Guidelines
for
Design
of
Wind Turbines

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DNV/Risø

Second Edition

Guidelines for Design of Wind Turbines
2nd Edition

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Preface

The guidelines for design of wind turbines have been developed with an aim to compile into one book much of the knowledge about design and construction of wind turbines that has been gained over the past few years. This applies to knowledge achieved from research projects as well as to knowledge resulting from practical design experience. In addition, the various rules and methods required for type approval within the major markets for the wind turbine industry form a basis for the guidelines, with emphasis on the international standards for wind turbines given by the International Electrotechnical Commission, IEC.

The objective is to provide guidelines, which can be used for design of different types of wind turbines in the future. The guidelines provide recommendations and guidance for design together with application-oriented solutions to commonly encountered design problems.

The guidelines can be used by wind turbine manufacturers, certifying authorities, and wind turbine owners. The guidelines will also be useful as an introduction and tutorial for new technical personnel and as a reference for experienced engineers.

The guidelines are available as a printed book in a handy format as well as electronically in pdf format on a CD-ROM.

The development of the guidelines is the result of a joint effort between Det Norske Veritas and Risø National Laboratory. The development has been founded by Danish Energy Agency, Det Norske Veritas and Risø National Laboratory.

These guidelines for design of wind turbines have been thoroughly reviewed by internal and external experts. However, no warranty, expressed or implied, is made by Det Norske Veritas and Risø National Laboratory, as to the accuracy or functionality of the guidelines, and no responsibility is assumed in connection therewith.

Contents

1. Wind Turbine Concepts

1.1 Introduction

Wind-powered ships, grain mills, water pumps, and threshing machines all exemplify that extraction of power from wind is an ancient endeavour. With the evolution of mechanical insight and technology, the last decades of the 20th century, in particular, saw the development of machines which efficiently extract power from wind. ”Wind turbines” is now being used as a generic term for machines with rotating blades that convert the kinetic energy of wind into useful power.

In the 20th century, early wind turbine designs were driven by three basic philosophies for handling loads: (1) withstanding loads, (2) shedding or avoiding loads, and (3) managing loads mechanically, electrically, or both. In the midst of this evolution, many wind turbine designs saw the light of day, including horizontal axis and vertical axis turbines. Turbines that spin about horizontal and vertical axes, respectively, and are equipped with one, two, three or multiple blades.

Modern turbines evolved from the early designs and can be classified as two or three-bladed turbines with horizontal axes and upwind rotors. Today, the choice between two or three-bladed wind turbines is merely a matter of a trade-off between aerodynamic efficiency, complexity, cost, noise and aesthetics.

Additional key turbine design considerations include wind climate, rotor type, generator type, load and noise minimisation, and control approach. Moreover, current trends, driven by the operating regime and the market environment, involve development of low-cost, megawatt-scale turbines and lightweight turbine concepts. Whereas turbines operating at constant rotor speed have been dominating up to now, turbines with variable rotor speed are becoming increasingly more common in an attempt to optimise the energy capture, lower the loads, obtain better power quality, and enable more advanced power control aspects.

1.2 Conceptual aspects

Some early wind turbine designs include multiple-bladed concepts. These turbines are all characterised by rotors with high solidity, i.e. the exposed area of the blades is relatively large compared to the swept area of the rotor.

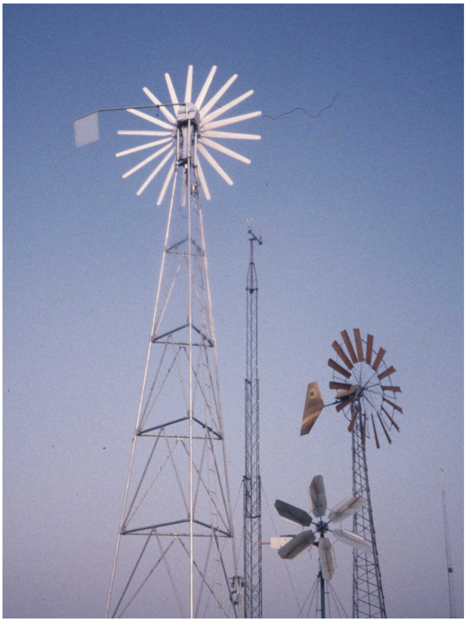

Figure 1-1. Multiple-bladed wind turbines of various designs.

A disadvantage of such a high-solidity rotor is the excessive forces that it will attract during extreme wind speeds such as in hurricanes. To limit this undesirable effect of extreme winds and to increase efficiency, modern wind turbines are built with fewer, longer, and more slender blades, i.e. with a much smaller solidity. To compensate for the slenderness of the blades, modern turbines operate at high tip speeds.

1.2.1 Vertical axis turbines

Vertical axis wind turbines (VAWTs), such as the one shown in Figure 1-2 with C-shaped blades, are among the types of turbine that have seen the light of day in the past century.

Figure 1-2. Eole C, a 4200 kW vertical axis Darrieus wind turbine with 100 m rotor diameter at Cap Chat, Québec, Canada. The machine, which is the world's largest wind turbine, is no longer operational. From www.windpower.org (2000), © Danish Wind Turbine Manufacturers Association.

Classical water wheels allow the water to arrive tangentially to the water wheel at a right angle to the rotational axis of the wheel. Vertical axis wind turbines are designed to act correspondingly towards air. Though, such a design would, in principle, work with a horizontal axis as well, it would require a more complex design, which would hardly be able to beat the efficiency of a propeller-type turbine. The major advantages of a vertical axis wind turbine, as the one illustrated in Figure 1-2, are that the generator and gearbox are placed on the ground and are thus easily accessible, and that no yaw mechanism is needed. Among the disadvantages are an overall much lower level of efficiency, the fact that the turbine needs total dismantling just to replace the main bearing, and that the rotor is placed relatively close to the ground where there is not much wind.

1.2.2 Horizontal axis turbines

Horizontal axis wind turbines (HAWTs), such as the ones shown in Figure 1-3, constitute the most common type of wind turbine in use today. In fact all grid-connected commercial wind turbines are today designed with propeller-type rotors mounted on a horizontal axis on top of a vertical tower. In contrast to the mode of operation of the vertical axis turbines, the horizontal axis turbines need to be aligned with the direction of the wind, thereby allowing the wind to flow parallel to the axis of rotation.

Figure 1-3. Three-bladed upwind turbines being tested at Risø, August 1986.

Insofar as concerns horizontal axis wind turbines, a distinction is made between upwind and downwind rotors. Upwind rotors face the wind in front of the vertical tower and have the advantage of somewhat avoiding the wind shade effect from the presence of the tower. Upwind rotors need a yaw mechanism to keep the rotor axis aligned with the direction of the wind. Downwind rotors are placed on the lee side of the tower. A great disadvantage in this design is the fluctuations in the wind power due to the rotor passing through the wind shade of the tower which gives rise to more fatigue loads. Theoretically, downwind rotors can be built without a yaw mechanism, provided that the rotor and nacelle can be designed in such a way that the nacelle will follow the wind passively. This may, however, induce gyroscopic loads and hamper the possibility of unwinding the cables when the rotor has been yawing passively in the same direction for a long time, thereby causing the power cables to twist. As regards large wind turbines, it is rather difficult to use slip rings or mechanical collectors to circumvent this problem. Whereas, upwind rotors need to be rather inflexible to keep the rotor blades clear of the tower, downwind rotors can be made more flexible. The latter implies possible savings with respect to weight and may contribute to reducing the loads on the tower. The vast majority of wind turbines in operation today have upwind rotors.

1.2.3 Number of rotor blades

The three-bladed concept is the most common concept for modern wind turbines. A turbine with an upwind rotor, an asynchronous generator and an active yaw system is usually referred to as the Danish concept. This is a concept, which tends to be a standard against which other concepts are evaluated.

Relative to the three-bladed concept, the two and one-bladed concepts have the advantage of representing a possible saving in relation to the cost and weight of the rotor. However, their use of fewer rotor blades implies that a higher rotational speed or a larger chord is needed to yield the same energy output as a three-bladed turbine of a similar size. The use of one or two blades will also result in more fluctuating loads because of the variation of the inertia, depending on the blades being in horizontal or vertical position and on the variation of wind speed when the blade is pointing upward and downward. Therefore, the two and one-bladed concepts usually have so-called teetering hubs, implying that they have the rotor hinged to the main shaft. This design allows the rotor to teeter in order to eliminate some of the unbalanced loads. One-bladed wind turbines are less widespread than two-bladed turbines. This is due to the fact that they, in addition to a higher rotational speed, more noise and visual intrusion problems, need a counter-weight to balance the rotor blade.

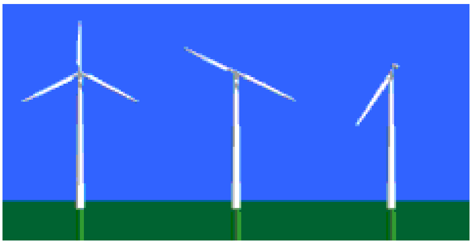

Figure 1-4. Three, two and one-bladed wind turbine concepts. From www.windpower.org (2000), © Danish Wind Turbine Manufacturers Association.

1.2.4 Power control aspects

Wind turbines are designed to produce electricity as cheap as possible. For this purpose, wind turbines are in general designed to yield a maximum power output at wind speeds around 15 m/s. It would not pay to design turbines to maximise their power output at stronger winds, because such strong winds are usually too rare. However, in case of stronger winds, it is necessary to waste part of the excess energy to avoid damage on the wind turbine. Thus, the wind turbine needs some sort of power control. The power control is divided into two regimes with different concepts:

- power optimisation for low wind speeds
- power limitation for high wind speeds

These regimes are separated by the wind speed at which the maximum power output is achieved, typically about 15 m/sec.

Basically, there are three approaches to power control:

- stall control
- pitch control
- active stall control

Stall-controlled wind turbines have their rotor blades bolted to the hub at a fixed angle. The stall phenomenon is used to limit the power output when the wind speed becomes too high. This is achieved by designing the geometry of the rotor blade in such a way that flow separation is created on the downwind side of the blade when the wind speed exceeds some chosen critical value. Stall control of wind turbines requires correct trimming of the rotor blades and correct setting of the blade angle relative to the rotor plane. Some drawbacks of this method are: lower efficiency at low wind speeds, no assisted start and variations in the maximum steady state power due to variation in the air density and grid frequencies.

Pitch-controlled wind turbines have blades that can be pitched out of the wind to an angle where the blade chord is parallel to the wind direction. The power output is monitored and whenever it becomes too high, the blades will be pitched slightly out of the wind to reduce the produced power. The blades will be pitched back again once the wind speed drops. Pitch control of wind turbines requires a design that ensures that the blades are pitched at the exact angle required in order to optimise the power output at all wind speeds. Nowadays, pitch control of wind turbines is only used in conjunction with variable rotor speed. An advantage of this type of control is that it has a good power control, i.e. that the mean value of the power output is kept close to the rated power of the generator at high wind speeds. Disadvantages encompass extra complexity due to the pitch mechanism and high power fluctuations at high wind speeds.

Active stall-controlled turbines resemble pitch-controlled turbines by having pitchable blades. At low wind speeds, active stall turbines will operate like pitch-controlled turbines. At high wind speeds, they will pitch the blades in the opposite direction of what a pitch-controlled turbine would do and force the blades into stall. This enables a rather accurate control of the power output, and makes it possible to run the turbine at the rated power at all high wind speeds. This control type has the advantage of having the ability to compensate for the variations in the air density.

Figure 1-5 shows iso-power curves for a wind turbine as a function of the blade angle and the mean wind speed. The ranges for pitch control and active stall control are separated at a blade angle of 0° with the rotor plane. At low wind speeds, the optimal operation of the wind turbine is achieved at a blade angle close to 0°. At higher wind speeds, the turbine will overproduce if the blade angle is not adjusted accordingly. With pitch control, the blade is pitched positively with its leading edge being turned towards the wind. With active stall control, the blade is pitched negatively with its trailing edge turned towards the wind. The power control and, in particular, the power limitation at higher wind speeds are indicated in an idealised manner for both control approaches by the dashed curves in Figure 1-5. The dashed curves illustrate how the transition between operation with 0° blade angle at low wind speeds and power-limiting operation along an iso-power curve at high wind speeds can be achieved for a three-bladed rotor at a rated power of 400 kW. In this example, the rated power is reached at a wind speed of about 12 m/sec.

1.3 Economical aspects

The ideal wind turbine design is not dictated by technology alone, but by a combination of technology and economy. Wind turbine manufacturers wish to optimise their machines, so that they deliver electricity at the lowest possible cost per unit of energy. In this context, it is not necessarily optimal to maximise the annual energy production, if that would require a very expensive wind turbine. Since the energy input (the wind) is free, the optimal turbine design is one with low production costs per produced kWh.

The choice of rotor size and generator size depends heavily on the distribution of the wind speed and the wind energy potential at a prospective location. A large rotor fitted with a small generator will produce electricity during many hours of the year, but it will only capture a small part of the wind energy potential. A large generator will be very efficient at high wind speeds, but inefficient at low wind speeds. Sometimes it will be beneficial to fit a wind turbine with two generators with different rated powers.

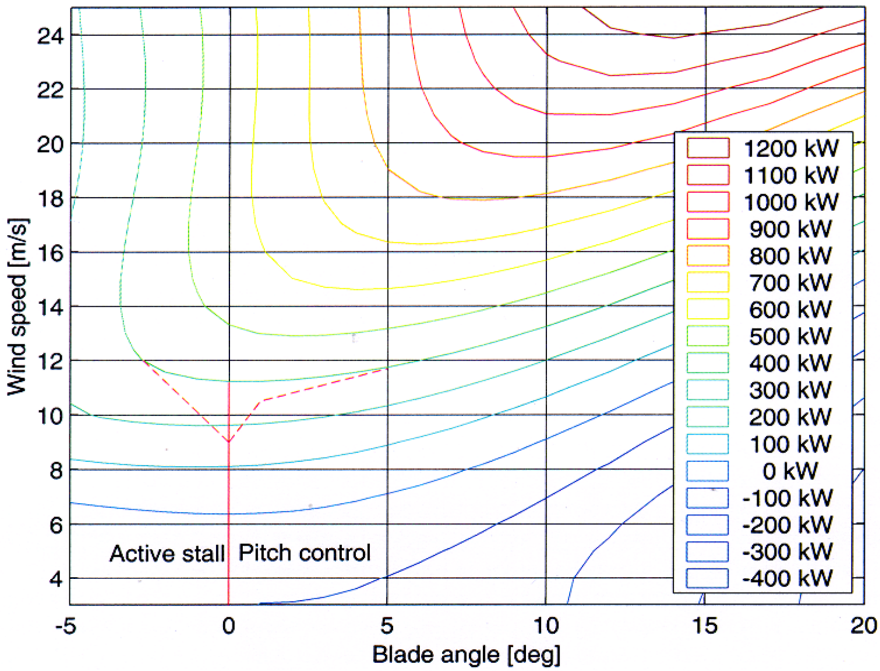

Figure 1-5. Iso-power curves for a wind turbine at 26.88 rpm vs. blade angle and mean wind speed

1.4 Power production

A study of different Danish wind turbine designs shows that the specific power performance in terms of produced energy per m^2 rotor area per year ($kWh/m^2/year$) is almost independent of the rotor size. See Petersen, 1998.

Hence, the main consideration in the evaluation of the cost of the turbine is the specific rotor power (kW/m^2) and the specific cost ($cost/m^2$ rotor) together with expected service life and cost and availability. An availability factor, i.e. the amount of time that the turbine is producing energy, or is ready for production, of 98 % is common for commercial turbines.

Thus the primary factor affecting the power performance is the rotor size. Secondary factors are the control principle such as stall- or pitch control and single- dual- or variable speed.

1.4.1 Power curve

The power being produced by any type of wind turbine can be expressed as

$$P = \tfrac{1}{2} \cdot \rho \cdot V^3 \cdot A \cdot C_P$$

P	output power
ρ	air density
V	free wind speed
A	rotor area
C_P	efficiency factor

The power coefficient C_P is a product of the mechanical efficiency η_m, the electrical efficiency η_e, and of the aerodynamic efficiency. All three factors are dependent on the wind speed and the produced power, respectively. The mechanical efficiency η_m is mainly determined by losses in the gearbox and is typically 0.95 to 0.97 at full load. The electrical efficiency covers losses in the generator and electrical circuits. At full load η_e = 0.97 - 0.98 is common for configurations with an induction generator. It can be shown that the maximum possible value of the aerodynamic efficiency is 16/27 = 0.59, which is achieved when the turbine reduces the wind speed to one-third of the free wind speed (Betz' law).

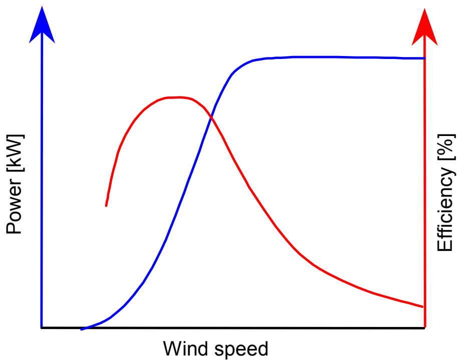

Figure 1-6. Power- and efficiency curve

The produced power varies with the wind speed as can be seen from the blue graph in Figure 1-6. The form of the graph varies slightly from different concepts. Assuming constant efficiency (e.g. constant tip speed ratio) the graph basically consists of a third degree polynomial up to the rated wind speed at which the nominal power is reached. At this point the power regulation sets in, either by the blades stalling or by pitching the blades to attain an approximately constant power. The power curve and the power efficiency curve are often presented in the same graph, with the power and the efficiency scales on each side of the graph as shown in Figure 1-6.

Figure 1-7 illustrates the controlled power curve of a wind turbine, in the case of 1) stall controlled, fixed speed configuration, and 2) pitch controlled, variable speed configuration.

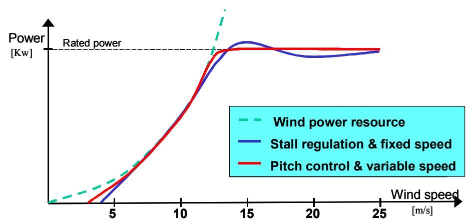

Figure 1-7. Examples of power curves for two types of wind turbines.

The efficiency factor C_P typically reaches a maximum at a wind speed of 7-9 m/sec and, normally, it does not exceed 50%. The electric power typically reaches the rated power of the turbine at a wind speed of 14-16 m/sec.

In the Danish approval scheme as well as in the IEC wind turbine classification system, the power curve is required to be determined from measurements.

1.4.2 Annual energy production

The wind speed distribution is often represented by a Weibull distribution. The density function of the Weibull probability can be expressed as shown in Figure 1-8.

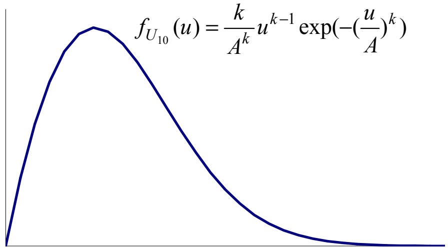

Figure 1-8. Weibull density function.

Hence, for a specific site the wind climate can be described in terms of the parameters *A* and *k,* and from these the average wind speed $V_{ave,}$ as defined in IEC 61400-1, can be calculated

$$V_{ave} = \begin{cases} A\Gamma(1+1/k) \\ A\sqrt{\pi}/2, \quad if\ k=2 \end{cases}$$

in which Γ is the gamma function.

In the Danish standard it is common to describe the wind climate in terms of the roughness class, and an explicit correlation exists between the roughness class and the average wind speed.

For a particular wind turbine, the power production is defined by the power curve as described above. By combining the power curve with the wind distribution the actual energy production is yielded, often expressed in terms of the annual energy production E_{year}.

$$E_{year} = N_0 \int_{V_{start}}^{V_{stop}} P(u) f(u)\, du$$

P(u)	power curve function
f(u)	wind distribution function
V_{start}	cut-in wind speed
V_{stop}	cut-out wind speed
N_0	= 8765 hours/year

Dividing E_{year} by the rotor area yields the specific power performance, which is another common way to express the turbine efficiency.

Yet another way of expressing the efficiency of a particular turbine is given by using the capacity factor, which is defined as the ratio of actual average power to the rated power measured over a period of time (average kW/rated kW). The total energy that would be produced by a wind turbine during a one-year period, assuming a certain distribution of wind speed probability density and assuming 100 per cent availability, is referred to as the potential annual energy output.

1.5 Configurations and sizes

Wind turbines are erected as stand-alone turbines, in clusters of multiple turbines, or – on a larger scale – in park configurations. Before the 1980's, wind energy development focused on the individual wind turbine. By the late 1980's, this perspective began to change as attention shifted to collective generation of electric power from an array of wind turbines located in the vicinity of each other and commonly referred to as wind parks or wind farms. In the early 1980's, the typical size of a wind turbine was about 55 kW in terms of rated power, whereas turbine sizes today have exceeded 2 MW. Table 1-1 gives examples of typical combinations of rotor diameter and rated power for a number of different tower heights.

Table 1-1. Typical wind turbine sizes

Tower height (m)	Rotor diameter (m)	Rated power (kW)
22	21	55
31	30	225
35	35	450
35-40	41-44	500
44	43	600
50	48	750
50	54	1000
60	58	1500
64-80	72-76	2000
85	115	5000

Figure 1-9. Vindeby Offshore Wind Farm. From www.windpower.org (1997) © Bonus.

While wind energy is already economic in terms of good onshore locations, it is currently about to cross the economic frontier set by shorelines: offshore wind energy is becoming competitive with other power-generating technologies. Offshore wind energy is a promising application of wind power, in particular, in countries with high population density and thus with difficulties in finding suitable sites on land. Construction costs are much higher at sea, but energy production is also much higher. Currently, wind energy from turbines erected on fixed foundations in up to 15 m water depth is considered economically feasible. Figure 1-9 shows an example of an early offshore wind farm.

1.6 Future concepts

Figure 1-10. A conception of a flexible wind turbine. During stand-still, the blades deflect as a rush in the wind.

Until now the development of large wind turbines has mainly been prompted by upscaling the dominating concepts described in this section. Still, new concepts for wind turbine designs and components are being developed in an attempt to anticipate the demands for the continuing growth of wind turbines.

One proposal for a future concept is characterised by more flexible wind turbine concepts. One element in this is an expected increase in the structural flexibility of wind turbines. Figure 1-10 exemplifies how the latter can be conceived. Another element is an expected increase in the flexibility of the drive train, e.g. in terms of gearless designs with variable rotational speeds, and a more extensive use of power electronics can also be expected.

Also, more flexible control systems can be foreseen as an increasing number of computers and sensors are incorporated to allow for adaptive operation. In this context, it is possible that a shift may take place from focusing on wind turbine control to focusing on wind farm control. A development which will inevitably, put other requirements on the individual wind turbine in addition to the ones we are experiencing today.

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2. Safety and Reliability

2.1 Safety philosophy

A wind turbine should be designed, dimensioned and manufactured in such a way that it, if correctly used and maintained over its anticipated service life, can withstand the assumed loads within the prescribed level of safety and possess a sufficient degree of durability and robustness. Calculation, or a combination of calculation and testing, can be used to demonstrate that the structural elements of a wind turbine meet the prescribed level of safety.

The prescribed level of safety for a structural element can be expressed in terms of a requirement for the probability of failure and be determined on the basis of so-called risk acceptance criteria. It depends on the type and consequence of failure. The type of failure can be characterised by the degree of ductility and the amount of reserve capacity or structural redundancy. The consequence of failure can be characterised in terms of the fatalities and societal consequences involved. The more severe the consequence is, and the more limited the reserve capacity is, the smaller is the acceptable failure probability. The prescribed safety is standardised in terms of safety classes as described in more detail in Section 2.3. A distinction is made between low, normal and high safety class. The higher the safety class is, the heavier is the requirement for the level of safety, i.e. the smaller is the acceptable failure probability.

A wind turbine is equipped with a control and protection system, which defines an envelope of possible design situations that the wind turbine will experience. To keep the wind turbine within this envelope, it is part of the safety philosophy that the protection system shall possess a sufficiently high level of reliability to render the joint probability negligible that a failure should occur during an extreme event and that the protection system should be unable to fulfil its task. Usually, non-redundant structural parts of the protection system are therefore designed to high safety class.

The prescribed level of safety or the choice of safety class may differ for different parts of the wind turbine. The rotor is usually designed to at least normal safety class. Other structural parts such as tower and foundation are usually assigned to safety classes according to the possible consequences of a failure. Since failure of the foundation will have consequences for the tower and the rotor, while failure of the rotor or the tower may not necessarily have consequences for the foundation, an attractive approach to the choice of safety classes for various structural parts could be to attempt a so-called fail-grace sequence, i.e. a sequence of failures in which the foundation will be the last structural part to fail. This sequence is based on a feasibility study of the consequences of failure for the wind turbine structure and its foundation only. However, usually the rotor is designed to normal or high safety class, which is not necessarily in accordance with the above fail-grace philosophy. Requirements for designing a wind turbine rotor to normal or high safety class derive from the hazards that the rotor poses on its surroundings, when the turbine runs away, or when the rotor fails. In such events, parts of the rotor may be shed in distances up to one kilometre or even farther away from the turbine location.

It should be noted that the level of safety is usually the result of a trade-off with economy. In DS472, emphasis is placed on safety. However, in terms of offshore turbines it is inevitable that economical aspects will become more predominant than

they are onshore, and that more emphasis will eventually be placed on financial factors when it comes to safety issues and determination of acceptable safety levels.
Limit state design is used to achieve the prescribed level of safety. It is common to verify the safety of a wind turbine with respect to the following limit states:

- ultimate limit state
- serviceability limit state
- accidental limit state

For this purpose, design loads are derived from multiplying characteristic loads by one or more partial safety factors, and design capacities are derived from dividing characteristic capacities by one or several other partial safety factors. Partial safety factors are applied to loads and material strengths to account for uncertainties in the characteristic values. Verification of the structural safety is achieved by ensuring that the design load, or the combination of a set of design loads, does not exceed the design capacity. In case a combination of loads is used, it should be noted that it is common always to combine one extreme load with one or several "normal" loads. Two or several extreme loads are usually not combined, unless they have some correlation.

Characteristic loads and characteristic capacities constitute important parameters in the design process. Characteristic loads for assessment of the ultimate limit state are usually determined as load values with a 50-year recurrence period, and they are therefore often interpreted as the 98% quantile in the distribution of the annual maximum load. This choice does not necessarily imply that a design lifetime of exactly 50 years is considered. It is more a matter of tradition and convenience. Nor should it be taken as a 50-year guarantee within which failures will not occur. For assessment of fatigue, a design lifetime is needed, and in this context it is common to consider a 20-year design lifetime for wind turbines. Characteristic capacities are usually chosen as low quantiles in the associated capacity distributions. The partial safety factors that are applied in the design account for the possible more unfavourable realisation of the loads and capacities than those assumed by the choice of characteristic values. Note in this context that some of the partial safety factors, which are specified in standards, are not safety factors in the true sense, but rather reduction factors which account for degradation effects, scale effects, temperature effects, etc. and which happen to appear in the design expressions in exactly the same manner as true partial safety factors.

With structural safety being a major goal of the design, it is important to make sure that the characteristic values of load and material quantities, which have been assumed for the design, are achieved in practice. Non-destructive testing of completed structural parts plays a role in this context, and control of workmanship another. Material certificates also come in handy in this context. In general, one may say that inspection is an important part of the safety philosophy. Not least, as it will allow for verification of assumptions made during the design and for taking remedial actions if averse conditions are detected during the service life of the wind turbine.

For details about structural safety and limit state design, reference is made to Section 2.3. For details about combinations of design situations and external conditions, as well as a definition of load cases, reference is made to Chapter 4.

2.2 System safety and operational reliability

A wind turbine is to be equipped with control and protection systems which are meant to govern the safe operation of the wind turbine and to protect the wind turbine from ill conditions. Some components will act in both the control and the protection function, but distinction is made in that the control system monitors and regulates the essential operating parameters to keep the turbine within defined operating range whereas the protection system ensures that the turbine is kept within the design limits. The protection system must takes precedence over the control system.

2.2.1 Control system

Controls are used for the following functions:

- to enable automatic operation
- to keep the turbine in alignment with the wind
- to engage and disengage the generator
- to govern the rotor speed
- to protect the turbine from overspeed or damage caused by very strong winds
- to sense malfunctions and warn operators of the need for maintenance or repair

The control system is meant to control the operation of the wind turbine by active or passive means and to keep operating parameters within their normal limits. Passive controls use their own sensing and are exercised by use of natural forces, e.g. centrifugal stalling or centrifugal feathering. Active controls use electrical, mechanical, hydraulic or pneumatic means and require transducers to sense the variables that will determine the control action needed. Typical variables and features to be monitored in this respect include:

- rotor speed
- wind speed
- vibration
- external temperature
- generator temperature
- voltage and frequency at mains connection
- connection of the electrical load
- power output
- cable twist
- yaw error
- brake wear

The control system is meant to keep the wind turbine within its normal operating range. As a minimum, the normal operating range should be characterised by the following properties and requirements:

- a maximum 10-minute mean wind speed at hub height, V_{max}, i.e. the stop wind speed below which the wind turbine may be in operation
- a maximum long-term mean nominal power P_{nom}, interpreted as the highest power on the power curve of the wind turbine in the wind speed interval $[V_{min};V_{max}]$, where V_{min} denotes the start wind speed for the turbine
- a maximum nominal power P_{max}, which on average over 10 minutes may not be exceeded for a wind speed at hub height of $V_{10min,hub} < V_{max}$
- a maximum operating frequency of rotation $n_{r,max}$ for the wind turbine
- a maximum transient frequency of rotation n_{max} for the wind turbine
- a wind speed below which the wind turbine may be stopped

The wind turbine is kept within its normal operating range by means of the control system, which activates and/or deactivates the necessary controls, e.g.:

- yaw (alignment with the wind)
- blade angle regulation
- activation of the brake system
- power network connection
- power limitation
- shutdown at loss of electrical network or electrical load

In addition, it must be possible to stop the wind turbine, e.g. for the purpose of inspection and repairs, or in case of emergencies. Monitoring of the control system and its functions must be adapted to the actual design of the wind turbine. Design of a wind turbine control system requires a background in servo theory, i.e. theory dealing with control of continuous systems.

The control system is of particular importance in areas where weak grids are encountered. Weak grids can, for example, be found in sparsely populated areas where the capacity of the grids can often be a limiting factor for the exploitation of the wind resource in question. Two problems are identified in this context:

- increase of the steady-state voltage level of the grid above the limit where power consumption is low and wind power input is high
- voltage fluctuations above the flicker limit may result from fluctuating wind power input caused by fluctuating wind and wind turbine cut-ins.

The solution to the above problems is to use a so-called power control as part of the control system. The power control concept implies buffering the wind turbine power in periods where the voltage limits may be violated and releasing it when the voltage is lower. This method is combined with a smoothening of the power output, such that fluctuations are removed, in particular those that would exceed the flicker limit.

2.2.2 Protection system

The protection system is sometimes referred to as the safety system. Mechanical, electrical and aerodynamic protection systems are available. The protection system is to be activated when, as a result of control system failure or of the effects of some other failure event, the wind turbine is not kept within its normal operation range. The protection system shall then bring the wind turbine to a safe condition and maintain the turbine in this condition. It is usually required that the protection system shall be capable of bringing the rotor to rest or to an idling state from any operating condition. In the IEC standard an additional requirement is that means shall be provided for bringing the rotor to a complete stop from a hazardous idling state in any wind speed less than the annual extreme wind speed. The activation levels for the protection system have to be set in such a way that design limits are not exceeded.

Situations which call for activation of the protection system include, but are not necessarily limited to:

- overspeed
- generator overload or fault
- excessive vibration
- failure to shut down following network loss, disconnection from the network, or loss of electrical load
- abnormal cable twist owing to nacelle rotation by yawing

The protection system should therefore as a minimum cover monitoring of the following:

- rotational speed or rotational frequency
- overload of a generator or other energy conversion system/load
- extreme vibrations in the nacelle
- safety-related functioning of the control system

As overspeed is by far the most critical error, rotational speed monitors form a crucial element of the protection system.

A protection system consists of:

- a registering unit
- an activating unit
- a brake unit

The protection system shall include one or more systems (mechanical, electrical or aerodynamic) capable of bringing the rotor to rest or to an idling state. In the Danish standard at least two brake systems must be included, and at least one of these must have an aerodynamically operated brake unit. See Section 2.3.3.

To ensure immediate machine shutdown in case of personal risk, an emergency stop button, which will overrule both the control and normal protection system, shall be provided at all work places.

In addition to what is stated above, the protection system is, as a minimum, to be subjected to the following requirements:

- the protection system must take precedence over the control system
- the protection system must be fail-safe in the event that the power supply fails
- structural components in mechanisms of the protection system shall be designed to high safety class
- the protection system must be able to register a fault and to bring the wind turbine to a standstill or to controlled freewheeling in all situations in which the rotor speed is less than n_{max}.
- the protection system must be tolerant towards a single fault in a sensor, in the electronic and electrical as well as the hydraulic systems or in active mechanical devices, i.e. an undetected fault in the system must not prevent the system from detecting a fault condition and carrying out its function
- the reliability of the protection system must ensure that situations caused by failures in the protection system, whereby the extreme operating range is exceeded, can be neglected

The reliability of the protection system may be ensured by means of either (1) the entire protection system being of a fail-safe design, or (2) redundancy of the parts of the protection system where it cannot be made fail-safe, or (3) frequent inspections of the functioning of the protection system, in which risk assessment is used to determine the interval between inspections.

Fail-safe is a design philosophy, which through redundancy or adequacy of design in the structure, ensures that in the event of a failure of a component or power source, the wind turbine will remain in a non-hazardous condition.

2.2.3 Brake system

The brake system is the active part of the protection system. Examples of brake systems are:

- mechanical brake
- aerodynamic brake
- generator brake

An aerodynamic brake system usually consists of turning the blade tip or, as commonly seen on active stall- and pitch-controlled turbines, of turning the entire blade 90° about the longitudinal axis of the blade. This results in aerodynamic forces that counteract the rotor torque. Also, spoilers and parachutes have been used as aerodynamic brakes.

Figure 2-1. Tip brake, from www.windpower.org (2000), © Danish Wind Turbine Manufacturers' Association.

The reliability of a brake system is of the utmost importance to ensure that the system will serve its purpose adequately. In this respect, it is important to be aware of possible dependencies between different brakes or different brake components. For example, if all three blades are equipped with tip brakes, some dependency between the three tip brakes can be expected, cf. the common cause failures that can be foreseen for these brakes. This will influence the overall reliability against failure of the system of the three tip brakes and needs to be taken into account if the failure probability exceeds 0.0002 per year.

Brakes or components of brake systems will be subject to wear. Thus, current monitoring and maintenance are required.

IEC61400-1 requires that the protection system shall include one or more systems, i.e. mechanical, electrical, or aerodynamic brakes, capable of bringing the rotor to rest or to an idling state from any operating condition. At least one of these systems shall act on the low-speed shaft or on the rotor of the wind turbine. The idea behind this is to have a brake system which ensures that a fault will not lead to a complete failure of the wind turbine.

DS472 is more strict by requiring at least two fail-safe brake systems. If the two systems are not independent, i.e. if they have some parts in common, then the turbine shall automatically be brought to a complete stop or to controlled idling in the event of a failure in the common parts. At least one brake system is required to have an aerodynamic brake unit.

2.2.4 Failure mode and effects analysis

A failure mode and effects analysis is a qualitative reliability technique for systematic analysis of mechanical or electrical systems, such as a wind turbine protection system. The analysis includes examination of each individual component of the system for determination of possible failure modes and identification of their effects on the system. The analysis is based on a worksheet that systematically lists all components in the system, including:

- component name
- function of component
- possible failure modes
- causes of failure
- how failures are detected
- effects of failure on primary system function
- effects of failure on other components
- necessary preventative/repair measures

The failure mode and effects analysis can be supplemented by a criticality analysis, which is a procedure that rates the failure modes according to their frequency or probability of occurrence and according to their consequences. The assigned ratings can be used to rank the components with respect to their criticality for the safety of the system. An example of a worksheet is given in Table 2-1.

A failure mode and effects analysis can be conducted at various levels. Before commencing, it is thus important to decide what level should be adopted as some areas may otherwise be examined in great detail, while others will be examined at the system level only without examination of the individual components. If conducted at too detailed a level, the analysis can be rather time-consuming and tedious, but will undoubtedly lead to a thorough under-standing of the system.

Table 2-1. Example of worksheet.

COMPONENT	FAILURE MODE	FAILURE CAUSE	FAILURE EFFECT	FAILURE DETECTION	FREQUENCY RATING	SEVERITY RATING
Valve	Leak past stem	Deteriorated seal	Oil leak	Visual by ROV	Low	Low
	Fails to close on command	Control system failure	Valve will not shut off flow	Flow does not shut off	Medium	Low

The failure mode and effects analysis is primarily a risk management tool. The strength of the failure mode and effects analysis is that, if carried out correctly, it identifies safety-critical components where a single failure will be critical for the entire system. It is a weakness, however, that it depends on the experience of the analyst and that it cannot easily be applied to cover multiple failures.

2.2.5 Fault tree analysis

A fault tree is a logical representation of the many events and component failures that may combine to cause one critical event such as a system failure. It uses “logic gates” (mainly AND and OR gates) to show how “basic events” may combine to cause the critical “top event”.

Application
Fault tree analysis has several potential uses in relation to wind turbine protection systems:

- In frequency analysis, it is common to quantify the probability of the top event occurring based on estimates of the failure rates of each component. The top event may comprise an individual failure case, or a branch probability in an event tree.
- In risk presentation, it may also be used to show how the various risk contributors combine to produce the overall risk.
- In hazard identification, it may be used qualitatively to identify combinations of basic events that are sufficient to cause the top event, also known as “cut sets”.

Construction of a fault tree
Construction of a fault tree usually commences with the top event and then works its way downwards to the basic events. For each event, it considers what conditions are necessary to produce the event, and it then represents these as events at the next level. If one of several events causes the higher event, it is joined with an OR gate. If two or more events must occur in combination, they are joined with an AND gate.

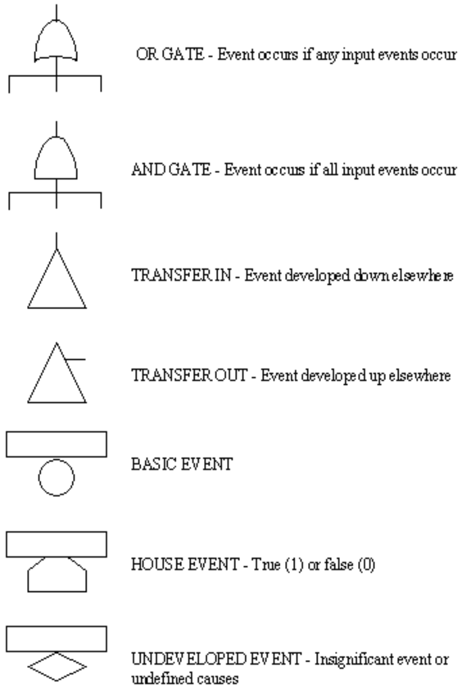

Figure 2-2. Fault tree symbols.

If quantification of the fault tree is the objective, downward development should stop once all branches have been reduced to events that can be quantified in terms of probabilities or frequencies of occurrence. Various standards for symbols are used – the most typical ones are shown in Figure 2-2. An example of a fault tree is shown in Figure 2-3.

Some types of events, for example a fire or power failure, may affect many components in the system at once. These are known as “common-cause failures” and may be represented by having the same basic event occurring at each appropriate place in the fault tree.

Combination of frequencies and probabilities
Both frequencies and probabilities can be combined in a fault tree, providing the rules in Table 2-2 are followed.

Table 2-2. Rules for Combining Frequencies and Probabilities

Gate	Inputs	Outputs
OR	Probability + Probability	Probability
AND	Frequency + Frequency	Frequency
	Frequency + Probability	Not permitted
	Probability × Probability	Probability
	Frequency × Frequency	Not permitted
	Frequency × Probability	Frequency

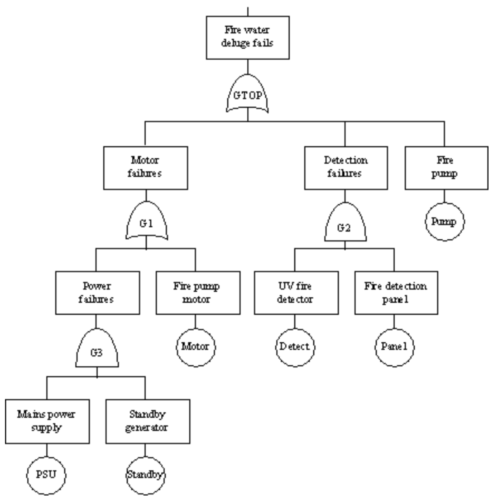

Figure 2-3. Example of fault tree.

Minimal cut set analysis
Cut sets comprise combinations of events that are sufficient to cause the top event. Minimal cut sets contain the minimum sets of events necessary to cause the top event, i.e. after eliminating any events that occur more than once in the fault tree. In case of simple fault trees, with each basic event only occurring once, the minimal cut sets can be identified by means of inspection. For more complex trees, formal methods such as the Boolean analysis are required. Most often, computer programs are used to identify minimal cut sets.

Minimal cut sets can be used in hazard identification to describe combinations of events necessary to cause the top event.

Minimal cut sets can, moreover, be used to rank and screen hazards according to the number of events that must occur simultaneously. In principle, single event cut sets are of concern because only one failure can lead to the top event. In reality, larger cut sets may have a higher frequency of occurrence. Nevertheless, the method can be useful for hazard screening and for suggesting where additional safeguards may be needed.

Quantification of a fault tree
Simple fault trees may be analysed by using a gate-by-gate approach to determine the top event probability, provided that all events are independent and that there are no common cause failures. This gate-by-gate approach is useful for QRA (Quantitative Risk Analysis), because it quantifies all intermediate events in the fault tree and provides a good insight into the main contributors to the top event and the effectiveness of safeguards represented in the tree. However, because it cannot represent repeated events or dependencies correctly, it is normally not used for formal reliability analysis. Reliability analysis of more complex fault trees requires minimal cut set analysis to remove repeated events.

Strengths and weaknesses
Preparation and execution of a fault tree analysis is advantageous in the sense that it forces the wind turbine manufacturer to examine the protection system of his wind turbine systematically. When probabilities can be assigned to events, the fault tree methodology can be applied to assess the overall reliability of the wind turbine

protection system. Furthermore, it can be used to determine the most critical events and parts of the protection system.

Beware, however, that it is often hard to find out whether a fault tree analysis has been carried out properly. Fault tree analyses become complicated, time-consuming and difficult to follow for large systems, and it becomes easy to overlook failure modes and common cause failures. It is a weakness that the diagrammatic format discourages analysts from stating assumptions and conditional probabilities for each gate explicitly. This can be overcome by careful back-up text documentation. It is a limitation that all events are assumed to be independent. Fault tree analyses lose their clarity when applied to systems that do not fall into simple failed or working states such as human error, adverse weather conditions, etc.

2.3 Structural safety

2.3.1 Limit states

During the lifetime of a structure, the structure is subjected to loads or actions. The loads may cause a change of the condition or state of the structure from an undamaged or intact state to a state of deterioration, damage, or failure. Structural malfunction can occur in a number of modes covering all failure possibilities that can be imagined for the structure. Although the transition from an intact state to a state of malfunction can indeed be continuous, it is common to assume that all states with respect to a particular mode of malfunction can be divided into two sets: 1) states that have failed, and 2) states that have not failed or are safe. The boundary between the safe states and the failed states is referred to as the set of limit states. The safety or reliability of a structure is concerned with how likely it is that the structure will reach a limit state and enter a state of failure.

There are several types of limit states. Two types are common, ultimate limit states and serviceability limit states. Ultimate limit states correspond to the limit of the load-carrying capacity of a structure or structural component, e.g. plastic yield, brittle fracture, fatigue fracture, instability, buckling, and overturning. Serviceability limit states imply that there are deformations in excess of tolerance without exceeding the load-carrying capacity. Examples are cracks, wear, corrosion, permanent deflections and vibrations. Fatigue is sometimes treated as a separate type of limit state. Other types of limit states are possible, e.g. accidental limit states and progressive limit states.

2.3.2 Failure probability and other measures of structural reliability

In structural design, the reliability of a structural component is evaluated with respect to one or more failure modes. One such failure mode is assumed in the following. The structural component is described by a set of stochastic basic variables grouped into one vector **X**, including, e.g. its strength, stiffness, geometry, and loading. Each of these variables are stochastic in the sense that they – owing to natural variability and other possible uncertainties – may take on random degrees of realisation according to some probability distribution. For the considered failure mode, the possible realisation of **X** can be separated into two sets:1) the set for which the structural component will be safe, and 2) the set for which it will fail. The surface between the safe set and the failure set in the space of basic variables is denoted the limit state surface, and the reliability problem is conveniently described by a so-called limit state function $g(\mathbf{X})$, which is defined such that

$$g(\mathbf{X})\begin{cases} >0 \text{ for } \mathbf{X} \text{ in safe set} \\ =0 \text{ for } \mathbf{X} \text{ on limit state surface} \\ <0 \text{ for } \mathbf{X} \text{ in failure set} \end{cases}$$

The limit state function is usually based on some mathematical engineering model for the considered limit state, based on the underlying physics, and expressed in terms of the governing load and resistance variables.

The failure probability is the probability content in the failure set

$$P_F = P[g(\mathbf{X}) \le 0] = \int_{g(\mathbf{X})\le 0} f_{\mathbf{X}}(\mathbf{x})d\mathbf{x}$$

where $f_{\mathbf{X}}(\mathbf{x})$ is the joint probability density function for $\mathbf{X}$ and represents the uncertainty and natural variability in the governing variables $\mathbf{X}$. The complement $P_S = 1-P_F$ is referred to as the reliability and is sometimes also denoted the probability of survival. The reliability may be expressed in terms of the reliability index,

$$\beta = -\Phi^{-1}(P_F),$$

where Φ is the standardised normal distribution function. The failure probability, the reliability, and the reliability index are all suitable measures of structural safety.

For the simple example that $\mathbf{X}$ consists of two variables, the load L and the resistance R, and the limit state function can be specified as $g(\mathbf{X}) = R-L$, the failure probability becomes a simple convolution integral

$$P_F = P[R-L<0] = \int_{R-L<0} f_R(r)f_L(l)drdl$$

$$= \int_{-\infty}^{\infty}\int_{-\infty}^{l} f_R(r)f_L(l)drdl$$

$$= \int_{-\infty}^{\infty} F_R(l)f_L(l)dl$$

where f_R and f_L are the probability density functions of R and L, respectively, and $f_R(r) = dF_R(r)/dr$, where F_R is the cumulative distribution function of R.

2.3.3 Structural reliability methods

The reliability index β can be solved in a structural reliability analysis by means of a reliability method which can be any amongst several available methods, including numerical integration, analytical first- and second-order reliability methods, and simulation methods. Reference is made to Madsen et al. (1986). Some of these methods are approximate methods, which will lead to approximate results for the reliability index. Numerical integration is usually only feasible when $\mathbf{X}$ consists of very few stochastic variables such as in the example above. Analytical first- and second-order solutions to the failure probability are often sufficiently accurate, and they are advantageous to simulation results when failure probabilities are small.

A useful by-product of a structural reliability analysis by these methods is the so-called design point $\mathbf{x}^*$. This is a point on the limit state surface and is the most likely realisation of the stochastic variables $\mathbf{X}$ at failure.

2.3.4 Code format, characteristic values, and partial safety factors

A structural design code specifies design rules that are to be fulfilled during the design of a structure or structural component. The general layout of the design rules in a design code is known as the code format.

The code format most frequently used in design codes today is a format which is expressed in terms of design values of governing load and resistance variables. These design values are defined as characteristic values of the load and resistance variables, factored by partial safety factors. Such a form of code format results from requirements for an easy and yet economical design and is known as a design value format. Design according to a design value format is sometimes referred to as load and resistance factor design (LRFD).

In its simplest form, a code requirement can be expressed as a design rule in terms of an inequality

$$L_D < R_D$$

in which L_D is the design load effect and R_D is the design resistance. The design load effect is calculated as

$$L_D = \gamma_f L_C$$

where L_C is the characteristic load effect and γ_f is a load factor. Similarly, the design resistance is calculated as

$$R_D = \frac{R_C}{\gamma_m}$$

where R_C is the characteristic resistance and γ_m is a material factor.

Usually, a number of different load effects have to be combined into a resulting load effect, and often the largest of several different such load combinations is used for the load effect in the design rule. An example of such a load combination is the combination of gravitational loads and wind loads.

The characteristic values are usually taken as specific quantiles in the load and resistance distributions, respectively. The characteristic values are often the mean value for dead load, the 98% quantile in the distribution of the annual maxima for variable (environmental) load, and the 2% or 5% quantile for strength. Reference is made to Figure 2-4. The code also specifies values to be used for the partial safety factors γ_f and γ_m .

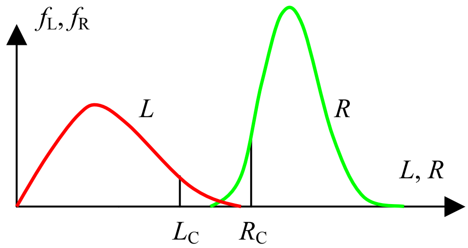

Figure 2-4. Probability density functions and characteristic values for load L and resistance R.

The design equation is a special case of the design rule obtained by turning the inequality into an equality, i.e., $R_D = L_D$ in the example.

2.3.5 Code calibration

Fulfilment of the design rules, as required by a structural design code, is meant to ensure that a particular prescribed structural safety level is achieved. The purpose of a code calibration is to determine the set of partial safety factors to be used with the chosen code format, such that structural designs according to the code will meet this prescribed level of safety.

Structural reliability analysis results, obtained as outlined above, play an important role in codified practice and design. Their application to calibration of partial safety factors for use in structural design codes is of particular interest.

Structural reliability analysis directly capitalises on the variability and uncertainties in load and strength and therefore produces a reliability estimate, which is a direct measure of the structural safety. Because of this, structural reliability analysis forms the rational basis for calibration of partial safety factors, which are used in code checks during conventional deterministic design. With structural reliability method available, it is possible to determine sets of equivalent partial safety factors which, when applied with design rules in structural design codes, will lead to designs with the prescribed reliability.

As a first step, a target reliability index β_T must be selected. The choice of the target reliability index can be derived from a utility-based feasibility study in a decision analysis, or by requiring that the safety level as resulting from the design by a structural reliability analysis shall be the same as the one resulting from current deterministic design practice. The latter approach is based on the assumption that established design practice is optimal with respect to safety and economy or, at least, leads to a safety level acceptable by society.

When the target reliability index β_T cannot be established by calibration against established design practice, or otherwise, then its value may be taken from Table 2-3, depending on the type and consequence of failure. Note that the numbers given in Table 2-3 are given for a reference period of one year, i.e. they refer to *annual* probabilities of failure and corresponding reliability indices. Reference is made to NKB (1978).

In the case of a prescribed reliability index, which is different from the one that results from an actually executed reliability analysis of a structural component, the geometrical quantities of this component must be adjusted. The adjustment is made in such a way that the required reliability index will result from a new reliability analysis of the modified component. The geometrical quantities, which can be adjusted to achieve a specified reliability index, are sometimes denoted design parameters. It is most practicable to operate on just one such design parameter when adjusting the design in order to reach the specified reliability index.

A design case is formed as a specific combination of environmental loading regime, type of material, and type and shape of structure. For a particular design case, which can be analysed on the basis of a structural reliability method, a set of partial safety factors can thus be determined that will lead to a design which exactly meets the prescribed level of reliability. Different sets of partial safety factors may result from different design cases. A simple example of a calibration of partial safety factors is given below for an axially loaded steel truss. A structural design code usually has a scope that covers an entire class of design cases, formed by combinations among multiple environmental loading regimes, different structural materials, and several types and shapes of structures. The design code will usually specify one common set of partial safety factors, which is to be applied regardless of which design case is being analysed. This practical simplification implies that the prescribed level of reliability will usually not be met in full, but only

Table 2-3. Target annual failure probabilities P_{FT} and corresponding reliability indices β_T.

	Failure consequence		
Failure type	**Less serious** **LOW SAFETY CLASS** (small possibility for personal injuries and pollution, small economic consequences, negligible risk to life)	**Serious** **NORMAL SAFETY CLASS** (possibilities for personal injuries, fatalities, pollution, and significant economic consequences)	**Very serious** **HIGH SAFETY CLASS** (large possibilities for personal injuries, fatalities, significant pollution, and very large economic consequences)
Ductile failure with reserve capacity (redundant structure)	$P_F = 10^{-3}$ $\beta_T = 3.09$	$P_F = 10^{-4}$ $\beta_T = 3.72$	$P_F = 10^{-5}$ $\beta_T = 4.26$
Ductile failure with no reserve capacity (significant warning before occurrence of failure in non-redundant structure)	$P_F = 10^{-4}$ $\beta_T = 3.72$	$P_F = 10^{-5}$ $\beta_T = 4.26$	$P_F = 10^{-6}$ $\beta_T = 4.75$
Brittle failure (no warning before occurrence of failure in non-redundant structure)	$P_F = 10^{-5}$ $\beta_T = 4.26$	$P_F = 10^{-6}$ $\beta_T = 4.75$	$P_F = 10^{-7}$ $\beta_T = 5.20$

approximately, when designs are carried out according to the code. Hence, the goal of a reliability-based code calibration is to determine the particular common set of partial safety factors that reduces the scatter of the reliabilities, achieved by designs according to the code, to a minimum over the scope. This can be accomplished by means of an optimisation technique, once a closeness measure for the achieved reliability has been defined, e.g. expressed in terms of a penalty function that penalises deviations from the prescribed target reliability. For principles and examples of such code optimisation, reference is made to Hauge et al. (1992), Ronold (1999), and Ronold and Christensen (2001).

2.3.6 Example – axially loaded steel tower

The example given below deals with design of an axially loaded steel tower against failure in ultimate loading. The probabilistic modelling required for representation of load and capacity is presented. A structural reliability analysis of the tower is carried out, and a simple calibration of partial safety factors is performed.

The design of the axially loaded tower is governed by the maximum axial force Q in a one-year reference period. The maximum axial force Q follows a Gumbel distribution

$$F_Q(q) = \exp(-\exp(-a(q-b)))$$

in which a = 0.4275 and b = 48.65 correspond to a mean value $E[Q]$ = 50 MN and a standard deviation $D[Q]$ = 3 MN. The yield strength of steel σ_F follows a normal distribution with the mean value $E[\sigma_F]$ = 400 MPa and the standard deviation $D[\sigma_F]$ = 24 MPa. The cross-sectional area of the tower is A. Failure occurs when the axial force Q exceeds the capacity $\sigma_F A$, thus a natural format of the design rule is $\sigma_{F,D}A \geq q_D$. The subscript D denotes design value. The limit state function is correspondingly chosen as

$$g = \sigma_F A - Q$$

and the area A is used as the design parameter.

Analysis by a first-order reliability method leads to determination of $A = 0.2007\ \text{m}^2$ in order to meet a target reliability index $\beta = 4.2648$, which corresponds to an annual failure probability $P_F = 10^{-5}$. The characteristic value of the axial force is taken as the 98% quantile in the distribution of the annual maximum force, $q_C = q_{98\%}$ = 57.78 MN. The characteristic value of the yield strength is taken as the 5% quantile in the strength distribution, $\sigma_{F,C} = \sigma_{F,5\%}$ = 360.5 MPa. One partial safety factor, γ_1, is introduced as a factor on the characteristic force, and another one, γ_2, is introduced as a factor on the characteristic capacity. Substitution of the expressions for the design force and the design capacity in the design equation yields

$$\gamma_2\sigma_{F,C}A - \gamma_1 q_C = \gamma_2\cdot 360.5\cdot 0.2007 - \gamma_1\cdot 57.78 = 0$$

which gives a requirement to the ratio of the partial safety factors $\gamma_1/\gamma_2 = 1.252$. There is thus an infinite number of pairs (γ_1,γ_2) that will lead to the required reliability. This implies an arbitrariness in selecting the partial safety factor set (γ_1,γ_2) for the code. The reliability analysis gives the design point values q^* = 70.89 MN for the force and σ_F^* = 353.2 MPa for the strength. These are the most likely values of the governing variables at failure. A robust choice for the partial safety factors (γ_1,γ_2) can be achieved by designing to the design point values from the reliability analysis. The partial safety factors are therefore selected as

$$\gamma_1 = \frac{q^*}{q_C} = 1.227 \text{ and } \gamma_2 = \frac{\sigma_F{}^*}{\sigma_{F,C}} = 0.980$$

According to current design practice, a load factor is used as a factor on the characteristic load to give the design load, and a material factor is used as a divisor on the characteristic resistance to give the design resistance. Hence, these factors become

$$\gamma_f = \gamma_1 = 1.227 \text{ and } \gamma_m = \frac{1}{\gamma_2} = 1.021\,,$$

respectively.

Note that the example is purely tutorial to explain a principle. In reality, the capacity may be more uncertain than assumed here, e.g. owing to model uncertainty not accounted for. Moreover, a larger degree of variability in the axial force may also be expected, depending on the source and type of loading and the amount of data available. The resulting partial safety factors may then become larger than the ones found here.

2.3.7 Example – fatigue of FRP blade root in bending

The example given here deals with design of an FRP blade root against fatigue failure during its design life of 20 years. The probabilistic modelling required for representation of load and resistance is presented. A structural reliability analysis of the blade root is carried out, and a simple safety factor calibration is performed.

The design of the blade root is governed by the long-term distribution of the bending moment range X. In the long term, the bending moment ranges are assumed to follow an exponential distribution

$$F_X(x) = 1 - \exp(-\frac{x}{x_0})$$

in which x_0 = 50 kNm is recognised as a Weibull scale parameter. The total number of bending moment ranges over the design life T_L = 20 years is n_{tot} = $0.9 \cdot 10^9$. The bending moment ranges X give rise to bending stress ranges $S = X/W$, where W denotes the section modulus of the blade root. Hence, the bending stress range distribution becomes

$$F_S(s) = 1 - \exp(-\frac{sW}{x_0})$$

For a given stress range S, the number of bending stress cycles N to failure is generally expressed through an S–N curve, which on logarithmic form reads

$$\ln N = \ln K - m \ln S + \varepsilon$$

where the pair $(\ln K, m)$ = (114.7,8.0) describes the expected behaviour. The zero-mean term ε represents the natural variability about the expectation and follows a normal distribution with a standard deviation σ_ε = 0.86. The cumulative damage is calculated as the Miner's sum

$$D = \sum_i \frac{\Delta n(s_i)}{N(s_i)}$$
$$= \int_0^\infty \frac{n_{tot} \frac{dF_S}{ds} ds}{K \exp(\varepsilon) s^{-m}}$$
$$= \frac{n_{tot}}{K \exp(\varepsilon)} \Gamma(m+1) (\frac{x_0}{W})^m$$

where Γ denotes the gamma function.

According to Miner's rule, fatigue failure occurs when the cumulative damage exceeds a threshold of 1.0. A natural format of the design rule is $D_D \leq 1$, where D_D is the design damage. The limit state function is chosen as

$$g = 1 - D$$

and the section modulus W is used as the design parameter.

Analysis by a first-order reliability method leads to determination of W = 0.00209 m^3 in order to meet a target reliability index β = 3.29, which corresponds to a target failure probability $P_F = 0.5 \cdot 10^{-3}$ over the design life of 20 years.

For design against fatigue failure it has hardly any meaning to choose the 98% quantile of the annual maximum load, or any other quantile for that matter, as the characteristic load value. A characteristic load *distribution* is needed rather than a characteristic load *value*. The long-term stress range distribution, $F_S(s)$, is chosen as the characteristic stress range distribution, and a load factor γ_f = 1.0 on all stress ranges according to this distribution is prescribed.

This is based on the assumption that the long-term stress range distribution is known. The validity of this assumption in the context of wind turbines is discussed later. It is also assumed that variability in the individual damage contributions from the individual stress ranges averages out over the many contributing stress ranges in the long-term distribution. This assumption would not hold if the cumulative damage was dominated by damage contributions from only one or a very few large stress ranges, which could be the case for very large m values, say m>10.

The characteristic S–N curve is taken as the expected S–N curve minus two standard deviations. A partial safety factor, γ_m, is applied as a divisor on all stress range values of the characteristic S–N curve.
The design damage D_D is then obtained as

$$D_D = \frac{n_{tot}}{K_C}\Gamma(m+1)(\frac{\gamma_m x_0}{W})^m$$

in which $K_C = K\exp(-2\sigma_\varepsilon)$ reflects the chosen characteristic S–N curve. Substitution of numbers into the design equation D_D = 1.0 leads to the following requirement to the material factor

γ_m = 1.149

Discussion
Note that this example is purely tutorial to explain a principle. In reality, the resistance may be more uncertain than assumed here, e.g. when there is a limited amount of material data available, such that the estimated values of K and m are uncertain. Moreover, model uncertainty may be associated with the application of Miner's rule. With such uncertainties properly accounted for, the value of the resulting material factor, γ_m, will become larger than the one found here.

Note also that with γ_f = 1.0 prescribed, all levels of uncertainty and variability associated with a fatigue problem such as the present, are accounted for by one single safety factor, γ_m. This factor is thus applied as a safety factor on resistance, regardless of whether some of the uncertainty is associated with load rather than with resistance. This is in accordance with most standards. Note, however, that in the new Danish standard DS409/DS410, a partial safety factor, γ_f, on load is introduced which, under certain conditions, is to be taken as a value greater than 1.0. This applies to situations where the loads causing fatigue damage are encumbered with uncertainty or ambiguity, such as if they are traffic loads, or if the various quantiles of the long-term stress distribution over the design life are statistically uncertain.

As regards design of wind turbines against fatigue, the loads causing fatigue damage are dominated by loads generated by the wind. Whereas the distribution of the 10-minute mean wind speed on a location may be well-known, the distribution of the turbulence intensity is usually not well-determined, owing to local conditions and influence from the presence of the turbine. Nor is the transfer function to stress response in the wind turbine always clear. The distribution of wind-generated loads in a wind turbine can therefore be expected to be known only with some uncertainty, and a load factor γ_f greater than 1.0 would thus be required. However, in practice, one would account for such uncertainty or ambiguity in the load distribution by choosing a load distribution "on the safe side", a conservative "envelope load spectrum", so to speak. In the presented example, this would imply the choice of a conservatively high value of the Weibull scale parameter x_0, which could then be used in conjunction with γ_f = 1.0.

2.3.8 Tests and calculations for verification

It is important to demonstrate that the structural strengths or capacities of the various components that constitute the wind turbine structure are sufficient. This can be done by undertaking calculations according to some theory or calculation method, and it can be supported by carrying out full-scale tests of the component in question. Note that a full-scale test of a structural component may give a more accurate estimate of the component strength than theoretical calculations, because model uncertainty and bias, owing to simplifications and limitations associated with the applied calculation method, will be reduced or removed.

When carrying out a full-scale test of a structural component such as a blade, it is important to acknowledge that the loads used in the test are generated and controlled in a completely different manner than the variable natural loads (such as wind loads) which the component will experience in reality and which it should be designed for. For selection of loads to be used in full-scale tests for verification, it is therefore not relevant to apply partial safety factors for loads that are prescribed for design in accordance with particular codes and standards. The loads to be used in tests need to be chosen after thorough consideration of the variability and uncertainty in the strength, given the degree of knowledge about the strength or capacity available prior to the test.

In this context it should be noted that the effect of proof loading represents an increase in confidence in the structural strength or capacity, resulting from prior successful loading of the component.

2.3.9 Inspection and inspection intervals

The design process is only one element in ensuring safe and reliable structures. In fabrication and service, other safety elements can be introduced such as quality control, alignment control, visual inspection, instrumented monitoring, and proof loading. Each of these items provide information about the structure, additional to the information present at the design stage, and may hence reduce the overall uncertainty associated with the structure. The probabilistic model used in design can then be updated and calibrated against reality by including the additional information.

The additional information obtained during fabrication and in service may be obtained either directly as information about some of the governing variables themselves, e.g. strength, or indirectly by observing substitute variables, which are functions of the governing variables, e.g. cracks or deformations.

It is of interest to update the failure probability from its value in the design stage to a value which reflects the additional information gained by inspection. Probability updating by inspection is based on the definition of conditional probability. Let F denote the event of structural failure. In the design process the probability of failure $P_F = P[F]$ is solved according to the procedures described above. Let I denote an event such as the observation of a governing variable or the observation of a function of one or more of the governing variables, obtained by inspection when the structure is in service. The updated probability of failure is the probability of failure conditioned on the inspection event I,

$$P[F \mid I] = \frac{P[F \cap I]}{P[I]}$$

The probability in the numerator can be solved by a reliability analysis of a parallel system, for which solutions are available. The probability in the denominator can be solved by a reliability analysis of a structural component as described above, once a suitable limit state function has been defined, and with due account for measurement uncertainty and probability of detection, which are two contributing uncertainty sources of importance in this context.

For some limit states, e.g. crack growth and fatigue failure, the failure probability P_F increases as a function of time. For such limit states, prediction of the failure probability as a function of time can be used to predict the time when the failure probability will exceed some critical threshold, e.g. a maximum acceptable failure probability. This predicted point in time is a natural choice for execution of an inspection. The failure probability can then be updated as outlined above, depending on the findings from the inspection and including improvements from a possible repair following the inspection. The time until the failure probability will again exceed the critical threshold and trigger a new inspection can be predicted and thus forms an inspection interval. This can be used to establish an inspection plan.

Note in this context that for some limit states such as the fatigue limit state, it may actually be a prerequisite for maintaining the required safety level over the design life that inspections are carried out at specified intervals.

2.4 Mechanical safety

There are several mechanical systems in a wind turbine:

- transmission: hub, shaft, gear, couplings, brakes, bearings and generator
- mechanical control systems: pitch system, teeter mechanism, yaw system, hydraulic system and pneumatic system

The safety of mechanical components will usually be determined by their structural safety as described in previous sections. However, as the components are part of mechanical systems, there are several aspects to be considered in addition to the structural safety when the safety of mechanical systems is to be evaluated.

The structural strength will in many cases become limited by surface damages due to wear such as fretting corrosion in connections due to micro movements, or gray staining of gear teeth due to poor lubrication conditions. Hence, aspects like friction and lubrication conditions as well as surface treatment are essential for the mechanical safety.

Mechanical components are often made of rather brittle high-strength material such as case-hardened steel for gears and induction-hardened roller bearing steel. Furthermore, the strength of mechanical components often relies on extremely fine tolerances, e.g. correction grinding of gear teeth or mating surfaces in connections.

Non-metallic materials such as rubber are often used in mechanical components to achieve damping, or they are used as sealing in hydraulic components. Ageing properties and temperature dependence are of importance for such materials.

Mechanical components are in many cases subjected to internal forces such as pressure in hydraulic systems, pretension in bolts and shrinkage stress in shrink fit connections. In other cases, strength requirements rely on the rotational speed as is the case with an internal gear shaft, which will experience one complete bending cycle for each revolution.

Mechanical safety will thus depend on several more or less well-defined parameters, often in a rather complex combination. It may be difficult to define all governing phenomena adequately, and assumptions may not always hold in practice. In terms of failure probability, it may therefore not always be feasible to take a probabilistic approach to assess mechanical safety.

Due to the complexity of mechanical systems, the required level of safety needs to rely on experience together with the consequences of a given failure. Typically, codes and standards used for mechanical design do not define requirements for safety factors. This also applies to the most commonly used standards, which are the gear standards ISO 6336 and DIN 3990, and the bearing dynamic load rating standard ISO 281. Hence, minimum safety requirements need to be determined on the basis of the manufacturers' experience and, if available, on requirements from authorities, certification bodies and wind turbine developers. As a general guideline, the requirement for structural safety shall at the same time constitute the lower limit for the requirement for mechanical safety.

Machine components may be vulnerable to lightning and may fail as a result. They should therefore be bonded to local ground. DEFU (1999) may be consulted for requirements for cross sections of equipotential bonding connections. Due to their small contact areas, rotating and movable components such as roller bearings may burn if struck by lightning. They can be protected by a protection system consisting of two parts: a diversion of the current via an alternative part with low impedance, and a reduction of current through the movable components, e.g. by means of electrical insulation.

2.5 Labour safety

The safety of personnel working on a wind turbine or nearby shall be considered when designing a wind turbine, not least when issuing instructions and procedures for transportation and assembly, operation, maintenance and repair.

It shall be possible to operate the control levers and buttons of the wind turbine with ease and without danger. These levers and buttons should be placed and arranged in such a manner that unintentional or erroneous operation, which can lead to dangerous situations, is prevented. The wind turbine shall in general be designed in such a manner that dangerous situations do not occur. If a wind turbine has more than one control panel or control unit, it shall only be possible to operate it from one panel or unit at a time.

The Danish "National Working Environment Authority Regulation No. 561" of June 24, 1994 as later amended, cf. the "National Working Environment Authority Regulation No. 669" of August 7, 1995, regarding design of technical facilities, commonly referred to as "Maskin-direktivet", shall be complied with at all times.

Reference is also made to prEN 50308, Wind turbines - Labour safety - December 18, 1998.

2.5.1 Transportation, installation and commissioning

Requirements concerning personnel safety shall be described in the instructions in the wind turbine manuals and in the procedures for assembly, installation and commissioning.

2.5.2 Normal operation

During normal operation of the wind turbine, the safety of personnel inside and outside the wind turbine shall be considered. Normal operation of the wind turbine shall be possible without accessing the nacelle.

Operational procedures and operation of the wind turbine shall be described in the user manual, which is furnished to the turbine owner or to the person responsible for the operation of the wind turbine. It shall appear from any instructions how personnel safety has been accounted for.

2.5.3 Service, maintenance and repair

The manufacturer or supplier of the wind turbine shall provide instructions and procedures, which consider wind speeds and other external conditions in such a manner that service, maintenance and repair work on the wind turbine can be performed safely. The wind turbine shall be designed with a view to ensuring safe access to and safe replacement of all components to be serviced.

Access
It shall be made clear by means of locks and/or signs that it can be dangerous to ascend the wind turbine. It shall be prevented that unauthorised persons get access to the control panel and the machinery of the wind turbine. Operation of the wind turbine and access to its local control system shall not require access to electrical circuits with a higher voltage than 50V.

Wherever screens and shields are used for protection, it shall be ensured that, during normal operation, personnel cannot get in contact with any rotating, moving or conducting parts.

The light in access routes shall have an intensity of at least 25 lux. This shall also apply when the main switch of the wind turbine is turned off.

Working conditions
The wind turbine shall be constructed in such a way that replacing components subject to service does not entail working postures or movements which are hazardous to health or otherwise dangerous. It shall be possible to block the rotor and yaw system of the wind turbine in a safe and simple manner other than by using the ordinary brake and yaw system of the turbine. For pitch-controlled turbines, fixation of the pitch setting shall be possible. Blocking of the rotor shall be done by mechanical fixation of the rotor and shall be capable of keeping the rotor fixed at all wind speeds below the defined normal stop wind speed. Blocking of the yaw and pitch systems shall keep the yaw and pitch systems, respectively, fixed at all wind speeds below the defined normal stop wind speed.

Operation of the blocking mechanisms and of their area of application shall be described in the user manual of the wind turbine in order to avoid incorrect use.

It shall be possible to illuminate working areas with a light intensity of at least 50 lux. In addition, the lighting must be designed such that glare, stroboscopic influences and other disadvantageous lighting conditions are avoided.

It shall be possible to initiate emergency shutdown close to the working areas in the wind turbine. As a minimum, it shall be possible to initiate emergency shutdown at the bottom of the tower, i.e. at the control panel, and in the nacelle.

2.6 Codes and standards

DS472
"Load and Safety for Wind Turbine Structures", DS472, 1st edition, Dansk Ingeniørforening, Copenhagen, Den-mark, 1992.

This is the Danish standard for design of wind turbine structures. This standard, with its two annexes A and B, and with the standards DS409 and DS410 and relevant structural codes for materials, forms the Danish safety basis for structural design of horizontal axis wind turbines. The standard is valid for the environmental conditions of Denmark and for turbines with rotor diameters in excess of 5 m.

IEC61400-1
"Wind turbine generator systems – Part 1: Safety requirements", 2nd edition, International Electrotechnical Commission, Geneva, Switzerland, 1999.

This is an international standard that deals with safety philosophy, quality assurance and engineering integrity. Moreover, it specifies requirements for the safety of wind turbine generator systems. It covers design, installation, maintenance, and operation under specified environmental conditions. Its purpose is to provide an appropriate level of protection against damage from all hazards during the design life. The standard is concerned with control and protection mechanisms, internal electrical systems, mechanical systems, support structures, and electrical interconnection equipment. The standard applies to wind turbines with a swept area equal to or greater than 40 m^2. The standard shall be used together with a number of other specified IEC standards and together with ISO2394.

NVN11400-0
"Wind turbines – Part 0: Criteria for type certification – technical criteria," 1st edition, Nederlands Normalisatie-institut, The Netherlands, 1999.

This is the Dutch standard for safety-based design of wind turbine structures. It is valid for wind turbines with a swept rotor area of at least 40 m^2. To a great extent, it is based on IEC61400-1, however, since it is to be used also for type certification of wind turbines in the Netherlands, it covers requirements for additional aspects such as type testing.

DIBt RICHTLINIEN
"Richtlinie. Windkraftanlagen. Einwirkungen und Standsicherheits-nachweise für Turm und Gründung" (in German). Guidelines for loads on wind turbine towers and foundations. Deutsche Institut für Bautechnik (DIBt), Berlin, Germany, 1993.

GL REGULATIONS
"Regulation for the Certification of Wind Energy Conversion Systems," Vol. IV – Non-Marine Technology, Part 1 – Wind Energy, in "Germanischer Lloyd Rules and Regulations," Hamburg, Germany, 1993.

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3. External Conditions

3.1 Wind conditions

The wind climate that governs the loading of a wind turbine is usually represented by the 10-minute mean wind speed U_{10} at the site in conjunction with the standard deviation σ_U of the wind speed. Over a 10-minute period, stationary wind climate conditions are assumed to prevail, i.e. U_{10} and σ_U are assumed to remain constant during this short period of time. Only when special conditions are present, such as tornadoes and cyclones, representation of the wind climate in terms of U_{10} and σ_U will be insufficient.

3.1.1 10-minute mean wind speed

The 10-minute mean wind speed will vary from one 10-minute period to the next. This variability is a natural variability and can be represented in terms of a probability distribution function. In the long run, the distribution of the 10-minute mean wind speed can for most sites be taken as a Weibull distribution

$$F_{U_{10}}(u) = 1 - \exp(-(\frac{u}{A})^k)$$

in which the shape parameter k and the scale parameter A are site and height-dependent coefficients. The scale parameter A at height z can be calculated as follows

$$A = A_H \frac{\ln \frac{z}{z_0}}{\ln \frac{H}{z_0}}$$

where z_0 is the terrain roughness parameter which is defined as the extrapolated height at which the mean wind speed becomes zero, if the vertical wind profile has a logarithmic variation with height. A_H is the scale parameter at a reference height H. A common choice for the reference height is H = 10 m. However, in the context of wind turbines, the hub height is a natural choice for H. The expression for A is based on a logarithmic wind speed profile above the ground

$$u(z) = \frac{u^*}{\kappa} \ln \frac{z}{z_0}$$

where u^* is the frictional velocity, $\kappa = 0.4$ is von Karman's constant, and neutral atmospheric conditions are assumed. The frictional velocity is defined as $u^* = (\tau/\rho)^{1/2}$, in which τ is the surface shear stress, and ρ is the air density.

For engineering calculations it may sometimes prove useful to apply the following empirical approximation for the scale parameter A

$$A = A_{10} \left(\frac{z}{H} \right)^{\alpha}$$

where the exponent α depends on the terrain roughness. Note that if the logarithmic and exponential expressions for A given above are combined, a height-dependent expression for the exponent α results

$$\alpha = \frac{\ln \left(\frac{\ln \frac{z}{z_0}}{\ln \frac{H}{z_0}} \right)}{\ln \left(\frac{z}{H} \right)}$$

Note also that the interpretation of the limiting value $\alpha = 1/\ln(z/z_0)$ is similar to that of a turbulence intensity as z approaches the reference height H, cf. the definitions given in Sections 3.1.2 and 3.1.3. As an alternative to the quoted expression for α, values for α tabulated in Table 3-1 may be used.

A homogeneous terrain is characterised by a constant z_0 over the terrain. Typical values for z_0 are given in Table 3-1 for various types of terrain. For offshore locations, where the terrain consists of the sea surface, the roughness parameter is not constant, but depends on:

- wind speed
- upstream distance to land
- water depth
- wave field

Table 3-1. Wind speed parameters for various types of terrain.

Terrain type	Roughness parameter z_0 (m)	Expon ent α
Plane ice	0.00001	
Open sea without waves	0.0001	
Open sea with waves	0.0001-0.003	0.12
Coastal areas with onshore wind	0.001	
Open country without significant build-ings and vegetation	0.01	
Cultivated land with scattered buildings	0.05	0.16
Forests and suburbs	0.3	0.30
City centres	1-10	0.40

A widely used expression for the roughness parameter of the open, deep sea far from land is given by Charnock's formula

$$z_0 = A_c \frac{u_*^2}{g}$$

in which g is the acceleration of gravity, and

$$u_* = \sqrt{\frac{\tau_0}{\rho}}$$

is the frictional velocity expressed as a function of the shear stress τ_0 at the sea surface and the density ρ of the air. A_c = 0.011 is recommended for open sea. As an approximation, Charnock's formula can also be applied to near-coastal locations provided that A_c = 0.034 is used. Expressions for A_c, which include the dependency on the wave velocity and the available water fetch, are available in the literature, see Astrup et al. (1999). Based on a logarithmic wind speed profile, Charnock's formula leads to the following expression for the roughness parameter for a water surface

$$z_0 = \frac{A_c}{g}\left(\frac{\kappa U_{10}}{\ln(z/z_0)}\right)^2$$

from which z_0 can be determined implicitly, and from which the dependency on the wind speed in terms of U_{10} is evident. For offshore locations, this implies that determination of z_0 and of the distribution of $U_{10,}$ respectively, involves an iterative procedure. κ= 0.4 is von Karman's constant.

The basic wind speed $v_{B,}$ used in the Danish design code, is the 50-year return value of the 10-minute mean wind speed at 10 m height above land with terrain roughness z_0 = 0.05. The 10-minute mean wind speed with a 50-year recurrence period at other heights and with another terrain roughness can be found as

$$v_{10\,\min,50yr} = v_B k_t \ln\frac{z}{z_0}$$

in which $k_t = 0.19(z_0/0.05)^{0.078}$

3.1.2 Standard deviation of wind speed

For a given value of U_{10}, the standard deviation σ_U of the wind speed exhibits a natural variability from one 10-minute period to another. This variability of the wind speed is known as the turbulence, and σ_U is therefore often referred to as the standard deviation of the turbulence components. Measurements from several locations show that σ_U conditioned by U_{10} can often be well-represented by a lognormal distribution

$$F_{\sigma_U|U_{10}}(\sigma) = \Phi(\frac{\ln\sigma - b_0}{b_1})$$

in which Φ() denotes the standard Gaussian cumulative distribution function. The coefficients b_0 and b_1 are site-dependent coefficients conditioned by U_{10}. See Ronold and Larsen (1999).

The coefficient b_0 can be interpreted as the mean value of $\ln\sigma_U$, and b_1 can be interpreted as the standard deviation of $\ln\sigma_U$. The following relationships can be used to calculate the mean value $E[\sigma_U]$ and the standard deviation $D[\sigma_U]$ of σ_U from the values of b_0 and b_1

$$E[\sigma_U] = \exp(b_0 + \frac{1}{2}b_1^2)$$

$$D[\sigma_U] = E[\sigma_U]\sqrt{\exp(b_1^2) - 1}$$

These quantities will, in addition to their dependency on U_{10}, also depend on local conditions, first of all the terrain roughness z_0, which is also known as the roughness length. When different terrain roughness prevails in different directions, i.e. the terrain is not homogeneous, $E[\sigma_U]$ and $D[\sigma_U]$ may vary with the direction. This will be the case for example if a house is located nearby. Houses and other "disturbing" elements will, in general, lead to more turbulence, i.e. larger values of $E[\sigma_U]$ and $D[\sigma_U]$, than will normally be found in smoother terrain. Figure 3-1 and Figure 3-2 give examples of the variation of $E[\sigma_U]$ and $D[\sigma_U]$ with U_{10} for onshore and offshore locations, respectively. The difference between the two Figures is mainly attributable to the different shape of the mean curve. This reflects the effect of the increasing roughness length for increasing U_{10} on the offshore location.

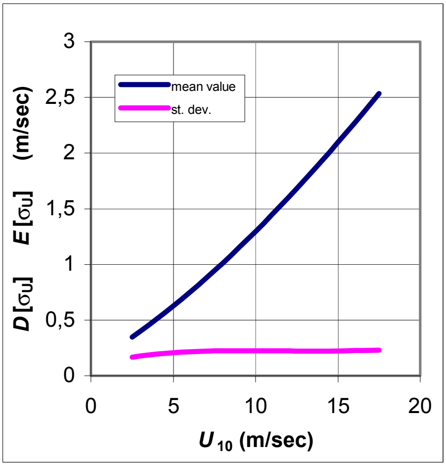

Figure 3-1. Mean value and standard deviation of σ_U as functions of U_{10} – onshore location.

In some cases, a lognormal distribution for σ_U conditioned by U_{10} will underestimate the higher values of σ_U. A Frechet distribution may form an attractive distribution model for σ_U in such cases, hence

$$F_{\sigma_U|U_{10}}(\sigma) = \exp(-(\frac{\sigma_0}{\sigma})^k)$$

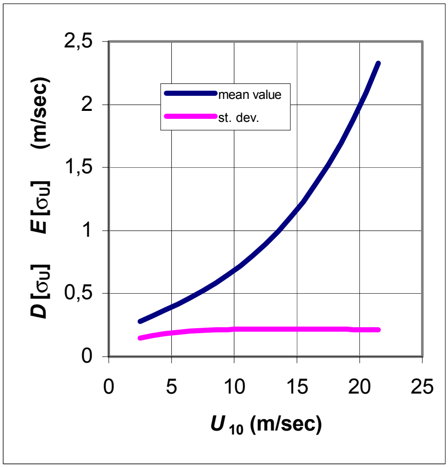

Figure 3-2. Mean value and standard deviation of σ_U as functions of U_{10} – offshore location.

The distribution parameter k can be solved implicitly from

$$\left(\frac{D[\sigma_U]}{E[\sigma_U]}\right)^2 = \frac{\Gamma(1-\frac{2}{k})}{\Gamma^2(1-\frac{1}{k})} - 1$$

and the distribution parameter σ_0 then results in

$$\sigma_0 = \frac{E[\sigma_U]}{\Gamma(1-\frac{1}{k})}$$

where Γ denotes the gamma function.

Caution must be exercised when fitting a distribution model to data. Normally, the lognormal distribution provides a good fit to data, but utilisation of a normal distribution, a Weibull distribution or a Frechet distribution is also seen. The choice of distribution model may depend on the application, i.e. whether a good fit to data is required for the entire distribution, only in the body, or in the upper tail of the distribution. It is important to identify and remove data, which belong to 10-minute series for which the stationarity assumption for U_{10} is not fulfilled. If this is not done, such data may confuse the determination of an appropriate distribution model for σ_U conditioned by U_{10}.

Based on boundary-layer theory, the following expression for the mean value of the standard deviation σ_U, conditioned by U_{10}, can be derived

$$E[\sigma_U] = U_{10} A_x \kappa \frac{1}{\ln \frac{z}{z_0}}$$

for homogeneous terrain, in which $\kappa = 0.4$ is von Karman’s constant, z is the height above terrain, z_0 is the terrain roughness, also known as the roughness length, and A_x is a constant which depends on z_0. Measurements from a number of locations with uniform and flat terrain indicate an average value of A_x equal to 2.4, see Panofsky and Dutton (1984). Dyrbye and Hansen (1997) suggest $A_x = 2.5$ for $z_0 = 0.05$m and $A_x = 1.8$ for $z_0 = 0.3$m. A conservative fixed choice for σ_U is desirable for design purposes, i.e. a characteristic value, and DS472 suggests

$$\sigma_{U,c} = U_{10} \frac{1}{\ln \frac{z}{z_0}}$$

Note that this value, although higher than the mean value of σ_U, may not always be sufficiently conservative for design purposes.

The IEC61400-1 standard requires utilisation of a characteristic standard deviation for the wind speed

$$\sigma_{U,c} = I_{15} \frac{U_{10,15} + aU_{10}}{a+1}$$

in which $U_{10,15}$ = 15 m/s is a reference wind speed, $I_{T,15}$ is the characteristic value of the turbulence intensity at 15 m/s, and a is a slope parameter. $I_{T,15}$ = 0.18 and a = 2 are to be used in the category for higher turbulence characteristics, while $I_{T,15}$ = 0.16 and a = 3 are to be used in the category for lower turbulence characteristics. The expression for the characteristic value $\sigma_{U,c}$ is based on a definition of the characteristic value as the mean value of σ_U plus one standard deviation of σ_U.

3.1.3 Turbulence intensity

The turbulence intensity I_T is defined as the ratio between the standard deviation σ_U of the wind speed, and the 10-minute mean wind speed U_{10}, i.e. $I_T = \sigma_U/U_{10}$.

Note that the presence of a wind turbine will influence the wind flow locally, and that the turbulence in the wake behind the turbine will be different from that in front of the turbine. This phenomenon of a wind turbine influenced turbulence is known as a wake effect. Typically, the presence of the wind turbine will lead to increased turbulence intensity in the wake. Wake effects need to be considered for wind turbines installed behind other turbines with a distance of less than 20 rotor diameters. This is of particular interest wherever wind farms with many turbines in several rows are to be installed.

The following method, Frandsen 2001, can be used to take wake effects into account. By this method, the free flow turbulence intensity I_T is modified by the wake turbulence intensity $I_{T,w}$ to give the total turbulence intensity $I_{T,total}$. In the evaluation of the wake effect, a uniform distribution of the wind direction is assumed. The formulas can be adjusted if the distribution of wind direction is not uniform. Reference is made to Frandsen, 2001.

$$I_{T,total} = \sqrt[m]{(1 - N \cdot p_w) I_T{}^m + p_w \sum_{i=1}^{N} I_{T,w}{}^m \cdot s_i}$$

$$p_w = 0.06$$

$$s_i = x_i / D$$

$$I_{T,w} = \sqrt{\frac{1}{(1.5 + 0.3 \cdot s_i \cdot \sqrt{v})^2} + I_T{}^2}$$

N	number of closest neighbouring wind turbines
m	Wöhler curve exponent corresponding to the material of the considered structural component
v	free flow mean wind speed at hub height
p_w	probability of wake condition
x_i	distance to the i'th wind turbine
D	rotor diameter
I_T	free flow turbulence intensity
$I_{T,w}$	maximum turbulence intensity at hub height in the centre of the wake

The number of closest neighbouring wind turbines N can be chosen as follows:

2 wind turbines:	$N = 1$
1 row:	$N = 2$
2 rows:	$N = 5$
in a farm with more than 2 rows:	$N = 8$

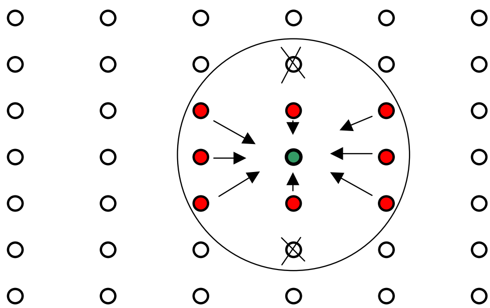

Figure 3-3. Example of determination of neighbouring wind turbines.

If the wind farm consists of more than five rows with more than five turbines in each row, or if the distance between the turbines in the rows that are located perpendicular to the predominant wind direction is less than $3D$, the increase in mean turbulence intensity shall be taken into account. This is done by substituting the free flow turbulence I_T with I_T^*:

$$I_T^* = ½\sqrt{I_w^2 + I_T^2} + I_T$$

$$I_w = \frac{0.36}{1 + 0.08\sqrt{s_r s_f v}}$$

$$s_r = x_r / D$$

$$s_f = x_f / D$$

where x_r is the distance within a row, and x_f is the distance between rows.

3.1.4 Lateral and vertical turbulence

The 10-minute mean wind speed, the standard deviation of the wind speed, and the turbulence intensity presented above all refer to the wind speed in the constant direction of the mean wind during the considered 10-minute period of stationary conditions. During this period, in addition to the turbulence in the direction of the mean wind, there will be turbulence also laterally and vertically. The mean lateral wind speed will be zero, while the lateral standard deviation of the wind speed can be taken as $\sigma_{Uy} = 0.75\sigma_U$ according to Dyrbye and Hansen (1997) and as $\sigma_{Uy} = 0.80\sigma_U$ according to Panofsky and Dutton (1984). The mean vertical wind speed will be zero, while the vertical standard deviation of the wind speed can be taken as $\sigma_{Uz} = 0.5\sigma_U$. These values all refer to homogeneous terrain. For complex terrain, the wind speed field will be much more isotropic, and values for σ_{Uy} and σ_{Uz} very near the value of σ_U can be expected. Beware that calculations for changes in the direction of the wind in complex terrain may come out very wrongly, if values for σ_{Uy} and σ_{Uz}, which are valid for homogeneous terrain, are applied.

Very often, the wind climate at a particular location cannot be documented by site-specific measurements. In such situations, the distribution of U_{10} can usually be well-represented, for example on the basis of wind speed measurements from a nearby location. However, the distribution of σ_U will usually be harder to obtain as it is highly dependent on the local roughness conditions. Thus, it cannot be inferred automatically from known wind speed conditions at nearby locations. On a location where wind speed measurements are not available, determination of the distribution of the standard deviation σ_U of the wind speed is often encumbered with ambiguity. It is thus common practice to account for this ambiguity by using conservatively high values for σ_U for design purposes, viz. the characteristic values for σ_U given in DS472 and IEC61400-1 and referenced above.

3.1.5 Stochastic turbulence models

Wind in one direction is considered, i.e. in the direction of the 10-minute mean wind speed. The wind speed process $U(t)$ within a 10-minute period of constant U_{10} and σ_U is considered and can be assumed to be stationary. The spectral density of the wind speed process expresses how the energy of the wind turbulence is distributed between various frequencies. Several models for the spectral density exist. A commonly used model for the spectral density is the Harris spectrum

$$S_U(f) = \sigma_U{}^2 \frac{3.66 \frac{L}{U_{10}}}{(1+\frac{3}{2}(\frac{2\pi fL}{U_{10}})^2)^{5/6}}$$

in which f denotes the frequency, and L is a characteristic length, which relates to the integral length scale L_u by $L = 1.09L_u$. A calibration to full scale data indicates values for L in the range 66-440 m with $L \cong 200$ m used to match the high frequency portion of the spectrum. Based on experience, the Harris spectrum is not recommended for use in the low frequency range, i.e. for $f < 0.01$ Hz.

Another frequently used model for the power spectral density is the Kaimal spectrum

$$S_U(f) = \sigma_U{}^2 \frac{6.8 \frac{L_u}{U_{10}}}{(1+10.2 \frac{fL_u}{U_{10}})^{5/3}}$$

in which the integral length scale is given by

$L_u = 100Cz^m$

where z is the height and C and m depend on the roughness length z_0 as given in Figure 3-4. This spectrum is used in Eurocode 1.

Towards the high frequency end of the inertial subrange, IEC61400-1 requires that the power spectral density used for design shall approach the form

$$S_U(f) = 0.05 \cdot \sigma_{U,c}{}^2 \left(\frac{\lambda}{U_{10}}\right)^{-2/3} f^{-5/3}$$

in which the turbulence scale parameter λ depends on the height z above the terrain

$$\lambda = \begin{cases} 0.7z & \text{for } z < 30\text{ m} \\ 21\text{ m} & \text{for } z > 30\text{ m} \end{cases}$$

The turbulence scale parameter is by definition the wavelength where the non-dimensional, longitudinal power spectral density is equal to 0.05.

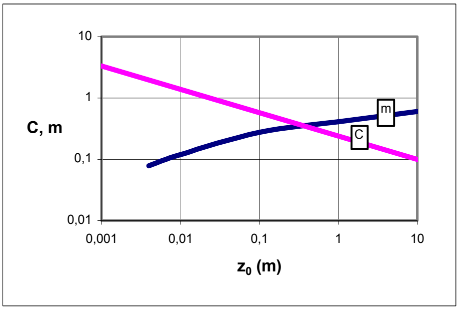

Figure 3-4. Coefficients C and m for the integral length scale of the Kaimal spectrum.

For design purposes it is common to relate calculations to wind conditions at the hub, i.e. U_{10} and σ_U refer to the wind speed at the hub height. Note that the turbulence scale parameter λ relates to the integral length scale L through $L = 4.76\lambda$. This gives the following expression for the Kaimal spectrum, which is well-known from IEC61400-1

$$S_U(f) = \sigma_U{}^2 \frac{4 \frac{L_k}{U_{10}}}{(1+6 \frac{fL_k}{U_{10}})^{5/3}}$$

with $L_k = 8.1\lambda$

For calculation of spectral densities for lateral and vertical wind speeds, the above formulas can be used with σ_{Uy} and σ_{Uz}, respectively, substituted for σ_U, and with $\lambda_y = 0.3\lambda$ and $\lambda_z = 0.1\lambda$, respectively, substituted for λ.

Note that there is some arbitrariness in the models for power spectral density. Each model implies idealization and simplification and is usually calibrated to provide a good fit to data within a limited frequency range. At low frequencies, in particular, the models show significant differences. In Figure 3-5 three models for power spectral densities are plotted on dimensionless scales for comparison

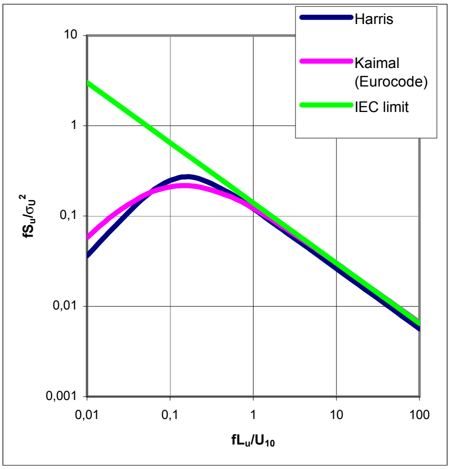

Figure 3-5. Comparison between the Harris, Kaimal and IEC power spectral densities.

Spectral moments are useful for representation of the wind speed process $U(t)$. The jth spectral moment is defined by

$$m_j = \int_0^\infty \omega^j S_U(\omega) d\omega$$

In the short term, such as within a 10-minute period, the wind speed process $U(t)$ can usually be represented as a Gaussian process, conditioned by a particular 10-minute mean wind speed U_{10} and a given standard deviation σ_U. The arbitrary wind speed U at a considered point in time will then follow a normal distribution with the mean value U_{10} and the standard deviation σ_U. This is usually the case for turbulence in a homogeneous terrain. However, for turbulence in a complex terrain it is not uncommon to see a skewness of −0.1, which implies that the Gaussian assumption has not been fulfilled.

Note that although the short-term wind speed process will be Gaussian for homogeneous terrain, it will usually not be a narrow-banded Gaussian process. This comes about as a result of the spectral density and is of importance for prediction of extreme wind speed values. Such extreme values and their probability distributions can be expressed in terms of spectral moments. Reference is made to textbooks on stochastic process theory.

At any point in time there will be a variability in the wind speed from one point to another. The closer together the two points are, the higher is the correlation between their respective wind speeds. The wind speed will form a random field in space. A commonly used model for the autocorrelation function of the wind speed field can be derived from the exponential Davenport coherence spectrum

$$Coh(r, f) = \exp(-cf \frac{r}{u})$$

where r is the distance between the two points, u is the average wind speed over the distance r, f is a frequency, and c is the non-dimensional decay constant, which is referred to as the coherence decrement, and which reflects the correlation length of the wind speed field. The auto-correlation function can be found as

$$\rho(r) = \frac{1}{\sigma_U^2} \int_0^\infty \sqrt{Coh(r, f)} S_U(f) df$$

in which $S_U(f)$ is the power spectral density of the wind speed. The coherence model can be refined to account for different correlation lengths, horizontally and vertically. Note that it is a shortcoming of the Davenport model that it is not differentiable for r = 0. Note also that, owing to separation, the limiting value ρ(0) will often take on a value somewhat less than 1.0, whereas the Davenport model always leads to ρ(0) = 1.0.

Note that the integral length scale L_u, referenced above as a parameter in the models for the power spectral density, is defined as

$$L_u = \int_0^\infty \rho(r)dr$$

3.1.6 Wind shear

Wind shear is understood as the variation of the wind speed with the height. Its effects are not considered important for small wind turbines, with rotor diameters in the order of 10 m. Wind shear may be important for large and/or flexible rotors. A number of failures have been attributed to blade loads induced by wind shear.

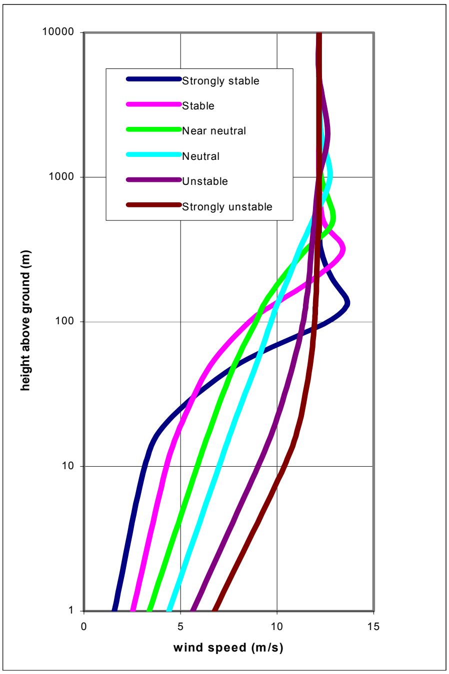

Figure 3-6. Wind shear profiles for various stability conditions on a location with roughness z_0 = 0.02 m and geostrophic wind speed G = 12 m/s.

The wind profile depends heavily on the atmospheric stability conditions, see Figure 3-6 for an example. Even within the course of 24 hours, the wind profile will change between day and night, dawn and dusk.

Wind shear profiles can be derived from the logarithmic model presented in Section 3.1.1, modified by a stability correction. The stability-corrected logarithmic wind shear profile reads

$$u(z) = \frac{u^*}{\kappa}(\ln\frac{z}{z_0} - \psi)$$

in which ψ is a stability-dependent function, which is positive for unstable conditions, negative for stable conditions, and zero for neutral conditions. Unstable conditions

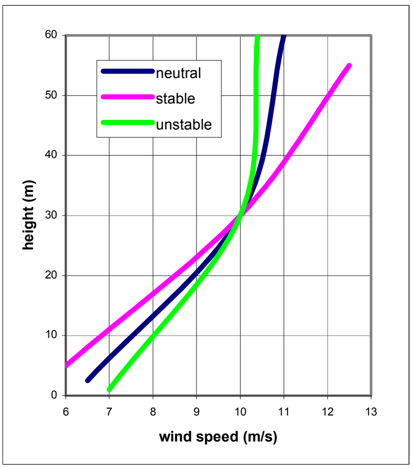

Figure 3-7. Wind profiles for neutral, stable and unstable conditions.

typically prevail when the surface is heated and the vertical mixing is increasing. Stable conditions prevail when the surface is cooled, such as during the night, and vertical mixing is suppressed. Figure 3-7 shows examples of stability-corrected logarithmic wind shear profiles for various conditions on a particular location.

The stability function ψ depends on the non-dimensional stability measure $\zeta = z/L_{MO}$, where z is the height, and L_{MO} is the Monin-Obukhov length. The stability function can be calculated from the expressions

$$\psi = -4.8\zeta \text{ for } \zeta \geq 0$$

$$\psi = 2\ln(1+x)+\ln(1+x^2)-2\tan^{-1}(x) \text{ for } \zeta < 0$$

in which $x = (1-19.3\cdot\zeta)^{1/4}$.

The Monin-Obukhov length L_{MO} depends on the heat flux and on the frictional velocity u^*. Its value reflects the relative influence of mechanical and thermal forcing on the turbulence. Typical values for the Monin-Obukhov length L_{MO} are given in Table 3-2.

Table 3-2. Monin-Obukhov length.

Atmospheric conditions	L_{MO}(m)
Strongly convective days	−10
Windy days with some solar heating	−100
Windy days with little sunshine	−150
No vertical turbulence	0
Purely mechanical turbulence	∞
Nights where temperature stratification slightly dampens mechanical turbulence generation	>0
Nights where temperature stratification severely suppresses mechanical turbulence generation	>>0

If data for the Richardson number R are available, the following empirical relationships can be used to obtain the Monin-Obukhov length

$$L_{MO} = \frac{z}{R} \text{ in unstable air}$$

$$L_{MO} = z\frac{1-5R}{R} \text{ in stable air}$$

In lieu of data, the Richardson number can be computed from averaged conditions as follows

$$R = \frac{\frac{g}{T}(\gamma_d - \gamma)}{\left(\frac{\partial \bar{u}}{\partial z}\right)^2 + \left(\frac{\partial \bar{v}}{\partial z}\right)^2}(1+\frac{0.07}{B})$$

g	acceleration of gravity
T	temperature
$\gamma = -\partial T/\partial z$	lapse rate
$\gamma_d \approx 9.8°C/km$	dry adiabatic lapse rate

Further, $\partial\bar{u}/\partial z$ and $\partial\bar{v}/\partial z$ are the vertical gradients of the two horizontal average wind speed components $\bar{u}$ and $\bar{v}$, and z denotes the vertical height. Finally, the Bowen ratio B of sensible to latent heat flux at the surface can near the ground be approximated by

$$B \approx \frac{c_p}{L_{MO}}\frac{(\bar{T}_2 - \bar{T}_1)}{(\bar{q}_2 - \bar{q}_1)}$$

in which c_p is the specific heat, LMO is the Monin-Obukhov length, $\bar{T}_1$ and $\bar{T}_2$ are the average temperatures at two levels denoted 1 and 2, respectively, and $\bar{q}_1$ and $\bar{q}_2$ are the average specific humidity at the same two levels. The specific humidity q is in this context calculated as the fraction of moisture by mass. Reference is made to Panofsky and Dutton (1984).

Topographic features such as hills, ridges and escarpments affect the wind speed. Certain layers of the flow will accelerate near such features, and the wind profiles will become altered. Theories exist for calculation of such changed wind profiles, see Jensen (1999). An example of effects of a ridge is given in Figure 3-8.

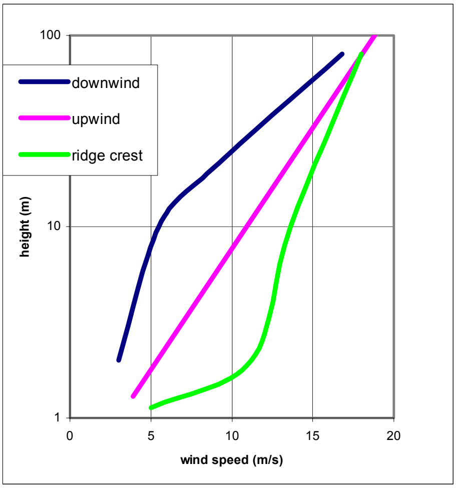

Figure 3-8. Wind profiles observed upwind, at the crest, and at the foot downwind of a two-dimensional ridge.

3.1.7 Wind direction

The wind direction and changes in the wind direction are determined by geography, global and local climatic conditions and by the rotation of earth. Locally, the wind direction will vary with the lateral turbulence intensity and for coast near locations, in particular, the wind direction can vary between day and night.

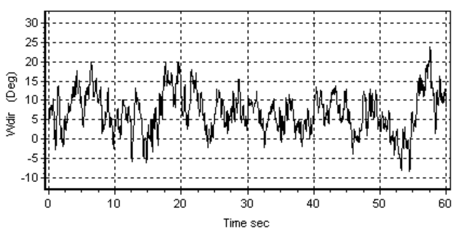

Figure 3-9. Example of fluctuations in the wind direction.

Though the yaw system of the wind turbine will hold the rotor in the direction of the mean wind direction, the short-term fluctuations in the wind direction give rise to fatigue loading. At high wind speeds sudden changes in the wind direction during production can give rise to extreme loads.

Wind rose

The distribution of the wind direction is of particular interest with respect to installation of turbines in wind farms. As can be seen in Section 3.1.3, wind turbines installed behind obstacles, such as for example other turbines, cause a considerable increase in turbulence intensity.

The distribution of the wind direction is often represented by a wind rose as the one seen in Figure 3-10.

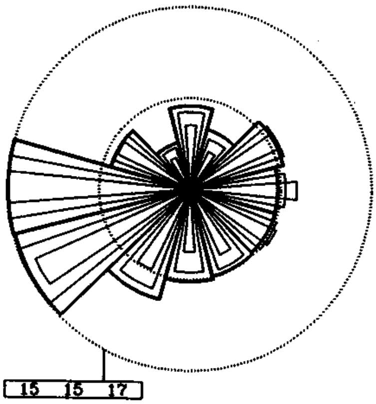

Figure 3-10. Wind rose for Kastrup, Denmark. Lundtang et al. 1989.

The 360° around the site is typically divided into 12 sectors of 30° each. The radius of the outer wedge in each sector represents the relative frequencies of wind from that direction. The middle wedge shows the contribution from each sector to the total mean wind speed, and the inner wedge shows the contribution to the total mean cube of the wind speed. The scale for each