Wind Energy

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Chapter 14

Wind Energy

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Over the years, wind energy has become a major source of renewable energy worldwide. The present chapter addresses the wind resource, which is available for exploitation for large-scale electricity production, and its specific physical properties. Furthermore, the technical options available to convert the energy of the air flow into mechanical energy and electricity are described. Specific problems of large-scale integration of wind energy into the grid as well as the present and future market developments are described in this chapter. Finally, environmental aspects are discussed briefly.

1 Introduction

Despite the fact that only a small portion of the solar radiation that reaches the earth is converted to wind energy, the potential of the wind to contribute to the world's energy needs is significant. About 0.7% of the captured solar radiation is converted into the earth's pressure system. The pressure differences cause the air to flow. About 0.8% of the energy contained in the pressure system is converted into kinetic energy in the lower boundary layer of the earth. If 10% of this energy were converted to electricity (this would be an extremely high degree of utilization of the earth's winds), it could meet the world's current total electricity demand. However, the distribution of wind energy is highly uneven across the world.

Wind has been used for about 15 centuries to generate useful energy. The first applications (Persia, 8th century BC) were very basic. A drag-driven vertical axis rotor was used to drive a scoop wheel for water pumping and to drive milling stones for grinding cereals. In 1759, John Smeaton of the UK performed the first systemic scientific experiments on a model of a (classical) windmill rotor, mounted at the tip of a rotating beam, to determine the maximum "effect" as a function of the rotor blade configuration. His results are still valid to this day.[1]

The history of wind energy can be divided in two main periods. The first period, which spans from the ancient times until the 1800s, is characterized by classical windmills. During the classical period, wind "devices" (windmills) converted the kinetic energy of moving air into mechanical energy. Only when electric generators (dynamos and alternators) were invented and introduced for public electricity supply, were windmills used for generating electricity. This development effectively started in the late 1800s and became a great commercial success after the energy crisis of 1973. For instance, at the end of 2011, wind energy generated 6.3% of Europe's electricity consumption.[2] In Denmark, wind energy already meets over 25% of the electricity demand. Wind energy has become a booming multibillion dollar worldwide business, with annual growth rates varying from over 30% about a decade ago down to 10% at present.

2 Wind Resource

2.1 *The Origin of the Wind and its Variations*

The sun emits 63.2 MW of power per unit area of its surface,[3] a small fraction (1367 W per sqm of surface on average) of which reaches the earth. Solar radiation heats the surface of the earth, causing the warmer, and thus lighter, air in the atmosphere to rise. Inhomogeneities in this process subsequently produce pressure differences, which result in the displacement of air parallel to the earth's surface. The speed of the horizontal air flow is much larger than that of the vertical flow. The characteristics, speed, and direction of wind vary with time and place. The motion of the air is influenced by the rotation of the earth (Coriolis forces) which, depending on the latitude and the velocity of the air, exerts an extra force on the moving air.

Second, the actual value of the power per unit area received from the sun depends on the day of the year and the latitude of the location. In addition, it depends on the hour of the day and the composition of the atmosphere. Third, the surface roughness of the earth varies between locations, from low for seas and oceans to high for urban and industrial regions. Fourth, the surface heating and the heat flux generally depend on the heat capacity of the surface layer, ranging from small (deserts) to large (oceans). And finally, the elevation of the terrain affects the motion of the air. Together, these variations of the drivers of the wind are responsible for the complex patterns and variations in the wind that is observed over the earth's surface.

2.2 *Power of the Wind*

One of the physical properties of moving air is its kinetic energy. The kinetic energy of the wind is a function of the speed and the density of the air.

The power in the wind per unit of area perpendicular to the direction of the wind is:

$$p_{\mathrm{w}} = \frac{1}{2} \cdot \rho \cdot v^3, \tag{1}$$

where p_{w} is the power density, ρ is the air density, and v is the momentary value of the wind speed. Air density depends on the air temperature (1.225 kg/m^3 at sea level and 15°C, 1.29 kg/m^3 at 0°C, and 1.16 kg/m^3 at 30°C) and pressure ($\rho = 0.73$ kg/m^3 at 4000 m height and 20°C). The nonlinear relationship between power and wind speed [see Eq. (1)] has many important consequences for the establishment of the wind power potential at a certain location, for the design of a wind turbine, and for the control of the turbine.

In order to determine the wind power available at a certain height and location, the long-term frequency distribution of the values of the wind speed needs to be known. The most common method to describe the frequency distribution is the Weibull function.

$$f(v) = k/a \cdot (v/a)^{k-1} \cdot \exp[-(v/a)^k]. \tag{2}$$

Here $f(v)$ is the probability density of the wind speed v. The parameter k is the shape factor, which determines the shape of the frequency distribution (see Fig. 1). For coastal areas, such as in North Western Europe, the value of k is approximately 2. The Weibull function with $k = 2$ is also called the Rayleigh distribution. And a is the scale factor, which is proportional to the average wind speed (see Fig. 2.)

By means of the Weibull function, the average wind power per m^2 area, perpendicular to the wind speed direction p_w, can be represented as follows:

$$\bar{p}_{\mathrm{w}} = \int_0^\infty \frac{1}{2} \cdot \rho \cdot v^3 \cdot f(v)dv = k_{\mathrm{E}} \cdot \frac{1}{2} \cdot \rho \cdot \bar{v}^3 \quad [W/m^2]. \tag{3}$$

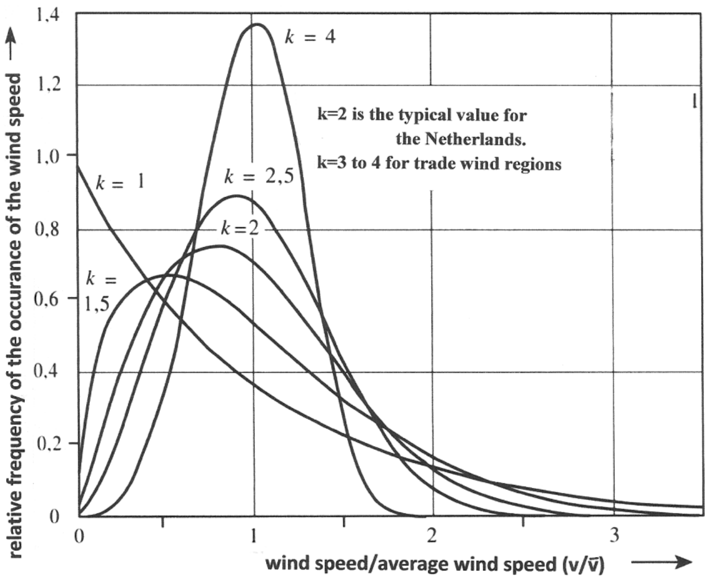

Fig. 1. Weibull distributions for various values of the shape factor k: $k = 4$ is a typical value for the trading winds, $k = 2$ is typical for moderate coastal areas e.g. in North Western Europe, and $k = 1$ for polar areas.[4]

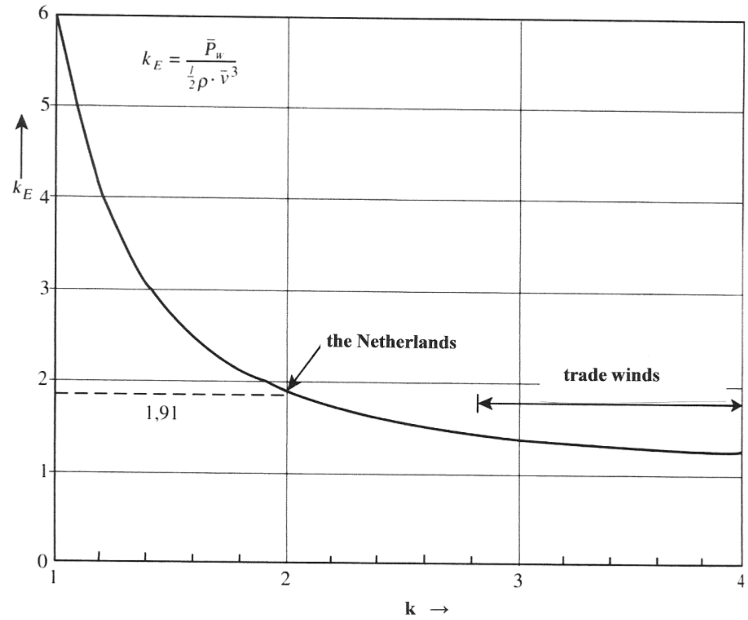

Fig. 2. The energy pattern factor k_E as a function of the Weibull shape parameter k.[4]

The last part of this equation resembles the expression for the momentary wind power [Eq. (1)]. The real content of the wind power, thus taking into account the larger contribution of the high wind speed, can be established by replacing the momentary wind speed by the average value and by including the factor k_E. This factor has a unique relationship with the shape factor k (see Fig. 2). The sensitivity of k_E for variations of k decreases with increasing values of k larger than, say, 2.

This approach enables a quick estimation of the wind energy potential at a site when the climatological regime and the (annual) average wind speed are known.

2.3 *Variability of the Wind*

As described in Sec. 2.1, the wind varies at several time and spatial scales.

Following Orlanski,[5] the wind characteristics can be represented at different time scales: inter-annual, intra-annual, diurnal, inter-minute, and intra-minute scale, but also with variations at scales ranging from a few meters to several thousand kilometers. These processes are sketched in Fig. 3.

Processes at the largest or terrestrial scale last the longest and span the earth. They are relevant for wind energy exploitation because they are the main drivers for the secondary circulations and allow for an assessment of the energy production in the long term, typically 30 years.

The terrestrial wind systems are not constant with respect to time or place. They may have changed position in the past and may change position in the future under the influence of changes in the global temperature. This change will have an

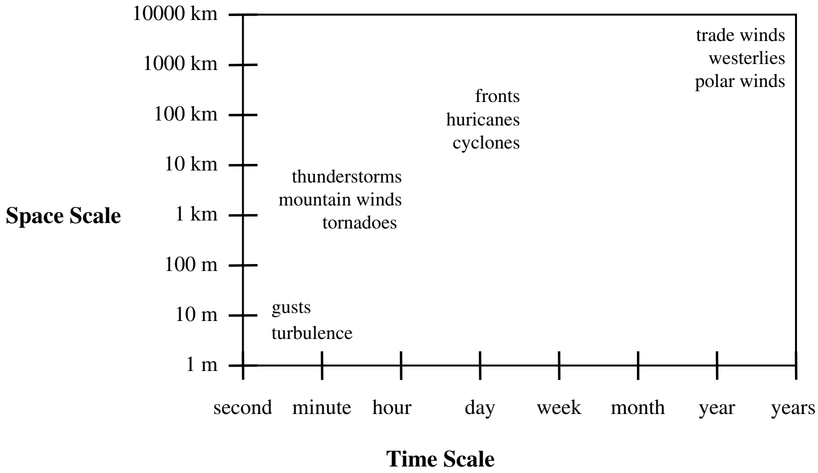

Fig. 3. Processes in the planetary boundary layer according to the classification by Orlanski.[5]

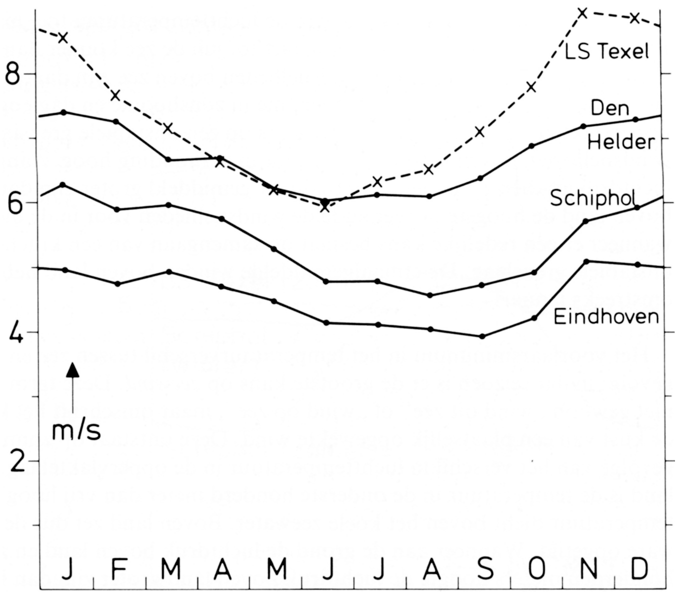

Fig. 4. Average monthly change of the wind speed at four metrological stations in the Netherlands.[7]

impact on weather in general and wind in particular.[6] Overall, the changes in the wind speed are expected to be regional and small. On the other hand, the impact on the distribution of the wind, in particular, the likelihood of the occurrence of very small and very large wind speeds, is significant.

The secondary circulations are an order of magnitude faster and smaller than the terrestrial wind systems. Variations at the scale of the secondary circulations are relevant for the design and operation of wind farms. Atmospheric systems, such as fronts, occur quite often, typically once per day, and affect the diurnal energy production and the ultimate loading of the wind turbines. Hurricanes and cyclones occur less often, and as a result, have little effect on the energy production. They might however cause maximum mechanical loading of a wind turbine.

Also, average annual wind speeds vary considerable compared to the long-term (typically 10 years) average value. Maximum annual deviations can be less or more than 10% of the long-term average value.[7]

Tertiary circulations are an order of magnitude faster and smaller. Variations at the scale of the tertiary circulations are relevant for the design and operation of single wind turbines. Relatively persistent but not very frequent processes, such as thunderstorms, mountain winds, and tornadoes, determine the extreme events that might cause maximum mechanical loading of wind turbine components. And the always present short-lived and small-sized events, such as gusts and turbulence, are responsible for the fatigue loading of the wind turbine structure and the decay of the turbine wake.[8]

As far as a wind turbine is concerned, extreme events are related to extreme wind speeds, extreme wind speed changes, and extreme wind direction changes. The extreme wind speed is expressed in terms of the reference wind speed, which is the extreme 10-min average wind speed at turbine hub height with a recurrence period of 50 years. The reference wind speed is expected to increase under the influence of climate change. For more information on extreme events the reader is referred to the Chapters 3 and 7 of *European Wind Turbine Standards II*.[9]

Since the wind is slowed down by the roughness of the earth's surface, generally the wind speed increases with the distance above the surface.

The vertical wind gradient (wind shear) depends on the terrain roughness and can, for example, be calculated by means of the following experimental expression from the potential wind speed at 10 m height. The potential wind speed is a fictitious

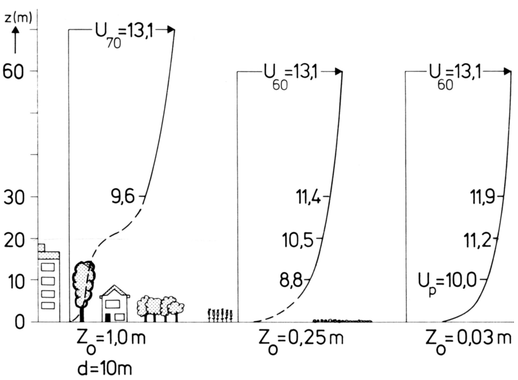

Fig. 5. Vertical wind shear for various values of the terrain roughness z_0 for the same value of the meso wind speed $U_m = 13.1\,\mathrm{m/s}$.[7]

Table 1: Relation Between Terrain Type and Roughness Length.[17]

Class	Brief description of terrain	Roughness length z_0 (m)
1	Open sea, fetch at least 5 km	0.0002
2	Mud flats, snow, no vegetation, no obstacles	0.005
3	Open flat terrain, grass, few isolated obstacles	0.03
4	Low crops, occasional large obstacles	0.1
5	High crops, scattered obstacles	0.25
6	Parkland bushes, numerous obstacles	0.5
7	Regular large obstacle coverage (suburbs, forest)	1.0 (R&D intensified)
8	City center with high- and low-rise buildings	>2 (R&D ongoing)

wind speed, which would have been observed if the surrounding terrain were flat and open with a terrain roughness class of 3 (see Table 1). In order to achieve the real wind speed, corrections for actual roughness and obstacles have to be made.

$$v/v_p = 1.3084 \ln(z/z_0)/\ln(60/z_0), \tag{4}$$

where v is the average wind speed at the height z (mostly taken as the hub height of the wind turbine) and v_p is the potential wind speed.

Terrain roughness has been classified according to various types of terrain, which are listed in the Table 1.[7]

This approach is an example that can be applied in relatively uniform and flat terrain. If the terrain is complex, advanced modeling, based on Computational Fluid Dynamics (CFD), must be applied and has to be supplemented with actual long term (>1 year) measurements in the field.

In addition to causing wind shear, friction due to surface roughness is the main source of turbulence. Another source, or sink, of turbulence is provided by the vertical heat flux. This heat flux can, depending on the direction of the heat flow, effectively increase or decrease the vertical gradient of the wind speed as well as the variations in the wind speed. The roughness of the surface and the rotation of the earth together also affect the way the wind direction depends on the distance above the surface.

2.4 *World and Regional Wind Potential*

The patterns in the wind can be observed either on a global or regional scale or in the long or short term. A wind pattern can be revealed by averaging the wind over climatologically relevant periods and geographically homogeneous regions. Such a pattern is called a wind map.

In general, there are two types of wind maps. One type gives a rough guide to the wind resource in a location as expressed by the long-term mean of the wind speed at a height of 10 m. Another type does the same for the prevailing wind direction. Usually this information is presented visually. Long term here indicates the period in which the climate, more specifically, the mean air temperature at a height of 2 m, is supposed to be constant. It is a meteorological standard to consider

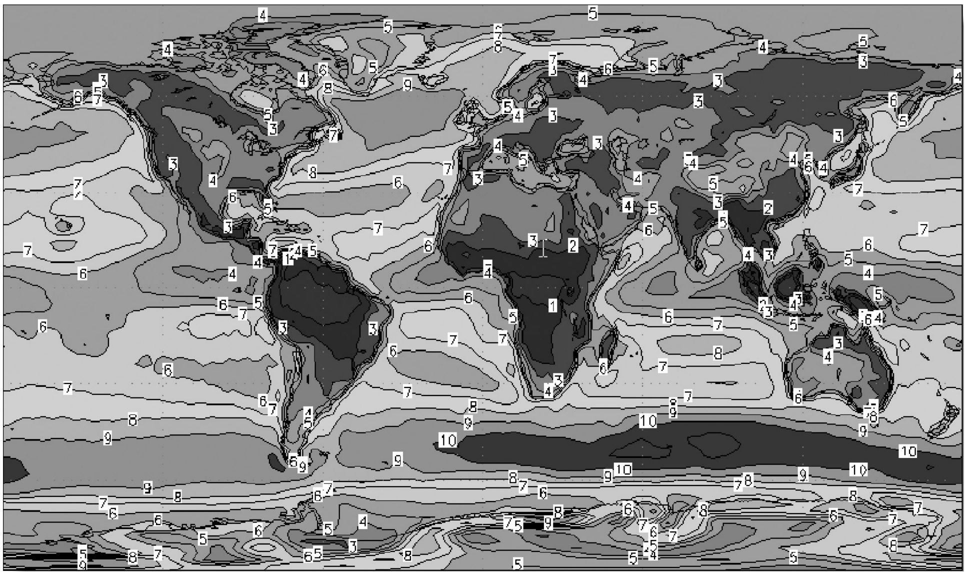

Fig. 6. The mean wind speed in meters per second at a height of 10 m above ground level or mean sea level for the period 1976–1995, according to the NCEP/NCAR reanalysis data set.[10,11]

periods of 30 years and to update the data every 10 years. The height of 10 m is another standard from the meteorological sector. Figure 6 shows a global wind map.

From Eq. (3) and Fig. 1, it appears that knowing the average wind speed at a location is not sufficient to determine the wind energy resource of that location. For accurate wind resource assessment, the frequency distribution of the wind speed and the wind direction, averaged over periods of 1 h (minimum requirement) or 10 min (preferred) are needed. In the past, wind maps were made by analyzing long-term records from meteorological stations. This resulted in the wind maps for the maritime sector in the 19th century, revealing the trade winds over the oceans.

Later, in the 1980s, wind maps dedicated to wind energy applications appeared. Among the first were overviews of the global wind climate[12] and the *Danish Wind Resource Atlas*.[13] These maps were followed by wind atlases of the US[14] and Europe.[15] The information in these first maps, valid for onshore locations only, is given for a relatively coarse grid and were given for the hub heights of wind turbines mostly used at that time. Subsequently, maps for offshore regions and maps with higher resolutions and/or for larger heights were made. An overview of all maps and atlases is given in *Wind Atlases of the World*.[10]

Currently, the source of information on which wind maps are based is shifting from data from meteorological stations toward data from atmospheric models and new instruments, although the measured data is expected to play a role for some time to come. The atmospheric model data includes the reanalysis data sets from NCEP/NCAR[11] and the ECMWF.[16] An example of a new instrument is the NASA

Modern-era Retrospective Analysis for Research and Application,[17] which combines information from various sources.

In the near future, wind maps will, besides providing information on wind speed and direction, also include information on turbulence intensity and atmospheric stability. This will open the door to the use of wind maps for site-specific design of wind turbines.

3 Wind Turbines

3.1 *Drag Machines and Lift Machines*

The type of aerodynamic forces that the Wind Energy Conversion System (WECS) utilizes to generate energy is the basis for the classification of wind turbines. Two main categories can be distinguished: Drag machines and Lift machines.

Drag, the driving force of a drag machine, moves the active part of the rotor in the direction of the wind speed, whereas the driving force of a lift machine is the (component) of the aerodynamic force which is perpendicular to the incident flow. The basic difference in these two types of wind turbines is explained in Fig. 7.

With the axial momentum theory (see Fig. 8), the maximum power coefficient C_p for both types of wind turbines can be derived. C_p is defined as the quotient of the power produced by the machine and the undisturbed wind energy flow through the area which is swept by the wind turbine rotor.

$$C_p = P/\left(\frac{1}{2}\rho v^3 A\right), \tag{5}$$

where A is the rotor swept area.

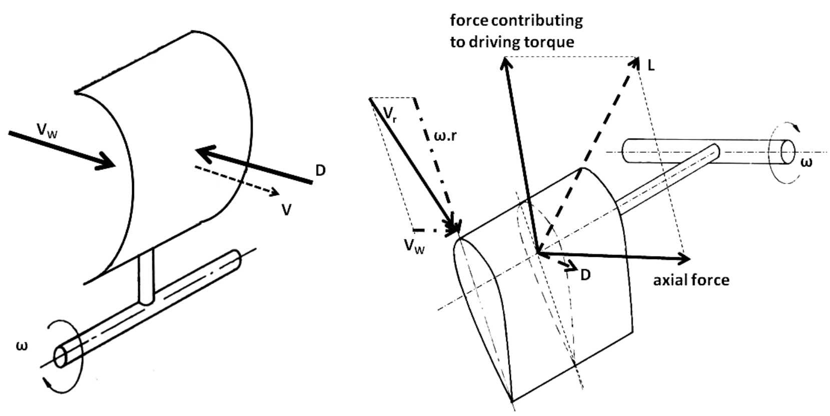

Fig. 7. The working principle of a drag-driven wind turbine (left) and a lift-driven wind turbine (right). The essential difference between the two types of machines is the movement of the blade compared to the driving force ($V_R//D$) (left) and Lift ($V_R^{\perp}L$) (right). (D = drag, L = lift force, ω = rotational speed, r.ω = translational speed of blade segment, v_w = local wind speed, v_r = relative incident flow speed). [Figure 7 by Jos Beurskens based on information from Erich Hau, *Wind Turbines: Fundamentals, Technologies, Application, Economics.*[18]]

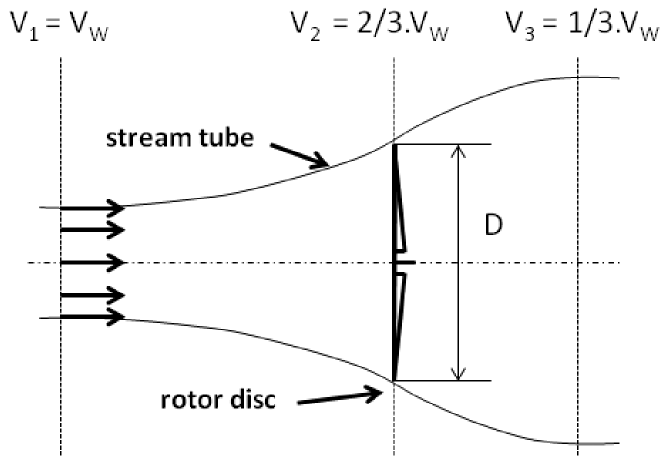

Fig. 8. The flow tube of a wind turbine rotor, explaining the momentum flow theory. The volume behind the rotor is called the wake.

For drag-type wind turbines, the maximum value of C_p is 4/27 C_D and for lift-type wind turbines, this value is 16/27 (if there are no radial forces acting on the flow, e.g. by a diffuser). Assuming that the value of C_D is 1.4 (for a concave cup), than the maximum value of C_p is 0.25. In practice however, this value seldom exceeds 0.15 because of energy losses caused by the reverse movement of the active area against the wind.

Apart from the low values of C_p of the drag-driven machine, the amount of material to construct the rotor of a drag-driven machine is much larger than for a lift machine. The rotor swept area of a drag machine has to be fully covered with material, whereas the rotor area of a lift machine only has to be covered partly. The solidity σ (the projected area occupied by the blades compared to the rotor swept area) for a drag machine is 1, whereas σ for a lift machine can be as low as 0.03.

For these reasons only lift machines are used for generating electricity on a competitive basis. Most lift machines have a horizontal axis, with the exception of (variations of) Darrieus rotors (egg-beater type of rotors) (see also Fig. 12).

3.2 *Rotor Characteristics*

Flow conditions are optimal (maximum lift and minimum drag) only for a specific angle of the rotor profile compared to the local velocity (Fig. 7, right). As the angle of attack of the local wind speed varies along the radius of a blade, the angle of the blade section compared to the plane of rotation has to vary as well. At the section of the blade which is closest to the hub, the root, this angle is much larger than that at the blade tip. In the case where the flow conditions deviate from the optimum configuration, the power output will be lower than the maximum achievable value. Figure 9 represents an example of the power output of a wind turbine rotor as a function of the rotor speed, at various constant values of the wind speed. These

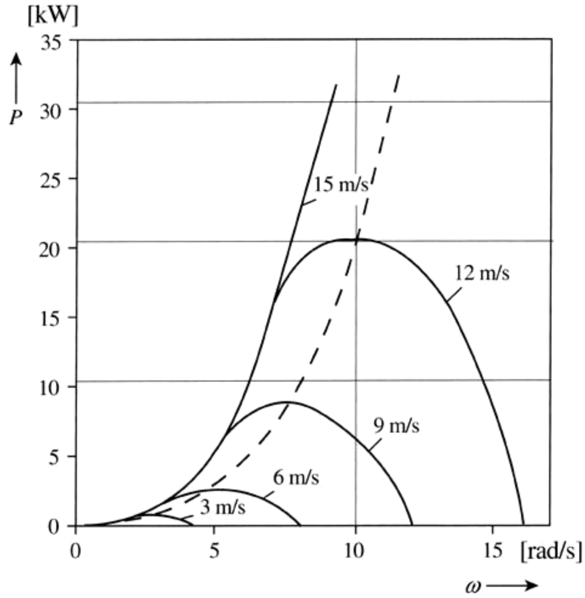

Fig. 9. Power characteristics of a rotor for various constant wind speeds. ($P =$ power output at the rotor shaft, $\omega =$ rotational speed of the rotor shaft. The dotted curve ($P \sim \omega^3$) indicates the point of maximum efficiency for various wind speeds.[4]

curves result, for example, from wind tunnel measurements. Flow phenomena are usually characterized by dimensionless parameters.

For wind turbines, the independent dimensionless parameters that characterize the rotor are:

- the power coefficient C_p [see Eq. (5)]
- the tip speed ratio $\lambda = v_{\text{tip}}/v$, where v_{tip} is the absolute value of the speed of the rotor tip and v is the undisturbed wind speed

As the behavior of a wind turbine system is almost completely independent of viscous effects, the Reynolds number is not relevant to characterize the behavior of a wind turbine. In order to characterize the power performance of a rotor, the $C_p - \lambda$ curve is constructed from the power curves according to Fig. 9. From such a curve, of which Fig. 11 is an example, the maximum rotor efficiency and the tip speed ratio at which maximum efficiency is realized, can be determined. It is obvious that the ratio between wind speed and rotational speed for a given wind turbine has to be kept constant in order to let the wind turbine rotor operate at maximum efficiency in a wide range of wind speeds.

The value of the tip speed ratio at which C_p has its maximum value is used to divide rotors into different types, such as slow runners, fast runners, etc. (see Fig. 13). Slow-running rotors are used for driving loads which need a high torque, combined with low rotational speed (like a piston pump), while fast-running rotors

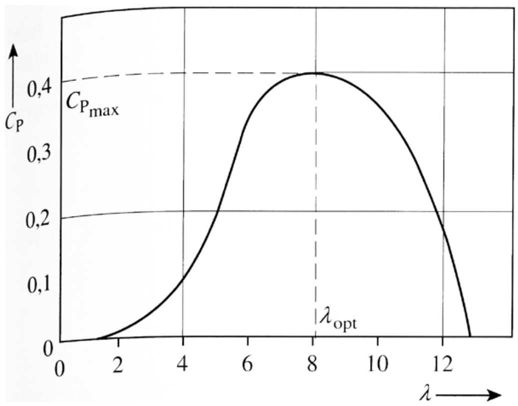

Fig. 10. The $C_p - \lambda$ curve of a rotor with an optimum tip-speed ratio of 8.[4]

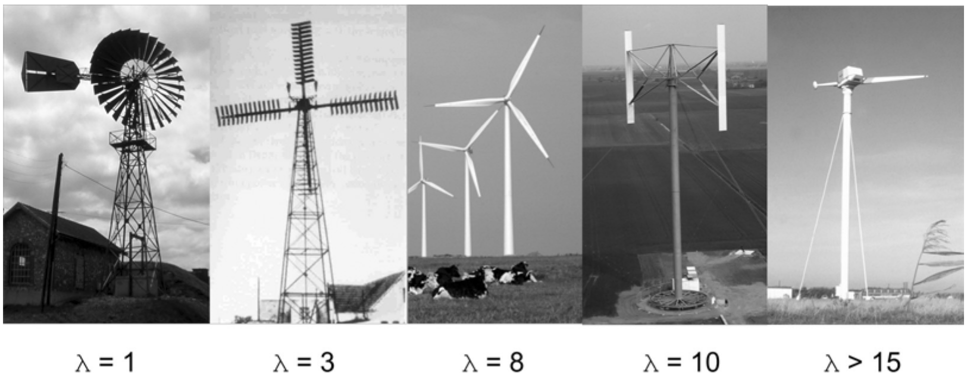

Fig. 11. Various types of rotors. On the left a slow-running wind pump. The other wind turbines are electricity-producing machines with increasing tip speed ratio. Three-bladed machines are the most applied ones because of the tradeoff between dynamic mechanical loading and rotational speed of the main shaft. Photographs 1,3,4 and (from left to right): Jos Beurskens.

are used to drive electric generators which require high speeds at a relatively low torque.

3.3 *Energy Conversion and Control*

More than 99% of the present wind turbines are used to generate electricity. The first wind turbines to generate electricity date from the late 1800s [Blyth (UK), Brush (US), La Cour (DK)].[1] The very first wind turbines generated electricity for battery charging and the electrolysis of water (La Cour). As the appearance of the first modern wind turbines coincided with the introduction of the commercial dynamos (DC) and alternators (AC) and the first electricity plants (New York, 1880) feeding small grids, wind turbines were also used to feed electricity into the grid. The generators which were driven by the wind rotors were induction machines which were running at a frequency that was slightly higher than the grid frequency, thus at almost constant rotational speed. The rotor blades were fixed to the hub and had no pitch control. As the wind rotor is able to produce much more energy than the maximum rating of the generator, a control system is needed to limit the maximum rotor power to the rated power of the generator. The first wind turbines used stalling of the flow around the blade profiles to achieve this effect. As the wind speed increased and the rotational speed of the rotor was kept constant, the angle of attack of the blade profile at higher wind speed became so large that the flow around the profile detached and the lift force stabilized or dropped but the drag forces increased significantly. As a result, the aerodynamic efficiency of the rotor became so low that the rotor power did not increase anymore with increasing wind speed. This passive control system had the advantage of having no moving parts in the hub structure.

The disadvantages, however, included load fluctuations, as the occurrence of stall occurred suddenly and was difficult to control. Furthermore, the tip speed ratio in the operational wind speed range of the wind turbine could not be kept constant for maximum efficiency. So with the appearance of power electronic convertors and the introduction of the insulated gate bi-polar transistors (IGBTs) as an alternative electronic switching device for thyristors, the power quality of electronic power invertors was revolutionized. The extremely high efficiency of IGBTs and the high switching frequency enabled power conversion from a variable frequency and voltage generator output via a rectifier stage into fixed frequency AC output with very low harmonic distortion and with adjustable reactive power production. As a result, all modern wind turbines are equipped with power electronic invertors, fed by generators, operating at variable rotational speed (either synchronous or doubly fed induction generators), and allowing the wind turbine to operate independent from the grid. The inverter actually forms an interface between the grid and the wind turbine generator. The rotor blades have adjustable pitch. This system thus allows operation with constant tip speed rotation in the operational wind speed range and limiting rotor power to the rated generator power.

With the increasing number of parameters which could be adjusted, control actions also increased (see Table 2).

Table 2: Controlling Wind Turbines (First and Second Columns are not Correlated).

Control actions	What is controlled?
Blade pitch (individually or collectively	Power efficiency
Yaw Angle	Aligning wind turbine nacelle with the wind direction
Magnetic Field of Generator	Limiting power output to rated generator power
Firing Angle of electronic switching devices	Avoiding peaks resulting from wind gusts
	Active structural vibration control
	limiting fatigue and ultimate loads
	Supervision for safety
	Stops, starts, and grid connection

The architecture of the electric conversion systems varies considerably. The major difference between the concepts is the path the generated electricity is following from generator to grid. In the oldest concept, i.e. the direct grid-connected induction generator, the electricity is directly fed into the grid. Applying a synchronous generator running at variable rotational speed generates AC with a variable frequency and voltage. After rectifying the electricity, it is converted in a grid-compatible AC. All generated electricity has to pass through the AC–DC–AC convertor. The rotational speed interval is relatively large. A somewhat cheaper solution is using a doubly fed induction generator in combination with an invertor. The generator is directly connected to the grid, where most of the electricity flows. In order to minimize losses caused by the rotor of the generator, this rotor has windings which are connected to an AC–AC convertor. Now only a minor part of the generated electricity (about 30%) has to pass through the convertor, which saves investment cost. The rotational speed range of this concept is smaller than the previous full convertor design. The first concept requires fixed blades, whereas the second and third concepts need pitchable blade angles.

The generators first used in wind turbines were derivatives of commercial high-speed electric motors and generators. As the rotational speed of the wind rotor was usually much lower than the required generator speed, gearboxes were needed in between the rotor and the generator. In practice, it appeared that the gearbox was expensive and sensitive to damage (not fully understood dynamic loading). As a natural strategy, direct-driven (DD) multi-pole generators were introduced. The fact that DD wind turbines were lacking one major component promised higher levels of reliability, especially in areas with extreme external conditions, like offshore. An important disadvantage of the first-generation DD generator was its size and weight. DD generators come in various concepts. The magnetic field can be generated by electric coils (the oldest types), and at present more and more DD generators are equipped with permanent magnets. As the prices in world markets for copper and the (rare earth) feed stock material for the strongest permanent magnets (neodymium) are highly volatile, an additional concept is being developed. The research community and the industry are now exploring the use of high-temperature superconductors (HTSs) to generate extreme strong magnetic fields for wind turbine generators. By applying either permanent magnets or HTSs, DD generators can be built very compact and will decrease considerably the tower head mass of wind turbines.

Figure 12 illustrates two types of modern wind turbine nacelles with rotor and drive train.

3.4 *Power Curves and Energy Output*

Combining the power curve, as indicated in Fig. 13, with the load curve of the generator or pump results in the wind turbine power curve. Each type of wind turbine comes with such a curve.

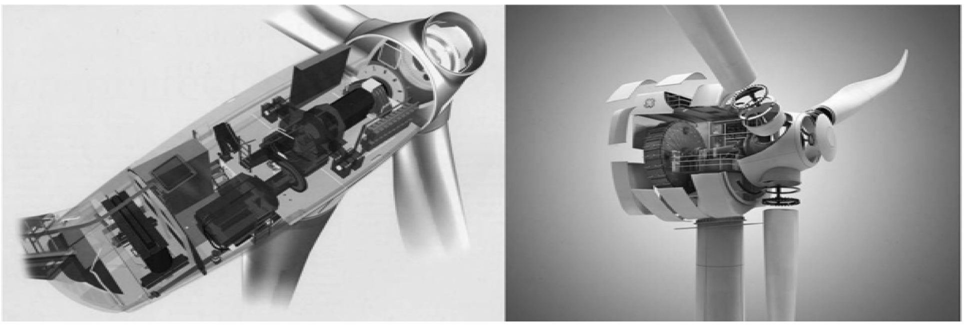

Fig. 12. A classical drive train (left) (*Source*: Neg-Micon) and a DD drive train (right) (*Source*: GE).

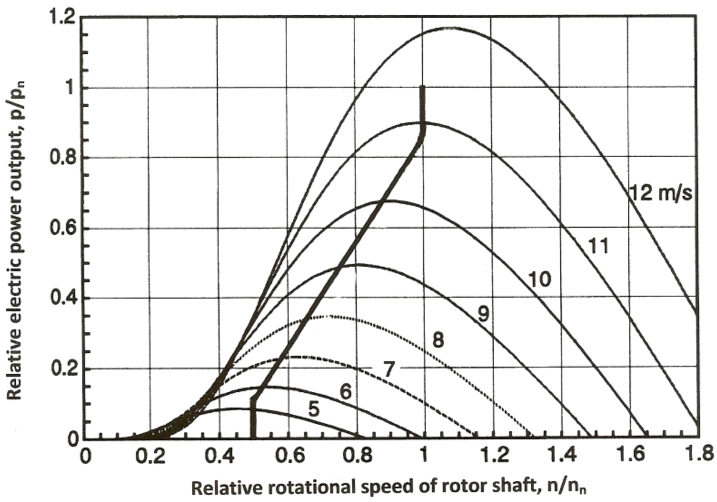

Fig. 13. Power–rotational speed curves of the wind turbine rotor and the electric generator load. From the points where both curves cross, the power–wind speed curve of a wind turbine can be constructed (see Fig. 15).[19]

Multiplying the power curve with the wind speed frequency distribution curve results in the annual energy output of a wind turbine:

$$\bar{P}_{\mathrm{T}} = \int_0^\infty P_{\mathrm{T}}(v) \cdot f(v) \cdot dv, \tag{6}$$

where $f(v)$ is the frequency distribution curve according to (2) and $P_T(v)$ the power–wind-speed curve according to Fig. 14.

Similar to reducing the wind speed frequency curves in a region to one curve with the Weibull expression (2), it is possible to generalize the power–wind-speed curves of wind turbines by taking constant values of the cut-in speed and rated

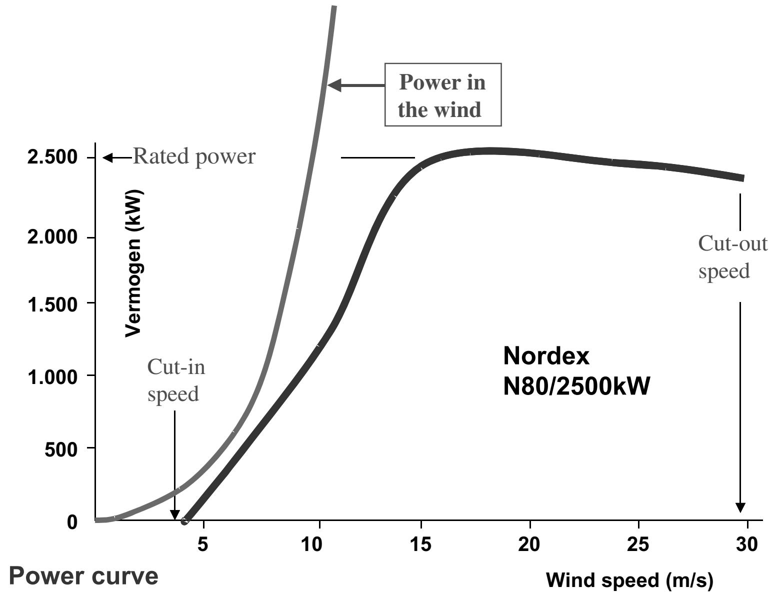

Fig. 14. Power–wind-speed curve as provided by the wind turbine manufacturer. These curves are being established according to standardized methods by independent testing stations.

wind speeds divided by the local average wind speed at hub height. By doing so, a rule of thumb can be derived for the annual average long-term energy production E of a wind turbine at 100% technical availability.

$$E = \mathrm{b}\bar{v}^3 A[\mathrm{kWh}]^4, \tag{7}$$

where $\bar{v}$ is the annual average wind speed at hub height. In this expression, b is the output-quality factor.

In the pioneering phase of modern wind energy technology (late 1970s and early 1980s), the value of b was about 2. By applying advanced control conversion and control systems in combination with improved aerodynamic efficiency of rotors, the value has increased to 3.5 at present. Note that this value only applies for wind regimes with a Weibull shape factor of 2 (although the output is not very sensitive to values slightly deviating from 2). It must also be mentioned that the actual output of a wind turbine is the potential energy production E multiplied by the technical availability. Modern land based wind turbines have long-term availability values exceeding 0.95.

The requirement that the ratio between rated wind speed and average wind speed has to be constant, also implies that there is a specific value for the rated generator power per m^2 rotor swept area for various wind regimes. The lower the local average wind speed at hub height is, the lower the specific power has to be

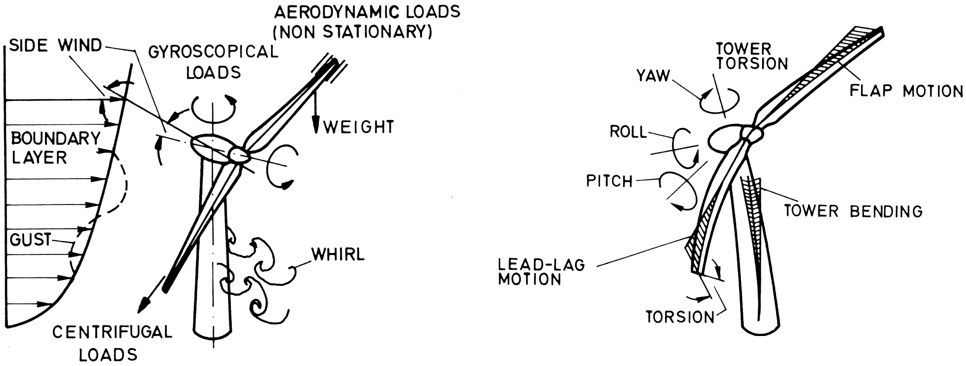

Fig. 15. Mechanical excitations and responses of a wind turbine structure.

and vice versa. Typical values for specific power are:

$$300\,\mathrm{W/m^2} \text{ for low wind speeds (e.g. wind class IV)}$$
$$450\,\mathrm{W/m^2} \text{ for medium wind speeds (e.g. wind class III), and}$$
$$600\,\mathrm{W/m^2} \text{ for very high wind speeds (e.g. class I)}$$

For the exact definition of wind classes, see Ref. 20.

Installing a wind turbine with a high value of the specific power in a low-wind regime leads to loss of energy, but worse, to a low level of equivalent full load hours. The amount of wind power which can be connected to the grid is primarily determined by the rated power of the wind turbine and not by the number of kWh absorbed by the grid. To make wind energy as grid friendly as possible, one should actually apply wind turbines with system parameters designed for low-wind regimes, but mechanically adopted to high winds.[4,21] Varying the specific power for a given location within a limited wind speed interval has a big impact on the equivalent full load hours (or capacity factor) and only a minor effect on the long-term energy output.

3.5 *Concepts and Structural Aspects*[18,19,22–24]

Apart from being a flow device and an electricity plant, a wind turbine is a highly compliant structure for which the integrity and safe operation has to be guaranteed. Figure 15 illustrates the sources of mechanical excitations and the various responses of a wind turbine structure.[5]

Actually a wind turbine is a highly dynamically loaded structure taking into account the number of cyclic loads it experiences during its lifetime and the amplitude and irregularity of the loads (see Fig. 16).

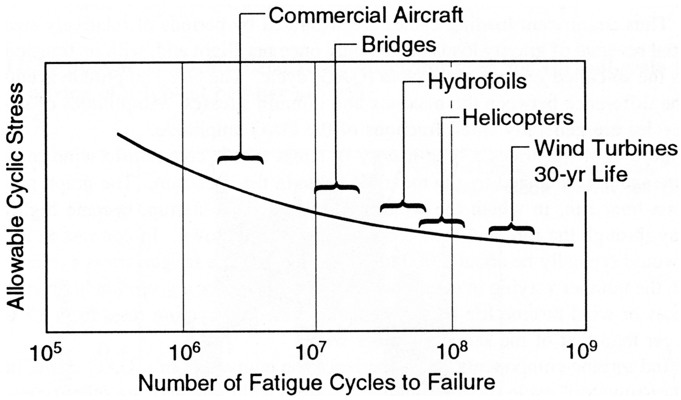

Fig. 16. Fatigue loading of a wind turbine compared with other structures and machines.[25]

With increasing size, the intrinsic flexibility of a wind turbine increases and structural dynamic design becomes more and more critical. Because of the introduction of offshore wind energy systems, both the size of wind farms and the wind turbines themselves have increased spectacularly (see Sec. 6).

Upscaling does not automatically lead to cheaper electricity from a particular wind turbine as appears from the so-called cubic upscaling law. Expressed in economic terms, it postulates that the mass, but also the initial investment cost of the entire structure, is proportional to the cube of the rotor diameter D. The electricity-generating capacity is proportional to the rotor swept area, thus to the rotor diameter squared. The cost of energy (COE) is approximately proportional to the quotient of investment cost and energy output and thus proportional to $D^3/D^2 = D$. If the wind turbine concept is not changed when upscaling, the cost would increase proportionally to D. Nevertheless, upscaling takes place throughout the entire wind energy sector. The main driver is cost reduction at other places in a wind energy project. For example, in offshore technology, the cost of support structures is dominant and relatively independent of the load-carrying capacity. So offshore designers want wind turbines to be as large as possible. Furthermore, there are cost reductions of operation and maintenance (O&M) if fewer units per MW of installed power have to be maintained. Besides, the COE per turbine can be reduced or kept constant by using materials with a better strength to mass ratio. Optimized control strategies, built-in structural compliance, and smart rotors with distributed aerodynamic blade control have the potential to further reduce costs.

A basic difference between offshore and onshore concepts is the foundation. As the tower for offshore turbines is higher because of the water body between the foundation and the tower structure, the total moment of the wind turbine structure with the interface between the foundation & the sea floor, is significantly larger than that for land-based wind turbines. The moment of force is caused by the axial force on the turbine rotor. At optimum working conditions, the tower top "feels" a force which is equal to the axial force of the wind encountering a solid disk with the size of 8/9 of the swept rotor area! The moment depends on the water depth. That is why the type of foundations for offshore wind turbines primarily — but not solely — depends on the water depth. If water depths exceed about 50 m, floating structures have to be used. Reference 27 gives, among others, an overview of foundations which have been used up till now.

At present, most modern wind turbines have three blades. The main reasons are:

- The blades of a three-bladed rotor have lower tip speeds than the blades of a two-bladed rotor and thus have lower acoustic noise emission levels. (Acoustic noise levels are proportional to, among other things, the absolute value of the tip speed.)
- Dynamic loading on the hub and shaft of a three-bladed rotor is less than that of a two-bladed one. In order to reduce cyclic loading of two-bladed turbines, these often have complex hubs (teetering hub, individually hinged blades, etc.).
- Visual impact of three-bladed wind turbines is less severe than that for two-bladed wind turbines.

4 Wakes and Clusters

4.1 *Clusters of Wind Turbines: Wind Farms*

A wind farm is a cluster of wind turbines that is operated as a single electricity-generating unit, connected to the electricity grid. In the past, wind farms were only placed onshore as single units or in small wind farms, but over the years, more offshore wind farms have been commissioned (see Fig. 17). The size of the wind turbines and the wind farms has increased considerably. The size of the area matters because, together with the size of the wind turbines and the number of wind turbines, it determines the array efficiency. The array efficiency is the collective effect of the wind turbines on their power production and mechanical loading.

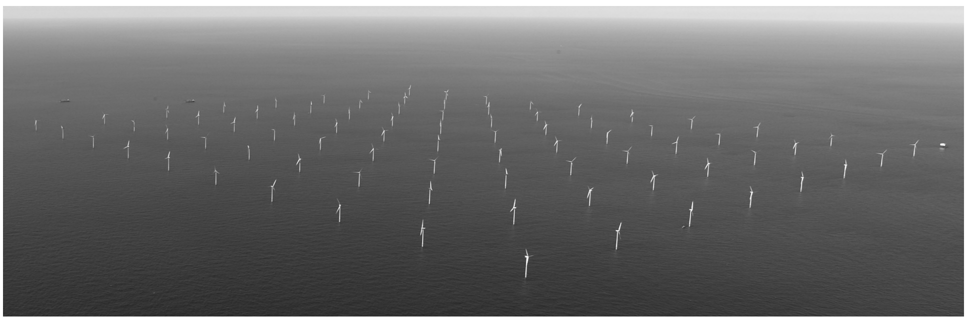

Fig. 17. 160 MW Horns Rev I offshore wind farm, consisting of 80 wind turbines of 2 MW each, near Esbjerg (Denmark). (Photo: Elsam, Vestas).

The distance between the wind turbines in terms of rotor diameters is the most important parameter that determines the array efficiency. If the separation distance is sufficiently large, say more than 20 rotor diameters, the wind turbines can be considered to be aerodynamically independent of each other. In that case, a wind turbine in the cluster has no effect on the power production and the mechanical loading of another wind turbine. If, on the other hand, the turbine separation distance is smaller, a wind turbine might find itself operating in the wake (see also Sec. 3.1) of one or more other wind turbines. This may lead to lower power production and a higher mechanical loading.

The aerodynamic aspects of the wakes are discussed in the following order:

- Wake of a single wind turbine
- Internal wakes inside a wind farm
- Wake of a wind farm
- Effect of wind farm wakes on wind farm clusters

4.2 *Single Wind Turbine Wakes*

The separation distance at which significant wake interaction between wind turbines is observed depends on the upwind wind conditions: the wind velocity and the turbulence intensity. The velocity in the wake of a wind turbine depends on the amount of power the rotor is extracting from the wind compared to the maximum possible power extraction (the value of C_p from Sec. 3). In other words, it depends on the aerodynamic state of the wind turbine. The aerodynamic state also determines the static mechanical loading and the initial values of the velocity deficit in the wake. The turbulence intensity in the wake is also increased compared to the turbulence intensity of the incident flow. The turbulence intensity of the flow in the rotor plane determines the fatigue loading of the wind turbine.

As a result of these processes, Milborrow and Elliott, who are among the pioneers in wind turbine cluster research, distinguish two types of wind turbine wakes: the velocity wake and the turbulence wake.[26,28] In the velocity wake, the mean velocity is equal to the sum of the upwind mean velocity and the velocity deficit. In the turbulence wake, the velocity variance is equal to the sum of the variances of the upwind and the added turbulences. The velocity deficit, as well as the added turbulence, is reduced with increasing distance from the wind turbine. This is caused by mixing of the wake flow and the undisturbed flow surrounding the rotors under the influence of the turbulence. The upwind turbulence originates from two independent sources: a mechanical source driven by the surface roughness and a thermal source, or sink, driven by the vertical temperature gradients (see Sec. 2).

More information about modeling the turbulence wake can be found in Brand *et al.*[29]

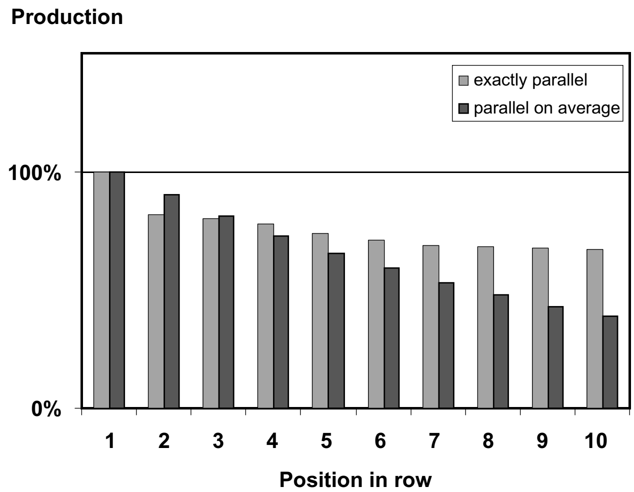

Fig. 18. Production along a row of wind turbines if the wind is blowing (a) exactly parallel to the row and (b) parallel to the row on average only.

4.3 *Internal Wakes Inside a Wind Farm*

Depending on the wind direction, a wind turbine can be completely or partially positioned in the wake of one or more other wind turbines. In such a multiple wake situation, the wind field a wind turbine is exposed to is composed of the velocity deficits and the added turbulence of the other wakes. The consequences for power production and the fatigue loading are severe.

To illustrate the effect of wakes on power production (see Fig. 18), the normalized power of a row of wind turbines is shown for the wind blowing exactly parallel to a wind turbine row. The second turbine in the row only produces a fraction of the power of the most upwind turbine, whereas the other turbines more or less produce the same. If, on the other hand, the wind direction changes so that only on average the wind is parallel to the row, a more gradual decrease of the production along the row results, as shown in Fig. 18.

4.4 *Wind Farm Wakes*

A wind farm is a flow disturbing object which exerts a force on and extracts energy from the flow of the lower part of the atmospheric boundary layer (Fig. 19). As a result, a wind farm decreases the velocity and increases the turbulence at the downwind side of the wind farm.[30–34] The key parameter determining the initial value of the velocity deficit and the added turbulence due to a wind farm is the thrust force per unit horizontal area, covered by the wind farm. It loosely translates into the power density being the aerodynamic power of the turbines per unit horizontal area. If the thrust per unit area is large, the initial values of the velocity deficit and the added turbulence are large, and vice versa. The initial velocity deficit and the

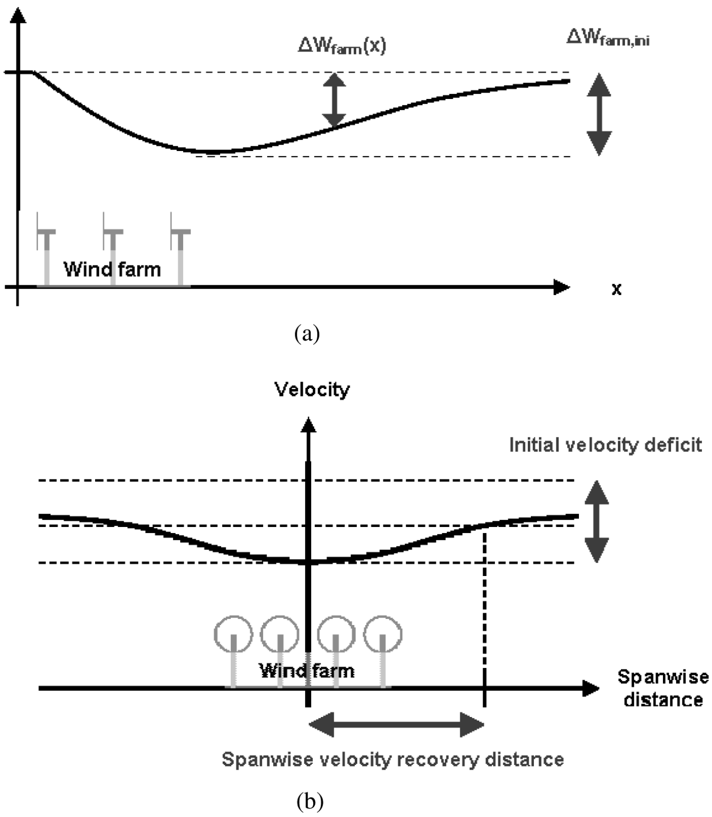

Fig. 19. Recovery of the velocity wake behind (a) and besides (b) a wind farm.[32]

initial added turbulence decay under the influence of the turbulence in the wake, which is the sum of the upwind and the added turbulence. The key parameters determining these decays are the downstream distance behind the wind farm, to be distinguished in the streamwise distance and the spanwise distance, and the decay parameter.

With the appearance of large offshore wind farms, the possibility has been created for measurements to verify and validate analytical models and to further develop them.

4.5 *Wind Farm Clusters*

Wind farms form a cluster if they are located close together and are operating in the same microclimate.

The placing of wind farms close together started with the huge onshore clusters in the windy valleys in California in the 1980s and is evolving into a trend to concentrate as many wind farms as possible in designated offshore areas. Examples of this trend can be found in the North Sea with the Horns Rev I and II (separation 23 km) wind farms in the Danish Exclusive Economic Zone (EEZ) of the North Sea, the OWEZ and Q7 wind farms in the Dutch EEZ (separated by 15 km), and the Alpha Ventus and MEG Offshore I wind farms in the German EEZ (separated by 4 km).

As explained in Sec. 4.4, each wind farm produces a wake of its own, dispensing the velocity deficit and the added turbulence over the downwind wind field. As a result, a cluster of wind farms has a complex system of internal velocity and turbulence wakes, similar in appearance but of a larger scale than the internal wake system of a single wind farm. Because of the strong impact of a wind farm cluster on the wind, such a cluster is expected to change the local wind climate. This will result not only in modifications in the sectorwise Weibull distribution of the mean wind speed in a given location but also in modifications in the distribution of the turbulence intensity.

To date, reliable measuring data from the few clustered offshore wind farms are lacking, but this is expected to change with the commissioning of the new wind farms in the North Sea.

Apart from influencing the wind, some researchers argue that large concentrations of wind turbines may affect the local weather, in particular, temperature or precipitation.[34] The rationale is that the added turbulence dissipates into extra heat, which causes an increase in temperature and humidity and eventually more precipitation. The magnitude of these changes, however, is expected to be small, as is the expected effect on the local climate.

While information on observed wind farm wake effects is scarce, predicted effects are available from a number of models. Wind farm wake modeling requires simulation of mesoscale atmospheric flow together with energy extraction/redistribution due to wind turbines. A critical review of the different approaches is given in Ref. 32.

5 Grid Integration

5.1 *Introduction*

When feeding electricity from wind energy systems into the electricity supply system on a large scale, the challenge of balancing total electricity supply and demand at all times becomes greater as wind energy is a variable source and wind farms output is only controllable to a limited degree. Various means are available for balancing: back-up by, for instance, fossil-fuel and hydro plants, load matching, storage, and curtailing wind farms output. At present, these actions are controlled by price setting in the electricity market at various time scales. Grid integration of wind energy and balancing has a hardware side as well as a "software" side. A lack of appropriate hardware, such as an offshore electrical infrastructure, may be considered as the most serious showstopper for large-scale introduction of wind energy. That is why grid integration of wind energy has become a prominent topic in project development and research agendas.[35,36] To solve the urgent problem of creating an electricity transport network in the North Sea, for instance, at least 15 concepts circulate. The dilemma is that investors will make financial resources for the infrastructure available only if the offshore wind power sites are legally identified and the financial market structure is known far into the future. On the other hand, projects will only be built if the infrastructure is available. Otherwise, individual project designers will create their own transport structure to connect to the grid. This is widely considered as a sub-optimal solution. Another challenge for the grid operators is the sheer capacity of wind farms which need to be connected in the medium term. The peak power of these variable output plants is of the same order of magnitude as the presently installed capacity of conventional power. Transmission Systems Operators (TSOs) have never been faced with the task of integrating this type of generating capacity into their systems. For a deeper understanding of the hardware side, see Chapter 20 of this book and Refs. 36–38.

In the next section, the "software" side of grid integration is addressed as far as it is related to meteorology.

5.2 *Grid Requirements*

5.2.1 *System balance*

A wind turbine or a wind farm is just another electricity generator which has to meet grid code requirements. These codes are aimed at maintaining balance in the electricity system. If balance is not maintained, a blackout may occur.

There are specific rules for frequency control, voltage control, reactive power control, and energy flows. Each rule is valid for a specific time scale, ranging from sub-second (frequency and voltage control) to 15 min and longer (energy control). Primary services are aimed at delivering active power to the grid, whereas ancillary services provide reactive power.

5.2.2 *Program imbalance*

Requirements on wind energy generators differ between countries, but in general electricity from the wind has to contribute to the imbalance control at a time scale of 15 min. This is referred to as program imbalance control. Program balance control may either be the responsibility of market parties or the grid operator. Imbalance control at the sub-15-min scale, on the other hand, usually is the responsibility of the grid operator but may be subcontracted to market parties. The same goes for the ancillary services.

In program imbalance control, each so-called program-responsible party has to issue schedules for the production and the consumption of electricity in its portfolio. Such a schedule is called the energy program and is valid for each 15-min period of the day before actual production/consumption. At each 15-min period, the scheduled production must be equal to the scheduled consumption of energy. The energy program must be submitted to the grid operator usually — gate closure times differ between countries — by noon on the day before production/consumption. On the day of production/consumption, the program-responsible party may not be able to balance production and consumption in its portfolio on its own. If the production is larger than the consumption, the party feeds surplus energy into the grid. On the other hand, if the production is smaller than the consumption, it contributes to a shortage of energy supply in the grid. In both cases, the difference, called the imbalance energy, is supplied by the grid operator. Usually the grid operator charges the party for the settlement of imbalance energy against the price for imbalance energy. Actually there are two prices, one for feeding energy into the grid (positive program imbalance) and the other for extracting energy from the grid (negative program imbalance). Both prices may be negative and are highly volatile as they differ from one 15-min period to the other.

For a program-responsible party with wind energy in its portfolio, program imbalance control boils down to making a schedule for the production of wind energy every 15 min of the day of delivery. This is the day-ahead forecast, which usually is to be issued before noon of the day before delivery. On the day after delivery, the program imbalance, being the difference between the observed and the forecasted energy, is assessed.

A program-responsible party can select from several instruments to minimize program imbalance. These include short-term forecasts, short-term forecast updates, aggregation, storage, fast start-up units, and wind farm shut-down strategies.[39] Although falling beyond the scope of the system of program imbalance, the instrument of short-term forecasting of wind energy supply has opened the door to trading wind energy at the day-ahead market.

5.3 *The Natural Variability and the Limited Predictability of Wind Energy*

5.3.1 *Variability*

Natural variations in the wind[5,40–42] are either mitigated or augmented by a wind turbine.[43] Since the output of a wind turbine is zero if the wind speed is too low (cut-in speed) or too large (cut-out speed) and because the output is approximately proportional to the third power of the wind speed (see Sec. 3.2), the output of a single wind turbine can change significantly both during a 15-min period and during an hour or a day.

The output variations are smoothed if the output of more than one wind turbine is fed into the same electricity grid as one electricity plant. Generally, the very short-term fluctuations in the minute and faster time-frame are small and have little coherence. Longer-term variations in the hourly or daily time frame can be of the order of the turbine capacity. These fluctuations have medium coherence and can be mitigated by aggregating from an area proportional to the secondary weather

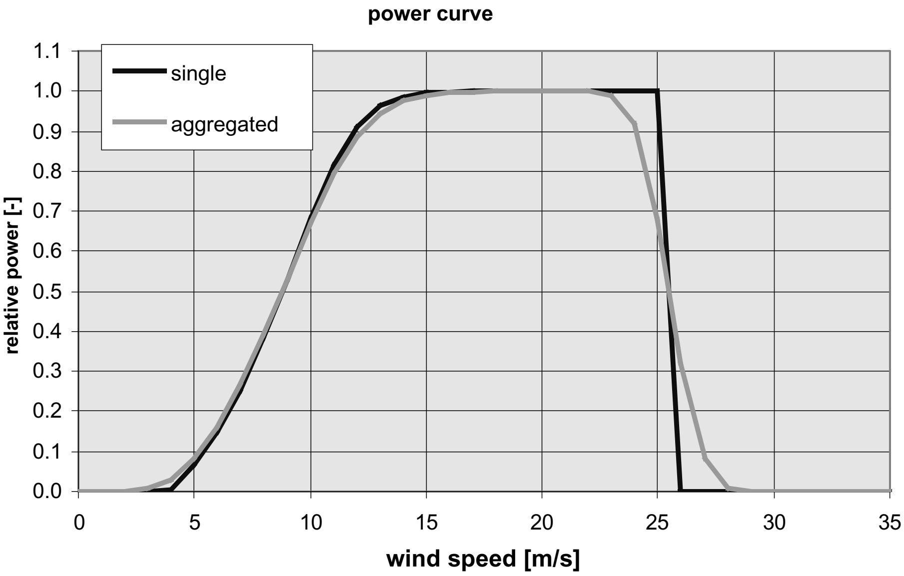

Fig. 20. Regionally averaged and single turbine power curve. The relative power is the power as normalized to the rated power.

systems. (The secondary weather systems have a time scale of several hours and a spatial scale of several hundreds of kilometers, see Sec. 2.) Aggregating on a still larger scale smoothes modulations at seasonal and annual time scales.

The level of smoothing increases with the size of the region where the turbines are placed. This is because the correlation between the wind speed in two points decreases with the distance between those points. The number of turbines in the region also has an impact on the level of smoothing.

The output from the wind turbines operating in a specific region can be represented in a regionally averaged power curve (Fig. 20). Regional averaging provides the average power output of a cluster of wind turbines in an area where the wind climate is known, assuming the turbines do not interact with each other. The regionally averaged power curve is created by applying a Gaussian filter to a single-turbine power curve[44–47] within the same wind climate zone. One of the important parameters in this analysis is D_{decay}, which is a measure of the distance over which the wind is correlated. Typical calculated values for the characteristic distance D_{decay} are: 500 km, based on Danish and Scandinavian data, respectively,[39] 610 km, based on data in the Netherlands[48] and 723 km, based on 60 locations spread throughout the European Union.[47]

The variability of wind energy is relevant for the grid because all variations must be compensated for by either the other generators or demand side management. The level of the extra capacity required for balancing is a matter of dispute but in general depends on the layout of the electricity system. For example, in a thermal system with high ramping rate capability, the requirements for extra capacity are small, in particular if the penetration of wind energy is relatively low. An electricity system with a high penetration of low ramping-rate plants, may require a significant amount of extra capacity. Note that in both cases, the capability to exchange energy with connected grids must be taken into account.

5.3.2 *Predictability*

Apart from predictions for the long term, to estimate annual energy production, predictions are needed at the inter-day (day before delivery) and the intra-day (day of delivery) levels. The requirements originate from program imbalance control. It essentially consists of a mandatory forecast of the per 15-min period, to be issued before noon of the day before delivery, in combinations with the possibility to change the forecast no later than 1 h before delivery.

Wind power forecast consists of the expected value of the wind power output in a given 15-min period, together with the confidence interval. Although other methods exist, for example, methods based on persistence of the actual wind power output, in general a wind power forecast is made by transforming the relevant output of a numerical weather prediction model.[39,49,50] To do so, there are two different methods: the physical and the statistical forecasting methods.

A physical method, as its name suggests, uses physical models of the local atmospheric processes in combination with specific information from the site. The relevant output of the numerical weather prediction model consists of the expected values of the wind speed, the wind direction, the air temperature, and the air pressure, up to two days ahead in time. The physical models describe the processes relevant to a wind turbine or a wind farm, such as the wind shear due to the surface roughness near the site or the vertical temperature differences. The site-specific information consists, for example, of descriptions of the surface roughness near the site, the power curve of the wind turbine or wind farm and a compensation mechanism for systematic forecasting errors. Eventually, this gives the expected value of the production up to two days ahead in time.

A statistical method uses data from a numerical weather prediction model too but relies on statistical models to make the translation to wind power. Again, the data from the numerical weather prediction model consist of the expected values of the relevant physical quantities, but now estimated relations are employed in order to obtain the expected values of the wind power.

Physical as well as statistical methods in general not only provide the expected value of the wind power but also specify a measure of the uncertainty of the prediction. In addition, both methods need some measured data in order to allow the correlation between predictions and measurements to be established (physical methods) or to train the estimated relations (statistical methods).

Over the years, quite a large number of wind power forecasting methods and systems have been developed. The market does not seem to be saturated as new methods and tools are still being introduced.[51] A typical wind power forecast is shown in Fig. 21.

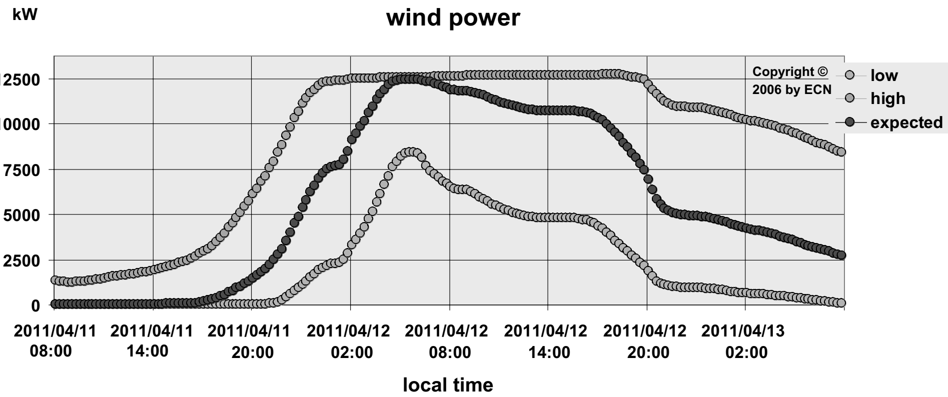

Fig. 21. Typical wind power forecast, consisting of the expected value and the confidence interval of the wind power. This forecast is valid for a wind farm with a nominal power of 12.5 MW and a turbine hub height of 70 m.

The wind power forecasting error is the difference between the observed and the forecasted power and is of two types: the systematic and the stochastic forecasting errors. The systematic error originates from processes that are not represented in the forecasting method but remain the same over time. This error can be compensated for by correlating the observed and forecasted productions. The stochastic forecasting error, on the other hand, originates from non-modeled processes that vary from one moment to the other. This error implies that the probability of a correct forecast is less that 100%. For this reason, a confidence interval is used in order to specify the range in which the observation will fall with a given probability.

The main source of wind power forecasting error is the numerical weather prediction model.[51] These models are not so much inaccurate in predicting the weather patterns but generally fail to predict the moment an event occurs. And predicting the exact time is essential in the energy sector as accurate point estimates at the 15-min level are required.

The wind power forecasting error is directly related to the program imbalance. A positive value of the forecasting error indicates surplus energy and a negative forecasting error is a shortage of energy supply, as explained in Sec. 5.2.2.

6 Market Developments[52]

The wind energy market has developed very quickly since the beginning of the 21st century. The market is very dynamic in terms of technology supply, regional development, and industrial development.

At the end of 2012, the total installed wind power in the world amounted to 241 GW and was estimated to provide 2.26% of the world's electricity demand. Short-term forecasts predict that this percentage will be 8% by 2021. In some countries, wind energy is already (at the end of 2011) a significant electricity provider. Some examples[36] at the top of the list include Denmark (25.9%), Spain

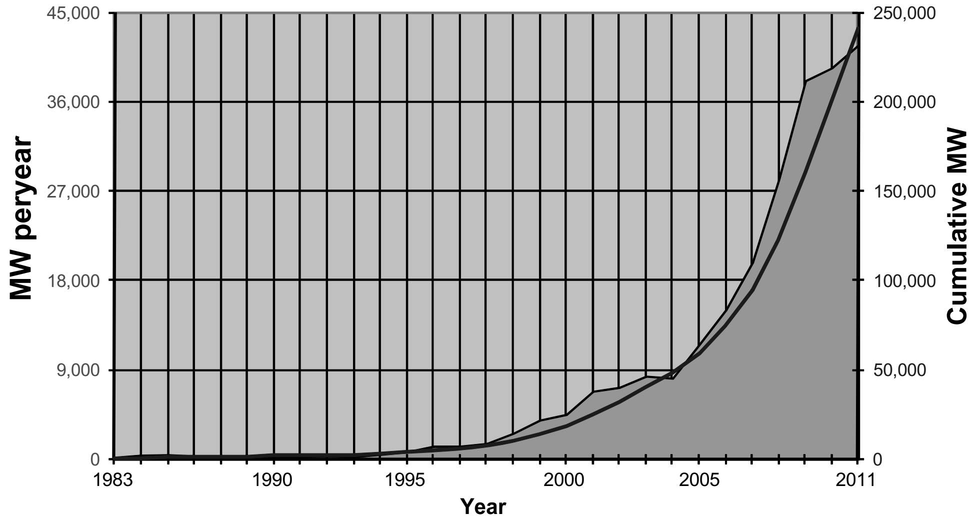

Fig. 22. Historic development of installed wind power in the world.[52]
Source: BTM Consult — A Part of Navigant — March 2012.

(15.9%), Portugal (15.6%), Ireland (12.0%), and Germany (10.6%). The average annual growth from 2007 until 2011 was 22.7%. The annual growth rate, however, is decreasing, and for the years 2012 to 2016 it is estimated at 10%, with a slight increase during the period thereafter (see Fig. 22).

Most of the variations are due to regional developments. In some regions (Netherlands, Denmark, Northern Germany), wind energy on land is reaching its limit because of public resistance or for technical reasons like reaching maximum grid penetration levels. The alternative to land-based projects, offshore wind energy, began 10 years ago, but is not yet at full implementation speed to maintain the earlier growth rates. Other regions in the world, notably the new economies of countries like China, India, and Brazil, are installing wind energy systems on a very large scale as part of their strategy to compensate for a shortage of electricity supply as soon as possible. The global turnover of the wind energy sector in 2011 was €52.2 billion and is expected to increase to €86.3 billion.[52]

Table 3 illustrates the distribution of installed wind power in the world in 2010 and 2011. At the end of 2011, Europe still had the largest amount of installed wind power, but the highest growth rate took place in South and East Asia.

We can see a similar shift of suppliers of wind turbine systems from Europe and the US toward Asia. In the recent past, more than 80% of wind turbines were manufactured in the western world. As can be seen from Table 4, in 2011, the balance is beginning to tip toward Asia.

In the middle of 2012, with a total amount of installed offshore power of 4.1 GW (3.9 GW in Europe and 0.2 GW in China), offshore wind power is only at the beginning (1.7% of the total installed wind power) of its expected growth curve

Table 3: Regional Distribution of Wind Power Around the World in 2010 and 2011.[52]

	Installed MW 2010	Cumulative installed MW 2010	Installed MW 2011	Cumulative installed MW 2011	% of installed MW 2011
Total Americas	6,639	46,990	9,573	56,563	22.9%
Total Europe	10,980	87,565	10,226	97,563	24.5%
Total South and East Asia	21,130	58,277	21,005	79,282	50.4%
Total OECD Pacific	478	5,368	694	6,062	1.7%
Total Africa	98	1,112	133	1,245	0.3%
Total other continents and areas	79	208	81.6	290	0.2%
Annual MW installed capacity	39,404		41,712		
Cumulative MW installed in the world		199,520		241,029	

Source: BTM Consult — A part of Navigant — March 2012.

Table 4: Top 10 Global Suppliers of Wind Turbines in 2011 as a Percentage of the Total Installed Power of 40.4 GW in 2011.[52]

Suppliers (region)	Percentage of total installed power
Vestas (Germany)	12.9%
Goldwind (China)	9.4%
GE Wind (US)	8.8%
Gamesa (Spain)	8.2%
Enercon (Germany)	7.9%
Suzlon Group (India)	7.7%
Sinovel (China)	7.3%
United Power (China)	7.1%
Siemens (Germany)	6.3%
Mingyang (China)	2.9%
Others	21.5%

(see also Table 5). On average, offshore wind energy is still more expensive than wind energy onshore by a factor of 1.5 to 2. Experience with the 50 existing offshore projects and technical innovations promise to bring the cost down by 30% to 50% within a period of about 10 years. Offshore applications actually form the backbone of almost all national R&D programs in the world. As already mentioned in Sec. 3, offshore is the driver for upscaling the size of wind turbines. This is well illustrated by Fig. 23, where the product cycle of wind turbines in Germany is depicted. The development in Germany may be considered to be representative for the world. In Fig. 24, this trend is illustrated in more detail. It is most likely that upscaling of wind turbines for land-based application will end at levels of 130-m diameter due to logistical limitations. Offshore up scaling will continue to dimensions of well over 130-m diameter. The largest wind turbines which are now being designed and built have diameters of over 150-m. Technically, it is feasible to construct wind turbines of 200-m diameter and 20 MW installed power.[53] Economic feasibility, of course, still has to be proven.

Table 5: Distribution of Offshore Wind Power in the World in 2010 and 2011.[52]

Country	Installed MW 2010	Accu. MW 2010	Installed MW 2011	Accu. MW 2011
Belgium	165	195	0	195
P.R. China	39	102	107.9	209.9
Denmark	207	832.9	0	832.9
Germany	108	168	30	198
Ireland (Rep.)	0	25	0	25
Netherlands	0	246.8	0	246.8
Norway	0	2.3	0	2.3
Portugal	0	0	2	2
Sweden	0	163.3	0	163.3
UK	925	1775	330	2105
Total capacity — World	1,444	3,510	470	3,980

Source: BTM Consult — A Part of Navigant — March 2012.

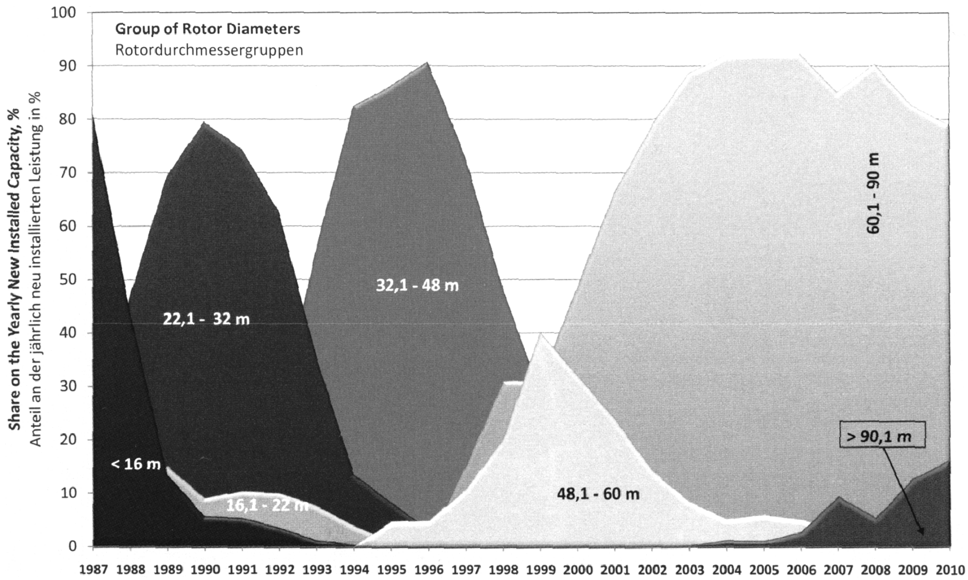

Fig. 23. Product cycles of commercial wind turbines based on rotor diameters.[55]

The developments sketched earlier could be summarized in a forecast for the growth of the market for the next (starting point 2012) 10 years, divided between onshore and offshore applications (see Fig. 25). The regional breakdown is presented in Fig. 26.

Apart from the technical and economic issues, other institutional and environmental issues play a crucial role in further expanding wind energy capacity. Although wind energy in general is an environmentally sound technology — illustrated, for instance, by a energy payback time (time to produce an equivalent amount of energy to that needed to produce the wind turbine) of three to nine

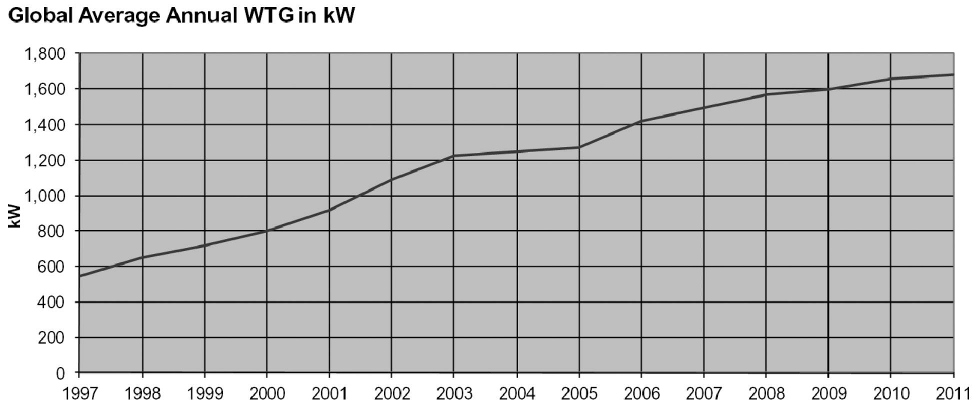

Fig. 24. Global average installed power per wind turbine within one year.[52]

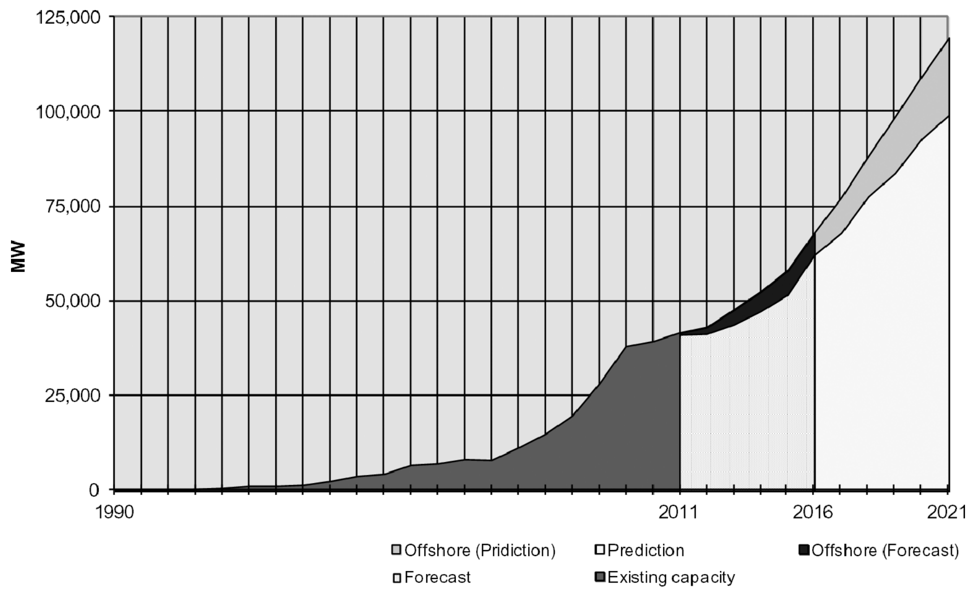

Fig. 25. Forecast of annual wind power installations.[52]
Source: BTM Consult — A Part of Navigant — March 2012.

months — the following, most important, aspects need to be taken into account in the planning process:

- Visual impact (landscape)
- Visual flickering effect by shadow of blades
- Acoustic noise emission
- Impact on birds (collisions, habitat, migration routes, and forage areas)
- Collision with bats

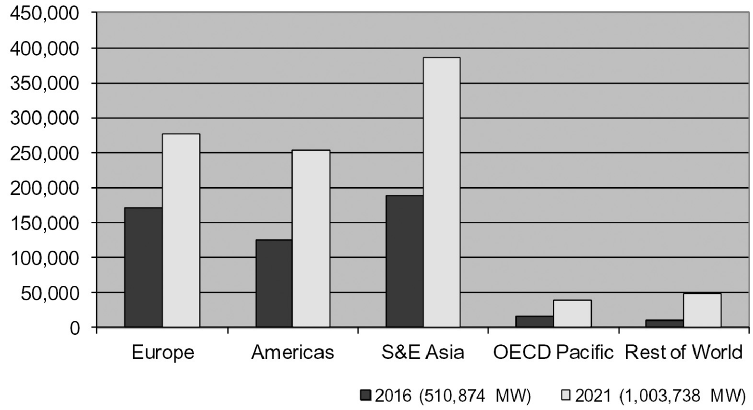

Fig. 26. Regional distribution of accumulated installed wind power until 2021.[52]
Source: BTM Consult — A Part of Navigant — March 2012.

- Effect of construction noise on hearing capability of sea mammals
- Effect on Fish (many positive effects have been observed as well)
- Offshore shipping safety

In many cases, but not always, the problems can be mitigated by careful planning or temporary mitigating measures, such as high-frequency pingers to induce porpoises to leave the construction areas offshore during construction work and stopping wind turbines for short periods during the passage of migrating birds.

Finally it has to be kept in mind that lack of electrical infrastructure, legal provisions, and public and political support, based on perceived negative effects of wind turbines, in practice can be showstoppers for further expansion of wind power. For offshore effects, see Ref. 27 for further reading.

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