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Lightning Damage of OWECS

Part 1: “Parameters Relevant for Cost Modelling”

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1. INTRODUCTION

1.1 Background

Lightning is a phenomenon that has often caused severe damage to wind turbines. Direct hits may cause for instance structural failure of the blades, whereas indirect hits, e.g. through the electrical infrastructure in the wind farm, may cause damage to vulnerable parts like the controller.

For onshore turbines, a lot of knowledge has been gained on the effects of lightning. The knowledge has been gained by analysing field experience and by R&D activities. Based on this, recommendations and practical guidelines have been developed on how to prevent the turbines from severe damage due to lightning strikes, e.g. [1] and [2]. In [1], a method is presented to determine the risk of lightning for wind turbines. The risk is expressed as the product of the number of lightning strikes times the consequence damage. The consequence damage is partly determined by the lightning protection method for the various components [1]. A method to compare the extra investments for lightning protection with the reduced consequence damage is given in [1].

Statistics on damage due to lightning strikes are given in e.g. [1] and [3]. Some major conclusions presented in [3] are given below.

- In total 914 lightning damages have been reported over 11,364 operational years, which corresponds to 8 incidents per 100 turbine years[1].
- Approximately 25% was reported as a direct lightning strike.
- The 914 lightning damages represent approximately 4% of the total number of reported damages.
- The average downtime per damage is approximately 30 hours.
- The rotor blades seem to be the most vulnerable components. They show the highest frequency, the highest repair costs (approximately € 20.000,-- per incident for turbines above 450 kW), and the longest downtime (approximately 10 days per incident).
- As compared to smaller turbines, the larger and newer turbines show fewer failures in the control system. This suggests that the lightning protection of control systems has improved in recent years.

Presently, plans are being developed in Europe to develop large offshore wind farms. It is to be expected that damage due to lightning may influence the cost effectiveness of such wind farms to a large extent for the following reasons.

1. Costs for repairing lightning damage are higher offshore than onshore, because more expensive transportation equipment (supply vessels or helicopters) and cranes are needed.
2. The downtime for certain damage events and thus the revenue losses will be higher because repair can only be carried out if the weather conditions are suitable for the equipment.

Before developing an offshore wind farm, it is necessary to gain insight in the effects of lightning on the operational costs. To calculate the costs due to lightning damage one has to deal with inherent variability and with statistical uncertainty in the input variables. Inherent variability is a result of the physical process and it can not be reduced; examples are the wind speed, the wave height, the number of lightning flashes during a thunderstorm and the type and amount of damage due a lightning strike. Statistical uncertainty is caused by lack of knowledge about the parameters, and sometimes it can be reduced through further measurements or study, or through consulting more experts. The total uncertainty, which is a combination of inherent variability and statistical uncertainty, results in uncertainty in the calculated results, in this case the total costs. For financiers and insurance companies these uncertainties are considered as a financial risks, which is a complicating factor for financing offshore wind projects.

[1] Danish and Swedish databases report 3.9 and 5.8 incidents per 100 turbine years [1].

Quantification of the expected uncertainties facilitates the judgement of this risk and is therefore of great importance.

Recently, one of the two offshore turbines in Blyth Harbour has failed. According to the press release [11], a lightning strike was the failure cause. As expected, the repair costs and downtime are high and difficult to estimate. (See Fig. 1.1.)

Fig. 1.1: *Blade failure of an offshore wind turbine in Blyth Harbour (UK) due to a lightning strike [11,12]*

Aspects that contribute to the cost of lightning damage and which are covered with uncertainties are among others the following:
1. The frequency of thunderstorms and lightning flashes at an offshore location.
2. The amount of damage resulting from a lightning strike (which is strongly dependent on the lightning protection of the turbine) and the material costs.
3. The actions needed to repair the damage, including costs for personnel and hiring transportation and lifting equipment.
4. The downtime and revenue losses due to time needed for mobilisation of necessary equipment and time waiting for good weather conditions.

1.2 The Project: "Cost Modelling of Lightning Damage for Offshore Wind Farms"

In order to obtain a better understanding of the costs resulting from lightning damages, ECN has defined the project "Cost Modelling of Lightning Damage for Offshore Wind Farms". The objectives of this project are threefold:

1. Data Collection

Above, four aspects have been mentioned that contribute to the costs of lightning damage and which are covered with (large) uncertainty or variability.

Parameters with inherent variability, are for instance the frequency of thunderstorms per year, the frequency of lightning flashes per thunderstorm, the current value per lightning flash, the wind speed and the wave height. Such parameters all have their own natural scatter: the number of thunderstorms differs from year to year. This variation can be described by means of statistical distribution functions, for instance a Weibull distribution for the wind speed distribution or a Poisson distribution for the number of thunderstorms in a year. These distribution functions are characterised by one or two statistical parameters. The Weibull distribution has two parameters: the shape parameter and the scale parameter. In order to quantify these statistical parameters, it is necessary to perform measurements over a certain period of time and the longer the measurement period, the more accurate they can be determined including the variability. If desired the variability in the statistical parameters can be dealt with by considering these parameters as stochastic quantities.

Furthermore one has to deal with parameters which are uncertain due to lack of knowledge, for instance the costs of equipment and the availability of equipment. Two types of uncertainty can be distinguished.

1. In case data is derived from generic databases or other generic sources a large amount of scatter might be expected, because information originating from different situations is combined. However, quite often no specific data is available and it is inevitable to use generic data, for instance the types of damage caused by lightning that might be expected.
2. The cost model is mainly applicable for offshore wind farms. However, at the moment only limited or no experience is present with maintaining offshore wind turbines. This implies that experts from the onshore wind industry and experts from offshore maintenance companies have to be consulted. For instance the availability and the costs of equipment are strongly dependent on the contracts. The costs will be different if e.g. a supplier is hired for one day or for a longer period. The costs can be derived from investigating the current market prices and by estimating the upper and lower day rates. However, different experts have different opinions and consequently the estimates are covered with uncertainty. Characteristic for this type of uncertainty is that it can be reduced through feed back of operational experience.

The first objective of this project is to make an inventory of all relevant variables that contribute to the costs and to parameterise them. Not only the most likely values have been determined but if necessary also the scatter and the distribution function. The present report describes the parameterisation of the relevant variables, a.o.:

- annual frequency of thunderstorms and lightning flashes for offshore locations;
- expected damage distribution due to lightning;
- wind and wave statistics to determine the accessibility of repair equipment and for calculating the revenue losses;
- costs and weather windows for repair equipment, e.g. supply vessels, helicopters and jack-ups;
- costs of labour and of components and materials to repair lightning damages;
- investment costs for lightning protection systems.

2. Development of Probabilistic Cost Model

The scatter and uncertainty of most variables will lead to scatter in the annual costs for lightning damage and the annual downtime. To evaluate the effect of lightning damage on the annual costs and downtime it is necessary to use a probabilistic model. The second objective of the project is to develop such a model. The model has been implemented in MS Excel with the add-in module @Risk [4] to perform probabilistic calculations. With such model, the annual costs and downtime are not only expressed as fixed values. The program provides additional information like the probability that the annual costs will become higher than a certain value. A description of the model can be found in [5].

3. Case Studies and General Conclusions

With the probabilistic model, certain wind farm configurations on various offshore locations can be analysed. The annual costs and downtime can be determined and the influence of e.g. a repair strategy, the size of the turbine and the wind farm, and the effect of lightning protection can be investigated. In total four wind farm configurations have been defined for which sensitivity studies have been performed, see Table 1.1.

The third objective of the project is to draw general conclusions and recommendations from the case studies in order to:

- estimate the annual costs and downtimes due to lightning damage;
- determine the most important cost drivers;
- assess the influence and importance of certain aspects like the offshore location, the repair strategy, the lay-out of the wind farm, etc. on the costs and downtimes;
- derive guidelines on the amount of money that should be spend on lightning protection;
- identify which uncertainty contributes the most to the uncertainty in the outcome of the calculations.

The case studies and the conclusions have been reported in [6].

Table 1.1: *Overview of wind farm configurations considered in the case studies*

<table>
<tr><th>Near shore (12 km offshore)</th><th>Near shore (30 km offshore)</th><th>Far offshore (300 km offshore)</th></tr>
<tr><td></td><td>67 * 1,5 MW turbines</td><td></td></tr>
<tr><td>34 * 3,0 MW turbines</td><td>34 * 3,0 MW turbines</td><td></td></tr>
<tr><td></td><td>17 * 6,0 MW turbines,
orientated east - west</td><td rowspan="2">17 * 6,0 MW turbines</td></tr>
<tr><td></td><td>17 * 6,0 MW turbines,
orientated north - south</td></tr>
</table>

1.3 Data Collection and Quantification of Parameters

This report contains data and parameters necessary to estimate

- the annual costs;
- the annual downtime; and
- their uncertainty.

The annual probability of thunderstorms and the number of lightning flashes per thunderstorm has been determined in Chapter 2 for two near shore locations at 12 and 30 km offshore and for one far offshore location at 300 km offshore. Moreover, a comparison has been made between the statistics onshore and offshore. Chapter 3 discusses the measures for lightning protection, their efficiencies and their costs. Examples and statistical data on lightning damages of onshore turbines can be found in Chapter 4. The data have been used to rank the most vulnerable components and to estimate how often components are damaged if the turbine is hit by a lightning strike.

The costs to repair lightning damage consist of, a.o. material costs, labour costs, and costs for equipment. Cost data have been collected by investigating the current market prices in Chapter 5 together with other relevant data like travel times, and weather windows for equipment.

The downtime resulting from lightning damage strongly depends on the repair strategy. Various repair strategies are given in Chapter 6. The downtime is mainly caused by the wind and wave conditions at which a repair can be carried out. To determine how often the appropriate weather conditions are available for the required period of time, a detailed analyses of 20 years wind and wave data has been carried out in Chapter 7.

2. LIGHTNING

2.1 Introduction

Lightning strokes are produced following a separation charge in thunderstorm clouds. A lightning stroke is observed when this charge is discharged to the earth or to the neighbouring cloud. A lightning stroke can be regarded as a current source. In a lightning flash hitting a turbine, a value of charge travels between thunderclouds and the earth a few times (strokes).

Variables in the probabilistic model that need to be parameterised are:

- the frequency of thunderstorms per year and per season (winter, spring, summer and autumn);
- the amount of flashes per thunderstorm;
- the distribution of lightning currents, because not all flashes that hit the turbines will cause damage.

The Dutch Meteorological Institute KNMI has determined the frequency of thunderstorms per year and the number of flashes per thunderstorm for three locations at the North Sea (see Annex A). The distribution of the lightning currents has been derived from IEC 61400-24 [1].

2.2 Lightning Strike Probability

The probability that a wind turbine in a wind farm will be hit by a lightning strike depends amongst others on the following.

- The height of the wind turbine.
  High structures receive more lightning strikes than low ones. This effect is accounted for by defining a collection area around the structure and assuming that the number of lightning strikes for the elevated structure equals the number of ground flashes within this collection area. So the ground flash density has to be considered when assessing the lightning strike frequency of an elevated structure.

- The location.
  The average number of thunderstorms and the average number of lightning strikes per thunderstorm vary from one location to another. Consequently the ground flash density varies from one location to another.

- The wind farm layout.
  Two aspects might be of importance. First, the distance between the turbines can be such that the collection areas of the turbines do overlap, so that the collection area of the total wind farm is less than the sum of the collection areas of all separate turbines. Secondly, the direction in which a thunderstorm travels might be of importance for elongated wind farm configurations. In general a thunderstorm that passes a row of turbines in a direction perpendicular to the row will be less severe.

In practice it might happen that during a thunderstorm more than one turbine is hit. To account for this phenomenon, in the cost model the following has to specified:

- the expected number of thunderstorms per year that will pass the wind farm;
- the expected number of lightning strikes per thunderstorm that will hit one or more turbines within the wind farm.

To determine these numbers for wind farms located at the North Sea, KNMI has made an inventory of thunderstorms and the number of lightning strikes within each thunderstorm. Because of the dependency of these numbers on the location, three different locations at the North Sea were considered, viz. (See Fig. 2.1.):

- a near shore location at 12 km from the coast;
- a near shore location at 30 km from the coast;
- and a location 300 km from the Dutch coast, the Doggerbank.

The results of the inventory made by KNMI are described in Annex A. For the two near shore locations, measured data over 6 full years, from 1995 until 2000, were available from the SAFIR network. However, the Doggerbank is outside the reach of this detection system, and for this location estimations were made based on data coming from the UK Meteorological Office.

Furthermore, to consider the influence of the wind farm layout and the height of the wind turbines, three different configurations were considered, with wind turbines representative for 1,5 MW, 3 MW and 6 MW turbines. The number of turbines was chosen, such that the total amount of installed power is about 100 MW. The characteristic values of the wind farms and the wind turbines are summarised in Table 2.1.

Table 2.1: *Wind farm and wind turbine characteristics*.

Name wind farm	**WF_1.5**	**WF_3.0**	**WF_6.0**
Number of wind turbines	67	34	17
Rated power of wind turbine [MW]	1.5	3.0	6.0
Rotor diameter [m]	70	90	120
Height of nacelle above water level [m]	55	70	80
Max. height of tip above water level [m]	90	115	140
Wind farm layout	10 rows	5 rows	3 rows
Distance between wind turbines [m]	400	500	650
Distance between rows [m]	550	700	900
Size [km x km]	3.6 x 3.3	3.0 x 2.8	3.25 x 1.8
Collection area [km^2]	13.1	10.8	8.4

The wind farms denoted with WF_1.5 and WF_3.0 have an almost rectangular shape, while WF_6.0 has a more elongated shape. To study the orientation effects this wind farm was considered with the rows in north south direction (denoted with WF_6.0NS) and with the rows in east west direction (denoted with WF_6.0EW).

The statistics on lightning strikes for the three locations and the four park configurations are given in the following sections.

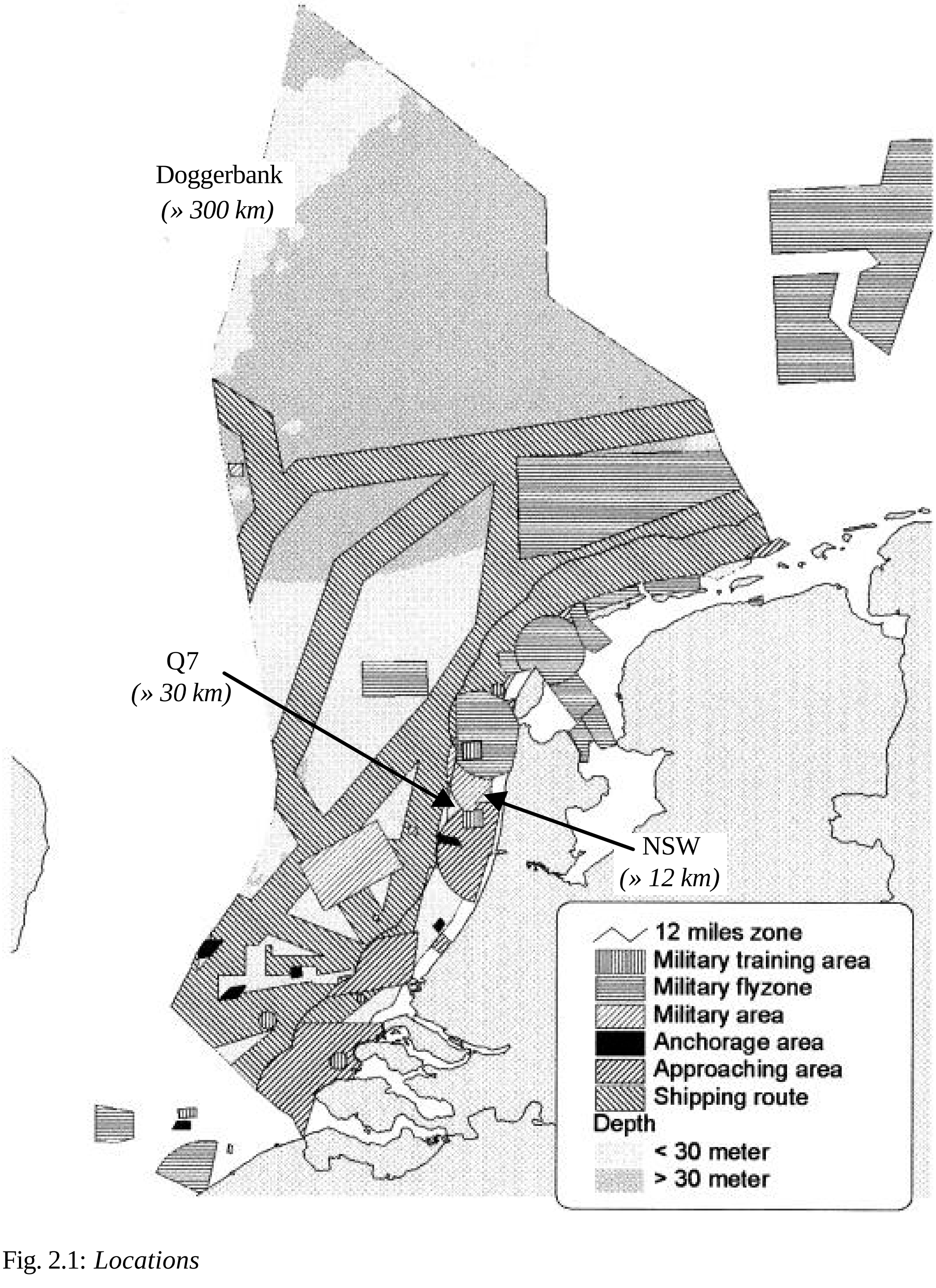

Fig. 2.1: *Locations*

2.2.1 Near shore locations

Near Shore 1 (12 km Offshore)

The data derived for the first near shore location are presented in detail in Annex A. These data give the number of thunderstorms each year and the number of lightning strikes per thunderstorm. So the mean values for the number of thunderstorms per year and the number of lightning strikes per thunderstorm are determined straightforward. The standard deviation for the estimated mean values is needed to take into account the statistical uncertainty in these values due to the limited number of measurements. The standard deviation can be estimated by a resampling technique such as the jackknife [10]. The calculated results are summarised in Table 2.2.

Table 2.2: *Lightning data for near shore location 1*

	Wind farm configuration			
	WF_1.5	WF_3.0	WF_6.0NS	WF_6.0EW
Collection area [km^2]	13.10	10.80	8.40	8.40
Number of thunderstorms per year				
Mean value	3.17	2.67	1.83	2.17
Standard deviation	0.63	0.44	0.23	0.17
Coefficient of variation	0.20	0.16	0.13	0.08
Number of flashes per thunderstorm				
Mean value	2.47	2.19	2.18	2.00
Standard deviation	0.28	0.23	0.18	0.15
Coefficient of variation	0.11	0.11	0.08	0.08
Number of flashes per year per km^2	0.60	0.54	0.48	0.52

Near Shore 2 (30 km Offshore)

The data derived for the second near shore location are presented in detail in Annex A. These data are processed in the same way as the data of Near Shore 1 and the results are summarised in Table 2.3.

Table 2.3: *Lightning data for near shore location 2*

	Wind farm configuration			
	WF_1.5	WF_3.0	WF_6.0NS	WF_6.0EW
Collection area [km^2]	13.10	10.80	8.40	8.40
Number of thunderstorms per year (average)				
Mean value	2.67	2.67	1.83	2.17
Standard deviation	0.24	0.24	0.16	0.23
Coefficient of variation	0.09	0.09	0.09	0.11
Number of flashes per thunderstorm				
Mean value	1.75	1.69	1.55	1.54
Standard deviation	0.10	0.07	0.06	0.07
Coefficient of variation	0.06	0.04	0.04	0.05
Number of flashes per year per km^2	0.36	0.42	0.34	0.40

Comparing the results of near shore 1 and of near shore 2 it appears that the number of thunderstorms for both locations are corresponding reasonably well. The number of flashes per thunderstorm shows a trend to be lower for location 2, which is at a greater distance from the coast.

2.2.2 Far Offshore, Doggerbank (300 km Offshore)

For the two near shore locations measured data was available from the SAFIR network. However, the Doggersbank is outside the reach of this detection system, and for this location estimations were made based on data coming the UK Meteorological Office, as outlined in Annex A. The average yearly number of thunderstorms and the mean number of lightning strikes are given in Table 2.4. Because no measured data is available the standard deviation and coefficient of variation can not be determined. To include the statistical uncertainty in the cost model the coefficient of variation to be used can be based on the results for the near shore locations. As a conservative approach the maximum values, 0.20 for the number of thunderstorms per year and 0.11 for the number of lightning flashes per thunderstorm (WF_1.5 at location 1) can be used.

Table 2.4: *Lightning data for far offshore location*

	Wind farm configuration			
	WF_1.5	WF_3.0	WF_6.0NS	WF_6.0EW
Collection area [km^2]	13.10	10.80	8.40	8.40
Mean umber of thunderstorms per year (average)	2	2	1.5	1.5
Mean number of flashes per thunderstorm	1.5	1.5	< 1.5	< 1.5
Mean number of flashes per year per km^2	0.23	0.28	< 0.27	< 0.27

2.2.3 Influence of Wind Farm Orientation

In the previous sections, the statistics for the different locations and wind farm configurations have been presented. The configurations WF_6.0NS and WF_6.0EW have been selected to find out if a wind farm that is oriented north-south (parallel to the prevailing direction of thunderstorms) is more vulnerable or less vulnerable than one which is oriented east-west. The data of the near shore locations show slightly higher numbers for the east-west orientated wind farm. However, the elongation is probably not pronounced enough to quantify this effect and no conclusions with respect to the orientation of a wind farm can be drawn.

2.2.4 Seasonal Variations

To quantify the variation over the time of the year, the thunderstorms reported for the largest wind farm at both near shore locations are divided in the following seasons:

- Winter : December, January, February;
- Spring : March, April May;
- Summer : June, July, August;
- Autumn : September, October, November.

The results are given in Table 2.5 and Figure 2.2.

Table 2.4: *Variability through the year of the average number of thunderstorms*

Season	Number of thunderstorms in 6 years			Variability		
	Near shore 1	Near shore 2	Total	Near shore 1	Near shore 2	Total
winter	0	2	2	0%	13%	6%
spring	2	0	2	11%	0%	6%
summer	10	9	19	53%	56%	54%
autumn	7	5	12	37%	31%	34%
Total	19	16	35	100%	100%	100%

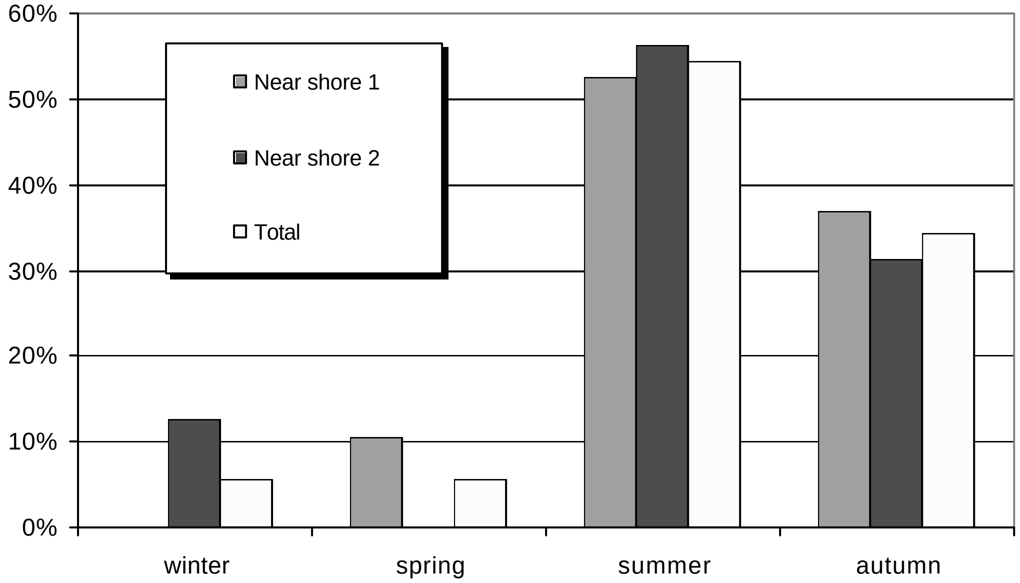

Fig. 2.2: *Variation over the year of the average number of thunderstorms*

2.3 Distribution of Lightning Current

Not all lightning flashes that hit a turbine will cause damage. The damage is strongly dependent on the current value. The maximum-recorded value of lightning current produced by a single stroke is in the region of 300 kA. Similarly, the maximum-recorded values of charge transfer and specific energy are 400 C and 20 MJ/? respectively. These maximum values only occur in a small percentage of flashes world-wide. The median value of peak lightning current is approximately 30 kA with median values of charge transfer and specific energy of 5.2 C and 55 kJ/? .

Two basic types of lightning discharges exist, downward or upward initiated. A downward initiated discharge starts at the thundercloud and heads towards the earth. In contrast an upward initiated discharge starts at an exposed location of the earth (for example at the top of a tall earthed structure) and heads towards a thundercloud. Commonly these basic types are referred to as "downward flash" or "upward (initiated) flash".

Both types of lightning are further sub-divided according to the polarity of the transferred charge. A negative downward discharge brings negative charge from the thundercloud to the earth. A positive downward discharge transfers a positive charge from the thundercloud to the earth. About 90 % of all cloud-to-ground discharges are negative. The remaining 10 % of all the cloud-to-ground discharges are positive. The distribution of the cloud-to-ground currents is given in Table 2.5.

Table 2.5: *Cloud-to-ground lightning current parameters*

Parameter		Stroke type	Probability level		
			95 %	50 %	5 %
Peak current	kA	1st negative	14	30	90
		Subsequent negative	4.6	12	30
		Positive	4.6	35	250
Total charge 1)	C	1st negative	1.1	5.2	24
		Subsequent negative	0.2	1.4	11
		Positive	20	80	350
Specific energy 2)	kJ/Ω	1st negative	6.0	55	550
		Subsequent negative	0.55	6.0	52
		Positive	25	650	15000
Maximum di/dt	kA/μs	1st negative	9.1	24	65
		Subsequent negative	10	40	162
		Positive	0.2	2.4	32
1) $Q = \int i(t)dt$		2) $E = \int i^2(t)dt$			

2.4 General Remarks and Trends

The data given in the previous sections applies to three different locations at the North Sea. The data has been derived from measurements and can be used as input in the probabilistic cost model. In this section, the offshore data will be compared with onshore data in order to identify differences and similarities.

From the NEN 1014 [7] the number of thunderstorm days has been derived and varies between 22 and 30 in the Netherlands. For coastal regions and near shore locations the number of thunderstorm days is approximately 24 to 26. The internet site of KNMI (www.knmi.nl/onweerswaarnemingeninnederland.htm) shows that the average number of thunderstorm days onshore is 24.

The IEC 61024-1-1[8] presents an equation with which it is possible to determine the lightning ground stroke density, N_g in [1/km^2/year], from the annual number of thunderstorm days, T_d.

$$N_g = 0.04 \cdot T_d^{1.25} \qquad (2.1)$$

With 24 thunderstorm days per year, the number of strokes per year per km^2 is 2.3 in the Netherlands. However, measurements from the KNMI between 1960 and 1998 show that the average number of strokes per year per km^2 is 1.3, which is much lower than derived from eq. (2.1). It should be concluded that eq. (2.1) is not very accurate, especially not over the North Sea. This is underpinned in more detail in Annex A.

The average number of strokes per year is 1.3 per km^2, which corresponds to 1.0 flashes per year per km^2 (see also Annex A, Section A3). From Section 2.3 it can be concluded that the number of flashes per km^2 is lower offshore than onshore. The values are given in Table 2.6. From [2] it can be concluded that similar trends have been observed in Denmark, see Fig. 2.3.

Table 2.6: *Comparison between the number of flashes onshore and offshore*

	Onshore	Near shore 1	Near shore 2	Far offshore
Number of flashes per year per km^2	1.0	0.48 – 0.60	0.34 – 0.42	0.23 – 0.28

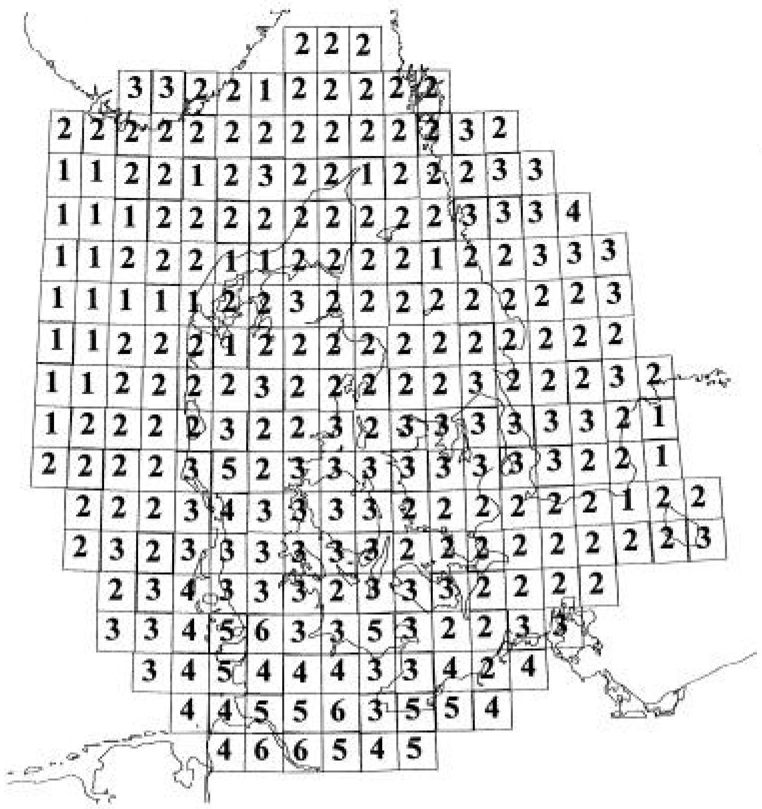

Fig. 2.3: *Average annual lightning flash density per 10 km^2 (based on lightning flashes registered during the years 1991 – 1997) [2]*

3. LIGHTNING PROTECTION

3.1 Efficiency of Protection Systems

When a lightning strike hits (or starts from) a turbine, an amount of charge travels between earth and a thundercloud (or opposite) using the turbine structure as a more preferable path than the air. The charge enters (or leaves from) the blade and travels through the blade and through the pitch bearing into the hub and the main shaft, through the main shaft bearing into the nacelle bed, through the yaw bearing into the tower and after that into the foundation and to earth.

To minimise the damage from lightning hitting a turbine, a turbine can be equipped with a lightning protection system. The primary damaging effect of the lightning current is a direct one and related to the current carrying capacity of the protection system. This effect can damage blades by penetrating at unwanted locations or melting down the protection system and can damage bearings by melting down material from balls and raceways. The secondary damaging effects of the lightning current are indirect and related to the mechanical forces coming with the high pulse energy and also to the raising of earth potentials and/or induction of high voltages in wiring. The mechanical effects can crack or rupture blades and the raising of earth potentials can damage the electrical installation by breaking down the insulation or overloading sensitive components.

For the probabilistic model, it is important to gain insight in the amount of damage that occurs after a lightning hit. This of course depends on the intensity (current value, specific energy, rate of current rise, and charge transfer levels) of the lightning flash and of the protection level. Not all flashes will result in the same amount of damage. The distribution of the intensity is given in Table 2.5. To characterise the amount of protection, standards for lightning protection identify four protection levels for the protection of a structure with each a successive efficiency. This classification applies to the external protection systems, e.g. protection of the blades and the meteo sensors on top of the nacelle. The efficiency of lightning protection for internal systems, mainly for the electrical and control systems, cannot be determined directly.

In this chapter, some backgrounds are given on external and internal protection systems. To the extent possible, the efficiency of protection will be quantified including its uncertainty. Furthermore, an estimate will be made for the costs of a protection system.

3.2 External Protection

The external protection system is intended to intercept direct lightning strokes and brings the discharge to earth without any damage or danger. Wind turbine blades are assigned to be a part of the external protection system. For the design of external lightning protection systems, IEC 61024-1 defines four lightning protection system levels: level I through level IV. These have the efficiencies shown in table 3.1.

Table 3.1: ***Lightning protection system levels***

Protection levels	Interception efficiency E_i	Sizing efficiency E_S	Efficiency $E = E_i \times E_S$
I	0.99	0.99	0.98
II	0.97	0.98	0.95
III	0.91	0.97	0.90
IV	0.84	0.97	0.80

Physically, the more efficient lightning protection system will have larger conductor diameters and larger earthing systems (to improve the sizing efficiency) and will be designed with an increased quantity and/or reduced spacing of lightning interception points (to improve the interception efficiency). The current, specific energy, rate of current rise and charge transfer levels needed to obtain the various lightning protection system sizing efficiencies are shown in table 3.2.

Table 3.2: *Maximum values of lightning parameters corresponding to protection levels*

Protection level	Peak current [kA]	Specific energy [$kJ\Omega^{-1}$]	Average rate of current rise [kA/μs]	Total charge transfer [C]
I	200	10000	200	300
II	150	5600	150	225
III	100	2500	100	150
IV	,,	,,	,,	,,

The level of protection that should be chosen depends on the risk that one wants to accept. Risk in this context means the product of the frequency of damages times the costs for repairing the damages. The frequency of damage corresponds to the number of flashes that exceed the maximum current that the protection system can transport to the ground. A level I lightning protection system must, for example, be able to carry a peak current of 200 kA without damage. Approximately 2 % of the hits will lead to damage of the structure because the current is higher than 200 kA.

In [1], a method is given on how to determine an adequate protection system. It is based on the philosophy that an extra investment in the protection system will lead to a reduction of the annual damages and repair costs. In [1] it is assumed that:

- the annual number of lightning flashes at the intended location is known;
- the efficiency of the protection system is known;
- the amount of damage and the repair costs can be quantified.

(It should be noted that the above given assumptions can hardly be quantified for offshore wind farms. In fact, this project was partly initiated to quantify them.)

Up to 20 m length GRP (Glass fibre Reinforced Plastic) blades and sometimes wood epoxy blades have as lightning attachment point a metal receptor of some square surface at one or both blade sides at or near the tip. A metallic down conductor of sufficient cross-section in the centreline of the blade connects the receptor to the blade root. Arcs forming inside the blade must be avoided because they lead to blade destruction. Therefore all metal parts inside the blade are connected to the down conductor.

Above 20 m blade length additional receptors are installed every 5 m to prevent uncontrolled side attachment to the blade followed by a penetration to the internal down conductor.

Another protection method has metallic conductors placed along both the leading and the trailing edge of the blade.

CRP (Carbon fibre Reinforced Plastic) blades need their own protection method. For offshore wind turbines carbon fibres as reinforcement material are used in blades of about more than 40 m length. Carbon fibres are conductive but highly resistive. High charges passing through layers of this material in the very short time as lightning is, develop high amounts of energy destroying the matrix between the fibres and sometimes the fibres as well. The blade parts containing layers of carbon fibres are (to be) covered on the outside with a highly conductive shield of e.g. copper mesh. From this material the charge must be conducted to the blade root.

So far the blade manufacturers claim to have a protection system that covers the demands of the standards for lightning protection. For wind turbine blades no specific standards exist. (For more details on blade protection systems, also see [1], and [2].)

In the probabilistic model, the adequacy of the protection level can be described by the efficiency. The efficiency expresses the ratio between the number of annual lightning flashes and the number of severe damages. In addition it is worthwhile to remark that the interception efficiency of blades is covered with uncertainty. Even if blades are equipped with receptors, still some damage of the skin may be found close nearby the receptors. The receptors themselves will also suffer from wear if they work well and they will require inspections and small repairs. These damages are considered as small for onshore turbines (approx. € 4.000,-- per event), see also Chapter 4), but may be expensive for offshore turbines due to the difficult accessibility.

3.3 Internal Protection

Internal protection systems are necessary to protect those components through which a major part of the current is flowing like for instance the pitch bearings, the hub, the main bearing, the yaw bearing, the gearbox, and the tower. The internal protection system also has to protect the electrical and control systems that are sensitive to over voltage, overload and induction currents.

3.3.1 Bearings

A practical experience with lightning damage is scarce since wind turbine bearings are not normally checked after lightning strikes. A lightning strike may cause arcing between bearing raceways and rolling elements. This may cause severe pitting which will become apparent some time later.

Pitch bearings

The pitch bearings are of a heavily loaded slow rotating pre-stressed type. They offer many contact surfaces for passing through charges. A possibly small damage does not influence the bearing lifetime. Pitch bearings often have no specific lightning protection. It is recommended to provide an alternative current path across the bearing at risk with flexible conductors, sliding contacts or similar arrangements.

Main shaft bearings

For the main shaft bearings, the gearbox and generator bearings, it is difficult to combine the need for lubrication to reduce friction with the good metallic contact needed to conduct lightning currents. Attempts at reducing the fraction of lightning currents passing through the main shaft bearings by providing alternative current paths with sliding contacts, brushes and spark gaps, are being made by most manufacturers. Large bearing structures have very low impedance, whereas sliding contacts, brushes or spark gaps with their connections to local ground have higher impedance. Therefore, such measures cannot divert all of the lightning current away from the bearings.

To guarantee no discharges coming from the hub will pass through the main shaft (and gearbox) bearings these parts of the turbine have to be electrically insulated from the machine bed and an alternative path is to be offered to the current. This has never been demonstrated and there is no information about possible costs. The currents passing from the gearbox into the generator shaft bearings can be blocked by installing insulating components in a flexible coupling if available.

Yaw bearings

For yaw bearings the same aspects as for pitch bearings are valid. Some manufacturers are installing spark gaps.

The efficiency of the lightning protection systems is difficult to quantify for the bearings. In theory it should be possible to design the protection systems in such way that the four levels as given in Table 3.1 apply. However, at present there is not a standard design approach that ensures that the four levels can be applied to the structural parts

3.3.2 Electrical and Control System

The voltage in the turbine can locally be very high at the moment the lightning strike and the lightning current is heading for earth through all the available resistive and/or inductive conductive paths. Earth or zero potentials used for reference can temporarily being raised too high for the electrical installation nearby and also for touching by personnel.

Different effects influence the operational safety of the electrical system.

- A part of the lightning current is expected to enter the electrical installation on its way to (or coming from) earth. Over voltages can than break down insulation or overload components or circuits.
- Over voltage in circuits also results from capacitive and/or magnetic coupling with the steep voltage and current rises of the passing discharge.

Capacitive and/or magnetic coupling is reduced by increased separation between the lightning-current-carrying conductors and the electrical circuits, the use of twisted pair cables and by the use of shielding.

To equalise earth or zero potentials bonding has to be done consistently and with conductors that are capable of carrying the predicted fraction of lightning current to pass through the path in question.

Over voltages need to be reduced to the insulating value of the circuits. Therefore proper 'surge protection' is needed in combination with proper equipotential bonding, shielding and earthing.

For surge protection, a turbine is divided into physical areas that roughly define the nature of the influence of a lightning flash to components in that zone. Inside every next zone a lower value of the lightning pulse is to be expected. To obtain surge protections 'surge arresters' are installed to block and divert surges to earth. For the different voltage systems to be protected this is done at the different voltage levels and with a capacity compared to the influence zone. Ideally, signals used by sensitive circuits should be transmitted via fibre optics containing no metallic wires.

If protected by a proper air-termination system lightning coming from above or aside can not directly reach the sensors on top of the nacelle. Only a part of the full lightning current is than to be taken care of. In case the meteo sensors are protected by air termination, the nacelle has a metal or shielded cover, the electrical installation parts are in metal panels and all cables are shielded, than the meteo area, the inside of the nacelle or tower and the inside of a metal panel is to be seen as successive 'lightning protection zones' (LPZ)[2] according to IEC 61312.

Wiring for sensors placed on or inside blades must be protected by appropriate equipotential bonding to the down conduction system. Wiring should either be shielded cables or be placed in

[2] LPZ 0_A : Direct lightning attachment, full lightning current, unattenuated electromagnetic field.
LPZ 0_B : No lightning attachment, full lightning current, unattenuated electromagnetic field.
LPZ 1 : No lightning attachment, reduced lightning current, attenuated electromagnetic field.
LPZ 2 : Further reduced lightning current, further attenuated electromagnetic field.

metal tubes. The shielded cable or metal tube should be placed as close as possible to the down conduction system and bonded to it.

The efficiency of the lightning protection systems is difficult to quantify for the electrical and control systems. It is postulated that, due to the voltage rise of the earth potential(s) in the most unfavourable situation and in LPZ 0, with no protection at all, half of the level I peak current (100 kA maximum) can enter the electrical installation. Therefore a surge protection device in LPZ 0 is designed to handle a peak current of 100 kA with a defined rise time. For the surge protection in the successive lightning protection zones the maximum peak currents and rise times are defined. Hinged on the sensitivity of the circuit or equipment being protected, the correct array of SPD's is to be selected and placed at zone boundaries. The adequacy of such a protection in wind turbines is at present not proven

3.3.3 Other items

Part of the lightning current can enter the gearbox and the generator. Therefor, and special in case these parts are insulated from the nacelle frame, they have to be bonded to the frame having sufficient current carrying capacity. Proper bonding of turbine parts is needed especially in the nacelle area to prevent dangerous touch voltages for personnel in case a lightning current is running.

Offshore earthing is not a problem due to the low resistance and impedance of the see water. In offshore situations overhead power and/or communication lines do not exist and all cables are in deep salty (well conducting) water. No over voltages, from lightning to the sea surface nearby or coming from other turbines, are expected to enter the turbine from the grid connection or from the communication connection.

3.4 Costs for Lightning Protection Systems

3.4.1 Wind Turbine Blades

The costs of the lightning protection system of wind turbine blades are related to the manufacturing costs of the blade. For GRP (Glass fibre Reinforced Plastic) blades having lightning protection with a central down conductor the protection costs are about 2 % of the blade costs. For CRP (Carbon fibre Reinforced Plastic) blades the protection costs are at least 2.5 % of the blade costs.

Price information from three manufacturers for blades of 20 m up to 40 m is available. From this available information the blade prices for rotors of 70 m, 90 m and 120 m are evaluated in Table 3.3 as well as the costs for lightning protection provisions in GRP and CRP blades.

Table 3.3: *Lightning protection costs for blades*

Turbine power [MW]	1,5	3	6
Rotor diameter [m]	**70**	**90**	**120**
˜ blade length [m]	35	45	60
Price/set (3 blades) [k€]	220,2	375,6	680,0
2% costs/GRP rotor [k€]	**4,4**	**7,5**	**13,6**
2,5% costs/CRP rotor [k€]	**5,6**	**9,5**	**17,2**

3.4.2 Bearings

Wind turbine manufacturers install hardware provisions as brushes, sliprings, and/or spark gaps to protect bearings. From one wind turbine manufacturer the structural costs to protect the bearings of a 1 MW wind turbine are estimated to be k€ 2.5. There will be not much more constructive provisions to protect the bearings of a 6 MW turbine. Assuming the protection costs for a 6 MW turbine to be 5 k€, Table 3.4 gives the accompanying values.

Costs related to the bonding of machine parts as referred to in Section 3.3.3 BOVEN are expected to be included.

Table 3.4: *Lightning protection costs for bearings (and bonding)*

Turbine power [MW]	1,5	3	6
Rotor diameter [m]	**70**	**90**	**120**
Bearing costs [k€]	**2.75**	**3.5**	**5**

As written in Section 3.3.1, no cost estimation for a tested lightning protection system is available for the main bearings.

3.4.3 Electrical and Control Systems

The protection of electrical installations is part of the internal protection system. Additional hardware costs are made to install correct surge protection devices. No additional costs are expected for the prevention of capacitive and/or magnetic coupling. Capacitive and/or magnetic coupling is to be prevented by a proper design of the routing and shielding of the wiring. Shielded wiring for signal cables is already standard in turbine design.

To be able to estimate the costs for the lightning protection of the electrical installations of a wind turbine, a hypothetical number of voltage levels and number of sensors including the specific lightning protection zones are decided and given in the tables 3.5 and 3.6. No Surge Protection Devices (SPD) are foreseen at the grid connection side of the turbines electrical and communication installations. (Note that once the turbine design is known in detail, better estimates can be made.) For the three different power sizes of 1,5 MW, 3 MW and 6 MW the same number of supply voltages and sensors are presupposed. The hardware costs for the surge protection devices (SPD) to be installed are given in the last column of table 3.5 and 3.6.

Table 3.5: *Protection of voltage levels (hypothetical)*

Supply voltages to protect		Voltage	Pole number	LPZ	SPD [k€]
Generator supply (double) in nacelle		4000 Vac	3	1	2.00
Power supply	in bottom of tower	400 Vac	4	1	1
	in nacelle	400 Vac	4	1	1
	in hub	400 Vac	4	1	1
Service voltage	in bottom of tower	230 Vac	2	1	0.5
	in nacelle	230 Vac	2	1	0.5
Control voltage	in bottom of tower	24 Vdc	2	1	0.08
	in nacelle	24 Vdc	2	1	0.08
	in hub	24 Vdc	2	1	0.08
			Costs subtotal		**8,5 k€**

Table 3.6: *Protection of sensors (hypothetical)*

Sensors or Hydraulic valves to protect		LPZ	[k€]
On top of nacelle (meteo)	4 x	0	0.5
Inside hub	20 x	1	2
Inside nacelle	30 x	1	3
		Costs subtotal	**5.5 k€**

For the three power sizes of 1.5MW, 3 MW and 6 MW the total of the additional hardware SPD costs to protect the supply voltages and the sensors against over voltages can be estimated to be 14 k€.

4. DAMAGE EVENTS

During a thunderstorm, a wind turbine can be hit by a lightning strike with the results that some components or systems might be damaged in such a way that repair is required. The total repair costs due to lightning damage depend on the type of damage. Statistics on damage due to lightning strikes are given in e.g. [1] and [3]. Some major conclusions presented in [3] are given below.

- In total 914 lightning damages have been reported over 11,364 operational years, which corresponds to 8 incidents per 100 turbine years. Danish and Swedish databases report 3.9 and 5.8 incidents per 100 turbine years.
- Approximately 25% of the damages resulted from a direct lightning strike; the rest of the damages resulted from indirect hits, for instance if the electrical network was hit.
- The average downtime per damage is approximately 30 hours.
- The rotor blades seem to be the most vulnerable components. They show the highest frequency, the highest repair costs (approximately € 20.000,-- per incident for turbines above 450 kW), and the longest downtime (approximately 10 days per incident).
- As compared to smaller turbines, the larger and newer turbines show fewer failures in the control system. This suggests that the lightning protection of control systems has improved in recent years, but there is no actual proof for that because it was not reported to what extent the turbines were protected against lightning.

Some detailed conclusions form the WMEP database of ISET are given here. Over the period 1991 – 1998, representing about 9200 turbine years, 739 wind turbines have been damaged by lightning. A total of 1032 faults were reported, which implies that one lightning strike might lead to damage in more than one system or component. The division of these 1032 faults for the different components and systems is summarised in Table 4.1 and depicted in Figure 4.1.

Table 4.1: *Distribution of faults*

component	old (< 450kW)		new (>= 450 kW)		total	
	number of faults	%	number of faults	%	number of faults	%
control system	283	31.1%	27	22.0%	310	30.0%
electric	248	27.3%	23	18.7%	271	26.3%
rotor blades	165	18.2%	40	32.5%	205	19.9%
sensors	115	12.7%	17	13.8%	132	12.8%
generator	29	3.2%	2	1.6%	31	3.0%
hub	19	2.1%	4	3.3%	23	2.2%
hydraulic system	15	1.7%	3	2.4%	18	1.7%
yaw system	11	1.2%	1	0.8%	12	1.2%
gear box	8	0.9%	2	1.6%	10	1.0%
mechanical brake	7	0.8%	2	1.6%	9	0.9%
drive train	5	0.6%	1	0.8%	6	0.6%
structural parts	4	0.4%	1	0.8%	5	0.5%
Total	909	100%	123	100%	1032	100%

To enable a comparison between older and newer turbines, the reported faults are given for turbines smaller than 450 kW and above 450 kW together with the totals. As stated by ISET the turbines above 450 kW are considered to be of recent production and should reflect some implementation of lightning protection. From Fig. 4.1 it can be seen that the distribution over the different components is different for the newer and the older turbines. For the older turbines faults in the control and electrical system are dominating, while for the newer turbines damage to the blades is the most common type of damage. The decrease in faults in the control and electrical system might be a result of successful application of protection systems. However this can not be underpinned with numbers, because it is not specified to what extend protection systems have been installed in the turbines considered. (It should be noticed that these numbers are also reported in Chapter 3 of the IEC-61400- part 24: Lightning protection for wind turbines.)

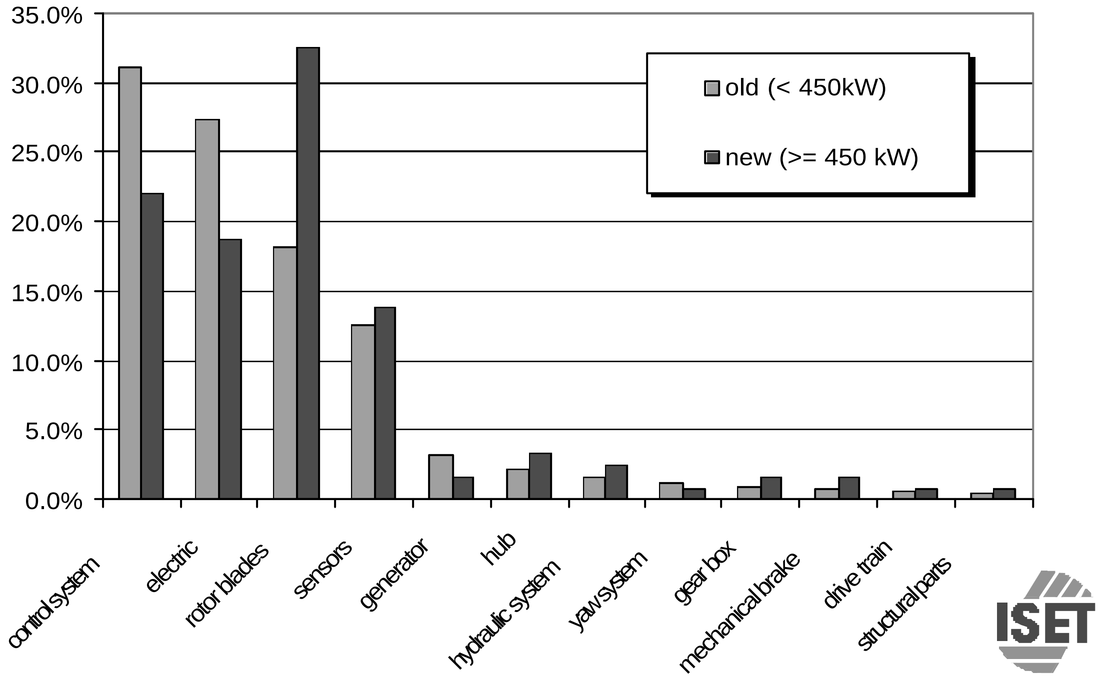

Fig. 4.1: *Distribution of faults*

When applying the numbers presented in Table 4.1 the following points should be considered.

1. Only lightning events leading to damage have been reported in the database. However sometimes it occurs that a turbine is hit in such a way that the turbine is not damaged and will continue operation. This means that the probability that damage will occur is in general less than the probability that the turbine is hit by a lightning strike. However, it is not possible to quantify the probability that a turbine is hit without being damaged subsequently.
2. Modern turbines are more and more equipped with lightning protection systems. It is not clear to what extend the turbines in the database are equipped with protection systems. The older turbines were probably not provided with protection systems, so it appears reasonable to use these numbers as a starting point for the distribution of faults.
3. Due to one lightning strike more than one component or system might incur damage.

A disadvantage of using the generic databases like the WMEP database from ISET is that only very little background is given on the actual damages. E.g. the type of turbine, the amount of damages during one thunderstorm, or the amount of damage (total failure or just a little damage), are not given. Therefore, 20 lightning damage reports in the Netherlands have been investigated in more detail.

Fig. 4.2 shows the number of turbines that was hit during the passage of one thunderstorm. The 20 incidents correspond to 28 turbines. This means that more turbines can be hit by only one thunderstorm, in one case even four.

Fig. 4.3 shows the number of components that were damaged, 38 in total. Approximately 75% were blade failures. About 55% of these blade failures were complete failures; the blades had to be replaced. 45% of the blade failures could be repaired. A cost analysis revealed that replacing a blade is approximately a factor of 8 more expensive than repairing a blade: € 32.000,-- vs. € 4.000,-- per event.

Finally, the analysis of the lightning events revealed that although some blades were equipped with a state-of-the-art lightning protection system, damage could not be avoided completely. Most damages had to do with little holes near the receptors. However, one incident was reported were a tip was split open.

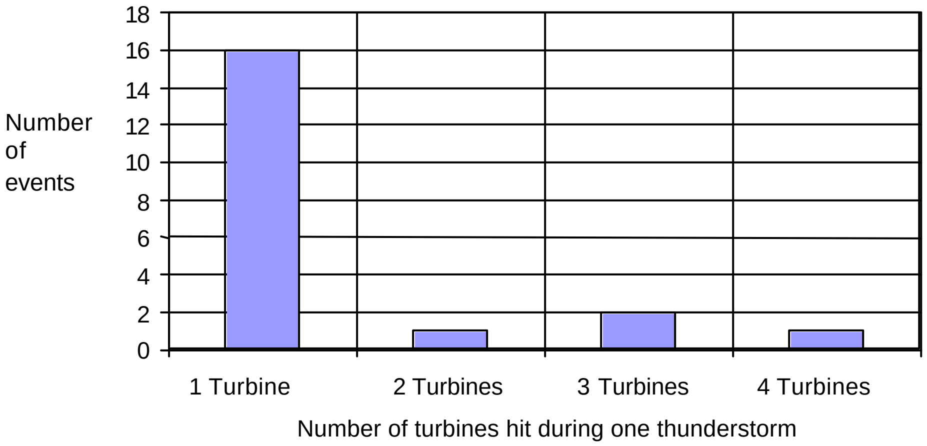

Fig. 4.2: *Number of turbines that was damaged during one thunderstorm*

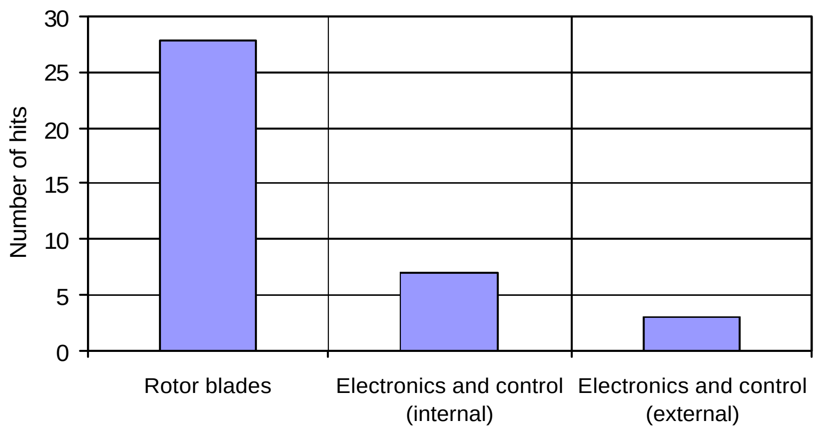

Fig. 4.3: *Distribution of damages over the components*

5. COST OF LIGHTNING DAMAGE

5.1 Failure Type Classes

In the probabilistic model, the components that may fail due to a lightning strike have been based on the classification as used in the WMEP database of ISET, see Table 4.1. For the analyses and case studies in this project, only the distribution in the column "total" will be considered further on. I.e. no distinction will be made between the damage of small turbines and damage of large turbines.

To estimate the offshore repair costs, it is necessary to consider the failure modes per component in addition to the component itself. The reason for this is that a e.g. failed *rotor blade* does not only mean *completely destroyed*. It also includes a damaged gel coat or a damaged lightning receptor and each failure mode requires its own repair strategy. Different failure modes and different repair strategies will result in different:

- material costs
- labour costs
- logistics and repair times
- costs for equipment and access systems
- travel times

Since the probabilistic model is generic for the purpose of this project, it has been decided to identify three failure type classes (FTC) per component at maximum. Each class corresponds to more or less the failure modes and their consequences. A complete overview of the cost breakdown and of the parameters chosen to calculate the costs is given in Annex B. In this chapter backgrounds are given on the chosen values and guidance on how to read Annex B.

FTC-1: Repair, Cleaning, and Reset

A visit of two technicians[3] is required. In this failure type class, the toolbox with small spare parts and consumables is sufficient to carry out the repair. The technicians can also make use of spare parts present in the turbine. Only personnel need to be transported to and from the turbine.

FTC-2: Replacement

After the inspection is carried out, an additional visit from two technicians is required. The small spare parts and consumables that are either in stock in the turbine or in the toolbox are not sufficient. Other (larger) spare parts should be transferred to the turbine, lifted from the supplier (or helicopter) into the tower (or nacelle) and hoisted with an internal winch to the nacelle.

FTC-3: Failure of large components

This class includes failures of components that need to be hoisted outside the tower. One can think of the gearbox, generator, blades, hub, or entire nacelle.

Based on "engineering judgement", a distribution has been made of the distribution of the failure type classes. In Table 5.1, an example is given of the generator. It is assumed that 70% of the observed failures in the ISET database can be categorised as "FTC-1". In 10% of the failures it is necessary to replace the entire generator. In the sixth column, conditional probability of the failure type classes (the product of the PDF and FTC-occurrence) is given. To take into account the efficiency of lightning protection in the cost model in accordance with the conclusions of Chapter 3, the efficiency can be assigned to each of the Failure Type Classes. The values for the generator are given in the right hand column of Table 5.1.

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[3] Each visit requires at least two technicians due to the labour safety rules.

(At a later stage if the exact type of turbine is known, it is possible to fill in the actual failure probabilities and protection efficiencies for the components and their failure modes.)

Table 5.1 *Example of FTC classification for the generator*

Component	# of faults	PDF	FTC	Probability of - FTC-occurrence	Conditional PDF	Efficiency of Lightning Protection
Generator	31	0.030	1	70%	0.021	60 %
			2	20%	0.006	60 %
			3	10%	0.003	90 %

5.2 Material Costs

In order to make the model flexible, it has been decided to express the material costs as a percentage of the investment costs. As can be seen in Table 5.2, five "material cost classes" have been identified. The investment costs of the turbine only. I.e. excluding the support structure and the electrical infrastructure have been assumed to be 850 Euro/kW. Note that the material costs show some scatter around the most likely (ML) values.

Table 5.2 *Material classes, values relative to the investment costs*

		Material Costs [% of Inv]		
Material Classes		**Min**	**ML**	**Max**
1	No materials	0.00%	0.00%	0.00%
2	Consumables	0.01%	0.03%	0.09%
3	Replacement of small components	0.05%	0.16%	0.47%
4	Replacement of medium sized components	2.50%	5.00%	10.00%
5	Replacement of major components	7.50%	15.00%	18.00%

To each fault type class, a material class has been assigned. In case of the generator (Table 5.1), the authors have assumed that FTC-1 requires the consumables of material class 2. Replacement of the entire generator, FTC-3, corresponds to material class 5.

The determination of the material classes, the relative costs and the uncertainties has been done by the authors based on experience and should be considered as best guesses. At a later stage if the exact type of turbine is known, it is possible to fill in the actual prices of spare parts and consumables.

5.3 Labour Costs

The labour costs are mainly determined by:
- the actual repair time;
- the travel time;
- the crew size; and
- the hourly rate (or the day rate).

In this probabilistic model, the actual repair time and the crew size have been related to the material classes as indicated in Table 5.3 and 5.4. The hourly rate is assumed to be 60 Euro.

The travel time depends on the time of equipment that is going to be used, on the location of the wind farm, and on the layout of the wind farm. The equipment and the corresponding travel times will be discussed in Section 5.4.

Table 5.3 *Material classes and corresponding repair times*

		Repair Time [hrs]		
Material Classes		**Min**	**ML**	**Max**
1	No materials	1.0	1.5	2.0
2	Consumables	1.0	2.0	4.0
3	Replacement of small components	2.0	4.0	8.0
4	Replacement of medium sized components	6.0	8.0	12.0
5	Replacement of major components	20.0	36.0	72.0

Table 5.4 *Material classes and the crew size needed for repair*

		Crew Size [-]		
Material Classes		**Min**	**ML**	**Max**
1	No materials	2	2	3
2	Consumables	2	2	3
3	Replacement of small components	2	2	3
4	Replacement of medium sized components	2	3	4
5	Replacement of major components	4	6	8

5.4 Equipment

The major cost drivers in the operation and maintenance of offshore wind farms are the costs for transportation systems and access systems. From literature surveys, interviews, and discussions with experts in the field of offshore maintenance, key figures have been derived for the following systems:

- Helicopter
- Supplier with Zodiac or MOB boat (= Man Over Board)
- Modified supplier with OAS (= Offshore Access System)
- Sheerleg
- Crane ship
- Jack-up with crane
- Pontoon with tug

The key figures with some remarks are given in the tables below. (The values for the travel time correspond to a wind farm at approximately 10 to 15 km offshore.)

Helicopter		
Specification	**Value**	**Remarks**
H max at transfer	n.a.	
V max at transfer	15 m/s	Maximum wind speed for landing and flying approximately 30 m/s
Travel time to turbine, (one way)	25 minutes	20 minutes one way, 5 minutes hoisting Second flight necessary to pick-up personnel.
Mobilisation time	1 to 4 hr	
Availability	Reasonable, on contract basis	
Maximum size of repair crew	2-4	Depends on size of helicopter. Bell 430 has 9 seats
Maximum size and weight of load	600 kg	Depends on size of helicopter. Bell 430: ~ 1200 kg
Hourly rate	4.100,- Euro	Rates may vary, in between 3.400,- Euro and 4.100,- Euro
Mob/demob costs	1.250,- Euro	Rates may vary, depending on contract 300,- Euro to 1.250,- Euro
Visibility	1.500 m (2.500 at night)	
Clouds	180 m	

Supplier with Zodiac		
Specification	**Value**	**Remarks**
H max at transfer	0. 5 m (- 0.75 m)	
V max at transfer	6 m/s	
Travel time to turbine and accessing turbine (one way)	2 hrs	Supplier remains at site
Mobilisation time	1 to 4 hrs	
Availability	Good	
Maximum size of repair crew	10-20	
Maximum weight of load	Medium size (with crane)	
Hourly rate	1.200,- Euro	Rates may vary: 850,- to 1.600,- Euro
Mob/demob costs	Depends on contract	Assumed is zero costs for mob/demob because the supplier will be rented for a longer period.

Supplier with OAS		
Specification	**Value**	**Remarks**
H max at transfer	2 m	Technically access up to 3 m; personnel not allowed on deck
V max at transfer	12 m/s	
Travel time to turbine (one way)	2 hrs	Supplier remains at site
Mobilisation time	1 to 4 hrs	
Availability	Good	
Maximum size of repair crew	10-20	
Maximum weight of load	500 kg	With crane, medium sized components possible; lower H and V (see supplier with zodiac)
Hourly rate	1.100,- Euro	Day rate = 8.500,- Euro
Mob/demob costs	Depends on contract	

Sheerleg* *) Most experts consider a sheerleg not as a serious option for hoisting large wind turbine parts due to its instability		
Specification	**Value**	**Remarks**
H max at positioning	0,5 m	
Hmax during hoisting	0,5 m	Up to 1m given by different sources
V max during hoisting	6 m/s	Up to 12 m/s given by different sources
Travel time to turbine	12 hrs	
Travel time back	12 hrs	
Mobilisation time	48 hrs	
Availability	reasonable	
Maximum height of crane	44 to 54 m	Auxiliary hoist = 77- 84 m 60 m
Maximum weight of load	> 1000 ton	Values for main hoist
Day rate	30.000,- to 45.000,- Euro	Strongly dependent on type of barge, maximum height and capacity and availability at certain time
Mob + demob costs	90.000,- + 45.000,- Euro	Up to 250.000,- Euro mentioned in other sources
Positioning	Anchors	

Crane ship		
Specification	**Value**	**Remarks**
H max at positioning	1.5 m	
Hmax during hoisting	1.5 m	
V max during hoisting	6 m/s	Technically 12 m/s possible. Load close to tower. Additional features necessary for 12 m/s
Travel time to turbine	12 hrs	
Travel time back	12 hrs	
Mobilisation time	48 hrs	
Availability	limited	
Maximum height of crane	??	
Maximum weight of load	> 1000 ton	
Day rate	45.000,- to 90.000,- Euro	
Mob + demob costs	45.000,- + 45.000,- Euro	Up to 280.000,- mentioned in other sources
Positioning	DP	

Jack-up with crane		
Specification	**Value**	**Remarks**
H max at positioning	0.5 to 0.75 m	
Hmax during hoisting	n.a.	
V max during hoisting	6 m/s	Technically 12 m/s possible. Load close to tower. Additional features necessary for 12 m/s
Travel time to turbine	24 hrs	
Travel time back	12 hrs	
Mobilisation time	48 hrs	
Availability	limited	
Maximum height of crane	70 m	
Maximum weight of load	20 to 50 ton	
Day rate	11.300,- to 16.000,- Euro	
Mob + demob costs	57.000,- + 45.000,- Euro	
Positioning	legs	

Pontoon with tug		
Specification	**Value**	**Remarks**
H max at positioning	1 m	(with special measures)
Hmax during hoisting	1 m	
V max during hoisting	6 m/s	Technically 12 m/s possible. Load close to tower. Additional features necessary for 12 m/s
Travel time to turbine	6 hrs	
Travel time back	6 hrs	
Mobilisation time	48 hrs	
Availability	good	
Maximum weight of load	sufficient	
Day rate	9.000,- Euro	
Mob + demob costs	9.000,- Euro	
Positioning	Anchors	

The costs for the various systems have been incorporated in the probabilistic model as given in Table 5.5. It is necessary to distinguish fixed costs and variable costs.

Fixed costs in fact apply to the MOB and DEMOB costs mainly. In the model, also the travel costs to and from the wind farm are considered as fixed costs since the travel time and the rates are more or less fixed and known on beforehand.

Variable costs should be paid:

- if an equipment is hired and waiting in the harbour for good weather conditions; and
- during the repair itself.

As can be seen in Table 5.5, distinction has been made between the phase for positioning the equipment and the phase during the actual repair (crane ship and jack-up). The reason for that is that both phases may require different weather conditions. Making such distinction was the best method to incorporate it in the model.

Table 5.5: *Costs for transportation and access systems*

Nr	Desription	H_{max}	V_{max}	Fixed costs for mission (MOB/DEMOB)			Variable costs during waiting and repair period		
		m	m/s	Euro/mission			Euro/hr		
				min	ML	max	min	ML	max
1	Supplier with zodiac	0.50	6.0	0	0	0	850	1,100	1,700
2	Supplier with MOB	1.00	12.0	0	0	0	850	1,100	1,700
3	Supplier with OAS	2.00	12.0	0	0	0	1,000	1,100	1,300
4	Helicopter	-	15.0	300	775	1,250	3,400	3,750	4,100
5	Pontoon with tug	1.00	6.0	8,000	9,000	10,000	1,000	1,100	1,200
6	Jack-up with crane (positioning)	0.50	6.0	90,000	100,000	120,000	1,400	1,600	2,000
7	Jack-up with crane (operation)	-	6.0	0	0	0	1,400	1,600	2,000
8	Crane ship (positioning)	1.50	6.0	80,000	90,000	110,000	5,700	7,800	11,400
9	Crane ship (operation)	1.50	6.0	0	0	0	5,700	7,800	11,400
10									
11									
12									

If at a later stage an actual wind farm will be analysed, it is very likely that the actual costs for e.g. a supplier or helicopter are known in more detail. This also means that the uncertainty bounds become smaller. In this generic example, the uncertainty bounds are based on a broad range of supply vessels and helicopters. On the other hand, the costs of some equipment may even show larger scatter. The costs of e.g. jack-ups and crane ships, strongly depend on the availability of the equipment and the distance the equipment has to travel before it reaches the wind farm.

6. REPAIR STRATEGY

Each type of failure requires its own "repair strategy". The following questions should be answered.

- Which materials and consumables are necessary?
- How large does the crew have to be?
- What equipment and access system (or combinations) should be used?

The crew size and the materials have been linked to the *material classes* (Table 6.3 and 6.4). In this chapter, possible repair strategies are described. Based on these descriptions, suitable repair strategies have been derived for all components and failure modes to be used in the probabilistic model. In general five possible repair strategies can be identified, RS-1 through RS-5.

RS-1: Inspection and repair (inside)

At least two technicians have to be transported to the turbine in order to carry out the repair. No additional equipment needs to be transported. Possible means for transportation are:

- Helicopter:
  1: Bringing two technicians to turbine (20 min)
  2: Hoisting of technicians
  3: Return of helicopter
  4: Carrying out repair with helicopter stand-by
  5: Flying back to turbine
  6: Picking up technicians
  7: Return of helicopter with technicians
- Supplier with Zodiac
  1: Bringing technicians to turbine (~ 2 hours)
  2: Personnel into zodiac and accessing turbine
  3: Carrying out repair; supplier remains near turbine
  4: Personnel from turbine into zodiac and back to supplier
  5: Accessing supplier
  6: Travelling back to harbour
- Supplier with OAS (Offshore Access System)
  As previous situation but with OAS instead of zodiac which provides the possibility to work during higher significant wave heights.

Hoisting personnel from a boat to the platform with a crane in e.g. a basket or hoisting the entire sloop can be considered but some remarks should be made.

1. The crane has to be operated remotely and a monthly inspection is required.
2. Legal position is not clear
3. Personnel are not insured during this operation.

RS-2: Inspection and repair (outside)

At least two technicians need to be transported to the turbine in order to carry out an inspection or repair at the outside of the turbine. For instance cleaning of the blades or inspection of the tower, or repairing the gel coat of the blades. It is likely that the turbine will be equipped with special facilities like a hoisting system, steps, etc. If not, an external crane is needed for blade repairs.

The equipment and procedures needed to transport personnel is identical to RS-1.

RS-3: Preventive maintenance and replacement

It has been decided from inspections that a medium sized component has to be replaced. ("Medium sized" in this context means that the component can be hoisted through the tower.) A sufficiently large crew needs to be transported to the turbine together with the spare parts. If preventive maintenance has to be carried out, the procedure is identical. The crew has to be transported together with consumables that cannot be carried by the personnel.

For crew transport, the same equipment and procedures as in RS-1 can be used. Transporting and hoisting the "medium sized" equipment should be done by

- Helicopter
- Supplier with crane
- Internal crane at steps or nacelle
- Supplier with OAS (offshore access system of P&R systems)

Depending on the type of failure, it is possible that the crew needs more than one shift to carry out the repair. This means that more than one access needs to be considered for downtime and cost calculation.

RS-4: Replacement of large components (internal crane)

If e.g. a generator or gearbox has to be replaced, an internal crane can be used. It is to be expected that most turbines with a rated power of 2 MW or more and that are especially designed for offshore applications will be equipped with cranes that can hoist all components in the nacelle and even the rotor blades. As opposed to the medium sized components, the equipment cannot be transported through the tower. It has to be hoisted outside the turbine. Low wave heights and low wind speeds are required for such operation. It is recommended to design a kind of guidance system to ensure that the generator or gearbox does not collapse against the tower at higher wind speeds. Furthermore, some facilities should be designed and applied to avoid that the generator or gearbox does not collapse against the deck of the supplier or pontoon.

Available transportation equipment is:

- Pontoon with tug for blades;
- Supplier for e.g. gearbox, hub, and generator

The procedure for replacing a large component could look as follows.

1. Waiting for good weather conditions.
2. Transporting personnel to the turbine (similar to RS-1) in order to dismount the component. It is possible that more than one preparatory visit is necessary.
3. Bringing transportation device to the turbine and mooring if necessary.
4. Hoisting of failed component and spare parts.
5. Return of transportation device.
6. Mounting spare part in turbine (probably in a few shifts, which means additional visits of personnel) and travelling back to harbour.

RS-5: Replacement of large components (external crane)

Not all turbines are equipped with an internal crane that can hoist all heavy equipment. In these cases an external crane is needed. Before the operation can start, the following steps need to be carried out.

1. Waiting for good weather conditions.
2. Transporting personnel to the turbine (similar to RS-1) in order to dismount the component.
3. Bringing equipment (crane and transportation device) to the turbine and mooring if necessary.
4. Hoisting of failed component and spare parts.
5. Return of transportation device and crane.
6. Mounting spare part in turbine (probably in a few shifts, which means additional visits of personnel) and travelling back to harbour.

Applicable equipment:

- Jackup with crane
- Crane ship
- (Floating sheerleg (Flat bottom crane barge))

In the probabilistic model, four types of equipment can be assigned to a certain failure type class. In Table 6.1 and 6.2, this is illustrated for two configurations: near shore with small turbines and far offshore with large turbines. In the latter case, the external crane is only needed for assembling the turbine and for dismounting the entire nacelle. The internal cranes have sufficient capacity to hoist all components, including the rotor blades.

Table 6.1: *Repair strategy for near shore wind farm; (small turbines with limited crane capacity)*

			Transportation of Personnel	*Transportation of component*	*Positioning of equipment*	*Hoisting of component*
Component	**FTC**	**Material Class**	EQ1	EQ2	EQ3	EQ4
generator	1	2	Supplier			
	2	3	Supplier	Supplier		
	3	5	Supplier	Supplier	Jack-up with crane	Jack-up with crane

Table 6.2: *Repair strategy for far offshore wind farm; (large turbines with internal cranes)*

			Transportation of Personnel	*Transportation of component*	*Positioning of equipment*	*Hoisting of component*
Component	**FTC**	**Material Class**	EQ1	EQ2	EQ3	EQ4
generator	1	2	Helicopter			
	2	3	Helicopter	Helicopter		
	3	5	Supplier	Supplier		

The values that will be chosen depend on the actual situation. Examples are given in the report on the case studies [6].

7. WIND AND WAVE DATA

7.1 Introduction

A wind turbine that is shut down due to damage will not produce electricity until it has been repaired and started up again. The period of time between the moment the turbine is stopped and the moment it is available for production again is called the Time To Repair (TTR). The TTR can be split up in several phases as shown in Fig. 7.1.

Time To Repair (TTR)			
T_logistics	*T_wait*	*T_mission*	
		T_travel	*T_repair*
Arrangement of device, personnel and spare parts	Waiting due to bad weather conditions	Trip to failed WT	Repair of WT

Fig. 7.1: *Phases during time to repair.*

T_logistics: In the logistic phase, all arrangements are made for the spare parts, the personnel, and the device required. In case of a certain type of damage a specific device (supplier, crane ship, helicopter, etc.) will be required for transportation of technicians and spare parts, and possibly for support during repair, for instance for hoisting.

T_wait: After all arrangements have been made during the logistic phase, it might happen that the device cannot leave the port due to bad weather conditions. It has to wait until the characteristic wave height H, and the wind speed V are more benign than the maximum values Hmax and Vmax required to carry out the mission.

T_mission: The mission phase comprises the time it takes to travel to the wind turbine (T_travel) and the time needed for the actual repair (T_repair). As an example a wind turbine with a damaged blade is considered. This blade has to be replaced and for this activity a crane ship is deployed. During positioning and hoisting, the wave height has to less than 1.5 m, while the wind speed during hoisting has to be less than 6 m/s. So in this case Hmax = 1.5 m and Vmax = 6 m/s. The duration of the phase in which the device has to wait for suitable weather conditions, depends on the duration of the whole mission (T_mission) and the expected weather conditions during the mission. The waiting time (T_wait) is a stochastic quantity mainly due to dependence on the weather conditions, notably wave height and wind speed. In section 7.2 a model to estimate the waiting time is described.

Furthermore, the parameters required for this model have been determined for several values of Hmax and Vmax, representing several devices. These parameters are based on the wave and wind data published on the Internet by Rijkswaterstaat for the location “IJmuiden Munitiesortplaats”, in the following denoted with YM6 (see in Fig. 7.2) [13]. The co-ordinates of YM 6 are 52^{o}33’00’’ east and 4^{o}03’30’’ north, and the water depth is 21 m.

It should be noted that the scheme depicted in Fig. 7.1 can be preceded by an inspection phase. During the inspection phase a failure of the wind turbine is detected and an inspection is made. For an inspection the same aspects have to be considered as shown in Fig. 7.1. Arrangements of personnel and device have to be made. The inspection crew has to travel to the turbine and has to carry out the inspection. For reasons of simplicity the inspection phase has been omitted here, but will be included in the cost model.

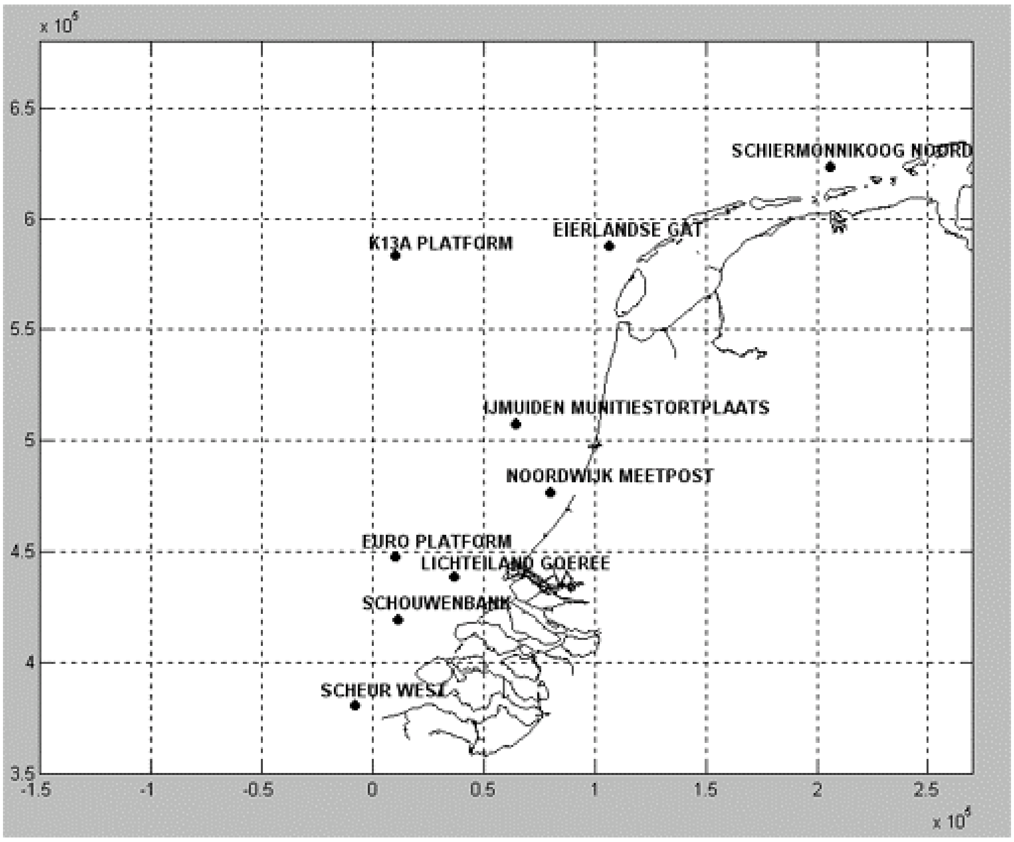

Fig. 7.2: *Location for which Rijkswaterstaat measures wind and wave data*

The TTR is an important quantity as it determines the loss of production when combined with the wind climate and the power curve of the wind turbine. The distribution of the wind speed is generally described by a Weibull distribution. As both the occurrence of lightning and the distribution of the wind speed vary strongly over the year it is desired to determine the wind speed distribution for the four seasons separately. Based on the wind data available for YM6 the Weibul parameters characterising the wind speed distributions have been determined in section 7.3.

7.2 Weather Windows for Accessibility

7.2.1 Procedure

Fig. 7.4 shows a small part of the time series for the wind speed V and the wave height Hm0. Furthermore the lines corresponding with Vmax = 12 m/s and Hmax = 1.5 m are drawn (to demonstrate the procedure it is assumed that the waiting time has to be determined for a device requiring these maximum values). At the horizontal axis corresponding with the minimum y-value (V = 0 m/s) the low time intervals are indicated. During a low time interval V < Vmax and Hm0 < Hmax and repair is possible provided that the length of the interval is sufficient to complete the mission. At the horizontal axis corresponding with the maximum y-value (V = 27.0 m/s) the high time intervals are indicated. During a high time interval V > Vmax or Hm0 > Hmax and it is not allowed for the chosen device to leave the port. The length of the ith low interval is indicated by T_i^{low} and covers the time interval starting on $t_{i,1}^{\mathrm{low}}$ and ending on $t_{i,2}^{\mathrm{low}}$. The same definition holds for the high intervals.

To determine the duration of the waiting phase (T_wait) a stylistic time series consisting of alternately low and high intervals is considered. The first low interval T_i^{low} with a length greater than T_mission is looked up and waiting time now equals $t_{i,1}^{\text{low}}$.

To determine the TTR in the cost model it is not practical to work with measured time series because of the amount of data to be handled. For this reason a stylistic time series consisting of alternately low and high intervals will be constructed in the cost model. This construction will be done by means of Monte Carlo simulation using statistical distribution functions for the low and high intervals derived from measured times series. This procedure is shown schematically in Fig. 7.3 and is outlined below to clarify the way the measured time series have to be parameterised for application in the cost model.

The process starts with generating the first interval in which the failure does occur, and it has to be determined whether the failure occurs in a high or low interval and subsequently the length of the interval has to be computed. It is assumed that failures do occur randomly in time, so the probability that the first interval is low is equal to the fraction of all low intervals compared to total duration of the time series considered or

$$P_{\text{low}} = 1 - P_{\text{high}} = \frac{\sum T_i^{\text{low}}}{\sum T_i^{\text{low}} + \sum T_i^{\text{high}}}$$

Furthermore the length of the 1st interval has be determined. As failures occur randomly one is interested in the probability that the point of time at which the failure occurs lies in an interval with a certain length. The probability that a failure occurs in a low interval with a certain length is determined by the fraction of the total duration of all low intervals with this length compared to total duration of all low intervals considered. For instance n_k^{low} low intervals with a length of T_k^{low} are found. In case the 1st interval is low the probability that this has length T_k^{low} is $\dfrac{n_k^{\text{low}} \cdot T_k^{\text{low}}}{\sum T_i^{\text{low}}}$.

The same holds for the high intervals. In this way the statistical distribution function of the length of the intervals can be determined for the low intervals as well as for the high intervals. The corresponding cumulative distribution function (CDF) is denoted by $F_D^{\text{low}}(T)$ for the low intervals and by $F_D^{\text{high}}(T)$ for the high intervals and gives the probability that a certain point in times lies in a interval with a length less than T.

The subsequent intervals are chosen randomly from all intervals possible, so the probability that the length of next low interval equals T_k^{low} is now given by $\dfrac{n_k^{\text{low}}}{\sum n_i^{\text{low}}}$.

The same holds for the high intervals. In this way the statistical distribution function of the number of the intervals can be determined for the low intervals as well as for the high intervals. This cumulative distribution function (CDF) is denoted by $F_N^{\text{low}}(T)$ for the low intervals and by $F_N^{\text{high}}(T)$ for the high intervals and gives the probability that the length of a randomly chosen interval is less than T.

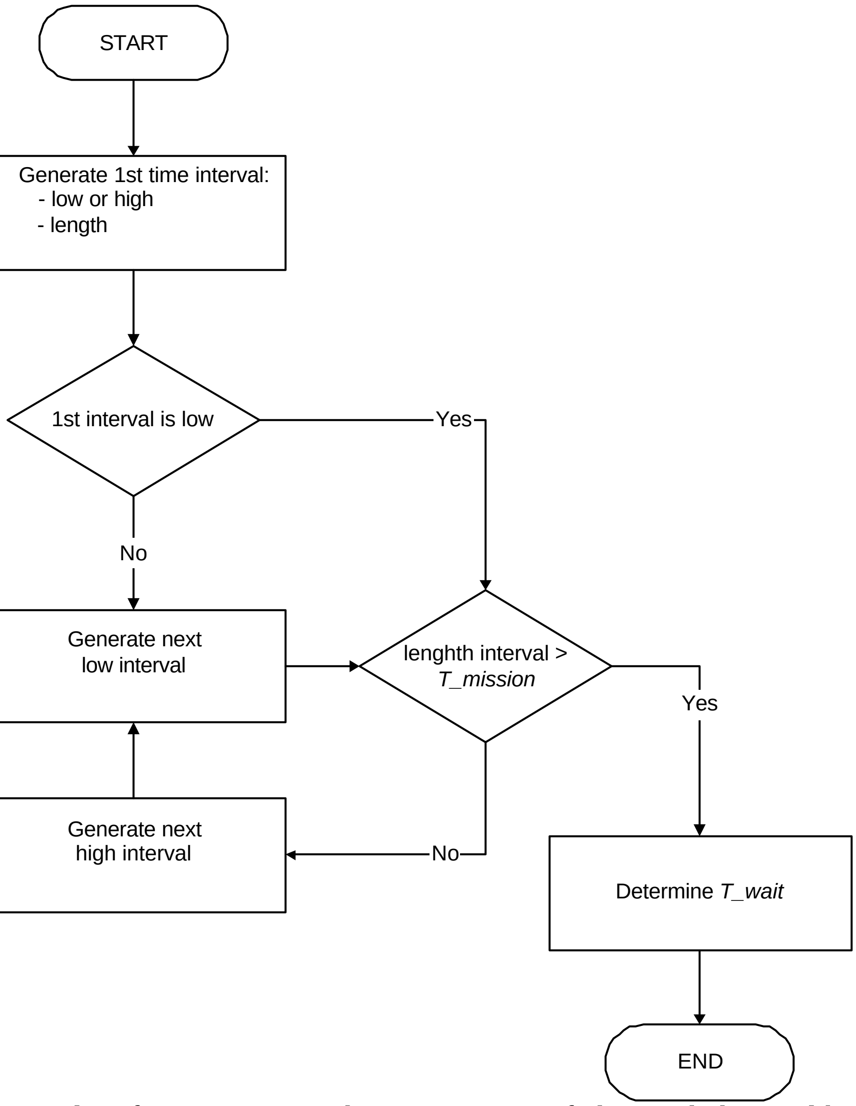

Fig. 7.3: *Procedure for generating stylistic time series of alternately low and high intervals.*

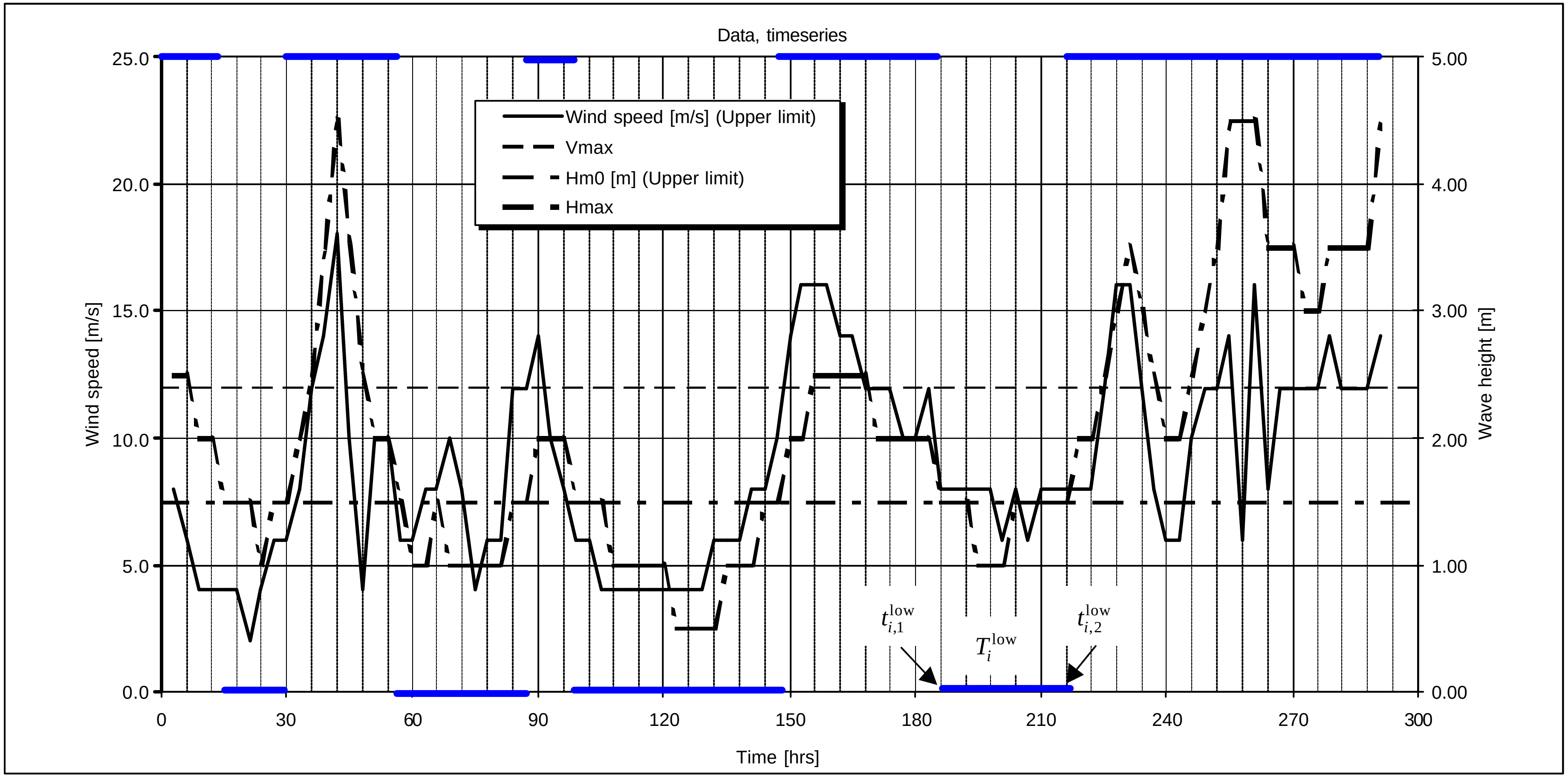

Fig. 7.4: *Schematisation of time series*

7.2.2 Data

Rijkswaterstaat measures the wind speed and the wave height at several locations in the North Sea (see Fig. 7.2). These measurements concern 3 hour mean values and are published on the Internet [13]. The 3 hour mean wind speed and the 3 hour mean wave height published for YM6 for the period 1979-1998 have been processed in the way described in section 7.2.1 for a number of combinations of maximum wind speed and maximum wave height, as listed in Table 7.1. To enable the possibility to make a cost break down for the seasons of a year the time series were split up into 4 pieces, each piece covering a season. The results of processing the time series over the whole year are calculated also.

Table 7.1: *Overview of combinations of maximum wind speed and maximum wave height for which the measured time series of YM6 have been processed.*

Weather window number	Maximum wave height [m]	Maximum wind speed [m/s]
1	n.a.	6.0
2	n.a.	15.0
3	0.5	n.a.
4	0.5	6.0
5	1.0	n.a.
6	1.0	6.0
7	1.5	n.a.
8	1.5	6.0
9	1.5	12.0
10	2.0	12.0
11	1.0	12.0

The result of applying the procedure described in section 7.2.1 is that the CDF's are given in tabular form. As the CDF results should be used as input for the cost model it would be more convenient if the CDF could be described by a standard distribution function. In this case the CDF is defined by its parameters only. To investigate whether it is possible to parameterise the CDF of the duration of the intervals ($F_D^{\text{low}}(T)$ and $F_D^{\text{high}}(T)$) and the CDF of the number of intervals ($F_N^{\text{low}}(T)$ and $F_N^{\text{high}}(T)$) the tabulated values of the CDF have been fitted by means of the @Risk function "Fit distribution to data". Because the measured data concern 3-hour means this fit was done with an offset of 3 hours. Although several statistical functions showed a good agreement it appeared the shifted Weibull distribution could be used for all data sets (duration and length of intervals for both high and low). Figure 7.5 shows the results for weather window 9 (Hmax = 1.5 m and Vmax = 12.0 m/s) during the winter period, the data derived from the measurements are denoted with crosses and the fitted Weibull function is represented by the drawn line.

The CDF of the shifted Weibull distribution is defined as

$$F_X(x) = 1 - e^{-\left(\frac{x-V}{b}\right)^a} \qquad , x \geq V$$

where:

a : shape parameter;
ß : scale parameter;
? : amount by which the domain of the distribution is shifted.

The calculated Weibull parameters for the weather windows specified in Table 7.1 are given in Table 7.2 – 7.6 for the four seasons and the whole year respectively. Furthermore the probability P_{low} is given in these Tables.

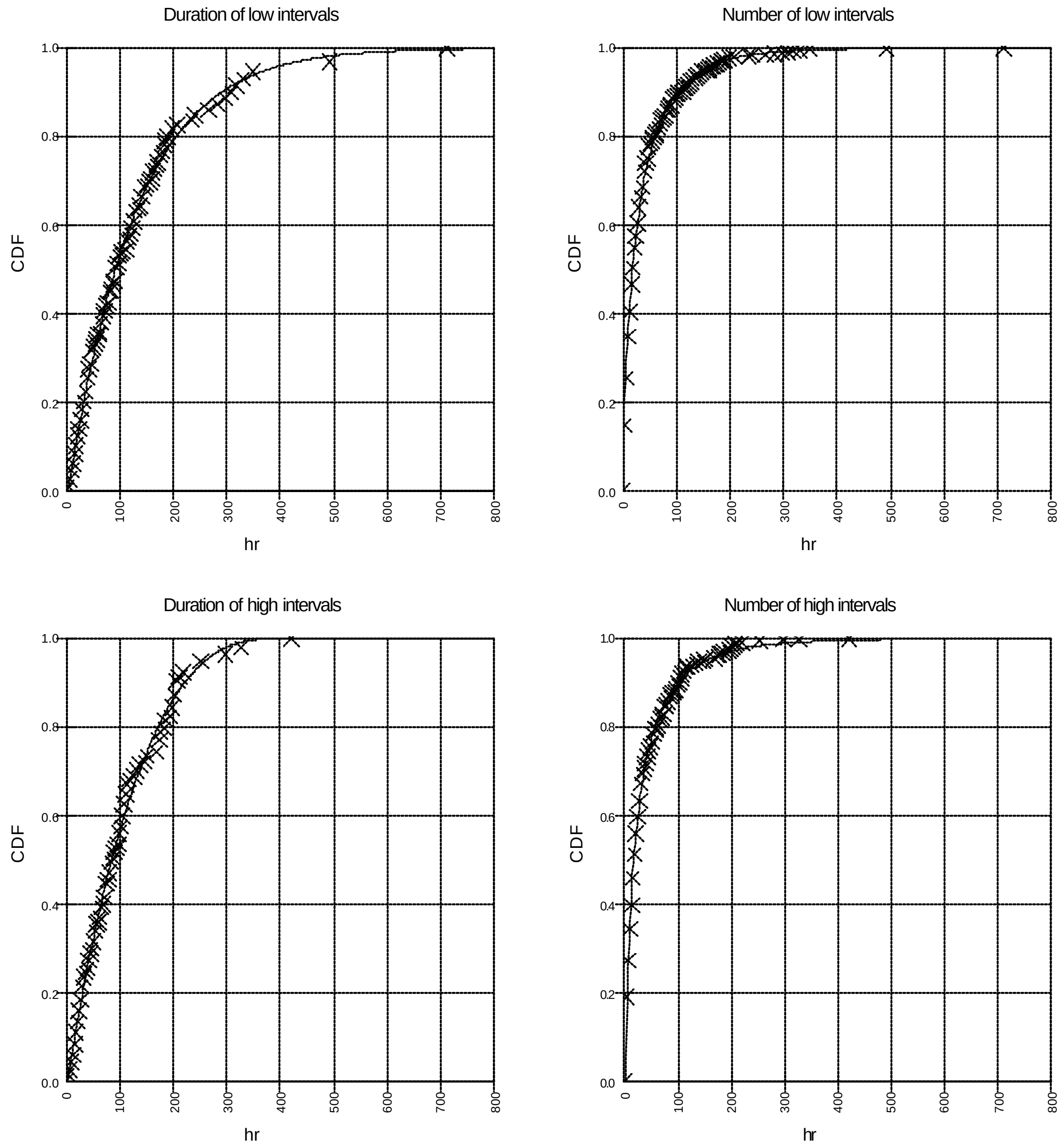

Fig. 7.5: *Calculated CDF (denoted by crosses) and fitted Weibull distribution (line) for duration and length of low and high intervals determined for the weather window with* $H_{max} < 1.5$ *m and* $V_{max} < 12.0$ *m/s during the winter period.*

Table 7.2: *Weibull parameters of the CDF for the duration and the number of low and high intervals and the probability P_{low} valid for the winter period. The domain of the Weibull distributions has been shifted with ? = 3 hrs.*

Winter

				Low intervals				High intervals			
				duration		number		duration		number	
Nr	Hmax [m]	Vmax [m/s]	Plow [%]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	ß [hr]
1	n.a.	6.0	35.3	0.907	42.2	0.536	7.38	1.02	95.1	0.542	15.8
2	n.a.	15.0	90.0	0.991	411	0.447	33.8	1.03	12.5	0.643	4.08
3	0.5	n.a.	7.0	1.09	36.3	0.669	10.9	1.38	931	0.412	117
4	0.5	6.0	6.8	1.13	34.4	0.660	10.4	1.39	929	0.407	116
5	1.0	n.a.	29.1	1.01	78.1	0.572	15.1	1.11	218	0.589	42.2
6	1.0	6.0	22.7	0.954	46.1	0.562	9.10	1.07	254	0.482	30.4
7	1.5	n.a.	52.2	1.02	132	0.600	25.5	1.13	112	0.612	25.0
8	1.5	6.0	31.8	1.08	36.5	0.615	9.23	0.988	47.7	0.554	9.17
9	1.5	12.0	52.0	1.03	127.6	0.609	25.5	1.13	111.3	0.610	24.7
10	2.0	12.0	67.9	0.968	201	0.534	27.9	1.09	61.1	0.648	15.8
11	1.0	12.0	29.1	1.012	78.1	0.574	15.1	1.11	218	0.592	42.4

Table 7.3: *Weibull parameters of the CDF for the duration and the number of low and high intervals and the probability P_{low} valid for the spring period. The domain of the Weibull distributions has been shifted with ? = 3 hrs.*

Spring

				Low intervals				High intervals			
				duration		number		duration		number	
Nr	Hmax [m]	Vmax [m/s]	Plow [%]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	ß [hr]
1	n.a.	6.0	45.0	0.895	37.1	0.580	7.77	0.895	37.1	0.580	7.77
2	n.a.	15.0	95.9	1.29	643	0.495	100	0.905	8.50	0.583	2.51
3	0.5	n.a.	17.5	0.957	58.7	0.581	11.7	1.25	372	0.495	58.7
4	0.5	6.0	15.1	0.883	38.1	0.573	7.68	1.21	376	0.429	39.7
5	1.0	n.a.	52.3	1.11	124	0.631	28.9	1.21	109	0.606	25.6
6	1.0	6.0	35.5	0.910	38.0	0.598	8.46	1.06	104	0.486	13.7
7	1.5	n.a.	74.3	1.32	221	0.604	53.5	1.13	58.7	0.695	17.5
8	1.5	6.0	42.9	0.911	37.7	0.585	8.08	0.990	64.3	0.514	9.89
9	1.5	12.0	74.1	1.31	209	0.606	50.3	1.12	58.2	0.665	16.2
10	2.0	12.0	83.8	1.20	311	0.560	60.3	1.13	34.4	0.695	11.0
11	1.0	12.0	52.2	1.13	121	0.632	28.8	1.21	108	0.605	25.4

Table 7.4: *Weibull parameters of the CDF for the duration and the number of low and high intervals and the probability P_{low} valid for the summer period. The domain of the Weibull distributions has been shifted with ? = 3 hrs.*

Summer

				Low intervals				High intervals			
				duration		number		duration		number	
Nr	Hmax [m]	Vmax [m/s]	Plow [%]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	ß [hr]
1	n.a.	6.0	48.3	1.08	36.2	0.603	8.99	0.998	42.8	0.580	9.15
2	n.a.	15.0	98.9	1.38	1313	0.493	226	1.06	6.69	0.700	2.65
3	0.5	n.a.	22.8	1.18	53.0	0.691	16.2	1.36	250	0.571	56.6
4	0.5	6.0	19.9	1.15	33.7	0.677	10.5	1.31	248	0.475	38.0
5	1.0	n.a.	59.3	1.09	130	0.631	29.4	1.14	78.4	0.647	20.4
6	1.0	6.0	40.9	1.09	36.8	0.613	9.43	1.06	76.0	0.515	12.0
7	1.5	n.a.	83.0	1.27	298	0.558	59.9	1.18	39.5	0.655	11.7
8	1.5	6.0	47.6	1.08	36.5	0.615	9.23	0.988	47.7	0.554	9.17
9	1.5	12.0	82.4	1.27	272	0.556	53.8	1.16	38.8	0.631	10.6
10	2.0	12.0	91.6	1.23	449	0.541	76.5	0.948	22.9	0.568	5.21
11	1.0	12.0	59.2	1.08	126	0.642	29.2	1.14	78.3	0.636	19.9

Table 7.5: *Weibull parameters of the CDF for the duration and the number of low and high intervals and the probability P_{low} valid for the autumn period. The domain of the Weibull distributions has been shifted with ? = 3 hrs.*

Autumn											
				Low intervals				High intervals			
				duration		number		duration		number	
Nr	Hmax [m]	Vmax [m/s]	Plow [%]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	ß [hr]
1	n.a.	6.0	44.1	1.02	44.46	0.545	8.57	1.06	60.4	0.564	11.8
2	n.a.	15.0	94.0	1.17	682	0.632	3.91	0.953	13.1	0.632	3.90
3	0.5	n.a.	10.6	1.15	32.5	0.720	11.2	1.33	551	0.445	78.9
4	0.5	6.0	10.0	1.12	29.5	0.667	9.19	1.35	549	0.417	70.0
5	1.0	n.a.	37.3	1.08	88.6	0.603	19.7	1.21	164	0.590	35.8
6	1.0	6.0	30.6	1.13	45.3	0.598	11.0	1.12	165	0.474	21.2
7	1.5	n.a.	59.4	1.04	175	0.540	27.8	1.29	80.0	0.697	24.7
8	1.5	6.0	39.8	1.08	46.5	0.565	9.68	1.11	85.6	0.534	14.9
9	1.5	12.0	59.2	1.05	172	0.537	27.4	1.29	79.9	0.691	24.3
10	2.0	12.0	75.3	1.13	244	0.530	38.3	1.31	47.9	0.668	14.7
11	1.0	12.0	37.3	1.08	88.7	0.605	19.8	1.21	164	0.588	35.8

Table 7.6: *Weibull parameters of the CDF for the duration and the number of low and high intervals and the probability P_{low} valid for the whole year. The domain of the Weibull distributions has been shiftedwith ? = 3 hrs.*

Year											
				Low intervals				High intervals			
				duration		number		duration		Number	
Nr	Hmax [m]	Vmax [m/s]	Plow [%]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	ß [hr]	a [-]	? [hr]
1	n.a.	6.0	43.2	0.971	39.6	0.571	8.20	0.986	61.4	0.550	10.93
2	n.a.	15.0	94.6	1.10	754	0.429	60.6	0.961	11.4	0.635	3.56
3	0.5	n.a.	14.5	1.05	48.3	0.651	12.9	1.12	507	0.501	67.6
4	0.5	6.0	12.9	1.04	34.2	0.639	9.33	1.11	507	0.446	50.1
5	1.0	n.a.	44.6	1.06	111	0.607	23.2	1.07	145	0.600	29.0
6	1.0	6.0	32.4	1.01	40.7	0.599	9.37	0.964	144	0.484	16.3
7	1.5	n.a.	67.5	1.11	217	0.558	37.3	1.07	78.6	0.650	19.5
8	1.5	6.0	40.6	0.992	40.6	0.580	8.71	0.959	80.1	0.521	11.9
9	1.5	12.0	67.1	1.11	205.1	0.564	36.2	1.07	78.0	0.634	18.5
10	2.0	12.0	80.0	1.09	311	0.528	44.5	1.08	46.3	0.631	11.8
11	1.0	12.0	44.6	1.06	109	0.610	23.2	1.07	145	0.597	28.7

7.3 Wind Speed Distribution for Energy Production

The wind speed distributions for the four yearly seasons and for the whole year have been determined based on the measured 3 hour mean values published for station YM6 [13]. The results are given in Table 7.7. The wind speed is measured at 10 m height. For offshore locations the wind speed at height H can be calculated with

$$V_H = V_{10}\left(\frac{H}{10}\right)^{0.1}$$

where

H	:	height [m];
V_H	:	wind seed at height H;
V_{10}	:	wind speed at 10 m height;

For offshore locations the power law factor is assumed to be 0.1.

Table 7.7: *Weibull parameters for wind speed distribution at 10 m height measured at YM6*

Parm	Winter	Spring	Summer	Autumn	Year
Shape (a)	1.97	2.09	2.10	1.85	1.96
Scale (ß) [m/s]	9.23	7.71	7.33	8.22	8.09

8. CONCLUDING REMARKS

In this report, data has been collected that is relevant to estimate the costs for lightning damage of OWECS. Data has been collected on the probability of lightning hitting a turbine in an offshore wind farm, the resulting damage, measures for lightning protection, the costs for repair actions, and wind and wave data to estimate the downtime for certain repair actions. The project team has succeeded in collecting and quantifying the relevant data, including their uncertainties.

The team has concluded that the damage that may occur after a lightning strike has hit a turbine is the quantity with the largest uncertainty and which is the most difficult to quantify. The first reason for that is that only very little data on lightning damages is available. The data has been collected from onshore turbines but not detailed enough to estimate damages for offshore turbines. The second reason is that the efficiency of protective measures is unclear and difficult to quantify. Damage reports give very little insight in this. The number of damages is not a measure for the number of hits. Some hits may have been guided safely through the turbine without causing any damage.

More detailed conclusions on the individual topics are given below.

Lightning

The number of thunderstorms per year and the number of flashes per thunderstorm have been determined for three different offshore locations, viz. 12 km, 30 km, and 300 km offshore. The size of the wind farms and the size of the turbines has impact on the number of flashes per km^2 and has been taken into account. The number of flashes has been compared with onshore data and it can be concluded that the number of flashes per year is lower for offshore locations. The further offshore, the lower the number of flashes, see Table 2.6.

Table 2.6: *Comparison between the number of flashes onshore and offshore*

	Onshore	Near shore 1 *(» 12 km)*	Near shore 2 *(» 30 km)*	Far offshore *(» 300 km)*
Number of flashes per year per km^2	1.0	0.48 – 0.60	0.34 – 0.42	0.23 – 0.28

Lightning Protection

The efficiency of the lightning protection of external systems, mainly the rotor blades, is a product of the *interception efficiency* and of the *sizing efficiency*. The IEC 61024-1 distinguishes four levels. A rotor blade equipped with the highest level, Level I, is able to survive 98% of the lightning flashes without substantial damage. Damages near the interception points still may occur.

Internal protection is required for the electrical and control systems mainly. The bearings seem to be the most vulnerable mechanical part for which protection systems need to be applied. For electrical and control systems in buildings, a well-proven method is available to design lightning protection systems. The electrical systems are divided into four “lightning protection zones”. The efficiencies of protection systems that have been designed in accordance to that method are well known. The IEC 61400 recommends to use the same method for wind turbines. However, only very little is known on the efficiency of that method. It has been decided that the efficiency of the protection is a variable in the cost model that can be defined later on if the final turbine configuration is known, including the detailed engineering of the lightning protection systems.

The costs to protect for example a 3 MW turbine in 98 % of the flashes is in the order of magnitude of 27 k€.

Damage Events

Analyses of reported lightning damages in Germany, Denmark, and the Netherlands have revealed that rotor blades are the most vulnerable parts in terms of frequency and repair costs. The number of damaged controllers is larger for older turbines than for new turbines. This could indicate that the protection systems for the electrical system are efficient but that cannot be proven with the limited background data on the statistics.

For the cost model, a kind of distribution function has been derived from the failure analyses. This function defines which component will be damaged most often after a lightning flash has hit the turbine.

Cost of Lightning Damage

After a component has been damaged, costs should be made to repair the component and restart the turbine. The costs depend on:

- the severity of the damage (little damage or complete failure)
- material costs
- labour costs
- logistics and repair times
- costs for equipment and access systems

For the probabilistic cost model, the material costs have been expressed as a function of the investment costs. The material costs and the labour costs in fact depend on the severity of the failure.

The costs for equipment and access systems have been derived from the current market prices. The prices are covered with large uncertainties and depend strongly on the final contract. Once a certain boat or vessel is chosen for an a offshore wind farm, the prices can be determined with less uncertainty and put in the cost model.

Down Times

The down time needed to repair the lightning damage and the resulting revenue losses can be a major cost driver. The down time depends largely on the selected repair strategy and on the selected equipment and access systems. In the report, various possible strategies have been given to repair little damages or to replace main components. Each type of equipment has its own limits with respect to wave height and wind speed.

A method is presented in the report to determine the repair time as of:

- the maximum wave height at which equipment can be used;
- the maximum wind speed at which equipment can be used;
- the duration of the repair.

The time to repair is a stochastic variable, which means that not only the average value can be calculated but also the probability that the repair action will take two times longer.

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ANNEX A: ESTIMATES OF LIGHTNING INCIDENTS FOR NORTH SEA WIND FARMS

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A.1 Introduction.

In establishing the risk due to lightning it is customary to separate the strike probability from the expected damage caused by each lightning flash. This section is limited to the lightning probability only, because damage depends on other factors like impact point, turbine type and protection level.

Lightning flash density *N* is expressed in units of 'ground flashes per square kilometer per year'. Attempts have been made to relate this quantity to the traditional 'number of days per year with thunder heard'. In recent years it has become possible to obtain *N* directly from measurements with a lightning detection system. Especially over the North Sea the value of *N* is small, namely about $1/km^2/y$. The distribution in time and space of these lightning flashes is very irregular: they occur in groups (travelling thunderstorms) and thunder days are relatively rare. Large differences from year to year may be expected. One or two summer days may contribute most of the yearly total over the Netherlands.

Estimates of *N* must therefore be based on many years of measurements and the counting surface must be large enough to avoid sampling errors. If e.g. 25 flashes are counted (i.e. in 5 years over 5 km^2), the standard deviation of the estimate is $\sqrt{25} = 5$ (20%), if a Poisson distribution is assumed. For this particular problem, not only the value of *N* is of interest, but also the distribution of flashes with time. The number of repair visits can be reduced if the flashes occur clustered on a few days rather than distributed evenly over the year.

A.2 The lightning collection area of a wind farm.

It is well known that elevated objects receive more lightning strikes than low ones. Approximate formulae relate the collection area *A*, a circle with radius *R*, with the height *H* of the tower. An example is:

$$R(m) = 2.98H$$

or

$$A = 0.000028\,H^2 \quad [\mathrm{km}^2]$$

with *H* in m.

The yearly number of flashes follows then as $N \cdot A$.
In the case of multiple towers the collection areas may partly overlap. The fractional overlap *F* of a circle with radius *R* by another circle around a tower at distance *D* is given by

$$F = \frac{a - \sin(a)}{p}$$

with

$$a = 2\cos^{-1}\left(\frac{D}{2R}\right)$$

the angular span of the overlapping sector.

Because it was impossible to derive data for the whole North Sea within this project, three different locations have been considered (see Chapter 1 of this report). For each location three different wind farm configurations were specified with turbines of different capacity, but in sufficient number (*M*) to generate a total maximum of 100 MW.

The highest point of a turbine will depend on the position of the blades. Two contrasting positions are with one blade straight up resp. with one blade down. If the collecting area for this lower tip height is A^*, then the collecting area of both blades is $(2-F)\cdot A^*$.

The results in Table A.1 show that the collection area is about 20% larger than for the 'one blade up' situation. However, with two blades up there is more chance of overlap with the next turbine in the row, at least if the wind blows across the row. Therefore, we assume here the turbines having a single blade in top position.

Table A.1: *Effect of blade position on collection area of a single turbine.*

H (m, single/double)	90 /72	115 /92	140 /110
A (km^2)	0.227 /0.273	0.370 /0.446	0.549 /0.632

From Table 2.1 in Chapter 2 it can be found that the distance *D* of turbines within a row is small enough to make the collection areas partly overlap. The collection surface of the wind farm is therefore some 15% smaller than *M**A* (see Table A.2, where the factor F^* accounts for the actual number of overlap sectors in a row).

Table A.2: *Steps in the computation of the collection area of a wind farm*

M	67 (7 rows)	34 (5 rows)	17 (3 rows)
H (m)	90	115	140
A (km^2)	0.227	0.370	0.549
D (m)	400	500	650
F	0.150	0.162	0.122
F^*	$9/10\cdot F=0.135$	$6/7\cdot F=0.139$	$5/6\cdot F=0.102$
$M\cdot A\cdot(1-F^*)$ (km^2)	13.1	10.8	8.4

These collection areas are larger than the footprint area of the farm concerned, because the surrounding part of the collection area is larger than the narrow gaps between the rows were lightning may strike to the sea surface.

A.3 Lightning flashes on wind farms.

Data from the SAFIR network (Wessels, 1998) are available over 6 full years from 1995 until 2000. The lightning archive contains information on individual lightning strokes: time, location, type (horizontal/vertical), lightning current and other physical parameters. The two near-shore sites investigated were centred at:

- 52 deg 36 min N, 4 deg 28 min E - Near-shore 1;
- 52 deg 35 min N, 4 deg 10 min E - Near-shore 2.

National grid co-ordinates were 512.775 km N by 92.612 km E resp. 511.222 km N by 72.260 km E. For these locations the detection efficiency and location accuracy can be regarded optimal. For our purpose random location errors of an individual flash do not matter, because the results are used for statistical purposes only. The sites were relatively close (20 km), so the difference between the results can be regarded as a measure for their representativity. A third site, Doggerbank is outside the reach of the detection system. Only the third configuration is sufficiently elongated to attempt studying orientation effects. The surface over which the data were collected is based on the last row of table A.2: squares of 3.6 and 3.3 km resp. a rectangle of 3.6 x 2.4 km.

Table A.3. *Lightning recorded over wind farm 'Near shore - 1': each asterisk represents a lightning flash.*

Date	hour	axis height (m)			
		55	70	80 N/S	80 E/W
1995 09 03	07	*	*	*	*
1995 09 06	02	***	***	**	**
1996 07 23	15	********	*******	****	**
1996 08 06	17	*	*		*
1996 08 10	06	*	*	*	*
1996 08 20	19	**	*		
1996 08 24	14	*			
1997 06 27	15	*	*		*
1997 10 06	23)	****	**	**	***
1997 10 07	00)	*	*	*	*
1997 11 07	17	*			*
1999 05 07	22	*	*		
1999 06 02	15	******	*****	***	****
1999 07 03	09	*	*	*	
1999 08 26	00	**	*	*	
1999 09 26	14	*			
2000 05 16	22	*	*	*	*
2000 08 13	23)	***	***	***	***
2000 08 14	00)	****	**	**	**
2000 09 01	19	*	*		*
2000 10 10	15)	*	*	*	*
2000 10 10	18)	**	*	*	*

Table A.4. *Lightning recorded over wind farm 'Near-shore - 2': each asterisk represents a lightning flash.*

Date	hour	axis height (m)			
		55	70	80 N/S	80 E/W
1995 07 14	03	*	*		
1995 09 03	08	*	*		*
1995 09 05	22	*	*	*	
1996 07 06	04	*	*		*
1996 07 23	08	*	*	*	*
1996 08 27	06	****	****	*	***
1996 10 05	06	*	*	*	*
1997 06 27	16	*****	****	****	****
1997 08 25	13	**	**	**	**
1998 07 21	03	**	**	*	**
1998 08 24	01	*	*		*
1999 07 03	09	*	*	*	*
1999 09 24	16	*	*		*
1999 09 29	15	*	*	*	
1999 12 14	02	**	**	*	*
2000 01 29	05)	*	*	*	
2000 01 29	10)	**	**	**	*

Multiple flashes have been treated as single: if two strokes occurred within 0.5 sec at a distance within 5000 m, only the one with the largest current was counted.

For location Doggerbank no SAFIR data were available. However, from a recent publication (Holt et al., 2001) lightning location data can be obtained for the years 1990-1999. The data come from the UK Met. Office’s ATD (arrival time difference) system, that covers most of Western Europe. The publication includes small maps for each of the 4 seasons from which the yearly number of thunderdays may be reconstructed.

For the location ‘Doggerbank’ at 55 deg 03 min N, 3 deg 10 min E the yearly number is about 4, for the two other locations about 8-10. Most of the lightning over the sea occurs in summer and autumn. Both figures are about two times smaller than the traditional ‘number of days with thunder heard’ for these locations (see European map at www.knmi.nl/voorl/nader/onweerswaarnemingeninnederland.htm). The reason is that Holt et al. counts the number of days with lightning within 7.5 km from the map-point considered. In the Netherlands we use a circle of 15 km around a manned station to arive at (on average) an equal number of days for the observer and SAFIR. We conclude that the number of days with thunder at Doggerbank is about 8. For the other locations we arrive at about 16-20 in accordance with historic results from light vessels.

A common formula for estimating the yearly flash rate per km^2 from the number of thunder days T is

$$N = 0.04T^{1.25}$$

For Doggerbank we get 0.5 compared to 1.5 for the other locations. As the lower value of N is probably caused by less thunder days as well as less flashes per thunder day, the situation at Doggerbank can best be simulated by randomly deleting stars in Table A.3 or A.4. The results so obtained are presented in the conclusions (section A.4).
Note that the results from Table A.3 or A.4 indicate a value of N of about 0.6 rather than 1.5. This could mean that the period 1995-1999 was too short to estimate a long-time average, but the horizontal lightning distribution and the average Netherlands flash rate in the 5 individual years do not support this suspicion. The long-term average over the land surface of the Netherlands is about 1.3 strokes/ km^2/y. Considering the average multiplicity this means about 1.0 flashes/km^2/y. Offshore values will be lower like is the number of days with thunder. So the flash counts of tables A.3 and A.4 are expected to be within 20% of the long-term average. From these results it seems that the empirical formula $N(T)$ is not accurate, especially not over the sea.

A.4 Conclusions

At the two near-shore locations the number of lightning periods with duration of at most a few hours was for the four configurations respectively 19, 16, 11 and 13 for the first location and 16, 16, 11 and 13 for the second location, all in 6 years. The differences between the locations are small; this suggests that the representativity of the numbers is good. The average yearly number of incidents is 3 for the large farm and 2 for the small farm with high turbines. The average number of lightning flashes in an incident is about 2.
At the location Doggerbank the lightning risk is lower. The average yearly number of incidents is estimated at 2 for the large and 1.5 for the small farm with the high turbines. The number of flashes per incident is about 1.5 for the large and even less for the small farm.
Differences between years may be considerable. More than 65 % of the incidents occurred in the three months July- September.
These figures provide no information of the possible damage caused by these lightning flashes. Conclusions about which configuration is to be preferred, are not drawn at this point, because other - non meteorological – factors have to be considered.

A.5 References

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ANNEX B: FAULT TYPE CLASSES AND MATERIAL CLASSES

In the cost model, a distribution is assumed of the damaged components after a lightning strike. The default distribution is based on data from the ISET database (see Section 6.1 and Table 4.1 in the main report). The values are given in the columns B, C, and D in the table below.

Since not all damages are equally severe, the occurrence probability of one of the three Fault Type Classes has to be chosen in column F. The resulting conditional probabilities are given in column G. (See also Section 6.2).

To carry out the repair of a certain Fault Type Class, a material class has to be chosen in column H. Once the *material class* is chosen, the *labour costs*, *repair time*, and the *logistics time for spare parts* are chosen too. They are given in the columns I through X. (Note that in the cost model the default values for *logistics time for spare parts* are zero.)

B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X
Distribution of Fault Type Classes						**Material Costs**					**Labour Costs**				**Repair Time**				**Logistic time spareparts**			
			Fault Type Classes			Material Classes [% of Inv]		Min	ML	Max		Crew			T_Repair [Hours]				T_Repair [Hours]			
			1	Repair, Cleaning Reset		1	No materials	0.00%	0.00%	0.00%		2	2	3		1	2	2.01		0	0	0
			2	Replacement, hoisting inside.		2	Consumables	0.01%	0.03%	0.09%		2	2	3		1	2	4		0	0	0
Turbine parameters			3	Replacement, hoisting outside.		3	Replacement of small components	0.05%	0.16%	0.47%		2	2	3		2	4	8		0	0	0
Turbine size	1500	[kW]				4	Replacement of medium sized components	2.50%	5.00%	10.00%		2	3	4		6	8	12		0	0	0
Investment costs	850	[Euro/kW]				5	Replacement of major components	7.50%	15.00%	18.00%		4	6	8		20	36	72		0	0	0

Component	# of faults	PDF	FTC	Probability of FTC Occurrence	Conditional PDF	Material Class	Material Costs [Euro/Event]	Min	ML	Max	Euro/ h_repair	Min	ML	Max	hours	Min	ML	Max	hours	Min	ML	Max
control system	310	0.300	1	70%	0.210	1		0	0	0		120	121	180		1	2	2		0	0	0
			2	30%	0.090	2		128	383	1148		120	121	180		1	2	4		0	0	0
			3		0.000	3		667	2002	6005		120	121	180		2	4	8		0	0	0
electric	271	0.263	1	40%	0.105	1		0	0	0		120	121	180		1	2	2		0	0	0
			2	50%	0.132	2		128	383	1148		120	121	180		1	2	4		0	0	0
			3	10%	0.026	4		31875	63750	127500		120	180	240		6	8	12		0	0	0
rotor blades	205	0.199	1	40%	0.080	2		128	383	1148		120	121	180		1	2	4		0	0	0
			2		0.000	3		667	2002	6005		120	121	180		2	4	8		0	0	0
			3	60%	0.119	4		31875	63750	127500		120	180	240		6	8	12		0	0	0
sensors	132	0.128	1	100%	0.128	2		128	383	1148		120	121	180		1	2	4		0	0	0
			2		0.000	2		128	383	1148		120	121	180		1	2	4		0	0	0
			3		0.000	2		128	383	1148		120	121	180		1	2	4		0	0	0
generator	31	0.030	1	70%	0.021	2		128	383	1148		120	121	180		1	2	4		0	0	0
			2	20%	0.006	3		667	2002	6005		120	121	180		2	4	8		0	0	0
			3	10%	0.003	5		95625	191250	229500		240	360	480		20	36	72		0	0	0
hub	23	0.022	1	70%	0.015	2		128	383	1148		120	121	180		1	2	4		0	0	0
			2	20%	0.004	4		31875	63750	127500		120	180	240		6	8	12		0	0	0
			3	10%	0.002	5		95625	191250	229500		240	360	480		20	36	72		0	0	0
hydraulic system	18	0.017	1	20%	0.003	2		128	383	1148		120	121	180		1	2	4		0	0	0
			2	80%	0.014	3		667	2002	6005		120	121	180		2	4	8		0	0	0
			3		0.000	4		31875	63750	127500		120	180	240		6	8	12		0	0	0
yaw system	12	0.012	1	20%	0.002	2		128	383	1148		120	121	180		1	2	4		0	0	0
			2	80%	0.010	3		667	2002	6005		120	121	180		2	4	8		0	0	0
			3		0.000	4		31875	63750	127500		120	180	240		6	8	12		0	0	0
gear box	10	0.010	1	20%	0.002	2		128	383	1148		120	121	180		1	2	4		0	0	0
			2	70%	0.007	3		667	2002	6005		120	121	180		2	4	8		0	0	0
			3	10%	0.001	4		31875	63750	127500		120	180	240		6	8	12		0	0	0
mechanical brake	9	0.009	1	20%	0.002	1		0	0	0		120	121	180		1	2	2		0	0	0
			2	80%	0.007	2		128	383	1148		120	121	180		1	2	4		0	0	0
			3		0.000	3		667	2002	6005		120	121	180		2	4	8		0	0	0
drive train	6	0.006	1	20%	0.001	2		128	383	1148		120	121	180		1	2	4		0	0	0
			2	70%	0.004	3		667	2002	6005		120	121	180		2	4	8		0	0	0
			3	10%	0.001	5		95625	191250	229500		240	360	480		20	36	72		0	0	0
structural parts	5	0.005	1	20%	0.001	2		128	383	1148		120	121	180		1	2	4		0	0	0
			2	20%	0.001	3		667	2002	6005		120	121	180		2	4	8		0	0	0
			3	60%	0.003	5		95625	191250	229500		240	360	480		20	36	72		0	0	0
Inspection			**2**			**1**		0	0	0		120	121	180		1	2	2		0	0	0
Total	**1032**	**1.001**	**1**		**0.571**			**32**	**97**	**291**		**69**	**69**	**103**								
			2		**0.275**			**197**	**451**	**1072**		**33**	**33**	**50**								
			3		**0.156**			**5518**	**11035**	**20724**		**20**	**30**	**39**								

Hourly rate technician	**60**	Euro/hr
Daily allowance technician	**180**	Euro/day
Lenght of working day	**9**	hr
Max lenght of work overtime	**2**	hr