008 euro.

$$C_{rate,2006} = \frac{600}{743} \cdot \frac{175.67}{145.73} = 0.97 \tag{2.7}$$

Some costs are calculated in 2003 dollar and some in 2002 dollar which gives the following constants to change the costs to 2008 euro.

$$C_{rate,2003} = \frac{700}{743} \cdot \frac{175.67}{120.64} = 1.37 \tag{2.8}$$

$$C_{rate,2002} = \frac{840}{743} \cdot \frac{175.67}{115.85} = 1.71 \tag{2.9}$$

Furthermore, if [Fingersh et al., 2006] is used to estimate the cost of the tower and turbine components a marinization cost equal to 13.5% is added.

Project development

The project development includes all aspects concerning design and testing of a new wind turbine. The cost is assumed to be 7% of the turbine initial capital cost ICC which is expressed in (2.10). Hereby the project development is indirectly dependent on the rotor diameter.

$$C_{pd} = 0.07 \cdot ICC \tag{2.10}$$

Rotor blades

Using a simple scaling of the rotor blades without any technology improvement, the mass should increase with the cubic power of the rotor diameter [Chaviaropoulos, 2006]. This corresponds to the α_{comp}-value in (2.1) and (2.2). However, due to technology improvements the mass has not increased cubically. Especially by using more light weighted designs, where the materials have a higher strength and stiffness, the weight of the rotor blades has been reduced. If the blade mass of the already fabricated turbines ranging from 750kW to 4.5MW is plotted as a function of the rotor diameter, the best fit between the two gives an exponent equal to 2.35 [Veers, 2003]. This corresponds well to the value proposed in [Bulder, 2008] which is 2.32.

The radius is raised with an exponent equal to 2.53 in [Fingersh et al., 2006] when the advanced model is used to find the blade mass. This value is higher than the values in [Bulder, 2008] and [Veers, 2003]. The exponent suggested by Veers is used in this cost model. The reference cost $C(D_0,T_0)_{comp}$ is calculated from the advanced model from [Fingersh et al., 2006]. If a rotor radius equal to 63m is used with C_{rate}, the cost per blade is 243k€ giving a total of 729k€. Using (2.5) the cost model for the rotor is written as follows.

$$C_{Blades}(D,T) = 729 \cdot \left(\frac{D}{126}\right)^{2.35} \cdot (1+r)^{-(t-t_0)} \tag{2.11}$$

Concerning the blades it has to be mentioned that the cost might not be linearly dependent on the blade mass. The deflection of the blades is a critical design situation which has to be taken into account when designing the wind turbine. When the blade mass and size is increased the stiffness of the material has to be increased in order to get an acceptable deflection. Hereby, the material unit prize is increased. This however, is not taken into account in this model.

Rotor hub

The design of the hub will scale differently depending on the critical design situation. If the aerodynamic loading is the most critical design situation, the hub size is dependent on the surface area of the rotor blades and the distance from the aerodynamic loads to the hub. This implies that the hub mass and costs will scale cubically. However, if the fatigue loading is critical the blade weight and the centre of gravity are important due to increased moment. The moment increases as 4th power of the diameter and assuming that the stresses will do the same, the hub mass and costs will also increase as 4th power of the diameter [Jamieson, 2007a].

In [Fingersh et al., 2006] the hub cost is linearly dependant on the blade mass. This gives a scaling exponent equal to 2.53. However, in [Jamieson, 2007b] the moments in the three directions are examined as function of the diameter when the hub is stationary and when the hub is rotating. In these six cases the scaling exponent varies between 2.58 and 3.50 and the mean value is 3.02. It is expected that the hub size will vary linearly with the moment in order to maintain the same stresses. The results in [Jamieson, 2007b] correspond better to the general up-scaling laws than the scaling exponent found in [Fingersh et al., 2006]. Therefore a scaling exponent equal to 3.02 is used.

The reference cost is again calculated from [Fingersh et al., 2006]. Using C_{rate} and D_0 the reference cost is 141k€ when the blade mass is calculated by the baseline model in the report. This gives the following cost model.

$$C_{hub}(D,T) = 141 \cdot \left(\frac{D}{126}\right)^{3.02} \cdot (1+r)^{-(t-t_0)} \tag{2.12}$$

Rotor bearings and pitch mechanism

There are not any general scaling laws which explain the relation between the mass of the rotor bearings or pitch mechanism and the rotor diameter. The model in [Fingersh et al., 2006] is therefore used to model this cost. The reference cost is 202k€ and the cost model is as follows.

$$C_{pitch}(D,T) = 202 \cdot \left(\frac{D}{126}\right)^{2.66} \cdot (1+r)^{-(t-t_0)} \tag{2.13}$$

The scaling exponent is almost equal to the scaling exponent of the blade mass which indicates that there is an almost linear relation between the blade mass and C_{pitch}.

Main shaft

The main shaft is mainly designed for the torsional moment from the rotor aerodynamics and the bending moments due to the weight of the rotor and the aero tilt and yaw moments. The weight of the rotor increases cubically and therefore, if the length of the shaft is similarly increased, the bending moment increases with D^4. The shaft bending moduli increases cubically. The torsional moment from rotor dynamics and aero tilt increase cubically with the rotor diameter [Chaviaropoulos, 2006]. According to [Jamieson, 2007a] the design stress is constant choosing a cubic increase in shaft size. This implies that the aero tilt and torsional moments are the most critical forces. If the rotor weight was the most critical design parameter, and the length of the shaft was increased with D, the diameter of the shaft should increase with more than D to keep the stresses constant. This would give a size dependency equal to D^{3+}.

Due to the above a scaling parameter equal to three should be chosen. This is a higher than the scaling parameter used in [Bulder, 2008] and [Fingersh et al., 2006]. Here the scaling parameter is 2.32 and 2.887 respectively. This implies that the technology improvement has to be taken into account. Therefore a scaling parameter equal to 2.8 is chosen. The reference cost is calculated using [Fingersh et al., 2006]. The reference cost is hereby 128k€ and the cost model is shown in (2.14).

$$C_{shaft}\left(D,T\right)=128\cdot\left(\frac{D}{126}\right)^{2.8}\cdot\left(1+r\right)^{-\left(t-t_0\right)} \tag{2.14}$$

Main bearings

There are no general scaling laws concerning the bearings as a function of the rotor diameter. However, it is clear that the bearings must depend on the rotor diameter when the size of primary shaft does.

[Fingersh et al., 2006] propose that the mass of the bearings is a sum of two contributions – one negative contribution where the scaling exponent on the rotor diameter is 2.5 and one where the scaling exponent is 3.5. [Bulder, 2008] suggests that the shaft bearings are independent of the rotor diameter. The models differ a lot from each other and a new model is therefore created.

It is assessed that the bearings for the shaft must depend on the rotor diameter since the mass of the shaft theoretically increase cubically. It is assumed that the scaling exponent is 2.5. The theoretical exponent is 3 and hereby the technology improvement is taken into account [Chaviaropoulos, 2006]. The reference cost is calculated from [Fingersh et al., 2006]. The reference cost is hereby 105k€ and the cost model is shown in (2.15).

$$C_{bearing}\left(D,T\right)=105\cdot\left(\frac{D}{126}\right)^{2.5}\cdot\left(1+r\right)^{-\left(t-t_0\right)} \tag{2.15}$$

Gearbox and generator

Several types of gearboxes are used in the wind turbine industry. The choice of gearbox is dependent on the generator. If a direct drive is chosen there is no gearbox. However, the purpose of the gearbox is to decrease the torque at the generator and increase the rotational speed. Therefore the size and cost of the generator will increase, if a direct drive is chosen. Since the cost of the gearbox depends on the generator, a cost model which includes both costs is made.

To simplify the cost model only a wind generator system with a 3 staged gearbox is examined. The generator configurations can be one of the following; PM synchronous, wound rotor induction, or squirrel cage induction. Wound rotor induction is chosen since it gives the lowest costs [Chen, 2008]. In tab. 2 corresponding values between rated power and generator system cost is written.

Tab. 2: Machine rating and cost concerning gear and generator system [Chen, 2008].

Machine rating [kW]	750	1500	3000	5000	10000
Costs [k€]	100	200	410	655	1760
Rotor diameter [m]	49	69	98	126	178

The values are fitted so the general cost model can be used. This can be seen in fig. 3.

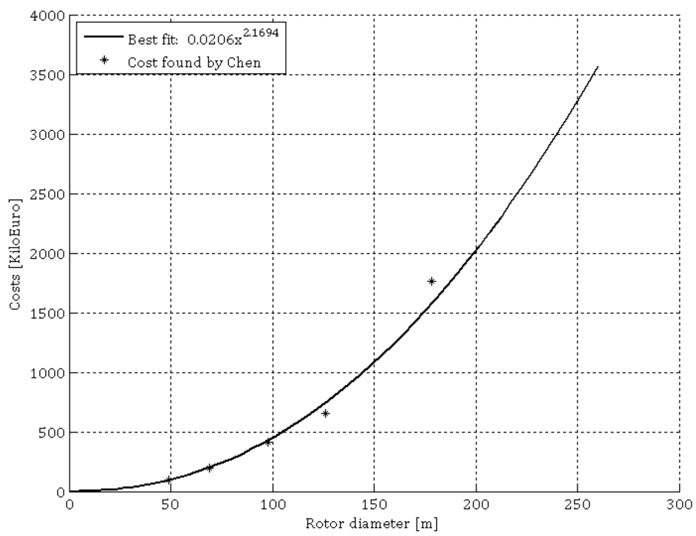

Fig. 3: Fit between rotor diameter and costs of gear and generator system.

It can be seen that the scaling exponent is equal to 2.17. However, if the results in [Hemmelmann, 2009 is used the scaling exponent for the cost of the gearbox, generator, and converter is equal to 2.63. The converter is not taken into account in [Chen, 2008] but the converter has a scaling exponent close to two and the converter can therefore not explain the difference between the two scaling exponents. Both sources seem reliable and therefore the scaling exponent used is the mean value equal to 2.4. The reference cost is found by [Hemmelmann, 2009] and it is equal to 822k€.

$$C_{generator}\left(D,T\right)=822\cdot\left(\frac{D}{126}\right)^{2.4}\cdot\left(1+r\right)^{-(t-t_0)} \tag{2.16}$$

The theoretical scaling exponent for the gearbox weight is 3 while it is 2 for the generator weight if a gearbox solution is chosen. The combined scaling exponent lies between the two theoretical exponents which were also expected.

Yaw

The cost of the yaw depends on the cost of the yaw bearing and the yaw drive. The yaw bearing mass depends on the tilting moment due to the weight of the rotor and the aero tilt [Fingersh et al., 2006]. The mass of the yaw drive depends on the yaw torque which scales with D^4 when the acceleration is held constant. It is assumed that the drive mass scale with the applied yaw torque and that the bearing mass scales cubically [Chaviaropoulos, 2006]. Hereby if the technology improvement was not taken into account the scaling parameter should lie between three and four. In [Fingersh et al., 2006] the scaling parameter is equal to 2.96 which imply that the technology improvement is taken into account. Therefore, the same value is used in this model. The reference cost is also calculated using [Fingersh et al., 2006].

$$C_{yaw}(D,T) = 126 \cdot \left(\frac{D}{126}\right)^{2.96} \cdot (1+r)^{-(t-t_0)} \tag{2.17}$$

Main frame and nacelle housing

The design of the main frame depends on the chosen drivetrain. The length, height and weight vary due the choice of drivetrain and therefore the load size and load distribution also varies. In [Fingersh et al., 2006] a model has been made for the three-stage drive with a high speed generator. This model suggests a scaling exponent equal to 1.953. The nacelle housing depends linearly on the machine rating and hereby the scaling exponent is equal to two. An exponent equal to 1.95 is chosen and the initial cost is calculated as a sum of the mainframe cost and nacelle housing cost. The cost model can be seen in (2.18).

$$C_{frame}(D,T) = 206 \cdot \left(\frac{D}{126}\right)^{1.95} \cdot (1+r)^{-(t-t_0)} \tag{2.18}$$

Electronics and hydraulic system

There are many electronic systems in a wind turbine. The most expensive system converts the power produced by the generator to the net frequency so it can be distributed to the buyer. The system has to be able to convert the power at any service level. There are also many minor electronic systems which monitor the turbine and service the different components in the nacelle. According to [Fingersh et al., 2006] the electronic system cost varies linearly with the machine rating giving a scaling component equal to 2. The hydraulic and cooling system cost does the same. In [Bulder, 2008] the scaling exponent concerning the hydraulics is 2.32. This is close to the proposal in [Fingersh et al., 2006]. An exponent equal to 2 is chosen and the initial cost is calculated as a sum of the cost for electronics and hydraulics in [Fingersh et al., 2006].

$$C_{elec}(D,T) = 721 \cdot \left(\frac{D}{126}\right)^{2.00} \cdot (1+r)^{-(t-t_0)} \tag{2.19}$$

Control system

Both in [Bulder, 2008] and in [Fingersh et al., 2006] it is stated that the cost for the control system is independent of the wind turbine size. In [Bulder, 2008] it is suggested that the number of turbines purchased, determines the cost per turbine. This seems reasonable but the model in [Bulder, 2008] makes an estimate of the cost which is much less than in [Fingersh et al., 2006] regardless of the number of turbines. Using the model in [Bulder, 2008] the cost is roughly 20k€ when the model in [Fingersh et al., 2006] is used the cost per turbine is equal to 55,000 2002dollar giving 94k€ per wind turbine. An average value of these two values is used in this cost model.

$$C_{control}(D,T) = 57 \cdot \left(\frac{D}{126}\right)^{0} \cdot (1+r)^{-(t-t_0)} \tag{2.20}$$

Tower

According to [Fingersh et al., 2006] the tower mass depends on the swept area multiplied with the hub height. This gives a third degree polynomial. If the cost is written in the general form as above, it is therefore expected that the scaling exponent is approximately 3. The report [Jamieson, 2007a] proposes that the exponent used to calculate the tower mass is equal to 2.63. The reference mass for the tower corresponding to a rotor diameter equal to 126m is 386ton.

The tower mass, mass of the transition piece, and mass of the foundation is also found using the Excel sheet referred to in [Vries, 2008]. The transition piece is the transition between the platform and the foundation. The excel sheet is also placed on the CD (*Support mass.xls*). The mass of the three constituents is based on the following input parameters:

- Rotor diameter [m]
- Turbine mass [ton]
- Minimum rotor speed [rpm]
- Maximum rotor speed [rpm]
- Number of blades [-]
- Water depth [m]
- Soil quality [-]

The turbine mass is calculated by summarizing the weight of the nacelle and rotor components. The weight of the constituents can be found in appendix D. The maximum tip speed which is 80m/s, the minimum rotor speed which is set to 30.3m/s, and the rotor diameter are used to calculate the maximum and minimum rotor speed. There are three blades, the water depth is 12m, and the soil quality is assumed 'good'. The input parameters for four different diameters can be seen in tab. 3.

The excel sheet is an advanced model which e.g. takes the correlation between the turbine mass, tower mass, transition piece mass, and foundation mass into account. This is illustrated in fig. 4 where only the turbine mass is changed. Accept for the turbine mass, the input parameters are the ones in tab. 3 corresponding to a rotor diameter equal to 126m

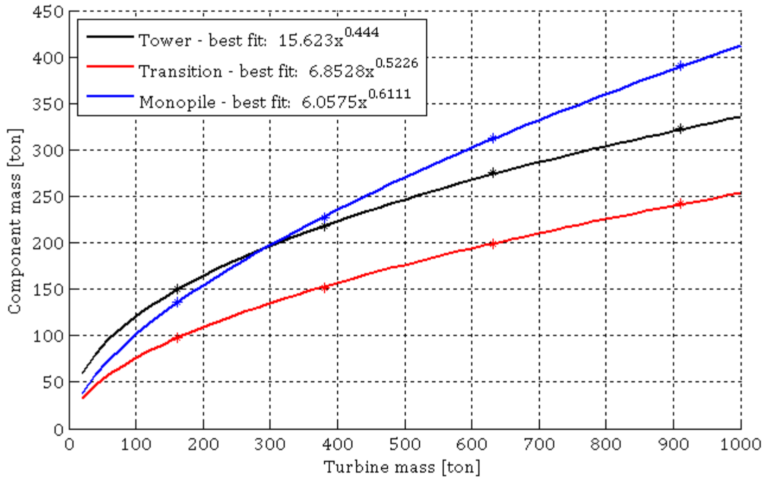

Fig. 4: Correlation between turbine mass and the mass of the tower, transition, and monopile.

In tab. 3 the output parameters can be seen when all the input parameters dependent on the rotor diameter are changed. It has to be mentioned that the model assumes a distance from the mean sea level to the blades equal to 24m instead of 27m. This however, only gives a small error since the tower and transition piece are significantly higher.

Tab. 3: The relation between the rotor diameter and the input and output parameters in Vries model used to calculate the tower, transition piece, and foundation mass. [Vries, 2008].

Rotor diameter [m]	126	178	218	252
Top mass [ton]	260	639	1093	1613
Maximum rotor speed [rpm]	12.1	8.6	7.0	6.1
Minimum rotor speed [rpm]	4.6	3.3	3.7	2.3
Number of blades [-]	3	3	3	3
Water depth [m]	12	12	12	12
Soil quality [-]	Good	Good	Good	Good
Tower mass [ton]	185	516	1034	1733
Mass transition piece [ton]	125	287	530	808
Mass foundation [ton]	181	478	966	1649

In tab. 3 it can be seen that the reference mass of the tower and the transition piece is 310ton using the model in [Vries, 2008]. This is less than found by [Fingersh et al., 2006] which was 389ton. However, it is assessed that the model created by Vries is the most reliable. The scaling exponent for the tower and transition piece is also examined using the values in tab. 3. In fig. 5 a fit between rotor diameter and mass of tower and transition piece is made. It can be seen that there is a good correlation between the values which are 3.22 and 2.69 respectively. However, the exponents are higher than estimated in [Fingersh et al., 2006].

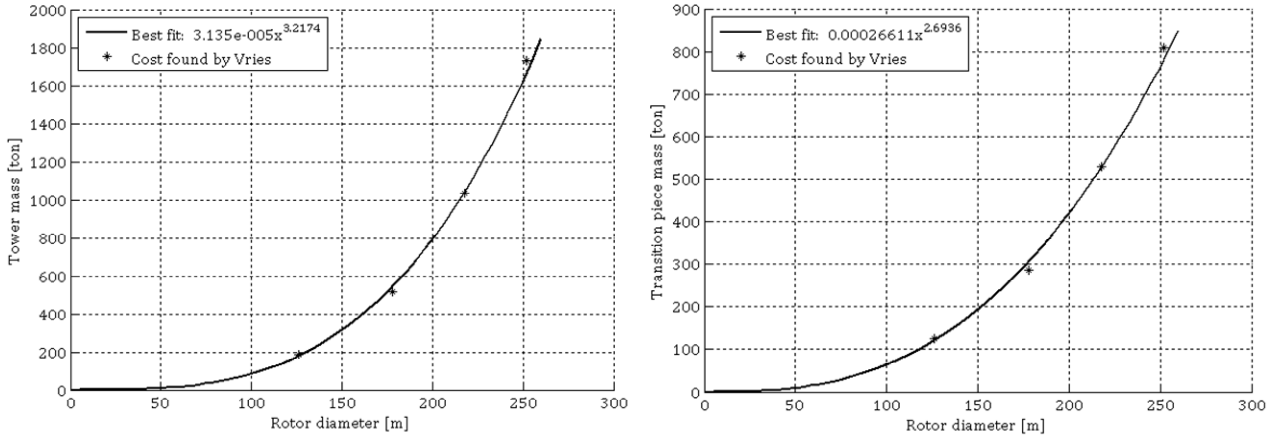

Fig. 5: (Left) Fit between tower mass and rotor diameter. (Right) Fit between mass of transition piece and rotor diameter.

In [Jamieson, 2007a] it is shown that the tilting moment M_x at the tower base scales with a little more than three. The tower bending moduli also scales cubically when the tower diameter and material thickness is increased. The height increases linearly with the rotor diameter which confirms that the mass of the tower should increase a little more than cubically. This supports the results obtained by [Vries, 2008] and therefore both the scaling exponents and the reference masses used are the ones found by [Vries, 2008]. In [Bulder, 2008] the cost for the tower is set to 2.65€/kg which gives the following cost model.

$$C_{tower}\left(D,T\right) = 476 \cdot \left(\frac{D}{126}\right)^{3.22} \cdot \left(1+r\right)^{-(t-t_0)} + 314 \cdot \left(\frac{D}{126}\right)^{2.69} \cdot \left(1+r\right)^{-(t-t_0)} \tag{2.21}$$

Foundation

A monopile foundation is the most commonly used support structure for an offshore wind turbine. Designing a monopile foundation it is important that the natural frequency of the foundation does not coincide with the excitation frequencies with high energy. Wave frequencies with high energy and the rotational frequency of the turbine are some of the frequencies which have to be taken into account. Furthermore, the soil conditions and the water depth are important parameters [Vries, 2008].

The results in tab. 3 are used to examine the correlation between the rotor diameter and the foundation mass. The best fit gives a scaling exponent equal to 3.17 and the reference mass is equal to 173ton.

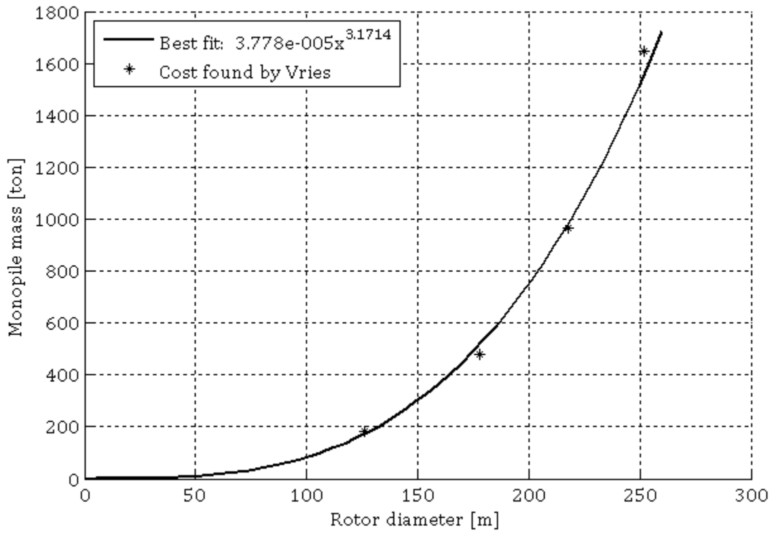

Fig. 6: Fit between foundation mass and rotor diameter.

If the model in [Fingersh et al., 2006] is used to determine the scaling exponent, the scaling exponent would be equal to 2.0. This model is derived with the wind turbine industry and is only based on the machine rating which according to the above is a very crude assumption. It is assessed that [Vries, 2008] gives the most correct reference cost and therefore these values are chosen in (2.22). The cost is still set to 2.65€/kg.

$$C_{foundation}\left(D,T\right)=459\cdot\left(\frac{D}{126}\right)^{3.17}\cdot\left(1+r\right)^{-(t-t_0)} \tag{2.22}$$

Scour protection

Offshore wind turbines in shallow water are normally supported by monopiles. The sea bottom around the pile has to be protected by scour protection due to the current swirling around the pile. If the material is scoured away from the base, the strength of the foundation will be reduced and failure of the foundation can occur. The cost of the scour protection depends on the seabed. A very loose seabed needs a more extensive scour protection. In this thesis the nature of the seabed is not taken into account. The model made in [Fingersh et al., 2006] is used. This model is based on information from the wind turbine industry. The reference cost is equal to 377k€ and the scaling parameter is equal to two.

$$C_{scour}\left(D,T\right)=377\cdot\left(\frac{D}{126}\right)^{2.0}\cdot\left(1+r\right)^{-(t-t_0)} \tag{2.23}$$

Electrical connection

Most offshore wind turbine farms require their own electrical transmission system to bring the power to shore. However, the most significant cost concerns the cable between the turbines and from the transmission system to shore. The model in the report [Fingersh et al., 2006] is calculated specially where the water depth is 10 meters, the distance to shore is eight kilometres, and the array spacing is 7 by 7. The preconditions made in this thesis are the same concerning the array spacing but the distance to shore is 14 kilometres and the water depth is 12 meters. It is assumed that the increased water depth does not influence the costs significantly.

Using the reference turbine with a rotor diameter equal to 126m, [Fingersh et al., 2006] gives a reference cost equal to 1781k€. In [Fingersh et al., 2006] a 50MW wind farm has been used to calculate the cost. This corresponds to 10 reference turbines. With an array spacing equal to 7x7 and a diameter equal to 126m the cable length between the turbines is approximately eight kilometres. So is the distance to shore and therefore the cable cost between the turbines is equal to the cable cost connecting the wind turbine farm to shore. It is assumed that connecting the turbine to the cables makes up 20% of the reference cost corresponding to 365k€. This cost does not vary when up-scaling and therefore the scaling exponent is equal to zero.

The reference cost of the cables inside the wind farm is equal to 712k€ per turbine and 1247k€ per turbine to the shore. This is calculated using the increased distance to shore in this model compared to the assumptions in [Fingersh et al., 2006]. The area of the wind turbine site and the rated power of the wind farm do not vary when up-scaling which is shown in appendix B. Therefore, the share of the cable cost increase with the decreasing number of turbines when up-scaling. This gives a scaling exponent equal to two and the following cost model can be written.

$$C_{connection}(D,T) = 1959 \cdot \left(\frac{D}{126}\right)^{2.0} \cdot (1+r)^{-(t-t_0)} + 365 \cdot \left(\frac{D}{126}\right)^{0} \cdot (1+r)^{-(t-t_0)} \tag{2.24}$$

Offshore permits

A new offshore site has to be examined thoroughly before it can be decided which turbines that are suitable for the location and how they are going to be supported. Furthermore, to secure the offshore permits, environment studies have to be conducted to document that the sea environment will not be harmed. The costs are highly dependent on the location, environmental conditions, distance to shore, and local permitting requirements. In the report [Fingersh et al., 2006] the scaling parameter is equal to two which is also used in this cost model. The reference cost is equal to 253k€.

$$C_{permits}(D,T) = 253 \cdot \left(\frac{D}{126}\right)^{2.0} \cdot (1+r)^{-(t-t_0)} \tag{2.25}$$

Transportation, port, and staging equipment

The transportation of offshore wind turbines can be divided into two parts; transportation of the wind turbine to the port and assembly area and transportation of the turbine to the offshore site. The offshore transportation cost is included in the installation costs. In [Fingersh et al., 2008] the onshore transportation costs are scaled with the diameter raised to the power of 6. This model is based on the development in transportation costs for already raised on- and offshore turbines. Due to difficulties transporting large structure by rail and roads the scaling parameter is so high. When even larger turbines are produced it must be assumed that the costs will be reduced by moving the fabrication closer to shore. This is taken into account in the following cost model.

In the report [Bulder, 2008] the transportation cost depend on the rotor diameter and transportation distance. This model is used to find the reference cost for the onshore transportation. It is assumed that the transportation length is 20km and rotor diameter is 126m which gives a reference cost equal to 193k€.

The scaling parameter concerning port and staging equipment is according to [Fingersh et al., 2006] equal to two. This seems realistic since the area where the turbines are staged is proportional to the diameter squared. The reference costs concerning port and staging equipment is according to [Fingersh et al., 2006] equal to 97k€. It is assumed that a scaling parameter equal to two can be used for both the onshore transportation, when the fabrication is moved closer to the port, the port, and the staging equipment. This gives the following cost model.

$$C_{trans,port}(D,T) = 290 \cdot \left(\frac{D}{126}\right)^{2.0} \cdot (1+r)^{-(t-t_0)} \tag{2.26}$$

Installation

In the future, when larger turbines are going to be transported offshore and installed, new specialized equipment has to be used in order to lower the costs. Due to the greater capacity of larger barges and larger offshore cranes the costs are not expected to increase dramatically. In [Fingersh et al., 2006] it is expected that the scaling parameter is equal to two. However, it has to be noted that this cost model only can be applied for turbine sites close to shore [Fingersh et al., 2006]. The reference cost is equal to 485k€.

$$C_{inst}(D,T) = 485 \cdot \left(\frac{D}{126}\right)^{2.0} \cdot (1+r)^{-(t-t_0)} \tag{2.27}$$

Offshore personnel access equipment

To do operation and maintenance service, when a wind turbine is installed, it is important that it can be assessed by boats and helicopters. Furthermore, the environment is very harsh and therefore several safety requirements have to be fulfilled. It is assumed that the costs concerning access ramps, docking equipment, life saving equipment, fall protection and so forth does not increase very much when up-scaling the wind turbine. A scaling parameter equal to 1.1 is chosen. The reference cost for a turbine is set to 82k€ [Fingersh et al., 2006].

$$C_{inst}(D,T) = 82 \cdot \left(\frac{D}{126}\right)^{1.1} \cdot (1+r)^{-(t-t_0)} \tag{2.28}$$

Offshore warranty

Getting an offshore warranty is according to the industry relatively expensive due to the extreme operating condition. However, when offshore wind turbines are getting more and more normal, it is expected that the risks will be reduced and the warranty costs will fall. However, this has to be examined further in this model. The offshore warranty premium is set to 15.0% of the turbine and tower cost [Fingersh et al., 2006].

O&M and land lease

Initially the operation and maintenance costs and the land lease are calculated as a percentage of the annual energy production. The O&M cost is highly dependent on many stochastic variables such as wind speed, failure probability, and wave height and the cost model is therefore improved later. In [Fingersh et al., 2006] the annual O&M cost and land lease cost is respectively 0.00148€/kWh and 0.0274€/kWh. This gives the following cost model.

$$C_{OM,L}\left(D,e,T_0\right)=\sum_{t=T}^{T+T_L}\left(0.02888\cdot AEP\right)\cdot\frac{1}{\left(1+r\right)^{t-t_0}} \tag{2.29}$$

(2.29) is a very crude reduction of (2.6).

2.6 Analyses of cost model

The overall cost model is now analysed to evaluated the cost models for the various components. (*Simplecost.for*) is used to find the costs when up-scaling. The rate of interest r is set to six percent. The rate of interest can be defined in various ways. As an example it can take the inflation rate and the deposit rate into account. It is reasonable to set the inflation rate equal to two and the deposit rate equal to four and therefore a rate of interest equal to six percent seems reasonable.

Accept for the O&M cost, land lease cost, and the annual energy production, the time t_0 and t are set to 0. This is a crude assumption since the costs concerning project development, production of the turbine, and installation of the turbine do not occur at the same time. However, the time difference is not significant and it is therefore neglected. In tab. 4 the results of the cost model using four different rotor diameters are shown. The calculation of the annual energy production can be seen in appendix B where the 5MW FAST turbine is used. The FAST Code is an aero elastic simulator which can also be used to calculate e.g. fatigue and extreme loads of a three bladed wind turbine [Jonkman et al., 2005].

The percentage share of the overall cost for each component is also written in tab. 4. Compared to fig. 2 in chapter 1 the percentage share of the turbine cost are relatively low. For a rotor diameter equal to 126m the wind turbine cost is only 19.3% while [Hendriks, 2007] has estimated it to be approximately 24%. The tower and support costs are 4.8% and 5.0% which is much less than estimated in [Hendriks, 2007] where the combined share is 18%. The support and tower cost is highly affected by the prize of steel, the water depth, the soil conditions, and the labour cost. The cost pr. kg might be to low in this thesis which could explain the difference. Another possible explanation is that the turbine mass calculated in appendix D is too low or the assumptions concerning water depth and soil conditions made in this thesis differ from the ones in [Hendriks, 2007]. It is noted that the O&M cost has a large percentage share compared to the result in [Hendriks, 2007]. If the O&M cost is lowered, the percentage share of the other costs is also increased.

Tab. 4: The cost of the different constituents in the cost model when the lifetime of the turbine is equal to 20 years.

D [m]	126		178		218		252	
	Cost/EP [c€/kWh]	[%]	Cost/EP [c€/kWh]	[%]	Cost/EP [c€/kWh]	[%]	Cost/EP [c€/kWh]	[%]
Project development	0.13	3.7	0.14	3.8	0.14	3.9	0.15	4.0
Rotor	0.22	6.4	0.26	7.2	0.28	7.6	0.30	7.8
Blades	0.14	4.4	0.16	4.6	0.17	4.8	0.19	4.8
Hub	0.03	0.8	0.04	1.1	0.05	1.3	0.06	1.4
Pitch and bearing	0.05	1.2	0.06	1.4	0.06	1.5	0.07	1.6
Nacelle	0.45	12.9	0.47	13.1	0.49	13.2	0.50	13.2
Shaft	0.03	0.8	0.03	0.8	0.04	0.9	0.04	0.9
Bearings	0.02	0.5	0.02	0.6	0.02	0.6	0.03	0.7
Gearbox & Generator	0.18	5.1	0.19	5.3	0.20	5.5	0.21	5.5
Yaw	0.03	0.9	0.03	1.0	0.04	1.1	0.05	1.3
Mainframe	0.04	1.2	0.04	1.1	0.04	1.1	0.04	1.0
Electronics	0.14	4.2	0.14	4.1	0.13	3.9	0.13	3.7
Control system	0.01	0.2	0.01	0.2	0.01	0.1	0.01	0.1
Tower	0.16	4.8	0.23	6.3	0.28	7.4	0.32	8.3
Support structure	0.18	5.0	0.22	6.0	0.24	6.7	0.28	7.2
Foundation	0.11	2.8	0.15	3.9	0.17	4.7	0.21	5.3
Scour protection	0.07	2.2	0.07	2.1	0.07	2.0	0.07	1.9
Electrical connection	0.48	14.0	0.43	12.1	0.41	11.1	0.40	10.5
Transportation & Inst	0.23	6.7	0.23	6.1	0.21	5.8	0.20	5.5
Permits	0.05	1.6	0.05	1.5	0.05	1.4	0.05	1.4
Transportation	0.06	1.7	0.06	1.6	0.06	1.6	0.05	1.6
Installation	0.10	3.1	0.10	2.8	0.9	2.6	0.09	2.5
Personnel access	0.02	0.3	0.01	0.2	0.01	0.2	0.01	0.2
Warranty	0.12	3.6	0.14	4.0	0.15	4.2	0.17	4.4
O&M and Land lease	1.48	42.8	1.48	41.4	1.48	40.2	1.48	39.1
Total		100		100		100		100
Total COE [c€/kWh]	3.45		3.58		3.70		3.81	
Total EP [GWh]	480.1		989.7		1513.3		2050.1	

In tab. 4 the total energy production during the wind turbine lifetime is also found. The cost of energy is the ratio between the total cost during the lifetime and the total energy production. In fig. 7 the COE is plotted as a function of the rotor diameter. It can be seen that the cost of energy increases when the rotor diameter is increased and the simple cost model has to be examined to find out if this reflects the reality.

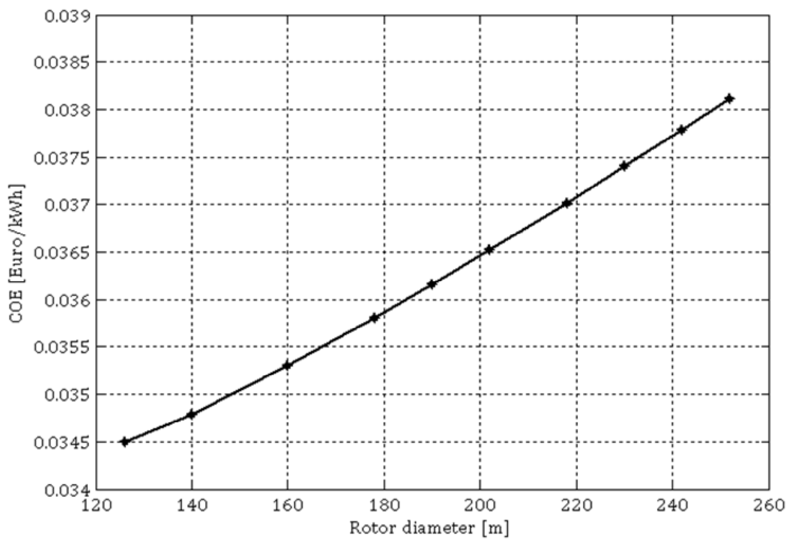

Fig. 7: Cost of energy as a function of the rotor diameter calculated using the simple cost model.

In fig. 8 the development in cost of energy can be seen. It can be seen that the cost concerning the tower, support structure, rotor, warranty, and nacelle increase more than the increase in energy production. However, as expected the cost concerning electrical connection and transport and installation is reduced compared to the energy production. The project development is set to 7 percent of the initial capital cost. The offshore wind turbine industry is still in a start-up phase and it seems realistic that the development cost will be reduced in the future when gaining experience about offshore wind turbine sites. This also goes for the warranty which is very expensive now. However, this experience is beneficial for all turbine sizes and therefore it cannot be used as an argument for up-scaling.

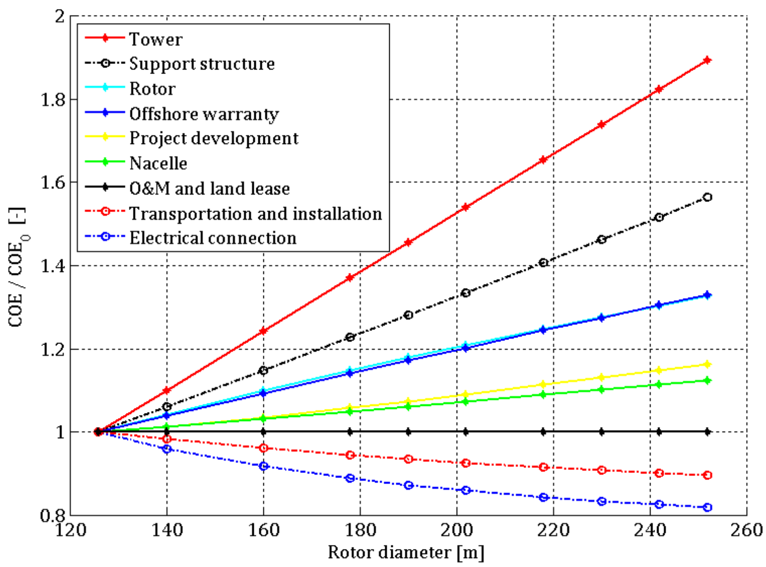

Fig. 8: The development in component cost with respective to the total cost when up-scaling.

In fig. 8 it can be seen that the cost of energy concerning the tower, support structure, and rotor is the main reason why the up-scaling is not beneficial. However, it does not seem possible to change the fact that there are some significant penalties concerning these components when up-scaling. The rotor and tower costs will inevitable increase compared to the AEP since the AEP increases with $D^{2+3\alpha}$ equal to $D^{2.33}$, with α equal to 0.11, while the scaling exponents for the hub, blade, and tower costs are higher than 2.33. Therefore, it has to be examined further if the penalties can be off-set by a reduction of the other components.

It has to be mentioned that an important aspect when up-scaling is not taken into account in model. The number of turbines at the wind turbine site decreases when up-scaling. To make a 500MW offshore wind farm with 5MW turbines, 100 turbines have to be installed, while only 25 turbines have to be installed if the rated power of the turbines is 20MW. Logically this might decrease the transportation, installation, and the O&M cost. It can be seen in tab. 4 that the operation and maintenance cost are approximately 39-43% of the overall cost. Due to the large influence on the result, the sensitivity of the overall cost model when changing the O&M cost is examined in the following sensitivity analysis.

2.7 Sensitivity analysis

The previous results are obtained by values which are based on theoretical scaling exponents and the historical technical development within the wind turbine industry. However, the models are used to predict the COE of turbines which do not even exist. This gives a natural uncertainty concerning the results which have to be examined by a sensitivity analysis. The sensitivity of the model is examined when changing the following:

- the rate of interest
- the reference power curve
- the O&M model
- the rotor diameter to less than 126m

Rate of interest

The rate of interest is examined by using three values; 3%, 6%, and 10%. In fig. 9 it can be seen, that the COE is highly dependent on the rate of interest since the COE is approximately 30% higher when the rate of interest is equal to 3% instead of 10%. The lowest point concerning COE is for all three values when the diameter is equal to 126m.

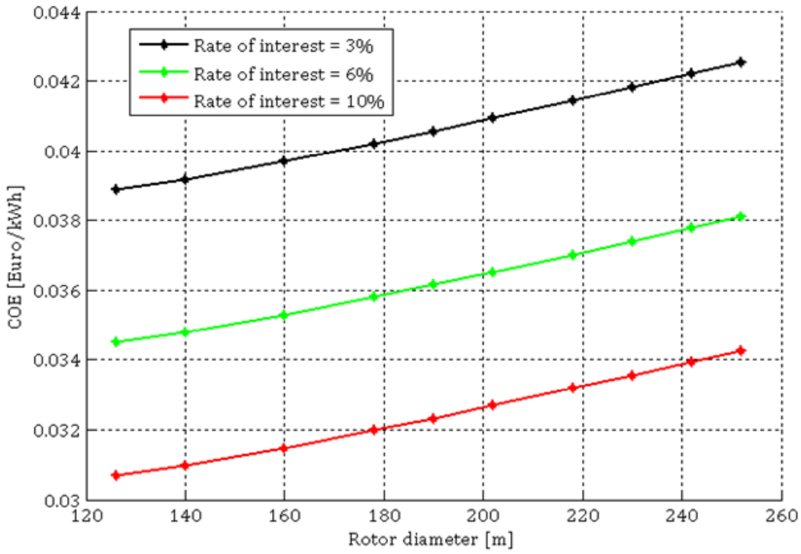

Fig. 9: Sensitivity of COE when changing the rate of interest.

Since the present value of the overall energy production is reduced more than the O&M costs, when the rate of interest is increased, the increased COE in fig. 9 was also expected. Despite the change in rate of interest it has to be stated that up-scaling is still not beneficial. Furthermore, when the rate of interest is large the O&M costs are less significant reducing the possible benefits when up-scaling. The O&M costs are approximately 49.2% of the overall costs when the rate of interest is equal to 3% while it is only 35.7% when the rate of interest is equal to 10%.

Power curve

In appendix B it is explained how the power curves are up-scaled. To get a reliable result when up-scaling it is important that the energy production is calculated properly and therefore it is examined if the result changes if another power curve is used. The used reference power curve is from the 5MW FAST wind turbine. The 3MW Vestas wind turbine and the 2MW Bonus wind turbine are used to examine if the result changes if their power curves are used instead. In fig. 10 the power curves for the different turbines can be seen.

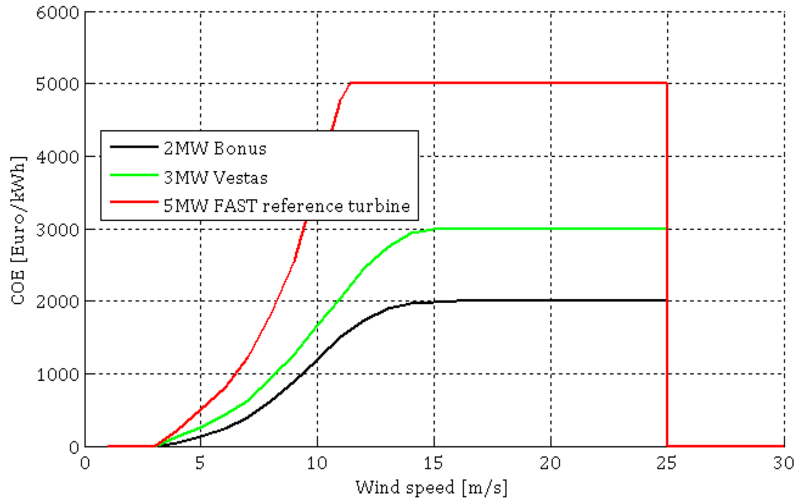

Fig. 10: Power curves for the 2MW Bonus, 3MW Vestas and 5MW FAST wind turbine [Vestas, 2009] og [Jonkman et al., 2005].

The Bonus and the Vestas wind turbines reach the maximum machine rating when the wind speed is approximately 15m/s while the power curve from FAST reaches the maximum machine rating when the wind speed is equal to 11.4m/s. This gives a higher energy production which can also be seen in fig. 11 where the COE is lower if the 5MW turbine is used. Since the turbines, which are examined in this thesis, are large it seems reasonable to use the 5MW FAST wind turbine. It also has to be concluded that up-scaling is not beneficial for any of the three reference power curves. However, it has to be mentioned that if the maximum machine rating can be reached at lower wind speeds when up-scaling, it might be beneficial to up-scale the wind turbine. This is not examined further.

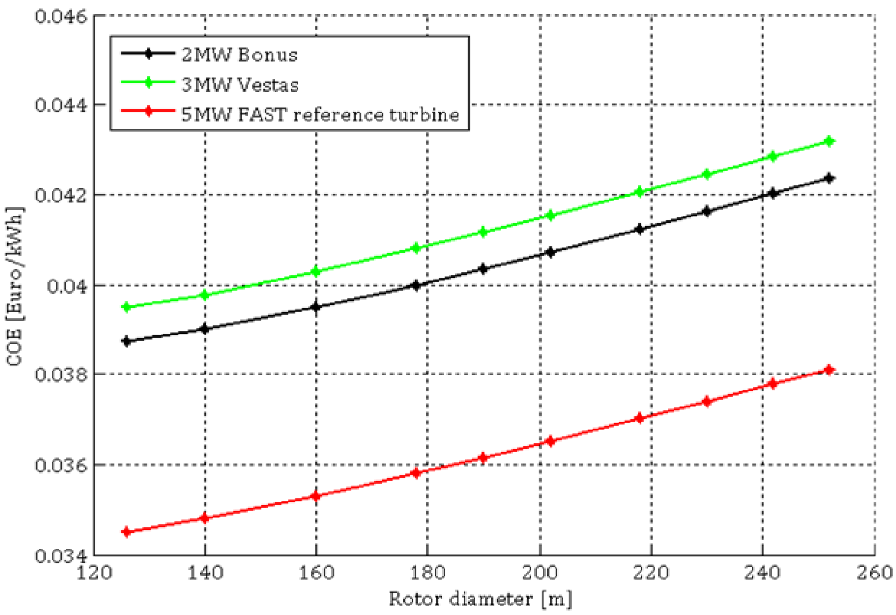

Fig. 11: Development in COE due to three different power curves.

O&M model

The sensitivity of the model used to calculate the O&M cost is examined to find out how much the scaling exponent has to be changed to make up-scaling beneficial. As shown, the scaling exponent is equal to 2+3α since the O&M cost is linearly dependent on the AEP. However, if the scaling exponent is varied with a parameter ε, the dependency will be equal to $D^{2+3\alpha-\varepsilon}$. In fig. 12 it can be seen that changing the exponent from 2.33 to 1.93 makes up-scaling beneficial until the rotor diameter reaches a size equal to approximately 165m. If the exponent is changed to 1.73, it is beneficial to up-scale the wind turbine even more. Hereby, it can be concluded that changing the development in the O&M costs affects the overall result dramatically. Therefore, in order to get a reliable result the O&M cost model has to be examined further.

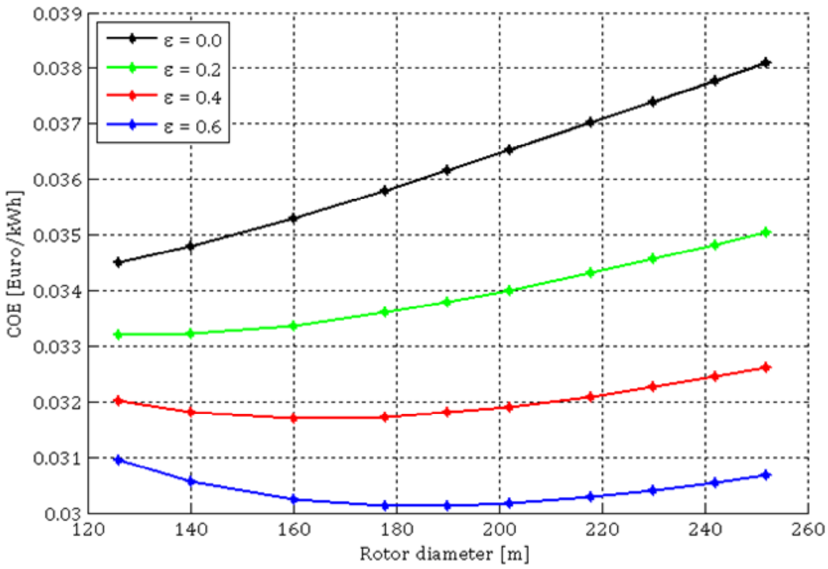

Fig. 12: Change in cost of energy due to the parameter ε.

Down-scaling

Finally, the model is examined if the rotor diameter is reduced instead of increased. In the previous it is found that it is not beneficial to up-scale the wind turbine. However, if the model is reliable there must be an optimal size of the rotor diameter within an acceptable range. This is also seen in fig. 13. The cost model is based on experience from the industry where the rotor diameter has increased for the last years. This implies that the industry has concluded that it is beneficial to up-scale the rotor diameter to more than 80-90m which is the typical rotor diameter of the 2-3MW turbines. Therefore, it was also expected that the optimal size had a larger value than 90m. In fig. 13 it can be seen that the optimal size of the wind turbine corresponds to a rotor diameter equal to 100m. It can hereby be concluded that it is not beneficial to up-scale the wind turbine significantly. However, it has been shown that the O&M cost has a large influence on the result and the O&M costs are therefore examined further in the following chapters.

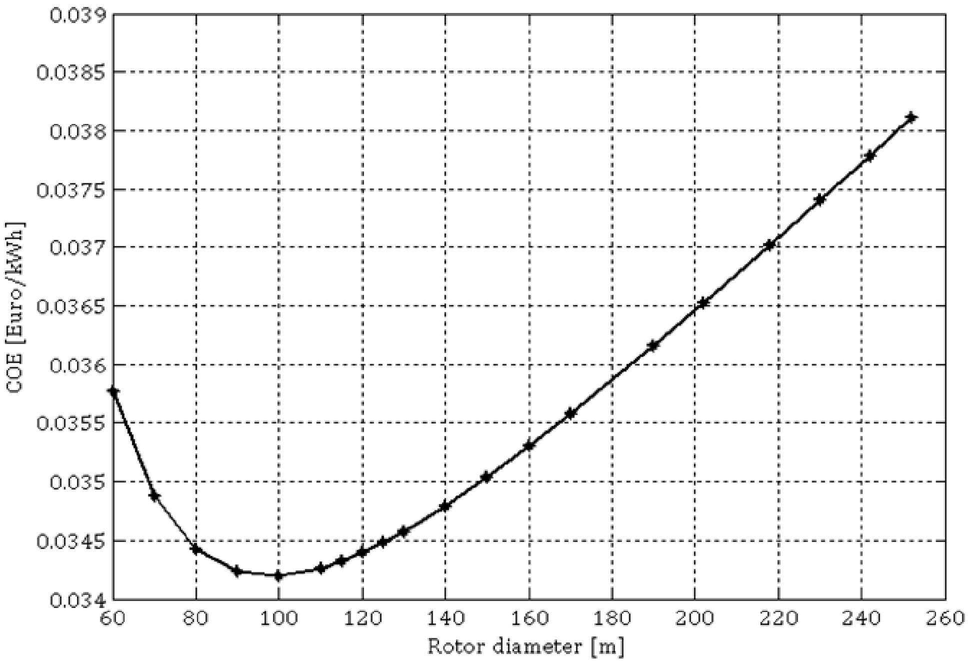

Fig. 13: COE due to the rotor diameter.

3 Introduction to operation & maintenance

In chapter 2 it has been shown, considering a total lifecycle of a wind turbine, that the O&M cost account for 39-43% of the total wind turbine cost. Therefore, the overall COE when up-scaling is highly dependent on the cost model calculating the O&M cost and a better cost model has to be made. In [Gestel, 2008] the O&M cost in an offshore wind farm has been calculated to account for 35.3% of the total cost with a machine rating equal to 5MW but only 26.8% with a machine rating equal to 20MW. This implies that it is reasonable to believe that the O&M cost might help offset the penalties when up-scaling.

A wind turbine is a very complex structure with several components and the big challenge is therefore to make a relatively simple model which is still representative for the wind turbine O&M cost. This might be done by evaluating the turbine components which are described in the previous section. 14 representative technical components are selected and these can be seen in chapter 2.

In addition to the many wind turbine components it is possible to use different maintenance strategies and the costs and damage accumulation can be modelled in various ways. Before a damage model is made the different maintenance strategies and the cost constituents are described in this chapter. This gives an introduction to the damage models which are analysed in the forthcoming chapters.

3.1 Maintenance strategies

In general there are two types of maintenance strategies– corrective maintenance and preventive maintenance. The preventive maintenance is further divided into scheduled and condition-based maintenance. This is also illustrated in fig. 14.

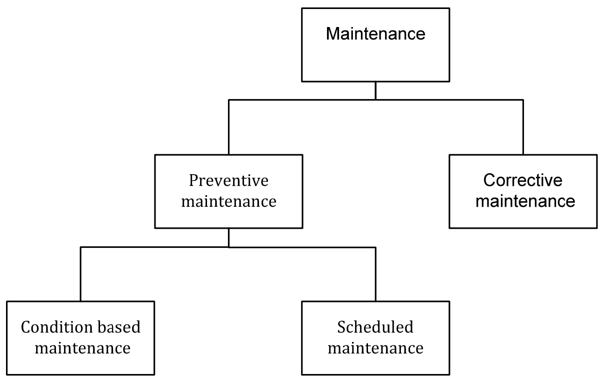

Fig. 14: Different types of maintenance strategies.

If corrective maintenance is chosen, the wind turbines will only be maintained/repaired when failure of a component occurs. This is illustrated in fig. 15. When failure has occurred the wind turbine is repaired and put back to service. The time of failure is unforeseen and the wind turbine can therefore be out of service for a long time if spare parts and/or the equipment needed for repair are not available. It might also be necessary to replace the component and it can therefore preferable to repair the component before it reaches failure.

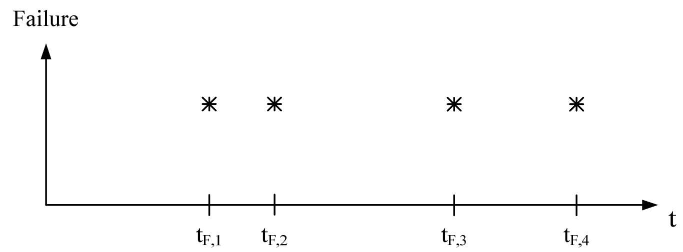

Fig. 15: Illustration of corrective maintenance.

Scheduled or condition-based maintenance is based on the assumption that a damaged component might be detected before it reaches failure and then maintained/repaired, lowering the total repair costs. This is illustrated in fig. 16 where the first failure might have been foreseen due to the inspections at time t_1 or t_2. The scheduled maintenance is planned in advance and it is therefore mostly carried out in the spring and the summer months. In these periods the climate is less rough which improves the accessibility and lowers the cost concerning lost energy production if the turbine is stopped.

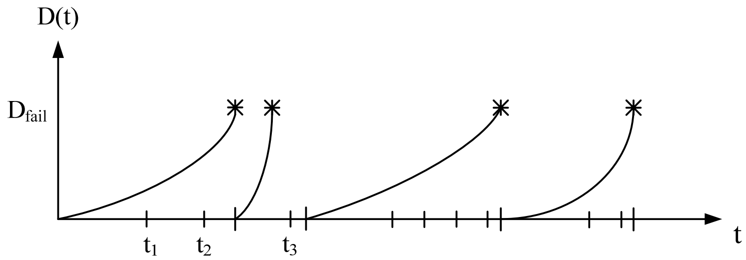

Fig. 16: Examples on damage accumulation for a wind turbine component. t_1 and t_2 shows the time for two inspections.

During the inspections some spare parts are scheduled to be replaced while other spare parts might have to be replaced due to unforeseen errors. The possibility to find a damaged component at an inspection also has to be taken into account. If the damaged component is not found, the damage can evolve and lead to a complete operation stop of the turbine which is also illustrated in fig. 16.

The maintenance costs, if the scheduled maintenance strategy is chosen, are highly dependent on the thoroughness of the inspections and the inspection interval. If an error evolves rapidly between the inspections there is no chance to repair the wind turbine before failure occurs. This is illustrated for failure number two in fig. 16. In these cases condition-based maintenance, also called risk based maintenance, might be advantageous.

In condition-based maintenance a model concerning the damage accumulation of the various components is assumed to be available in order to predict the condition of the component. Hereby an estimate of the damage level can be used to make decisions concerning maintenance. The estimate is typically made by a damage model which describes the damage over time and the uncertainties related to the model. The damage level can evolve as shown in fig. 16. Both monitoring and inspection results can be used to update and correct the model in order to make it more reliable. Monitoring of e.g. vibrations and particles in lubricate can be made online while inspections of e.g. magnets in the generator have to be made manually. Therefore, condition based monitoring can be divided further into online/remote and inspection/manual condition monitoring [Scheffler, 2007]. Concerning fig. 16, online monitoring results might have shown the rapidly increasing damage level leading to failure number two. Hereby the inspection at t_3 could have been moved forward and the wind turbine could have been repaired before failure occurred. Opposite, if the damage level was very low the inspection could have been postponed lowering the O&M cost.

There are of cause some significant uncertainties when a damage model is made. Therefore, the model has to be evaluated and up-dated continuously using the new information which can improve the model. This is illustrated in fig. 17. At time t_1 an inspection is made and a damage level is determined. There is an uncertainty concerning the determination of the damage level which is illustrated in the figure. At the second inspection a new damage level is determined and by using Bayesian statistical methods the model uncertainty can be updated and often lowered. This is examined further in chapter 6.

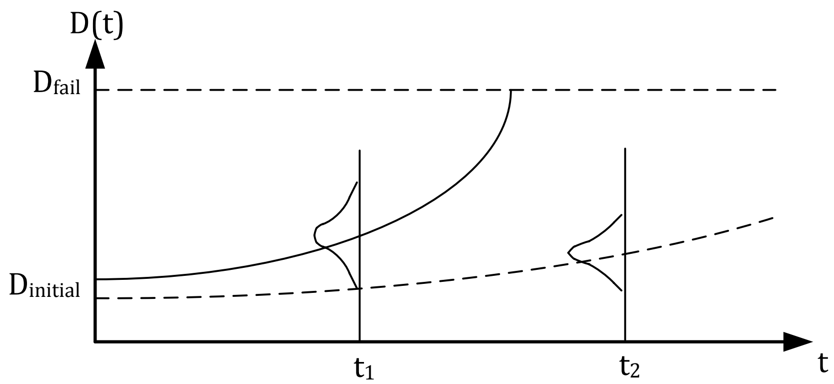

Fig. 17: Uncertainties and up-date of damage model due to two inspections [Sørensen, 2008b].

During operation of the wind turbine it is important to have a systematic approach when decisions concerning maintenance of the wind turbine have to be made. A decision tree can be used as a tool to get an overview of the O&M operations and decisions. The decision tree related to a total lifecycle of an engineering structure such as a wind turbine or wind farm is described in [Sørensen, 2008b]. The decision tree is shown in fig. 18.

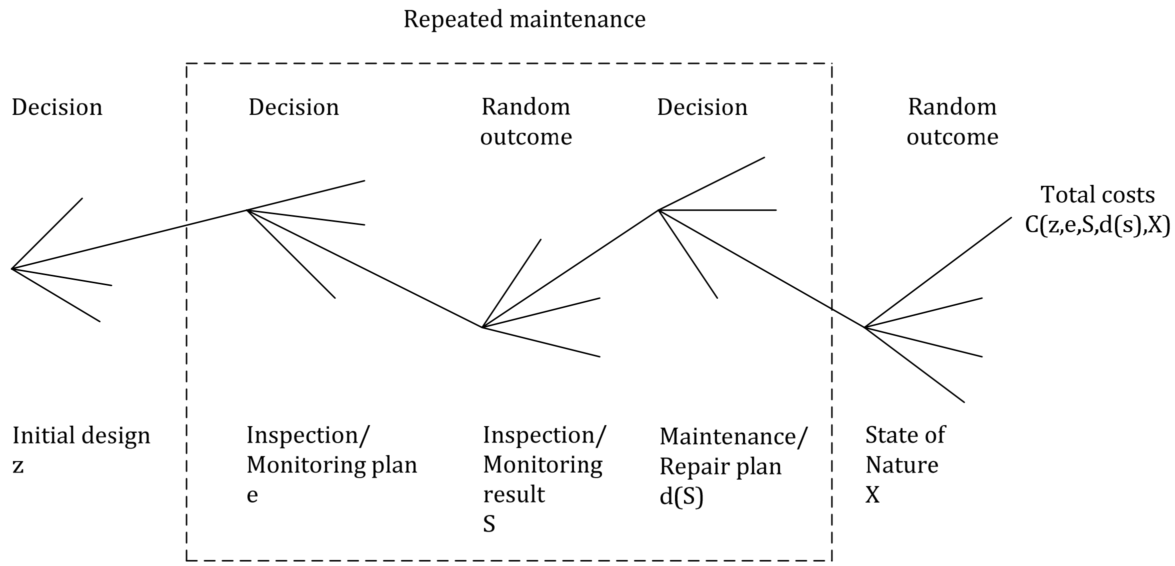

Fig. 18: Decision tree for optimal maintenance planning [Sørensen, 2008b].

At the design phase optimal decisions concerning the design parameters $z=(z_1, z_2,....z_n)$ is made in order to maximize the total benefits considering the wind turbine lifetime. The safety requirements also have to be fulfilled during the whole wind turbine lifetime. The decision concerning the design determines the initial capital cost of the component $C_{comp}(D,T)$ and has a large influence on the damage accumulation of the component during the lifetime of the turbine. A low initial cost might lead to large O&M costs while a large initial cost might lead to low O&M costs. The optimal solution might vary from turbine to turbine and therefore a thorough analysis has to be made in the design phase. The design decision is taken at time t equal to zero.

During operation of the wind turbine continuous monitoring and inspections of the wind turbine are performed if scheduled or condition-based maintenance is chosen. These are indicated in the box 'repeated maintenance'. Firstly, the maintenance strategy e is chosen. The three main types are described above but also the time of the inspections has to be scheduled. The inspections and the monitoring are followed by some results S and due to these results decisions $d(S)$ concerning maintenance and repair are made. The decisions concerns e.g. if the component have to be repaired or replaced, what type of equipment which is used for repair, if the time of repair have to be postponed, etc. It is evident that the decision rule is made in advance in order to find the optimal O&M plan.

The state of nature X is the uncertainty parameters which will be realised during the wind turbine lifetime. It is stated that the uncertainties can be divided into aleatory and epistemic uncertainties. The aleatory uncertainties are irreducible and concern the physical system or the environment. The uncertainties concerning the wind speed can e.g. not be removed or reduced. Opposite it is possible to reduce epistemic uncertainties. Epistemic uncertainties are uncertainties due to lack of knowledge concerning a given system or the environment. A part of the uncertainty concerning a damage model might be due to lack of knowledge concerning e.g. the correlation between wind load and damage accumulation.

If scheduled maintenance is chose, an expanded decision tree can be made to get an overview of the O&M operations and decisions. The decision three is shown in fig. 19.

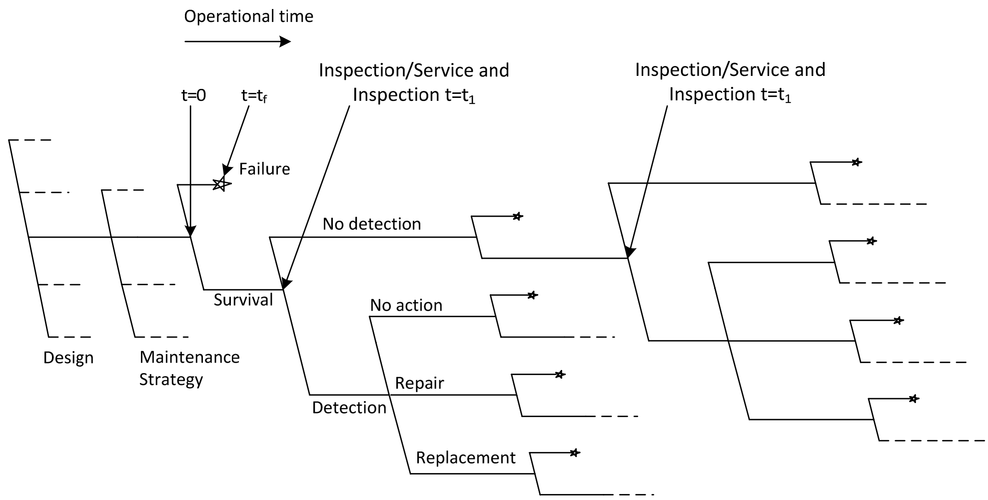

Fig. 19: Decision three concerning design and maintenance of a wind turbine [Sørensen et al., 2000].

It is assumed that both inspections and service visits are made during the WT-lifetime. During an inspection the wind turbine components are examined in order to find possible errors such as cracks, extensive wear, corrosion, etc. Small subcomponents such as oil filters might also be changed. During a service visit it is assumed that some larger subcomponents with a short lifetime are replaced. Hereby, the cost is higher compared to an inspection but it is also assumed that the damage level is lowered after a service visit. At a service visit it is also assumed that the wind turbine will be inspected for possible errors.

In fig. 20 examples on damage accumulations and levels for repair or replacement are shown.

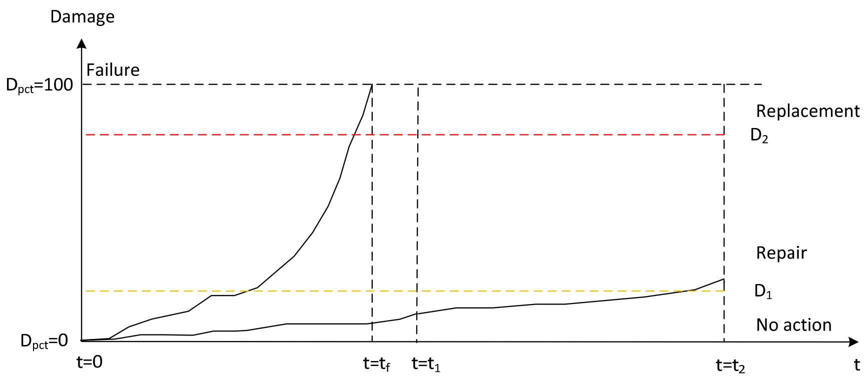

Fig. 20: Examples on damage accumulation.

As explained there are many uncertainties concerning the damage accumulation but there are also several uncertainties concerning the cost. The O&M cost is divided into five different components which are all dependent on the initial design *z*, the maintenance strategy *e*, and the decisions *d*. The costs are as follows.

- Cost of unscheduled repair due to failure $C_{comp,F}$ (z,e,d)

- Cost of scheduled repair $C_{comp,R}(z,e,d)$
- Cost of service and inspection $C_{comp,S}(z,e,d)$
- Cost of inspection $C_{comp,I}(z,e,d)$
- Cost of monitoring $C_{comp,M}(z,e,d)$

Some of the above costs are of cause not relevant if corrective or scheduled maintenance is chosen. For corrective maintenance it is only the failure cost which is relevant while the monitoring cost is not relevant when scheduled maintenance is chosen.

If the wind turbine fails and unscheduled repair is needed it is also necessary to distinguish between if the component can be repaired or if the component has to be replaced. Concerning scheduled repair it possible to keep the wind turbine in operation while the repair crew is organised. However, if a component is badly damaged and it has to be replaced, the wind turbine will most likely be stopped in order to avoid serial failure.

It can be seen in fig. 19 that there is a difference between regular inspections and service visits. An inspection is only made in order to examine the wind turbine for possible errors while some smaller components, oil, or otherfluids might be changed, during a service visit. Therefore, a service visit is more expensive than an inspection.

Due to the many uncertainties modelled by stochastic variables and the fact that the total lifetime of the wind turbine has to be examined, it is difficult to find the optimal solution without examining several solutions using e.g. numerical simulations. The different solutions are examined in the following chapters but before the five different costs are analysed.

3.2 Cost modelling

In general the costs concerning unscheduled repair of a component, scheduled repair of a component, service visits, and inspections are divided into four constituents; crew cost, spare part cost, equipment cost, and loss of energy yield. The overall costs for one event are described by (3.1).

$$C_{comp,x}(D,t) = C_{comp,x,crew}(D,t) + C_{comp,x,spare}(D,t) + C_{comp,x,equip}(D,t) + C_{comp,x,yield}(D,t) \tag{3.1}$$

where

$C_{comp,x}(D,t)$ is the cost concerning event x. The cost is dependent on the WT/component design symbolized with the rotor diameter D and, since the cost is capitalized, the time t [€]

$C_{comp,x,crew}(D,t)$ is the cost of the crew for the event x [€]

$C_{comp,x,spare}(D,t)$ is the cost of the spare parts for the event x [€]

$C_{comp,x,equip}(D,t)$ is the cost of the equipment due to event x [€]

$C_{comp,x,yield}(D,t)$ is the cost concerning the lost energy production due to the event x [€]

The time to repair the wind turbine *TTR* and the mission time are very important factors in order to calculate the above costs. The repair process and the corresponding periods are illustrated in fig. 21.

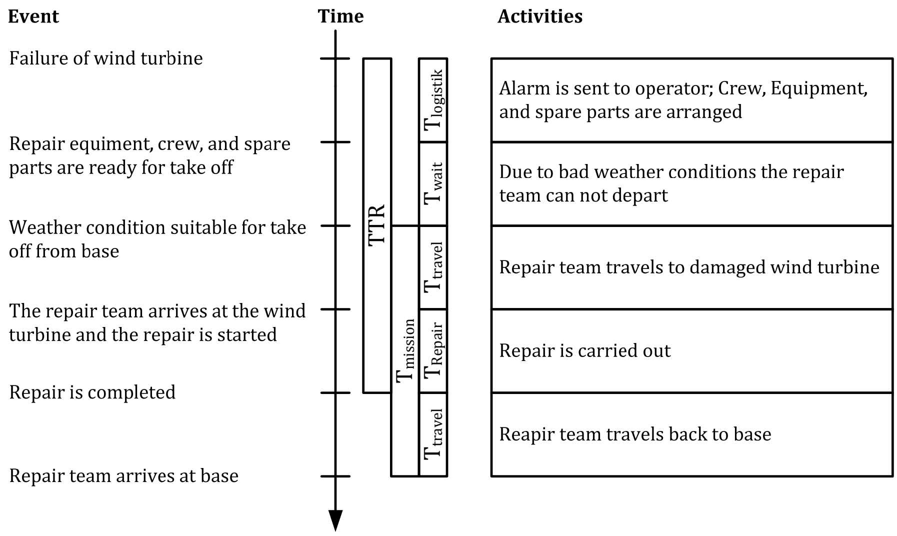

Fig. 21: The repair process [Rademakers et al., 2008a].

The period $T_{logistic}$ denotes the time from where the wind turbine is put out of service until the repair team is organized and ready for departure. The length of the period is dependent on the time to organize crew, equipment, and spare parts. It is assumed that the time to organize crew and equipment is independent on the time to get the needed spare parts and materials. It is therefore the longest period which determines the period $T_{logistic}$.

When the repair team is ready for departure to the damaged wind turbine, it has to wait until the weather is sufficiently calm for a sufficiently long period. This waiting time is denoted T_{wait}. The waiting time depends on the climate but also the maximum wave height and maximum mean wind speed allowed due to the equipment which has to be used for the repair. If e.g. a helicopter is used, there is a maximum limit concerning the wind speed while there is both a maximum limit concerning the wind speed and wave height if a mobile crane mounted on a jack-up vessel is needed. It is stated that the weather windows are highly dependent on the time of year and if an error occurs during the winter it might be advantageous to postpone the repair until the spring or summer months. In appendix A it is shown how the time, before a sufficiently long weather window is available, is calculated.

The travel time from the port to the wind turbine is denoted T_{travel} while the repair time at the site is denoted T_{repair}.

The following models are used to calculate the four constituents to the total cost shown in (3.1).

$$C_{comp,x,crew}\left(D,t\right)=C_{crew}\cdot N\left(x,comp\right)\cdot\left(T_{wait}+T_{mission}\right)\cdot\frac{1}{\left(1+r\right)^{t-t_0}} \tag{3.2}$$

$$C_{comp,x,spare}\left(D,t\right)=C_{comp,x}\left(D,t\right)\cdot\frac{1}{\left(1+r\right)^{t-t_0}} \tag{3.3}$$

$$C_{comp,x,equip}(D,t) = C_{equip}\left(M_{sparepart,comp}\right)\cdot\left(T_{wait}+T_{mission}\right)\cdot\frac{1}{(1+r)^{t-t_0}} \tag{3.4}$$

$$C_{comp,x,yield}(D,t) = \sum_{i=4}^{25}\left(P(v_i)\cdot f(v_i,season)\right)\cdot TTR\cdot\frac{1}{(1+r)^{t-t_0}} \tag{3.5}$$

where

C_{crew}	is the crew cost per time unit written in tab. 1 [€/h]
$N(x,comp)$	is the number of crews needed to solve the event *x* for a given component [-]
$C_{comp,z,x}(D,T)$	is the cost of the spare parts [€]
$C_{equip}\left(M_{sparepart,comp}\right)$	is the cost of the equipment used to repair the component. The types of equipment which have to be used depend on the spare part mass $M_{sparepart,comp}$ and the event [€/h]
$\sum\left(P(v_i)\cdot f(v_i,season)\right)$	is the average energy production due to the season. This is also explained in appendix B [kWh/h]

The monitoring costs mainly consist of the initial cost when installing the monitoring devices. It is assumed that the system is highly automatic and therefore that personnel cost is negligible.

It can be seen in this chapter that several decisions influences the result of an O&M model. There are many parameters which influence the O&M costs and therefore a model for only one component is made in the following chapter.

4 O&M model for a gearbox

In order to make a reliable O&M cost model, firstly a cost model for one component is made in order to find the relation between various input parameters and the output parameters. The model is a generic model and the input parameters have to be adjusted in order to give reliable results. Furthermore, in this model condition monitoring is not taken into account. The maintenance strategy can therefore be characterized as scheduled or corrective if it is chosen to leave out the inspection and service visits.

The program is Fortran code (*VERSION10MODEL.dsw*) and it is described more thoroughly in appendix E were also the input parameters are listed. The input parameters concerns both cost of spare parts, repair time, and so forth. Some of the most important assumptions are listed below.

- Wind turbine data: D=126m
  Tip speed=80m/s
  Component: Gearbox
  Component mass=56,000kg cf. appendix D
  Component failure rate if corrective maintenance is chosen:
  0.5 per year
- Wind turbine lifetime: 20 years
- Operation start month: Month 4 – corresponding to April
- Type of damage accumulation: Exponential or linear
- Rate of interest: 6 pct.
- Time step: One month
- The damage level is reset when the component is repaired or replaced

In [Hahn et al., 2009] failure rates and average downtime per failure of 12 wind turbine components are shown. The data is collected in Germany in a period of 17 years and the data is divided into various wind turbine concepts and operating conditions. Unfortunately there are no data from offshore wind turbines but it gives an idea about the probability of failure. For a gearbox in a wind turbine near the coast line the failure rate is approximately 0.12 per year. This is more than four times lower than used in this model. However, this difference is made deliberately in order to be able to use the repair model in the O&M-program several times when the model is tested. In chapter 5 the O&M model is updated so all the 14 technical components, which are listed chapter 2, are included. In this model the failure rate of each component is adjusted to the values in [Hahn et al., 2009].

The input parameters in this O&M model made for the gearbox is also adjusted so the down time seems realistic. In [Hahn et al., 2009] the average down time per failure for a gearbox is approximately 6.8days if the wind turbine is operating in highlands. It is assumed that the down time is 4-5 days longer for an offshore wind turbine due to the limited availability of offshore repair vessels and the risk of bad weather conditions.

In chapter 3 it is described that a damage model can be used to model the development in damage level over time. The uncertainties also have to be taken into account. Two damage models are used in this O&M model– a linear and an exponential – and in the following section the theory concerning damage models is shortly described and afterwards the two damage models, which are used in this thesis, are described.

After the damage models are described, the results of the O&M model will be analysed. Both corrective and scheduled maintenance will be examined and afterwards a sensitivity analysis will be made in order to test the model and find the important input parameters concerning cost and downtime.

4.1 Damage models

In general, a damage model is a model which describes the damage accumulation in a component or structure over time. The damage model is often based on a damage process which can be described physically. This can either be wear, erosion, corrosion, or fatigue of the material [Sørensen, 2008b].

There are several uncertainties which have to be taken into account when analysing the damage model. Concerning a wind turbine there are significant uncertainties due to change in operational conditions, varying environmental conditions, and change in material parameters, which have to be evaluated. In this O&M model the two damage models are used to simulate the damage level over time. It is also possible to use the models to optimize the operation and maintenance strategy using condition monitoring and pre-posterior Bayesian decision theory. This is described in chapter 6. In the following the linear and the exponential damage model, which are used in this thesis, are described.

Linear damage model

The linear damage model is simply based on linear accumulation of damage in time - e.g. wear might be described by this process. It is assumed that the damage accumulation is a stochastic process which depends on the time of year and that the independent damage increment can be modelled by a Rayleigh distribution. A Rayleigh distribution is chosen since the wind speed with good approximation follows this distribution. It is obviously a very crude assumption since the wind turbulence, the wind turbine control system, material parameters, and possible production errors also influence the system. The values used to model the damage accumulation is the accumulated damage during one month ΔD_i and the damage level after a certain time period D is found by (4.1).

$$D = \sum_{i=1}^{n} \Delta D_i \tag{4.1}$$

where

ΔD_i is the monthly damage increment which is Rayleigh distributed [-]

The Rayleigh distribution is a Weibull distribution with a shape parameter equal to 2.0. The formula for the Weibull distribution is explained in appendix A and the parameters which are initially used are plotted in tab. 5.

Tab. 5: Rayleigh parameters used to simulate in increment in the damage accumulation.

	Winter	Spring	Summer	Autumn
Rayleigh scale parameter [-]	0.065	0.045	0.035	0.055

The parameters are relatively large and the failure rate is therefore very high. However, this is accepted in the first O&M model since it gives a good opportunity to find the parameters which have a significant influence on the repair costs. The contribution to the damage level is found by simulating a random number between 0 and 1. The random number and the distribution function corresponding to the time of year are used to find the damage accumulation during the relevant month.

Fig. 22 to the left shows an example of how the damage level can evolve during the wind turbine lifetime if corrective maintenance is chosen and the parameters in tab. 5 are used. After the damage level reaches 1.0, the wind turbine component is repaired and the damage level is reset. The parameters are fitted so an annual failure frequency equal to approximately 0.5 is expected. To the right it is shown how the damage level evolves if the scale parameters in tab. 5 are half end. As expected, since the model is linear, the annual failure frequency is lowered to 0.25 which is half the prior failure frequency.

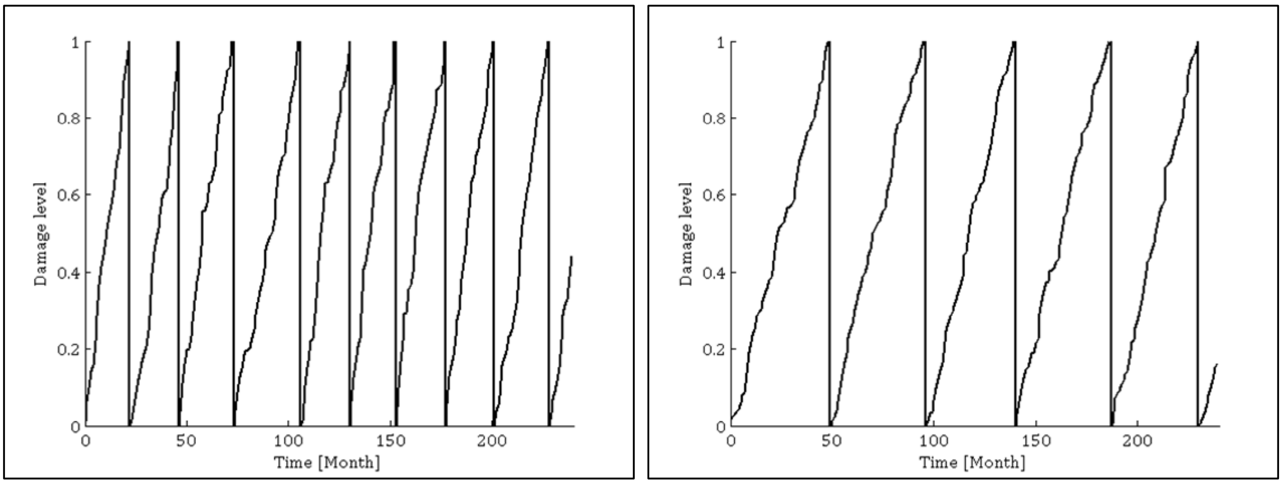

Fig. 22: Realisations of the damage level of the wind turbine gearbox. The graph to the left is for the values in tab. 5

Exponential damage model

The exponential damage model is based on the theory on fatigue of materials. Fatigue of materials is caused by cyclic loading such as wind or wave loads and it is therefore very important for wind turbines. The critical load can be much lower than the material strength but due to repeated load cycles fatigue failure can occur.

The crack propagation can be divided into two periods; the crack initiation period and the crack growth period. The initiation period is characterized by crack nucleation and crack growth at a microscopic scale at the material surface. The crack growth period commence when the fatigue cracks grow into the subsurface. These cracks are initially of a macroscopic level [Schijve, 2001].

The damage can be described by the crack length a but in the initiation period the crack length and growth are very small and difficult to describe mathematically. Instead the initial crack length a_0 at the crack growth period and the length of the initiation period T_0 can be determined by statistical methods. The initial crack length and the length of the initiation period are assumed to be Weibull distributed. This assumption is validated in [YOON, 2007].

In the crack growth period, Paris Law can be used to calculate the crack growth. (4.2) shows Paris law and (4.3) is used to find the updated crack length.

$$\frac{da_{i+1}}{dN} = C \cdot \Delta K^m \tag{4.2}$$

$$a_{i+1} = a_i + \frac{da_{i+1}}{dN} \cdot N \tag{4.3}$$

where

N	is the number of load cycles [-/min]
$\frac{da}{dN}$	is equal to the crack growth per load cycle [m]
ΔK	is the change in stress intensity factor [MPa$\sqrt{m}$]
C	is the crack growth coefficient [-]
m	is the crack growth exponent [-]

C and m are material properties. The constants are correlated stochastic variables and can be described by a lognormal distribution. Since the variables are highly correlated, it is generally sufficient to make C a stochastic variable while m can be assigned a deterministic value. The lognormal distribution is formed by a mean value μ and a standard deviation σ of the examined parameter. ΔK is found by (4.4) which comes from Paris' law.

$$\Delta K = \beta \cdot \Delta s \cdot \sqrt{\pi a_i} \tag{4.4}$$

where

β	is equal to the geometry factor [-]
Δs	is the cyclic stress range. For a harmonic varying load Δs is equal to the amplitude but for a stochastic load varies constantly. The rain flow counting method might be used for stochastic loads to find the amplitude and period for the cycle [MPa]

If the exponential damage accumulation is chosen, values of a_0 and T_0 are initially simulated. Until the life of the component has reached T_0 the damage level is zero. This gives the initial condition shown in (4.5).

$$a(T_0) = a_0 \tag{4.5}$$

At this time the crack will start to propagate. A critical crack length equal to 50mm is assumed and the damage level is found by dividing the actual crack length with the critical crack length. This is shown in (4.6).

$$D_{level,i} = \frac{a_i}{a_{critical}} = \frac{a_i}{50mm} \tag{4.6}$$

In tab. 6 values used for the crack propagation are shown.

Tab. 6: Stochastic models used in the numerical model for crack propagation.

Variable	Distribution	Expected value	Standard deviation	Weibull shape parameter	Weibull scale parameter
β	D	1.0			
a_I	W			2.0	2mm
T_I	W			1.8	20months
C	LN	$1.0 \cdot 10^{-11}$	$0.2 \cdot 10^{-11}$		
m	D	3			
Δs_{winter}	W			1.5	32MPa
Δs_{spring}	W			2.0	20MPa
Δs_{summer}	W			2.0	18MPa
Δs_{autumn}	W			1.5	27MPa
N	D	12.1 per min.			

It can be seen that the stress variation is assumed Weibull distributed. Physically the stress variation will be dependent on the wind speed, turbulence, and wind turbine control system. A Weibull distribution is therefore again a very crude assumption.

The number of cycles N is chosen equal to 12.1 per minute which corresponds to the maximum RPM of the rotor with a maximum tip speed equal to 80m/s and a rotor diameter equal to 126m. The rotor speed is not always at the highest level and the value is therefore high. However, this is neglected.

Each time the component is repaired or replaced the damage level, and hereby the crack size, is set to zero. New values of a_0, T_0, and C are simulated. This is again a crude assumption since it is highly probable that there is a correlation between the previous values and the new values. However, this is neglected.

The exponential damage model can also be used for other types of damage than fatigue. Therefore, crack propagation can be changed by damage propagation. In these cases the growth factor, which is the most important parameter, concerning the speed of the damage accumulation, might be changed. The large dependency of m is also shown in fig. 23 where the values in tab. 6 are maintained and only m is changed.

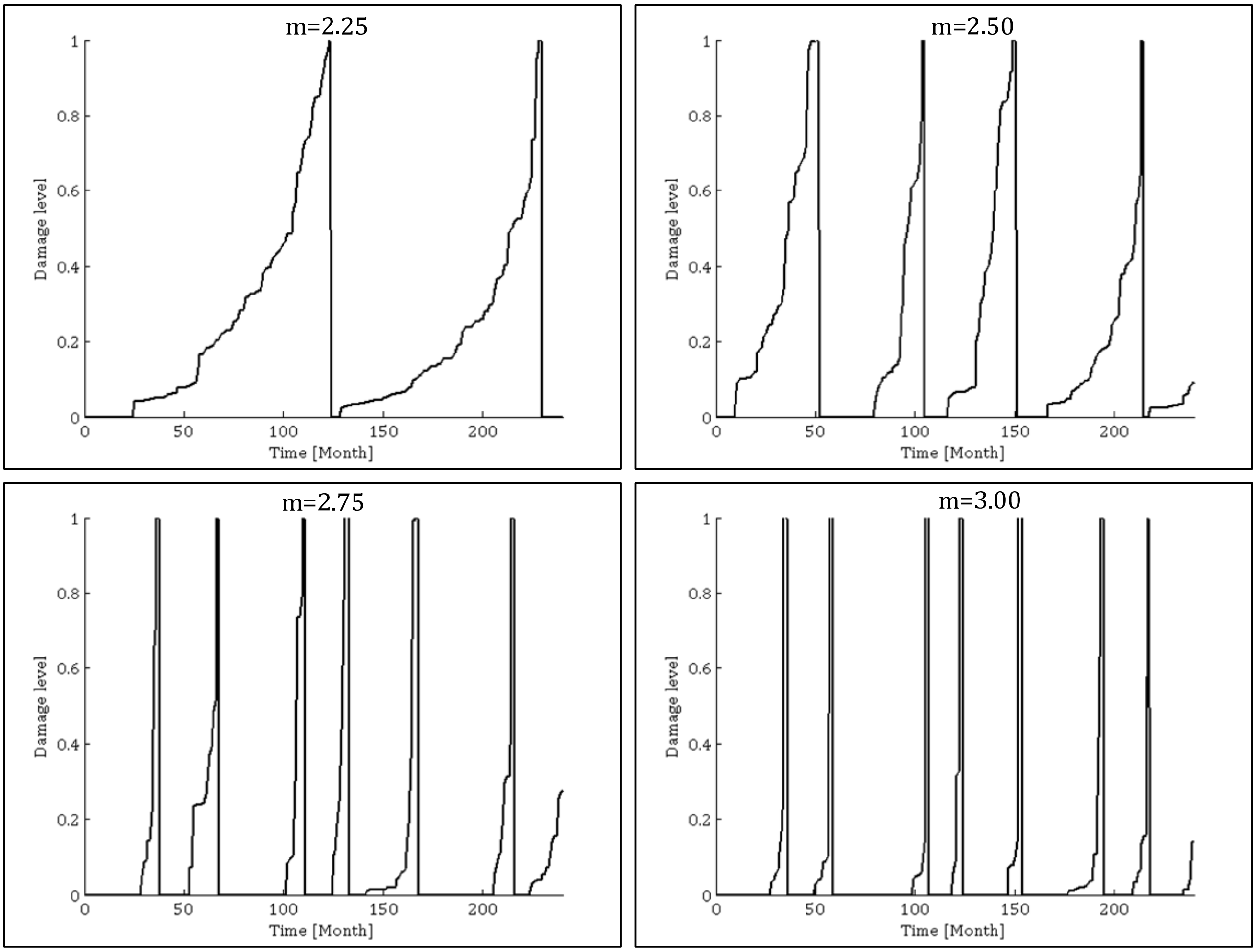

Fig. 23: Various realisations of the damage accumulation during the wind turbine lifetime dependent on the growth parameter *m*.

It is expected that *m* has a large effect on the most optimal service and inspection strategy since *m* determines how fast the damage accumulates. This is examined in the following sections where firstly corrective and afterwards scheduled maintenance is examined.

4.2 Corrective maintenance

Firstly, the expected cost and downtime of the wind turbine is examined when corrective maintenance is used together with the two damage models. During the simulation of the wind turbine lifetime finding the costs and downtime, several realisations of stochastic and none stochastic variables are made – this is called Crude Monte Carlo simulation. In tab. 7 is written the variables which are simulated when corrective maintenance is chosen. Some of the variables are simulated for each time step – corresponding to one month - while others are simulated after a given event. The time of the simulation is explained in the table. The values concerning the linear damage accumulation is only simulated if this damage model is chosen. This also goes for the exponential model. Further explanation concerning the various input parameters can be found in appendix E.

Tab. 7: Variables which are simulated continuously in the O&M model.

Variable	Symbol	Distribution	Time of simulation	Note
Power price	C_{kWh}	N	Each month	
Linear accumulation	ΔD_i	R	Each month	Linear damage model
Initial crack length	a_0	W	Initially or when the component has been repaired	Exponential damage model
Initial crack growth period	T_0	W	Initially or when the component has been repaired	Exponential damage model
Crack growth coefficient	C	LN	Initially or when the component has been repaired	Exponential damage model
Cyclic stress range	Δs	W	Each month	Exponential damage model
Spare part cost	C_{spare}	N	After a repair	
Spare part availability	A_{spare}	N	After a repair	
Spare part mass	M_{spare}	-	After a repair	
Vessels needed	-	-	After a repair	
Equipment availability	A_{equip}	N	After a repair	

In the following, firstly the linear damage model is examined and afterwards the exponential damage model is examined. For both the linear and the exponential model the maximum number of simulations is equal to 100000 and since the maintenance strategy is corrective, there are no inspections or service visits.

Linear damage model

As explained in chapter 3 the cost is divided into four constituents; crew cost, equipment cost, spare part cost, and loss of energy yield. In fig. 24 a convergence analysis is made for the total O&M cost and the cost of the four constituents. The percentage share of the total cost for each of the constituents is also shown in the figure.

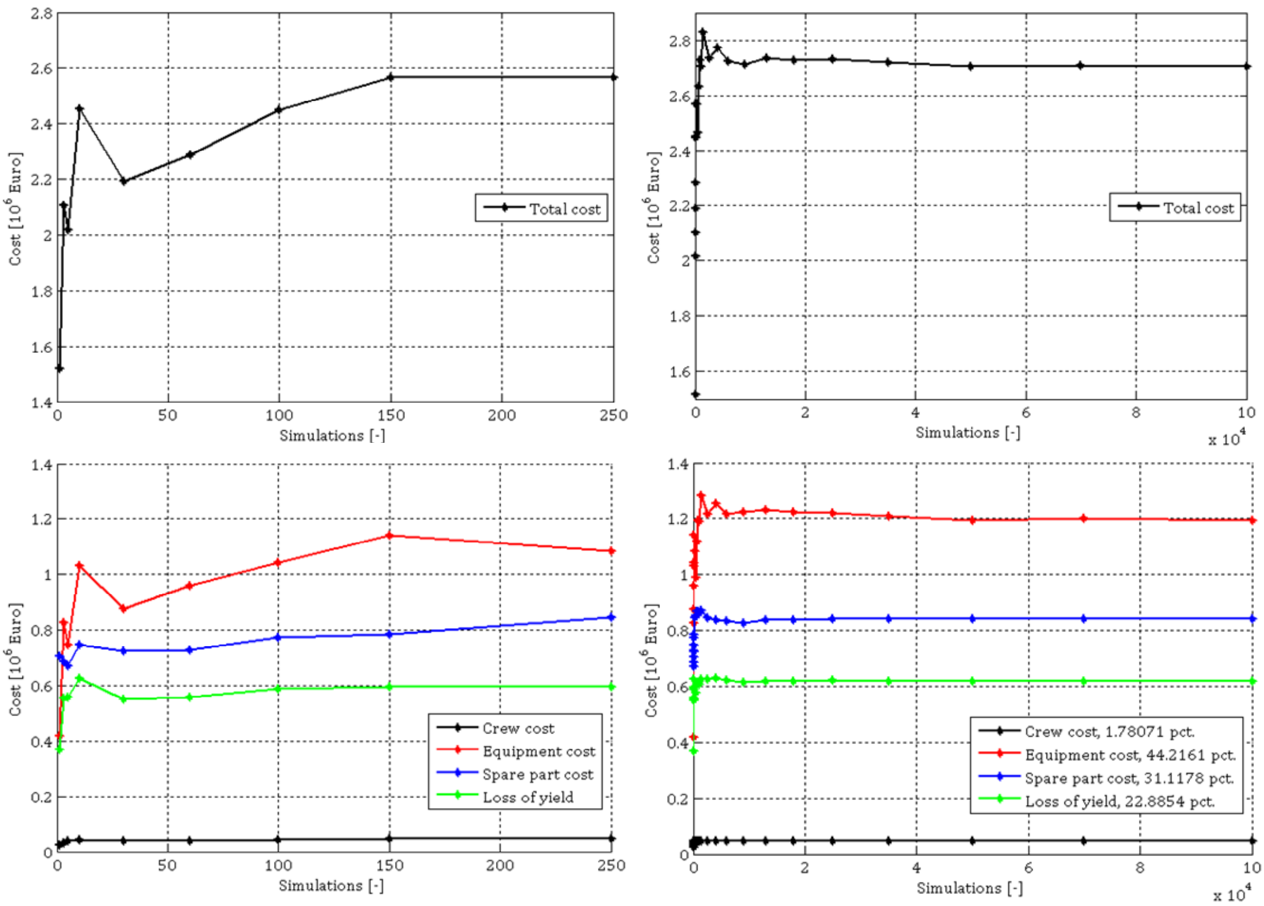

Fig. 24: On top it is shown how the total expected O&M cost during the wind turbine lifetime develop due to the number of simulations. On the bottom it is shown how each of the four different constituents develops due to the number of simulations. The damage accumulation is linear and the costs are capitalised.

In fig. 24 it can be seen that the costs vary significantly when the number of simulations is below 6000. Concerning the total cost, there is only a difference equal to 20k€ or less than 1% between 6000 and 100000 simulations. This difference is acceptable and since the four different constituents to the overall O&M costs are converged also, 6000 simulations are acceptable in further studies.

In [Rademakers et al., 2008a] an example of the output of the O&M program made by ECN in Holland is shown. The percentage share of the four constituents is calibrated so it gets close to the values in [Rademakers et al., 2008a] which make the values more reliable. The values in [Rademakers et al., 2008a] are equal to 2%, 22%, 27%, and 49% for the crew, spare part, yield, and equipment cost respectively. The spare part cost has a relatively large value when corrective maintenance is used and this could explain the difference from this O&M model and the model made by ECN.

In tab. 8 the results concerning downtime and availability of the wind turbine is given. It can be seen that the downtime is mainly caused by the time used to organise the repair team. This is caused by the fact that each time the wind turbine has to be repaired it is unscheduled and spare parts and equipment are therefore not always available. It is assumed that the repair teams work 24 hours a day since the daily rate of the repair vessels are very high. Combined with the short distance from Esbjerg Port to Horns Rev I, the downtime due to travel is very low.

As expected the availability is largest during the spring and summer months. The downtime per failure is equal to 10.7 days which is found by dividing the total downtime with the number of failures. The number of total failures is equal to 10.4 which give an annual failure rate equal to 0.52 which is satisfying close to the assumed component failure rate equal to 0.5.

Tab. 8: Downtime, availability, and costs when the linear damage model and corrective O&M is used.

		Winter	Spring	Summer	Autumn	**Total**
Downtime	Organisation [hrs]	583	409	282	419	1693
	Waiting [hrs]	384	93	37	195	705
	Travel [hrs]	5	4	2	3	14
	Repair [hrs]	86	60	40	60	246
	Total [hrs]	1058	566	361	677	2662
Availability	[%]	97.5	98.7	99.2	98.4	98.5
Cost	Crew [k€]	23	7	4	14	48
	Equipment [k€]	522	172	87	414	1195
	Spare parts [k€]	305	200	132	204	841
	Loss Yield [k€]	266	110	64	179	619
	Total [k€]	1117	489	287	811	2703
Inspection	N [-]	0	0	0	0	0
	Cost [k€]	0	0	0	0	0
Service	N [-]	0	0	0	0	0
	Cost [k€]	0	0	0	0	0
Scheduled repair	N [-]	0	0	0	0	0
	Cost [k€]	0	0	0	0	0
Unscheduled repair	N [-]	3.6	2.5	1.7	2.6	10.4
	Cost [k€]	1117	489	287	811	2703

The four constituents to the total cost are also listed in tab. 8. As expected the total O&M costs are highest during the winter and autumn months. The O&M cost is also divided into inspection cost, service cost, cost due to scheduled repair, and cost due to unscheduled repair. Since the repair type is corrective it is only the unscheduled repair which contributes to the O&M costs.

From tab. 8 it can be seen that it is preferable if the wind turbine is repaired during the spring and summer months. It is highly expensive to repair the wind turbine during the autumn and winter months. In average it costs 260k€ to repair the wind turbine which is a very high value. It must therefore be examined is scheduled maintenance can lower the costs by reducing the number of unscheduled repairs. However, before scheduled maintenance is examined the exponential damage model is analyzed.

Exponential damage model

Convergence studies have also been made for the exponential damage model. As expected the number of simulations needed is also equal to 6000 in order make sure that the result is converged.

The results concerning downtime, availability, and costs can be seen in tab. 9. It can be seen that the failure rate during the winter and autumn months are higher than for the linear damage accumulation. The annual failure rate is 0.49 which is less than for the linear damage accumulation. However, the costs are slightly different which is caused by the fact that there are more failures during the winter and autumn months. The total availability is also maintained at the same level even though the failure rate is slightly decreased.

Tab. 9: Downtime, availability, and costs when the exponential damage model and corrective O&M is used.

		Winter	Spring	Summer	Autumn	**Total**
Downtime	Organisation [hrs]	651	259	187	503	1600
	Waiting [hrs]	435	60	24	235	754
	Travel [hrs]	6	2	2	4	14
	Repair [hrs]	96	38	26	70	230
	Total [hrs]	1188	359	239	812	2598
Availability	[%]	97.2	99.2	99.4	98.1	98.1
Cost	Crew [k€]	49	11	8	37	104
	Equipment [k€]	533	99	66	446	1145
	Spare parts [k€]	299	114	80	228	720
	Loss Yield [k€]	216	58	40	169	482
	Total [k€]	1097	281	193	881	2452
Inspection	N [-]	0	0	0	0	0
	Cost [k€]	0	0	0	0	0
Service	N [-]	0	0	0	0	0
	Cost [k€]	0	0	0	0	0
Scheduled repair	N [-]	0	0	0	0	0
	Cost [k€]	0	0	0	0	0
Unscheduled repair	N [-]	4.1	1.5	1.1	3.2	9.9
	Cost [k€]	1215	306	196	1017	2734

As expected the results concerning costs are almost the same for the linear and the exponential damage model. For the exponential damage model the failures occurs a little more often during the winter and autumn, since the effect of a higher cyclic stress range Δs is enforced by the exponent m. This gives a lower availability during these months. Therefore, the cost per failure is a little higher. For the exponential damage model the annual failure frequency is equal to 0.5.

For both the linear and exponential damage accumulation it can finally be concluded that the costs due to failure of the wind turbine is very high - especially during the winter and autumn months. It is therefore examined in the next section if it is beneficial to use the scheduled maintenance strategy.

4.3 Scheduled maintenance

In chapter 3 the difference between corrective and scheduled maintenance is described. In many cases it is profitable to inspect the turbine continuously in order to repair the wind turbine before a given component reaches failure. Using the O&M-program it is possible to examine various inspection and service plans in order to find the most optimal plan due to the assumptions made in appendix E. As explained in the appendix, probability of detection curves (POD-curves) are used in order to find the probability that the damage level of the component is acknowledged. It is also explained in appendix E at which damage levels the component will be repaired and when the component is replaced. In addition to the variables in tab. 7, which are simulated continuously for corrective maintenance, a few extra variables are simulated when scheduled maintenance is chosen. The extra variables are written in tab. 10.

Tab. 10: Extra variables which are simulated continuously in the O&M model when scheduled maintenance is used instead of corrective maintenance.

Variable	Symbol	Distribution	Time of simulation	Note
Damage detection (Yes/no)	-	*POD-curve*	At an inspection or service visit	
Damage reduction	χ	N	At a service visit	

It has to be stated that the optimal O&M plan is very difficult to find since many variables influences the solution. Firstly, the cost concerning inspection, service, scheduled, and unscheduled repair has to be calculated with a satisfying accuracy. Since there are limited data available from the industry this is extremely difficult to manage. The optimal inspection and service plan is also highly dependent on the damage accumulation, the repair and replacement barriers, the POD-curves, the choice of repair vessels, and so forth. A correlation between the POD-curves and the inspection and service costs could also be made. However, in order to simplify the model this is not taken into account. To find the correlation, an extremely good knowledge and experience with inspections also have to be gained and this is not possible due to the sensitivity of the industry data.

In the following the linear and the exponential damage model are examined in order to find the most optimal service and inspection plan. It is also examined if it possible to reduce the operation and maintenance costs by changing the repair barrier. In fig. 25 it can be seen that also for scheduled maintenance the number of simulations needed to get a satisfying result is equal to 6000.

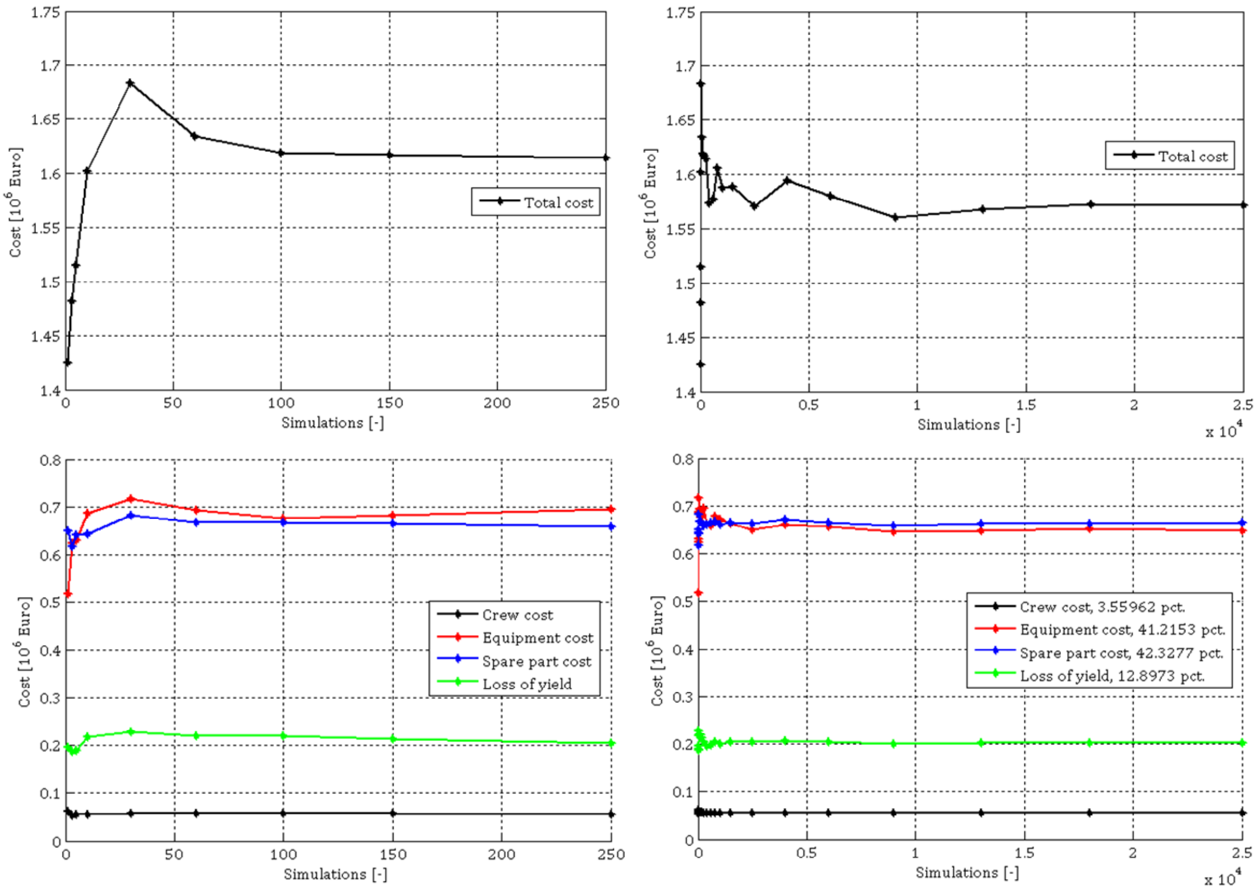

Fig. 25: Convergence curves when scheduled maintenance and the linear damage model are used.

The result in fig. 25 is obtained by having an inspection each year in March and by having a service visit each year in August. Cf. appendix E the repair barriers are initially set to 0.4 for repair and 0.9 for replacement of the component. When the wind turbine has to be repaired due to an inspection or a service visit, the wind turbine is stopped 60% of the times in order to avoid serial failure of the components in the wind turbine. In case of unscheduled repair or an immediate operation stop due to an inspection the loss in energy yield has a large influence on the result. Further information about spare part cost, equipment cost, crew cost, and yield cost can be found in appendix E. It can be seen that for scheduled maintenance the O&M cost is equal to 1573k€ which is a reduction equal to 42% compared to corrective maintenance.

In fig. 25 it can be seen that the percentage share of the cost constituents change when scheduled maintenance is chosen. The percentage share of the crew cost change from 1.8% to 3.6% which is due to the crews which are needed to perform the maintenance. The share of the equipment is almost constant since it is 44.2% for corrective maintenance and 41.2% for scheduled maintenance. The spare part cost rises from 31.1% to 42.3% which is due to the fact that the gearbox is very expensive to repair. E.g. if it was the electronics which had to be repaired the spare parts would probably be less expensive giving a minor percentage share. The yield cost is reduced from 22.9% to 12.9%. This was also expected since several operation stops are avoided. It can be seen in tab. 8 and tab. 9 that avoiding failure during the winter decreases the downtime significantly. This can also be seen in tab. 11 where the downtime and costs are written for the respective O&M strategy.

Tab. 11: Downtime, availability, and costs when the linear damage model and scheduled O&M is used. An inspection is made each year in March and a service visit is made each year in August.

		Winter	Spring	Summer	Autumn	**Total**
Downtime	Organisation [hrs]	43	668	555	12	1278
	Waiting [hrs]	26	101	34	11	172
	Travel [hrs]	1	7	6	1	15
	Repair [hrs]	6	214	299	2	521
	Total [hrs]	76	990	894	26	1986
Availability	[%]	99.8	97.7	97.9	99.9	98.8
Cost	Crew [k€]	2	14	40	2	58
	Equipment [k€]	42	291	308	6	647
	Spare parts [k€]	21	158	483	3	665
	Loss Yield [k€]	19	86	95	3	203
	Total [k€]	84	549	926	14	1573
Inspection	N [-]	0	20	0	0	20
	Cost [k€]	0	164	0	0	164
Service	N [-]	0	0	20	0	20
	Cost [k€]	0	0	625	0	625
Scheduled repair	N [-]	0	8.1	6.3	0	14.4
	Cost [k€]	0	255	162	0	417
Unscheduled repair	N [-]	0.3	0.7	0.7	0.1	1.8
	Cost [k€]	84	132	139	12	367

In tab. 11 it can be seen that the cost constituents are changed significantly compared to the results in tab. 8 where corrective maintenance is used. First of all the availability during the winter and autumn is increased dramatically. Since the damage model is linear and the probability of detecting a possible error is relatively high and the gearbox hardly ever reaches failure before is has been repaired or the damage level has been lowered due to a service visit. The model made to estimate the probability of detecting an error is explained in appendix E where it is also shown how much the damage level is reduced after a service visit. Since the inspections, service visits, and the following repairs are made during the spring and summer months all the costs are almost related to this period. It has to be noted that of course this cannot be related to the reality for a given wind turbine component since some failures might occur almost instantaneously due to e.g. an extreme event. However, theoretically if the damage level of the component varied linearly and it was physically possible to detect almost every error the model gives a correct result.

Looking at tab. 11 it is surprising that the number of unscheduled repairs is highest during the spring and summer months. However, this can be explained by the fact that often the wind turbine is repaired in March or August and with an annual failure rate equal to approximately 0.5, afterwards in average a damage level equal to 1.0 will be reached after two years. This is often in the spring and summer months. If the exponential damage model was examined instead the number of unscheduled repairs would be equal to 2.2, 0.63, 0.39, and 0.78 for the winter, spring, summer, and autumn, respectively. This corresponds well to the expected result.

Compared to the corrective maintenance strategy the organisation time has been lowered by 320hours which is 20%. This is due to the fact that the risk that a jack-up vessel is needed is reduced significantly when the component is repaired before it reaches a damage level equal to 1.0. A jack-up vessel is needed for very large components where the wind turbine crane is not sufficient. Furthermore, in 40% of the cases where the wind turbine is scheduled to be repaired, it can stay in operation until the repair team is organised. The organisational time is used to calculate the loss in energy yield while the spare parts are gathered and the equipment needed is available and therefore the organisation time is set to zero when the wind turbine stays in service.

The waiting time is reduced by almost 75% from 705hours to 172hours. This is both because the jack-up, which has more strict demands concerning maximum wind speed and wave height, is used less and because the repairs are made during the spring and summer months. Opposite from the organisation time the waiting time is season dependent and a larger percentage reduction was therefore also expected. The repair hours has increased significantly which is due to the inspection and service visits which per visit are set to last 6hours and 14hours, respectively.

Concerning the costs shown in tab. 11 the most significant changes is the reduction in equipment cost equal to 548k€ or approximately 50% and the reduction in lost energy yield cost equal to 416k€ or approximately 70%. The reduction in equipment cost is due to the limited use of jack-up vessels and the reduced waiting time when the repair team is organised. As it can be seen in appendix E the daily rate for a jack-up vessel is set to 150k€ for a jack-up and 8k€ for a small boat. The limited yield cost is due to the reduced organisation time, waiting time, and the fact that the energy production per hour is higher during the winter and autumn months than during the summer and spring. The spare part cost is only reduced by 20%. This is due to the fact that the spare parts are very expensive for the gearbox and since the number of repairs is increased it does not help significant that the average spare part cost per repair is decreased. For scheduled repair the average spare part price is set to 20k€ while the replacement cost cf. chapter 2 is 562k€. However, for unscheduled stop the probability that the component has to be replaced is only 5% but if it only has to be repaired, it is assumed that the spare part cost is 120k€ since the gearbox has reached a damage level equal to 1.0.

In tab. 11 it can be seen that the unscheduled repair cost is equal to 29k€ per repair compared to 260k€ for the unscheduled repair in tab. 8. This is of course a huge difference. It can also be seen that the service cost is equal to 40% of the overall cost O&M cost. This is a very large value and it is therefore examined if an inspection in March and a service visit in August give the most optimal inspection and service plan.

In tab. 12 the expected O&M cost for various inspection and service plans are given. Both the linear and the exponential damage model are examined. For the linear damage model it can be seen that the most optimal inspection and service plan is when an inspection is made each year in August and a service visit is made each year in March. As described the cost is reduced by 42% compared to the corrective maintenance strategy. For a gearbox it has been shown that the unscheduled repair costs are very high and therefore it was also expected that the O&M costs could be reduced significantly. A service visit every year is very often and it is not expected that this is beneficial when the whole wind turbine is examined. Some components might be cheaper to repair which relatively would make the inspection and service costs higher.

It can be seen in tab. 12 that scheduled maintenance is not optimal when the exponential damage model is used. For the exponential damage model, which is based on the theory on fatigue of materials, the damage level is zero before a macroscopic crack appears. However, due to the values used in this model the crack evolves very fast when it reaches a damage level above 0.1 to 0.2. When the repair barrier is equal to 0.4 it is very unlikely that an inspection or service visit is made when the damage level is above this barrier. It is examined if it is possible to change the conclusion if the repair barrier is lowered. Another possibility is to use online condition monitoring which is described in chapter 6.

Tab. 12: Expected O&M cost dependent on various inspection and service plans. The results are given for both the linear and the exponential damage model. The reduction in cost is also given but if the cost is increased the result is shown as (XX).

Inspection/-s	Service and inspection/-s	Linear damage model Cost [k€]	Linear damage model Reduction [%]	Exponential damage model Cost [k€]	Exponential damage model Reduction [%]
0	0	2723	-	2776	-
Month 8	0	1929	29	2971	(7)
Month 8 and month 3	0	1743	36	3102	(12)
Month 3	Month 8/(5. year)	1710	37	3171	(14)
Month 3 and month 8	Month 8/(3. year)	1692	38	3213	(16)
Month 3 and month 8	Month 8/(2. year)	1669	39	3279	(18)
Month 3 and month 8	Month 8	1573	42	3464	(25)
0	Month 3 and month 8	1922	29	4002	(44)

As it can be seen in fig. 26 it is also possible to find the most optimal repair barrier. For the linear damage model, the optimal repair barrier is examined for two different inspection and service plans – one with an annual inspection in August and one with an annual inspection in March and a service visit in August. The exponential damage model is also examined for the inspection and service plan where an annual inspection is made in March and a service visit is made in August.

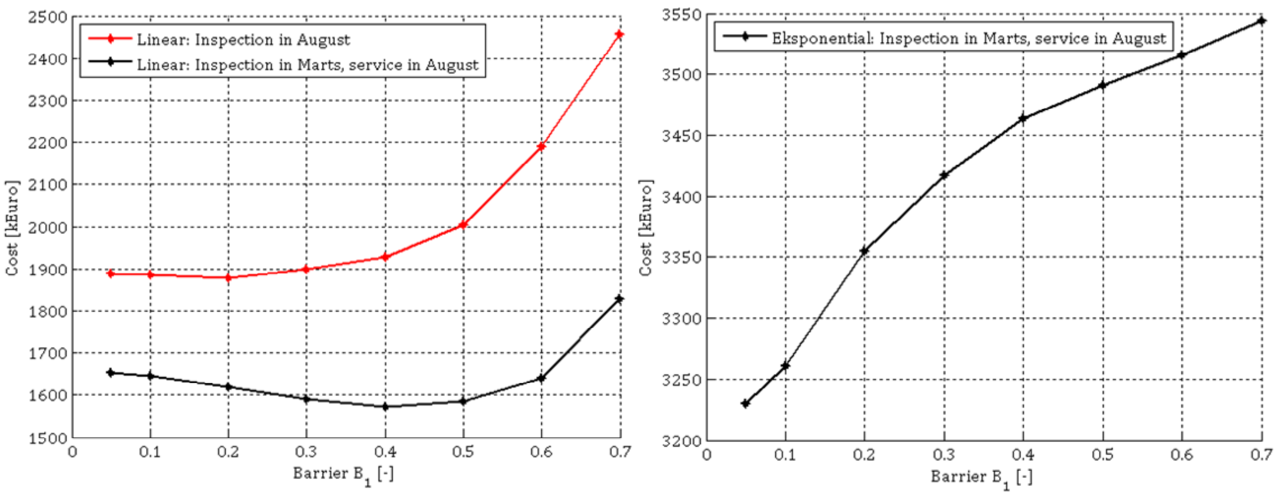

Fig. 26: O&M cost due to various repair barriers, service and inspection plans, and damage models.

For the linear damage model the most optimal repair barrier is equal to 0.4 when an inspection is made in March and a service visit is made in August. If a lower repair barrier is used, the gearbox will be repaired too often, compared to the time between the inspections and the damage accumulation. However, if only the gearbox is inspected in August it can be seen in fig. 26 that the most optimal repair barrier is lowered to 0.2. The lower repair barrier was also expected when the time between the inspections was increased. Finally it can be seen that for very low repair barriers the cost only varies insignificantly when the repair barrier is changed. This is due to the low probability of detection at low damage levels.

For the exponential damage model, where it was not beneficial to use scheduled maintenance, it can be seen in fig. 26 that changing the repair barrier does not change this conclusion. However, it can be seen that, if it is decided that scheduled maintenance is used, a very low repair barrier is optimal. Also concerning the exponential model it is expected that the exponent m has a large influence on the optimal inspection and service plan. This is examined in the following sensitivity analysis.

4.4 Sensitivity studies

The previous results are obtained only by limited data from the wind turbine industry and the model can therefore only be seen as a generic model which makes it possible to examine the influence and importance concerning O&M costs of various input parameters. The sensitivity analysis is made in order make this examination and to validate the model. The effect of changing the following input parameters will be made in this analysis:

Crew

- Crew price

Equipment

- The maximum wind speed V_{max} and wave height H_{max} for the vessels used for repair
- The equipment cost
- The availability of the equipment and spare parts
- Possibility during the winter that a helicopter is used for repair instead of a small boat
- Use of fixed cost concerning the small repair boat compared to using a variable cost

Spare parts

- The spare part weight
- The spare part cost

Extra

- Time to repair the component
- Power sales price
- Damage accumulation
    - Linear: Variation of load
    - Exponential: Variation of m
- Probability of detecting a damaged component
- The damage reduction due to a service visit
- The probability that a wind turbine is immediately stopped if after an inspection it is decided that the component has to be repaired
- The risk that a component has to be replaced if the damage level reaches 1.0.

In some cases the optimal inspection and service plan (I&S plan) is examined. The different plans, which are taken into account, are shown in tab. 12 and are named as follows:

- Plan 1: No service or inspection visits – corrective maintenance
- Plan 2: Inspection in August
- Plan 3: Inspection in Marts and in August
- Plan 4: Inspection in Marts and in August. Every 5. Year in August a service visit is made instead
- Plan 5: Inspection in Marts and in August. Every 3. Year in August a service visit is made instead
- Plan 6: Inspection in Marts and in August. Every 2. Year in August a service visit is made instead
- Plan 7: Inspection in Marts and service visit in August.
- Plan 8: Service visits in Marts and in August

In general the linear damage model and I&S plan 7 is used. In some cases it is relevant to change these assumptions in order to show the sensitivity more clearly. When doing so, the new assumptions are listed in the respective section. Furthermore, 6000 simulations are made for each result which according to the previous section is satisfying.

Crew price

In appendix E the number of crews needed for the various events – inspection, service, scheduled repair, and unscheduled repair – is written. The number of workmen in one crew is set to three and the hourly wage is initially set to 25€/hour. Using the linear damage model it can be seen in that the crew cost has a percentage share equal to 3.5% and the O&M cost is equal to 1573k€. In fig. 27 the development in overall O&M cost and the percentage share of the crew cost is given.

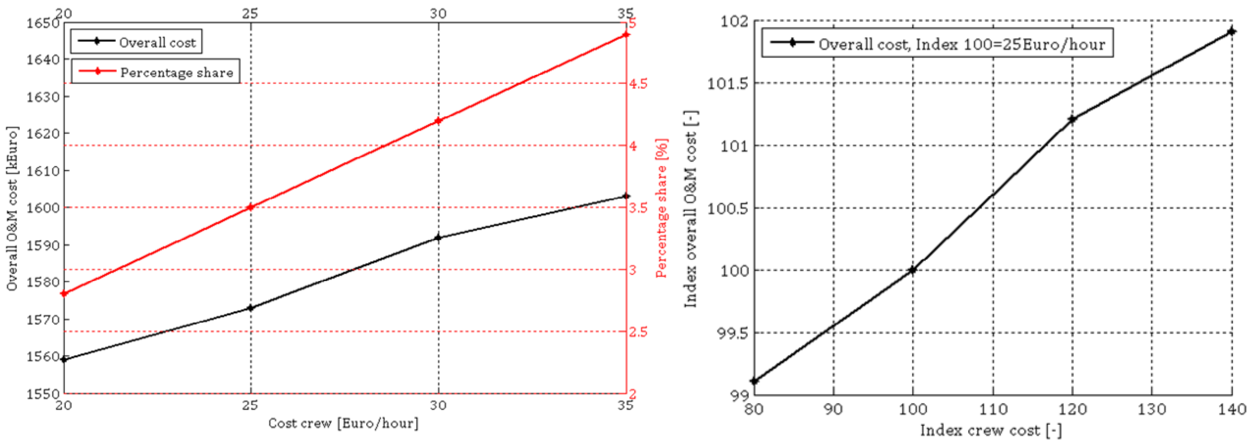

Fig. 27: The development in expected O&M cost and percentage share of the crew cost when the cost of workmen is changed. I&S plan 7.

It can be seen in fig. 27 that the percentage share of the crew cost is relatively low even though the hourly wage for the workmen is changed. The overall O&M costs are changed with less than 3% when the hourly wage is changed from 20€/hour to 35€/hour. This is an increase equal to 75% and it can therefore be concluded that the crew price is not an important area if the O&M cost has to be brought down.

V_{max} and H_{max}

The result when changing the maximum wind speed V_{max} and the maximum wave height H_{max} is examined in this section. It is only the limits concerning the small boat which is changed and only one annual inspection is made in order to make sure that in some occasions repair is needed during the winter where the waiting time is longest. The annual inspection is in August corresponding to I&S plan 2.

In the previous analyses of the O&M model the maximum wave height and the maximum wind speed for the small boat have been set to 1.2m and 14m/s, respectively. In fig. 28 it can be seen that the following combinations of wind speed and wave height is examined:

- H_{max}=0.7m – 1.5m/s
- V_{max}=9m – 17m/s

The wave height and wind speed is not examined separately since the values are correlated cf. appendix A.

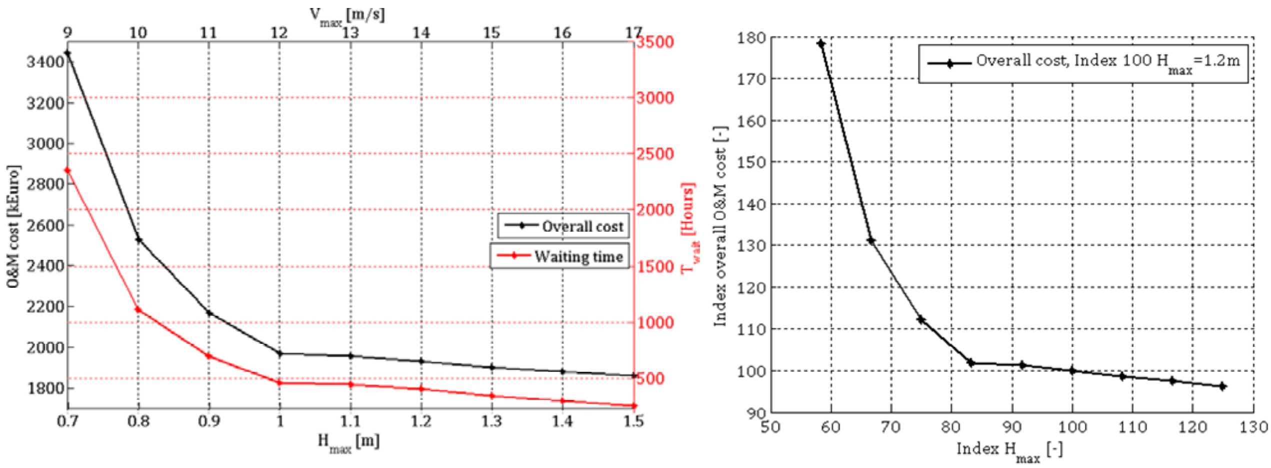

Fig. 28: Expected O&M cost and waiting time due to various combinations of maximum wave height and maximum wind speed for the small boat. One inspection is made in August – I&S plan 2.

In fig. 28 both the overall O&M cost and the waiting time is examined. It can be seen that the curves for the cost and the waiting time the slope is almost similar. This was also expected since the cost depends on the waiting time before the repair team has a sufficiently long weather window to repair the gearbox.

It can also be seen that for low maximum values the cost is reduced significantly when the wind and wave requirements are increased. Opposite for large wave heights and wind speeds the slope of the curves are lowered meaning that the impact of changing the requirements is smaller. Changing the maximum wave height from 0.7m to 1.0m gives an expected cost reduction equal to 1471k€ while changing the maximum wave height from 1.0m to 1.3m gives an expected cost reduction equal to 65k€.

When vessels are being fabricated, this is important to take into account. It might not be beneficial to change the requirements concerning the maximum wave height from 1.0m to 1.3m. However, it is probably beneficial to change the requirements from 0.7m to 1.0m if the investment per turbine is less than 1471k€. This also has to be taken into account when the wind turbine crane is being designed.

Equipment cost

Since the equipment cost has a high percentage share of the overall cost, the daily cost is expected to have a significant impact on the overall cost. It can be seen in fig. 29 that this is also the case for this O&M model.

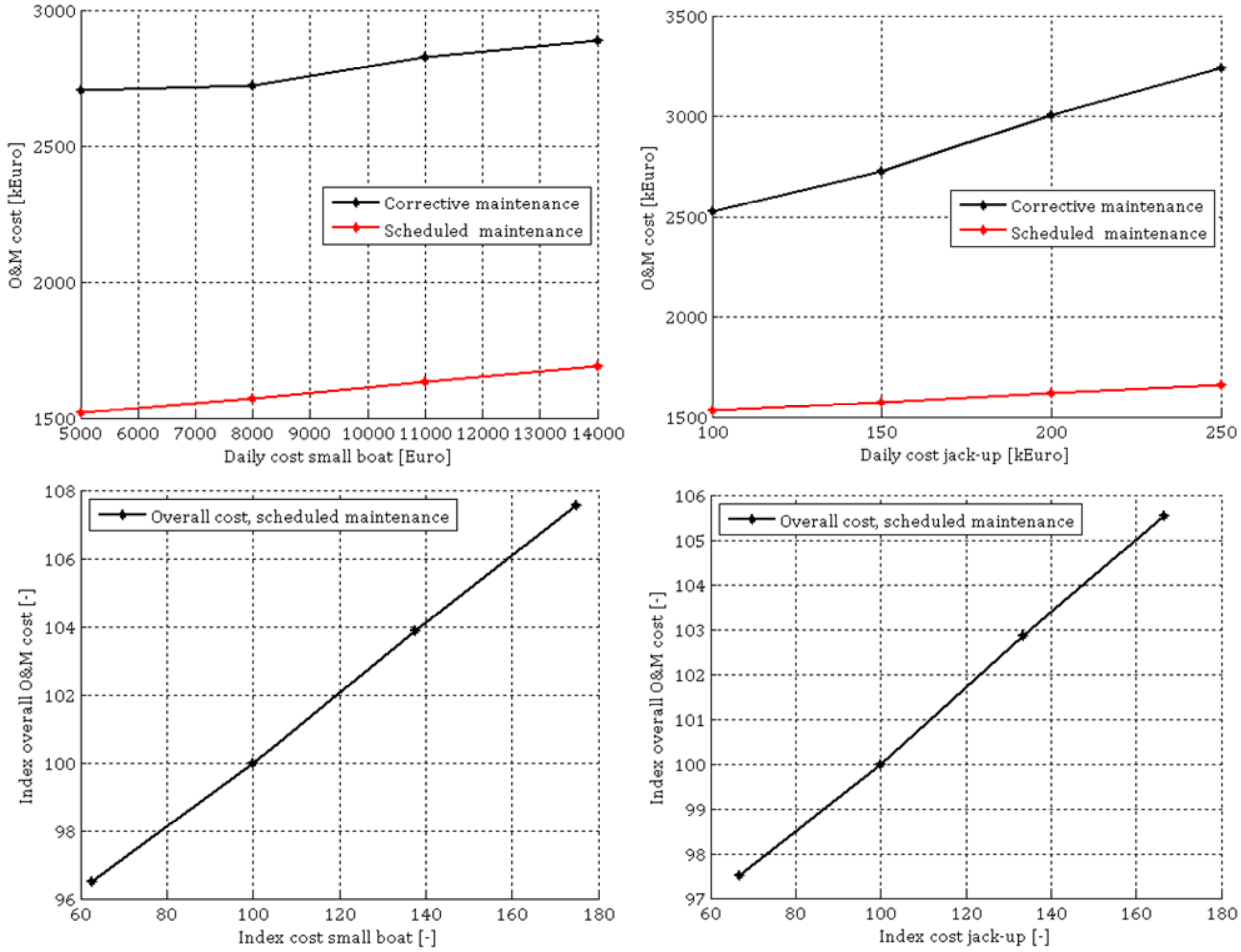

Fig. 29: Overall O&M cost dependent on the daily cost of a small and the daily cost of a jack-up. On the bottom an index is made showing the development in expected O&M cost due to the vessel cost if scheduled maintenance is chosen. The I&S plan is either plan 1 or plan 7.

In fig. 29 both the corrective maintenance strategy and the scheduled maintenance strategy are examined. For the small boats it can be seen that a change in daily cost results in an almost similar extra cost. This is due to the fact that for scheduled maintenance the small boat is used more often compared to corrective maintenance. However, when the boat is used for corrective maintenance it is in a longer period due to the longer time to repair the gearbox. Hereby the waiting time is also longer.

Concerning the jack-up it can be seen in fig. 29 that a change in cost only have a small influence for scheduled maintenance. This is due to the fact that only a few times the gearbox reaches a damage level equal to 1.0 and therefore the risk of needing a jack-up is minimized significantly. Opposite for corrective maintenance the jack-up is used relatively often and therefore the overall cost is highly affected by the change in cost.

From the previous it can be concluded that for corrective maintenance both the cost of the small boat and the jack-up vessel has a significant impact on the overall cost. However, for corrective maintenance a change in cost of the jack-up vessel gives the largest change in expected O&M cost. For scheduled maintenance, where inspection and service visits are made regularly, the cost of the small boat and the cost of the jack-up has almost the same influence on the O&M cost. At index 160 the index of the overall cost is equal to 106 and 105 for the small boat and the jack-up respectively.

Availability spare parts and equipment

The availability of spare parts and the equipment needed is also a very important factor. This analysis is made for corrective maintenance corresponding to I&S plan 1. It can be seen in appendix E that the availability of the spare parts are described by a normal distribution. Since corrective maintenance is used, only the availability of spare parts for unscheduled stops, where replacement is not needed, are examined. Cf. appendix E the initial values are equal to N(5days, 2days). As it can be seen in fig. 30 the mean value and standard deviation is changed in pairs since it is expected that this reflects the reality.

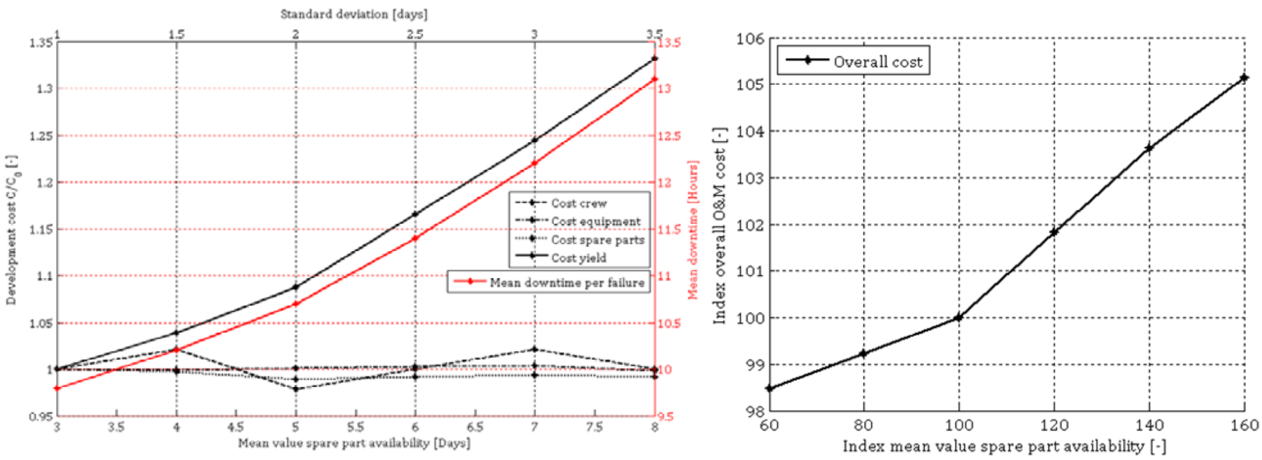

Fig. 30: Development in cost and the average downtime per failure due to the availability of the spare parts. I&S plan 1.

In fig. 30 it can be seen that the development of the four different cost constituents are plotted as a function of the spare part availability. It can be seen that the crew, equipment, and spare part cost are almost unaffected by the change in spare part availability. This was also expected and the small variation is only due to the relatively limited number of simulations. That the crew and equipment cost are unaffected also shows the assumption that the repair vessels and crews are assumed not to arrive to the nearby port before the spare parts are available. Of course this is difficult to manage in reality but especially for the expensive vessels this is very important to achieve.

The loss in energy yield is the only cost which is affected by the availability of the spare parts. It can be seen that the yield cost is increased by almost 35% when the mean value for the availability is changed from three days to eight days. The mean downtime per failure is also increased by more than three days and as expected loss in energy yield is dependent on the mean downtime.

In fig. 30 it can also be seen that the slope of the curves concerning loss in energy yield and mean downtime per failure change at an availability equal to five days. This is due to the fact that in many cases a small boat, where the mean availability is set to five days, is needed for repair. If the period to purchase equipment is larger than the availability of the spare parts, the availability of the spare parts does not influence the downtime. If the mean value of the availability concerning both the spare parts and a small boat is lowered to three days the mean downtime per failure is equal to 8.7days. This is a significant reduction compared to the 9.8hours if the availability of the boat is not improved. It can hereby be concluded that it is important to lower the availability of both the spare parts and the equipment in order to get the most optimal effect. This was also expected.

Use of helicopter contra small boat

If the wind turbine has to be repaired, especially during the autumn or winter months, it is in some cases beneficial to use a helicopter instead of a boat. This is due to the fact that the helicopter does not have any requirements concerning maximum wave height. As explained in appendix E the probability of using a helicopter is given for each of the four seasons. It is assumed that the maximum loading capacity is equal to 1000kg so it is only if the spare parts weigh less than 1000kg that a helicopter is an option. In this sensitivity analysis it is assumed that corrective maintenance is used. Initially the probability of using a helicopter, if the spare part mass is less than 1000kg and it is winter, is equal to 50%. In this analysis the probability is varied from 0% to 100%. The results can be seen in fig. 31 when corrective maintenance is chosen.

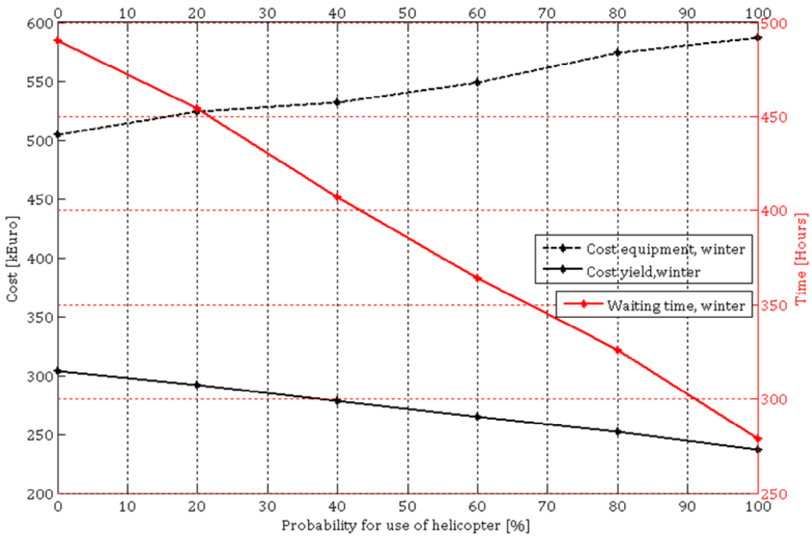

Fig. 31: Equipment cost, loss in energy yield, and waiting time during the winter dependent on the probability of using a helicopter instead of a small boat. I&S plan 1.

The equipment cost, the loss in energy yield, and the waiting time during the winter is plotted as a function of the probability that a helicopter is used. It can be seen that the waiting time is almost halved if the helicopter is used every time compared to if a boat is used every time the wind turbine has to be repaired during the winter. The minor waiting time results in a reduction in loss of energy yield equal to 67k€. However, the equipment cost is increased by 82k€ and it is therefore not beneficial to use the helicopter. This result is due to the relatively simple model where the probability of using the helicopter and a simulation decides if a helicopter is used. In reality the use of a helicopter would be dependent on the weather forecast which could make it beneficial to use the helicopter. This however, is not examined further in this thesis.

Small boats: Use of fixed cost contra variable cost

Instead of renting a small boat each time a boat is needed, it is also possible to purchase a small boat which only purpose is to service the wind turbines in the given wind turbine farm. This gives a fixed cost concerning the small boat instead of a variable cost. It is assumed that one boat can service 40 wind turbines giving that the monthly cost is divided by 40 in order to find the contribution to the O&M cost for one wind turbine. The monthly boat cost is the variable which is examined in this analysis. Both corrective and scheduled maintenance with an inspection in March and a service visit in August is examined. For corrective maintenance the cost was equal to 2703k€ and for scheduled maintenance the cost was equal to 1573k€ if the small boat cost is a variable cost. In fig. 32 it can be seen how the overall cost develop due to the fixed monthly cost for one boat.

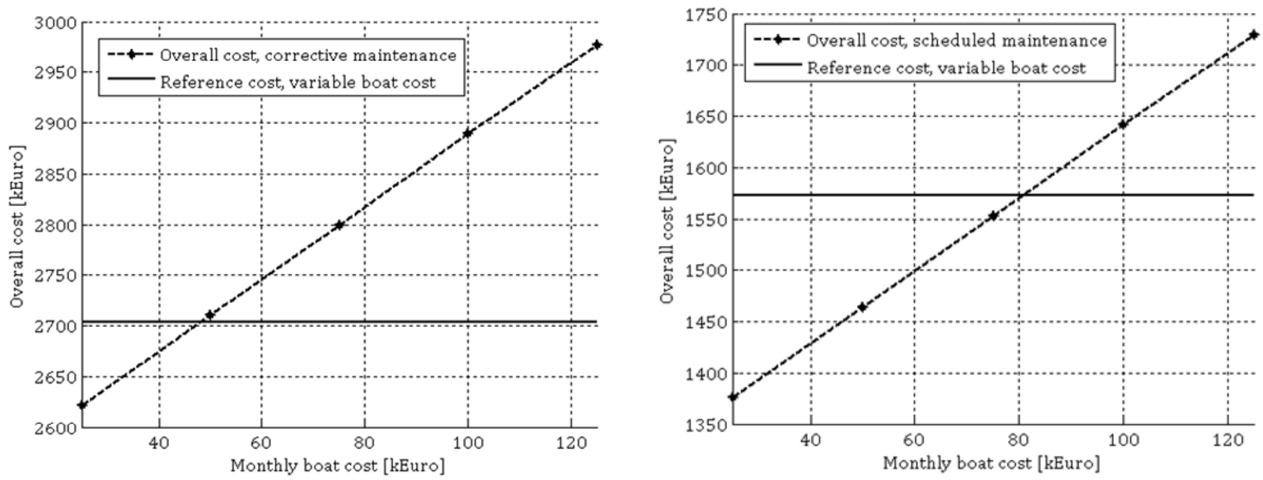

Fig. 32: Overall cost due to various values of fixed monthly boat cost. The I&S plan is either plan 1 or plan 7.

It can be seen that it is beneficial to have a fixed cost if the monthly boat cost is less than 50k€ and corrective maintenance is used. This corresponds to 1250€ per wind turbine. If scheduled maintenance is used it is beneficial to have a fixed cost if the monthly cost per wind turbine is less than 2000€. It was also expected that a fixed boat cost was more beneficial for scheduled maintenance than for corrective maintenance. This is due to the fact that a small boat is used more often for scheduled maintenance.

Spare part weight

As described in appendix E the spare part weight is found using (4.7). The gearbox mass is 56ton and for unscheduled repair α is set equal to six. In this sensitivity analysis α will be changed.

$$M_{spare} = Rand^{\alpha} \cdot M_{component} \qquad (4.7)$$

where

M_{spare}	is the spare part mass [ton]
$M_{component}$	is the component mass [ton]
α	is an exponent used to determine the spare part mass [-]
$Rand$	is a random number between 0 and 1 [-]

In fig. 33 it can be seen how the overall cost, the waiting time, and the organisation time depend on α. Corrective maintenance is assumed. The random number which is generated receives a value between 0 and 1 and a large exponent therefore gives a small spare part mass and a small risk that a jack-up vessel is needed. It is therefore expected that the cost is lowered when the exponent is increased and this is also shown in fig. 33.

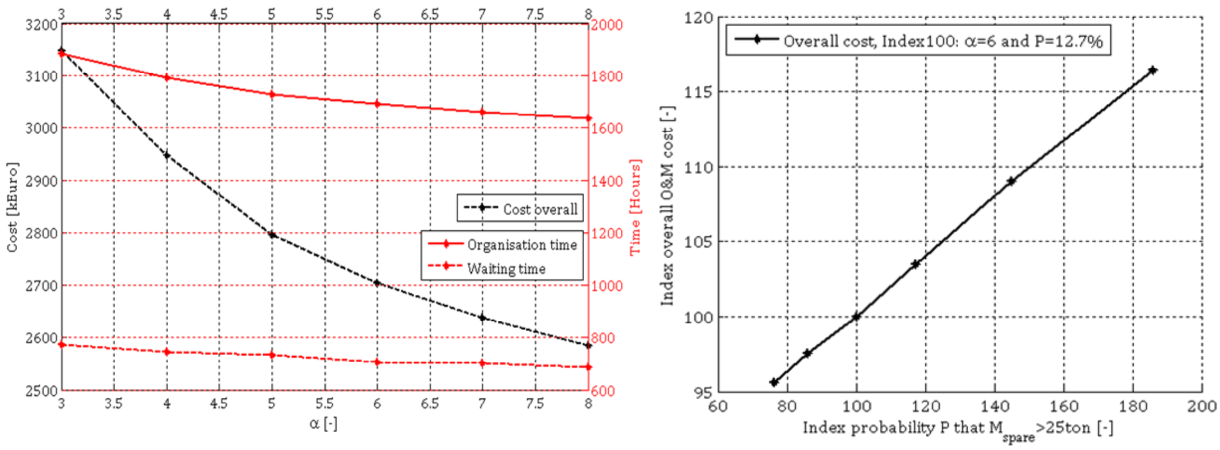

Fig. 33: (Left) Overall cost, organisation time, and waiting time dependent on the exponent used to calculate the spare part mass. (Right) Development in overall cost dependent on the index of the probability that the spare part mass is higher than 25ton. This is dependent on the exponent α. I&S plan 1.

It can be seen in fig. 33 that both the waiting time and the organisation time is dependent on the spare part mass. This is due to the fact that the jack-up vessel has more strict demands concerning maximum wave height and maximum wind speed. The availability of the jack-up vessel is also smaller.

To the right in fig. 33 is shown how the overall cost develops due to the probability that the spare part weight is higher than 25ton. Cf. appendix E a jack-up vessel is needed in these situations instead of a small boat. It can be seen that the expected O&M cost is highly affected by the spare part weight and the probability that a jack-up vessel is needed. This was also expected since compared to a small boat the availability of a jack-up is very poor and the daily cost is very high.

Spare part cost

It is examined how the O&M costs develop when the spare part cost is changed. Corrective maintenance is assumed and it is only the spare part cost for unscheduled repair of the gearbox which is changed. The standard deviation is maintained equal to 20k€. In fig. 34 the overall cost and percentage share of the four constituents are plotted as a function of the spare part cost.

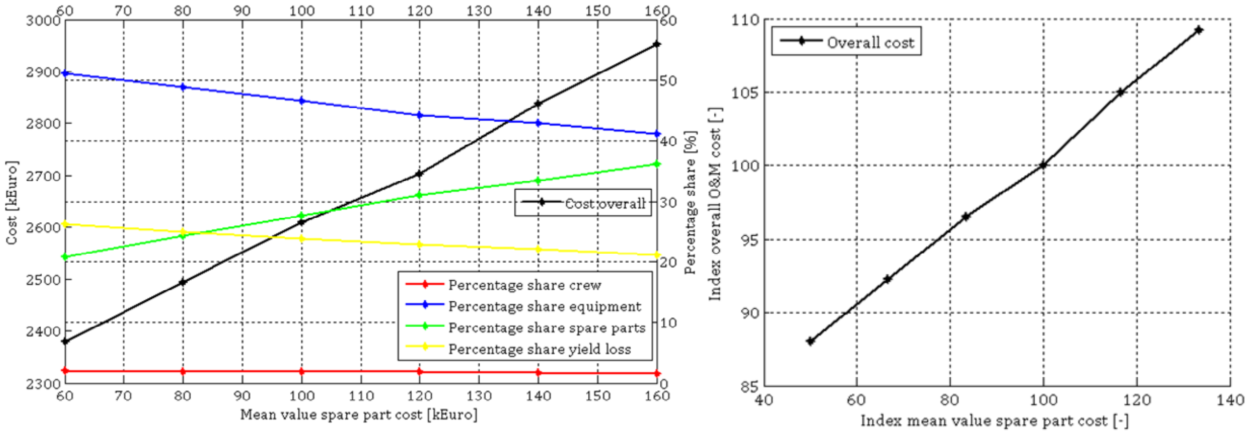

Fig. 34: Expected O&M cost and percentage share of the four different cost constituents due to the mean value of the spare part cost. I&S plan 1.

As expected the overall cost increases when the spare part cost is increased. The percentage share of the spare part cost is also increase. Concerning the crew it is difficult to see the development in percentage share but it varies from 2.0%, when the mean value of the spare part cost is equal to 60k€, to 1.6% when the mean value is 160k€.

Time to repair the gearbox

The sensitivity concerning the time to repair the gearbox is examined for scheduled maintenance. Cf. appendix E the time to repair the gearbox is initially set to 8 hours if the repair is scheduled. As explained in appendix E it is assumed that the wind turbine is stopped 60% of the times after an inspection or service visit if the gearbox has to be repaired. In these cases it is expected that the time to repair affects the loss in energy yield and the equipment cost. This is also shown in fig. 35.

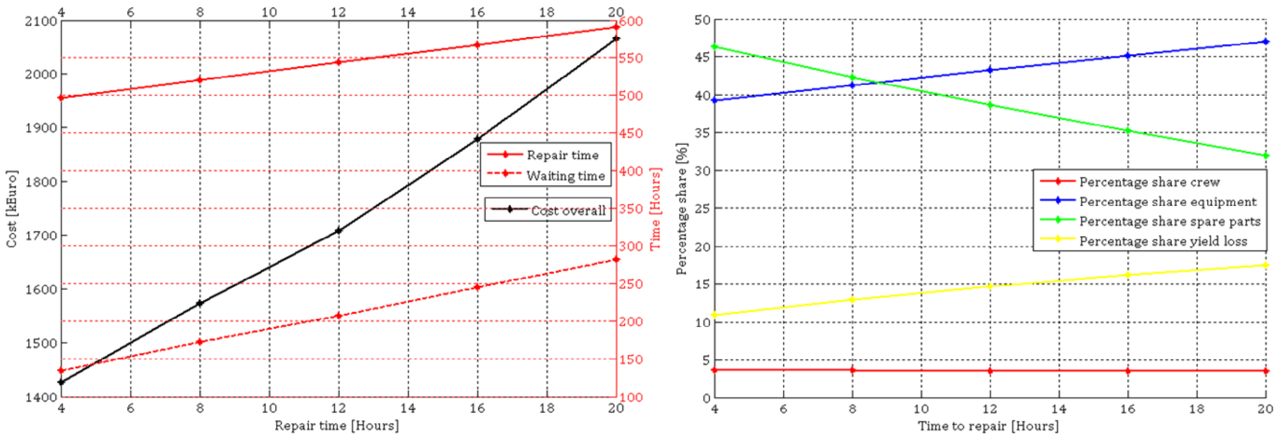

Fig. 35: Sensitivity of the O&M-model concerning the time to repair the gearbox at a scheduled repair. I&S plan 7.

It can be seen in fig. 35 and in fig. 36 that the overall cost is highly affected by the repair time. Furthermore, it can be seen that the percentage share of the loss in energy yield and equipment cost increases compared to the spare part cost. This was also expected since the spare part cost is independent of the repair time.

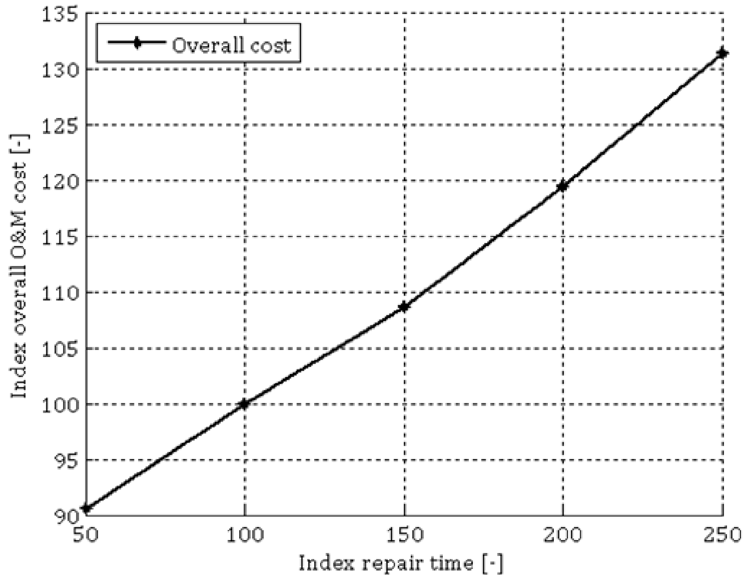

Fig. 36: Development in expected O&M cost dependent on the repair time. I&S plan 7.

Power sales price

The sales price of the produced power is of course expected to influence the loss in energy yield. This can also be seen in fig. 37 where scheduled maintenance is examined. The price is normal distributed and the standard deviation is maintained equal to 0.03€/kWh.

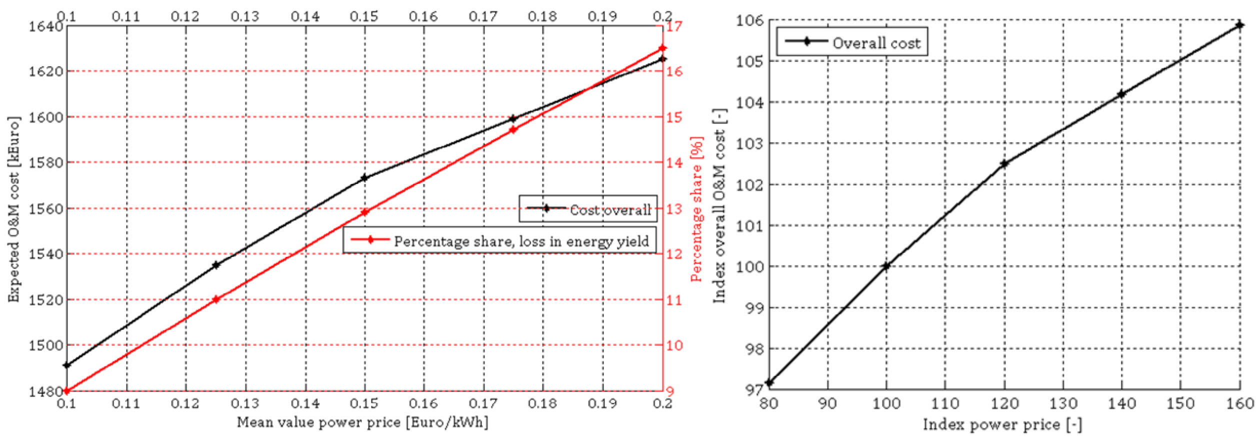

Fig. 37: O&M cost and percentage share of the loss in energy yield dependent on the mean value of the power price. I&S plan 7.

It can be seen that the percentage share is almost doubled when the power price is doubled. It is therefore important to give a reliable estimate on the average power price throughout the wind turbine lifetime even though the power price probably varies significantly.

Damage accumulation

As shown in section 4.3 the damage accumulation has a strong influence on the optimal service and inspection plan. For the linear damage model it was found that the most optimal service and inspection plan was to make an inspection in March and a service visit in August. In order to examine how the optimal inspection and service plan depends on the damage accumulation this contribution is multiplied with a factor 0.5, 0.75, 1.0, 1.25, and 1.5. The result can be seen in fig. 38.

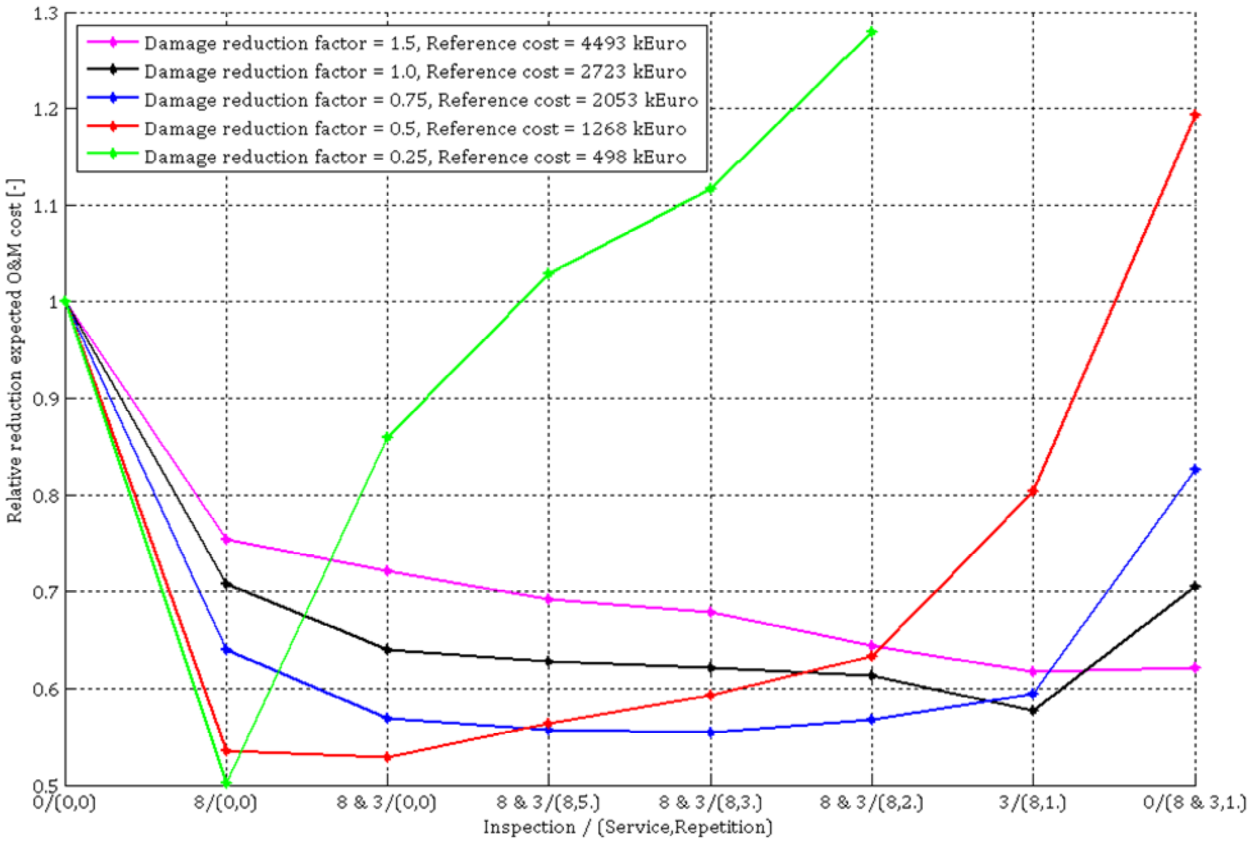

Fig. 38: Optimal service and inspection plans due to the damage accumulation.

Firstly, it can be seen in fig. 23 that the O&M cost is highly affected by the damage accumulation. For a damage reduction equal to 75% the O&M cost for corrective maintenance is 498k€ while it is 4493k€ for an increase equal to 50%. In order to make a reliable model it is therefore important to make sure that the damage accumulation is realistic. There is of course many uncertainties concerning the damage accumulation and the only way to find suitable values is trough an extensive testing program or by analysing data from existing turbines.

In fig. 38 it can also be seen that the optimal O&M strategy is highly affected by the damage accumulation. If the damage accumulation is reduced by 75% the most optimal service and inspection plan is only to make a service visit each year in August. As the damage accumulation is increased more inspections and service visits are optimal. This was also expected.

In section 4.3 it is shown that using the assumptions made in appendix E concerning crack propagation, it is not beneficial to use scheduled maintenance. However, if the parameter *m* is lowered enough, it is beneficial to use scheduled maintenance. This is illustrated in fig. 39. When *m* is lowered to 2.5 it is beneficial to make an inspection once every year and if *m* is lowered further to 2.25 the advantage is increased further.

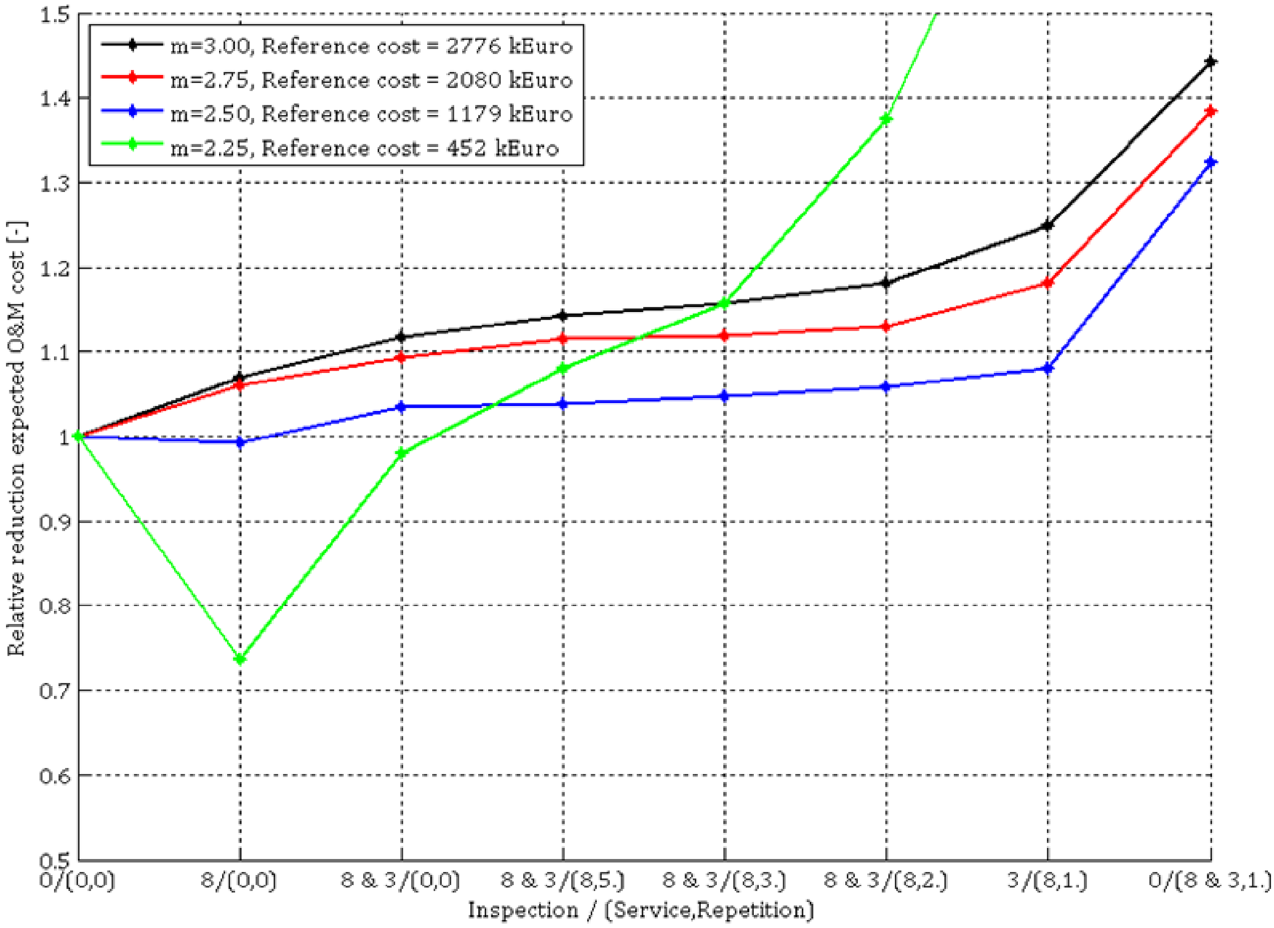

Fig. 39: Optimal service and inspection plan if the crack growth exponent m is changed.

It can be seen in fig. 39 that reference cost is very low when *m* is lowered. This is due to the slower damage accumulations reducing the repair costs. The dependency between the damage accumulation and *m* can be seen in fig. 23.

Probability of detecting a damaged component

In appendix E it can be seen that POD-curves are used to estimate the probability that a given damage level is acknowledge at an inspection or a service visit. The probability curves can be changed by varying the parameters P_0 and λ. P_0 is the maximum probability of detection and λ is a distribution parameter which depends on the inspection method. It is only λ which is varied in this analysis and it can be seen in appendix E that a small value of λ gives a large POD. P_0 is equal to 0.9. Scheduled maintenance with an inspection in March and an inspection in August is examined and the result can be seen in fig. 40.

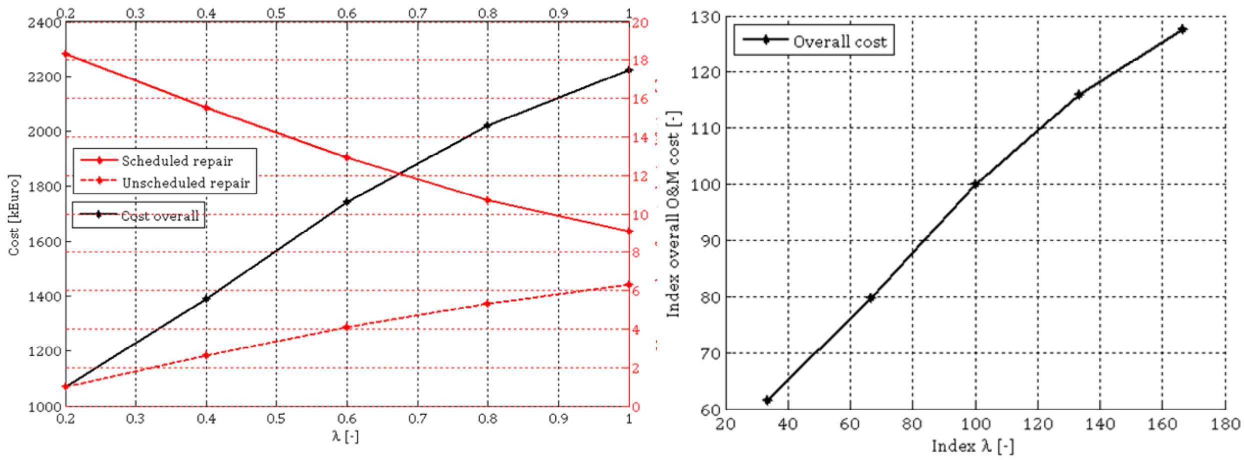

Fig. 40: Expected O&M cost and number of scheduled and unscheduled repairs dependent on the POD-curve for an inspection. I&S plan 3. Index 100 is equal to 0.2.

As expected the overall cost increases when the POD is lowered – λ is increased giving a poorer inspection. This is due to the increasing number of unscheduled repairs and the corresponding lower number of scheduled repairs. Furthermore, the availability is changed from 98.8 to 98.5 when λ is equal to 0.2 and 1.0 respectively.

The optimal inspection and service plan is also affected by the quality of the inspection and service visits. This is shown in fig. 41. If λ is set equal to 0.6 the optimal inspection and service plan is an inspection each year in March and a service visit each year in August. If λ is changed to 0.2 an annual inspection in August is the most optimal plan.

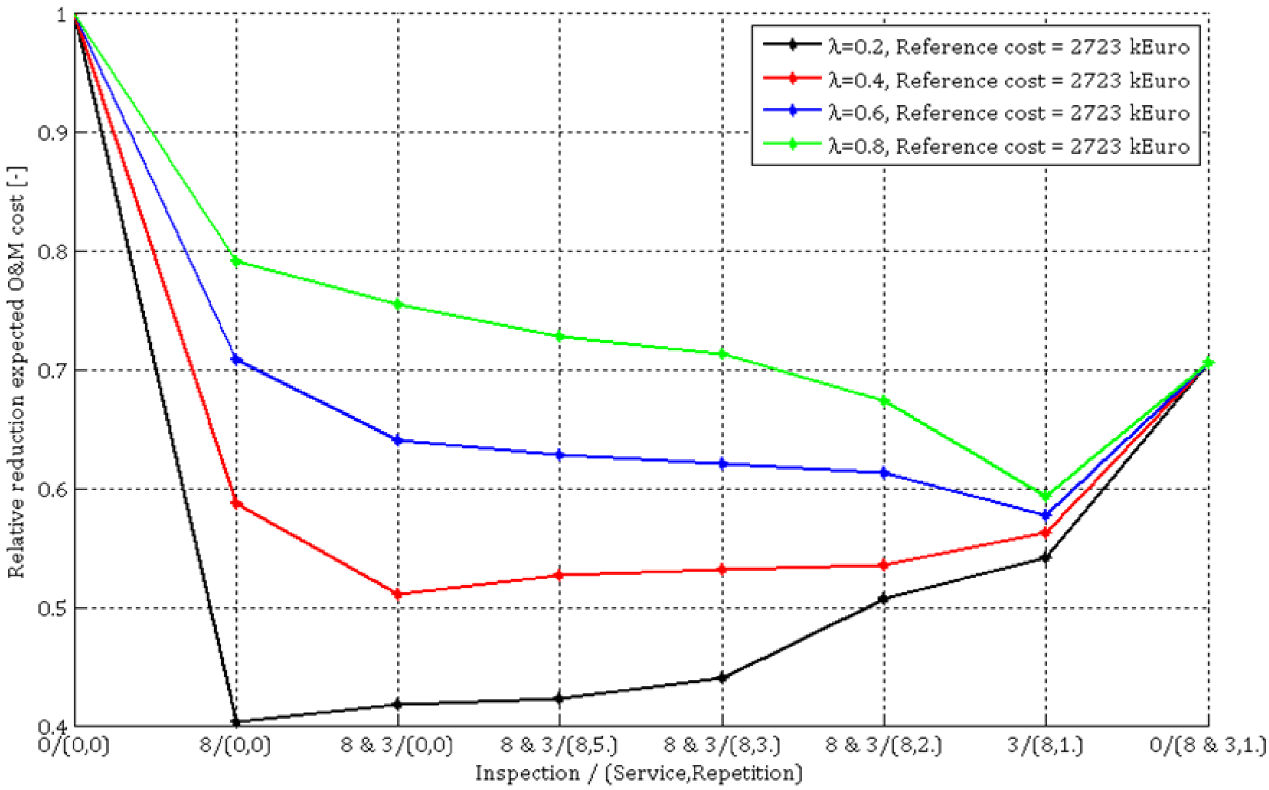

Fig. 41: Optimal inspection and service plan dependent on the quality of the inspections.

Finally it can be concluded that the overall cost is highly affected by the thoroughness of the inspections. In fig. 41 it can be seen that the largest relative reduction in expected O&M cost is equal to 0.40 for λ equal to 0.2. For λ equal to 0.4 it is equal to 0.51. Hereby 300k€ in capitalised costs can be used to improve the quality of the inspections from λ equal to 0.4 to λ equal to 0.2.

Damage reduction due to a service visit

It is assumed that the damage level of the gearbox is reduced when a service visit is made. This is due to the fact that normally some sub-components or lubricate is changed during a service visit. As explained in appendix E the damage reduction is normal distributed and initially the mean value of the damage reduction is set to 40%. This corresponds to multiplying the current damage level with a factor 0.6. The standard deviation is set to 0.2 and this value is maintained in this analyses. In fig. 42 the optimal service and inspection plan is examined dependent on the mean damage reduction at a service visit.

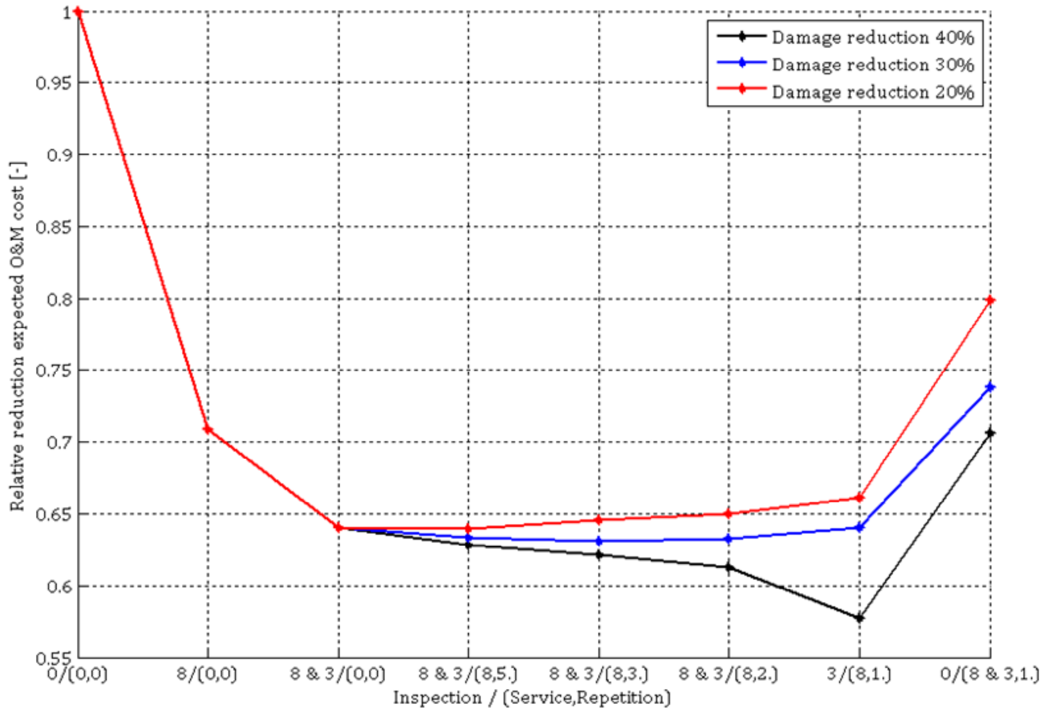

Fig. 42: Optimal service and inspection plan due to the damage reduction at a service visit.

It can be seen in fig. 42 that it is less and less beneficial to make a service visit if the damage reduction is decreased. At a damage reduction equal to 40% it is optimal to make a service visit each year but if the damage reduction is equal to 30% or 20% it is optimal to make a service visit every 3. and 5. year respectively. Again it can be concluded that the optimal service and inspection plan is highly dependent on the results when inspecting or servicing the wind turbine or in this case the gear box.

Probability of wind turbine stop if repair

As explained in appendix E it is assumed that in some cases the wind turbine is stopped after an inspection or service visit if the wind turbine has to be repaired. This is done to make sure that the wind turbine dos not reach failure which could lead to serial failure. In this analysis the scheduled maintenance strategy is chosen. In fig. 43 it can be seen how the overall cost and downtime due to waiting and organisation of the repair team varies due to the probability that the wind turbine has to be stopped immediately if the gearbox has to be repaired. As expected both the downtime due to organisation and due to waiting time increases.

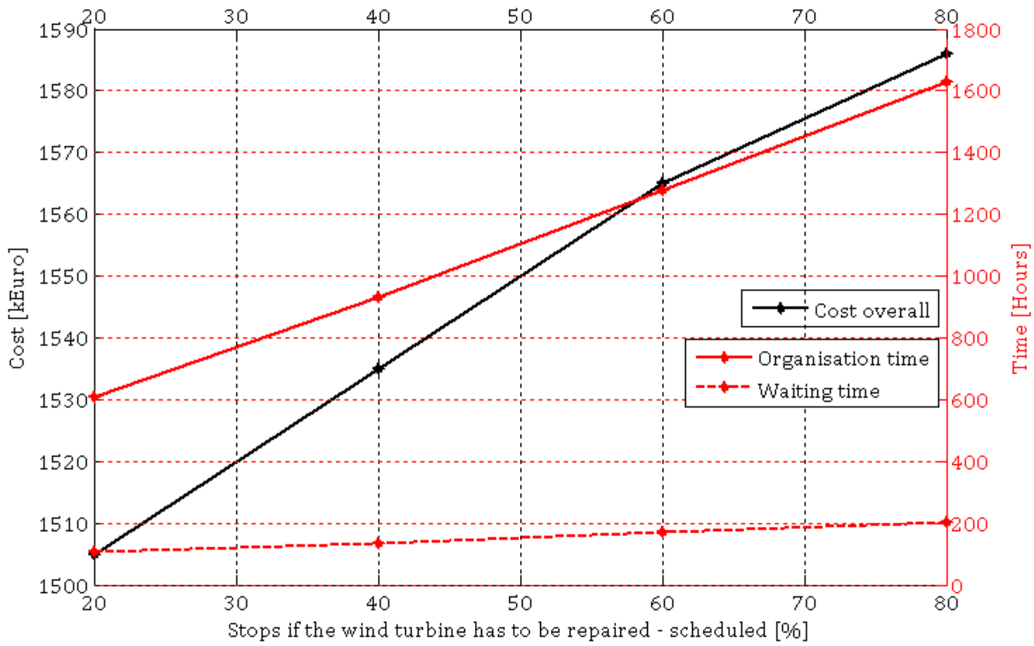

Fig. 43: Overall cost, organisation time, and waiting time dependent on the probability that the wind turbine is stopped if it has to be repaired after an inspection or service visit. I&S plan 7.

In section 4.3 it can be seen that the loss in energy yield only contributes with approximately 13%. This is due to the fact that the energy production is low during the spring and summer months. This also explains why the overall cost only increases with 80k€ even though the downtime is increased significantly.

Probability that a component has to be replaced

If the gearbox reaches failure the probability that the gearbox has to be replaced affects the O&M costs significantly. This can also be seen in fig. 44 where corrective maintenance is the used maintenance strategy. Changing the probability from 0% to 15% increases the overall cost with more than 70%. Designing the gearbox it is therefore important to make sure that the gearbox can be repaired.

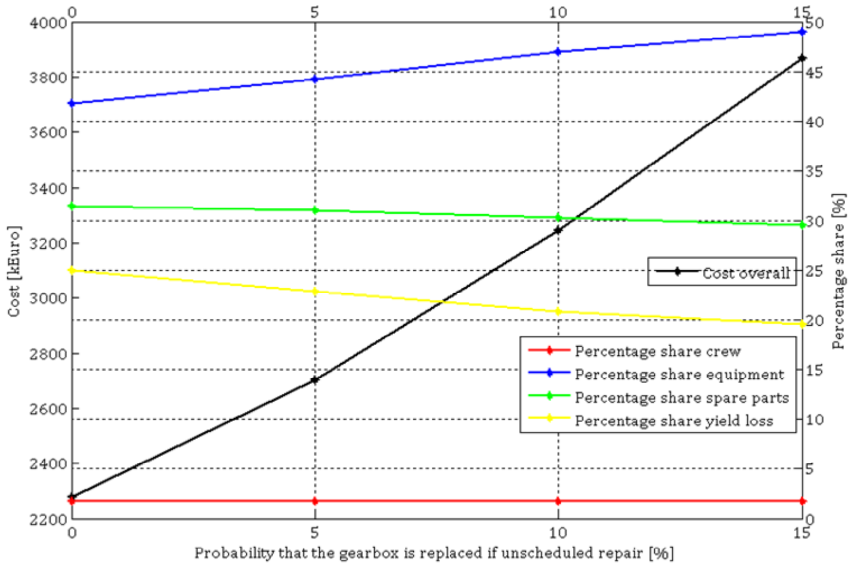

Fig. 44: Overall cost and percentage share of the four different cost constituents due to the mean value of the spare part cost. I&S plan 7.

In fig. 44 it can also be seen that the percentage share of the equipment cost increases while the share of other cost constituents decreases. This implies that the expensive jack-up vessels, which is needed when the gearbox has to be changed, is important to focus on if the O&M cost shall be minimized. In appendix E it can be seen that it is assumed that the jack-up has a starting price equal to 150k€ and a daily rate equal to 150k€.

4.5 Summary

In the previous section the expected O&M cost has been examined for a gearbox. There are many input parameters with significant uncertainties which determine the expected O&M cost and also the optimal inspection and service plan. Both corrective and scheduled maintenance have been examined in order to evaluate the optimal O&M strategy. It has been found that the following parameters have a large influence on the optimal O&M strategy.

- The damage progress speed
- The repair barrier
- The reliability/Quality of inspections
- The cost inspections and service visits
- The cost repair actions

Both a linear and an exponential damage model is examined, determining the **damage progress speed**, and in general it is found that corrective maintenance is the most optimal service and inspection plan if the damage progress speed is very high. In these cases only a few errors are found before the gearbox reached failure. Hereby, the inspection and service costs are higher than the reduced repair cost. If the linear damage model is used or the exponent *m* is reduced for the exponential model it might be beneficial to use scheduled maintenance. Again it is the damage progress speed which determines the optimal inspection and service plan. In general, if the damage progress speed is low and *m* has a low value a few inspections are needed. It can hereby be concluded that the damage progress speed has a significant influence on the optimal O&M strategy and it is important to take this into account when designing the wind turbine. The O&M department has to be aware of the damage progress speed of the different components and online condition monitoring might be used for components where the damage progress speed is high. This is also explained in chapter 6.

The optimal **repair barrier** also has to be found for each wind turbine component which is inspected or monitored. The optimal repair barrier is dependent on the inspection and service plan and hereby also the damage progress speed. Changing the inspection and service plan, maybe due to a change in expected damage progress speed, might change the optimal repair barrier of the component.

The **reliability** or **quality of the inspections** also affects the optimal inspection and service plan and the expected O&M cost. In this thesis λ is varied in order to evaluate the quality of the inspections. As expected more inspections are needed when the quality of the inspections are lowered. The significance concerning expected O&M cost is also shown in tab. 13.

The **inspection and service cost** of course also influences the optimal O&M strategy and the expected O&M cost. An important aspect when determining the operation and maintenance strategy is to examine the correlation between the inspection and service cost and the quality of the inspections. In the previous section it is shown that it might be beneficial to use a significant extra cost to improve the quality of the inspections and still lower the expected O&M cost. Furthermore, the correlation between the damage reduction at a service visit and the service cost has to be taken into account.

The **repair costs** also affect the optimal O&M strategy. If the repair costs are high it gets more beneficial to make service and inspection visits. Some input parameters have a large influence on the expected O&M cost and the repair cost and these are therefore important to focus on when designing the wind turbine and when making the O&M plan. In tab. 13 are shown the change in expected O&M cost when some important input parameters are changed. Based on the figures showing the change in index, the elasticity coefficient is also calculated.

Tab. 13: Rayleigh parameters used to simulate a contribution to the damage accumulation. The linear damage accumulation is used.

Input parameter	Inspection and service	Index 100	Elasticity coefficient [%]	Note
Hourly wage workmen	Plan 7	25€/hour	3.2	
H_{max} for small boat	Plan 2	12m	-12.0	Correlated with V_{max}
Cost small boat	Plan 7	8k€	6.3	
Cost jack-up	Plan 7	150k€	5.5	
Availability spare parts	Plan 1	5 days	3.4	Unscheduled repair
$P(M_{spare} > 25ton)$	Plan 1	12.7%	15.5	→ jack-up needed
Spare part cost	Plan 1	120k€	14.0	Unscheduled repair
Repair time	Plan 7	8hours	10.2	Scheduled repair
Power sales price	Plan 7	0.125€/kWh	9.0	
POD - λ	Plan 3	0.6	31.2	

It can be seen in tab. 13 that the requirements concerning maximum wave height and maximum wind speed of the small boat has a significant influence on the expected O&M cost. However, it is shown in fig. 28 that the elasticity coefficient is highly affected by the reference wave requirements and if index 100 was set at 7m the elasticity coefficient would be even lower. This is important to take into account when the installation and transportation equipment is designed.

As expected the hourly wage of the workmen does not affect the cost as much as the cost of the transportation vessels. The availability of the spare parts only affects the loss in energy yield and the influence of this factor is therefore relatively low. However, it has to be mentioned that the availability of the equipment also influences this result. If the availability of the equipment was close to zero days the availability of the spare parts had a larger influence on the expected O&M cost. This is also explained in the previous section.

The spare part mass has an influence on the need for various transport vessels. As expected the probability that a jack-up vessel is needed has a large influence on the expected O&M cost. This also has to be taken into account when designing the internal wind turbine crane. In order to lower the equipment cost a significant amount of money can be used to design a crane with a high lifting capacity. The spare part cost, repair time, and power sales price also have a large influence on the expected O&M cost.

It is also examined if it is beneficial to make the cost of the small boat fixed. Hereby a boat is always available to service the wind turbines in the wind turbine farm. For corrective maintenance it is found that it is beneficial to have a fixed cost if it is less than 1250€ per month per wind turbine. If scheduled maintenance and inspection and service plan 7 is used it is beneficial to have a fixed cost if the monthly cost per wind turbine is less than 2000€.

The use of a helicopter might also be beneficial. However, this is not the conclusion in this thesis since the use of a helicopter has to be dependent on the weather forecast. This is not implemented. If e.g. the weather forecast shows that the wind speed is going to be low in a satisfyingly long period it might be advantageous to use the boat. Opposite, if the weather forecast shows that the wind speed is going to be high in a long period it might be advantageous to use the more expensive helicopter lowering the loss in energy yield but increasing the equipment cost. Studies should be made of the wind turbine operators in order to find the optimal decision dependent on the weather forecast.

Finally, the expected O&M cost is also highly affected of the probability that the wind turbine component has to be replaced instead of repaired. It is therefore important to make repair possible when designing the wind turbine.

In the next chapter the present results are used to make an O&M model for a whole wind turbine which is simplified to consist of the 14 technical components written in chapter 2.

5 O&M cost for an offshore wind turbine

In the previous section it is shown how the many input parameters and the related uncertainties, when calculating the expected O&M cost, influence on the cost and the optimal O&M strategy. In this chapter, taking these results into account, the expected O&M costs for a whole wind turbine are examined and the optimal O&M strategy is found. The expected O&M cost is also found when up-scaling in order to examine the O&M cost model used in chapter 2.

Firstly, the assumptions for the reference wind turbine are explained. The O&M program for the whole wind turbine is based on the program for the gearbox but anyways the program is shortly described before the results are analysed. As for the gearbox a convergence analysis is made and afterwards the results for the 5MW reference wind turbine are analysed. An analysis of the costs when up-scaling is also made and finally the sensitivity of the model, concerning the assumptions made when up-scaling, is examined.

5.1 Assumptions for the reference wind turbine

The O&M program is based on the program made for the gearbox and it is named (*OMwindturbine.dsw*). As written in chapter 2 the wind turbine is divided into 14 technical components which represents the many components in the wind turbine. The components are listed below.

- Rotor blades
- Rotor hub
- Rotor bearings and pitch mechanism
- Main shaft
- Main bearings
- Gearbox
- Generator
- Yaw
- Main frame and nacelle housing
- Electronics and hydraulic system
- Control system
- Tower
- Foundation
- Electrical connection

In order to be able to use the results to update the up-scaling model in chapter 2 the same 5MW reference turbine is evaluated. The climate data from Horns Rev I is also used. The general assumptions for the reference turbine are as follows.

- Wind turbine data: D=126m
P=5MW
H_{hub}=90m
Tip speed=80m/s
14 technical components
Component costs cf. chapter 2
Component masses cf. appendix D
Reference power curve: 5MW FAST wind turbine
- Wind turbine lifetime: 240 months – or 20 years
- Failure modes: Serial failure does not occur
- Structural components: Damage model exponential
- Electrical components: Damage model linear
- Operation start month: April
- Inspections: March and August
- Service visits: None
- Transport equipment: Only boats are used
- Distance to port: 38km
- Climate: Data from Horns Rev I
- Rate of interest: 6 pct.
- O&M strategies: Corrective and scheduled

In chapter 4 it was shown that the use of a helicopter was negligible if the weather forecast was not taken into account. In order to make the model as simple as possible, the opportunity of using a helicopter is disregarded.

The initial inspection and service plan is to make an annual inspection in March and in August. This is changed when the optimal inspection and service plan is found.

It is extremely difficult to obtain input data from the wind turbine industry. Therefore, a model has been made by a combination of both knowing some reliable input parameters and some reliable output data. Many considerations has of course also been made for all the other input parameters, which can be found in appendix F but the following input parameters are the most reliable.

- The power price – found by evaluating data from the Nordic power exchange Nord pool ASA.
- The loss in energy yield due to a given downtime – found by evaluating the climate at Horns Rev I and by using the 5MW FAST power curve.
- The component cost – values from the cost model in chapter 2 which is based on literature studies.
- The component weight – values from appendix D.

The output parameters which are determined in advance concerns the annual failure rate, the downtime per failure, the expected O&M cost, and the percentage share of the four cost constituents of the expected O&M cost. The annual failure rate is found in [Hahn et al., 2009] where the failure rate for different technology concepts has been compared. The results are based on a German database where reports have been gathered over a period equal to 17 years. For a pitch controlled wind turbine with a gearbox and a standard variable speed the annual failure frequency is equal to the values in tab. 14. It is assumed that the annual failure frequency is for a scheduled O&M strategy where an inspection is made in March and in August. It is not taken into account that the annual failure rate might be higher for offshore wind turbines due to the harsh environment. Furthermore, [Hahn et al., 2009] does not consider the tower, foundation, and electrical connection to shore. Therefore, the values concerning these components are assumed.

Tab. 14: Reliable output data concerning the annual failure rate when an inspection is made in March and in August. The downtime per failure and the assumed damage model is also shown. *1 shows that the values concerning the component are assumed.

	Annual failure rate [-]	Downtime per failure [Days]		Damage model
Source	[Hahn et al., 2009]	Adjusted	[Hahn et al., 2009]	Assumed
Blades	0.27	7.5	4.5	Ex
Hub	0.19	5.5	4.0	Ex
Rotor bearings and pitch system	0.40	6.0	5.0	Ex
Shaft	0.05	7.5	5.5	Ex
Main bearings	0.10	5.5	4.0	Ex
Gearbox	0.16	10.0	7.0	Li
Generator	0.18	8.5	6.0	Li
Yaw	0.18	5.5	1.5	Li
Main frame	0.10	6.5	3.5	Ex
Electrical system and hydraulics	1.16	4.5	0.8	Li
Control system	0.52	4.5	1.0	Li
Tower	0.08*1	6.0*1	-	Ex
Foundation	0.05*1	6.0*1	-	Ex
Electrical connection	0.05 *1	8.0*1	-	Li

In [Hahn et al., 2009] the downtime per failure is also given. The downtime for the various components is dependent on the location but there are no values concerning offshore wind turbines. The highest downtimes are for wind turbines in highlands and these are shown in tab. 14. It is assumed that the downtime for an offshore wind turbine in average is 2-4 days longer. The longer downtime is caused by the lower accessibility due to the climate and the extra time used to purchase a repair vessel. Since these parameters influence both the components with a low repair time onshore and a high repair time onshore the percentage increase in downtime per failure is highest for the components with the low downtime onshore. Furthermore, it is assumed that the spare part mass for the gearbox and the blades are relatively high. This gives a relatively large probability that a jack-up is needed and hereby the downtime offshore is assumed relatively long compared to onshore. The adjusted values are shown in tab. 14.

It is shown in chapter 4 that the damage model has a large influence on the O&M cost and the optimal inspection and service plan. In tab. 14 it is shown which damage models are assumed for the different components. For the structural components in a wind turbine the critical situation is often fatigue failure and therefore the exponential damage model has been used for the structural components. It is difficult to predict the damage model for the electrical components but a linear damage model is assumed. Many of the above components e.g. rotor bearings and pitch mechanism and the yaw consist of both structural and electrical components while the others are often monitored by e.g. sensors. Therefore, in reality the damage model varies. However, this is neglected. Concerning the exponential damage models it is shown in chapter 4 that the exponent *m* has a large influence on the results. The values for *m* can also be seen in appendix F.

In [Rademakers et al., 2008a] the percentage share of the four constituents is equal to 2%, 22%, 27%, and 49% for the crew, spare part, yield, and equipment cost respectively. The input parameters are also fitted so the percentage share is close to these values.

In [Hendriks, 2007] it is estimated that the O&M cost for an offshore wind turbine is approximately 27% of the total costs considering the full wind turbine lifetime while in [Gestel, 2008] the O&M cost for a 5MW turbine is approximately 35%. Therefore, the expected O&M cost is set approximately 31% of the total cost for the reference wind turbine. Using the results in chapter 2 this corresponds to a capitalized O&M cost equal to approximately 4300k€ for the reference wind turbine.

5.2 Description of the program

As explained the program is a modified version of the program used to calculate the O&M cost for the gearbox. However, many input parameters are changed in this program and the O&M cost for the gearbox in the previous model and the O&M cost for the gearbox in this model are therefore not similar. As for the single component program, the program is Fortran code and it is divided into a main program which consists of subroutines calculating the damage accumulation, the cost due to a given event, and so forth. The structure in this program will not be described since it is the same as for the program for the gearbox. It is also the same stochastic variables which are simulated during the program. However, some important aspects are listed below.

- The damage level of the different components does not influence each other.
- The inspection and service costs are divided equally between the 14 components. This also goes for the downtime. Hereby it is assumed that the inspection and service costs are similar for the 14 components.
- If more than one component needs repair, the organisation cost, the waiting cost, and travel cost is divided equally between the components which needs repair. This also goes for the downtime. Hereby, it is assumed that failure occurs at the same time if more than one component reaches failure the respective month. This gives a lower cost concerning crew, equipment, and yield than if failure could occur at different times during the respective month. In tab. 8 it is shown that failure of the wind turbine occurs 67 times during the 240 months. The probability that two failures occur the same month is therefore relatively low and therefore the error is also insignificant.
- If more than one component needs repair, the repair time is found by summarising the repair time for each component.
- If the wind turbine is stopped the damage accumulation is unaffected. The wind turbine is only stopped in short periods and therefore this error is negligible.
- At a repair no other components are examined.
- The damage level is reset after a repair.

5.3 O&M results for the 5MW wind turbine

In the following a convergence analysis is firstly made and afterwards the model is validated by showing that the output parameters are close to the values in tab. 14. The optimal inspection and service strategy is also found and this strategy will be used to analyse the expected costs for the 5MW wind turbine.

Convergence analysis and validation of model

There are significant uncertainties concerning the input parameters and therefore a convergence analysis is firstly made. The convergence analysis is shown in fig. 45 where both the total O&M cost and the cost of the four constituents are shown.

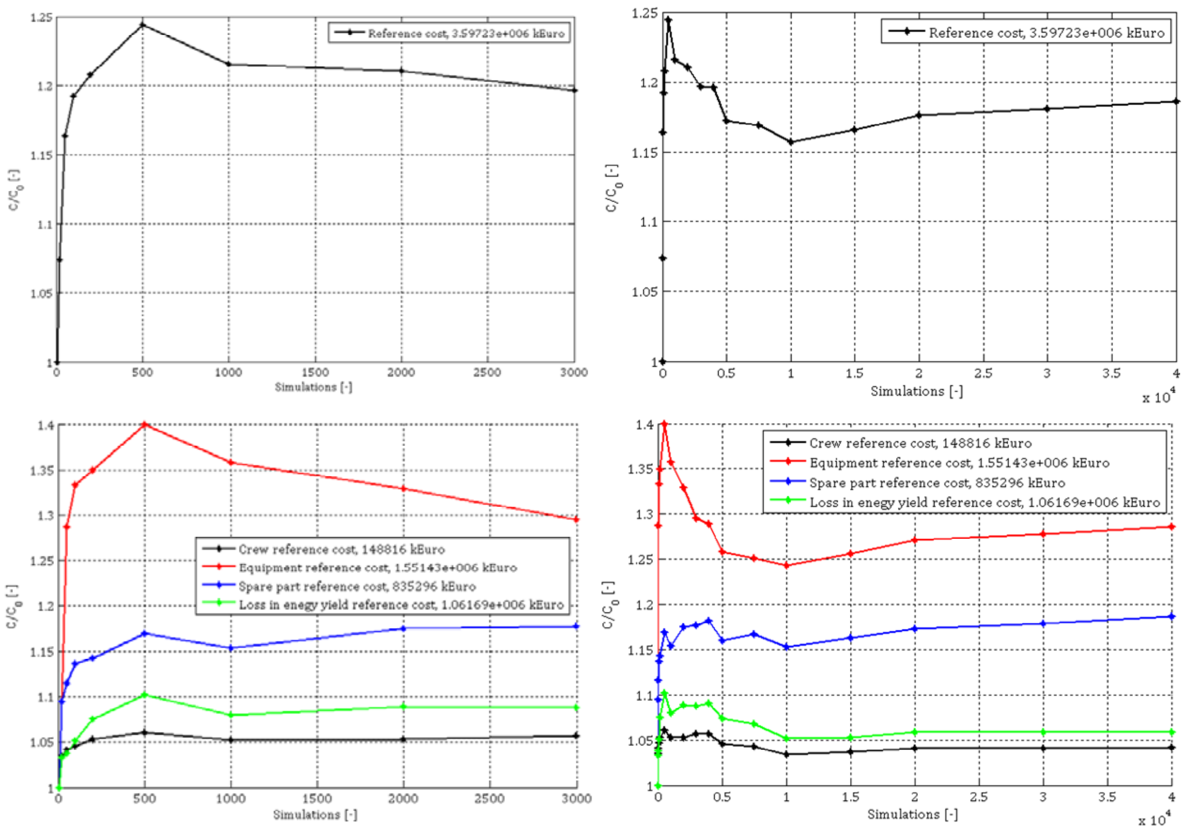

Fig. 45: Convergence study for the WT O&M cost model.

It can be seen that concerning the costs convergence is not even fully achieved at 40000 simulations. However, 100 simulations takes one minute and in order to lower the simulation time only 1000 simulations are made when using the O&M program. This is of course not enough but taking the many uncertainties concerning the input parameters into account this does not affect the uncertainty concerning the overall result.

It can be seen in fig. 45 that using 1000 simulations might give an expected O&M which is too high. At 1000 simulations the expected cost is equal to 4373k€ while it is equal to 4230 k€ at 40000 simulations. This seems like a large difference but it only corresponds to a decrease in expected cost equal to 3.3%. Therefore, it can again be concluded satisfying to use 1000 simulations.

In tab. 15 the expected cost has been split up in the individual components. In this table it can be seen that the percentage share of the technical components are not fully converged at 1000 simulations. It is especially the blade cost and the gearbox cost which is different from 1000 simulations to 40000 simulations. This is again neglected.

Tab. 15: Relative contribution of the components to the expected cost when an inspection is made in March and in April.

Simulations	100	1000	3000	10000	20000	40000
Blades	13.6	11.3	12.0	12.0	12.6	13.4
Hub	6.7	6.4	6.3	6.1	6.1	6.0
Rotor bearings and pitch system	10.4	10.4	10.7	10.7	10.5	10.5
Shaft	2.0	2.0	1.9	1.9	1.9	1.9
Main bearings	2.3	2.3	2.2	2.3	2.2	2.2
Gearbox	15.2	15.6	14.6	14.5	14.6	14.3
Generator	8.5	8.9	9.1	9.1	9.0	8.9
Yaw	6.4	6.7	6.4	6.6	6.4	6.4
Main frame	2.5	3.2	3.0	3.2	3.2	3.2
Electrical system and hydraulics	17.3	16.5	16.7	16.8	16.5	16.5
Control system	7.7	8.3	8.2	8.2	8.2	8.1
Tower	3.2	3.6	3.7	3.5	3.7	3.6
Foundation	2.0	2.2	2.4	2.5	2.5	2.5
Electrical connection	2.3	2.5	2.6	2.6	2.6	2.6

Using 1000 simulations the results concerning downtime per failure and annual failure rate are shown in tab. 16. It can be seen in the table that the results are satisfyingly close to the output parameters in [Hahn et al., 2009].

Tab. 16: Annual failure rate and downtime per failure at 1000 simulations.

	Annual failure rate [-]		Downtime per failure [Hours]	
Source	Output	[Hahn et al., 2009]	Output	[Hahn et al., 2009]
Blades	0.27	0.27	7.7	7.5
Hub	0.21	0.19	5.6	5.5
Rotor bearings and pitch system	0.42	0.40	6.0	6.0
Shaft	0.06	0.05	7.7	7.5
Main bearings	0.11	0.10	5.6	5.5
Gearbox	0.16	0.16	10.0	10.0
Generator	0.17	0.18	8.5	8.5
Yaw	0.18	0.18	5.4	5.5
Main frame	0.11	0.10	6.3	6.5
Electrical system and hydraulics	1.13	1.16	4.7	4.5
Control system	0.52	0.52	4.7	4.5
Tower	0.08	0.08	5.6	6.0
Foundation	0.04	0.05	5.8	6.0
Electrical connection	0.04	0.05	8.0	8.0

The validation concerning the total cost and percentage share of the crew, equipment, spare part, and lost in energy cost is made in the next section when the optimal inspection and service strategy is found.

Optimal inspection and service strategy

As shown in chapter 4 the inspection and service strategy has a large influence on the expected O&M cost. In fig. 46 it is shown how the expected cost depends on the inspection and service strategy. 1000 simulations are again used.

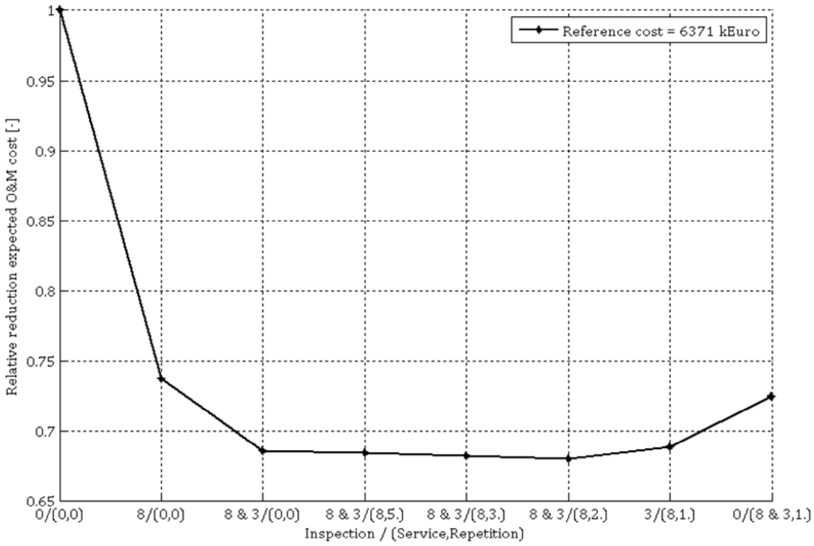

Fig. 46: Expected O&M cost dependent on the inspection and service plan.

It can be seen that the optimal inspection and service plan is to make an annual inspection in March and August. However, every second year a service visit is made in August instead of an inspection. Using this I&S plan the expected O&M cost is equal to 4337k€. This is satisfyingly close to the estimated output in section 5.1 which is 4300k€. Cf. chapter 2 the cost per kWh produced is equal to 0.9c€/kWh when the O&M cost is capitalised. If the capitalisation was not taken into account the O&M cost would be equal to 1.5c€/kWh.

Compared to using corrective maintenance, the costs are reduced by more than 30% which is a significant difference. The probability of detecting a damaged component is cf. appendix F not significantly different when making a service visit instead of an inspection. The reason why it is beneficial to make service visits is that some initially defined subcomponents are changed at a service visit. This reduces the damage level. It is assumed that most subcomponents are changed for the pitch mechanism, gearbox, generator, yaw, electrical and hydraulic system, and control system. Therefore, the damage reduction is the highest for these components compared to the structural components.

In fig. 46 it can be seen that the difference between the expected O&M costs using the various I&S plans are relatively low when using a service visit or not using a service visit. Taking the uncertainties of the input parameters and the low difference into account further studies should be made in order to find the optimal period between a service visit. However, it can be concluded that one annual inspection is not sufficient. Cf. chapter 4 the speed of the damage accumulation or the reliability of the inspections have to be improved if an annual service visit should be the most effective I&S plan.

Expected O&M costs for the 5MW wind turbine

In the following the O&M cost and downtime is evaluated. 1000 simulations and the service and inspection plan determined in the previous section are used. In tab. 14 it is shown how the downtime, availability, and costs are season dependent. It can be seen that most of the downtime is caused by the organisation time where the spare parts and equipment needed is purchased. The overall availability of the wind turbine is calculated equal to 93.4% and it can be seen that the availability is lowest during the winter where it is equal to 88.5%. It is surprising that the availability is highest during the autumn but this is caused by a simplified probability of detection model. In the probability of detection model the result of the previous inspection is not taken into account. Looking at e.g. a gearbox where an internal subcomponent is damaged, it might not be impossible to detect the error. Therefore, if the error is not found in Marts the probability that it is found in August should be lowered. This is not taken into account which results in a large number of detections both in Marts and in August. This gives a low average damage level of the components when the autumn starts and hereby the number of failures is relatively low. The missing correlation between the inspection results also gives an unrealistic high probability of detection if two inspections are made in two following months.

Tab. 17: Downtime, availability, and costs. The values are found by summarising the contributions from the 14 technical components. The costs are capitalised.

		Winter	Spring	Summer	Autumn	**Total**
Downtime	Organisation [hrs]	2386	1560	1205	1037	6188
	Waiting [hrs]	2205	598	222	470	3495
	Travel [hrs]	30	22	17	15	84
	Repair [hrs]	335	649	734	145	1863
	Total [hrs]	4956	2829	2178	1703	11630
Availability	[%]	88.5	93.4	95.0	96.1	93.4
Cost	Crew [k€]	56	47	40	15	158
	Equipment [k€]	693	647	493	206	2039
	Spare parts [k€]	256	286	396	102	1041
	Loss Yield [k€]	503	236	176	184	1099
	Total [k€]	1508	1216	1105	508	4337
Inspection	N [-]	0	20	10	0	30
	Cost [k€]	-	131	58	-	189
	Cost/N [k€]	-	7	6	-	6
Service	N [-]	0	0	10	0	10
	Cost [k€]	-	-	248	-	248
	Cost/N [k€]	-	-	25	-	25
Scheduled repair	N [-]	0	47	39	0	86
	Cost [k€]	-	635	527	-	1162
	Cost/N [k€]	-	14	13	-	13
Unscheduled repair	N [-]	28	16	11	12	67
	Cost [k€]	1509	431	291	507	2738
	Cost/N [k€]	54	28	27	41	41

In tab. 14 it can be seen that the expected O&M cost is equal to 4337k€. The percentage share of the four cost constituents is equal to 4%, 47%, 24%, and 25% for the crew, equipment, spare part, and loss in energy yield cost respectively. This is satisfyingly close to the estimated output in section 5.1 which is 2%, 49%, 22%, and 27%. In the table it can also be seen that even though the 30 inspections and 10 service visits are made, the main part of the costs are due to repair actions which are unscheduled. The share is approximately 63% which is caused by the fact that the average repair cost is more than three times higher for unscheduled repair compared to scheduled repair, the repair time is higher, the spare parts are larger, etc. This can be seen in appendix F.

In fig. 47 the cost and downtime has been split up in the individual technical component. It can be seen that the rotor bearings and pitch mechanism, the gearbox, and the electrical and hydraulic system cause a large share of the expected O&M cost. Opposite, the structural components has a low percentage share of the cost and downtime. When designing the wind turbine this is important to take into account. One of the opportunities is to install a direct drive in the offshore wind turbines. Some wind turbine manufactures have already developed this type of turbine and some have just started to design a prototype. For the rotor bearings and pitch mechanism it is assumed that the pitch mechanism is the most critical component concerning O&M since this component consists of electrical and hydraulic subcomponents.

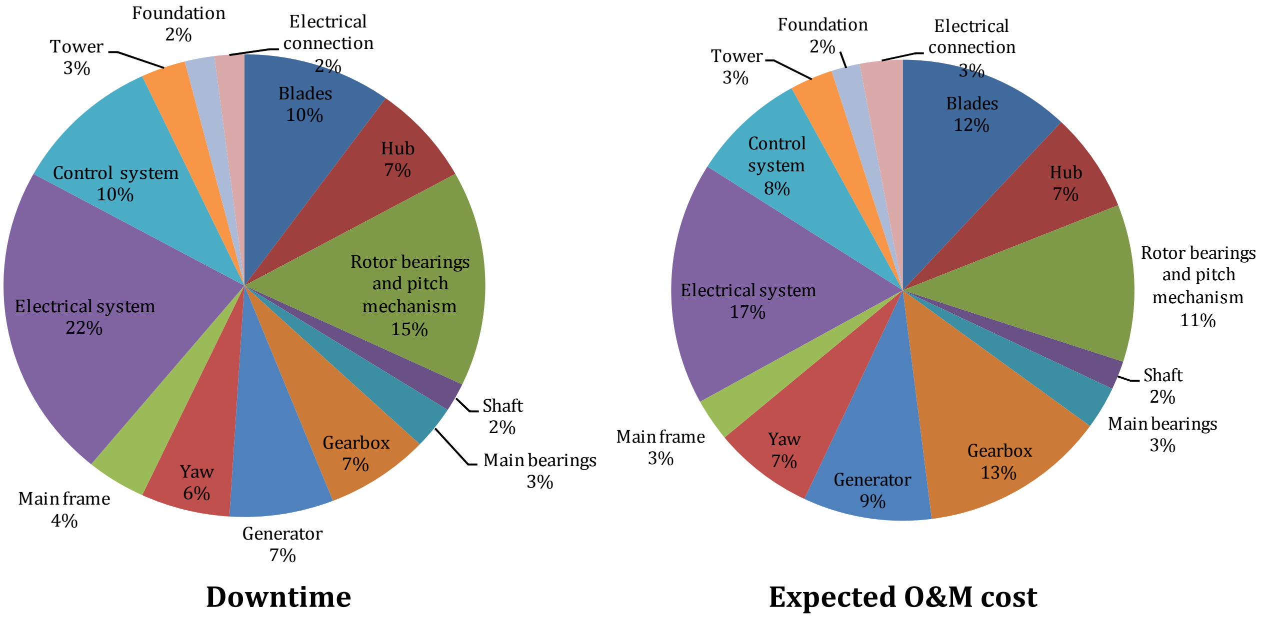

Fig. 47: Breakdown of expected cost and downtime per technical component.

In fig. 47 it can be seen that for some technical components there is a difference between the share of the expected cost and the expected downtime. The components with a large spare part cost compared to the availability of spare parts and equipment are the ones where the share concerning the cost is higher than the share concerning the downtime. This is e.g. the gearbox and the generator.

In fig. 48 the downtime caused by the 14 technical components are broken up into organisation time, waiting time, travel time, and repair time. For each component is also shown the share of the four constituents to the downtime. It is difficult to make a valid conclusion from this figure due to the uncertainties concerning the input parameters but it can be seen that organisation and waiting time has a large influence on the downtime for all components. The share of the waiting time is almost similar for the 14 components. This is not realistic but it is caused by the fact that the wave and wind requirements only concern the two types of boats. In order to get a more reliable result more types of boats could have been included. Furthermore, an important aspect concerning maximum wind speed when hoisting the spare parts could also have been taken into account.

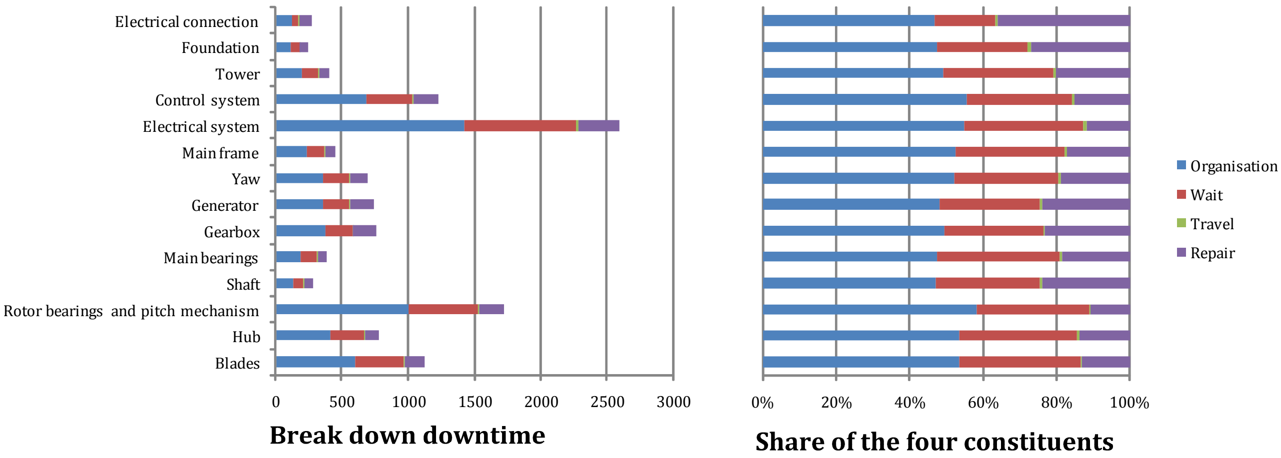

Fig. 48: Breakdown of the downtime per component.

For some of the important technical components in found by fig. 47 and fig. 48 it could be advantageous to split the components into more subcomponents. This is e.g. the electrical and hydraulic system which could be divided into the following.

- Cooling system
- Sensors
- Transformer
- Inverter cabinet
- Hydraulic system

This is not done in this thesis but it could give a better knowledge of how to lower the O&M costs for future wind turbines.

5.4 O&M cost when up-scaling

In the previous section the expected O&M costs has been found for the reference wind turbine. However, the model is made so it is possible to analyse the expected O&M cost when up-scaling. In the following, the assumptions will be explained and afterwards the results will be analysed. It will be examined if the conclusion, made in chapter 2, concerning optimal wind turbine size is changed if the new O&M up-scaling model is used. No convergence analysis is made so the number of simulations is maintained equal to 1000 and the service and inspection plan is maintained.

Assumptions concerning up-scaling

It is difficult to predict the change of the various input parameters, which are described in appendix F, when up-scaling the wind turbine. However, the following assumptions are made in order to get the most reliable results.

- The repair time is unaffected when up-scaling
- The availability of equipment and spare parts are unaffected when up-scaling
- The damage accumulation is unaffected when up-scaling even though e.g. the rotor angular speed ω cf. appendix C is reduced
- The probability of needing a small boat and a jack-up is unaffected when up-scaling. Hereby, it is assumed that the capacity of the boats follows the component and spare parts mass. This also seems realistic
- The 5MW reference wind turbine is used to find the loss in energy yield when up-scaling. The method is shown in appendix B
- The maximum wave height and wind speed is unaffected when up-scaling. This is also a crude assumption since large boats are more resistant to waves
- The up-scaling exponents found in chapter 2 can be used to find the spare part cost and component cost when up-scaling
- The start cost and the daily cost of equipment when up-scaling can be found using the same up-scaling formula which is used for the spare parts and the components

Formula (5.1) is cf. chapter 2 used to find the cost when up-scaling.

$$C_X(D,T) = C_{X,ref}(D,T) \cdot \left(\frac{D}{126}\right)^{\alpha_X} \cdot (1+r)^{-(t-t_0)} \tag{5.1}$$

Where

$C_X(D,T)$	is the up-scaled cost of the respective spare part or equipment [k€ or k€/day]
$C_{X,ref}(D,T)$	is the reference cost of the respective spare part or equipment [k€ or k€/day]
α_X	is the scaling exponent for the vessel, the component, or the spare part [-]

The reference cost and the exponents for the spare parts are given in chapter 2. The exponent concerning the equipment is varied in the following analysis.

Optimal wind turbine size

The optimal wind turbine size is examined by using the results in chapter 2. In this O&M model the O&M costs was fixed and equal to 2.89c€/kWh. The general up-scaling model in chapter 2 is used to find an expression for the O&M cost when up-scaling. The expression is shown in (5.2).

$$C_{OM,L}(D,e,T_0) = \sum_{t=t_0}^{t_0+T_L} \left(\left(C_{M,t}(D,e) + C_{F,t}(D,e)\right) \cdot \left(\frac{D}{D_0}\right)^{b_{OM}} + C_{L,t}(D) \cdot \left(\frac{D}{D_0}\right)^{\alpha_L} \right) \cdot \frac{1}{(1+r)^{t-t_0}} \tag{5.2}$$

In chapter 2 it is found the land lease cost is equal to 5% of the operation and maintenance and land lease cost. Therefore, the land lease cost can be considered negligible $C_{L,t}(D)$ and this term is set equal to zero. The up-scaling exponent is found after the costs have been capitalized therefore (5.2) is rewritten to (5.3).

$$C_{OM}\left(D,e,T_0\right)=\sum_{t=t_0}^{t_0+T_L}\left(\left(C_{M,t}\left(D,e\right)+C_{F,t}\left(D,e\right)\right)\cdot\frac{1}{\left(1+r\right)^{t-t_0}}\right)\cdot\left(\frac{D}{D_0}\right)^{b_{OM}} \tag{5.3}$$

For the 5MW reference wind turbine the expected capitalized O&M cost was found equal to 4337k€. This finally gives (5.4) where the cost is in k€ and the rate of interest is included.

$$C_{OM}\left(D,e,T_0\right)=4337\cdot\left(\frac{D}{D_0}\right)^{b_{OM}} \tag{5.4}$$

The exponent b_{om} is found using the O&M program for the whole turbine. As described in the previous section the up-scaling exponents for the spare parts are determined in chapter 2. Therefore, initially the only variable is the exponent used to determine the equipment cost α_{equip} when up-scaling. If the exponent is assumed equal to 1.5, which is relatively low, the results concerning expected O&M cost when up-scaling is shown in fig. 49. The best fit is also shown and it can be seen that the exponent is equal to 1.57.

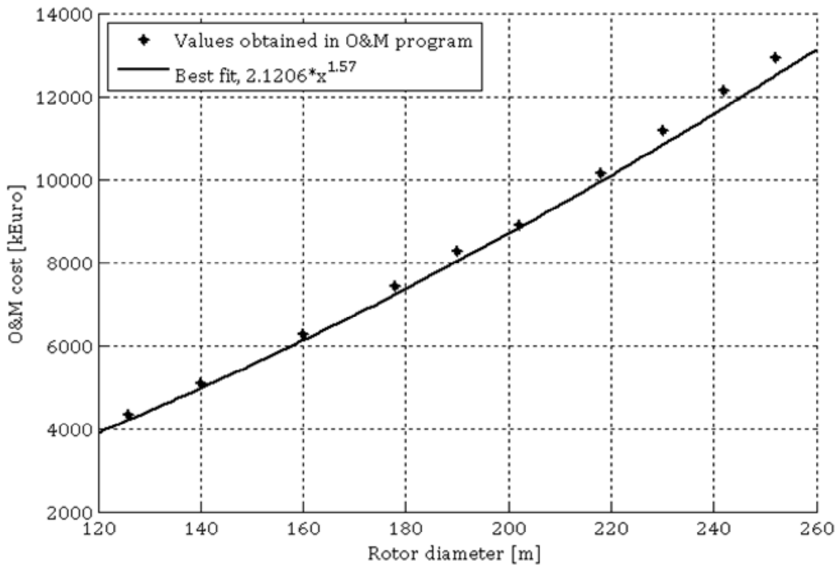

Fig. 49: Fit of the expected O&M cost when the up-scaling exponent on the equipment cost is equal to 1.5.

This gives the following equation used to determine the capitalized expected O&M cost.

$$C_{OM}\left(D,e,T_0\right)=4337\cdot\left(\frac{D}{D_0}\right)^{1.57}$$

If this results is used to update the cost model made in chapter 2 the development in cost of energy dependent on the rotor diameter is as shown in fig. 50. It can be seen that instead of having an optimal rotor diameter equal to 100m the optimal rotor diameter is equal to 160m with the new model. CF. chapter 2 this corresponds to a rated power equal to 8MW. The COE at the optimal rotor diameter is also changed from 3.42c€/kWh to 2.85c€/kWh.

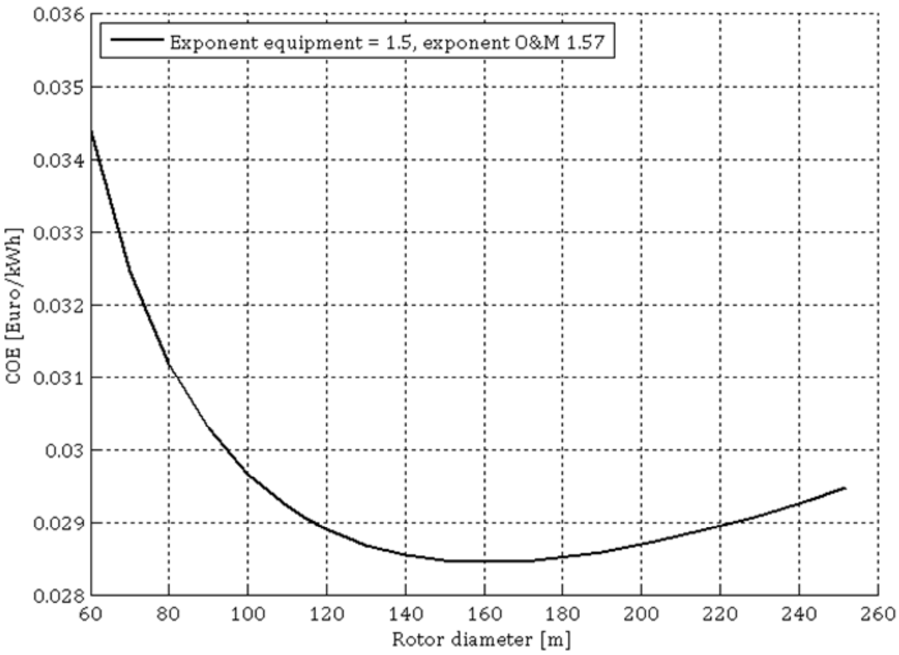

Fig. 50: Development in cost of energy when the new O&M cost model is used.

It is difficult to define up-scaling exponents for the various maintenance and operation cost. Significant uncertainties are related to the exponents and therefore in the following sensitivity analysis it is examined how the optimal rotor diameter varies if the assumptions concerning up-scaling are changed.

5.5 Sensitivity analysis

The sensitivity analysis is made in order to examine the change in optimal rotor diameter when changing the assumptions concerning up-scaling. The effect of the following is analysed.

- The up-scaling exponent on the equipment cost is changed
- The repair time is up-scaled

For all the results 1000 simulations have been made and the service and inspection strategy is maintained with an annual inspection in March and an inspection or service visit in August. The service visit is made every second year.

Up-scaling coefficient equipment

The effect when changing the up-scaling coefficient on the equipment α_{equip} is analysed. In fig. 50 the coefficient was set equal to 1.5 which gave an optimal rotor diameter equal to 160m. In fig. 51 it is shown how the result varies if α_{equip} is changed to 2.0 or 2.5.

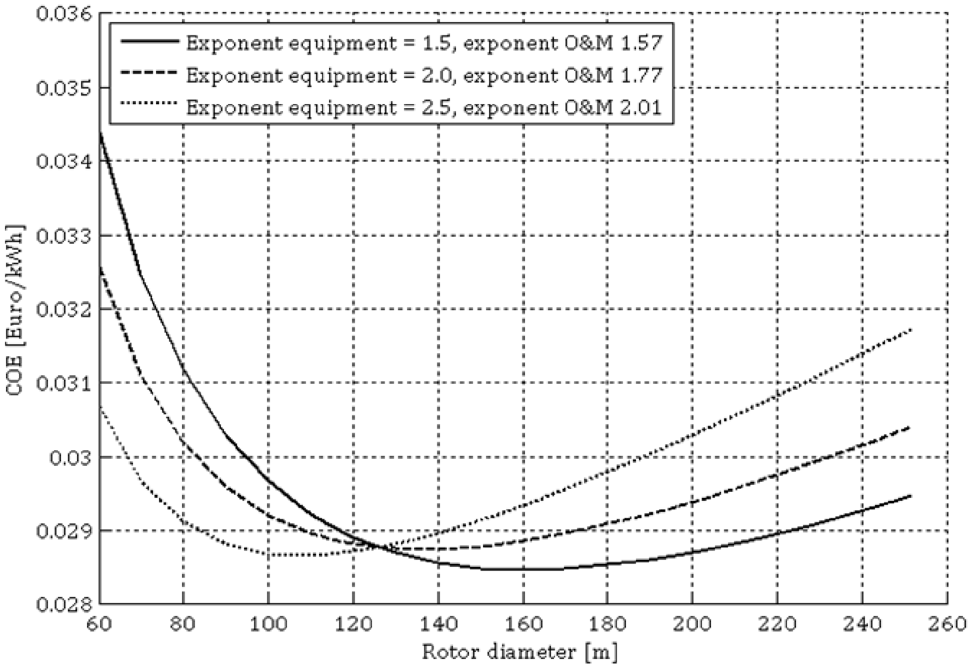

Fig. 51: Optimal rotor diameter dependent on the up-scaling exponent for the equipment.

It can be seen that the optimal rotor diameter and the O&M up-scaling exponent b_{om} is highly affected by the equipment up-scaling exponent. Having an up-scaling coefficient on the equipment cost equal to 1.5 seems very low and it is therefore assumed that the op-scaling coefficient is equal to 2.0. Hereby, the optimal rotor size is equal to 140m which corresponds to a machine rating equal to approximately 6MW.

Repair time

It is also examined how much a change in repair time affects the result concerning optimal rotor diameter. The repair time when up-scaling is calculated using (5.5).

$$T_{repair}(D) = T_{repair}(D_0) \cdot \left(\frac{D}{D_0} \right)^{\alpha_{repairtime}} \tag{5.5}$$

The reference repair time for the various components are written in appendix F. Using an up-scaling coefficient for the equipment equal to 2.0 it is examined how the optimal rotor diameter is dependent on the up-scaling coefficient for the repair time. The same procedure, followed in the previous sections, is used to find the resulting O&M up-scaling coefficient. The result can be seen in fig. 52 where an up-scaling coefficient for the repair time equal to 0.5 and 1.0 is examined.

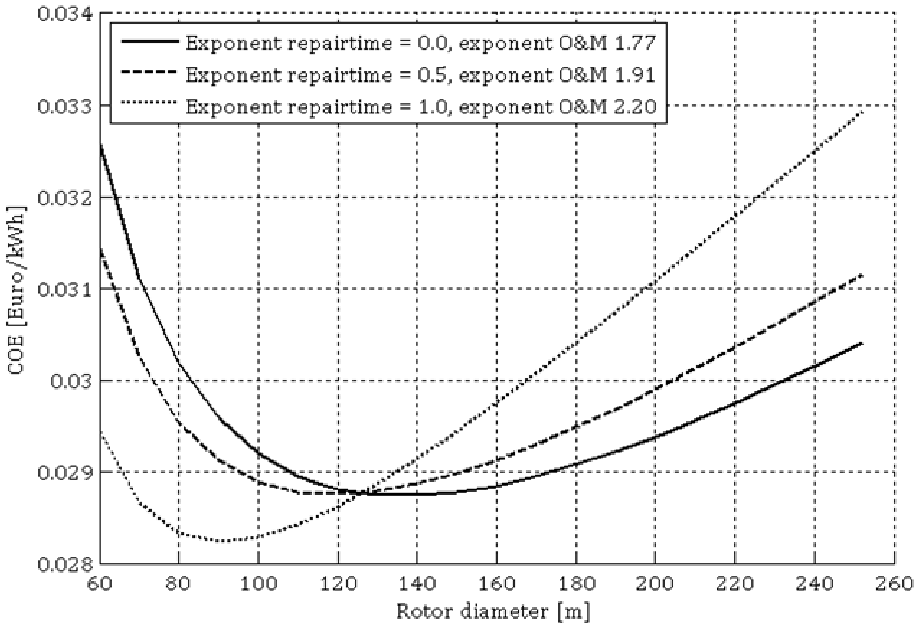

Fig. 52: Optimal rotor diameter dependent on the up-scaling exponent for the repair time.

It can be seen that up-scaling the repair time has a large influence on the expected O&M cost and the optimal rotor diameter. The reason why the repair time is so important is that the relation between the mission time and the waiting time can be described by a third degree polynomial. This is shown in appendix A. Hereby, the equipment cost, crew cost, and loss in energy yield are increased significantly, due to the extra waiting time in the port, when the repair time and hereby the mission time is increased.

As mentioned earlier in this chapter O&M costs due to unscheduled repair of the wind turbine accounts for more than 60% of the expected O&M cost. A possibility to lower these costs might be to use Bayesian statistics and reliability up-dating. This is explained further in the next chapter.

6 Condition monitoring and Bayesian statistics

As described in chapter 3 maintenance of offshore wind turbines are often scheduled before the wind turbine is put into operation, meaning that the inspections and service visits are made with fixed time intervals. However, in this chapter it is shown how Bayesian statistics can be used to optimize the inspection and service plan continuously during the wind turbine lifetime, in order to lower the O&M cost, by using monitoring and inspection results. Bayesian statistics is only used to update one stochastic variable. Therefore, it is finally described how observations can be used if an event or damage accumulation is described by more than one stochastic variable.

6.1 Bayesian statistics

In general, Bayesian statistics can be used to update a stochastic model using new data in order to approach the "real" stochastic model. The principle is illustrated in fig. 53. For e.g. a stochastic parameter X with distribution $F_X(\mu,\sigma)$, one or both of the two parameters are assumed uncertain and described by a prior distribution. If e.g. the expected value is assumed uncertain, a guess concerning expected value and the standard deviation is initially made (prior). After a given period where e.g. a wind turbine component has been in operation, measurements during the operation period, the prior values, and a physical model describing the damage accumulation can be used to find the posterior parameters. Finally, the posterior values can be used to find new predictive values for the stochastic parameter X.

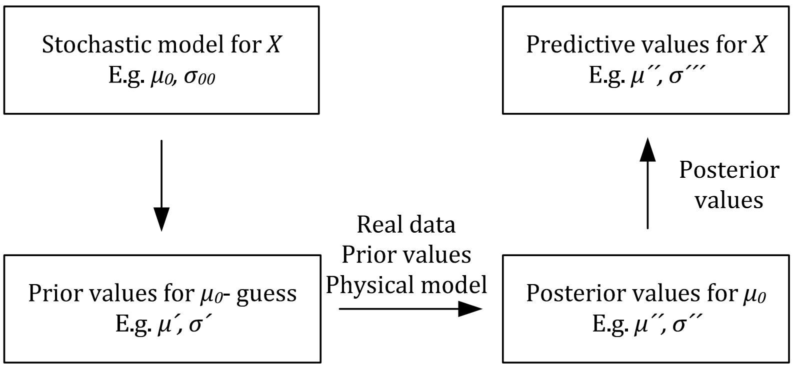

Fig. 53: Principle of Bayesian statistics.

The exponential damage model, which is described in chapter 4, is used to illustrate the principle. The exponential damage model is based on the theory concerning crack propagation which states that Paris Law can describe the crack growth when a macro crack has occurred after a given initiation period.

Compared to chapter 4 the model is simplified by changing some of the parameters. It is assumed that the crack growth parameter C models a significant part of the uncertainty and therefore, except for the load, this is assumed to be the only stochastic variable. C is still assumed lognormal distributed. a_o, which is the initial crack length, is set equal to 2mm. The initiation period is set equal to zero, m is set equal to 2.25, N is maintained equal to 12.8 per minute, and Δs is made independent of the season and Rayleigh distributed with A=32MPa. The critical crack length a_c is assumed equal to 30mm.

(6.1) shows how Paris Law is used to estimate the crack size after a given period T. It is assumed that the mean cyclic stress range Δs_1, Δs_2, … , Δs_l for the corresponding time intervals T_1, T_2, … , T_l are measured for the respective component. A realization of C can thus be calculated using (6.1).

$$a\left(T=\sum_{i=1}^{l}T_i\right)=\sum_{i=1}^{l}\left(C\cdot\left(\Delta s_i\cdot\sqrt{\pi\cdot a_{i-1}}\right)^m\cdot N\left(T_i\right)\right)+a_0 \tag{6.1}$$

As mentioned C is assumed lognormal distributed with expected value μ_0 and standard deviation σ_{00}. This can also be described by (6.2) where U is normal distributed [Sørensen, 2004].

$$U=\ln C \tag{6.2}$$

(6.3) and (6.4) are used to calculate the mean and standard deviation for U.

$$\mu_{U0}=\ln\mu_0-\frac{1}{2}\sigma_{00}{}^2 \tag{6.3}$$

$$\sigma_{U0}=\sqrt{\left(\frac{\sigma_{00}{}^2}{\mu_0{}^2}+1\right)} \tag{6.4}$$

The expected value μ_{U0} is assumed uncertain – stochastic – while the standard deviation σ_{U0} is known. μ_{U0} is Normal distributed with a prior expected value μ_U' and prior standard deviation σ_U'. The total standard deviation for U is calculated using (6.5).

$$\sigma_{\mu_{U0}}=\sqrt{\sigma_U{}'^2+\sigma_{0U}{}^2} \tag{6.5}$$

The prior stochastic parameters for μ_{U0} are initially guessed and therefore the possibility of estimating a value of U close to the actual value is relatively small. The real values μ_{U1} and σ_{U1} are assumed equal to -25.3 and 0.47, respectively. As an example the crack propagation in a component is examined. It is assumed that the prior values are equal to:

μ_U'=-25.7
σ_U'=0.83
σ_{U0}= σ_{U1}=0.47

This gives a total standard deviation equal to 0.95 and it corresponds approximately to the following prior values of μ_0.

$$\mu'=\exp\left(\mu_U'\right)=0.7\cdot10^{-11} \tag{6.6}$$

$$COV = \frac{\sigma'}{\mu'} = \sigma_U' = 0.83 \qquad (6.7)$$

A realisation of C is made using μ_{U1} and σ_{U1}. The output is unknown and therefore if the prior values for C are used the probability that C_{prior} is lower than the realised C is relatively high due to lack of knowledge. If an inspection is made six months after operation start, the crack size is measured and since the realizations $\Delta s_1, \Delta s_2, \dots \Delta s_6$ is known the realization of C can be found by iterating backwards using (6.1) and knowing that $a_6=a_{inspection}$ and a_0=2mm. Since C is known and Δs is measured continuously the crack length can be calculated for the following months. Initially, a decision rule determining that the component is replaced when it reaches 70% of the critical crack length might have been made. Each time the component is replaced a new value of C is realised using μ_{U1} and σ_{U1}. Bayesian statistics can be used to update the predictive values for C increasing the probability that the prior value of C is close to the realised value. The process is shown in fig. 54.

Prior model for | **Predictive model for**

$$\begin{tikzcd}
\ln C\text{: } N(\mu_0, \sigma_{00}) & & \ln C\text{: } N(\mu'', \sqrt{\sigma_{00}^2+\sigma''^2}) \\
N(\mu', \sigma') \arrow[u] \arrow[r] \arrow[d] & \text{Data} \arrow[r] & N(\mu'', \sigma'') \arrow[u] \\
\textbf{total } N(\mu', \sqrt{\sigma_{00}^2+\sigma'^2}) & & \textbf{Posterior}
\end{tikzcd}$$

Fig. 54: Process when using Bayesian statistics for the stochastic variable *C*.

In fig. 55 it is shown how the crack is expected to develop due to the prior and posterior value of C. At the inspection the actual value of C for the component is calculated and real crack size is calculated and plotted. Afterwards the actual crack size can be calculated each time a new realisation of Δs is made. It can be seen that in many cases the prior value of C gives a crack development which develops significantly different from the real crack length. For the first realisation the crack would have reached the critical length before the component was replaced if the prior value was used. According to the previous chapters this would increase the O&M costs due to a significant loss in energy yield due to organisation and waiting time.

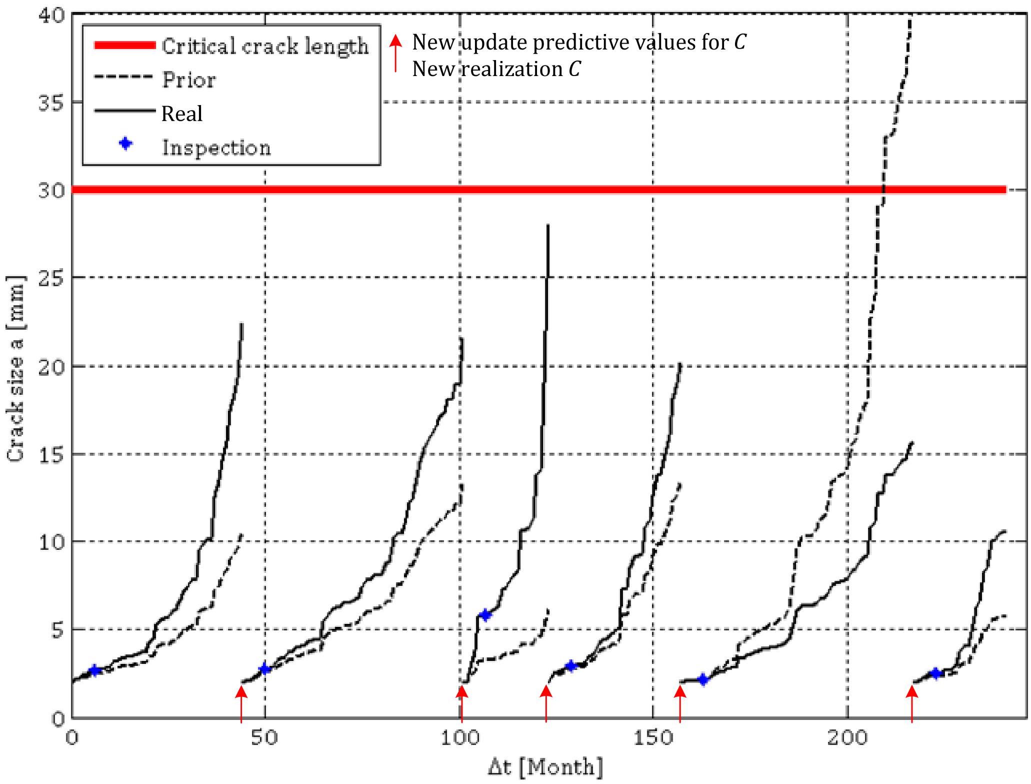

Fig. 55: Crack propagation due to the prior and posterior value of *C*.

Each time the component is replaced the new predictive value for C is used to estimate the crack growth. The estimate should hereby be better which gives the opportunity to postpone the inspection. If e.g. the loads are extreme during the period before the inspection giving the need for a replacement before the inspection, the predictive value would also give a higher probability that this is effectuated – again lowering the expected O&M cost.

In the following it is shown how the predictive values are calculated using the prior values and the posterior values based on the new data which in this case is the value of C for the component. Firstly, the test statistic is estimated using (6.8).

$$\bar{X} = \frac{1}{n}\sum_j \ln C_j^* \tag{6.8}$$

C is lognormal distributed but the method used for Normal distributed values described in [Sørensen, 2004] can be used to find the predictive values for U and afterwards the corresponding predictive values for C can be found. For the stochastic value U the updated mean and standard deviation for the posterior Normal distribution for μ_{U0} are calculated using (6.9) and (6.10).

$$\mu_U'' = \frac{n\bar{X}\sigma_U'^2 + \mu_U'\sigma_{U0}}{n\sigma_U'^2 + \sigma_{U0}^2} \tag{6.9}$$

$$\sigma_U'' = \sqrt{\frac{\sigma_U'^2 \sigma_{U0}^2}{n\sigma_U'^2 + \sigma_{U0}^2}} \tag{6.10}$$

where

μ_U'' is the posterior mean value for the stochastic value U [-]

σ_U'' is the posterior standard deviation for the stochastic value U [-]

The predictive standard deviation can now be found using (6.11).

$$\sigma_U''' = \sqrt{\sigma_U''^2 + \sigma_{U0}^2} \tag{6.11}$$

The predictive parameters for C μ'' and σ''' are obtained from (6.12) and (6.13).

$$\mu'' = \exp\left(\mu_U'' + \frac{1}{2}\sigma_U'''^2\right) \tag{6.12}$$

$$\sigma''' = \mu''\sqrt{\exp\left(\sigma_U'''^2\right) - 1} \tag{6.13}$$

24000 months has been simulated in MATLAB with the above written prior values. With a lifetime equal to 20 years, this corresponds to a possible experience obtained from a wind turbine farm with 100 wind turbines. The component is replaced 536 times and the following prior, posterior and predictive values are found.

Prior values for μ_0

μ_U'=-25.7 $\mu'=0.7 \cdot 10^{-11}$

σ_U'=0.83 $\sigma'=0.7 \cdot 10^{-11}$

Prior values for C

μ_U'=-25.7 $\mu'=0.7 \cdot 10^{-11}$

$\sqrt{\sigma_U'^2 + \sigma_{U0}^2}$ =0.95 $\sqrt{\sigma'^2 + \sigma_0^2}$ $=0.86 \cdot 10^{-11}$

Posterior values for μ_0.

μ_U''=-25.3 $\mu''=1.01 \cdot 10^{-11}$

σ_U''=0.02 $\sigma''=0.02 \cdot 10^{-11}$

Predictive values C

μ_U''=-25.3 $\mu''=1.01 \cdot 10^{-11}$

σ_U'''=0.47 $\sigma'''=0.501 \cdot 10^{-11}$

This corresponds well with the fact that the predictive values should approach the "real" values, which was equal to $1.0 \cdot 10^{-11}$ and $0.5 \cdot 10^{-11}$. Hereby, a better estimate on the damage accumulation can be made as experience is gathered during the wind turbine lifetime, giving a possibility to lower the O&M costs by choosing a more optimal inspection and service plan. In fig. 56 the prior and posterior distributions for C are plotted.

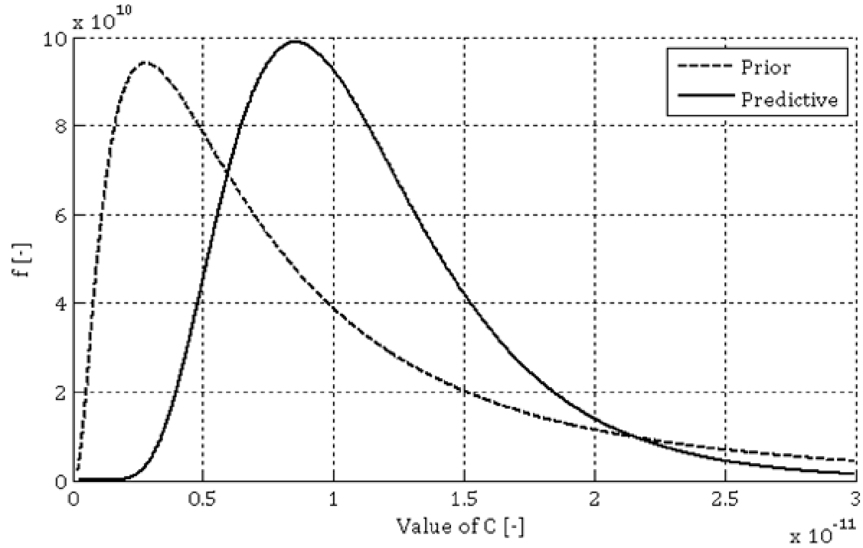

Fig. 56: Plot of prior and predictive distributions for *C*.

It has to be stated that the previous example is simplified significantly. In order to make a reliable model several other uncertainties also have to be taken into account. This is e.g. the uncertainty of an inspection result, the uncertainty of the measurements, the uncertainty of the physical model, the uncertainty of initiation period and crack width, etc. A method, which can be used to take several uncertainties into account, is shown in the following section.

6.2 Reliability updating

If the failure criteria depends on more than one stochastic variable, Bayesian statistics cannot be used. Instead reliability updating can be used to update the component reliability. The following section is based on [Sørensen, 2004].

Firstly, an event function *h* is introduced.

$$H = h(X) \tag{6.14}$$

The event function models the observed events and it corresponds to the limit state function *g*. *X* are the stochastic variables X_1, X_2, ... , X_n. At an inspection or a service visit the observations are considered as realizations of the stochastic variable *H*. For the exponential damage model, which e.g. describes the crack development in the steel components exposed to fatigue loading, this is measurements of the crack size or no-detection of cracks.

The observations can either be modeled by inequality events or equality events. For the crack size in case of no-detection of cracks at an inspection it is reasonable to model the observation by inequality events, where the crack size is less than or equal to the critical crack size. In this case the updated probability of failure can be estimated by (6.15).

$$P_f^U = P\left(g(X) \le 0 \mid h(X) \le 0\right) \tag{6.15}$$

where

P_f^U	is the probability of failure [-]
$M = g(X)$	is the safety margin related to the limit state function $g(X)$ [-]

For the exponential damage model a limit state function g can be determined using (6.1).

$$g = a_c - \left(\sum_{i=1}^{I} \left(C \cdot \left(\Delta s_i \cdot \sqrt{\pi \cdot a_{i-1}} \right)^m \cdot N(T_i) \right) + a_0 \right) \tag{6.16}$$

As mentioned earlier C, a_c, Δs, a_0, and N should be modelled as stochastic variables. After the failure function has been formulated it is possible to estimate the reliability using the FORM method. The monthly reliability index can be found by (6.17).

$$\beta(T) = -\Phi^{-1}\left(P\left(g(X,T) \le 0 \right) - P\left(g(X,T-1) \le 0 \right) \right) \tag{6.17}$$

If e.g. an inspection is made at time T_i the reliability index can be updated due to the inspection result. As described in appendix E the probability of detecting a crack can be modelled by a POD-curve. A possible POD-curve for a crack is shown in (6.18).

$$POD(a) = F_{a_d}(a) = 1 - \exp\left(-\frac{a}{b} \right) \tag{6.18}$$

where

a_d	is the smallest detectable crack [m]
b	is a parameter modelling the expected value of a_d [m]
λ	is the distribution parameter depending on the inspection method [-]

If no cracks are found at T_i the inspection event can be modelled by an event margin. The following event margin can be formulated.

$$h = a_d - \left(\sum_{i=1}^{I} \left(C \cdot \left(\Delta s_i \cdot \sqrt{\pi \cdot a_{i-1}} \right)^m \cdot N(T_i) \right) + a_0 \right) \le 0 \tag{6.19}$$

The updated annual reliability index can afterwards be formulated using (6.15).

$$\beta^U(T) = -\Phi^{-1}\left(P\left(g(X,T) \le 0 \,|\, h(X) \le 0 \right) - P\left(g(X,T-1) \le 0 \,|\, h(X) \le 0 \right) \right) \tag{6.20}$$

7 Conclusion

The wind turbine technology has been improved significantly during the last decades but, considering cost of energy, fossil fuels are still the most beneficial energy source. Therefore, wind turbine power plants have to be improved even more in order make wind energy cost competitive.

In this thesis it is examined if it is beneficial to up-scale offshore wind turbines with the present technology in order to lower the COE. In general, the energy production depends on the rotor area and therefore the energy production scales with $D^{2+3\alpha}$ while the load, and hereby also the mass/cost of several structural components, scales with $D^{3+2\alpha}$. α is the exponent describing the wind profile. It is therefore obvious that, if up-scaling shall be beneficial, other costs such as installation, transportation, and operation maintenance costs have to result in an up-scaling exponent lower than $2+3\alpha$.

Considering the full wind turbine lifetime an operation and maintenance model for a wind turbine component and a whole wind turbine is also made. With respect to lowering the O&M costs, the important input parameters are found and the optimal wind turbine size considering all the costs is evaluated. This final chapter gives an overview of the main conclusions and results achieved throughout the thesis. Chapter 3 is an introduction to the following chapters and therefore this chapter will not be mentioned.

Chapter 2 Considering the whole wind turbine lifetime and dividing the costs into 21 constituents, a cost model is made in order to calculate the total cost and energy production during the wind turbine lifetime dependent on the wind turbine size. The maximum wind turbine size evaluated is a 20MW turbine. The model is based on literature review and it shows that the optimal wind turbine size is a 3MW wind turbine with a rotor diameter equal to approximately 100m. In this case the capitalized cost of energy is equal to 3.42c€/kWh.

The O&M and the rotor and nacelle cost account for approximately 40% and 20% of the total cost, respectively. These constituents are significantly higher than e.g. the tower and foundation cost which is only 10% of the total cost. However, this might be changed if the water depth is larger than 12m, which is assumed in this thesis.

The COE for most of the structural components increase when the wind turbine is up-scaled. It is therefore found that cost constituents such as installation and transportation, electrical connection, and O&M costs have to be focused on if up-scaling shall be beneficial. This is also shown in the sensitivity analysis where the up-scaling exponent is changed for the O&M cost. If the exponent is changed from 2.33 to 1.93 the optimal offshore wind turbine size changes from approximately 3MW with a rotor diameter equal to 100m to 8.5MW with a rotor diameter equal to 165m. In this case the minimal COE is changed to 3.17c€/kWh.

Chapter 4 In chapter 2 it is found that the O&M cost account for approximately 40% of the total cost and that it might be beneficial to up-scale wind turbines if the COE concerning operation and maintenance is lowered when up-scaling offshore wind turbines. Therefore, the key input parameters, if the O&M cost has to be lowered, is found in this chapter considering only the O&M cost for a gearbox in a 5MW wind turbine. In order to take the many uncertainties concerning the input parameters into account, Crude Monte Carlo simulation is used to find the expected O&M cost.

Firstly it is shown that the O&M cost is highly affected by the damage model and the O&M strategy. The optimal inspection and service plan is also dependent on the damage model. In general, the damage model determines the damage progress speed and it is shown that for a high damage progress speed corrective maintenance might be the most optimal O&M strategy. However, if the damage progress speed can be lowered the scheduled maintenance strategy might be advantageous. The quality of the inspections and the repair barriers also influences the O&M cost and the optimal inspection and service plan significantly.

If the wind turbine needs repair and the repair team is ready and organised, the waiting time before a sufficiently long weather window occurs has a significantly influence on the total O&M cost. It is therefore important to design future repair vessel so they are suitable for the climate where the offshore wind turbine power plant is operating. E.g. in the Atlantic Ocean it might be beneficial to use large and expensive repair vessels which can withstand large waves while smaller and cheaper repair vessels might be advantageous in the Mediterranean Sea. Furthermore, it is shown that the risk of needing a jack-up instead of a smaller vessel increases the cost significantly. This is also important to take into account when designing the crane in the wind turbine.

It is finally shown that it might be advantageous to invest in a repair vessel to service the offshore wind turbine farm. Only considering the gearbox it might be beneficial to have a fixed cost if the cost is less than 1300-2000€ per turbine per month.

Chapter 5 In this chapter the expected cost and downtime for a 5MW wind turbine is examined. It is found that the optimal inspection and service plan is to make an annual inspection in March and in August. However, every second year a service visits has to be made in August instead of an inspection. Using this inspection and service plan the expected capitalised O&M cost is equal to 4337k€ which corresponds to a COE equal to 0.9c€/kWh. This is less than used in chapter 2 where the O&M cost is equal to 1.48c€/kWh. If this O&M cost model is used the cost of energy for the 5MW offshore wind turbine is hereby equal to 2.87c€/kWh corresponding to that the O&M cost only account for 31% of the total cost. This is a significant difference and it can hereby be stated that O&M models are related with significant uncertainties and this have to be taken into account when designing future turbines. The availability and downtime is significantly higher during the winter months - both due to the higher failure frequency but also due to the limited availability. This also has to be taken into account when designing the wind turbines. It might be advantageous to design the control system so the loads are lowered during the winter, possibly decreasing the energy production but also decreasing the O&M costs.

The expected O&M cost is also found when up-scaling the wind turbine from 5MW up to 20MW. It is assumed that only the spare part cost and equipment cost is affected when up-scaling the wind turbines. The up-scaling exponents found in chapter 2 are used for the spare part costs while the exponent for the equipment cost is varied from 1.5 to 2.5. As expected the optimal wind turbine size is highly affected by the up-scaling exponent on the equipment. The optimal wind turbine size is changed from 8MW to 3.5MW when changing the exponent from 1.5 to 2.5. It is therefore important to examine how the equipment cost varies when wind turbines are up-scaled. It is also shown that the repair time has a significant influence on the cost since the waiting time is increased significantly when the mission time is increased. The assumption that the repair time is unchanged when up-scaling therefore has to be examined carefully when designing new and possibly larger offshore wind turbines.

Considering the 5MW turbine the total cost is also divided into crew, equipment, spare part, and loss in energy yield cost, the percentage share is equal to 4%, 47%, 24%, and 25%, respectively. Hereby it can again be concluded that it is extremely important to focus on the transportation and installation equipment in order to lower the O&M cost.

Focusing on the 14 technical it is shown that the rotor bearings and pitch mechanism, the gearbox, and the electrical and hydraulic system cause a large share of the expected O&M cost and downtime. It is therefore important to focus on the O&M costs when designing these components. The gearbox contributes with more than 13% of the total O&M cost which corresponds to 563,000€. This has to be taken into account when determining if future offshore wind turbines have to be installed with direct drives.

It is also shown in this chapter that unscheduled repair costs account for more than 60% of the total O&M cost. It is extremely difficult to predict the damage accumulation due to uncertainties concerning material properties, damage models, loads, and so forth. Bayesian statistics might be able to diminish these uncertainties lowering the O&M costs.

Chapter 6 Using the exponential damage model it is shown in chapter 6 how Bayesian statistics can be used to decrease the uncertainties concerning the damage accumulation in a component. In order to use Bayesian statistics it is important to create a reliable damage model. Furthermore, the load has to be measured and stored continuously in order to use future inspection and service results to update the uncertainties concerning e.g. the material parameters. This gives the opportunity to change the inspection and service plan continuously in order to increase the detection probability of future errors.

8 Future work

In order to increases the reliability of the models, it would be interesting to examine some of the subjects in the present thesis even further. New studies can also be made in order to examine how the wind turbine technology can be improved in order to make wind energy more cost competitive. The following topics might be interesting to examine further:

- The up-scaling model concerning installation and transportation should be examined further since these costs among others should make up-scaling beneficial. The distance to shore and the water depth should also be taken into account.
- The input parameters in the O&M cost models are related to significant uncertainties due to lack of data from the wind energy industry. It would be interesting to update the models if the input data was available.
- It would be interesting to examine how the input parameters concerning O&M upscale. The costs concerning transportation are especially interesting since these costs account for a large percentage of the total O&M cost.
- The increase in O&M, installation and transportation, foundation, and connection cost would be interesting to examine when the wind farms are moved far from shore.
- It would be interesting to examine the O&M cost related to a gearbox even further in order to evaluate if e.g. the direct drive solution is beneficial.
- Reliability up-dating is extremely difficult to manage due to the many stochastic variables. It would therefore be interesting to examine further how the theory can be applied on wind turbines using the information available in practice. Further, these models could be used for identify areas where collection of data is most profitable.

Finally, it has to be mentioned that collaboration with wind turbine manufactures and operators could be extremely beneficial in order to validate the input and output parameters. However, due to the sensitivity of the data this might be extremely difficult to manage.

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A. Wind and sea climate

To be able to find vital information such as annual wind farm energy production and structural loads, it is important to investigate the wind and sea climate at a given wind farm site. To ensure realistic results, this thesis is based on the wind climate at an already erected wind turbine farm; Horns Rev I. Horns Rev is a 160MW wind farm which was commissioned in 2002. It is situated 14km off Jutland. Two marine stations and one meteorology station are situated close to the site which can be seen in fig. 57. The wind data from the meteorology station and the wave data from the marine stations are analysed in the following [Winddata, 2008].

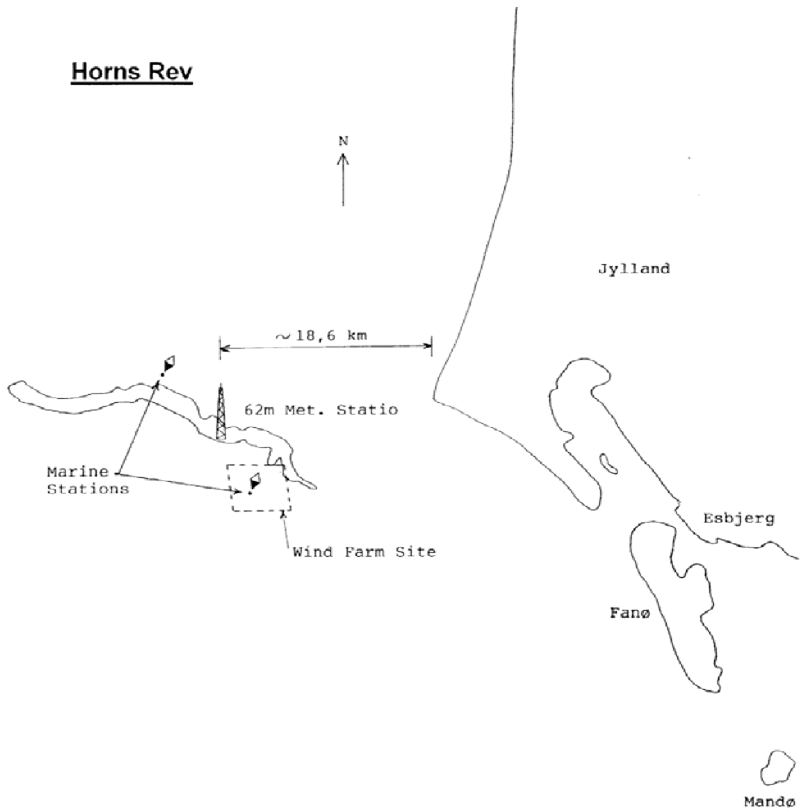

Fig. 57: Location of the wind farm site at Horns Rev and the location of the measuring sites. [Winddata, 2008]

A.1 Wind climate

The wind climate at Horns Rev I is analysed, based on measurements from the 62 meter high meteorology mast next to the wind farm Horns Rev I. The wind speed is measured in four different heights; 15.0m, 30.0m, 45.0m and 62m above mean sea level. Two cup anemomenters are placed at each level – one at the south-western side of the tower and one on the north-eastern side. To reduce the data processing only wind data from the lowest anemomenters are analysed. The wind speed in other heights can be found by the power law which is shown later.

At the measurement station the sampling rate is 1Hz but the data are condensed to 10-min average values. Furthermore, the maximum value of a 5-second gust during the 10 minutes is stored. Normally, it is the 3-second gust which is used but since these values are not available the 5-second gust is used instead. This will give a minor turbulence intensity but this is neglected in this thesis. The analysed wind data can be found on the CD (*Kote 15.txt*). The first four columns show the date and time of each measurement, the next two show the 10-min average wind speed and the maximum gust measured by the anemomenter at the south-western side, and the last two columns show the 10-min average wind speed and maximum gust measured by the anemomenter at the north-eastern side of the tower. Dependent on the wind direction one of the anemometers can be situated at the leeside of the mast and therefore only the highest wind speed, measured by the anemometers, is used.

The measurements are gathered from the 14th of May 1999 to the 23th of June 2006. There is a period between the 20th of January 2005 and 20th of April 2005 where no data have been gathered. However, this period is relatively short compared to the whole period from 1999 to 2006 and it is therefore not considered a problem.

The season variation of the wind is also examined. There are 83763 measurements from the winter-months, 87823 from the spring-months, 95780 from the summer-months, 91604 from the autumn-months, giving a total of 358780 measurements. The following gives a presentation of the results and the program used to analyse the data is named (Windanalysis.for).

Mean and standard deviation

The mean wind speed and standard deviation is calculated using (A.1) and (A.2), respectively. The corresponding standard deviation is also found. The results can be seen in tab. 18.

$$\overline{X} = \frac{1}{N}\sum_{i=1}^{n} v_i \tag{A.1}$$

$$S = \sqrt{\frac{1}{N}\sum_{i=1}^{n}\left(v_i - \overline{X}\right)^2} \tag{A.2}$$

where

$\overline{X}$	is the mean value [m/s]
N	is the size of the population [-]
v	is the 10-minute wind speed [m/s]
S	is the standard deviation [m/s]

Tab. 18: Mean wind speed and standard deviation.

	10-min. wind Winter	10-min. wind Spring	10-min. wind Summer	10-min. wind Autumn	10-min. wind Year	v_{max}/v_{mean} Year
Mean [m/s]	8.80	7.34	7.06	9.12	8.05	1.23
Standard deviation [m/s]	4.03	3.30	3.35	3.89	3.76	0.33

Wind speed distribution

The wind speed distribution is assumed to follow a 2-parameter Weibull distribution given by (A.3) and (A.4).

$$F(v) = 1 - \exp\left(-\left(\frac{v}{A}\right)^k\right) \tag{A.3}$$

$$f(v) = \frac{dF(v)}{dv} = \frac{k}{A^k} v^{k-1} \exp\left(-\left(\frac{v}{A}\right)^k\right) \tag{A.4}$$

where

k is equal to the Weibull shape parameter [-]

A is equal to the Weibull scale parameter [m/s]

The Weibull parameters are found using the Maximum Likelihood method. The Maximum Likelihood method of finding the parameter k is to solve equation (A.5) iteratively by varying k [Frigaard et al., 2001].

$$N + k\sum_{i=1}^{N} \ln(v_i) = N \cdot k \sum_{i=1}^{N} \left(v_i^{\,k} \ln(v_i)\right) \cdot \left(\sum_{i=1}^{N} v_i\right)^{-1} \tag{A.5}$$

Afterwards the parameter A can be determined using (A.6).

$$A = \left(\frac{1}{N}\sum_{i=1}^{N} v_i^{\,k}\right)^{1/k} \tag{A.6}$$

In tab. 2 the calculated Weibull parameters have been listed. The season dependent wind distributions are also plotted in fig. 58.

Tab. 19: Weibull parameters.

	Winter	Spring	Summer	Autumn	Year
Weibull shape parameter [-]	2.29	2.35	2.20	2.50	2.26
Weibull scale parameter [m/s]	9.895	8.276	7.951	10.315	9.086

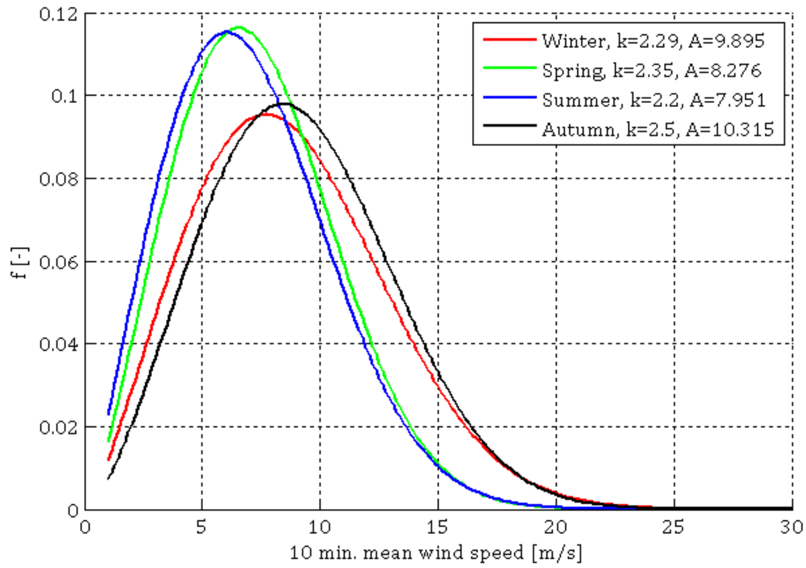

Fig. 58: Plot of the four wind distributions.

The used wind data shown in a frequency histogram and the non-season dependant wind distribution described by the Weibull distribution is plotted in fig. 59. As expected, there is a good correlation between the Weibull distribution and the used wind data.

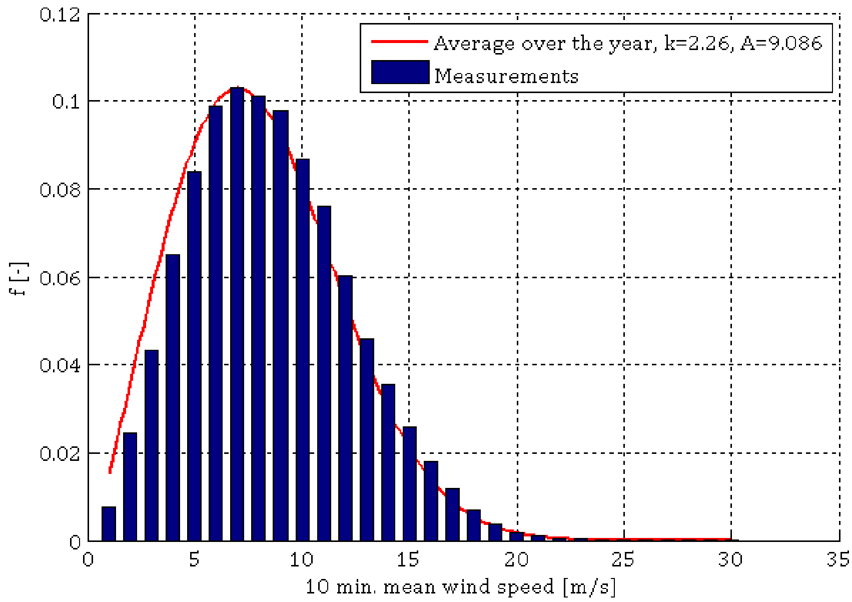

Fig. 59: The non-season dependant Weibull distribution compared to the actual data.

Wind direction and wind profile

It is also important to know the wind direction distribution. Fig. 60 shows the directional distribution measured 62m above mean sea level from May 1999 to January 2000. There is an uncertainty since the data do not cover a whole year. However, this uncertainty is neglected. It is assumed that the wind direction is independent of the height.

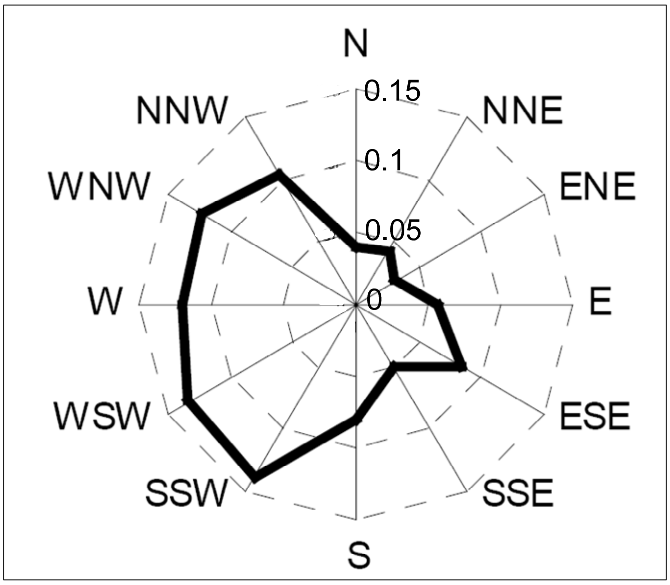

Fig. 60: Wind directional distribution measured 62m above mean sea level. Data from May 1999 to January 2000. [Winddata, 2008]

The average wind speed depends on the wind direction. This is shown in fig. 61.

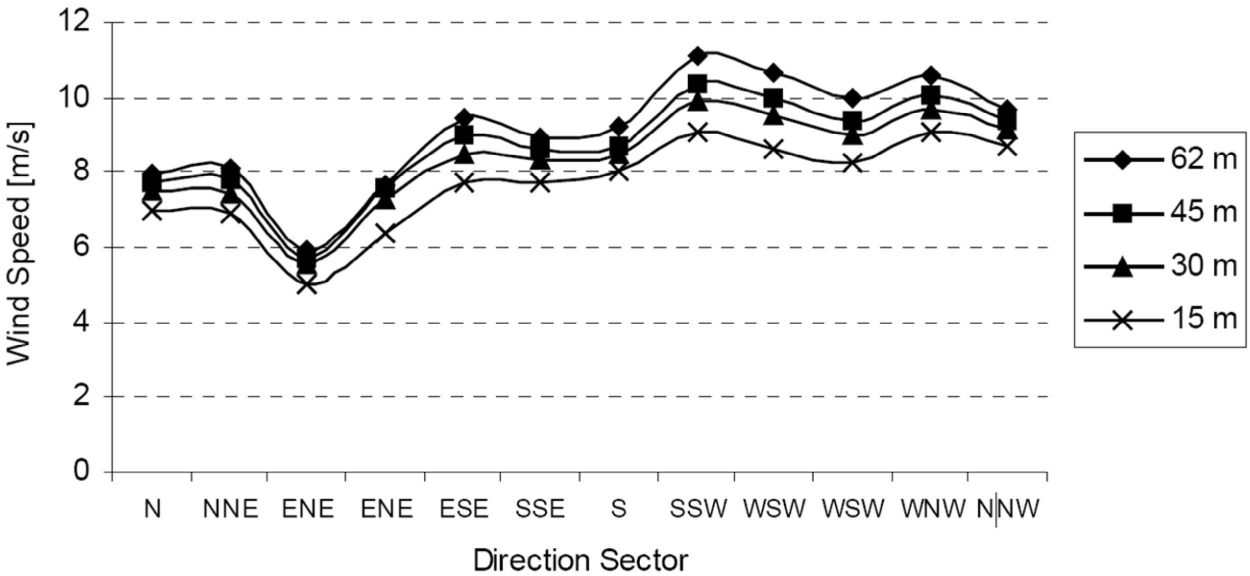

Fig. 61: Average wind speed as a function of the direction sector. Data from May 1999 to January 2000. [Winddata, 2008]

The wind speed profile is also examined. The IEC 61400-3 code recommend that the wind profile is calculated by the power law and propose a power law exponent α equal to 0.11. The power law formula is shown in (A.7).

$$v = v_{ref}\left(\frac{H}{H_{ref}}\right)^{\alpha} \qquad \text{(A.7)}$$

where

H is the height calculated as 27m plus the rotor radius [m]

H_{ref} is the reference height equal to 15m [m]

The formula can also be used to describe the variation of the Weibull scale parameter as a function of the height. A report analysing wind data from May 1999 to January 2000 at Horns Rev, gives the mean wind speed and Weibull scale parameter at the four different measuring heights [Winddata, 2008]. The results are shown in tab. 20.

Tab. 20: Mean wind speed and Weibull scale parameter as a function of the height [Winddata, 2008].

Height [m]	62	45	30	15
Mean wind speed [m/s]	9.7	9.2	8,8	8.2
Weibull scale parameter [m/s]	10.9	10.4	10.0	9.3

Using the results the power law exponent is examined. The results for the mean wind speed gives an exponent equal to 0.116 while it is equal to 0.109 using the results for the Weibull scale parameter. This implies that it is reasonable to use an exponent equal to 0.11.

Turbulence intensity

The turbulence intensity I is calculated using (A.8).

$$I_i = \frac{\sigma_i}{v_i} \tag{A.8}$$

where

σ is the standard deviation of the wind speed in the 10-minute period [m/s]

It has not been possible to receive values concerning the standard deviation and since the turbulence intensity is not used in the thesis, it is not examined further.

A.2 Wave climate

Since the O&M cost are highly dependent on the wind and wave climate, the wave climate at Horns Rev I is also examined. The climate varies throughout the year. This can also be seen in tab. 21 where results concerning the significant wave height H_s calculated each hour, the maximum wave height H_{max} measured each hour, the period corresponding to the significant wave height T_{02}, and the peak period T_p measured each hour are shown (Waveanalysis.for). H_s is the average size of the one third largest waves in a given period while T_{02} is the average values of the periods corresponding to the values used to calculate H_s.

Tab. 21: Results due to the wave data from Horns Rev I.

	Winter		Spring		Summer		Autumn	
	Mean	Standard Deviation	Mean	Standard Deviation	Mean	Standard Deviation	Mean	Standard Deviation
H_s [m]	1.31	0.39	0.89	0.57	0.83	0.48	1.20	0.33
H_{max} [m]	1.98	0.80	1.35	0.89	1.31	0.62	1.86	0.73
T_{02} [s]	4.53	0.62	4.07	0.75	3.83	0.59	4.23	0.53
T_p [s]	6.99	2.42	6.33	2.56	5.42	1.87	6.23	2.12

The wave data is measured from the 1th of July 1999 to the 23th of June 2006. The measurements are condensed into data representing an interval equal to one hour.

In fig. 62 the relation between significant wave height and wave period can be seen (hsts.m). The results can be divided into an upper cluster and a lower cluster. In the upper cluster there is an obvious almost linear relation between the wave height and the wave period. This is the wind generated waves. The waves giving the lower cluster originate are swell waves [Winddata, 2008].

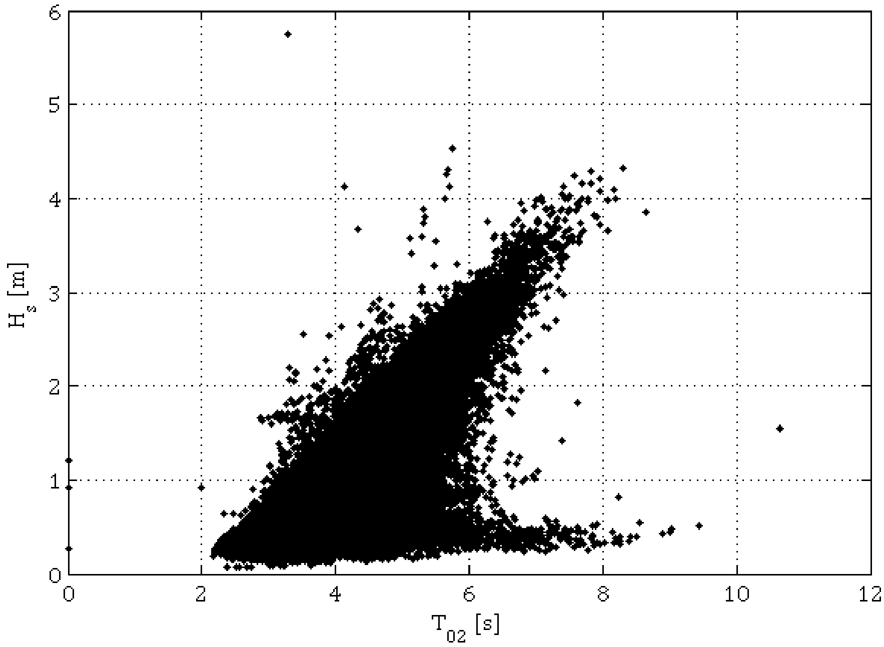

Fig. 62: Relation between wave period and significant wave height.

It is expected that the wave height and wind speed is correlated which is also shown in fig. 63. There is an almost linear relation between the two. However, at wave heights equal to approximately 4 m an upper limit occurs due to the relatively shallow water causing the waves to break.

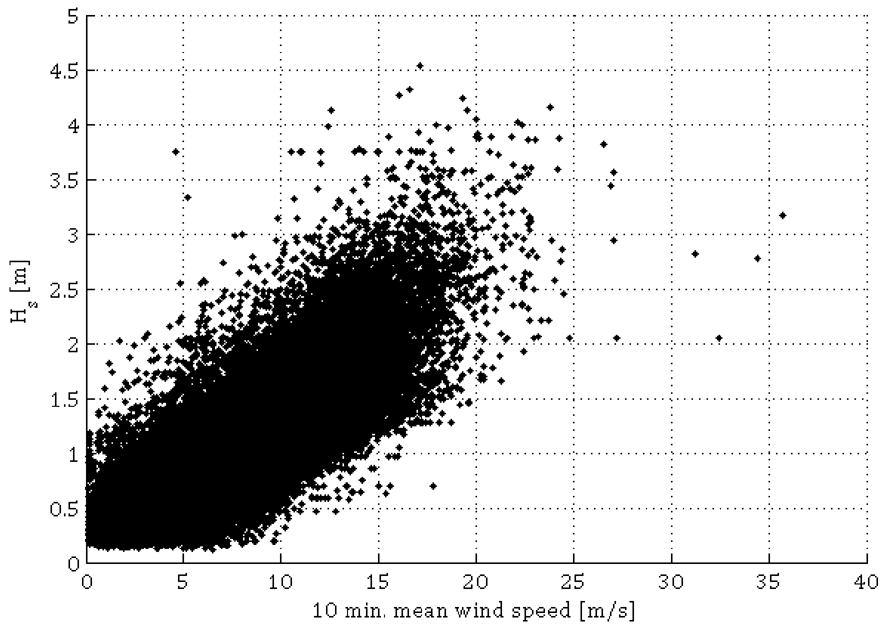

Fig. 63: Relation between wind speed and significant wave height.

A key point in selecting the O&M strategy is to know the accessibility at the wind turbine site. Many boats have an upper limit which is approximately 1.5m [Wind energy, 2008]. In fig. 64 the probability of exceeding a giving wave height is plotted. It can be seen that there is a huge difference on the exceedance probability depending on the time of year. In the winter and autumn the wave heights are significantly higher than during the spring and summer months which were also expected due to the higher wind speeds these seasons.

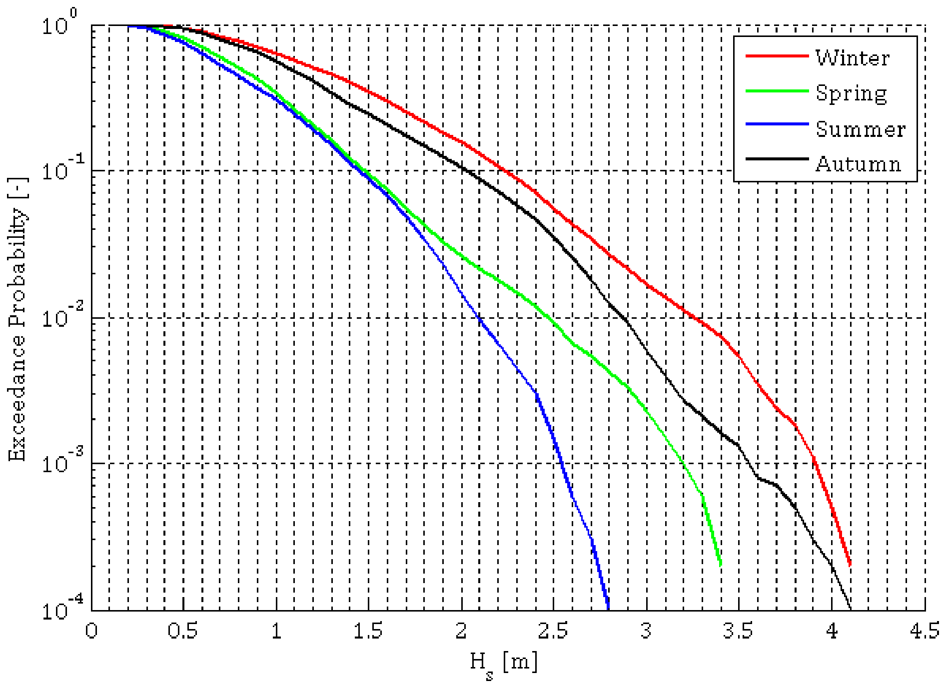

Fig. 64: Exceedance probability of a giving wave height depending on the time off year.

If the maximum wave height is 1.5m, it can be seen in fig. 64 that the accessibility is approximately 65% during the winter. However, the probability of exceedance is not sufficient to find out if repair can be carried out. The mission time also has to be taken into account which is done in the following.

In order to find the loss in energy yield when a wind turbine due to failure is stopped, the expected time before an adequate weather window appears has to be found. The time depends on the maximum wave height allowed, the maximum wind speed allowed, and the required mission time $T_{mission}$. The mission time depends on the travel time and the repair time needed. This is explained further in chapter 3. The data from Horns Rev is again used to find the waiting time T_{wait}. The waiting time depends on the time of year why the winter, spring, summer, autumn months are evaluated separately. The waiting time due to the three criteria are calculated as a mean. In fig. 65 the mean waiting time during the winter is plotted as a function of the required mission time. It is not expected that any repair action will last more than a week and the maximum mission time is therefore set to 180hrs. In fig. 65 the maximum significant wave height is set to 1.5m while the maximum wind speed is set to 12m/s. To be able to calculate the expected waiting time for all values of $T_{mission}$, a 3rd degree polynomial is fitted to the data.

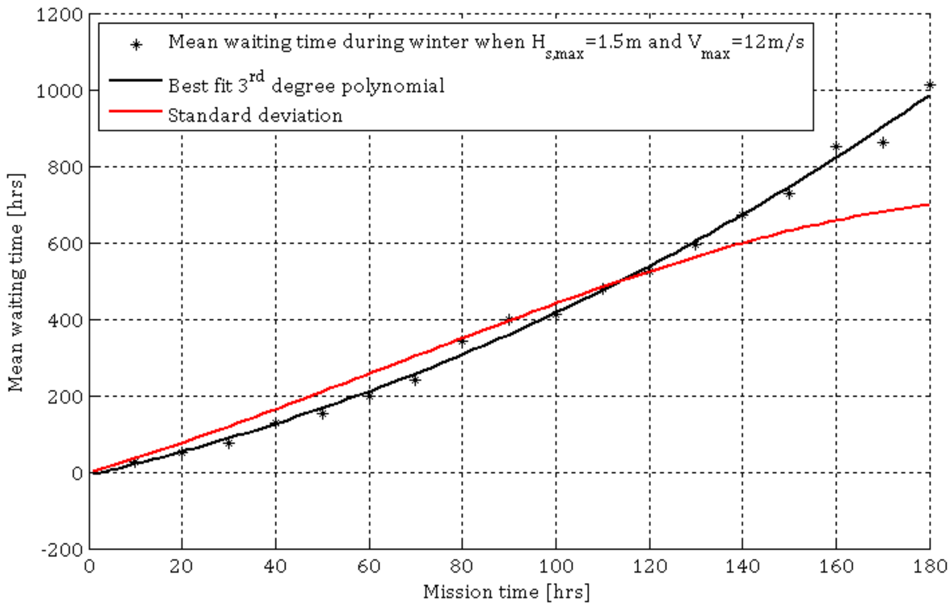

Fig. 65: Mean waiting time due to the required mission time. The standard deviation is also plotted.

In fig. 65 the standard deviation is also plotted. It can be seen that the standard deviation is very large compared to the mean value. However, this is not taken into consideration when the O&M cost model is made.

As mentioned the maintenance equipment has different restrictions concerning maximum wave height and maximum wind speed. The mean waiting time also depends on the time of year. Therefore 3rd degree polynomials for all combinations of the following are made.

- Maximum H_S; 0.5m, 0.6m, 0.7m, 0.8m, 0.9m, 1.0m, 1.1m, 1.2m, 1.3m, 1.4m, 1.5m, 1.6m, 1.7m, 1.8m, 1.9m, 2.0m

- Maximum V_{mean}; 5m/s, 6 m/s, 7 m/s, 8 m/s, 9 m/s, 10 m/s, 11 m/s, 12 m/s, 13 m/s, 14 m/s, 15 m/s, 16 m/s, 17 m/s, 18m/s, 19m/s, 20m/s
- Time of year; winter, spring, summer, autumn

This gives 1024 combinations and therefore the coefficient values are plotted in data files which can be loaded by the O&M program.

In fig. 66 it is shown how the mean waiting time varies due to the time of year. The waiting time is approximately the same during the spring and summer months. When the mission time exceeds 100hrs the waiting time is longest during the autumn while the waiting time is longest during the winter when the mission time is bellow 100hrs.

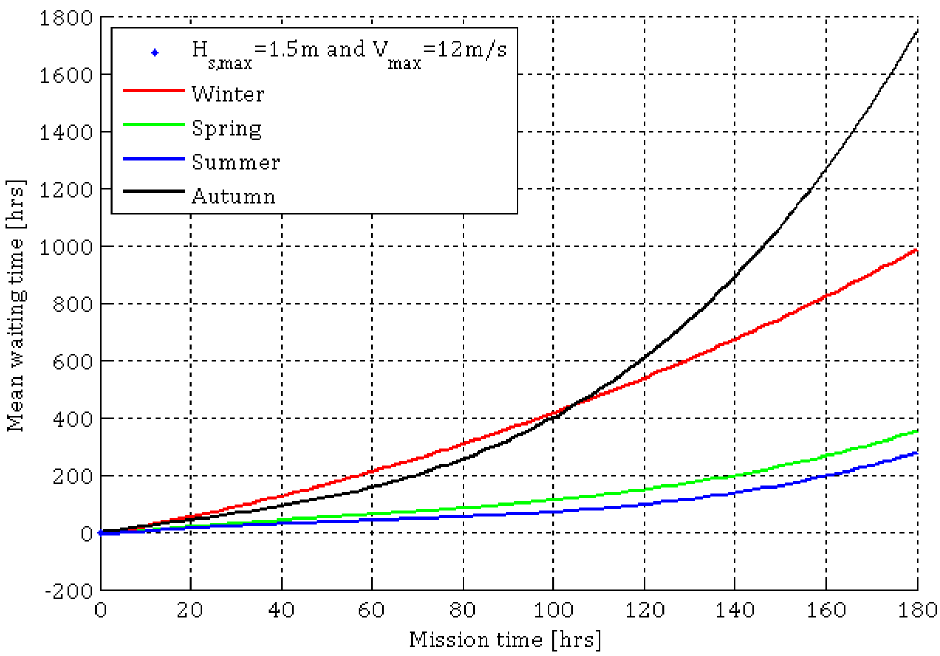

Fig. 66: Mean waiting time due to the time of year.

If a vessel has very strict demands concerning maximum wave height and maximum wind speed, it is not always expected that a suitable weather window occurs if the mission time is very long. This is illustrated in fig. 67.

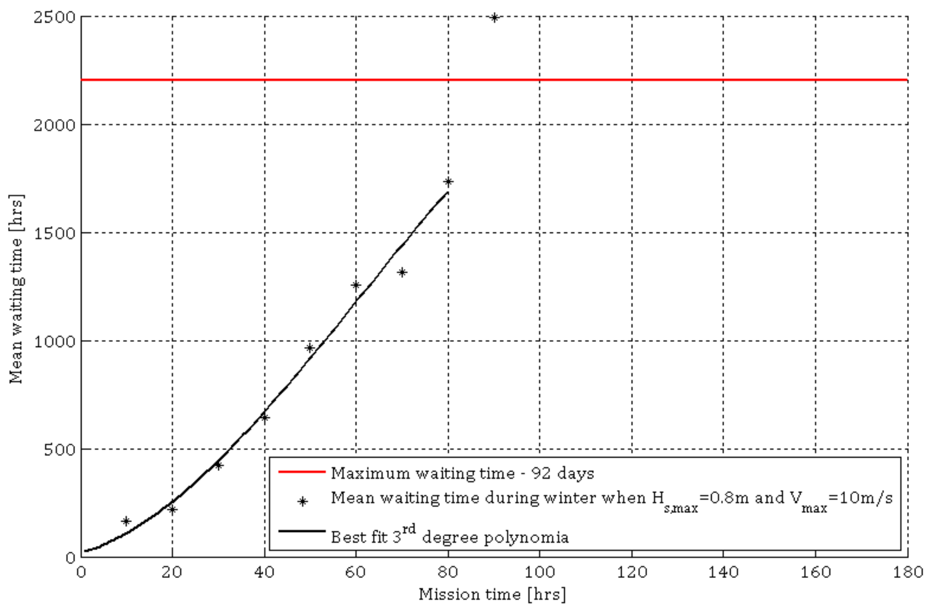

Fig. 67: Implementation of maximum mission time.

If the mission lasts more than 80hrs the mean waiting time will exceed 2208hrs corresponding to 92 days. Regardless if failure occurs in the early winter months a suitable weather window will not occur before spring or during the summer. Therefore, it is not beneficial to organise a repair team before spring. The maximum mission time, due to the time of year, the maximum wave height, and the maximum wind speed, is also registered in order to be able to postpone the repair action if necessary. To make the best 3rd degree polynomial fit, it is only the samples below the barrier equal to 2208hrs which is used.

The wave direction is not examined but due to the limited fetch length at eastern wind directions, the waves are largest at western wind directions. It is presupposed that the wind and wave direction is fully correlated which makes it possible to use fig. 60 to determine the possibility of a given wind direction. Furthermore, the size dependency concerning wind direction and wave height is disregarded.

B. Annual energy production

The annual energy production has to be calculated in order to calculate the cost of energy. Firstly, it is explained how the *AEP* is calculated for a wind turbine which is not affected by surrounding turbines. When the turbines are installed in wind farms, the wind is not undisturbed and the wind velocity decreases and the turbulence increases – this is called the wake effect. This decreases the *AEP* and increases the loads on the turbine. This is described in the end of the appendix.

B.1 Single standing turbine

To calculate the *AEP*, it is necessary to know the wind distribution in the respective area and the power curve of the wind turbine. As mentioned in appendix A the wind is described by a Weibull distribution. For a whole year, the *A*-value is 9.086m/s and the *k*-value is 2.26. During the up-scaling the rotor diameter changes which leads to a larger hub height. The corresponding *A*-value is calculated by the power law cf. appendix A.

Every turbine has its oven power curve. It is therefore not possible to find a power curve for a 10MW, 15MW, or 20MW turbine. Instead the power curve for the 5.0MW FAST wind turbine has been used to model the power curve for a wind turbine with an arbitrary machine rating (*MR*). The FAST wind turbine has a rotor size equal to 126m and hub height equal to 90m. The cut-in speed is 3m/s and the cut-out speed is 25m/s. Corresponding values between the wind speed and power output is listed in tab. 22. Furthermore, the ratio between the power out-put and machine rating is calculated.

Tab. 22: Corresponding values between the wind speed and power output for the 2MW bonus wind turbine [WASP, 2008].

Wind speed v [m/s]	4	5	6	7	8	9	10	11	11.4
Power P [kW]	225	500	800	1220	1830	2555	3666	4777	5000
Pct. of *MR* [-]	0.045	0.10	0.16	0.24	0.37	0.51	0.73	0.96	1.00

Wind speed v [m/s]	12	13	14	15	16	17	18	19	20-25
Power P [kW]	5000	5000	5000	5000	5000	5000	5000	5000	5000
Pct. of *MR* [-]	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

The energy in the wind is calculated by (B.1).

$$P_{wind} = \frac{1}{2}\rho v^3 A_R \qquad \text{(B.1)}$$

where

ρ is the density of the air [kg/m³]

A_R is the rotor area calculated from the rotor diameter [m²]

The efficiency of the wind turbine is equal to the ratio between the power production P and the energy in the wind. The ratio is expressed by the power coefficient C_p which is calculated by (2.2).

$$C_p = \frac{P}{P_{wind}} = \frac{2P}{\rho v^3 A_R} \tag{2.2}$$

In fig. 68 the power curve for the 2MW turbine from Bonus can be seen (poweroutput.m).

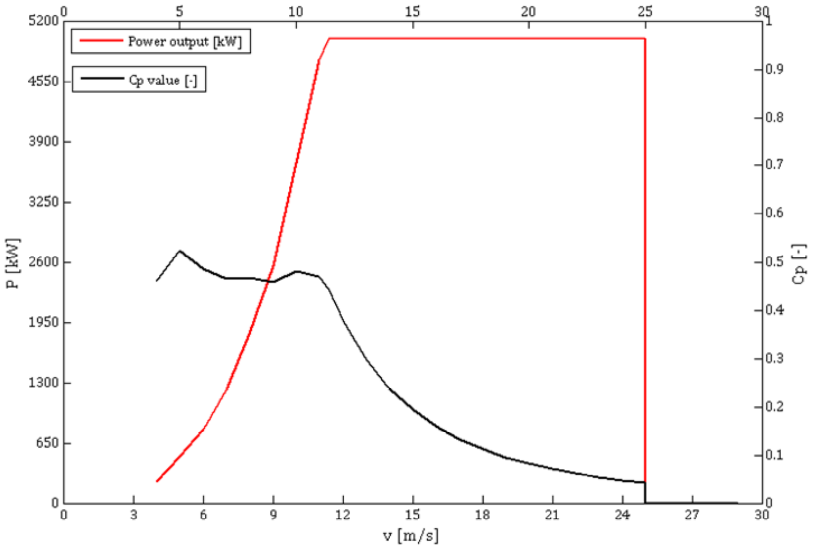

Fig. 68: Power curve for the 2MW turbine.

The maximum efficiency is 0.44 which is reached when the wind speed is 8m/s. According to Betz Law the maximum theoretical efficiency possible is 0.59 but this is not physically possible [Risø, 2002].

The power curve for a turbine with an arbitrary machine rating is calculated by multiplying the percentage of the machine rating in tab. 22 with the new machine rating. The power curve for a 20MW turbine with a rotor diameter is equal to 252m is shown in fig. 69.

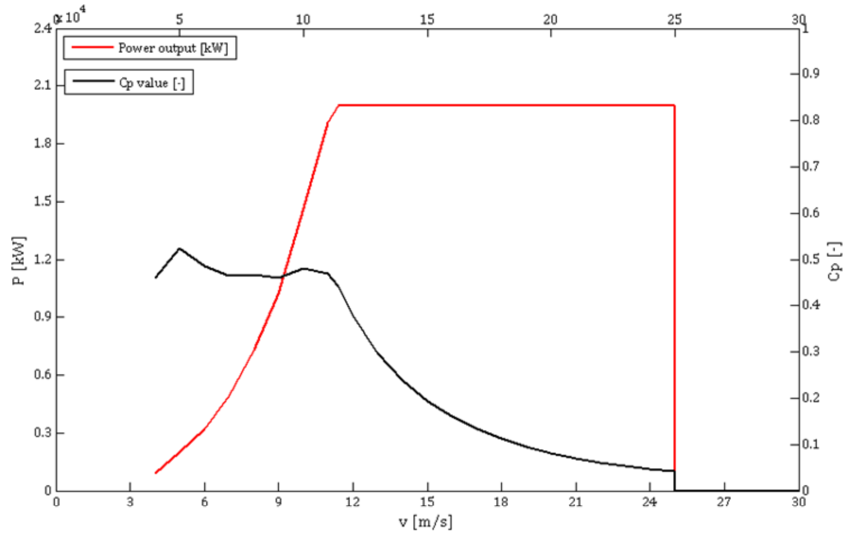

Fig. 69: Power curve for the 20MW turbine.

The average energy production is calculated, multiplying the frequency at each wind speed found by the Weibull distribution function with the power output at the corresponding wind speed. The frequency can be calculated as shown in appendix A. This is expressed in (B.3) when the cut-in speed is 4m/s and the cut-out speed is 25m/s. The energy production is calculated in (ENERGIP.for).

$$EP_{average} = \int_0^\infty \left(P(v) \cdot f(v) \right) dv = \sum_{i=4}^{25} P(v_i) \cdot f(v_i) \tag{B.3}$$

To find the annual energy production (B.4) is used.

$$AEP = EP_{average} \cdot 24 \cdot 365 \cdot C_{avail} \tag{B.4}$$

where

$EP_{average}$ is the average energy production throughout the year [kWh]

C_{avail} is the availability which is set to 0.98. Cf. chapter 5 this is a high availability but this is neglected. [-]

In tab. 23 the calculated annual energy production for five different turbines has been shown. The Weibull scale parameter A increases due to the power law explained in appendix A.

Tab. 23: Annual energy production for four different turbines.

	5MW	10MW	15MW	20MW
Machine rating, MR [kW]	5000	10000	15000	20000
Rotor diameter, D [m]	126	178	218	252
Hub height, H [m]	90	116	136	153
A-value [m/s]	11.1	11.4	11.6	11.7
k-value [-]	2.26	2.26	2.26	2.26
AEP [GWh]	25.0	51.0	77.8	106.3

As mentioned the values in tab. 22 does not take the wake effect into account. This is done in the next section.

B.2 Wind farm

When the wind turbines are placed in a wind farm, up-scaling the wind turbines do not affect the area of the wind turbine sight when the rated power of wind farm is constant. This is illustrated in fig. 70.

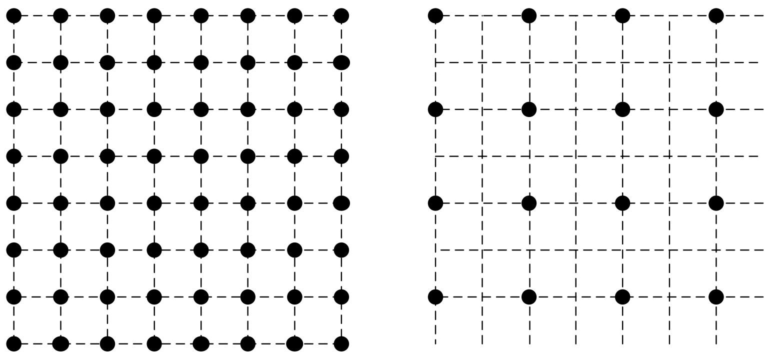

Fig. 70: Wind turbines placed in a wind farm grid equal to 8 x 8. (Left) wind turbines with a rotor diameter equal to D. (Right) wind turbines with a rotor diameter equal to 2D.

The machine rating and the power production is increased squarely increasing the rotor diameter and the same goes for the area occupied by the turbine. However, it is mentioned above that the wake effect has to be taken into account when wind turbines are placed in a wind farm. In general the wake effect is a name for the disturbance in the wind field made by a wind turbine. The turbines which are on the leeside of the first turbines in a wind farm are therefore affected by the wake.

The wake effect influences the mean wind speed, the length scale, and the turbulence. In general the mean wind speed is reduced since the turbine reduces the energy in the wind. In [Frandsen, 2007] the wake effect in the wind farm Nørrekær Enge II with 42 300kW turbines is examined. The results concerning the wind speed and standard deviation can be seen in fig. 71. The reduction in wind speed is clearly dependent on both the height above ground and the wind speed in the undisturbed field. The largest reduction in wind speed is at hub height and therefore this value is used to reduce the energy production calculated in (B.3). According to appendix A the frequency function is largest at wind speeds between 3m/s and 15m/s. Fig. 71 shows that in this area the reduction can be considered constant.

A computer model is also used to predict the influence of the wake effect. The results are shown to the right in fig. 71. The computer model predicts higher values of the standard deviation and lower values of the wind speed. It is assumed in the computer model that the wind turbine farm is infinitely large and this might explain the difference. It is expected that the down- and upwind will be constant inside an infinitely large farm since the wind is not only affected by the turbine immediately upwind but also many of the other turbines [Frandsen, 2007].

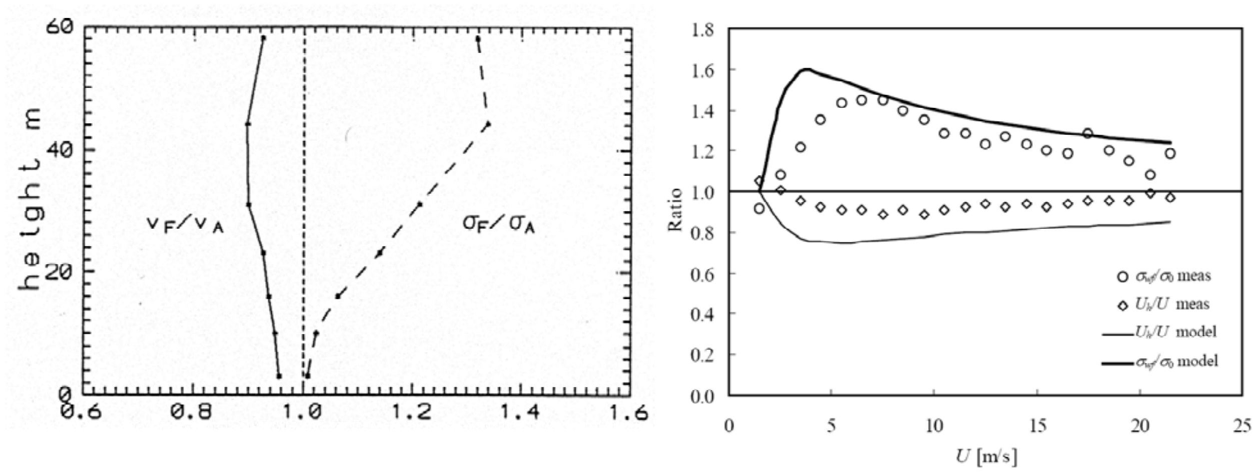

Fig. 71: (Left) Test results concerning the change in wind speed and standard deviation due to wake as a function of the height. (Right) Test results concerning the change in wind speed and standard deviation due to wake as a function of the ambient wind speed. The wind speed is measured 31m above the ground while the standard deviation is measured 58m above ground level [Frandsen, 2007].

When the energy production is calculated, the wind speed will be reduced by 12%. This is not enough compared to the computer model assuming an infinitely large farm. However, the energy production of the first up-wind turbines is also reduced and it is therefore assumed reasonable. It has to be stated that the guidelines concerning wake in the IEC-standard is not used. In tab. 24 the new Weibull parameters are written together with the reduced annual energy production.

Tab. 24: Annual energy production when the wind speed is reduced due to the wake effect.

	5MW	10MW	15MW	20MW
A-value [m/s]	10.7	11.0	11.2	11.4
k-value [-]	2.26	2.26	2.26	2.26
$AEP_{reduced}$ [GWh]	24.0	49.5	75.7	102.5
Reduction [%]	4.0	3.9	3.7	3.6

It can be seen in fig. 71 that standard deviation above hub height increases more than the wind speed is reduced. The increased standard deviation and decreased mean wind speed increases the turbulence intensity and the load significantly. In fig. 72 the change in turbulence intensity between rows of turbines are shown. The row separation is 6D and the turbulence is modelled numerically. The illustration shows the importance of having a sufficient distance between the turbines to avoid very extreme loads. In this project the distance between the turbines are set to 7D since the turbulence intensity is almost constant after this distance.

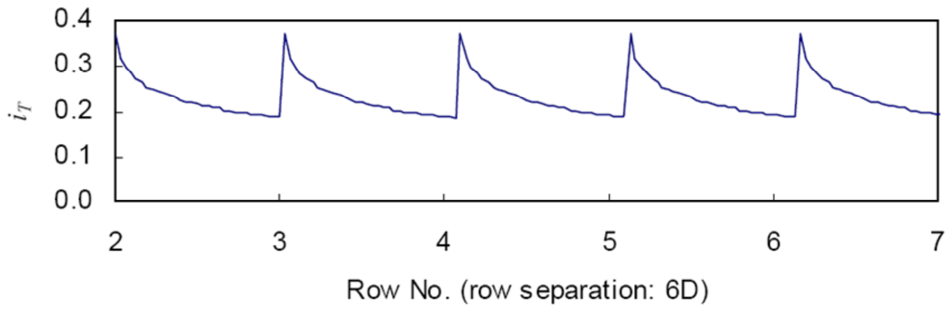

Fig. 72: Change in turbulence intensity between rows of turbines. The undisturbed turbulence intensity is 0.1 [Frandsen, 2007].

The scale of turbulence, which is the dominating size of the turbulence eddies, is also decreased due to the wake effect. In many cases the size of the vortexes is reduced by 1/2 to 1/5 depending on the distance from the wind turbine [Frandsen, 2007]. This is also concluded in [Sørensen et al., 2008] where it is shown that the scale length is reduced to 25-30% of the ambient level one rotor diameter downwind. Large eddies might act simultaneously over a whole rotor while smaller eddies act locally but possibly at lower frequencies close to the structural eigenfrequencies. This might cause resonance and therefore it is important to take into account [Sørensen et al., 2008].

According to [Sørensen et al., 2008] the gust factor k_p is not increased significantly during wake conditions. However, at heights greater than 60-80m the normally used gust factor should be reduced. The normal gust factor is approximately 3.0. This is not taken into account in this thesis.

In [Cockerill et al, 2000] it is also shown that the energy yield per turbine in a wind farm is lower than for a single standing turbine. If a single standing turbine is index 100, the energy yield of a turbine in a wind farm is found equal to index 89. Opposite, the fatigue blade root flapwise moment is increased to index 121.

C. Similarity rules when up-scaling

The following appendix introduce some of the similarity rules when up-scaling a wind turbine. Firstly, the fundamentals of wind turbine scaling are reviewed and afterwards some of the wind turbine components are examined. The similarity rules are primarily used to predict the component mass when up-scaling the wind turbine. When the technology is not changed, the component cost is generally proportional to the component mass. The appendix is based on [Jamieson, 2007a] and [Chaviaropoulos, 2006].

C.1 Fundamentals

Tip speed

The tip speed has to be constant when using similarity rules to up-scale a wind turbine. If the tip speed is changed the relationship between rotor speed and wind speed is changed. However, is has to be mentioned that the Reynolds number increases with increasing wind turbine size but the influence is negligible for large megawatt turbines. The rotor angular frequency ω is decreased linearly when up-scaling due to the maintained tip speed and the increased rotor diameter D.

Aerodynamic moment scaling

The aerodynamic moments of a wind turbine blade about any axis are scaled cubically changing D. The moments are calculated dividing the surface area of the blades into sufficiently small areas and multiply with the local wind pressure and moment arm. The resulting moment is finally calculated by summarising the constituents. The wind pressure is independent of the scale while the surface area maintaining the design scale with D^2 and the moment arm scale with D. Hence the aerodynamic moment scale with D^3.

Bending section modulus scaling

The bending section modulus W for a beam such as the wind turbine blade is a product of the width and the thickness squared. If the proportions of the wind turbine blade are maintained, W hereby changes cubically with D. The bending stresses are calculated dividing the moment with W. Therefore, when both the moment and bending section modulus scales cubically the stress is constant when up-scaling.

Tension section scaling

During operation of the wind turbine the blade sections are usually under tension due to the centrifugal force caused by the blade rotation. The centrifugal force is a product of the mass M, ω^2, and the rotor radius R. M scales cubically with the diameter, ω scales inversely, and R scales linearly giving that the centrifugal force scales with the diameter squared. The section stress is calculated by diving with the section area which obviously scales with D^2. Hereby the stress due to the centrifugal force is constant when up-scaling.

Self weight load scaling

The moment due to the self weight of the wind turbine blade is a product of the blade mass and the moment arm. Hereby the moment scales with D^4 and therefore, if the moments caused by the self weight are design drivers, the mass of the wind turbine blade scales with more than D^3. The surface geometry might be maintained in these circumstances but the bearing internal structure has to be changed.

Scale effect

Considering fracture mechanics the "size effect" has to be taken into account when up-scaling. For larger samples of a given material the possibility of a critical flaw is increased. The flaw might be a small crack which due to fatigue loading will increase and finally become critical to the structure. To take the size effect into account the design stress has to be lowered giving that the mass scale more than cubically.

Wind shear and turbulence

The earth boundary layer causes a strong gradient in the wind speed v affecting the wind turbine. The boundary layer is associated with surface roughness and air viscosity and the gradient is called wind shear. The increased wind speed when increasing the height is described by the power law (C.1).

$$v = v_{ref} \left(\frac{H}{H_{ref}} \right)^{\alpha} \tag{C.1}$$

The height of the wind turbine increases when up-scaling which, according to (C.1), increases the wind speed. This affects e.g. the aerodynamic moment scaling. The moment is a function of the wind speed squared giving that the aerodynamic moment scale is equal to $D^{3+2\alpha}$ instead of D^3. Hereby, the mass of the blade also scale more than D^3.

The increased wind speed also causes that the power output increases more than the increase in rotor area. The power production is proportional to v^3R^2 giving that the power production scales with $D^{2+3\alpha}$.

Loads due to wind turbulence are often design drivers for the wind turbines. An important parameter concerning wind turbulence is the turbulence length scale giving the dominating size of the turbulence eddies. The length scale is comparable to the rotor size of a large wind turbine and therefore the load variation across the rotor disc is increased significantly when up-scaling. This increases the dynamic loads which have to be taken into account when up-scaling.

C.2 Components

The following outlines how the mass of the main technical components are increased when up-scaling the wind turbine.

Rotor blades

The rotor blades are cantilever beams which design is driven mainly by the aerodynamic bending moments explained in the previous section. As mentioned the stresses caused by the aerodynamic bending moments are constant when up-scaling as long the design is maintained. Hereby, the section area increases with D^2 and the blade length with D giving that the blade mass increase with D^3.

Hub

The hub size and mass will also scale cubically if the aerodynamic loads are the main design drivers. However, up-scaling the wind turbine the fatigue loading due to blade weight will become the main design driver at some point. As mentioned in the previous section the loading due to weight will scale with D^4 giving that the hub mass will increase with more than D^3.

Shaft

The shaft is mainly affected by bending moments due to aerodynamic tilt, yaw moments, and weight of the rotor. The weight of the rotor is a sum of the blade and hub mass which vary with D^3. If the design is maintained the shaft length and hereby the moment arm scales linearly giving that the moment due to weight scale with D^4. The aerodynamic tilt and yaw moments increase with D^3. As for the blades the bending moduli vary with D^3 giving that the stress is constant when up-scaling if the aerodynamic tilt and yaw moments are the design drivers. Hereby the size and weight scale with D^3. If the moment due to the rotor weight is dominating the weight will increase with more than D^3.

Gearbox

The primary purpose of the gearbox is to provide gear ratio so the generator shaft speed is maintained at a sufficient level to produce power. If the generator speed shaft ω_{gen} is maintained the overall gearing ratio have to be increased since the angular frequency ω is reduced when up-scaling. This gives the need for larger gears or additional stages in the gearbox. Since the gearbox torque varies with D^3 the size and weight of the gearbox components vary with D^3 if ω is held constant. Combining the structural aspect and the need for a higher gear ratio it is concluded that the weight of the gear must vary with more than D^3.

Generator

For a conventional gearbox drive train where the output speed of the gearbox is maintained the generator mass scale with D^2. However, as stated above the size of the gearbox increases significantly when up-scaling and alternatively a direct drive generator can be chosen. However, this increases the generator size which instead will increase cubically with the rotor diameter.

Support structure

The support structure is divided into three parts; the tower, the transition piece, and the foundation. The tower can again be considered as a cantilever beam giving that the bending modulus scale with D^3. The wind load again scales with approximately D^3 giving that the weight of the tower scale with approximately D^3. As for the hub the fatigue loads might be the design driving loads which have to be taken into account.

The cross section area of the transition piece is expected to scale with D^2 but the length of the transition piece depends on the water depth and not the rotor diameter. Therefore, the weight of the transition piece scales with D^2.

The foundation length under mud line, foundation radius, and wall thickness all scale with D and therefore the weight of the foundation scale with D^3.

Electrical systems

Concerning the cost, other electrical systems than the generator approximately scale with the wind turbine power output. As mentioned the power output scale with D^2 or if the wind shear is taken into account $D^{2+3\alpha}$. It is reasonable that α is set to 0.11 giving that the electrical systems scale with D^2 to $D^{2.33}$.

D.Component masses

The following shows the component masses when up-scaling. The reference masses are found using [Fingersh et al., 2006] and if nothing else is mentioned the scaling exponents is equal to the scaling exponent used in chapter 2 where the cost is found. The unit for the masses M is ton when the diameter D is inserted in meters.

$$M_{Blades}(D,T) = 53 \cdot \left(\frac{D}{126}\right)^{2.35} \tag{D.1}$$

If the model in [Fingersh et al., 2006] is used to estimate the hub mass, the reference mass would be equal to 23ton. However, a Nordex wind turbine with a rotor diameter equal to 80m has a mass equal to approximately 22ton and therefore this value does not seem realistic [Jamieson, 2007a]. A reference mass equal to 40ton is therefore assumed.

$$M_{Hub}(D,T) = 40 \cdot \left(\frac{D}{126}\right)^{3.02} \tag{D.2}$$

$$M_{pitch}(D,T) = 10 \cdot \left(\frac{D}{126}\right)^{2.66} \tag{D.3}$$

$$M_{shaft}(D,T) = 17 \cdot \left(\frac{D}{126}\right)^{2.8} \tag{D.4}$$

$$M_{Bearing}(D,T) = 2.7 \cdot \left(\frac{D}{126}\right)^{2.5} \tag{D.5}$$

The results in [Hemmelmann, 2009] are used to estimate the gearbox mass and generator mass. The scaling exponents concerning the masses are also found.

$$M_{gearbox}(D,T) = 56 \cdot \left(\frac{D}{126}\right)^{2.96} \tag{D.6}$$

$$M_{generator}(D,T) = 17 \cdot \left(\frac{D}{126}\right)^{2.0} \tag{D.7}$$

$$M_{yaw}(D,T) = 13 \cdot \left(\frac{D}{126}\right)^{2.96} \tag{D.8}$$

$$M_{frame}(D,T) = 34 \cdot \left(\frac{D}{126}\right)^{1.95} \tag{D.9}$$

The reference mass if the electronics and hydraulic system is found by [Hemmelmann, 2009] where the converter mass is equal to 15ton for a 5000kW turbine. It is assumed that the hydraulic system gives a contribution equal to 1000kg. The results in [Hemmelmann, 2009] also confirm that the scaling exponent can be set equal to 2.00.

$$M_{elec}(D,T) = 16 \cdot \left(\frac{D}{126}\right)^{2.00} \tag{D.10}$$

The mass of the control system is assumed equal to be equal to 10000kg.

$$M_{control}(D,T) = 10 \cdot \left(\frac{D}{126}\right)^{0} \tag{D.11}$$

$$M_{tower}(D,T) = 150 \cdot \left(\frac{D}{126}\right)^{3.16} + 99 \cdot \left(\frac{D}{126}\right)^{2.63} \tag{D.12}$$

$$M_{foundation}(D,T) = 137 \cdot \left(\frac{D}{126}\right)^{3.07} \tag{D.13}$$

The mass of the connection is assumed. It is not expected that the whole connect to shore is damaged at the same time and therefore only a minor part of the connection has to be replaced.

$$M_{connection}(D,T) = 1.0 \cdot \left(\frac{D}{126}\right)^{2.0} \tag{D.14}$$

In tab. 1 the component masses is shown when the wind turbine is up-scaled.

Tab. 25: Mass of the wind turbine components which might have to be repaired.

	Weight - 126m [ton]	Weight - 178m [ton]	Weight - 218m [ton]	Weight - 252m [ton]
Rotor blades	53	119	192	270
Rotor hub	40	114	209	324
Rotor bearings and pitch mechanism	10	26	44	65
Main shaft	17	47	87	134
Main bearings	3	6	11	15
Gearbox	56	156	284	436
Generator	17	34	51	68
Yaw	13	37	67	103
Main frame and nacelle housing	34	67	100	133
Electronics and hydraulic system	16	32	48	64
Control system	1	1	1	1
Tower top mass	260	639	1093	1613
Tower top mass [Jamieson, 2007a]	*264*	*526*	*709*	*1054*
Tower	249	693	1267	1954
Foundation	137	396	737	1150
Connection	1.0	2.0	3.0	4.0

In [Jamieson, 2007a] the tower top mass of several wind turbines is plotted as a function of the rotor diameter. The data is fitted to a function which makes it possible to estimate the tower top mass of larger wind turbines. The results obtained by [Jamieson, 2007a] are also plotted in tab. 25 and it can be seen that the tower top mass at a rotor diameter equal to 126m is almost similar. However, the exponent is only equal to 1.998 in [Jamieson, 2007a] and therefore the results diverge at larger rotor diameters. The exponent equal to 1.998 seems very small and it is therefore assumed that the model concerning the top tower mass in [Jamieson, 2007a] is imprecise for large wind turbines.

E. Description of gearbox O&M cost model

This appendix describes the program made in order to calculate the O&M costs for a single component in one wind turbine. It is a generic model and the input parameters have to be adjusted in order to give reliable results. Firstly, condition monitoring is not taken into account. The maintenance strategy can therefore be characterized as scheduled or corrective if it is chosen to leave out the inspection and service visits. However, the model can be used to show how the O&M costs can be calculated, taking the whole wind turbine lifetime into account. It is also possible to examine the many parameters influencing the O&M cost, downtime, and availability.

The model is implemented in a Fortran code and it is divided into a main program which also consists of subroutines calculating damage accumulation, cost due to a given event, and so forth. In the following the main program will firstly be described. The initial input parameters are also given. Afterwards the important subroutines will be described and the input values will be written.

E.1 Main program – MAIN.FOR

The main program consists of a few input parameters so many of the input parameters are changed in the various sub-routines. In fig. 73 the five input parameters which have to be decided in the main program is written. Initially the input parameters are as follows:

- Wind turbine data: D=126m
P=5MW
H_{hub}=90m
Tip speed=80m/s
Component mass: 56ton – which according to appendix D is the gearbox mass when D=126m.
- Wind turbine lifetime: 240 months – or 20 years
- Number of simulations: *Varied in the analysis*
- Operation start month: Month 4 – corresponding to April
- Inspection: *Varied in the analysis*
- Inspection and service: *Varied in the analysis*
- Type of damage accumulation: Exponential or linear
- Distance to port 38km
- Rate of interest: 6 pct.

Concerning the inspection and service plan it is assumed that an inspection can be made without making service of the wind turbine but it is not possible to make service without inspecting the wind turbine. A service visit is more expensive than an inspection but there is also a larger opportunity to find a possible fault. Initially, a service visit does not affect the damage accumulation.

In the first model there can be chosen between a linear and an exponential damage accumulation. This is explained further in chapter 4.

In fig. 73 it can be seen that the main program consists of an outer loop and a while loop. The description is simplified and it is only the main components of the program which are shown. The first loop repeats the calculations a number of times in order make sure that the result is converged. Before the while loop the output values are reset and after the while loop the output values are summarized. It is hereby possible to find the cost, downtime, and availability by dividing the summarized values with the number of simulations.

In tab. 26 the stochastic variables which are modelled in the O&M program is written. It is also shown in which subroutines the variable/output is simulated.

Tab. 26: Stochastic variables in the O&M model.

Variable	Symbol	Distribution	Location	Note
Power price	C_{kWh}	N	PRICE.FOR	
Linear accumulation	ΔD_i	W	DAMAGEACCUMULATION.FOR	Linear damage model
Initial crack length	a_I	W	DAMAGEACCUMULATION.FOR	Exponential damage model
Initial crack growth period	T_I	W	DAMAGEACCUMULATION.FOR	Exponential damage model
Crack growth coefficient	C	LN	DAMAGEACCUMULATION.FOR	Exponential damage model
Cyclic stress range	ΔS	W	DAMAGEACCUMULATION.FOR	Exponential damage model
Damage detection (Yes/no)	-	*POD-curve*	COMPONENTPOD.FOR	
Damage reduction due to a service visit	χ	N	SERVICE.FOR	
Spare part cost	C_{spare}	N	COMPONENTREPAIR.FOR	
Spare part availability	A_{spare}	N	COMPONENTREPAIR.FOR	
Spare part mass	M_{spare}	-	EQUIPMENTNEEDED.FOR	Model: See section 0
Vessels needed	-	-	EQUIPMENTNEEDED.FOR	Model: See section 0
Equipment availability	A_{equip}	N	EQUIPMENT.FOR	

The lifetime of the wind turbine is simulated by the while loop which is shown in fig. 73. The time step is equal to one month. There are several steps in the while loop and these are explained briefly. The steps which are marked with a box are subroutines and will all be explained more thoroughly in the following sections.

The first step is to estimate the power price which is a realisation of a stochastic process. The power price varies both daily and for each month. Therefore, for each month an average value of the power price is found using a normal distribution function. The loss in energy yield is influenced by the power price and it is therefore also assumed that the realised stochastic ariable represents the mean value of the power price the period where the wind turbine is out of operation.

The damage accumulation during the month is afterwards found by a subroutine and the damage level is afterwards updated. If the damage level is above 1.0, failure occurs and the repair cost is calculated. The repair cost and time is recorded and the damage level is reset. Hereby it is assumed that the repair is perfect. It is assumed that failure occurs the first day in the month and dependent on the repair time there might be a number of days in the month left where the wind turbine is repaired and put back to service. Only one failure is possible each month. Before the new time step, the damage level is therefore again updated to take the missing days into account.

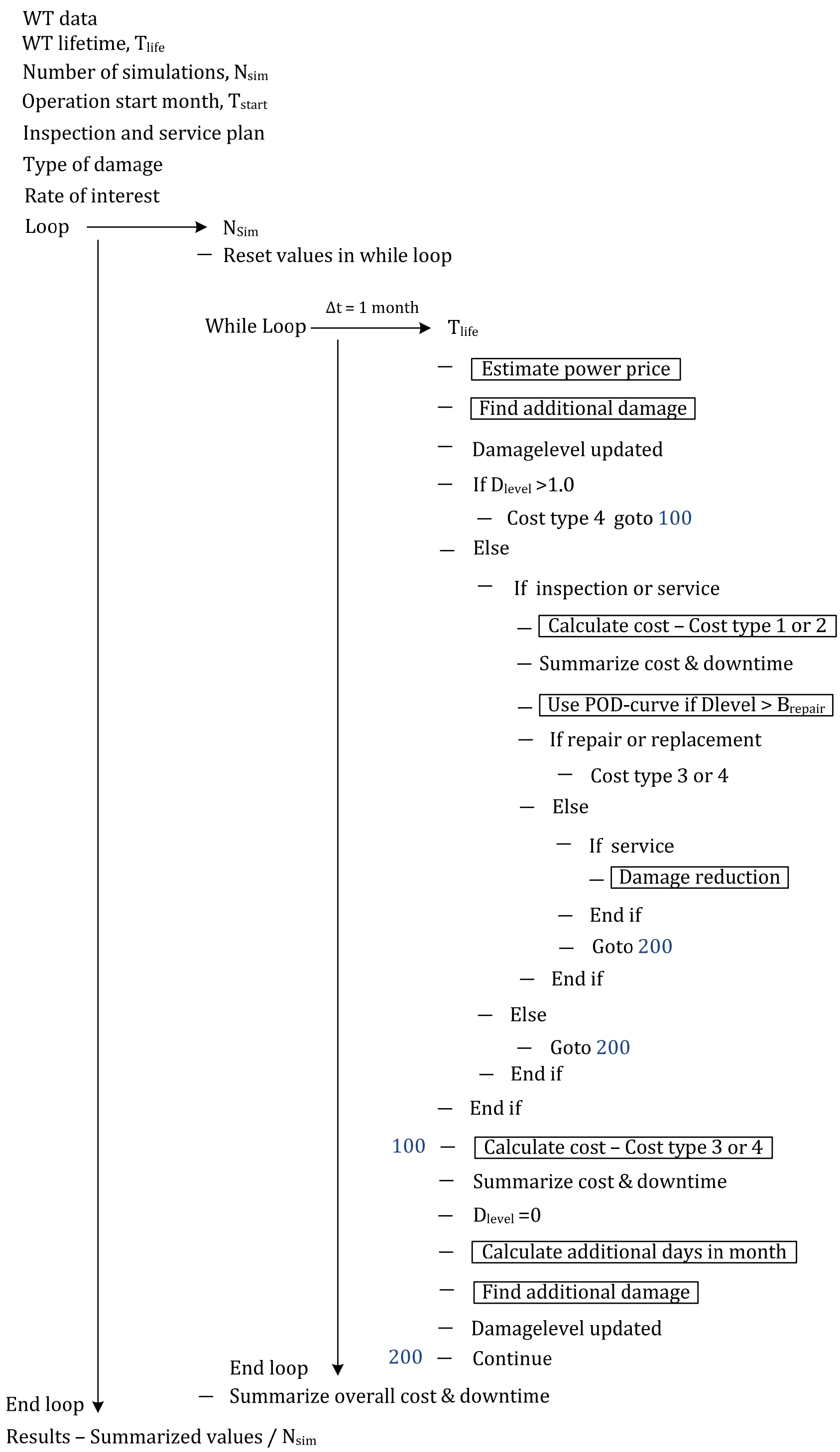

Fig. 73: Generalized structure of the main program of the O&M cost model. The steps, which are marked with boxes, are sub-routines.

If the damage level is under 1.0 after it has been updated, it is examined if there is an inspection or a service visit the relevant month. If not, the time will be updated and the procedure repeated. If there is an inspection or a service visit the probability of detection of damage is taken into account by using POD-curves (Probability of detection curves). However, firstly the costs concerning the inspection or service visit is recorded. If the damage is detected and is above the critical levels described in chapter 3, the component will either be repaired or changed. All costs are calculated by the same subroutine but it is dependent on the cost type which cf. chapter 3 is one of the following:

- Cost type 1 Inspection cost
- Cost type 2 Service and inspection cost
- Cost type 3 Repair cost
- Cost type 4 Replacement cost

For both repair and replacement of the component, the damage level is set to zero afterwards. If the component is repaired, it is assumed that the component can be repaired on site which, compared to if it has to be replaced, lowers the cost. During a service visit it is assumed that some sub-components are replaced. The service visit is also more thorough than an inspection and therefore the damage level is reduced even though the component is not repaired or replaced.

In the following sections the subroutines in fig. 73 will be described more extensively in order to show the input parameters, calculation methods, and assumptions.

E.2 Estimation of power price – PRICE.FOR

The program is used to generate a value for the mean price of energy C_{kWh} during a month which is a stochastic variable. Studies concerning the energy sales price have not been made before for this model was made. It is assumed that a normal distribution can be used. The expected value and the standard deviation are initially set to N(μ,σ)=N(0.125€/kWh , 0.03€/kWh). The normal distribution function is shown in (E.1).

$$F_X(x) = \Phi\left(\frac{x-\mu}{\sigma}\right) \quad \text{(E.1)}$$

To find the price of energy, a random number $\hat{F}$ uniformly distributed between 0 and 1 is simulated and the price is found by (E.2). The price is independent from month to month which is not likely in reality. However, this is neglected.

$$C_{kWh} = x = \Phi^{-1}\left(\hat{F}\right)\cdot\sigma + \mu \quad \text{(E.2)}$$

In the complete O&M model for the whole wind turbine the mean power price and standard deviation are lowered to 0.05€/kWh and 0.012€/kWh. This is due an examination of the power price from May 2008 to May 2009. The examination is based on data from Nordpool which is the Nordic Power Exchange. The high power price in the initial model influences the cost due to loss in energy yield but it does not affect the overall conclusions concerning the importance of the different input parameters.

E.3 Additional damage – COMPONENTACCUMULATION.FOR

This subroutine is made in order to find the updated damage level after a given time step. The damage accumulated is cf. chapter 4 either found by a linear model or an exponential model. The exponential model is based on the theory behind crack propagation. The theory is explained in chapter 4.

E.4 POD-curve – COMPONENTPOD.FOR

Making an inspection or a service visit, the possibility of finding a possible failure has to be evaluated. It is obvious that the probability of detection increases when the damage level increases. The POD-curve can be modelled by (E,3), see e.g. [Rangel-Ramirez et al., 2008].

$$POD(x) = P_0 \cdot \left(1 - \exp\left(-x / \lambda\right)\right) \qquad \text{(E.3)}$$

where

x	is the damage level or crack size [-]
P_0	is the maximum probability of detection [-]
λ	is the distribution parameter depending on the inspection method [-]

In fig. 74 five different POD-curves are made by changing the parameters P_0 and λ.

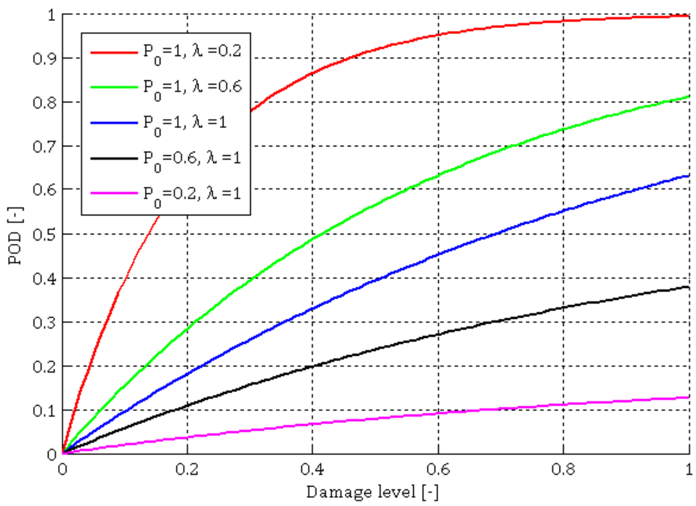

Fig. 74: Different POD-curves.

At a service visit some subcomponents are replaced giving an extra possibility of detecting damage in other subcomponents while also the same inspections are made as for the inspections. Therefore, the POD-curves are modelled to give a higher POD-value at a service visit than an inspection. Initially the following values have been chosen.

- Inspection: P_0 =0.9 and λ = 0.6
- Service and inspection: P_0 =0.9 and λ = 0.5

It is expected that some internal errors are impossible to see and therefore the maximum damage level which is possible to detect is equal to 0.9. The service visits are more thorough than the inspections and therefore the λ-value is smallest for the service visits. This gives a higher probability of detection.

After the POD-value has been calculated in the program, a random number between 0 and 1 is simulated. If the random value is below the POD-value the damage level is recognised. The damage levels where repair or replacement of the component has to be made is also defined in this subroutine and if the recognised damage level is above the repair barrier the component either have to be repaired or replaced. The result is the output of the program. Initially the repair and replacement barriers are set to the following.

- Repair barrier D_1=0.4
- Replacement barrier D_2=0.9

It is assumed that the wind turbine is shut down immediately if the component has to be replaced. Opposite if the component has to be repaired, it is assumed that the wind turbine can continue until the repair team is organized.

E.5 Damage reduction – SERVICE.FOR

It seems logical that the damage reduction during service is dependent on the current damage level of the component. If the damage level is very low it is not possible to reduce the damage level significantly while the opposite goes for a relatively high damage level. In this model it is assumed that the damage level is reduced with a certain percentage of the damage level. Hereby it is not possible to reset the damage level but this also seems logical looking at e.g. a gearbox. If some expensive and internal sub-components are damaged it is not probable or maybe possible to change these sub-components and the damage level will therefore not be reset even though other sub-components are replaced.

The damage reduction of the component depends on if the damaged subcomponents are among the components which are replaced during the service visit. This might vary from service visit to service visit. Therefore, the damage reduction χ is modelled as a stochastic variable. The updated damage level is calculated by (E.4).

$$D_{level,updated} = \chi \cdot D_{level} \tag{E.4}$$

χ is assumed to be truncated normal distributed and initially the mean value is set to 0.6 and the standard deviation is set to 0.2. The maximum value of χ is one meaning that the service visit cannot affect the damage level of the component negatively.

E.6 Calculate cost – COMPONENTREPAIR.FOR

This subroutine calculates the cost of a given event and it is the most complex subroutine since it consists of five other subroutines. Each of the subsections however is explained thoroughly in this section. The input parameters from the main program tell if the subroutine has to estimate an inspection cost, service cost, repair cost, or cost due to an operation stop. The cost is influenced on the time of year and the simulated price of power. As described in chapter 3 the cost is divided into four constituents; crew cost, equipment cost, spare part cost, and loss in energy yield.

If the wind turbine is stopped due to failure of a component, the component either have to be repaired or replaced in order to put the wind turbine back to service. The probability that the component only have to be repaired P_{repair} is initially set to 95%. However, there is a difference between the repair costs dependent on if the repair is decided after an inspection or service or if the repair is caused by an unscheduled operation stop. It is assumed that the damage is worse, and therefore also the spare part cost is higher, after an operation stop. However, if the component has to be repaired after an inspection or service visit it is assumed that the wind turbine is stopped 60% of the times. Therefore, the availability of the spare parts and equipment can be important for both unscheduled operation stops and repairs due to an inspection or service visits. Initially, some values influencing the cost are determined. These values are shown in tab. 27.

Tab. 27: Input parameters in the cost of repair model. The availability of spare parts after a scheduled inspection only has an influence on the costs if the wind turbine has to be repaired and if it is immediately stopped.

	Distribution	Inspection	Service visit	Repair - Scheduled	Repair - Unscheduled	Replacement
Spare part cost [€]	N	μ=1000 COV=0.1	μ =30000 COV =0.17	μ =20000 COV =0.15	μ =120000 COV =0.25	μ =562000 COV =0.09
Spare part availability [Days]	N	0	0	μ =3 COV =0.17	μ =5 COV =0.4	μ =18 COV =0.4
Repair crews needed [-]	D	1	2	1	2	2
Repair time [Hours]	D	6	14	8	22	50

The covariance is small for the inspections and service visits since it is assumed that the spare parts needed for the two operations are known in advance. It is assumed that some smaller spare parts, lubricates, and so forth are changed during a service visit and therefore the spare part cost is relatively high for a service visit. Concerning scheduled repair it is assumed that the repair actions are relatively similar since the same things are examined during an inspection or service visit. This leads to a low covariance. Opposite the covariance is high for the unscheduled repair where both failure of small and large subcomponents and serial failure might have occurred. Concerning the replacement of the gearbox it is assumed that the spare part cost is relatively fixed but either way the covariance value is set to 0.09 since the cost is affected by the currency, the material prices, etc. Since a gearbox is an expensive part of the wind turbine, it is assumed that a gearbox is not in stock and therefore the number of days to purchase this spare part is relatively high.

As explained several subroutines are used in this subroutine and it is therefore rather complex. However, the following shows the main structure of the subroutine.

1. Input parameters are defined.
2. **Subroutine EQUIPMENTNEEDED.FOR**: Used to find the vessels which have to be used.

3. **Subroutine EQUIPMENT.FOR:** Used to define the daily cost of equipment and to find the mission time which defines the required weather window. It is assumed that the repair cannot be made in two stages and the waiting time can therefore be substantial.
4. **Subroutine WAITINGTIME.FOR:** Data from Horns Rev I is used to find the waiting time before the mission can be started.
5. The waiting time in hours and days is calculated. Initially, the wind turbine is still in operation when no components have to be replaced. Therefore, the organisation time and the waiting time for a satisfying weather window do not influence the cost of repair. However, if replacement is needed it has a strong influence on the cost. It is assumed that the vessels are waiting in the nearby harbour when they are ready and organised. The cost of equipment is therefore highly influenced on the waiting time.
6. **Subroutine COSTYIELD.FOR:** Finds the cost due to lost energy production.
7. **Subroutine CREWCOST.FOR:** Finds the crew cost per day.
8. The cost of equipment is calculated multiplying the price per day with the sum of the waiting time, the travel time, and the repair time, and finally the start cost is added. It is assumed that the inspections and services can be planned to the waiting time is equal to zero.
9. The crew cost is found.
10. **Subroutine ROUNDDAY.FOR:** Finds the day where the wind turbine is back to service.
11. Downtime and costs are transferred to the main program.

Concerning inspection and service visits it is taken into account that if more than one turbine can be inspected the costs concerning equipment and crew is divided into the number of turbines which are examined the relevant day. When scheduled repairs are made it is also assumed that other turbines can be repaired or inspected and therefore the equipment and crew cost is also reduced in these occasions.

In the following the subroutines mentioned above are described further.

EQUIPMENTNEEDED.FOR

The mass of the spare parts and the time of year are used to find the equipment needed for the given event. It is assumed that the spare part mass can be found by a model where the mass of the mass of the spare part depends on the component mass. It is assumed that the probability that the spare part mass is very low compared to the component mass is high and therefore an exponent is used on the random number to model this effect. The model used to calculate the is shown in (E.5).

$$M_{sparepart} = Rand^{\alpha} \cdot M_{component} \tag{E.5}$$

where

Rand is a realisation of a random number uniformly distributed between 0 and 1

With a component mass equal to 56ton the exceedance probability concerning the spare part mass is shown in fig. 75. Two plots are shown; one where the exponent is equal to six and one where the exponent is equal to twelwe. As expected a higher exponent gives a lower exceedance probability. The probability that the spare part mass is larger than 1000kg is equal to 28.5% and 48.9% for an exponent equal to twelve and six, respectively.

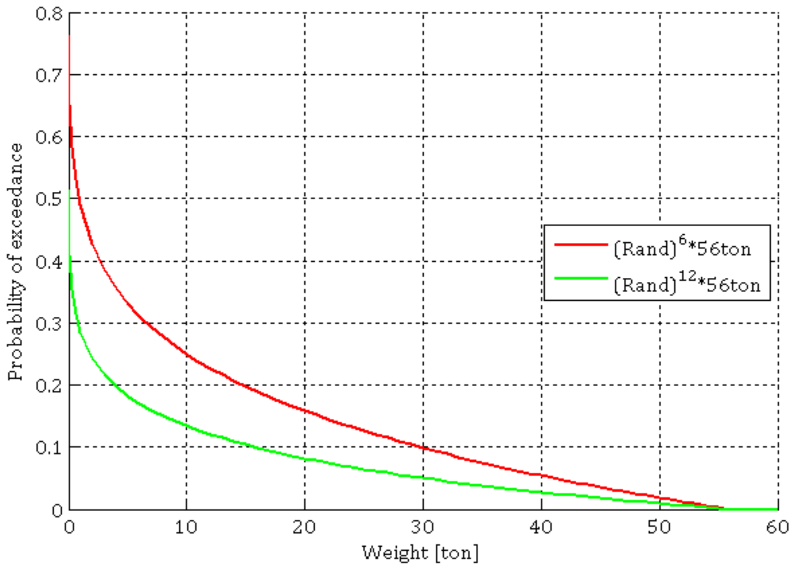

Fig. 75: Exceedance probability due to the exponent on the random variable used to find the weight of the spare parts. One million simulations have been made.

It is assumed that the spare part mass is higher for an unscheduled repair than for a scheduled. The exponent is therefore set to six for the unscheduled repair while it is set to twelve for the scheduled repair. For the inspection and service visit it is assumed that the spare part mass is deterministic. The spare part mass for an inspection and a service visit is set to 100kg and 500kg respectively. If the component has to be replaced the spare part weight is set equal to the component mass corresponding to α=0.

As mentioned the spare part mass is used to find the vessels needed for the given operation. It can be seen in tab. 29 that there are three types of vessels to choose between; a helicopter, a boat, and a jack-up with towing boats. The loading capacity is also written in the table. In tab. 8 the probability of needing a given vessel due to the time of year and the spare part mass is shown.

Tab. 28: Probability that a given vessel is needed due to the spare part mass and the time of year.

		Winter	Spring	Summer	Autumn
M_{spare} < 1.0ton	Helicopter	0.5	0.15	0.05	0.3
	Boat	0.5	0.85	0.95	0.7
	Jack-up	0.0	0.0	0.0	0.0
1.0ton < M_{spare} < 25.0ton	Helicopter	0.0	0.0	0.0	0.0
	Boat	0.95	0.95	0.95	0.95
	Jack-up	0.05	0.05	0.05	0.05
25.0ton < M_{spare} < 100.0ton	Helicopter	0.4	0.2	0.1	0.4
	Boat	0.2	0.4	0.5	0.2
	Jack-up	1.0	1.0	1.0	1.0

If a boat is used, it is assumed that the crane inside the wind turbine can be used to hoist the spare part while it is assumed that the jack-up has a crane with a satisfying lifting height.

It can be seen in tab. 8 that either a boat or a helicopter is used if the spare part mass is below 1000kg. The probability of using one of the two types is season dependent. During the winter and autumn the probability of using a helicopter is higher than during the summer since the wind and wave climate is rougher. The limits concerning maximum wind and wave height can be seen in tab. 29.

Since the loading capacity of the helicopter is set to 1000kg, it is not possible to use the helicopter if the spare part mass is larger. If the spare part mass is higher than 1000kg and lower than 25000kg, which is the loading capacity for the boat, it is assumed that there is an 95% probability that a boat is used while there is a probability equal to 5% that a jack-up has to be used.

If the spare part mass is larger than 25000kg a jack-up has to be used independently of the time of year. It is furthermore assumed that there is a 60% probability that a boat or a helicopter also have to be used. Again during the autumn and winter the probability that a helicopter has to be used is the largest.

EQUIPMENT.FOR

This subroutine is mainly used to calculate the mission time and to define the cost of equipment. In tab. 29 the data defined in the subroutine is shown.

Tab. 29: Input parameters concerning equipment. *1 The helicopter price is equal to the start price plus an amount per kilometre used.

	Helicopter	Boat	Jack-up
Distance from port/landing pat [km]	200	38	38
Start cost [€]	10,000	8,000	150,000
Daily cost [€/day]	500*1 [€/km]	8,000	150,000
Length of workday T_{day} [hours/day]	24	24	24
Speed [kmh]	200	30	10
Loading capacity [ton]	1	25	100
Availability [days]	N(1,0.3)	N(5,1)	N(21,7)
H_{max} [m]	-	1.2	1.0
V_{max} [m/s]	15	14	10

Firstly, the effective repair time is calculated. The travel time T_{travel} is obtained using the values in tab. 29 and afterwards the effective repair time $T_{repair,effective}$ for a day is calculated using (E.6).

$$T_{repair,effective} = T_{day} - 2 \cdot T_{travel} \tag{E.6}$$

However, if T_{day} is equal to 24 hours, the effective repair time will be set to 24hours. It is expected that the helicopter pilot returns when the repair crew has been dropped off on the wind turbine. Therefore, the cost is equal to a start cost plus the travel distance which is twice the distance from the landing pat to the wind turbine.

The number of days to complete the inspection, service, repair, or replacement is afterwards calculated by dividing the repair time needed by the effective repair time. The equipment costs are found on a daily basis and therefore the number of days which are started is used to calculate the cost.

The output of the program is the initial cost of equipment, the equipment cost per day, the mission time, the maximum wind and wave height, and the travel time.

WAITINGTIME.FOR

In this program the waiting time is calculated based on the maximum wave height, maximum wind speed, and the mission time. The method is explained in appendix A.

COSTYIELD.FOR

When the downtime in each season is calculated, the loss in energy yield is found. In appendix B it is explained how the annual energy production is calculated. The loss in energy yield is found using the same principals. The Weibull parameters for each season is found in appendix A and for each season the mean energy production for one hour is calculated. The loss in energy yield is found by multiplying with the downtime for each season, summarize the values, and finally multiply with the price per kWh which is found in the main program.

CREWCOST.FOR

Initially the number of workmen in a crew is set to three persons and the wage is set to 25€/hour. The crew cost per day is found by multiplying the number of needed crews, the number of workmen in a crew, the hourly wage, and the length of a workday.

ROUNDDAY.FOR

The only function of this subroutine is to find the day where the wind turbine is repaired and started once again.

E.7 Calculate additional days – RESTACCUMULATION.FOR

In this subroutine the number of days left in the relevant month is found. The number is used to calculate the damage accumulation when the wind turbine is started again and until a new month is going to begin.

F. Description of wind turbine O&M cost model

This appendix describes the input parameters defined in order to calculate the O&M costs for the 5MW reference wind turbine. Cf. chapter 5 the program is also used to estimate the O&M cost when up-scaling the wind turbine. The assumptions made in order to make the program are written in chapter 5.

As explained in chapter 5 the input parameters are fitted in order to achieve certain values concerning annual failure frequency, downtime per failure, percentage share of costs, and total expected O&M cost. The values are found by literature studies in order to get a reliable cost model and they can be seen in chapter 5. Some input parameters are found by other reliable sources - e.g. the power prize which is found by analysing data from Nord pool ASA. A combination of having these reliable input parameters and also reliable output data helps to give a reliable cost model.

In the following the input parameters will be listed and some will be described further. Firstly, the general input parameters are listed and afterwards the input parameters which are individual for the 14 components are listed.

F.1 General input parameters

In tab. 30 are given the input parameters concerning power price, inspection and service cost, and crew cost. The mean value and the covariance for the power price are found by analysing data from Nordpool. The analysed data is the market price for power during a period from May 2008 to May 2009.

As for the O&M model for the gearbox some spare parts are changed during a service visit and the spare part cost is therefore significantly higher for a service visit compared to an inspection. Also, sometimes it might not be necessary to change a given sub-component during a service visit and therefore the covariance is also higher. This is also the reason why the repair time/inspection time is significantly lower for the inspection than for a service visit. For a service visit the equipment is needed more than one day since the repair time is higher than 24hours. This increases the cost significantly since the equipment cost is per day. This can also be seen in tab. 32.

Tab. 30: Input parameters concerning power price, inspection and service visits, and crews. SP – spare parts.

	Distribution	Mean Value	COV	Note
Power price	N	0.5€/kWh	0.24	Data from Nordpool
Crew – Workmen	D	2	-	
Crew – Hourly wage	D	15€/hour	-	
Inspection – SP cost	N	500€	0.1	
Inspection – SP availability	D	0days	-	
Inspection – repair time	D	8hours	-	
Inspection – SP weight	D	100kg	-	
Inspection – crews needed	D	1	-	
Service – SP cost	N	20000€	0.14	
Service – SP availability	D	0days	-	
Service– repair time	D	25hours	-	
Service – SP weight	D	500kg	-	
Service – crews needed	D	1	-	

In tab. 31 the probability that a given vessel is needed for transport due to the spare part mass and the time of year is given. Compared to the O&M model for the gearbox, it is not possible to use a helicopter.

Tab. 31: Probability that a given vessel is needed due to the spare part mass and the time of year.

		Winter	Spring	Summer	Autumn
M_{spare} < 1.0ton	Boat	1.0	1.0	1.0	1.0
	Jack-up	0.0	0.0	0.0	0.0
1.0ton < M_{spare} < 25.0ton	Boat	0.98	0.98	0.98	0.98
	Jack-up	0.02	0.02	0.02	0.02
25.0ton < M_{spare} < 100.0ton	Boat	0.3	0.3	0.3	0.3
	Jack-up	1.0	1.0	1.0	1.0

In tab. 32 the input parameters concerning the equipment are given. It is difficult to get a jack-up vessel instead of a small boat and therefore concerning the availability the covariance is higher for a jack-up than a small boat. It can also be seen that the length of the workday is set to 24 hours. This has a large influence on the waiting time since more days might be needed if the length of the workday was e.g. 8 hours. Hereby, the mission time would be much longer. However, this assumption is maintained since the workday should be 24hours when the cost of equipment and loss in energy yield is so high compared to the crew cost. The crew cost will probably be a bit higher since the crews are changed two to three times during one day giving that they need extra payment for transport.

Tab. 32: Input parameters concerning equipment.

	Boat	Jack-up
Distance from port/landing pat [km]	38	38
Start cost [€]	4000	50,000
Daily cost [€/day]	2000	100,000
Length of workday T_{day} [hours/day]	24	24
Speed [kmh]	30	10
Loading capacity [ton]	25	100
Availability	N(μ=3.0 days, COV=0.1)	N(μ=21days, COV=0.19)
H_{max} [m]	1.2	1.0
V_{max} [m/s]	14	10

The method to calculate the waiting time is explained in appendix A but it has to be mentioned that the large standard deviation is not taken into account in the first O&M model. The yield cost is calculated as explained in appendix E.

F.2 Component specific input parameters

In this section the individual input parameters for the 14 technical components are given. The input parameters are shown in the following order.

- Linear damage accumulation (6 components)
- Exponential damage accumulation (8 components)
- Inspection and service parameters (Barriers, POD, Damage reduction χ)
- Repair cost parameters

In tab. 33 the components, which are assumed to have a linear damage accumulation, are shown. The theory concerning the linear damage accumulation is described in chapter 4. In general, it can be seen that the damage accumulation is highest during the winter and lowest during the summer. Together with the values concerning inspections and service visits the size of the damage accumulation is chosen in order to get a specific output concerning the annual failure rate when an inspection is made in Marts and an inspection is made in August. The annual failure rate can be seen in chapter 5.

Again in tab. 33 most of the values concerning the monthly damage accumulation are Rayleigh distributed since in many cases the load is correlated with the wind load.

Tab. 33: Weibull parameters used to simulate the monthly damage accumulation ΔD. k is the shape parameters while A is the scale parameter.

	Winter		Spring		Summer		Autumn	
	k [-]	A [-]	k [-]	A [-]	k [-]	A [-]	k [-]	A [-]
Gearbox	2.0	0.045	2.0	0.025	2.0	0.025	2.0	0.040
Generator	2.0	0.050	2.0	0.025	2.0	0.025	2.0	0.042
Yaw	2.0	0.060	2.0	0.040	2.0	0.040	2.0	0.060
Electrical system and hydraulics	2.0	0.150	2.0	0.120	2.0	0.120	2.0	0.150
Control system	2.0	0.085	2.0	0.065	2.0	0.055	2.0	0.085
Electrical Connection	1.5	0.021	2.0	0.017	2.0	0.017	1.5	0.021

The eight other components, which can be seen in tab. 34, are assumed described by an exponential damage accumulation. The theory concerning the exponential damage accumulation is described in chapter E and it can be seen that several input parameters are needed for the exponential damage accumulation. However, for all the eight components the geometry factor β is assumed to be equal to one and the number of load cycles per minute is set equal to 12.1. The explanation is written in chapter 4.

In tab. 34 and in tab. 35 the values concerning the critical crack length, initial crack length, initiation period, crack growth coefficient, and crack growth exponent is given. Again it is stated that the values are only used to describe the damage accumulation and other types of damage such as wear and corrosion are also assumed to be included. However, based on the fatigue theory some general considerations are made concerning the values in the tables in order to make a realistic model. These are as follows.

- It is assumed that the blades which are made of mainly glass and carbon fibres have a higher crack growth coefficient which gives a higher risk concerning fatigue. However, the critical crack length is assumed longer than for the steel casting and steel elements.
- The tower and the foundation are extremely expensive elements where failure will destroy the whole turbine. It is therefore assumed that the elements are designed so low cyclic stress ranges occur.
- The covariance is higher for blade material than steel due to the uncertainties in the manufacturing process.
- The loads are higher during the winter and autumn period than during the spring and summer period.

Tab. 34: Input parameters used to simulate the monthly damage accumulation for the exponential damage model.

	A_c - Deterministic		a_0 - Rayleigh		T_0 - Rayleigh		C-Lognormal		m- Deterministic	
	μ [mm]	COV [-]	k [-]	A [mm]	k [-]	A [Month]	μ [-]	COV [-]	μ [-]	COV [-]
Blades	20	-	2.0	2.0	2.0	12	$5 \cdot 10^{-11}$	0.1	2.35	-
Hub	10	-	2.0	2.0	2.0	12	$2 \cdot 10^{-11}$	0.05	2.35	-
Rotor bearings	10	-	2.0	2.0	2.0	10	$2 \cdot 10^{-11}$	0.05	2.50	-
Shaft	10	-	2.0	1.0	2.0	13	$2 \cdot 10^{-11}$	0.05	2.65	-
Main bearings	10	-	2.0	1.0	2.0	35	$3 \cdot 10^{-11}$	0.07	2.35	-
Main frame	10	-	2.0	2.0	2.0	30	$3 \cdot 10^{-11}$	0.07	2.30	-
Tower	10	-	2.0	2.5	2.0	5	$3 \cdot 10^{-11}$	0.07	2.95	
Foundation	10	-	2.0	2.0	2.0	5	$3 \cdot 10^{-11}$	0.07	2.85	

Tab. 35: Cyclic stress ranges used to simulate the monthly damage accumulation for the exponential damage model. All the parameters are assumed Weibull distributed.

	Δs_{winter}		Δs_{spring}		Δs_{summer}		Δs_{autumn}	
	k [-]	A [MPa]	k [-]	A [MPa]	k [-]	A [MPa]	k [-]	A [MPa]
Blades	1.5	28	2.0	20	2.0	16	1.5	24
Hub	1.5	33	2.0	23	2.0	20	1.5	30
Rotor bearings	1.5	32	2.0	20	2.0	18	1.5	27
Shaft	1.5	16	2.0	10	2.0	9	1.5	13
Main bearings	1.5	32	2.0	20	2.0	18	1.5	27
Main frame	1.5	32	2.0	20	2.0	18	1.5	27
Tower	1.5	8	2.0	5	2.0	4	1.5	7
Foundation	1.5	8	2.0	5	2.0	4	1.5	7

In tab. 14 the values concerning the repair barriers and the values used to calculate the probability of detection is shown. The theory concerning the values is described in appendix E. The 14 technical components are divided into the following three categories:

Maintenance category 1: A component where it is relatively easy to detect an error but where it is difficult to lower the damage level by changing some subcomponents during a service visit. This is typically a structural component.

Maintenance category 2: A component where there is a medium possible to detect an error dependent on what type of error which is about to occur. Dependent on the type of damage there is medium possibility to lower the damage level by changing some subcomponents during a service visit. This is typically a structural component with significant electrical subcomponents, e.g. the rotor bearings with the pitch mechanism and the yaw.

Maintenance category 3: A component where, due to e.g. the complexity of the component or the access level, it is relatively difficult to detect an error. However, it is expected that this is taken into account when designing the wind turbine and making the strategy concerning the service visits. Therefore, the possibility of reducing the damage level at a service visit is large. The electrical and hydraulic system, the gearbox, and the generator are typical components in this category.

The component maintenance categories are written in tab. 14.

Tab. 36: Repair barriers and parameters used to estimate the probability of detection. The damage reduction at a service visit, which is normal distributed, is also given. The maintenance categories are mentioned with (x) after the component name.

	Barriers		Inspection		Service		Damage reduction X	
	B_1[-]	B_2 [-]	P_0 [-]	λ [-]	P_0 [-]	λ [-]	μ [-]	COV [-]
Blades (1)	0.4	0.9	1.0	0.3	1.0	0.3	0.8	0.11
Hub (1)	0.4	0.9	1.0	0.3	1.0	0.3	0.8	0.11
Rotor bearings (2)	0.3	0.9	0.7	0.5	0.8	0.5	0.5	0.4
Shaft (1)	0.4	0.9	1.0	0.3	1.0	0.3	0.8	0.11
Main bearings (1)	0.4	0.9	1.0	0.3	1.0	0.3	0.8	0.11
Gearbox (3)	0.3	0.9	0.6	1.0	0.8	0.5	0.5	0.4
Generator (3)	0.3	0.9	0.6	1.0	0.8	0.5	0.5	0.4
Yaw (2)	0.3	0.9	0.7	0.5	0.8	0.5	0.5	0.4
Main frame (1)	0.4	0.9	1.0	0.3	1.0	0.3	0.8	0.11
Electrical system and hydraulics (3)	0.3	0.9	0.6	1.0	0.6	1.0	0.5	0.4
Control system (3)	0.3	0.9	0.6	1.0	0.6	1.0	0.5	0.4
Tower (1)	0.4	0.9	1.0	0.3	1.0	0.3	0.8	0.11
Foundation (2)	0.3	0.9	0.7	0.5	0.8	0.5	1.0	0
Connection (3)	0.3	0.9	0.6	1.0	0.8	0.5	1.0	0

In chapter 4 it is found that the parameters which determines the POD is extremely important when estimating the expected O&M cost and finding the optimal inspection and service plan. Therefore, if useful data from the industry could validate the values in tab. 14, this would be an important validation of the O&M model. However, the following considerations are made when determining the values in tab. 14.

- The repair barrier is lowered for the category 2 and category 3 components since it is difficult to detect an error.
- By adjusting P_0 and λ the POD at an inspection and service visit is adjusted to correspond to the maintenance strategy.
- At a service visit many subcomponents are changed for the category 2 and category 3 components. This gives a higher probability of detecting a damaged subcomponent. However, it is still assumed that possible errors concerning the electrical systems are difficult to detect. The category 1 components are unaffected concerning the POD since a very limited number of subcomponents is changed.
- The covariance concerning the damage reduction is high for the category 3 components since the damage reduction is dependent on if it is the damaged components, which are changed.
- No subcomponents are changed for the foundation and the connection. Therefore, the damage reduction is equal to 1 and the POD is not dependent on if an inspection or a service visit is made.

In tab. 37 the possibility of repair if the damage level reaches 1.0 – unscheduled repair - is written. The alternative is a complete replacement of the component. The possibility that the wind turbine is stopped after an inspection or service visit if repair is needed is also given. It can be seen that it is assumed unlikely that the mainframe, tower, and foundation are replaced.

Tab. 37: Possibility of repair instead of replacement when a component is broken down P_{rep}. The possibility of the wind turbine is stopped if scheduled repair is needed is also given.

	P_{rep} [-] Unscheduled repair	P_{stop} [-] Scheduled repair
Blades	0.95	0.20
Hub	0.99	0.05
Rotor bearings	0.97	0.20
Shaft	0.99	0.05
Main bearings	0.99	0.05
Gearbox	0.97	0.20
Generator	0.97	0.20
Yaw	0.99	0.05
Main frame	0.99	0.05
Electrical system and hydraulics	0.99	0.05
Control system	0.99	0.05
Tower	1.0	0.05
Foundation	1.0	0.05
Connection	1.0	0

The following considerations concerning the values in tab. 37 have been made:

- Due to the material it is difficult to repair the blade and therefore the probability that a blade can be repaired is relatively low. It is shown in chapter 4 that this has a large influence on the result and therefore this parameter is important to verify.
- Due to the complicity of the pitch mechanism, the gearbox, and the generator it is assumed that the probability that the components need to be replaced at an unscheduled repair is relatively high. Therefore, the probability of stopping the wind turbine, if the respective components need to be repaired after an inspection or service visit, is also relatively high.
- It is assumed that the electrical system and the hydraulics can be replaced. It is of course not possible to change the whole electrical system and therefore a replacement is defined as a significant repair action where e.g. one of the electrical cabinets has to be changed.

In tab. 38 the repair time and the crews needed for scheduled repair, unscheduled repair, and replacement of the component are given. For these input parameters and the input parameters in the following tables it is assumed that there is a significant difference in how much the component is damage dependent on if the damage level has reached 1.0 or if the component is repaired before it reaches 1.0.

Tab. 38: Crews needed for the three repair events. The repair time is also given.

	Crews needed [-]			Repair time [Hours]		
	Scheduled repair	Unscheduled repair	Replacement	Scheduled repair	Unscheduled repair	Replacement
Blades	1	1	2	6	14	24
Hub	1	1	2	4	10	30
Rotor bearings	1	1	1	6	14	20
Shaft	1	1	1	4	10	24
Main bearings	1	1	2	4	10	30
Gearbox	1	1	2	10	24	40
Generator	1	1	2	10	22	40
Yaw	1	1	2	4	12	40
Main frame	1	1	2	4	10	20
Electrical system	1	1	1	6	10	12
Control system	1	1	1	6	10	16
Tower	1	1	-	4	10	-
Foundation	1	1	-	4	10	-
Connection	1	1	-	8	15	-

In tab. 38 it can be seen that concerning the repair time there is a significant difference between scheduled repair, unscheduled repair, and replacement of the component. One of the major differences between the scheduled repair and the unscheduled repair is the fact that the damaged subcomponent is already located for scheduled repair while the component has to be located for unscheduled repair.

In tab. 39 the input parameters for the spare part cost are given. The replacement cost is set equal to the reference cost of the components which are found in chapter 2.

Tab. 39: Spare part cost for the 14 technical components. A normal distribution is used. *1 Only 10 % of the reference cost found in chapter 2 is used.

	Scheduled repair		Unscheduled repair		Replacement	
	μ [€]	COV [-]	μ [€]	COV [-]	μ [k€]	COV [-]
Blades	3000	0.17	10000	0.20	729	0.1
Hub	500	0.10	2500	0.15	141	0.1
Rotor bearings	5000	0.20	10000	0.25	202	0.1
Shaft	500	0.10	2500	0.15	128	0.1
Main bearings	500	0.10	2500	0.15	105	0.1
Gearbox	20000	0.25	50000	0.30	562	0.1
Generator	20000	0.25	50000	0.30	260	0.1
Yaw	5000	0.20	20000	0.25	126	0.1
Main frame	2000	0.10	5000	0.15	206	0.1
Electrical system	1500	0.20	10000	0.25	72.1*1	0.1
Control system	1500	0.20	10000	0.25	57	0.1
Tower	500	0.10	2500	0.15	-	-
Foundation	500	0.10	2500	0.15	-	-
Connection	5000	0.10	30000	0.15	-	-

Concerning the values in tab. 39 the following considerations and assumptions are made.

- The spare part cost for unscheduled repair is considerable larger than for scheduled repair.
- The covariance for electrical systems, hydraulic systems, and partly electrical systems is higher than for structural components. This is due to the assumption that for electrical systems and hydraulic systems subcomponents might be changed during repair. Opposite the structural components are often repaired on site without changing any subcomponents. The number of subcomponents is also lower for the structural elements.
- The covariance for unscheduled repair is higher than for scheduled repair. This is due to the fact that serial failure might have occurred damaging other subcomponents.
- The covariance is relatively low concerning replacement of the components since the price might be fixed if sub suppliers manufacturer the components. However, in these cases the currency might affect the cost. If the wind turbine manufacturer makes the spare part itself the material price, the inflation, and the general fabrication uncertainties affects the cost. This however is not assumed to justify a larger covariance.
- Concerning scheduled and unscheduled repair it is assumed that in many cases the structural components only needs a small repair – e.g. a welding which needs to be repaired. Therefore, the spare part cost is low.
- Concerning the mainframe the internal crane and the nacelle housing are also included. Therefore this structural component varies a little from the others.
- As mentioned it is assumed that the electrical and hydraulic system and the electrical connection are not fully replaced if replacement is needed. Therefore, only 10% of the reference cost in chapter 2 is used concerning replacement cost for these two components.

In tab. 40 the input parameters concerning the spare part availability is written.

Tab. 40: Spare part availability for the 14 technical components. A normal distribution is used.

	Scheduled repair		Unscheduled repair		Replacement	
	μ [Days]	COV [-]	μ [Days]	COV [-]	μ [Days]	COV [-]
Blades	3	0.10	5	0.15	15	0.2
Hub	2	0.10	4	0.15	18	0.2
Rotor bearings	3	0.15	4	0.20	20	0.2
Shaft	2	0.10	4	0.15	14	0.2
Main bearings	2	0.10	4	0.15	14	0.2
Gearbox	3	0.15	5	0.20	24	0.2
Generator	3	0.15	5	0.20	22	0.2
Yaw	2	0.15	3	0.20	10	0.2
Main frame	3	0.10	5	0.15	14	0.2
Electrical system	2	0.15	2	0.20	5	0.2
Control system	2	0.15	2	0.20	5	0.2
Tower	2	0.10	3	0.15	-	-
Foundation	2	0.10	3	0.15	-	-
Connection	3	0.10	7	0.15	-	-

Concerning the values in tab. 40 the following considerations and assumptions are made.

- The spare part availability of the electrical components and the hydraulic system and the partly electrical components are highest since in more cases new subcomponents are needed.
- The covariance is highest for unscheduled repair since serial failure might have occurred.
- If replacement is needed and the component is in stock the organisation time concerning the spare parts is relatively low. However, it might take a long time to purchase the component if it is not in stock. Therefore, the covariance is set relatively high when the component has to be replaced.

In tab. 41 the input parameters concerning the spare part mass is shown. The spare part mass does not affect the cost directly but it has an influence on the type of boat which has to be used. In tab. 31 it can be seen that the interesting parameters are the probability that the spare part mass is higher than 1ton and that the spare part mass is higher than 25ton. In appendix E it is shown how the spare part mass is found. The reference mass is found in appendix D and the exponent α is fitted so the probability of exceedance of the respective mass has reasonable value. The reference mass, the exponent, and the resulting probability of exceeding a spare part mass higher than 1ton and 25ton is written in tab. 41 for both scheduled and unscheduled repair.

Tab. 41: Input parameters used to determine the type of equipment which is needed.

		Scheduled repair			Unscheduled repair		
	M_{ref} [ton]	α	P(M_{spare}>1ton)	P(M_{spare}>25ton)	α	P(M_{spare}>1ton)	P(M_{spare}>25ton)
Blades	53	30	0.12	0.02	20	0.18	0.04
Hub	40	22	0.16	0.02	12	0.31	0.05
Rotor bearings	10	8	0.25	0	6	0.44	0
Shaft	17	22	0.13	0	6	0.38	0
Main bearings	3	10	0.10	0	6	0.17	0
Gearbox	56	20	0.18	0.04	10	0.33	0.08
Generator	17	15	0.17	0	10	0.25	0
Yaw	13	15	0.16	0	10	0.22	0
Main frame	34	30	0.11	0.01	20	0.16	0.01
Electrical system	16	40	0.06	0	20	0.13	0
Control system	10	30	0.07	0	20	0.11	0
Tower	249	70	0.08	0.03	40	0.13	0.06
Foundation	137	50	0.10	0.04	20	0.15	0.06
Connection	1	12	0	0	6	0	0

In chapter 4 it is concluded that the probability of needing a Jack-up - P(M_{spare}>25ton) – has a large influence on the O&M cost. It is therefore not satisfying that the above values are estimated without any documentation except for the reference mass. It is not possible to get the information from the industry and therefore the values cannot be validated. However, the following considerations have been made in order to get some reliable values.

- The spare part mass is highest for unscheduled repair
- The exponent α is equal to 0 if the component has to be replaced. The spare part mass is hereby equal to the reference mass.
- It is assumed that most spare parts, with a mass higher than 1ton, are necessary for the rotor bearings and pitch mechanism, the gearbox, the generator, and the yaw. It is also assumed that the spare part weight for the electrical and hydraulic system is relatively low.

- If more than one component needs repair, the spare part mass is summarised.
- In tab. 31 it can be seen that if the spare part mass it between 1ton and 25ton there is a probability equal to 2% that a jack-up is needed. This probability is the same for all components which is not realistic. The internal crane might not hoist the spare parts for the rotor bearings and pitch mechanism. In these cases the nose cone might also has to be uninstalled in order to install the new spare parts. This however, is neglected.