Chapter 14
Power Output and Energy Yield

The assessment of the performance of a wind turbine is frequently a cause of heated discussion. As is the case with all systems which utilise solar energy, the parameters borrowed from conventional energy technology are only applicable to a limited extent. In contrast to conventional energy generation systems, the rated power of the electric generator of a wind turbine is of less significance. This fact cannot be pointed out often enough, as it is the source of many a misjudgement concerning this technology. This especially applies to many users who are used to thinking only in terms of "kilowatts".

The correct measure of the economic value of a wind turbine is the energy it yields on the basis of its power characteristics with a given wind regime. As in other systems for the utilisation of solar energy, too, this is primarily determined by the size of the energy collector, the rotor-swept area in this case. A wind turbine's size and performance must, therefore, be assessed in accordance with its rotor diameter and not according to its rated power. Primarily, the installed generator power also has an influence on the energy yield, but to a lesser degree. With a given rotor diameter, the design task, therefore, consists of maximising the turbine's power output over the entire wind speed range. The rotor's aerodynamic design, the control and operational sequence systems, the maximum installed generator power as well as the efficiency of the mechanical-electrical chain of energy conversion must all be optimised with this goal in mind.

The electric power output versus the wind speed, the so-called *power curve,* is the result not only of the technical characteristics of the turbine but to a certain extent also of the wind data forming the basis of the turbine design. Against the background of the "design wind regime", the optimum rotor speed and also the most favourable rated generator power can be selected. Considering this aspect, the wind turbine here, too, turns out to be an "environment-related" energy generation system the technical design of which must be adapted to its environmental conditions.

In this chapter the main steps in the calculation process are outlined. Following the influence of the essential design parameters on the performance of a wind turbine are discussed in more detail. For this purpose the example of a 3 MW wind turbine with a rotor diameter of 100 m has been used. Its design and performance characteristics correspond to the “state of the art”.

14.1 From Rotor Power Characteristics to Turbine Power Curve

The starting point for determining the performance of a wind turbine is the family of aerodynamic rotor power curves. Its origin and its significance are described in Chapter 5. However, the power curves only describe the performance of the rotor, the effective power of the wind turbine is additionally also influenced by a number of turbine-related technical parameters. A number of losses must be taken into consideration before the rotor power coefficients result in effective turbine power coefficients. The effective turbine power, and thus the energy yield, are influenced by the restriction to the permissible maximum power of the electric generator, the losses in the electromechanical drive train, the control and operational sequence of the turbine and also by the yaw drive and the cutting-in and -out characteristics of the turbine.

14.1.1 Installed Generator Power and Rotor Speed

The first step from the rotor power curves to the effective turbine power is to determine the generator power to be installed. After the rotor diameter and the rotor hub height, the maximum permissible continuous output of the generator, the rated power, has the greatest influence on the energy yield. It also influences the optimum rotor speed. It is not a simple matter to determine the optimum correlation between rotor diameter and the installed generator power theoretically on the basis of a predetermined wind speed distribution [1]. Optimization requires including the manufacturing costs of the wind turbine since these rise with increasing power rating. This means finding a further optimum between increasing energy yield and rising manufacturing costs since it is not only maximizing the energy yield but also minimizing the power generating costs which is the aim to all the efforts. However, the manufacturing costs of a wind turbine are influenced by numerous, mathematically intangible factors so that, in practice, the rated power is specified empirically with a given rotor diameter, taking into consideration the intended conditions of use, primarily the wind conditions (s.a. Chapt. 14.6.5).

After a certain rated power has been specified with a given rotor diameter, or vice versa, there is the problem of finding the "correct" rotor speed. The power characteristics of the rotor or, more precisely, the shape of the c_{PR}-lines, shows that the maximum power coefficient is only achieved with a certain tip-speed ratio. Keeping the rotor speed constant, if a c_{PR}-line is plotted against the wind speed, it can be seen immediately that the maximum of the power coefficient is reached at a certain wind speed. The maximum can be shifted towards lower or higher wind speeds for different rotor speeds (Fig. 14.1). On the other hand, the frequency distribution of the wind speeds at a given site also has its peak only at a certain wind speed.

It is obvious that the available wind can be utilized best when the greatest possible proportion of the wind speeds is used with high rotor power coefficients. In other words: The rotor speed must be selected in such a way that the highest power coefficients of the rotor are used within the wind speed range where the energy density of the wind frequency distribution has its maximum. It is only then that the energy yield will reach its highest value. However, the position of the maximum energy density of a wind frequency distribution is not identical with the maximum of the wind speed distribution but is located near higher wind speeds (Fig. 14.1).

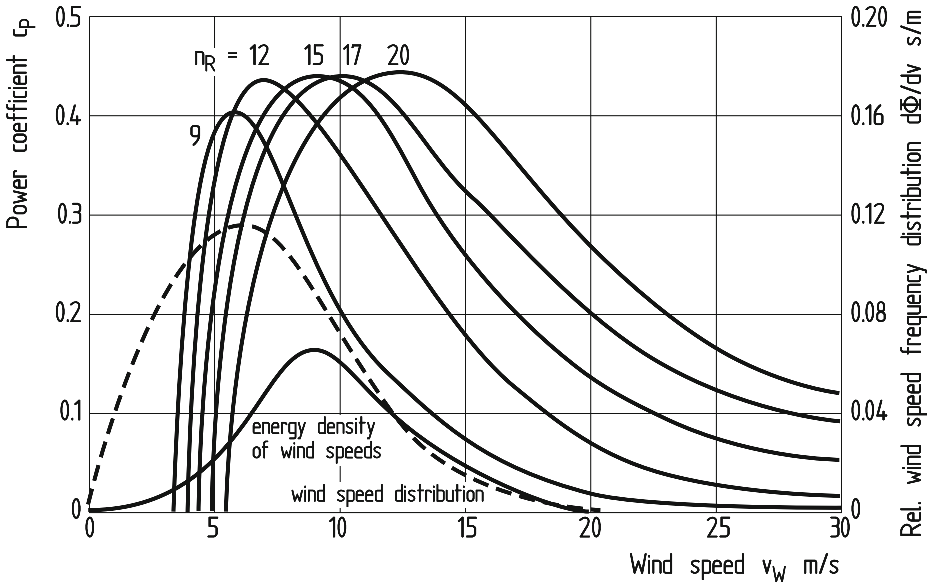


Fig. 14.1. Rotor power coefficient against wind speed for different rotor speeds and relative wind speed frequencies

Since the aim is to maximise the energy yield, the optimum rotor speed can only be found by simultaneously calculating the energy yield. For this purpose, a certain frequency distribution of the wind speeds to be expected, the so-called *design wind data*, must be specified. The wind speed at the peak of the energy density distribution becomes the *design wind speed* v_D. In addition, the choice of cut-out wind speed, i.e. the wind speed at which power generation should stop, has a certain effect even if only a small one. Using a generator with direct grid coupling means that the rotor speed has to be constant so that the optimum rotor speed is a particularly important factor in this case. But the limited speed range must also be specified with regard to maximising the energy yield for a variable-speed turbine.

In theory, the rotor speed should be optimised for each site with a different wind speed distribution. Since the dependence of the optimum rotor speed on the usual wind speed frequency distributions is not very serious and the rotor speed cannot be changed for every site for technical reasons, the optimisation is done for the design wind data. These, however, must be selected carefully, having regard to the intended range of use of the wind turbine. The optimum rotor speed and the energy yield are calculated simultaneously as follows: For a selected rotor speed, a certain rotor power c_{PR}-curve versus wind speed can be determined from the rotor power chart (Fig. 14.2).

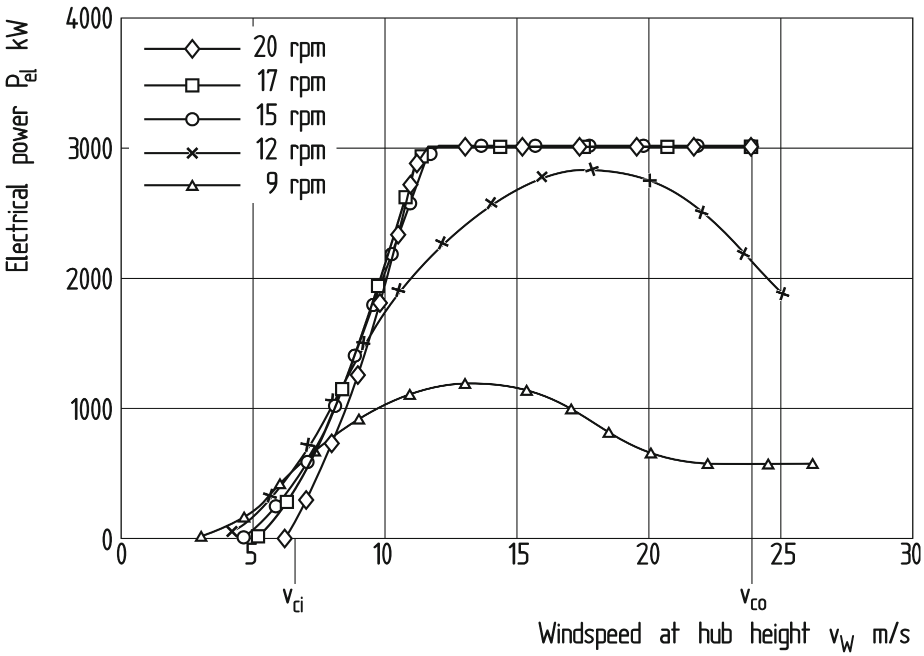


Fig. 14.2. Power curves for various rotor speeds

The calculation of the energy yield is based on the wind speed data, the rotor power coefficients at different rotational speeds and needs the efficiencies of the energy conversion system in the wind turbine. In the calculation procedure a combined mechanical-electrical efficiency will be used. It includes the losses in the rotor bearings, in the gearbox, and the electrical losses in the generator and inverter (see Chapt. 14.1.3).

Considering this mechanical-electrical efficiency the wind turbine's power coefficient is as follows:

$$c_P = c_{PR}\, \eta_{mech.-electr.}$$

This can be used for calculating the electrical output power as a function of wind speed.

$$P_{el} = c_P \frac{\varrho}{2} v_W^3 \; A_{Rotor}$$

These "power curves", which in each case apply to one rotor speed, are used for calculating the energy yield with the given wind speed distribution. The energy yield in a certain time interval is equal to the power output at a certain wind speed, multiplied by the time interval during which this wind speed is to be expected within the given period of time, usually one year. For this purpose, the relative frequency distribution or cumulative frequency distribution of wind speed is used. This is subdivided into wind speed classes Δv and the frequency value Φ is read off the distribution function (Chapt. 14.3).

The energy yield is obtained by summing over the wind speed, from the cut-in speed v_{ci} to the cut-out speed v_{co}:

$$E = \sum_{v_{ci}}^{v_{co}} \Delta E = \sum_{v_{ci}}^{v_{co}} P_{el}\,(v_W)\,\Delta t$$

The numerical evaluation provides the energy yield for a certain rotor speed. The calculation must be carried out for a number of assumed rotor speeds. The graphical plot of the results versus the rotor speed shows the maximum energy yield and the corresponding optimum rotor speed (Fig. 14.3). The determination of the optimal rotor speed, 14.5 rpm in the example shown, makes it possible to determine the corresponding characteristic. This establishes the power curve of the wind turbine for the design wind data used as a basis.

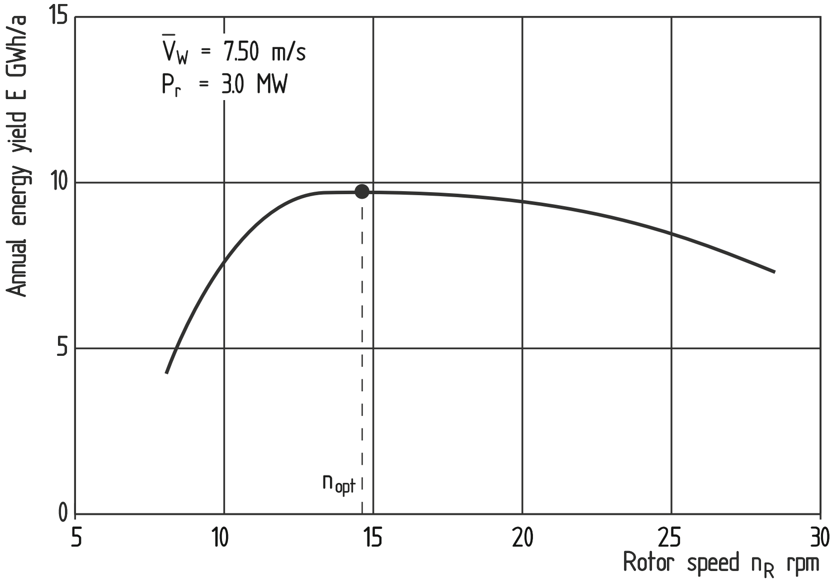


Fig. 14.3. Annual energy yield as a function of the rotor speeds

The flow chart below provides an overview of the entire mathematical process with the required parameters and interconnections (Fig. 14.4). The many interdependencies and variables influencing the energy yield of a wind turbine become clear again. Naturally, these relationships are primarily of importance to the designer of a wind turbine who is involved in all the details of the design and calculation processes.

The process is simpler for the operator of the turbine who has nothing to do with the optimisation methods described here but bases his decisions on the established power curve of the turbine, combining this with the expected wind data of the intended site and thus obtaining the energy yield to be expected from the turbine. The required – not very complex - calculation procedure will be explained in Chapter 14.5. It belongs to the basic techniques of the planning in wind-power project.

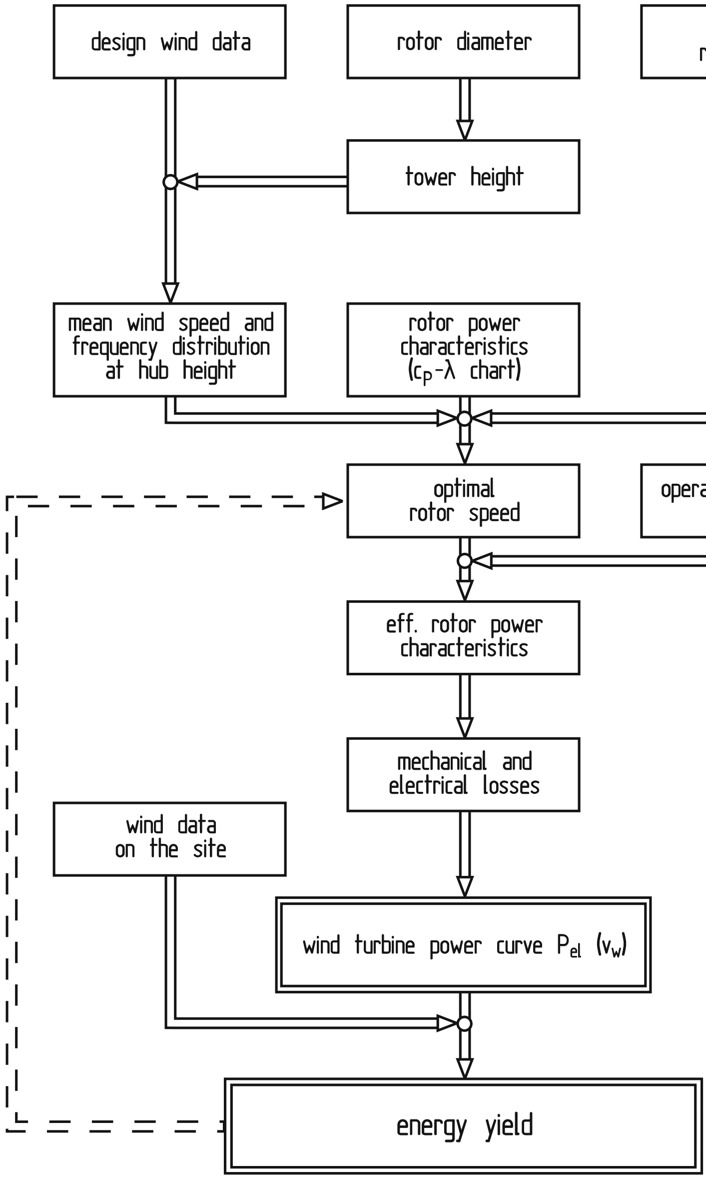


Fig. 14.4. Flow chart with parameters for calculating the optimum rotor speed and energy yield

14.1.2 Losses due to Power Control and Operational Sequence

The control procedure and the operational sequence inevitably impose certain restrictions on the operation of the wind turbine which lead to losses in performance with respect to its theoretically possible capacity. In evaluating the performance losses due to aerodynamics - and also the losses in the mechanical-electrical drive train - it must be taken into consideration that these only become effective in the partial-load range. In the full-load range, i.e. at wind velocities above the rated wind velocity, there is more than enough wind power available so that the wind turbine can deliver the maximum generator power virtually independently of its efficiency.

Power control

From a practical point of view, the operation of the rotor, that is to say its speed control and the control of the blade pitch, cannot be arranged in such a way that, compared with the theoretical performance capacity, no losses in performance will occur. An optimum operation of the rotor with respect to its performance is prevented by several restrictions:

- Wind turbines equipped with an electrical generator which is directly coupled to the grid must be operated at a constant rotor speed. This prevents the tip-speed ratio from being adapted to the variable wind speed. The rotor can only be operated at one point with the theoretically best possible c_{PR} value. Determining a constant rotor speed which, however, is optimal with respect to the maximization of the energy yield requires the frequency distribution of the wind speeds to be included (Chapt. 13.3.1). The optimum rotor speed thus established and the installed rated generator power determine the nominal operating point in the rotor power characteristics. In normal circumstances, the nominal operating point is located on the left and below the maximum c_{PR} value (Fig. 14.5).
- In the partial load range, i.e. in the wind speed range below the rated wind speed, generator power cannot be used as a reference parameter for controlling the blade pitch angle. For this reason, the rotor is generally operated with a constant blade pitch angle in this range. This constraint, too, results in some loss of power. It is only with the aid of a complex, so-called “adaptive control procedure", that the rotor can be operated with variable blade pitch angle without loss of power along the envelope of the c_{PR}-λ characteristics.
- In the full load range, in which the maximum generator power is achieved, the rotor power output is limited at wind speeds above the rated wind speed. The blade pitch angle is controlled such that the maximum generator power is not exceeded.

Given these constraints, the following rotor operating characteristics for partial- and full-load operation are obtained (Fig. 14.5). For rotors without blade pitch control, there are no rotor power characteristics in the form described above. The set of curves is reduced to one power curve based on the design blade pitch angle. On the right-hand side, this curve corresponds to partial-load operating conditions of the controlled rotor with constant blade pitch angle. On the left-hand side, the controlled full-load curve is replaced by the limited power yield due to stalling caused by flow separation at the rotor blades (Chapt. 5.3.2).

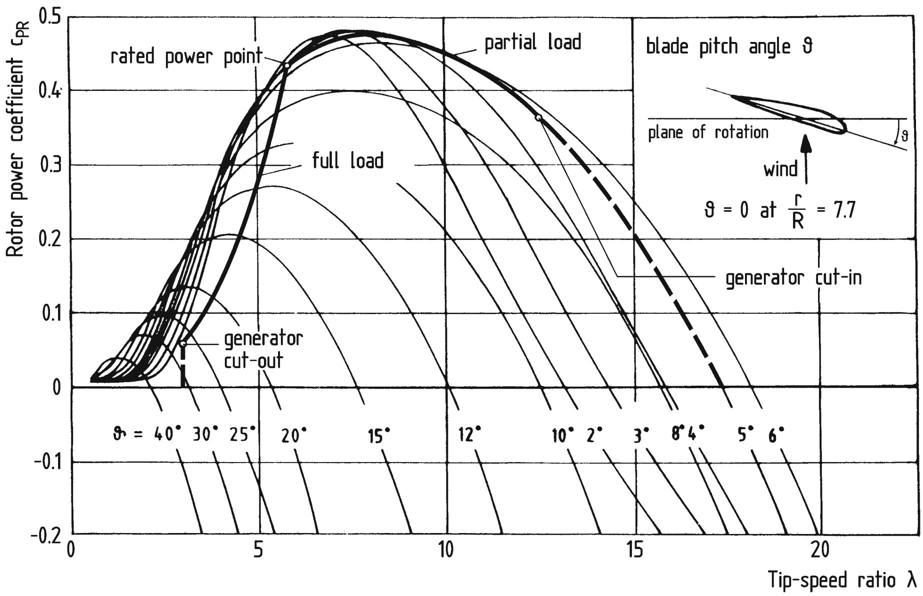


Fig. 14.5. Operating characteristics in the c_{PR}-λ chart

Yawing

The unavoidable inertia of rotor yawing with the wind direction is one cause of reduced output. As discussed in Chapter 5.7, an average incorrect angle with respect to the wind direction must be expected even with sensitive yawing, resulting in a certain power loss. Various investigations have shown the result that a loss of the order of 2 to 3% in the energy yield of the turbine must be expected with a yawing mechanism operating correctly. In principle, this loss is accounted for in a measured power characteristic since the turbine also exhibits incorrect angles during the measuring. Nevertheless, losses exceeding the losses determined under test conditions can occur on sites having very frequent wind direction changes.

Cut-in and cut-out characteristic

The operational sequence logic cuts the wind turbine in at a certain wind speed and limits power operation at a predetermined wind speed. At a first glance, this means a restriction of the usable wind speed range and thus also a loss in energy yield (s.a. Chapt. 14.6.7). Beyond that, cutting the turbine in and out has a certain control characteristic which leads to the processes exhibiting a hysteresis. When the cut-in and cut-out criteria are not set optimally, this hysteresis can lead to a noticeable power loss at sites having frequently changing mean wind velocities and thus having many cut-in and cut-out processes. This "control loss" must, therefore, be minimised by careful adjustment in operation.

14.1.3 Efficiencies in the Mechanical-Electrical Energy Conversion

The unavoidable power losses occurring along the mechanical-electrical drive train have various causes:

- Frictional losses in bearings and seals of the rotor shaft,
- Efficiency of the gearbox,
- Efficiency of the electric generator and of the inverter,
- Losses in the transformer to the grid,
- Self consumption of the turbine.

These losses depend on the conceptual design of the wind turbine and the efficiencies of the components. But there is also an influence of the size of the wind turbine and the rated power. Small wind turbines in the power range of several ten kilowatts may not be compared with wind turbines in the Megawatt power range. Small gearboxes and electrical generators are of much simpler design, thus their efficiencies are lower.

Example of the WKA-60 experimental turbine

Using the experimental WKA-60 turbine as an example, Figure 14.6 shows the energy flow through the drive train at the rated power. Approximately 140 kW occurs along the way through the drive train to the power line transformer. Moreover, an internal consumption of approximately 34 kW must be taken into consideration which, in the case of the WKA-60, is drawn directly from the grid. The comparatively high internal consumption is explained by the fact that this experimental turbine is equipped with a number of measuring instruments and test facilities and that the auxiliary units are by no means dimensioned for minimum consumption. It must also be taken into consideration that not all loads are operated at the same time so that the value indicated only corresponds to the theoretical peak value. The average value which determines the "energy loss" is considerably lower and can be expected in the range of about 1 % of the energy yield.

Figure 14.7 provides an overview of the order of magnitude of the power losses in the rotor power diagram, starting with the theoretically possible rotor power up to the effective electrical power yield. Starting with the envelope of the rotor power characteristics, i.e. the aerodynamically possible optimum, the mechanical-electrical losses in the drive train firstly reduce the power coefficient. In addition, a slight loss in power is produced by the selected constant blade pitch angle under partial load. In the full-load range, the permissible generator power limits the effective turbine power to a constant value. The power coefficients required for achieving the rated power decrease with increasing wind velocity. The associated power loss is comparatively large whilst the loss in energy yield is less since the higher wind velocities only occur comparatively infrequently. Taking into account these losses, the effective turbine power coefficients are obtained from the aerodynamically related rotor power coefficients. The variation of the turbine power coefficient with wind velocity forms the direct basis for the power characteristic of the wind turbine.

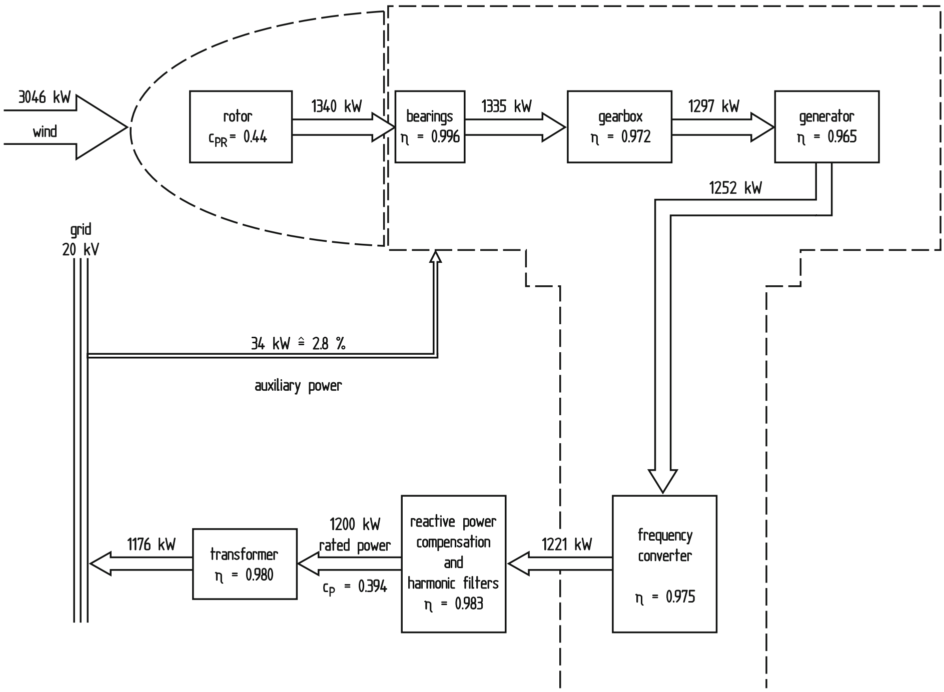


Fig. 14.6. Energy flow through the mechanical-electrical energy conversion chain at nominal operating point, for the WKA-60

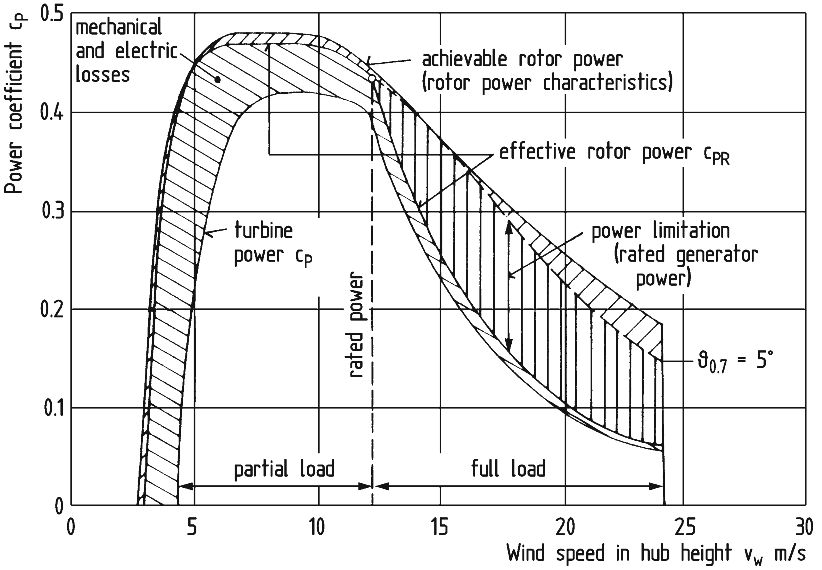


Fig. 14.7. Power losses of the WKA-60 indicated in the chart of power characteristics

Different drive train concepts

The previous example is a variable-speed system with synchronous generator and rectifier with DC link. Naturally, other electric and mechanical designs have different losses and the mechanical-electrical efficiency will, therefore, be different (Fig. 14.8). At full load, the total mechanical-electrical efficiencies are very close in the range of 92 to 94 %. The very high efficiency of the today´s inverters eliminate previous backlashes in the efficiencies of the variable-speed systems compared to the fixed-speed systems without inverter.

Larger differences are obvious in the partial load range. The gearless concepts show a remarkable advantage at a load range below 50 % of the rated power. The practical experiences with a better performance of these concepts on sites with lower wind speed confirm this. But also concepts with high-speed permanent magnet generators and gearboxes perform better at partial load conditions (s. Chapt. 10.1.3).

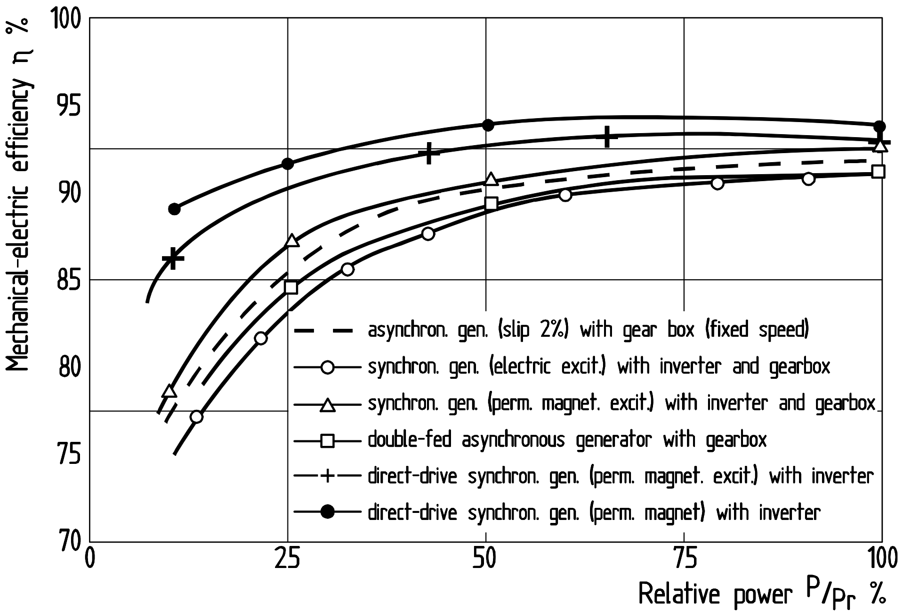


Fig. 14.8. Efficiency vs. Relative power for different drive train configurations

14.1.4 Power Coefficients of Today´s Turbines

Considered in greater detail, the power characteristics of present-day wind turbines show distinct differences which are definitely significant for the economic assessment. A better power curve, recognized more easily from the variation of the turbine power coefficient vs. wind velocity, means a noticeable advantage with respect to the energy yield to be expected. The existing differences are marked not only by the losses in the mechanical-electrical drive train but even more by the aerodynamic quality of the rotor and the speed control of the rotor (Fig. 14.9).

About ten years ago, the maximum power coefficient of the wind turbines was still just over 0.40 (Fig. 14.9). In the turbines operated with constant speed, the variation of the power coefficient with wind velocity only had a narrowly limited maximum. The variable-speed mode of operation enabled a much greater range with almost maximal power coefficients to be used.

The greatest advance was achieved in recent years by means of aerodynamically optimised rotor blades. It was especially the performance of the more recent models by Enercon from about 2004 onward which revealed the dominant influence of rotor aerodynamics. The yield-optimised, newly developed rotor blade airfoils together with the also novel rotor blade shape in the root area has resulted in the maximum power coefficient achieved being distinctly prominent in these turbines and reaching a level which was unknown even just a few years ago.

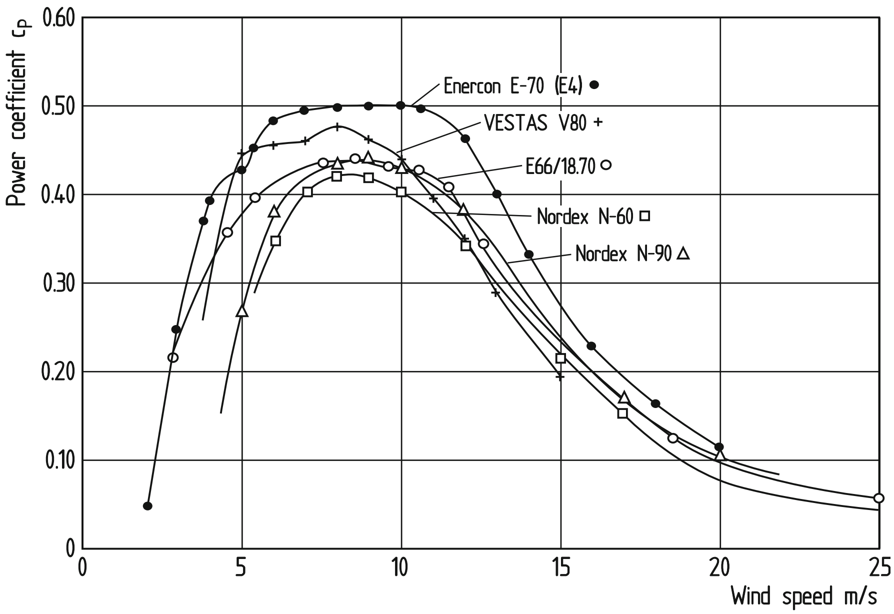


Fig. 14.9. Power coefficients of today's wind turbines

14.2 Determination of the Power Curve

The electrical power output versus wind speed is referred to as the *power curve.* As discussed in Chapter 5.2, its calculation is based on the set of rotor power characteristics (c_P-curves), the efficiency of the mechanical-electrical energy conversion, the optimized speed of the rotor with respect to a given wind frequency distribution and, finally, the limit imposed on the absorbed rotor power by the permissible maximum power of the electrical generator. It thus summarizes all the characteristics which are essential for the energy yield of the wind turbine. The power curve is a wind turbine's official certificate of performance, which has to be guaranteed by the manufacturer. This is why the accurate description and confirmation of the power curve is of special significance.

14.2.1 Definitions, Characteristics and Warranty

A group of experts of the International Energy Association (IEA) developed recommendations for the definition and testing of the power curve back in the nineteen-eighties [2]. These have been improved continuously in subsequent years and were then adopted in a Guideline of the IEC [3]. This Guideline - IEC 63400-12-1 - is generally accepted as the binding basis for the definition and measuring of the power curve. Accordingly, the shape of the power curve is characterised by following key elements relating power output to wind speed (Fig. 14.10):

- The *cut-in velocity* v_{ci} is the wind speed where the turbine starts to deliver power. In other words, the rotor must already be delivering enough power to compensate for the power loss in the drive train and to cover internal consumption.
- The *rated wind velocity* v_R is the wind speed at which the rated generator power is reached. The latter is identical with the permanently permissible maximum generator power output. In practice, it is not possible to determine the rated wind speed very precisely. Due to the wind turbulence and characteristics of the blade pitch control, the power curve shows a more or less marked "rounding" as it nears the rated power (Fig. 14.10).
- The *cut-out velocity* v_{co} is the highest wind speed at which the turbine may be operated while delivering power.
- Power is understood to be the net power. It is the electric power output minus all power losses caused by the turbine's internal consumption. The power line transformer is the only element left out of the equation, as it is not a turbine-specific element but depends on the conditions on the site. In wind turbines in which the intermediate-voltage transformer is an integrated component of the electrical system, this must be correspondingly taken into consideration.
- The atmospheric conditions are based on the standard atmosphere according to DIN 5450 (air density 1.225 kg/m³ at MSL, temperature 15 °C). The air density, and thus the temperature and the altitude, influence the power output.

The measurement campaigns have to be performed within a range of specified properties of the measuring site. The IEC standard mentions several parameters, for example the turbulence intensity, the shear wind exponent, the cross wind and some others which must not exceed the specified range. Against this background it becomes clear that the measured power curve has to be understood as “measured” performance of the wind turbine under standardised measuring conditions. It is not identical with the wind turbine performance on a specific site if the topography of the site or the wind regime differs significantly. In the following chapters the influence of site specific conditions will be discussed in more detail.

However a measured power curve even measured under standardised conditions is to a certain degree a site specific performance test. Not all the parameters influencing the power curve are covered by the IEC regulations. Furthermore the individual wind turbines of a series production show some variations in their power curve. Against this background some leading manufacturers base their warranty upon a “calculated” power curve. This power curve is based on the theoretical power curve and considers the results from several measurements with different individual turbines measured on different test sites.

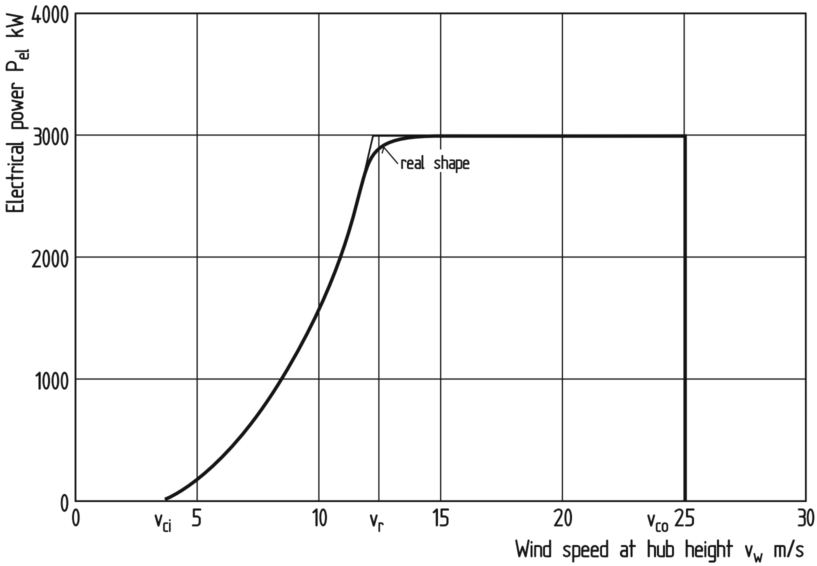


Fig. 14.10. Calculated power curve of a 3 MW wind turbine (rotor diameter 100 m)

The supplier of the wind turbine must provide the purchaser with a guarantee for the power curve. The curve is generally specified both as a graph and in tabular form. Like with any technical property, a certain tolerance is unavoidable, especially if it is the product of complex interrelationships. A deviation of the curve in the lower wind speed range has different effects on the energy yield, and thus on the economic viability, than a deviation at rated wind speed. Whereas power deficits in the partial-load range point to technical deficits in the rotor power coefficients or the other mechanical and electrical efficiencies involved, a reduced power in the full-load range can be cancelled out by a different adjustment of the power control if this is a turbine with blade pitch control.

Considering these problems, it does not make sense to relate the condition under which the guarantee is given, to maintaining the geometric shape of the power curve. Instead, it is the calculated energy yield achieved with a given power curve which is guaranteed by the wind turbine manufacturer. However, this presupposes that manufacturer and purchaser agree on the basis for the mathematical comparison. It is necessary to agree on what wind speed distribution is to be used as a basis for the comparison. The IEC standard recommends the use of a Rayleigh distribution with mean wind speeds in a range from 4 to 11 m/s for this purpose. In most cases, the claim for damages in the event of non correspondence with the power curve is agreed at the monetary value of the deficit in energy yield over a specified period.

The definition of the power curve is less precise for wind turbines with fixed blade rotors (Fig. 14.11). This can be caused by errors in the twist of the rotor blades or inaccurate pitch angles. Stall, and with it power limiting, often occurs later than expected and the maximum power exceeds the specified rating at higher wind velocities and, on the other hand, the power curve is worse than expected at low wind speeds. Moreover, stall-controlled turbines often have a very "individual" power curve. Small constructional variations in the rotor blades or soiling in operation have a much greater influence on the power curve than in the case of turbines with blade pitch control (s. Chapt. 5).

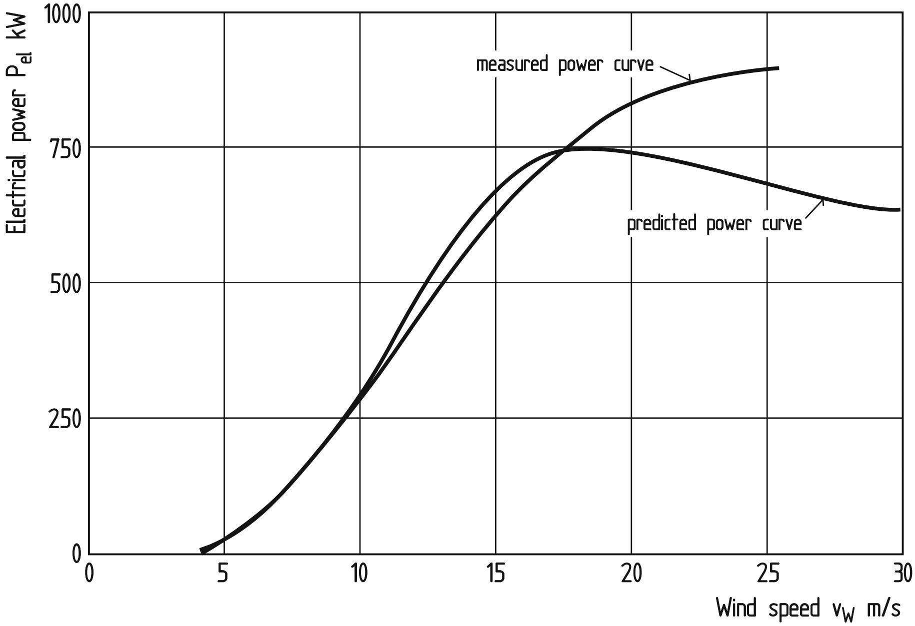


Fig. 14.11. Typical deviation of a measured curve from the calculated curve for a stall-controlled turbine

14.2.2 Measuring the Power Curve

Wind turbines having a power curve based only on theoretical calculations are sold only in exceptional cases. The power curves of all commercial wind turbines are measured and certified by independent institutions in connection with their *type approval* (Chapt. 14.6.8). In Europe, this has become the special task of the national wind energy institutes, the "Deutsche Windenergie-Institut (DEWI)" and the "Windtest-Kaiser-Wilhelm-Koog" in Germany, the National Institute and Wind Turbine Test Station Risø in Denmark and the "Dutch Energy Research Institute" (ECN) Petten in the Netherlands. These institutes are linked via an organisation (MEASNET) initiated by the EU Commission and are continuously working on the improvement and standardisation of the measuring methods [4].

The measurement of the power curve has its own particular difficulties. Because of the great importance of the power curve and its accuracy the main influences on the measurement procedure and the results shall be mentioned here. The IEC 61400-12-1 comprises a detailed description of the procedures, test equipment, and in particular of the unavoidable uncertainties of the results.

Test site

The test site shall show only minor variations from a plane and shall be free from larger obstacles. The wind turbine under test and the wind measuring mast shall not be influenced by neighbouring wind turbines. If the test site shows significant deviation from a plane and includes obstacles a *site calibration* is recommended to quantify the flow distortions for all wind directions.

Wind speed measurement

Measuring the correct wind speed is a key element in determining the wind turbine's power curve. The first task is to find a suitable position of the meteorological mast. The physically correct correlation of power and wind speed can only be carried out successfully with a wind speed representative of the generated power. For this purpose, the rotor's flow field must influence the site of the wind speed measurement as little as possible, so that the "true" undisturbed wind speed can be recorded. However, due to the necessary spatial distance from the rotor of several rotor diameters in front of the rotor plane, there is a time delay between the instantaneous wind speed measurement and the power output of the wind turbine. The IEC standard recommends a layout according to Figure 14.12.

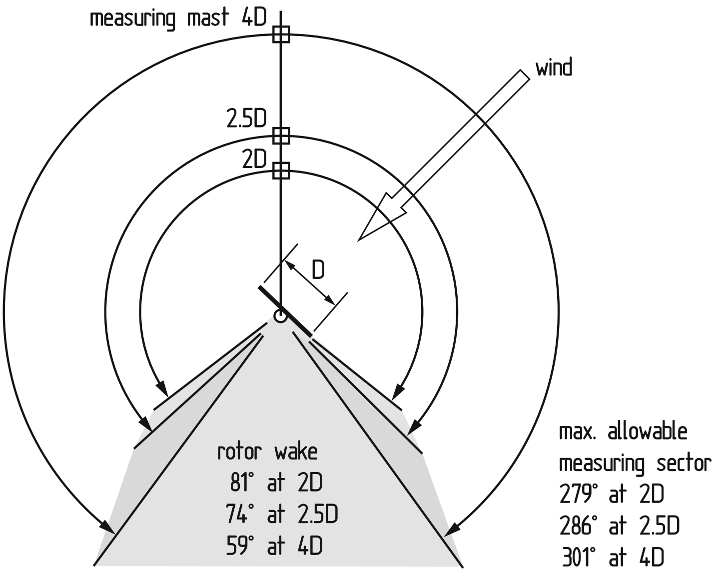


Fig. 14.12. Position of the meteorological mast for measuring the power curve of a wind turbine according to IEC 6100-12 [2]. Wind measurement 2 to 4 rotor diameters from the wind turbine (recommended distance 2.5 D)

In connection with measuring the power characteristic, the influence of the anemometers used for measuring the wind speed must be pointed out. The anemometers used in past years exhibit design-related differences which lead to the measurement results being clearly affected by the non-steady-state and turbulent flow conditions in the atmosphere. In Denmark, anemometers are used in many cases which were developed by the Risø Test Station. These anemometers essentially only respond to the horizontal component of the wind velocity vector. The types of anemometer used in Germany respond more strongly to the total amount of the wind velocity vector, i.e. also to the cross-wind component. With a given power, the wind velocity measured in this way is higher so that the power characteristic appears to be worse. The differences become greater with increasing turbulence at the measuring site and have been measured with differences of 5-7 % in individual cases [5]. In the meantime, a uniform anemometer classification is to be prescribed for the power curve measurement according to IEC.

Electric power output

The net electric power of the wind turbine shall be measured using a power measurement device (e.g. power transducer) and shall be based on measurements of current and voltage on each phase. The power measurement device shall be mounted between the wind turbine and the electrical connection to ensure that only the net active electric power (i.e. reduced by self consumption) is measured. It shall be stated whether the measurements are made on the turbine side or the network side of the transformer.

Data normalisation

The measured data shall be normalized to two reference air densities. One shall be the sea level air density, referring to ISO standard atmosphere (1.225 kg/m³). The other shall be the average of the measured air density data at the test site during periods of valid data collection.

Data base

After data normalization the data shall be sorted using the *method of bins* procedure. The data shall at least cover a wind speed range extending from 1 m/s below cut-in to 1.5 times the wind speed at 85 % of the rated power of the wind turbine. The wind speed range shall be divided into 0.5 m/s (bins).

Determination of the measured power curve

The measured power curve is determined by applying the "method of bins" for the normalised data sets, using 0.5 m/s bins and the calculation of the mean values of the normalized wind speed and normalized power output for each wind speed bin. The power values are the ten-minute means in each bin of wind velocity. The result is the *normalized and averaged power curve.* As mentioned before this curve represents the basis for the calculation of the annual energy yield, which can be expected on a site with a “normal” wind regime.

Power coefficient

The power coefficient c_p of the wind turbine shall be added to the test results and presented as a curve vs. wind speed at hub height and as a table. The c_p will be derived from the normalized and averaged power curve.

Uncertainty analysis

The measured power curve shall be supplemented with an estimate of the uncertainty of the measurement. The estimate shall be based on the ISO information publication "Guide to the expression of uncertainty in measurement". Following the ISO guide, there are two uncertainties: category A, the magnitude of which can be deduced from measurements, and category B, which are estimated by other means.

Category B includes all the inaccuracies and deviations, which can be determined systematically. First of all these are effects related to the instrumentation, the data acquisition system and the terrain surroundings of the test site. In category A variations of the electric power output are comprised which cannot be assessed systematically. Other influencing parameters, for example specific climatic factors on the site like high turbulence can cause significant deviations from the power curve measured on the test site. In both categories, uncertainties are expressed as standard deviations and are denoted *standard uncertainties.*

Presentation of measured data

The power curve shall be presented in a diagram and in a form of a table. For each wind speed bin the table shall list (Figs. 14.13 and 14.14):

- normalized and averaged wind speed,
- normalized and averaged power output,
- number of data sets,
- calculated c_p value,
- standard uncertainties of category A,
- standard uncertainties of category B,
- combined standard uncertainty.

Annual energy production

The annual energy production (AEP) will be calculated by applying the normalized and averaged power curve to the reference wind speed frequency distribution. A Rayleigh distribution, which is identical to a Weibull distribution with a shape factor of 2, shall be used as the reference wind speed frequency distribution. The uncertainties in the annual energy production, only deal with uncertainties originating from the power performance test and do not take into account uncertainties due to other important factors relating to actual energy production for a given installation, for example site-related influences in complex terrain (s.a. Chapt. 14.3).

DEWI

Extract from Test Report
DEWI-PV 0308-08.4

The reference report DEWI-PV 0308-08.4 was prepared according to IEC 61400-12 (1998) and MEASNET (2000)

DEWI · Deutsches Windenergie-Institut · German Wind Energy Institute · measnet

Extract from Test Report DEWI-PV 0308-08.4 for power curve
of wind turbine type ENERCON E-70 E4 with a rated power of 2300 kW

Wind Turbine Type:	**ENERCON E-70 E4**	**Technical data (Manufacturer Data)**	
Turbine Manufacturer:	**ENERCON GmbH**	**Rated Power:**	**2300 kW**
	Dreekamp 9	**Rated Wind Speed:**	**13 m/s**
	D-26605 Aurich	**Rotor Speed:**	**6 - 21.5 rpm**
		Rotor Diameter:	**71 m**
Turbine Site (approx.):	**x: 2588308 y: 5945565**	**Hub Height:**	**65 m**
Serial Number:	**701482**	**Blade Angle: pitch**	**Blade Type: ENERCON 70-4**

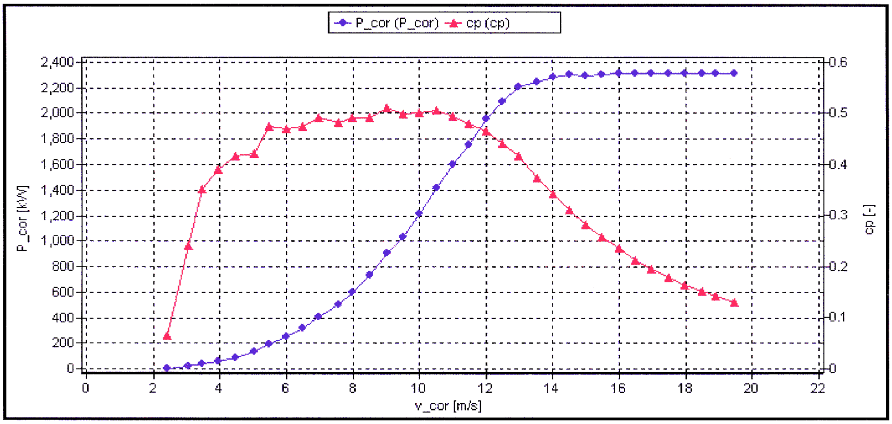
Scope of Measurement and Information about Sensors

Measuring Period (CET):	**11.01.2005 (17:00) – 10.02.2005 (14:00)**	**Measurement Accuracy**	
Measurement sector of wind direction:	**243° – 32°**	**Power transducer:**	**13 kW**
Height of wind measurement:	**65 m**	**Calibration of anemometer: Vector A100LK**	**0.1 m/s**
Standard air density:	**1.225 kg/m³**	**Air temperature sensor:**	**1.0 °C**
		Ai pressure sensor:	**1.5 hPa**

Deviation(s) from the standard

No deviations from IEC 61400-12 (1998) and MESANET (2000).

Power Curve according to IEC 61400-12 (1998) and MEASNET (2000)



Measured power curve for standard air density 1.225 kg/m³.

Fig. 14.13. Measured and certified power curve of a wind turbine (DEWI)

Extract from Test Report DEWI-PV 0308-08.4

Measurements of Power Curve ENERCON E-70 E4
Standard air density 1,225 kg/m³

Bin-No.	Wind Speed (at hub height) V_i [m/s]	Effective Power P_i [kW]	$c_{p,i}$-value [-]	Number of Data N_i [-]	Category A Uncertainty S_i [kW]	Category B Uncertainty u_i [kW]	Combined Uncertainty $u_{c,i}$ [kW]
5	2.43	2.27	0.07	3	0.6	8.0	8.0
6	3.07	16.85	0.24	10	2.6	8.5	8.9
7	3.48	35.97	0.35	33	1.5	10.1	10.2
8	3.97	58.95	0.39	35	2.0	10.4	10.6
9	4.48	90.99	0.42	25	3.0	12.2	12.6
10	5.05	131.55	0.42	11	3.7	13.8	14.3
11	5.49	190.06	0.47	13	9.1	23.5	25.2
12	6.02	247.08	0.47	16	7.3	20.7	22.0
13	6.50	315.23	0.48	25	4.9	27.1	27.6
14	6.99	405.31	0.49	33	9.1	36.5	37.6
15	7.56	503.54	0.48	51	8.4	35.9	36.9
16	7.97	602.36	0.49	60	9.0	52.3	53.1
17	8.49	728.07	0.49	75	9.9	54.6	55.4
18	9.01	901.66	0.51	104	8.5	78.3	78.7
19	9.50	1034.54	0.50	118	7.8	67.0	67.5
20	10.01	1215.20	0.50	131	8.9	89.3	89.8
21	10.51	1420.41	0.51	117	9.7	109.4	109.9
22	11.01	1596.47	0.50	108	11.7	97.8	98.5
23	11.48	1756.72	0.48	89	14.9	97.4	98.6
24	12.02	1958.17	0.47	73	14.4	111.5	112.4
25	12.51	2093.26	0.44	76	12.1	85.5	86.4
26	12.98	2209.05	0.42	63	9.0	79.8	80.3
27	13.53	2242.87	0.37	41	11.5	25.3	27.8
28	14.03	2286.15	0.34	53	5.3	33.2	33.6
29	14.49	2299.19	0.31	41	3.5	18.5	18.9
30	14.99	2298.40	0.28	22	5.7	15.7	16.7
31	15.47	2299.01	0.26	23	17.1	15.7	23.3
32	15.98	2316.12	0.24	23	1.1	20.4	20.4
33	16.48	2310.24	0.21	36	3.4	16.4	16.8
34	16.98	2314.83	0.20	22	2.4	16.2	16.4
35	17.47	2315.49	0.18	31	1.4	15.8	15.9
36	17.98	2316.40	0.17	27	0.3	15.8	15.8
37	18.50	2316.06	0.15	21	0.3	15.8	15.8
38	18.90	2313.43	0.14	19	2.9	16.1	16.3
39	19.48	2315.90	0.13	10	0.5	15.9	15.9

Annual Energy Production (AEP) Standard air density: 1,225 kg/m³, cut-out wind speed: 25 m/s (Extrapolation with constant effective power starting from last bin)

Yearly mean wind velocity (Rayleigh-Curve) [m/s]	Measured AEP (measured power curve) [MWh]	Uncertainty of measured power curve, displayed as standard deviation of AEP [MWh]	[%]	Extrapolated AEP (extrapolated power curve, 100 % availability) [MWh]
4	1185.0	130.3	11.0	1185.0
5	2360.2	204.9	8.7	2360.3
6	3874.3	277.5	7.2	3878.5
7	5510.4	331.7	6.0	5549.3
8	7033.9	363.1	5.2	7195.6
9	8274.2	374.9	4.5	8692.5
10 *	9156.9	372.5	4.1	9960.3
11 *	9687.8	361.1	3.7	10956.5

*) Incomplete according to IEC 61400-12 (AEP-measured less than 95% of the AEP-extrapolated)

This attachment to Test Report is accountable only in conjunction with the "Manufacture's certificate on specific data of the type of the installation" from 24.01.2005. This data sheet does not replace the Test Report mentioned above.

Measured by: Deutsches Windenergie-Institut GmbH
Ebertstraße 96
D-26382 Wilhelmshaven

Date: 14.02.2005

H. Mellinghoff
(i.V. Dipl.-Phys. H. Mellinghoff)
DEWI

DEWI · Deutsches Windenergie-Institut · German Wind Energy Institute
measnet

U. Bunse
(i.A. Dipl.-Ing. U. Bunse)
DEWI

Fig. 14.14. Measured power curve and calculated annual energy production standard uncertainties according to IEC 61400-12-1 (DEWI)

14.3 Site-Related Influences on the Power Curve

The power curve specified by the manufacturer guarantees the power yield of the wind turbine under the conditions described and specified in the measuring process according to IEC 61400-12. Beyond that, however, the power of a wind turbine is also influenced by certain factors at the actual site. This fact, which cannot be argued away, is often a cause of conflict between manufacturer and operator. To estimate the site-related influences is the task of technical project planning which, if possible, should include the manufacturer. Whether the manufacturer will guarantee the power curve "on site" in this case is another question which should be agreed from case to case.

14.3.1 Complex Terrain

Experience in recent years has shown that the guaranteed power curve can be noticeably affected by environmental influences in difficult terrain (Fig. 14.15). It is especially the increasing siting of wind turbines in mountainous and wooded inland regions which has shown a distinct deviation of the actual annual energy yield achieved from the expected value, resulting in numerous disputes regarding the validity of the power curve issued by the manufacturer.

Fig. 14.15. Wind turbines in "complex terrain" at the Straits of Gibraltar (Thyssen, Krupp)

It is difficult to estimate the flow conditions in complex terrain in detail but they change the inflow conditions for the rotor. The flow field is affected by specific topographic shapes such as depressions or slopes running at an angle to the direction of incident flow. Depending on the wind direction, wooded areas cause greatly variable vertical wind shear profiles of the wind velocity. Ridges or other obstacles, when overflown, lead to turbulent wake regions. These and similar effects will prevent a uniform rotor inflow as exists under test conditions in the test terrain which, as a rule, is level and free of obstacles. Experience has shown that the power curve of a wind turbine can be noticeably impaired, as a result. The lower the tower height selected in relation to the rotor diameter, the stronger these effects will be. High towers are, therefore, almost indispensible in complex terrain in the interior also from this point of view.

14.3.2 Air Density

The density of the air varies with altitude and temperature. As the utilisation of wind energy spreads inland, wind turbines are also being erected in lower mountain regions. In Germany, the altitude of the sites in these regions rarely exceeds 600 m. In other countries, higher altitudes are encountered. In Italy, for example, wind turbines are being installed at altitudes of up to 1500 m in some areas in the Abrucci range. The power curve specified by the manufacturer, which is referred to "Mean Sea Level" (MSL), must be corrected by the air density prevailing at the installation site.

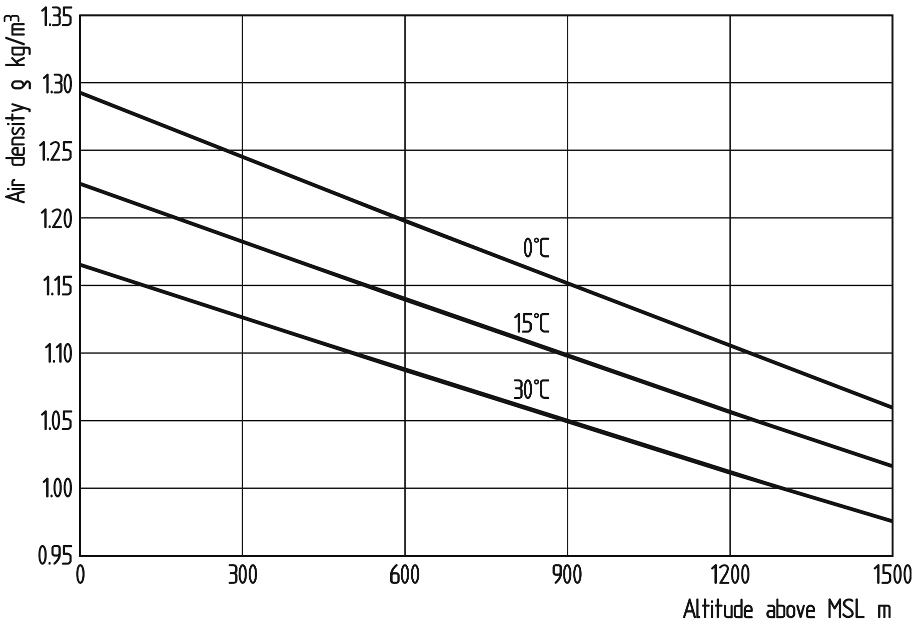


Fig. 14.16. Air density as a function of the geographic altitude and temperature

The decrease in mean air density as a function of the temperature at zero altitude can be calculated by means of Boltzmann's barometric equation as follows:

$$\varrho_H = \varrho_0 \frac{T_0}{273.15 + t} \frac{P_H}{P_0}$$

where:

ϱ_H = air density at altitude H above MSL
ϱ_0 = air density at altitude MSL (ϱ_0 = 1.225 kg/m³)
T_0 = 288.15 K or 15 °C at MSL
p_0 = air pressure at MSL (p_0 = 1013.3 mbar)
t = temperature at altitude H (°C)

The decrease in air density is already noticeable at a few hundred meters, as well as the change in the temperature range between summer and winter, so that its influence on turbine performance cannot be neglected (Fig. 14.16). According to the equation, the influence of air density on power output is linear, i.e. the change in power is directly proportional to air density. However, there are considerable differences with respect to the technical design of the wind turbine.

Stall controlled turbines

The power of stall-limited wind turbines is reduced over the entire range of wind speeds (Fig. 14.17).

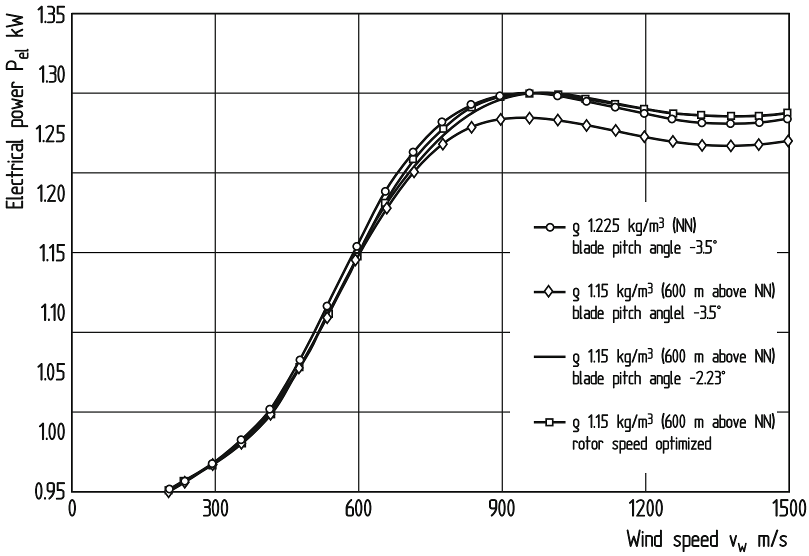


Fig. 14.17. Optimization of the power curve of a stall-controlled turbine at an elevation of 600 m above MSL

Stall occurs at approximately the same wind speed but the power is less than that at sea level in proportion to the air density. The power deficit can be partially compensated for by correcting the blade pitch angle but this shifts the maximum (rated) power towards higher wind velocities (Fig. 14.18). Shifting the power curve towards higher wind velocities, in turn, influences the optimum rotor speed with respect to energy yield so that in the case of relatively large displacements in the power curve, the rotor speed must also be corrected to achieve optimum adaptation to the site elevation. In the example of Figure 14.17 with an altitude of 600 m, the above adaptations have the following influence on the energy yield:

- Energy yield at mean sea level	100 %
- after correcting for air density without technical adaptations	94 %
- with corrected blade pitch angle	96 %
- with corrected blade pitch angle and corrected rotor speed	98 %

These numbers show clearly that a calculation of the energy yield without correcting for the air density at 600 m altitude leads to a not inconsiderable overestimation of the amount of power to be expected. Correct application of the air density has such a great influence on the energy yield that it pays for the costs of the technical correction measures taken. While on this subject, the differences in air density between summer and winter must also be taken into consideration, especially in hot countries. In turbines with fixed blade pitch angle, there is no possibility for adapting the blade pitch angle to winter or summer operation so that this, too, is associated with certain power losses, either in summer or in winter. Better adaptation is only possible with active stall control (Chapt. 5.5.3).

Wind turbine with blade pitch control

In turbines with blade pitch control, the influence of the decrease in air density with increasing site elevation is not as severe as in the case of stall-controlled turbines. In the full load range, the only reference value for the control system is the electrical power so that there is no power deficit in this range. In the partial-load range, the power curve initially decreases in proportion to the air density as with a stall-controlled turbine. The point of rated power shifts towards a higher wind speed (Fig. 14.18). An approximate correction is given by the formula:

$$v_H = v_0 \cdot \left(\frac{\varrho_H}{\varrho_0}\right)^{1/3}$$

The blade pitch angle can be adapted without technical modifications, which also applies to the rotor speed since almost all new blade-pitch controlled turbines can be operated at variable rotor speed. Thus, blade-pitch controlled turbines suffer some loss in energy yield with increase in site elevation but can be operated lossless optimally with blade pitch angles corrected for changing temperatures.

Assuming an average wind regime the energy loss can be expected at

- 0 m	100 %
- 500 m	98 %
- 1000 m	95 %

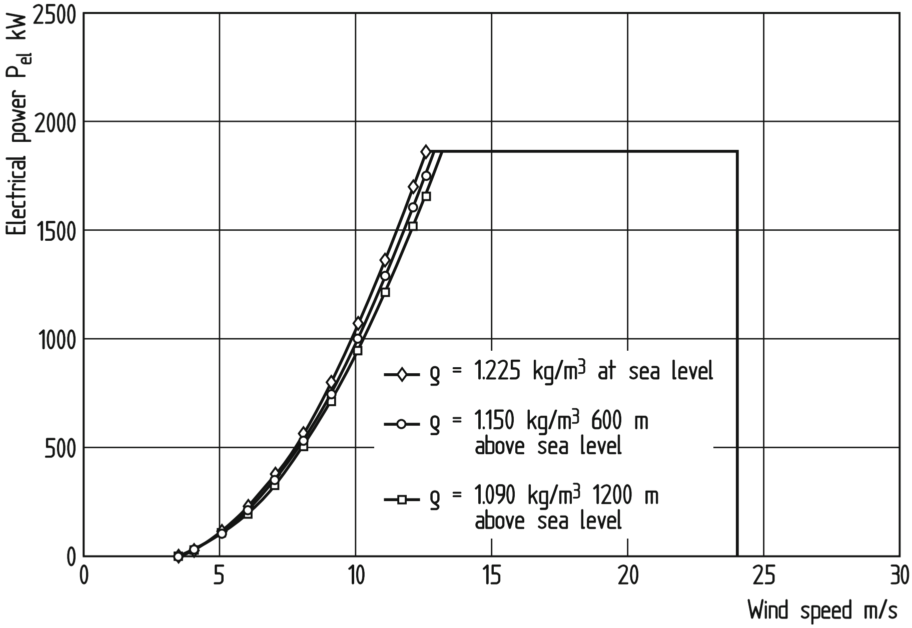


Fig. 14.18. Variation of the power curve of a blade-pitch controlled turbine at an altitude of 600 m and 1200 m above MSL

14.3.3 Turbulence

The wind turbulence has an influence on the power curve of a wind turbine. There are two different aspects: Firstly the air turbulence increases the power density of the air stream through the rotor. Using 10-minute mean values instead of instantaneous values as a basis for representing the power curve leads to an underestimation of the power density in the airflow. The power is a function of the third power of the wind velocity. The contribution of the cubes of the instantaneous wind peaks above the mean value is, therefore, greater than of those below the mean.

However, the measured or specified turbulence intensity does not take into consideration the spatial variation of the turbulence including the lateral and vertical components. Considering the rotor swept area, a large proportion of the turbulence effects is levelled out due to the rotor. And, not lastly, the wind speed measurement serving as reference for the electrical power output is based on 10-minute mean values and thus itself contains a component of the turbulence which contributes to the air power density.

The point of view of the practical operation of the wind turbine, the influence of turbulence on the energy yield of the turbine is, as a rule, not severe.

In practice, a positive effect of turbulence on the power curve can only be found in the lower wind speed range, if at all. This is contrasted by a negative effect in the area of rated power. The inertia of the blade pitch control causes greater rounding of the characteristic (Fig. 14.19), Figure 14.20 shows an example of the differences in the power curve with different turbulence intensities. This shows at least clearly that consideration of turbulence is indispensible for a precise measurement of the power curve

[6]. Regarding the practical operation of a wind turbine the influence on the energy yield is very low. It is more important to check the turbulence with respect to the loading on the turbine (s. Chapt. 6).

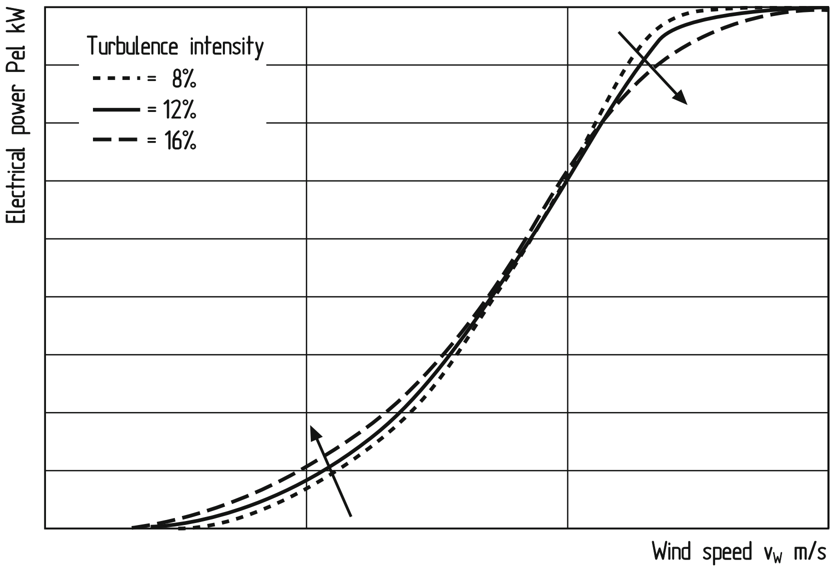


Fig. 14.19. Influence of the turbulence on the power curve [6]

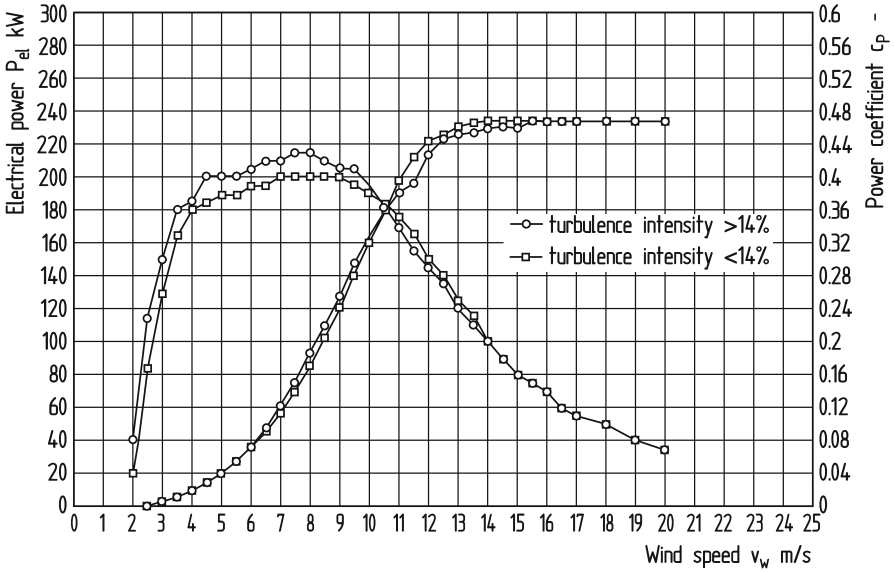


Fig. 14.20. Measurements of the power curve at different turbulence intensities on the example of an Enercon E-30 [7]

14.3.4 Other Weather-Related Influences

Apart from the turbulence of the wind, other, weather-related factors can also influence the power curve. Primarily, the icing of the rotor blades occurring at some sites can alter their aerodynamic profile to such an extent that the rotor power disappears completely (s.a. Chapt. 8.2 and 18). However, there is no sense in taking the influence of icing on the power curve into consideration since, for safety reasons, the turbine has to be switched off in cases of icing.

The influence of strong, longer-lasting rain, possibly also of snowfall, can have a more practical significance. There are some relevant studies [1] according to which a quite measurable power loss was measured in cases of rain. The cause is considered to be less the loss of impulse of the rotor due to the collision with rain drops but rather the change in surface roughness of the rotor blades due to the rain drops impinging and dispersing on the leading edge. As a result, the airfoil boundary layer becomes turbulent already in the nose area, with corresponding consequences for the airfoil performance (s.a. Chapt. 5.4.3). IEC Standard 61400-1 does not yet contain any specifications for measuring performance with rain.

14.3.5 Soiling of the Rotor Blades

After a certain operating period, the rotor blades of wind turbines more or less distinctly exhibit soiling phenomena. The extraordinary sensitivity to an increase in surface roughness of the laminar airfoils used was discussed in detail in Chapter 5.4.3. Soiled rotor blades can, therefore, be the cause of a considerable deterioration in the power curve.

The dirt on the surface of the blades is produced with prolonged dryness and higher temperatures in summer. It consists of a mixture of fine dust and dead insect bodies which remain stuck to the surface at the leading edge, especially in summer, similar to the conditions on the windscreen of a car. This type of soiling is not only weather-dependent but also depends on the site. Extreme conditions are observed in desert-like sites (California or also certain regions in Spain) where there is much dust in the air with the right wind in summer. In Germany, where the surrounding terrain consists of meadows and forests, there is much less soiling.

The size of the installations or, more precisely, the height of the rotor above ground, also plays a role. The dust, and also the number of insects in the air, clearly decreases with tower heights of 100 m and more.

With respect to the effects on wind turbines, stall-controlled units with fixed rotor blades respond particularly badly to soiled rotor blades. Not only is the lift-drag ratio of the airfoils reduced but the onset of stalling is also shifted towards lower wind velocities, with the consequence of a drastic deterioration of the power curve. In Californian wind farms, only half the rated power has often been achieved in smaller stall-controlled turbines after prolonged operating periods in summer. The rotor blades had to be cleaned with great effort in relatively short intervals.

Turbines with blade pitch control respond less severely to the increase in surface roughness of the rotor blades due to soiling because there can be no premature onset of stalling and the blade pitch control responds to the change in airfoil characteristics up to a certain degree. But in these turbines, too, a noticeable reduction in performance is observed in the partial-load region.

Soiling of the blades causes much more problems at stall controlled wind turbines. Figure 14.21 shows an example of the deterioration in the power curve due to soiled rotor blades. This is a 750-kW stall-controlled unit with a tower height of 50 m which is standing at about 600 m above MSL in a wind park in Northern Spain on a plateau with little growth, but a sandy ground surface. The power curve was measured after an operating period of about three months in summer. The soiling on the blade surface is partly washed off again by rain - but almost never completely -, so a significant power deficit remained without cleaning the rotor blades.

The relatively elaborate washing of the rotor blades may, therefore, be advisable at some sites. A prolonged operation with badly soiled rotor blades would lead to a too great a loss in energy yield.

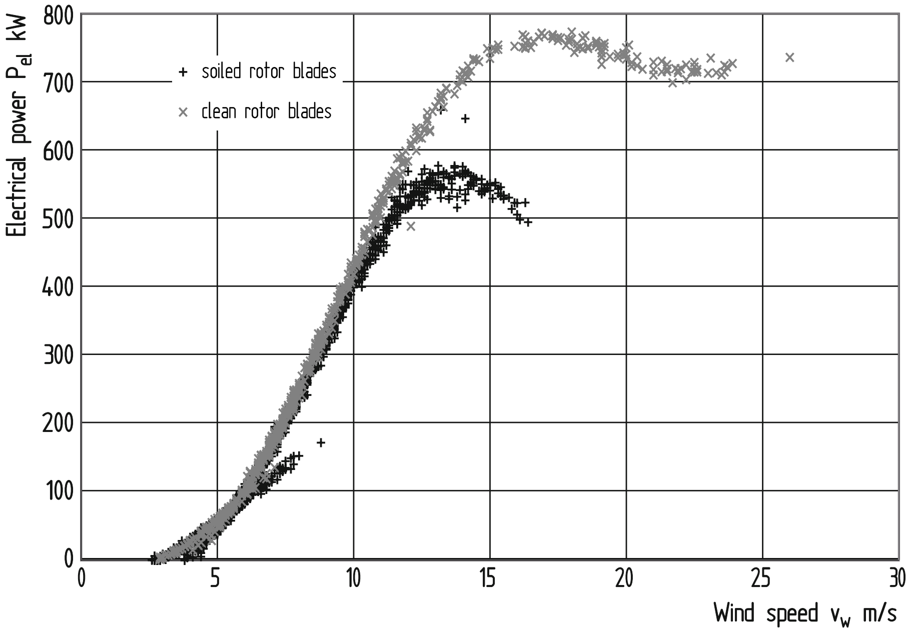


Fig. 14.21. Measured power curve of a stall-controlled wind turbine with clean rotor blades and after three months in summer with soiled rotor blades

14.4 Uniformity of Power Output

The power curve of a wind turbine provides information on the quantitative output capacity, but it does not disclose anything about the quality of the electric power generated.

Apart from the electric quality criteria discussed elsewhere (Chapt. 9.2), the uniformity of the power output is also a criterion for quality. Figures 14.22 to 14.24 illustrate the wide range of power variations for different technical wind turbine concepts.

Older wind turbines without blade pitch control have particularly high variations in their power output (Fig. 14.23). This does not apply to more recent stall-controlled turbines, however. With increasingly refined optimisation of the rotor's aerodynamic properties, a more uniform power output is also achieved in stall-controlled turbines.

The power variations of wind turbines with conventional blade pitch control are dependent on the turbine's control characteristics, particularly the rate of pitch adjustment. Recent investigations show that favourable conditions are achieved only at certain pitch rates [8]. In any case, there is a not inconsiderable fluctuation which becomes visible at a certain temporal resolution (Fig. 14.24), whereas power output becomes almost completely smooth with variable speed operation (Fig. 14.25).

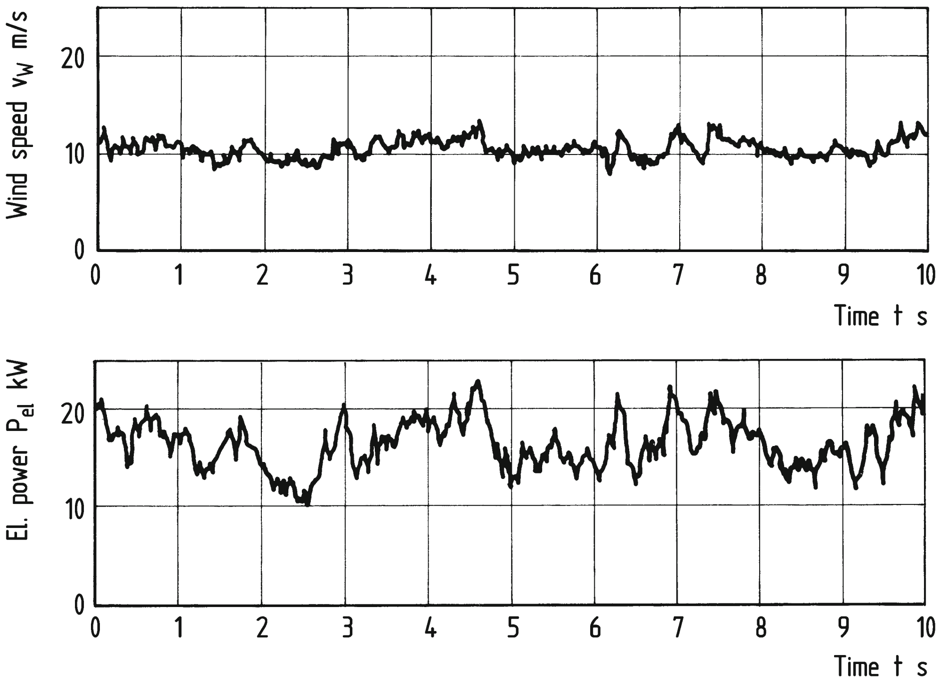


Fig. 14.22. Electrical power output of a small wind turbine with fixed blade pitch angle and a grid coupled induction generator

It depends on the individual case how highly a steady power output is valued. A large fixed-frequency grid can cope with relatively great power variations. In a small isolated grid, for example where wind turbines are combined with small diesel generator power stations, high short-term power variations cause stability and control-system problems. Moreover, it must again be pointed out in this context that high power variations are tantamount to high dynamic loads on the turbine. A smooth power output is, therefore, a worthwhile goal in any case.

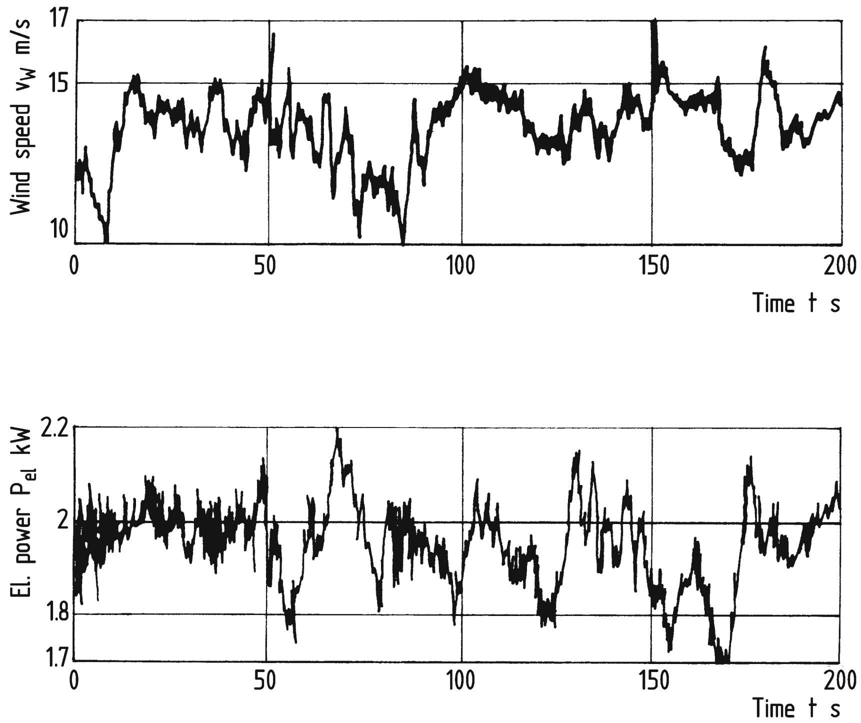


Fig. 14.23. Power output of the Tjaereborg wind turbine with blade pitch control and a direct coupled induction generator (generator slip approx. 2 %) [9]

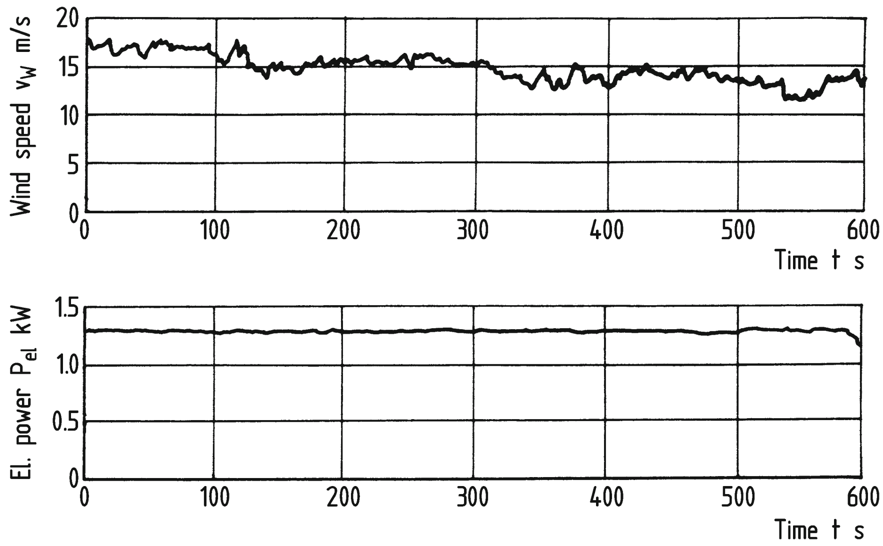


Fig. 14.24. Power output of the WKA-60 wind turbine with blade pitch control and variable speed generator system (speed variation ± 15 %) [10]

14.5 Annual Energy Yield

It is common practice to specify the energy output of a wind turbine over one year and as “Annual Energy Production” (AEP). Next to the investment costs, it is the second decisive quantity with respect to the economics of wind energy utilisation. From the point of view of the operator, the reliability of the forecasting is, therefore, of fundamental importance for the entrepreneurial decision to operate a wind turbine. Against this background, the reliability of the power curve and the site-related wind regime take priority. Unfortunately the power curve of the wind turbine as well as the wind data cannot be determined without uncertainties. On the one hand the measurement of the power curve includes uncertainties, on the other hand there are site-related influences which have to be considered. Therefore a certain conception about the influence of the most important technical design parameters of the wind turbine on the energy yield is also of great use. Given this understanding, the trust in the statements of the "experts", which normally cannot be checked in detail by the operator, also increases.

14.5.1 Method of Calculation

Calculation of the annual energy yield of a wind turbine at a given site requires the power curve of the turbine and the frequency distribution of the wind speeds at hub height at the site (Figs. 14.25 and 14.26). In this example, the cumulative frequency distribution is divided into intervals (bins) with a width of $\Delta v_W = 1$ m/s and the mean generated power is read off the power curve in the corresponding interval. The annual energy yield can be calculated in one calculation as follows:

$$E = \frac{8760}{100} \sum_{v_{ci}}^{v_{co}} P_{el} \, \Delta\phi \quad (\mathrm{kWh/a})$$

where the power output P_{el} is given in kW and the wind frequency distribution $\Delta\Phi$ in %. The annual energy yield is then obtained by summing from v_{ci} to v_{co} the duration of the wind velocity within an interval being given in hours in accordance with the frequency distribution.

An illustrative graphical representation of the annual power output is given in Figure 14.27 where the number of hours at full load, partial load and stand-still are systematically plotted in turn against hours of operation during the year. The annual energy yield, as the integral of power over time, is the area below the curve. The mean annual power output of the wind turbine is indicated by a rectangle of equal area with a base line of 8760 hours and the mean power output along the ordinate.

In energy technology the energy output is usually characterised by the rated power and the *equivalent full-load hours* or the *usage time.* In other words, the calculated energy output is the product of rated power and usage time.

As in the definition of the power curve, some preconditions and agreed terms of reference must also be clarified when indicating the annual energy yield.

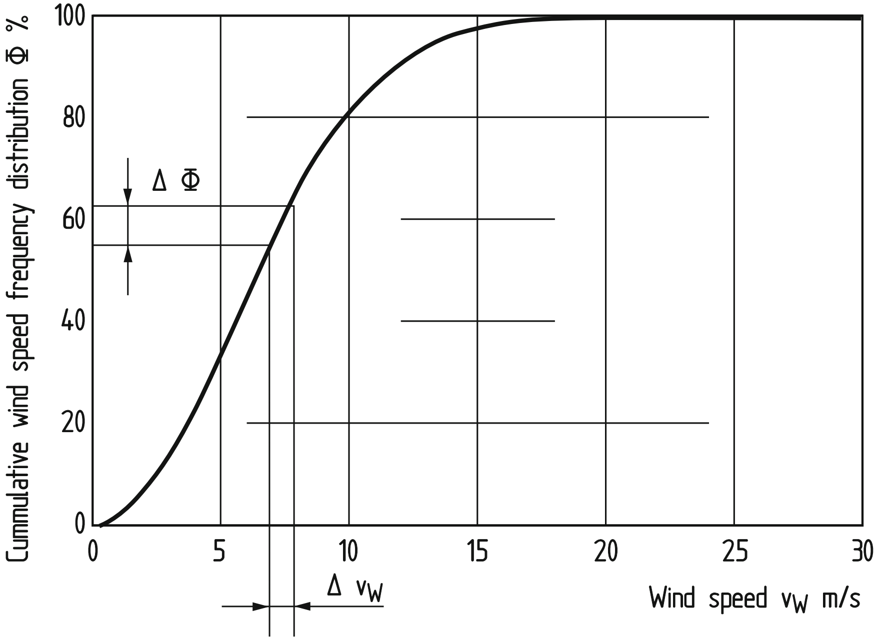


Fig. 14.25. Subdividing the frequency distribution of the wind speeds into wind speed intervals (method of bins)

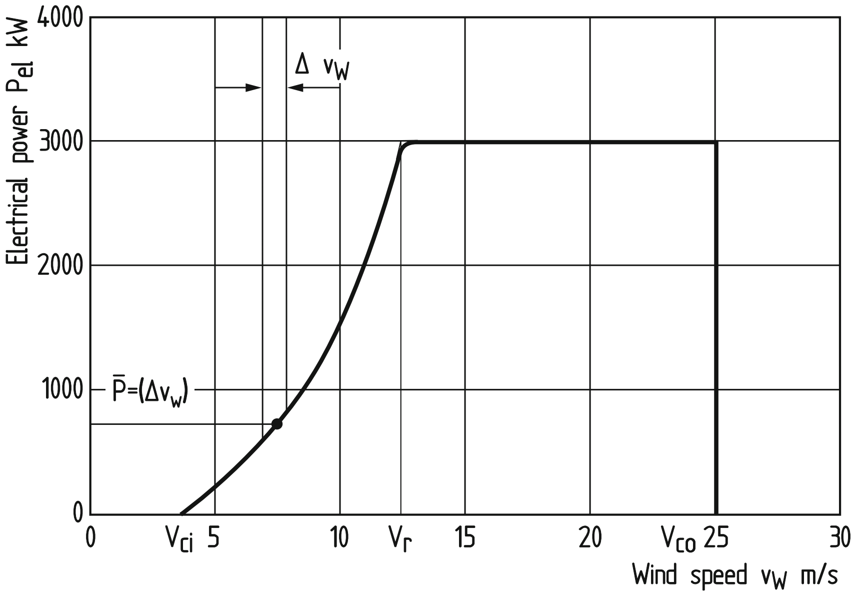


Fig. 14.26. Power curve of the wind turbine

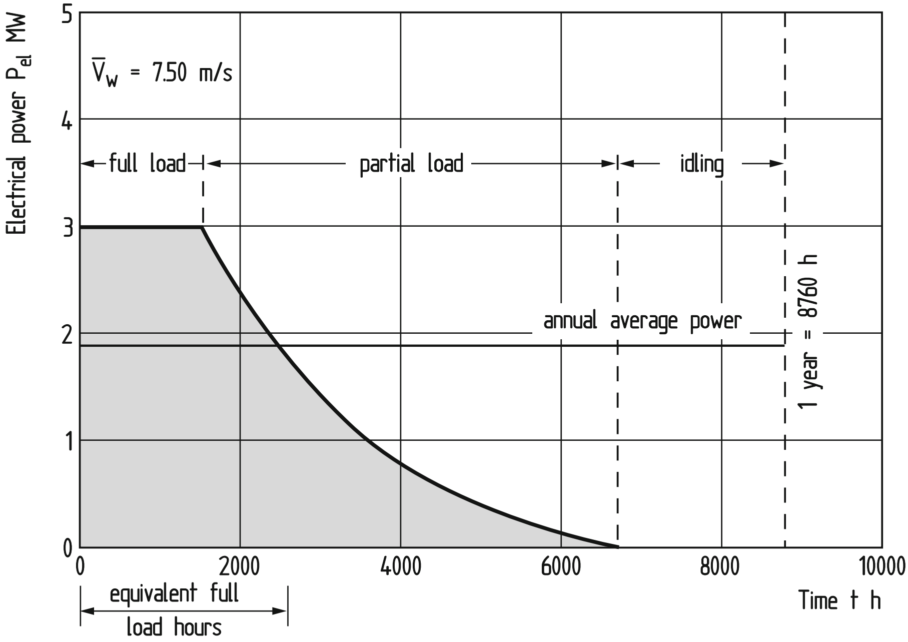


Fig. 14.27. Power duration curve and related technical terms

These are of importance especially in the case of calculated values. For this case, too, the IEC 61400-12 has several recommendations [3]:

- The performance of the wind turbine is represented by the "normalized and averaged power curve".
- One year is assumed to consist of 8760 hours.
- Unless other information is provided, the indicated annual energy yield assumes a technical availability of 100 % for the wind turbine.

The IEC recommends a reference wind regime for comparing the energy output of different wind turbines. This should be based on a range of annual wind speeds from 4 to 11 m/s at rotor hub height. The frequency distribution of the wind speeds should be assumed as a Weibull function with a shape parameter of $k = 2$ (Rayleigh distribution).

14.5.2 Approximate Calculation of the Energy Yield

In the planning phase of a wind turbine project, there is the frequent problem of having to estimate the energy yield without the possibility of a precise calculation. Often, only the turbine's rotor diameter and its rated power are known. Naturally, the mean annual wind speed of the site must also be known. If the wind turbine is a modern turbine with aerodynamically designed three-bladed rotor, the rotor power coefficients and the efficiencies of the mechanical-electrical energy conversion will differ only slightly. Therefore, a standard power coefficient can be assumed for the turbine.

Based on this assumption, the rated wind speed can be calculated from the rotor diameter and the installed rated generator power by means of an approximation formula:

$$v_R = \sqrt[3]{\frac{\pi}{\frac{\varrho}{2}\, c_{PR}}}$$

where:
π = ratio of rated power to rotor-swept area (W/m^2)
ϱ = air density (1.225 kg/m^3 at MSL)
c_{PR} = rotor power coefficient at rated power (approx. 0.45 for three-bladed rotors)

Figure 14.28 shows that, the relationship between the rated wind speed and the ratio of rated power to rotor-swept area can be calculated quite well using this approximation. This formula can also be used to answer the question of how much the rated wind speed increases when the installed generator power is raised.

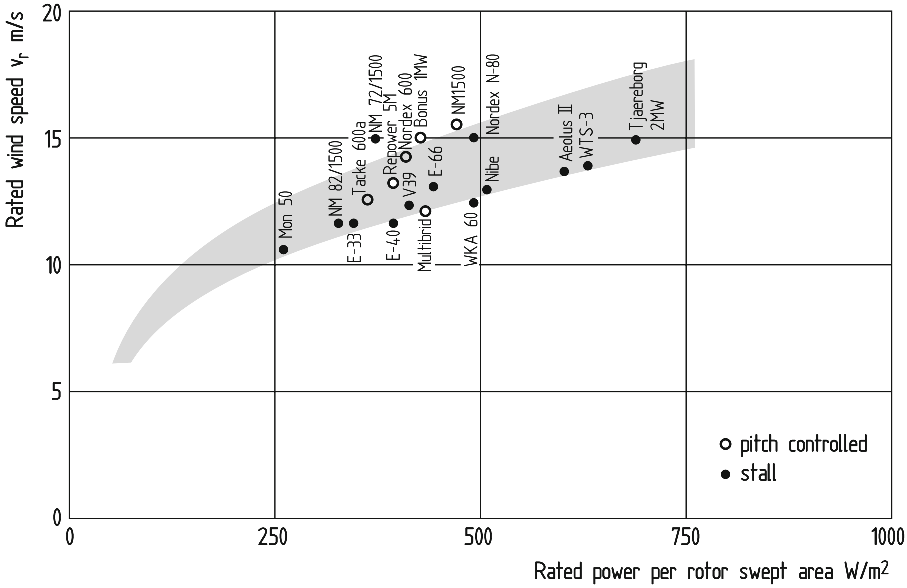


Fig. 14.28. Relationship between the rated wind speed and the ratio of rated power to rotor-swept area

The accuracy of the determination of the rated wind speed, and of the approximate determination of the energy yield, is not the same for stall-controlled turbines as for pitch-controlled turbines. At higher wind speeds, there is not necessarily a relationship between rated generator power and actually absorbed rotor power in stall-controlled turbines. In addition, many of these rotors are operated at a lower speed than that which produces optimum results with respect to energy yield. On the other hand, stall-controlled turbines in most cases have a higher ratio of rated power to rotor-swept area than turbines with blade pitch control so that the disadvantage of a non-optimal rotor speed is somewhat counteracted again. Using a slight amount of caution, therefore, diagrams 14.28 and 14.29 can be applied to turbines with fixed blade pitch angle. The energy yield to be expected can be determined approximately via the annual equivalent hours at full load Figure 14.29 shows the usage time versus mean annual wind speed at hub height with

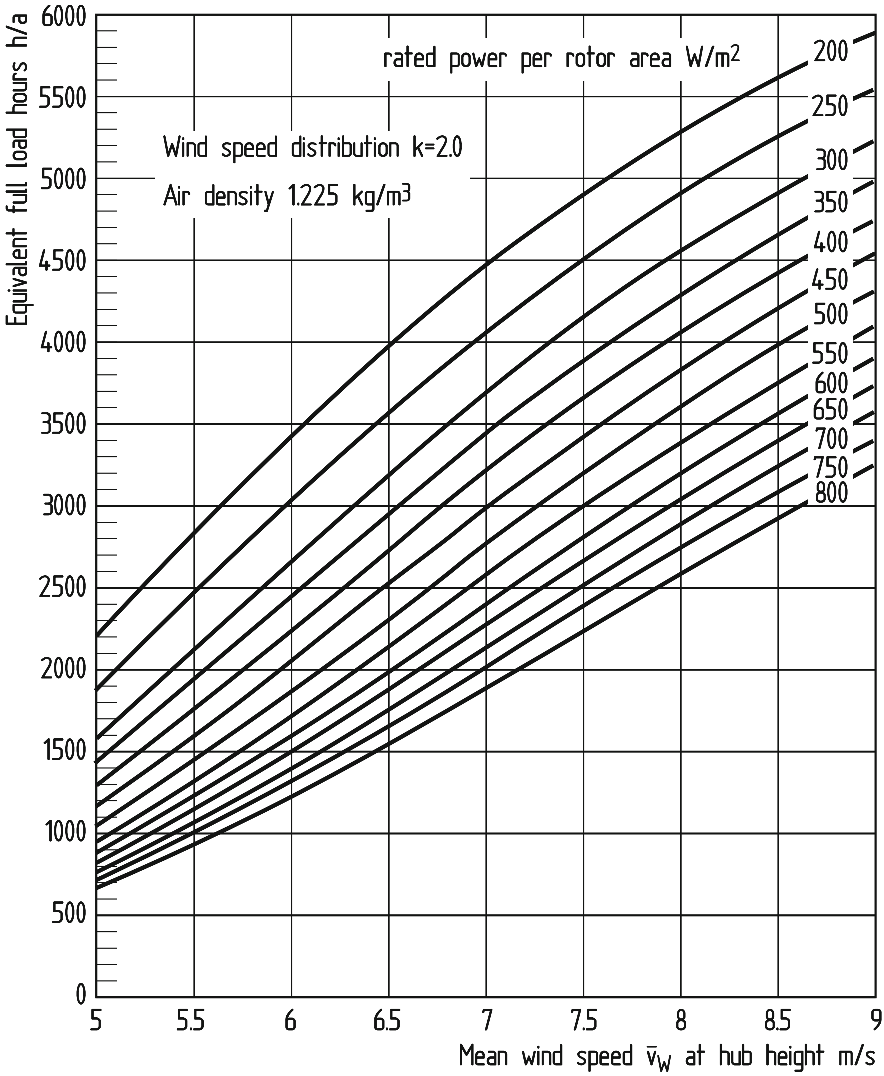


Fig. 14.29. Approximate calculation of the full-load hours of a wind turbine as a function of the mean annual wind speed and the rated power per rotor-swept area (assumed technical availability 100 %)

the parameter of rated power per rotor-swept area. Multiplying the indicated annual full-load hours by the rated power provides the annual energy output. It must be pointed out again that this rough calculation of the rated wind speed and the energy output is only suitable for wind turbines of standard concept and design (pitch-controlled and variable-speed operation). If the prevailing conditions differ from the average, an accurate calculation must be performed, taking into consideration all the turbine data.

As a very rough estimation for wind turbines which differ from the standard design it can be stated: The earlier Danish wind turbines with fixed blade pitch angle and comparatively low rotor speed, which in some cases is below the optimum speed with respect to energy yield, all achieved values which were lower by about 15 %. The more recent turbines with power limiting by aerodynamic stall are operated at approximately the aerodynamically optimum speed and thus largely avoid this loss in power.

A reduction of about 5 % must be taken into consideration for turbines with two-bladed rotors. Turbines with blade pitch control of the latest generation and with yield-optimized rotor aerodynamics (especially Enercon) achieve an energy yield which is 8 to 10 % higher than the average conditions specified in the diagram.

14.5.3 Technical Availability

In practical use, the highest possible energy yield is never achieved one hundred percent. Maintenance, but also unforeseen repairs, cause periods of inactivity which lead to a reduced annual energy yield. How closely the turbine approaches to the theoretically possible operation time or, in other words, the extent to which it is "available", is expressed by the term *technical availability*.

In the energy industry, the availability of a power plant is of vital significance. For this reason, the term of availability and the conditions implied by it have been defined very clearly [11]. Availability characterises a power plant's capability of generating energy or of performing any other operational function. Three different definitions of availability are used:

- Availability in time,
- Availability of power,
- Availability of energy.

The most important term used for thermal power plants is availability in time, as it can be defined and measured with the highest precision. It is directly linked to the system's technical reliability and low maintenance characteristics. In general, the published availability data always refer to temporal availability. For a thermal power station, the availability K_T is formed from the *available time* T_V and the *nominal time* T_N:

$$K_T = \frac{T_V}{T_N}$$

The nominal time is the overall contiguous observation period without any interruption (calendar time). In general, this is one year, corresponding to 8760 hours. The reference time is significant in as much as it is always easy to pretend high availability by using shorter periods of time. When comparing availability data, one should, therefore, ensure that the values indicated actually designate annual availability. The availability in time is the sum of the *operating time* T_B and the *stand-by time* T_R:

$$T_V = T_B + T_R$$

The operating time is the period of time during which the power plant generates usable energy, stand-by time is the period of time during which the turbine is ready for operation.

The following figures illustrate the availabilities of energy yield commonly achieved by conventional power stations. In 1986, the overall availability of fossil-fuel burning power stations in Germany amounted to 83 %. Different types of power stations produced the following figures [12]:

- Nuclear power stations	80 %
- Coal-fired power stations	88 %
- Hydroelectric power stations	ca. 76 %

The availability of a wind turbine is determined by two factors, the availability of the wind and the availability of the wind turbine itself. For this reason, the nominal time has occasionally only been calculated from those periods of time during which the wind speed was within the operating wind speed range of the turbine. This definition has proven to be impractical since it presupposes the existence of reliable wind speed measurements independent of the wind turbine. Today, the nominal time is customarily referred to the full calendar time also for wind turbines. The assured availability in the guarantee time is defined analogously to the definitions of terms in the power station industry. The times which are not counted as non-availability are the important factor in the contractual specifications:

- Recovery times for routine maintenance,
- Standstill times due to intervention by the operator or third parties (authorities),
- Standstill times due to external causes (grid outage, lightning strike, ice accumulation),
- Times with wind speeds below cut-in and above cut-out wind speed,
- "Trivial" standstill times for whatever reasons, e.g. of less than 5 hours per year.

Because of the difficulties to determine the relevant time periods for the operation of the wind turbines, more manufacturers prefer an energy based availability guarantee. In the overall warranty agreement which is part of the purchase agreement the conditions are described in detail. More or less sophisticated procedures are used for calculating the loss of energy yield in combination to a reference situation. In some cases the reference situation weights the non-availability with the wind speed distribution on the site. In this way the "liquidated damages", the manufacturer of the service provider has to pay to the customer, are very close to the real loss of income.

An important aspect of the definition of availability is the acquisition and documentation of the data in a way which is comprehensible to the operator. Experience has shown that, although the availability is precisely defined in the purchase or maintenance contract, operational data acquisition is quite frequently inadequate for calculating the actual availability achieved in accordance with the contractual agreements. On concluding a contract, a potential purchaser is well advised to have the corresponding data acquisition and documentation explained to him, and to obtain contractual assurances in this respect. It is especially in the initial years of operation, in which the guaranteed availability is frequently not achieved in its full extent because of technical retrofits, that it is a "matter of cash" for the operator.

What levels of availability can be expected from wind turbines today? In the initial years of the commercial utilisation of wind energy, the average availabilities achieved were still relatively modest (Fig. 14.30). However, the reliability of the turbines increased continuously. For the last ten years, availability values of 98 % and more have been achieved [13]. Thus, wind turbines are exhibiting extremely high availability values which bear comparison even with other power-generating plants.

When assessing the availability figures, the required maintenance effort must not be ignored. From an economic point of view, a technical availability of 98 %, achieved by servicing and maintenance costing, e.g. 20 or 30% of the income, is a disastrous result. A commercially viable situation requires an availability of about 98 % with annual maintenance costs of no more than 10 % of the income.

A statement about the overall availability of a wind turbine including the wind regime for a certain site is sometimes desirable from an economic point of view, regardless of the intermingling of technical and meteorological conditions. The term *capacity factor c* is commonly used to this end. It is defined using the mean power $\bar{P}$, which is output by the wind turbine yields in a calendar year, and the rated power P_r:

$$c = \frac{\bar{P}}{P_r}$$

or it is calculated from the annual energy yield:

$$c = \frac{annual\ energy\ yield\ (kWh)}{rated\ power\ (kW) \cdot 8760\ h}$$

The usage time or equivalent full-load hours mentioned above are calculated even more simply from the annual energy yield divided by the turbine's rated power

$$usage\ time = \frac{annual\ energy\ yield\ (kWh)}{rated\ power\ (kW)}$$

Both terms are somewhat problematic in that they can be manipulated by way of the installed rated generator power.

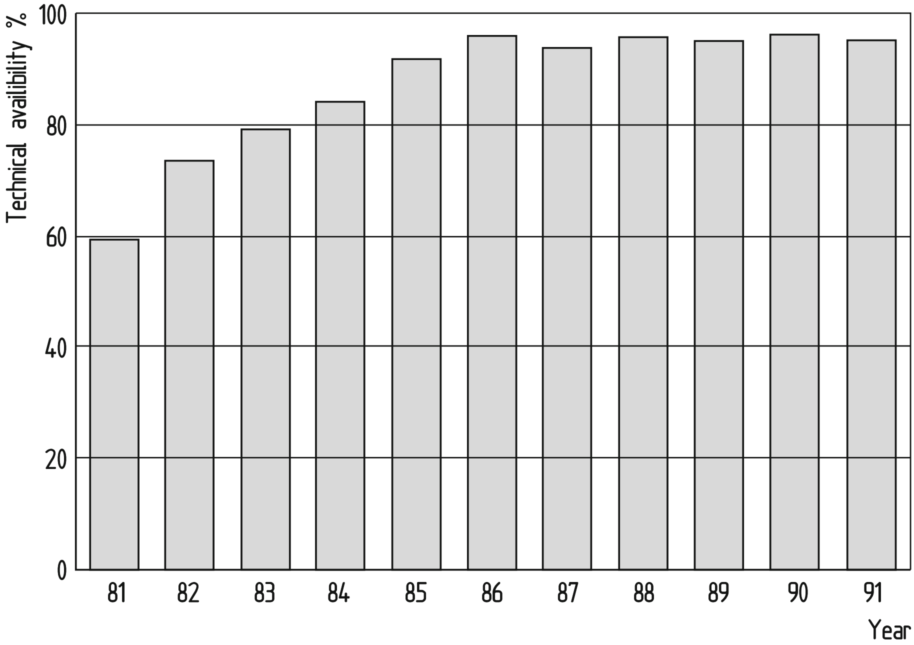


Fig. 14.30. Development of the technical availability of the Danish wind turbines over the last ten years [14]

A measure for assessing the capacity factor or usage time can be derived from two examples. At a good wind site with a mean annual wind speed of 6 m/s at 10 m height (German Bight), the following capacity factors can be achieved:

- Small turbine: 15 m rotor diameter, 55 kW rated power, rotor hub height 20 m,
  power per rotor-swept area 311 W/m^2,
  annual energy yield 120 000 kWh,
  capacity factor = 0.25,
  usage time = 2180 hours,

- Large turbine: 77 m rotor diameter, 1500 kW rated power, rotor hub height 80 m,
  power per rotor-swept area 322 W/m^2,
  annual energy yield 5 million kWh,
  capacity factor = 0.38,
  usage time = 3333 hours.

A comparison of the capacity factors and usage times of different wind turbines is only possible when the values of the ratio of rated power per rotor-swept area are approximately equal. Otherwise, the rated power must be converted to the same ratio per rotor-swept area. However, this method only makes sense in wind turbines of approximately the same size.

14.5.4 Safety Deductions for Economic Calculations

The calculated forecast for the energy yield to be expected is of great significance for the economic assessment of the "wind turbine at a certain site" investment project. The banks providing the finance and the investors, therefore, demand a certain "safety deduction" from the calculated annual energy yield. Neither can this demand be rejected off hand, keeping in mind the factors influencing the energy yield discussed in this chapter. Before arguing about the appropriateness of a safety deduction, however, one must visualize the background on which the forecast is based. According to experience, there are considerable differences involved. A generous safety deduction is visually attractive, but not worth very much if the forecast is already based on unsafe assumptions. A systematic check of the bases for the forecast should answer the following points and the associated questions:

Power curve of the wind turbine

The assumed power curve of the wind turbine should be based on a power curve conforming to IEC Standard, verified by independent institutions. In this connection, the following questions arise: Has the power curve been adapted to the standard conditions, for example with regard to the installed height above MSL? Has the power curve only been measured on a prototype or is it already "hardened" by a wider basis of experience from the operation of a number of units in practical use? Have safety margins been deduced already in the power curve (a procedure not normally used)?

Technical losses

Taking into consideration technical losses has nothing to do with safety deductions. It is necessary to consider the so-called “parking efficiency” in cases of wind park siting, and the electrical transmission losses to the grid which occur in every case.

Technical availability

The assumption of a realistic technical availability should also be included in the discussion of an appropriate safety deduction. As discussed in Chapter 14.5.4, wind turbines achieve high availability values today but values above 98 % should not be suggested.

Wind forecast

This field contains the greatest uncertainties. Several independent expert "wind assessments" are, therefore, generated for the larger investment projects. This raises the question whether a mean value should be used in the case of several different results or if the worst assessment is used for calculating profitability. An additional question is to what extent the "theoretical" assessments can be confirmed by empirical values, particularly from neighbouring wind turbines. In Germany, wind forecasts according to the WASP method are largely used (s.a. Chapt. 13.5.2). For the WASP-compliant calculation, an overall uncertainty range of ±10 % is specified. Assuming the energy yield value calculated without deduction lies within the limits of a uniformly distributed probability curve, it will be achieved with a probability of 50 % (often called "P50 value" (probability 50 %) in English literature). A positive or negative transgression is assumed to have equal probability in both directions.

Overall safety deduction

As discussed in Chapter 14.3, other energy losses may occur. Frequent yawing, hysteresis phenomena when cutting the wind turbine in and out, negative influences in the case of complex terrain, high turbulence on site, air density effects in summer and winter operation and soiling of the rotor blades in operation have already been mentioned. These losses are generally not quantified since they do not always occur. They must, therefore, be accounted for by an overall safety deduction from the calculated energy yield.

If all questions contained in the above-mentioned points can be answered positively, an additional overall safety deduction of 5 % is high enough to cover these unquantifiable losses which may possibly occur. In the case of an uncertain wind forecast or difficult siting conditions, a greater safety deduction, for example 10 %, may also be appropriate. If, however, the conditions are estimated to be extraordinarily uncertain, then the wind forecast and the siting conditions should be analysed in detail. There is little sense in covering over planning defects with ever-increasing overall safety deductions. Comprehensive and accurate planning must definitely be accorded priority, at least in the case of relatively large investment projects.

14.6 Wind Regime and Energy Yield

In almost every real case a certain doubt remains as to the reliability of the measured or assumed wind data. For this reason, one should recall the sensitivity of the expected energy output with respect to the wind data. The determining factors for the energy yield are: the mean annual wind speed, the frequency distribution of the wind speeds and the increase of wind speed with height. By far the most important parameter is the mean annual wind speed. Theoretically, the turbine's energy output increases with the third power of the mean wind speed. However, this only applies as long as the power capture of the rotor is not limited by the control system, i.e. only with partial load operation. The increase in the energy yield thus depends on the ratio partial-load to full-load, i.e. on the installed power per rotor-swept area, taking into account all operating modes, and is lower than the theoretically possible increase (Fig. 14.31).

The frequency distribution of the wind speeds has considerably less influence on the energy output. It changes with geographic location, topography, mean wind velocity and altitude (Fig. 13.32). The shape factor k determines the shape of the distribution curve, whereas A depends on the mean wind velocity (see Chapt. 13).

With respect to the topographic and/or geographic dependence, the bandwidth extends from e.g. about $k = 1.5$ on the Aegean islands up to a value of $k = 2.5$ for typical

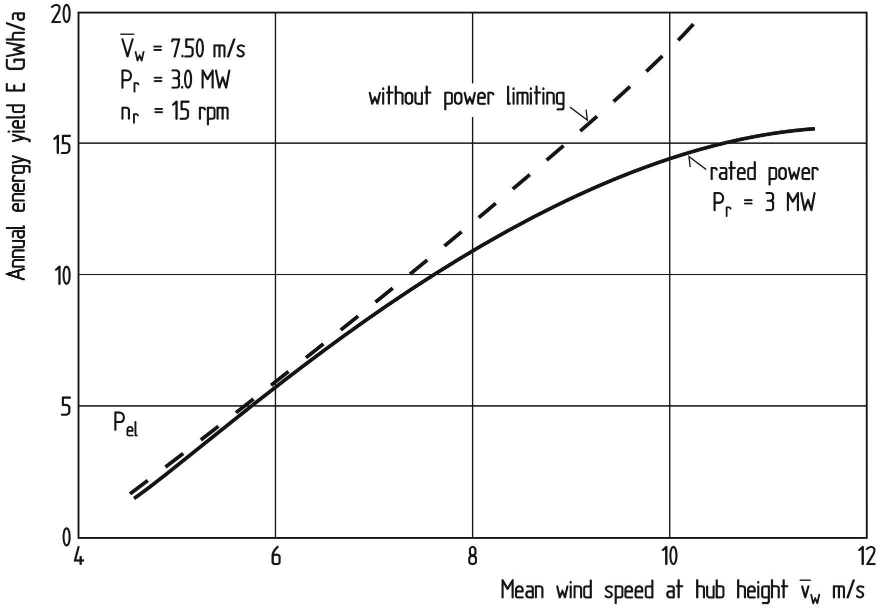


Fig. 14.31. Increase in the annual energy yield with increasing mean annual wind speed, for a wind turbine with 100 m rotor diameter and rated power of 3MW

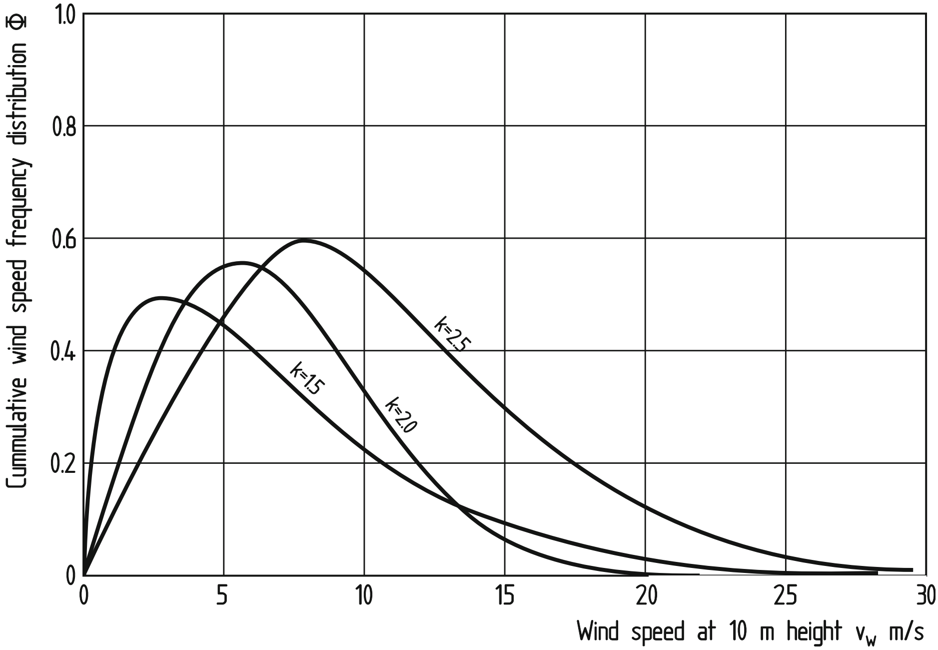


Fig. 14.32. Frequency distribution of wind speed for typical sites

inland sites with great surface roughness and moderate mean wind velocity. A factor of k = 2.0 (Rayleigh distribution) reproduces the conditions at the coastal sites in good approximation. The k-factor generally increases with height, also because of the increasing wind speed. The energy yield of a wind turbine various with different shape factors for a given annual wind speed (Fig. 14.33).

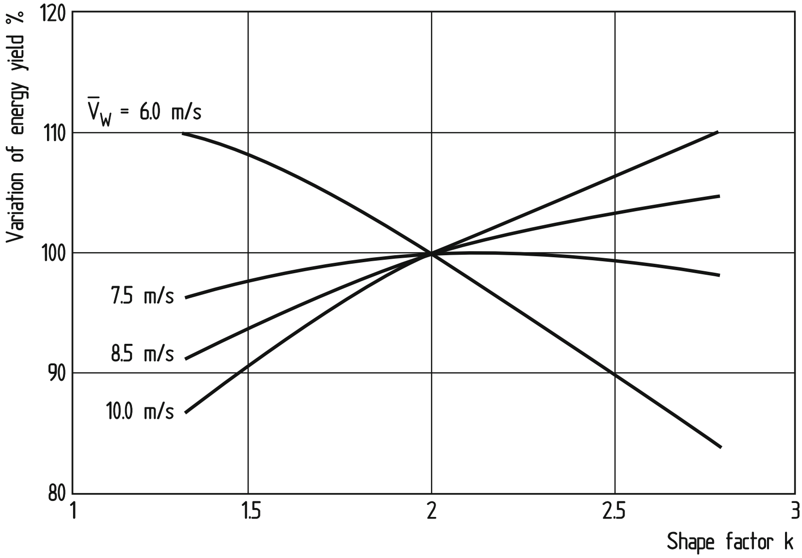


Fig. 14.33. Variation of the energy yield for different shape factors of the frequency distribution at a given annual wind speed

14.7 Major Design Features and Energy Yield

At the design stage and also when planning for the application of a wind turbine, questions continuously arise as to what extent certain technical features will affect the power curve and the energy yield. The operator should develop a feeling for the quantitative significance of these parameters even without the aid of a computer. This assessment is important to the user not only in his search for a suitable site, but also with regard to a possible adaptation of some of the turbine's technical parameters. For instance, the installed generator power or the tower height can be varied within certain limits.

It should be recalled that with turbines with blade pitch control, the efficiency parameters affect the energy output only under partial load. Above the rated wind speed, the power is limited anyway. This means that, the greater the partial load range of the turbine, that is, the higher the installed generator power per rotor-swept area, the greater the influence on the energy output by any measures effecting improvements or degradations. This applies only to a limited extent to turbines the power capture of which is controlled by aerodynamic stall. There is no clear-cut dividing line between partial and full load in these turbines. The rotor's aerodynamic properties or certain site-related factors also have an effect on the maximum power output.

The next chapters show the influence of the most important parameters on the energy yield by means of a parameter study performed using the former mentioned example of a 3 MW wind turbine with a rotor diameter of 100 m. The underlying wind regime has an annual wind speed of 7.5 m/s at hub height and a wind speed frequency distribution of $k = 2.0$.

14.7.1 Rotor Power Coefficient

The aerodynamic design of the rotor of a wind turbine poses the problem of having to estimate the economic effects of altered aerodynamic performance data. This concerns, for example, the choice of rotor blade airfoils, the number of blades and other aerodynamically significant characteristics of the rotor. The effects become apparent in the rotor power coefficient or, more precisely, in the variation of the c_{PR}-lines in the set of rotor power characteristics. In a slightly simplified way, the maximum rotor power coefficient achieved can be used as a criterion (Chapt 5.5). From the point of view of the operator of a wind turbine, the question arises of how much a better power coefficient is "worth" from economic angles of view.

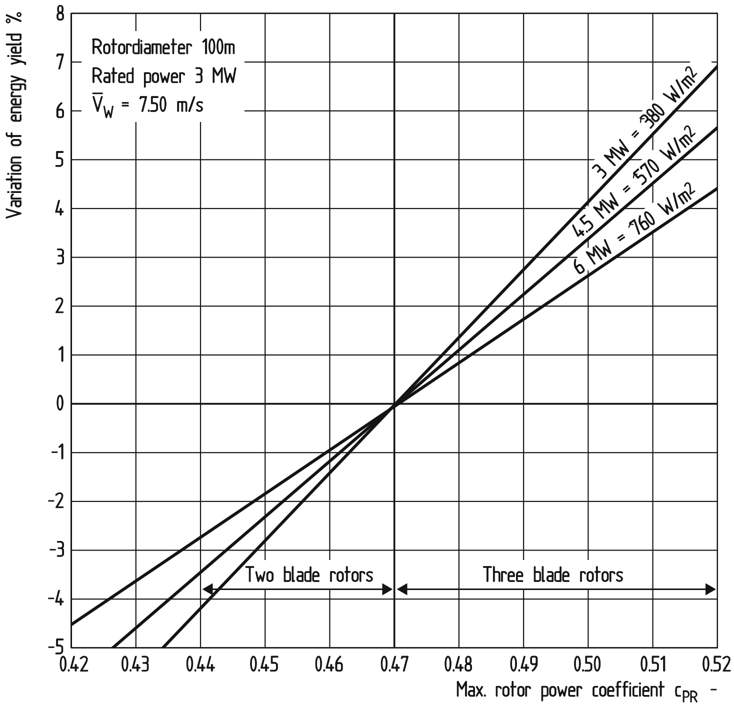


Fig. 14.34. Influence of the maximum rotor power coefficient on the energy yield

The effects of a change in the rotor power coefficient on the energy output also depend on the wind data of the site and on the installed generator power. The greater the partial-load range of the turbine, the more noticeable will be the effect on the energy yield. The aerodynamic quality of the rotor has a decisive influence especially in conditions of low wind speeds. Figure 14.34 shows the influence of the maximum rotor power coefficient on the energy yield.

14.7.2 Rotor Diameter

When discussing the relationship between rotor diameter, power curve and energy output, it should not be mistakenly assumed that the rotor diameter is a "variable parameter" of a wind turbine. The rotor size is tantamount to the size of the wind turbine, with all what that means with regard to loads and manufacturing costs (Chapt. 19.4). The conclusion "We'll just give the rotor diameter another few meters", when attempts are made to compensate for the poor performance of a certain configuration, is wrong. The real task is to achieve a technical and economic optimum performance for a given wind turbine size. The trend to increase the rotor diameter of existing turbines, which can frequently be observed in practice, is also not proof of the contrary. At best, the "rest" of the wind turbine with the smaller rotor had not been exploited to its full economic potential, at worst the turbine with the larger rotor will be overloaded, at the cost of reliability and operating life.

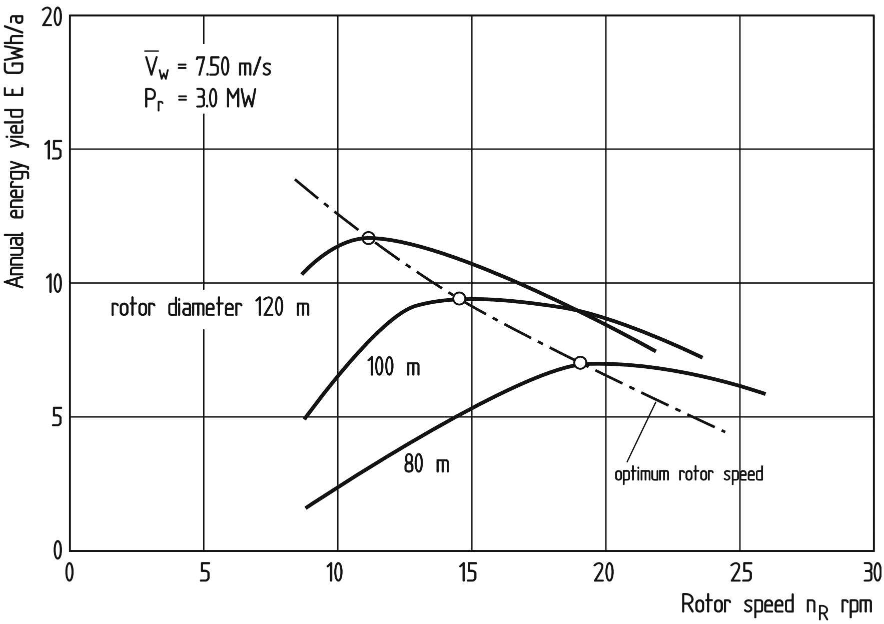


Fig. 14.35. Optimum rotor speed for different rotor diameters

Regardless of these fundamental considerations, some manufacturers offer their wind turbines with rotors of varying diameters. In nearly all cases the variants having a larger rotor diameter are only suitable for a lower level of loading, i.e. they are licensed only for a lower wind turbine (Chapt. 6.8).

A change in rotor diameter has a considerable influence on the aerodynamically optimum rotor speed and it is, therefore, scarcely possible to change the rotor diameter without at the same time changing the rotor speed, i.e. the gear transmission ratio (Fig. 14.35).

Theoretically, the energy yield increases proportionally to the rotor swept area, i.e. with the square of the rotor diameter, with an increase in diameter. But above the rated power, where the power output is limited by the control system, there is no increase in the energy yield. A significant gain in energy yield is only achieved with a simultaneous increase in rated generator power, that means to maintain the installed power per rotor swept area on the same level for example 450 W/m².

Figure 14.36 shows the real increase for the calculated example. It can be seen that in this case, a significant gain in energy yield is only achieved with a simultaneous increase in the rated generator power and the appropriate rotor speed.

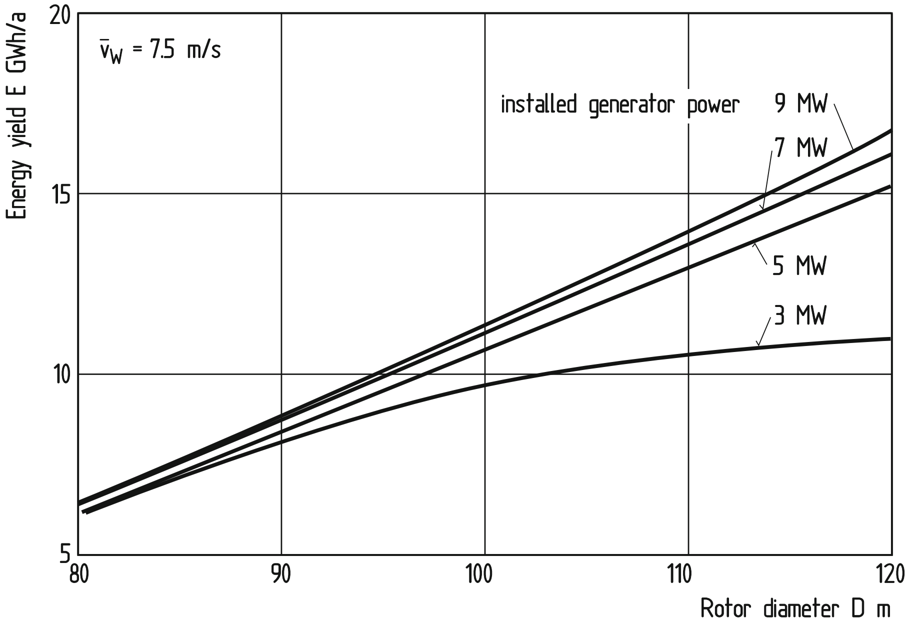


Fig. 14.36. Annual energy yield in dependence on rotor diameter and the installed generator power

14.7.3 Optimal Rotor Speed and Variable Rotor Speed Operation

The significance of the selected rotor speed with respect to the energy output has already become apparent in the preceding discussions. The fact that the energetically optimal rotor speed is dependent on the wind regime should not lead to the conclusion that the rotor speed can thus be modified for any site. The technical complexity of such a modification, for example changing the gearbox, would be too high. Using the above example, Figure 14.37 shows the extent to which sites with different mean wind speeds influence the optimal rotor speed.

The peaks are located in very flat sections of the power curves so that even considerable deviations from the optimal speed do not change the energy yield dramatically. In practical designs, therefore, the wind data of a representative site which are typical of a large number of sites considered will be used as a basis. It is worth changing the nominal rotor speed only if there are considerable variations in the wind regimes. This would then be carried out simultaneously with an adaptation of the installed generator power.

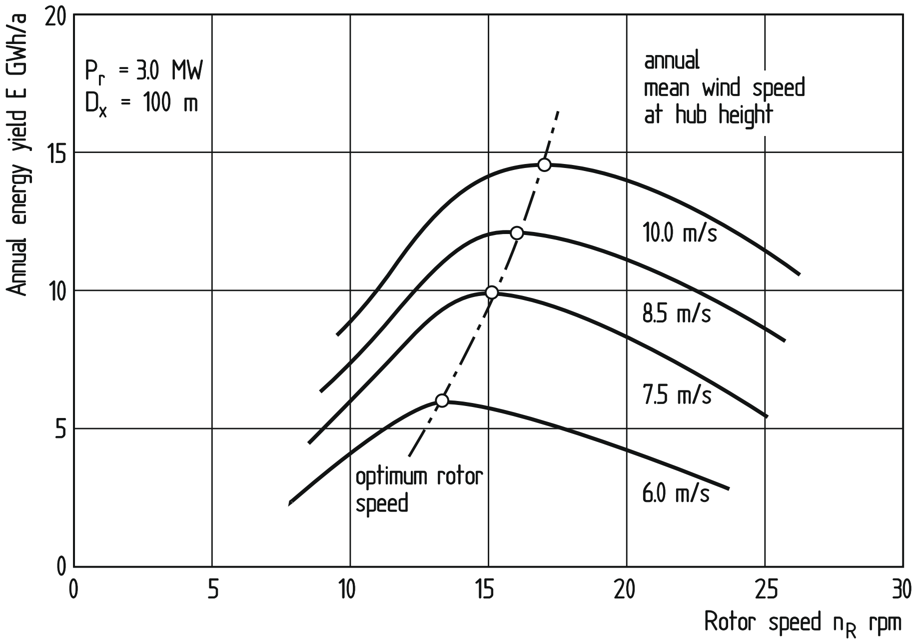


Fig. 14.37. Influence of the mean annual wind speed on the optimal rotor speed

One fundamental question that keeps recurring is: Is it worthwhile, from an energy output point of view, to have a variable rotor speed? The range of speed variation must be considerable to permit effective wind-oriented operation. It should cover the complete partial-load range, from cut-in to rated wind speed. For common values of the rated power per rotor-swept area, this means a speed range from approximately 40 to 100 %. Depending on the wind turbine characteristics and the wind regime, the achievable increase in energy output ranges from 3 to 5 % (Figs. 14.38 and 14.39). This may be not high enough to more than compensate for the added costs of a generator system with frequency inverter. However, the advantages of variable speed rotor operation are not restricted to the gain in energy output alone. Reduced dynamic loads on the mechanical components, a reduced aerodynamic noise during partial-load operation and a smoother power output may possibly count for more than the modest increase in energy yield. Instead of a continuous speed variation, some smaller wind turbines have two generators which permit speed stepping. Numerous earlier Danish turbines made use of this possibility (s. Chapt. 9). Two fixed rotor speeds provide almost the same energetic yield as

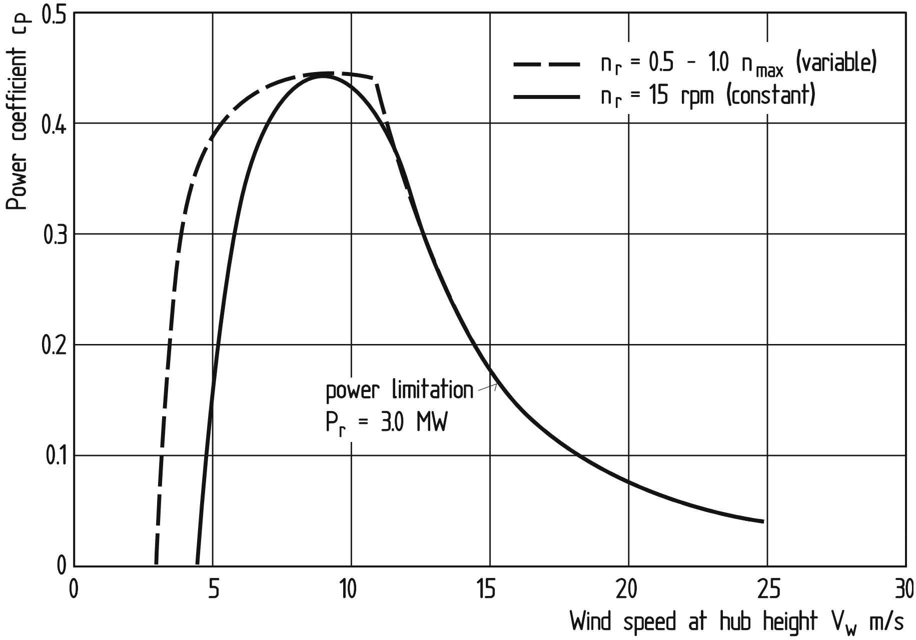


Fig. 14.38. Power variable speed and constant speed operation

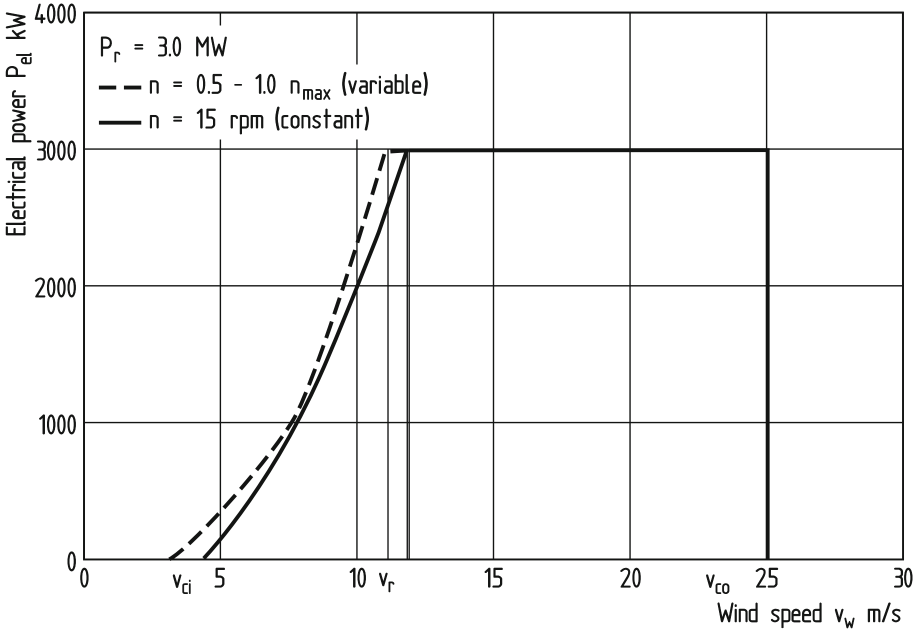


Fig. 14.39. Influence of variable speed operation on the power curve.

continuous speed variation. On the other hand, this concept does not bring about a reduction in the dynamic loading or a smoothing of the power output as these turbines are operated with two "fixed" speeds on the grid.

14.7.4 Power Control: Blade Pitch Contra Stall

A frequent question with regard to wind turbines without blade pitch control is whether blade pitch control has advantages compared with stall-controlled turbines with respect to energy yield. There is no generally applicable answer to this question since both methods have positive and negative features in this respect.

Rotors with a fixed blade pitch angle have the same disadvantage in the partial-load range and are not operated at the energetically optimal rotor speed. Mainly in older wind turbines, a lower operating speed is often chosen in order to bring about the aerodynamic stall at the desired wind speed. The associated energy loss in old designs amounted to up to 20 % of the aerodynamically possible optimum. For safety reasons, the aerodynamic flow separation in some cases sets in at such low wind speeds that power output also suffered in the full-load range. On the other hand, the generally high ratio of rated power to rotor-swept area and the fact that there were no losses at low wind speeds due to inferior pitch control systems, were positive factors with regard to the energy output.

Wind turbines with blade pitch control have the advantage that they can be operated at the aerodynamically optimal rotor speed. On the other hand, the strict limitation of the power capture to the given rated power entails a loss of energy, depending on the wind regime. The pitch-controlled wind turbines are frequently designed with a relatively low ratio of rated power to rotor-swept area for structural strength reasons. Moreover, the power control system does not always operate optimally all the time, particularly in small turbines. Especially at low wind speeds, some turbines tend to operate with undesirably frequent start-up and shut-down sequences. Apart from the mechanical wear and tear, this also involves a degree of power loss.

Blade pitch-controlled turbines cannot always be operated at their optimum in the partial-load range. The usual method of operating with a constant blade pitch angle at partial load results in a certain loss of power and energy output. Depending on the aerodynamic design, this loss amounts to approximately 1 to 3 % of the annual energy yield. More advanced control methods, therefore, attempt to operate with an optimum pitch angle adapted to the wind speed at partial load (adaptive control).

It is these characteristics which in each real individual case decide whether blade pitch control or stall control is advantageous with respect to the energy output. Generally, given an optimal design and operational framework and the provision of a high enough rated generator power for the prevailing wind regime, blade pitch control provides better preconditions for full exploitation of the energy potential.

The more recent wind turbines with blade pitch control are nowadays operated almost exclusively with variable speed. Variable-speed turbines achieve a higher energy yield than stall-controlled turbines in every case. For this reason, the comparison between blade pitch control and power control by stall on the basis of a fixed rotor speed is actually no longer relevant.

14.7.5 Installed Generator Power

Although the rated power of the installed generator is not the decisive parameter of the output capacity of a wind turbine, it is, nevertheless, not without significance for the energy output. The installed generator power per rotor-swept area is, therefore, frequently the subject of controversial discussions. As no theoretical optimum can be calculated, opinions differ widely (Fig. 14.40).

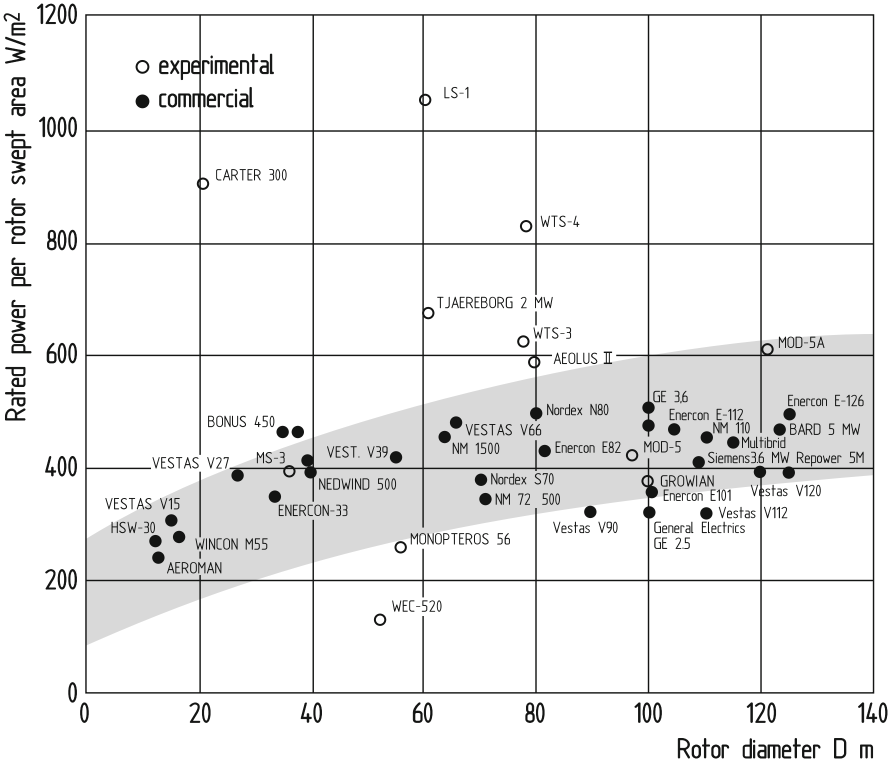


Fig. 14.40. Ratio of rated power per rotor-swept area of existing wind turbines

There are several explanations for the highly differing values obtained for installed generator power per rotor-swept area: One essential reason is to be found in the wind regime on which the wind turbine's design is based. Higher mean wind speeds justify a higher specific power output density if the theoretical optimum is to be exploited as much as possible. This is also the reason why larger turbines normally have a higher ratio. The usable mean annual wind speed increases with increasing hub height in accordance with the vertical wind shear. Furthermore, the type of rotor power control also plays a role.

Stall-controlled turbines must be installed with a relatively high value of installed power to rotor area so that the electrical generator torque is high enough to "hold" the turbine in grid operation even during strong wind gusts (Chapt. 5.3.2).

The only factor speaking against a high rated power is basically the increasing load level with increasing rated power. However, this influence is very difficult to assess. It is undisputed that the load on the turbine increases with increasing generator power or increasing generator torque but it is hardly possible to make any generally valid statements as to what extent this is the case and which influence this has on the costs of the turbine.

The turbine's technical concept plays a certain role. A stiff and heavy concept, the dimensioning of which is largely determined by the components' natural weight, reacts much less sensitively to a high rated power level than does a lightweight construction. For this reason, high ratios of rated power to rotor area can be found mainly in the older heavily-built wind turbines of the "Danish line", whereas lightweight turbines are very restrained with respect to installed generator power.

From the aerodynamic point of view, the maximum possible theoretical energy output is obtained with an "infinitely" high generator power. In practice, however, the poorer electrical efficiency at partial load operation increasingly leads to a decreasing energy yield when the ratio of rated power to rotor area becomes very high.

For a weaker wind site with a mean wind velocity of 6 m/s at rotor hub height, about 90 % of the theoretically possible value is exploited with a specific power output per unit area of 300 W/m² (Fig. 14.41).

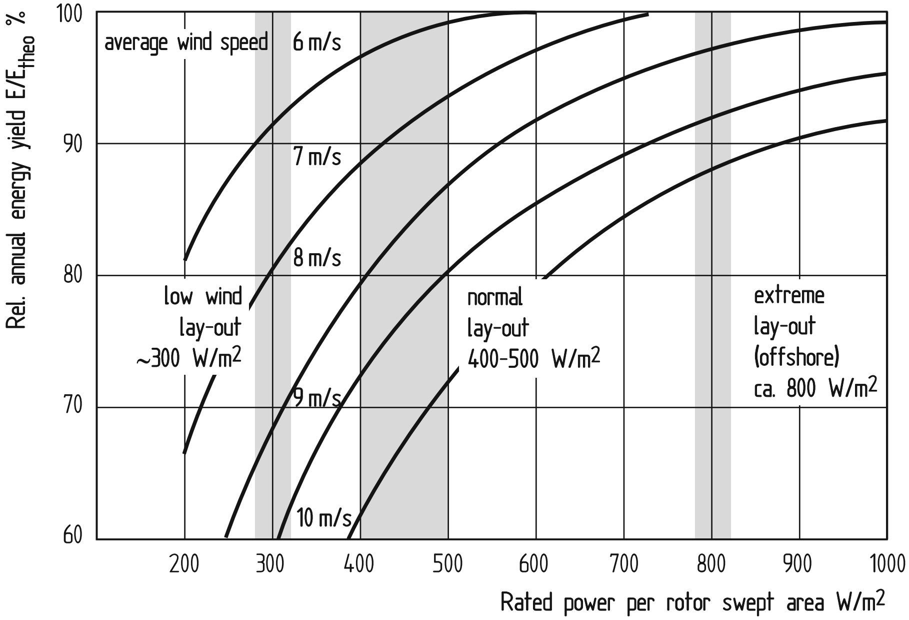


Fig. 14.41. Exploitation of the theoretically possible energy yield with a given mean wind velocity by limiting the specific power per unit area (rated generator power referred to the rotor-swept area)

With a rotor diameter of 77 m, this corresponds to a rated generator power of about 1500 kW or to an installed power of approx. 2000 kW with a 90 m rotor.

A site with stronger wind, with a mean wind velocity of about 7 m/s requires a specific power output per unit area of 400 to 450 W/m^2 in order to exploit about 90 % of the potential. In the offshore area, mean wind velocities of up to 10 m/s are achieved at rotor hub height. Under these extreme conditions, the specific power output per unit area should be between 800 and 900 W/m^2 which would mean a generator power of about 10 MW for a turbine with a rotor diameter of 125 m. Current prototypes in this class are not installed at such a level but it can be expected that the development will head in this direction as increasing experience is gained.

14.7.6 Rotor Hub Height

Within certain limits, a wind turbine's tower height, even more than the installed generator power, is available for adaptation to various site requirements. If the tower meets the stiffness requirements with regard to the vibrational behaviour, its height can be adapted to the conditions prevailing at the site. The economic tower height depends on the local shear-wind profile. In general, offshore sites and land sites close to the coast differ from typical inland sites. The increase in wind speed with height is higher at inland locations because of the greater roughness of the ground. Under these conditions, high towers are more effective on inland sites than near the coast. The tower heights of 100 m or more, which have been achieved for some years, are a decisive prerequisite for the economic utilisation of wind energy in inland areas (Fig. 14.42).

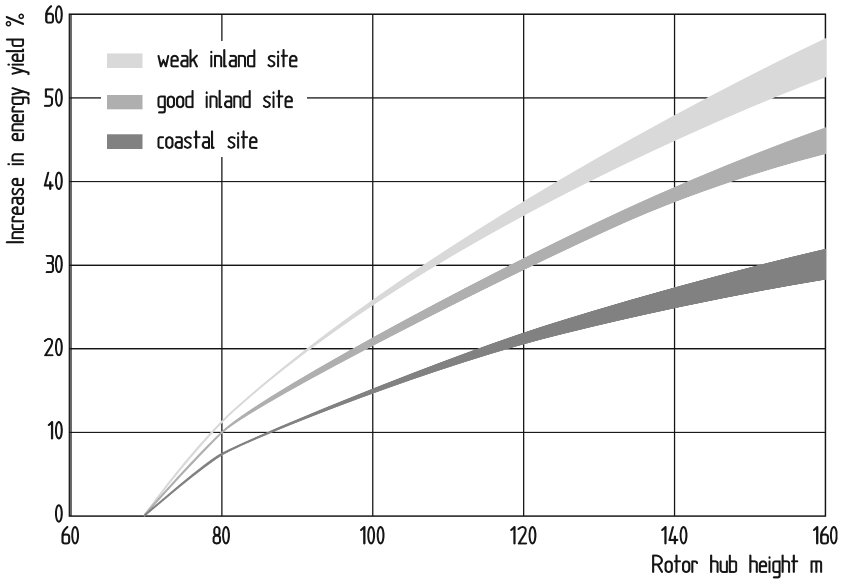


Fig. 14.42. Energy yield at different rotor hub height (tower height) for a coastal site and for an inland site

Determining the optimum tower height requires quantitative knowledge of the relationship between the additional cost for the increase in tower height and the additional gain in energy yield (s.a. Chapt. 12.8). Whilst the tower costs can be determined relatively accurately, calculating the additional gain in energy yield is much more difficult and inaccurate. It is related to the site and, moreover, accompanied by considerable uncertainty when the rotor hub height exceeds about 100 m.

14.7.7 Operational Wind Speed Range

The cut-in and cut-out wind speeds of a wind turbine are, to a certain extent, arbitrary choices. The cut-in speed does have a lower limit due to the power required for overcoming the friction losses in the drive train. It can, however, be given a certain tolerance at the top for operational reasons, i.e. to avoid an excessive number of start-up and shut-down operations during periods of low wind speeds.

At very high wind speeds, between about 20 and 25 m/s, the turbine's operation under load is stopped for safety reasons. With regard to the energy yield, it is of no consequence whether the rotor is braked into a parked position or whether it continues to rotate without load. There is no generally valid criterion indicating at what wind speed the turbine should be shut down.

Against this background, the question needs to be asked in what way a restricted operational wind speed range would affect the energy yield. Figure 14.43 shows the effect of a deviation of the cut-in and cut-out speeds from the specified "nominal values" on the annual energy yield. Both the relatively low energy content of the low wind speeds and the infrequency of high wind speeds are reasons why the influence of the operational wind speed range on the energy yield is not too great, as long as the variations remain within reasonable limits. It should be noted that the wind turbine's sequence control criteria can cause a hysteresis in the cut-in and cut-out behaviour. The cut-out hysteresis, in particular, can reduce the production time on the grid. A certain energy loss due to this effect cannot be avoided.

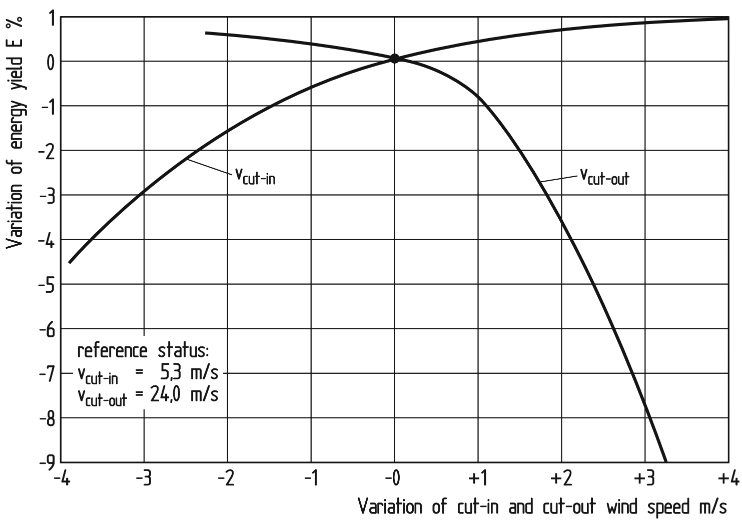


Fig. 14.43. Influence of the operational wind speed range on the annual energy yield

14.7.8 Efficiency of a Wind Turbine as Energy Converter

The significance of the various parameters relating to the energy yield of a wind turbine becomes especially clear to understand, as well as appealing, when a comprehensive balanced overview is considered. The graph shown in Figure 14.44 is intended to serve this purpose.

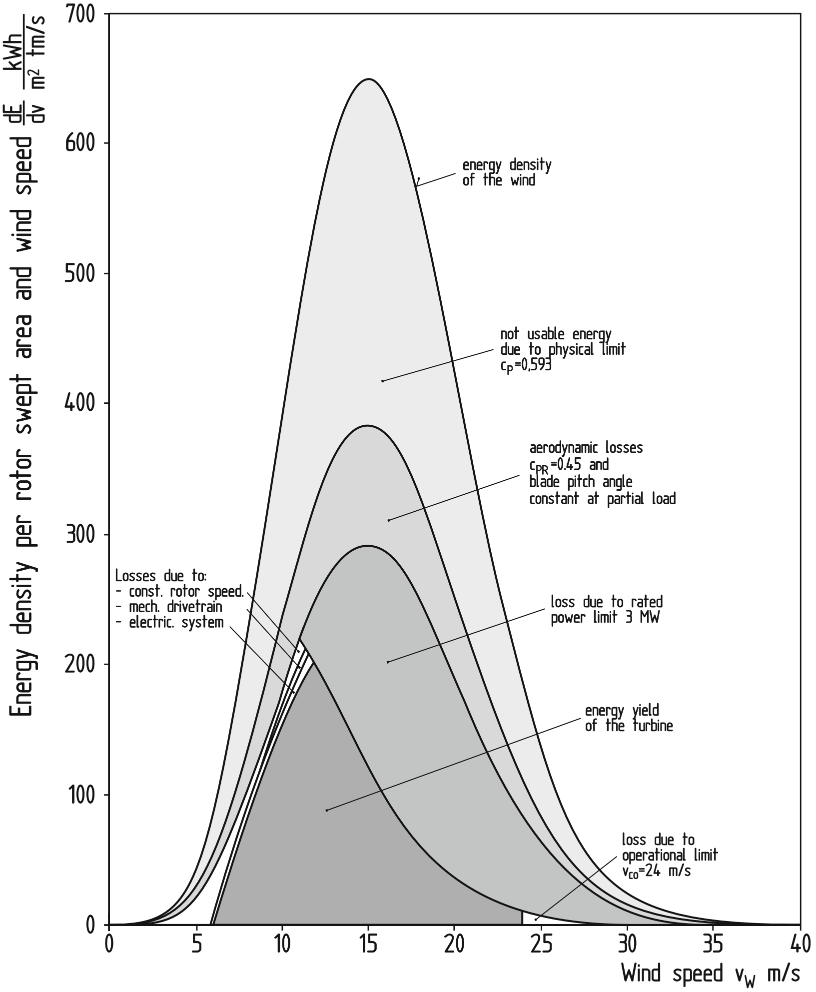


Fig. 14.44. The wind turbine as energy converter

In this diagram, the energy content related to the rotor-swept area is plotted against the wind speeds of a basic frequency distribution of wind speeds. Based on the kinetic energy content of the wind speeds and their proportion of the annual energy yield, the first sectional area represents the non-usable wind energy due to the physical principle of wind energy conversion into mechanical energy. This loss cannot be avoided.

The second portion shows the aerodynamic losses of a real wind rotor compared to the ideal wind energy converter according to the impulse theory (Betz). These losses have technical reasons and are an indication of the rotor's aerodynamic quality. A remarkably large share of the loss of the possible energy yield is indicated by the third section, which is caused by limiting the rotor's power capture to the installed rated generator power. It must be noted here, however, that in this example the specific power output per rotor-swept area of 380 W/m^2 was relatively low for such a large turbine. The rest of the losses due to mechanical and electrical efficiencies and due to the limited operational wind speed range appears to be very small but it must be taken into consideration that they should be related to the small range of usable energy and thus gain in significance.

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