Erich Hau

Wind Turbines

Fundamentals, Technologies, Application, Economics

2nd edition

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With 552 Figures and 41 Tables

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Foreword to the Second English Edition

Twenty-five years have passed since I began work on the first edition of this book. In this period, the utilisation of wind turbines has undergone an upsurge which one could only dream of then but was never predicted. It is not only the number of electricity-generating wind turbines which are in existence now but also the advance of them into new fields of application, such as off-shore installation, which bears witness to this development. Starting out from a wide variety of ideas and different concepts, the technology of wind turbines has now become focussed on a few practicable solutions. This standardisation process has provided the foundation for being able to produce turbines efficiently and in large numbers and has made it possible to build up an industry which has created a considerable number of new jobs orientated towards the future.

However, due to their very success, the utilisation of wind turbines is now encountering problems in some areas and the conflict in aims which exists between global protection of the environment and opposition by conservationalists arising from the increase in numbers of installed wind turbines can no longer be denied. Against this background, careful project planning and finding new regions for installing wind turbines is of the utmost importance for any further development. In this second English edition of my book, which is based on the third edition in German, I have attempted to take account of this development or rather to keep up with it.

These general remarks about the present state of wind energy utilisation apart, I will refrain from commenting further on the energy and environmental crises. However, I do feel that some helpful hints on what this book is about will not be misplaced.

The title *wind turbine* refers to industrially developed and manufactured machines for generating electrical power. Those looking for a do-it-yourself manual for putting together a windwheel, as interesting a hobby as this may be, will, therefore, be disappointed. Instead, this book is intended to give a general overview of modern wind turbine technology and to provide a means of orientation in the associated technical and economic fields and its contents and form of representation are structured with this objective in mind. Apart from the initial chapters, which deal with the history and physical and technical principles of wind turbines, all subsequent chapters have been extensively revised and in some cases considerably extended. An important new chapter has been added which deals with off-shore wind energy utilisation. Overall, however, the basic structure of the original book has been retained in its successful earlier format.

I have tried to analyse and to describe the problems involved and their technical solutions phenomenologically and to avoid mathematical equations as much as possible.

Equations have been included only where a presentation of fundamental principles was deemed to serve a better understanding but for those interested, I have indicated relevant literature at the end of each chapter, which would provide the first steps to the mathematical treatment of the problems described. Those who are responsible for decisions about investments or steer the technical and scientific work do not commonly sit at the computer themselves. However, they must have a clear picture of the state of the art, what technical options are available and what lessons are to be learnt.

A book of this scope which touches on a variety of special disciplines cannot be written without assistance. I must, therefore, thank the many people who have helped me along the way and without whose contributions the book could not have been completed. Primarily, I am very much obliged to my former colleagues at M.A.N. and, above all, to my friend and colleague of many years, Gerald Huß, who supported me very much in the first phase of the work, as early as 1980.

Finally, I also wish to thank all those who have assisted me in my work on these recent editions. In particular, I am indebted to Horst von Renouard in London who translated this second edition and who has also contributed to the clarity of the text and its presentation with numerous suggestions. This also applies to Dr. Hilmar Schlegel who was responsible for the typesetting and composition of the final book. As before, Tanja Rüth again edited the diagrams for this present edition, and Petra Schemmerer and Martin Loderer supported me in many ways in writing the text and selecting the photos.

Last, but not least, I owe thanks to my publishers Springer Verlag for publishing this voluminous book in its second edition.

Munich, April 2005 Erich Hau

Contents

Frequently used Symbols

D	rotor diameter (m)
R	rotor radius (m)
A	rotor swept area (m^2)
H	height (hub height) (m)
Φ	wind speed frequency distribution (%)
A	scale parameter (wind speed distribution) (m/s)
k	form (shape) parameter (wind speed distribution) (—)
σ_o	turbulence intensity (%)
α	wind shear exponent (—)
p	air pressure (mbar)
t	temperature (°C)
ϱ	air density (kg/m^3)
ν	kinematic air viscosity (m^2/s)
v_w	wind speed (m/s)
$\bar{v}_w$	mean (annual) wind speed (m/s)
v_e	extreme wind speed (m/s)
$v_{(e),ref}$	(extreme) reference wind speed (m/s)
v_g	gust wind speed (m/s)
v_{CI}	cut-in wind speed (m/s)
v_{CO}	cut-out wind speed (m/s)
v_{wR}	rated wind speed (m/s)
v_{res}	relative flow velocity (m/s)
n	rotor speed (rpm)
ω	angular velocity (deg/s)
r	local rotor radius (m)
$r \cdot \omega$	local tangential velocity (m/s)
α	angle of attack (deg)
ϑ	blade pitch angle (deg)
λ	tip-speed ratio
c	rotor blade chord length (m)
L	aerodynamic lift (N)
D	aerodynamic drag (N)
M_T	aerodynamic torsional moment (Nm)
T	thrust (force) (N)

Q	torque (Nm)
P	power (W)
$c_{P\,R}$	rotor power coefficient (—)
c_P	turbine power coefficient (—)
c_L	lift coefficient (—)
$c_{L\,D}$	design lift coefficient (—)
c_D	drag coefficient (—)
c_Q	rotor torque coefficient (—)
c_T	rotor thrust coefficient (—)
c_M	coefficient of aerodynamic torsional moment (rotor blade) (—)
ψ	azimuth angle (of rotation) (deg)
f	frequency (Hz)
U	voltage (V)
R	resistance (electrical) (Ω)
I	current intensity (A)
φ	phase angle (deg)
n_{syn}	synchronous speed (rpm)
n_{mech}	mechanical speed (rpm)
s	slip (electrical) (—)
η	efficiency (electrical, mechanical) (%)
a	year
E	annual energy yield (kWh/a)

Chapter 1

Windmills and Windwheels

The utilisation of wind energy is not a new technology but draws on the rediscovery of a long tradition of wind power technology. It is no longer possible now to tell from the remainders of historical "wind power plants" just how important a role wind power played in the past. The triumphal spread of the cheap coal and oil fuels and of easy energy distribution in the form of electricity was so complete that the losers, windmills and windwheels, could only survive in economic niches of little importance. Today, while energy production based on the burning of coal and oil or on the splitting of the uranium atom is meeting with increasing resistance, regardless of the various reasons, the re-emergence of wind power is an almost inevitable consequence.

The objection could be raised that nostalgia is not a useful tool for solving future energy problems. Today, the argument is not about milling grain or pumping water, but about the energy requirements of modern industrial societies. Looking back, however, it becomes obvious that wind energy technology at the beginning of the 20th century had by no means lost out to the energy form of "electricity", to which currently no alternative concept exists, nor that was it even unsuitable for the purpose. Measured against the modest means of some pioneers, the successes they achieved in generating electricity by means of wind power were remarkable. In some cases the generation of electricity by means of the power captured from the wind had even passed beyond the stage of experimentation.

When discussing modern wind turbines, recalling the historical roots of wind power technology is, therefore, more than just passing time. The technical solutions and economic conditions which led to the successes and failures of the past will still provide hints for the development of today and the future. Thus, this book starts out with a look at the past.

1.1 The Origins of Windmills

There are contradictory speculations about the historical origins of windmills. Some authors maintain that they have discovered the remains of stone windmills in Egypt, near Alexandria, with a supposed age of 3000 years [1]. There is no convincing proof, however, that the Egyptians, Phoenicians, Greeks or Romans really knew windmills.

The first reliable information about the existence of windmills from historical sources originates from the year 644 A.D. [2]. It tells of windmills from the Persian-Afghan border region of Seistan. A later description, including a sketch, dates back to the year 945 and depicts a windmill with a vertical axis of rotation. It was obviously used for milling grain. Similar, extremely primitive windmills have survived in Afghanistan up to the present time (Fig. 1.1).

Some centuries later, the first news arrived in Europe that the Chinese were also using wind wheels for draining rice fields. Whether the Chinese knew windmills even before the Persians and whether the European mills might have been only an offshoot of the Chinese invention, can no longer be determined with certainty today. It is remarkable, however, that the Chinese windwheels, too, were simple structures made of bamboo sticks and fabric sails and that they had a vertical axis of rotation (Fig. 1.2).

The windmill with a horizontal axis of rotation, which is the traditional windmill, was probably invented in Europe independently of the vertical-axis windwheels of the Orient. The first verifiable information has its origin in the year 1180 in the Duchy of Normandy. According to this source, a so-called "post or trestle mill" is supposed to have stood there. Similar information also points to the province of Brabant, where a post windmill was

Figure 1.1. Vertical-axis windmill for milling grain, Afghanistan (Deutsches Museum)

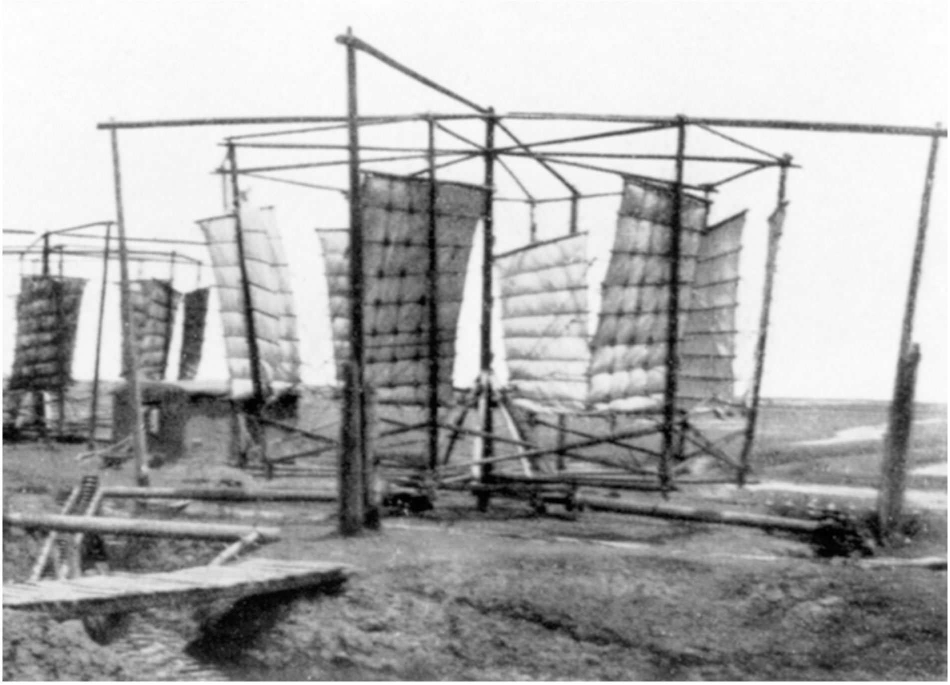


Figure 1.2. Ancient Chinese windwheel for pumping water (Deutsches Museum)

said to have been built as early as 1119. From this northwestern corner of Europe, windmills quickly spread all over North and Eastern Europe as far as Finland and Russia [3]. Numerous post windmills could be found in Germany in the 13th century (Fig. 1.3).

In addition to the post windmills, which are made entirely of wood, the so-called tower windmills make their appearance one or two centuries later. In this type of construction, the windwheel rests on a round tower made of stone. This type of mill mainly spread from the Southwest of France into the Mediterranean region, which is why it is frequently referred to as the Mediterranean type of windmill.

There is no reliable information as to whether the first post and tower windmills could already be yawed into the wind. However, yawing soon became a commonly found property of post windmills. The post windmill in its simple and serviceable form remained in existence right into the 20th century.

In Holland, several decisive improvements were made on windmills in the 16th century, leading to a new type of mill, the so-called "Dutch windmill". It is not known whether it was the post windmill or the tower windmill, of which some examples were also to be found in the north, which had served as the prototype. The fixed millhouse structure of the Dutch mill, where only the tower cap turned with the windwheel, permitted both the dimensions and the range of applications to be increased. Thus, the historical windmill reached its perfection towards the middle of the 19th century.

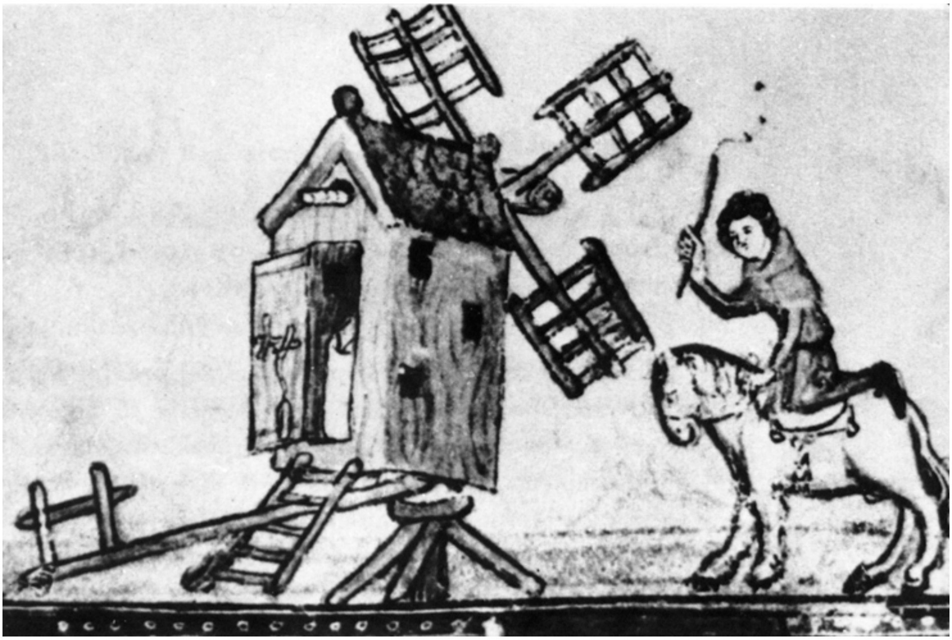


Figure 1.3. German post windmill in the 15th century (Deutsches Museum)

1.2
European Windmills

It is interesting to note that the windmill types which evolved in the course of history were able to maintain their original forms, coexisting with each other right up to the present time. Even the archaic vertical-axis windwheels of the Orient have not entirely disappeared. In Europe, the more powerful Dutch mill was not able to displace the simpler post windmill. It seems that the considerably cheaper post windmill was the more economical solution, as long as it was only a matter of milling grain in relatively small amounts. Against this background, a look at the technology behind the various windmill types is quite rewarding.

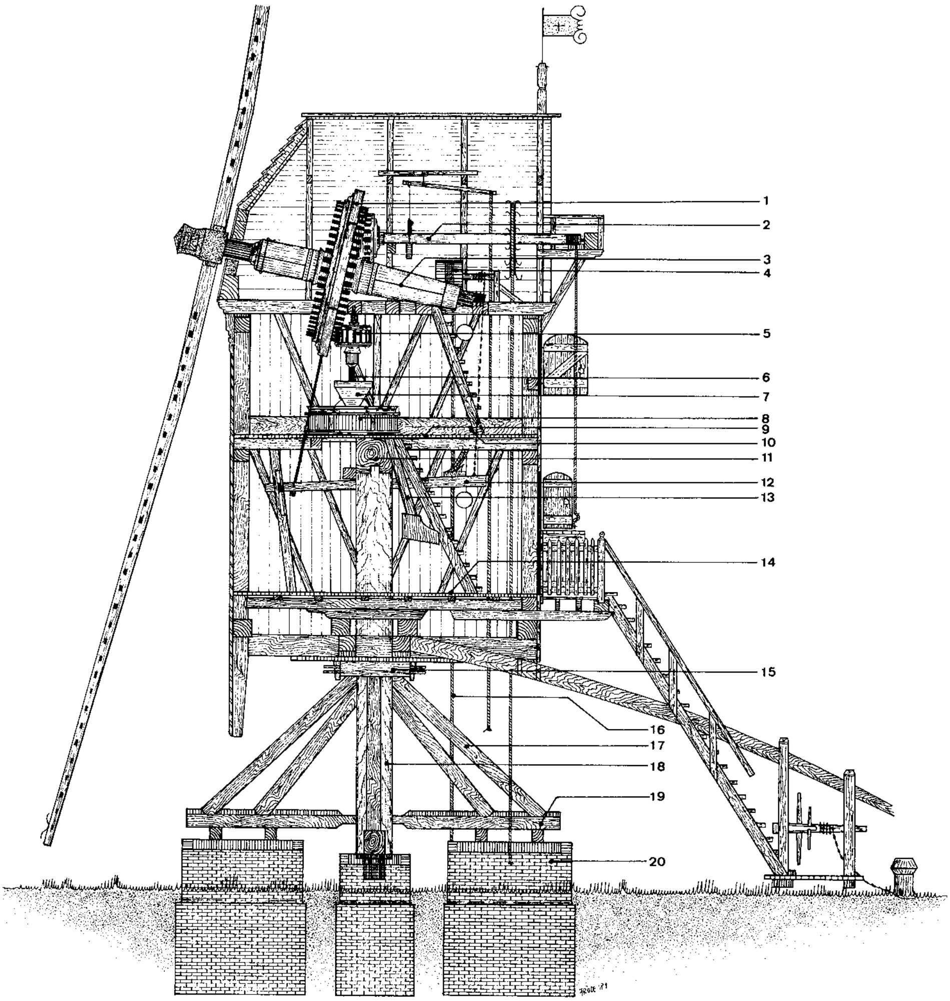
Post windmill

The post or trestle on which the entire millhouse rests and around which it revolves is the main feature of the post windmill (Fig. 1.4). The trestle consists of a central main post which is braced by four diagonal quarter bars. It extends upwards into the millhouse to about half its height where it is joined to the so-called meal beam which supports the millstone (Fig. 1.5). The meal beam divides the millhouse into an upper level, the stone floor, and a lower level, the meal floor.

The wind wheel, which commonly had four sails, is mounted in the upper part of the millhouse. The slightly inclined "wind shaft" supports the large-diameter "cog wheel". The cogwheel drives the spindle or upright shaft via the smaller horizontal spindle gear or

Figure 1.4. German post windmill (photo Fröde)

“wallower”. The upright wallower shaft is joined to the millstone. In Central Europe, the sails of a post windmill were almost always covered by fabric. In Northern and Eastern Europe wood-covered sails were also common. The millhouse was turned into the wind direction with the help of the so-called “tail” fixed to the back wall, which extended outwards and down almost reaching the ground. The turning motion was facilitated by a rope winch



post windmill

1	Cog wheel	8	Millwork	15	Crown tree
2	Sack "take-off"	9	Stone floor	16	Brake chain
3	Windshaft	10	Meal boad	17	Quarter bars
4	Brake	11	Meal beam	18	Main post
5	Wallower	12	Brake beam	19	Cross trees
6	Upright Shaft	13	Meal spout	20	Piers
7	Hopper	14	Meal floor		

Figure 1.5. Construction of a post windmill [2]

the rope of which was looped around posts arranged concentrically around the mill. Post windmills were made almost completely from wood and were used exclusively for milling grain. Their external shapes varied greatly according to regional preferences.

Hollow post mill

In the early 15th century, efforts were made to use post windmills for driving scoop wheels for pumping water. However, the rotatable millhouse was unsuitable for this purpose. In Holland, this situation inspired the development of the post windmill into the so-called "hollow-post mill" or "Wipmolen" (Fig. 1.6). In this type of mill, a fixed, usually pyramid-shaped base was introduced which housed the scoop wheel drive. The small rotatable millhouse now contained only the windwheel bearing, with cogwheel and wallower. A hollow post, through which the extended vertical wallower shaft was passed, formed the connection between millhouse and fixed base. Due to this hollow post, this type of mill was also sometimes called "Kokermolen". In Holland, these mills were used mainly for draining, later also for milling grain and sawing wood.

Figure 1.6. Hollow post mill or "Kokermolen"

Tower windmill

The tower windmill with its round stone-tower millhouse was widespread mainly in the Mediterranean regions. Originally, the windwheel could not be yawed. Later, the wind shaft was supported such that it could be repositioned — with some manual effort — to a number of supporting positions thus providing for at least a rough orientation into the wind. In the eastern Mediterranean regions the medieval tower windmills typically had windwheels with triangular sails (Fig. 1.7). In other regions framed sails were also commonly used. Large tower windmills were built much later. They should rather be regarded as variants of the Dutch windmill and probably developed independently from the Mediterranean type.

Dutch windmill

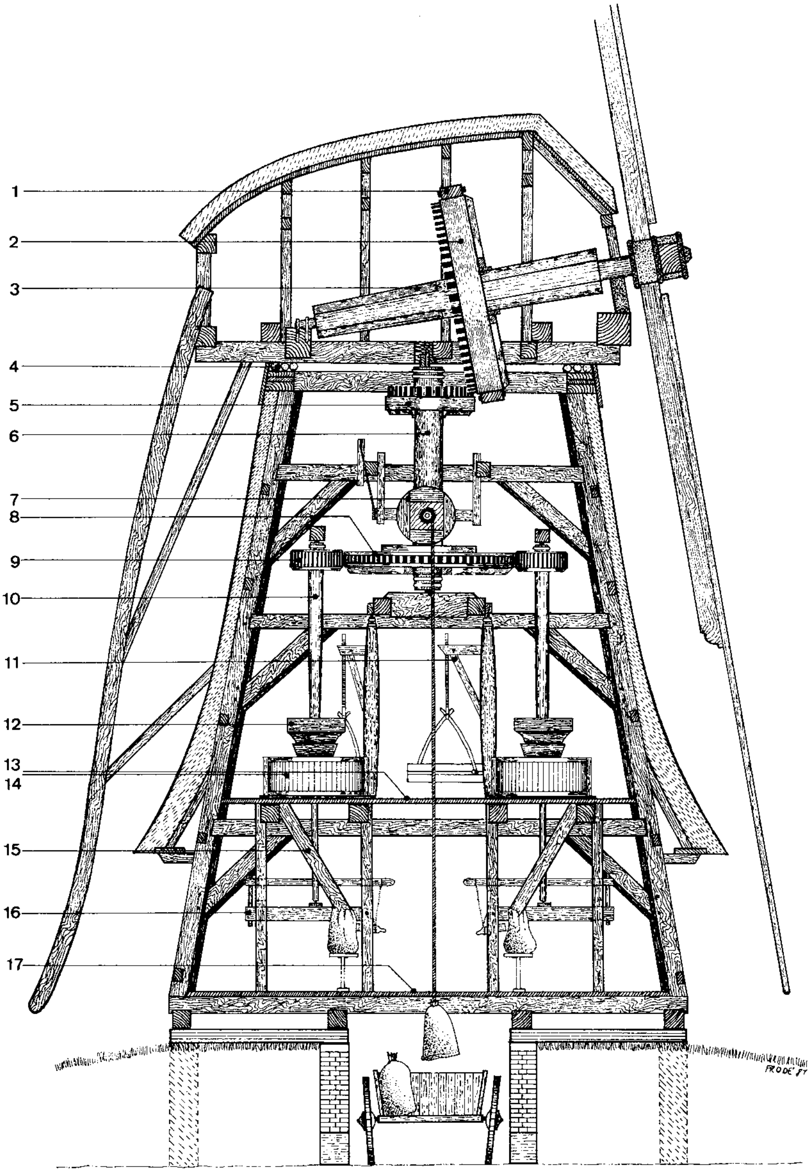
The basic idea which led to the design of the Dutch windmill was that which had already triggered the evolution from post windmill to hollow post mill. The intention was to provide the mill with a firm base in order to have better conditions for driving the various machines. It was an obvious solution to build the entire millhouse as a fixed structure and to only allow the roof cap to rotate with the windwheel.

This design was a decisive step towards larger and more powerful windmills. The voluminous, fixed millhouse could now accommodate various machines. Apart from scoop wheels, grain millstones, heavy pan grinders for milling dyes and the like, hammering machines and wood saws were also driven by the Dutch windmill.

Figure 1.7.
Greek tower windmill

By the middle of the 19th century, Dutch windmills started to develop into powerful prime movers with a remarkable range of applications. At this time their external shape was also refined with regard to aerodynamics and they became the dominant windmill type both technically and economically in several variations, for example the "Dutch ground mill" or the "gallery mill" (Fig. 1.8 and (Fig. 1.9).

Figure 1.8. Dutch windmill (gallery type) (photo Fröde)



Dutch windmill
1 Brake
2 Cog wheel
3 Windshaft
4 Rail bearing
5 Wallower
6 Vertical shaft
7 Sack "take-off"
8 Spur wheel
9 Spindlegear
10 Spindle
11 Stone crane
12 Feed of grain
13 Stone floor
14 Millstones
15 Mealslide
16 Lift for millstones
17 Meal floor

Figure 1.9. Construction of a Dutch windmill [2]

Paltrock mill

The Paltrock mill, which is far less well known than the other types of mill, represents a special variety which evolved in Holland in the 16th or 17th century (Fig. 1.10). As in post windmills, the entire millhouse rotates in these mills. They are supported on a wooden and later an iron rim bearing, which was set into the ground or placed on a brick substructure. The millhouse rotates on numerous rollers or small wheels. Initially, Paltrock mills were built exclusively as wood saw mills directly on the water. The heavy logs were unloaded straight from the cargo boats directly onto the protruding work platform. Later, Paltrock mills were also used to a lesser extent for milling grain.

Figure 1.10. Paltrock windmill

1.3 Economic Importance of Historical Windmills

In Europe, windmills were initially only used for milling grain. A vitally important task such as the milling of grain was a welcome source of income for the countries' rulers. In addition to water rights, they now also claimed the "wind rights" — a sure indication of the economic importance which windmills had rapidly achieved in this field. As a consequence, the construction and operation of windmills were subject to complex "mill laws". Terms such as "milling obligation" or "mill construction ban" appear in numerous chronicles of old.

"Milling obligation" prescribed that the inhabitants of a certain area were only allowed to have their grain ground in a mill assigned to them — for a certain levy, of course. This mill frequently was a "sovereign" mill. The "mill construction ban" prevented more than one windmill being allowed to be built within a certain area. This restriction often prevented a continued spreading of windmills. In many countries the outdated mill-right was abolished only as late as 1800 with the invasion of Napoleonic troops. Combined with the introduction of the freedom of trade, these events triggered a new boom in windmill construction.

In no other country did windmills achieve as high a significance as in the Netherlands. Apart from the need for grain mills, the draining of land evolved here as the second field of application. The Dutch started to build dikes and to reclaim land in the 15th century. Without the utilisation of wind-powered scoop wheels, initially used for draining and then for permanently drying out the volumes of water which kept returning into the newly reclaimed land areas, the Netherlands would not have become what they were in the 16th and 17th century (Fig. 1.11).

Figure 1.11. Windmills in Holland, for draining polders

Compared with other European countries, the economy of the Netherlands experienced an unrivalled boom in the 17th century, the country's golden era. Holland became an international distribution centre for imported goods of all kinds. Windmills were now also used for other industrial processes. They ground dyes, spices, oil-seeds and similar products. Holland achieved a monopoly in the export of sawed wood due to the deployment of large wood sawmills. Around 1700, there were about 1200 windmills in the Zaan region, north of Amsterdam, which supplied a complete industrial area with power [2].

The economic significance of windmills continued to grow until the middle of the 19th century. In the middle of the century, the Netherlands had more than 9000 windmills and in Germany there were more than 20 000. For all of Europe, the total number was estimated at about 200 000 [2]. Then came the decline. With the introduction of steam engines, the number of windmills started to decrease. Even though the number of windmills started to decline distinctly in the second half of the century, it stood up quite well against its steam-driven competition. The last windmills were still being built right up into the 20th century. This fact is significant as it shows that the uncertain availability of wind power, as compared to steam, was obviously not considered such a grave disadvantage.

The actual death of the windmill only began with the electrification of the rural areas. The connection of the last farm to the grid, frequently carried out with not inconsiderable pressure from the utility companies, made windmills an obsolete technology. When electricity came out of the wall socket, no-one was interested in having to battle with work-intensive windmilling and the maintenance of the mills which had become quite costly.

In 1943 only 1400 windmills were counted in Holland. The decline in Germany was similar. The total of the windmills still more or less well preserved today comes to a bare 400 in Germany, to about 1000 in Holland and to 160 in Belgium [2]. In the meantime, however, figures are moving up again. Historical windmills, which are increasingly protected today as cultural heritage monuments, are being restored and maintained in many places with the help of government funding.

1.4 Scientific and Technical Development of Windmills

The development of the various types of windmill from medieval times to the 17th century can hardly be considered the result of systematic research and development. The basis for advances in development and the diversification of windmill designs were improvements found more or less incidentally and an empirically founded evolution.

The first fundamental ideas concerning the design of windwheels were raised in the Renaissance period. Italian artists and scientists contributed numerous suggestions for new windwheel shapes, even though windmill construction was of little significance there. Sketches of windmills by Leonardo da Vinci are known. Veranzo, in his book "Machinae Novae", proposed various interesting designs of vertical-axis wind wheels [1]. However, these ideas had no great practical significance. In accordance with the spirit of the time, playful or artistic aspects dominated such deliberations about mechanics to a great extent.

It was not until the 17th and 18th century, when physical-mathematical thinking became more established, that windmill technology was systematically considered for the first time.

The subject was first picked up by the emerging natural sciences. It was no other than Gottfried Wilhelm Leibniz (1646–1716) who involved himself deeply in the matter. In a paper on the "Wind Arts", he provided numerous impulses for the construction of windmills, also proposing new designs. Daniel Bernoulli (1700–1782) applied his recently formulated basic laws of fluid mechanics to the design of windmill sails. The mathematician Leonhard Euler (1707–1783) was the first to correctly calculate the twist of the sails.

Important technical improvements came from Great Britain. In about 1750, the Scotsmen Meikle and Lee invented the fantail which permitted automatic yawing for the Dutch windmill (Fig. 1.12).

Some time later (1792), Meikle built the first windmills with so-called spring sails (Fig. 1.13). The sailcloth frames, which had to be reefed by hand by the miller when the wind was too strong, had been replaced by sails with hinged shutters interconnected by an iron rod, which could be opened and shut easily. Initially, the slats were made of wood, later of sheet metal. Some windmills were even built with self-regulating shutters, the segments of which were connected to the surrounding frame by steel springs. These innovations became established mainly in Great Britain.

For the first time ever, a certain amount of speed and power regulation of the windmill was possible due to the spring sails. This, in combination with the automatic yawing carried out by the fantail, enabled the Dutch windmill to reach the peak of its technical development and a remarkable degree of perfection.

However, the aerodynamic efficiency of the spring sails was not as high as that of good sailcloth sails. This fact became apparent after the physicist Charles Augustin de Coulomb had started to carry out systematic aerodynamic experiments with windmill sails in 1821 and when the Danish professor Poul La Cour, in about 1890, carried out comprehensive scientific research in windmill sail aerodynamics and windmill design. Poul La Cour deserves the merit of having comprehensively analysed and described the fundamentals of

Figure 1.12. Dutch windmill with fantail for automatic yawing

Figure 1.13. Windmill (Dutch ground windmill) with spring sails (photo Fröde)

windmill technology — even though this was at a time when this technology had almost become obsolete. However, he was quite aware of the fact that his findings would no longer have any practical consequences for windmill construction. For this reason, he quickly turned to the experiments described later (Chapt. 2.1), namely how to generate electrical current with the help of wind power. The second half of the 19th century also saw efforts of using new materials in windmill construction. Up to this point, windmills had almost exclusively been built from wood (Fig. 1.14).

Above all, the wind shaft, which had to bear high loads, was made of cast iron (Fig. 1.15). It quickly turned out, however, that the traditional oakwood wind shaft was able to sustain such loads at least as well due to its better material damping properties and higher fatigue strength.

After the aerodynamicist Albert Betz had formulated the modern physical principles of wind-energy conversion in 1920 and, moreover, modern airfoil designs had been developed in aircraft engineering, Major Kurt Bilau applied this knowledge to the design of windmills.

The "Ventikanten" sail developed by him in co-operation with Betz was formed of aluminium sheets, like an aircraft airfoil, and had an adjustable auxiliary flap which permitted power and speed regulation of the windmill (Fig. 1.16 and 1.17).

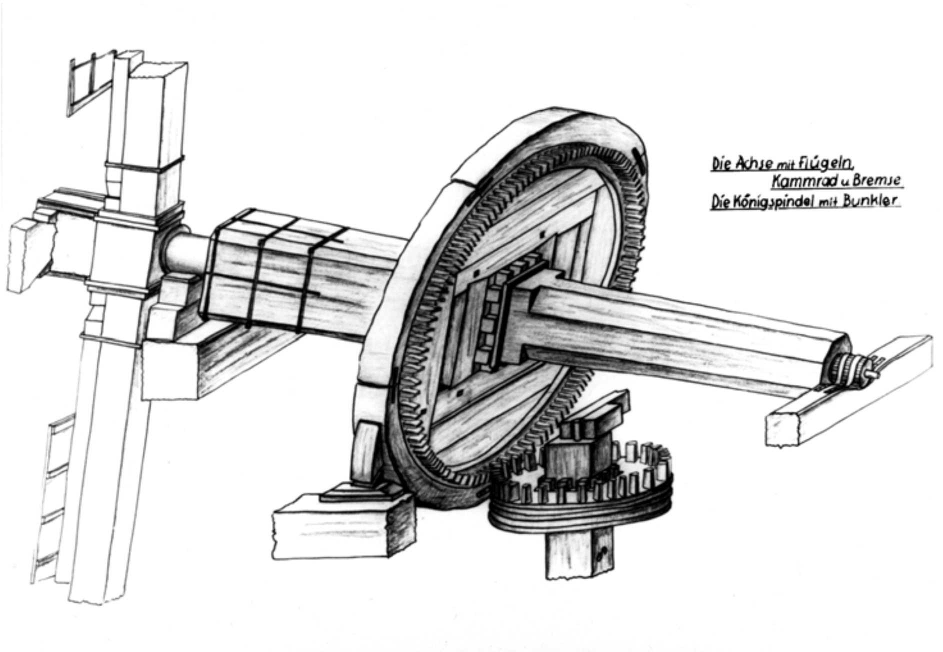


Figure 1.14. Wooden "wind shaft" with "cogged wheel" and "wallower" of a Dutch windmill (Deutsches Museum)

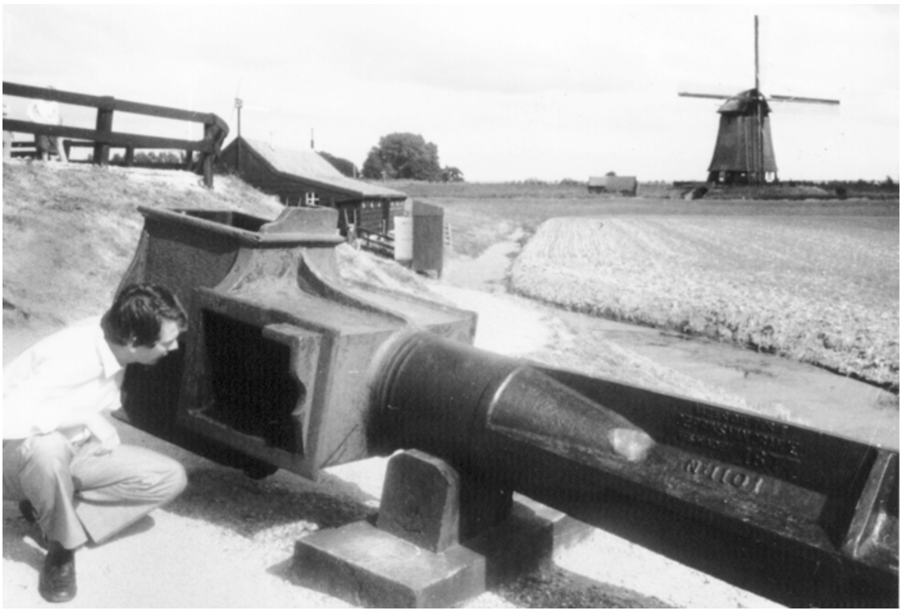


Figure 1.15. Cast iron wind shaft of a Dutch windmill

Figure 1.16. Windmill with subsequently added "Ventikanten" sails (photo Fröde)

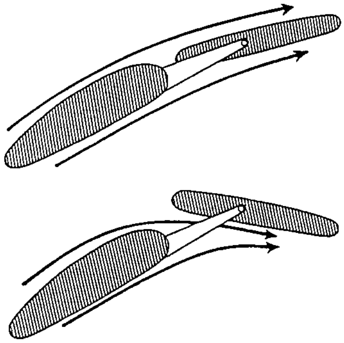


Figure 1.17. Function of the Ventikanten sail [2]

By 1940 Bilau had equipped about 130 windmills with these sails, achieving a considerable increase in their power output. Looking at such a windmill it becomes evident that this technology probably did transcend traditional windmill technology, while it managed to extract a last breath of life from some of the mills.

1.5 The American Wind Turbine

In the early 19th century, when windmill technology was reaching its peak in Europe, numerous windmills were also built in the New World, mainly on the East Coast where the Dutch and British had their settlements. Simultaneously, the great movement to the West started in the USA. The settlers of the great plains of the Mid-West needed water, above all, when they wanted to settle down. In those places which did not have natural surface water, water had to be pumped up from wells. The large windmills were of little help for this purpose. They were too heavy to follow those pioneers rapidly enough. But in the land of unlimited possibilities, solutions were also found for this problem.

In about 1850, the mechanic Daniel Halladay from Connecticut found the first solution. Reportedly, Halladay heard frequent complaints that the few windwheel pumps existing at the time, the wind wheels of which were sailcloth-covered like the windmills, were a downright nuisance to their owners. The hard-working settlers simply did not have the time to permanently look after their windpumps, and to reef the sails in time when bad weather threatened. Frequent damage was the consequence. After having listened to the complaint of one such sufferer, Halladay is said to have answered: "I can invent a self-regulating windmill that will be safe from destruction in violent windstorms, but I don't know of a single man in the world who would want one" [4]. Time would prove him wrong.

In steam engines Halladay had seen flyweight governors which opened a safety valve in the case of overspeeding. With this concept in mind, he designed a windwheel the blades of which were not directly joined to the shaft, but suspended loosely on a ring. Using a second movable ring collar, the blades were connected such that a movement of the ring effected a change in the blade pitch angle. The movement of the ring was triggered by flyweights. He also divided the wheel into six sections. At low wind speeds, the windwheel

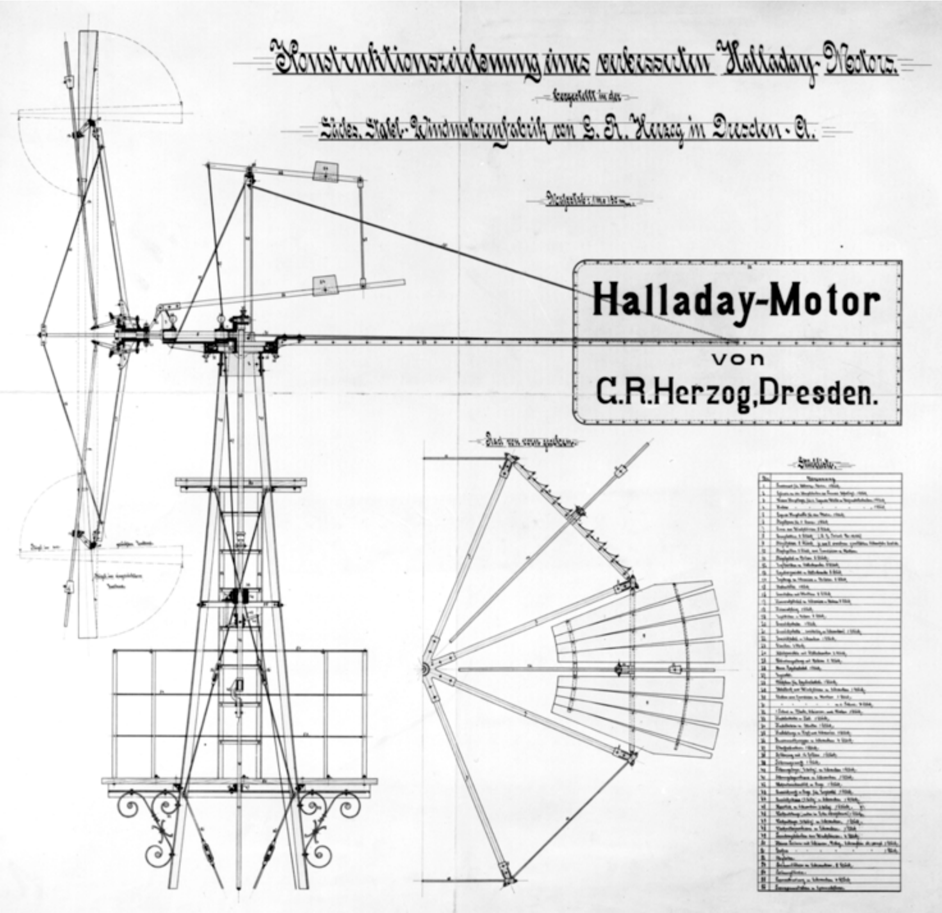


Figure 1.18. Design of a Halladay wind turbine, built under license by Herzog, Dresden, Germany in 1904

turned slowly, with the flyweight governor keeping the blade pitch at a shallow angle. With increasing wind speed and higher revolutions, the blade-pitch angle became continuously steeper, until ultimately the six wheel sections swung completely out of the plane of the wheel (Fig. 1.18).

Initially, Halladay used only a few thin wooden blades, but he increased their number until the entire wheel surface was covered with blades, like a turbine. A wind vane took care of yawing. The aerodynamic characteristics of such a "wind turbine" thus differed greatly from the previously known windmill sails. His wind turbine already started turning at low wind speeds, it turned comparatively slowly and developed a high torque at low speeds, exactly the right preconditions for driving a reciprocating water pump. The water pump was driven via a crank mechanism with a long vertical shaft which reached to the foot of the lattice mast.

Despite his scepticism, Halladay started manufacturing wind turbines and soon sold large units to the American railroad companies. These had an increasing need for water pumps for refilling their water tanks en route (Fig. 1.19).

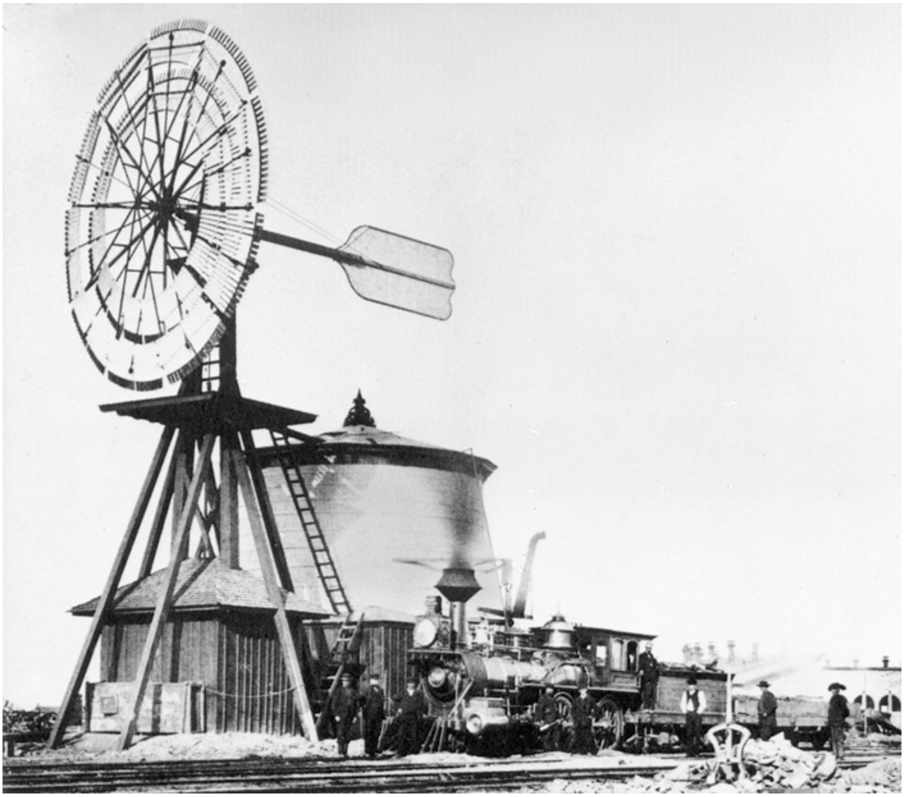


Figure 1.19. Halladay wind turbine for refilling water tanks of the Union Pacific Railroad in Laramie, 1868 [4]

With its many joints and bolts, Halladay's wind turbine was a comparatively complex machine. Although it was manufactured until 1929, it remained rather a rarity. The Reverend Leonhard R. Wheeler of Wisconsin found a simpler solution a few years later. Instead of dividing the windwheel into sectors, Wheeler mounted an additional wind vane which was positioned at right angles to the wind direction. This vane was used to turn the entire wind wheel out of the wind. The vane was connected to a weight, so that when the wind speed decreased, the wheel turned back into its original position (Fig. 1.20). Wheeler's concept was manufactured under the name of "Eclipse" and became the standard design of the American wind turbine.

Figure 1.20. American wind turbine of the "Eclipse" design (Deutsches Museum)

The two new wind turbine concepts were presented to the general public at the World Exhibition in 1876 in Philadelphia. Farmers were highly interested in this relatively simple and cheap piece of equipment. In the following years, wind turbines were manufactured in ever greater numbers by an ever increasing number of relatively small firms, especially the model developed by Wheeler, which was built in numerous variants.

By 1899, as many as 77 "windmill factories" were counted. By 1930 their number had increased to almost 100 companies with a total of about 2 300 employees [4]. Wind turbines also became a lucrative export article and were sold almost worldwide. However, they were no longer able to establish a foothold in Europe, as wind power utilisation was too much on the retreat there by that time. Some German firms like Herkules or Köster nevertheless manufactured wind turbines under license in modest numbers.

By 1930, more than six million American wind turbines had been manufactured. For the first time ever, the utilisation of wind energy was based on an industrially mass-produced article. A remarkable fact, and it can hardly be considered a coincidence that it was in the USA where it happened for the first time. However, the "Rural Electrification Program" of the thirties which provided electrification to the rural areas put paid to wind turbines also in the New World and their numbers dwindled rapidly. The remaining stock is estimated to be about 150 000 units in the USA today. In recent years, several manufacturers have resumed production, so that possibly their numbers are on the rise again.

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Chapter 2

Electrical Power from the Wind — The First Attempts

Large-scale utilisation of electricity started with the construction of the first power plants. The world's first power plants were built in New York with a power output of about 500 kW (in 1882) and in Berlin (1884) [1]. Three-phase current was introduced as early as 1891. Power plant technology evolved rapidly and produced ever-increasing power outputs. By the beginning of the twentieth century, almost all large cities in the industrialised countries were supplied with electricity.

Electrification of the rural areas took place at a considerably slower pace. The necessary preconditions were only created by the interconnection of various types of power plants and the setting up of extensive transmission networks. Whereas in Europe and particularly in Germany, this development reached almost the remotest village by the twenties, the opening up of the rural areas in the large territorial states required enormous efforts. In the USA, the large regions of the West were supplied with electricity as late as 1932 in the so-called "Rural Electrification Program".

The first attempts to generate electric current with the help of wind power were being made in that period of time when the large cities were already being supplied with electricity, but complete coverage of users in rural areas was not yet feasible. The spread of traditional windmills in Europe and of wind turbines in America was still nearly at its peak. It was probably inventive do-it-yourself enthusiasts in America who were the first to try to drive electric "dynamos" with their wind turbines which were actually designed for pumping water. However, the first systematic development aimed at utilising wind power for the generation of electricity took place in Denmark.

2.1 Poul La Cour — A Pioneer in Denmark

Like no other, the name Poul La Cour marks the turning-point from historical windmill building to the modern technology of power generating wind turbines (Fig. 2.17). His is the merit of perfecting traditional windmill technology on the basis of the scientific principles worked out by him, and he was a pioneer of electricity generation by means of wind power — all this in the nineteenth century [2].

Poul La Cour was a professor at an adult education centre in Askov. Encouraged by the Danish government which was looking for ways of supplying also Denmark's rural areas with electricity, La Cour built an experimental wind turbine driving a "dynamo" in 1891 (Fig. 2.1). The remarkable fact is that he also at once tackled the problem of energy storage. He used the direct current generated by his wind turbine for electrolysis and stored the hydrogen gas thus produced. From 1885 to 1902, gas lamps using this method illuminated the school grounds in Askov.

As far as the wind wheel was concerned, La Cour's electricity-generating wind turbine strongly followed the model of the traditional windmills. Although he was well aware of the advantages of aerodynamically shaped windmill sails, he used a rotor with four shutter sails. He knew that this technology could be managed much better in the country.

In the subsequent years La Cour expanded his activities in Askov to establish a well-equipped test station for wind turbines. He was possibly the first to carry out tests in a wind

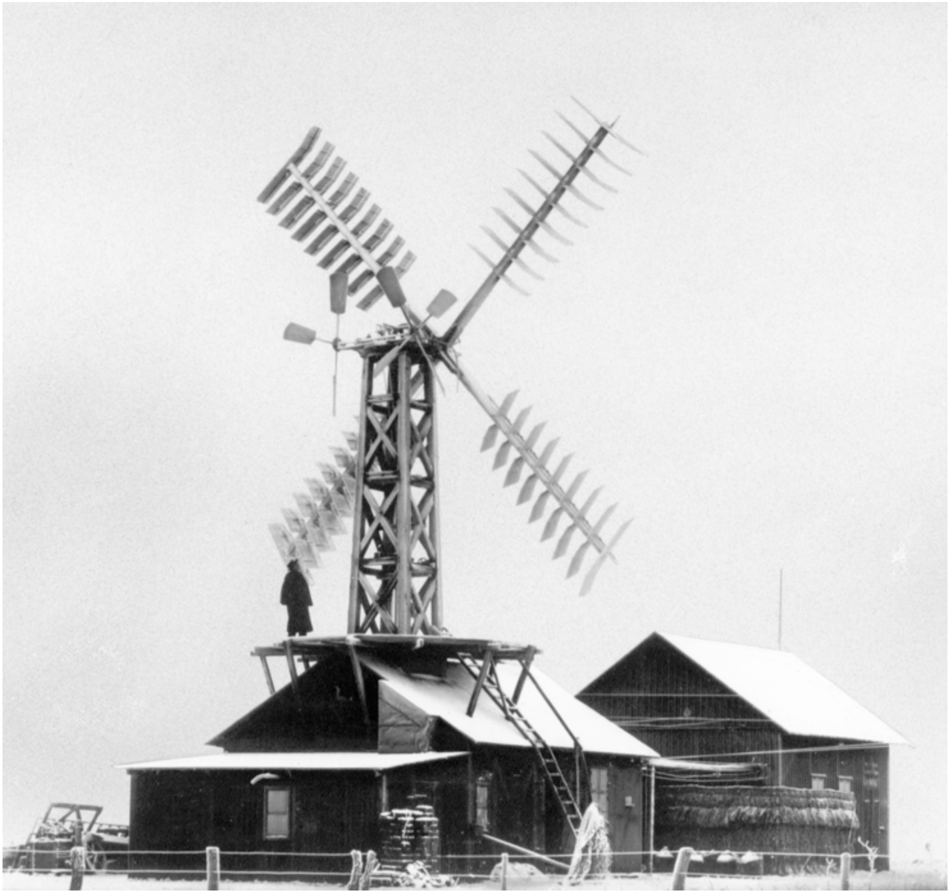


Figure 2.1. Poul La Cour's first electricity producing wind turbine in 1891 in Askov, Denmark [1]

tunnel, which he had built himself, and he set up a second, larger test station in 1897. In his book "Forsøgsmøllen", published in Copenhagen in 1900, he reported on this work [3]. In 1903 La Cour founded the Association of Danish Wind Power Engineers (DVES) which, among other things, offered training courses for "wind electricians".

The extent of La Cour's success became apparent when the Lykkegard company began with the industrial utilisation of his developments. By 1908, it had already built 72 electricity-generating wind turbines, modelled after the test station at Askov, which supplied power to rural settlements. This development was accelerated by the dramatic rise in fuel prices during World War I., so that by 1918, about 120 wind turbines were in operation [4].

One of the main technical reasons for this success of wind power utilisation for the generation of electricity was the fact that many rural areas of Denmark were supplied with direct current even after World War II. Operating a wind turbine in parallel with diesel- or gas-engine-type power stations generating direct current was technically easier than with alternating current.

The La-Cour-Lykkegard turbines were built in various sizes with power outputs ranging from 10 – 35 kW. The rotor, with a diameter of up to 20 m, had four shutter sails, making it possible to remain below a certain rotational-speed limit. Yawing was carried out by two fantail type side wheels. The electrical generator was installed at the base of the latticed steel tower and was driven by the rotor via a long shaft and intermediary gearbox. Electricity was fed into the small isolated consumer grids via a buffer battery (Fig. 2.2).

These grids were fed by diesel- or gas-engine generators and supplied larger farms or small settlement areas. The overall efficiency of the wind turbines was indicated to be about 22 %. At a good site, the annual energy yield amounted to about 50 000 kWh.

The operational experience gained with these wind turbines was analysed in depth later on behalf of the "Reichsarbeitsgemeinschaft Windenergie" (Working Group Wind Power of the German Reich) [4]. It turned out that their reliability was normally extremely high. There are reports of wind turbines of this type, which were operated between 1924 and 1943, where the bearings and gears had to be replaced for the first time after 20 years of operation.

In Denmark, interest in the generation of electricity by means of wind power waned after World War I. Diesel fuel was relatively inexpensive during this period. However, the situation changed again with the outbreak of World War II. Fuel prices soared and immediately the interest in using wind power for the generation of electricity was reawakened. Lykkegard wind turbines which had been closed down were taken into service again and several new ones were built.

In addition to the La Cour concept, which was somewhat outdated by now, a new manufacturer entered the market with more modern designs. The F. L. Smidth company, a manufacturer of machines for the production of cement whose entire export market had collapsed due to the events of the war, turned to building wind turbines [5]. Using the name of "Aeromotor" for their design, Smidth started by developing a wind turbine with a rotor diameter of 17.5 m and a power output of about 50 kW at a wind speed of approx. 11 m/s. The aerodynamic design of the rotor with two profiled rotor blades made of laminated wood was in keeping with the state of-the art achieved in the meantime. The two-bladed rotor was designed for a tip-speed ratio of about 9. The rotor blades had no twist and could not be pitched. Speed was limited by an aerodynamic brake. Twelve wind turbines of this

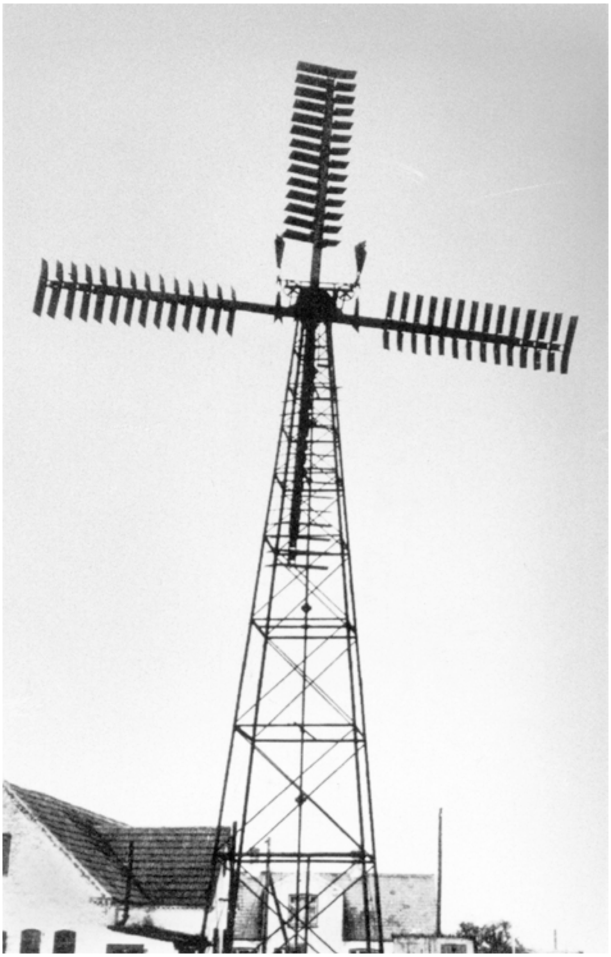


Figure 2.2. La-Cour-Lykkegard wind turbine in Denmark (rotor diameter 18 m, approx. 30 kW power output at 12 m/s wind speed) [4]

type were built, some with a lattice steel tower (Fig. 2.3), the majority with concrete towers (Fig. 2.4).

Problems with the dynamic characteristics of the two-bladed rotor caused the company to develop a second, larger type with three rotor blades (Fig. 2.5). With a rotor diameter of 24 m, it yielded a power output of about 70 kW at a wind speed of about 10 m/s. Seven wind turbines of this type were built, all of them with concrete towers.

Except for one, all Smidth Aeromotors were equipped with DC generators. Many of the features of their aerodynamic and mechanical design are typical of the "Danish line" to the present day. It can be rightly stated that in the first half of the 20th century, electricity generation from wind power was already more than an experiment in Denmark. Even if, measured against the total electricity generation, the proportion of "wind electricity" will have been a matter of only a few percent, in some areas at least electricity from wind power was a first solution for supplying electric energy.

Figure 2.3. Smidth "Aeromotor" (rotor diameter 17.5 m, rated power approx. 50 kW), 1941/2 [5]

Figure 2.4. Smidth "Aeromotor" with concrete tower (rotor diameter 17.5 m, rated power approx. 50 kW), 1942 [5]

Figure 2.5. Smidth "Aeromotor" with three-bladed rotor (rotor diameter 24 m, rated power approx. 70 kW), 1942/3 [5]

2.2
Large Wind Power Plants — Ambitious Projects in Germany

In Germany, the first attempts of using wind power for the generation of electricity go back to before World War I. Some companies, Köster and Hercules among others, manufactured American wind turbines under license. Until the thirties, a total of 3600 wind turbines were built in Germany by about ten manufacturers. Most of these were used for pumping water, their intended purpose, but some of them were modified for the generation of electricity.

After World War I, Major Kurt Bilau tried to develop electricity-generating wind turbines based on more advanced technical concepts. Bilau recognised that the American low-speed rotor did not have the appropriate characteristics. His "Ventimotor", with a four-bladed rotor and higher tip-speed ratio, was one of his first attempts. Bilau described his results in two books and thus contributed not inconsiderably to the idea of also utilising wind power for generating electricity in Germany [6]. However, physics was not one of his strong points. In his second book, which was published in 1942, he still tried to prove that his Ventimotor, with its "streamlined" airfoils, could achieve a higher power coefficient than the maximum value of 0.593, which had been calculated by Betz in the meantime [7].

In Germany, however, the decisive impulse came from the theoretical camp. Against a background of aircraft aerodynamics, the physicist Albert Betz, director of the Aerodynamische Versuchsanstalt (Aerodynamic Research Institute) in Göttingen, approached the problem of the wind rotor's physics and aerodynamics from a strictly scientific point of view (Fig. 2.17). In an article published in the "Zeitschrift für das Gesamte Turbinenwesen" (Journal of Turbine Science) in 1920, he proved that the maximum physically possible utilisation of the wind by a disk-shaped, turbine-like wind energy converter is restricted to 59.3 % of the power contained in the air current [8]. In his book "Wind Energy and Its Exploitation by Windmills", which was published in 1925, he summarised the results of his research and formulated a theoretical basis for the aerodynamic shaping of wind rotor blades, which has kept its validity to the present day [9]. This theoretical basis now permitted modern high-speed wind rotors to be calculated reliably. In addition to the principles of aerodynamics, advanced lightweight design principles in aircraft engineering were also developed in the twenties which was also an important prerequisite for implementing large rotors.

One of the first to work with these new scientific findings was the steel construction engineer Hermann Honnef who developed concepts for absolutely gigantic wind power plants (Fig. 2.6). Colossal lattice towers were to have carried up to five wind rotors, each with a diameter of 160 m and a power output of 20 000 kW. These wind rotors were to consist of two concentric contrarotating wheels. In order to provide the necessary rigidity, the very slender rotor blades were configured as "double spokes" in the inner area. The two contrarotating rotors each bore a metal ring with a diameter of 121 m. These two contrarotating rings formed a so-called "ring generator", with one ring acting as the pole ring and the other as armature ring. In cases of extreme wind speeds, the upper part of the lattice tower, which carried the rotors, was intended to tilt into an inclined position and eventually to a horizontal position.

In retrospect, it must be noted that Honnef's plans were indeed based on mathematical and engineering principles [10]. Their realisation would, however, have most certainly caused considerably more problems than Honnef imagined in 1932. It is, therefore, less the technical concept which is fascinating about Honnef's plans but the idea in itself. Honnef wanted to utilise wind energy on a large-scale technical basis. It was no longer the idea of supplying remote farms with electricity which inspired him, he wanted to build large "wind power plants" which were to generate electricity in combination with conventional

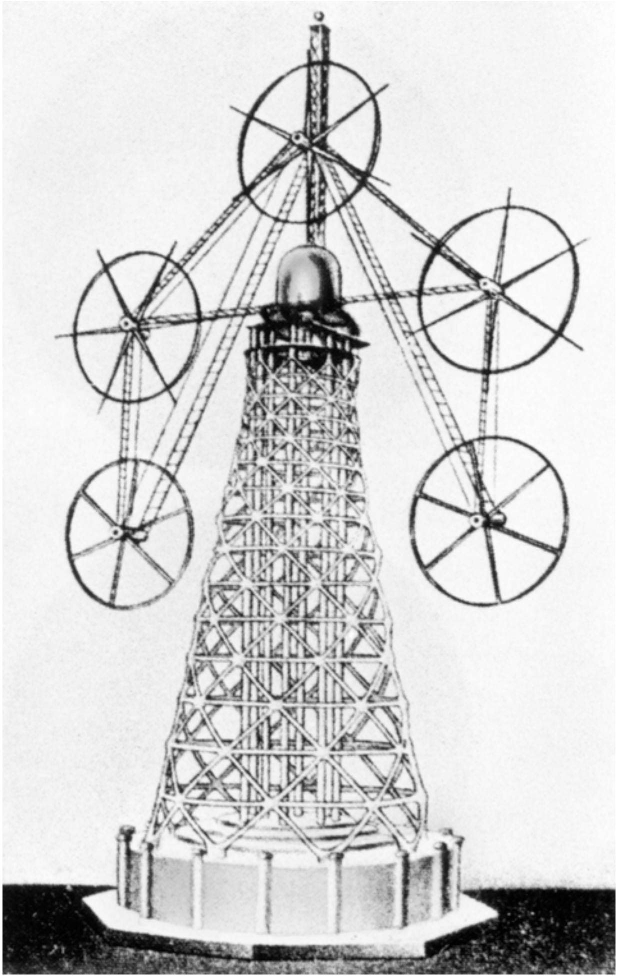


Figure 2.6. Vision of a large wind power plant by Hermann Honnef.
5 rotors, each with 160 m diameter and 20 000 kW power output; tower height 250 m, 1932

power plants at an economical price. In this respect, Honnef was a pioneer of the large wind turbines.

In the years from 1930 to 1940, Germany saw much theoretical and design activity in the field of wind power technology. The motivation behind this was in part certainly the striving by the German Reich for self-sufficiency in the supply of fuel and power. In 1939, the "Reichsarbeitsgemeinschaft Windkraft", RAW, was formed, where renowned scientists, technicians and industrial firms worked together. The RAW supported numerous projects and published their results in so-called "memoranda".

Among the projects on which the work of the RAW was concentrated, one deserves special mention. In 1937, the engineer Franz Kleinhenz published plans of a large wind turbine project [11]. Unlike Honnef, Kleinhenz knew how to win the co-operation of renowned scientists and industrial firms. His plans took shape in co-operation with the Maschinenfabrik Augsburg-Nürnberg (MAN). His concept was improved and refined in many details in a number of stages from 1938 to 1942 [12] (Fig. 2.7).

Even today, the technical data of the MAN-Kleinhenz project convey an impression of advanced technology:

- 130 m rotor diameter,
- three or four rotor blades,
- 10 000 kW rated power,
- tip-speed ratio of 5,
- rotor positioned down-wind,
- 250 m hub height,
- directly driven generator with a diameter of 28.5 m or several generators via a mechanical transmission,
- tower as guyed tubular steel tower, upper part yawing with the rotors.

Figure 2.7. Project MAN-Kleinhenz (rotor diameter 130 m, rated power 10 000 kW), 1942

By 1942 the project was ready for implementation, but the war prevented its actual construction.

While Germany was busy mainly with theories and great plans in the thirties, some pioneers set to work in another country. In 1931 a large wind turbine was built in the USSR in Balaklava, not far from Yalta on the Crimean peninsula (Fig. 2.8). The wind turbine with the name of Wime D-30 had a three-bladed rotor with 30 m diameter and a generator rated power of 100 kW. The rotor speed was regulated with the aid of control flaps. Yawing was carried out by moving the entire wind turbine on a circular rail track [13].

This wind turbine was operated from 1931 to 1942 and was said to have operated comparatively reliably. The electricity it generated was fed into a small grid, which was supplied by a 20 MW steam power station. A second, similar wind turbine with the name of Zwei D-30 was installed a few years later on the coast of the Arctic Ocean. It had a conventional tower and a yawing system with two fantails.

The apparently good results of these experimental turbines encouraged the builders to design a 5000-kW wind turbine with a rotor diameter of 100 m. Similar to the MAN-Kleinhenz project, however, these plans, too, fell victim to the war.

Figure 2.8. Russian wind turbine Wime D-30 in Balaklava on the Crimea (rotor diameter 30 m, rated power approx. 100 kW), 1931

2.3 1 250 kW from the Wind – The First Large Wind Turbine in the US

A decade before the beginning of the rural electrification program, first efforts were made in the US to develop advanced electricity-generating wind turbines. As the declared aim was to supply power to those private consumers who were not yet connected to the public utility grid, development was concentrated on small wind turbines with rated powers of a few kilowatts. These small wind turbines, which became known as "wind chargers", were used for recharging batteries and thus provided a modest power supply for rural settlements and remote weekend houses.

The brothers Marcellus and Joseph Jacobs deserve special mention here. In 1922, they started to develop a small wind turbine [14]. After initial tests with two-bladed aircraft propellers, they developed a three-bladed rotor with a diameter of 4 m, which directly drove a low-speed DC generator (Fig. 2.9). This Jacobs "wind charger" proved to be a vanguard design and a sensational sales success. From 1920 to 1960, tens of thousands of these wind turbines were produced in various versions from 1.8 to 3 kW rated power. They won wide acclaim for their reliability and low maintenance requirements. One of these wind turbines was taken along by the American Admiral Byrd in 1932 on his expedition to the Antarctic and operated without maintenance for more than 22 years until 1955 [14].

As the electricity supply of the rural areas no longer presented a general problem, plans were made in the USA to deploy large wind turbines within the public utility grid, interconnected to conventional power plants. The American engineer Palmer Cosslett Putnam (Fig. 2.17) must be given the credit of being the first to implement these plans. In 1940, he approached the S. Morgan Smith Company, a water turbine manufacturer in York (Pennsylvania), with his concept and some ideas of the technical design of a large electricity-generating wind turbine. Morgan Smith entered into a contract with the Central Vermont Public Service Company concerning the erection of a wind turbine based on Putnam's plans.

Palmer C. Putnam won over renowned scientists and technicians of the Massachusetts Institute of Technology (MIT) to co-operate in this project. Among others, Theodore von Kármán was responsible for the aerodynamic design of the rotor. In October 1941, the turbine was installed on Grandpa's Knob, a hill in the state of Vermont. It was the world's first really large wind turbine (Fig. 2.10) as proven by the technical data:

- 53.3 m rotor diameter
- 1 250 kW rated power
- 35.6 m tower height.

The two-bladed rotor with stainless-steel rotor blades was positioned downwind from the lattice tower. The rotor blades were connected to the rotor shaft via flapping hinges in order to reduce the dynamic loads caused by wind gusts. The speed and power output of the wind turbine were controlled by an hydraulic blade-pitching mechanism. Electricity was generated by a synchronous generator with 1 250 kW rated power.

The Smith-Putnam wind turbine operated for about 4 years and fed electricity into the utility grid of the Central Vermont Public Service Company for about one thousand operating hours until March 26, 1945, when a rotor-blade fracture interrupted its operation.

Figure 2.9. Jacobs "wind charger" (rotor diameter about 4 m, rated power 1.8 to 3 kW), 1932

This structural weakness at the blade root had in fact been detected by technicians at an early stage, but, due to a lack of funding, no preventive repair was carried out. The later repair was also not carried out for the same reason and the turbine was disassembled.

In the course of the project, Putnam undertook detailed investigations with regard to a later series production of his wind turbine and he compiled these in 1947 in his still highly readable book "Power from the Wind" [15]. Due to his earlier experience, he first tackled

Figure 2.10. Smith-Putnam wind turbine, in Vermont, USA (rotor diameter 53.3 m, rated power 1 250 kW), 1941 [15]

the question of the economically optimal size of a wind turbine and drew the following conclusions:

- rotor diameter 175 – 225 feet (53.3 – 68.5 m)
- tower height 150 – 175 feet (45.7 – 53.3 m)
- generator power 1 500 – 2 500 kW.

These results, achieved by Putnam in 1942, are remarkable when compared with currently prevailing opinions.

Putnam proposed to the S. Morgan Smith Company a pre-production model with a rotor diameter of 200 feet (60.69 m) producing a power output of 1 500 kW. The technical concept largely corresponded to that of the experimental turbine, but the design had been improved in many details, above all from the point of view of reducing the manufacturing costs. Based on a series of 6 to 10 wind turbines, economic calculations yielded specific investment costs of 190 Dollars/kW (1945). The utility company, in contrast, calculated with economically affordable specific costs of 125 Dollars/kW, based on the then electricity-generation costs of 0.6 Cents/kWh. and, as a result, no further wind turbines were manufactured. In 1945, therefore, the Smith-Putnam wind turbine was off the mark by a factor of 1.5 with respect to economic efficiency.

2.4 Wind Turbines in the Fifties — Before the "Energy Crisis"

After World War II, the prices of the primary fuels coal and oil dropped again and a period of extremely cheap oil imports began. The availability of fuels for the generation of electricity was no problem at all. The subject of environmental protection had not yet been thought of and if so, not in connection with the production of electricity. Nevertheless, attempts at generating electrical power by means of wind turbines continued in the fifties in some places, after the shortages of the first post-war years had been mostly overcome.

In England, the John Brown Company erected an experimental wind turbine on the Orkney Islands in 1950 for the North of Scotland Hydroelectric Board (Fig. 2.11). However, the three-bladed wind turbine with a rotor diameter of 15 m and a rated power of 100 kW was not a success and its interconnected operation with the diesel power station on the Orkney Islands lasted only a few months. The main reason for the failure was probably the complex rotor design, with blades connected to the shaft via flapping hinges and drag hinges.

At about the same time the Enfield Cable Company also built a 100-kW wind turbine in England, based on the plans of the French engineer Andreau (Fig. 2.12). The Andreau-Enfield wind turbine is based on a technical concept which has maintained its uniqueness to this day [16]. Instead of the usual mechanical gearbox for connecting the rotor directly to the generator, Andreau thought up a pneumatic power transmission system. Air, which was sucked in at the base of the hollow tower, flowed through the tower and hollow rotor blades, and being submitted to centrifugal forces, left the rotor blades at the blade tips. This caused a fast-moving air stream in the tower, which drove the generator via an air turbine in the tower.

Figure 2.11. Wind turbine of the John Brown Company on the Orkneys (rotor diameter 15 m, rated power 100 kW), 1950 [4]

However, although this method avoided the problematic fixed-speed connection of the rotor to the generator, it was not convincing in its overall efficiency which, at about 20 %, was uneconomically low when measured against the building costs. The wind turbine was first set up in St. Albans (Hertfordshire) in 1951, but was dismantled again due to the unfavourable site. In 1957, it was set up again for a short period of time in Grand Vent (Algeria).

Apart from the French engineer Andreau, who implemented his ideas in England, a number of other engineers in France worked on designing larger wind turbines [16]. In 1958, L. Romani built a large experimental wind turbine in Nogent le Roi near Paris with the support of the public utility company "Electricité de France" (EdF) (Fig. 2.13). The Best-Romani wind turbine had a rotor diameter of 30.1 m and operated with a synchronous generator with 800 kW rated power. It was tested until 1963 and dismantled after some blade damage had occurred.

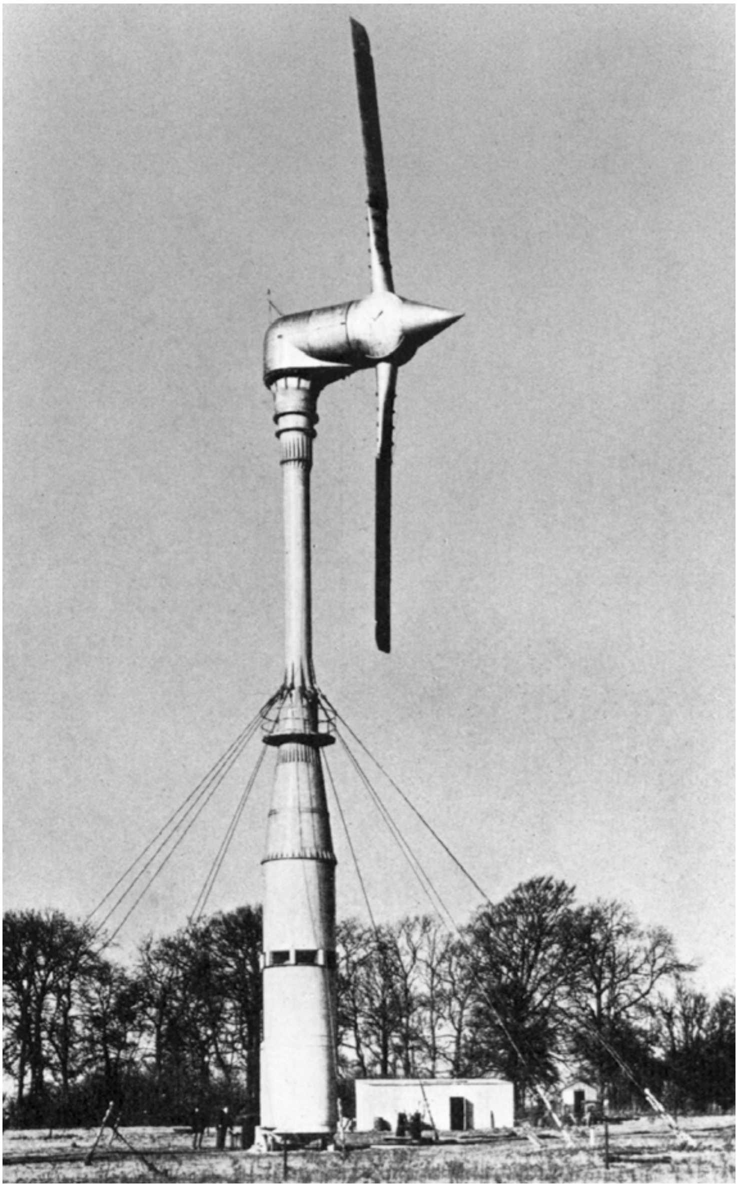


Figure 2.12. Andreau-Enfield wind turbine in St. Albans (Hertfordshire) (rotor diameter 24.4 m, rated power 100 kW), 1956

In parallel with this project, Louis Vadot developed two wind turbines which were set up in Saint-Rémy-de-Provence, France, on the coast of the English Channel. Vadot started out with a smaller wind turbine with a rotor diameter of 21.1 m and a rated power of 132 kW

Figure 2.13. Wind turbine by Best-Romani, France (rotor diameter 30.1 m, rated power 800 kW), 1958 [16]

(Fig. 2.14). A larger wind turbine with a rotor diameter of 35 m and an installed generator power of 1000 kW followed which was based on the same technical concept. Both wind turbines had induction generators. Operational experience with these two wind turbines is said to have been comparatively good [16]. However, both wind turbines were dismantled in 1964 and 1966, respectively, as the EdF was no longer interested in the utilisation of wind power.

Naturally, the Danes were also represented with experimental wind turbines in the fifties. Basing his concept on the technical model of the Aeromotors, J. Juul built a 200-kW wind turbine with a rotor diameter of 24 m in Gedser in 1957 (Fig. 2.15) [17].

The Gedser wind turbine operated from 1957 to 1966, but then shared the fate of all other wind turbines of this period and was decommissioned. Remarkably, or possibly prudently, it was not disassembled. It was thus the only historical wind turbine which survived to see the

Figure 2.14. Neypric-Vadot wind turbines in Saint-Rémy-de-Provence
Small wind turbine (rotor diameter 21.1 m, rated power 800 kW); large wind turbine (rotor diameter 35 m, rated power 1000 kW) 1962–1964 [16]

renaissance of wind power technology after 1975. Due to an agreement between America's NASA and the Danish authorities, the Gedser wind turbine was recommissioned in 1977 and served as an experimental turbine for several years. The results obtained here, together with the technical documentation from the Hütter W-34 wind turbine, formed the starting point for NASA's research work in the field of wind power technology from 1975 onward.

In the Federal Republic of Germany, the "Studiengesellschaft Windkraft e.V." (Society for the Study of Wind Power) was founded in 1949. Ulrich Hütter (Fig. 2.17), who had already distinguished himself with his papers on the theory of wind turbines in 1942, had a leading role in this. On behalf of the Allgaier Werkzeugbau GmbH in Uhingen, Germany, Hütter initially designed a small wind turbine with a 10-m rotor diameter and 8 to 10 kW rated power [18]. About 90 units of this wind turbine were built and proved to be quite satisfactory. In 1958, Hütter then started to develop a larger wind turbine, the W-34, which was to have a rotor diameter of 34 m and a rated power of 100 kW. In 1958, the wind turbine was erected in Stötten (now Schnittlingen, near Stuttgart) in the Swabian Alb in Germany (Fig. 2.16). The technical concept of Hütter's W-34 has been influencing wind turbine design in numerous features right to the present day. It was particularly the designers of the large experimental wind turbines which marked the first phase of modern-day wind-energy technology after 1975, who followed Hütter's ideas, some of them borrowing directly from the technical example of the W-34.

Figure 2.15. Danish Gedser wind turbine (rotor diameter 24 m, rated power 200 kW), 1957

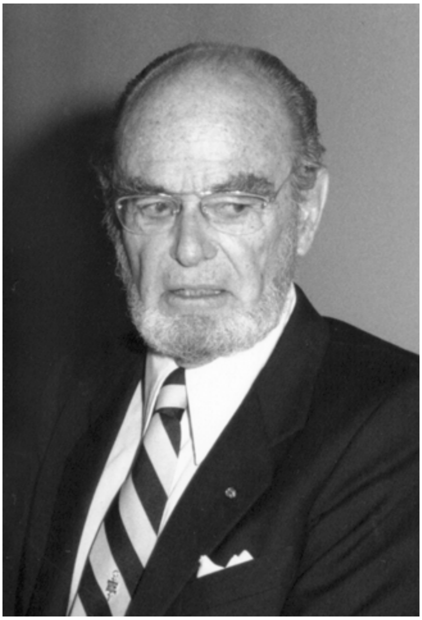
Hütter made the rotor blades of the aerodynamically refined, two-bladed high-speed rotor of an advanced glass-fibre composite material, a method which was later generally used, especially in glider construction. The rotor blades were joined to the rotor shaft via a teetering hub, which permitted teetering movements of the rotor to compensate for asymmetrical aerodynamic loads. The rotor's teetering movements were damped aerodynamically by mechanically coupling the teetering angle to the blade-pitch angle. With this "teetering hub", Hütter had found a more efficient way than Putnam who had introduced the more complex, individual flapping hinges for the rotor blades and was forced to counter the full force of the flapping movement by means of hydraulic dampers (Chapt. 6.6.2).

In relation to its rotor diameter, the W-34 had only a relatively low-rated generator power of 100 kW compared with most other wind turbines of this period. Hütter aimed at utilising the relatively low average wind speeds in the interior of the country. Moreover, he gave high priority to a lightweight construction of the wind turbine, ideas which considerably influenced the design of the later German wind turbines after 1980.

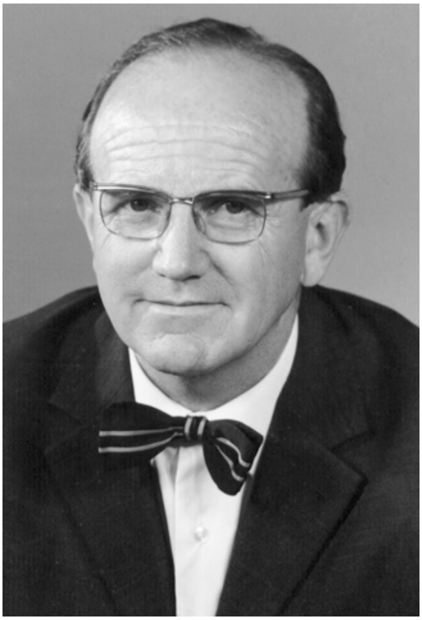
Figure 2.16. W-34 wind turbine by U. Hütter in Stötten in the Swabian Alb, Germany (rotor diameter 34 m, rated power 100 kW), 1959–1968

Poul La Cour, Denmark
1846 – 1908

Albert Betz, Germany
1885 – 1968



Palmer Cosslett Putnam, USA
1910 – 1986



Ulrich Hütter, Germany
1910 – 1989

Figure 2.17. Pioneers of wind-power technology

The W-34 was operated in the Swabian Alb in Germany from 1958 to 1968. However, compared to the ten-year period, the number of operating hours was not very high. Also, the funds available for the project were so scarce that only rudimentary systematic measuring and testing could be carried out [19]. In 1968, the wind turbine had to be dismantled as the lease for the land had expired.

If one tries to draw a conclusion from the experience gained with the first large wind turbines of these years, essentially two reasons for their lack of success will emerge: all of the wind turbines described bore the hallmarks of improvisation to a greater or lesser extent. In practical operation, numerous problems and faults had to be dealt with not all of which originated on the technical side alone but which were also due to poor organisation. All in all, this situation led to relatively modest energy yield values despite the fact that some of the wind turbines were in existence for many years.

The real reason for the discontinuation of these developments, however, is to be found in the overall energy situation of these years. Due to the extremely low prices of primary fuels, electricity from the wind had no chance economically. This technology had no way of lifting itself out of its position as outsider under the given circumstances, a position which seemed rather bizarre to most contemporaries in any case. Accordingly, the operators were not highly motivated to invest new funds in order to overcome technical difficulties.

2.5 After the Energy Crisis — A New Start toward Modern Wind Power Applications

Occasionally, when the subject of energy is being discussed, one can still see television pictures of empty roads and freeways on the so-called "car-free" days in 1973. What had actually happened was that the price of crude oil had risen to a multiple of its original price within a few months and the Western industrialised countries were suddenly made aware of their dependence on this economically vitally important primary energy source. Suddenly, everyone spoke of an "energy crisis".

In retrospect we know that the actual problem was not the availability of the oil but its increased costs and, above all, the awareness of how dependent we were on the oil exporting countries, the political stability of which could not be assessed to any degree of certainty. The primary aim was, therefore, to reduce our dependence on oil as a primary energy source. In 1973, the problem of environmental pollution due to the excessive combustion of oil scarcely figured yet in public discussions. The terms 'energy crisis' and 'environmental protection' were not yet quoted in one breath as they are today and it took another ten years for this theme to be accorded any importance.

The "oil price shock" of 1973 initially triggered a fierce public debate about how the dependence of the Western economies on oil imports could be reduced. In addition to energy saving measures, the popularity of which is still limited despite all protestations to the contrary, the politicians turned their attention to the search for other energy sources. In particular, the utilisation of renewable energy sources — i. e. of solar energy in its various forms — was discussed in countless studies and working groups and increasingly the aspect of environmental protection in the years to come.

In the United States of America, where they are even more dependent on crude oil than the European countries, NASA, the National Aeronautics and Space Administration, was given the task of developing approaches to a solution to this problem. After the Lunar Program had been wound down, NASA was interested in new fields of activity and was considered to be extremely competent technologically after its success with the Moon landing. At the same time, large industrial companies, primarily in the aerospace industry co-operating with NASA, were engaged to study the subject.

In 1973, the *U.S. Federal Wind Energy Program* was adopted. Its political management was handed to the *Department of Energy (DOE)* and a budget of approx. $ 200 million was authorised. In the following years, numerous theoretical and experimental studies were conducted, the results of which are still of significance and, in addition, several large experimental wind power plants were built and intensively tested [20]. Apart from the state funded projects, there were also some noticeable private initiatives in which it was attempted to develop modern wind power plants without much public funding. Neighbouring Canada, too, became involved in the development of wind energy technology for generating power. Similarly to the USA, the initiative came from governmental research institutions [21].

It was not long after that that the beginnings of the development of modern wind energy technology appeared in Europe where, in particular, Denmark, Sweden and the Federal Republic of Germany took the lead.

In Denmark, a commission of experts declared in 1974 "that it should be possible to generate 10 % of the Danish power requirement from wind energy without creating particular problems in the public power grid". The initial research work was concentrated on recommissioning the 200-kW plant near Gedser, built in 1957 by J. Juul. The turbine, which had been decommissioned in 1967, was overhauled in collaboration with NASA, and an extensive test program was carried out. This led directly to the erection of two large experimental turbines in the vicinity of Aalborg [22]. At the same time, as well as the development of large turbines, the private use of small turbines was being promoted. Picking up where developments had stopped in the forties, it was now possible to produce and sell the first commercially usable small 55-kW turbines in relatively large numbers. To start with, the buyers of these turbines received considerable subsidies but these were reduced over the years. By 1990, more than 2500 turbines, with outputs from 55 to about 300 kW, had been installed. This was a total of approximately 200 MW and formed the foundation stone for the Danish wind turbine industry.

In the neighbouring country of Sweden, the *National Swedish Board for Energy Source Development (NE)* was founded in 1975. In a ten-year program, about 280 million Swedish crowns were made available for the development of wind energy. In addition to theoretical and experimental research work, two large experimental turbines with a rated power of two and three Megawatt, respectively, were built [23].

In the Federal Republic of Germany, the state subsidised work on the development of wind energy goes back to the year 1974. The starting point was a program study which needs to be mentioned in some detail at this point since it had a decisive influence on the first phase of wind energy technology in Germany. The then *Bundesministerium für Forschung und Technologie* (BMFT — Federal Ministry for Research and Technology), headed by H. Matthöfer, commissioned a study with the title "Energy Sources for Tomorrow?" from the *Kernforschungsanlage (KfA) Jülich GmbH* (Jülich Nuclear Research Plant) (note the ironical question mark!).

In Part III of the study, the possibilities and limits of the "Use of Wind Energy" are dealt with [24]. Both the *Deutsche Forschungs- und Versuchsanstalt für Luft- und Raumfahrt* (now DLR — German Aerospace Research Institute) and the *Forschungsinstitut für Windenergie (FWE)* (Research Institute for Wind Energy) established by Prof. U. Hütter played a leading role in the study, as did a number of large industrial companies. The central view of the study was that the experimental turbine W-34 constructed by U. Hütter in the fifties (s. Chapter 2.4) provided the appropriate technology for modern wind turbines and that this technical concept could be adopted without major technical problems for a rotor size of up to 110 m in diameter and a rated power of 3 Megawatts.

In a first estimate of cost and economic viability, two sizes were examined in greater detail: a variant with a rotor diameter of 80 m and 1 MW power, and a larger variant with 113 m diameter and 3 MW output. The low ratio of power to rotor diameter in present-day terms is due to the fact that Hütter favoured a lightweight construction (he was an aircraft designer) and that he intended to use the wind turbines also inland under weaker wind conditions. The larger variant with 3 MW output was accorded a somewhat better economic viability, which is why the more extensive sample calculations for the power generation costs of a 100- and 300-MW wind park were carried out with this variant. The authors formulated the résumé of the study as follows:

"Although, from a technical point of view, a 3-MW turbine with a hub height of 72 m and a rotor diameter of 113 m could be built immediately, it appears to be appropriate, to maintain continuity, to proceed with a smaller step in researching the problems of vibration and control of a large turbine. For this reason, a 1-MW turbine with a tower height of about 52 m and a rotor diameter of 80 m should be constructed in the short term. The size of the turbine is already adequate for interconnection with the grid since the power output reaches a significant level" [27].

This warning was ignored by the politicians who had commissioned this study and who wanted to present the public with a quick and spectacular result. They called for the 3-MW project to be built, thus giving birth to the "Growian" (Große Windkraft-Anlage — large wind turbine) project which was to gain much notoriety in subsequent years. It is also part of this story that, although the 'engineers' expressed doubts, they did not mount any determined resistance against the demands of the 'politicians' to immediately construct a project of this magnitude. The author of this book, too, must confess to having adopted this attitude, having come into contact with the subject of wind energy for the first time in 1978 when working on the so-called "Construction Documentation for Growian" commissioned from MAN (Maschinenfabrik Augsburg Nürnberg AG).

The older reader will still remember the headlines associated with the name "Growian" in the German press. All the technical problems — of which there were more than enough naturally — were quoted as proof that the generation of power from wind energy was a fantasy of backward-looking green ideologists. Some presumed that the Growian project had been built intentionally in order to discredit the use of wind energy right from the start and suspected a conspiracy between the utilities and "big industry".

In the ensuing years, however, the success of wind energy utilisation was not hampered by the technical problems and the associated headlines about Growian. The successful small turbines from Danish and later also from German production became more and more numerous until the so-called *"Einspeisegesetz für Strom aus regenerativen Energien"* (Law relating to supplying power from regenerative energy sources) brought the breakthrough in Germany.

2.6 The Large Experimental Turbines of the Eighties

In the eighties, the state-subsidised and state-initiated programs for developing the wind energy technology were primarily orientated towards the construction of large experimental turbines. Apart from political motives, the opinion prevailing initially that the large utilities should be the potential buyers of these turbines was a decisive argument for concentrating on the development of wind turbines in the Megawatt power range, a development which came much too early from today's point of view.

The large experimental turbines were built almost exclusively by large and well-known industrial companies since only these were able to develop and build projects of this magnitude from a standing start, as it were. The names read like a "Who's Who?" guide through industry: Boeing, General Electric and Westinghouse in the US, MAN, MBB, Dornier, Voith in Germany or Kvaerner in Sweden.

The development began in the United States. From 1975 to 1987, a series of large experimental turbines designated MOD-0 to MOD-5 were erected and tested (Fig. 2.18 to 2.22) and a number of duplicates were built of some of these, e. g. of MOD-0 and MOD-2.

Figure 2.18. MOD-0 (rotor diameter 38 m, 200 kW), NASA (USA), 1975

Figure 2.19. MOD-1 (rotor diameter 61 m, 2000 kW), General Electric (USA), 1979

Figure 2.20. MOD-2 (rotor diameter 91 m, 2500 kW), Boeing (USA), 1980

Figure 2.21. MOD-5 (rotor diameter 97 m, 3200 kW), Boeing (USA), 1987

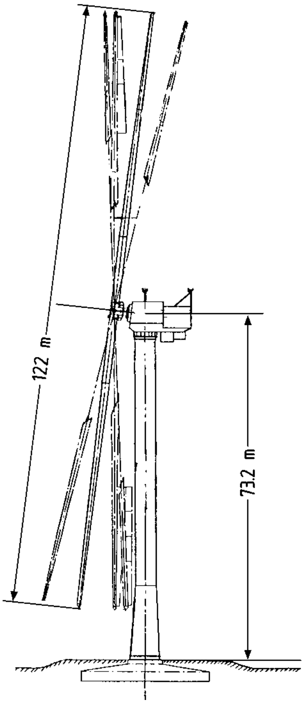


Figure 2.22. Project MOD-5A (rotor diameter 122 m, rated power 7 300 kW), General Electric (USA), 1983

The final and largest project, the MOD-5A designed by General Electric, no longer reached completion. The turbine was intended to have a rotor diameter of 122 m and a rated power of 7 300 kW (Fig. 2.22). A so-called aileron-controlled two-bladed rotor was provided as a special feature (see also Fig. 5.52). The project was cancelled in 1993 in favour of the MOD-5(B) since this design was largely based on the preceding MOD-2 turbines and could be implemented more rapidly and inexpensively with the subsidies by the DOE which were still available. After the MOD-5(B) had been tried out in the Hawaiian Islands, the state subsidised development for the large experimental turbines came to a halt in the United States.

In Denmark, a start was made by a private initiative. In 1975, the "Tvind Turbine" was erected by a syndicate at an adult education school in Ulfborg (Fig. 2.23). The turbine was built with much enthusiasm and idealism but constructed rather amateurishly in some respects. After that, the Danish utilities built the experimental systems Nibe A and Nibe B (Fig. 2.24).

In Germany, the Growian project formed the focus of the program (Fig. 2.25 and 2.26). In addition, however, innovative designs such as the Voith WEC-520 (Fig. 2.27) or several systems of the single-bladed design "Monopteros" (Fig. 2.28) were constructed. Some years later — as a second beginning as it were — the Aeolus II turbine followed in co-operation with Sweden (Fig. 2.37), and the WKI-60 on the island of Heligoland (Fig. 2.39).

In the Swedish program, the first experimental turbine bearing the designation WTS-75 (later Aeolus I), with a rated power of 2 MW and a rotor diameter of 75 m, was erected in 1982 on the island of Gotland (Fig. 2.29). A few months later, this was followed by another large turbine with 3 MW output and a rotor diameter of 78 m (Fig. 2.30). It was installed in the South of Sweden in Marglarp, not far from Malmö. The technical design of the two experimental systems was deliberately selected to be different. The turbine on Gotland represented the so-called "stiff line" with a hingeless rigid rotor hub and a rigid prestressed concrete tower. The WTS-3 in Marglarp embodied lighter-weight and more flexible principles of construction. The two-bladed rotor was provided with a teetered hub and the tower was a steel shell tower in a "soft" design from the point of view of vibration characteristics.

The two Swedish prototypes were developed in co-operation with a US company (WTS-3) and a German company (WTS-75), respectively. In the United States, the sister model to the WTS-3, the WTS-4, was built by Hamilton-Standard, and in Sweden and in Germany, the WTS-75 was developed — a few years later — and became the Aeolus II (Fig. 2.37).

In these years, the governmental research institutions in Canada initiated a development program focused on a particular technology. Managed by the *National Research Council (NRC)*, the program was concentrated on the development of vertical axis wind turbines (VAWTs) of the Darrieus type of construction. Some small-scale experimental turbines were tried out in remote regions in conjunction with diesel generators. The program reached its peak in the construction of the largest ever Darrieus rotor in 1985. The "Éole" project had an equatorial diameter of 64 m, a height of 100 m and a generator power of 4 MW (Fig. 2.31). However, the experiences gained in the relatively short operating time were not very encouraging and the turbine was dismantled and only a few test results were published. Not long after that, the Canadian development program was terminated since

Figure 2.23. Tvind turbine near Ulfborg (rotor diameter 52 m, 2000 kW), (Denmark), 1978 (photo Oelker)

Figure 2.24. Nibe A and Nibe B (rotor diameter 40 m, 630 kW), Elsam (Denmark), 1979

Figure 2.25. Growian on the Kaiser-Wilhelm-Koog (rotor diameter 100 m, 3000 kW), MAN (Germany), 1982

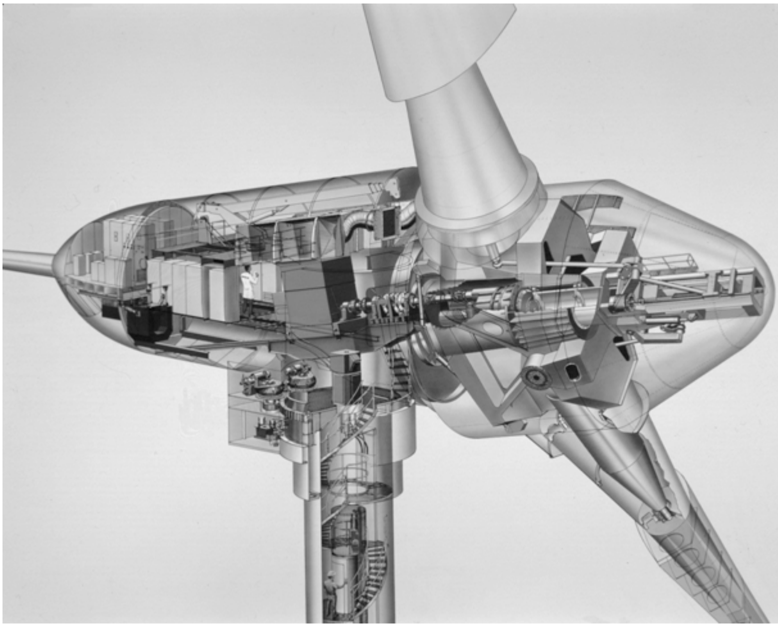


Figure 2.26. Nacelle and teetered hub of Growian

Figure 2.27. WEC-520 (rotor diameter 52 m, 270 kW), VOITH (Germany), 1982

Figure 2.28. Monopteros (rotor diameter 48 m, 600 kW), MBB (Germany), 1985

Figure 2.29. WTS-75 (Aeolus I) (rotor diameter 75 m, 2000 kW), Kvaerner (Sweden), 1983

Figure 2.30. WTS-3 (rotor diameter 78 m, 3000 kW), Swedyard (Sweden), 1982

Figure 2.31. Darrieus turbine Éole (4 MW rated power), Hydro-Québec (Canada), 1987

it was clear by now that the Vawt type of construction did not offer an alternative which was economically equivalent to the horizontal-axis turbines.

Some other countries also built government-funded experimental wind turbine systems in these years. On the island of Sardinia, the Gamma-60 was built (Fig. 2.32), In the United Kingdom, the 3-MW LS-1 by Windenergy Group and the HWP-55 turbine by the Scottish Howden Company can be mentioned (Figs. 2.33 and 2.34) and in Holland, the Newecs-45 was tested (Fig. 2.35).

A further generation of European experimental turbines, taken into operation towards the end of the eighties, was less ambitious with regard to dimensions, and was of smaller scale throughout. In contrast to the first units which were produced in national programs, these systems were developed and tested in a co-ordinated EU program. They were promoted by the EU Commission in two large research and demonstration programs *Joule* and *Thermie* [25].

In the Wega-1 programme, the operating results of a number of large wind turbines in Europe were evaluated, particularly those of the experimental Danish Tjaereborg turbine, the British HWP-55 turbine and the exerimental German WKA-60 turbine on the island of Heligoland (Fig. 2.36, 2.34 and 2.39). The evaluation programme also included experience from other large turbines, especially from the Aeolus-1 turbines, which had been built in Germany and Sweden during a Swedish-German development programme (Fig. 2.37 and 2.38), and from the Awec-60 turbine in the North-West of Spain which was implemented as sister model to the WKA-60 in a German-Spanish cooperation (Fig. 2.39 and 2.40).

Figure 2.32. Gamma-60 (rotor diameter 60 m, 1500 kW), Aeritalia (Italy), 1987

Figure 2.33. LS-1 (rotor diameter 60 m, 3000 kW), WEG (United Kingdom), 1988

In addition, the Commission placed an order with an international group of experts for a comprehensive analysis and strategic study. Apart from fundamental theoretical approaches relating to the relationship between turbine size and economic feasibility, this study also contained proposals for the further development of wind turbines in the megawatt power range (see Chapt. 19.4.1). Given this basis, the subsequent Wega-II subsidy programme was already focussed on promoting commercial prototypes [26].

Numerous governmental and private organisations were involved in the research programs, the development tasks and the evaluation of the test results. A special role was played by the *International Energy Agency (IEA)* which organized an international exchange of tests results in a working group created especially for this purpose.

The large first-generation prototypes were intensively tested in the first years of their existence and were then operated for another ten years, interrupted by relatively long periods of rest. If one wants to measure their success from the number of operating hours, the "most successful" turbines reached numbers of "a few thousand" operating hours whereas the least successful ones only attained "a few hundred" hours [27]. Compared with the politically motivated expectations, this was disappointing. Looking more closely at the whole picture, however, one arrives at a quite different assessment. This first generation of large experimental turbines largely laid the technological foundations for the modern wind energy technology and, above all, provided the necessary documentation, available to a wider public.

For the first time, a wide scientific technical foundation was created by governmental research establishments and industry and the electrical utilities, on the basis of which the

Figure 2.34. HWP-55 (rotor diameter 55 m, 1000 kW), Howden (United Kingdom), 1989

Figure 2.35. Newecs-45 (rotor diameter 45 m, 1000 kW), Stork (Holland), 1985

Figure 2.36. Tjaereborg experimental turbine (rotor diameter 61 m, 2000 kW), Elsam (Denmark), 1985

Figure 2.37. Aeolus II in Wilhelmshaven (rotor diameter 80 m, 3000 kW), MBB (Germany), 1985

Figure 2.38. Aeolus II (rotor diameter 80 m, 1500 kW), Vattenfall/MBB (Sweden), 1993

Figure 2.39. WKA-60 on Heligoland (rotor diameter 60 m, 1200 kW), MAN (Germany), 1990

Figure 2.40. AWEC-60 (rotor diameter 60 m, 1200 kW), UNION FENOSSA/MAN (Spain), 1989

personal and factual preconditions could be established to bring wind energy technology to its present-day level. This assessment in no way ignores the personal contributions of many individual "pioneers" who, with much commitment, have already designed and successfully constructed wind turbine systems long before this but the creation of an enduring and successful wind energy technology required a diversified foundation based on scientific and technical principles. This development crystallised around the large experimental turbines of the nineteen-eighties which, in serving this task, have consumed themselves, which can also be said of numerous other examples in technology.

2.7 First Successes with the Small Wind Turbines in Denmark

After the energy crisis in 1973, there was only one country in which there was a certain tradition of successfully operating small wind turbines for power generation and this was Denmark (s. Chapt. 2.1). The basic technical concept had been developed in the nineteen-forties and had found relatively wide application, although this was still modest by today's standards.

Some small and medium-sized firms in Denmark, which were active in manufacturing agricultural machinery (for example Vestas) or in some other fields of constructing simple machines and equipment, took their chance and began to build small wind turbines after the traditional model of three-bladed rotors and grid-connected induction generators and to sell these initially to private owners or agricultural holdings.

Compared with today's commercial units, the first wind turbines gaining any numerical importance in this field of application were still comparatively small with an output of 50 to 60 kW and a rotor diameter of 15 to 16 m (Fig. 2.41). In 1986, the contribution made in this way to Danish power generation was still less than one percent, but rose steeply in the following years. In Denmark, the wind turbines were not only operated by individual users of electric power. Many turbines or small groups of turbines were built and operated as "community installations" by consumer associations. This made it easier to organise their financing and operation and the legal regulations in Denmark presented no obstacles to this way of supplying oneself with electrical energy.

Until 1985, the operators in Denmark received about 30 % of the purchase value of the units as a direct subsidy from the government. Moreover, no tax was levied on the supply of energy by the wind turbines. Given this prerequisite, the utilities were able to pay a relatively favourable price for the kilowatt-hour fed into the grid (about 40 Øre, or about $US 0.07/kWh, in 1994). The governmental subsidy was greatly reduced after 1986 and was eliminated completely not much later. Nevertheless, the installation of wind turbines, which in the meantime were offered at better prices, never came to a complete standstill.

In addition to these economic background conditions, a number of other factors must also be mentioned which encouraged the successful use of wind turbines in Denmark. For example, the practice of issuing building permits was already based on generally recognised assessment criteria at a very early point in time. The technical maturity and safety of the

Figure 2.41. Remote installation of a small wind turbine at a private electricity user's holding in Denmark, 1985 (photo Rüth)

units have been attested with a test certificate by the Wind Turbine Test Station in Riso since the early nineteen-eighties. The meteorological and geographic preconditions for the successful use of wind turbines have also been researched relatively extensively and published in the *Danish Wind Atlas*. And, not least, the pattern of rural Danish settlements with its many single farms generally favoured the decentralised installation of wind turbines.

2.8 The Wind Farms in the United States

In parallel with the federal support for the development of large-scale wind power plants, the State of California, in a different type of initiative, supported subsidies for the utilisation of regenerative energy sources by indirect measures. In 1976, the Senate decided to provide for a direct tax credit of 10 % of the investment costs for solar energy utilisation. This tax credit could only be claimed by private investors. The Federal Government followed suit two years later. In their *National Energy Act* passed in 1978, further concessions were granted for the tax to be paid to the Federal Government and, over the years, supplementary tax laws were added including one relating to the accelerated depreciation of investments of this type. By the end of 1985, the tax advantages for the investors had accumulated into a maximum of 50 % of the investment costs and, in some cases, even more, taking into account the possibilities of accelerated depreciation.

The revenue from power sales had the same degree of importance as the fiscal measures. Under the *Public Utilities Regulatory Policy Act* (PURPA), the public utilities were obliged to accept the power generated from regenerative energy sources in their grids and to pay for it in accordance with the principle of "maximum avoided costs". This means that they had to use as a basis for their calculations the highest costs saved at the conventional power stations. In 1984/'85, the two largest utilities in California, the Pacific Gas and Electric Company (PG & E) and the Southern California Edison Company (SCE), paid up to 10 cent for the power fed into their grids depending on the time of day and the season. In 1986, they still paid $US 0.07–0.09/kWh on average.

There is one more comment which should be made regarding the energy industry in general. The construction of conventional power stations had decreased dramatically since the beginning of the seventies, partly because the building of new power stations was hampered severely by the environmental conditions imposed by now. Many projects for nuclear power stations came to nothing because of the enormous increase in the capital costs involved. In this situation, the utilities were only too willing to purchase power without having to risk any investments of their own and this willingness, ultimately, proved to be of benefit to the wind farms financed by private investments.

Against this economic background, the first wind farms were built between 1979 and 1980. So-called "developers" or "wind farmers" concluded delivery contracts with the utilities mentioned above, purchased or leased suitable stretches of land and encouraged private investors — especially those taxed highly — to buy wind turbines which were then erected and operated on their land.

At the beginning, the technical basis for the wind farms consisted of relatively small wind turbine units with a power of up to about 100 kW which were developed by US companies and constructed quickly by mass production techniques. Unlike Denmark, however, these manufacturers had no basic fund of proven technical designs and experience that they could tap into. Their systems, whilst quite innovative technically in some cases, turned out to be generally not very reliable so that there was an increasing demand for more thoroughly proven designs. In the meantime, the Danish manufacturers had been able to accumulate a considerable amount of experience in their home market and used the opportunity to expand their production by exporting to the United States.

After a tardy beginning, the development took off dramatically around 1981. New wind farms sprang up almost daily, many of which disappeared as quickly as they had come into being. Some regions of California were virtually in the grip of a gold rush mentality which also extended to business practices.

The Californian wind farms were essentially concentrated in three regions: the area of the Altamont Pass, east of San Francisco; the Tehachapi Mountains, not far from Bakersfield; and the area of the San Gorgonio Pass, near Palm Springs, about four hours' driving east of Los Angeles (Fig. 2.42). There are an additional number of relatively small regions where wind farms are installed but these are not very significant numerically.

Some explanations are needed with regard to the local meteorological conditions since these are somewhat unique. The Californian wind farms are located on the heights of the coastal foothills bounding the Central Valley to the west and to the east. In the interior east of the Sierra Nevada range, there are the desert regions of the Great Basin, for example the Mojave Desert and Death Valley. During the hot season, which lasts almost all year in California, the air over the desert regions heats up considerably and the rising masses of air produce a low-pressure region into which the cooler air from the Pacific flows via the coastal foothills. At exposed heights, mean annual wind velocities of up to 9 m/s are reached. In the mountainous terrain, however, the wind conditions are extremely dependent on the location.

This meteorological mechanism is also responsible for the diurnal variation of the wind velocity. The heating up of the desert reaches its peak only around noon which means that the wind over the mountains does not rise up before noon either, and it then blows quite consistently in the afternoon and evening until about midnight. This diurnal variation creates a special advantage for the wind farms. The peak of the power production coincides well with the noon and evenings peaks in demand and the payments for the power generated, calculated in accordance with the "maximum avoided costs" formula, are also highest at these times.

The number of installed wind turbines rose rapidly until 1985. By the end of 1985, about 40 % of all wind turbines in California had come from Denmark. The Danish wind turbine industry, with an annual production of more than 3000 units in 1985, had been built up mainly for the Californian wind farms. At the beginning of 1987, about 15 000 units with a total power output of approximately 1400 MW had been installed in the wind farms of California (Figs. 2.43 to 2.46).

In the years between 1986 and 1987, the economic situation of the Californian wind farms changed considerably. On the one hand, the high tax credits for the investors expired at the end of 1985 and, on the other hand, the power generation costs, which are closely linked to the oil price in California, dropped. For these reasons, the utilities offered much

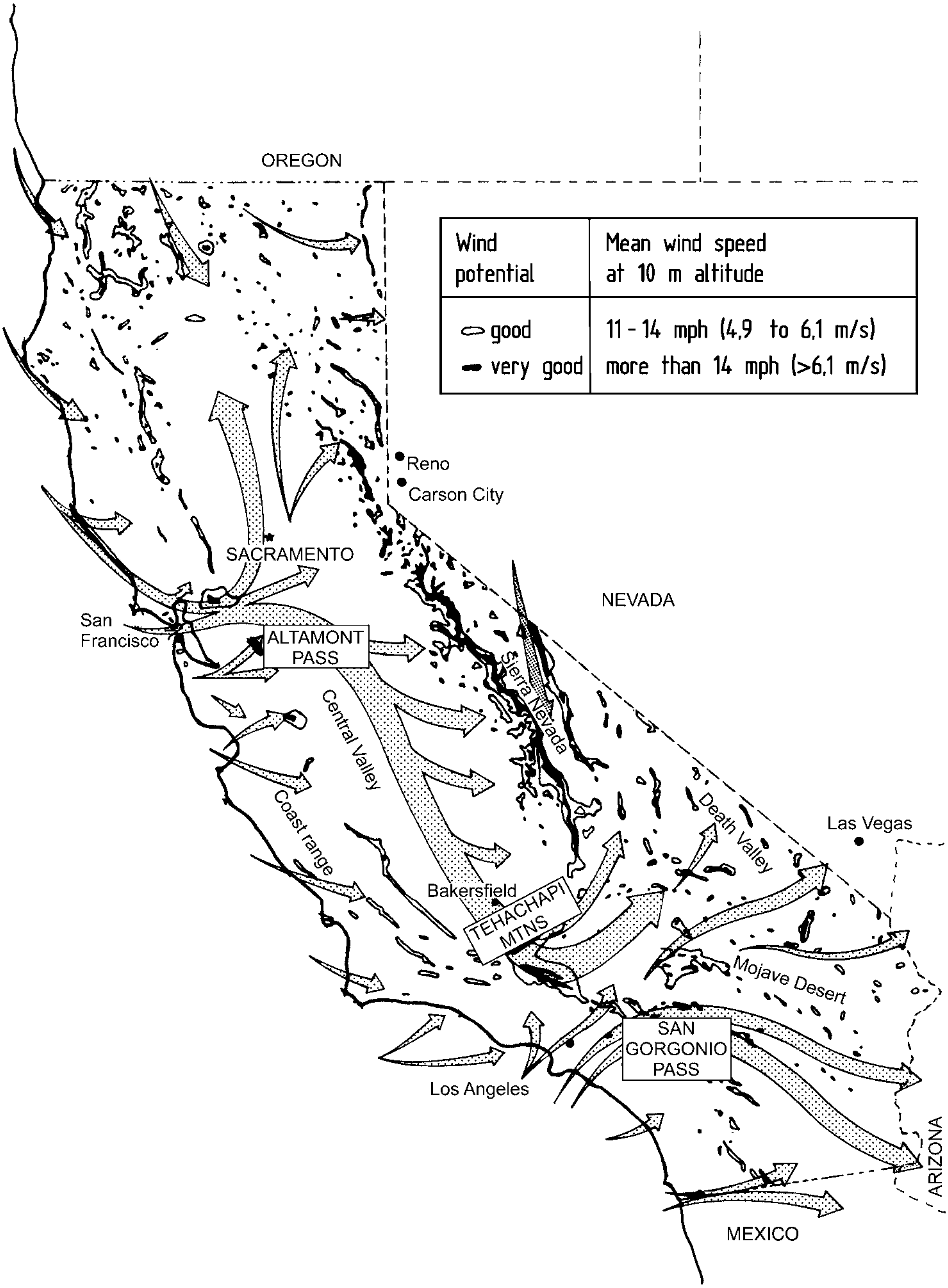


Figure 2.42. The most important areas of installation and the wind conditions of the wind farms in California

Figure 2.43. Wind turbines (US Windpower) at the Altamont Pass, 1985

Figure 2.44. Wind farm with Danish Micon turbines at the San Gorgonio Pass, 1986

Figure 2.45. Wind farm with MAN-Aeroman turbines, on the Tehachapi Mountains, 1986

Figure 2.46. Flowind wind farm with vertical axis Darrieus turbines on the Tehachapi Mountains, 1986

lower supply tariffs for new contracts and the wind farmers thus came under pressure from two sides.

Nevertheless, the pessimists did not win the day. Wind farms continued to be built, albeit at a somewhat slower rate. It was especially the undertakings which were reasonably well off and had long-term supply contracts with the utilities which survived the loss of the tax credits. The manufacturers of the wind turbines also played a role in the survival of the wind farms. Producing new and larger units, which were offered at much lower specific costs than the first series, they created the prerequisites for power generation costs which approach economic viability even without tax advantages for the investors so that those wind farms which were well organised survived.

Today, however, after more than fifteen years, the wind farms in California leave an impression which is rather depressing. Due to the further deterioration in the economic background conditions at the beginning of the nineteen-nineties, all development came to a virtual standstill. No new wind farms were being built and those still in existence are hopelessly outdated.

On the other hand, there are other States in the US in which wind energy is being utilised again to a greater extent, particularly in the States of Iowa, Texas and some others. In the US a wind energy capacity of 4 500 MW was registered towards the end of 2003. New wind farms have been built and are being built and in these new installations, larger and more advanced wind turbines are being used. The Californian wind farms with their excellent wind conditions, however, are still largely waiting to be resurrected and to be re-equipped with new and larger and much more efficient wind turbines.

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Chapter 3

Basic Concepts of Wind Energy Converters

There are many different ways in which devices to convert the kinetic energy contained in an air stream into mechanical work can be realised and the most bizarre concepts have been proposed [1]. Museums and patent offices are filled to the rafters with more or less promising inventions of this type. In most cases, however, the practical applicability of these "wind power plants" falls far behind the inventors' expectations.

An attempt to develop an orderly and systematic classification of wind energy converter types is certainly an interesting task, but it brings little reward as the number of significant designs is drastically limited by their practical usefulness. When speaking of varying designs one should be aware of the fact that primarily varying designs of the wind energy converter, the wind rotor, are meant. But the wind rotor is not the only component of a wind turbine. Other components for the mechanical-electrical energy conversion such as gearbox, generator, control systems and a variety of auxiliary units and items of equipment are just as necessary for producing usable electric energy from the wind rotor's rotational motion. Many inventors of novel wind rotors, however, do not seem to be aware of this fact when they are hoping that their invention of a different rotor design will improve everything.

Wind energy converters can be classified firstly in accordance with their aerodynamic function and, secondly, according to their constructional design. The rotor's aerodynamic function is characterised by the fact of whether the wind energy converter captures its power exclusively from the aerodynamic drag of the air stream acting on rotor surfaces, or whether it is able to utilise the aerodynamic lift created by the flow against suitably shaped surfaces. Accordingly, there are so-called "drag-type rotors" and "rotors which make use of the aerodynamic lift". Occasionally, the aerodynamic "tip-speed ratio" is used to characterise wind rotors and one speaks of "low-speed and high-speed rotors" in this case (Chapt. 5.2). These characteristics, however, are of little significance to modern wind turbines. Apart from the American wind turbine, almost all other wind turbines designs are of the high-speed type.

Classification according to constructional design aspects is more practicable for obvious reasons and thus more common. The characteristic which most obviously meets the eye is the position of the axis of rotation of the wind rotor. Thus, it is important to make a distinction between rotors which have a vertical axis of rotation, and those with a horizontal axis of rotation.

3.1 Rotors with a Vertical Axis of Rotation

The oldest design of wind rotors features rotors with a vertical axis of rotation (Fig. 3.1). At the beginning, however, vertical-axis rotors could only be built as pure drag-type rotors. The "Savonius rotor", which can be found as ventilator on railroad carriages or delivery vans, and the cup anemometer used to measure wind velocity are well-known examples of rotors with a vertical axis of rotation.

It was only recently that engineers succeeded in developing vertical-axis designs which could also effectively utilise aerodynamic lift. The design proposed in 1925 by the French engineer Darrieus, in particular, has been considered as a promising concept for modern wind turbines (Fig. 3.2). In the "Darrieus rotor", the blades are shaped and rotate in the pattern of a surface line on a geometric solid of revolution, a *troposkien* (i. e. "turning rope" in Greek), with a vertical axis of rotation. This makes the geometric shape of the rotor blades complicated and thus difficult to manufacture. As is the case with horizontal-axis rotors, Darrieus rotors are preferably built with two or three rotor blades.

The specific advantages of vertical axis turbine concepts are that their basically simple design includes the possibility of housing mechanical and electrical components, gearbox

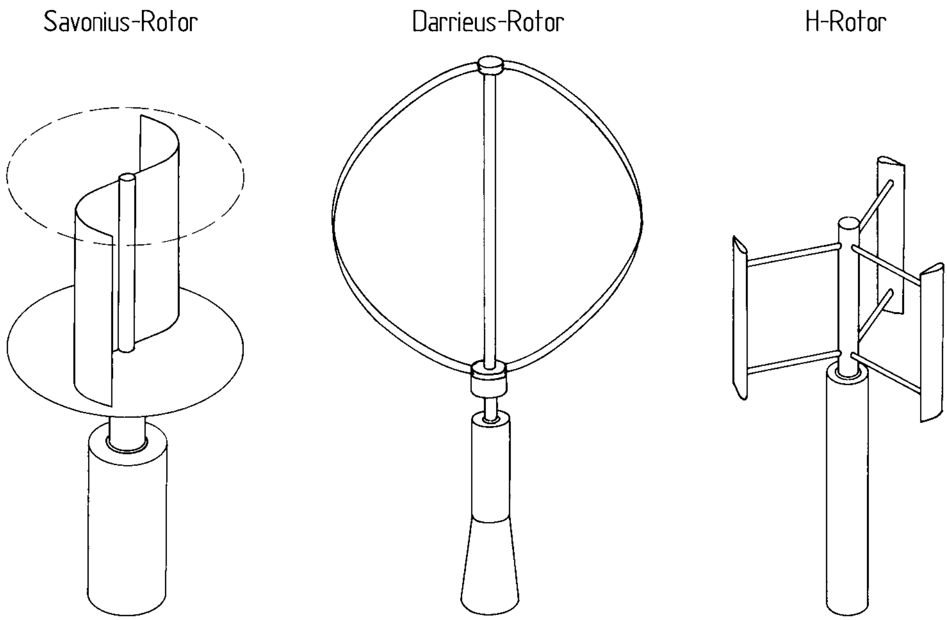

Figure 3.1. Rotor concepts with a vertical axis of rotation

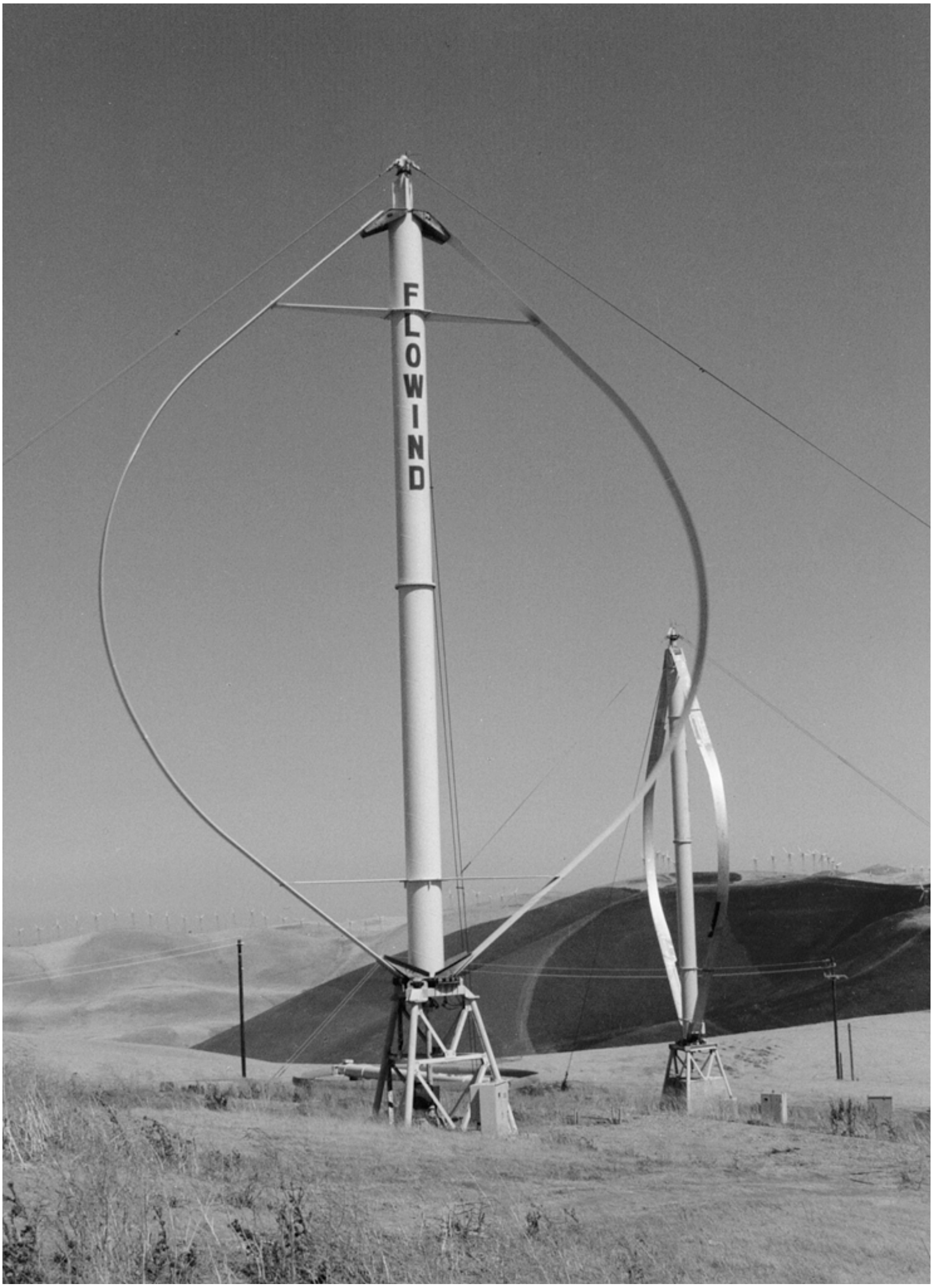

Figure 3.2. Darrieus wind turbines of the former American Flowind company (rotor diameter 19 m, power output 170 kW)

and generator at ground level and that there is no yaw system. This is countered by disadvantages such as its low tip-speed ratio, its inability to self-start and not being able to control power output or speed by pitching the rotor blades.

A variation of the Darrieus rotor is the so-called H-rotor. Instead of curved rotor blades, straight blades connected to the rotor shaft by struts are used. Attempts were made particularly in the UK, in the US and in Germany to develop this design to commercial maturity. Based on plans of the British engineer Musgrove, H-rotors with variable rotor geometry were also tested in order to permit at least a rough degree of power and speed control [2]. However, to the present day, the production costs of these systems are still so high that they cannot compete with horizontal-axis rotors (Chapt. 5.7). H-rotors of a particularly simple structure, with the permanently excited generator integrated directly into the rotor structure without intermediary gear-box, were developed by a German manufacturer up

Figure 3.3. H-rotor wind turbine (rotor diameter 35 m, 300 kW rated power) (Heidelberg)

until the beginning of the nineties [3] (Fig. 3.3) but the development was halted then since there was no economic success in sight.

Occasionally, the *Savonius* design is used for small, simple wind rotors, especially for driving small water pumps. It is not suitable for electricity-generating wind turbines due to its low tip-speed ratio and its comparatively low power coefficient. With an optimised aerodynamic design, the Savonius rotor can also make use of aerodynamic lift and its maximum power coefficient is then of the order of 0.25 (Chapt. 4.2).

Apart from these concepts, a number of proposals for vertical-axis rotors with a great variety of geometries are known, for example with blades in a V-shaped configuration and tilted rotor axis. The inventors expect this to be a particularly simple and inexpensive design but it remains to be seen whether these hopes will be fulfilled. Moreover, rotor designs such as these inevitably have a much lower power coefficient, which, in turn, has economic repercussions despite the potentially lower installation costs.

Altogether, it can be said that wind rotors with vertical axes and among these primarily the Darrieus rotor, might still have a potential for development which has not been exhausted yet. Whether the basic advantages of this design can prevail over its disadvantages and whether it will become a serious rival to the horizontal-axis rotors cannot be foreseen for the long-term. In any case, this will still require a relatively long period of development.

3.2 Horizontal Axis Rotors

Wind energy converters which have their axis of rotation in a horizontal position are realised almost exclusively on the basis of "propeller-like" concepts (Fig. 3.4). This design, which includes European windmills as much as the American wind turbine or modern wind turbines, is the dominant design principle in wind energy technology today. The undisputed superiority of this design to date is largely based on the following characteristics:

- In propeller designs, rotor speed and power output can be controlled by pitching the rotor blades about their longitudinal axis (blade pitch control). Moreover, rotor blade pitching is the most effective protection against overspeed and extreme wind speeds, especially in large wind turbines.
- The rotor blade shape can be aerodynamically optimised and it has been proven that it will achieve its highest efficiency when aerodynamic lift is exploited to a maximum degree.
- Not least, the technological lead in the development of propeller design is a decisive factor.

Together, these advantages are the reason why almost all wind turbines for generating electricity built to date have horizontal-axis rotors.

Fig. 3.5 shows the schematic arrangement of a horizontal-axis wind turbine. The components and their configuration are typical of a large modern wind turbine. Naturally, designs differing from this standard concept are also possible and constructional simplifications such as the absence of pitch control can be found, particularly in small wind turbines.

Figure 3.4. Horizontal-axis wind turbine: Bonus/Siemens Wind Power, (rotor diameter 107 m, rated power 3.6 MW) prototype, 2005 (Siemens)

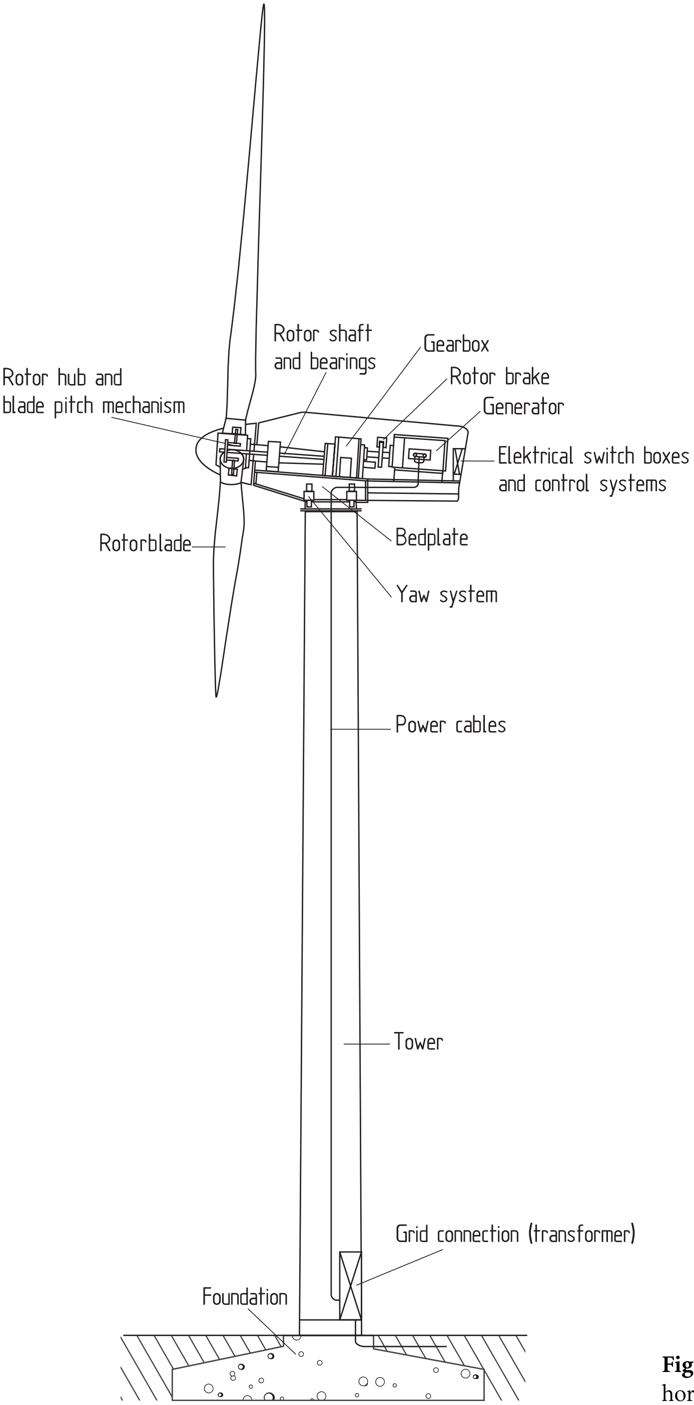

Figure 3.5. Components of a horizontal-axis wind turbine

3.3 Wind Energy Concentrators

Before discussing the technology of the propeller type in more detail, some innovative concepts will be described, as they play a role in this discussion and some are also being tested in experimental programs. It is doubtful, however, at least in some cases, whether these "wind power plants" will ever achieve practical significance. The individual assessment of inventions in the field of wind energy is a thankless task and the author will, therefore, refrain from doing so in this book.

The basic idea common to all these concepts is to increase the power yield in relation to the rotor-swept area. Basically, this can be achieved by static, i. e. non-rotating structures which produce an acceleration in the flow velocity to the rotor or, in some cases, even generate concentrating vortices (Fig. 3.6). The intention is to achieve a drastic reduction in rotor size whilst at the same time hoping that the additional construction required for "pre-concentrating" the wind energy will not become too expensive.

Ducted rotor

The simplest method for increasing rotor efficiency is to enclose it in a duct. The duct prevents narrowing of the flow tube before it reaches the converter, which is unavoidable with a rotor in a free air stream. The achievable power coefficient exceeds the Betz value and is about $c_P = 0.66$ [5]. Instead of using a full duct, effects similar to those of a ducted flow can, to a smaller degree, be achieved with the help of endplates at the blade tips [4].

Turbine with a diffuser duct

An obvious idea aimed at "capturing more wind" is to mount a funnel in front of the rotor. However, theoretical and experimental investigations have shown that this does not achieve an increase in power capture in practice. Apparently, the airflow through the funnel is determined by the smaller opening, and the funnel additionally produces a circulatory flow counteracting the wind stream.

It is more effective to place the rotor in a duct in the shape of a reversed funnel, a diffuser. This results in an additional circulatory flow the speed components of which in the diffuser have the same direction as the wind stream, thus reinforcing it. The power coefficient of the rotor rises to values of 2.0 to 2.5 relative to the rotor-swept area [5] but, to obtain fair results, the power coefficient must now be related to the maximum cross-sectional area of the diffuser. This reduces the power coefficient to about 0.75, which is still a modest gain compared to the free-stream rotor.

Vortex tower

An increase in wind concentration can also be achieved by superimposing a stationary vortex on the wind flow so that the velocity field of the vortex has an extra driving effect on the rotor. This effect can be produced by various types of concentrator. One idea is the so-called "vortex tower" or "tornado tower" [6]. In a tower with shutters arranged on the cylinder jacket, the wind flows tangentially into the interior of the duct where it forms

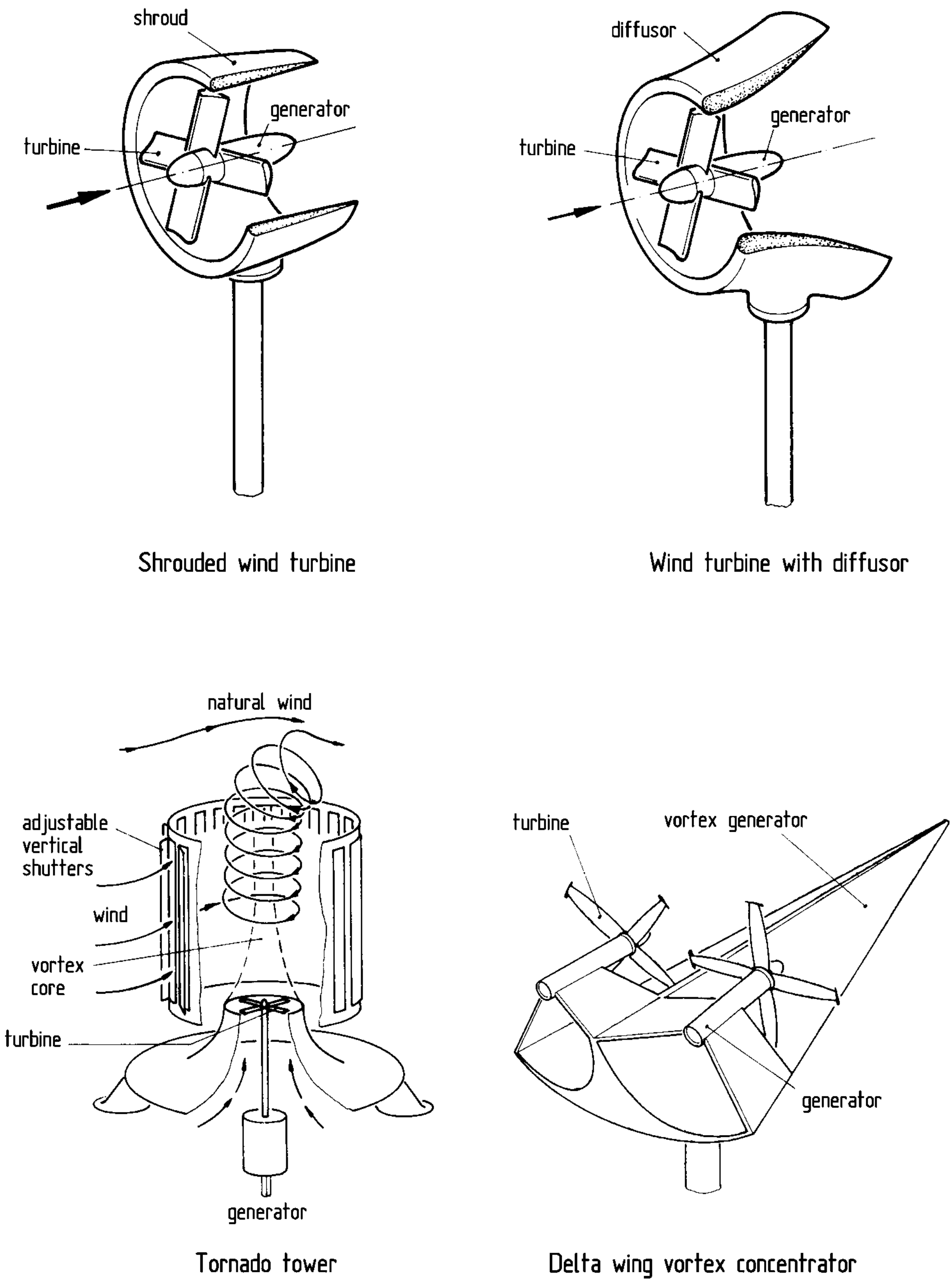

Figure 3.6. Wind rotor concepts combined with static structures for concentrating wind energy

a tornado-like air vortex. Due to the low pressure in the vortex centre, air is sucked in from the bottom of the tower into the duct from the outside, thus driving a turbine with a diameter which is about a third of the tower diameter. However, this principle has only been examined in the wind tunnel so far. Applying it to a real, full-sized wind turbine would probably meet with considerable problems, for example noise emission. The conclusion drawn by theoretical assessments of this design concept is that the power coefficient related to the maximum plan-view swept area of the entire structure reaches values of only 0.1 [5].

Vortex concentration with a "delta wing"

Concentrated air vortices occur as so-called boundary vortices in the flow around an aircraft wing. This occurs to a particularly high degree with delta wings with large angles of attack. Attempts have been made to utilise this effect for wind energy technology. The wind rotors are mounted on a static structure in the shape of a delta wing so that they work in the boundary vortices of the delta wing. A reliable theory for this complex case was not available but theoretical estimates led to the hope that the power yield would increase by a factor of 10, compared to a rotor with in a conventional free air stream. In the end, the result of model measurements in the wind tunnel turned out to be so disappointing that the project was cancelled [7].

Concentrator wind turbine

The Technical University of Berlin has proposed and investigated another variant of wind concentrator with the name of "Berwian" (Fig. 3.7). A fixed stator wheel with a number of blades generates a strong vortex in the centre of the concentrator. The six- to eight-fold increase in wind power is utilised by a small wind rotor in the centre of the stator construc-

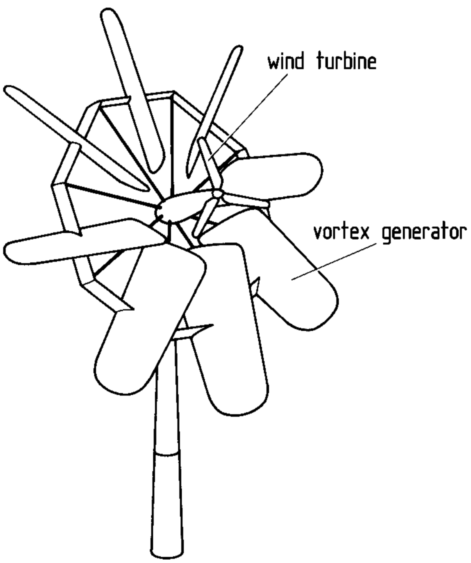

Figure 3.7. Concentrator-type wind turbine "Berwian" [8]

tion. Several variants of this design concept have been tested in the wind tunnel and in the free atmosphere and have confirmed the concentration factors predicted in theory [8]. One main problem is the strength of the stator in extreme winds. The blades of the stator have to be movable so that they can be turned out of the wind in order to avoid extreme wind loads. Structural complexity and the cost of the static structure are, therefore, considerable also in this case.

Thermal upwind concept

The so-called thermal upwind power plant is based on the idea of generating an air flow, as occurs naturally due to a rise in temperature, i. e. due to differences in air density. In this concept, an updraft or upwind is generated in a high tower surrounded by a ground-level canopy which absorbs solar radiation (Fig. 3.8) and this upwind drives an air turbine.

Strictly speaking, this is not a wind turbine utilising natural wind but rather a solar power concept utilising solar radiation. An advantage of this principle is its application in areas otherwise inaccessible to "normal" wind power utilisation. An experimental plant with a projected power output of 100 kW was tested in Spain, funded by the German Ministry of Research and Technology (Figs. 3.9 and 3.10). The tests and measurements carried out in 1982 and 1983 yielded a power output of about 50 kW. The promoters pointed out, however, that this design achieves its maximum efficiency only with considerably larger dimensions and that, moreover, cost comparisons would have to be made with plants for the direct utilisation of solar radiation and not with conventional wind turbines [9].

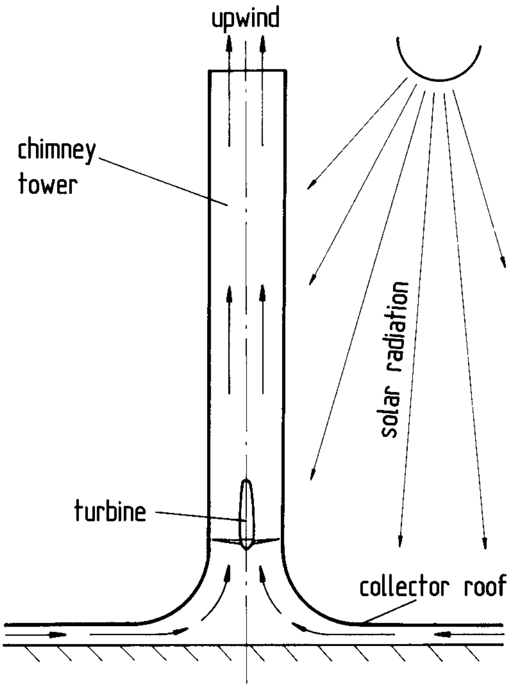

Figure 3.8. Schematic concept of a Thermal upwind power plant

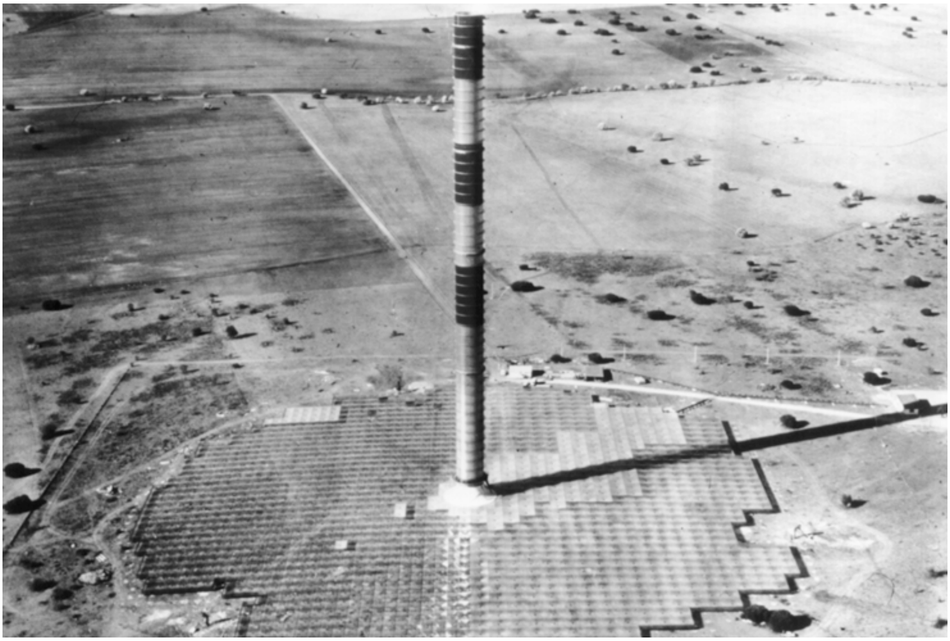

Figure 3.9. Experimental thermal upwind power plant in Manzanares, Spain, 1985. Tower height 200 m, tower diameter 10 m, diameter of collector roof about 250 m (Schlaich & Partner)

Figure 3.10. Wind turbine inside the tower (Schlaich & Partner)

3.4 Terms and Expressions

"Before you argue, clarify your terms" (Confucius, 551 to 479 BC.). It would certainly be better to follow the advice of this Chinese philosopher than to justify later confusion with pleasant-sounding phrases like "What's in a name?". Clear and unambiguous definitions of terms are the indispensable prerequisite for a systematic modus operandi and wind energy technology is no exception in this respect.

The designation of the subject matter of this book will be considered first. The title of this book is "Wind Turbines". Specialist literature offers a wide variety of similar, but not quite identical terms of which windmill, windwheel, wind generator, wind energy converter, wind energy plant, wind power plant are the most common ones.

It is obvious that a term like windmill is unsuitable for a machine generating electricity. The term windmill, by the way, in many cases was not correct even in its time, as windmills were by no means used exclusively for milling grain. As to the selection of the remaining terms, this is a matter of taste. They capture the meaning of the object to a varying degree. The decision for "wind turbine", in contrast to "wind power plant", seemed more appropriate to the author. Considering the relatively modest power output compared to conventional power plants, wind power plant seems somewhat pretentious. It should be noted that "wind turbine" is used for the whole system and not for the turbine in its narrower sense which is called the "rotor".

The main components of a horizontal-axis wind turbine have already been described (Fig. 3.5). The technical terms used there also require some description and explanation.

The actual wind energy converter, the "windwheel" in an old windmill, is called the "rotor" in a modern wind turbine. Different rotors have differing numbers of "rotor blades". The term "sails", still frequently used, should be avoided. Rotor blades should definitely not go sailing off into the sunset!

The rotor blades are connected to the rotor shaft by means of a "hub". In wind turbines with "blade pitch control", the hub contains the blade bearings and the "blade pitch mechanism". Many smaller wind turbines are not fitted with a blade pitch control. The rotor blades then have a fixed connection to the hub.

The "drive train" of the wind turbine converts the rotor's mechanical rotational motion into electrical energy. In its narrower sense, the term "drive train" is only used for the mechanical components, excluding the electrical system. The rotor hub, with the blade pitch mechanism, the "rotor shaft", also called "low-speed shaft", the gearbox and the generator drive shaft, which, in contrast to the rotor shaft is called the "high-speed shaft", are all part of the drive train. The drive train components are housed in the "nacelle".

The nacelle and rotor is turned into the wind direction by the "yaw system" or "azimuth drive". The nacelle is mounted on top of a "tower" or "mast". The term "mast" is more suitable for very small wind turbines.

Apart from these terms, a number of other terms and designations are used in the various chapters of this book. These, however, have nothing to do with wind power technology per se, but have their roots in other fields such as aerodynamics, electrical engineering or power plant technology. It is recommended to take notice of this nomenclature and not to change it at will only because one is not familiar with the specific field. The author certainly has made an effort to do so. In an age where communication between different scientific disciplines tends to be replaced by dialogue with a computer screen, the remainders of commonly understood terms and language should be preserved and protected.

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Chapter 4

Physical Principles of Wind Energy Conversion

The primary component of a wind turbine is the energy converter which transforms the kinetic energy contained in the moving air, into mechanical energy. For the initial discussions of principles, the exact nature of the energy converter is irrelevant. The extraction of mechanical energy from a stream of moving air with the help of a disk-shaped, rotating wind energy converter follows its own basic rules.

The credit for having recognised this principle is owed to Albert Betz. Between 1922 and 1925, Betz published writings in which he was able to show that, by applying elementary physical laws, the mechanical energy extractable from an air stream passing through a given cross-sectional area is restricted to a certain fixed proportion of the energy or power contained in the air stream [1]. Moreover, he found that optimal power extraction could only be realised at a certain ratio between the flow velocity of air in front of the energy converter and the flow velocity behind the converter.

Although Betz's "momentum theory", which assumes an energy converter working without losses in a frictionless airflow, contains simplifications, its results are quite usable for performing rough calculations in practical engineering. But its true significance is founded in the fact that it provides a common physical basis for the understanding and operation of wind energy converters of various designs. For this reason, the following sections will provide a summarised mathematical derivation of the elementary "momentum theory" by Betz. The reader who is not, or no longer, familiar with mathematical equations may skip these. The most important results are also explained in the text.

4.1 Betz's Elementary Momentum Theory

The kinetic energy of an air mass m moving at a velocity v can be expressed as:

$$E = \frac{1}{2} m v^2 \qquad \text{(Nm)}$$

Considering a certain cross-sectional area A, through which the air passes at velocity v, the volume $\dot{V}$ flowing through during a certain time unit, the so-called volume flow, is:

$$\dot{V} = v A \qquad (\text{m}^3/\text{s})$$

and the mass flow with the air density ϱ is:

$$\dot{m} = \varrho\, v\, A \qquad \text{(kg/s)}$$

The equations expressing the kinetic energy of the moving air and the mass flow yield the amount of energy passing through cross-section A per unit time. This energy is physically identical to the power P:

$$P = \frac{1}{2} \varrho\, v^3 A \qquad \text{(W)}$$

The question is how much mechanical energy can be extracted from the free-stream airflow by an energy converter. As mechanical energy can only be extracted at the cost of the kinetic energy contained in the wind stream, this means that, with an unchanged mass flow, the flow velocity behind the wind energy converter must decrease. Reduced velocity, however, means at the same time a widening of the cross-section, as the same mass flow must pass through it. It is thus necessary to consider the conditions in front of and behind the converter (Fig. 4.1).

Here, v_1 is the undelayed free-stream velocity, the wind velocity, before it reaches the converter, whereas v_2 is the flow velocity behind the converter.

The mechanical energy which the disk-shaped converter extracts from the airflow corresponds to the power difference of the air stream before and after the converter:

$$P = \frac{1}{2} \varrho\, A_1 v_1^3 - \frac{1}{2} \varrho\, A_2 v_2^3 = \frac{1}{2} \varrho \left(A_1 v_1^3 - A_2 v_2^3 \right) \qquad \text{(W)}$$

Maintaining the mass flow (continuity equation) requires that:

$$\varrho\, v_1 A_1 = \varrho\, v_2 A_2 \qquad \text{(kg/s)}$$

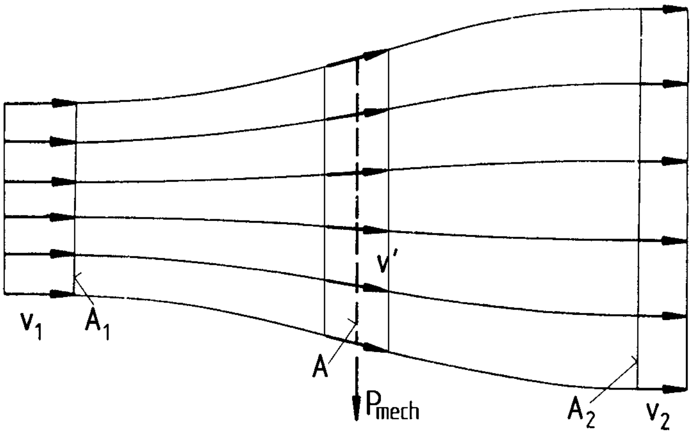

Figure 4.1. Flow conditions due to the extraction of mechanical energy from a free-stream air flow, according to the elementary momentum theory

Thus,

$$P = \frac{1}{2} \varrho \, v_1 A_1 \left(v_1^2 - v_2^2 \right) \qquad \text{(W)}$$

or

$$P = \frac{1}{2} \dot{m} \left(v_1^2 - v_2^2 \right) \qquad \text{(W)}$$

From this equation it follows that, in purely formal terms, power would have to be at its maximum when v_2 is zero, namely when the air is brought to a complete standstill by the converter. However, this result does not make sense physically. If the outflow velocity v_2 behind the converter is zero, then the inflow velocity before the converter must also become zero, implying that there would be no more flow through the converter at all. As could be expected, a physically meaningful result consists in a certain numerical ratio of v_2/v_1 where the extractable power reaches its maximum.

This requires another equation expressing the mechanical power of the converter. Using the law of conservation of momentum, the force which the air exerts on the converter can be expressed as:

$$F = \dot{m} \left(v_1 - v_2 \right) \qquad \text{(N)}$$

According to the principle of "action equals reaction", this force, the thrust, must be counteracted by an equal force exerted by the converter on the airflow. The thrust, so to speak, pushes the air mass at air velocity v', present in the plane of flow of the converter. The power required for this is:

$$P = F v' = \dot{m} \left(v_1 - v_2 \right) v' \qquad \text{(W)}$$

Thus, the mechanical power extracted from the air flow can be derived from the energy or power difference before and after the converter, on the one hand, and, on the other hand, from the thrust and the flow velocity. Equating these two expressions yields the relationship for the flow velocity v':

$$\frac{1}{2} \dot{m} \left(v_1^2 - v_2^2 \right) = \dot{m} \left(v_1 - v_2 \right) v' \qquad \text{(W)}$$

$$v' = \frac{1}{2} \left(v_1 - v_2 \right) \qquad \text{(m/s)}$$

Thus the flow velocity through the converter is equal to the arithmetic mean of v_1 and v_2:

$$v' = \frac{v_1 + v_2}{2} \qquad \text{(m/s)}$$

The mass flow thus becomes:

$$\dot{m} = \varrho A v' = \frac{1}{2} \varrho A \left(v_1 + v_2 \right) \qquad \text{(kg/s)}$$

The mechanical power output of the converter can be expressed as:

$$P = \frac{1}{4}\varrho A \left(v_1^2 - v_2^2\right)(v_1 + v_2) \qquad \text{(W)}$$

In order to provide a reference for this power output, it is compared with the power of the free-air stream which flows through the same cross-sectional area A, without mechanical power being extracted from it. This power was:

$$P_0 = \frac{1}{2}\varrho v_1^3 A \qquad \text{(W)}$$

The ratio between the mechanical power extracted by the converter and that of the undisturbed air stream is called the "power coefficient" c_P:

$$c_P = \frac{P}{P_0} = \frac{\frac{1}{4}\varrho A \left(v_1^2 - v_2^2\right)(v_1 + v_2)}{\frac{1}{2}\varrho A v_1^3} \qquad (\text{—})$$

After some re-arrangement, the power coefficient can be specified directly as a function of the velocity ratio v_2/v_1:

$$c_P = \frac{P}{P_0} = \frac{1}{2}\left|1 - \left(\frac{v_2}{v_1}\right)^2\right|\left|1 + \frac{v_2}{v_1}\right| \qquad (\text{—})$$

The power coefficient, i.e. the ratio of the extractable mechanical power to the power contained in the air stream, therefore, now only depends on the ratio of the air velocities

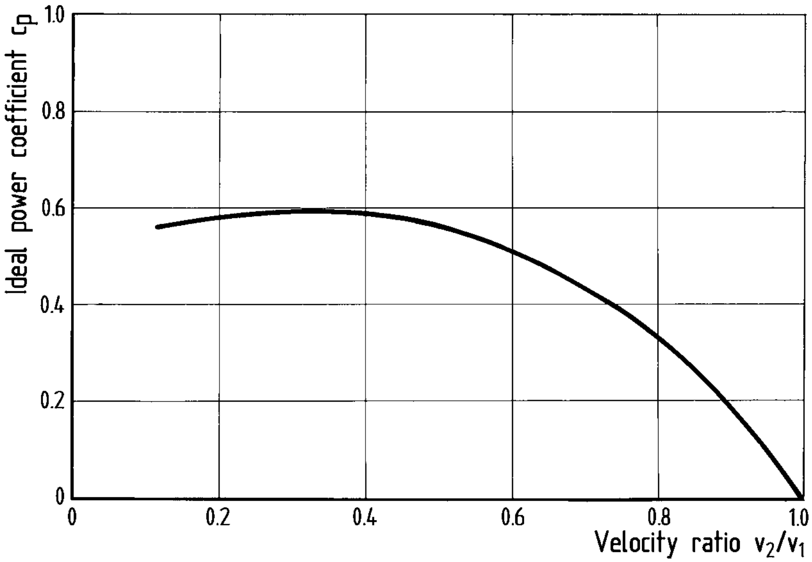

Figure 4.2. Power coefficient versus the flow velocity ratio of the flow before and after the energy converter

before and after the converter. If this interrelationship is plotted graphically — naturally, an analytical solution can also be found easily — it can be seen that the power coefficient reaches a maximum at a certain velocity ratio (Fig. 4.2).

With $v_2/v_1 = 1/3$, the maximum "ideal power coefficient" c_p becomes

$$c_p = \frac{16}{27} = 0{,}593$$

Betz was the first to derive this important value and it is, therefore, frequently called the "Betz factor".

Knowing that the maximum, ideal power coefficient is reached at $v_2/v_1 = 1/3$, the flow velocity v'

$$v' = \frac{2}{3} v_1$$

and the required reduced velocity v_2 behind the converter can be calculated:

$$v_2 = \frac{1}{3} v_1$$

Fig. 4.3 shows the flow conditions through the wind energy converter once again, in greater detail. In addition to the flow lines, the variations of the associated flow velocity and of the static pressure are indicated. When approaching the converter plane the air is

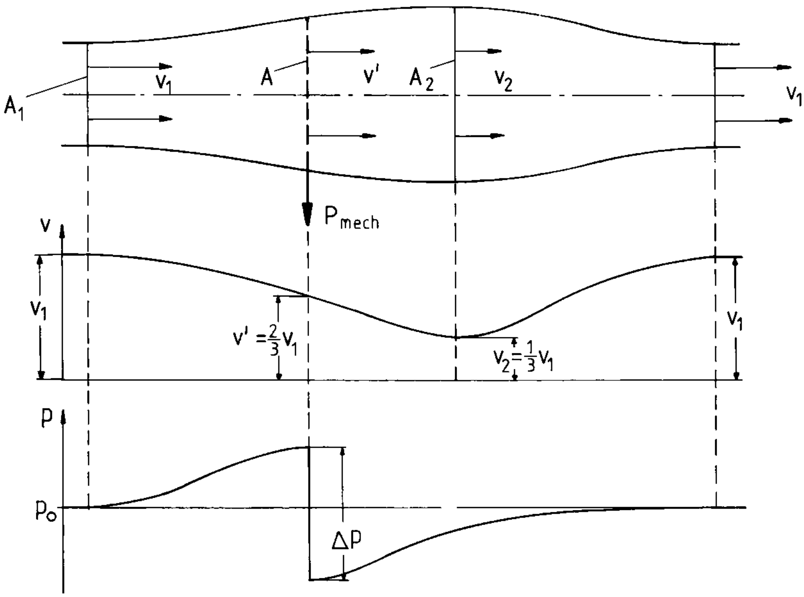

Figure 4.3. Flow conditions of the stream through an ideal disk-shaped energy converter with the maximum possible extraction of mechanical power

retarded, it flows through and is then slowed down further to a minimum value behind the turbine. The flow lines show a widening of the stream tube to a maximum diameter at the point of lowest air velocity. Approaching the turbine, the static pressure increases, and then jumps to a lower value, to level out again at the ambient pressure behind the converter due to pressure equalisation. The flow velocity then also increases again to its initial value far behind the converter and the widening of the stream tube disappears.

It is worthwhile to recall that these basic relationships were derived for an ideal, frictionless flow, and that the result was obviously derived without having a close look at the wind energy converter. In real cases, the power coefficient will always be smaller than the ideal Betz value. The essential findings derived from the momentum theory can be summarised in words as follows:

- The mechanical power which can be extracted from a free-stream airflow by an energy converter increases with the third power of the wind velocity.
- The power increases linearly with the cross-sectional area of the converter traversed; it thus increases with the square of its diameter.
- Even with an ideal airflow and lossless conversion, the ratio of extractable mechanical work to the power contained in the wind is limited to a value of 0.593. Hence, only about 60 % of the wind energy of a certain cross-section can be converted into mechanical power.
- When the ideal power coefficient achieves its maximum value $c_p = 0.593$, the wind velocity in the plane of flow of the converter amounts to two thirds of the undisturbed wind velocity and is reduced to one third behind the converter.

4.2 Wind Energy Converters Using Aerodynamic Drag or Lift

The momentum theory by Betz indicates the physically based, ideal limit value for the extraction of mechanical power from a free-stream airflow without considering the design of the energy converter. However, the power which can be achieved under real conditions cannot be independent of the characteristics of the energy converter.

The first fundamental difference which considerably influences the actual power depends on which aerodynamic forces are utilised for producing mechanical power. All bodies exposed to an airflow experience an aerodynamic force the components of which are defined as aerodynamic drag in the direction of flow, and as aerodynamic lift at a right angle to the direction of flow. The real power coefficients obtained vary greatly in dependence on whether aerodynamic drag or aerodynamic lift is used [2].

Drag devices

The simplest type of wind energy conversion can be achieved by means of pure drag surfaces (Fig. 4.4). The air impinges on the surface A with velocity v_W, the power capture P of which can be calculated from the aerodynamic drag D, the area A and the velocity v with which it moves:

$$P = D\, v_r$$

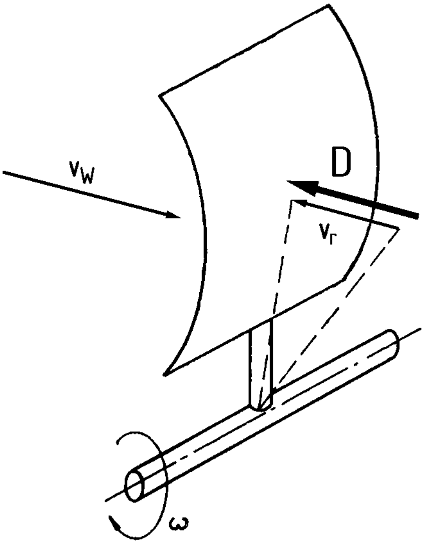

Figure 4.4. Flow conditions and aerodynamic forces with a drag device

The relative velocity $v_r = v_W - v$ which effectively impinges on the drag area is decisive for its aerodynamic drag. Using the common aerodynamic drag coefficient c_D, the aerodynamic drag can be expressed as:

$$D = c_D \frac{\varrho}{2} (v_W - v_r)^2 F$$

The resultant power is

$$P = \frac{\varrho}{2} c_D (v_W - v_r)^2 A v_r$$

If power is expressed again in terms of the power contained in the free-stream airflow, the following power coefficient is obtained:

$$c_P = \frac{P}{P_o} = \frac{\frac{\varrho}{2} c_D A (v_W - v_r)^2 v_r}{\frac{\varrho}{2} v_W^3 A}$$

Analogously to the approach described in Chapt. 4.1, it can be shown that c_P reaches a maximum value with a velocity ratio of $v/v_w = 1/3$. The maximum value is then

$$c_{P\max} = \frac{4}{27} c_D$$

The order of magnitude of the result becomes clear if it is taken into consideration that the aerodynamic drag coefficient of a concave surface curved against the wind direction can hardly exceed a value of 1.3. Thus, the maximum power coefficient of a pure drag-type rotor becomes:

$$c_{P\max} \approx 0{,}2$$

It thus achieves only one third of Betz's ideal c_p value of 0.593. It must be pointed out that, strictly speaking, this derivation only applies to a translatory motion of the drag surface. Fig. 4.4 shows a rotating motion, in order to provide a more obvious relationship with the wind rotor.

Rotors using aerodynamic lift

If the rotor blade shape permits utilisation of aerodynamic lift, much higher power coefficients can be achieved. Analogously to the conditions existing in the case of an aircraft airfoil, utilisation of aerodynamic lift considerably increases the efficiency (Fig. 4.5).

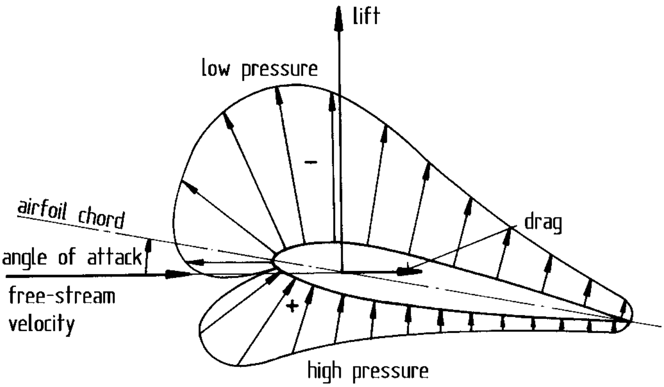

Figure 4.5. Aerodynamic forces acting on an airfoil exposed to an air stream

All modern wind rotor types are designed for utilising this effect and the type best suited for this purpose is the propeller type with a horizontal rotational axis (Fig. 4.6). The wind velocity v_W is vectorially combined with the peripheral velocity u of the rotor blade. When the rotor blade is rotating, this is the peripheral velocity at a blade cross-section at a certain distance from the axis of rotation. Together with the airfoil chord the resultant free-stream velocity v_r forms the aerodynamic angle of attack. The aerodynamic force created is resolved into a component in the direction of the free-stream velocity, the drag D, and a component perpendicular to the free-stream velocity, the lift L. The lift force L, in turn, can be resolved into a component L_{torque} in the plane of rotation of the rotor, and a second component perpendicular to its plane of rotation. The tangential component L_{torque} constitutes the driving torque of the rotor, whereas L_{thrust} is responsible for the rotor thrust.

Modern airfoils developed for aircraft wings and which also found application in wind rotors, have an extremely favourable lift-to-drag ratio (E). This ratio can reach values of up to 200. This fact alone shows qualitatively how much more effective the utilisation of aerodynamic lift as a driving force must be. At this stage, however, it is no longer possible to calculate the achievable power coefficients of lift-type rotors quantitatively with the aid of elementary physical relationships alone. More sophisticated theoretical modelling concepts are now required as will be described in the next chapter.

One more note: Some rotor types, for example the Savonius rotor, can be built both as pure drag-type rotors and, with the appropriate aerodynamic shape, as rotors which partly utilise lift. This is one reason for the frequently greatly varying figures quoted for the power coefficient.

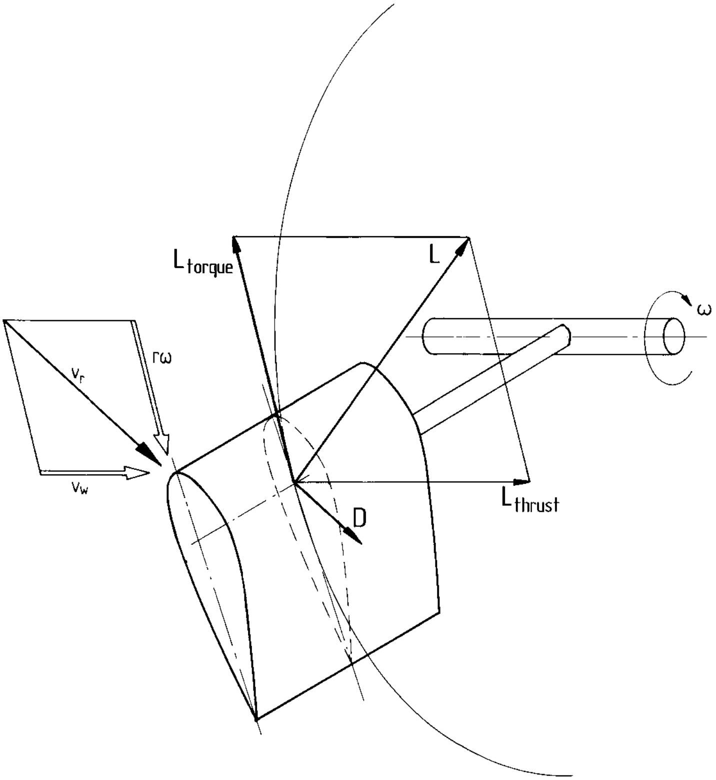

Figure 4.6. Flow velocities and aerodynamic forces acting on a propeller-like rotor

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1. Betz, A.: Windenergie und ihre Ausnutzung durch Windmühlen, Vandenhoek und Ruprecht 1926; Vieweg, Göttingen, 1946
2. Molly, J. P.: Windenergie in Theorie und Praxis, C. F. Müller-Verlag, Karlsruhe, 1978

Chapter 5

Rotor Aerodynamics

The rotor is the first element in the chain of functional elements of a wind turbine. Its aerodynamic and dynamic properties, therefore, have a decisive influence on the entire system in many respects. The capability of the rotor to convert a maximum proportion of the wind energy flowing through its swept area into mechanical energy is obviously the direct result of its aerodynamic properties which, in turn, largely determine the overall efficiency of the energy conversion in the wind turbine. As in any other regenerative power generation system, it is this efficiency of the energy collector which is of prime importance with regard to the overall economics of the system.

Less obvious, but just as important, are the aerodynamic — and dynamic — properties of the rotor with respect to its capability to convert the fluctuating power input provided by the wind into uniform torque whilst, at the same time, keeping the unavoidable dynamic loads on the system as low as possible. The magnitude of the load problems imposed on the downstream mechanical and electrical elements will depend on how well the above requirements are met by the rotor. The control system of the wind turbine is another aspect to be considered when looking at the aerodynamic properties. Poor torque characteristics or critical flow separation characteristics of the rotor blades can be a severe handicap for the operational control of the unit and the control system must, therefore, be adapted to the aerodynamic qualities of the rotor.

These aspects illustrate the importance of rotor aerodynamics to the entire system. It would not be possible to achieve an overall understanding of the operation of a wind turbine without at least some knowledge of the aerodynamic characteristics of the rotor and its most important parameters. Moreover, to a certain extent, the rotor of a wind turbine is the "wind-turbine-specific" element of the system and hence must be designed and constructed without any prior examples from other fields of technology to which one could refer.

It is for these reasons that a comparatively large amount of space in this book is devoted to the aerodynamic characteristics of the rotor. However, the aim is less to provide a detailed description of the theory of rotor aerodynamics but rather to illustrate the interrelationship between the essential design parameters of the rotor and its properties as an actuator disc, i. e. an energy converter.

5.1 Mathematical Models and Calculations

The aerodynamic design of wind turbine rotors requires more than knowledge of the elementary physical laws of energy conversion. The designer faces the problem of finding the relationship between the actual shape of the rotor, e.g. the number of rotor blades or the airfoil of its blades, and its aerodynamic properties.

As with most technical designs, this design process is carried out iteratively, in practice. In the beginning, there is the concept of a rotor which promises to have certain desired properties. A calculation is then carried out for this configuration and checked to see the extent to which the expected result is actually obtained. As a rule, the results will not be completely satisfactory in the first instance but the mathematical/physical model provides an insight into how the given parameters of the rotor design have affected the end result. This provides an opportunity for improving the design by applying the appropriate corrections.

It would exceed the scope of this book to describe the mathematical models currently used in designing the aerodynamics of wind turbine rotors. Nevertheless, the main approaches to the theory of rotor aerodynamics will be explained since they are useful in understanding the results of the calculations, and thus the shape of wind turbine rotors.

The fundamental theoretical approaches are based on the work of numerous aerodynamicists who, in the 1920s, were faced with the task of providing reliable and scientifically founded calculation tools for aircraft engineers who had been working on a rather more empirical basis up to that point. It was the task of finding the aerodynamically optimum wing, in particular, which was of crucial significance to the advancement of aviation and which, ultimately, resulted in the evolution of a special discipline of applied flow mechanics, the so-called "wing theory". Notable names in this field are Prandtl, Glauert, Multhopp, Schlichting and Truckenbrodt. Together with this wing theory, the theoretical models of propeller and turbine design calculation form the starting point for the calculation of the aerodynamics of wind turbine rotors.

It is German aerodynamicist Albert Betz's merit to have formulated not only the basic physical laws of energy conversion but also a complete theory of the wind rotor. In the years to follow, this theory was developed further by numerous other authors. Among others, it was Ulrich Hütter who distinguished himself by significantly advancing and refining Betz's theory in the years between 1940 and 1942 [1]. These efforts have been furthered in recent decades by intensive work conducted on helicopter rotors. The Americans Wilson and Lissaman have published computation methods designed especially for use on computers [2].

Betz's simple momentum theory is based on the modelling of a two-dimensional flow through the actuator disc (s. Chapter 4). The airflow is slowed down and the flow lines are deflected only in one plane (Fig. 5.1).

In reality, however, a rotating converter, a rotor, will additionally impart a rotating motion, a *spin*, to the rotor *wake*. To maintain the angular momentum, the spin in the wake must be opposite to the torque of the rotor.

The energy contained in this spin reduces the useful proportion of the total energy content of the air stream at the cost of the extractable mechanical energy so that, in the extended momentum theory, taking into consideration the rotating wake, the power coef-

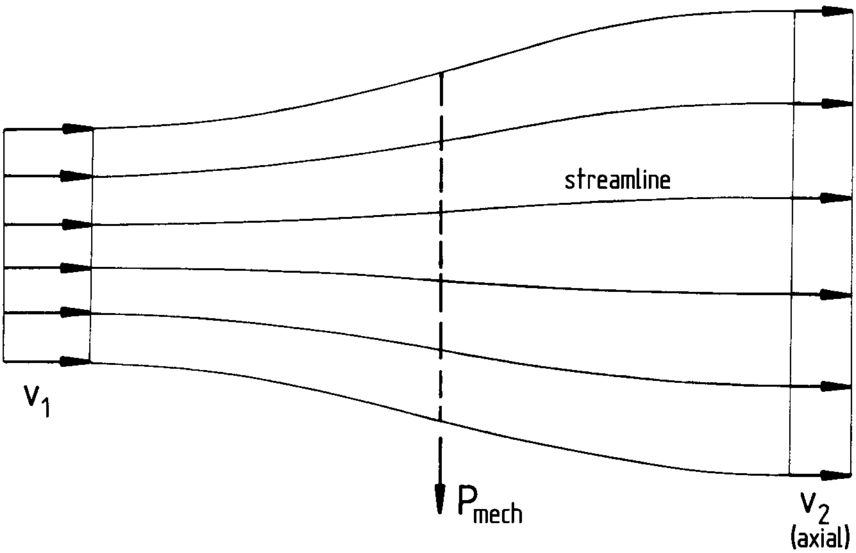


Figure 5.1. Flow model of Betz's momentum theory

ficient of the turbine must be smaller than the value according to Betz (Fig. 5.2). Moreover, the power coefficient now becomes dependent on the ratio between the energy components from the rotating motion and the translatorial motion of the air stream. This ratio is determined by the tangential velocity of the rotor blades in relation to the undisturbed

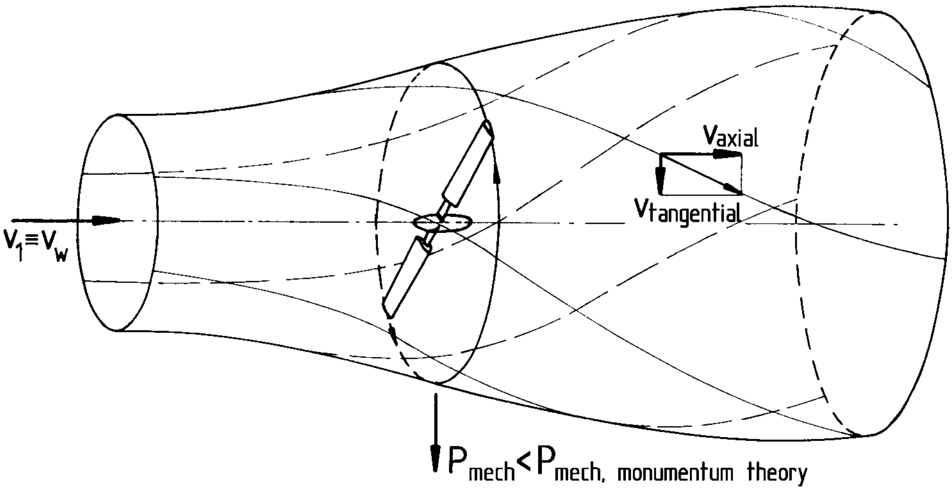


Figure 5.2. Extended momentum theory, taking into consideration the rotating rotor wake

axial airflow, the wind velocity and is called the *tip speed ratio* λ, commonly referenced to the tangential velocity of the rotor blade tip.

$$\text{Tip speed ratio } \lambda = \frac{u}{v_W} = \frac{\text{tangential velocity of the rotor blade tip}}{\text{speed of wind}}$$

A fundamental element of the power curve of a rotor is that the power coefficient is a function of the tip speed ratio, as it is for any other turbine-like prime mover or machine. In conventional turbine engineering and in propeller theory, the tip speed ratio is called *coefficient of advance* which, however, is defined reciprocally.

The decisive step from an essentially physical approach to technical rotor aerodynamics is taken by introducing rotor blade geometry. It is the only means to finding the interrelationship between the actual shape of the rotor and its aerodynamic properties. A method commonly used to this end in wind energy technology is called the *blade element or strip theory* [2].

In this theory, the upwind conditions and aerodynamic forces acting on blade elements rotating at a distance r from the rotor axis are determined. To simplify matters, it is assumed that the aerodynamic forces, moving in concentric strips, do not interfere with one another (Fig. 5.3). The blade element is formed by the local rotor blade chord (aerodynamic airfoil) and the radial extent of the element dr.

The airfoil cross-section at radius r is set at a local blade pitch angle ϑ with respect to the rotor plane of rotation (Fig. 5.4). The axial free stream velocity v_a in the rotor plane and the tangential speed u at the radius of the blade cross-section combine to form a resultant flow velocity v_r. Together with the airfoil chord line, it forms the local aerodynamic *angle of attack* α. For the benefit of those readers unfamiliar with aerodynamics, the difference

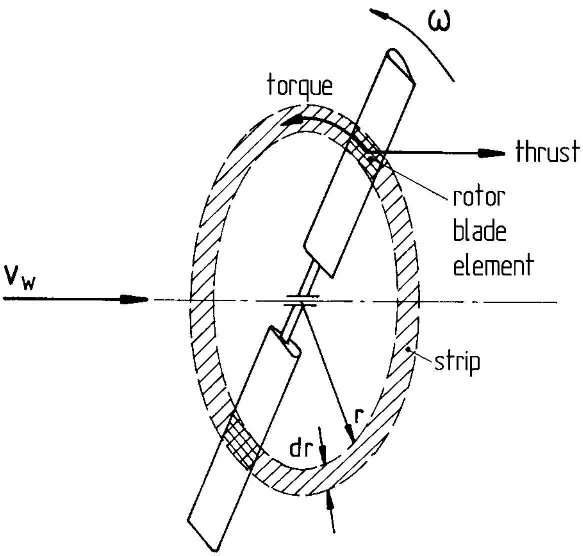


Figure 5.3. Strip theory model

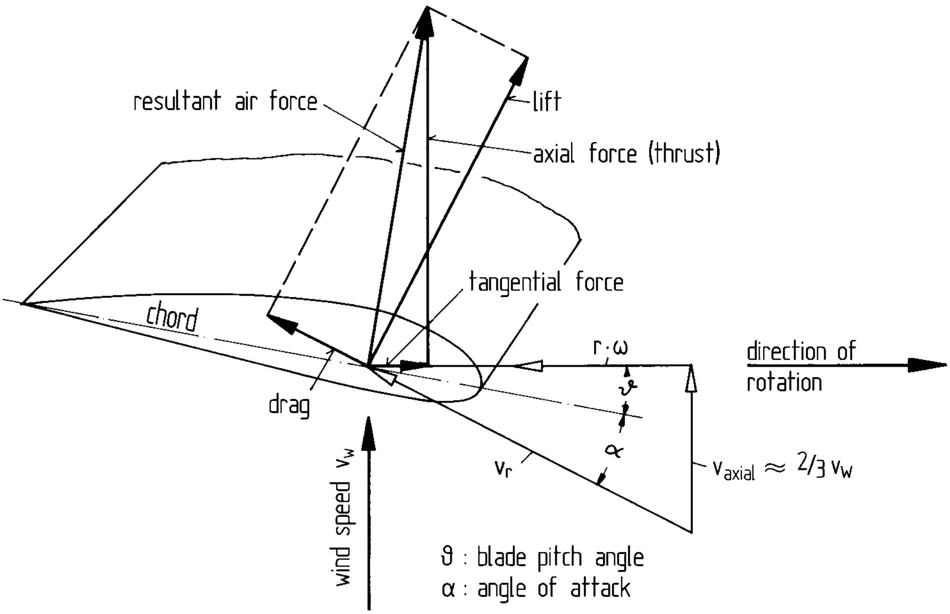


Figure 5.4. Flow velocities and aerodynamic forces at the airfoil cross-section of a blade element

between the aerodynamic angle of attack α and the blade pitch angle ϑ should be noted: the angle of attack is an aerodynamic parameter and the blade pitch angle is a design parameter. The two angles are often confused, making it more difficult to understand the aerodynamic relationships.

Linking the relationships of fluid mechanics for the momentum of the axial flow and of the radial flow components of the rotating wake with the formulations for the aerodynamic forces at the blade element allows the flow conditions at the blade element to be determined so that the local aerodynamic lift and drag coefficients can be read off from the polar airfoil curves (s. Chapter 5.3.4).

The calculation of the balance of forces includes not only the pure airfoil drag but also other drag components which derive from the spatial flow around the rotor blade. In particular, the flow around the blade tip, a result of the pressure difference between the top and the underside of the blade, produces the so-called *free tip vortices*. The resultant drag is called *induced drag*, a function of the local lift coefficient and the *aspect ratio* ('slenderness') of the blades. The higher the aspect ratio, i. e. the more slender the blades, the lower the induced drag. These *blade tip losses* are introduced as additional drag components, as are the *hub losses* which are the result of vortices in the wake of the flow around the hub. They are derived from a complex *vortex model* of the rotor flow (Fig. 5.5). Several semi-empirical approaches for these vortex losses have been described in the literature [2].

With its calculation of the local aerodynamic lift and drag coefficients, the blade element theory provides the distribution of aerodynamic forces over the length of the blade. This is usually divided into two components: one in the plane of rotation of the rotor —

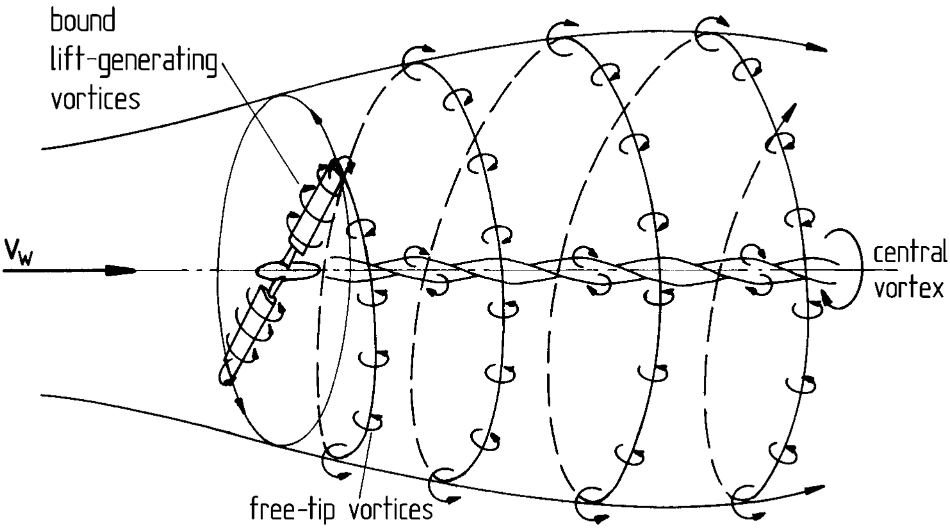


Figure 5.5. Vortex model of the rotor flow [2]

the tangential force distribution, and one at right angles to it — the thrust distribution (Fig. 5.6). Integrating the tangential force distribution over the rotor radius provides the driving torque of the rotor and, with the rotational speed of the rotor, the rotor power or power coefficient, respectively. Integrating the thrust distribution yields the total rotor thrust for instance to the tower. The blade element or strip theory thus provides both the rotor power and the steady-state aerodynamic loading for a given blade geometry.

Taking the rotor power characteristic, i. e. the variation of the power coefficient as a function of the tip speed ratio, as an example, the approximation of the theoretical models to reality can be illustrated retrospectively (Fig. 5.7). Referred to the power rating of the air stream, the simple momentum theory by Betz provides the ideal constant power coefficient of 0.593 which is independent of the tip speed ratio. Taking into consideration the angular momentum in the rotor wake shows that the power coefficient becomes a function of the tip speed ratio. It is only when the tip speed ratios become infinitely high that the power coefficient approaches Betz's ideal value. Introducing the aerodynamic forces acting on the rotor blades, and particularly the aerodynamic drag, further reduces the power coefficient; in addition, the power coefficient now exhibits an optimum value at a certain tip speed ratio.

The aerodynamic rotor theory based on the momentum theory and on the blade element theory, yields the real rotor power curve with good approximation. Nevertheless it should be kept in mind that the momentum theory as well as the blade element model include several simplifications which limit their validity to a disc shaped wind energy converter. Sometimes the momentum theory is therefore called "disc actuator theory". The propeller type rotor is very close to this model, but not all the other unconventional designs acting as wind energy converters, are disc-shaped devices, converting the wind energy to mechanical energy in one step.

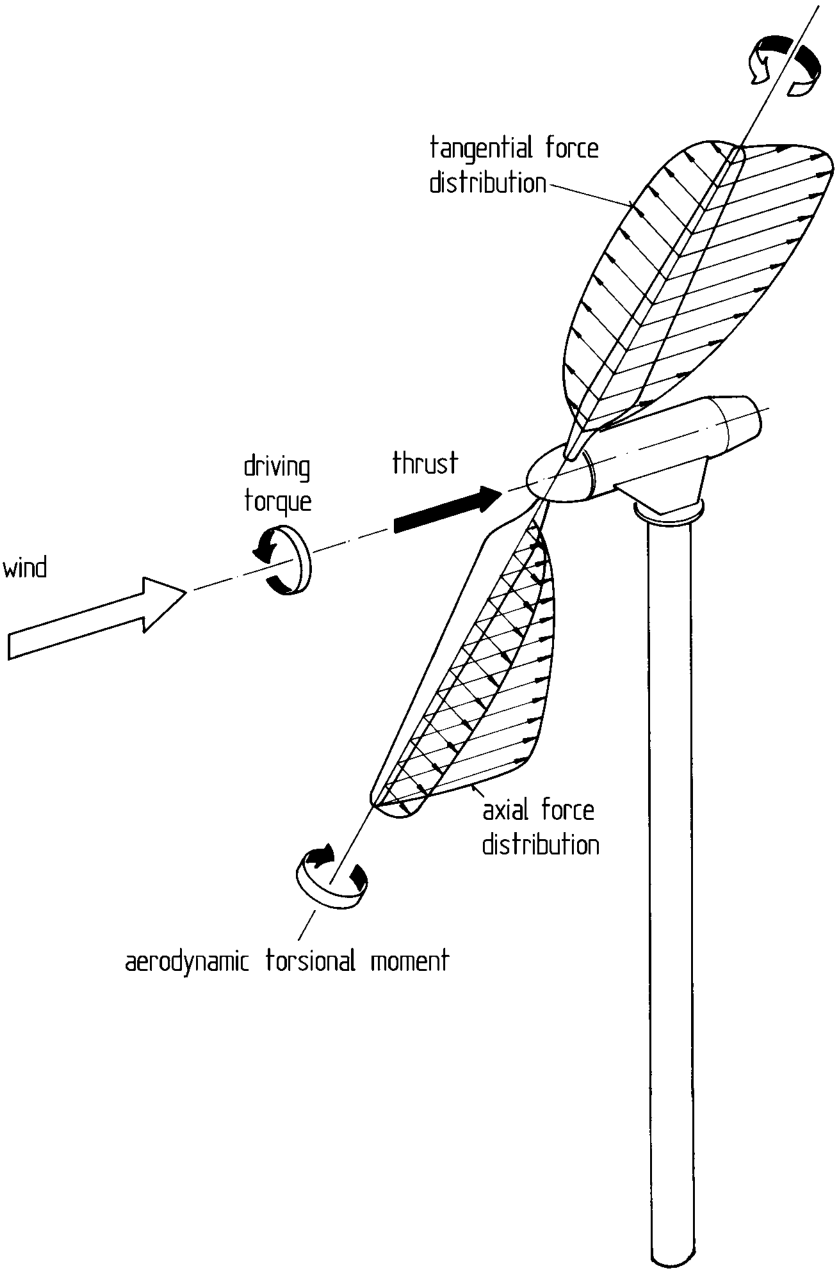


Figure 5.6. Distribution of aerodynamic forces over the blade length and total rotor forces and torques

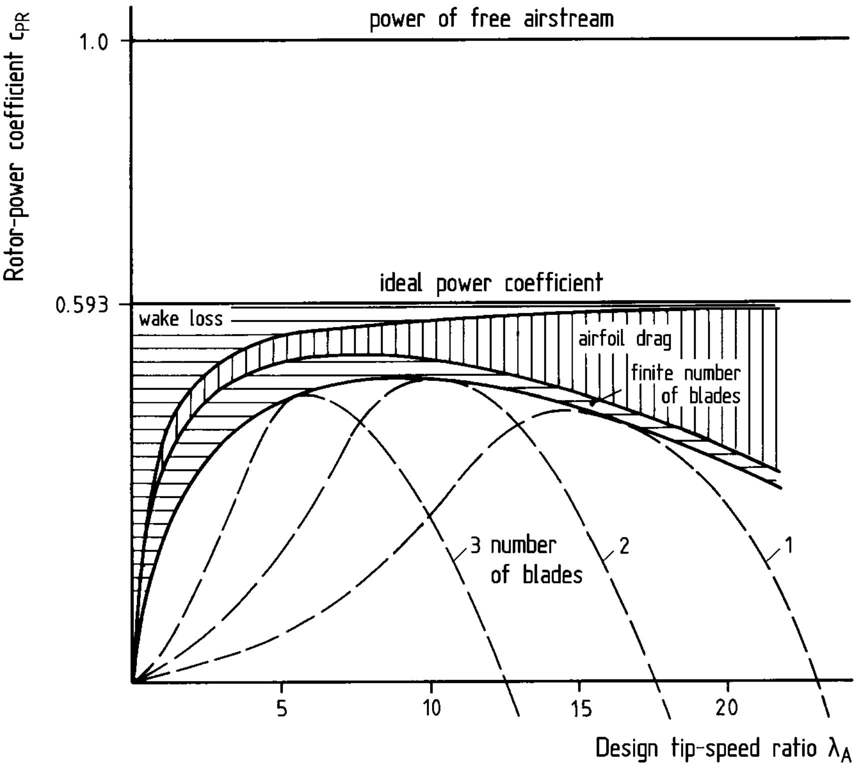


Figure 5.7. Approximation of the real rotor power curve by various theoretical approaches

5.2 Rotor Power Characteristics

The simple momentum theory has already provided the basic relation for the order of magnitude of the mechanical power output of the rotor. The aerodynamic rotor theory, i. e. the strip model, yields the interrelationship between the geometrical shape of a real rotor configuration and its detailed power characteristics. Using the rotor power coefficient c_{PR}, the rotor power can be calculated as a function of the wind speed, as follows:

$$P_R = c_{PR} \frac{\varrho}{2} v_W^3 A$$

where:

A = swept area of the rotor (m^2)
v_W = wind velocity (m/s)
c_{PR} = rotor power coefficient (—)
ϱ = air density (kg/m^3 at MSL)
P_R = rotor power (W)

The power coefficient c_{PR} will be calculated using the strip theory for a certain rotor speed/wind speed ratio, i.e. a given tip speed ratio. Repeating this for a number of tip speed ratios yields the variation of the power coefficient with the tip speed ratio. This provides the rotor power coefficient for different wind speeds at a fixed rotor speed or for different rotor speeds at one wind speed. If the rotor is equipped with blade pitch control, the power coefficient curves must be calculated for every blade pitch angle used in its operation. The single power coefficient curve for rotors with fixed blades becomes a family of rotor power curves for rotors with blade pitch control (Fig. 5.8).

Apart from the rotor power, there are other parameters which are of significance in characterizing rotor performance. The most important of these is the behaviour of the torque (Fig. 5.9). Analogously to the power, the rotor torque can also be calculated by using a so-called torque coefficient, as follows:

$$M = c_Q \frac{\varrho}{2} v_W^2 A R$$

where the rotor radius R is the reference parameter.

Since the torque can be calculated by dividing power by the rotational speed, the following simple relationship between power and torque coefficient is obtained:

$$c_{PR} = \lambda c_Q$$

The rotor power curves and the torque curves are the characteristic features of each rotor configuration. The magnitude of the power coefficients and the shape of the curves both

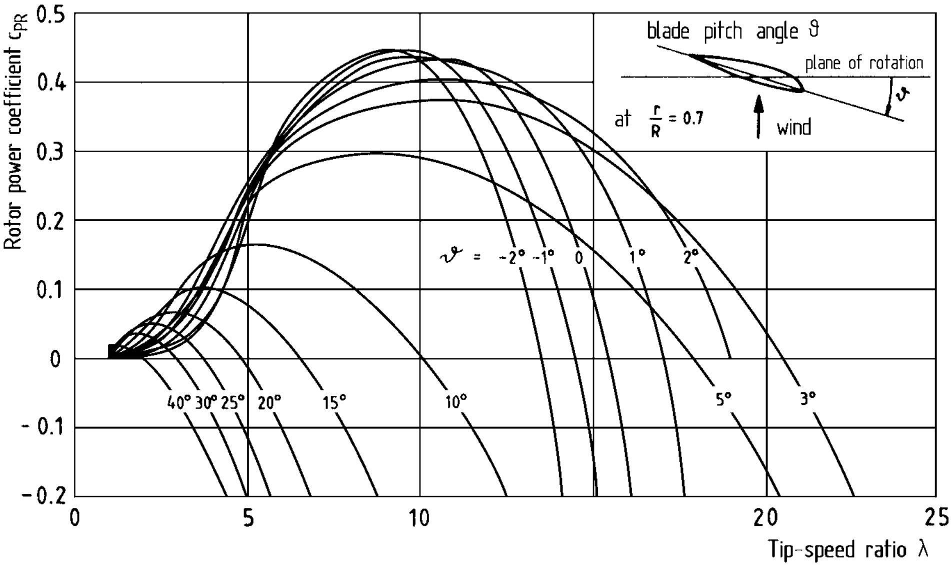


Figure 5.8. Rotor power characteristics for the experimental WKA-60 wind turbine

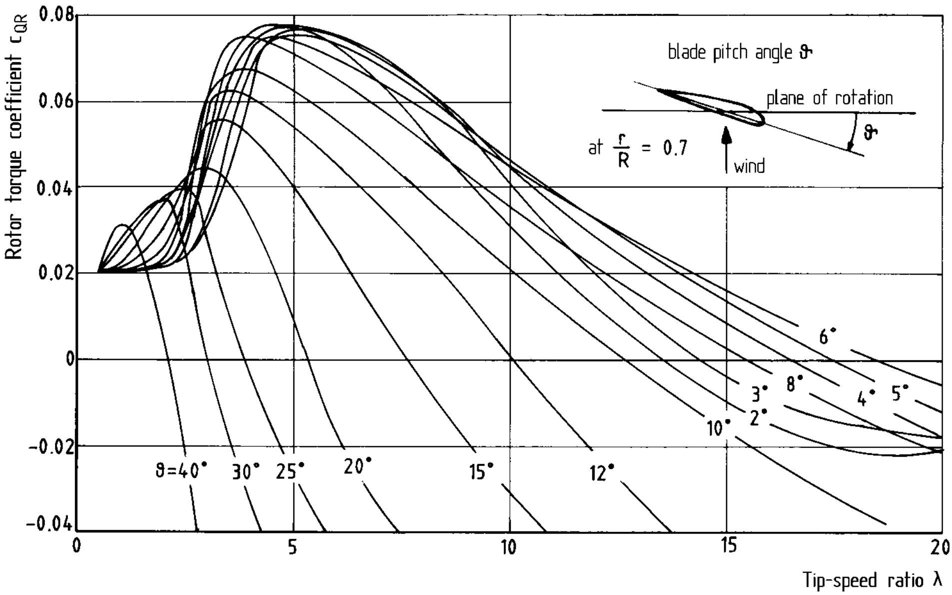


Figure 5.9. Rotor torque characteristics for the WKA-60

show distinct differences. The main parameters dominating the c_{PR} map are:

- number of rotor blades
- chord length distribution of the blades (planform)
- aerodynamic airfoil characteristics
- twist variation of the blades

The extent to which the rotor power characteristics are influenced by these parameters will be described in greater detail in the chapters to follow.

Fig. 5.10 shows the qualitative differences in the power coefficients (the envelope of the family of power characteristics in the case of adjustable-pitch rotors) for rotors of various configurations. The advantages of modern rotors with high tip speed as compared with traditional rotors are quite obvious. Whereas the historical wind wheels, which essentially only operated with aerodynamic drag, only achieved power coefficients of about 0.3, at the most, modern rotors achieve power coefficients of almost 0.5 which clearly demonstrate the superiority of the principle of using aerodynamic lift.

Similar differences can be seen in the torque characteristics (Fig. 5.11). In this case, however, the fast rotors are at a disadvantage. While the slow multi-bladed rotors have a high torque, the torque is much lower for rotors with low blade solidity and few blades. This is especially true of the starting torque. Two-bladed rotors have such a poor starting torque that they can barely start unless the blades are pitched to an optimum pitch angle.

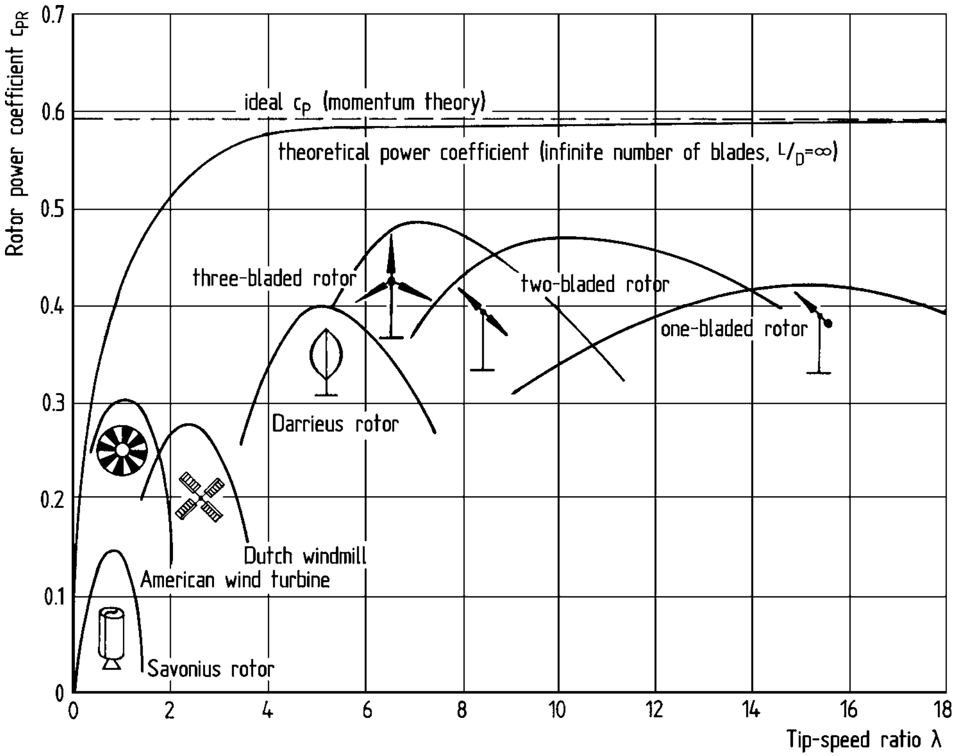


Figure 5.10. Power coefficients of wind rotors of different designs [2]

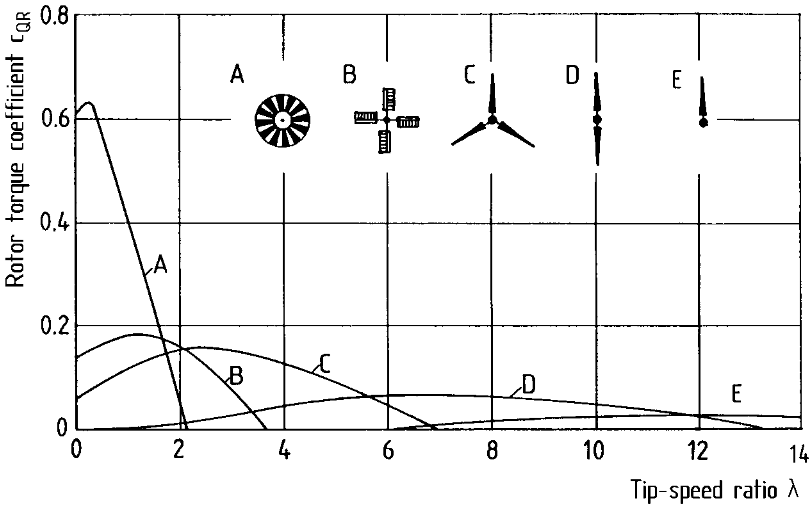


Figure 5.11. Torque coefficients of wind rotors of different designs [2]

5.3
Aerodynamic Power Control

At high wind speeds, the power captured from the wind by the rotor far exceeds the limits set by the design strength of the rotor structure. This is especially true of large wind turbines as the safety margins of the strength limits of the components become narrower with increasing turbine size. In addition, the power output of the rotor is limited by the maximum permissible power of the generator. Fig. 5.12 shows the extent to which the power input of the rotor increases when it is not subject to intervention by a control system.

Apart from limiting rotor power at high wind speeds, there is the problem of maintaining rotor speed at a constant value or within predetermined limits. Speed limitation becomes a question of survival when, for example during a grid outage, the generator torque is suddenly lost. In such a case, rotor speed would increase extremely rapidly and would certainly lead to the destruction of the turbine unless countermeasures were taken immediately. The rotor of a wind turbine must, therefore, have an aerodynamically effective means for limiting its power and its rotational speed.

Basically, the driving aerodynamic forces can be reduced by influencing the aerodynamic angle of attack, by reducing the projected swept area of the rotor, or by changing the effective free-stream velocity at the rotor blades. Since the wind speed cannot be influenced,

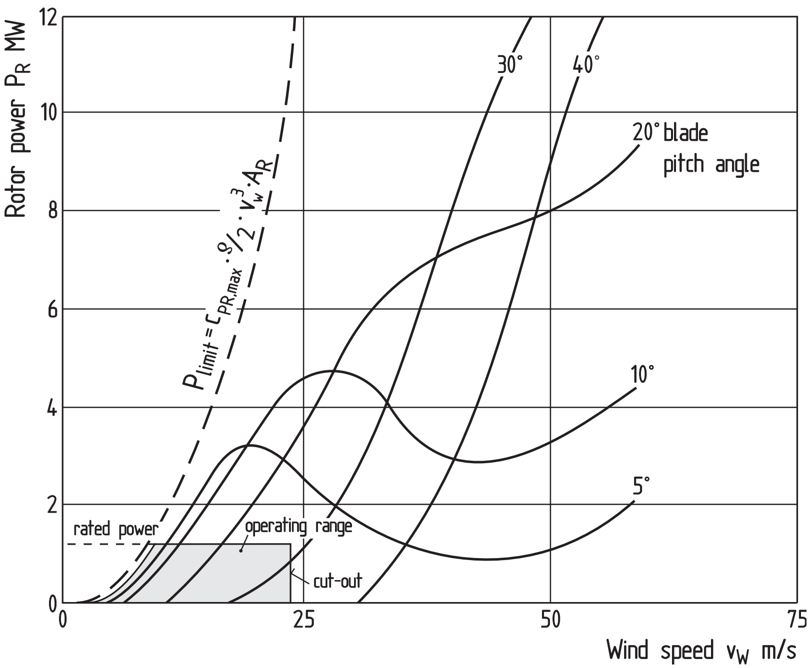


Figure 5.12. Power input of the WKA-60 rotor for various fixed blade pitch angles and at a fixed rotor speed

the effective free-stream velocity at the rotor blades only changes with the rotor speed. The rotor speed can, therefore, be used as a correcting variable for controlling power, provided the wind turbine permits variable-speed operation. However, the power range which can be controlled by varying the rotor speed is very limited so that changing the rotor speed can only be considered as a supplementary option. Reducing the aerodynamically effective rotor swept area, i. e. turning the rotor out of the wind (furling), is only practicable with very small rotors.

5.3.1 Power Control by Rotor Blade Pitching

By far the most effective way of influencing the aerodynamic angle of attack, and thus the input power, is by mechanically adjusting the rotor blade pitch angle (Fig. 5.13). For this purpose, in general, the rotor blade is turned about its longitudinal axis with the aid of actively controlled actuators. There have also been attempts to achieve passive pitch control by utilizing the effect of centrifugal forces (s. Chapter 8.4).

In principle, power control by changing the aerodynamic angle of attack of the rotor can be achieved by two methods. The conventional approach is by adjusting the angle of attack of the blade to a smaller angle in order to reduce power input. Conversely, increasing the angle of attack increases the power input. The other possibility is to change the blade

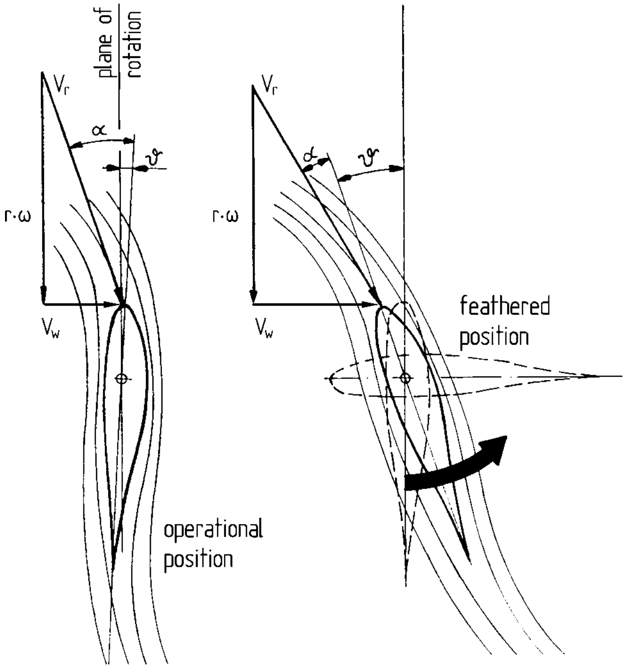


Figure 5.13. Controlling the rotor input power by pitching the blade towards feather or towards stall

pitch angle to a larger angle of attack up to the so-called critical aerodynamic angle of attack, at which point the airflow separates at the surface of the rotor blades, thus limiting the aerodynamic power input. This effect is known as a *stall*. The advantage of this method is that the necessary turning angle for pitching the blade is smaller.

Both methods for controlling power have been demonstrated, for example, in 1980 by the experimental Danish Nibe wind turbines (Figs. 5.14 and 5.15). The Nibe A model had a rotor with partially adjustable rotor blades the outer sections of which could be set such that the power input was limited by the aerodynamic stall at the blades. The rotor blade

Figure 5.14. Rotor of Nibe A with adjustable outer parts of the rotor blades, power limitation by stall at different fixed positions of the blade pitch angle

Figure 5.15. Rotor of Nibe B with full-span adjustable rotor blades, power control by pitching the blades into feathered direction

pitch angle had three fixed positions which were set in dependence on the wind speed (s. Chapter 5.3.3). Power limiting by aerodynamic stall proved to be not very precise and, moreover, was accompanied by severe loading on the rotor and the entire turbine. Up to a certain extent, flow separation at the rotor blades was intermittent so that, under certain operating conditions, fluttering could occur at the rotor blades (s. Chapter 11.1).

In contrast, model B operated with a continuously controlled blade pitch angle setting towards feather. Practical experience has shown that this method, which had already been used with earlier turbines (Smith-Putnam, Hütter W 34 etc), leads to a much steadier operation which is why almost all the larger wind turbines have this type of power control. Using continuous blade pitch control, the electrical output power can be kept at a constant level at wind speeds from rated wind speed up to cut-out wind speed. Fig. 5.16 shows the power curves of the Nibe A and Nibe B turbines.

The continuous adjustment of the blade pitch angle towards the feathered position provides for an effective and precise control of the output power and, if necessary, also of the rotor speed over a wide range of wind velocities. Control of the rotor speed is of importance when the electrical generator is not connected to a fixed-frequency grid which would otherwise govern the rotor speed. This mode of operation has to be used while the rotor accelerates up to the speed of synchronization with the grid frequency and when the wind turbine is operated in isolation (*stand-alone* mode) (s. Chapter 10.3.3).

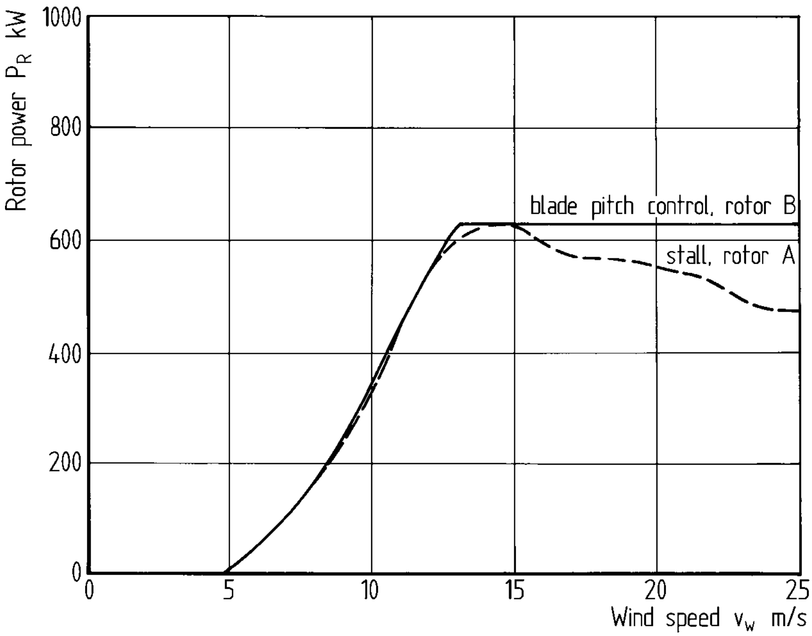


Figure 5.16. Power output versus wind speed (power curve) of Nibe A with stall-limited power input and of Nibe B with continuous blade pitch control [3]

Adjusting the pitch angle towards the feathered position offers further advantages. As power control takes effect above the rated wind speed, rotor thrust drops markedly, while this is hardly the case with stall-regulated rotors (Fig. 5.17). In addition, the rotor blades can be feathered completely when wind speeds are extremely high, thus greatly reducing the wind loading on the rotor blades and on the entire turbine.

The rotor blades do not necessarily have to be adjusted over their entire length, although *full-span pitch control* is aerodynamically the most effective and most satisfactory solution. In view of the fact that power is generated mainly in the outer blade area of the rotor, *partial-span pitch control* by adjusting the pitch of only 25 to 30 % of the blade length is sufficient from the point of view of aerodynamic efficiency. This method was applied mainly in large two-bladed rotors, for example in the American MOD-2 turbine (Fig. 5.18), which was equipped with an hydraulically operated pitch control system where 25 % of the blade length could be varied. This concept allowed the two-bladed rotor to be manufactured in one piece without break due to a hub — an elegant solution from the manufacturing point of view.

Apart from the practical difficulties of implementing a reliable pitch control mechanism in the outer blade area, however, some aerodynamic disadvantages must not be overlooked. In the outer, adjustable area of the rotor blades the aerodynamic loads increase. At extreme

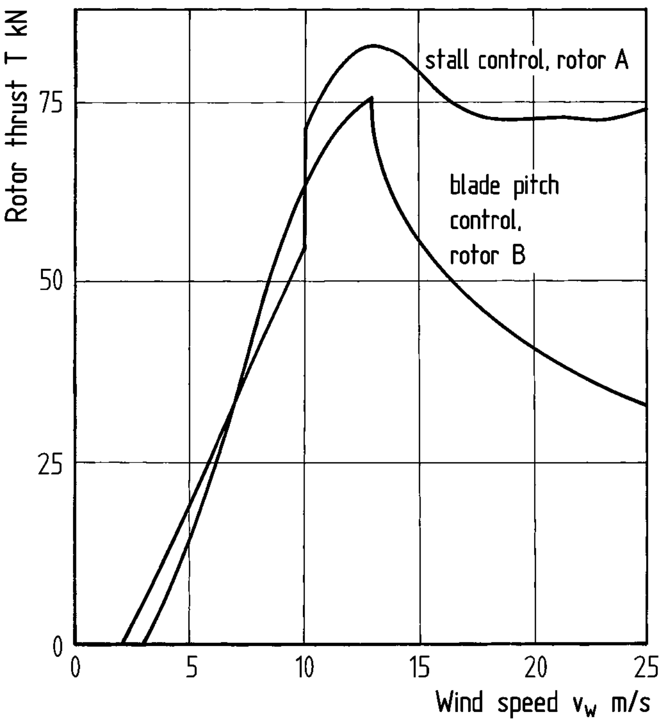


Figure 5.17. Rotor thrust versus wind speed for the Nibe A and Nibe B turbines, stall-controlled rotor (A) and pitch-controlled rotor (B)

Figure 5.18. Partial-span blade pitch control on the American MOD-2 wind turbine

wind velocities, loads on the parked rotor are also higher as it is not possible to turn the complete rotor blade into the feathered position. Moreover, partial-span pitch control requires a wider range of pitch angles to achieve the same efficiency as with full-span pitch control. In unfavourable free stream situations there is thus a risk that the rotor blades will approach stall conditions, particularly in the critical outer areas, due to the wider pitch angle there. This is the reason why the MOD-2 turbines exhibited a certain power instability with high turbulence, a shortcoming which initially could only be eliminated by making compromises in the control system which reduced power output. Later on, so-called *vortex generators* were installed in the outer blade area which improved stall characteristics (s. Chapter 5.3.4). Another disadvantage of partial-span pitch control is the poor start-up torque of the rotor. Practical experience with the MOD-2 has confirmed that the rotor accelerates relatively sluggishly.

Another variety of partial-span pitch control is represented by the *aileron-controlled rotor* where the idea is to control the wind rotor in a similar way to aircraft wings which are controlled by ailerons. This concept was considered as an alternative to adjusting the blade tip, particularly for very large rotors such as the former MOD-5A project of the General

Electric Company [4]. However, this method requires a complicated control system with positive and negative aileron deflections in order to achieve power control comparable to that with full-span pitch control. So far, no practical experience with aileron-controlled rotors has been available.

5.3.2 Passive Stall Control with Fixed Blade Pitch

The flow diagrams shown in Fig. 5.13 have already shown that, even without adjustment of the rotor pitch angle, aerodynamic stall will occur with increasing wind velocity and with the tangential velocity of the rotor kept constant. It is this passive, self-regulating mechanism for controlling the power input of the rotor which gives stall control its practical significance, especially for small turbines which in most cases do not have blade pitch adjustment. At higher wind velocities, the rotor power is only limited by the aerodynamic stall occurring at the rotor blades (Fig. 5.19).

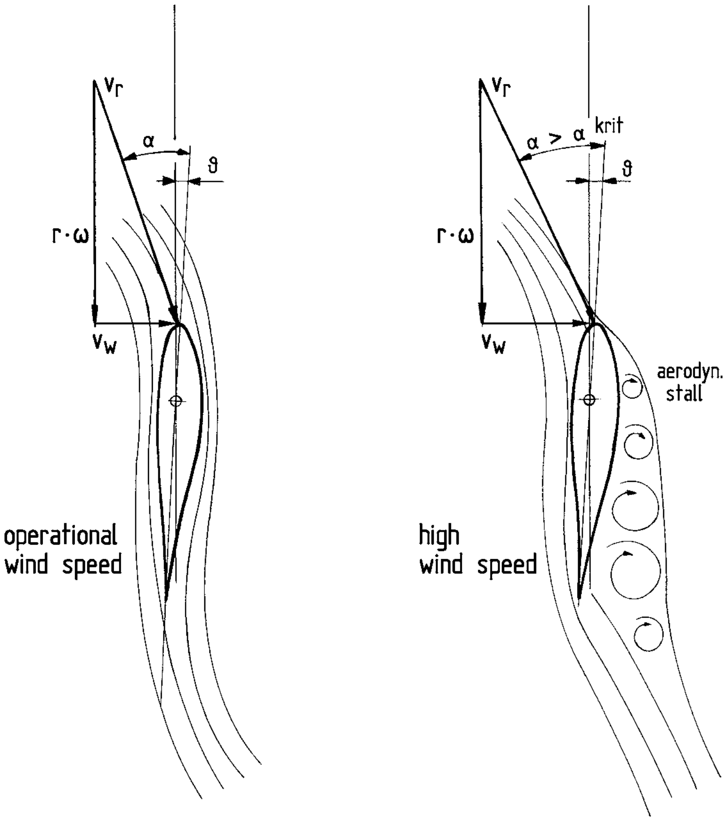


Figure 5.19. Aerodynamic stall at a rotor blade with fixed blade pitch angle at increasing wind velocities and fixed rotor speed

Using this type of *passive stall control* requires carefully designed rotor blade geometry and carefully selected rotor speed. To ensure that at a certain wind speed, the flow does indeed separate so that an increase in power is effectively prevented, the rotor must be generally operated at a speed below the aerodynamically optimum rotational speed.

As a rule, wind rotors of this type are designed in such a way that their aerodynamic power input decreases above a wind velocity of about 15 m/s (Fig. 5.20). The power rises again theoretically at much higher wind velocities but the turbines are no longer in operation at these wind speeds. The rotor is braked to a standstill or furled and spins freely at low speed without capturing any significant amount of power.

However, for this "Danish" design to be practicable, a number of preconditions must be met:

- The strength and stiffness of the rotor and of the entire turbine must be relatively high in order to withstand the high aerodynamic loads. Lightweight designs present problems under these circumstances.
- The installed generator power must be comparatively high so that the generator does not lose synchronization with the grid in the event of strong wind gusts (s. Chapter 9.1).
- The rotor should have a good start-up torque as there is no favourable starting position for the blade pitch. As a rule, this applies only to rotors with three or more blades. Two-bladed rotors with fixed blade pitch angle must be brought up to speed electrically.
- The operation of wind turbines without blade pitch control is restricted primarily to parallel grid operation on a fixed-frequency grid. Isolated operation requires additional technical equipment (s. Chapter 10.3.8).

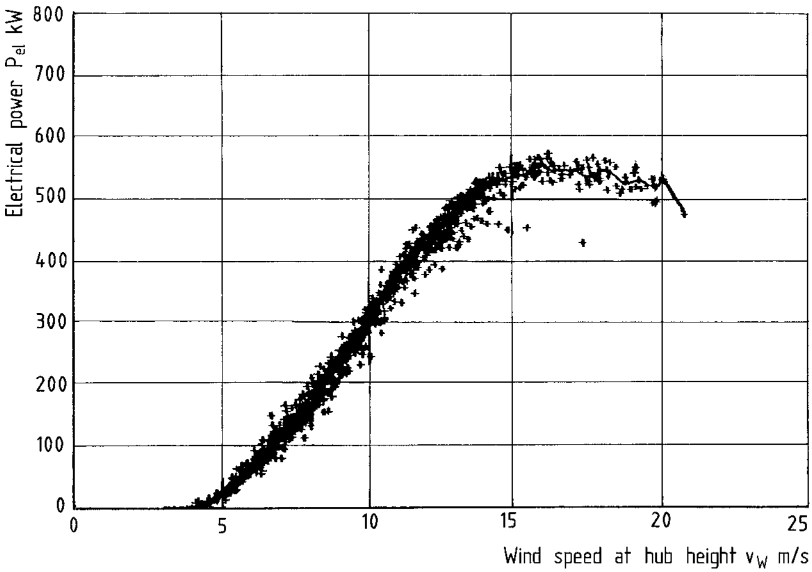


Figure 5.20. Power curve of a wind turbine with passive stall control, the Nordtank NTK 37/500; mean values over ten minutes as measured at the Risø test station

– Last but not least, the rotor must be prevented from "runaway" in the event of a loss of the generator torque. For safety reasons, this requires aerodynamically effective brakes at the rotor blades, in addition to a mechanical rotor brake.

Smaller turbines with a rotor diameter of up to about 20 m, and in some cases also with larger diameters, often have fixed-blade rotors, the power input of which is restricted by aerodynamic stall at a certain wind speed. This type of design has been perfected especially by Danish manufacturers (Fig. 5.21), the three-bladed rotor with fixed pitch angle being a characteristic feature of the "Danish Line".

The provision of aerodynamic brakes to limit overspeed is absolutely mandatory for rotors with fixed blades. A large variety of *spoiler* designs are known from aircraft but wind turbines use almost exclusively adjustable rotor blade tips (Fig. 5.22). Spoilers which disappear into the blade profile when retracted are no longer in use today (Fig. 5.23). They are not very effective and are at least as complex constructionally.

In principle, other types of air brakes which increase the aerodynamic drag can also be used. Some test turbines even used parachute brakes which were ejected from the blade tips in the case of an emergency shut-down (Newecs-45). Such brake systems are obviously out of the question for commercial operators as their operation is too impractictal. In wind

Figure 5.21. Typical Danish wind turbine with three-bladed rotor and fixed blade pitch for stall control

Figure 5.22. Adjustable rotor blade tips as aerodynamic rotor brake

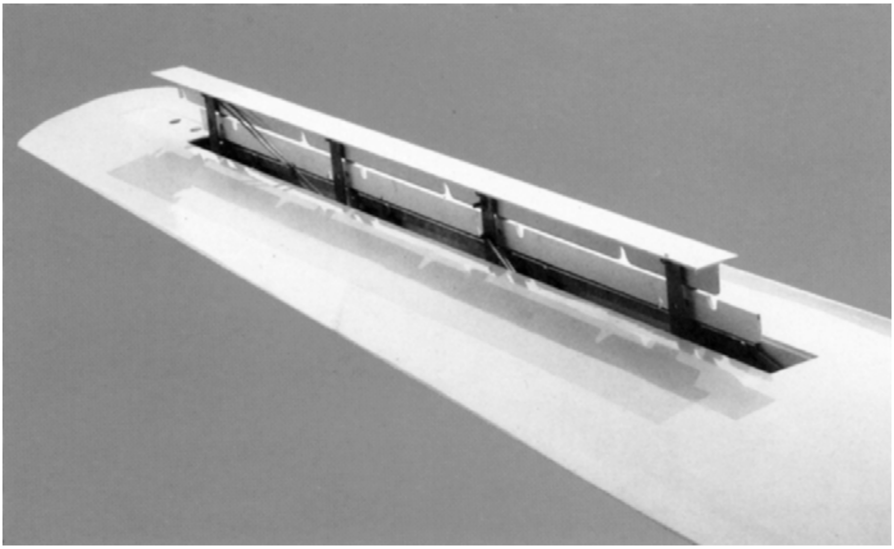


Figure 5.23. Aerodynamic spoiler in an LM type rotor blade of an earlier Danish wind turbine

turbines with active stall control, the complete rotor blade is used for braking (as with blade pitch control) (s. Chapter 5.5.3).

As a rule, the aerodynamic brakes are released by a centrifugal switch at a certain permissible overspeed of the rotor. In more recent turbine types, the air brakes are operated hydraulically, permitting the brakes to be retracted automatically. This considerably simplifies operation when starting up again. However, it is also associated with considerable constructional complexity which somewhat negates the basic simplicity of a rotor with fixed blade pitch angle.

5.3.3 Active Stall Control

Many Danish manufacturers of wind turbines intially attempted to transfer the proven technology of stall control with fixed blade pitch angle to the larger systems of the megawatt power range. Practical operation, however, soon revealed considerable disadvantages of doing so.

The adjustable rotor tips, an indispensable feature of aerodynamic rotor braking especially in the case of large rotors, became more and more complex constructionally. The concentrated loads on the outer area of the blade during braking proved to be very unpleasant. In addition, the loads experienced with extreme wind velocities in standstill are also much higher than with pitch-controlled turbines, resulting in economic disadvantages for the larger dimensions of the tower and its foundations. Not least, the stall characteristics also became more difficult to calculate aerodynamically and to predict reliably with increasing size of the rotor (s. Chapter 5.3.4).

In operation, too, the familiar disadvantages of fixed-blade rotors became more apparent with increasing turbine size. In the megawatt range, the large fluctuations of the turbine output power can no longer be tolerated in an increasing number of situations of grid operation. Another problem is the influence of air density on the onset of stall at different geographic altitudes and with changing seasonal temperatures. To avoid losses in the energy supply, a different fixed blade pitch angle must be selected at lower air density, and the rotor speed may also have to be adapted (s. Chapter 14.4.7). The surface roughness due to the operational contamination of the rotor blades also has a noticeable negative effect on the power curve of the stall-controlled system which does not occur in this form in pitch-controlled systems.

As a result of all these problems, the advocates of the simpler principle of stall control decided to change to a more complex type of construction which is generally called *"active stall"*. The rotor blades are adjusted in operation over their entire length and in each case a matching blade pitch angle is selected for different levels of wind speed, taking into consideration changes in air density (i.e. summer and winter operation) and different surface qualities of the rotor blades (soiling). At extreme wind velocities, the rotor blades are placed into their stand-still position and turned with their trailing edge "forward" into the wind to reduce the wind load (Fig. 5.24).

Actually, the term "stall control" is not justified, even in this method. As before, this is still passive power limiting by flow separation at the rotor blades, without using a closed control loop where the power is the reference input variable.

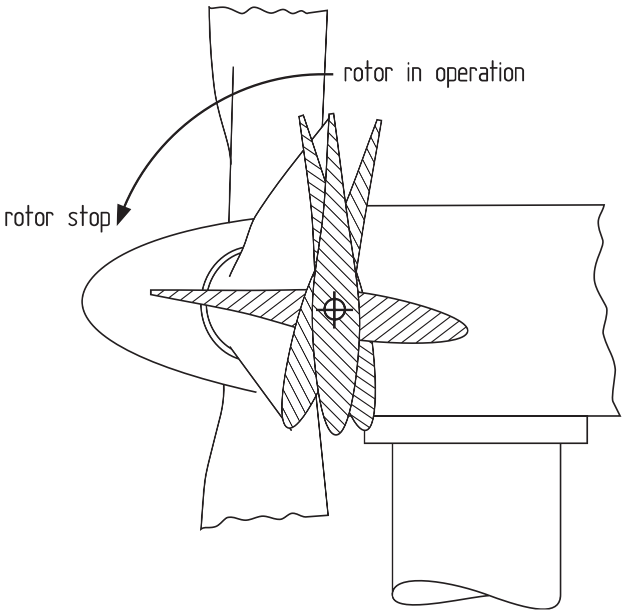


Figure 5.24. Active stall control with a number of blade pitch angles in operation and in standstill

The constructional complexity of the active stall systems scarcely differs any more from that for pitch angle controlled systems. The rotor blades are joined rotatably about their longitudinal axis via roller bearings to the rotor hub and, in principle, the adjustment of the blade pitch angle requires the same type of actuators (s. Chapt. 8.4).

The advocates for the active stall method point out that, because there are fewer and shorter adjustments in comparison with the conventional blade pitch control arrangement, the wear characteristics are better. Furthermore, they emphasize that the influence of wind turbulence can be absorbed better by the stall effect so that, even without elaborate variable-speed generator systems, the power and load peaks are lower than with pitch-angle-controlled rotors. In principle, these advantages are confirmed by mathematical models and also by some experimental investigations. It remains to be seen whether the active stall concept can become established as an alternative to turbines with blade pitch angle control and variable-speed generators in the long term.

5.3.4
Aerodynamic Problems with Stall Control

Working with rotor aerodynamics requires accurate knowledge of the physical phenomenon of flow separation at the rotor blades. Incidences of flow separation cannot be easily avoided at least locally even with rotors with conventional blade pitch angle control. This certainly applies in certain operating conditions as, e.g., when the rotor is being decelerated.

The theoretical prediction of the stall characteristics of the rotor is essentially based on the airfoil curve measured in the wind tunnel (s. Chapter 5.5.4). However, the three-dimensional flow around the rotor does not exactly conform to what one would expect from the two-dimensional airfoil curve. The *three-dimensional stall* is a separate, independent phenomenon which does not readily lend itself to any theoretical treatment [5].

In addition, flow separation at the airfoil cross-section does not always occur at the same aerodynamic angle of attack. The rate of change of the angle of attack also plays a role. These non-stationary aerodynamic processes are called *dynamic stall* [6].

The flow around the rotor blades which is close to the surface and the characteristic of which is largely determined by the surface friction, the so-called *boundary layer,* has a tendency of separating from the surface with rising static pressure in the flow. This also causes the more remote flow to separate, thus triggering a stall. Feeding energy into the boundary layer, i.e. mixing the faster flow remote from the surface with the slower flow in the boundary layer, causes the state of the laminar boundary layer at the front of the leading edge of the airfoil to become turbulent. The turbulent boundary layer "adheres" longer to the surface of the body around which it flows and the flow separation is shifted toward higher angles of attack.

This "mixing up" of the boundary layer flow can be achieved in a simple way by means of perturbation bodies which are installed in the front area of the top of the airfoil. These are small plates mounted at an angle to the direction of flow and often also at an angle to one another in order to enhance the generation of vortices in a particular way — so-called *vortex generators* (Fig. 5.25). Vortex generators are occasionally also used on aircraft wings in order to "hold" the flow longer in the area of the ailerons.

Using such vortex generators, stalling can be shifted towards higher angles of attack, particularly on thicker airfoils as can be found in the inner area of the blade. However, the perturbation bodies produce increased drag when the surrounding flow is adhering. It is, therefore, a matter of carefully considering whether the positive effect of delaying the stall in the inner area of the rotor is not balanced, or even overcompensated, by the power losses in other operating conditions above a certain wind velocity. Installing vortex generators has been quite successful in some cases. Thus it was possible to improve the poor flow conditions in the area of the adjustable outer rotor blades on the rotors of the experimental MOD-2 turbine (s. Chapter 5.3.1). Investigations on Darrieus rotors have shown that here, too, premature stalling in the blade areas close to the axle was delayed, resulting in a noticeable improvement to the power curve [7].

In practical operation, the maximum power input of stall-controlled rotors is not infrequently higher than planned. Due to the above-mentioned aerodynamic problems of the stall characteristics of large rotors, the theoretically calculated power curves are not reliable. To subsequently reduce the excessive power input, so-called *stall strips* can be mounted on the rotor blades. If they are used at the right places on the top of the blade in the area of the leading edge, they result in an earlier onset of flow separation and thus in a reduction of maximum power input. They have, therefore, the opposite effect from the vortex generators but their disadvantage is that the power curve is also degraded in the lower area and this is associated with power losses.

Using vortex generators and stall strips is not a universal patent recipe for achieving improvements in stall-controlled rotors. In principle, they are only effective where the flow

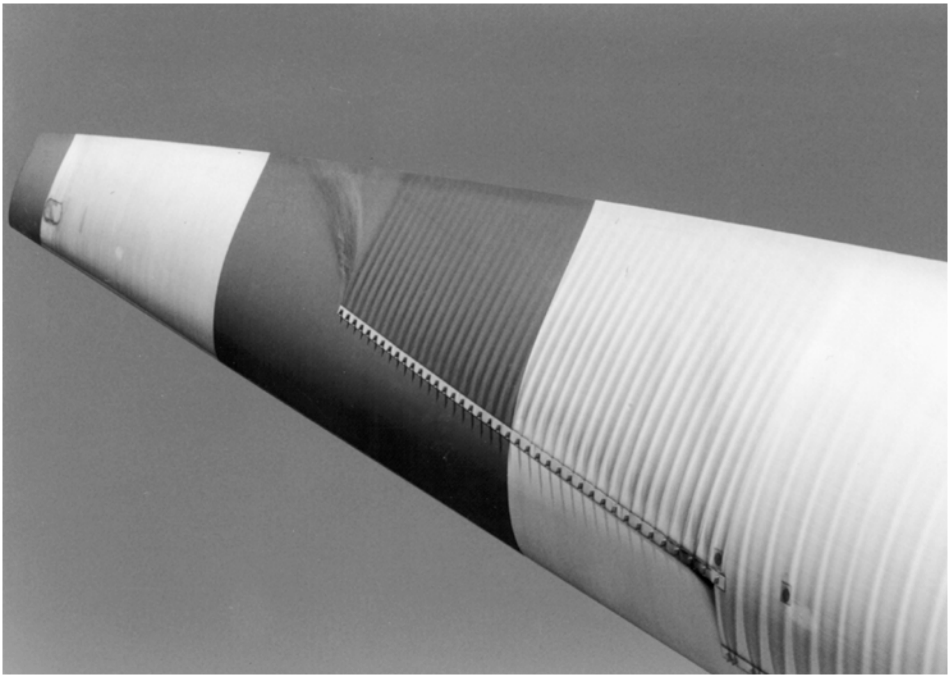


Figure 5.25. Vortex generator on the top of a rotor blade to improve its stall characteristic

conditions are not optimal right from the start. The better approach is rotor blades which are carefully designed aerodynamically.

In general, it must be noted that the stall characteristics, particularly of large rotors, have not as yet been researched in detail to any extent. The associated problems will remain to be a subject for aerodynamic research and development for a long time to come.

5.3.5 Turning the Rotor out of the Wind

Turning the rotor out of the wind, or *furling,* as it is sometimes called, is actually the oldest method of limiting the aerodynamic power input of the rotor. It has been used both in the windmills of history and in American wind turbines. Even today, most of the small wind wheels still use this technique for limiting power.

Yawing the rotor with respect to the wind direction reduces the wind velocity component acting perpendicularly to the rotor plane or, in other words, it reduces the effective swept area with respect to the wind direction. Moreover, it leads to an earlier, premature flow separation at greater yaw angles and, in consequence, to a severe decrease in the rotor power coefficient (Fig. 5.26). Both these effects combined bring about an effective reduction in the aerodynamic rotor power input at yaw angles above about 15 to 20 degrees.

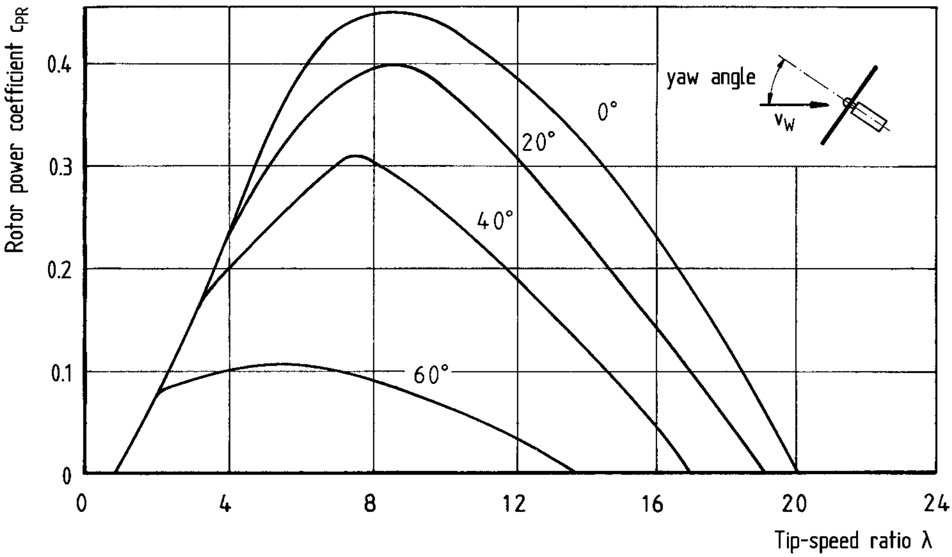


Figure 5.26. Decrease in the power coefficient of the rotor with increasing yaw angle [8]

This method is well suited to being used as a rough measure to limit power input but not really as a means for finely tuned control. It has been proposed as a power limiting method to be used in conjunction with variable-speed rotor operation. If the rotor has a wide speed range, its power input can be controlled within a relatively wide operating range by varying its speed, e. g. by controlling the torque of the electric generator. It is only at higher wind velocities that the speed range is no longer adequate enough to provide for effective power control. The rotor is then gradually turned out of the wind. It was hoped that this method would provide a practicable solution even in relatively large turbines, so that it would not be necessary to have complex blade pitch control mechanisms. The concept was tested in the experimental Italian turbine Gamma-60. The published results indicate that this unconventional type of power control had not caused any insurmountable problems but no further development took place [9].

5.4 The Rotor Wake

Consideration of rotor aerodynamics must also include the aerodynamic state of the flow behind the rotor. The wind turbines in a wind farm are so close together that the downwind turbines are affected by the wake of the upwind turbines. This interaction has a number of consequences which can be of considerable significance:

– The reduced mean flow velocity in the wake of the rotor reduces the energy output of the subsequent wind turbines.

– The turbulence in the rotor wake, which is unavoidably increased, also increases the turbulence loading on the downwind turbines, with corresponding consequences for the fatigue strength of these turbines. On the other hand, their steady-state load level is reduced due to the decrease in the mean upwind velocity.
– Under poor conditions, the influence of the rotor wake can affect the blade pitch angle control of the relevant turbines in an undesirable way.

The treatment of the rotor wake firstly requires the conception of a physical-mathematical model for calculating the wake of a single rotor. In a wind farm, this calculated wake is then superimposed in a suitable manner on the wake of the other turbines.

The mathematical modelling of the rotor wake has in recent years been increasingly refined in several steps and in numerous individual contributions. The first useable model was published in 1977 by Lissaman in connection with his work on the development of the blade element theory and of the momentum theory [10]. Lissaman based his work on his rotor model (blade element theory) and calculated the velocity profiles behind the rotor by using empirical values obtained from wind tunnel measurements. This resulted in a semi-empirical calculation method which provides useful results. Lissaman also developed a qualitative concept of the development of the shape of the *wake* behind the rotor (Fig. 5.27).

The area close to the rotor, its core area, is determined by the process of pressure equalisation with the ambient air immediately behind the rotor and by the vortex wakes resulting from the flow around the rotor blades. The pressure compensation causes the rotor wake to widen. The point of minimum speed in the centre of the wake occurs at a distance of between one and two rotor diameters behind the rotor.

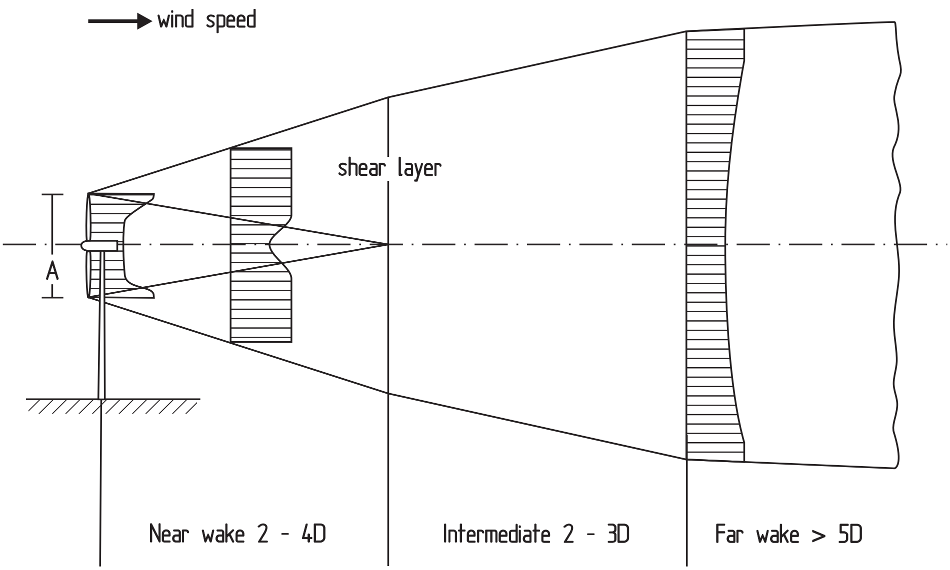


Figure 5.27. Model of the rotor wake [10]

In the transition region, considerable turbulence is generated in the boundary layer of the rotor wake and becomes mixed with the turbulence and higher wind velocity of the surrounding airflow. As the distance becomes greater, the air speed rises more and more and the vortices generated by the rotor blades largely disappear.

Farther away in the wake in the far region, at a distance of about five rotor diameters, the velocity profile of the wake develops into a Gaußian distribution. The reduction in speed deficiency in the wake is large determined by the intensity of the turbulence in the surrounding air.

The achievement of a qualitative understanding of the flow conditions in the rotor wake also provided the basis for the development of more sophisticated models for calculating the wake. In 1988, Ainslie presented a model which is based on the numeric solution of the Navier Stokes equations for the turbulent boundary layer and thus already closely approaches the physical situation given in the wake [12]. The influence of the surrounding turbulence was introduced by Ainslie with an analytical formulation for the viscosity, i. e. the shearing forces transferred by the turbulence. A similar model was developed by Crespo with the special aim of determining the additional turbulence generated in the rotor wake [13] and he introduced a more accurate model of dissipation in the turbulent flow for this purpose.

These mathematical models were confirmed and improved upon with numerous measurements made on wind turbines. The measurements which were taken of the rotor wake of a small wind turbine and compared with the results of Ainslie's model are used as an example [11] (Fig. 5.28).

The theoretical treatment of the rotor wake allows some important insights to be gained: The thrust coefficient of the rotor has a significant influence on the loss of impulse behind the rotor and thus on the extent of the wake. The rotor wake changes with the operating state of the turbine (tip speed ratio, blade pitch angle etc.). Rotors with fixed blades generate a further, increasing shearing force in the full-load range (s. Fig. 5.27) and the rotor wake is correspondingly prominent.

The wake area far from the rotor, from about five rotor diameters, is mainly shaped by the surrounding turbulence. The greater the intensity of the turbulence in the surrounding air, the faster the lack of speed in the wake is equalized.

Considerable turbulence is generated in the wake itself. In the case of downwind turbines, this combines with the surrounding air turbulence. The intensity of the superimposed turbulence amounts to about 130 to 150 % of the surrounding value. This effect may be of significance with respect to the fatigue strength of the turbines affected (s. Chapter 16.4.3).

The maximum deceleration in the centre of the rotor wake with respect to the surrounding wind velocity can be seen in Fig. 5.28, for example. It is:

- approx. 60 % at a distance from the rotor of 2 rotor diameters,
- approx. 30 % at a distance from the rotor of 4 diameters, and
- approx. 20 % at a distance from the rotor of 6 diameters.

These numerical values for the flow retardation cannot be unconditionally generalized. The thrust coefficient and the surrounding turbulence play a decisive role. The above example

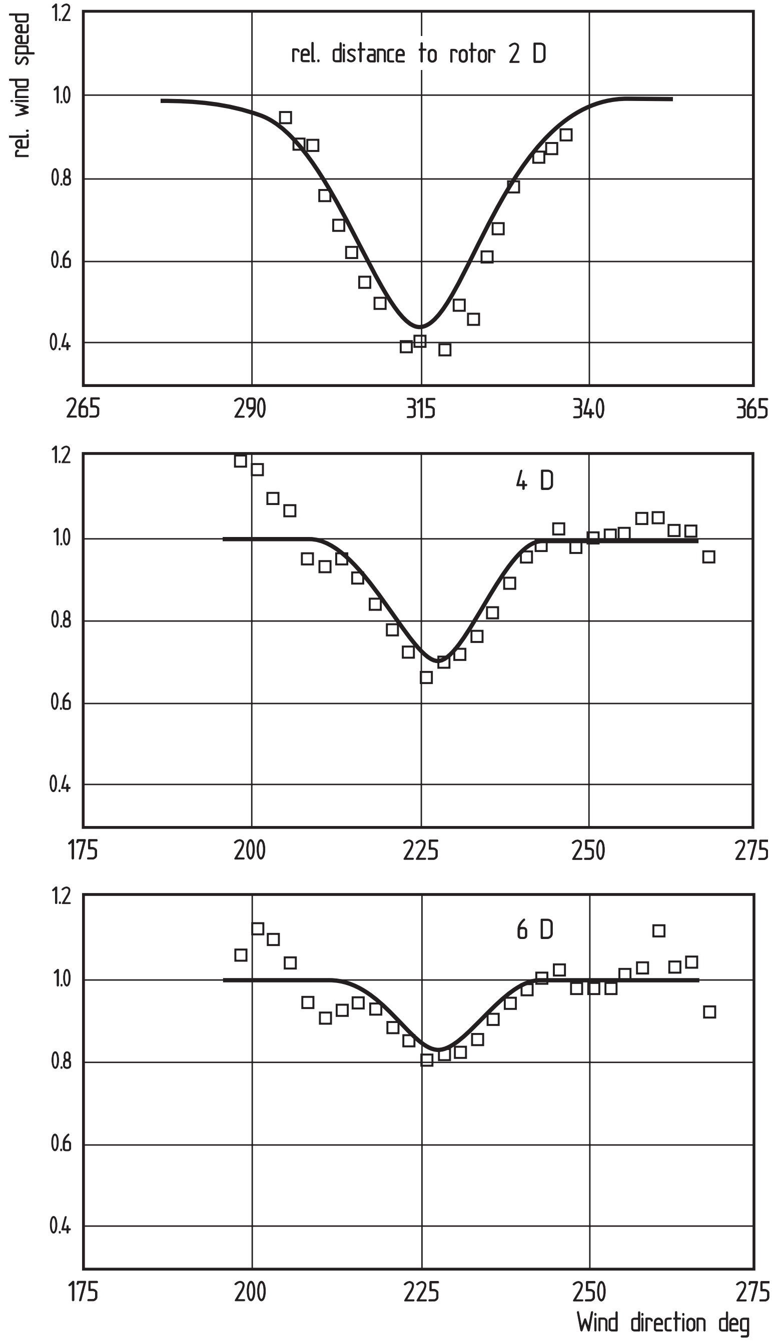


Figure 5.28. Horizontal speed profile in the wake of a wind turbine of the Enercon E-16 type, referred to the surrounding wind speed [11]

applies to a stall-controlled turbine so that the measured values would lie within the top range of the bandwidth.

5.5 Important Aerodynamic Design Features of the Rotor

Up to this point, the discussion of the aerodynamic performance characteristics of the rotor was based on the assumption that the concept of the rotor was known. This approach was necessary for developing the theoretical tools.

The designer of a wind turbine, however, has to tackle the problem from the opposite direction. His task is to find the best possible rotor concept on the basis of certain predetermined requirements and objectives. As a rule, the starting point of this complex engineering task will be a certain idea of the power output of the wind turbine at a particular wind speed. From this, the rotor diameter required can be derived by roughly estimating the rotor power coefficient. This first assumption of the rotor diameter is generally the start of the aerodynamic design of the rotor. Like all technical design tasks, aerodynamic rotor design, too, is not a problem which can be solved mathematically. Although it is possible, under certain conditions, to derive optimum shapes, for example for the rotor blades, by mathematical means, they serve merely as orientation aids in the design process. The practical task is to find the best possible design compromise for the geometric shape of the rotor, taking into consideration aerodynamic performance, strength and stiffness requirements and economical production techniques, to name only the most important aspects. This result can only be achieved in an iterative process.

The task of aerodynamic rotor design, therefore, consists in first finding the optimum rotor shape and then, considering the unavoidable compromises which will have to be made, quantifying the influence of required deviations from the aerodynamically desired shape. In the beginning, this optimisation process will have to be carried out with an eye on the rotor power coefficient. Ultimately, however, it is its influence on the turbine's energy generation that is decisive. But this is also influenced by other design parameters of the wind turbine, e.g., the installed generator power and rotor power control. As the correlation between the rotor power coefficient and energy generation can be calculated with great accuracy (Chapt. 13), it is sufficient to optimize the rotor aerodynamics initially with regard to the rotor power coefficient.

In an excellent study, C. Rohrbach, H. Wainauski and R. Worobel described the influence of the aerodynamic design parameters on the rotor power coefficient, using the calculation methods described in the previous chapters [14]. Several of the diagrams reproduced in this chapter have been taken from this work. Though calculated for a certain blade configuration, the results can be applied in a generalized way to modern wind rotors.

5.5.1 Number of Rotor Blades

The number of rotor blades is the most obvious characteristic of the rotor and is frequently the object of divisive discussions. In the chapter on physical basics it has already been pointed out that it is possible to calculate the mechanical power which can be extracted from the wind power existing in a given air stream cross-section with reasonable approximation without knowing the rotor configuration, i.e., without taking the number of rotor blades into consideration. This already indicates that the influence of the number of rotor blades on rotor power must be small. Put simply: rotors with a lower number of blades rotate faster, thus almost compensating for their disadvantage of a smaller physical blade area.

Figure 5.29 shows the influence of the number of blades on the rotor power coefficient. The reduced increase in power coefficient with increasing numbers of rotor blades can be clearly seen. While the power increase from one to two blades is still a considerable 10 percent, the difference from two to three blades amounts to only three to four percent. The fourth blade only produces a power increase of one to two percent.

In theory, the power coefficient continues to increase with the number of blades. Rotors with a very large number of blades, e.g., the American wind turbine, however, exhibit a decreasing power coefficient. When rotor solidity is very high, the aerodynamic flow conditions become more complicated (cascade flow) and cannot be described by the theoretical model concepts explained.

The variation of the c_{PR} curves as a function of the tip-speed ratio also shows the range within which the optimum tip-speed ratio for rotors with different numbers of blades has to fall. While the three-bladed rotor performs optimally at a design tip-speed ratio of between 7 and 8, a two-bladed rotor reaches its maximum c_{PR} value at a tip-speed ratio of approx. 10. The optimum tip-speed ratio of a one-bladed rotor is about 15. The optimum tip-speed

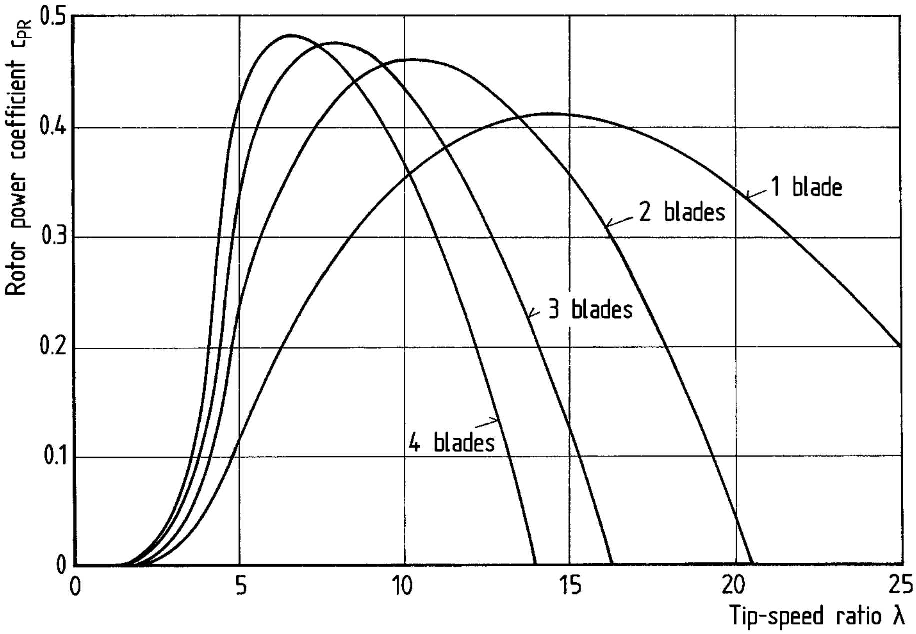


Figure 5.29. Influence of the number of blades on the rotor power coefficient (envelope) and the optimum tip-speed ratio

ratio is slightly dependent on the choice of airfoil. However, essentially only the maximum values of the c_{PR} curves are moved up or down by the airfoil characteristics, so that the correlations between number of blades, power coefficient and optimum tip-speed ratio are generally valid.

Looking at the dependence of the power coefficient on the number of rotor blades, it is immediately apparent why rotors with a low number of blades, i. e. two or three, are the preferred solution for wind turbines. As a rule, the possible gain in power and energy yield of a few percent is not enough to justify the cost of an additional rotor blade.

This statement would be entirely indisputable if it were not for several other criteria. The fewer blades there are the more and more unfavourable the dynamic behaviour of a wind rotor becomes. The difference between the aerodynamically symmetric three-bladed rotor and a two- or even single-bladed rotor is particularly marked (Chapt. 6.6.1). The high dynamic loads caused by an aerodynamically asymmetrical rotor require additional complexity in the other components of the wind turbine. Moreover, rotors with a high tip-speed ratio, i. e. two- or single-bladed rotors, cause a noise emission which is unacceptable at most sites. The visual effect of a rotating two- or even single-bladed rotor, too, is generally felt to be "restless" in comparison with the three-bladed rotor. All this has led to the three-bladed rotor having become completely established today in commercial wind turbines. As the size of the wind turbines increases, however, and their field of application is extended (offshore wind farms), the two-bladed rotor may quite easily become attractive again. The choice of the optimum number of rotor blades is, therefore, not only a question of aerodynamic power differences, but rather requires integrated consideration of the wind turbine and the conditions under which it is used as a total system.

5.5.2 Optimum Shape of the Rotor Blades

The mechanical power captured by the rotor from the wind is influenced by the geometrical shape of the rotor blades. Determining the aerodynamically optimum blade shape, or the best possible approximation to it, is one of the tasks of the designer.

Applying Betz's momentum theory and the strip theory, a theoretically optimum shape of the contour of the rotor blade can be calculated. The crucial criterion in this calculation is the demand that at each blade radius, the wind speed in the rotor plane be delayed to two thirds of its undisturbed value. This requirement can be met if the product of local lift coefficient and local chord length follows a hyperbolic course over the blade radius. The local lift coefficients must be derived from the polar curves of the selected airfoil and by considering the local angle of attack, i. e. the blade pitch angle and the blade twist angle. In other words, the aerodynamically optimum distribution of chord and twist of the rotor blades depends on the selection of a particular lift coefficient.

As a rule, this lift coefficient will be selected such that at the design tip-speed ratio of the rotor, the blade is operated at the best possible lift to drag ratio. With the standard airfoils, the corresponding angle of attack is several degrees below the maximum lift coefficient, thus providing sufficient margin with respect to flow separation. As a first approximation, the *design lift coefficient* can be assumed to be between 0.9 and 1.1. As a result, the rotor power characteristics will have the maximum c_{PR} value at the selected design tip-speed ratio.

With certain simplifications, mainly by neglecting airfoil drag and tip vortex losses, a mathematical formula which can be analytically resolved can be derived for the aerodynamically optimum chord distribution over the blade length [15]:

$$t_{opt} = \frac{2\pi r}{z} \frac{8}{9c_L} \frac{v_{WD}}{\lambda v_r}$$

where:

c_{opt} = optimum local blade chord length (m)
v_{WD} = design wind speed (m/s)
u = peripheral speed (m/s)
v_r = $\sqrt{v_W^2 + u^2}$ local effective flow velocity (m/s)
λ = local tip-speed ratio (—)
c_L = local lift coefficient (—)
r = local blade length (m)
z = number of rotor blades (—).

This formula provides useful results for an approximated calculation of the blade contour. The optimum chord length distribution is a hyperbolic function of the blade length or rotor radius, respectively.

Fig. 5.30 shows the actual shape of the rotor blades at different tip-speed ratios, for rotor designs with one, two, three and four blades.

It can be seen immediately that the rotor blades of a three or four-bladed rotor become extremely slender when the design tip-speed ratios are large ($\lambda = 15$). It is obvious that the construction of such slender blades is associated with problems of strength or stiffness. It is, therefore, mandatory for high-speed rotors to have only a small number of blades. One of the reasons given for building single-blade rotors is that it is thus possible to achieve high-speed rotors with a reasonable blade aspect ratio.

The hyperbolic contours of the theoretical optimum shape naturally present disadvantages with respect to manufacturing. From the point of view of cost-effective economical manufacturing, the aim should be straight-bladed planforms. Fig. 5.31 shows the extent of the power losses suffered due to deviations from the aerodynamically optimum shape. The trapezoidal planform with straight leading and trailing edges proves to be a very good approximation. The maximum power coefficient is only slightly below the optimum hyperbolically delimited shape.

The "basic shape" indicated in Fig. 5.31 constitutes the basis of reference for this comparison and in the following diagrams, showing the influence of the aerodynamic design parameters on the rotor power coefficient. It has been designed for a two-bladed rotor with a design tip-speed ratio of 10. On the basis of the optimum aerodynamic shape, a "hyperbolically delimited trapezoid" was chosen as the basic shape (Fig. 5.32). For characterizing the geometrical rotor blade shape, some parameters well-known in aircraft technology have been introduced which are defined as follows:

$$\text{Rotor solidity} = \frac{\text{Total blade planform area}}{\text{Rotor swept area}} \quad (\%)$$

$$\text{Aspect ratio} = \frac{(\text{Rotor radius})^2}{\text{Planform area of a rotor blade}} \quad (\text{—})$$

$$\text{Taper} = \frac{\text{Chord length at the blade tip}}{\text{Chord length at the blade root}} \quad (\text{—}).$$

One problem with these definitions is how to determine precisely the blade planform area and the chord length at the tip and the root. One makes do by somewhat vaguely determining the "aerodynamically effective" blade area or chord length.

The blade part near the hub is of less significance for the generation of power. Here, aerodynamic aspects can be put aside in favour of higher strength or greater simplicity in manufacturing. This applies primarily to airfoil thickness, providing for more constructional depth for strength and stiffness along with minimum weight. However the lower

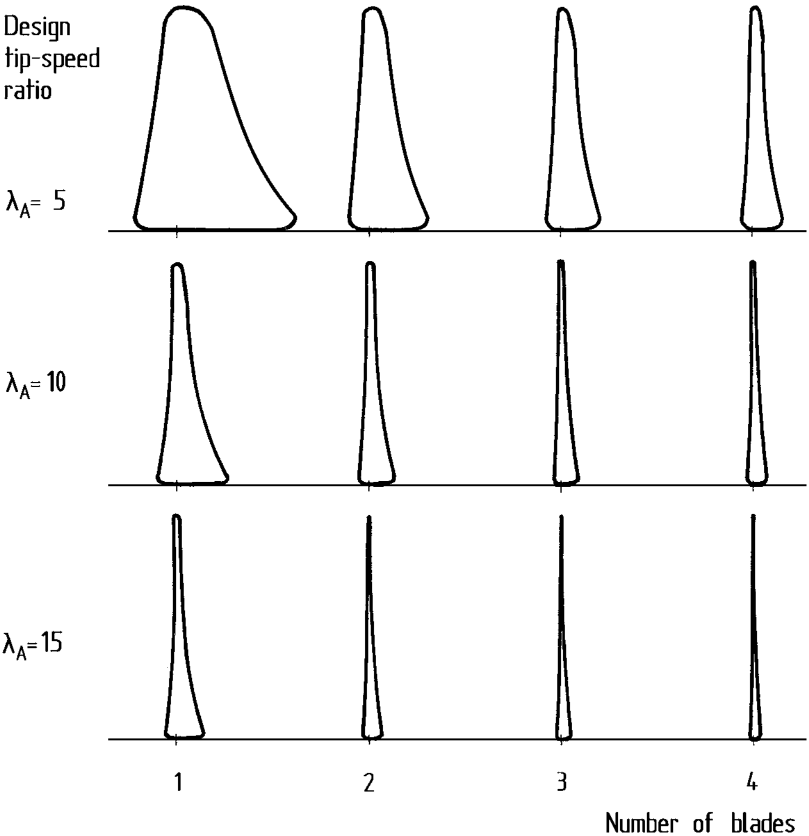


Figure 5.30. Aerodynamically optimum rotor blade shapes for different design tip-speed ratios and rotor blade numbers, calculated for the airfoil NACA 4415 and design lift coefficient $c_{\mathrm{LD}} = 1.1$

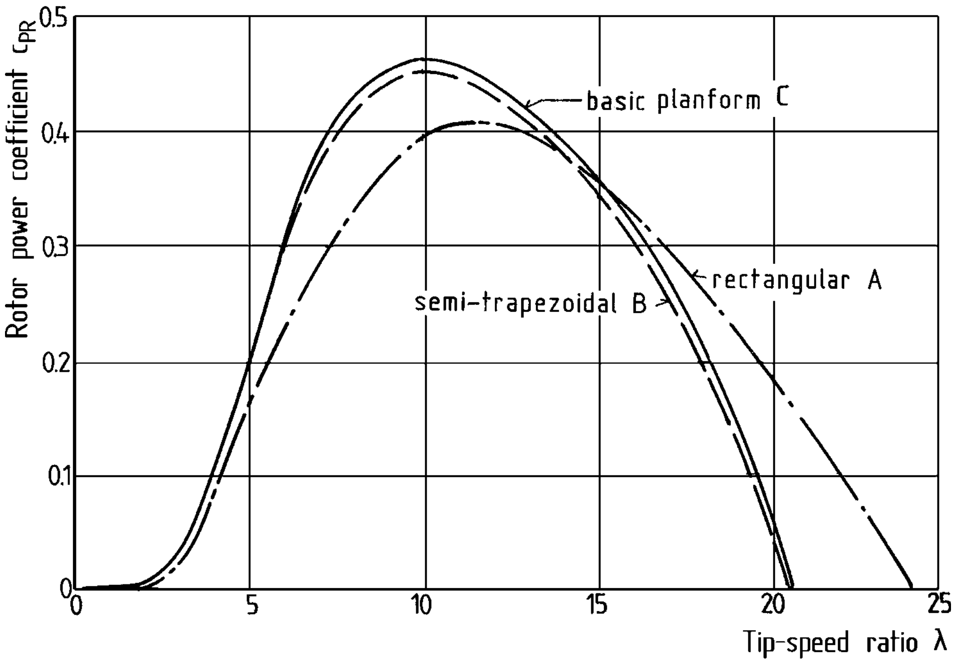


Figure 5.31. Influence of different blade planforms on the rotor power coefficient calculated for a two-bladed rotor [14]

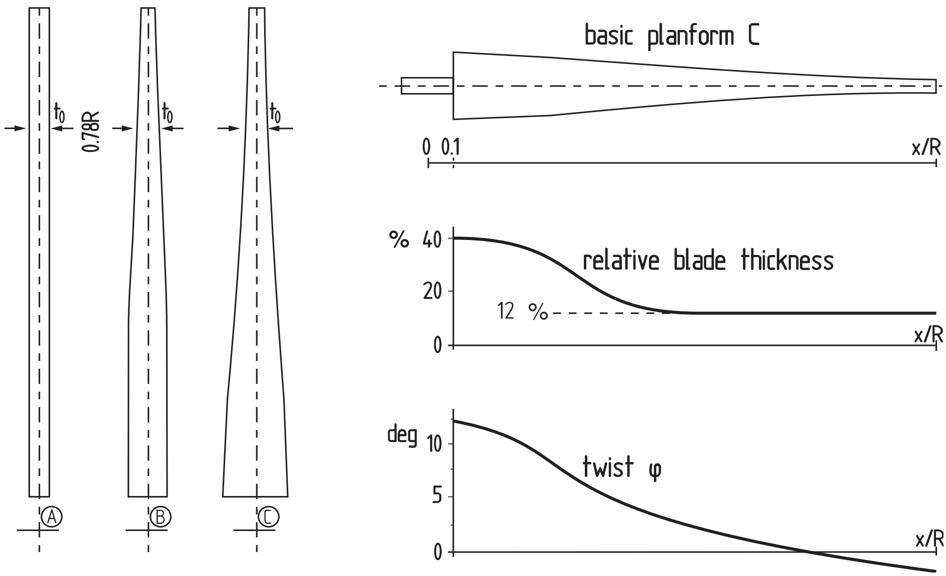


Figure 5.32. Rotor blade planforms: basic shape calculated for a two-bladed rotor; diameter 59.9 m; airfoil NACA 230XX; $c_{\mathrm{LD}} = 1.0$, $Re = 3 \cdot 10^6$ [14]

contribution by the root area to power generation must not lead to the mistaken idea that, to save weight or costs, this part of the blade can be dispensed with without any noticeable consequences for the power generated. Fig. 5.33 shows the influence on the power coefficient when different sections of the blade root area are omitted.

In special cases, it has been found that, regardless of the general rule, significant increases in performance were made possible by using special shaping on the inside area of the blade. In the more recent Enercon turbines, the inside area of the blade was constructed with a large chord length echoing the ideal shape, including the air flow around the nacelle into the calculations. In the given circumstances, this shape contributes to a noticeable increase in the power coefficient (Fig. 5.34). However, this effect is closely linked to the aerodynamic shape and the large cross-section of the nacelle. Both features lead to an extraordinary acceleration of the vortex-free flow around the nacelle which also affects the free stream velocity at the blade roots so that this area also becomes more significant aerodynamically.

The outer blade area is of much higher importance for the rotor performance from the aerodynamic point of view. The choice of blade shape and surface quality must be given close attention. Chord length distribution in the outer section should remain as close as possible to the theoretical optimum shape. This also applies to the shaping of the outer blade tip (Fig. 5.35). Analogously to conditions for airplane wings, the shape of the blade tip arc influences the tip vortices produced and thus the induced aerodynamic drag. According to recent investigations, power can be noticeably improved for wind rotors by optimizing the tip shape. Moreover, the shape of the tip arc has some influence on the aerodynamic noise emission of the rotor.

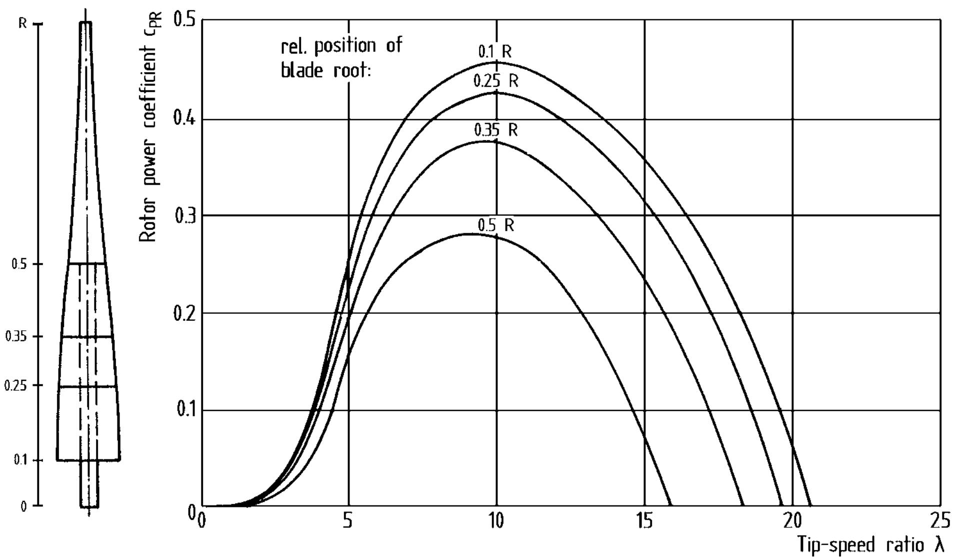


Figure 5.33. Influence of omitting sections of the blade area near the hub on the rotor power coefficient [14]

Figure 5.34. Rotor blade root sections of the Enercon E-70 E4 (Enercon)

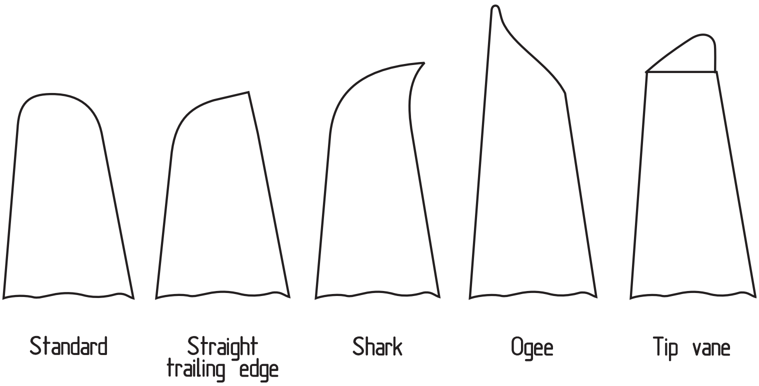


Figure 5.35. Rotor blade tip shapes and tip vane

The attachment of tip vanes to the blade tip as frequently proposed is aimed in the same direction. In the past few years, extensive wind tunnel measurements of the effectiveness of tip vanes have been carried out, especially by the Dutch NLR (National Aerospace Institute) [16]. But the promising results of wind tunnel investigations have not been confirmed on experimental rotors in the open atmosphere. Apparently, the effectiveness of tip vanes is greatly reduced by the unsteady and turbulent winds in the atmosphere. Nevertheless, tip vanes are used in some turbines (Fig. 5.36).

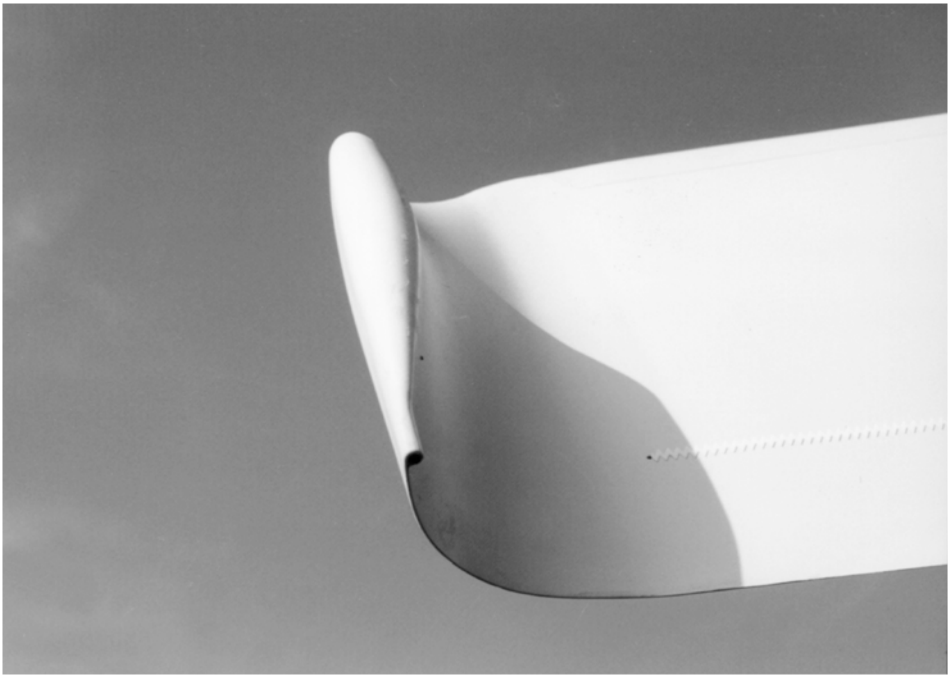


Figure 5.36. Tip vane extension on the rotor blade of the Enercon E-66 wind turbine

5.5.3 Rotor Blade Twist

The increase in effective flow velocity at the rotor blades from the blade root to the tip requires the blades to be twisted in order to achieve the optimum reduction in flow velocity over the entire length of the blade (Fig. 5.37). The twist angle is here defined as the angle between the local airfoil chord and that at 70 % rotor radius or that at the blade tip.

Naturally, determining the optimum blade twist can only be done for a certain ratio of peripheral speed to wind velocity, i. e. for one rotor operating point. As a rule, this is the rated power operating point. For all other operating conditions, the twist is non-optimal, making power losses unavoidable. Designing the blade twist for one point of operation unavoidably leads to locally limited areas of stall as the wind speed increases, mainly in the blade section near the hub. For manufacturing reasons, the inner blade area frequently does not have as strong a twist as would be desirable for aerodynamic reasons. Considering the low effective flow velocities in the inner blade area of the rotor, compromises are easily possible here.

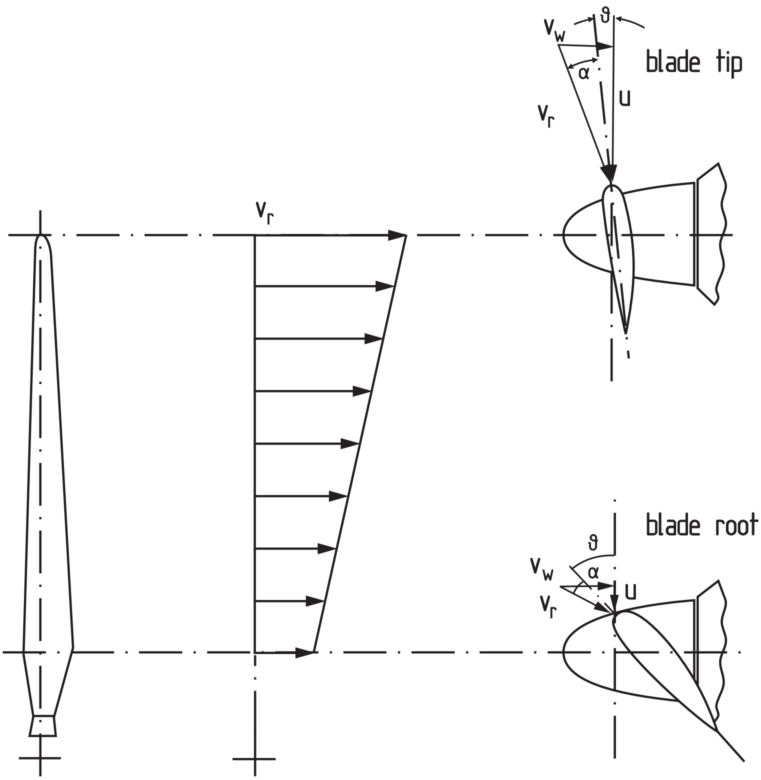


Figure 5.37. Twist of the rotor blade (linear variation for blade pitch control)

In an actual design case, the choice of twist characteristic is not only determined by the variation of the effective flow velocity over the length of the blade. In particular, it possible to use the twist to influence flow separation (stall) at a certain wind velocity. For this reason, rotor blades with fixed pitch angle are not linearly twisted but twisted to a greater extent in the inner area of the blade (up to 20 degrees) whereas the outer area has almost no twist. This variation in twist is determined not only by a certain stall characteristic but also by an improvement in the starting torque since the rotor blades cannot be adjusted to a blade pitch angle advantageous the start-up behaviour by pitching the blade.

Seen overall, determining the optimum blade twist requires a number of aspects to be taken into consideration which include both the type of power control — pitch or stall — and certain operational characteristics of the rotor. The choice of airfoil also has a certain influence.

The influence of different blade twist variations on rotor performance can be seen in Fig. 5.38. Aiming at simplifying rotor blade manufacturing, the question arises whether a blade entirely without twist is aerodynamically acceptable. Doing without any twist obviously leads to a considerable reduction in power. For large turbines, this is too much of a compromise to be made in favour of simplified blade manufacture.

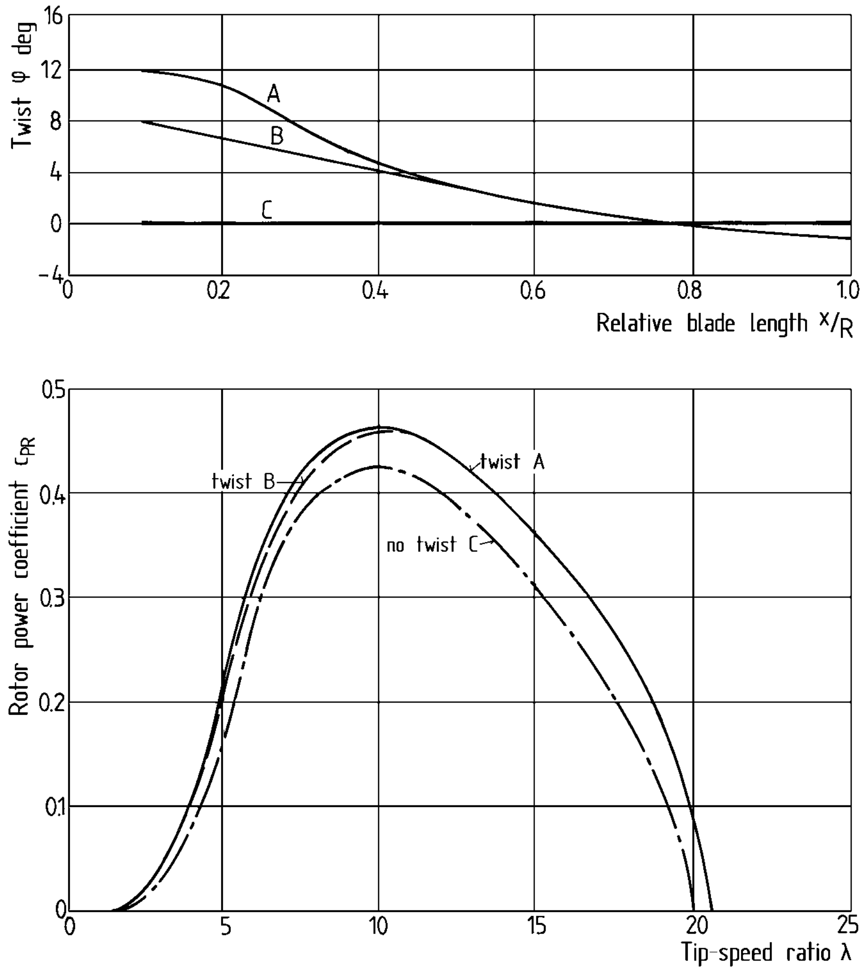


Figure 5.38. Influence of rotor blade twist on the rotor power coefficient [7]

5.5.4 Rotor Blade Airfoil

The efficiency and the control characteristics of fast turning wind rotors are determined to a great extent by the aerodynamic properties of the airfoils used. The most important parameter of the airfoil is characterized by the *lift-to-drag ratio* (L/D):

$$\frac{L}{D} = \frac{c_L}{c_D} \qquad (\text{—})$$

Its influence on the power coefficient of the rotor can be represented in a general way as shown in Fig. 5.39.

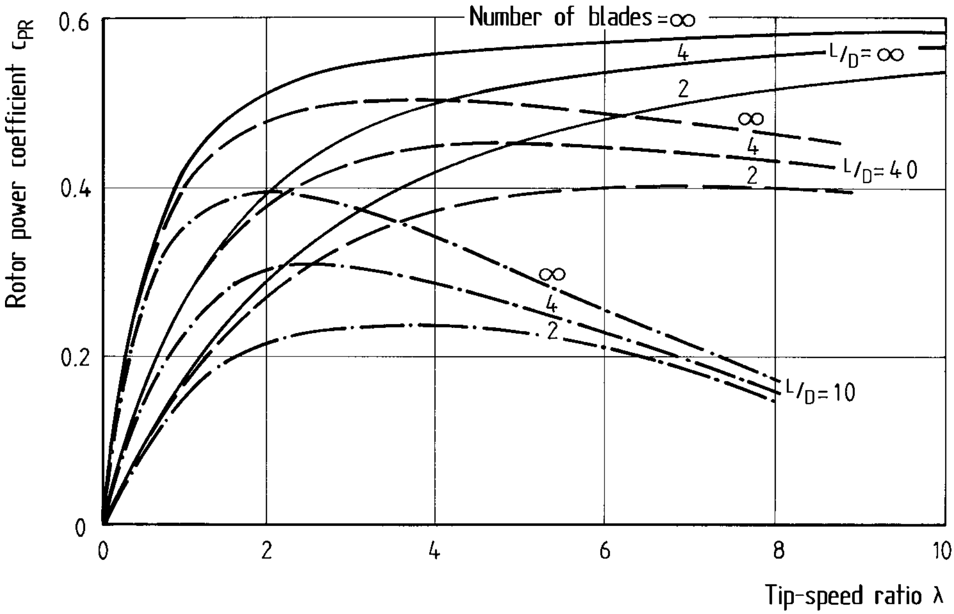


Figure 5.39. Influence of airfoil lift to drag ratio and number of blades on the rotor power coefficient [15]

As expected, when the lift to drag ratio (L/D) becomes smaller, the power coefficient which can be achieved also decreases. The optimum point of the power coefficient shifts to lower design tip-speed ratios. When the L/D ratio and tip-speed ratio are high (L/D = 100), the number of rotor blades (z) has relatively little influence on the achievable c_{PR} value, but when the L/D ratio and tip-speed ratio are low (L/D = 10), the number of blades apparently is of greater importance. In other words, low-speed rotors need many blades, but their airfoil characteristics are not so important. High-speed rotors manage all right with fewer blades, but the airfoil characteristics become a decisive factor for power generation.

Until the present day, wind power rotors in most cases use airfoils developed for aircraft wings. This is justified, as the flow velocity in the aerodynamically important outboard area of the rotor blades is comparable to the flying speeds of light planes or propeller-driven transport planes. Nevertheless, the requirements made on airfoils for wind rotors are not in every way identical to the requirements of aircraft design. For this reason, special airfoils have been developed for wind turbines in recent years. In the US, the LS and the SERI series have been developed with special attention to minimising performance losses due to surface roughness. But the stall behaviour particularly with a view to the requirements for wind turbine applications can also be improved, for example with the SERI airfoils.

The most common airfoils in aviation have been compiled in airfoil catalogues [17]. Selecting an airfoil, however, requires knowledge of airfoil classification. The first systematic airfoil developments for aircraft were carried out as early as 1923 to 1927 at an aerodynamics research institute in Germany (Aerodynamische Versuchsanstalt in Göttingen). Airfoils from the Göttingen airfoil system are scarcely used today. They were replaced later by the American NACA airfoil series which is characterized by the following parameters (Fig. 5.40):

- chord length c
- maximum camber f or camber ratio (f/c) in percent, as max. curvature over the median line
- position of maximum camber x_f
- maximum airfoil thickness d, as largest diameter of the inscribed circles with their centers on the mean camber line, or thickness-to-chord ratio (d/c) in percent
- position of maximum thickness x_d
- nose radius r_N
- airfoil co-ordinates $z_u(x)$ and $z_l(x)$ of the upper and lower side contours

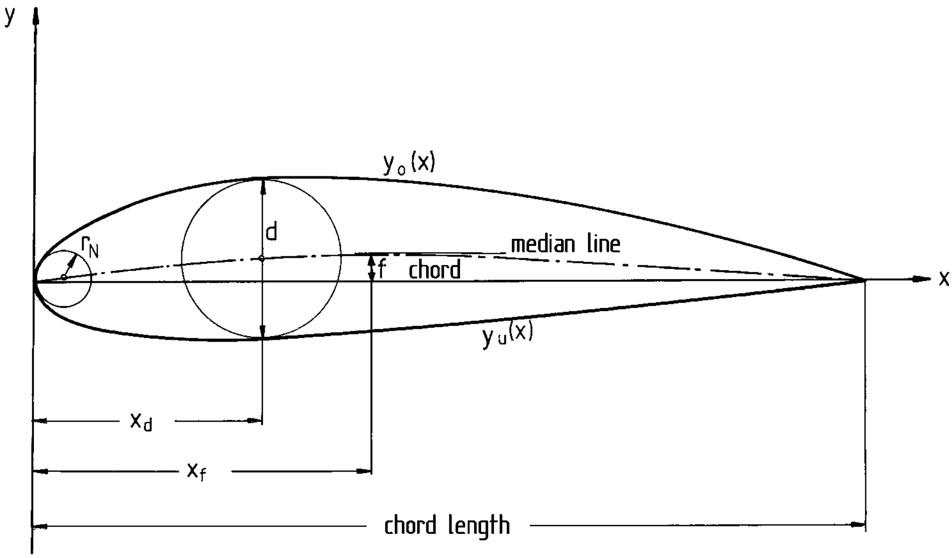


Figure 5.40. Geometric airfoil parameters of the NACA airfoil series

The contour co-ordinates are listed as tables in the airfoil catalogues. NACA airfoils are indexed with a multidigit code containing data on airfoil geometry and partly also on certain aerodynamic properties.

The most important airfoil families are:

Four-digit NACA airfoils:

1st digit:	maximum camber-to-chord ratio in percent
2nd digit:	camber position in tenths of the chord length
3rd/4th digit:	maximum thickness-to-chord ratio in percent

Example:
NACA 4412 4 % camber-to-chord ratio at 40 % of the chord length; maximum thickness-to-chord ratio of 12 %. The thickness position of all four-digit airfoils amounts to 30 % of the chord length.

Five-digit NACA airfoils:

In these airfoils the position of max. camber is closer to the nose than in the four-digit ones.

1st digit: index of so-called "shock-free" entry of the flow ($c_L^\star$)
2nd/3rd digit: twice the value of camber position in percent of the chord length
4th/5th digit: maximum thickness-to-chord ratio in percent.
Example:
NACA 23018 $c_L^\star = 0.3$, camber position 15 %, maximum thickness-to-chord ratio 18 %.

The NACA airfoil series and its nomenclature have undergone a multitude of changes and are constantly being supplemented. The more recent airfoils are indexed with more than five digits primarily indicating aerodynamic properties. Apart from the NACA airfoils, the laminar airfoils of the German "Stuttgart Airfoil Catalog" developed by F. X. Wortmann are of importance. These airfoils were developed primarily for gliders, but they are also basically suitable for wind rotors [18]. New airfoils, designed exclusively for wind turbines, have been developed in the US and in Sweden, for example the LS, SERI and FFA series.

The aerodynamic properties of the airfoils are measured on models in the wind tunnel. Lift and drag coefficients are measured as a function of the angle of attack up to the so-called critical angle of attack at which the flow separates from the top of the airfoil. Moreover, the aerodynamic moment coefficient c_m is determined in relation to the so-called "$c/4$ point" (25 % of the chord length from the leading edge). The aerodynamic force and moment coefficients are plotted in the form of so-called *polar airfoil curves*.

There are two common polar representations. The first one shows the variation of c_L, c_D and c_m versus the angle of attack, a resolved polar curve which occasionally is still called "Lilienthal polar diagram" (Fig. 5.41). The second one represents the direct interrelationship between the aerodynamic coefficients (Fig. 5.42). The angle of attack is entered in the curves as a parameter. One advantage of this type of plot is that the optimum lift to drag ratio can be visually identified as the tangent to the curve.

Apart from airfoil geometry, the polar airfoil curves are also influenced by the flow parameters, the main one of which is the *Reynolds number*. It is used as similarity parameter for the transferability of model measurements in the wind tunnel to the flow conditions at the original object. The Reynolds number is defined as:

$$Re = \frac{v\, l}{\nu}$$

where:

v = flow velocity (m/s)
c = chord length (m)
ν = kinematic air viscosity (m²/s) at m.s.l.: $\nu = 1.5 \cdot 10^{-5}$ m²/s.

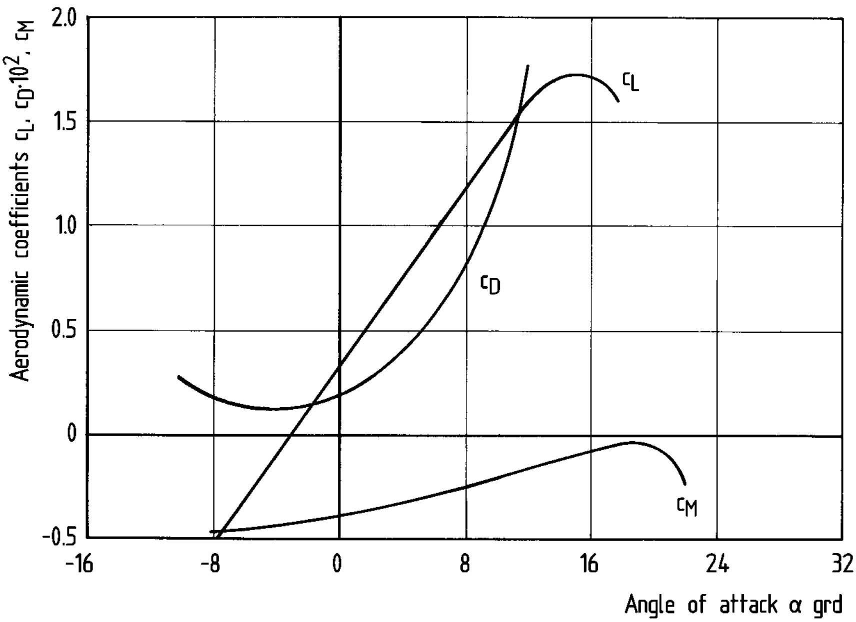


Figure 5.41. Resolved polar diagram (Lilienthal polar diagram)

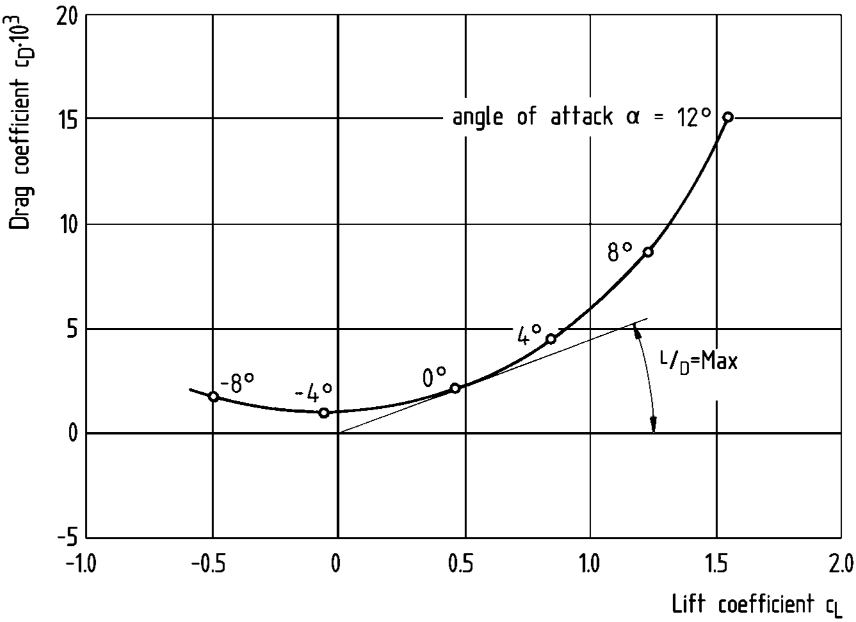


Figure 5.42. Polar diagram, American representation

At the blade tip, the Reynolds numbers of wind rotors range from 1 to $10 \cdot 10^6$ depending on the size of the rotors. The polar airfoil diagrams in the data catalogues usually show the curves for several Reynolds numbers.

Diagrams 5.43 and 5.44 show the polar diagrams of two typical airfoils used for wind turbines today. Like almost all modern airfoils, the NACA airfoil series 44 and the series 230, also frequently used, are so-called *laminar airfoils.* Laminar airfoils are shaped such that the flow boundary layer remains laminar along a long section of the chord length.

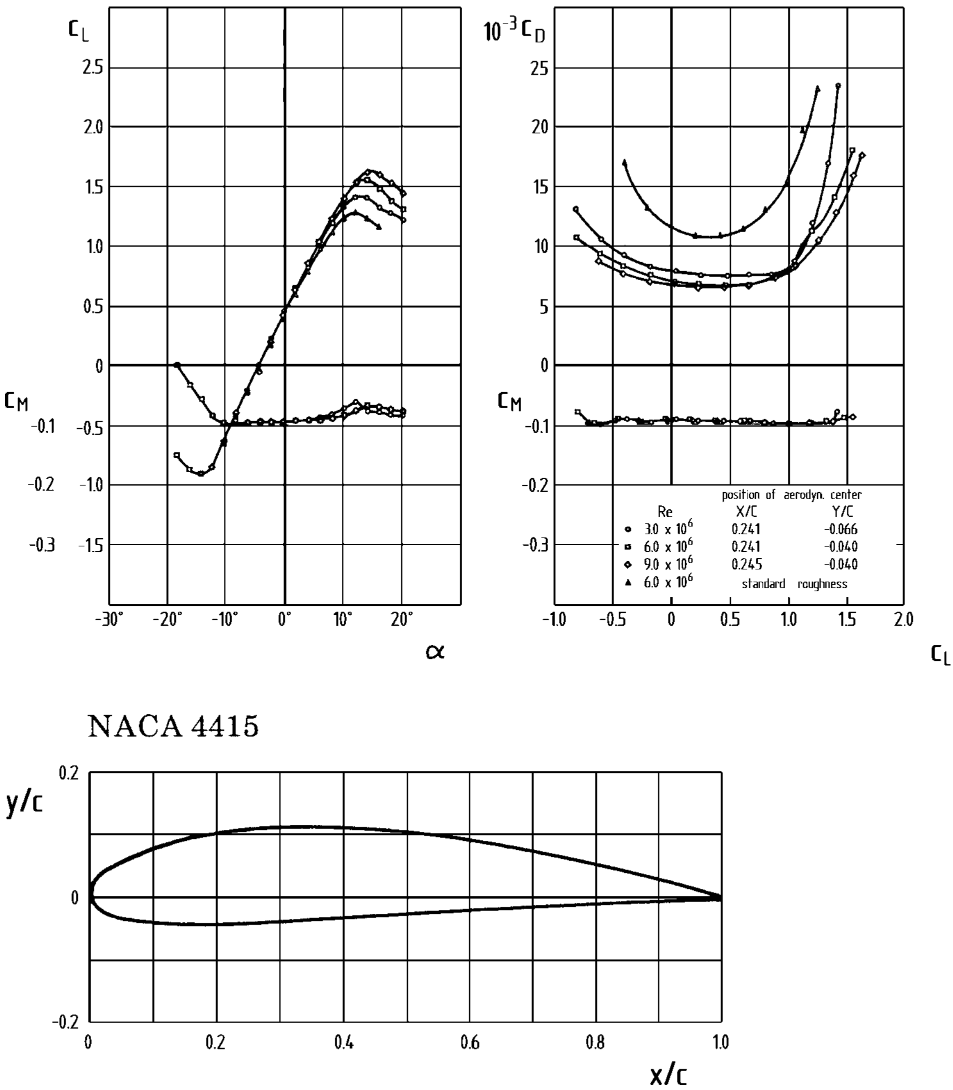


Figure 5.43. Geometry and lift/drag characteristics of the NACA 4415 airfoil [17]

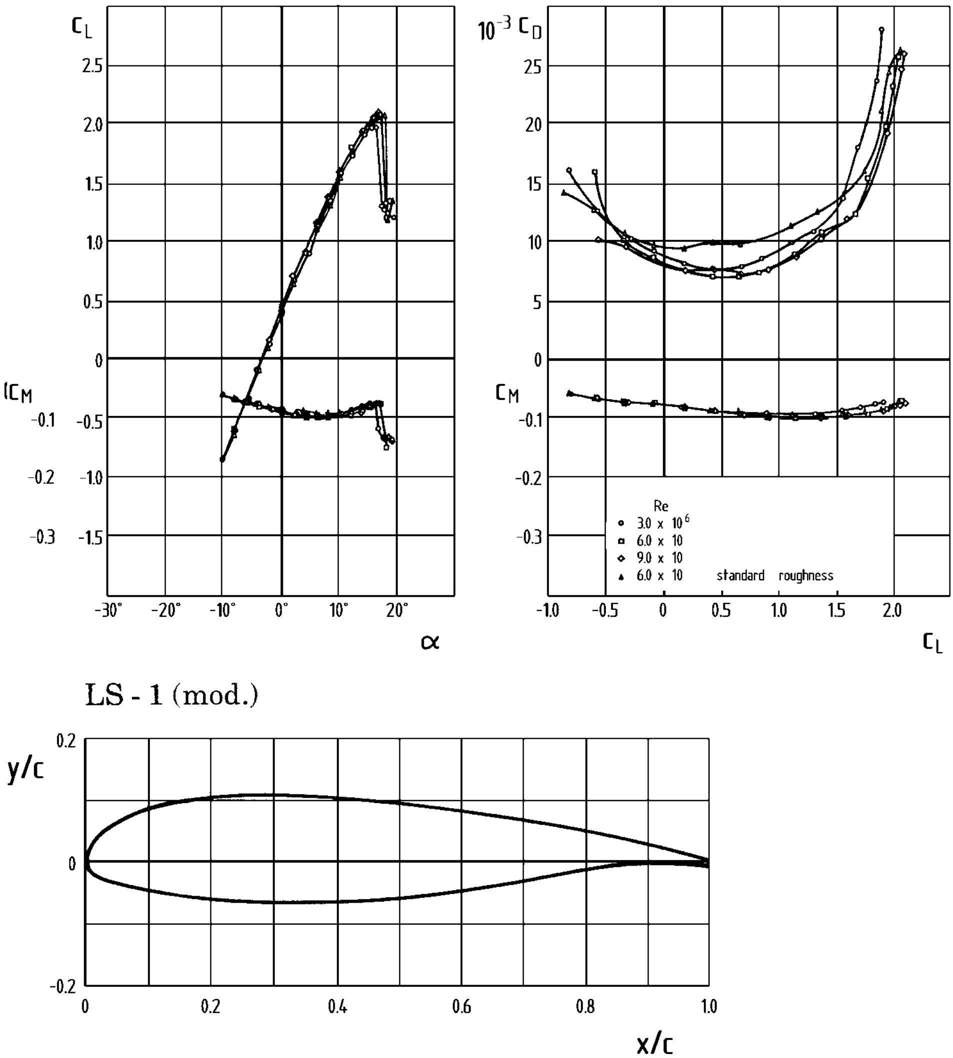


Figure 5.44. Geometry and lift/drag characteristics of the LS-1 airfoil [19]

These airfoils are distinguished by extremely low drag over a certain angle-of-attack range. Laminar airfoils are used almost exclusively nowadays.

Airfoils of the series 44 and 230 are used with approximately 15–16 % thickness to chord ratio in the outboard section of the rotor blade. They differ slightly in their performance. The 44 series has a slightly lower lift-to-drag ratio, but is less sensitive to surface roughness. The 230 series is a more recent airfoil family with a somewhat higher lift-to-drag ratio but it is also more sensitive to surface roughness.

The influence of the airfoil type on the rotor power coefficient is comparatively small, as long as the airfoils are aerodynamically of high quality and the airfoil surface is smooth (Fig. 5.45). Nevertheless, these differences should not be underestimated. Selecting a high-performance airfoil does not add to the cost, and the aerodynamic efficiency of the rotor is directly proportional to the energy yield and thus ultimately to the economy of the turbine.

For reasons of cost, the rotor blades for wind turbines cannot be manufactured with just any surface quality. Selecting a suitable airfoil should thus be done having regard to the surface quality which can be achieved in manufacture and taking into consideration the degradation under environmental influences during operation. Attention must be paid to both surface roughness and the accuracy of the airfoil contour (shape tolerances, rippled surface). High-performance laminar airfoils, in particular, are highly sensitive. Their high performance in a "smooth" condition can turn to the opposite when their surface is "rough". Soiling occurring during operation, which has turned out to be a serious problem for wind rotors, can be one of the causes of a rough surface. As with gliders, the dirt consists of a combination of dead insects and firmly caked-on dust. On large rotors with hub heights of more than 30 or 40 m, dirt is found only to a small degree whereas the problem is far more serious in smaller turbines (Fig. 5.46).

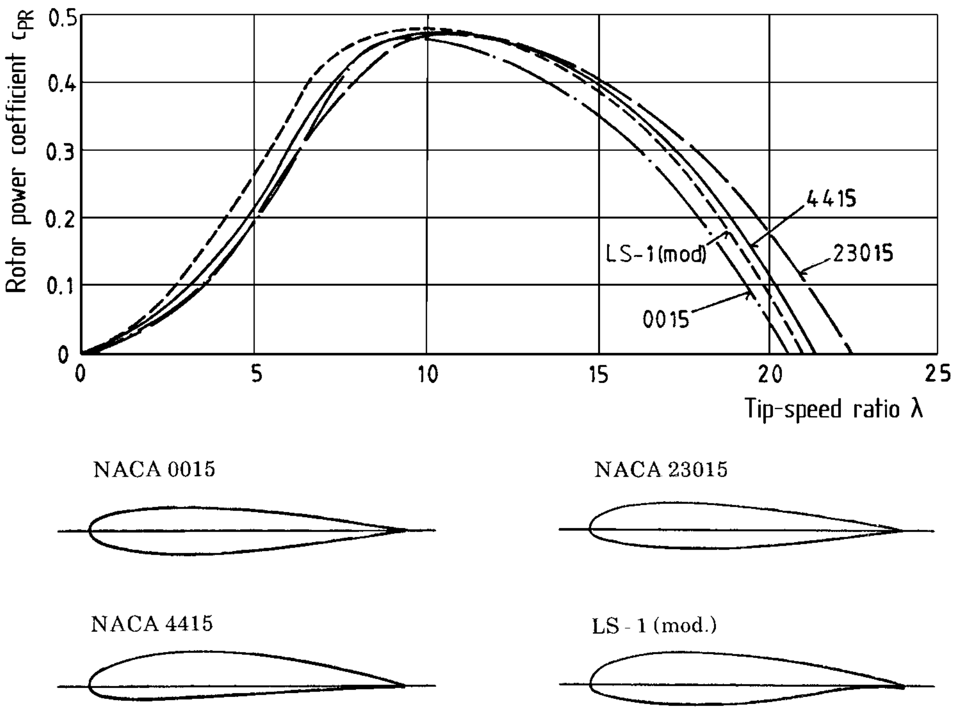


Figure 5.45. Influence of different types of airfoils on the rotor power coefficient

Figure 5.46. Soiled rotor blade of a Aeroman wind turbine after an operating period of only a few months in the Tehachapi mountains of California (USA)

In airfoil theory, performance calculations are normally based on a so-called *standard roughness* which is defined according to a certain "depth of roughness" [17]. From the practical point of view, the problem is one of translating real surface roughnesses into these idealized conditions and this requires some experience.

Stall-controlled rotors, in particular, react highly sensitively to an increase in surface roughness. When roughness is high, the airfoil performance changes particularly in the area of maximum lift coefficient. The point of flow separation is shifted towards smaller angles of attack, so that aerodynamic stall already takes place at low wind speeds, with the direct consequence of considerably diminished performance (Fig. 5.47).

Apart from those airfoil properties which influence the performance of the rotor, the ones affecting the rotor's control and operational behaviour are also of consequence. The stall behaviour of the airfoil, manifesting itself in the steep decline of the lift curve after the critical angle of attack has been exceeded, can follow a more or less "gentle" course. As, under certain operating conditions, the rotor will inevitably reach angles of attack where the flow separates, gentle stall behaviour of the aerodynamic airfoil is of importance.

The aerodynamic moment of the airfoil must also be taken into consideration with regard to pitch-controlled rotors. Some strongly cambered airfoils exhibit an undesirably large change in aerodynamic moment versus angle of attack. They do not have a fixed centre of pressure. This affects the necessary pitching moments to be generated by the blade pitch system.

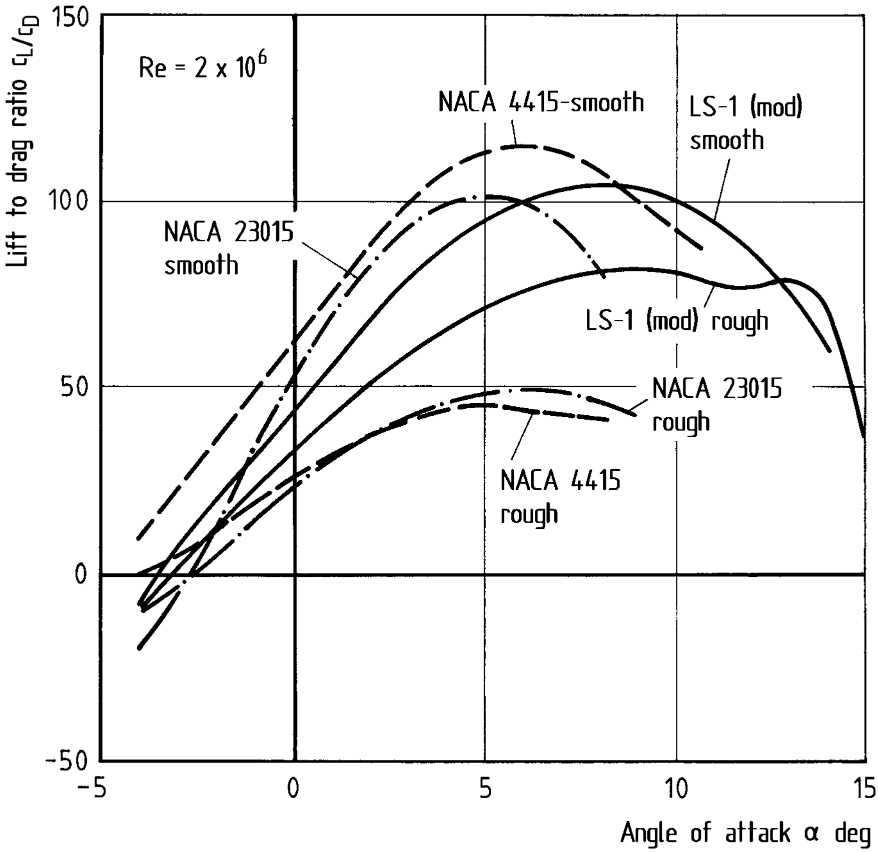


Figure 5.47. Lift to drag ratios for various types of airfoils with smooth and rough surfaces [20]

5.5.5 Blade Thickness

Rotor blade thickness is a subject in the classical conflict between aerodynamic efficiency and rotor blade stiffness and strength requirements. The aerodynamicist strives for the thinnest possible rotor blades, so as to be able to use high-performance airfoils. In contrast, structural requirements demand a sufficiently thick cross-section for the load-bearing elements. The maximum thickness, in particular, which is provided by the height of the spar box and influences the section modulus of the spars or spar box cross-sections to the third power, is the crucial parameter for meeting the stiffness requirements at a low structural weight. These two requirements of good aerodynamics and sufficient stiffness run counter to each other. The only possible optimum lies in offsetting the penalty for the structural weight against the differences in energy yield. For this reason, the task of the aerodynamic designer is restricted to showing the influence of thickness-to-chord ratio on rotor performance and energy yield (Fig. 5.48).

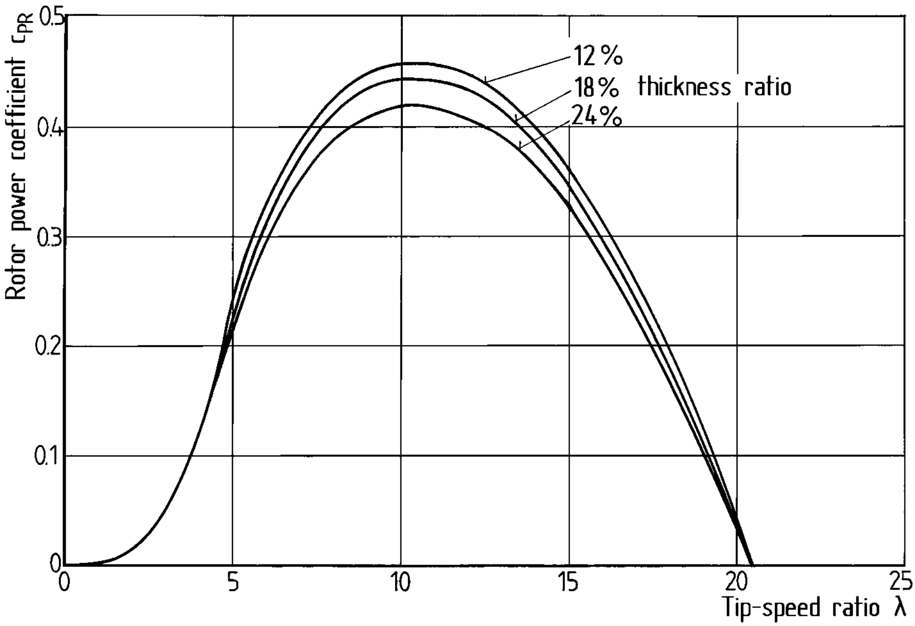


Figure 5.48. Influence of rotor blade thickness-to-chord on the rotor power coefficient [14]

5.5.6 Design Tip Speed Ratio of the Rotor

The rotor tip-speed ratio is a constantly recurring theme in the discussion of performance criteria and aerodynamic parameters. Many parameters show a strong dependence on the tip-speed ratio of the rotor. This raises the obvious question of what is the optimum tip-speed ratio for a wind rotor? Can it be optimized mathematically and what are the criteria for its selection?

To answer the second question first: it is not possible to determine the best tip-speed ratio "mathematically". It is, on the contrary, a system parameter for the entire wind turbine, the influence of which extends far beyond rotor aerodynamics. To make this clear, it is useful to ask about the motives for the comparatively large tip-speed ratio of modern wind rotors.

In the beginning, there was primarily the endeavour to bring the rotor speed as close as possible to the much faster rotating electric generator. Mechanical step-up gearboxes with very high gear ratios were expensive and also presented problems in other respects. However, gearbox development has made considerable progress in the past decades. At presently, gearboxes, as they are being used in the more recent turbines, are technically matured and, when compared to the complete system, relatively inexpensive. This largely reduces the necessity of having high-speed rotors. However, a higher design tip-speed ratio, which is tantamount to a higher rotational speed of the rotor, means that the desired power can be generated by a lower torque which, in turn, means a reduced weight of the rotor shaft and gearbox.

Another argument for a high tip-speed ratio is that with increasing tip-speed ratio, the required rotor solidity initially decreases rapidly (Fig. 5.49). Less rotor solidity means less material is required for the rotor blades and thus, in principle, lower costs. Practical experience shows, however, that rotors with very high tip-speed ratios need technologically complex and expensive rotor blades. The strength and stiffness requirements can only be met by using very expensive materials.

One example of these problems was the experimental German wind turbine WEC-520 with a design tip-speed ratio of 16. Its rotor blades were made entirely of carbon-fiber composite material. Nevertheless, the extremely slender rotor blades showed such difficult aeroelastic behaviour that rotor control was practically impossible (compare Fig. 2.21).

One way out of this dilemma was expected to be the one-bladed rotor. With only one blade high tip-speed ratios can be realized while keeping the aspect ratio and thickness of the single blade manageable. The experimental Monopteros wind turbine had approximately the same design tip-speed ratio as the WEC-520, but its single rotor blade had a normal aspect ratio and blade thickness (Fig. 2.21).

Another question could be to what extent the design tip-speed ratio has an effect on the achievable power coefficient. Fig. 5.50 provides information on this. The maximum power coefficient of the rotor changes only very little in the usual range for high-speed rotors, from 5 to 15. It is only at tip-speed ratios below 5, i. e. for low-speed rotors, that the c_P-value drops rapidly. The maximum is about 10 for the two-bladed rotor. Thus, from the point of view of energy yield, there is no reason to strive for very high tip-speed ratios.

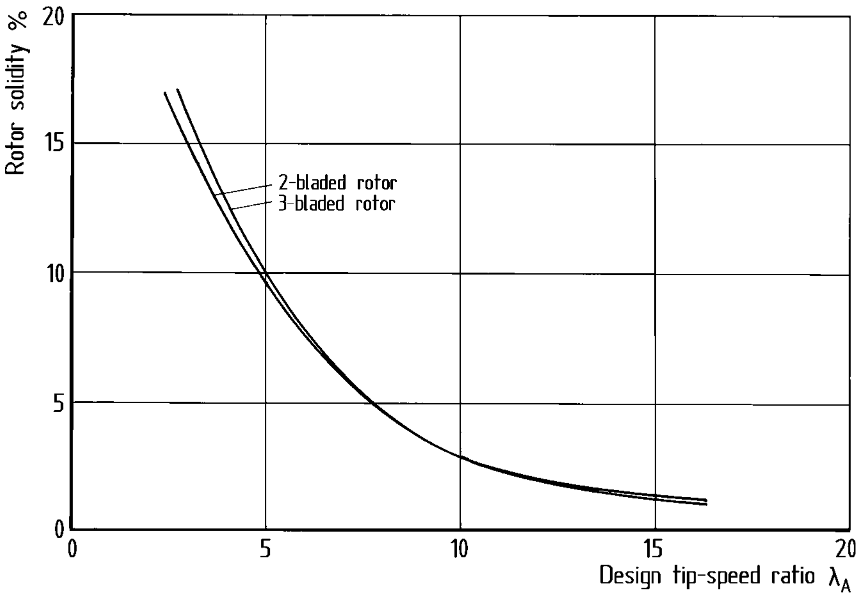


Figure 5.49. Rotor solidity as a function of the tip-speed ratio, calculated for the NACA 4415 airfoil, design lift coefficient $c_{LD} = 1.0$

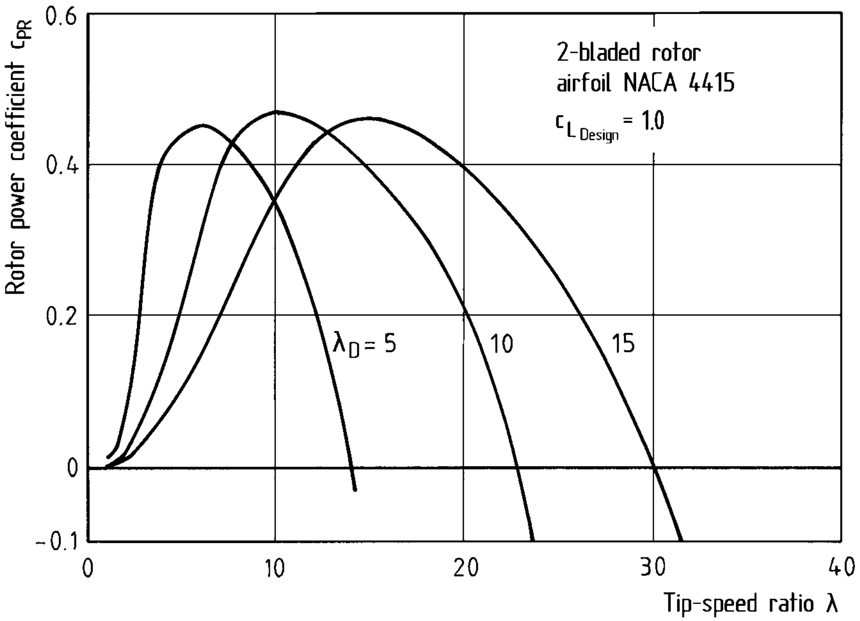


Figure 5.50. Rotor power coefficient versus wind speed for different design tip-speed ratios, calculated for the NACA 4415 airfoil, $c_{LD} = 1.0$

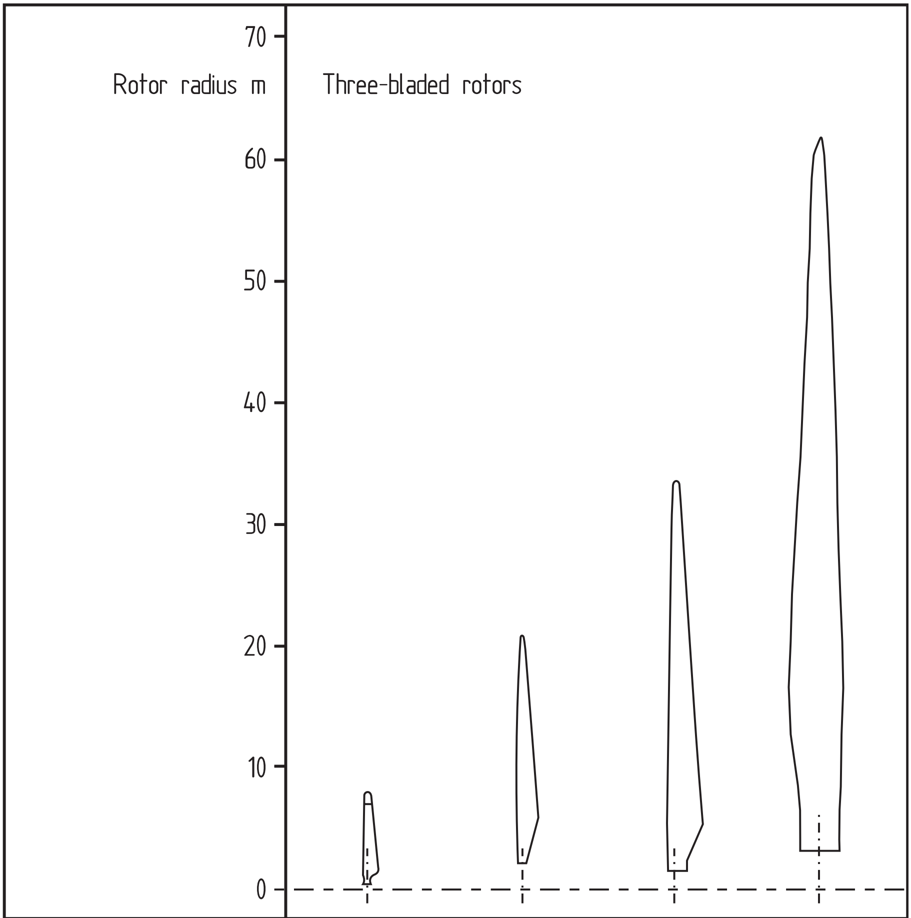
Last, but not least, an important aspect to be considered when choosing the tip-speed ratio is the aerodynamic noise emission of the rotor. The higher the tip-speed ratio, the greater the aerodynamic noise emission, and nowadays this factor is of decisive importance in the selection of the design tip-speed ratio (Chapt. 15.2.2).

As a conclusion, it may be stated that a trend in favour of extreme tip-speed ratios is no longer justified. For the foreseeable future at least, very high tip-speed ratios will cause additional problems rather than presenting a definite advantage. Design tip-speed ratios of 9 to 10 for two-bladed rotors and 6 to 8 with three-bladed ones are common today and should not be exceeded without a valid reason.

5.6 Existing Rotor Blade Designs

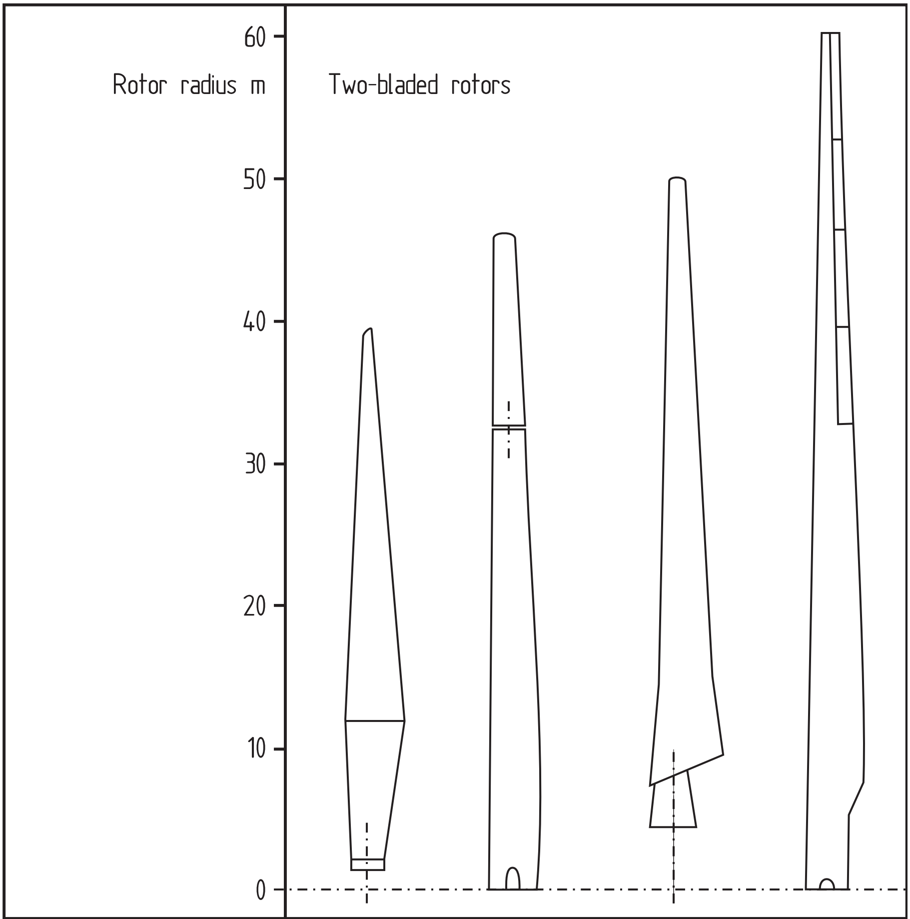
The rotor blades of current wind turbines reflect the different compromises between the optimum aerodynamic shape, the requirements of strength and stiffness and concessions to economic manufacturing (Fig. 5.51 and 5.52). Naturally, blade material also plays a significant part in the design. The optimum aerodynamic shape can be approximated much better by design concepts involving glass-fiber reinforced plastic (GFRP) than by rotor blades made, e.g., entirely of metal as in some earlier experimental turbines.

Nearly all rotor blades have a trapezoidal shape which more or less approximates the optimum aerodynamic contour. The aspect ratio is remarkably high compared to aircraft



Manufacturer / Type	Aerostar 1983, Series	LM 19 1999, Series	VESTAS V66 2003, Series	LM 61.5 2004, Series
Design tip-speed ratio (at c_{Pmax})	5.5	7	8	8.75
Solidity	8.9%	5.0%	4.8%	4.4%
Aspect ratio	11	19	19	20.7
Taper	0.33	0.21	0.14	0.18
Thickness ratio (at r/R=0.7)	18%	20%	16%	18%
Airfoil	NACA 44XX	NACA 63.4XX FFA-W3	FFA-W3	64.6XX

Figure 5.51. Existing rotor blades of wind turbines, three-bladed rotors



Manufacturer / Type	AEOLUS II (MBB) 1986, Exp.	MOD-2 (Boeing) 1982, Exp.	GROWIAN (MAN) 1982, Exp.	MOD-5A (GE) 1985, Proj.
Design tip-speed ratio (at c_{Pmax})	9	9	10	9
Solidity	4.2%	3.9%	3.0%	3.9%
Aspect ratio	15.2	16.2	17.8	16.4
Taper	0.25	0.44	0.26	0.35
Thickness ratio (at r/R=0.7)	17.0%	14.0%	18.0%	23.5%
Airfoil	FW84-W	NACA 230XX	FX-77W	NACA 64XXX

Figure 5.52. Existing rotor blades of wind turbines, large two-bladed experimental turbines (1980–1990)

wings where only the wings of high-performance gliders are built with such high aspect ratios. This extreme slenderness results in an aerodynamically optimum blade thickness which does not enable the requirements for the necessary strength and stiffness to be fulfilled.

The existing thickness-to-chord ratios of the airfoils used must, therefore, be chosen with consideration of stiffness and strength aspects. In the outboard section of the rotor blades, which is of special interest from the aerodynamic point of view, a thickness ratio of between 15 and 12 % is usual. In the inner section, near the blade root, blade thickness is increased. In almost all cases, the blade planform is chamfered at the root so that the airfoil section can converge into the circular cross-section of the hub flange.

The taper of the rotor blade planform varies considerably. Many manufacturers diverge strongly from the aerodynamically optimum taper. Less pointed tapering, that is a wider rotor blade in the outboard area towards the tip, improves the rotor power coefficient in the partial-load range and increases the starting torque.

Many manufacturers are paying increasing attention to the shaping of the blade tip, the edge curve. In some cases the rotor blades were retrofitted with aerodynamically more advantageous tip shapes in the hope of reducing the aerodynamic noise. The more recent rotor blades all have aerodynamically optimized blade tips. In practice, however, unconventional tip shapes have not really achieved any convincing successes.

The standard airfoils of the NACA series still predominate. Where as the airfoils of the earlier NACA 44 series disappear, the series 230, 63 and 64 are still widespread. Some German wind turbines are equipped with Wortmann airfoils, other turbines use LS-1 airfoil or airfoils from SERI which are less sensitive in respect to soiling. The trend towards using special aerodynamic airfoils for wind rotors will become more and more noticeable in the future. Innovative airfoils have been developed for some very recent turbines like Enercon V66/E-4 and Vestas V90. The airfoils feature particularly in the outer part of the blades a relative small thickness and a special camber. Sensivity to performance losses due to turbulence and soiling shall be minimized.

Among the three-bladed rotors, the relatively low design tip-speed ratio and correspondingly lower aspect ratio of the older Danish wind turbines is noticeable (Fig. 5.51). The older stall-controlled rotors required stiff blades which, with the material used, could only be realized with a low aspect ratio. The blades of the larger three-bladed rotors have a higher aspect ratio, both for rotors with pitch control and for limiting power by stall control. In most cases the selected tip-speed ratio is in the range of approximately 7 and thus near to the aerodynamic optimum. Another important criterion is the blade tip speed with respect to noise emission. The experience shows that tip speeds more than 70 m/s cause noise problems.

The large two-bladed rotors of the experimental turbines from the eighties exhibited a comparatively large bandwidth of blade geometries (Fig. 5.52). The selected tip-speed ratio was between 8 and 10 and there was also a greater variation in tapers. The solutions implemented for blade pitching differed. The rotor of the MOD-2, which was implemented with a continuous centre section, made do with partial span control (s.a. Chapter 5.3.1) whereas the MOD-5-A project, which was never completed, was provided with aileron-controlled rotor blades.

5.7 Yaw Control of the Rotor

If the rotor is to fully capture the power from the wind, it must be oriented correctly with respect to the wind direction. A yaw angle, i.e. an angle deviation between rotor axis and wind direction, causes a marked loss of power. The rotor can be oriented into the wind by three different methods:

– yawing by aerodynamic means: wind vanes or fan-tail wheels,
– active yawing with the help of a motorized yaw drive,
– free yawing of rotors located downwind.

Yawing with the help of a wind vane is the simplest method. It is feasible for small turbines with a diameter of a few meters where it has indeed been successfully employed. In larger turbines, however, the wind vane must be uneconomically large to yaw and stabilize the

Figure 5.53. Wind vane at a former American Wenco wind turbine (1980)

rotor and the nacelle effectively enough. Nevertheless, some manufacturers occasionally attempt to use wind vanes even for larger turbines (Fig. 5.53).

Yawing with the aid of a fan-tail wheel has already been successfully used in the Dutch windmills. Nowadays, this method can still be found in some smaller turbines (Fig. 5.54). However, they also have considerable disadvantages. Fantails and worm gears are relatively expensive components. Moreover, the yawing moment around the vertical axis of the rotor must be held by the teeth of the worm gear. Play in the worm gear, which is unavoidable, can cause vibrations around the azimuth axis (Chapt. 11.3.2). Many failures of older turbines with fantails are attributable to this effect. Fitting a fantail on one side also has the additional disadvantage of a not quite symmetrical yawing behaviour which is why two fantails have been used in some turbines.

Wind vanes or fantails are not found in larger turbines. The complexity of these components increases with the size of the turbine. If they are to be effective in moving tower-head masses of several tens of tons and overcoming the aerodynamic yawing moments of the

Figure 5.54. Yawing with a fan-tail wheel in a small wind turbine of the Aeroman type (1985)

rotor with a diameter of more than 30 m, they become very large. This especially applies to upwind rotors.

Another disadvantage of aerodynamically effected yawing is that azimuth adjustment of the nacelle is not possible without sufficient wind. This, however, is mandatory for servicing large turbines and it is also necessary for untwisting the flexible cables used for transferring electrical power from the nacelle to the ground. For these reasons, not least, active motor-driven yawing is the preferred solution for small units, too.

A more logically consistent idea for doing without motorized yawing, is the attempt to exploit the basic capability of a downwind rotor to yaw on its own. If successful, this could save manufacturing costs, which is why it requires a more detailed discussion.

If the rotor is positioned downwind, the point of attack of the total aerodynamic force of the rotor is located behind the axis of rotation of the tower head, the yaw axis, so that with the cross wind force, the aerodynamic forces produce a restoring moment on the rotor within a very wide yaw angle range. The question is whether this aerodynamic restoring moment is really strong enough to guarantee the "free yawing" of the nacelle with the wind direction and then to keep this position stable.

To turn the running rotor around the yaw axis, a number of different moments of resistance must be overcome. Among these are inertial and gyroscopic moments as well as the frictional moments in the towerhead bearings. Moreover, aerodynamic forces and moments become effective due to the uneven flow impacting the rotor swept area, e. g. as a result of the wind speed increasing with height. These moments can affect the balance of moments both in a supporting sense and in an impeding sense with respect to yawing. Furthermore, there are the unavoidable, periodically alternating rotor moments around the yaw axis, particularly in two-bladed rotors. In this complex balance of forces and moments there are some essential design parameters of wind turbines which permit at least a general indication of free yawing capability:

- An important design parameter with a distinct influence on yawing is the *cone angle* of the rotor blades. Similar to aircraft, where a dihedral position of the wings improves the aircraft's stability around the roll and yaw axis, respectively, the cone angle improves stability around the axis of yaw in the wind rotor.
- A blade-pitch angle coupling arrangement frequently incorporated in teetering rotors has a positive influence on yawing (Chapt. 6.6). It helps the asymmetrically blown rotor to rapidly find a yaw position with a new equilibrium.
- The tilt angle of the rotor axis with respect to the horizontal is also important. Many wind turbines have a tilted rotor axis in order to provide sufficient clearance between the rotor blades and the tower. This, however, creates a component of the rotor torque around the vertical axis which attempts to turn the tower head in a particular direction.

The preconditions for the free yawing capability of a wind turbine are, therefore: rotor positioned downwind, if possible without tilted rotor axis, but with a cone angle to the blades. The rotor should be a teetering two-bladed rotor with cyclic blade pitch actuation or a three-bladed rotor.

One decisive drawback to free yawing can be noted, however, in every case. Rapid changes of wind direction can lead to very high yawing rates of the rotor. As a consequence, very high gyroscopic moments occur and the resultant moment around the rotor pitch axis causes high bending moments in the rotor blades. This can result in breaking loads on the rotor blades. To avoid damage, carefully matched nacelle yaw damping devices are therefore absolutely essential for turbines working with free yawing.

Free yawing has been successfully used in some earlier American wind turbines of smaller and medium size (US-Windpower, Carter, ESI et al.). The ESI units had a downwind teetering rotor with a distinct coning angle. When fitted with additional dampers, free yawing apparently worked satisfactorily (Fig. 5.55). Other turbines, e.g. by Carter, combined free yawing in strong winds with small-scale motorized yawing at low wind speeds.

Attempts to introduce free yawing also to large turbines have not been successful so far. Thus, the WTS-3/4 turbine has the same features: downwind position, teetering rotor with

Figure 5.55. American ESI turbine with free yawing of the teetering downwind rotor (1985)

cyclic blade pitch actuation and no tilted axis. Motorized yawing had not been intended originally but initial tests with the prototype showed that correct and stable free yawing of the rotor was not possible, so that a motorized yaw drive had to be subsequently installed.

Extensive test programs were carried out on the experimental American MOD-0 turbine to investigate free rotor yawing [21]. These tests confirmed that accurate, passive yawing could not to be achieved. The rotor reached two more or less stable positions at yaw angles of approximately $-30°$ and $+30°$. The authors of the published test results pointed out that the reasons could not be fully explained. The assumption was that the influence of the vertical wind shear was the decisive factor, another reason to conclude that large wind turbines cannot do without motorized yawing for the time being.

5.8 Aerodynamics of Vertical-Axis Rotors

Even though this book primarily deals with horizontal-axis rotors, in accordance with the state of the art today, a small excursion into the aerodynamics of rotors with vertical axes of rotation is surely of interest. From an aerodynamic point of view, rotors with a vertical axis of rotation, which exist in numerous variations, have a number of aspects in common which distinguish them from the horizontal-axis type.

While horizontal-axis rotors (with the exception of the single-bladed rotor) experience steady-state aerodynamic forces in a steady and uniform wind, this is not the case in a rotor with a vertical axis of rotation. Here the rotor blades rotate on a rotational surface the axis of which is at a right angle to the wind direction (Fig. 5.56). The aerodynamic angle of attack of the blades thus varies constantly during the rotation. Moreover, one blade moves on the downwind side of the other blade in the range of 180° to 360° of rotational angle so that the wind speed in this area is already reduced due to the energy extracted by the upwind blades. Hence, power generation is less in the downwind sector of rotation. Consideration of the flow velocities and aerodynamic forces shows that, nevertheless, a torque is produced in this way which is caused by the lift forces A_1 and A_2. The braking torque of the drag forces W_1 and W_2 is much lower, by comparison.

In one revolution, a single rotor blade generates a mean positive torque but there are also short sections with negative torque (Fig. 5.57). The calculated variation of the total torque also clearly shows the reduction in positive torque on the downwind side. The alternation of the torque with the revolution can be balanced with three rotor blades, to such an extent that the alternating variation becomes an increasing and decreasing torque which is positive throughout (Fig. 5.58). However, torque can only develop in a vertical-axis rotor if there is circumferential speed. In other words: the vertical-axis rotor is not self-starting.

The qualitative discussion of the flow conditions at the vertical-axis rotor shows that the mathematical treatment must be more complex than with the propeller type. This means that the range of physical and mathematical models for calculating the generation of power and the loading is also wider. Various approaches, with a variety of weightings of the parameters involved have been published in the literature [22, 23, 24]. The results differ somewhat with respect to the power coefficients to be achieved. Most authors specify values of 0.40 to 0.42 for the maximum c_{PR} for the Darrieus-type of vertical-axis rotors.

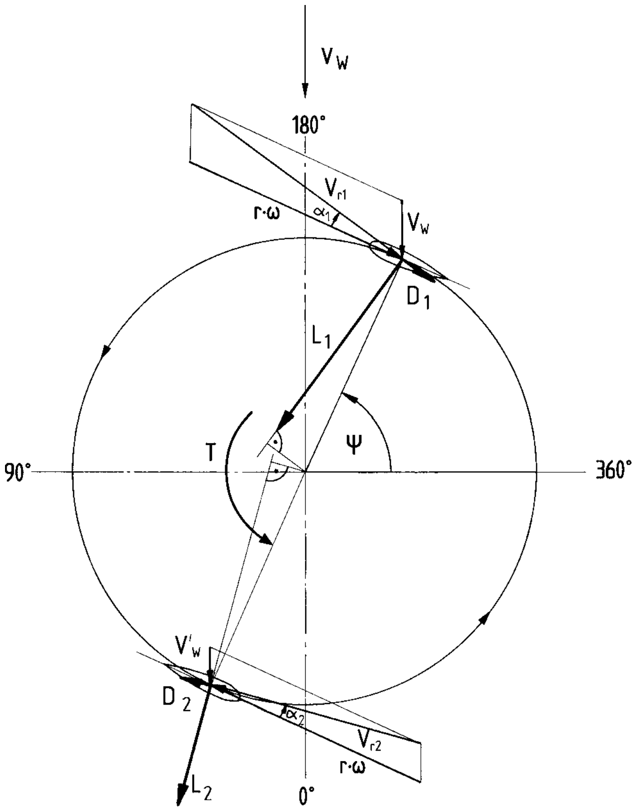


Figure 5.56. Flow velocities and aerodynamic forces on the blades of a vertical-axis rotor

This is slightly lower than for the horizontal-axis rotor at a comparable tip-speed ratio and number of blades.

In the US, more extensive research on Darrieus rotors has been carried out mainly by Sandia Laboratories in Albuquerque, New Mexico. The power coefficients measured confirmed the theoretical calculations and were lower than in comparable horizontal-axis rotors (Fig. 5.59). However, in recent years it has been possible to experimentally prove c_{PR} values of over 0.40 [25].

One variant of the Darrieus rotor, the so-called H-rotor, in theory, attains higher power coefficients, as its blade cross sections are all equidistant from the axis of rotation (Chapt. 3.1). It has not been possible to achieve this theoretically higher power coefficient in existing turbines. The mountings and struts of the rotor blades caused considerable aerodynamic drag, thus considerably reducing performance in practice.

The aerodynamic characteristics of vertical-axis rotors exhibit one essential difference compared to horizontal-axis rotors. The optimum power coefficient is achieved at relatively low tip-speed ratios. Due to the high drag components of the rotor blades in certain sections of their revolution, i. e. the poor lift/drag ratio, the optimum point of the power coefficient

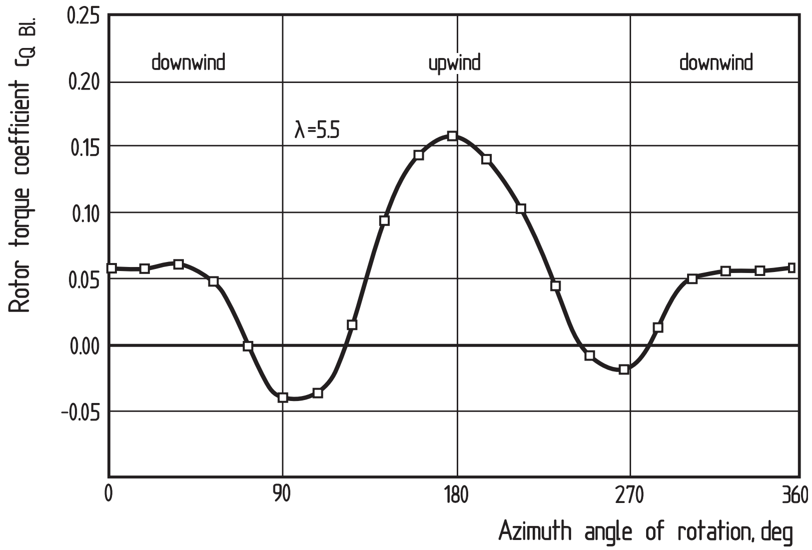


Figure 5.57. Variation of the torque of a single rotor blade of a vertical-axis rotor during one revolution

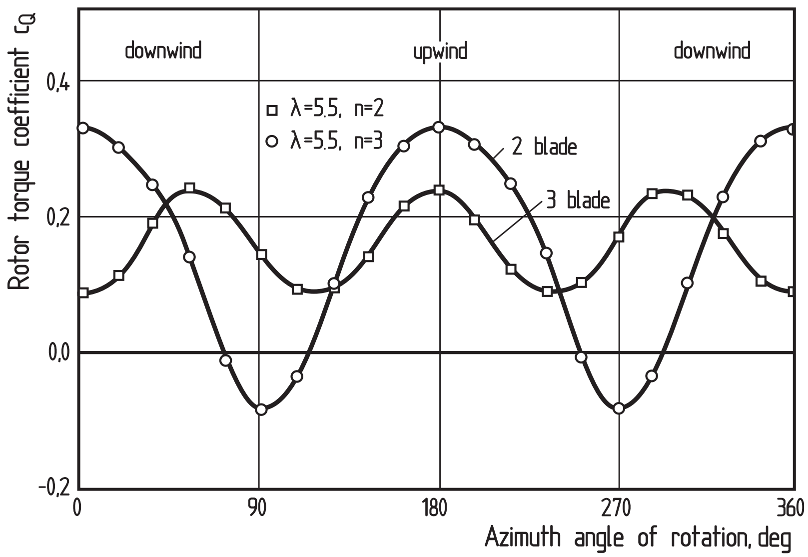


Figure 5.58. Variation of the total rotor torque of a vertical-axis rotor during one revolution, with 2 and 3 rotor blades [22]

is shifted towards lower tip-speed ratios (Chapt. 5.5.4, Fig. 5.39). The optimum tip-speed ratio of a two-bladed Darrieus rotor with a value of approximately 5 is only about half that of a comparable horizontal-axis rotor (Fig. 5.60). Vertical-axis rotors rotate at a slower

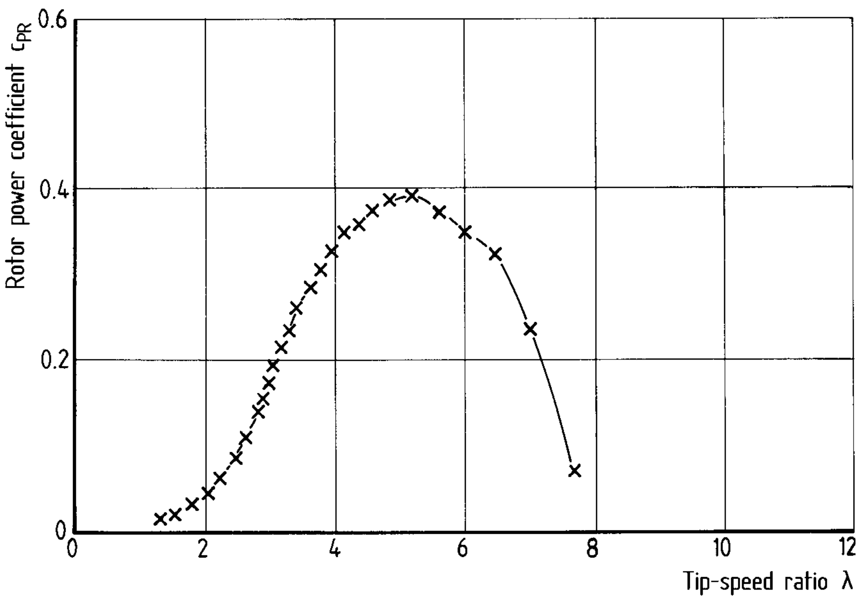


Figure 5.59. Measured variation of the rotor power coefficient vs. the tip-speed ratio for a Darrieus rotor [26]

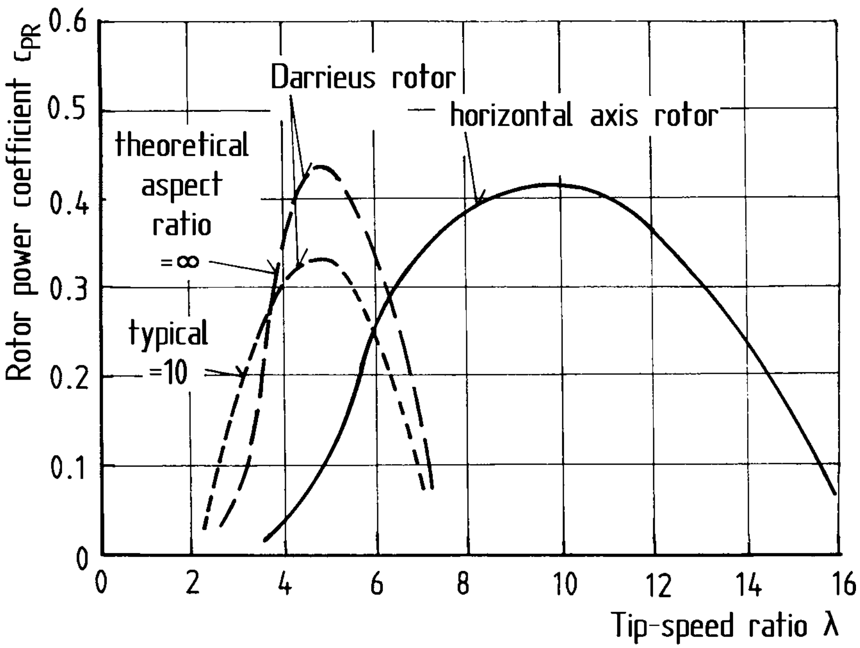


Figure 5.60. Rotor power coefficients versus tip-speed ratio for two-bladed vertical-axis and horizontal-axis rotors [27]

speed and their power must therefore be generated with higher torques. This is one of the main reasons why these rotors have a relatively high weight, and their production costs are correspondingly higher (Chapt. 17.3).

The lack of a generally accepted assessment of the aerodynamic efficiency of the vertical-axis rotor is a clear indication of its state of development. It lags behind the horizontal-axis design not only in terms of aerodynamic calculation but also other areas such as vibrational behaviour and control. If the vertical-axis rotor, hampered by its basic drawback of needing high torque for power generation, is to compete with horizontal-axis wind turbines it will still have to undergo a longer period of development until it reaches commercial maturity.

5.9 Experimental Rotor Aerodynamics

The discussion of aerodynamic rotor performance and loading up to this point has been based exclusively on theoretical model concepts and calculation methods. The question of how accurately these theories reflect real conditions still remained open. Naturally, the answer to this question depends on the possibilities of verifying these theoretical results by experimentation and measurement.

It is difficult to carry out aerodynamic measurements on wind turbines for a number of reasons. Without a lot of technical equipment, aerodynamic parameters can only be measured very indirectly, e. g. via the electric power output. Moreover, there is no definite reference wind speed in the free atmosphere. Moreover, suitable flow conditions cannot be produced "to order" and the wind unfortunately blows whenever and however it likes. One way out of these difficulties is to follow the example of aeronautics and use the wind tunnel.

5.9.1 Measurements on Models in the Wind Tunnel

The traditional measuring instrument in experimental aerodynamics is the wind tunnel. Aeronautical aerodynamics would be inconceivable without wind tunnel measurements. However, for several reasons, carrying out wind tunnel measurements on large wind rotors or even entire wind turbines involves certain difficulties.

Due to the large size of the wind turbines, it is not possible to carry out measurements on real rotors in the wind tunnel. Even the largest existing wind tunnels, with a cross-sectional measurement area of approximately 10 × 10 m, are too small. Model measurements can only be carried out at a scale where it becomes difficult to achieve useful Reynolds numbers, to say the least. Moreover, the constant and even flow conditions in the wind tunnel are an extreme simplification compared to the free atmosphere. Despite these restrictions, wind tunnel investigations are of useful service also to wind energy technology as long as the model measurements in the wind tunnel are carried out for solving specific questions and by using the right means. There are two different tasks to be considered in this context — one is measuring rotor power characteristics, the other is simulating the dynamic response of the rotor or of the entire turbine during unsteady flow conditions.

Power measurements do not require that the model is elastomechanically accurate and, moreover, can be carried out with steady-state flow conditions. The only condition to guarantee validity for the original is that a certain minimum value of Reynolds number be maintained. According to F. X. Wortmann, these types of measurement can be carried out with reasonable accuracy if, at the same blade tip speed, the model scale is selected such that the Reynolds number, referred to the chord length, is at least 2×10^5 [28]. E.g., for a rotor with a diameter of 100 m, this means a model diameter of approx. 4 m. Using a model of this size, rotor power measurements for the former German experimental Growian wind turbine were carried out in the low-speed wind tunnel of the German Aerospace Research Institute (Deutsche Forschungs- und Versuchsanstalt für Luft und Raumfahrt, DLR) in Göttingen, Germany (Fig. 5.61) [29]. The power coefficients measured were reasonably consistent with the calculated theoretical values (Fig. 5.62). Similar measurements on models in the wind tunnel were carried out during the development of the American MOD-2 and WTS-4 turbines.

Simulating the dynamic response of wind rotors for unsteady flow conditions requires special equipment, both for the model and the wind tunnel. At the Fluid Dynamics Institute of the University of Stuttgart, Germany, F. X. Wortmann built a special "gust wind tunnel" with the aid of which both power measurements and the dynamic response of the rotor to predetermined gusts were to be experimentally determined. In this gust wind tunnel,

Figure 5.61. Model rotor of the Growian turbine on a scale of 1/25 in the low-speed wind tunnel of the DLR in Göttingen, Germany

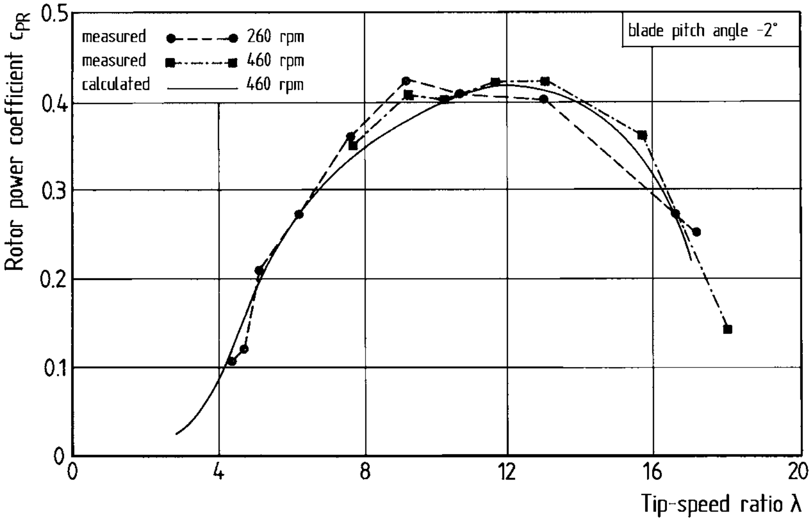


Figure 5.62. Power coefficients of the Growian model rotor measured in the wind tunnel, compared to calculated values

Figure 5.63. Single-blade model rotor Flair in the gust wind tunnel of the University of Stuttgart

research work has been carried out on various single-bladed configurations in the 80s (Fig. 5.63). With his "Flair" single-bladed concept, Wortmann pursued the goal of creating a flexible rotor which is connected to the rotor shaft without moments being transferred to the drive train, and which, under the influence of wind turbulence, is largely self-regulating as far as its aerodynamic response is concerned. This was to reduce the turbulence-related dynamic loads to a minimum.

Apart from the experimental investigations in the wind tunnel, the Flair design was also tested in the field in a demonstration object. The results were applied to the single-bladed turbines of the Monopteros series [30].

5.9.2 Measurements on Site

It goes without saying that with each newly developed wind turbine, the electrical power output as a function of wind speed must be measured (power curve) on the actual turbine. This is not without problems since neither do the appropriate wind speeds exist at the measuring time — as do in the wind tunnel — nor is it easy to measure the correct reference wind speed (Chapt. 14.2.2).

It is even more difficult to analyze the aerodynamic properties of a wind rotor with measuring instruments from other engineering aspects. One example of this is the measurement of the rotor's instantaneous power output with certain flow conditions, its response to gusts, or the structure of its wake.

Nevertheless, measurements carried out on real turbines are indispensable for certain tasks. Generally, these are effects which depend strongly on maintaining the model rules in fluid mechanics or on the turbulence of the real atmosphere, and thus cannot be simulated in the wind tunnel, or they are phenomena which cannot be dealt with theoretically, as they take place partially under separated-flow conditions. Moreover, only measurements done on actual turbines can reliably determine the influence of the ambient atmosphere.

A particularly complex program of measurements on site was carried out in connection with the former experimental German Growian turbine. A measuring grid was placed in front of the rotor with the help of two 170 m-high masts for measuring wind speed distribution over the entire rotor-swept area. It was intended to be used for gaining information on the gust structure of the wind and the loads on the rotor immediately ensuing from it (Fig. 5.64). Simultaneously, attempts were made to directly determine the aerodynamic forces by measuring aerodynamic pressure distribution on defined rotor-blade airfoil sections. It was hoped to gain information on the interrelationships between wind structure and rotor loads from this. However, the planned measurements never progressed past the initial stages because of the briefness of operation of the Growian turbine [31].

On-site measurements are also indispensable for investigating the interaction between wind turbines in a wind farm. There have been numerous research projects which investigated the flow conditions in the wake of the rotor and the resultant influences on adjacent turbines. This applies both to power losses due to mutual shading and to structural loads resulting from the self-generated turbulence of a field of wind turbines [32] (Chapt. 5.4).

A general problem with measurements carried out on original turbines is the time required. "Waiting for the right wind" can totally upset the best budgeting and scheduling

Figure 5.64. Wind measuring grid of the experimental Growian turbine for measuring wind-speed distribution over rotor-swept area and the interaction between turbulence and rotor loading

plans. The length of time required and costs of a field trip under real conditions should not be underestimated, therefore. Successful planning and execution require the knowledge of experts because, as a rule, the results of "incidental measurements" made in the commercial operation of wind turbines provide little valid information.

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Chapter 6

Loads and Structural Stresses

Wind turbines are subjected to very specific loads and stresses. Due to the nature of wind, the loads are highly variable. Varying loads are more difficult to handle than static loads because the material becomes fatigued. Moreover, as a working medium, the air is of low density so that the surface required for capturing energy must be large. If the dimensions of the rotor increase, the dimensions of other components must also increase, for example the tower height. Large structures are inevitably elastic and the changing loads thus create a complex aeroelastic interplay which induces vibrations and resonances and can produce high dynamic load components. The structural design of a wind turbine must be considered under three different aspects:

Firstly, attention must be paid to ensuring that the components are designed for the extreme loads encountered. This means that the turbine and its essential components must be able to withstand the highest wind speeds which may occur.

The second requirement is that the fatigue life of the components must be guaranteed for their service life, as a rule 20 to 30 years. While the stresses with respect to extreme loads can be estimated relatively easily, the problem of "fatigue life" is virtually the key issue with wind turbines. Wind turbines are the perfect "fatigue machines"!

The third requirement concerns component stiffness with respect to vibrations and critical deflections. The vibrational behaviour of a wind turbine can be kept under control only when the stiffness parameters of all its components are carefully matched. Apart from adequate strength, a further main criterion governing the dimensioning of some components, for example the rotor blades or the tower, is, therefore, the required stiffness.

An important set of problems, even before the design loads are calculated, concerns the situations in which the loads occur which determine the dimensions of the structure. This requires a complete overview of all operating conditions and of possible malfunctions of the turbine. On the basis of this, the so-called *load cases* can be defined.

The load cases and *load assumptions* for wind turbines were initially developed towards the end of the seventies as a basis for the construction of the large experimental turbines (see Chapt. 6.2). Since 1988, the International Electrotechnical Commission (IEC) has assembled an internationally applicable catalogue for wind turbines which is continually updated in accordance with the latest findings [1].

The mathematical methods needed for calculating structural loads and material stresses include some of the most complex theoretical tools required for developing wind turbines. The models are basically no different from those used in other fields of technology. Nonetheless, the course of action to be taken in relation to the structural design of a wind turbine is governed by its own set of problems.

The starting point for the entire load spectrum of a wind turbine are the loads acting on the rotor. The loads on the rotor blades are passed on to the other components and to a great extent determine their loading. Compared to these loads, the loads originating directly from downstream components are less significant. Discussions of the loads acting on a wind turbine can, therefore, be concentrated on the rotor and deal with it as being representative of all parts.

In any introduction to the problems of wind turbine loading and stresses, the state of knowledge in this field must be mentioned. There are still many unanswered questions in the field of wind energy technology and the research work and refinement of the mathematical models are not yet complete and proven in all details.

6.1 Loads on the Wind Turbine

The causes of all forces acting on the rotor are attributable to the effects of aerodynamic, gravitational and inertial forces. The different loads and stresses can be classified according to their effect with time on the rotating rotor (Fig. 6.1):

- Aerodynamic loads with a uniform, steady wind speed, and centrifugal forces, generate time-independent, steady-state loads as long as the rotor is running at a constant speed.
- An air flow which is steady, but spatially non-uniform over the rotor swept area causes cyclic load changes on the rotating rotor. This includes, in particular, the uneven flow towards the rotor due to the increase in wind speed with height, a cross-flow towards the rotor and interference due to flow around the tower.
- The inertia forces due to the dead weight of the rotor blades also cause loads which are periodic and thus unsteady. Moreover, the gyroscopic forces produced when the rotor is yawed must also be included among those which increase or alternate with each revolution of the rotor.
- In addition to the steady-state and cyclically changing loads, the rotor is subjected to non-periodic, stochastic loads caused by wind turbulence.

For an investigation of structural stresses, it is important to consider the effects of load variations with time. Fluctuating and alternating loads must be recognised, especially with respect to the fatigue life of the structure.

It is not possible to recognise beforehand which of the loads within the entire range of loads will be dominant. As is the case in all structures, the larger the turbine, the greater is the significance of the gravitational loads. Moreover, the elasticity of the structure plays an increasing role with respect to the extent to which the external loads are transformed into structural stresses. In other words, the stress levels on a wind turbine are determined to a high degree by its design.

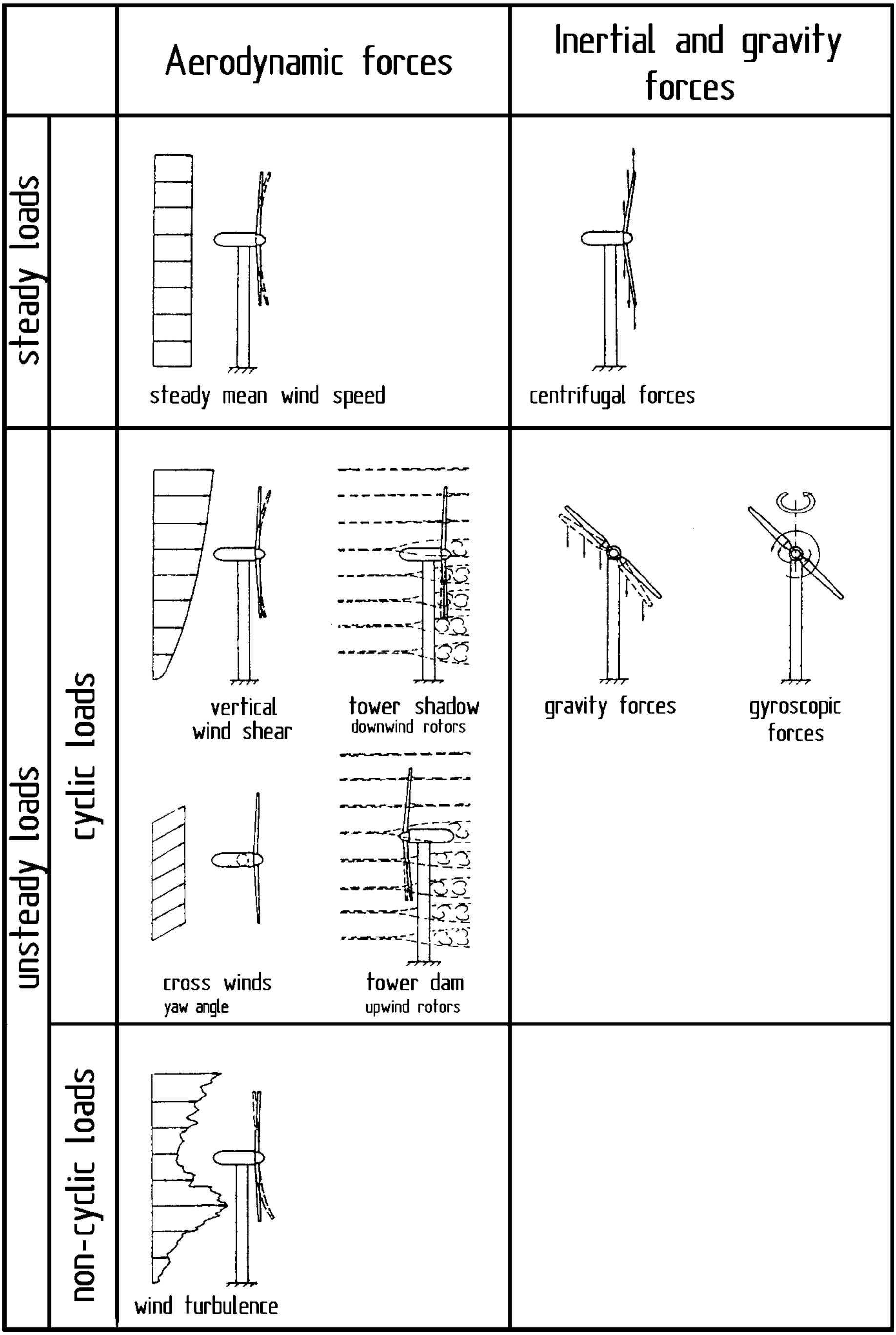

Figure 6.1. Effect of aerodynamic, gravitational and inertial loads on the rotor of a horizontal-axis wind turbine

To represent the loads on the rotor and the structural stresses, two co-ordinate systems are suitably used (Fig. 6.2). The forces and moments acting on the rotor blades are resolved in a rotating co-ordinate system with respect to the local rotor-blade cross-section. In the direction of the airfoil chord, the "chordwise" component is obtained and perpendicularly to the airfoil chord it is the "flapwise" component. This approach is practical when the loads on the rotor blades themselves are considered.

The breakdown with respect to the plane of rotor rotation provides the "tangential force components" in the plane of rotation and the "thrust components" perpendicularly to the plane of rotation. These co-ordinates express the total forces and moments on the rotor when they are passed on to the remaining parts of the turbine in the form of loads.

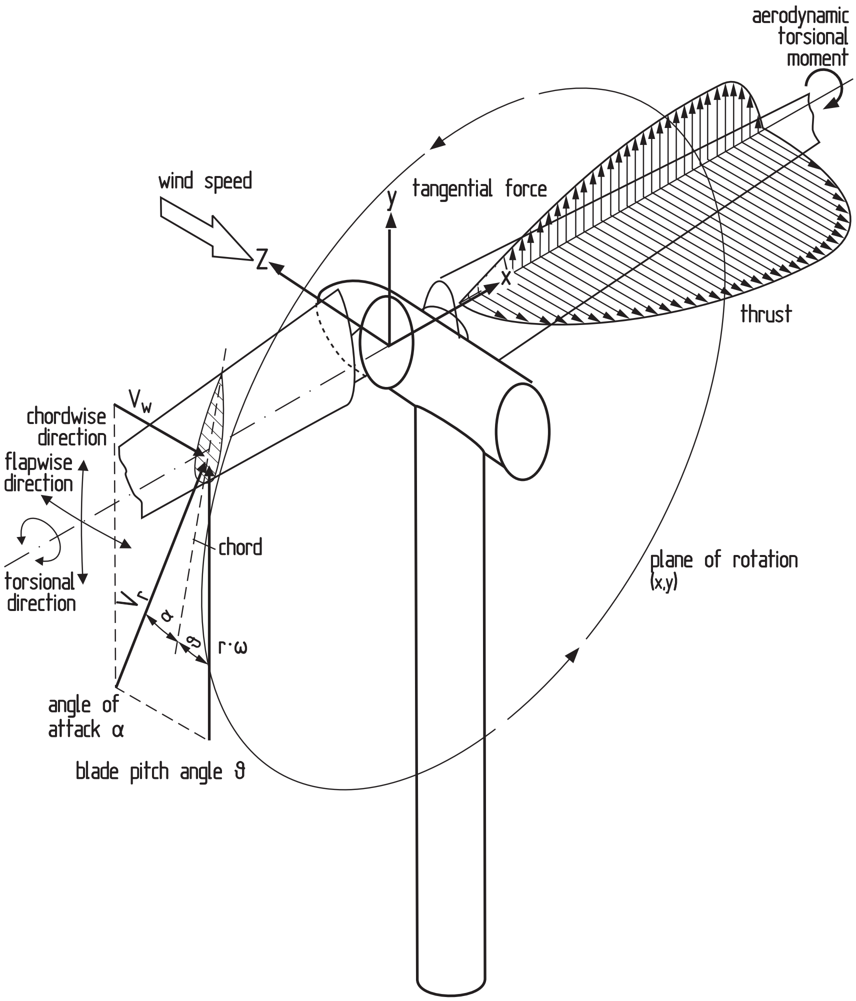

Figure 6.2. Co-ordinates and technical terms for representing loads and stresses on the rotor

At the transition from the chordwise and flapwise directions of the blade to the tangential and thrust directions of the rotor, the local twist angle and the blade pitch angle must be taken into consideration.

6.2 Sources of Loading

The sources of loading to be taken into account are aerodynamic, gravitational and inertial loads. There are also loads arising from operational actions and different operational states of the wind turbine. In the worst case, many of these sources produce loads simultaneously resulting in cummulative effects.

The complex load spectrum of rotor and the entire wind turbine becomes comprehensible only when the total loading is mentally resolved into components whose origins are independent of one other. This applies both to the loads due to aerodynamic forces and to those resulting from gravitational and inertial forces. As regards the aerodynamic loads, the load situation is determined by the varying flow conditions acting on the rotor.

6.2.1 Uniform and Steady-State Air Flow

Assuming a uniform, steady wind flow is, of course, an idealisation which does not exist in the open atmosphere. For practical purposes, this concept is nevertheless useful to calculate the mean load level occurring over a relatively long period of time. If a steady, symmetrical flow entering the area swept by the rotor is assumed, the rotor blades of a horizontal-axis rotor are subjected to steady-state aerodynamic forces. This characteristic distinguishes the horizontal-axis rotor from the rotors with a vertical axis of rotation. Darrieus rotors or similar types are already subject to time-variant loads due to aerodynamic forces under these conditions (Chapt. 5.8). The wind loads on the rotor blades during steady and symmetrical flows are largely determined by the effective wind speed varying from the blade root to the tip. In addition, the geometrical shape of the rotor blades influences the load distribution over the length of the blade. Diagrams 6.3 and 6.4 provide an impression of the aerodynamic load distribution on the rotor blades.

The bending moments on the rotor blades in the chordwise direction are the result of the tangential force distribution, whereas the thrust distribution is responsible for the blade bending moments in the flapwise direction. Owing to the rotor blade twist, in particular, the distribution profile changes distinctly from the start-up wind speed to the shut-down wind speed. The twist is optimised for a nominal wind speed only so that the distribution of aerodynamic loads corresponds approximately to the theoretical optimum only for this wind speed. At other wind speeds, especially higher ones, the flow separates in the blade sections near the hub. This causes the distribution of the aerodynamic loads to change considerably.

Integrating load distributions over the length of the rotor blade yields the overall rotor loads and moments. The tangential loading provides the rotor torque, and the thrust load distribution provides the total rotor thrust (Fig. 6.5). These two parameters essentially determine the static load level for the entire turbine. In rotors with blade pitch control,

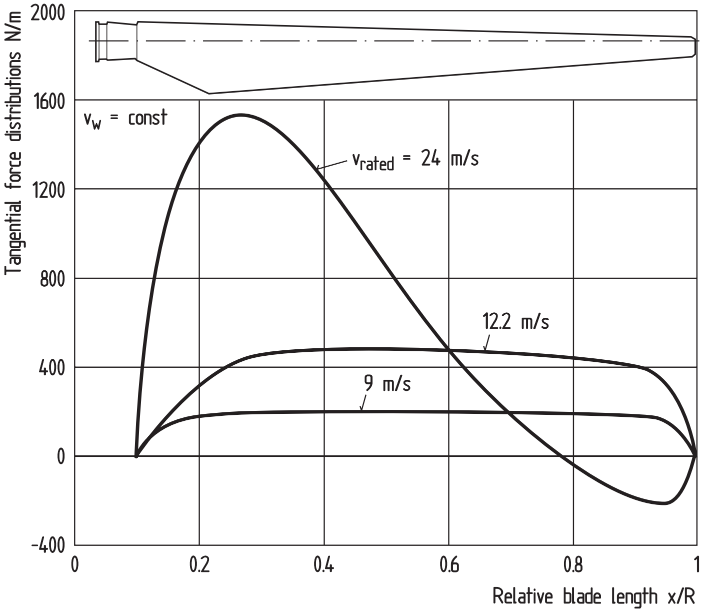

Figure 6.3. Tangential load distribution over the blade length of the experimental WKA-60 wind turbine

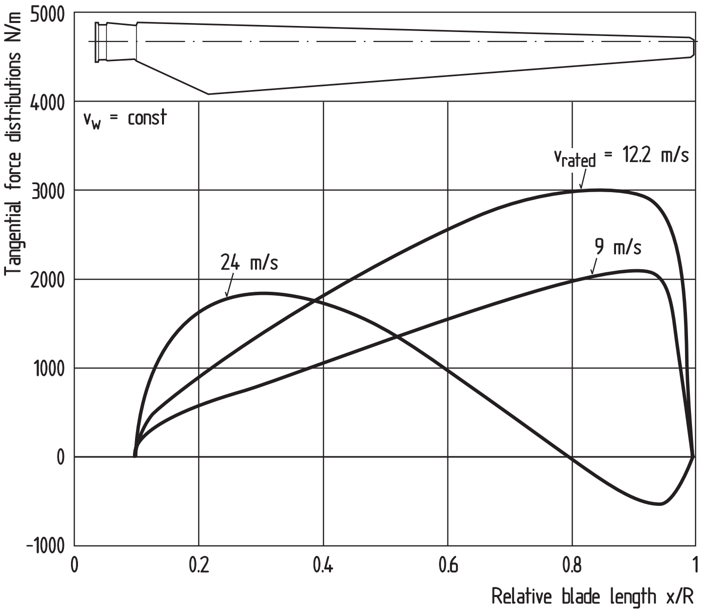

Figure 6.4. Thrust load distribution over the blade length of the WKA-60

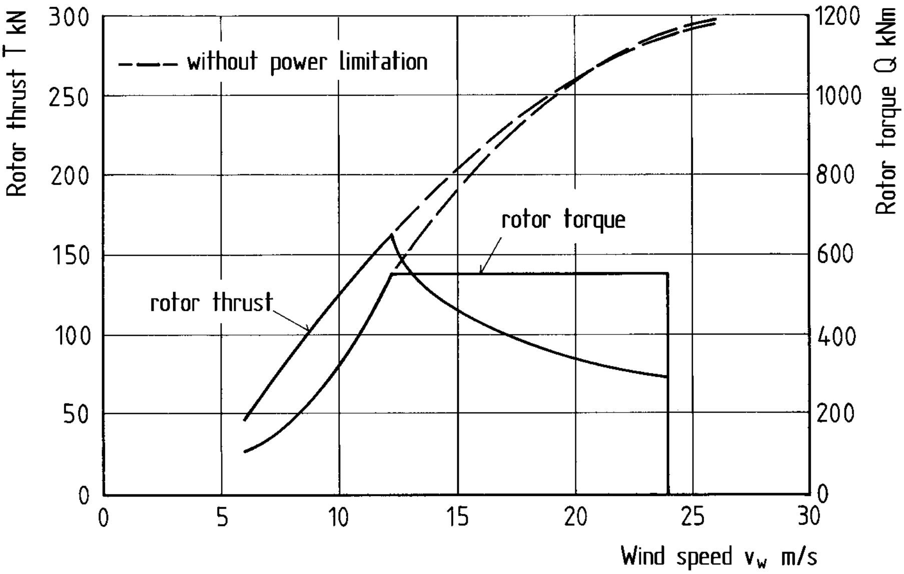

Figure 6.5. Torque and rotor thrust with a steady air flow on the WKA-60

rotor torque and rotor thrust increase up to the point where the control system of the rotor limits power capture to the rated power. Rotor thrust is greatest at the rated power point, then drops off again.

In the case of rotors not incorporating pitch control, where power capture is restricted merely by aerodynamic stall, rotor thrust continues to increase, or remains at an approximately constant level, after having reached rated power. For this reason, among several others, turbines without pitch control are subjected to higher steady-state loads (Chapt. 5.3.3).

The usual examination of the loads on rotor blades only relates to the distribution of loads in the direction along the blade. This two-dimensional load picture in reality masks a "mountain range" of loads which also extends in the direction of the blade chord. Information about load distribution over the blade chord is usually of minor significance but is, nevertheless, necessary for dealing with some problems concerning torsional stiffness of the blade. Furthermore, this load distribution must be taken into consideration when dimensioning the skin and ribs of the rotor blade, at least when dealing with large rotor blades with a correspondingly deep chord.

The chord-wise load distribution is usually derived from pressure distribution measurements, carried out on model airfoils in the wind tunnel. Airfoil catalogues contain information on these pressure distributions. They are characteristic of each airfoil and vary with the aerodynamic angle of attack (Fig. 6.6). Moreover, like the shape of the airfoil lift and drag characteristics, they are affected by the Reynolds number. Hence, applying them to the airfoil cross-sections of the original rotor blade must be done with some care.

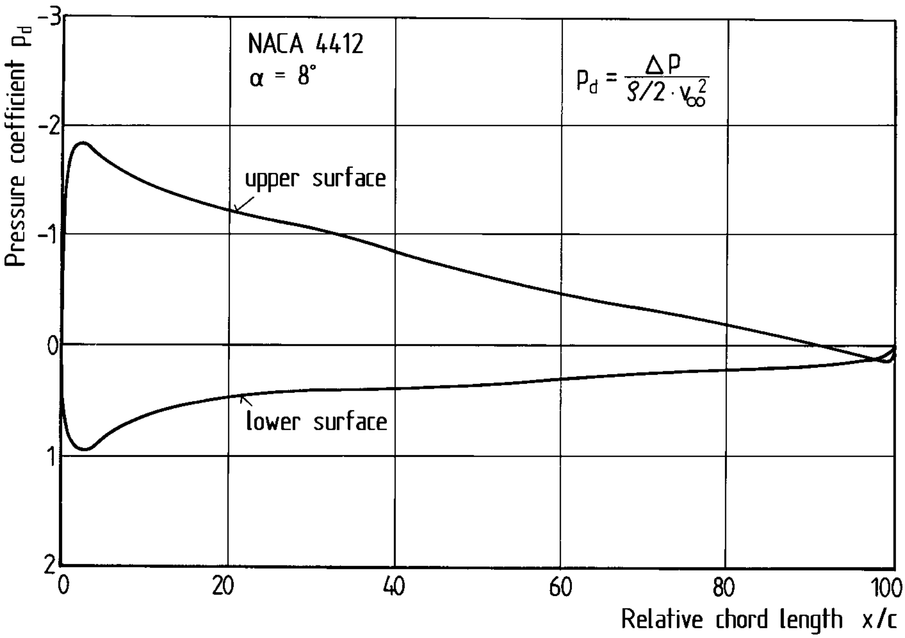

Figure 6.6. Aerodynamic pressure distribution for the NACA 4412 airfoil [2]

6.2.2
Vertical Wind Shear and Cross Winds

The wind flow produces unsteady, cyclically varying loads as soon as it strikes the rotor asymmetrically. One unavoidable asymmetry of the oncoming wind flow is caused by the increase in wind speed with height. During each revolution, the rotor blades are subjected to higher wind speeds in the upper rotational sector and are thus subjected to higher loads than in the sector nearer the ground. A similar asymmetry of flow at the rotor is caused by the largely unavoidable crosswinds which occur with fast changes in wind direction.

The vertical wind shear and crosswinds on the rotor lead to a cyclically increasing and decreasing aerodynamic load distribution over the rotor blades. Compared to the basic loading with a steady, symmetrical wind, there are considerable variations in load (Fig. 6.7). The linearly asymmetrical wind stream assumed here in this example qualitatively stands for the vertical wind speed profile or also for an asymmetrical wind flow due to a change in wind direction.

The changing aerodynamic loading on the rotor blades during one rotor revolution, of course, also means varying total rotor loads and hence varying loads for the remaining parts of the turbine. The cyclically changing pitching and yawing moments, in particular, represent considerable fatigue loads for the mechanical components of the yaw drive. This applies especially to hingeless two-bladed rotors. For this reason, large wind turbines with two-bladed rotors are usually built with a *teetering hub*, which more or less compensates for these changing loads.

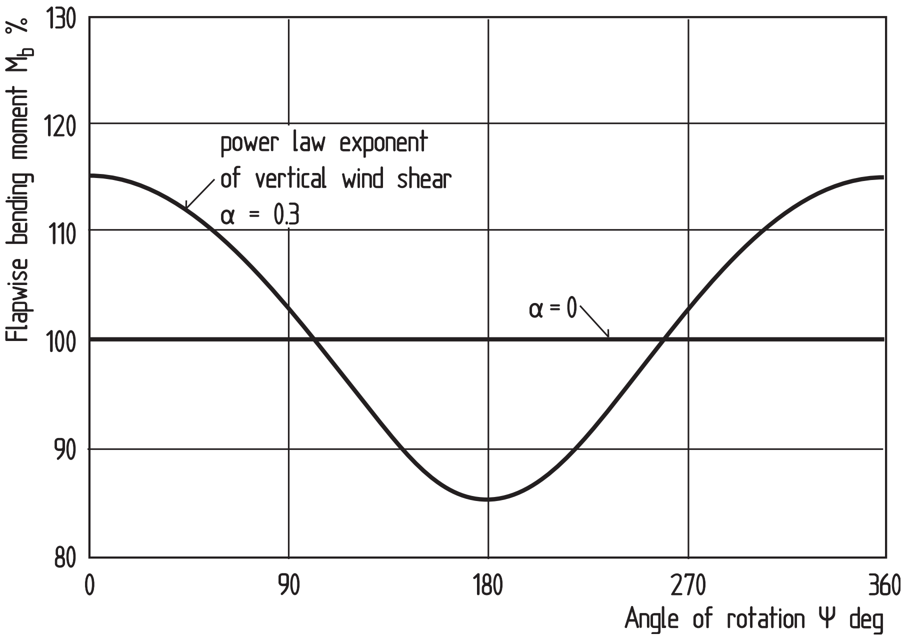

Figure 6.7. Cyclically changing flapwise bending moment at the blade root as a consequence of the wind shear on the WKA-60 as example

6.2.3 Tower Interference

The rotor of a horizontal-axis wind turbine necessarily rotates in close proximity to the tower. The clearance between the rotor rotational plane and the tower is generally kept as small as possible in order to limit the length of the nacelle. A nacelle which protrudes very far causes the rotor forces to act with great leverage with respect to the tower axis. In any case, however, the distance between rotor and tower is so small that the aerodynamic flow around the tower influences the rotor.

The influence of the aerodynamic flow around the tower on the rotor is at a minimum when the rotor is mounted in the traditional position up-wind of the tower. The up-wind rotor is affected merely by a retardation of the flow in front of the tower, the so-called bow-wave or *tower dam* effect. This tower dam effect was still a considerable factor with the old-style windmills and their mill houses, but with today's slender towers it is only slight. Its effect is still perceptible, but the practical effects on rotor loading are slight as long as a minimum clearance between rotor blade and tower of approximately one tower diameter is maintained (Fig. 6.8). However, the tower dam is a possible hazard with respect to the excitation of tower vibration if the rotor speed remains within the range of the natural bending frequency of the tower for any length of time (Chapt. 11.4).

A completely different problem arises when the rotor is mounted on the down-wind side of the tower. This type of design used to be considered to be advantageous in connec-

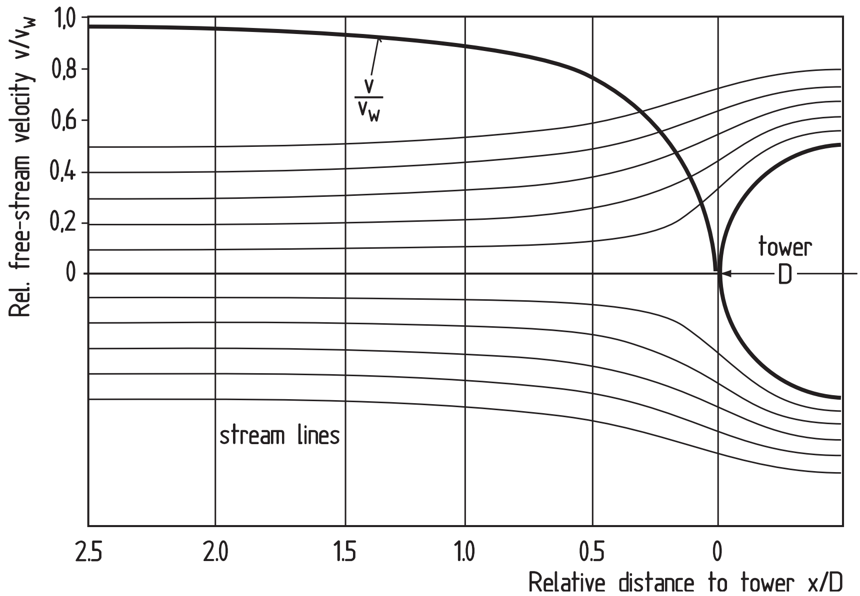

Figure 6.8. Flow field due to the tower dam ahead of a cylindrical tower with diameter *D* (potential flow theory)

tion with the slender towers in the large first-generation wind turbines. A reduction in flow velocity on the down-wind side of the tower is still perceptible even at a relatively large distance. The rotor blades must pass through this wind-sheltered area with each revolution. This *tower shadow* effect represents a serious problem for the wind turbine in several respects it must be discussed more extensively.

The aerodynamic influence of the tower has to be considered even in the case of an upwind rotor. As almost all towers of modern turbines have a circular cross-section, only the flow around a circular cylinder has to be considered. The internal friction of the flowing medium and the surface friction (boundary layer) of the body encountered cause an area of detached flow behind the body, the so-called *wake* area (Chapt. 5.4). The wake in the flow behind a circular cylinder consists of a more or less extensive area of increased turbulence with a considerably decreased mean flow velocity. Another typical characteristic of the wake behind a body with a circular cross-section are the alternating vortices on both sides, occurring with a defined frequency (*Kármán vortices*). Depending on the Reynolds number of the flow, which is referred to the cylinder diameter, three characteristic regions can be observed (Figs. 6.9 and 6.10).

Subcritical region

When the Reynolds number is below approximately 3 to 4 $\times$ 10^5, i. e., at a slow flow velocity, the boundary layer remains laminar. Flow separation takes place ahead of the widest point of the cylinder cross-section. The flow wake is relatively wide and distinct Kármán vortices

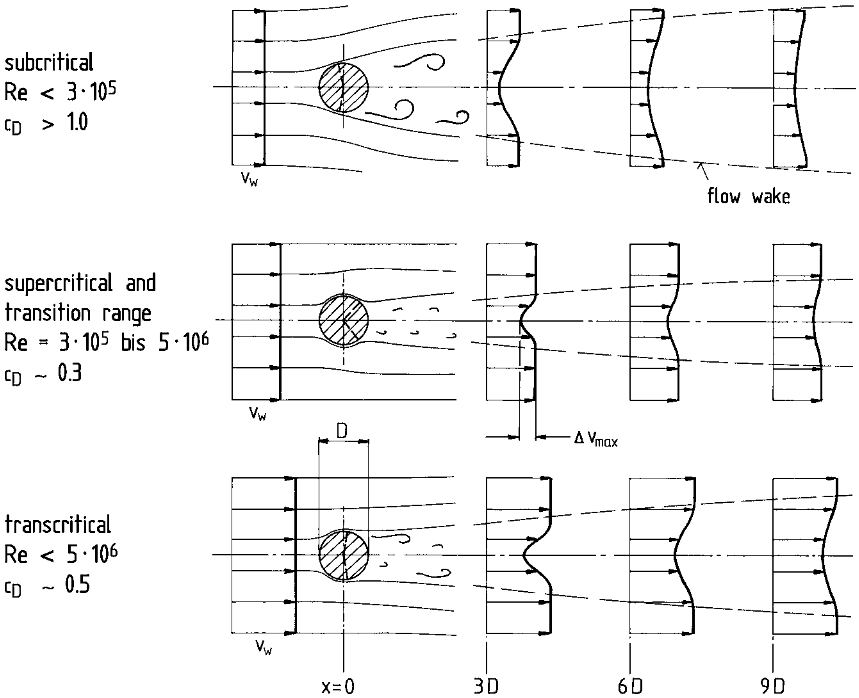

Figure 6.9. Flow around a circular cylinder in dependence on the Reynolds number

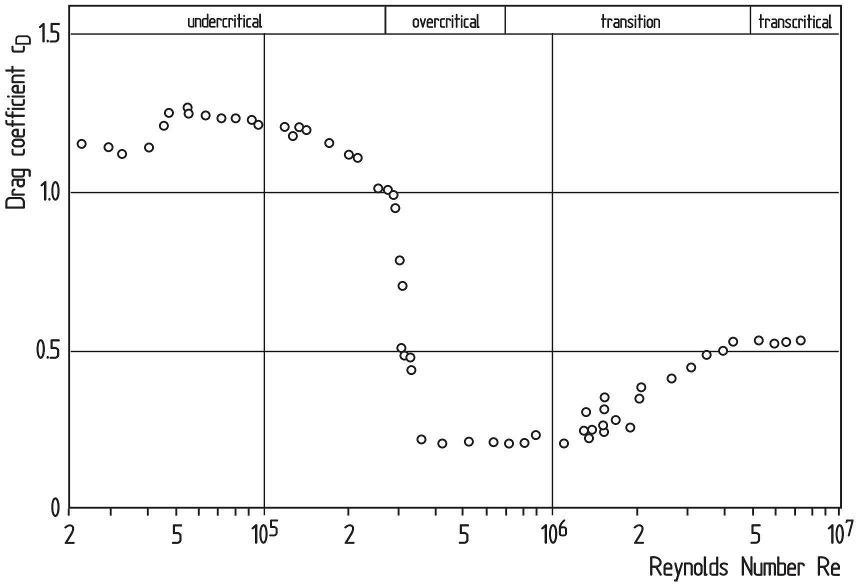

Figure 6.10. Air drag coefficient of a circular cylinder in dependence on the Reynolds number [3]

occur periodically. Under these conditions, the air drag coefficient of the circular cylinder is relatively high and equals approximately 1.0.

Supercritical region

At a certain flow velocity, characterised by the so-called "critical Reynolds number", the boundary-layer flow at the cylinder surface shifts from a laminar to a turbulent condition. This effect influences the shape of the wake considerably. The high-energy, turbulent boundary layer causes the flow around the body to persist, so that the flow wake is narrowed. The periodic Kármán vortices disappear almost completely. The drag coefficient is drastically reduced to values of between 0.25 and 0.35. As it is a boundary-layer effect, the point of change is influenced by the surface roughness of the object.

Transcritical region

Above the critical Reynolds number there follows a "transitional region" where the flow wake starts to become wider again. In the transcritical region, the drag coefficient rises to values of approximately 0.5. The Kármán vortices again occur periodically, but somewhat more weakly.

A brief estimate of the flow around a tower of a large wind turbine shows that with tower diameters of several meters and wind speeds of between 5 and 25 m/s, the Reynolds numbers are so high that a turbulent flow can always be expected. In this region, the maximum wind speed reduction in the flow wake can be estimated by the following formula:

$$\frac{\Delta v_{\max}}{\bar{v}_{\mathrm{W}}} = 1 - \sqrt{1 - c_{\mathrm{D}}}$$

How does the tower shadow affect the aerodynamics of the rotor? First of all, the reduced flow velocity to the rotor blades as they pass through the tower wake is an important factor. Reduced wind speed goes hand in hand with a change in the effective aerodynamic angle of attack. Both lead to a sudden decrease in the lift of the rotor blade. It affects both the aerodynamic loading and the torque generated.

This process is of very short duration, corresponding to the rotor speed, and represents an impulse-like disturbance at the rotor blade. From the aerodynamic point of view, this means that transient aerodynamic effects can play a role which means, for example, that the temporal gradient of the change in the angle of attack can have a significant influence on aerodynamic forces and moments. While the treatment of transient aerodynamic problems is difficult, it can, however, become necessary when attempting a theoretical treatment of the tower shadow problems of a down-wind rotor.

On the other hand, the disturbance due to the tower wake continues for long enough for elastic yielding of the rotor blades to have a damping effect. Thus, the tower wake is also a problem of aeroelastics, i.e. the dynamic response of the rotor blades. Figures 6.11 and 6.12 show two examples of the effects of the tower wake on a down-wind rotor.

The flapwise bending moment is an important parameter for rotor blade dimensioning. The influence of the tower shadow is considerable, especially considering the high number of load cycles of 10^7 to 10^8 during the life of the turbine (Fig. 6.11). The tower shadow effect

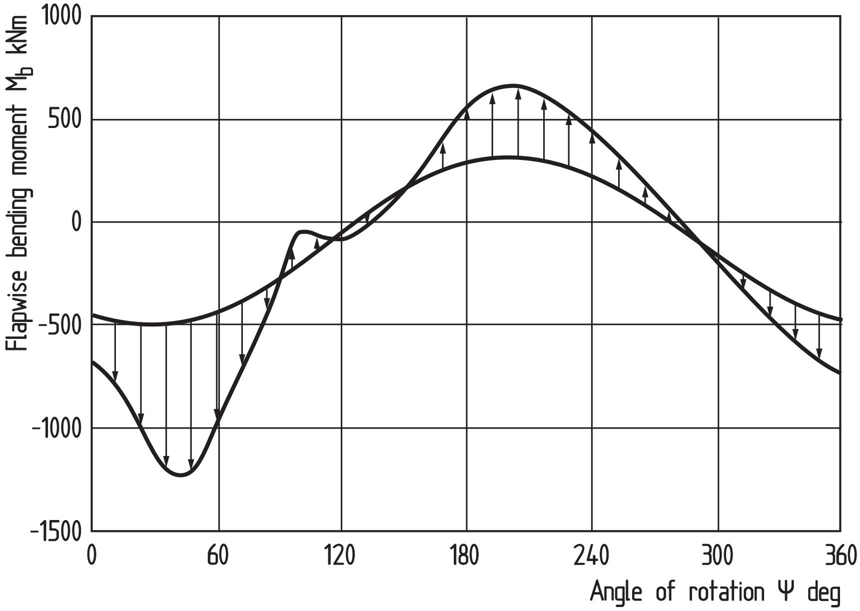

Figure 6.11. Calculated increase in the flapwise bending moment at the blade root due to the tower shadow, using Growian as an example

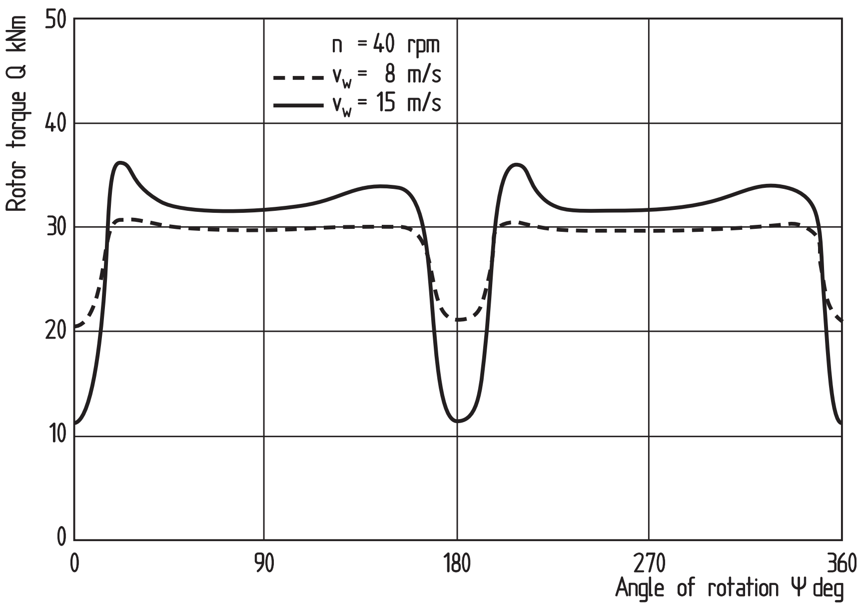

Figure 6.12. Influence of tower shadow on the rotor torque at the example of the experimental MOD-0 wind turbine [4]

thus becomes a factor which cannot be ignored with regard to the fatigue life of the rotor blades.

The electric power output of down-wind rotors is a clear indicator of the influence of tower shadow interference. In extreme cases, power losses of up to 30 or 40 % below the average output were measured (Fig. 6.12). At the usual rotor speeds, the frequency of tower shadow interference falls within the range of some of the critical natural frequencies of the turbine, in particular that of the drive train (Chapt. 11.2.4).

Last but not least, the influence of the tower shadow on the noise generated by the wind turbine must also be pointed out (Chapt. 15.2.2). This effect turned out to be of such importance that it caused the virtually complete disappearance of downwind rotors among today's wind turbines.

6.2.4 Wind Turbulence and Gusts

While power output and energy yield of a wind turbine are determined by the long-term variations of the mean wind speed, the non-cyclic fluctuating loads on the wind turbine are determined by the short-term fluctuations of the wind speed, the wind turbulence and the gusts. The ever-present wind turbulence contributes considerably to material fatigue, particularly of the rotor blades. Extreme wind speeds, though far more rare, must also be taken into consideration when designing for fatigue strength. Moreover, they can increase loads up to the point of fracture . The most serious problems as far as loading is concerned are presented by the stochastic fluctuations of the wind.

It is useful to think of the wind as consisting of a mean wind speed, which varies on a time-scale of one or several hours, with turbulent fluctuations superimposed (see Chapt. 13.3.4).

In the load calculations it is generally assumed with *turbulence spectral models* that this turbulence is a one-dimensional fluctuation of wind speed in the longitudinal direction. In reality, wind speed fluctuations naturally also have lateral components. Mathematical treatment of a two-dimensional turbulence model is very difficult, however, and generally not necessary when dealing with wind turbines. More important, as far as loading on the wind rotor are concerned, is the spatial distribution of longitudinal turbulence over the rotor-swept area.

Apart from the high-frequency fluctuations, occasional "considerable" deviations from the mean wind speed, ranging from a few to several tens of seconds, are observed. These peaks are called *gusts.* There is no generally accepted definition, but it has been largely established by general practice to classify gusts with the aid of a so-called *gust factor.* According to Frost, a gust is an increase in wind speed averaged over a certain period of time, with reference to the mean wind speed. It is also common practice in wind energy technology to call a sudden drop in wind speed from the average value a *negative gust* [5].

While the spectral model of turbulence is of a statistical nature, a deterministic approach can also be used. The basic idea is to define discrete idealised gust shapes, represented by increasing and decreasing wind speed over time. These gusts are then assumed to be discrete isolated events for the calculation of loads. It is obvious that in the process, the continuous nature of the turbulence is lost. The response of the structure shows only the reaction to an isolated gust, without taking into consideration the situation before and immediately after the event.

In the load assumptions for wind turbines, idealised forms of gusts are assumed which are used as loads with a defined probability of occurrence in the structural design. The relevant literature contains notes on the probability of occurrence, the duration and the spatial extent of the gusts.

The significance of these *discrete gusts* for load calculation primarily lies in the determination of extreme loads. For this purpose, the characteristic properties of the gusts must be known. Meteorological research has not given much attention to this special problem so far, so that no adequate data on gust factors, rise and fall times, spatial extent and similar parameters are available. Attempts to compile data usable for wind energy technology today were carried out, in particular, by Frost [5]. From such data, idealised gust shapes have been derived for calculating loads on wind turbines (Fig. 6.13).

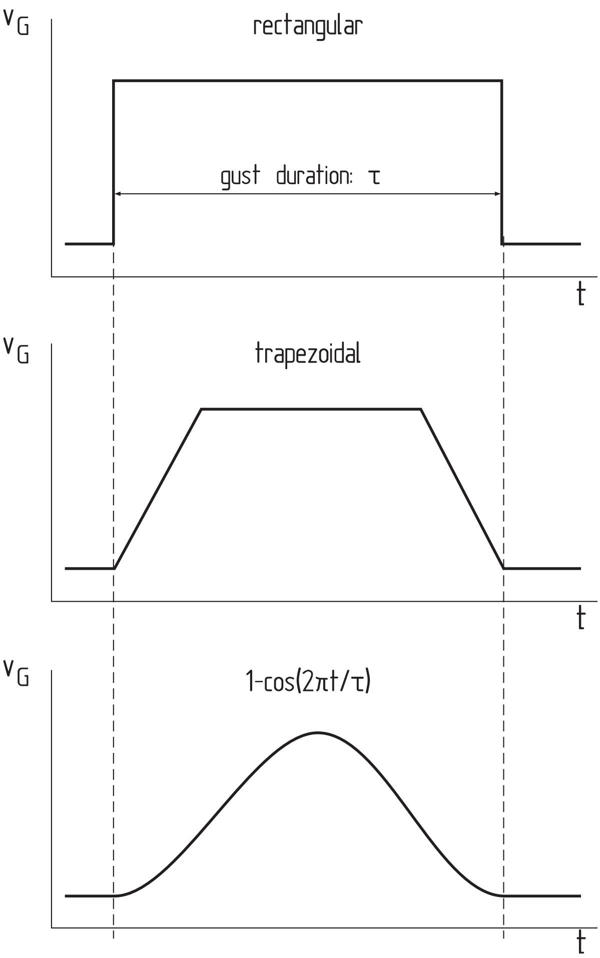

Figure 6.13. Idealised gust shapes [5]

Frost specified gust factors as a function of gust duration (Fig. 6.14). They also depend on the level of the mean wind speed. The higher this is, the smaller are the gust factors to be expected. The frequency of occurrence is also to be seen in connection with the mean wind speed and the gust factor (Fig. 6.15).

Figure 6.16 shows the effect of wind turbulence on the specific dynamic load situation of a wind turbine. Bending deflection in the rotor blades was initially calculated taking into account only the influence of the cyclic disturbances in the flow caused by wind shear, tower influence and similar parameters, but ignoring turbulence. Including the turbulence spectrum, the deflection values are almost doubled.

In this connection, the question also arises about the highest wind speeds occurring which occur like gusts in their extreme values and are often called *gusts of the century.* Meteorological literature talks about extreme values of the measured maximum wind speeds. According to this, extreme values of up to 47 m/s have been recorded over a period of 20 to 30 years in the North German coastal area. This value is exceeded above the open sea and reaches maximum values of more than 60 m/s. In exposed geographic positions like, for example, the Antarctic, values of 95 m/s are reported to have been observed. It is this background against which the reference wind speeds for the different wind turbine classes have been specified in the load assumptions for wind turbines. However the absolute extreme values of wind speeds require a special design of the wind turbine based on specific load assumptions for the intended site (compare Chapt. 6.3.1).

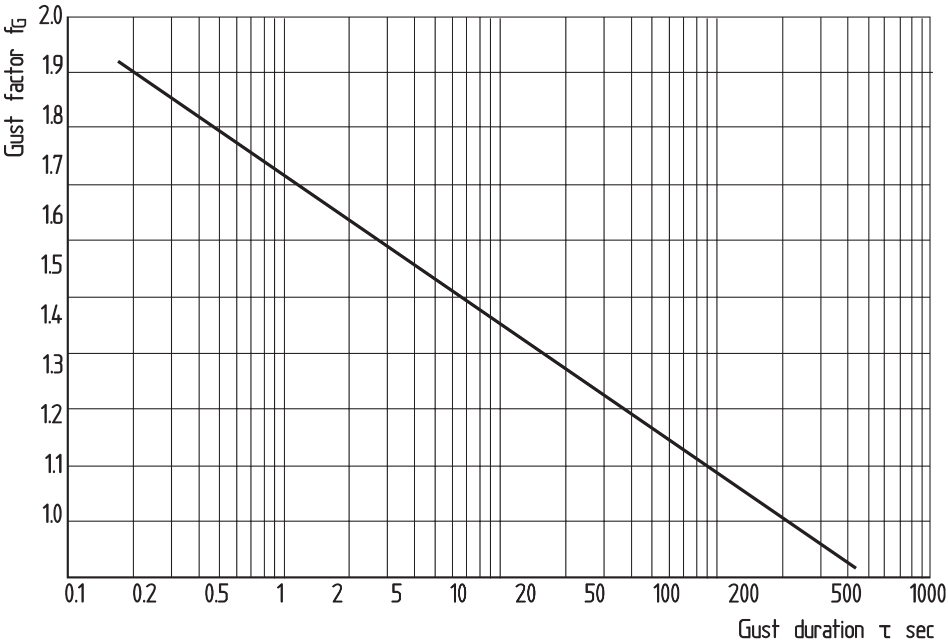

Figure 6.14. Gust factors in dependence on gust duration [5]

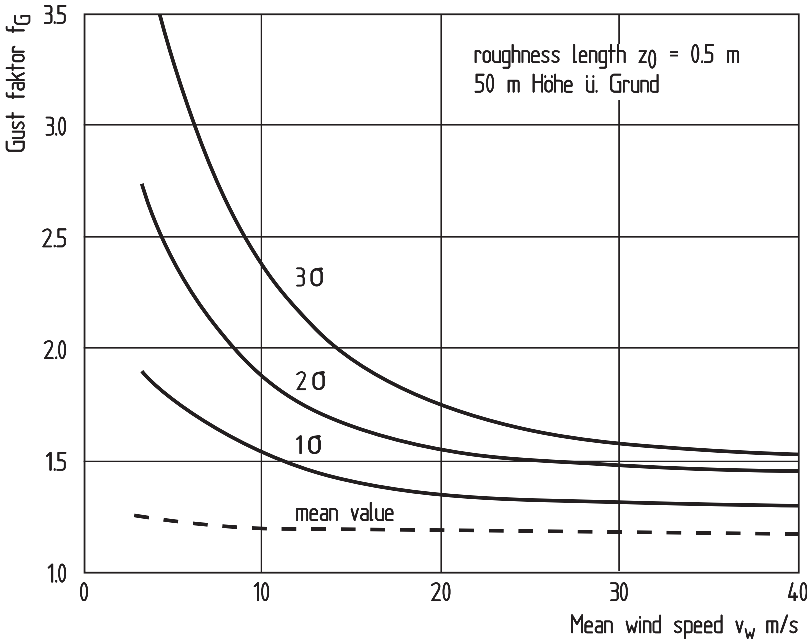

Figure 6.15. Gust factors in dependence on the mean wind speed and occurrence probability [5]

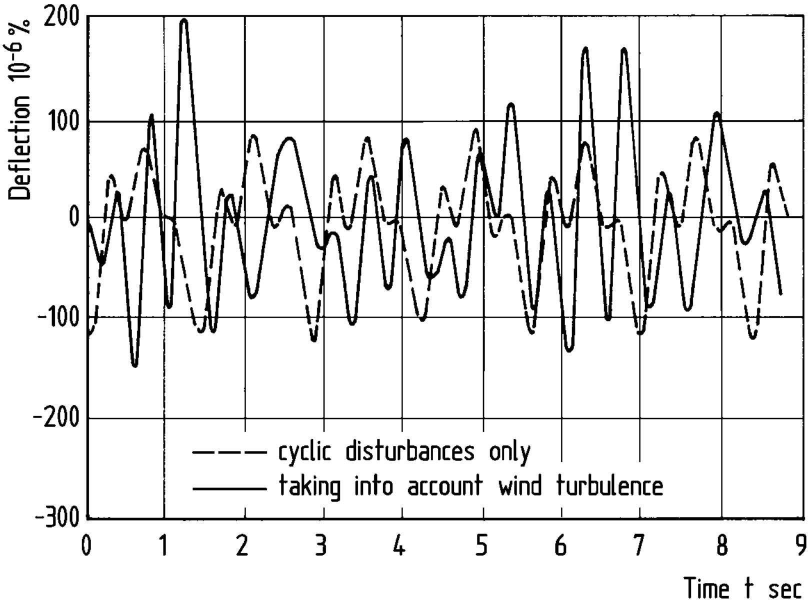

Figure 6.16. Rotor blade bending deflection in flapwise direction, at the HWP-300 wind turbine [6]

6.2.5 Gravity and Inertia Loads

Whereas the aerodynamic loading can only be calculated with difficulty, loads caused by the dead weight of the components and by centrifugal and gyroscopic forces are relatively simple to calculate. The only difficulty is that, at the beginning of the design phase, the masses of the components are not known. As mass can only be calculated as a consequence of the complete load spectrum, including the dead weight, several "iteration loops" are unavoidable when dimensioning the structure. First assumptions as to the weight are best taken from empirical data, prepared statistically from existing turbines.

Gravitational Loads

Loads resulting from the dead weight of the components must naturally be taken into consideration for all components of the turbine. In a wind turbine, the rotor blade weight is of special significance for the blades themselves, as well as for the "downstream" components.

The rotor blade weight generates alternating tensile and pressure forces along the length of the blade and large alternating bending moments around the chordwise and flapwise axes in the blades over one rotor revolution. The significance of this gravitational loading increases from the blade tip to the root, i. e. in the opposite direction from the influence of the aerodynamic loads. This cyclic loading and particularly the cyclic bending moments around the blade's chord axis, occur with 10^7 to 10^8 cycles during the life of a turbine, assuming a rotor speed of 20 to 50 rpm and a service life of 20 to 30 years. A number of 10^6 load cycles is reached after only approximately 1000 hours operating time. From this number of cycles onward, steel, for example, may only be stressed with its allowable fatigue stress.

Thus, together with wind turbulence, the influence of the gravitational forces becomes the dominant factor for the fatigue strength of the rotor blades. The larger the rotors, the greater these influences will be. As is the case with any other structure, as dimensions grow, it is ultimately the structure's weight which becomes the main problem with respect to strength. For horizontal-axis rotors, the situation is aggravated by the fact that the dead weight causes alternating loads. Proponents of the vertical-axis concept thus rightly point out that for this particular reason, the vertical-axis rotor is more suitable for extreme dimensions, as the alternating loads caused by the dead weight of the rotor blades are avoided.

In the past, some designers of horizontal-axis rotors attempted to compensate for these alternating bending moments by installing lead-lag hinges at the rotor blade roots. These did not, however, prove successful in practice. For one, the complicated mechanisms involved are too expensive and, for another, they are associated with additional problems of dynamics.

Centrifugal Loads

Centrifugal forces are not very significant in wind rotors, due to their comparatively low rotational speed. This is in contrast to helicopter rotors, where blade strength and dynamic behaviour are determined by the centrifugal forces.

With a special trick, centrifugal forces can even be used to relieve the load on the rotor blades. On some rotors, the rotor blades are inclined downwind out of the plane of rotation, in a slight V-shaped form. This so-called *cone angle* of the rotor blades has the effect that the centrifugal forces, in addition to the tensile forces, create a bending moment distribution along the blade length which counters the bending moments created by the aerodynamic thrust. However, complete compensation can only be achieved for one rotor speed and one wind speed.

If the rotor is subjected to other flow conditions, the effect of the cone angle can be reversed. When the aerodynamic angles of attack are negative, for example with a sudden drop in wind speed, or fast pitching of the blades (rotor emergency stop), the direction of thrust can be reversed for a short time so that the bending moments from the aerodynamic forces and the centrifugal force combine. Whether or not a cone angle of the rotor blades makes sense technically must, therefore, be decided after having taken several aspects into consideration. In more recent turbines there is a tendency to have rotors without cone angle.

Gyroscopic Loads

Loads caused by gyroscopic effects occur when the rotating rotor is yawed into the wind. A fast yawing rate leads to large gyroscopic moments, which manifest themselves as pitching moments on the rotor axis. However, as yawing rates are normally relatively low, the practical effects are very slight, or, in other words, the yawing rate must be so slow (appr. 0.5 degrees/sec) that gyroscopic moments do not play a role. It would be uneconomical to have to dimension the structure according to the gyroscopic forces (Chapt. 10.2).

The attempts to build wind turbines with passive yawing have shown that the gyroscopic forces become a serious problem for these turbines. When wind directions change rapidly, it is unavoidable that the rotor will also be yawed very quickly. Under these conditions, rotor blades, in particular, are subjected to extraordinary bending loads due to the gyroscopic forces involved. Abrupt changes of wind direction are to be expected above all during low wind speeds. This is another reason why passive yawing, which, in any case, can only be implemented on downwind rotors which are no longer being built, is more than problematic (Chapt. 5.6).

6.3 Design Load Assumptions

If the reasons for loads are known, the task is to recognise the conditions during which the wind turbine is subjected to the decisive loads. These conditions are recorded in the form of so-called *load cases* (see Chapt. 6.4). In the defined load cases the loads determined by calculations are always *load assumptions* which deviate from the real loads to a certain degree. However, this deviation from reality must always be to “the safe side”. In other words, the load assumptions used for the design must always be somewhat higher than the loads actually to be expected in operation.

According to their intended purpose, load assumptions should have general validity as far as possible, so that they form a generally accepted basis for the design a system, not vice versa. On the other hand, the technical concept of the turbine influences the nature and extent of the loading to a certain degree. A mixture of general validity and individual significance is thus largely unavoidable.

First attempts at a systematic definition of load assumptions and load cases had been undertaken towards the end of the seventies in the US and in Germany [8]. The first comprehensive load assumptions were developed especially in connection with the development of the experimental Growian and WKA-60 wind turbines [8]. At the same time, corresponding efforts were also made in Denmark and Sweden [9]. In Germany the most important load assumptions relates to the system used by Germanischer Lloyd [10]. The corresponding standards in Denmark, the Netherlands and other countries differ in some details (Chapt. 6.9). Today the standards and rules issued by the IEC are generally accepted as a common basis [1].

6.3.1 Wind Turbine Classes

Today's wind turbines are divided into four classes with respect to the design wind conditions. The classes are defined by wind speed and turbulence data (Table 6.17). The wind data forming the basis for the design are characterised by:

- the mean annual wind speed ($\bar{v}_w$)
- the maximum wind speed to be expected as a mean value over 10 min, the so-called *reference wind velocity* ($v_{e\,ref}$).
- the so-called *characteristic turbulence intensity* at a wind speed of 15 m/s (I_{15}).

Within the four classes, the two categories A and B characterise the design for different turbulence conditions. The standard deviation (σ_1) of the longitudinal wind velocity (turbulence) is specified by the parameter a.

Table 6.17. Basic wind parameters at rotor hub height for wind type classes [1]

WT Classes		I	II	III	IV	S
$v_{e\,ref}$	(m/s)	50	42.5	37.5	30	values to be specified by the designer
$\bar{v}_w$	(m/s)	10	8.5	7.5	6.0	
$v_{G50} = 1.4 v_{e\,ref}$		70	59.5	52.5	42	
$v_{G1} = 1.05 v_{G50}$		52.5	44.6	39.4	31.5	
A	I_{15}	0.18	0.18	0.18	0.18	
	a	2	2	2	2	
B	I_{15}	0.16	0.16	0.16	0.16	
	a	3	3	3	3	

The commercial wind turbines are designed and certified in accordance with these four classes. In addition, there is a special class S for special wind conditions. The data used as a basis here must be specified individually by the manufacturer. The characteristic turbulence intensity underlying the design of the wind turbine must be compared with the turbulence values of the intended site. The characteristic turbulence intensity is obtained from the average value of the 10-minute mean of the wind velocity at rotor hub height plus one standard deviation [1] (s. Chapt. 6.3.2).

6.3.2 Normal Wind Conditions

Naturally, the external loads acting on a wind turbine are determined almost exclusively by the meteorological conditions or, in simpler terms, by the wind conditions. In the system of load cases, these are subdivided into "normal" and "extreme" wind conditions. Normal events are considered to be those which occur frequently in the course of a year, whereas extreme events have a certain probability of occurring once within a period of 1 to 50 years.

Mean wind speed and wind speed frequency distribution

The mean annual wind speed at rotor hub height is the most important parameter in the wind turbine classification. The long-term variations of the mean wind speed have a certain influence on fatigue strength, although their frequency of cycles is lower by several magnitudes compared to other events. Seen from the point of view of the total load spectrum, they represent transitions from one wind speed class to another. They can be interpreted as long-wave, periodic "oscillations" with large amplitudes (Chapt. 6.5).

The wind frequency distribution is assumed to be a Rayleigh distribution, also referred to the 10-minute mean (Weibull distribution with a form factor of $k = 2$).

Vertical wind shear

At any wind speed, a cyclically varying load is generated by the wind shear, particularly with respect to the bending moment on the rotor blades. The number of load cycles is determined by the number of rotor revolutions and is correspondingly high.

The increase in wind speed is accounted for by Hellmann's power law (Chapt. 13.3.2). The exponent used is $\alpha = 0.20$.

Change in wind direction

Spontaneous changes in wind direction which the yawing system is unable to follow immediately, result in the rotor being subjected to cross winds. In operation, fluctuations in the wind direction of $\pm 30°$ with respect to the 10-minute mean value of the wind direction are assumed.

Wind turbulence

Apart from the cyclic loads resulting from the dead weight of the components and the asymmetrical flows on the rotor, wind turbulence is the second decisive factor for the fatigue strength. In the turbulence model the uneven distribution of the gusts over the rotor-swept area and the effect of the rotating rotor must be taken into consideration (Chapt. 6.5).

In this context, attention must be paid also to the fact that when wind turbines are installed in close proximity to one another (wind farm), the intensity of the turbulence in the field is increased (Chapt. 16.4.1). In the wind turbine classes a characteristic intensity of turbulence is assumed to have a value of 18 % and 16 % respectively. The standard deviation depending on the mean wind speed at hub height can be calculated by the formula:

$$\sigma_1 = I_{15} \cdot \frac{15\ \mathrm{m/s} + a\,\bar{v}_{\mathrm{w\,hub}}}{a+1}$$

The characteristic value of the turbulence intensity will be calculated by adding one standard deviation to the mean value of the turbulence intensity over 10 min.

6.3.3 Extreme Wind Conditions

A wind turbine must be dimensioned so that it can withstand the highest wind speeds occurring. This requirement can be qualified only in one respect, namely that extraordinary natural disasters are exempted. In the eye of a tornado or of a typhoon, winds occur at such high speeds that virtually any type of structure will be destroyed as experience has shown. In such a situation, the loss of a wind turbine will also have to be accepted.

Extreme wind speed and gusts

In the wind turbine classification (see Tab. 6.17) the extreme wind speed averaged over 10 min is used as a reference wind speed.

The basis for assessment for the survival of a wind turbine is the so-called *50-year gust,* the highest wind speed, averaged over 5 seconds, which is exceeded only once within a period of 50 years. The 50-year gust at hub height is derived from the extreme reference wind speed:

$$v_{\mathrm{e\,G50}}(h) = 1.4 v_{\mathrm{e\,ref}} \cdot \left(\frac{h}{h_{\mathrm{hub}}}\right)^{0.11}$$

A wind speed which is reached once annually statistically is defined as a so-called *annual gust.*

$$v_{\mathrm{e\,G1}}(h) = 0.75 v_{\mathrm{e\,G50}}(h)$$

Both the 50-year gust and the annual gust assume a cross-wind, i. e. a deviation from the 10-minute mean of the wind direction, of $\pm 15^\circ$.

The gusts occurring in normal operation and with increased frequency can be derived from the turbulence model and in dependence of the rotor diameter (IEC 61 400-1) or in a simplified form by using gust factors (see Fig. 6.14). The positive gust is defined as

$$v_G = k_b \bar{v}_W$$

The negative gust is:

$$v_G = \frac{1}{k_b} \bar{v}_W$$

The gust factor is taken into consideration by

$$k_b = 1 + \frac{v_G}{\bar{v}_W}$$

The gust amplitudes exceeded with a probability of once annually ("normal gust in operation") are defined as 9 m/s. Gusts which are exceeded only once in 50 years ("extreme gust in operation") are defined to have an amplitude of 13 m/s [10].

When conditions are unfavourable, wind gust loading on the rotor can become extremely asymmetrical. Gusts partially penetrating the rotor-swept area generate a high rotor yawing moment. The design limits of the yawing system or the rotor locking devices can be reached or even exceeded so that operation under these conditions must be verified, if necessary.

Loads during these extreme wind speeds are also a question of the operational status of the turbine. The wind turbine is normally shut down so that this wind load must be sustained by the parked rotor. However, the rotor does not necessarily have to be parked when wind speeds are extreme. Basically, the loads are less when the rotor is rotating slowly with a suitable blade pitch angle or actuated aerodynamic brakes than when the rotor is locked. This is the reason why some manufacturers do prescribe a shut-down wind speed but have the rotor continue at reduced speed.

Extreme change in wind direction

Extreme changes in wind direction are assumed to be $\pm 180°$ at low wind speeds (up to 5 m/s) and $\pm 15°$ at the extreme wind speed (once per 50 years).

6.3.4 Other Environmental Influences

Environmental influences other than wind can affect the structural strength and the operation of a wind turbine. Most of them are climatic conditions and the combination of these influences has a cummulative increase effect.

Temperature range

The verifications of strength should be carried out for a temperature range of from -20 °C to $+50$ °C. In the case of special operating conditions (e. g. "Arctic climate"), the appropriate individual verifications must be made.

Air density

The calculation of aerodynamic loads is based on the assumption of the air density of the standard atmosphere (at sea level):

$$\varrho = 1.225 \text{ kg/m}^3$$

Solar radiation

The solar radiation is assumed to be 1000 Watt/m² (Central European conditions).

Ice accretion

One of the environmental factors which may contribute to extraordinary loads is the build-up of ice on the rotor blades. As a rule, it can be assumed that even thick ice formations on the rotor blades do not cause any special loads. Similar to aircraft wings, aerodynamic lift is reduced, with the consequence that rotor performance is reduced, and with it the aerodynamic loading (Chapt. 18.8.2).

The load assumptions issued by Germanischer Lloyd distinguish between rotating parts (rotor) and non-rotating parts. For the non-rotating parts, an ice accretion of 30 mm is assumed. For the rotor blades, a varying mass distribution of the accreted ice from the root of the blade to its tip is assumed, and a difference in ice accretion between the individual blades [10].

Bird strike

One load case which is fortunately very rare can be caused by a large bird colliding with the rotating rotor. To take this rather theoretical hazard into consideration, the Swedish load assumptions suggest some assumptions about impact velocity and bird weight [8]. The resulting impact may be of significance for the dimensioning of the rotor blade shell.

Orographic influences

The influence of the orographic situation on the wind speeds (wind flow over hills and mountains) must be taken into consideration above a certain, predetermined influencing quantity and checked in each individual case

Lightning

The impact of a lightning strike has to be minimized by the lightning protection system. This is specified by the national standards and requirements.

Earthquakes

For installations in hazardous regions with a risk of earthquakes, the local building regulations concerning earthquake protection must be consulted.

6.4
Load Cases

The load cases must contain the conditions for the causes of the load situation, such as wind speed, as well as the corresponding parameters of the operational status of the turbine such as rotor blade pitch angle.

The maximum loads on the various structural components occur during differing load cases. The *definition of the load cases* must, therefore, be comprehensive enough so that the load cases determining the dimensioning for each component can be reliably recognised in calculations concerning strength and stiffness. It cannot be said in advance, for example, whether it is the load cases leading to fracture stress or the fatigue strength under continuous load that affect dimensioning. For this reason, it is necessary to have a large number of load cases.

Another problem is that the definition of load cases always involves a certain idealisation and simplification of a real situation. This applies particularly to relatively small turbines where the expenditure for calculations must be limited.

Closely linked to this problem is the question to what extent the simultaneous occurrence of several load cases must, or should be taken into consideration. An attempt to define combinations of load cases occurring simultaneously, covering all possible conceivable stress-inducing situations and events, far exceeds the limits of what makes sense technically. Load cases are, therefore, also a question of probability. This is especially true for load cases inferred from anticipated system faults.

6.4.1
Normal Operation

The loads to which the wind turbine is subjected under "normal" operating conditions are mainly relevant to fatigue life. The basis for the definition of load cases are the characteristic wind speeds which are used in the sequence of operational states.

The "extreme" loads mainly occur under extreme external conditions, that means extreme wind speeds. It will be assumed that extreme wind speeds occur mainly at normal operation excluding critical machine fault states (see Chapt. 6.5.1).

Power production

The range of wind speeds within which the turbine is operated is divided into "classes", each of which is characterised by a characteristic wind speed:

- cut-in wind speed
- partial-load wind speed
- rated wind speed
- full-load wind speed
- cut-out wind speed.

For each of these characteristic wind speeds a load case group is formed. The associated number of load alternations is derived from the fraction of time each wind speed class occupies within the wind speed distribution and from the number of rotor revolutions in these time segments. Considering the turbine's design life, this implies, for example, 10^7 to 10^8 load cycles for the bending stress of the rotor blades.

The asymmetrical flow conditions for the rotor and the random wind speed fluctuations and the loads resulting from any malfunctions are added to this "basic load spectrum". Having regard to the fatigue strength, the influence of the flow around the tower must not be forgotten. The loading by the flow around the tower occurs with the number of load cycles of the rotor revolutions during the life of the turbine for each individual rotor blade. For the total rotor force, this number is multiplied by the number of rotor blades.

Start-up and Shut-down of the Rotor

Rotor start-up and shut-down involve special load cases and load changes. These events occur so frequently during the life of the turbine that it must be assumed that they have an influence on fatigue life. They do in fact also represent a group of load cases, as different starting conditions with regard to wind speed, rotor speed or even blade pitch angle, must be considered.

When the rotor in wind turbines with pitch control starts up, the rotor blade pitch angle is either in the feathered position or in the starting position. In both cases, a more or less large component of the bending moment acts around the softer flapwise axis due to the inherent weight of the blades. If it occurs often enough, this special load case can be significant to the overall fatigue loading.

In larger wind turbines, the normal shut-down of the rotor is controlled by means of blade pitch control as the rotational speed varies, so that no special loads are involved. One exception is fast braking, the "emergency shut-down", where the reversed aerodynamic thrust can cause increased loads.

Parked Rotor at extreme wind speeds

It is generally when the rotor is parked that the wind turbine has to cope with the highest wind speed, the so-called *survival wind speed*. For turbines with pitch control it is assumed that the rotor blades are in the feathered position and that the rotor is aligned with the wind. Under these conditions, the load level is much lower than under cross-wind conditions. Naturally, the precondition for this is that the yawing system and the blade pitch control are functional when the survival wind speed occurs.

In the case of fixed-blade small turbines, this problem does not occur. The strength of the turbine must be verified with rotor blades under cross-wind conditions. The assumption of a correct drag coefficient is of essential significance here. For blades subjected to a cross-wind the c_D-values range from 1.3 to 1.8.

Some wind turbines do not stop the rotor at extreme wind speeds, because at rotor idling — using an appropriate blade pitch angle — the loads on the turbine are lower compared to fixed parked rotor.

6.4.2 Technical Faults

Technical faults and defects can subject the wind turbine to additional loads not covered by the other load cases. It can be assumed that most technical defects, in as much as they are relevant to operational reliability, lead to an emergency stop of the rotor via a safety system, so that these types of defects do not result in any "extraordinary" loads. On the other hand, some malfunctions are possible which cause abnormal loads on the structure before the rotor shuts down. These events must be recognised and included in the definition of load cases. Thus, a theoretical *failure mode and effects analysis* should be carried out for reliability-related areas of operation, such as blade pitch control and the rotor brake systems, at least in larger turbines.

Rotor emergency stop

Most technical failures will trigger the rotor emergency stop via the safety circuit, but the abrupt deceleration of the rotor results in an extraordinary loading situation for the wind turbine. With large rotors and under certain circumstances, this situation can increase the bending stress on the rotor blades up to the strength limit. In the case of a defect, for example a loss of the electrical system (generator release) or a fault in the control system, the rotor blades must be pitched very rapidly towards feather to prevent rotor "runaway". For this, the blade is pitched so fast that, for a short period of time, the rotor blades are subjected to negative aerodynamic angles of attack. The aerodynamic thrust then acts in the opposite direction. If the rotor blades are positioned at a cone angle to each other, the bending moments from thrust and centrifugal force are superimposed in the same direction. Instead of compensating for each other as in normal operation, they add up with the consequence of an extreme bending moment on the rotor blades. A very careful analysis and optimisation of the emergency shut-down procedure is required in order to remain within the given load limits under these conditions.

Control system fault

In turbines with blade pitch control, a failure in the control system can lead to a pitch angle which is inappropriate for the operating condition. This is directly associated with special aerodynamic loads and indirectly with other consequences, such as rotor overspeed.

A fault in the control system or in the yaw drive can result in extreme cross-winds acting on the rotor. Loads due to extreme cross-wind angles or yaw angles must, therefore, be seen not only against the background of extreme meteorological conditions but also with a view to technical defects.

Generator short-circuit

A short circuit in the electrical generator causes an extreme load on the drive train. The generator short-circuit torque can amount to up to seven times the value of the rated torque (Chapt. 9.1).

Rotor overspeed

Defects in the blade pitch control or a sudden loss of the electrical load, for example in case of a power system shut-down, can cause the operating speed of the rotor to be exceeded. Rotor "runaway" is basically the most severe safety hazard in a wind turbine (Chapt. 14.7). A large enough safety margin between the permissible operating speed and the "maximum speed before fracture" is therefore required.

Rotor unbalance

In the case of damage to the rotor blades, loss of a structural part or the formation of ice on the rotor blades, an unbalance of the running rotor must be expected until the rotor stops. Therefore, a certain unbalance mass must be assumed, the magnitude of which must be related to the size of the rotor. The resultant load case must be verified with respect to strength as well as any vibration problems which may be present.

6.5 Ultimate Loads and Fatigue Loading

The structural and mechanical components of the wind turbine are subject to the requirement of resisting the *ultimate* or *limit loads*, the fatigue loading and to meet the stiffness requirements. The requirement that governs the final selection of the materials and the dimensioning of the structures is referred to as the *design driver* of the components. The design drivers of the main components of a wind turbine illustrates Tab. 6.18.

In general fatigue is the design driver for the main components of a wind turbine even some tower designs can be sensitive to fatigue. However there are some components which have to be designed by limit loads and stiffness requirements.

Table 6.18. Typical situation of design drivers for the wind turbine components [11]

Design Driver		
Component	Ultimate	Fatigue
Rotor Blades and Hub		•
Drive Train Low-Speed Shaft Gearbox High-Speed Shaft	 • (breaking)	 • •
Nacelle Bedplate Yaw Drive	 • (stiffness) • (breaking)	 •
Tower	• (stiffness, stability)	
Foundation	• (breaking)	

6.5.1 Ultimate Loads

Calculating the limit loads for the design is a matter of identifying one-time or infrequent load situations that might damage the structure or the mechanical components. The ultimate load and stress calculation includes three types of analyses which respect to:

- breaking strength
  for example for the yaw drive and the tower/foundation at extreme wind speeds
- structural stability
  for example buckling of steel-tube towers
- stiffness
  for example critical deflections of the rotorblades with respect to rotor blade/tower clearance at extreme gusts or during fast rotor braking

The load cases selected for ultimate load design must cover realistic combinations of external wind conditions and machine states. The load cases for design are chosen from:

- normal wind conditions in combination with normal machine states.
- normal wind conditions in combination with machine fault states.
- extreme wind conditions in combination with normal machine states.

Limit strength design of a wind turbine is normally a problem of extreme wind loading on a static structure. Conventional calculation and design methods can be applied. For this reason only the fatigue design methods will be addressed in the next chapters.

6.5.2 Fatigue Load Spectrum

In simple stress situations with static loads, it is sufficient to calculate the structural strength separately for individual load situations or load cases. If a safe fatigue life is required with alternating loads, elementary fatigue strength theory assumes that stress fluctuations occur with constant amplitudes within the lifetime of a component. If the stress amplitudes are below the *fatigue strength* of the material, then the number of load cycles no longer plays a role, i. e. changes in load can be endured any number of times. If the stress amplitudes are higher than the fatigue strength allows, only a certain number of load fluctuations can be sustained, i. e. the material is only "fatigue-limited". In the case of steel, this mechanism is represented by the well-known "Wöhler line". This fatigue model has been found useful for "normal" engineering problems.

The elementary theory is no longer adequate for designing for the fatigue strength of dynamically highly stressed systems such as aircraft, automobiles and wind turbines. The load spectrum with regard to material fatigue consists of periodic and stochastic stress fluctuations, with varying mean values and fluctuations. The single stress situations can no longer be considered independently, but must be assessed in their totality, as a *load spectrum*. Against this background, calculating the *endurance strength* requires more complex models which can also be summarised under the title of *damage accumulation* [12].

The load spectrum summarises the stress situation of a component over its entire life in an idealised form. The load sequence within an operating cycle of the wind turbine, which the component has passed through a certain number of times within its life, forms the basis for the load spectrum. The progression of the cyclic bending moment experienced by the rotor blades of a wind turbine in the individual load cases serves as an example (Fig. 6.19).

According to the load case definition, operation under load is composed of five load cases, each characterised by a certain wind speed. During the start-up and shut-down process, the rotor blades are subjected to a higher load level as the blade pitch angle is set such that the dead weight bends around the flapwise axis. This condition has been assumed as occurring with a certain frequency in the lifetime of the wind turbine.

In full-load operation the amplitudes of the bending moment around the chordwise axis are determined primarily by the dead weight of the rotor blades. The influence of wind shear can also be recognised clearly but it must be noted that an extreme wind shear has been assumed. The effects of wind turbulence on the chordwise bending moment are only slight. It is the flapwise bending moment that is primarily affected. Naturally, the weight of the rotor blades in relation to the aerodynamic forces plays a decisive role in this.

Apart from the alternating amplitudes in the single load cases, the transitions from one load case to the next also play a role. Seen from the collective load point of view, these transitions result in additional stress amplitudes. In this example the maximum amplitude excursion is evidently created by the transition from operation at rated power to shut-down.

To each load case, load cycle numbers are assigned which are deduced from assumptions about the frequency of occurrence of the operating cycle within the life span and from the proportion of time occupied by each load case in the operating sequence. They range from around 10^4 for the occurrence of rare events such as extreme wind shear, up to around 10^8 for the alternating bending load at partial-load wind speed.

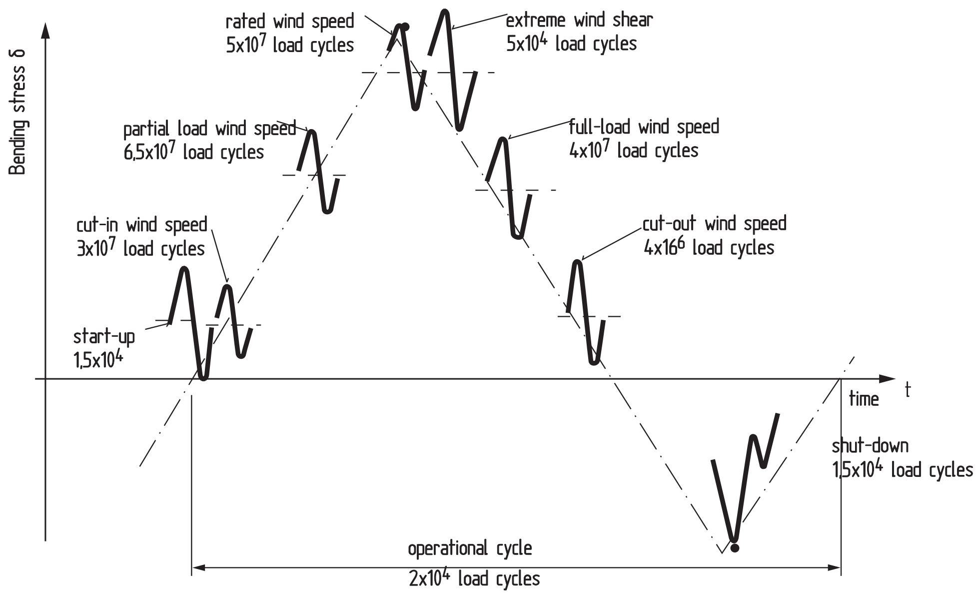

Figure 6.19. Idealised fatigue load sequence of bending stress in chordwise direction of a rotor blade

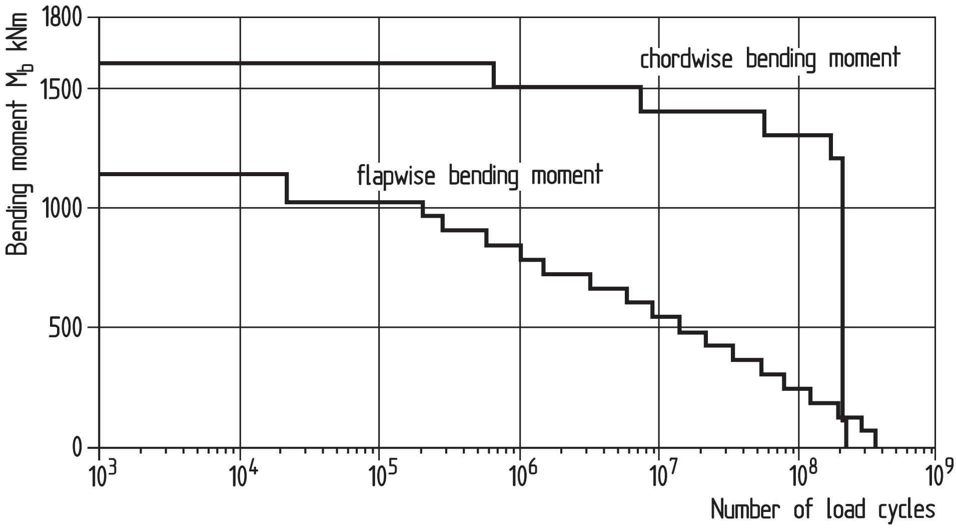

Figure 6.20. Measured stress amplitudes (without mean value) against load cycle number measured on the rotor blades of the WKA-60 [13]

Figure 6.20 shows an example of a measured load or stress spectrum as it is normally represented. The material stress measured at the rotor blades of the WKA-60 turbine has been plotted against load cycle numbers. In the form shown, the load spectrum is referred to the period of one hour and, therefore, be projected to a service life of 30 years, corresponding to about 10^8 load cycles, for assessing the fatigue situation. The two curves for the flapwise and chordwise components of the bending stress show clearly that the chordwise bending component is almost exclusively determined by the constant amplitude of the gravitational loading, whereas the flapwise component is determined by the aerodynamic loading and hence has a varying amplitude.

Such load or stress spectra must be prepared theoretically for every structural component subjected to dynamic stress, but in any case for the rotor blades and hub, the main shaft and gear box and possibly also for the highly stressed components of the yaw system. .On the other hand, the computation work must be restricted to an amount that makes economic sense. In the case of small systems, therefore, simplified methods will be used.

6.6 Calculation of Fatigue Loads and Structural Stresses

Before going into detail about the fatigue calculation methods for the structural design, it is advisable to become familiar with the procedure in general. It is basically no different from the calculation of other dynamically highly stressed lightweight structures such as aircraft or motor vehicles, but it is helpful nevertheless to focus on the problems of wind turbines. It is advisable to think beforehand about the results which are actually needed for the structural dimensioning. Only then, the individual calculation methods and theoretical aids can be employed economically. Whenever large computer programs are used, there is always the risk of producing "data trash". The best advice that can be given with respect to the structural design of wind turbines is "think before you calculate".

With this in mind, the thought could arise of compensating for a less accurate calculation with higher safety margins. Considering all the experience gained to date, this strategy would lead to success only with small wind turbines. Larger turbines must be loaded to the limit of the strength of the material or of the stiffness of the components, if component masses are to be restricted to a tolerable level. Large masses result in reduced stiffness and increased inertia forces. An attempt to compensate for these increased loads with higher safety margins again creates a vicious circle, the outcome of which is less, rather than more structural safety. Moreover, there are of course also economic reasons against large component masses (Chapt. 19).

6.6.1 Mathematical Models and Calculation Procedure

The starting point for calculating the structural loads are the defined load cases. If the conditions under which loads occur are clearly defined, the next question is that of the mathematical models by means of which the load calculation can be carried out. Essentially, four different mathematical models are required (Fig. 6.21):

Aerodynamic rotor model

The calculation of aerodynamic loading, both due to the steady-state flow against the rotor as well as from wind turbulence, requires an aerodynamic rotor model. Blade element theory, as outlined in Chapt. 5, is a suitable instrument for aerodynamic loads from a steady-state wind flow. Dynamic loads caused by wind turbulence and the elastic response of the structure can be calculated by means of a simplified aerodynamic model. A linear analytical approach for the dependence of the aerodynamic force coefficients on the angle of attack is often sufficient (Chapt. 6.5.2).

Wind turbulence model

There are basically two methods for determining wind turbulence by theoretical means. One is via the energy spectrum of the turbulence, the other is by means of an actual wind speed time history (Chapt. 13).

Independently of the chosen method, one phenomenon affecting the reaction of the wind rotor to turbulence must not be overlooked. In the open atmosphere, wind speed and turbulence are always unevenly distributed in space over the rotor-swept area. Many gusts strike the rotor not as a whole, but only on one side or only partially. This fact is significant for the response of the structure as regards the rotating rotor. The rotor blades "beat" into the gusts, i. e. the local wind speed changes, at their tangential speed. An observer travelling with the rotor blade experiences these speed changes considerably more strongly than he would in the steady-state system. Moreover, depending on the duration of the gust and the speed of the rotor, the rotor blade can encounter the same gust several times (Fig. 6.22).

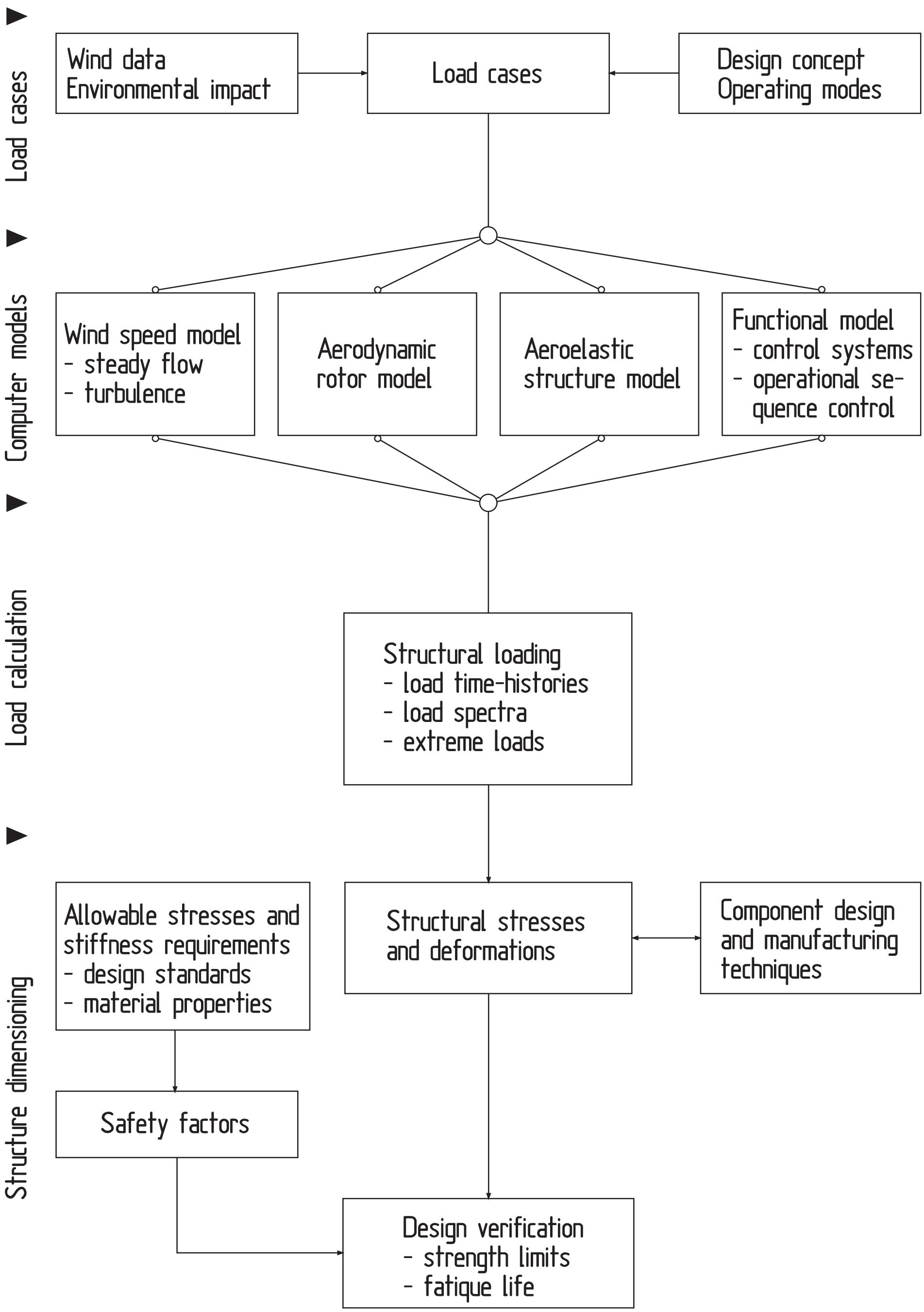

Figure 6.21. Flow chart for calculating loads and for dimensioning the structure

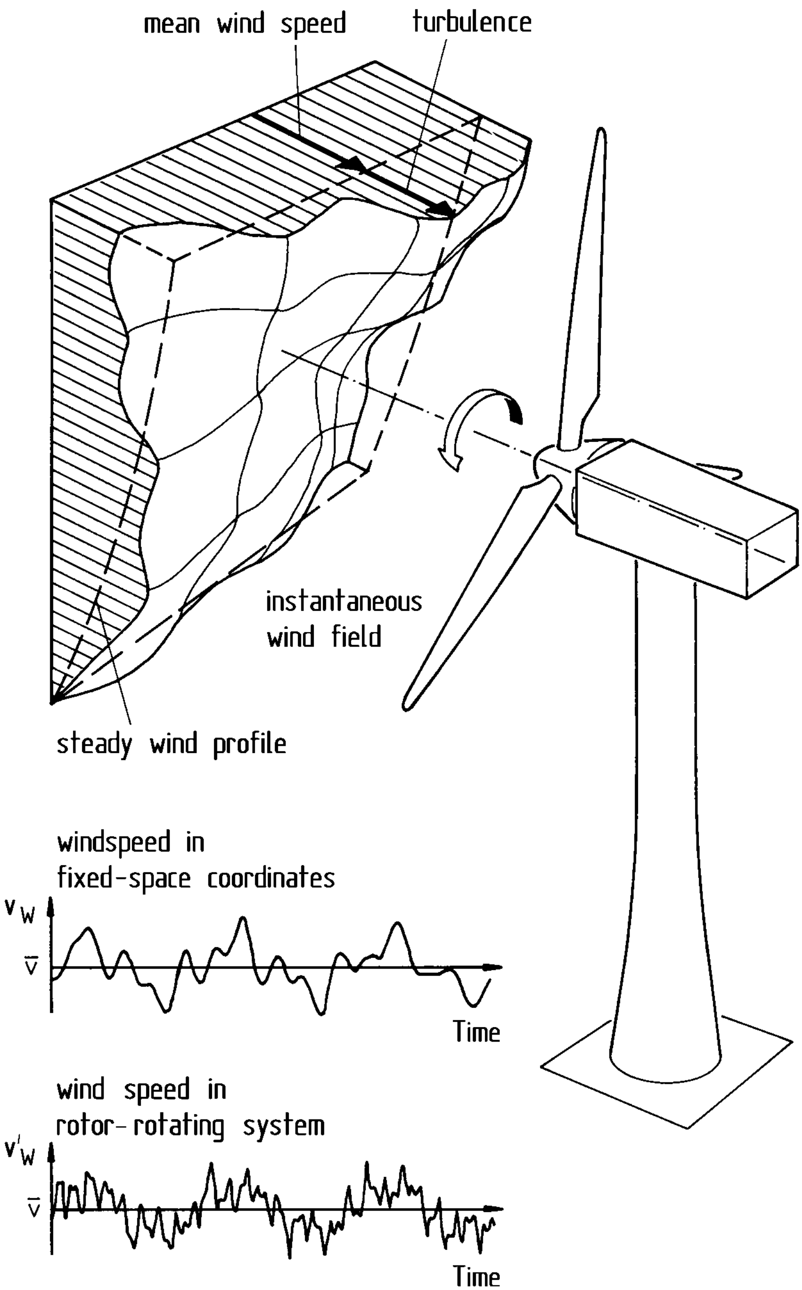

Figure 6.22. Effect of an uneven wind-speed distribution over the swept rotor area on the upwind velocity of the rotating rotor blades

This process of *rotational sampling* is of considerable significance for the effect of wind turbulence on the rotor blades, especially with large rotors. The fatiguing effect on the structure can increase by up to 50 % compared to a merely time-dependent approach to turbulences in a non-rotating, stationary reference system.

Elastic structure model

Theoretical tools for calculating elastic structures are currently in use in many areas of mechanical engineering. They are based almost without exception on the finite-element simplification, with the aid of which the natural frequencies and properties of the structural components can be calculated. Knowing the natural frequencies, the dynamic responses (deformations, accelerations, stresses) under the influence of external forces can then be calculated. The computer programs based on this can also be applied to the components of wind turbines.

It is of little help to proceed on the basically correct assumption, that the dynamic response, and with it the stresses, can only be calculated correctly if the elastic characteristics of the entire turbine are taken into consideration. An elastic structural model of the entire turbine would inevitably require an enormous computational effort resulting in a corresponding amount of data, with the associated risk of missing the critical points. It is therefore important to use a good measure of feel for how the components are dynamically coupled, in order to define subsystems with the aid of which the significant loads can be calculated. In most cases, for example, considering the rotor in isolation is sufficient.

Functional model of control and operational sequence

If the wind turbine is equipped with blade pitch control and a variable-speed rotor, its functional behaviour has an influence on the loading. An algorithm for the blade pitch and speed control of the rotor is thus necessary.

Safety Factors

The safety margins of the calculated stress level with respect to the permissible stress level are expressed by the safety factors. Determining the safety factors requires a great deal of experience. They are required for compensating for mathematical inaccuracies and deviations of the idealised mathematical models from reality and for the ever-present uncertainties in the load assumptions.

The structural dimensioning of wind turbines is under pressure to save weight for cost reasons, especially with increasing size, and cannot, therefore, be safeguarded by means of high safety factors as in the case of static structures. The safety factors justifiable in large wind turbines are of a similar level as in vehicle and aircraft construction. The national design standards applicable today are not yet fully harmonised in this respect. The differences only lie in the details, however, so that it must not be concluded that the safety standards are generally different.

The safety factors to be applied with respect to the ultimate strength analysis must be generally set at a higher level than in the case of fatigue failure analysis. Table 6.23 indicates the range of safety factors to be applied for ultimate strength by means of some typical numerical values. More detailed information can be obtained from the design standards quoted.

For the fatigue loads, safety factors in the range from 1.0 to 1.1 are demanded in accordance with the characteristic of the fatigue load spectrum (survical probability, confidence level).

In addition, additional safety factors are demanded for the permissible material stresses and characteristics if the material properties are encumbered by uncertainties.

Table 6.23. Safety factors for loads according to Germanischer Lloyd (GL), International Electrotechnical Commission (IEC) and to the Danish Standard (DS), for the ultimate stress analysis [13]

	Normal loads normal machine states with normal and extreme wind conditions			Abnormal loads machine fault states with normal wind conditions		
Source of loading	IEC	GL	DS	IEC	GL	DS
Aerodynamic	1.35	1.20	1.30	1.10	1.00	1.00
Operational	1.35	1.35	1.30	1.10	1.00	1.00
Gravity	1.10*	1.10*	1.00	1.10	1.00	1.00
Inertia	1.25	1.10*	1.00	1.00	1.00	1.00

*factor increased to 1.35 if masses are not determined by weighting

Calculation Procedure

In the procedure for structural dimensioning, the mathematical models outlined are combined with one another [7]. This provides the structural loads in the form of so-called "stress resultants" at pre-defined points of intersection of the structural components. Depending on the method selected, they appear either as plots against time or as frequency spectra (Chapt. 6.5.2). The combined stresses of all given load cases represent the load spectra for the individual components of the wind turbine.

The calculated material stresses are compared, as usual, with the permissible stress values. To be able to determine the permissible values, material properties and the design standards to be used, for example for the welded seams, are needed. With the consideration of *safety factors* to guard against fracture, or for some other defined threshold value, the structure can be dimensioned, or, if dimensioning has been determined, design verification can be carried out. (Chapt. 6.8)

6.6.2 Dynamic Response of the Structure and Fatigue Strength

Dynamic loading caused as a consequence of the response of an elastic structure to alternating loading acting on it must be seen under two different aspects: in the worst of case, the structure fails "abruptly" due to extreme vibration amplitudes. This problem of dynamic stability is dealt with in Chapter 11 under vibration problems. Even if there is no failure of stability, the continuous oscillations of the elastic structural components represent a considerable dynamic load as far as fatigue is concerned. This aspect predominates in this case. As this is a problem of fatigue life, it is important to identify the exciting forces, and the resultant responses of the structure, completely with respect to their natural frequencies and the frequency of occurrence within the life of the structure. For this reason, statistical methods are particularly well suited to this task. This is, of course, also true because of the stochastic nature of wind turbulence. The two most important mathematical methods are known as the *time-history method* and the *spectral method* (Fig. 6.24) [14].

Time history method

If the time history of the active force is known, for example the variation of wind speed with time, the resultant response of the structure versus time can be calculated. This requires an aerodynamic model of the rotor, so that the variation of the aerodynamic force can be determined from that of the wind speed. Using the elastic structure model, the response of the structure over time is obtained [15].

The advantage of this method is that all parameters are time-dependent, a form of presentation which is advantageous for several purposes. Moreover, functional algorithms, for example for the influence of the control system, can be taken into consideration. The influence of periodic forces, for example from the shear wind gradient or tower interference, can also be determined well by means of the time history approach. The serious disadvantage of this method is the more or less random "segment" of wind turbulence used as a basis. This does not lead to a comprehensive picture. If this were attempted, the calculation effort would become extremely high. Hence, this method is more suitable for a selective "check", rather than for comprehensive structural dimensioning with respect to fatigue life.

Spectral method

In the so-called spectral method, frequency-dependent representations (spectra) of forces and responses are processed instead of their progression over time. This method uses a statistical turbulence spectrum of the wind as the load input [16] (Chapt. 13).

It must be possible to represent the structure in the form of linear or linearised equations (linear systems theory). The excitation spectrum causes excessive dynamic peaks of response in the regions of the natural frequencies of the structure. The extreme values of the required parameters (deformations, forces etc.) which are decisive for the dimensioning of the structure can be represented as follows:

$$x_{\max} = \bar{x} + K\sigma_x$$

where $\bar{x}$ is the quasi-statically calculated mean value, σ_x the standard deviation of the dynamic excursions about the mean value and K the so-called peak factor based on statistical reliability calculations.

The link between the excitation spectrum and the spectra of the response reaction is established via so-called transfer functions. "Aerodynamic admittance" leads from the wind spectrum to the aerodynamic force parameters, "mechanical admittance" represents the link between the active forces and the deformations or stresses of the structure.

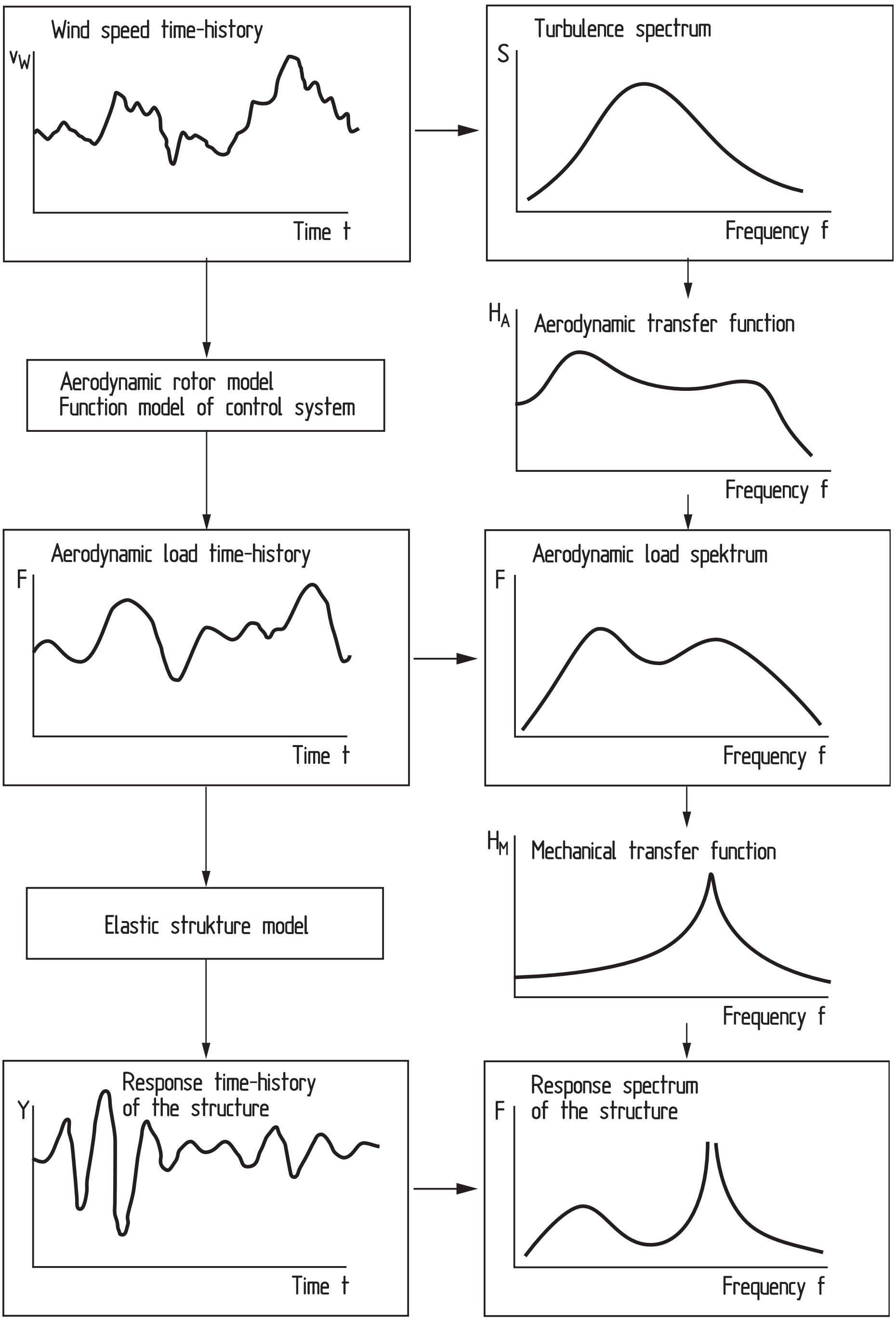

Figure 6.24. Mathematical models for calculating the structure's dynamic response to wind turbulence: time history and spectral approach

The decisive advantage of the spectral method is the reliable acquisition of the entire, real load spectrum caused by the wind turbulence. This method is thus predestined for calculating structural fatigue. The fact that the required deformation and stress parameters are only available as frequency-dependent spectra, and not as plots against time is, admittedly, a disadvantage in view of some of the technical problems at hand. For example, it is difficult to process the functional characteristics of a wind turbine methodically, with respect to the influence of the control system on the loads (functional model).

Deterministic approach

In contrast to the statistical methods described above, it is also possible to follow a deterministic approach for calculating the dynamic structure responses. As in the example of the time history method, one single event, for example a discrete gust, can be used as load input, rather than the continuous progression of wind speed (Chapt. 6.2.4). The structural response derived from this provides information on the dynamic load magnifications to be expected. From the results, all-inclusive "dynamic magnification factors" for the quasi-statically calculated stress can be derived.

The continuous nature of wind turbulence and of the response of the structure is, of course, lost in the process. It is also not possible to cover all of the load inputs with respect to the overall load spectrum by this method. Up to a certain point, one can get by with assuming a certain frequency of the various discrete events (gusts), but the validity of the results with respect to the structure's fatigue nevertheless remains questionable.

6.7 Influence of Conceptual Design Features on the Loading

The design engineer, with his choice of conceptual design features, determines the loading on the components within wide limits. The general aim must be to reduce the loads to a level which is the unavoidable minimum. The loading on the rotor and the turbine in a steady mean wind and that resulting from the weight of the components is unavoidable. Loads resulting from the turbulence of the wind are avoidable to a certain degree, however. Damping these dynamic loads by suitable design features, allowing the turbine to exhibit a "softer" dynamic response, is a key problem in the design:

As a first step, it will be attempted to reduce the high alternating loads on the rotor blades. The dynamic response of the rotor to the wind gusts affects, in particular, the flapwise bending moment in the root area of the blades. This load is of decisive significance for the fatigue loading on the rotor blades

In addition — and this aspect is just as important — the cyclically changing total rotor forces and moments must be evened out. These loads are passed on to the other turbine components and determine the dynamic load level for the mechanical drive train., the yawing system and the tower of the turbine.

The most important system features determining the dynamic load level of the wind turbine are the number of rotor blades, the function of the rotor hub in the case of two-bladed rotors, the type and quality of power control, and, not least, the stiffness of the electrical coupling to the fixed-frequency grid.

Out of these possibilities open to the design engineer, two basic philosophies emerge. On the one hand, there is the school still adhering to the old English motto: "Make it stiff and strong and you will never be wrong". The older, stall-controlled Danish wind turbines followed this principle. On the other hand, there is the endeavour to keep the dynamic response of the design and structure as soft as possible so as to reduce material stress. It goes without saying that this approach is the more promising one for large turbines even if it is associated with more development work.

6.7.1 Number of Rotor Blades

Considering the sum total of the rotor forces during a steady-state but asymmetrical wind flow, serious differences become apparent which depend on the number of rotor blades. This is clearly illustrates by the example of the aerodynamic yaw moment and the driving torque. While one- and two-bladed rotors generate considerable alternating loads with respect to the yaw moment and a pulsating drive torque, the rotor moments almost completely balance out overall during a revolution in rotors having more than two blades (Fig. 6.25). One-bladed rotors behave quite unfavourably in this respect. Their geometric asymmetry, and with it their aerodynamic asymmetry, causes extreme, alternating rotor forces and moments even with a symmetrical wind flow.

The critical influence of the number of blades becomes even clearer if the dynamic response of the elastic rotor is also considered. This is especially true of rotors with less than three blades, a fact which has long been known empirically. The deformations experienced by a rotor under the influence of external forces, primarily bending of the blades, produce inertia forces due to the structural masses being accelerated. The moment of inertia of the rotor around its instantaneous axis of motion is of importance to the dynamic response to these external loads. When the rotor is rotating, the moment of inertia changes during a rotor revolution in relation to a fixed axis when the rotor only has two rotor blades, i. e. behaves like a rotating rod. Whereas rotors with three or more blades behave like a disk as far as the moment of inertia is concerned, i. e. are symmetrical in terms of mass, the mass of the rod-shaped two-bladed rotor is asymmetrical and its moment of inertia has a pulsating profile during a revolution. Depending on whether the rotor blades are perpendicular or parallel to the axis under consideration, the mass moment of inertia varies from a maximum to a minimum value. This phenomenon has serious consequences with respect to the dynamic reaction of the rotor during excursions from its normal position. If an asymmetrical wind flow, for example in a horizontal rotor position, causes a deflection of the rotor blades, the resultant angular velocity around the vertical axis is comparatively small, as the moment of inertia of the rotor about its vertical axis is large in this position. If the rotor continues to turn towards the perpendicular, the moment of inertia about the vertical axis reduces. Since, for physical reasons, the rotational momentum is maintained, the angular velocity around the vertical axis becomes all the greater. The consequence is a dynamically-caused yaw moment about the vertical axis. This dynamic moment of reaction reinforces the aerodynamic yaw moment already existing from the asymmetrical flow. The pitching moment, triggered, for example, by the asymmetrical flow to the rotor due to shear wind, is thus reinforced in a two-bladed rotor.

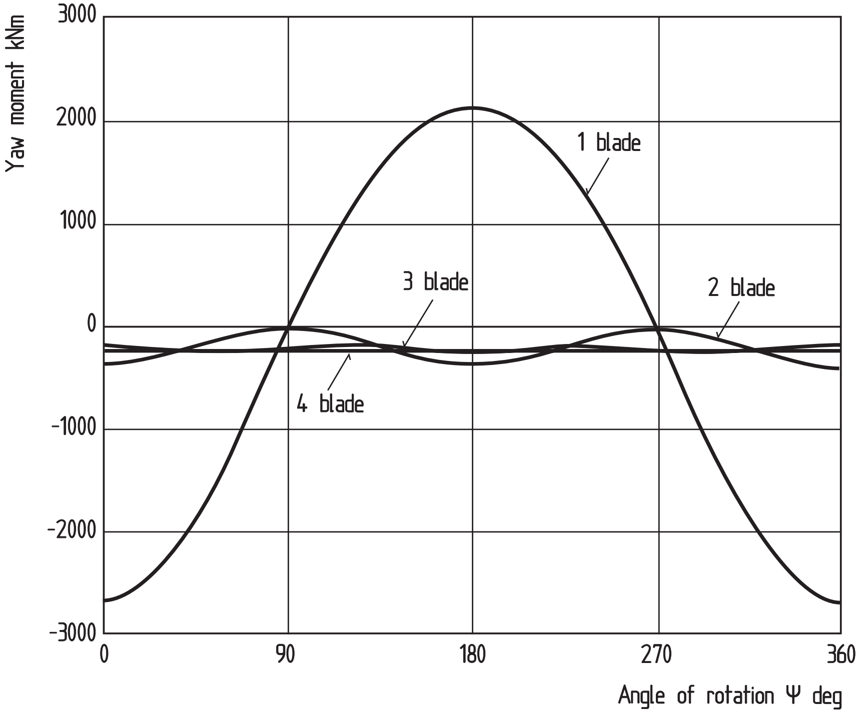

Figure 6.25. Aerodynamic yaw moment of a rotor with different numbers of blades with an asymmetrical wind flow, calculated using the WKA-60 as an example

Hence, wind turbines with two-bladed rotors are subjected to particularly high dynamic loads if the rotor blades are joined rigidly to the rotor shaft. In order to reduce the negative consequences for the total system, either the strength and stiffness of the turbine components must be dimensioned to accommodate this increased load, or the design concept of the two-bladed rotor must be selected such that it can largely reduce these dynamic loads itself by means of an appropriate controlled compliance.

6.7.2
Rotor Hub Hinges in the Two-Bladed Rotor

In order to reduce the poor dynamic response of the two-bladed rotor to asymmetrical flow conditions, a series of design ideas have been proposed and to a large part also been realised, at least in experimental wind turbines. The preferred solution is the introduction of hinges, providing the rotor blades with additional degrees of freedom of movement, so that the dynamic alternating loads can be reduced in the rotor itself by a "limited yielding" due to the acceleration of its own masses. The simplest way of achieving this compliance is by installing hinges between the rotor blades and the rotor shaft, i. e. in the rotor hub. Figure 6.26 shows the basic possibilities in the construction of two-bladed rotors.

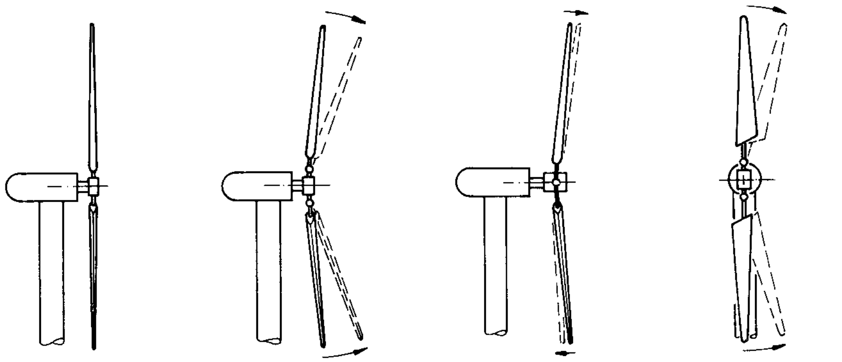

Figure 6.26. Hingeless rotor and rotor hub hinges in two-bladed wind rotors

Hingeless rotor

The hingeless rotor, i. e. with the rotor blades joined rigidly to the rotor shaft, represents the traditional design. The old-fashioned windmill rotor has always been a hingeless rotor. This simple type is completely adequate for rotors with three or more rotor blades, even today. Two-bladed rotors, too, were built with rigid hubs for reasons of simplicity (WTS-75, Aeolus II). The advantage is the simple construction of the rotor hub and the disadvantage is the fact that wind turbulence, in combination with the dynamic response of the two-bladed rotor which tends to amplify the asymmetrical and cyclic alternating loads, must be sustained fully by the structure. This requires a stiff design with corresponding expenditure on materials. This primarily affects the rotor blades, but also the loads on the mechanical drive train and the yaw mechanism and the tower. If the rotor is additionally subjected to tower shadow effects, the load situation becomes even more unfavourable. Hingeless two-bladed rotors should, therefore, not be set up in the downwind position.

Blade-flap hinges

Hinges permitting a limited flapping motion of the rotor blades were introduced as early as 1940 in Smith-Putnam's wind turbine (Chapt. 2.3). The main advantage of a rotor with individual blade-flap hinges is that it can evade symmetrical gusts, i. e. those striking the entire rotor area, as well as asymmetrical gusts.

One disadvantage of the flapping movement already became apparent in the turbine mentioned above. The relatively large flapping movement of the blades shifted the centre of gravity closer to the rotor axis. The conservation of rotational momentum forced the blade, which was closer to the rotational axis, to accelerate its rotational movement about the rotor axis. The consequence were dynamically produced lateral forces and torques acting on the rotor shaft. In operation, a rotor with individual flapping blade movement would, therefore, be found to be running relatively roughly. In more recent wind turbines, a blade flapping hinge has only been used on one-bladed rotors.

Teetering rotor

The mechanical complexity associated with individual blade-flap hinges can be reduced by connecting the entire rotor to the rotor shaft by means of a single hinge. The rotor is thus able to perform teetering movements about the rotor shaft. A teetering hub of this type was used for the first time in 1959 by Ulrich Hütter in his W-34 turbine (Chapt. 2.4).

The teetering rotor responds to symmetrical loads in the same way as a hingeless rotor. Asymmetrical loads, however, can be balanced out. The teetering rotor results in considerable improvement, particularly as far as the cyclic loads are concerned. The yaw and pitch moments of the rotor disappear almost entirely. Installing a teetering hinge on a two-bladed rotor achieves dynamic characteristics comparable to those of a three-bladed rotor. Hence, two-bladed rotors with teetering hubs and three-bladed rotors with hingeless hubs can be considered to be genuine alternative concepts. The first-generation teetering rotor of the large experimental turbines was the preferred design for the large two-bladed rotors.

Teetered rotors with blade pitch coupling

An elegant method of restricting the flapping or teetering movements of the rotor blades while reinforcing their load-compensating effect, is to couple the teeter movement to an adjustment of blade pitch angle (Fig. 6.27). Coupling teetering and blade pitch movements is achieved either by means of a mechanical linkage or by suitably tilting the teetering axis with respect to the rotor shaft. This latter method is called “ δ_3-coupling”, a term adopted from helicopter technology.

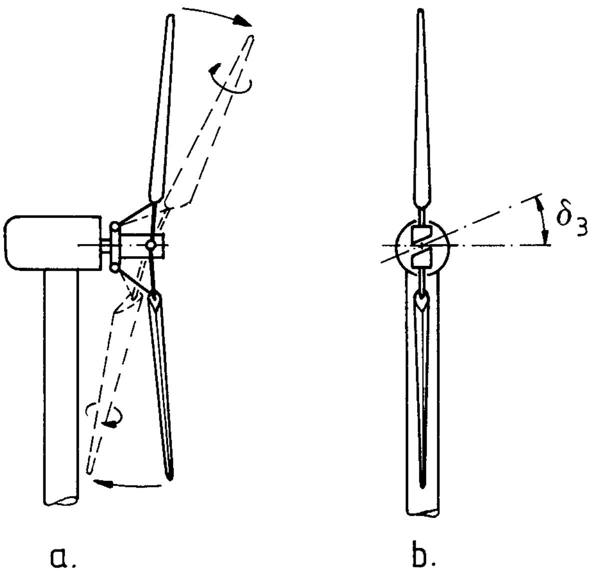

Figure 6.27. Teetered rotor with blade pitch coupling
a) by means of a mechanical linkage
b) by tilting the teetering axis (δ_3-angle)

Teeter angle and blade pitch angle are coupled together with a certain transmission ratio. When there is a teetering motion, the change in blade pitch angle produces a restoring aerodynamic force. In this way, a new state of equilibrium can be achieved already over a fraction of a rotor revolution. Thus, the rotor is provided with a passive self-regulating system to compensate for the impact of an asymmetrical flow. It is better able to adapt to changes in wind direction without creating large yaw moments.

As already mentioned, coupling the teetering angle to the blade pitch angle via a mechanical linkage was introduced by Hütter's W-34, and was later also adopted for the Growian turbine. A δ_3-coupling was tried out, for example, in the experimental Swedish-American wind turbines WTS 3 and WTS 4.

However, the effect of blade pitch coupling depends to a great extent on the aerodynamic sensitivity of the rotor. For heavy rotors, the effect is often considered too weak to justify the mechanical complexity (for example MOD-2). Some smaller turbines with teetering rotors, for example the earlier American ESI turbines, also managed without blade pitch coupling.

Blade lead-lag hinges

The theoretically greatest dynamic compliance of the rotor can be achieved by providing the rotor blades with additional lead-lag freedom. Helicopter rotors have flapping and lead-lag hinges, as is generally known. However, the mechanical complexity of these is enormous. There is the additional hazard of high degrees of instability, so that flapping and lead-lag hinges are not found in large wind rotors. An attempt in this direction was made by John Brown in 1955 with his 100 kW wind turbine, which was unnecessarily applied to a three-bladed rotor. The project turned out to be a failure for other reasons, too. It is easier to provide the rotor blades with lead-lag freedom by using a variable rotor speed, which can then be considered as a "collective lead-lag motion" of the rotor blades.

Rotor blade bending elasticity

It is obvious that the existing bending elasticity of the rotor blades can be used to reduce the symmetrical and asymmetrical external loads. This method has been applied successfully with helicopter rotors where the introduction of elastic rotor blade root hinges allows the rotor blades to perform a flapping motion. Generally, a appropriately tuned rotor blade bending elasticity over the entire blade length can have the same effect.

On wind rotors, the practical implementation of this solution is not easy. It is difficult to achieve a high bending elasticity of the blades without coupling together several degrees of elastic freedom, including undesirable ones. The aeroelastic behaviour is then difficult to control, above all with respect to blade pitch control. Controlled blade elasticity is, nevertheless, used to improve the dynamic response of the rotor in some experimental two-bladed turbines.

In principle, using the bending elasticity of the rotor blades specifically as a means for reducing the dynamic loading is independent of the number of rotor blades. It can also be used for reducing the level of dynamic loading for three-bladed rotors. This effect is also increasingly taken into account in the design of more recent turbines. For example, the rotor blades of the large Vestas turbines are relatively flexible. This design absorbs the loads more "softly" and saves weight in the rotor blades.

6.7.3 Blade Pitch Control

If the rotor is able to control its blade pitch angle, it can be used not only for controlling rotor power and speed but also for smoothing out variations in loading and torque. Its efficiency as to the levelling of load peaks is, however, a question of response time, and this means the rate of blade pitching. Due to the inertia of the masses to be moved, and because overloading of the actuators is to be avoided, the blade pitch control mechanism is not able to react very rapidly to short-term fluctuations in wind speed. Load peaks which are consequences of longer and heavier gusts, however, will evoke responses and are partially absorbed (Fig. 6.28). In comparison with more recent rotors with active power control by aerodynamic stall, it is questionable, according to recent findings, whether blade pitch control is better for coping with dynamic loading due to wind turbulence (Chapt. 5.3.2). In

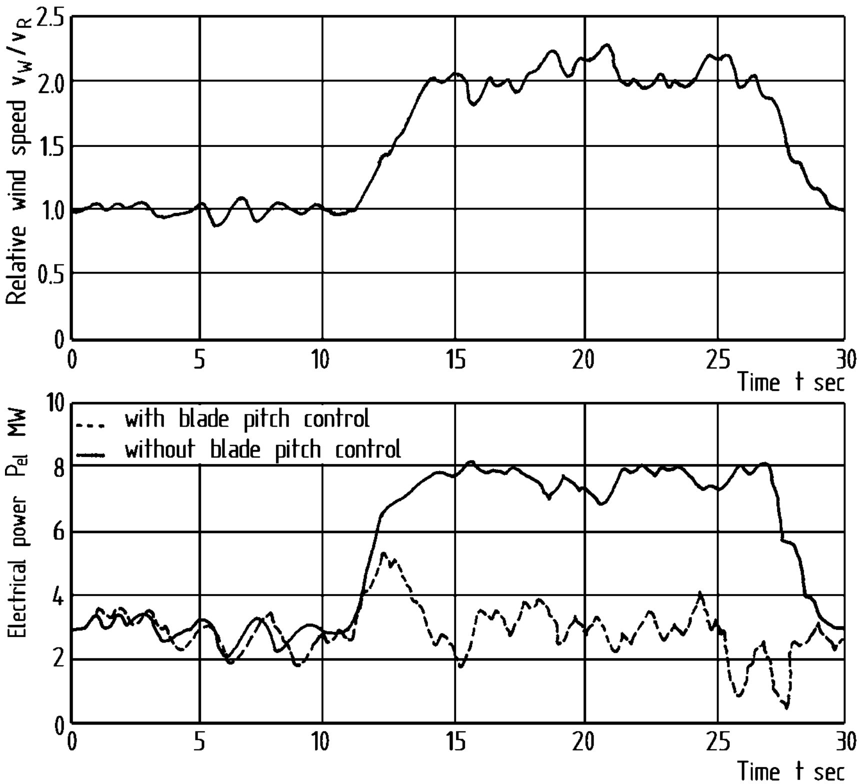

Figure 6.28. Influence of blade pitch control on the smoothing of the electric power output, using the Growian turbine as an example (without variable-speed operation)

pitch-controlled wind turbines, the loading is decisively determined by the interaction of a number of influencing variables (pitch rate, variable-speed operation, bending elasticity of the blades, size of the rotor).

In very recent wind turbines, e.g. Vestas V90, a cyclic adjustment of the blade pitch angle can be implemented. By controlling the blade pitch angle over the rotation of the rotor blades the increase of wind speed and thus the higher loading on the blades in the upper sector can be levelled out. By this means the loads on the rotor blades and on the entire wind turbine can be reduced significantly. The main difficulties lay in a reliable sensor system for the input signal for example the blade bending stress. Future experience will show whether such a sophisticated control procedure can be successfully implemented in series produced wind turbines.

6.7.4
Rotor Speed Slip and Variable-Speed Operation

The dynamic loads on the mechanical drive train and thus on the entire wind turbine can be reduced effectively by avoiding a fixed-speed mode of operation. In contrast to the aerodynamic wind-oriented operation, requiring a relatively wide range of speeds, a comparatively narrow rotor speed range of a few percent is already effective for producing a noticeable reduction in the dynamic loads (Chapt. 9.1.2). The mechanical and electrical elements for fully controlled variable-speed operation will be discussed in Chapt. 8.9 and 9.5. In this chapter, the technical solutions are only discussed with respect to the loading.

Torsional elasticity in the mechanical drive train

Wind turbines equipped with synchronous generators directly coupled to the grid must have a minimum of torsional elasticity and damping in the mechanical drive train. There are either torsionally elastic components which are built into the low-speed or high-speed shaft, or the gearbox must have a torsion-elastic suspension. Naturally, the effect of such measures depends greatly on the actual design adopted. Apart from torsional elasticity, adequate damping is required to keep the vibrational behaviour under control. Torsionally elastic gearbox suspensions were to be found in many large, experimental first-generation wind turbines (Chapt. 8.9). The gearbox was able to respond to an instantaneous torque peak with a torsional freedom of about 20 to 30 degrees to smooth out the load peak.

Mechanical slip in the drive train

An even more effective torsional compliance, being more strongly damped, is achieved by installing an hydraulic coupling into the mechanical drive train. Couplings of this type have a rotational slip of around 2 to 3 %, as a rule. A combination of synchronous generator coupled directly to the grid and hydraulic coupling in the mechanical drive train has been used in the past in several types of turbines, for example the Howden HWP-330 and the Westinghouse WWG-0600 or the MOD-0 turbine (Chapt. 8.9). Using the MOD-0 turbine as an example, Fig. 6.29 shows the effect of an hydraulic coupling with respect to power output smoothing.

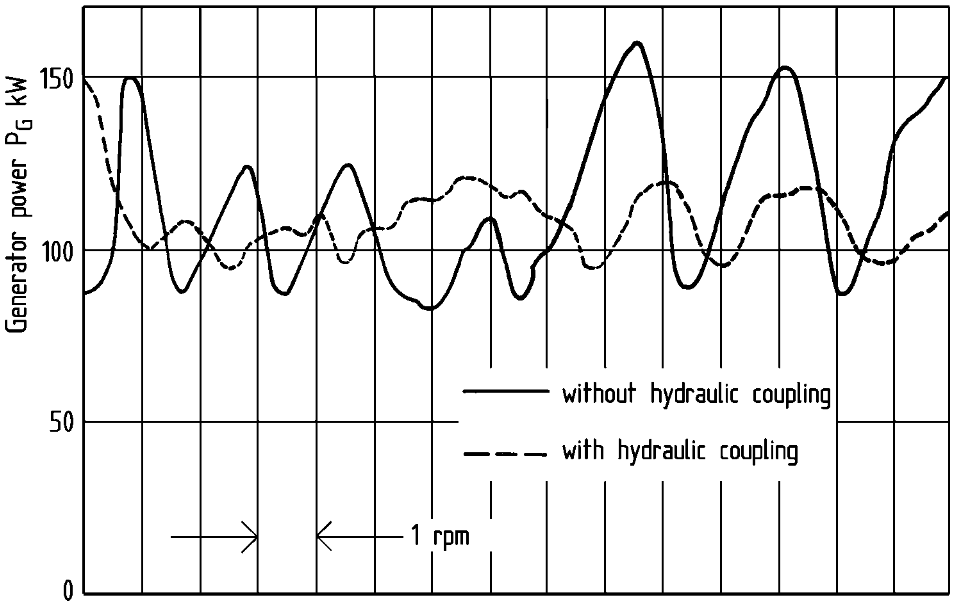

Figure 6.29. Smoothing of the power output due to the installation of an hydraulic coupling in the mechanical drive train of an MOD-0 [17]

Electrical slip of an induction generator

In wind turbines with induction generators, loading peaks can be smoothed out via the electrical slip of the generator (Fig. 6.30). However, large induction generators only have low slip values in their standard production models (Chapt. 9.1). It is only with a slip of at least 1 to 2 % that the dynamic load level is reduced perceptibly and, at the same time, unwanted drive train vibrations are avoided (Fig. 6.30).

Controlled variable-speed operation

True smoothing of the power captured by the rotor is only achieved by controlled variable-speed operation of the rotor. The generator can be operated in variable-speed mode if a frequency converter is connected (Chapt. 9.5). With this arrangement, the generator torque can be controlled to a constant value, independently of the speed, within a given speed range. The result is a complete smoothing out of the power transferred, and thus also of the loading, within the predetermined speed limits (Fig. 6.31).

This capability is, however, limited by the speed range implemented technically, so that larger fluctuations of wind speed cannot be compensated for. Effective smoothing of heavier wind gusts and their associated power and load peaks can only be achieved with the aid of blade pitch control. Rotor speed variability and blade pitch control should, therefore, always be considered together, as their effects complement each other. For this reason, nearly all recent turbines are equipped with both of these system features.

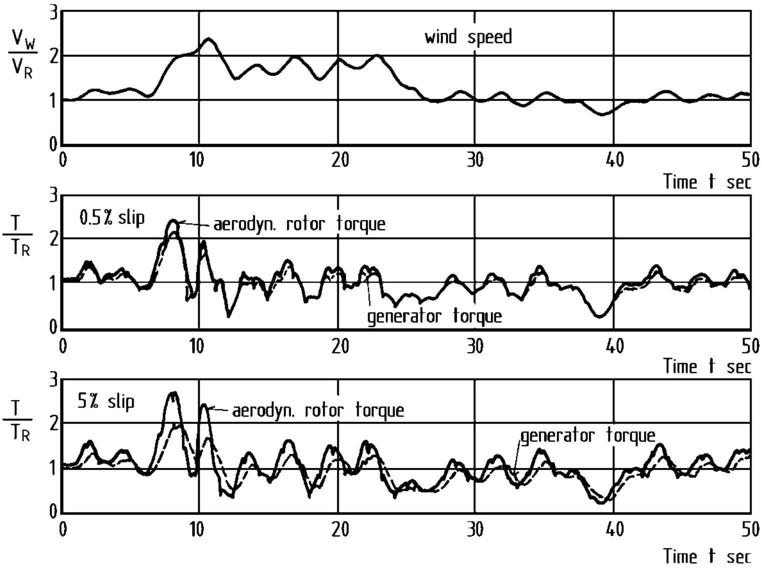

Figure 6.30. Smoothing of power and torque with an induction generator with a nominal slip of 0.5 and 5.5 % [18]

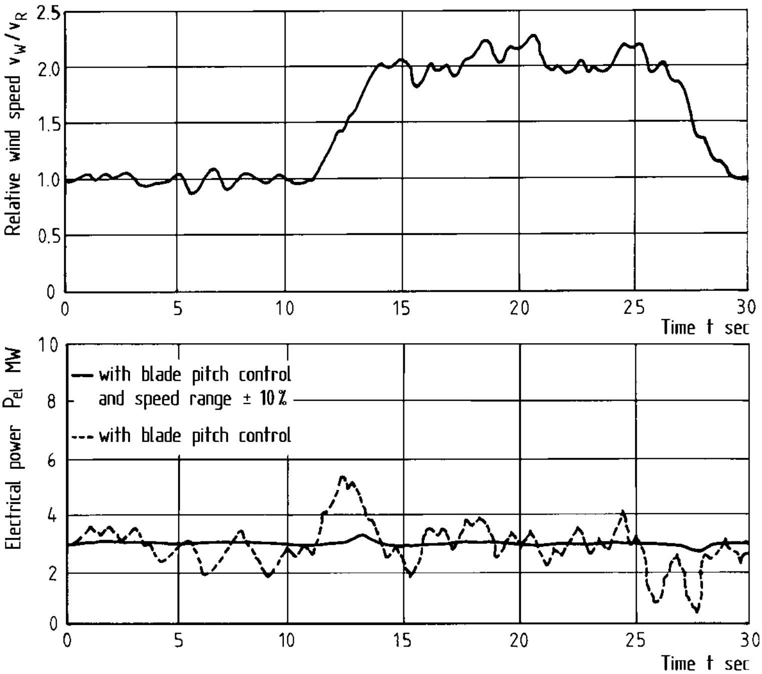

Figure 6.31. Control of the power output with a variable-speed synchronous generator with frequency converter, using the Growian turbine as an example

6.8 Test Data and Testing Facilities

In the introduction to this chapter it was already pointed out that the loads to which a wind turbine is subjected still represent an unexplored field in many respects. Although significant progress has been made in this field in recent years, a refinement of expertise, especially in the area of fatigue life prediction, is essential if the weights of the components, and thus and ultimately also the manufacturing costs, are to be reduced. Apart from the development of mathematical models, therefore, the measurement of stresses actually occurring occupies a predominant position in numerous research and development projects. Some of the former large experimental wind turbines had literally been designed as test-beds for the investigation of loads.

Naturally, the experimental load investigations also include measurements and tests which can be carried out on test stands for individual components. Tests carried out on test stands have the invaluable advantage of providing a correlation between set loads and the responses of the test objects under reproducible conditions. They are appropriate whenever unknown material properties, the interaction of different materials in a specific design, uncertainties concerning manufacturing techniques or even the verification of calculated results are to be investigated. The loads themselves must, however, be predetermined, i. e. the tests must be based on the assumption that the loads are correct.

6.8.1 Test-Bed Trials

Newly developed rotor blades have to be tested for their basic characteristics on test stands (Fig. 6.32). The static loading capacity of the blades is first verified experimentally and the precalculated stresses in the load-bearing structural elements are determined experimentally with the aid of strain gauges. The deflections measured are an additional criterion for checking the constructional design assumptions. Dynamic fatigue load spectra can only be simulated to a limited extent. The very high load cycle numbers in the lifetime of a wind turbine, combined with the associated amplitudes, can only be represented in elaborate long-term test programs. Only the critical elements of the design are, therefore, tested with a dynamic load spectrum, in the form of smaller test objects, for example the load-transferring elements between the rotor blade structure and the hub. This makes it possible to test the overall design for its fatigue life at least in critical sections. Another important task is the determination of the most important natural frequencies. On a test stand, where the cantilevered rotor blade is fixed at the root and is induced to vibrate, both natural frequencies and vibration modes can be measured with high precision. Although the natural frequencies determined under these conditions do not correspond exactly to the natural frequencies of the rotating rotor, the predicted stiffness parameters of the non-rotating blade can still be verified in this way.

Test-bed trials with other main components of a wind turbine are carried out with the gearbox and in some cases also with the assembled drive train including the electric generator. This requires a controlled electrical drive system, turning it into a large and complex testing facility.

Figure 6.32. Test rotor blade of the Growian turbine in a static load test

6.8.2
Data Acquisition Systems and Field Measurements

Inquiring into the loads and structural stresses actually existing is, of course, possible only on the wind turbine itself. The usual approach is to measure the deflections of the selected components by means of strain gauges and then to deduce the material stress values. However, to obtain a complete overview of the entire load spectrum requires arduous, long-term measurement campaigns the results of which only become meaningful after a large amount of data has been statistically processed.

Analysing the results in detail can be very difficult. Correlating the results with the causes of the loads can only be carried out to a limited extent, as the structural deformations only reflect the sum of all loads. To isolate aerodynamic loads, for example, is extraordinarily difficult. Similar problems are presented when particular load states are to be correlated with the events triggering them, for example individual gusts.

One of the first systematic measuring programmes was carried out by NASA in the years 1977 to 1979 during a Swedish-American test programme using the earlier Danish wind turbine at Gedser [19]. From 1976 to 1986 comprehensive measurements were taken out in the American wind energy program with the experimental MOD-0 [20]. This was followed by the publication of measurements made on the large experimental MOD-1, MOD-2, WTS-4 turbines. One of the results is shown in Fig. 6.33. The measured cyclic

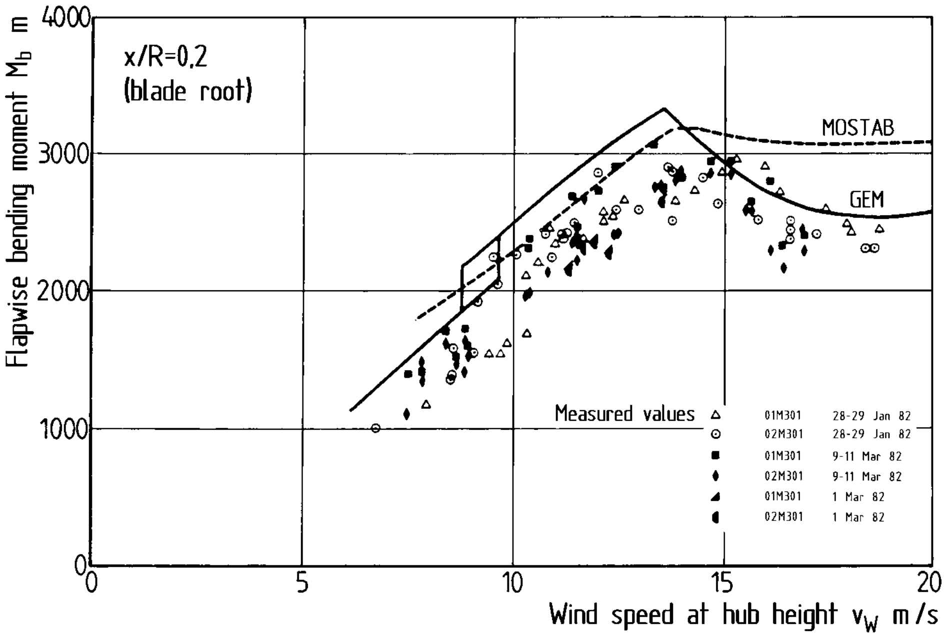

Figure 6.33. Calculated and measured bending moments of the rotor blade of a MOD-2 [21]

dynamic loads on the rotor blades of the MOD-2 correlate relatively well in the statistical mean with the values predicted by the computer programs MOSTAB and GEM. Obtaining such measurement data and the associated refinement of the computer programs are decisive prerequisites for the reliable structural dimensioning of progressive lightweight design concepts.

Some comments must be made regarding data acquisition and evaluation in connection with load measurements taken at wind turbines. As test objects, all newly developed prototypes are equipped with elaborate measuring and data acquisition systems. In the period of test operation, setting up and operating this measuring equipment takes up a large part of the development work. This applies both to assembling the hardware and to developing the software for data editing and evaluation. Figure 6.34 shows the basic set-up of a data acquisition and evaluation system used for an early prototype of the Enercon E-40 wind turbine.

Using various transducers such as strain gauges, accelerometers, force and displacement sensors, anemometers or instruments for measuring electric parameters, the data acquisition system can record approximately 200 test points. The measurement signals are amplified and sampled at a predetermined rate by a multiplexer. The analogue signals are then digitised and subsequently converted into a serial data stream by using PCM (pulse code modulation). PCM technology is generally required so that the data arriving in parallel from a large number of measuring points can be transferred using only one signal line.

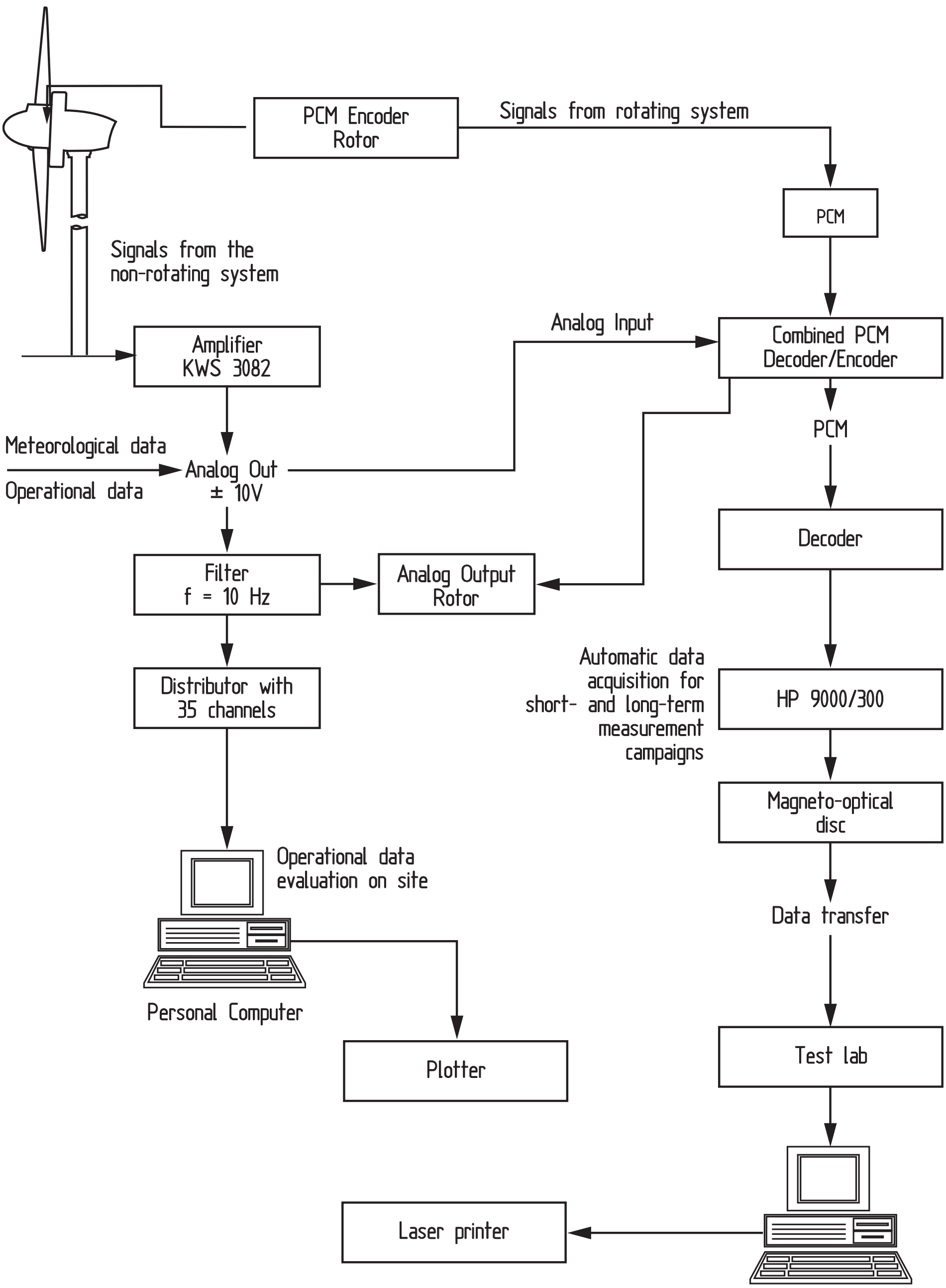

Figure 6.34. Data acquisition system of an Enercon E-40 prototype

The time-consuming statistical processing of the load data acquired requires extensive computer programs. A numerical method known as the "rainflow method" has proved to be especially helpful for this purpose [12].

An important point must also be raised with regard to the design of the data recording and processing system. If possible, this system, used only for test purposes, should be completely independent of the data processing system of the operational control system of the wind turbine. A functional link would give cause for grave concern for safety reasons.

6.9 Standards and Certification of Wind Turbines

When the large experimental wind turbines were built in the early eighties, the first attempts were also made to develop systems of rules and regulations for the load assumptions of wind turbines.

In the Federal Republic of Germany, comprehensive load cases were defined in connection with the development of the experimental Growian and WKA-60 wind turbines [9]. Similar attempts were also made during the Swedish wind energy programme.

In later years, a systematic collection of load cases and the specifications of details were developed further by Germanischer Lloyd in collaboration with technical and scientific institutions and the manufacturing companies [10].

At the same time, national standards were published in the Netherlands (NEN 6069) in 1988 and in Denmark (DS 472) in 1992. The initial rules were subsequently developed and refined as knowledge increased. In addition, efforts at harmonising the national standards were undertaken in the EU [22].

In 1998, the International Electrotechnical Commission (IEC) began work on the first international standard and published IEC 61400-1 "Wind Turbine Generator Systems — Part I, Safety Requirements" in 1999.

6.9.1 Important International and National Design Standards

At present, both national standards and the international IEC standard are still of importance when designing wind turbines. However, the manufacturers and the licensing authorities increasingly refer to the IEC standard in their decision making.

IEC 61400-1

In the IEC 61400-1 standard "*Wind Turbine Generator Systems — Part I, Safety Requirements*" issued by the International Electrotechnical Commission, the aforementioned classes for the design of wind turbines are defined. The system of load cases and load assumptions largely corresponds to the rules laid down by the Germanische Lloyd, but with some differences which must be taken into account. Thus, for example, the intensity of turbulence is specified slightly differently in the load assumptions. Whereas the GL rules quote this generally as 20 % at hub height, the IEC standard requires design values of 15–18 % in accordance with two different categories. For the rest, IEC 61400-1 contains rules and recommendations not only for the structural strength but also for the construction of the control and safety systems, the electrical equipment and the erection and operation of wind turbines.

Rules for Certification by Germanischer Lloyd

Since 1993, the rules *Regulation for the Certification of Wind Energy Conversion Systems,* issued by Germanischer Lloyd as national standard for Germany, have been expanded and refined time and again in several issues (1994 and 1998). The selection of load cases is greater than in the IEC rules and the individual regulations relating to calculation methods and the requirements for certain components are described more extensively. As mentioned above, the intensity of turbulence is specified differently in the load assumptions. The rules of the Germanische Lloyd are much more detailed from the special aspect of the certification of wind turbines — a major field of activity of the GL.

Danish Standard DS 472

The wind speed classes are defined slightly differently according to the Danish rules. These specify terrain types with different assumptions for the increase in wind speed with height, whereas the assumption for the mean wind speed is the same in the Danish standard. The load case definitions are identical, in principle, but fewer load cases are used. As a special feature, DS 472 contains simplified load cases for stall-controlled turbines with rotor diameters of up to 25 meters.

Dutch Standard NVN 1400-0

In the Netherlands, the first step towards creating a national Dutch standard was undertaken in 1994, when the NEN 6096/2 standard *Regulations for the Type Certification of Wind Turbines* was issued. In the meantime, this system of rules and regulations has been replaced by the expanded and revised standard NVN 1400-0. This standard has been largely harmonised with the IEC 61400-1 standard. The only remaining differences exist in the specification of the safety factors to be applied, in the characteristics of materials and in the process of certification, also in comparison with the German and Danish standards.

6.9.2
Certification of Wind Turbines

As with any other technically complex product, the buyer or operator of a wind turbine is not really able to assess the quality and safety of a wind turbine by himself. It is of even greater importance that the operation of wind turbines is associated with certain risks for the immediate environment so that it is a matter of public interest to have the product examined by neutral experts with respect to its conformity to safety standards.

Against this background, a comprehensive examination system has been developed for wind turbines which is reflected in the various test certificates. All areas, from the environmental conditions to the load assumptions, the design and the surveying of wind turbine installations, are the subject of certifications. The most important certification, which is the prerequisite for being granted a building permit in all countries, relates to the verification of functional reliability and structural strength of newly developed turbines. This check results in the so-called *type approval*. Presenting the type approval makes it easier to obtain a building permit and is a natural requirement for commercial wind turbines. In special cases, the building permit can also be granted on the basis of an *individual test* (Chapt. 18.2)

In Germany, the type approval currently only relates to the safety-related aspects of the "mechanical engineering" part of the turbine. The "structural engineering" part (tower and foundation) is tested separately in accordance with the applicable standards of the building trade. The performance features of the turbine and especially the power characteristic are not subject to type approval and are additionally certified on request by the manufacturer. The buyer should be aware of this fact and it is in his interest to demand the certificate for the power characteristic. In other countries, different regulations apply to the contents of the type approval and of other certificates.

In the different countries numerous regulations containing specifications for other technical installations are available, which were reinterpreted for wind turbines. Wind turbine manufacturers are primarily interested in the verification of load assumptions in order to be able to guarantee the stability and reliability of their products. The operator is interested in obtaining independent information on whether the product is congruent with his concept of operational safety, performance and operating life. These various interests do by no means focus on the same points and must therefore be harmonised.

The most important European organisations dealing with the certification of wind turbines are:

- Germanischer Lloyd (GL), Germany
- Det Norske Veritas, International
- Netherlands Energy Research Foundation (ECN), The Netherlands
- Risø National Laboratory, Denmark

Apart from the certificates for the type approval and the power characteristic, other certifications are being offered for numerous other areas such as:

- Quality of the power output,
- Electrical characteristics and grid compatibility,
- Production,
- Quality assurance,
- Test methods, et al.

At this point, some critical remarks with regard to the examination and certification of wind turbines are appropriate. It is an undisputed fact that the independent examination of the efficiency and environmental impact of wind turbines represent a significant progress in wind power utilisation. In central areas, particularly relating to safety (public interest) and to performance (buyer's interest), independent and neutral certificates are indispensable.

On the other hand, certification has now developed into a "business". The certification companies are often profit-oriented commercial companies which offer their services in a competitive market and, therefore, attempt to extend their products to all types of areas in which it is more than doubtful whether a "certificate" for, e. g. "production" or "transport" has any objective use. The situation has not been improved by the circumstance that the organisations have for some years been advertising so-called "accreditation certificates" which, in turn, are issued by private commercial organisations.

As ever, the decisive criterion for the quality of a product is the technical competence and financial capacity of its manufacturer. It is the manufacturer exclusively who has a position to lose in the market and who bears responsibility for his warranty. If something goes wrong, it is the manufacturer and his customer who are the financial losers, and never the certification companies. However high-sounding a certificate is, it will never replace confidence in the manufacturer and his product.

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Chapter 7

Rotor Blades

Structurally, the rotor of a wind turbine consists of a number of subsystems. Based on the definition that the rotor comprises all rotating parts of the unit outside the nacelle, these subsystems are the rotor blades, the hub, and the blade pitch mechanism, all three of which are largely autonomous components with regard to their design, their operation and the manufacturing techniques used.

The rotor hub and the blade pitch mechanism represent traditional mechanical engineering. From a technological point of view and with regard to their operation, they are closely associated with the mechanical drive train. Depending on the design, the blade pitch system and its control system are only partly rotor components. Parts of this system are almost always located in the nacelle. In any case, the "blade pitch mechanism" assembly represents the transition from the rotor to the wind turbine's mechanical drive train. Rotor hub and blade pitch mechanism are, therefore, dealt with in the context of the mechanical drive train.

Rotor blade technology is associated more with lightweight aeronautical engineering than with conventional mechanical engineering. In contrast to all other components of the wind turbine, which can be largely adopted or at least derived from other fields of mechanical engineering, the rotor blades must be developed from scratch. Design problems are similar to the tasks faced by aircraft engineering. The load spectrum to be applied with respect to fatigue strength, and the mathematical methods for the dimensioning of the structure, which is highly stressed dynamically, are both similar. The very tough load spectrum to which the rotor blades are subjected is one of the main reasons for the prominence given to this component in the design of the turbine. The bending moment due to the gravity load already results in up to 10^8 load cycle alternations within the lifetime of a turbine. In addition, there are the stochastic alternating loads caused by wind turbulence and the effects of ageing of the material due to the weather. The problems associated with durability of the rotor are thus far more difficult to solve than in any other component.

What is true of development problems does not necessarily apply to manufacturing, however. In this respect, borrowing from aircraft engineering is only possible to a limited extent because of the much narrower cost margin which prohibits the application of traditional aircraft manufacturing methods. The production technology is therefore frequently adopted from other fields. The transfer of technology primarily comes from modern boat building, where fibre glass composite materials or, for some time now, wood composites are used. The rotor blades of the older Danish wind turbines were almost always manufactured by former boat builders.

The search for designs which were suitable for very large rotor blades posed a special problem in the past. In countries in which the first large experimental turbines were developed specific technology programs for the development of large rotor blades had been established. The NASA MOD-0 test turbine in the USA, for example, was used for testing a large number of different rotor blades from various manufacturers. It can nowadays be said that some designs, for example those using steel or aluminium, were merely temporary solutions for the test turbines then used. Today's designs are determined by the use of composite fibre materials.

The rotor blades of the commercial wind turbines are supplied by specialised manufacturing companies, on the one hand, so that small wind turbine manufacturers are able to purchase well-tried rotor blades as vendor parts. On the other hand, the large, leading manufacturers of wind turbine units are increasingly developing and producing their own systems. The rotor blades are considered to be the key component for the further technical development of the entire wind turbine system.

Even though the rotor blades of present-day wind turbines are made almost exclusively of fibre composites and their type of construction is thus largely predetermined, the fundamental relationships and experience gained from the implementation of other designs will be discussed in the following sections. This experience with other types of construction may well prove to be useful in building the wind turbines of the future, where rotor diameters of 120 m and more are contemplated.

7.1 Materials

In the past, the starting point for the consideration of rotor blade design was the question as to which material is most suitable. Design and manufacturing methods are determined to a large extent by the properties of the material used. Conversely, the design also places certain constraints on the materials to be used and thus sets criteria for the selection of materials. In other words, the selection of material, the principle of the conceptual design and the production method cannot be considered independently of each other in a real situation. It nevertheless makes sense to initially analyse the available materials with respect to their suitability for wind rotor blades. Judging from experience gained in aircraft engineering, the following materials are considered as suitable in principle:

- aluminium,
- titanium,
- steel,
- fibre composite material (glass, carbon and aramide fibres),
- wood.

The most important material properties by which a first assessment can be made are:

- specific weight (g/cm^3)

- strength limit (N/mm²)
- modulus of elasticity (kN/m²)
- breaking strength related to the specific weight, the so-called breaking length (km)
- modulus of elasticity related to the specific weight, (10^3 km)
- allowable fatigue strength after 10^7 to 10^8 load cycles (N/mm²).

Cost of the material, manufacturing cost and the cost of the development involved are also significant. Of course, the last two items cannot be judged solely from the material point-of-view but must be seen in relation to the selected design concept. Table 7.1 provides an overview of the parameters listed above.

The traditional aircraft material aluminium does have suitable material properties, but the production techniques commonly used in aircraft engineering are too expensive. Aluminium, therefore, can only be considered if the rotor blades can be assembled from machine-made semi-finished parts. Titanium is ruled out as a material for reasons of cost. Its

Table 7.1. Strength and stiffness parameters of materials in principle available for rotor blades

Parameter / Material	Spec. weight γ g/cm³	Strength limit σ_B N/mm²	Modulus of elasticity E kN/mm²	Spec. breaking strength σ_B/γ km	Spec. modulus of elasticity E/γ 10^3 km	Fatigue strength $\pm\sigma_A$ 10^7 N/mm²
Steel St 52	7.85	520	210	6.6	2.7	60
Alloyed steel 1.7735.4	7.85	680	210	8.7	2.7	70
Aluminium AlZnMgCu	2.7	480	70	18	2.6	40
Aluminium AlMg5 (weldable)	2.7	236	70	8.7	2.6	20
Titanium alloy 3.7164.1	4.5	900	110	20	2.4	—
Fibre glass/epoxy* composite	1.7	420	15	24.7	0.9	35
Carbon fibre/ epoxy* composite	1.4	550	44	39	3.1	100
Aramide fibre/ epoxy* composite	1.25	450	24	36	1.9	—
Wood (Sitka Spruce)	0.38	appr. 65	appr. 8	appr. 17	appr. 2.1	appr. 20
Wood/epoxy*	0.58	appr. 75	appr. 11	appr. 13	appr. 1.9	appr. 35

*EP-matrix 40 vol.%

price as well the processing costs are prohibitively high. Carbon fibre is still very expensive, but its processing can be made very cost-effective if a suitable manufacturing method is used. In addition, the advantageous mass ratios achieved by the high-strength carbon fibres should be taken into consideration. Carbon fibre-reinforced composite material can, therefore, be regarded as a material with a promising future. Currently, carbon fibre is used only as an additional fibre to glass fibre in larger rotor blades.

Titanium and high-alloy steels are ruled out for reasons of cost. The selection is focused on aluminium, steel, glass fibre reinforced compound material (GFRP), mixed glass/carbon fibre designs and more recently also on wood/epoxy compound designs.

7.2 Aircraft Wings as Model

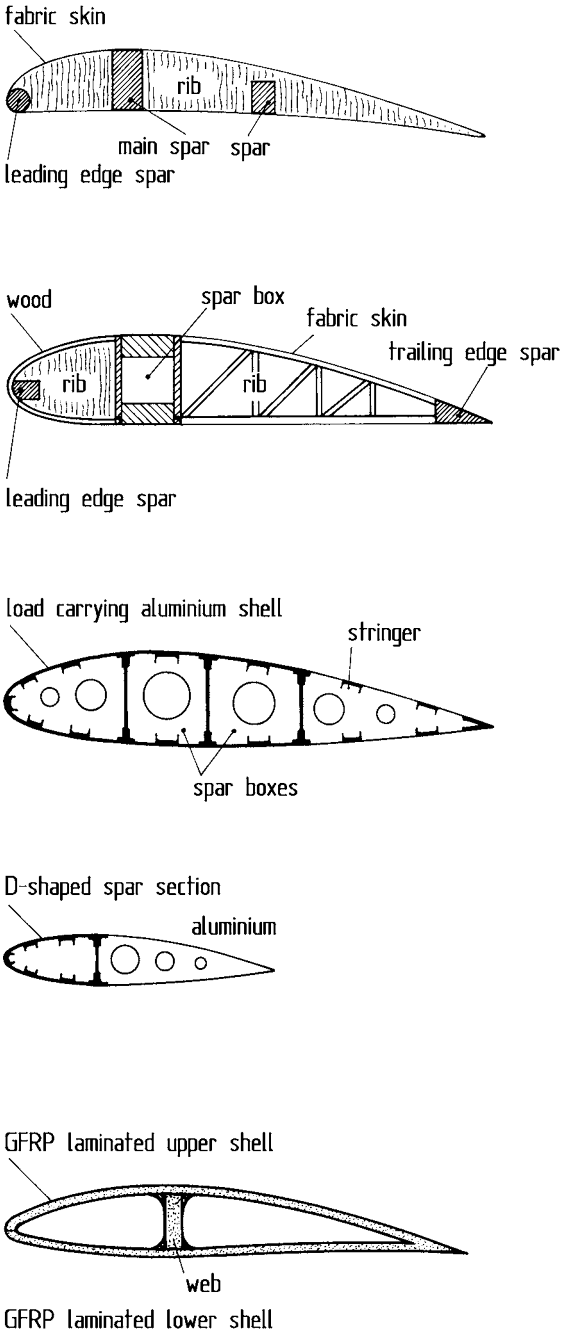
Regardless of the differences with respect to the economics of wind energy technology, the design of rotor blades has been borrowed almost without exception from aircraft technology. Even though weight does not play such an important role as in aeronautics, there are many reasons speaking for a light-weight construction similar to an aircraft wing. The geometric dimensions of a large turbine's rotor blades alone cannot be implemented in any way other than by applying the principles of light-weight design. The basic design patterns can best be exemplified by tracing the historical development of the aircraft wing.

Disregarding the first "flying machines", the design of which was often extremely confused and can hardly be grasped today, one finds that by about 1915 things had been clarified to such an extent that systematic design principles became recognisable (Fig. 7.2). The prevailing materials used were wood and lattice trusses made of steel pipes covered with fabric. The wing had supporting elements in the spanwise direction, the "spars", and cross bracings, the "ribs", which made up the airfoil. The covering fabric had no load-bearing function initially. Stability was provided by all kinds of struts and bracing cables.

In the course of the continuing development of aerodynamics, cantilever wings became necessary. It was realised that the inadequate torsional stability could be improved considerably by closed box structures. Firstly, the front part of the cross-section was shaped into a torsionally rigid nose box. The initially simple, beam-like main spar was refined into a box-like structure with top and bottom flange for absorbing tensile and compressive forces, and with vertical webs for absorbing transverse forces. The rear part of the cross-section remained fabric-covered. The ribs became lattice structures. These design elements can be found in small aircraft to the present day.

From around 1930 onwards, duraluminium became the prevailing material for large aircraft. The design underwent radical changes. The external skin, which was now of metal, was integrated into the load-bearing concept. The function of the spars was increasingly taken over by one- or multi-cell spar boxes, the top and bottom flanges of which were fused with the external skin. Only the spar webs remained as such. The riveted aluminium stressed-skin design prevails to this day in large aircraft.

The design configuration of the load-bearing elements is determined by several factors. The height should be as high as possible, in order to absorb the bending moment, hence the endeavour to position the spar boxes in the section having the greatest airfoil thickness.



Wood construction with fabric covering until about 1915

Wood construction (partly also steel tubing); box spar and torsionally rigid nose, until about 1940 in light aircraft

Riveted, stressed-skin construction of aluminium,
from about 1930 till today in large and light aircraft

D-spar construction in rotor blades of helicopters,
from about 1947

Stressed-skin sandwich construction of composite fibre glass and carbon fibre material in modern gliders and light aircraft from about 1960

Figure 7.2. Historical development of wing designs for aircraft

Torsional stiffness increases with the box area enclosed which is why the spar boxes were extended in the direction of the wing depth.

After the aspects of strength, the significance of aeroelastic stability was recognised (Chapt. 11.1). The farther the centre of mass of the cross-section is moved back, the more critical the flutter characteristics will become, particularly in comparatively elastic airfoils or rotor blades. This hazard is designed to be countered by a spar box, called a D-spar because of its shape, which only comprises the nose area. In this design, the centre of mass is shifted as far as possible to the front. The highly elastic rotor blades of helicopters are usually designed with a D-spar box.

The development of fibre-reinforced composite materials has been setting new impulses in aircraft engineering in the past decades. It was glider design engineers, above all others, who, for aerodynamic reasons, insisted on the highest quality surfaces and airfoil accuracy, who adopted these new materials. Moreover, the technique of laminating offered the possibility of manufacturing even without costly machinery. Fibre glass and increasingly carbon-fibre reinforced sandwich designs are state-of-the-art technologies in glider engineering today and the new materials are currently also making their entry into the load-bearing "primary structures" in the construction of large commercial aircraft.

The course of development and the associated design principles described by no means cover the entire spectrum of variations. In the thirties, i.e. at the beginning of modern aircraft engineering, a variety of the most varied design concepts existed. Some readers may recall the corrugated sheet-metal design of the legendary Junkers Ju 52 or the tubular-spar design of the Blohm + Voss flying boats.

The design concepts of aircraft wings are not necessarily the valid model for very small rotor blades of only a few meters length. For this size, semi-finished airfoil parts of aluminium or solid wooden materials, patterned after aircraft propellers, can be used. The blades of Darrieus rotors, for example, which have a comparatively shallow blade depth up to a power range of 100 or 200 kW, are frequently made from extruded aluminium airfoil sections.

Moreover, rotor blades based on historical windmill models can be found in slowly rotating small wind wheels such as those used for driving water pumps. Fabric-covered ribs as well as blades made entirely of wood or sheet metal are still in use for these purposes. Designs of this type are often suggested with reference to their application and to the production facilities available in developing countries of the Third World.

Apart from these examples, the construction of the rotor blades of large modern wind turbines is derived without exception from the fibre glass reinforced composites developed in the construction of aircraft, and the manufacturing techniques were often borrowed from boat-building.

7.3
Experimental Designs of Rotor Blades in the Past

In the development and testing of the first large wind turbines, the search for a suitable rotor blade design presented a central problem. Many materials and designs were tried out. Although these experimental designs were not successful, it is useful to have a look at these technical solutions. It is frequently the case that an understanding of the present-day solutions is only reached if the errors — or better the disadvantages — of the "wrong turns" taken in the past are understood.

7.3.1
Riveted Aluminium Designs

Duralumium, used in aircraft construction, is a high-strength material with which a weight advantage of approximately 30 % can be achieved against comparably loaded steel designs (Fig. 7.3). The good fatigue-strength values and resistance to corrosion are of advantage. For light-weight stressed-skin designs made of duralumium, the buckling strength of the skin panels is the dimensioning criterion, as a rule. Its decisive disadvantage lies in costly production. Duralumium sheets and stringers are practically unweldable and must, therefore, be riveted. In aircraft design, where weight is the factor which dominates everything, this labour-intensive production method is tolerated, but it is considered too expensive for the rotor blades of wind turbines. Nevertheless, rotor blades made of duralumium, fashioned exactly as in aircraft engineering, did get tested in a few test turbines (Fig. 7.4).

A possible alternative to using duraluminium would be a design with less strong but weldable aluminium, for example AlMg5. However, there would no longer be a weight advantage compared with steel, due to its much lower fatigue strength. Moreover, the shielded arc welding of aluminium sheets is labour-intensive. Altogether, aluminium rotor blades do not seem particularly promising at the present. This could change if rotor blades were

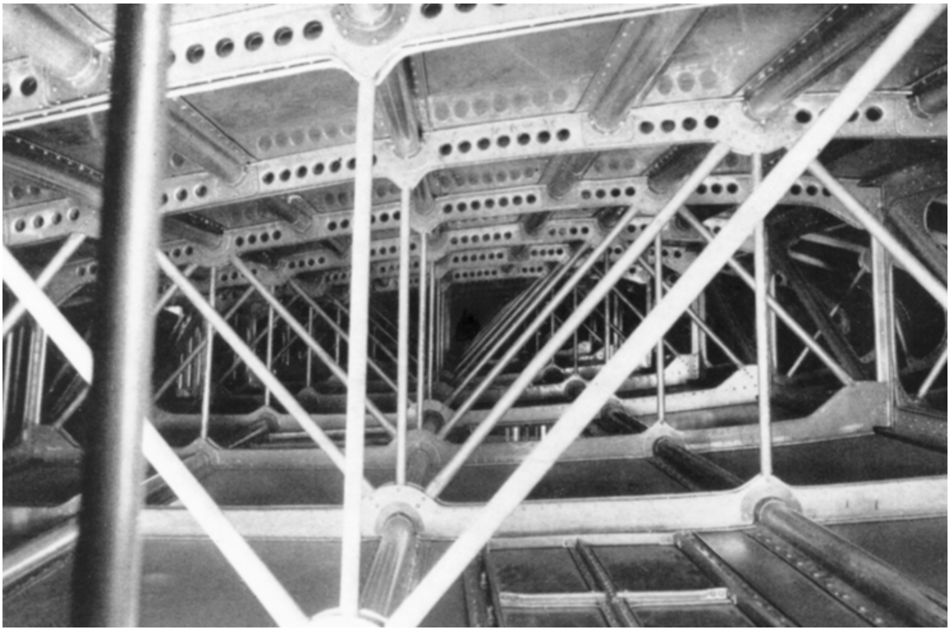


Figure 7.3. Aircraft wing in riveted duraluminium design (Dornier)

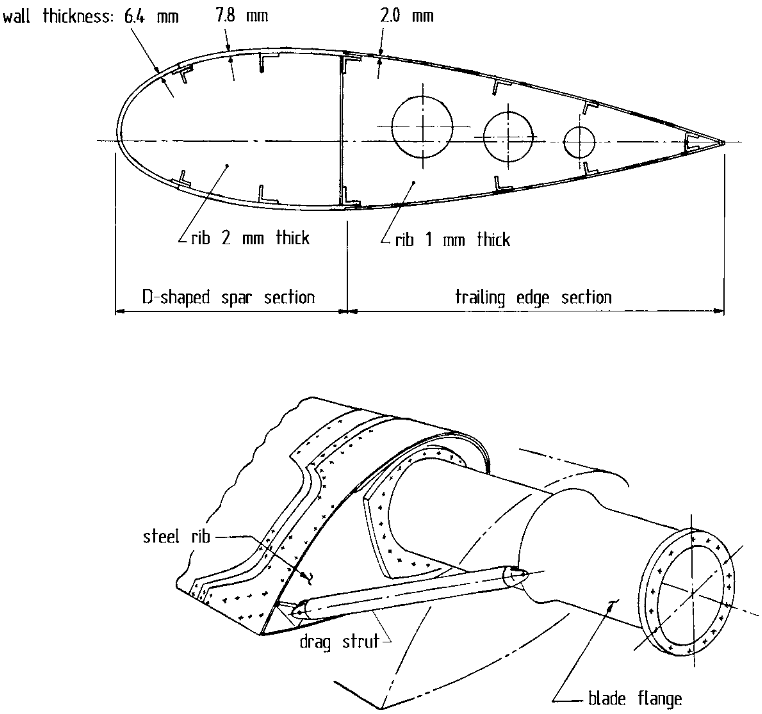


Figure 7.4. Rotor blade design with riveted duraluminium in the American MOD-0 test turbine [1]

to be produced in very large quantities and the use of elaborate production machinery permitting economical mass production were to become viable.

In contrast to the blades of horizontal-axis rotors, the blades of previous vertical-axis rotors following the Darrieus design were preferably made of aluminium. The blades of the Darrieus rotors are comparatively complex due to their geometry. With equal rotor-swept area, their overall length is greater than that of horizontal-axis rotors, and production of the curved shape is difficult. Mechanised production of the blades is almost mandatory in order to keep production costs down. As long as blade depth is not too great, the blades can be extruded from pre-fabricated aluminium sections in a single operation. Darrieus rotor blades made of extruded aluminium could, therefore, be found in most of the Darrieus turbines made in the eighties (Fig. 7.5).

7.3.2 Steel Designs

Steel was the prevailing rotor blade material in the large test turbines built in the early eighties. This includes the rotor blades of the German Growian turbine, the American MOD-2 turbine and the Swedish WTS-75 turbine. Steel has extraordinarily high stiffness values, whereas its breaking length has a comparatively low value. At 10^7 to 10^8 load cycles,

Figure 7.5. Rotor blades made of extruded aluminium profiles of the Flowind-Darrieus rotors (Alcoa)

the range of allowable fatigue-strength values is of the order of 50 to 60 N/mm². Fatigue strength thus becomes the dimensioning factor for steel designs.

The relatively low price of the material, as long as conventional non-alloyed steel was used, the comparatively low production costs with conventional welding techniques and the well-known material properties all spoke for steel. The development risks with regard to production were predictable. However, the deformability of steel remains a problem as far as production is concerned. Steel sheets for wall thicknesses of up to 20 mm can only with great difficulty be formed into the twisted shape of the rotor blades with their required aerodynamic airfoil cross-sections. The choice is between making unavoidable cuts in the requirements for the desired airfoil accuracy and surface quality or making corresponding compromises in the selection of airfoil and degree of twist. Regardless of these problems, the rotor of the American MOD-2 turbine was produced in all-steel monocoque (stressed-skin) construction (Fig. 7.6).

This heavy two-bladed rotor, weighing approximately 58 metric tonnes, consisted of three parts, the continuous centre-section of the hub, the interior blade sections and the pitchable outer blade tips. The cross-section design largely corresponds to the D-spar design with an additional web in the rear cross-section area (Fig. 7.7).

Steel-spar designs, where only the load-bearing spar is made of steel, were a variant of this type of construction. Although, strictly speaking, a design integrating steel and fibreglass composite material is a "mixed construction", the load concentration on the steel spar justifies its classification as a steel design. The rotor blades of the Swedish WTS-75

Figure 7.6. All-steel rotor of the experimental American MOD-2 turbine

turbine (Aeolus I) were a good example of such a type of design. They had a steel spar divided into two in its horizontal cross-section, the upper and lower shell of which were bolted together. The spar box took up approximately 70 % of the blade depth. The highly curved nose area and the rear area, which was not subjected to much loading, consisted of glass-fibre shells (Fig. 7.8).

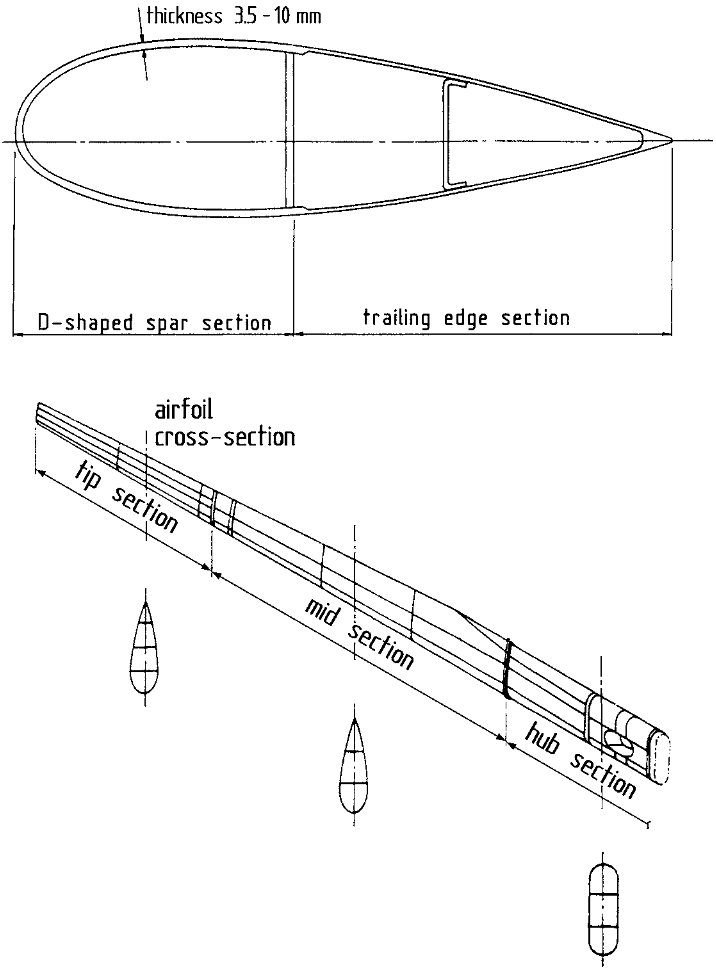


Figure 7.7. Rotor blade construction of the MOD-2 [2]

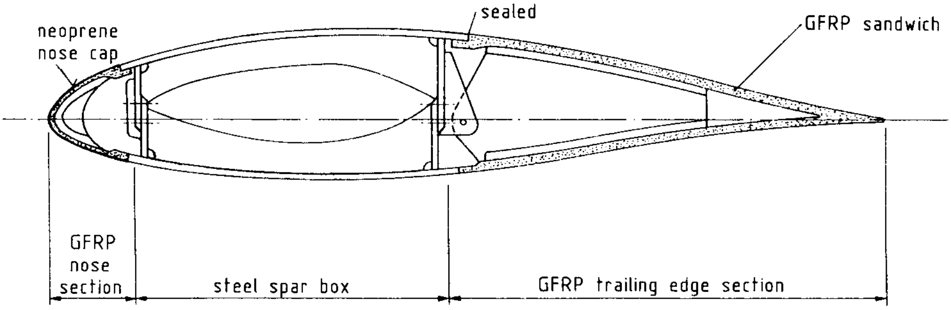


Figure 7.8. Rotor blade of the experimental WTS-75 turbine [3]

The rotor blades of the German Growian turbine were also an example of steel-spar design. The steel spar was positioned here on the inside of the airfoil cross-section (Fig. 7.9). The cross-section of the spar box varied from a circular shape at the blade root up to an increasingly flat hexagonal cross-section. The external skin of the blades making up the airfoil consisted of fibre-glass sandwiches of approximately 16 to 18 mm thickness. The fibres, in layers crossing over each other, were oriented so that the elongation properties of the external skin were compatible with the deformations of the steel spar. The rear area was stiffened by half-ribs of fibre-glass.

Despite its conventional material, the development and production of steel rotor blades posed several problems. Guaranteeing proper welding quality is in no way unproblematic considering the extreme load alternations. Allowable strength values must primarily refer to the strength limits of the welding seams. There were no binding standards standards specified for wind turbines. The Growian design was based on the slightly modified DIN standard 15 018. American manufacturers in some cases adhered to the AICE code. In Europe, the DIN standards have been reissued as the so-called "Eurocode" some time ago. In view of the high numbers of load alternations of up to 10^8, the permissible stress values have now been lowered distinctly compared with the older standards [4].

Another problem with steel is posed by corrosion. It is particularly the areas of the spar or rotor blade interior which are no longer accessible which are especially problematic in this respect. The corrosion leads to the formation of cracks which is particularly critical in steel. Continual checks are indispensable, as an undiscovered fatigue crack in the rotor blade can have devastating consequences not only for the wind turbine. In Growian, the critical

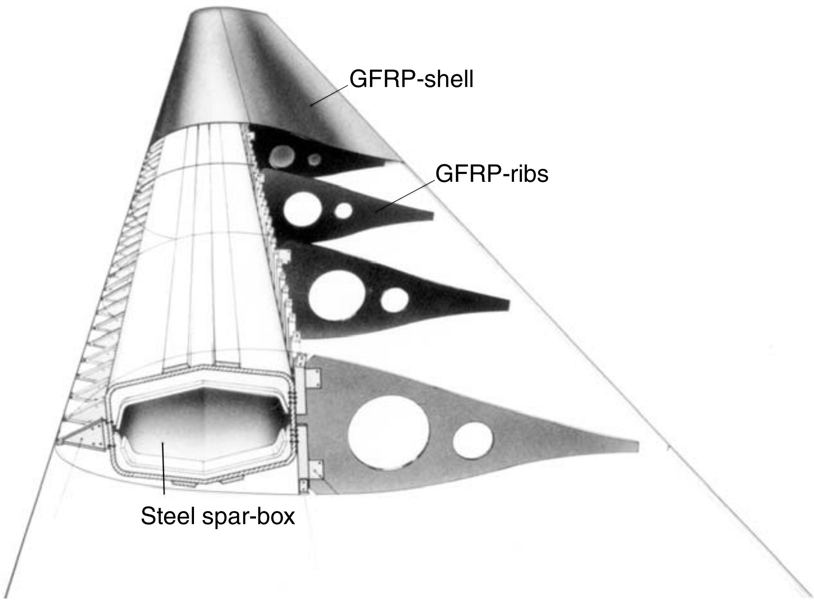


Figure 7.9. Rotor blade design of the German Growian experimental turbine

inside area of the spar could be checked in parts, as the rotor-blade spar was accessible over almost half of its length. Some other steel spars were provided with special crack warning arrangements. For this, the spar box or tubular spar was lightly pressurised with gas. A drop in pressure or a change in flow velocity indicated the presence of a crack.

From the present-day point of view, steel is no longer a realistic alternative as material for the rotor blades of wind turbines. The heavy weight alone is clearly against it. Using steel was more of a temporary solution for the first large experimental turbines.

7.3.3 Traditional Wood Construction

Although wood has a tradition of centuries as a material in the construction of windmills, its use in modern wind energy technology was considered to be more of a retrograde step. Nevertheless, there were some attempts of making rotor blades of wood. Solid wood construction as found in aircraft propellers can still be found today on small windwheels with a diameter of only a few metres. Moreover, the natural wood material is almost unbeatable with respect to fatigue strength. This fact was very well known to the old builders of windmills but had been largely forgotten today.

In Denmark, the experimental turbine Nibe-B was equipped with wooden rotor blades in 1980 (Fig. 7.10). The design derived from traditional wood constructions. The experience gained with these was not too bad after a trial run which, however, was only short [5].

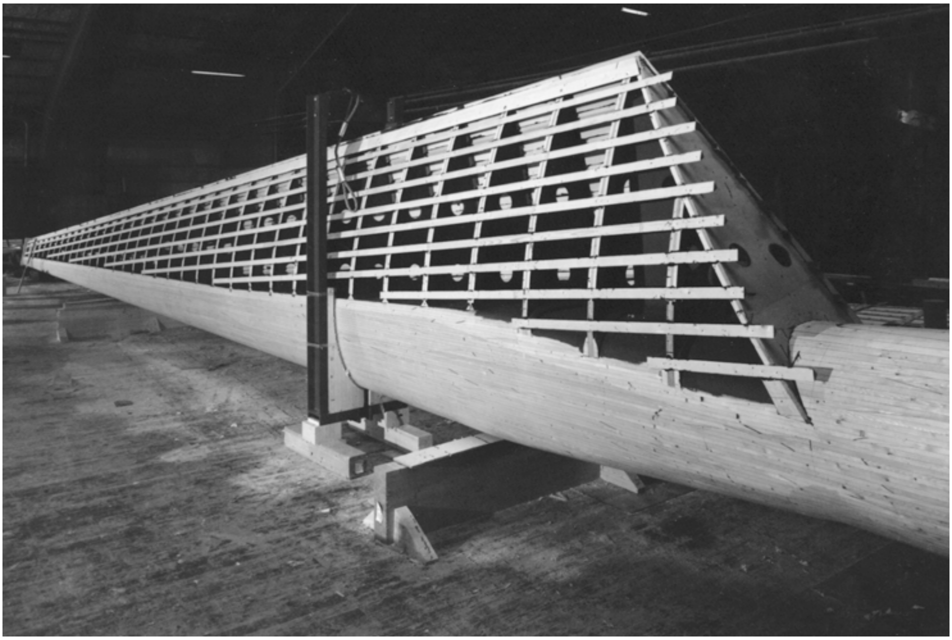


Figure 7.10. Rotor blade of the Nibe-B turbine in traditional wood design [5]

Nevertheless, the development was not pursued further. Problems were seen in, among other things, the durability of wood with regard to rot and the associated, necessary maintenance and, apart from that, wood composites appeared to be the better alternative (see Chapter 7.6).

7.4 Modern Fibre-Reinforced Composite Blades

Components of fibre-reinforced composites have been widely used for a number of decades. It was thus an obvious step, even at the beginning of modern wind energy technology, to use this material also for the construction of rotor blades.

The basic concept of fibre-reinforced composites consists in reinforcing the well-known synthetic resins by embedding fibres in them which have better strength properties than the basic material, so that these "cheap plastics" also meet more stringent demands. The historic development of this material technology and the associated designs and production methods took two different paths.

At the end of the 50's, high quality fibre-reinforced composites were developed in aviation and later also in aerospace engineering and in vehicle construction. This development was driven especially by the demand by the aerospace industry for light-weight materials with high strength, which was vital for their existence regardless of costs. Today, these industries are inconceivable without these materials.

The usefulness of these new materials was also discovered in other fields of technology. It was mainly the possibility of being able to produce dimensionally stable components in almost any shapes without expensive tools and devices which was considered to be a great advantage compared with traditional wood or metal designs. Maximum strength characteristics and low weight played less of a role than the low costs of manufacturing. Given these prerequisites, fibre-reinforced materials became successful mainly in the construction of boats and for manufacturing all possible types of containers.

The development of rotor blades for wind turbines in fibre-reinforced composites linked up with both paths of development. On the one hand, the requirements for strength and stiffness were as high as in aviation and, on the other hand, weight did not play such a predominant role so that the advantages of cheap materials and manufacturing processes could also be adopted from boat-building.

7.4.1 Fibre-Reinforced Composite Materials and Manufacturing Techniques

Fibre-reinforced composites differ, on the one hand, with regard to the type of fibre material used which is essentially responsible for the strength and the stiffness properties of the composite material. On the other hand, various resins are used as bonding material, the so-called *matrix*. It is the properties of the matrix material, but also the fatigue strength properties which largely determine the production process. Three different fibres materials are available:

- carbon fibre

- glass fibre
- organic aramide fibres (Kevlar®)

The fibres are available in greatly varying qualities, from high-quality aerospace quality down to low-grade fibre material for simple fairing structures. This is reflected in the pricing.

Although organic fibres like *Kevlar* have good strength properties, comparable to carbon fibre, their other properties present some problems with regard to their use in rotor blades. For one thing, they are hygroscopic, i.e. they absorb moisture. On the other hand, the fatigue strength of organic aramide fibres has not been tested much up to the present day which is why they are not taken into consideration for rotor blades for the time being.

The most widely used fibre is *glass fibre.* Its strength properties are extraordinarily high but its specific modulus of elasticity is not so good. This means that the stiffness of components made of glass fibre composites is not very high which is one of the reasons why glass fibre structures cannot be used unreservedly for very large rotor blades.

Carbon fibre stands out due to the fact that it has the longest braking length as well as a high modulus of elasticity. The stiffness of carbon-fibre components is comparable to that of steel structures. Their fatigue strength properties are good. It is only the price of carbon fibres, which continues to remain high, which speaks against it. This is why carbon fibre is frequently used only in combination with glass fibre material for the areas which are particularly subjected to stress. Carbon fibre has virtually no corrosion problems but needs special precautionary measures for protection against lightning when used in rotor blades.

Considering the practical aspects, the selection of matrix material is restricted to:

- polyester resins,
- epoxy resins

The resins are available in greatly varying qualities. When selecting a suitable quality, characteristics such as resistance to hydrolysis, dimensional stability under heat, shrinking characteristic and behaviour under long-period stressing must be taken into consideration.

Polyester resins are used, in particular, in boat-building and in comparable fields of application. They are inexpensive and quite suitable for medium stresses. Most of the earlier rotor blades, especially from Danish production, were manufactured on the basis of polyester resins.

However, many rotor blade manufacturers now prefer to use the expensive, high-quality *epoxy resins* which are exclusively used in aircraft construction. Their strength characteristics are better both with regard to the flow properties with high concentrated loads and to the fatigue strength. Moreover, they do not exhibit any shrinkage like the polyester resins. The weight of the components can be reduced significantly for the same stresses.

The properties of the resins also affect the surface protection of the components. Good surface protection is an important factor especially in the case of rotor blades which are exposed to environmental influences to a particular extent. At present, so-called *gelcoats* are widely used which, also based on synthetic resins, are inserted as the top layer in the production mould so that a smooth and permanent surface is produced without further painting.

There are various possibilities of processing fibre-reinforced composite material, the most common one of which is the *laminating technique*. For this, the mats of fibre material are laid in layers into a female mould of the component and are impregnated with synthetic resin. For high-strength structures, epoxy resin is used as the resin (matrix material). Simpler structural components are also manufactured using polyester as the matrix material. The laminated layers are then cured at ambient temperature or at higher temperatures of 70 to 80 °C in the case of epoxy resin

Depending on the desired strength properties, the fibres can be oriented, as a rule in the direction of the main stress, so that the strength of the material is exploited to its best advantage. Being able to adapt the structure of the material to the load direction like this is a major advantage of laminated composite design. As a rule, the weight ratio of fibre to matrix material is 1:1. Thicker-walled structures are manufactured as so-called *sandwich shells* where only the outer cover layers with a thickness of only a few millimetres are made of laminated fibre material, whereas the inner, much thicker layer consists of light-weight supporting material bearing virtually no load.

The laminating technique permits the production of almost any complicated shape with a high surface quality. The disadvantage, however, is that most of the work must be done by hand. True, a certain amount of rationalisation is possible by using pre-impregnated fibre mats (*prepregs*), but mechanisation is strictly limited.

The so-called *filament winding technique* is an attempt to avoid this disadvantage. The structure is mechanically wound around a core mould on a winding machine resembling a large lathe. During the winding process, the fibres are drawn through a resin bath and are thus impregnated with the matrix material. This process can be carried out almost fully automatically. Winding pattern and filament tension are controlled numerically with the aid of a computer program. This winding technique is used in the production of rotationally symmetric pressurised vessels where its success has been quite convincing. In principle, winding can also be used with more complicated shapes, but its disadvantages then become apparent. The fibre orientation can no longer be easily adapted to the direction of stress as is possible with laminating. Its orientation is determined by geometric shape and by the sequence of the winding process, with the consequence that the components become comparatively heavy. Moreover, surface quality is relatively poor due to the unavoidable grooves produced.

A general problem with the design and production of components made of fibre composite material is the joint of the composite material to the connecting metallic parts. In the case of rotor blades, in particular, the highest stress occurs at the blade root, at the same point at which the critical load transfer to the hub occurs. The solution to this problem with regard to structure and strength largely determines the quality of rotor blades made of fibre composite material (Chapt. 7.5).

Another aspect of assessing fibre composite materials with respect to their suitability for rotor blades is quality assurance in the manufacturing process. The relatively complicated manufacturing processes whereby the production of the material and of the component are inextricably linked, require intensive control measures. Even slight carelessness, such as deviations from curing conditions or soiled glueing surfaces, take their toll in a severe degradation in the strength properties of the finished product.

7.4.2
Previous Designs with Fibre-Reinforced Composites

The merit of having being one of the first to make the rotor blades of a wind turbine of composites is due to U. Hütter. Hütter designed the 17-m-long rotor blades of the W-34 in glass fibre composite technology as early as 1959 (Fig. 7.11). He solved the problem of load transfer from the composite material into the metal flange by means of a loop connection. The rotor blades were very successful and were used as a model for large components in high-quality fibre-reinforced composites generally, not only for the rotor blades of wind turbines, at least in Germany.

In the following years, glass fibre reinforced composite material became the preferred material for wind turbine rotor blades. In the beginning, blades with wound spars and laminated outer shells were produced for the smaller Danish turbines (Fig. 7.12), using the cheaper polyester as matrix material. The rotor blades were mainly produced by small boat-builders who had experience in the manufacturing of boats from FRP. Wound spars made of glass fibre material with bonded outer shells were typical of the Danish wind turbines for a long time. Rotor blades of this design were also used in the large experimental turbines Tjaereborg 2 MW and WKA-60.

The rotor blades of the experimental Swedish/US turbines WTS-3 and WTS-4 were produced as fully wound components (Fig. 7.13). The connecting structure to the hub consisted of an inner and an outer annular flange between which the composite structure was bonded and screwed together. A rotor blade with a length of 38 m weighed approx. 13 metric tonnes of which approx. 4.5 tonnes were attributable to the metallic flange.

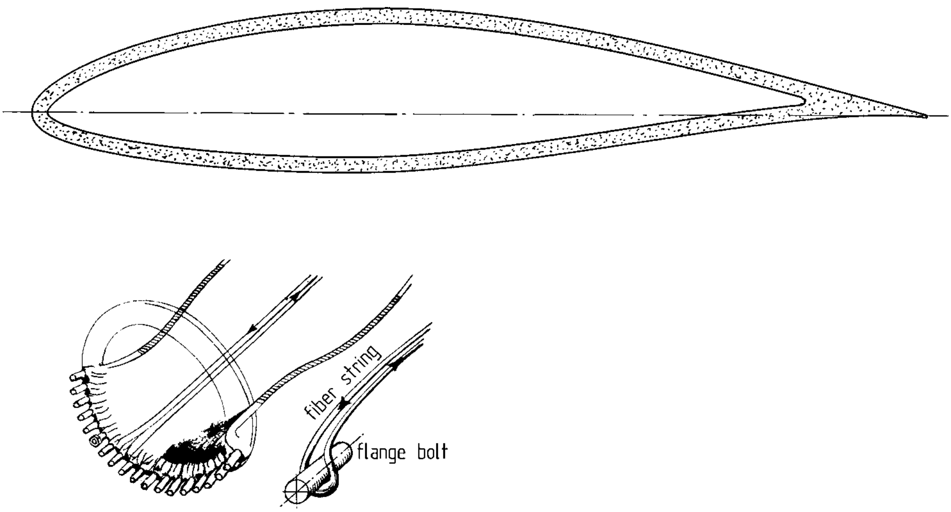


Figure 7.11. Rotor blade structure of Hütter's W-34 made of laminated fibre-reinforced composite material with so-called loop connection [6]

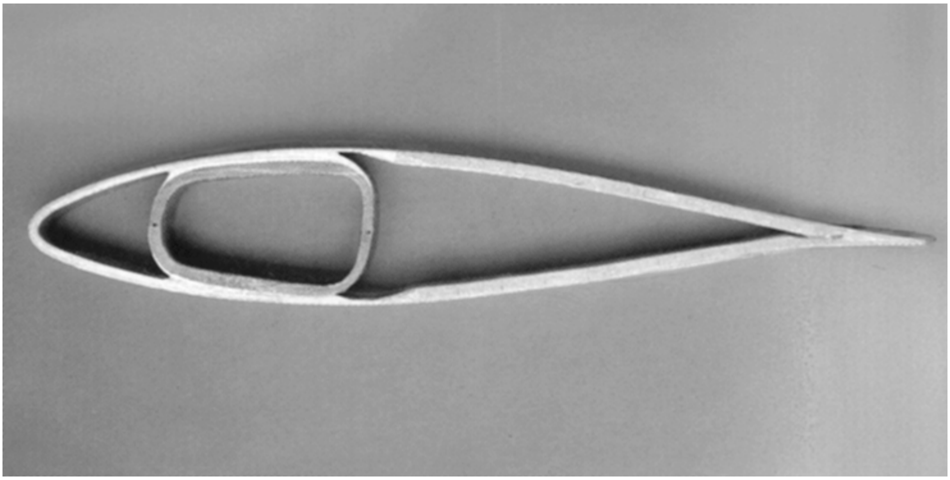


Figure 7.12. Rotor blade cross-section of the rotor blade of an earlier Danish wind turbine with wound spar and laminated shell of fibre-glass reinforced composite. (Aerostar)

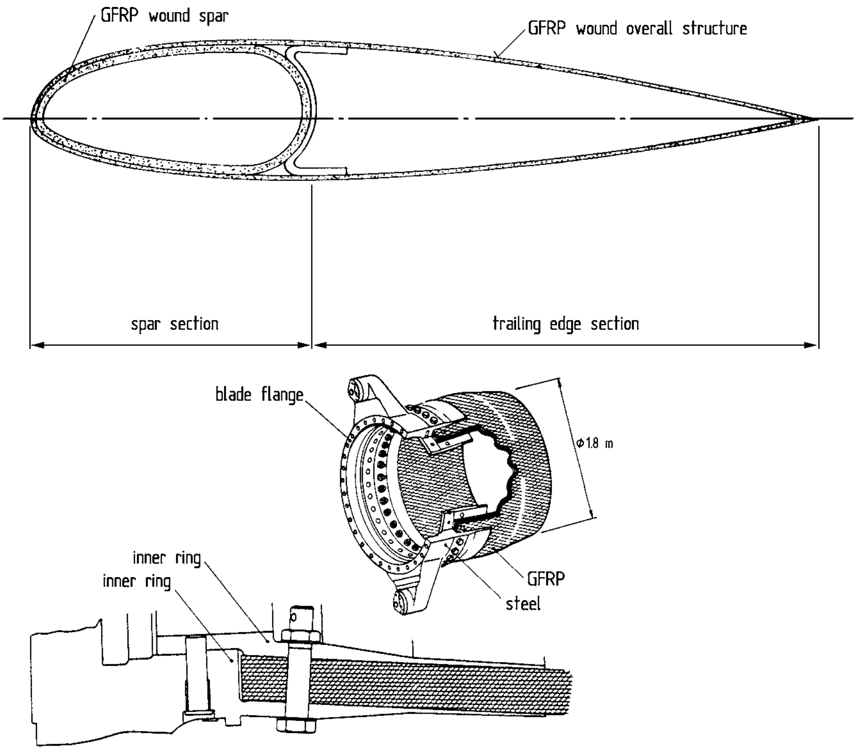


Figure 7.13. Rotor blade cross-section and hub connection (steel flange) of the Swedish WTS-3 turbine [7]

The fully mechanised production process began with the winding of the D-spar (Fig. 7.14 and 7.15). After that, a core in the geometric shape of the rear airfoil cross-section

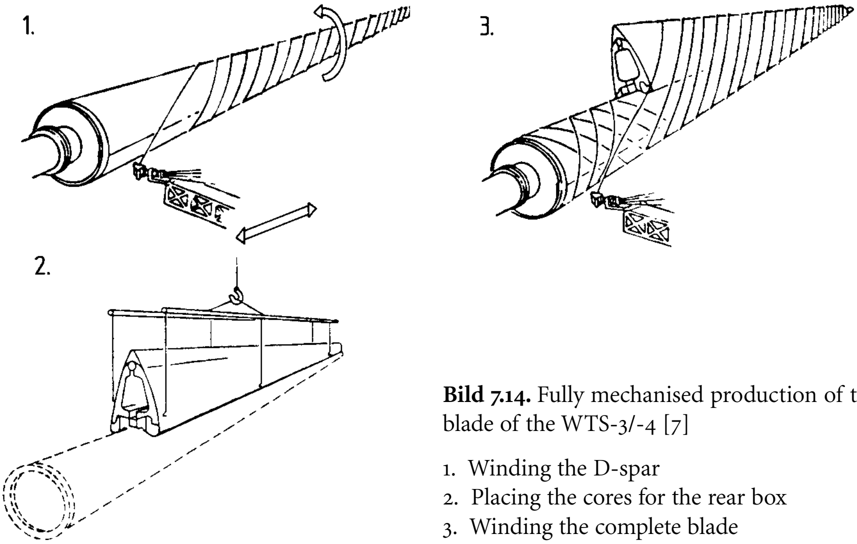


Bild 7.14. Fully mechanised production of the rotor blade of the WTS-3/-4 [7]

1. Winding the D-spar
2. Placing the cores for the rear box
3. Winding the complete blade

Figure 7.15. Rotor blade of the WTS-3 turbine on the winding machine (Hamilton Standard)

was positioned on the spar after which spar and core were again wrapped. After the whole assembly had been cured, the core was removed.

The winding technique is still used today for rotor blades made of fibre-reinforced composites. The disadvantage of not being able to orientate the directions of the wound fibres optimally in accordance with the direction of the stresses is compensated by implementing carbon-fibre spar elements with a spanwise fibre orientation (Vestas). The advantage of being able to mechanise the production to a large extent will be maintained.

7.4.3
Present Standard Design

In the course of continuing development, wound spars made of glass fibre reinforced composite material proved to be too heavy, for reasons already mentioned. Following the example of aircraft construction, rotor blade manufacturers replaced the wound spar with one or more light-weight spar webs (Fig. 7.16). Although the cheaper polyester resin, which is processed more easily, is still used for small rotor blades today, epoxy resin with its better strength properties has increasingly gained popularity for mass-produced rotor blades of commercial wind turbines (Fig. 7.17).

Producing rotor blades completely of carbon fibre composite material is still too expensive today for commercial wind turbines. For the time being, the price for carbon fibres of the required quality is still too high to achieve an economic advantage for the complete unit in spite of the low weight of the rotor blades. For this reason, carbon fibre is used only in small amounts at the highly loaded points on the rotor blades. For example, the spar flanges are reinforced with carbon fibre in the main stress direction. This mixed glass fibre/carbon fibre type of construction was used, e.g. in the rotor blades of the experimental Aeolus II turbine and is being used today in the mass production of large rotor blades (Fig. 7.18).

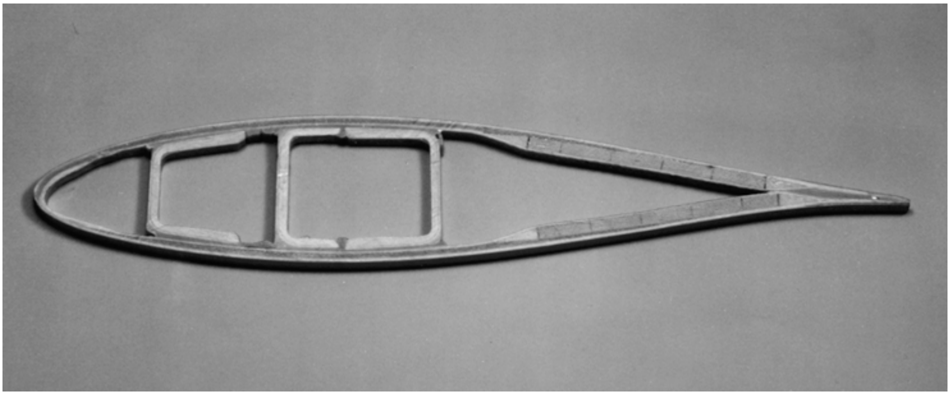


Figure 7.16. Rotor blade cross-section of a modern rotor blade in laminated shell construction with spar box and spar webs (LM)

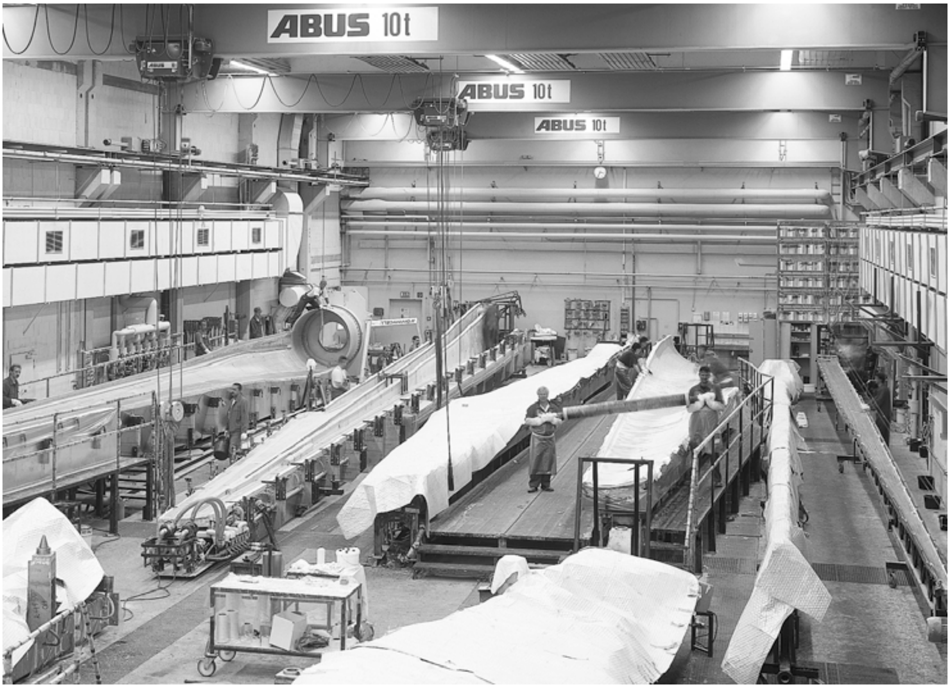


Figure 7.17. Rotor blade production at Enercon (Enercon)

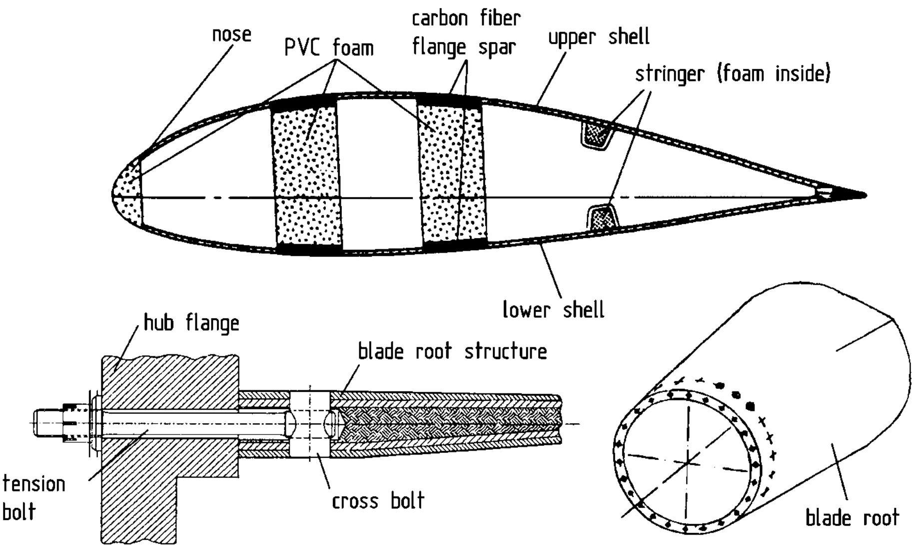


Figure 7.18. Rotor blade of the experimental Aeolus II turbine in mixed glass fibre/carbon fibre construction with crossbolt joint to the rotor hub [8]

7.4.4 Wood/Epoxy Composites

The fibre composites also include a special wood composite type of construction which is favoured by some manufacturers. The initiative for using wood composites came from boat-building. In their efforts to make wood resistant to seawater, the boat-builders developed a wood composite design in which the wood was completely embedded in epoxy resin similar to the glass or carbon fibres. This made it possible to eliminate a significant disadvantage of old-fashioned wood designs and to continue to make use of the good properties of wood, particularly its fatigue strength.

Rotor blades of this type had already been successfully tried out in 1980 on the experimental American turbines of the MOD-0 series (Fig. 7.19). Meanwhile, rotor blades in wood composite technology are used in numerous wind turbines. The English turbines of the former Wind Energy Group (WEG), for example, have rotor blades of this type. Several American manufacturers also used this technology for the blades on their turbines (ASI, Enertec, Westinghouse, et al.). These manufacturers are no longer represented on the wind turbine market today so that the blade manufacture Gougeon also no longer supplies rotor blades of this type for this reason or others. In Great Britain, the Aerolaminates company has adopted this technology and is producing large rotor blades for NEG Micon, today merged with Vestas.

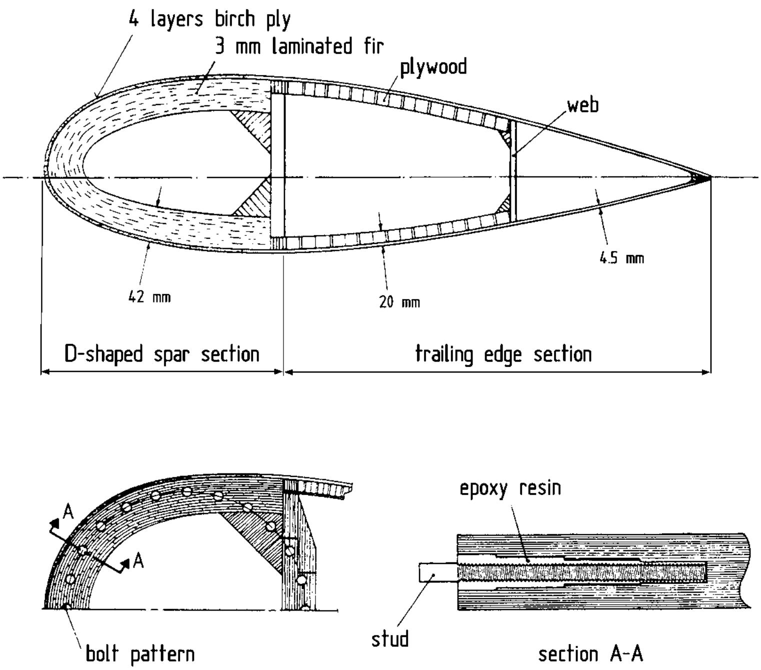


Figure 7.19. Wood/epoxy composite rotor blade of the MOD-0 (Gougeon design) [9]

The wood composites type of construction had been considered for a time as a promising alternative to the fibre-reinforced composite type of construction. Initially, its wider use was hampered by the fact that only a few manufacturers were capable of handling this very special technology. In the further course of events, however, most manufacturers also found that wood composites could not compete with the newer fibreglass/epoxy designs at least as far as their weight was concerned.

7.5 Blade Connection to the Rotor Hub

Apart from the actual rotor blade design, the quality and weight of the rotor blades are essentially determined by the design concept of the blade connection to the rotor hub. Designing the blade connection to the rotor hub is one of the most demanding tasks in the whole rotor blade design process. For one, transferring forces from fibre composite structures into metallic materials is difficult in principle, due to the greatly differing material properties. An additional problem with wind turbines is that the rotor forces are concentrated around the areas of the blade root and rotor hub and that, at the same time, the rotor is subjected to extremely high dynamic loading. Apart from the introduction of epoxy resin, progress with respect to rotor blade weight optimisation has in recent years been achieved, above all, by producing considerably lighter blade connecting structures. Current rotor blades display the following essential concepts for the design of the blade connection:

Steel flange connection

Particularly in older rotor blades with polyester matrix material, heavy dual steel flanges are common. The blade root is clamped between an inner and an outer flange and the two flanges are bolted together (Fig. 7.20). The connection to the rotor hub is via an external flange ring with heavy-duty tension bolts. Rotor blade flanges of this design frequently constitute up to one third of the total rotor blade weight. The proportion of manufacturing cost of the rotor blade is correspondingly high.

Cross-bolt connection

A decisive step towards reducing rotor blade weight, but also with a view to reducing manufacturing costs, was the introduction of the so-called cross-bolt connection in rotor blades. This design principle has been common practice in helicopter rotors for a long time. Rotor blades developed by the German company MBB (now EADS) for various test turbines were the first to be equipped with this advanced connection technology (Fig. 7.21). This design has since found its way also into commercial rotor blade production, one proviso being the use of epoxy resin composite material, as polyester is prone to plastic deformation when a high load is concentrated on one point. A well-known Scandinavian furniture manufacturer uses a similar connecting process for their inexpensive self-assembly furniture, which is why this connecting technique is occasionally also referred to as "IKEA Joint".

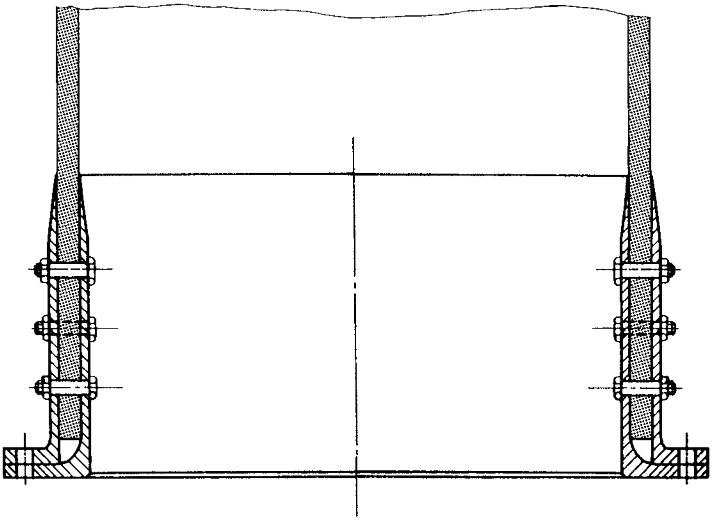


Figure 7.20. Heavy dual steel flange in earlier rotor blades (LM)

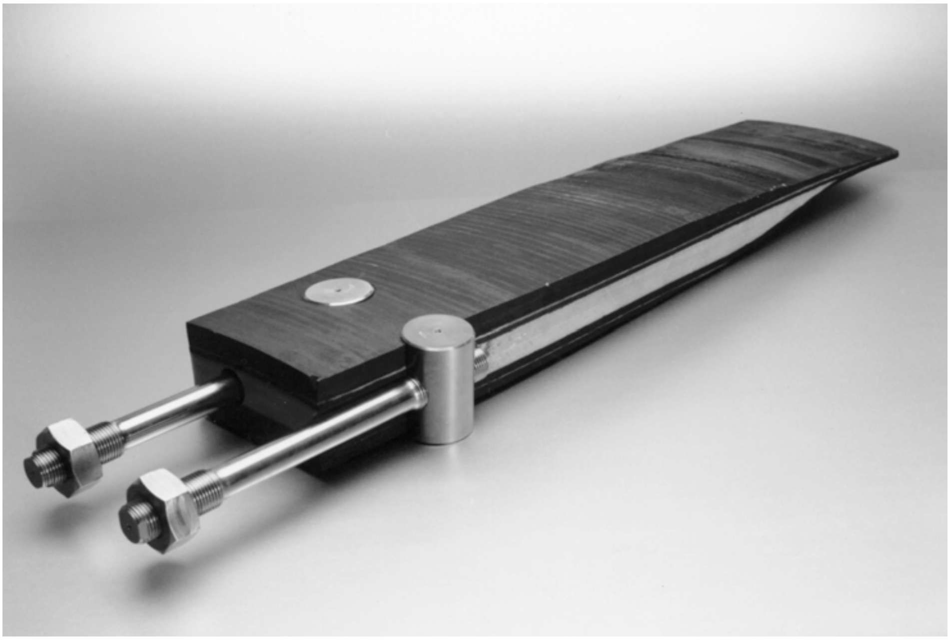


Figure 7.21. Blade connection with cross-bolts (MBB)

Bonded-in lightweight flanges or sleeves

One alternative to the cross-bolt connection is a blade connection with bonded-in aluminium flanges first developed by Vestas. The rotor blades of the larger Vestas turbines have extremely light blade flanges made of high-strength aluminium, which are bonded into the blade root structure (Figs. 7.22 and 7.24). In the rotor blades of the Vestas V-39, with a rotor diameter of 39 m, the flange weighs less than 50 kg. The total weight of the rotor blade is approximately 1100 kg.

A further variant is the blade connection developed by LM, which has bonded-in metallic sleeves into which the fastening bolts are screwed. Similar to the bonded-in flanges, the surface of the sleeves es shaped in such a way that a certain form-fitting connection is produced (Fig. 7.23).

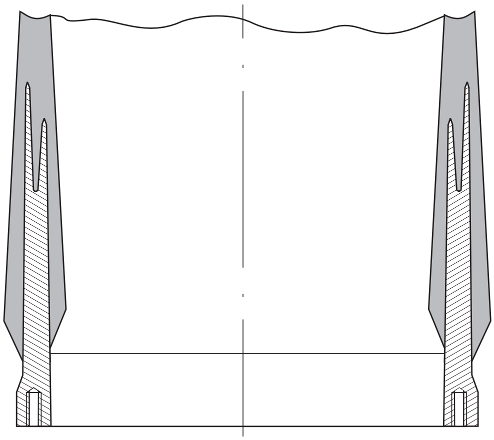


Figure 7.22. Bonded-in light aluminium flange of a rotor blade at the Vestas V39

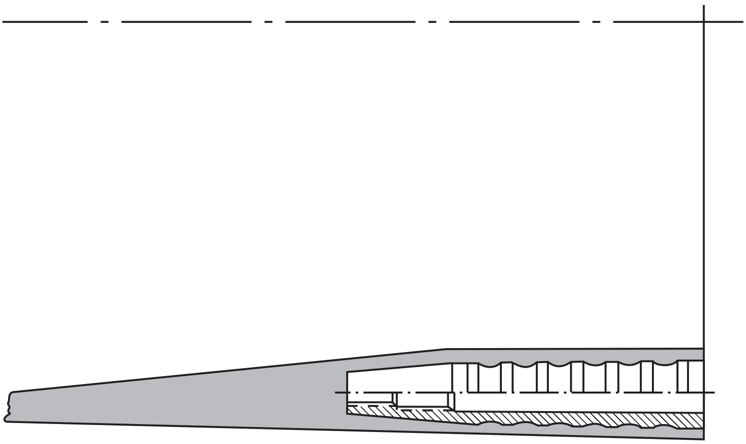


Figure 7.23. Bonded-in sleeves of a rotor blade for connection to the hub (LM)

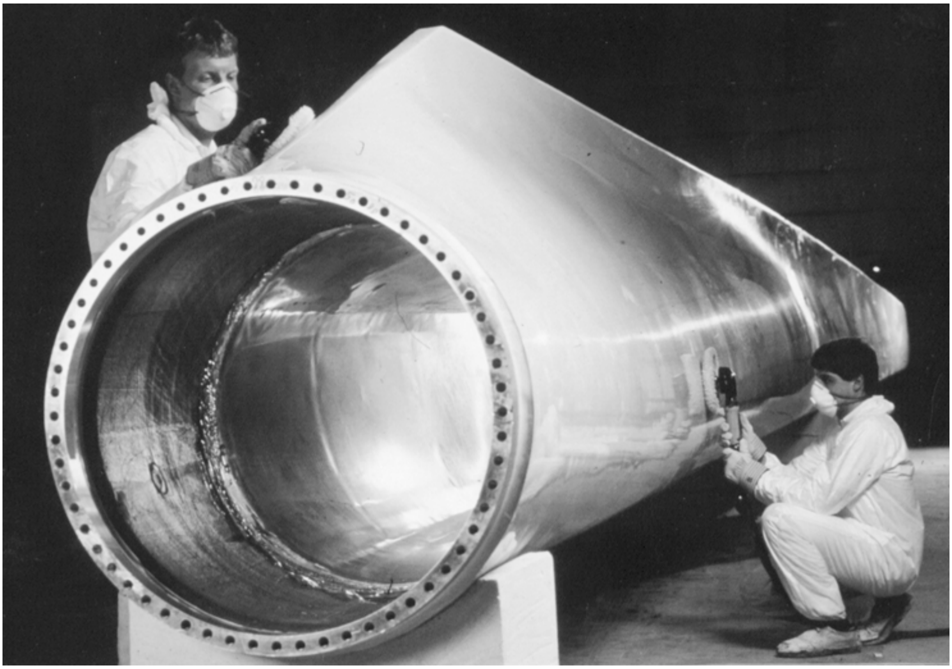


Figure 7.24. Rotor blade connection to the hub in the Vestas V-39 rotor blade

Bonded-in bolts

The simplest solution from a design point of view, and one which saves weight, is to bond the connecting bolts straight into the rotor blade root structure, without further form-fitting elements like the cross bolt (s. Fig. 7.19). However, this type of construction is considered to be risky. It may be possible to improve this design in future developments so that it, too, can be used in mass production.

7.6 Comparison of Rotor Blade Designs

Discussing different rotor blade designs inevitably leads to an attempt to compare one with the other in order to find the "best". First of all, as is always the case in engineering, there is no single best rotor blade design. Various aspects speaking for or against a certain design must be taken into consideration. Available experience, development costs and development risks, available production machinery as well as the overall concept of the wind turbine all provide different priorities on which the selection of the blade design must be based. On the other hand, more than 20 years of intensive development work and practical experience have shown that some types of construction are not suitable and this has resulted in a convergence in the design of the rotor blades.

There is one parameter, however, which can be rated as an objective criterion and that is the blade weight. The weight of the rotor blades is a decisive factor in the overall tower-head weight of a wind turbine. Moreover, the mass of the rotor blades is, of course, a factor not to be underestimated in connection with the manufacturing costs, at least when large quantities of rotors are to be produced.

Apart from the material and the design, the influence of the aerodynamic design of the rotor, the control method, the blade stiffness and the design of the rotor hub must not be ignored in a comparison of weights. Three-bladed rotors with a low design tip speed ratio have wider and heavier rotor blades than two-bladed rotors. In the case of two-bladed rotors, the type of hub design plays a role. A teetering hub reduces blade bending moments under most operating conditions. The design stiffness of the rotor blades has considerable influence on the weight. The rotor blades of the Vestas turbine, for example, are extremely flexible and, therefore, exhibit a much better weight in the comparison. However, such a design requires a particularly careful analysis of system vibrations and pitch control characteristics (see Chapters 10 and 11).

The load spectrum for the rotor blades is also influenced by the way the wind turbine power is controlled. The rotor blades of stall-controlled rotors are subjected to high extreme loads due to the lack of a capability of reducing the loading at extreme wind velocities by feathering the rotor blades. On the other hand, the fatigue loads from wind turbulence can be worse in rotors with blade pitch control. For these reasons, no significant difference is found in the weight of rotor blades for stall-controlled rotors and those with blade pitch control. In addition, any comparison of weights is made more difficult due to the fact that fixed-pitch rotors have aerodynamic spoilers which can increase the rotor blade weight by up to 20 %.

Regardless of such influences on rotor blade mass, the selected material and the design have a major influence on the weight of the blades (Fig. 7.25). The statistical evaluation of the rotor blade masses of manufactured wind turbines show firstly, that in each design concept, specific blade mass per square metre rotor-swept area increases with increasing rotor diameter. The weight of the rotor blades increases not only in absolute terms but also in relative terms. The physical explanation is based on the fact that, for one, the volume, and with it the mass of the components, increase by the rotor radius to the power of three, and that the most important load parameters such as the bending moment from the aerodynamic forces increase approximately by the power of three and the moments resulting from the intrinsic weight, which dominate with large diameters, increase even by the power of four. On the other hand, the influence of wall thicknesses of the components becomes relatively more favourable with increasing size, i.e. the load-carrying efficiency of the design improves. Empirically, the increase in blade mass with rotor diameter can be described with good approximation by the exponent 2.6. The increase in specific blade mass per rotor-swept area then contains the exponent 0.6:

$$m_2 = m_1 \left(\frac{D_2}{D_1} \right)^{0.6}$$

Strictly speaking, the exponent changes with rotor blade design. Heavy rotor blades differ from lighter blades in their ratio of the loads resulting from their intrinsic weight and the aerodynamic forces so that the growth exponent becomes somewhat smaller.

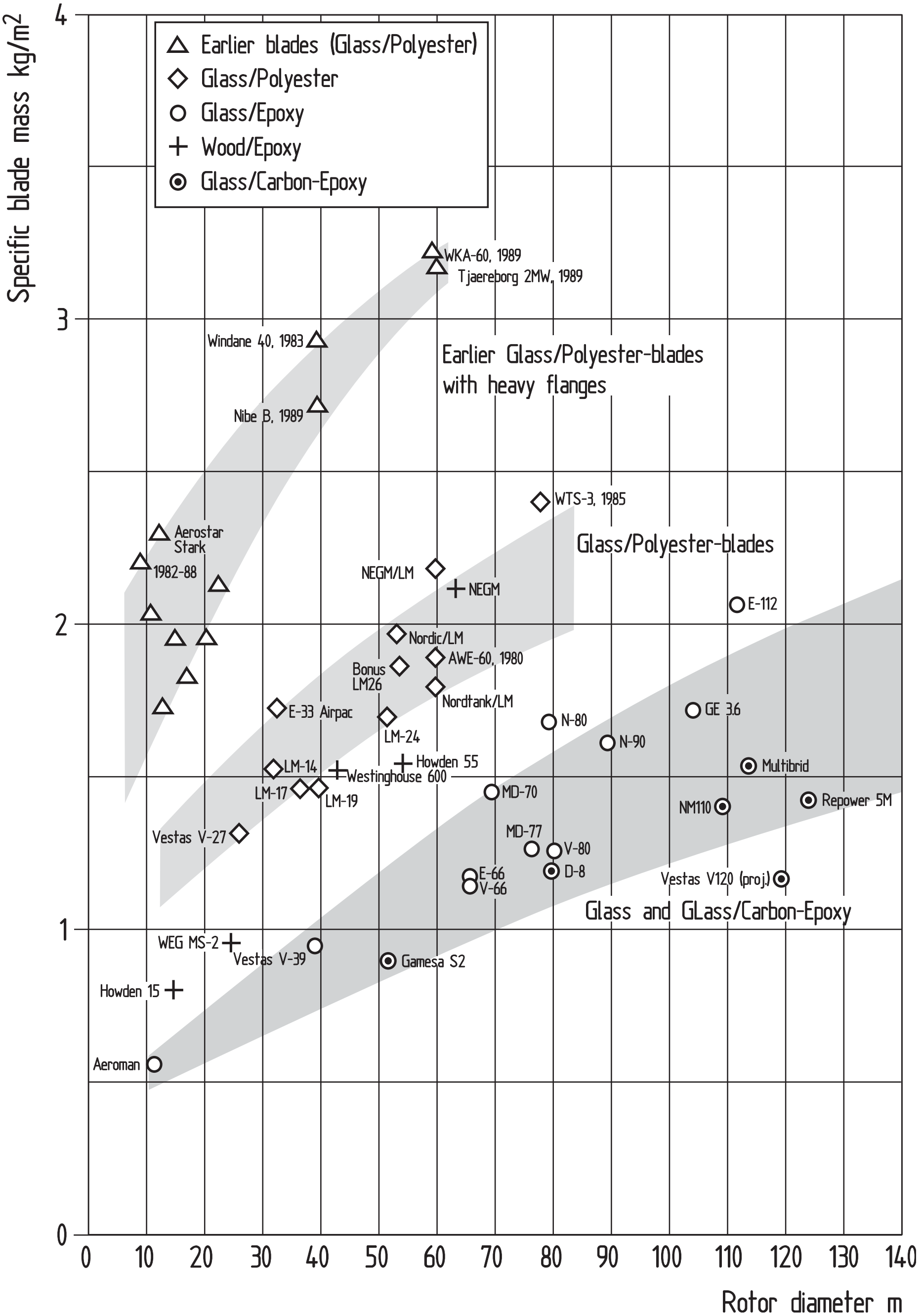


Figure 7.25. Specific mass of rotor blades of different design concepts with respect to rotor-swept area

If present-day rotor blades are classified according to their design, different categories emerge, each representing a weight class. However, the influence of the blade flange distorts the picture in some cases. For example, the blades seem disproportionately light in turbines where the rotor blades only have bonded-in connecting bolts. In addition, with rotor blades which are intended for stall-controlled turbines, the additional weight of the spoilers or of the adjustable blade tips must be taken into consideration.

Fibre glass/polyester design with wound spars

Heavy fibre glass rotor blades are mainly found in older Danish wind turbines. They consist of a wound spar with laminated contoured shells bonded to them. The matrix material used is the less expensive polyester resin. When comparing weights, however, it must be taken into consideration that these blades in most cases have built-in aerodynamic spoilers and that their rotor blade geometry is designed for relatively low tip-speed ratios.

Laminated fibre glass/polyester design

Rotor blades of laminated fibre glass composites with polyester resin as the matrix material are still widely used today. The laminating technique makes it possible to orientate the fibres in great lengths along the direction of the main loads, thus making full use of their tensile strength. Blades of this type are used for smaller and medium-sized turbines. The blade geometry is dimensioned for medium to high tip-speed ratios. Seen overall, the fibre glass/polyester type of construction is in retreat and epoxy is being used increasingly also for relatively small turbines.

Fibre glass/epoxy blades

Danish and Dutch rotor blade manufacturers, coming from a long tradition of boat-builders, hesitated for a long time to use this more expensive and difficult to process resin for their standard products. The more recent rotor blades from LM or Vestas, however, are also manufactured in fibre glass/epoxy design. Using the epoxy resin makes it possible to produce a low-weight blade connection to the rotor hub without a heavy flange. As the size of the rotors increases, the weight advantage of up to 30 %, which can be achieved in comparison with the polyester design, is too important to stay with the cheaper polyester. Fibre glass/epoxy material combined with a light-weight blade connecting structure represents the "state of the art". The specific weight of these rotor blades, referred to the rotor-swept area, is between 1.2 and 1.5 kg/m² for a rotor diameter of 70 m.

Mixed fibre glass and carbon fibre design

Using carbon fibres makes it possible to achieve rotor blades with extremely low weight. In some experimental turbines, rotor blades consisting mostly of carbon fibre were developed. Later on, the rotor blades were reinforced with carbon fibre only at the important locations, that is to say in the span direction (spar flanges) after the model of modern glider wings. Using this technology, a specific mass of close to 1 kg/m² rotor-swept area can be achieved for the above-mentioned reference rotor. Today, large rotor blades for rotors with a diameter of more than 70 or 80 m are almost always produced by using a certain proportion of carbon fibre. If only glass fibres are used, the stiffness requirements can only be met with a disproportionately large weight. Some manufacturers are also using a mixed design of fibre glass, carbon fibre and wood (Aerolaminates).

Wood/epoxy composite material

When rotor blades in laminated wood/epoxy construction were introduced, they were found to have a lower weight in comparison with older, fibre glass/polyester blades. This is due to the great stiffness of wood and its excellent fatigue strength at a low specific weight. With respect to their mass, however, the wood composite rotor blades are no longer comparable to the most recent designs of fibre glass/epoxy blades. The specific mass is approx. 1.5 kg/m².

Rotor blade technology will continue to exert a special influence on the further development of wind turbines also in the next few years. It is a distinct possibility that new approaches must be found for the coming rotors with diameters of more than 100 m. The problems of transportation and assembly alone will set new tasks to be solved by the designers.

7.7 Aerodynamic Brakes on Stall-Controlled Rotors

Rotors having a fixed blade pitch angle and stall-limited power must have an aerodynamically acting capability of preventing the rotor from "running away" in the event of a failure of the generator torque, for example due to a grid outage. This cannot be handled by the mechanical rotor brake on the rotor shaft, at least in large units. The rotor can only be decelerated by extendible drag surfaces on the rotor blades (see Chapter 5.3.2).

As a rule, the rotor blades have adjustable blade tips which are rotated by 90° before braking the rotor (Fig. 7.26). A blade tip adjustment is triggered by a flyweight and a loaded spring. The adjustment requires a certain amount of experience and the triggering threshold is in the range of about 120 % of the nominal rotor speed.

In older wind turbines, this mechanical system worked without any possibility being provided for resetting it. The result was that in the case of a grid outage, an entire windpark was brought to a standstill by the aerodynamic blade tip brakes and then every blade tip had to be reset again manually to its normal position.

To avoid this time-consuming restarting of the wind turbines, the more recent rotor blades of stall-controlled systems are equipped with an hydraulic resetting system (Fig. 7.27). However, this makes the structural complexity of rotors with a fixed blade pitch angle as great as that for rotors with blade pitch control and it also considerably increases the weight of the rotor blades.

Due to the structural complexity in the critical outside area of the rotor blade, associated with the fact that the load application point is also poor during braking, this type of construction, i.e. of rotor blades with aerodynamic tip brakes, becomes problematic for

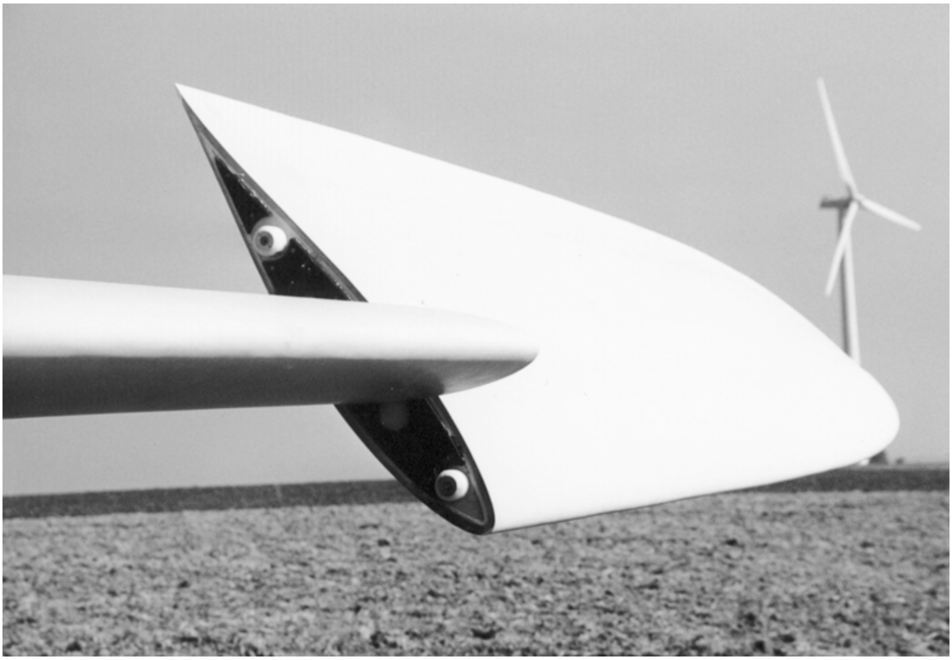


Figure 7.26. Turnable rotor blade tip for aerodynamic overspeed limitation

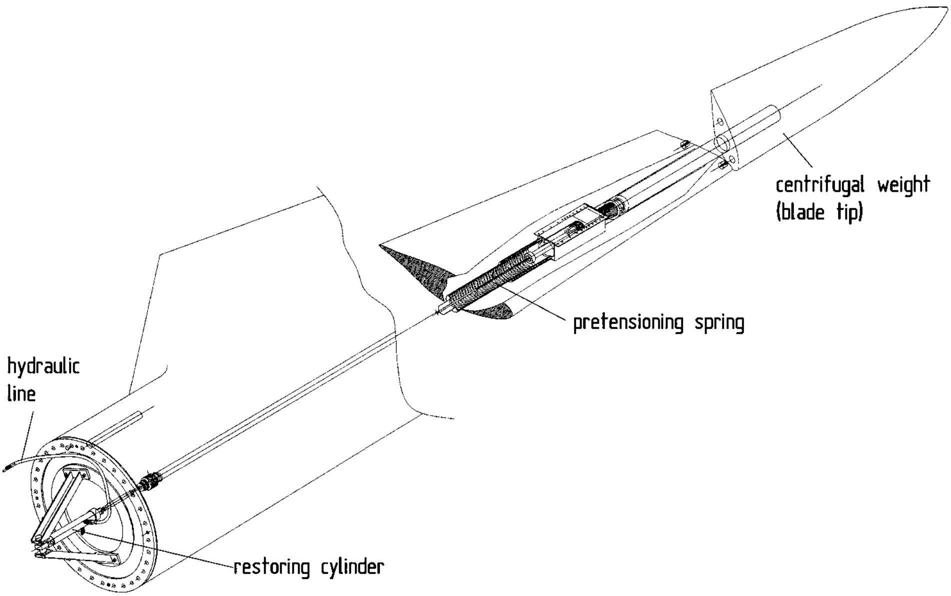


Figure 7.27. Rotor blade tip with hydraulic resetting system (LM)

very large rotors. For this reason, the advocates of the principle of using stall for limiting power are now changing over to an active stall control in their large systems in which the entire rotor blade can be adjusted when braking becomes necessary (BONUS, NEG MICON) (see Chapter 5.3.3).

7.8 Lightning Protection

Lightning strikes are unavoidable on large wind turbines (see Chapter 18.8.2). Most of the lightning strikes on the rotor blades hit the area of the blade tip, resulting in considerable damage. Although it was initially thought that one could dispense with a lightning protection system on rotor blades of nonconductive composite fibre glass material, this was found to be not true in actual operation. For this reason, the demands for effective lightning protection have become more and more vociferous as more and more wind turbines of increasing size were installed — especially from the insurers. Today, lightning protection systems are a standard feature with all new rotor blades (Fig. 7.28).

The lighting protection system consists of a so-called *receptor* in the area of the blade tip. In the simplest case, this is a metal part which is screwed in and thus can be easily exchanged. In the interior of the rotor blade, a thick metallic wire runs as "lighting conductor" down to the blade root where the conductor is connected with flexible metallic strips to the rotor hub and thus to the earthing system of the wind turbine (see Chapter 18.8).

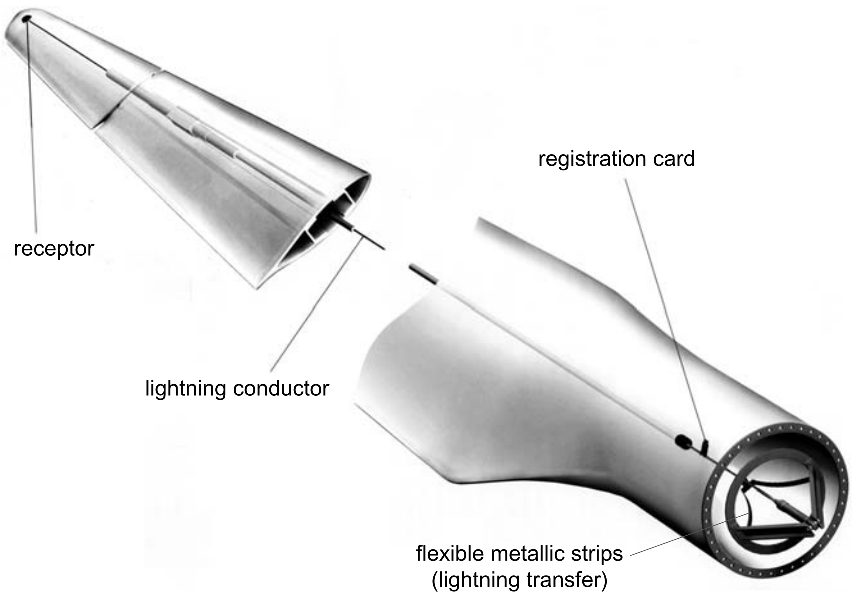


Figure 7.28. Lightning protection of a rotor blade (LM)

7.9 Ice Warning and De-icing

On some sites, there is a risk that ice becomes deposited on the rotor blades under certain weather conditions (see Chapter 18.8.2). For this reason, the manufacturers of rotor blades offer an optional ice warning system which switches the unit off as a preventative measure during certain weather conditions.

A much more complicated task is that of providing the rotor blades with a de-icing system. An electrical resistance heater developed by some rotor blade manufacturers and also being offered already in some cases (Fig. 7.29). In view of the permanent deformation of the blade structure under the bending stress, the mounting system and the material of the heating elements are subject to particularly high demands. In addition, there is the problem that the inbuilt metallic threads are extremely at risk from a lightning strike. In recent years it has also been attempted to largely prevent the blade surface from icing up by means of a special surface coating. However, a fully satisfactory de-icing system is not available at present.

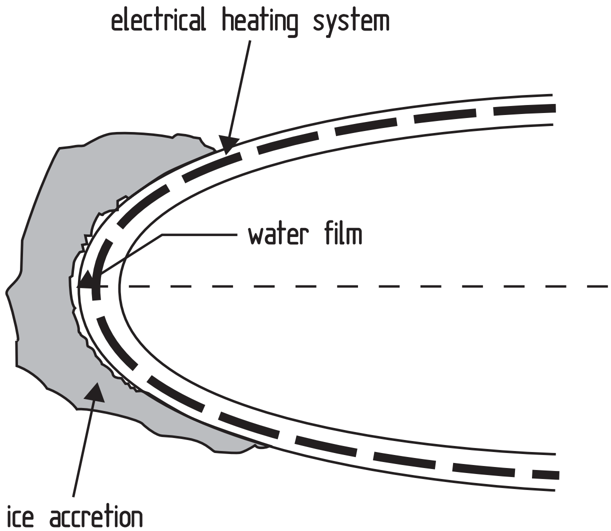


Figure 7.29. Electrical heating system for rotor blade de-icing (LM)

Enercon offers a de-icing system using heated air from an electric heater and from generator cooling (Fig. 7.30). The hot air is blown into the blade root. This seems to be a practical solution for the hub and inner blade area. So far there is, however, no comprehensive experience available regarding this solution, nor is there any for the electrical heating system.

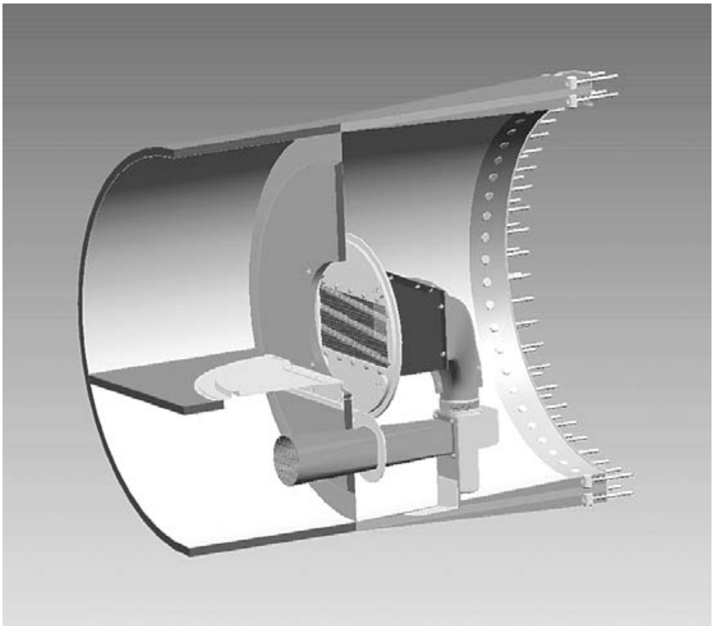


Figure 7.30. Rotor blade root section with the de-icing system using hot air (Enercon)

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Chapter 8

Mechanical Drive Train and Nacelle

The conversion of the kinetic energy in the air stream flowing through the rotor is determined by aerodynamics and by the type of lightweight design employed. Thus there are associations with aircraft engineering. A look into the nacelle provides a completely different picture. The components for converting mechanical energy into electrical energy represent "conventional" power plant technology, as it were. But a conclusion that this area would be "state-of-the-art" and that it should, therefore, not pose any particular problems is not completely true.

It is correct to say that the mechanical transmission of power, the "mechanical drive train", consists of conventional machine elements which are also used in other areas of mechanical engineering. For this reason, many components can be taken over relatively cost-effectively from existing series production runs. For the manufacturer of wind turbines, these are vendor-supplied parts. On the other hand, the mechanical-electrical conversion of energy in a wind turbine follows its own laws and presents its own specific problems. These are shaped by the special characteristics of the wind rotor as the prime mover. Both the unsteady torque caused by the characteristics of the wind and the bearing system for the heavy rotor assembly require intelligent design concepts, to avoid an unfavourable increase of masses in larger wind turbines. The design of the mechanical drive train is, therefore, by no means a conventional design task, but representative of a technology where innovation lies in the field of systems engineering.

The term "mechanical drive train" encompasses all rotating parts, from the rotor hub to the electrical generator. These components form a functional unit and should, therefore, always be considered together. Technologically, too, they belong to the same category of "mechanical engineering". The electrical generator, however, is a part only in so far as its installation presents a mechanical problem in the drive train assembly.

The mechanical drive train and the electrical system are generally accommodated inside a enclosed nacelle. This nacelle must also house the yawing system and the tower head bearings. Its static design is closely associated with the constructional arrangement of the drive train components and particularly with the rotor bearing arrangement. Not least, the design of the shape of the nacelle is a task which must also be considered from an aesthetic point of view.

8.1
Fundamental Considerations of Power Transmission

The generation of fixed-frequency alternating current — in Europe this generally means 50 Hz (compared with 60 Hz in the US) — is conventional technology as long as the prime mover driving the electric generator meets two requirements:

- good constant-speed characteristics, with variations in speed and torque of no more than approximately one percent,
- more or less matching speed levels of the prime mover and the generator. Common power station generators are designed to run at 1500 or 1600 r.p.m., respectively.

These requirements are met by steam or gas turbines and with some restrictions also by diesel engines, at least with respect to the especially important first item, but not by wind rotors. It is virtually a characteristic of the latter that their speed and torque are subject to particularly high variations. Another point is that the rotor's rotational speed is quite different from that required by the generator. These in a nut-shell are the problems of mechanical-electrical energy conversion in a wind turbine. The important factor is that the mechanical drive train must be able to absorb the unfavourable properties inherent in a wind rotor as the prime mover, thus creating the prerequisite for driving the electric generator. Given the conditions outlined above, the technical solutions available for connecting the electric generator to the rotor give rise to a series of fundamental technical questions. The first question arises when the rotor speed is to be matched to the speed of the electric generator:

Why not have the generator driven directly by the rotor? A simple calculation shows that, assuming the rotor speed of a large turbine to be 20 r.p.m., a generator running at the same speed would have to have 350 pairs of poles to provide alternating current with a frequency of 50 Hz. Accommodating such a number of poles on a generator rotor would require a diameter of at least 10 to 15 m. Multi-pole generators of this type are used in combination with hydro-electric turbines, but they have hitherto not been economically viable in wind turbines.

However, this situation has changed in recent years. Today, progress in frequency-converter technology permits cost-effective combinations of variable-frequency electric generators followed by frequency converters, providing the necessary constant grid frequency. A generator driven directly by the rotor hence need no longer be designed for the grid frequency, so that the required number of pole pairs and the resulting diameter can be reduced considerably. Gearless generator systems of this type with frequency converters have thus become a genuine alternative to the traditional generator/gearbox arrangement (s. Chapter 9.5.4).

Regardless of these more recent developments, most manufacturers still rely on the conventional drive train design with a gearbox between the rotor and the generator. What kind of transmission gearing is suitable for this purpose? A transmission with variable speed would be desirable. An infinitely variable transmission between rotor and electric generator would immediately have several advantages. On the one hand, the rotor could be operated at its optimal tip-speed ratio at any wind speed, which would increase energy yield. In addition, the rotor's surge-like dynamic torque and speed variations would be isolated. Unfortunately, a cost-effective continuously variable transmission operating with a wide speed range and at high efficiency has remained a technological development goal yet to be achieved to this day.

Some attempts in this field do, however, exist. So-called variable-speed power-splitting transmissions with electric or hydrostatic servo-motors are used in special-purpose vehicles or in certain areas of motive power technology. Basically, transmissions of this type are also suitable for wind turbines. However, these transmissions are relatively complex and require a lot of servicing [1].

A large wind turbine using continuously variable hydrostatic transmission technology was built in the late seventies in the US [2]. However, the experience gained from about two years of test operation proved to be quite negative. The design implemented there was neither convincing in efficiency nor in reliability, let alone in production cost. The turbine proved to be completely unreliable and was disassembled after only a few hours of operation. However, the defects were not only attributable to the continuously variable transmission: the overall concept of the project contributed at least as much.

Given the current state of the art, wind turbines with a transmission between rotor and generator will have to manage with fixed, mechanical gearing for the time being. The range of practicable solutions for a mechanical speed transmission is not very wide. For relatively low power outputs of up to a few hundred kilowatts, belt- or chain-drives are possible. They are occasionally used in small turbines even though their frictional losses are relatively high. In addition, V-belt drives have the advantage of providing a certain amount of elasticity in the transmission. For higher power outputs, however, gear trains are the only practicable solution.

Gearboxes suitable for application in wind turbines are available from many fields of machinery. But the dynamic loads and the requirements with respect to service life are too severe to ensure their successful use in wind turbines. Design and maintenance, therefore, have to be adapted to the specific requirements of wind turbine technology.

The rotor of a horizontal-axis wind turbine is inevitably mounted on a tower which must be at least as high as half the rotor diameter. But this does not mean that all components of the mechanical drive train and the electric generator must also be positioned on top of the tower. Efforts to relieve the tower of the weight of these components, and to facilitate assembly and accessibility, time and again lead to considerations of relocating the mechanical and electrical components "downstairs". There are indeed a number of alternatives worth considering, some of which have actually been implemented (Fig. 8.1).

Transport and erection of the very recent multi-megawatt wind turbines with rotor diameters of more than 100 m and tower-head weights up to 500 t impose new requirements on the drive train concept. The nacelles including the drive train could not be assembled on the shop floor before lifting them up on erection of the turbine — at least not for the first prototypes. However, assembling the nacelle when erecting the turbine on site is not very economical. Against this background, it remains a challenge for the future to find an optimum compromise for the technical concept of the drive train in view of the possibilities of the erection procedure. This is of particular importance for offshore installations. Because assembly and erection have to be carried out in short time depending on the wether and sea conditions.

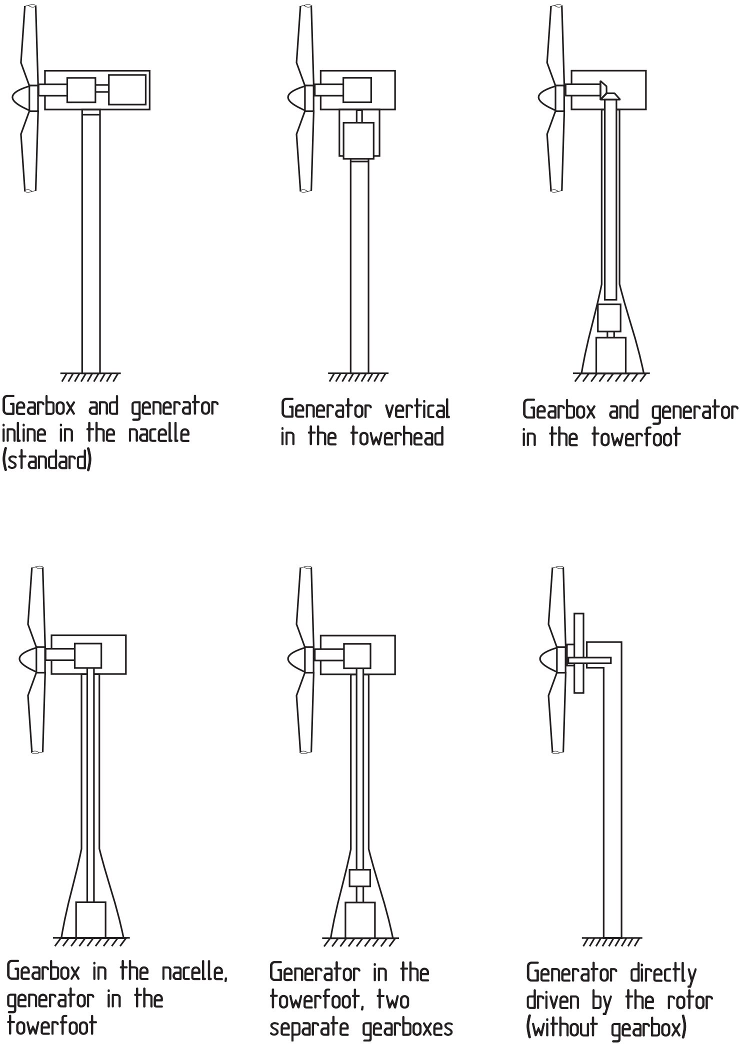


Figure 8.1. Basic possibilities of drive train configurations in a wind turbine

8.2
Previous Experimental Designs

However many basic solutions there are to the problem of transmitting power from the rotor to the electric generator, their implementation in large wind turbines is restricted in practice to only a few designs. In experimental concepts, turbines were tried out in which the generator was mounted in the tower instead of in the nacelle. Although these solutions have some indisputable advantages, they did not succeed in commercial wind turbines.

However, it may be of some benefit to cast a glance at these experimental designs. It would not be the first time in the history of technology if these concepts were revived again later when different technical preconditions exist.

8.2.1 Generator in the Tower Base

The most logical solution with respect to reducing the tower head weight is to accommodate the drive train components in the tower base. However, having the gearbox and the generator located in the tower base means that the low-speed rotor shaft, with its high torque, must be run through the entire tower. Weight and cost of such a shaft rule out this solution in practice.

It is much more realistic to run the faster and much lighter generator drive shaft to the tower base. Naturally, the gearbox must then remain at the top. But this solution also has numerous problems. Control of the shaft vibrations and the resultant bearing problems of a long, flexible shaft cause additional engineering problems.

The dynamic problems can at least be limited by splitting the gearbox into two transmission stages, thus providing a transmission shaft rotating at a "medium" speed. This type of drive train configuration was implemented in an experimental German wind turbine Voith WEC-520 (see Fig. 5.21). There was only a bevel-gear drive located on the tower head (there was no cased nacelle). A second gearbox was installed above the generator in the tower base (Fig. 8.2). This design permitted the tower head weight to be kept very low, paving the way for a stiff tower design with very small overall mass. The turbine's total weight, with a rotor diameter of 52 m and a nominal power of 270 kW, amounted to a mere 34 tonnes.

The design of the WEC-520 can be attributed to U. Hütter. The turbine was built in 1982 by the manufacturing company Voith which had a good reputation in the construction of water turbines. It was tested from 1982 to about 1985 at the wind turbine test establishment of Stötten in the Swabian Alb but the operational experience proved to be unsatisfactory. Despite great care having been taken in the construction of the turbine, the long transmission shafts tended to oscillate. Moreover, the noise developed by the rotor, which was designed to run at a very high speed, was not acceptable. Since Voith eventually withdrew from wind energy technology, the turbine was dismantled again.

Considered overall, relocating the generator to the tower base is worth a thought for small and medium-sized turbines and can definitely make it easier to assemble and operate a wind turbine provided it is designed properly.

8.2.2 Vertically Positioned Generator in the Tower Head

A step in the same direction, but less radical, is to place the generator in a vertical position in the stationary tower top (Fig. 8.3). Power transmission from the generator to the ground becomes easier and so does accessibility, possibly. There are, however, also some disadvantages. The complexity of the gearbox is increased. In addition, the rotor torque now has a component around the tower's vertical axis. This has special significance when the rotor is braked rapidly and must be taken into consideration in the design of the azimuth drive and its stopping mechanism.

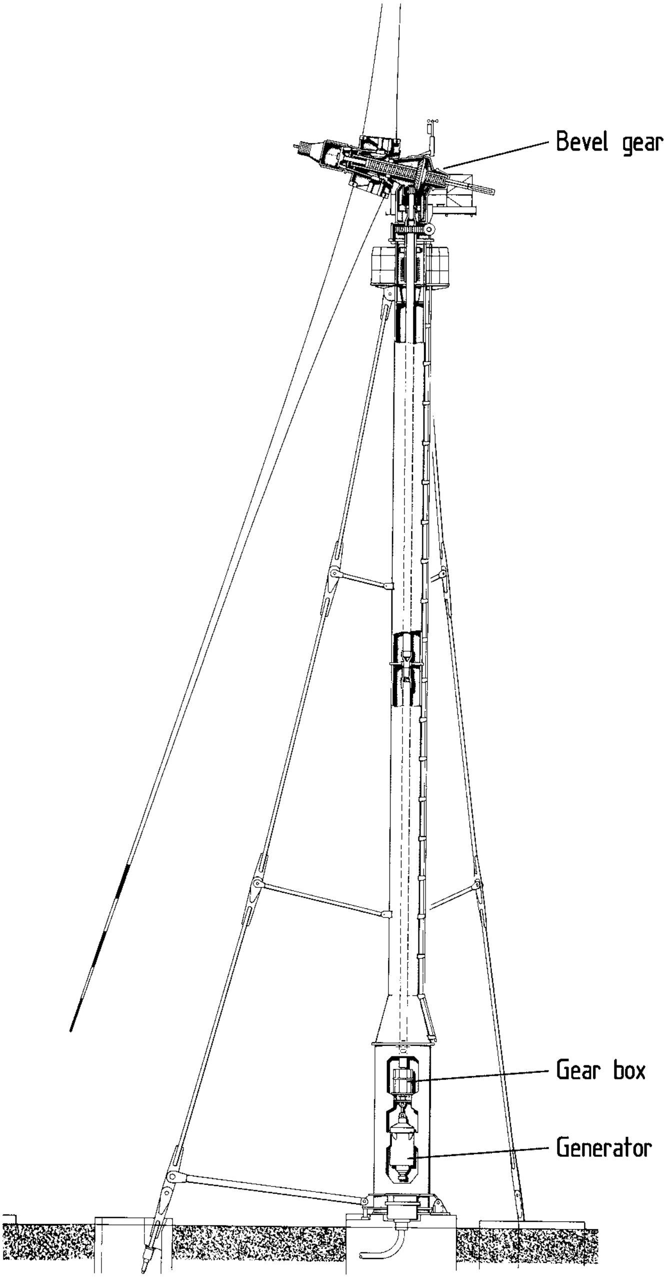


Figure 8.2. Drive train configuration of the earlier WEC-520 [3], 1980

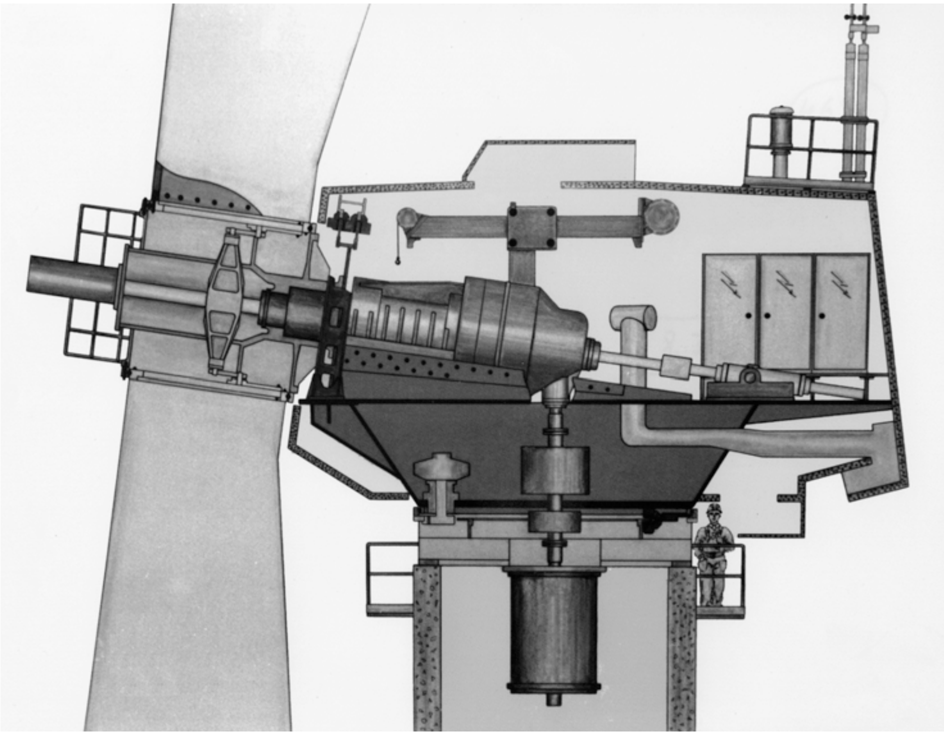


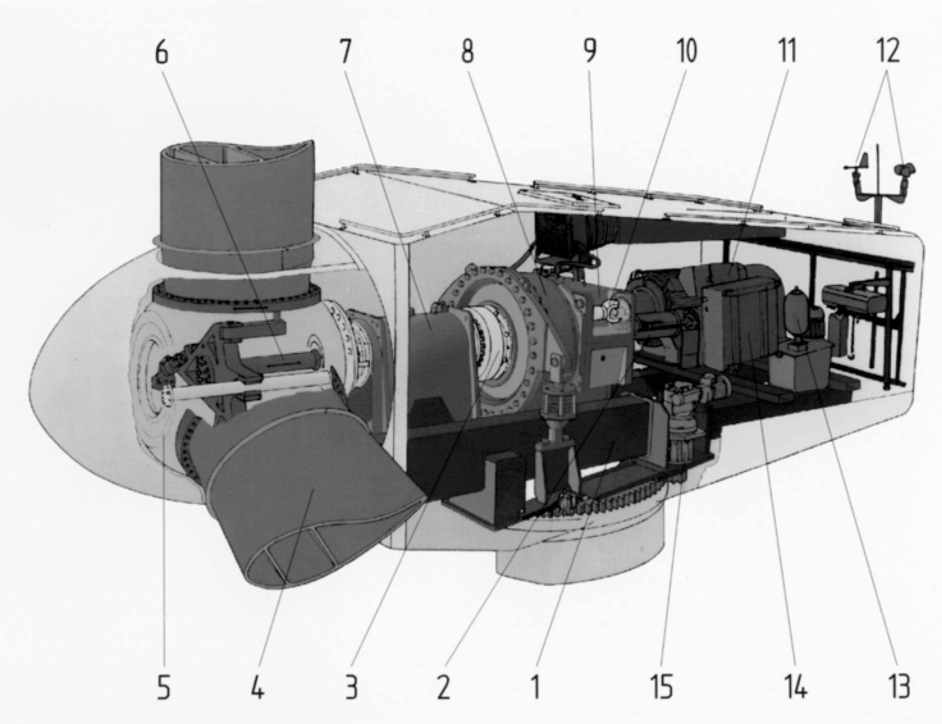
Figure 8.3. Nacelle of the German-Swedish Aeolus II turbine, with the generator placed vertically in the tower head, 1990 (MBB)

8.3 Current Standard Designs

There is no doubt that arranging all drive train components in the nacelle has its disadvantages. The tower structure must support the rotor and the nacelle which has consequences for its strength and stiffness. Installing the nacelle is complicated and it becomes more difficult to access and service the units. Nevertheless, arranging the mechanical and electrical components in line in the nacelle has become the "standard design". Using this approach, the mechanical transmission paths are shortest and the dynamic problems are managed most easily. Today, almost all wind turbine systems are built in this style.

8.3.1 Gearbox between Rotor and Generator

This is the traditional design. It allows conventional high-speed electric generators to be used. A good example of this is the drive train set-up of the Vestas V-39 turbine (Fig. 8.4). A supporting bedplate carries the drive train components mounted in line behind the rotor. All components are easily accessible and, in the a case of a repair, can be replaced individually without having to dismantle the turbine. Wind turbines of this design can be assembled easily from standardised components developed by the supporting industry.



1. Nacelle bedplate	6. Blade pitch mechanism	11. Generator
2. Blade pitch actuator	7. Rotor main bearings	12. Wind measuring system
3. Rotor shaft	8. Gearbox	13. Hydraulic supply system
4. Rotor blades	9. Rotor brake	14. Electrical control system
5. Rotor hub	10. Generator drive shaft	15. Yaw drive

Figure 8.4. Power train of the Vestas V-39 in standard design [4] (Vestas)

8.3.2 Direct Rotor-Driven Generator

Since about 1995, wind turbines with gearless drive train arrangements have been produced in series by the German manufacturer Enercon and have been successfully operated (Fig. 8.5). In the meantime, other manufacturers have adopted this type of design so that it has become established as "second standard design".

The turbines have variable-speed, directly rotor-driven synchronous generators with frequency converters. Due to the provision of the converter, the generator does not need to be designed for the 50 or 60 Hz grid frequency so that the required number of poles, and thus the diameter, remains within tolerable limits.

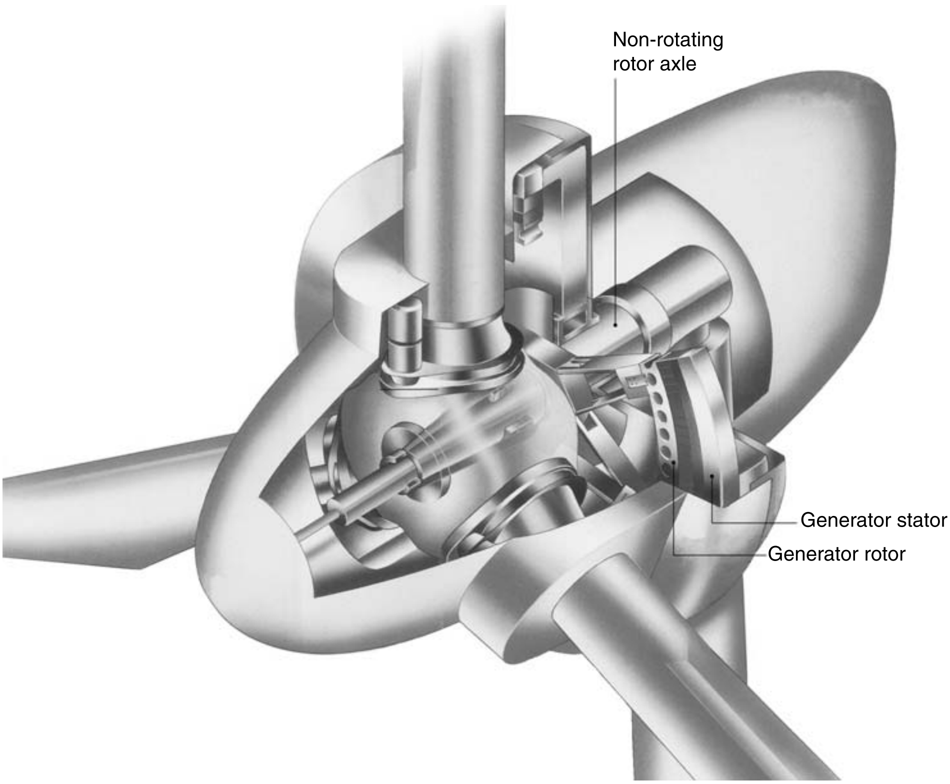


Figure 8.5. Nacelle of the Enercon E-40 with electric generator driven directly by the rotor (Enercon)

From the point of view of servicing and reliability, omitting the gearbox is definitely a step forward. On the other hand, the disadvantages must not be overlooked. The electric generator is a complex special-purpose design and its high weight and still comparatively large diameter lead to a turbine weight which is decidedly higher than in conventional turbine concepts.

One variant coming close to being a direct generator drive is the Multibrid design being tried out in Germany since the beginning of 2005 in a 5-MW turbine with a rotor diameter of 116 m (Fig. 8.6). The fully integrated drive train consists of a single-stage planetary gearbox which is accommodated in a common housing together with the permanent-field generator. The rotor bearing is also integrated in the cast-steel housing.

The basic concept is to combine the advantages of a direct drive with the conventional type of construction by means of a very simple low-speed transmission and generator. Using this compact design, it was at least possible to achieve a tower head weight which, with approx. 310 t specific is much lower than, e. g. in the Enercon E-112 (s. Chapt. 19.4). The Multibrid turbine is intended especially for offshore use [4].

Figure 8.6. Multibrid concept with single-stage planetary gearbox and a permanent-field generator integrated in a common cast housing (Multibrid)

8.4 Rotor Hub

The rotor hub is the first component of the mechanical drive train. Although it is a part of the rotor, however, it is closely associated with the mechanical drive train in terms of function and structure. In pitch controlled wind turbines, the hub includes the components of the blade pitch mechanism and in two-bladed rotors it often has a teetering or a flapping hinge to compensate for the unfavourable load conditions. In this way it becomes a complex system and represents a significant feature of the technical design of the wind turbine.

The rotor hub is one of the most highly stressed components of a wind turbine. All rotor forces and moments are concentrated here almost in a point. Its material must therefore be selected with the greatest care with respect to fatigue life. This involves an extraordinary amount of detailed work for the strength calculations and dimensioning in order to avoid local stress concentrations. There are essentially three possible solutions concerning the selection of materials and the associated design and construction:

– welded sheet steel,
– cast steel,
– forged steel.

In the past, all three variations could be found in wind turbines. In the course of time, the cast steel hub has become generally accepted.

Welded steel sheet designs

The advantage of welded designs is that they can be produced without large investments in production tools. They are for this reason the preferred solution for one-off production runs and for small quantities. Experimental turbines and first generation wind turbines frequently have welded rotor hubs (Fig. 8.7).

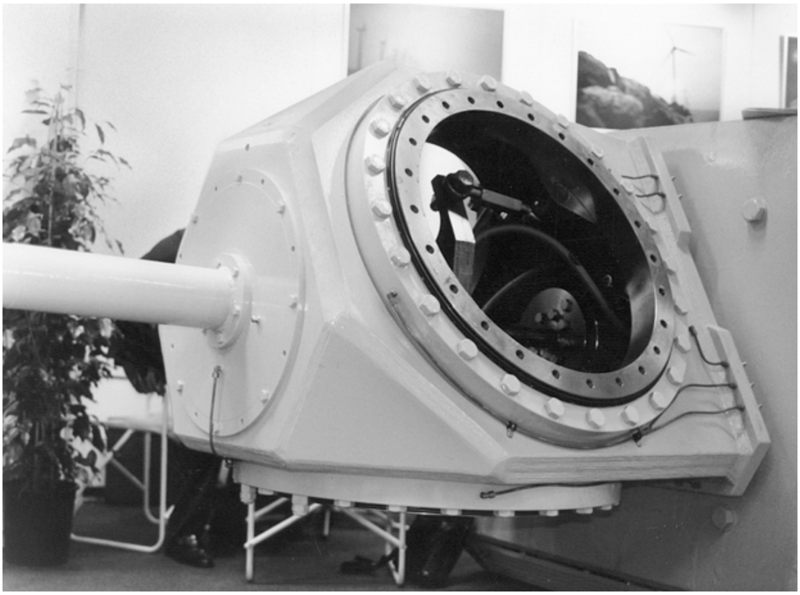


Figure 8.7. Rotor hub made of welded steel sheets in a small Windmaster 300 turbine

But welded hub constructions also have one decisive disadvantage. As in the case of rotor blades made of steel, the welded seams must be checked particularly carefully and for reasons of safety, the allowable stress values must be set extremely low. As a consequence, the weight, and the costs for mass production, are high which is why welded rotor hubs are now found only in small, older wind turbines.

Forged parts

Drop-forged or precision-forged components have the highest strength parameters. This generally known fact suggests that the rotor hubs in wind turbines should be forged. From the point of view of strength, forged hub bodies are indeed the ideal solution.

During forging the material is compacted, and thus strengthened. Moreover, the forging operation can be carried out such that the crystals are stretched in the direction of stress. In this way, high-strength components are obtained which are capable of withstanding the same stress, but which are considerably lighter than welded or cast components.

These advantages, however, are balanced by high cost. Particularly with larger components, production costs become extremely high. It is for this reason that, for example, the teetering hub of the experimental Swedish WTS-3/-4 turbine was made from a combination of forged and cast components. For very large series, however, when the construction of moulds becomes economical, the cost per piece of forged hub can be lowered considerably.

Given the current conditions, forged rotor hubs are no longer an option for economic reasons. The ever increasing dimensions of turbines are another reason. Forged parts with the dimensions of rotor hubs of wind turbines in the megawatt category are approaching the limits of production engineering.

8.4.1 Cast Steel Rotor Hubs for Three-bladed Rotors

The initial search for the optimum hub design was ended by the dominance of the three-bladed rotors in wind turbines, at least temporarily. Three-bladed rotors do not require hinges so that a rigid hub body is adequate. The preferred material is now cast steel.

Only decades ago, cast components for dynamically highly stressed machine components were eyed with great suspicion. The technology of cast materials has, however, made considerable progress since then. Today, cast steel is used for highly stressed components such as the turbine wheels in hydroelectric power plants and this technical advance is also reflected in the construction of wind turbines (Fig. 8.8).

It goes without saying that no "everyday" cast steel is used for this purpose. A much more suitable material for components having a dynamic load spectrum has been found to be spheroidal graphite cast-iron. The technology of casting these components is clearly

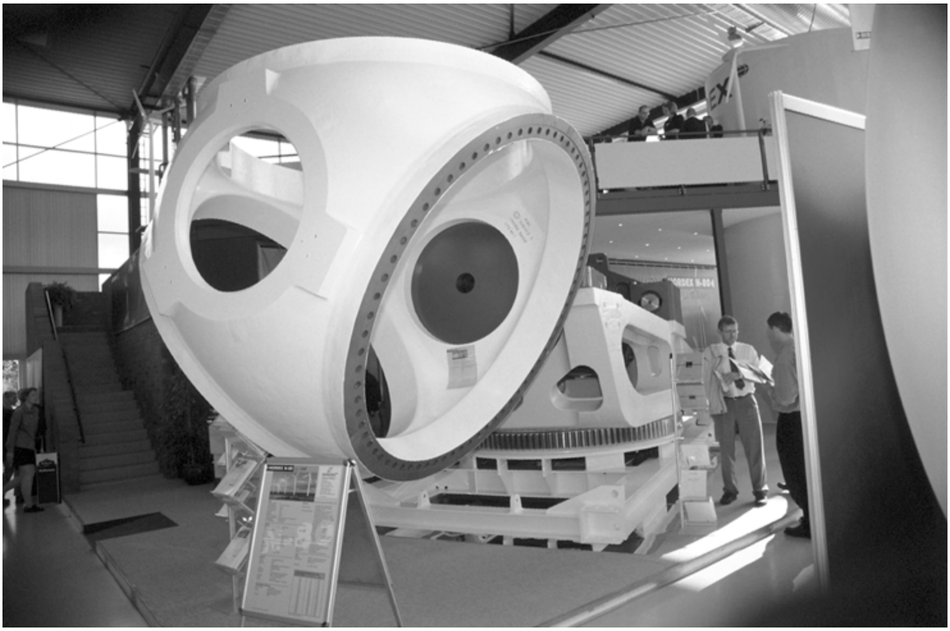


Figure 8.8. Cast rotor hub of the Nordex N-80 wind turbine (weight 15 t)

more demanding than for the usual castings. Various foundries have specialised in this technology, especially in Germany, and supply high-quality rotor hubs and increasingly also other components for wind turbines (rotor axles, load-bearing nacelle bedplates etc.). The cast hubs can be shaped with smooth contours following the load paths. Local stress peaks, resulting from corners and from discontinuities in the wall thickness profile, are avoided. The costs for the necessary casting moulds are, of course, a disadvantage. From the point of view of economics, these costs can only be justified if larger quantities are produced. Cast hubs are, therefore, to be found today in wind turbines which are in series production.

8.4.2
Rotor Hub Concepts for Two-bladed Rotors

The designers of the large two-bladed experimental turbines from the eighties spent a great deal of effort on trying to find a suitable design of the hub. They tried to incorporate a functional compliance in the rotor hub to compensate for the unfavourable response of the two-bladed rotor to loading. Numerous functional concepts and designs were tried and the findings from these trials will regain their significance if and when the two-bladed rotor again becomes an attractive solution with the increasing size of wind turbine installations, for instance in offshore wind farms. The material of the hub was welded steel in nearly all cases. Cast steel hubs appeared later when the three-bladed rotors were produced in larger series.

Hingeless hub

In large two-bladed rotors, the hingeless hub is rather an exception. Its simple design must be paid for with extraordinarily stiff and heavy components. As a consequence of the uneven flow against the rotor, the yawing moment about the vertical axis, in particular, is transferred undamped to the turbine and especially to the yaw system and ultimately to the entire wind turbine. A typical representative of this design philosophy is the experimental German-Swedish Aeolus II turbine. The rigid hub of the Aeolus II is shown in Fig. 8.9. It is welded from sheet steel and weighs approximately 30 metric tonnes.

Teetering hub

A teetering hub with blade pitch coupling was built for the first time in 1959 by U. Hütter (Fig. 8.10). Blade pitch coupling was effected by a mechanical linkage at a ratio of 1:3 to the teetering angle. This hub design became the model for all wind turbines with teetering hub in existence today. The teetering hub of the large Growian wind turbine was designed in direct derivation from the Hütter teetering hub. Using the W-34 as a model, blade pitch coupling was effected by means of a mechanical linkage. The coupling ratio between teetering angle and blade pitch angle varied between a factor of 1 and 2.5, depending on the blade pitch angle set.

In practical operation the welded steel construction of the Growian hub proved to be extremely problematic (Fig. 8.11). Cracks appeared in the trelliswork of the teetering frame structure after less than 100 hours of operation. Checks and stress measurements

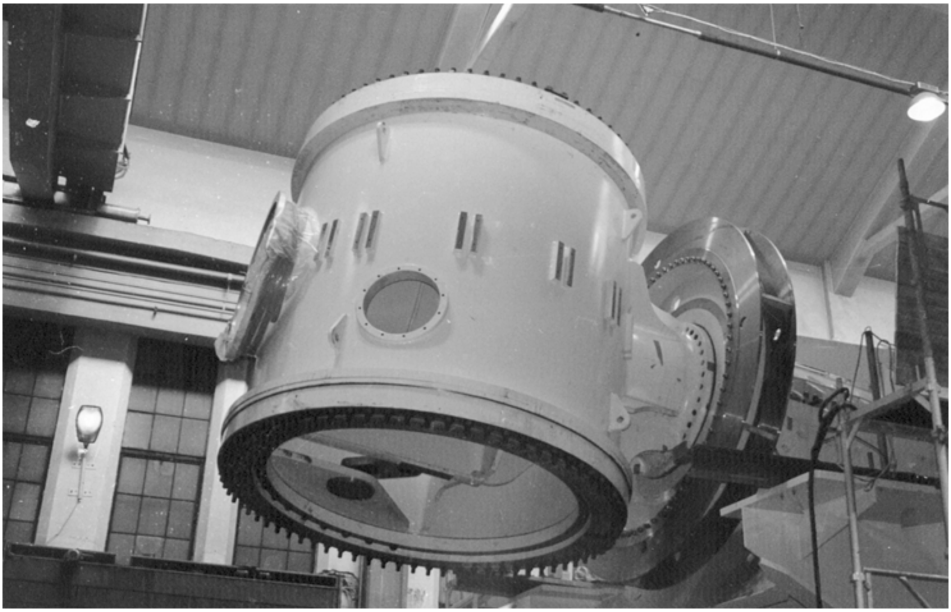


Figure 8.9. Hingeless two-bladed hub of the Aeolus II, made of welded sheet steel

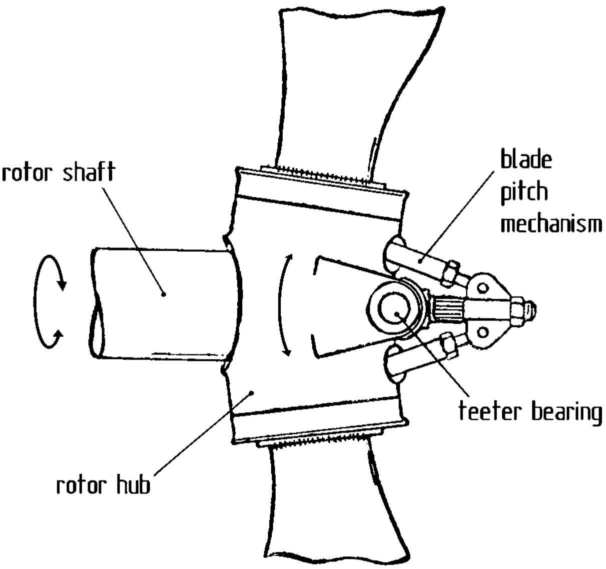


Figure 8.10. Teetering hub with blade pitch coupling of the Hütter W-34, 1959

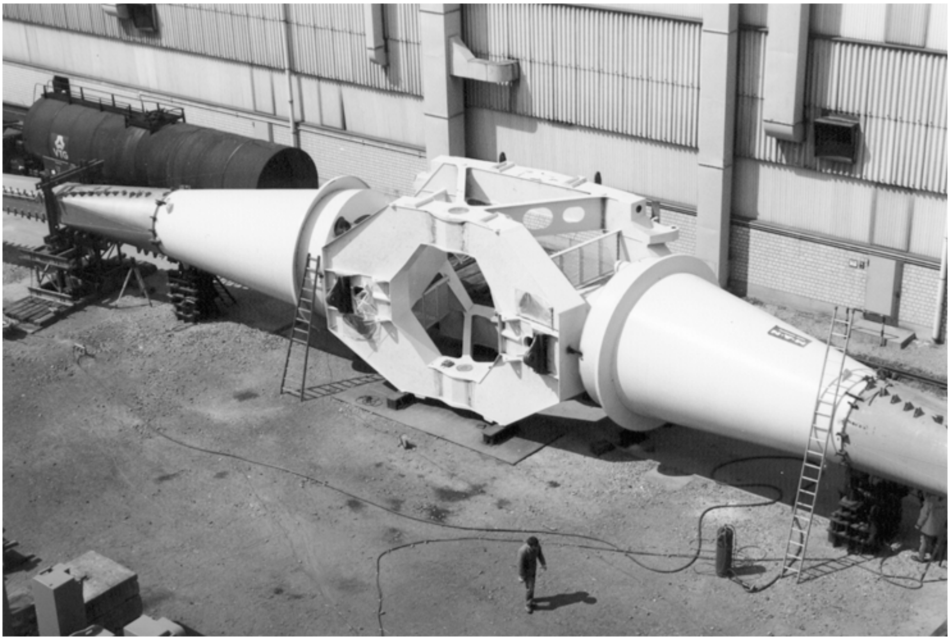


Figure 8.11. Teetering hub frame with rotor blade root segments of Growian, 1982

uncovered local stress concentrations considerably exceeding the allowable values. Despite multiple reinforcements, the fatigue strength of the hub could not be improved and it was this failed hub design which was the main reason for the short life of Growian.

Coupling the blade pitch angle to the teetering movement of the rotor can be realised very easily by tilting the teetering axis with respect to the rotor axis (δ_3 coupling). For geometrical reasons, the teetering movement is in this case automatically associated with a change of the aerodynamic angle of attack of the blade, without the blade pitch angle having to be changed (Chapt. 6.6.2). The Swedish-American WTS-3/-4 experimental turbines were equipped with such a teetering hub (Fig. 8.12).

This elegant solution is very simple, but has some disadvantages. The coupling factor becomes dependent on the teetering amplitude and is no longer constant. Moreover, the choice of transmission ratio between hub teetering angle and the aerodynamic angle of attack of the blade depends on the geometry of the axis tilt. For low rotor speeds in the WTS-3, hub teetering stabilisation was effected by means of a block on teetering up to approximately half the nominal speed, during the rotor start-up and shut-down sequences.

The American MOD-2 test turbines had simple teetering hubs without blade pitch coupling. For the heavy all-steel rotor with little aerodynamic sensitivity, blade pitch coupling was obviously not considered effective enough. From the design point of view, the MOD-2 teetering hub had a relatively simple structure (Fig. 8.13). The concept of a one-piece rotor core, and the blade pitch mechanism located in the blade tips completely removed the blade pitch mechanism from the hub, and thus provided the precondition for this very simple

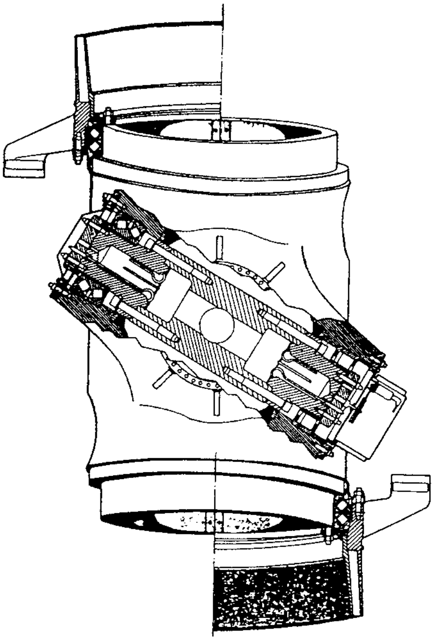


Figure 8.12. Teetering hub of the WTS-3/4 with the blade pitch angle coupled to the teetering angle by way of tilting the teetering axis [2], 1983

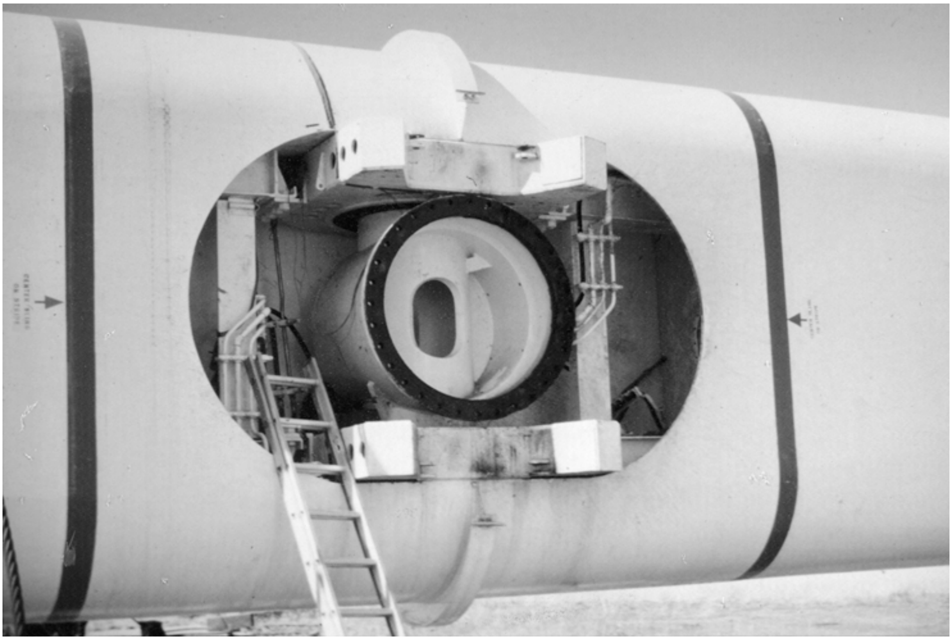


Figure 8.13. Teetering bearing on the MOD-2 in the hub section of the all steel rotor, 1982

hub concept. The teetering bearing consisted of a rubber-like, elastomer material which was glued in concentric rings, with rings of sheet steel in between. When rotor speed was low, the teetering rotor was arrested in a fixed position by a teeter brake. There were also mechanical stops.

In retrospect it must be said that none of the teetering hubs shown here have completely satisfactory operating characteristics. Among other things, the problem of restricting the teetering angle has never been solved satisfactorily. When rotor speed is slow, e. g. during the start-up and shut-down procedure, the aerodynamic damping and stabilisation of the rotor teetering movement is insufficient, presenting a risk of unstable teetering of the rotor with excessively large teetering amplitudes. To prevent this, the teetering hub must either have a brake which holds the teetering movement at the lower speeds, or it must have hydraulic teetering dampers to limit the teetering motion. In practical operation, both solutions have proved to be problematic. At low rotational speeds, and when there is a strong gusty wind, the teetering rotors strike the amplitude stops and, as a consequence, the hydraulic dampers or the mechanical stops wear prematurely.

8.5 Blade Pitch Mechanism

As a rule, larger wind turbines have rotors equipped with blade pitch control. The mechanism required for this must basically fulfil two tasks. The primary task is to adjust the blade pitch angle for controlling the power and speed of the rotor. A pitching range of around 20 to 25 degrees is enough for this purpose. But apart from this main function, there is a second task which has considerable influence on the design of the blade pitch mechanism. To brake the rotor aerodynamically, it must be possible to pitch the rotor blades to the feathered position. This increases the pitching range to approximately 90°.

The implementation of the blade pitch mechanics offers the designer possibilities for design creativity scarcely rivalled by any other system. The models implemented are accordingly varied and the proposals and patents are even more numerous. An better overview of this variety can be attained if the "blade pitch mechanism" system is broken down into its main components.

Rotor blade bearings

The prerequisite for implementing blade pitching is the ability to turn the rotor blades around their longitudinal axis. Even though the necessary angle of rotation and the rotating speeds are relatively small, the rotor blades are almost exclusively supported by roller bearings at the blade root.

In some earlier turbines, only the outer blade area was adjusted (Chapt. 5.3.1, Fig. 5.18). In this case the bearings and the blade pitch drive must be relocated into the outer blade area. This poses additional design problems with respect to spatial conditions and weight at an awkward place in the outer blade section.

Blade pitching drive

The main distinguishing feature of blade pitching systems is the type of drive. Hydraulic drives are still in the majority in older wind turbines but an alternative are electrical motors and these are increasingly found in more recent turbines. The reasons are the extended control possibilities and precision of the newer electronically controlled pitching motors, and the avoidance of the leakage problems experienced with hydraulic units.

Actuator elements

The design of the actuating elements depends on the selected drive units, on the one hand, and, on the other hand, on the arrangement of the blade pitch drive in the space of the nacelle or of the rotor hub. Hydraulic actuators acting directly on the blades are the simplest solution if they are drive units and actuating elements at the same time. If pitching drives other than direct actuators are used, it becomes necessary to effect the movement on the rotor blades via mechanical actuating elements. This job can be handled by pitching shafts, toothed gearing or any conceivable linkage mechanism.

Power supply

The blade pitching drive must be supplied with power. In most cases, the power supply system of the blade pitching system is housed in a fixed position within the nacelle. In the case of electrical systems, installation of the blade pitch motor or actuator in the rotating rotor hub requires the electric current to be transmitted into the hub via a slip-ring, whilst hydraulic systems require a rotary leadthrough of the supply line.

If, apart from the power supply, the pitching system is also installed in a fixed position in the nacelle, the connection to the rotating hub can be implemented with mechanical parts. This can be done by means of connecting rods or rotary shafts passing through a hollow rotor shaft. These designs have the advantage that all parts of the blade pitching system requiring frequent maintenance are housed in the nacelle.

Emergency blade pitching system

Wind turbines with blade pitch control can generally only brake the rotor by pitching the rotor blade to the feathered position. If the rotor loses all its load suddenly, say when the generator loses synchronisation, pitching the rotor blades to the feathered position must be done rapidly to prevent rotor runaway. Reliable operation of the rotor emergency stop is of considerable significance in the design of the blade pitch mechanism. Thus, most turbines have an additional emergency drive system for blade pitching which operates more or less independently of the normal blade pitching system.

Enumerating the main components of the blade pitch mechanism shows that this is a complex system. It involves both the rotor and the mechanical drive train. The blade pitch system is therefore one of the system-determining components of the wind turbine, the design of which is inextricably linked to the overall concept of the turbine.

8.5.1 Rotor Blade Bearings

The loading of the rotor blades is comparatively unfavourable with respect to roller bearings. The bearings are exposed to high static loads, even when the rotating movements are small. Moreover, permanent deformations of the bearing support is more or less unavoidable. Given these preconditions, the criteria of "rippling" and "frictional corrosion" must be considered in the design of the roller bearings. By comparison, the normal design parameter determining service life, the specified number of rolling cycles, only plays a subordinate role in the roller bearings of the rotor blades. Today's concept of rotor blade bearings is an in-plane bearing system where the roller bearings are grouped in one plane over a very short distance.

In the so-called "live-ring bearing" used in older types of wind turbine, the cylindrical rollers are arranged in planes perpendicular to each other (Fig. 8.14). This type is relatively complex and thus expensive. Double-row "angular-contact cylindrical" or "crossed roller bearings" are simpler.

More recently, so-called "four-point contact bearings" or "ball bearing slewing rims" are used almost exclusively (Fig. 8.15). These bearings are less sensitive to deformations of the bearing body, thus avoiding the concentrated peak loads occurring with cylindrical rollers under these circumstances. Where the blades are relatively small, a single-row arrangement suffices whereas large rotor blades require double-row four-point bearings.

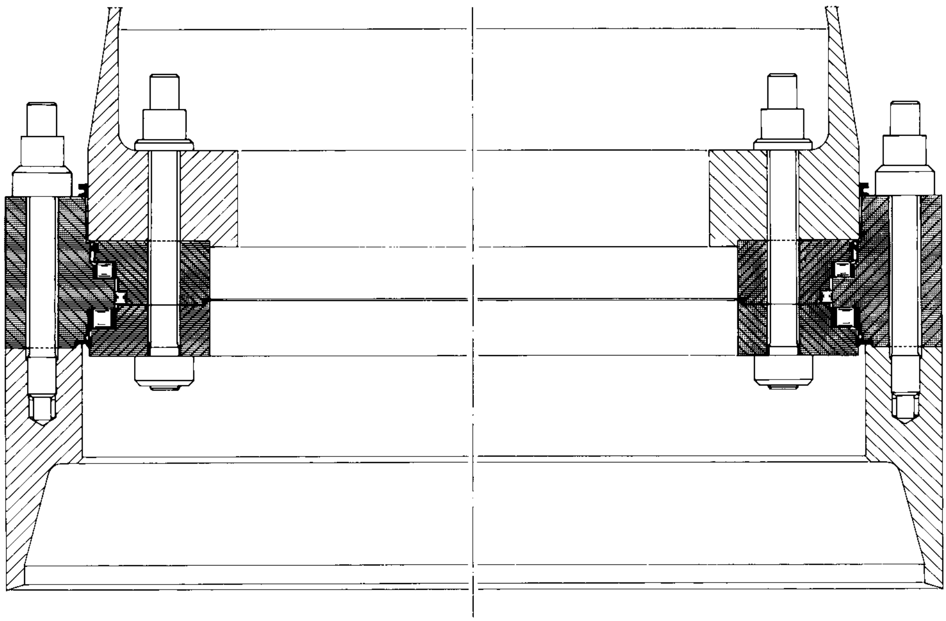


Figure 8.14. Rotor blade bearings with angular-contact roller bearings in the earlier Swedish WTS-75 (Rothe Erde Schmiedag AG)

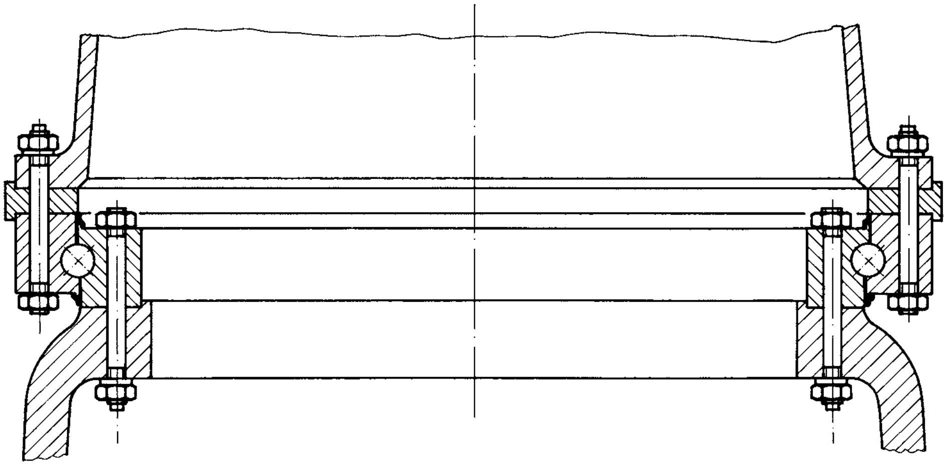


Figure 8.15. Single-row four-point ball-bearing in the rotor blades of the earlier WKA-60 (Rothe Erde Schmiedag AG)

Similar to the rotor bearings and the bearings of transmissions and generators, the service life of the rotor blade bearings has not always been satisfactory in the past. Although the bearings are designed for a service life of 20 years, the special conditions encountered in their use in wind turbines have led to premature failures in many cases. Special attention must, therefore, be paid to the dynamic design of the bearings (s. Chapt. 8.6.1).

The small angle of rotation of the rotor blades basically does not require a complicated bearing system. In some of the smaller turbines, occasional attempts have therefore been made to make do with relatively simple hinge bearings. In larger turbines, however, attention must be paid to see that the moments of friction of the bearing remain as small as possible so that the pitching forces do not become unnecessarily large. For this reason, the rotor blades are provided with conventional roller bearings in the rotor hub, as a rule.

In recent years, novel friction bearings have been developed which are also suitable for being used in wind turbines [10] These are not the conventional friction bearings with hydro-dynamic oil lubrication as are normally used, e.g. in large turbines, but bearings which have plastic-coated friction surfaces instead of rolling elements. The coating consists of a composition of teflon, reinforcing fibres and synthetic-resin adhesive. The friction releases the teflon which then acts as a lubricant. After a certain running-in phase, the wear rate decreases and with the dry lubricant, the bearings run with extremely low wear. The bearings are completely maintenance-free and are also said to meet the service life requirements.

Friction bearings of this type have already been used in wind turbines for slow turning movements in smaller components. In principle they can be built in larger dimensions. They could be used as rotor blade pitch bearings and for the azimuth bearing of the nacelle.

8.5.2 Hydraulic Blade Pitch Systems

The blade pitch control systems of wind turbines differ mainly in the type of drive used. The pitch systems of the earlier large wind turbines mostly had hydraulic actuators in the rotor hub, rotating the blades either directly or via mechanical linkages. The hydraulic power supply of the actuators is commonly housed at a fixed location in the nacelle so that the supply lines must be routed through the gearbox and the hollow rotor shaft into the hub. To reach the rotating hub from the stationary nacelle, a sealed hydraulic rotary transmission leadthrough is required. Figure 8.16 shows an hydraulic blade pitch adjustment system of this type.

In the example shown above, three hydraulic actuators are installed outside the rotor hub. The hydraulic supply and return lines for the actuators are routed through the hollow rotor shaft and through the gearbox into the rear part of the nacelle to the pressure supply system located there, which consists of a motor-driven pump and pressure accumulators. The rotating hydraulic leadthrough is easily accessible, being located directly behind the gearbox. The central passage of the lines through the gearbox is facilitated by a rear parallel-shaft-gear stage, which leads to a displacement of drive shaft and driven-shaft. The actuators are controlled by means of control valves via a change in mass flow or control pressure.

To avoid having to use a rotary leadthrough, one can either locate the entire hydraulic system in the revolving hub, or the actuators have to be installed in a fixed position in the nacelle. In the latter case, the pitch adjustment motion must be transmitted into the revolving hub by means of mechanical transmission elements, for example a connecting rod (Fig. 8.17). Blade pitch adjustment using an actuator housed in the nacelle has proved more successful. For this reason, the majority of the more recent wind turbines have been fitted with blade pitch systems of this type. The hydraulic units are located in the nacelle, providing easy access for servicing. The connecting rod from the nacelle into the rotor hub can be implemented easily if the rotor is mounted directly at the gearbox and the gearbox

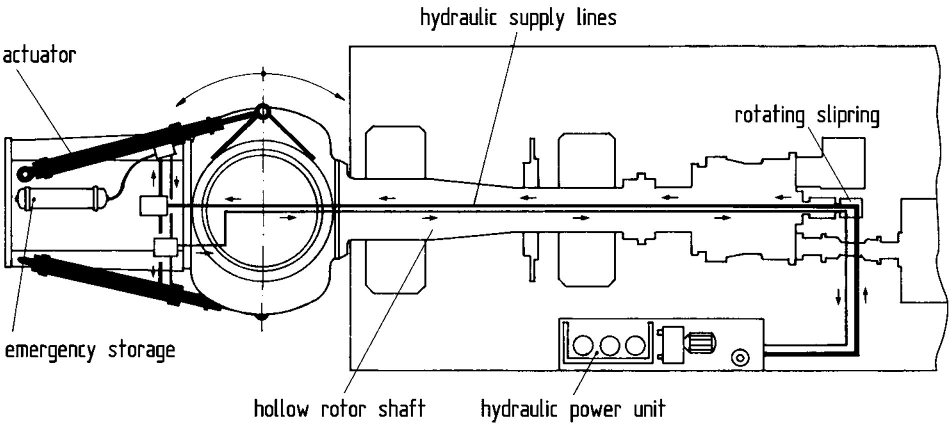


Figure 8.16. Blade pitch system of the WKA-60 with hydraulic drive and direct-acting actuators in the rotor hub

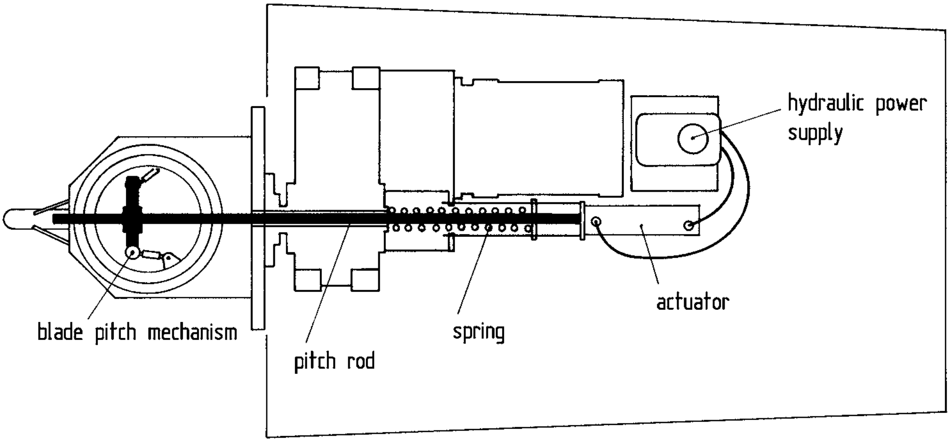


Figure 8.17. Blade pitch system in an earlier Windmaster turbine with hydraulic actuator in the nacelle and pushing rod to the rotor hub

has axially displaced input and output shafts. The hydraulic actuator works against a strong spring, so that in a breakdown involving the complete loss of system pressure, the rotor blades are forced into the feathered position by the spring, thus causing the rotor to stop. In the larger turbines, the actuators and the hydraulic accumulator for emergency pitch adjustment in case of a failure of the hydraulic units in the nacelle are accommodated inside the rotor hub.

In wind turbines with partial blade pitching, the pitch mechanism must be installed in the outer blade area (Fig. 8.18). Implementation of this involves some additional problems. The lack of headroom in the rotor blade cross-section in the outer third of the rotor diameter necessitates a very compact design of the pitch mechanism. Moreover, the additional weight in this section has an adverse effect on the blade stiffness and this effect can be highly undesirable as far as the dynamic properties of the rotor are concerned.

Another aspect is the pressure supply, particularly in hydraulic systems with long supply lines through the rotor blades, and a rotary transmission leadthrough close to the rotor hub. Seen overall, shifting the central blade pitch mechanism away from the hub only causes other complications. A convincing advantage is achieved only in two-bladed rotors, where partial blade pitching permits a one-piece rotor structure to be used in the area of the hub.

The general tendency in wind turbine technology indicates that hydraulic pitch mechanism will only be implemented in exceptional cases. Many problems with poor reliability, particularly with oil leakages, are the main reason for this. On the other side there is a considerable progress in controlled electric motors. They offer many advantages as rotor blade pitch drives.

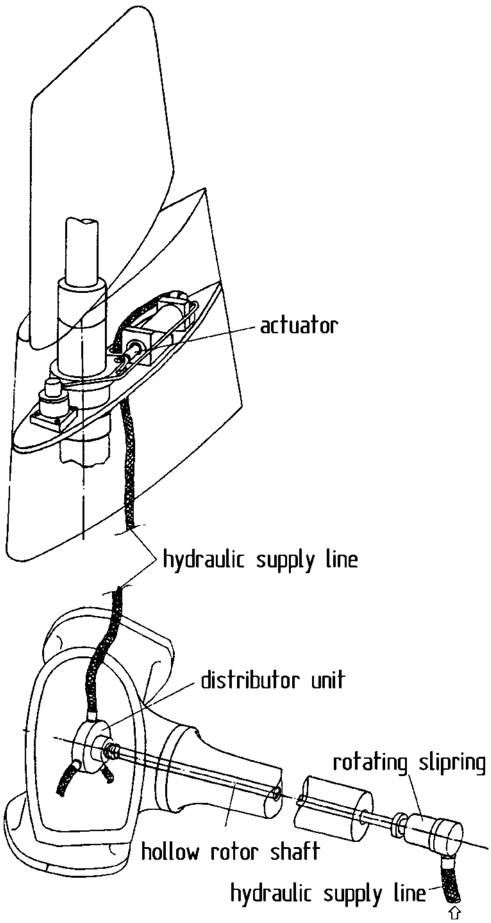


Figure 8.18. Partial blade pitching in the earlier Howden HWP-1000 turbine rotor [6]

8.5.3
Electrical Blade Pitch Systems

Until a few years ago, electrical blade pitching used to be an exception in wind turbines. In principle, it is much more difficult to control electrical pitching drives. The speed and torque of common electric motors can only be controlled in practice by using frequency converters. Otherwise highly expensive direct-current units must be used. The ability to control the rate of pitch adjustment is essential in large turbines so that the loads on the rotor blades can be limited. This requirement can be dispensed with in smaller turbines which, therefore, may be able to manage without controllable pitch motors (Chapt. 10).

Today, electronically-controlled pitch motors of very compact design are available which has led to the increasing use of electrical blade pitching drives by wind turbine manufacturers. The first one of these was Enercon where each rotor blade on their medium-sized range of turbines (E-40) has its own electric pitch motor mounted on the outside flange ring (Figs. 8.19). Other manufacturers place the electric pitching drive completely inside the rotor hub (Fig. 8.20).

The power supply for emergency pitch adjustment consists of two batteries which are also located in the rotor hub.

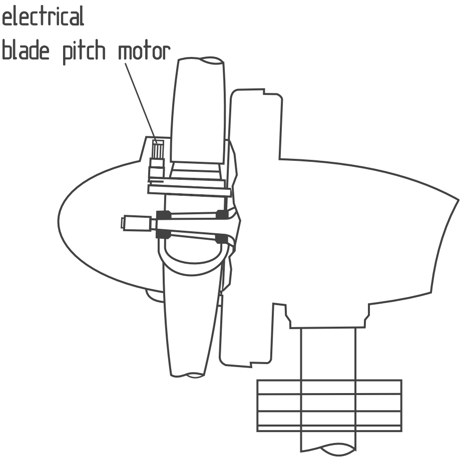


Figure 8.19. Individual electric pitch systems for each rotor blade in the Enercon E-40

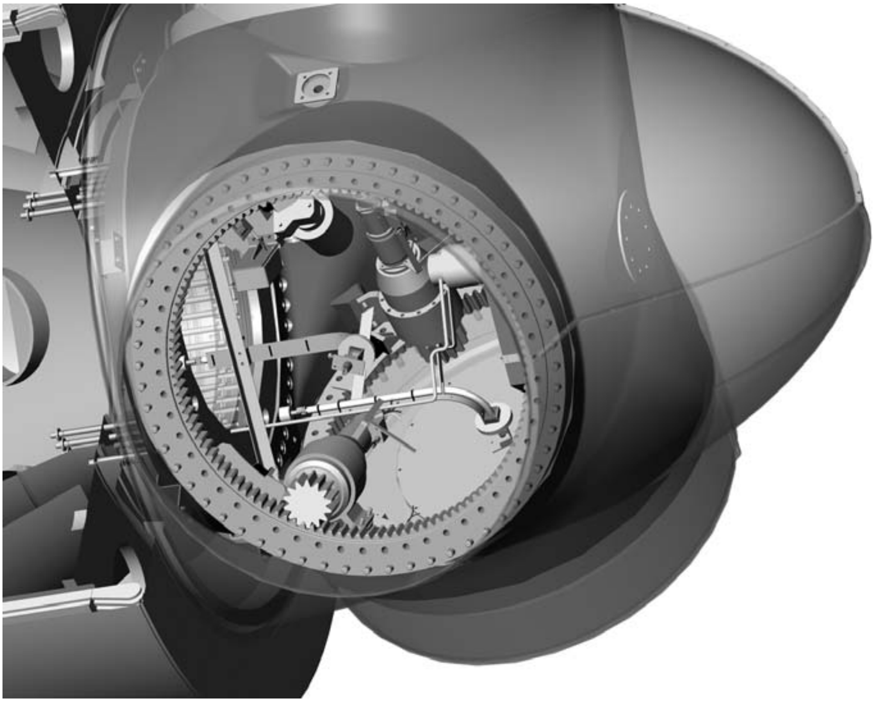


Figure 8.20. Electrical blade pitch system of the Dutch Lagerwey LW-72 inside the rotor hub

8.5.4 Passive Blade Pitching

The idea of using the aerodynamic or mass forces acting on the rotor blades to adjust the blades to the desired pitch is not new. Relevant attempts have been made in the past in several test turbines and prototypes to use of the wind-speed-dependent aerodynamic moment around the longitudinal axis of the blade, or the rotor thrust as the driving force for changing the pitch angle. However, it turned out that no usable "passive" pitch control could be achieved by this means. The correlation between these forces and the wind speed or the desired rotor speed and power output was not precise enough for them to be used as control parameters for blade pitching.

It was only in some relatively small turbines that attempts have been successful in implementing a practicable passive blade pitch mechanism. The key to success was the variable-speed rotor. This provided a clear correlation between rotor speed, or the resultant centrifugal force, respectively, and the desired power output. The older turbines of the Dutch manufacturer Lagerwey, for example, have passive blade pitching. The blades of the two-bladed rotor of the older Lagerwey turbines are connected to the rotor hub by means of individual flapping hinges. With increasing wind speed, the blade pitch angle is adjusted passively against a spring-loaded mechanism as the rotor speed also increases. The method has been successful in the smaller Lagerwey turbines with a rotor diameter of between 15 and 20 m (Fig. 8.21).

Passive blade pitch adjustment, and with it the absence of hydraulic or electrical drives and electronic power and speed control arrangements, is without doubt a desirable simplification. This concept has, therefore, also been taken into consideration for larger wind turbines. However, dispensing with an active control system would have much more severe consequences, for example for the start-up procedure or for an emergency shut-down, so that it is doubtful if a passive blade pitch system is a practicable solution for large wind turbines.

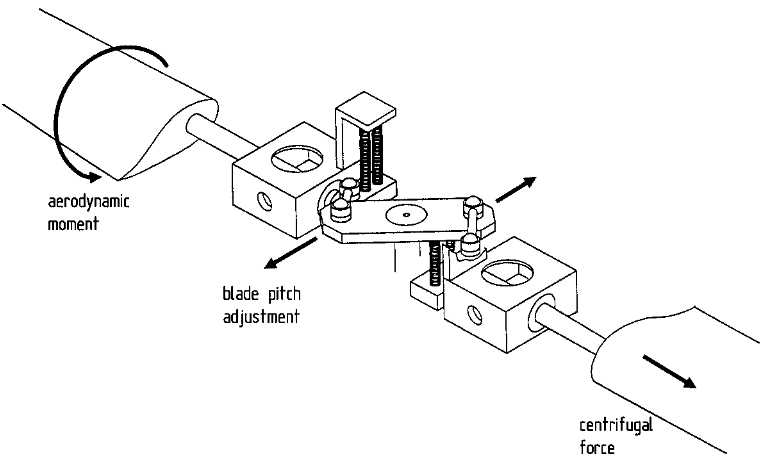


Figure 8.21. Passive blade pitch adjustment in the Dutch Lagerwey W-18/80 kW [7]

8.5.5 Redundancy and Safety Issues

To prevent a runaway of the rotor when its load is suddenly lost, large wind turbines can only brake the rotor by adjusting the pitch of the rotor blades (Chapt. 18.8). Apart from structural strength, the second most vital safety feature of a wind turbine is, therefore, the reliability of the blade pitching mechanism. With this in mind, redundancy in the components and control circuits involved in rotor blade pitching is an indispensable requirement. A thorough "reliability and failure-mode analysis" of the blade pitch mechanism should, therefore. be required for all wind turbines.

In order to assess the redundancy of the blade pitch adjustment mechanism in case of an emergency, three different functional areas must be considered:

- Sensor and release mechanism,
- Actuating elements,
- Power/pressure supplies.

Multiple redundancy type triggering via electrical circuits and mechanical switches, for example centrifugal switches and vibration sensors, can be implemented without a great deal of engineering effort.

Redundancy of the power/pressure supply is more difficult to resolve. In hydraulic systems, it can still be achieved relatively easily by providing additional hydraulic pressure accumulators. Electric power supply systems require batteries as backup.

The actuating elements of the pitch drive require the greatest engineering effort in order to achieve the desired redundancy. Although a second set of pitch motors or actuators is conceivable, it would still not be a complete solution. In the case of a seized rotor blade bearing, for example, it would not present additional reliability. In practice, redundancy in this respect is only possible because the pitching of one or two rotor blades is sufficient for preventing the rotor from running away. Consequently, it must be ensured that in cases of emergency, the rotor blades can be pitched independently of one another.

The safety philosophy of the hydraulic blade pitch system of the WKA-60 is illustrated by the diagrammatic representation in Fig. 8.22. In case of a failure of the hydraulic pump, sufficient pitching capability for a rotor stop remains due to the pressure accumulators in the nacelle. If supply lines are fractured, the emergency accumulators installed in the hub come into action. Each rotor blade has an independent actuator with an emergency accumulator. It is enough to turn one rotor blade into the feathered position in order to prevent a rotor runaway. Rotor shut-down or the emergency stop is triggered by a "fail-safe" circuit, either on the basis of a fault indication from the electronic monitoring system, or from an additional monitoring system which registers an excessive rotor speed by means of a centrifugally actuated switch. This doubly redundant release system is arranged for different overspeed values. The electrical trip is activated at an excess speed of 115 to 118 %. If this fails, the trip signal of the centrifugal switch is activated at 120 % excess speed.

In recent wind turbines, electrical pitch motors are used for each rotor blade. In the case of a loss of electric power batteries are used for emergency braking. The feathering of only one rotor blade provides enough drag to stop the rotor.

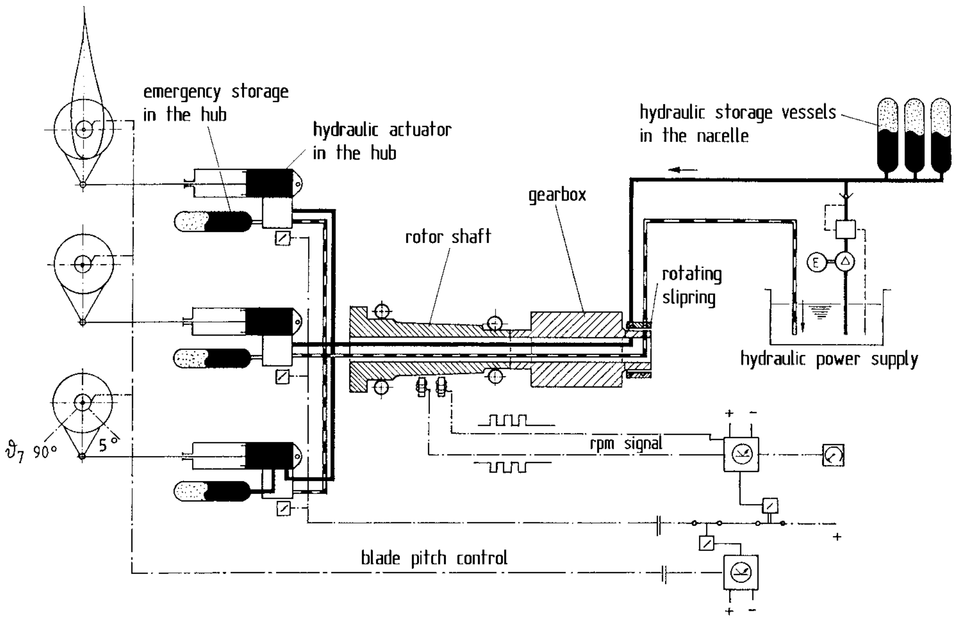


Figure 8.22. Redundant hydraulic blade pitch system of the WKA-60

8.6 Rotor Bearing Concepts

The design of the rotor bearings and their integration into the drive train has a decisive influence on the design of the drive train and the nacelle. The drive train arrangement and the static design concept of the nacelle are a direct consequence of the rotor bearing design.

The selection of the rotor shaft and bearing assembly is dominated by the basic issue as to how to transfer the rotor loads to the tower by the shortest path, thus making the construction as compact as possible. The other important issue is, to what extent the mechanical drive train components are to be integrated into the load-bearing structure of the nacelle. In other words, the trend towards integration of the components and the greatest possible constructional compactness is incompatible with the alternative solution of a less compact type of construction with easy access and maintainability. These points have a considerable influence on the tower-head mass of the wind turbine.

8.6.1 Bearing Technology and Service Life

The rotor bearings in wind turbines are normally roller bearings. As bending deformations of the rotor shaft can never be completely ruled out, the bearings must be designed accordingly. In the standard concept with a long shaft, the rotor bearings are double-cone or swivel-joint roller bearings at the fixed and at the movable bearing end (Fig. 8.23 and 8.24). Particularly the axial movements of the shaft are a danger of wear for the axial sliding roll bodies. This can be avoided by a special design of the bearings including the housing [8].

Figure 8.23. Svivel-joint roller bearing (FAG/INA)

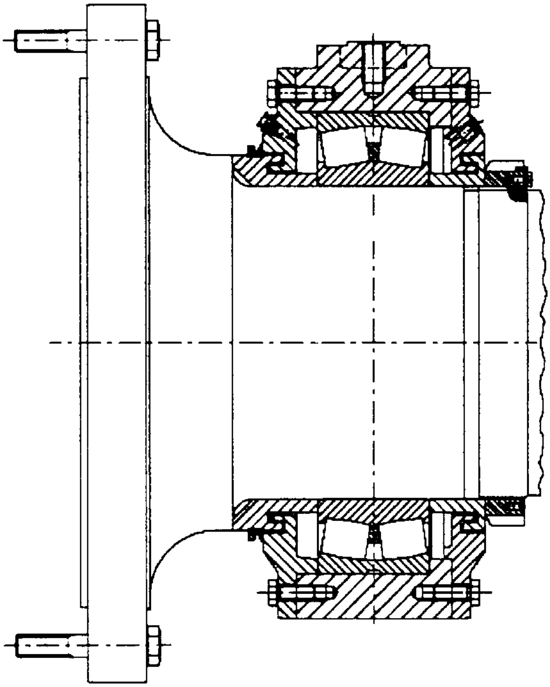


Figure 8.24. Section through a svivel-joint roller bearing with special housing for wind turbines [8] (SKF)

There are two ways of lubricating roller bearings. The most effective way is pressure lubrication with the aid of an external oil supply system. This type of lubrication has several advantages. Bearing temperature can be influenced by the rate of flow of the lubricating oil, and, moreover, contaminants and abraded metallic particles from the bearings are washed out. On the other hand, the oil supply system is relatively complex with pumps, vessels, valves and pipes. Numerous possible leakage areas, mainly in the bearings themselves, must be carefully sealed. There are always efforts, therefore, to use the much simpler grease lubrication whenever possible.

Lubrication with bearing grease is sufficient for many purposes. The bearing grease is placed into the bearings during assembly and can, under some circumstances, remain in the bearings throughout their entire operating life. Grease lubrication is independent of auxiliary units and thus practically maintenance-free. If the bearings are dimensioned properly, the bearing temperature remains within the allowable range since the grease cannot affect the temperature. Grease-lubricated rotor bearings are, therefore, used in almost all smaller wind turbines and also in some of the large ones.

In view of the persistent problems with the service life of roller bearings, some comments regarding service life design appear appropriate. They relate not only to the rotor bearings but even more to the pitch bearings of the rotor blades and also to the roller bearings in the gearbox and in the electric generator since the number of rolling cycles is very much higher in these components. According to DIN Standard ISO 281, roller bearings are designed with respect to the *nominal service life*:

$$L_{\mathrm{h}} = \frac{10^6}{n\,60}\left(\frac{C}{P}\right)^p$$

where:

L_{h} = nominal service life (h)
n = rotational speed (r.p.m.)
C = dynamic load rating (kN)
P = dynamic equivalent loading (kN)
p = life exponent (—)

The so-called life exponent contains the *dynamic index*

$$f_{\mathrm{L}} = 10\,\sqrt{L_{\mathrm{h}}/500}$$

This dynamic index is derived from empirical values and its value is between 2.0 and 5.0. The larger values apply to continuously operated machines with a nominal service life of up to 100 000 hours. For wind turbines, a service life of, for example, more than 130 000 hours with a 10 % failure probability is demanded. However, the dynamic index only takes into consideration the type of loading (fatigue load spectrum) and assumes the cause of a failure to be material fatigue. Unfavourable operating conditions must be taken into consideration additionally by means of certain factors. Experience from recent years has shown, however, that the operating conditions play a decisive role in wind turbines, especially the purity and the temperature of the lubricant.

In order to account for severe operating conditions, the *achievable modified service life* was introduced in DIN ISO 281 [9]. The problem is, however, that for the different operating conditions, corresponding influencing quantities must be found. The bearing manufacturers have not as yet found a common approach to this problem. The reliable calculation of the bearing life in wind turbines is still the subject of controversial expert discussions. It is probable that a service life design matching the total life of the wind turbine will only be achieved on the basis of long term experience in the next few years.

8.6.2 Rotor Shaft with Separate Bearings

The traditional solution of rotor shaft and bearing assembly is a "floating shaft" on a bedplate with two separate bearings. The rotor forces are transferred into the tower via the bedplate which, as a rule, is designed as a welded steel frame with longitudinal and cross beams. In this concept, the gearbox is arranged in most cases as a "slip-on" transmission and does not have to absorb any rotor loads other than the torque (Fig. 8.25).

In large turbines with this modular configuration of the drive train, the rotor shaft is a comparatively heavy and expensive component. For reasons of strength, forged shafts are mainly used. Cast rotor shafts have also been used recently, which saves costs but not weight. Machining is also a complex operation since the rotor shaft almost always has a certain "hidden life" since the hydraulic and electrical supply lines, and in some cases also mechanical actuating elements for blade pitch adjustment, are passed through the hollow rotor shaft.

This "modular" design results in a long structure and thus to a great overall mass of the load-bearing nacelle bedplate. In large quantities, where the amount of material used becomes the decisive cost factor, this type of design is disadvantageous. In small quantities,

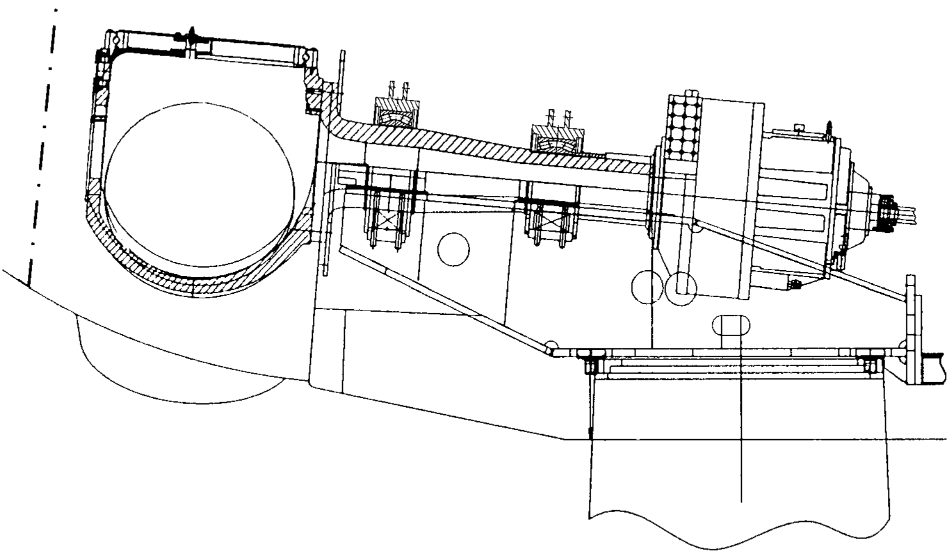


Figure 8.25. Rotor shaft with two separate bearings in the Vestas V-66

the advantages of this concept, i.e. its simple and clear arrangement on a nacelle bedplate, the use of standard gearboxes and bearings, the easy accessibility, all compensate for the disadvantage of the larger overall mass.

8.6.3 Three-Point Suspension of Rotor Shaft and Gearbox

A bearing design which has been used successfully more recently in large turbines is one in which the rear bearing is integrated into the gearbox. In this configuration, the rotor shaft and the gearbox are supported at three points: the front rotor bearing and the two side support bearings of the gearbox, which is why this design is called a *three-point suspension* (Fig. 8.26). The advantage is that the distance between the bearings becomes shorter and thus also the heavy load carrying part of the bedplate. Moreover, the "rotor shaft with bearing and gearbox" assembly can be preassembled and installed jointly which facilitates the efficient assembly of the nacelle. The gearbox is still largely a standard gearbox of the usual design and can thus be obtained from a number of suppliers.

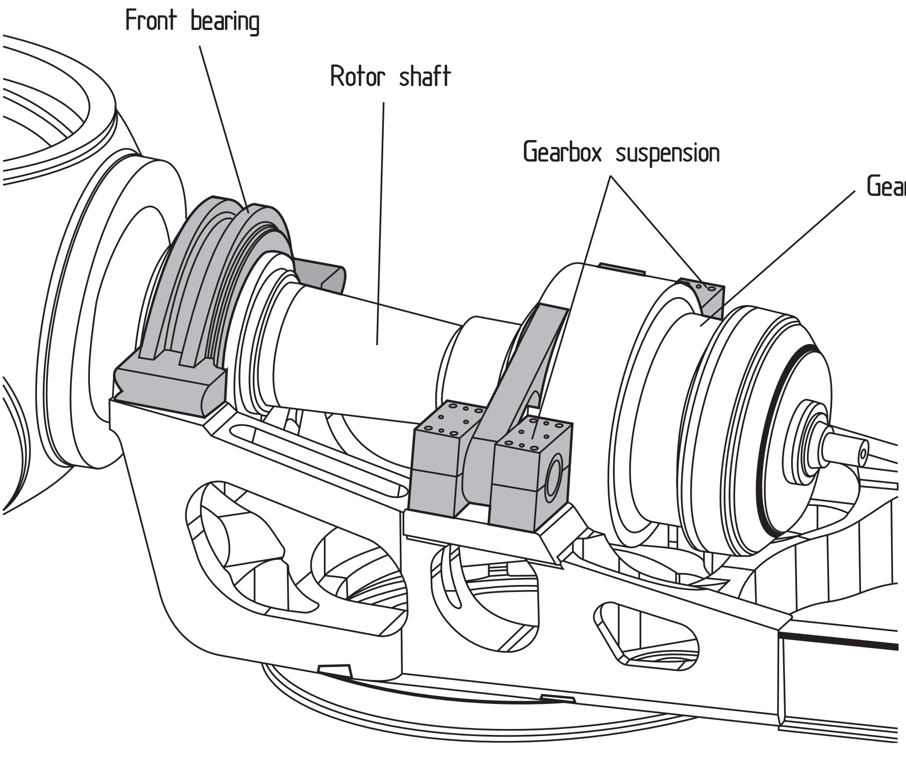


Figure 8.26. Three point suspension of the rotor shaft/gearbox assembly of the Nordex N 80

8.6.4
Rotor Shaft Integrated into the Gear Box

An even larger step towards a more compact design is supporting the rotor directly at the gearbox. This solution was implemented in some small and medium-sized wind turbines. The disadvantage is that the gearbox with flanged or totally integrated rotor bearings can no longer be adopted from other fields of application as a "universal gearbox" but must be specially designed for the wind turbine (Fig. 8.27).

The unavoidable deformations of the load-bearing housing and the bending of the rotor shaft must not affect the operation of the gear mechanism. Sticking cogwheels or axial displacements of the cogwheels and bearings which promote wear must be avoided. Gearbox manufacturers offer such gearboxes in series production for smaller to medium-sized turbines.

In this concept, the supporting bedplate of the nacelle becomes very small. Some turbines do without a supporting bedplate entirely. Like the rotor, the electric generator and all secondary units are flanged to the gearbox. The gearbox housing, connected directly to the tower, completely assumes the role of the load-bearing nacelle structure.

Figure 8.27. Drive train of an earlier Nordex wind turbine, with rotor and generator attached directly to the gearbox

Regardless of these basic advantages, this design is no longer widely used in more recent turbines. The three-point suspension of rotor and gearbox, for example, is less susceptible to failure and more easily repaired, if necessary.

8.6.5 Rotor Bearings Integrated into the Load-Bearing Nacelle Structure

An alternative step towards a more compact design is supporting the rotor directly by the front part of the nacelle structure. This requires a very stiff load-bearing part in the nacelle structure which contains the rotor bearing system. The bearing is designed as an in-plane bearing which has to sustain the axial and radial forces as well as the bending moment from the rotor weight, and external loads. In the past the experiences with this type of bearing for rotor bearing application were not very good, but progress has been achieved in the design of the in-plane bearing.

A recent example of such a design is the Vestas V90 (Fig. 8.28). The rotor bearing is completely integrated into the cast iron structure of the nacelle without any visible rotor shaft. The rotor loads are transferred to the tower over a very short distance by means of this stiff structure. The gearbox is flange-mounted to the rear of the support structure. Because of this concept, the weight of the mechanical drive train of the V90 could be kept

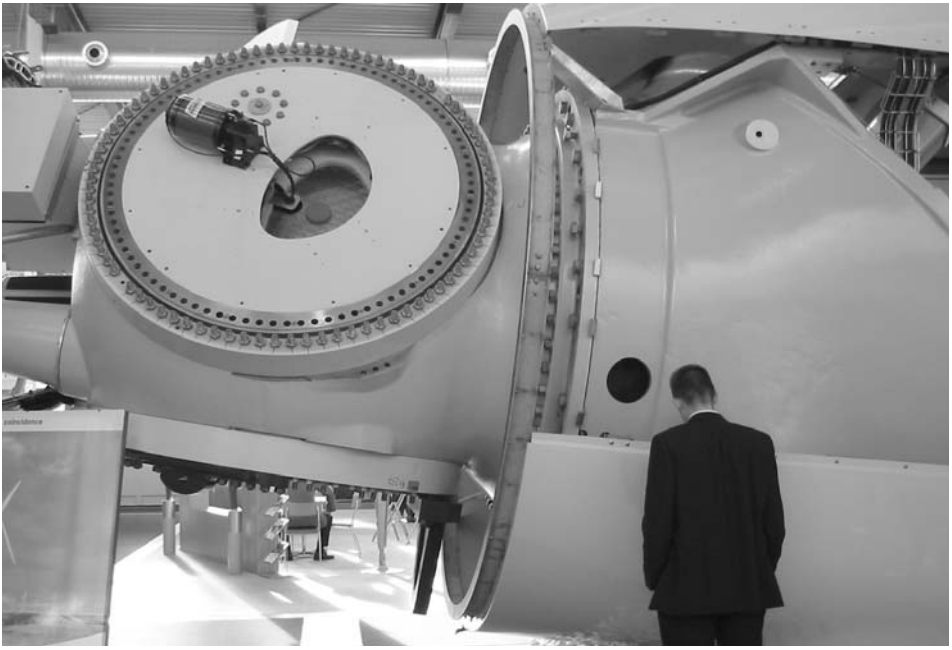


Figure 8.28. Cast load-bearing structure with in-plane rotor bearing on a Vestas V90 (photo Vorster)

at the same level as with the smaller V80 with a conventional rotor bearing assembly using a large rotor shaft.

8.6.6 Rotor Support on a Fixed Axle

The high alternating bending loads in the rotor shaft can only be absorbed by an expensive and heavy component. A concept which can be found in some of the more recent turbines tries to avoid this disadvantage. Here, the rotor is supported on a fixed shaft support which is not subjected to alternating bending loads, but only to a static bending load. This fixed shaft is designed as a cast element connected directly to the tower flange, supporting the entire drive train.

The concept of using the fixed shaft as rotor bearing has been tried in conventional wind turbines with gearbox, for example in an earlier Bonus Mk V, where the torque from the rotor is transferred to the gearbox by a light-weight torsionally flexible shaft through the hollow support shaft (Fig. 8.29). In the later Bonus models, the stationary rotor shaft was abandoned again in favour of the three-point suspension of rotor shaft and gearbox.

The approach of a fixed axle support is particularly well suited for gearless drive train designs since these do not require a torque to be transmitted from the rotor via the gearbox to the electric generator. The gearless systems by Enercon, Lagerwey and others, therefore, have a cast bearing journal which supports the rotor and the direct-driven generator (Fig 8.30).

The basic concepts described illustrate the most important ones of the existing design concepts. However, the complete range of technical solutions and their variants and interim solutions is much greater.

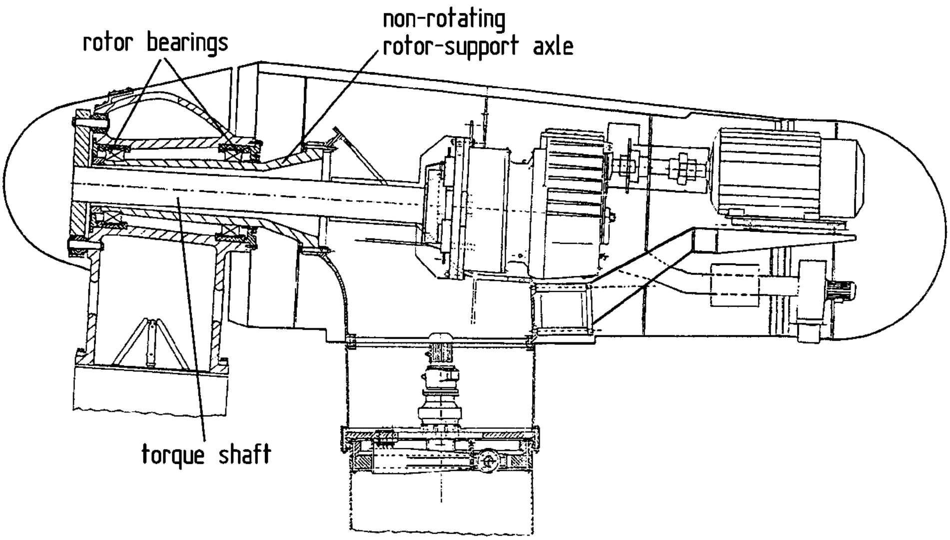


Figure 8.29. Rotor bearing assembly on a fixed support shaft in the Bonus Mk V turbine

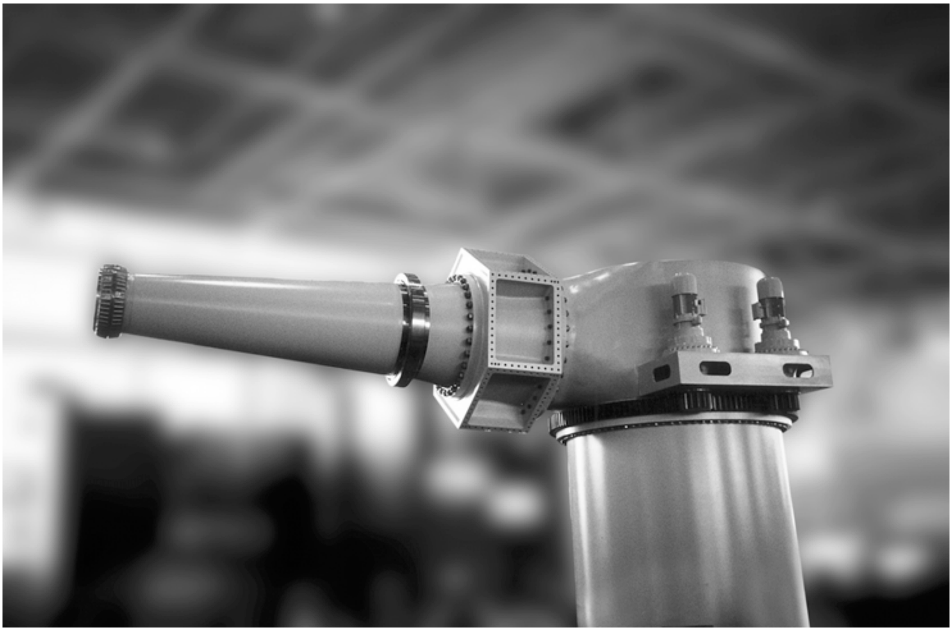


Figure 8.30. Spheroidal graphite cast rotor support axle of the Enercon E-40

Whatever approaches are used, the design optimisation of the rotor bearings, coupled with the static design of the load-bearing nacelle structure, is of considerable importance with respect to the weight of the nacelle and thus, in the end, to the production costs of the wind turbine (Chap 19.4)

8.7 Rotor Brake

A mechanical breaking system is besides the aerodynamic breaking function of the rotor an unavoidable component of a wind turbine. It is part of the mechanical drive train. The first task is to keep the rotor of a wind turbine in position when it is at a standstill. Locking the rotor is a must for servicing and repair work and is generally common practice during normal down times. Moreover, most turbines have locking bolts between rotor hub and nacelle for bridging extended periods of standstill and for servicing and repair work. The rotor can thus be secured in one or more positions.

Rotor brakes are almost always disk brakes. Suitable disk brakes can frequently be adopted cost-effectively from existing production runs intended for other machines or vehicles. Against this background, the design of the rotor brake itself poses few problems. Nevertheless, the rotor brake presents the systems designer of a wind turbine with issues which have consequences for the entire system.

The first and most important question is, which task the rotor brake is to fulfil within the operating concept. In the simplest case, its role is restricted to a mere holding function during rotor standstill. In this case, the brake must be dimensioned for the required holding torque of the rotor during standstill. This is determined in accordance with the aerodynamic forces calculated to occur at the assumed maximum wind speeds (Chapt. 6.3.2).

Apart from its function as a pure rotor parking brake, the rotor brake can also be dimensioned as a service brake. As long as the braking torque and braking power (thermal loading) can be absorbed, the mechanical rotor brake can be used as a second independent braking system in addition to aerodynamic rotor braking and the operational reliability of the wind turbine is considerably improved in this way. In small wind turbines, a mechanical rotor brake, which in cases of emergency prevents rotor runaway, has proved to be extraordinarily successful and is widely used today.

With increasing turbine size, it becomes more and more difficult to meet this requirement. For a turbine with a rotor diameter of 60 to 80 m, the rotor brake takes on almost absurd dimensions if it is to brake the rotor torque and power during full-load operation. For this reason, the task of the rotor brake in large turbines is always restricted to the function of pure parking brake.

Apart from the issue of the rotor brake's task with respect to operations, there is the question of where in the drive train the rotor brake is best installed. The alternatives are for the rotor brake to be on the "low-speed" or on the "high-speed" side of the gearbox. In most turbines, efforts to keep the brake disk diameter as small as possible lead to the rotor brake being installed on the high-speed shaft, i. e. between gearbox and generator (Fig. 8.31). Owing to the higher rotational speed, the torque is one or even two orders of magnitude lower than at the slower rotor shaft, depending on the gear ratio.

However, mounting the brake on the high-speed shaft has at least two disadvantages. It is inferior from the point of view of safety, since the braking function fails if the low-speed shaft or the gearbox break down. Moreover, the rotor must be held by the gears during a standstill. Gears react with increased wear of the tooth flanks to small oscillating movements, which are unavoidable in a stopped wind turbine due to air turbulence. In some turbines, it is attempted to solve this problem by no longer locking the rotor during standstill but by letting it "spin" at low speed.

To avoid these disadvantages, the rotor brake was installed on the low-speed rotor shaft in some earlier systems. In small wind turbines a fully effective operating brake can be implemented with justifiable effort on the low-speed side, as long as design of the rotor shaft bearing assembly does not present an obstacle. The rotor brake on the low-speed side was a common feature of many earlier stall-controlled Danish wind turbines up to a power rating of about 100 kW in the Eighties. At that time it was considered to be an extra safety element even though the rotor brake was only designed as a parking brake.

Installing the rotor brake on the slow side is much more problematic in large wind turbines, however. Even a parking brake already assumes a considerable size (Fig. 8.32). These disadvantages have led to the rotor brake being arranged on the high-speed side behind the gearbox in almost all new systems.

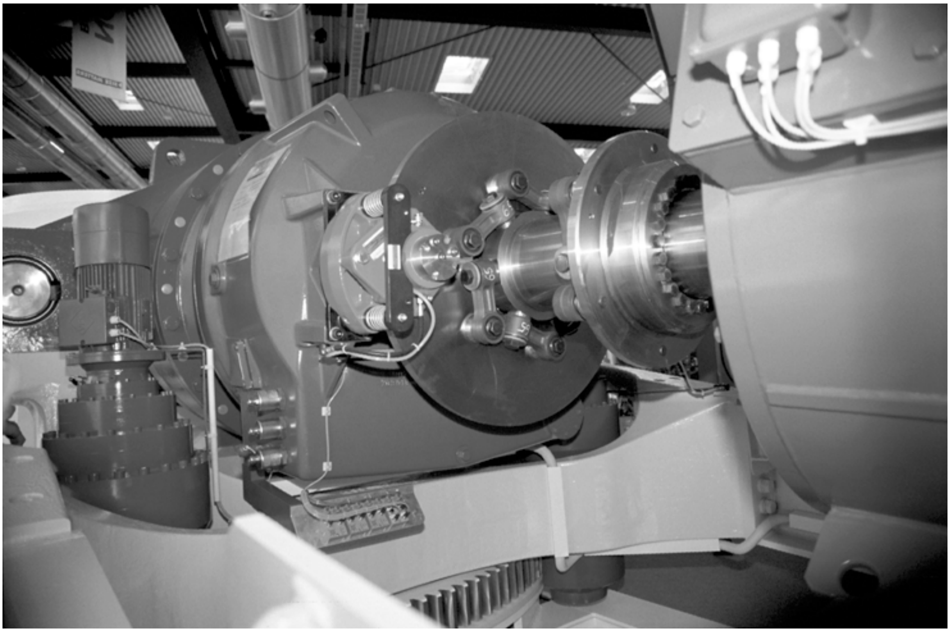


Figure 8.31. Rotor parking brake on the high-speed shaft of the gearbox in the Nordex N-80

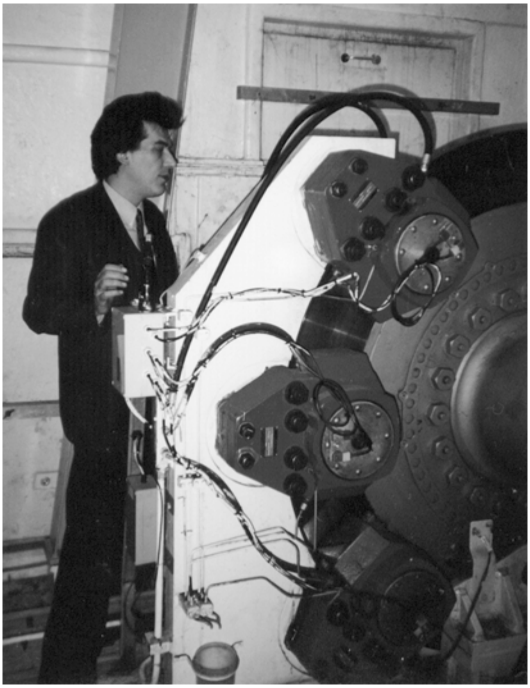


Figure 8.32. Rotor parking brake at the low-speed side directly behind the hub in the earlier Howden HWP-1000

8.8 Gearbox

The conversion of the greatly differing rotational speeds of the rotor and the electric generator has given the designers of the first wind turbines many headaches. This situation led to costly low-speed generator designs and to hydraulic or pneumatic transmission systems to the generator (Chapt. 8.1). Aerodynamicists made efforts to drive the rotor speed as high as possible in order to lower the gear ratio. It was assumed that costs would also increase considerably with increasing gear ratios, so that the development of rotors with extremely high tip-speed ratios was pushed forward.

This situation has changed with the progress which has been made in gearbox technology. Today, high-performance gearboxes with gear ratios of up to 1:100 and more are available. In many areas of mechanical engineering, gearboxes are used which are suitable for deployment in wind turbines, as regards their technical concept, their efficiency and their operating life. The gearbox for the wind turbine has become a "vendor-supplied component", which, with certain adaptations, can be taken from the standard product range of the gearbox manufacturers.

Regardless of this favourable situation, the gearbox has been and still is a source of failures and defects in many wind turbines. The cause of these "gearbox problems" is not so much the gearbox itself, rather the correct dimensioning of the gearbox with regard to the load spectrum. In wind turbines, it is easy to underestimate the high dynamic loads to which the gearbox is subjected. Thus, in the early phase, many turbines had gearboxes which were undersized. Having learned their lessons, successful manufacturers equipped their turbines with ever stronger gearboxes and thus, in the course of development, empirically arrived at the right dimension.

8.8.1 Gearbox Configurations

Toothed-wheel gearboxes are constructed in two different forms. One is the parallel shaft or *spur-gear system*, the other is the technically more elaborate *planetary gearing*. The gear ratio per single reduction is limited, so that the difference in diameter between the small and the large wheel does not become too unfavourable. Parallel-shaft-gear stages are built with a gear ratio of up to 1 : 5, whereas planetary stages have a gear ratio of up to 1 : 12. Wind turbines generally require more than one stage. Fig. 8.33 shows what effects different designs have on gearbox size, mass and relative cost [11].

It is noteworthy that the three-stage planetary design has only a fraction of the overall mass of a comparable parallel shaft system. The relative costs are reduced to about one half. In the megawatt power class, the multi-stage planetary gearbox is, therefore, clearly superior. In smaller power classes, the comparison is not quite as unambiguous. In the range up to about 500 kW, parallel-shaft gear designs are often preferred for cost reasons.

Small wind turbines are equipped with parallel-shaft gear systems. The prevailing models are two-stage gearboxes which are commercially available from numerous manufacturers as modified universal transmissions (Fig. 8.34).

In larger wind turbines, the planetary design definitely prevails. For outputs of several megawatts, two- or three-stage models are used (Fig. 8.35). Large gearboxes of this type are used, for example, in ship-building and several other fields of mechanical engineering,

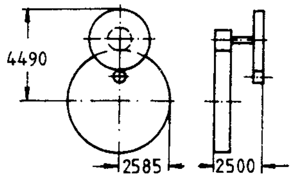
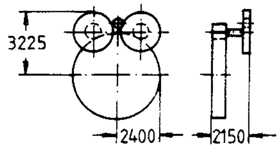
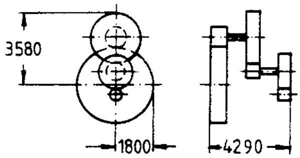
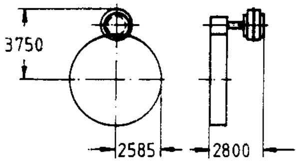
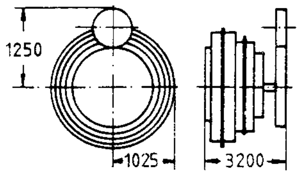
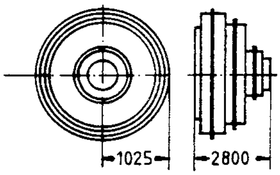
Configuration:		mass t	rel. costs %
two stages: parallel		70	180
two stages: parallel with torque splitting		56	164
three stages: parallel		77	192
two stages: one parallel one planetary		41	169
three stages: two planetary one parallel		17	110
three stages: planetary		11	100

Figure 8.33. Overall mass and relative cost of different gearbox designs [11]
Example: Rated power of the wind turbine: 2500 kW, rotor speed: 25 r.p.m., generator speed: 1500 r.p.m., gearbox service factor: 1.6

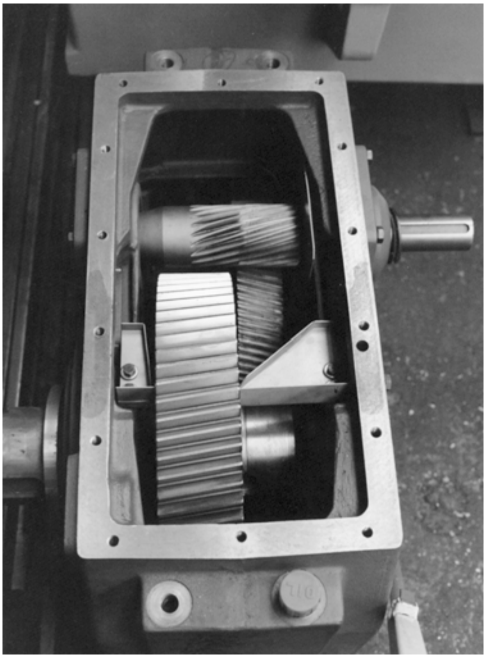


Figure 8.34. Two-stage parallel shaft gearbox for wind turbines of the 200 to 500 kW power class (Hansen)

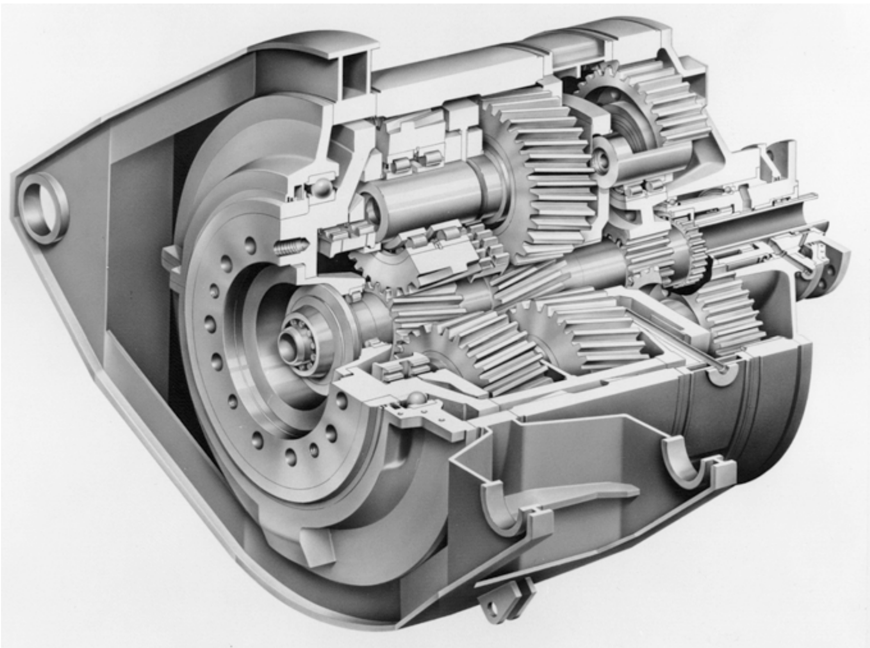


Figure 8.35. Three-stage planetary gearbox of the 2 to 3 MW power class (Thyssen)

so that suitable gearboxes for large wind turbines can be derived from these production sources.

Gearboxes with one planetary stage and two additional parallel-shaft stages are used in many late-model turbines (Fig. 8.36). With the additional parallel shaft, the primary and secondary shafts are no longer coaxial. This has the advantage that a hollow through shaft can be implemented more easily. In this way, power supply lines supplying power to the blade pitch drive, as well as measurement and control signals for the rotor, can be routed through the gearbox.

In larger gearboxes, an auxiliary rotor drive is frequently flanged to the gearbox housing. Using this electric motor, the rotor can be turned slowly. Such an auxiliary unit is indispensable for assembly and maintenance work in large rotors. Gearbox lubrication is usually carried out via a central oil supply in the nacelle. As a rule, it also contains an oil cooler and a filter.

In spite of indisputable advances having been achieved in the durability of the gearboxes, there is still "trouble with the gears" being experienced even in the latest wind

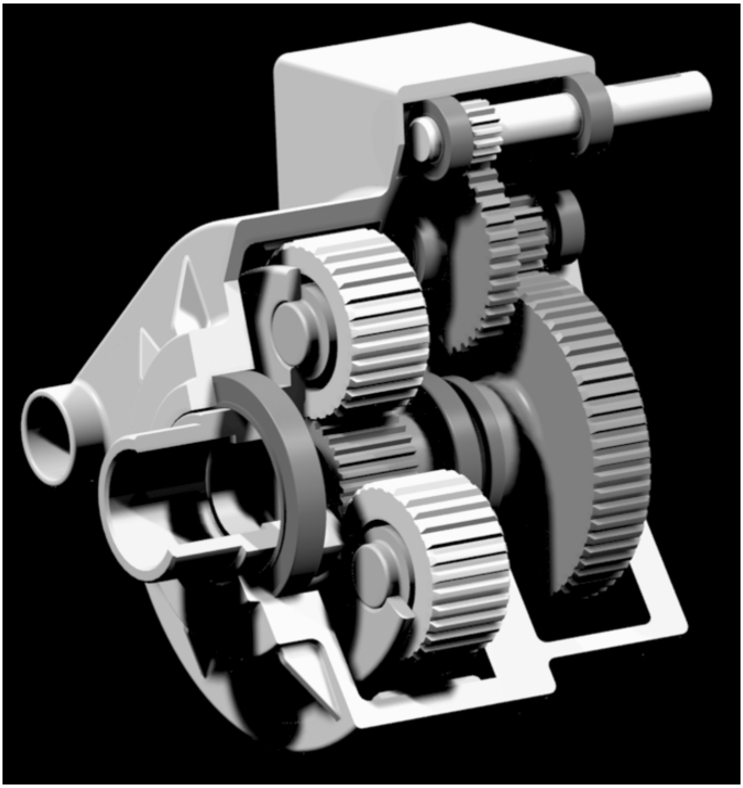


Figure 8.36. Standard gearbox for large wind turbines with one planetary stage and two parallel shafts (artist's concept by NEG Micon)

turbines. Although it is possible to adapt gearboxes for wind turbines from other types of machine, they are subject to special demands which are often not encountered in other applications. Much negative experience in recent years has provided important insights into this issue:

- Special attention must be devoted to the smooth running of the toothing. Particularly prominent gear meshing frequencies can cause resonances in the drive train. "Cheap" transmissions with simple toothing are unsuitable for use in wind turbines.
- Oil leaks in the transmission are a particular problem. Labyrinth seals have proven more reliable than slipring type seals. In many cases, the housing flanges also showed leaks after some time. A box design with a top flange is apparently more advantageous than gearbox housings with flanges on the input and output side.
- The quality of the lubrication has been found to be a decisive factor for the service life of the gearbox. Oil temperatures which are too high cause just as much damage as does contamination in the oil. Oil coolers and filters are indispensible for large gearboxes and so is the careful observance of oil change intervals.
- The stiffness of the gearbox housing is an important criterion for its service life if the housing is integrated into the static design of the nacelle.

Apart from these constructional measures, of course, the correct dimensioning has a decisive influence.

8.8.2
Gearbox Dimensioning

Dimensioning of the gearbox must be considered under two aspects. On the one hand, there is the "internal" dimensioning of the gear elements, such as gearteeth, shafts and bearings. This is primarily the task of the gearbox manufacturer. But the manufacturer can only solve this task if he is supplied with correct information about the "external" loads occurring in accordance with the operating conditions. Supplying the load assumptions is the task of the systems engineer of a wind turbine. For this reason, this problem must be dealt with in greater detail here, whereas internal gearbox dimensioning is better left to the manufacturer.

The most important load parameter is the torque to be transmitted. The rotor torque is, of course, not a constant value but is subject to more or less large variations, depending on the technical design concept of the wind turbine. The load spectrum contains torque variations, expressed as magnitude and frequency occurring over the entire operating life of a turbine. Based on this load spectrum, the transmission gearing is dimensioned by the manufacturer in such a way that the so-called fatigue strength limit (Wöhler line) has sufficient clearance above the load spectrum (Fig. 8.37).

This ideal method of proceeding is not always feasible in design practice, as a complete and reliable load spectrum for the gearbox is only rarely available. A simplified and empirically proven method for defining the external load situation is, therefore, used.

The starting point is the rated rotor torque T_N to be transferred by the gearbox. In rotors operated at a constant speed, the rated torque is obtained very simply by dividing the rated mechanical rotor power by the rotor speed. According to DIN 3990, a so-called

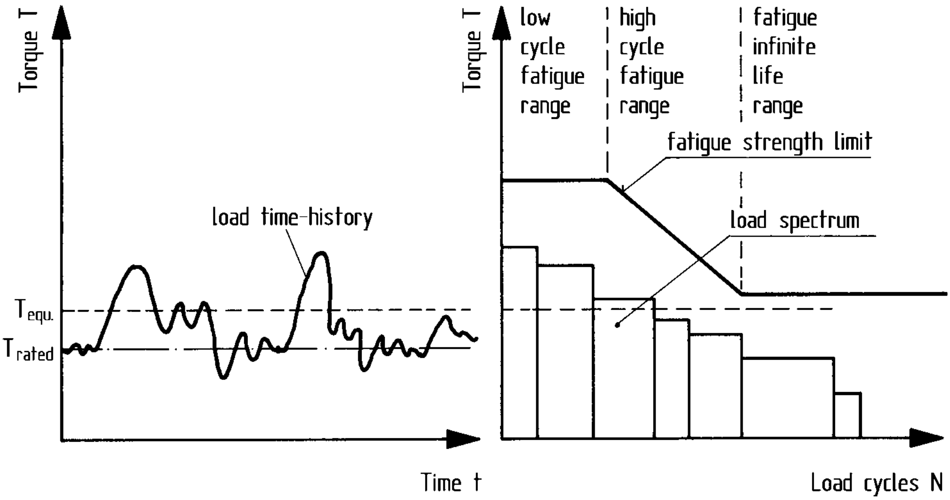


Figure 8.37. Torque characteristic and resulting load collective relative to the strength line of a gearbox (safe-life dimensioning)

"equivalent constant torque" T_{eq} can be defined which corresponds to the dynamic load spectrum in its effect on the gearbox dimensioning [12]. In other words: if the gearbox is subjected to this equivalent torque from an assumed constant steady load, it is subject to the same stress situation as if were subjected to the corresponding dynamic load spectrum. From the point of view of gear strength, the equivalent torque thus defined corresponds to the "maximum transferable continuous torque" of the gearbox.

According to DIN 3990, the quotient of the equivalent torque T_{eq} and the rated torque is defined as the so-called *application factor* K_A.

$$K_A = \frac{T_{eq}}{T_N}$$

Hence, the application factor is an external application-related load parameter for the gearbox. It includes all the forces which are introduced into the gearbox from the outside over and above the peripheral force at rated power. Internal gearbox reliability aspects are not covered by it and must be additionally taken into consideration by the manufacturer. The most important internal reliability factors for gears contain the following factors:

$s_H > 1.1$ against pitting,
$s_H > 1.5$ against tooth breakage.

If no load spectrum is available, the application factor K_A, and with it the equivalent torque, must be determined empirically from comparisons with similar cases of application (Tab. 8.38).

The central question is, naturally: Which application factors are to be applied for wind turbines? It almost goes without saying that the technical concept of the wind turbine plays

Table 8.38. Application factors for gearboxes [12]

Operating mode of the prime mover	Operating mode of the driven machine			
	uniform	light peaks	moderate peaks	heavy peaks
uniform	1.00	1.25	1.50	1.75
light peaks	1.10	1.35	1.60	1.85
moderate peaks	1.25	1.50	1.75	2.0 or higher
heavy peaks	1.50	1.75	2.0	2.25 or higher

a role in the answer to this question. The following are of importance on the rotor input side:

- Number of rotor blades,
- Type of rotor power control (blade pitch or stall control),
- Function of the rotor hub on two bladed rotors

The following must be taken into consideration on the gearbox output side:

- Shock-absorbing flexible elements in the high-speed generator drive shaft,
- Compliance of the electrical coupling to the grid (generator type).

In addition, the location of the mechanical rotor brake, which can be installed on the primary shaft or on the secondary high-speed side, plays a role (Chapt. 8.7). Up to now, no generally accepted quantitative correlation of these technical features of a wind turbine with the application factor to be selected for the gearbox is available. Sweeping "recommendations" for "wind turbines with three-bladed rotors" are clearly much too vague [13].

For the gearboxes of older stall-controlled three-bladed wind turbines with induction generators coupled directly to the grid, application factors of around 2.0 were chosen. More recent stall-controlled turbines make do with lower factors (approx. 1.6), but the gearboxes are greatly improved.

Wind turbines with effective blade pitch control generally manage with lower application factors for the transmission if they can be operated with variable speed. However, there are only very few systematic analyses of the gearbox load spectra available for this design. In comparison with the fixed-speed turbines, application factors of less than 1.5 should suffice.

There are at least two more factors in gearbox technology which are in use for characterising the external load situation for the transmission. The *operating factor*, according to VDI 2151, has basically the same definition as the application factor [14]. However, it also contains internal gearbox safety factors and is thus always about 5 to 10 % higher than the application factor. Due to the external load criteria being linked with internal gearbox safety factors in this way, the definition of the operating factor is less clear and it should, therefore, be increasingly replaced by the application factor.

In English-speaking countries, the so-called *service factor* is used. In the AGMA (American Gear Manufacturers Association) standard, it is defined much like the application factor, but it takes into consideration a given statistical gearbox failure probability. The numerical value of the service factor is approximately 10 to 20 % above the application factor [15].

Instead of the factors mentioned, some gearbox manufacturers characterise their gearboxes by specifying the rated power of the gearbox according to the AGMA standard. The quotient of the AGMA power and the rated power of the wind turbine corresponds to the application factor in practice (even if not precisely by definition).

In view of the numerous definitions, the designer of the wind turbine system must have a clear agreement with the gearbox manufacturer regarding the dimensioning factors to be applied. It would be desirable for the application factor to win general recognition.

A concluding remark on gearbox dimensioning relates to breaking strength. Dynamically loaded gearboxes which are dimensioned with application factors of the order of 2, generally have a breaking strength which is at least three times the rated torque. This failure moment is not achieved in normal wind turbine operation. Only the "generator short-circuit" load case can cause a higher torque peak in the drive train. In order to protect the gearbox and the rotor shaft from this, "overload clutches" are built into the high-speed shaft in most cases (Chapt. 8.9).

8.8.3
Efficiency and Noise Emission

Modern gearboxes produce only comparatively small power losses. Nevertheless, the efficiency of the gearbox should not be completely ignored, particularly in a wind turbine. Essentially, tooth-flank friction and oil flow splash losses are the main causes of power losses in the gearbox. They manifest themselves as heat and, to a much lesser extent, as noise emission. Heat can become a problem mainly in very compact planetary gearboxes, so that, apart from the surface cooling available in any case, additional cooling systems become necessary.

Efficiency essentially depends on the gear ratio, the type of gear and the viscosity of the lubricating oil. The following guide values apply:

– Parallel shaft gear: approx. 2 % power loss per stage,
– Planetary gear: approx. 1 % power loss per stage.

Due to their more sophisticated technology, larger gearboxes in the megawatt range generally operate with slightly better efficiency than smaller ones. An overview of the efficiencies to be expected is shown in Fig. 8.39. As efficiency depends on the number of gear stages, attempts are increasingly made to make do with two-stage transmissions at least for small and medium-sized wind turbines. A two-stage gearbox combined with a somewhat more expensive multi-pole generator operating at a lower speed may be a more effective configuration than a three-stage gearbox paired with a two-pole generator.

Apart from the gear ratio, the efficiency of a gear transmission also depends on the power transmitted. However, the manufacturers of gearboxes are very reticent about publishing information about the efficiency versus load curves, making it necessary to rely on approximations with regard to efficiency under partial load. In the case of planetary gears it can be assumed that about 50 % of the power loss is nearly constant whereas 50 % vary

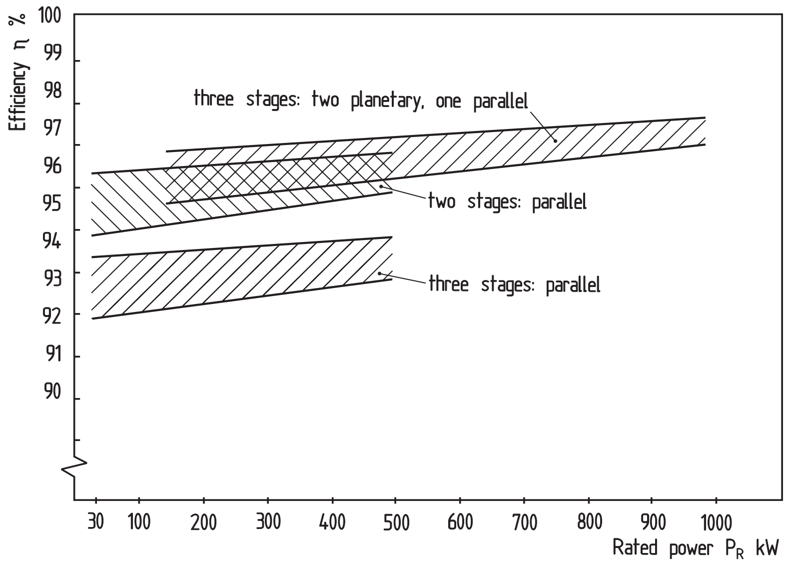


Figure 8.39. Ranges of the gearbox efficiencies to be expected depending on the type of gearbox and the rated power of the wind turbine

linearly with the transmitted power [16]. A significant drop in efficiency becomes perceptible only when the load is very small (Fig. 8.40) and it is generally sufficient, therefore, to assume a constant efficiency for calculations of power losses in the drive train.

Even if only a very small part of the lost power is emitted acoustically, the noise emission of gearboxes should not be underrated. In many cases where there are complaints about unacceptable noise produced by the wind turbine from residents living nearby, the gearbox turns out to be the cause of the annoyance. The use of low-noise gearboxes or possibly of appropriate sound absorbers is of considerable importance if wind power is to find wide acceptance in public.

The noise emission of a gearbox depends on its quality and naturally on its size. The quality of design and manufacturing is the main cause of the considerable range of sound power levels experienced. Gearbox manufacturers generally indicate the sound pressure level, measured at 1 m distance under test conditions according to DIN. The following approximate values are to be expected:

– Smaller parallel-shaft gearboxes	up to about 100 kW:	75 – 80 dB(A)
– Medium-size parallel shaft gearboxes	up to 1 000 kW:	80 – 85 dB(A)
– Large planetary gearboxes	about 3 000 kW:	100 – 105 dB(A)

It is obvious that acoustic sources of this intensity cannot do without protective sound-insulating measures. To prevent noise from reaching the outside, sound transmission by air must be reduced by a sound-absorbing nacelle fairing, and to prevent structure-borne sound from being transmitted from the gearbox to the nacelle and to the tower, the gears are mounted in special bearings of elastic material (Fig. 8.41). This type of bearing also

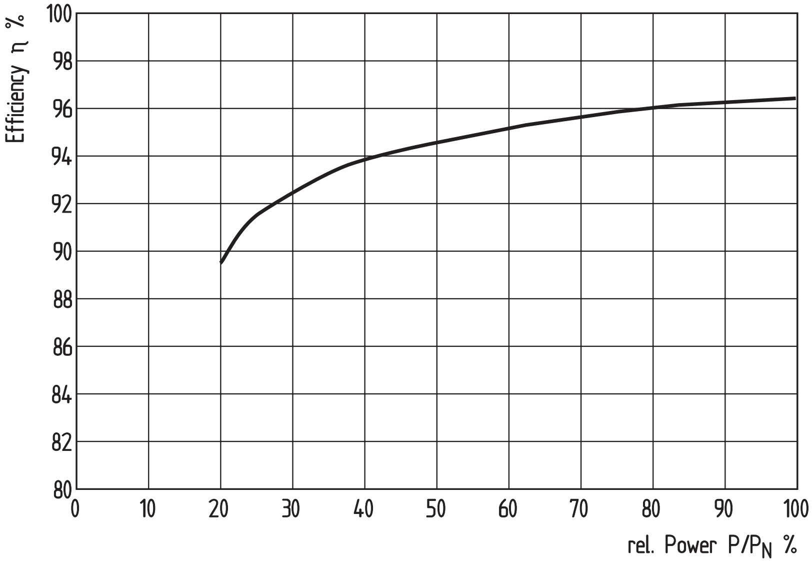


Figure 8.40. Measured efficiency versus power of a two-stage planetary gearbox with a rated power of approximately 1500 kW

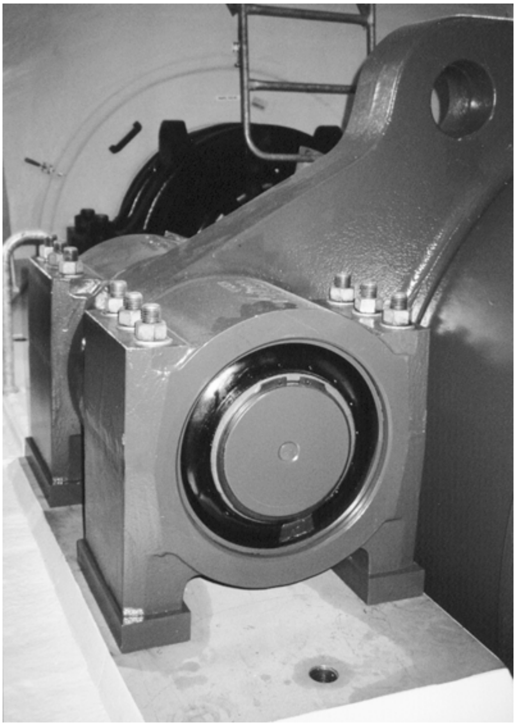


Figure 8.41. Elastic gearbox bearing in a GE TW 1.55

prevents torsional tensions in the mechanical drive train as a result of the unavoidable deformations in the supporting nacelle structure. Oscillations and relatively small torque concentrations from the rotor are damped to a certain extent by the (albeit small) elastic torsional motion of the gears.

8.9 Installation of the Electric Generator

The installation of the electric generator in the nacelle is a mechanical engineering problem in the area of the drive train design. The connecting shaft of the gearbox exit to the electric generator, the high-speed shaft, rotates at the nominal generator speed of 1500 r.p.m. in 50 Hz systems and 1800 r.p.m. in 60 Hz systems. Generators with more than two pole pairs are used in some cases, so that the required driving speed can also be, for example, 750 r.p.m. and 900 r.p.m., respectively. In any case, in comparison with the slower rotor shaft, the torque to be transferred is smaller by the gear ratio of the gearbox to the generator, so that the dimensioning of the generator drive shaft presents no problems in the prevailing range of loads. Nevertheless, several problems specific to wind turbines must be solved when the shaft and the generator are installed.

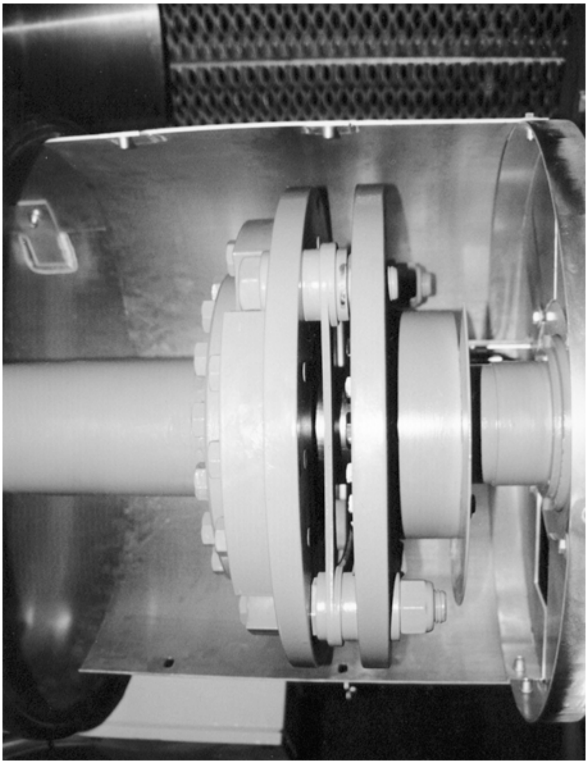


Figure 8.42. Flexible coupling between gearbox and generator in a GE TW 1.55 wind turbine

Basically, the generator can be flanged directly to the gearbox, so that provision of a long driving shaft can be avoided (Chapt. 8.8). This feature is used in some smaller wind turbines. The rigid connection from transmission to generator, however, is not without its problems. The drive train is always subjected to certain deformations. This almost certainly necessitates flexible connecting elements between the components, if twisting, and with it additional loads in the drive train, are to be avoided. Assembly and maintenance are considerably facilitated if small misalignments between generator and gearbox can be tolerated, which will be compensated for by a flexible coupling. In addition, accessibility of the rear of the gearbox and of the front of the generator should be ensured by providing a certain clearance between the two. For these reasons, detachable and flexible connecting couplings are generally built into the high-speed generator drive shaft.

The requirements of detachable connection and flexibility are met by the most varied types of couplings. They are used in industrial mechanical engineering in numerous designs and sizes. It is not the task of this book to provide a systematic overview of these. The designer of a wind turbine has the task of defining the requirements for the coupling function as precisely as possible, and then of consulting the manufacturers about the choice of design which best meets his requirements (Fig. 8.42).

In the past, simple couplings of elastic material were often used between gearbox and generator in small wind turbines (Fig. 8.43). Instead of a generator drive shaft, V-belt drives are also frequently used in small turbines. It is mainly the small turbines of Danish origin which occasionally have V-belts for driving their generators. The V-belt drive has the advantage that it combines the desirable flexible connection to the transmission with overload

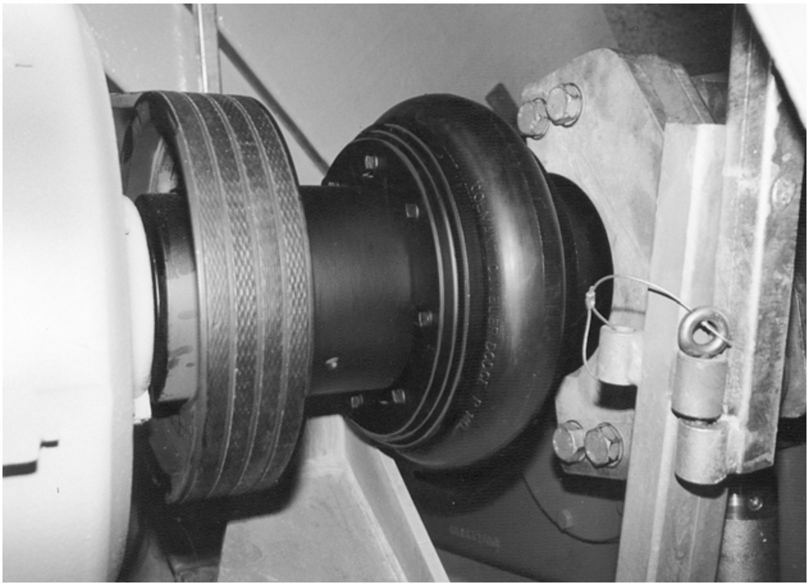


Figure 8.43. Flexible coupling of elastic material between gearbox and generator in a small Bonus wind turbine

protection. Its disadvantages are wear and lower efficiency (slippage), which is significant at higher outputs.

The couplings in the high-speed shaft can take on another important task beyond their connecting and compensating functions. In the case of a failure, extreme loads can occur in the mechanical drive train of a wind turbine which make it advisable to implement a rupture joint for safety reasons. The generator short-circuit torque, in particular, can reach a value of 5 or 6 times the rated torque (Chapt. 9.1). From the economic point of view, it would make little sense to dimension the entire drive train components for this load. The maximum transferable torque can be restricted with the help of overload couplings in the high-speed shaft. This task can be handled, for example, by a so-called "breaking ring coupling", dimensioned for a load three times the value of the gearbox rated torque.

When installing the electric generator, its cooling must also be taken into consideration, in addition to the mechanical drive. Wind turbines are often located near the sea. Air-cooled generators, as well as frequency converters and other electric systems, move a considerable volume of air in their cooling system. In case of salty sea air, salt deposits are unavoidable, with obvious consequences. Against this background, the system of protection used for the electric generator must be considered carefully, and the cooling system must be designed accordingly. The class of protection common today for electric generators is IP 54, according

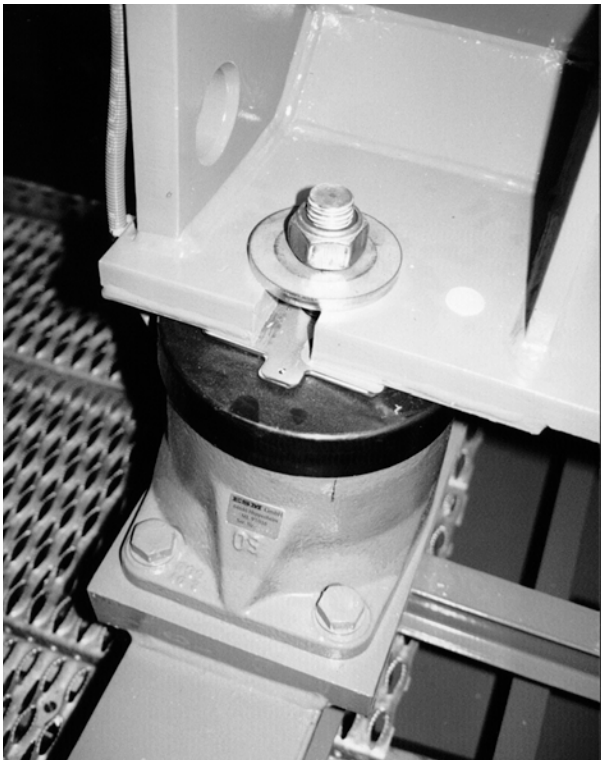


Figure 8.44. Flexible generator mounting on the nacelle bedplate in the GE 1.5S turbine

to the German VDE standard. In most large turbines, the generator is cooled indirectly by a closed air or water circuit which is connected to the outside air via a heat exchanger.

Designing the cooling system properly so that it includes not only the heat emission of the generator but also of the electronic equipment and the gearbox is of great importance for system reliability and operating life. Exceeding the maximum permissible service temperature of the lubricating oil or the bearings of the rotor shaft, of the gearbox and of the electric generator has been found to be a frequent source of trouble in many wind turbines.

Similarly to the gearbox, the generator is mounted on its supporting nacelle bedplate by means of elastomeric bearings (Fig. 8.44). The flexible mounting ensures that no stresses are produced in the mechanical drive train in the case of structural deformations, and also prevents structure-borne noise from being transmitted.

8.10 Torsional Compliance and Variable-Speed Transmission in the Mechanical Drive Train

Wind turbines with electric generators connected directly to the grid have the problem of high dynamic loads on the mechanical drive train. In smaller turbines, the load peaks are absorbed to a certain extent by the electrical slip of the commonly used induction generators (Chapt. 9.2). It is, therefore, possible to dispense with special constructional measures in the mechanical drive train in these systems.

It has frequently been attempted in the past to use synchronous generators coupled directly to the grid. In this case, it is necessary to use torsionally compliant, vibration-absorbing elements in the mechanical drive train for direct, parallel grid operation to be possible at all. At the same time it was also attempted to achieve a mechanical variable-speed capability

Today, these concepts are part of history and electrical speed control has become the clearly superior concept due to the advances achieved in frequency converter technology. Nevertheless, a brief glance at the possibilities for implementing a comparable flexibility in the speed of the mechanical drive train or even a controllable, variable-speed capability, will not come amiss. The technical solutions presented below had been implemented in various test installations and prototypes in the eighties.

Torsionally elastic rotor shaft

The American MOD-2 experimental turbines were equipped with synchronous generators directly connected to the grid and had a torsionally elastic rotor shaft, called "quill shaft" (Fig. 8.45), installed on the inside of the supporting hollow rotor shaft to the gearbox. The torsion angle under load reached a magnitude corresponding to a generator slip of approximately 5 %. However, the lack of damping proved to be a grave disadvantage, presenting considerable problems with drive train dynamics in these turbines. For the subsequent MOD-5 model, a variable-speed generator system was developed to replace the torsion-flexible rotor shaft.

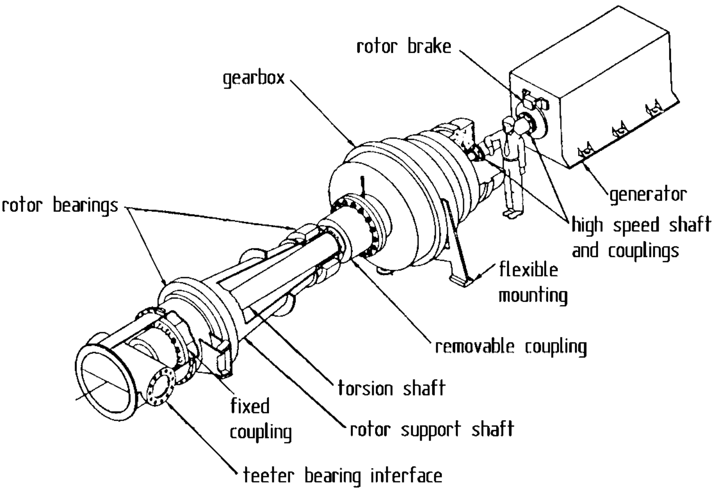


Figure 8.45. Rotor shaft of the MOD-2 with enclosed variable-speed shaft [17]

Torsionally elastic gearbox suspension

Another solution to achieve torsional compliance in the mechanical drive train is the elastic suspension of the gearbox. In the Swedish-American WTS-3/4 turbine, the gearbox was suspended in large H frames and was held by cup spring stacks and hydraulic dampers. The maximum torsion angle under load (severe wind gusts) amounted to approximately 30°. This type of gearbox suspension is technically quite complex, as is shown in Fig. 8.46. Like the American MOD-2, the turbine was equipped with a synchronous generator which was coupled directly to the grid, thus requiring this complex type of gearbox suspension.

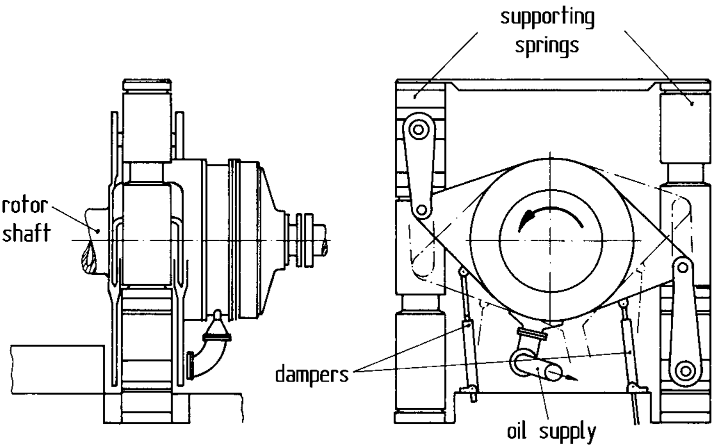


Figure 8.46. Torsionally elastically suspended gearbox of the WTS-3/4 [5]

Fluid coupling

The installation of a fluid coupling between gearbox and generator is a very effective solution for damping undesirable dynamic vibrations and load peaks in the drive train. In the American MOD-0A, which was equipped with a synchronous generator, a hydraulic clutch was subsequently built into the high-speed shaft. The load peaks in the drive train, which had initially occurred and which were caused by the strong tower shadow effect, complicated the synchronisation to the grid frequency to an intolerable extent. The fluid coupling acted to damp the vibration response of the synchronous generator and smoothed power output as well as the dynamic load on the drive train (Chapt. 6.6.4). However, the use of a fluid coupling is associated with noticeable power losses.

The combination of synchronous generator with fluid coupling was later adopted by some other manufacturers. For example, the Westinghouse WWG-0600 and the Howden HWP-300 with synchronous generators directly coupled to the grid were equipped with hydraulic clutches in the drive train (Fig. 8.47). According to the manufacturer's information, the power loss in the Howden HWP-300 amounted to approximately 2 to 3 % at full load.

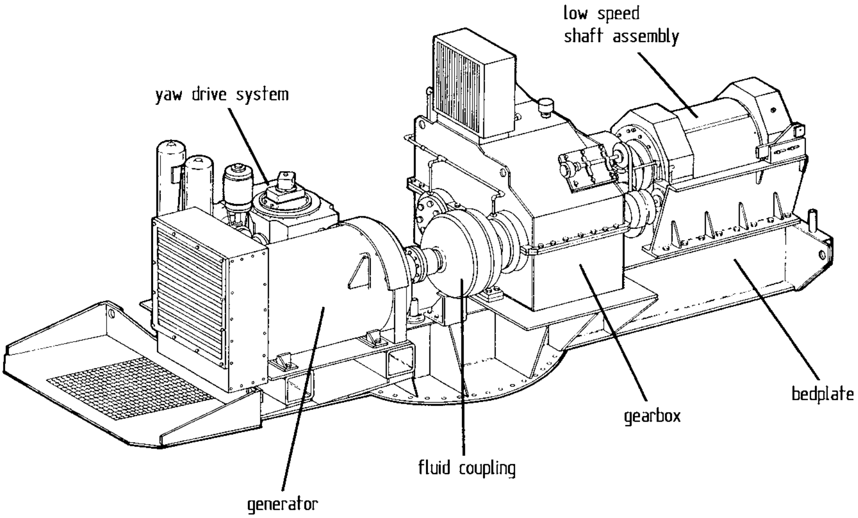


Figure 8.47. Fluid coupling in the high-speed shaft of the Westinghouse WWG-0600 [18]

Variable-speed transmission gearing

On the mechanical side, the problems of drive train dynamics could be basically solved by using a transmission with an infinitely variable transmission ratio. The British test turbine LS-1 was, for example, equipped with a variable speed gearbox system (Fig. 8.48). In this transmission gearing, the sun wheel of the planetary gearbox was set into motion by a controlled electric motor in dependence on the torque. This provided an infinitely variable transmission ratio between the low-speed shaft and the high-speed shaft. The power transferred was split into a mechanical flow and an electrical flow. The electrical part, however, amounted to only about 10 to 20 %. A narrow speed range of ±5 % had been chosen, so that the power needed for the control motor did not become too high.

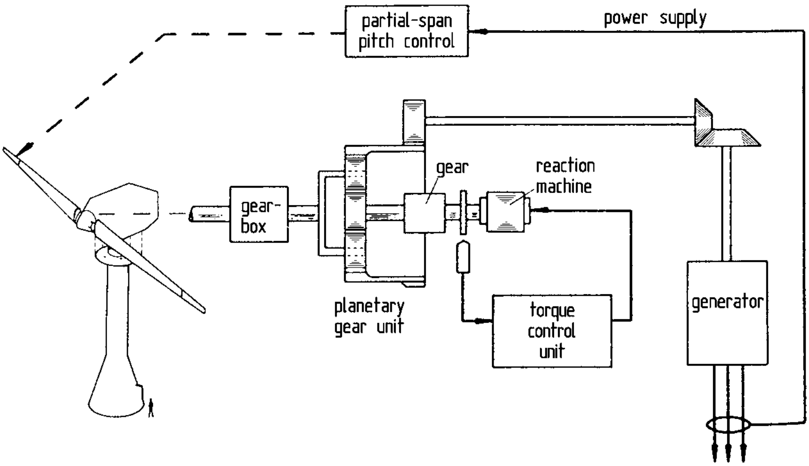


Figure 8.48. Drive train of the British LS-1 turbine with a variable-speed electro-mechanical transmission [19]

As already mentioned, the mechanical solutions shown here for torsional flexibility or a controllable variable speed capability in the drive train represent a line of development from the past. Variable-speed electrical generator systems with frequency converter have been found to be much more cost effective. (Chapt. 9.5).

8.11 Nacelle

In almost all turbines, the components of the mechanical drive train and of the electric generator are housed in a closed nacelle. Some smaller turbines make do without it. A completely closed housing could become redundant in case of a complete integration of the drive train components, for example by mounting the rotor bearings directly on the gearbox. After all, the nacelle does represent a considerable cost factor. On the other hand, many practical reasons speak for a closed nacelle, particularly in large turbines.

8.11.1 Design and Load Carrying Concept

As has been explained in Chapter 8.6, the design and static concept of the nacelle are closely associated with the arrangement of the drive train. The rotor bearing assembly, in particular, largely determines the design of the supporting nacelle structure. Assembly and cost considerations are also determining factors.

The most widely used design features a supporting bedplate with a non-load bearing fairing. In older turbines, the bedplate is commonly a welded steel structure (Fig. 8.49). This bedplate must transfer all rotor forces to the tower via the azimuth bearing in its front section. Considering the stiffness required for supporting the drive train components, the weight becomes correspondingly high. In more recent wind turbines, cast nacelle bedplates are increasingly found which results in cost advantages, particularly in series production. The heavy cast bedplate is often flanged to a more light-weight sheet steel structure for accommodating the generator (Fig. 8.50).

Various materials have been used for the non-load bearing fairing structure, for example aluminium or steel sheet structures, reinforced by struts. Today laminated shells made of glass-fiber reinforced composite material are used for most wind turbines (Fig. 8.51). One aspect which should be focused on when selecting material and design, is insulation against noise and temperature. Sound insulation of the nacelle is almost always necessary to provide shielding against the gearbox noise. The components of the electronic control system require a certain insulation against temperature and humidity, at least for a closed part-section of the nacelle. For these reasons, costly insulating material having these properties can be more economical than insulating the individual units.

A strategy for reducing overall mass, commonly used in motor vehicle and aircraft construction and developed there to perfection, is to integrate the fairing into the load-bearing structure. The most favourable design with high stiffness is a self-supporting stressed-skin construction. However, an optimal result will only be achieved if the geometric shape is

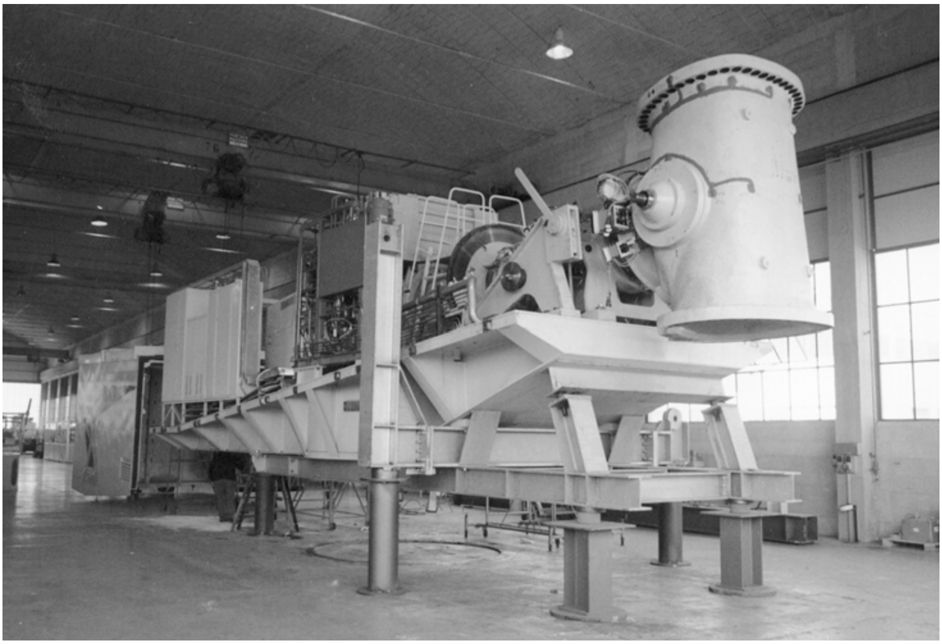


Figure 8.49. Welded nacelle bedplate of the experimental Gamma-60 turbine

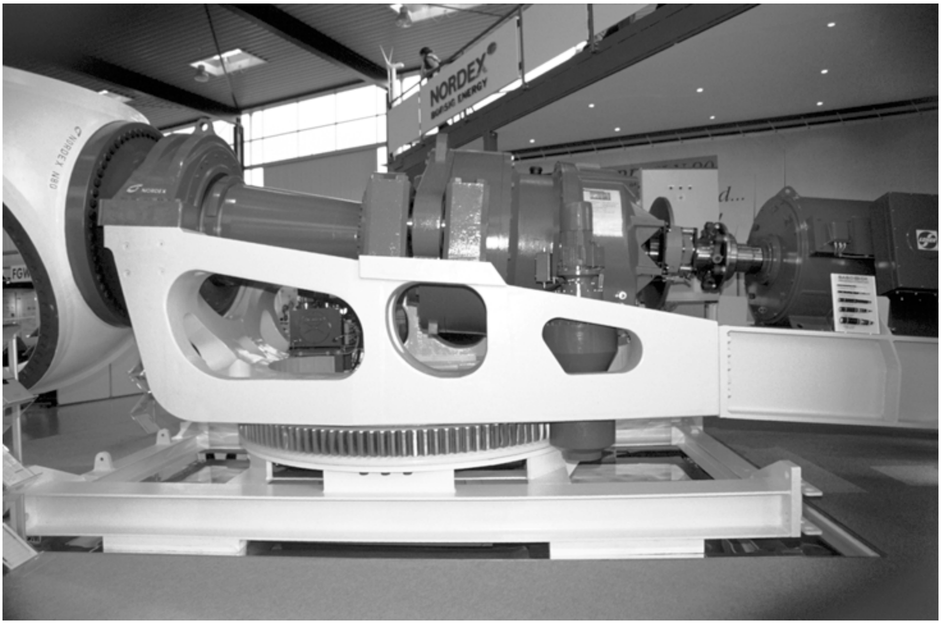


Figure 8.50. Cast bedplate of the Nordex N-80 wind turbine (material GG-6, weight approx. 19 t) with generator base flanged to it

Figure 8.51. Nacelle fairing of a Nordex N-60

chosen accordingly and the load-bearing shell is largely closed. Cylindrical bodies with circular cross-sections are best for this purpose (e. g.: aircraft fuselage). There are difficulties to be dealt with in production, though. The costs of manufacturing dual-curvature steel sheets are unjustifiably high. Another disadvantage is the difficulties experienced with respect to the insulation of the structure-borne sound from the high-noise components inside the nacelle. If, for example, the gearbox is joined directly to the skin, it will be difficult to avoid unpleasant resonances. For these reasons, self-supporting nacelle structures of welded steel sheet are rarely found today in wind turbines.

Apart from the technical concept, the size of the nacelle plays a role in production costs which is not to be underestimated. A compact design with "short paths" for load transfer from rotor to tower considerably reduces the tower head weight and thus the costs. In contrast to older experimental wind turbines, the more recent large wind turbines are, therefore, distinguished by their considerably smaller nacelles. Their sizes are dimensioned to provide space for the installation of the aggregates plus an absolute minimum of space for assembly and accessibility for maintenance work.

8.11.2
External Shape — Aesthetic Aspects

The outward appearance of a wind turbine is, to a considerable degree, determined by the external shape of the nacelle. The shaping of the rotor follows aerodynamic principles and is thus not open to discussions of aesthetics. Apart from the contour of the tower, the problem of style is concentrated on the shape of the nacelle.

Functional constraints concerning the shaping of the nacelle exist only to a limited extent, and those constraints possibly existing should not be overemphasised. Aerodynamic shaping is not necessary, even if some nacelles look as if it were. The wind is hardly disturbed by having to flow around the nacelle, which, moreover takes place in the aerodynamically less sensitive hub area of the turbine, so that it cannot serve as a reason for aerodynamic shaping. At most, the air flow around the nacelle needs to be considered in the context of positioning the anemometer. This local flow problem can be solved without great difficulty by choosing a suitable location for the instrument.

Arguments of cost should be countered decisively. The aesthetic design of large-scale structures, which includes wind turbines, should be worth "a few bucks". Apart from that, a good design or a bad design is in most cases not a question of money, but of thoughtlessness and, in a few cases, of bad taste. The shaping of the nacelle thus remains a task for the designer.

Initially, the manufacturers placed little value on the shape of the nacelle design. Mastering the function was the primary aim of design in the early years so that styling carried little weight as yet. As wind turbines became more widely installed and the associated discussion of their visual impact on the environment spread, this attitude changed. Moreover, the familiar maxim "ugliness does not sell" also applies to the marketing of wind turbines. Today, the manufacturers of wind turbines are keen on attracting well-known stylists for shaping their nacelles. Figures 8.52 to 8.55 provide some examples. Of course, the comments given merely reflect the subjective impression of the author and do not lay claim to a general public approval.

Figure 8.52. REpower 5M: Mighty and convenable

Figure 8.53. Vestas V-66: "Functional elegance with a family resemblance"

Figure 8.54. Enercon E-66: “Well-hidden large generator”

Figure 8.55. Dewind D-8: “Porsche style, even for wind turbines?”

Part of the overall aesthetic image of the nacelle and of the wind turbine as a whole is a well thought-out coat of paint. This considerably influences the visual impact of a turbine in the landscape. Whether the colour of the turbine is intended to visually "hide" the turbine or to emphasise it must be taken into consideration in each individual case. There are good arguments both for and against either way.

8.12 Yaw System

The motor-driven yaw system of the nacelle, the azimuth or yaw drive, has the task of automatically orienting the rotor and the nacelle into the wind. From an operational point of view, the yaw system is an independent subsystem. From the constructional point of view, it constitutes the transition from the nacelle to the tower head. Some of its components are integrated into the nacelle, some into the tower head. The entire system consists of the following components:

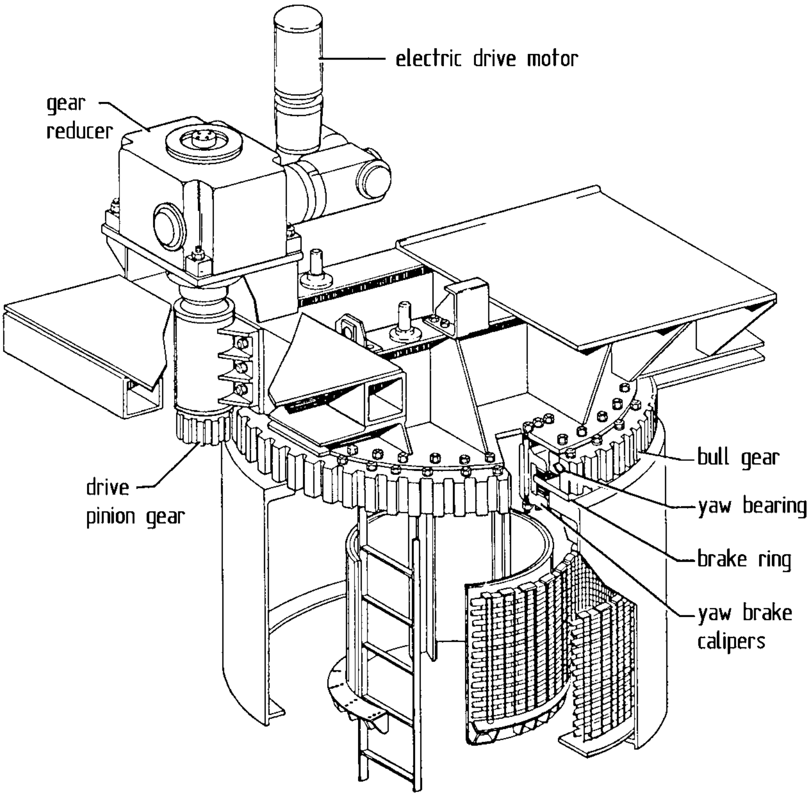


Figure 8.56. Yaw system with assembly of the Westinghouse WTG-0600 [18], 1985

Azimuth bearing

The azimuth or yaw bearing is subject to contradictory requirements. On the one hand, it should ensure easy-running yawing and a long service life and, on the other hand, yaw damping is desirable, even during the yawing, in order to avoid unwanted yawing oscillations (Chapt. 11.3). These requirements can be met both by a conventional roller bearing and by a friction bearing. The traditional design consists of a large roller bearing, whereas a four-point ball bearing is used as a rule in more recent designs (Fig. 8.56). In some cases, roller bearings with special yaw damping are also used (prestressed bearings).

The alternative is a friction bearing in which the nacelle moves on sliding elements made of a synthetic material. This design, initially only used in small-scale turbines, is now also being used successfully in large turbines, e.g. in the Vestas V-66 or NEG Micon NM 52 (Figs. 8.57 and 8.58). The advantage of the friction bearing consists in that no elaborate azimuth brakes and braking rings as in the example of Fig. 8.56 are required.

Figure 8.57. Azimuth friction bearing system of the NEG Micon NM 52

Yaw drive

The two choices for the yaw drive are hydraulic or electrical components, the same as for the blade pitch drive. Both configurations are common practice in wind turbines. In the first generation of larger turbines, hydraulic yaw drives outnumbered electric ones. Promoters of the hydraulic system name lower costs, smaller size and also higher torque as

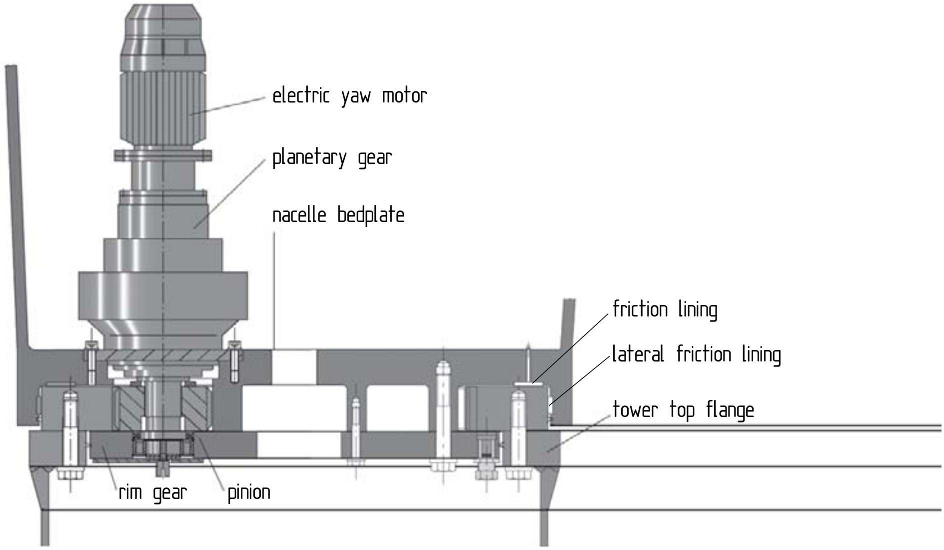


Figure 8.58. Yaw drive system of the NM 52

advantages. On the other hand, there are problems with stiffness, requiring careful analysis of the dynamic characteristics (Chapt. 11.2). Another advantage of hydraulic yaw drives is that they are easy to control compared with electric drives. The power of the drive motors depends on the rate of adjustment required (Chapt. 10.2).

Comparable to the blade pitch systems, electric motors are being increasingly used in more recent yaw drives. The hydraulic drives are being replaced by the controllable electric drive motors. Some manufacturers are using electric yaw drives with integrated brakes so that separate yaw brakes are no longer required (e. g. Enercon E-40). There have also been proposals for controllable yaw drives with a damping type of hydraulic clutch which go by the name "soft yaw drive" [20]

Yaw brakes

In order to avoid the situation of the drive motors having to absorb the yawing moment after a completed yawing operation, a yaw brake is required unless special yaw drives with integrated braking function are used. Otherwise, it would not be easily possible to guarantee the life span of the drive units or of the upstream gears. Smaller turbines usually make do with yaw damping in the azimuth bearing.

Two or more yaw brakes are common in larger turbines. These act on a brake ring on the inside of the tower or conversely on a ring in the nacelle. During yawing, one or two brakes are in operation to provide the necessary damping of the yawing dynamics. The yawing drive must be dimensioned so that it can yaw against this frictional damping.

Yaw drives with friction bearings can manage with much simpler braking systems. In most cases, a brake integrated into the electric yaw motors is sufficient.

Locking system

In larger turbines, the azimuth drive is positively locked in position for extended standstill periods, for example for maintenance. This job is handled by one or several locking bolts.

Control system

Yawing the nacelle into the wind requires a special control and operating logic. Yawing control is described in greater detail in Chapt. 10.2.

8.13 Assembly and Performance Testing

The assembly of wind turbines is carried out as conventional series production with quantities of several hundred turbines per year. Having said this, the turbines are still assembled in batches (Fig. 8.59). A genuine assembly-line mass production with automatic production machinery can be considered only when higher quantities are being produced.

The performance testing of wind turbines after their assembly requires special equipment. It goes without saying that there are limits to this testing. The behaviour of the turbine under realistic wind conditions cannot be simulated. Nevertheless, many functions such

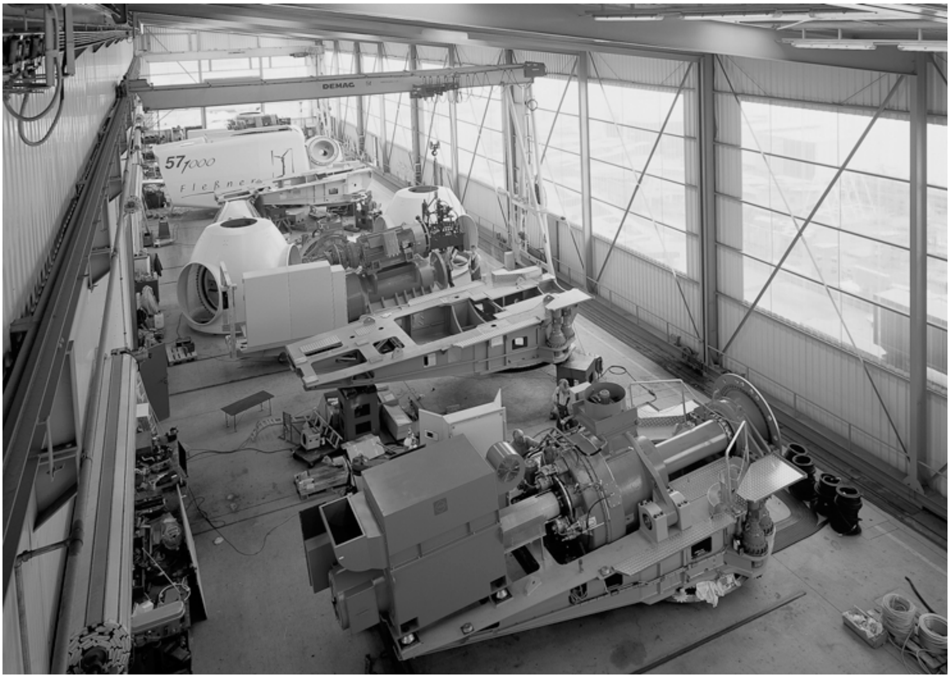


Figure 8.59. Series production of wind turbines at REpower (REpower)

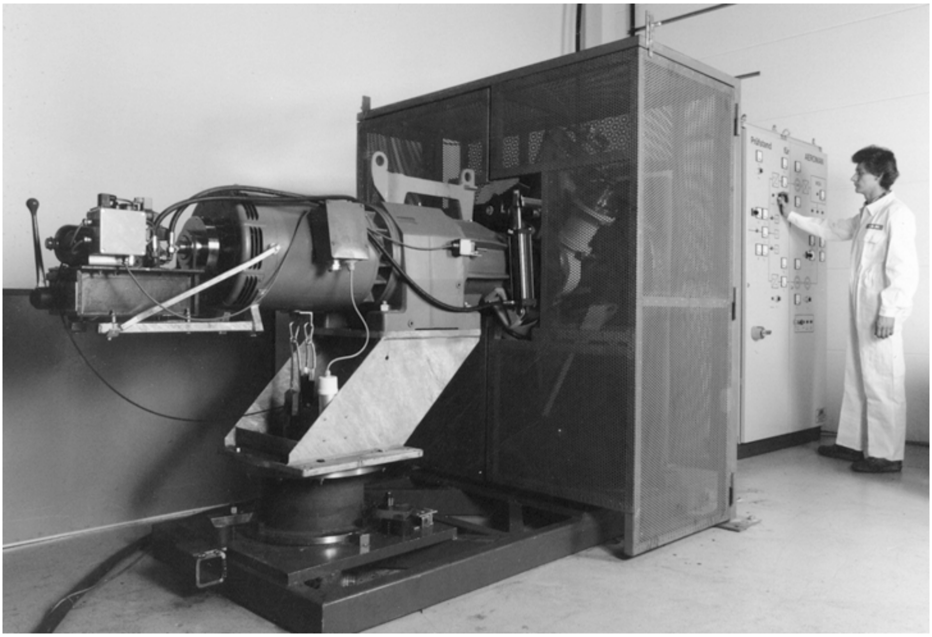


Figure 8.60. Test stand for a small wind turbine (Aeroman) (MAN)

Figure 8.61. Assembly of the nacelle of the Growian turbine at its test site "Kaiser-Wilhelm-Koog" in 1982 (MAN)

as blade pitch adjustment or rotor braking, but above all the electrical and electronic functions, can be checked after assembly. Fig. 8.60 shows a performance and acceptance test stand for a small wind turbine.

In the test set-up shown, the drive train is powered by a variable-speed electric motor on the rotor side. Mechanical functions such as rotor blade pitching, emergency pitching of the blades or the releasing of the rotor brake as over-speed control can be checked under different conditions. Moreover, electrical faults or malfunctions in the grid are simulated, thus enabling electrical protection and safety circuits to be tested. Test stands of this type are indispensable for development tasks and for quality assurance in series production.

For large wind turbines with a rotor diameter up to 80 m, it is still possible under present conditions to assemble the nacelle in the factory, to transport it to its installation site and to mount it completely as a unit on the tower (Chapt. 18.4). This is certainly the most economical method as long as transportation and installation facilities are available.

This method will reach its limits with the future generation of wind turbines with powers of up to 5 MW and nacelles weighing more than two or three hundred tonnes (Chapt 18.4.2). It may be necessary that the nacelles will have to be completely assembled only on site, as was already necessary in the case of the German experimental Growian turbine. The Growian nacelle was assembled at a height of about 10 m around the tower and pulled to the top by means of an hydraulic winch arrangement (Fig. 8.61).

The assembly and installation of the nacelle will become a significant aspect for this size of turbine and will have to be taken into consideration in the design of the drive train and of the nacelle. There are quite a few experts who see this point as a decisive criterion for the maximum economic size of a wind turbine.

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Chapter 9

Electrical System

The electrical system of a wind turbine includes all components for converting mechanical energy into electric power as well as the electrical auxiliaries and the entire control and supervisory system. Next to the mechanical drive train, the electrical system thus constitutes the second essential subsystem in a wind turbine.

In a wind turbine, the actual mechanical-electrical energy converter, the generator, as in a conventional power plant, is the focal point for all the preceding components in the functional chain (Fig. 9.1). Its characteristic properties are all the more important for a wind turbine as the rotor as prime mover with its unsteady torque causes the most varied problems.

In principle, a wind turbine for electric power generation can be equipped with any type of generator. The demand for grid-compatible electric current can be met today by connecting downstream inverters, even if the generator supplies alternating current of variable quality, or direct current.

Generators producing direct current have the advantage of being operable at variable speed. High power direct current generators are, however, no longer in common use today. Several other reasons such as a high-maintenance commutator and their comparatively high cost also speak against them. Very small wind turbines which are merely used for recharging batteries and are, therefore, only intended for generating direct current, are still in use today, of course. They are, however, unsuitable for larger wind turbines. Current wind turbines, therefore, have three-phase AC generators, or alternators, similar to those used in conventional power plants.

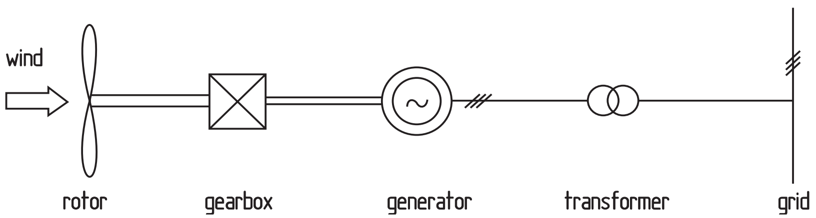


Figure 9.1. Mechanical-electrical functional chain in a wind turbine

As mentioned before, the electrical system of a wind turbine is by no means restricted to the electric generator. The generator merely represents the core of an extensive overall electric and electronic system. The electrical equipment used for current distribution, the connection to the grid, monitoring and control are all parts of this system. Wind turbines are current-generating power plants which must meet the requirements concerning automatic operation, monitoring and safety just like other conventional power plants of comparable output. This fact is sometimes overlooked, thus causing the complexity, and costs, of the electrical equipment to be underestimated.

Another aspect concerning the electrical system is its controllability. The control characteristics of the electric generator and the remaining control-related properties of wind turbines, particularly blade pitch control or stall behaviour, must always be considered collectively. They constitute an almost inseparable functional total system (compare Chapt. 10).

Not lastly, the quality of the electric current fed into the public utility grids is determined to a considerable degree by the technical concept of the electrical system. Particularly in weak grids, grid reactions in the form of power and voltage fluctuations or harmonics, are important criteria in the selection and design of the electrical system [1].

9.1 Synchronous and Asynchronous Generator

It is not the task of this book to provide a general introduction into electric generator technology. The standard literature of this field is better suited to this purpose [2]. Nevertheless, some of the essential properties of the two most important types of alternators will be summarised in the following sections. Knowledge of these is a prerequisite for understanding the functional behaviour of a wind turbine. Continuing from the general characteristics of the synchronous and induction generator, the most important electrical concepts of wind turbines will then be discussed.

From the point of view of their physical-electrical principle of operation, three-phase machines can be built as synchronous generators or as asynchronous (or induction) generators. Both machines have the same basic design with respect to the three-phase winding of the stator. The difference lies in the way the electric field is generated in the generator rotor.

9.1.1 Synchronous Generator

Synchronous electric machines have a rotor (pole wheel) which is excited with direct current via *slip rings* (Fig. 9.2). An alternating voltage is either generated in (generator operation) or applied to (motor operation) the stator windings. The currents flowing in the stator winding and having the frequency f generate the so-called armature field. The rotor winding, through which direct current flows, generates the exciter field, which is rotating at synchronous speed. The speed of the synchronous machine is determined by the fre-

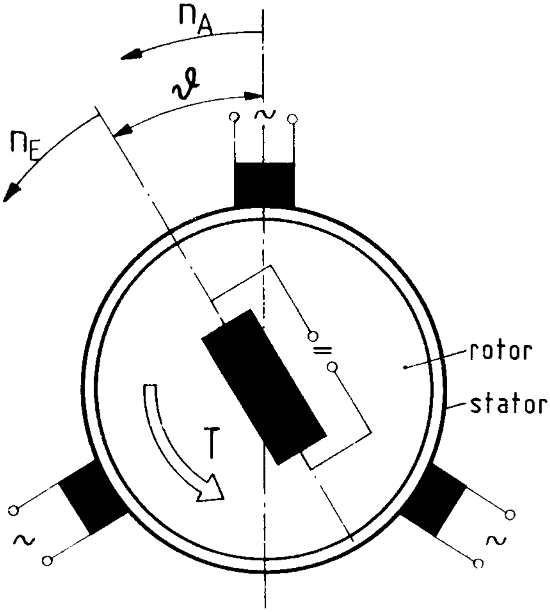


Figure 9.2. Synchronous generator

quency of the rotary field and the number of pole pairs of the rotor. The rotor speed n of a synchronous machine is:

$$n = \frac{f}{p}$$

where

f = frequency of the rotary field (grid frequency) in Hz
p = number of pole pairs, and
n =rotational speed in 1/s.

For the European grid frequency of 50 Hz, a speed of 1500 r.p.m. is obtained with two pole pairs. In the US with a 60-Hz grid, the rotational speed is 1800 r.p.m.

Synchronous generators are built as so-called "cylindrical-rotor" machines or as "salient-pole" machines. Cylindrical-rotor machines with only a few pole pairs and a rotor with a small diameter are suited to high rotational speeds. In large power plants they are used as turbine generators driven by steam turbines at a speed of 1000 to 3000 r.p.m. Salient-pole machines, with a larger number of pole pairs and correspondingly larger diameter, are used in combination with hydroturbines at 60 to 750 r.p.m. At a speed of for example 75 r.p.m., 40 pole pairs are required. In horizontal-axis wind turbines, salient-pole machines are used as a rule (Fig. 9.3).

The direction of rotation and the rotor speed of a synchronous machine are always synchronous with the rotation of the rotating stator field. Thus, there is no relative movement

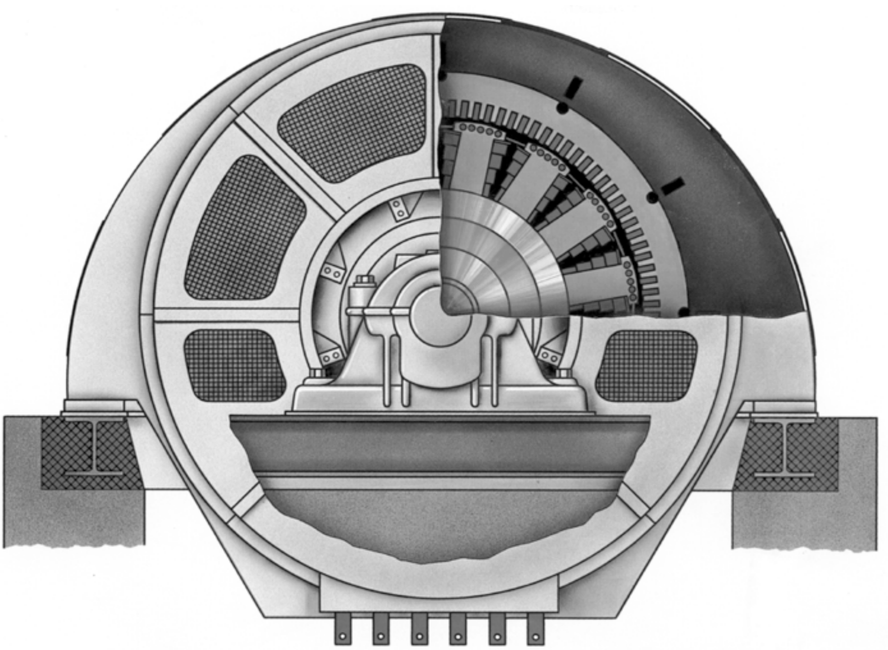


Figure 9.3. Synchronous generator (salient-pole machine) (AEG)

(*slip*) between rotor speed and the synchronous speed of the rotating stator field. Instead, the rotor is turned forward or back, compared to its idling position, by the so-called *load angle* (rotor displacement angle), when mechanical power is added or, respectively, taken out. The size of the load angle is a measure of the level of loading. During idling it is zero, when energy is released (generator operation) it has a positive value, and when energy is consumed it has a negative value (motor operation) (Fig. 9.4). The load angle is equivalent to the time lead or lag of the grid voltage compared to the pole-wheel (rotor) voltage.

The torque characteristic of a synchronous machine is represented as a function of the load angle. A stable operating point is only possible in the range of $\vartheta = -180°$ to $+180°$. The highest torque (*pull-out torque*) is reached at $\vartheta = 90°$. According to the VDE (Association of German Electrical Engineers) standard, the nominal operating point should be at $\vartheta = 30°$. Normally, the pull-out torque has twice the value of the nominal torque. The torque characteristic can be influenced to a limited extent by varying the excitation voltage of the pole-wheel.

The efficiency of synchronous machines is generally higher than in comparable induction machines. In practice, this difference is relatively small (1 to 2 %), at least in large machines. Efficiency increases with increased size (rated power), as is the case in other machines. The efficiency as a function of the load is of particular interest with respect to their use in wind turbines (Fig. 9.5). Smaller generators do not only have a lower nominal efficiency at full load, but also exhibit a greater drop in efficiency at partial load.

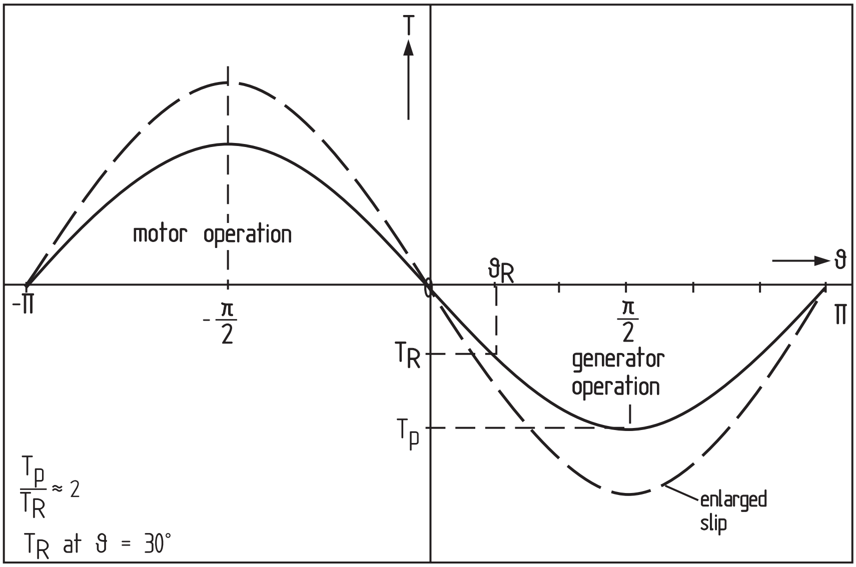


Figure 9.4. Torque vs. load angle of a synchronous machine [1]

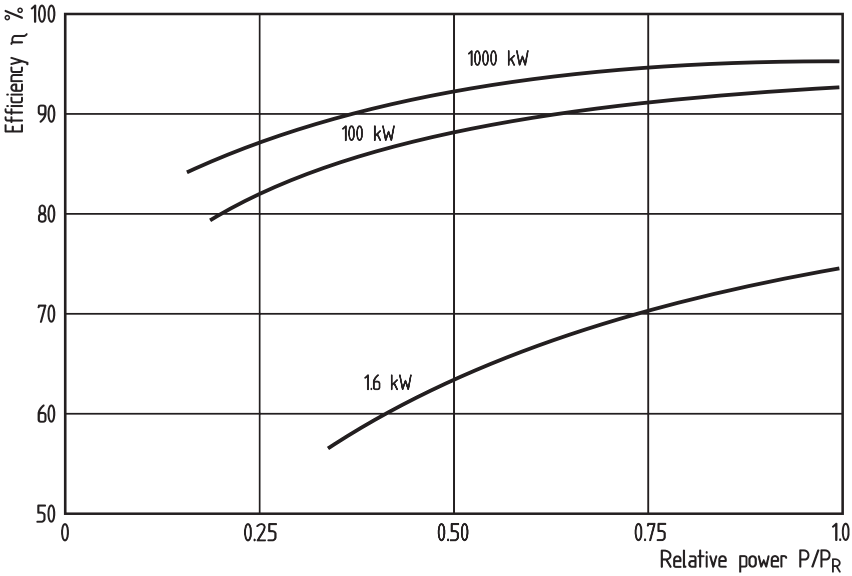


Figure 9.5. Efficiency of synchronous generators of different rated power as a function of load [3]

Next to efficiency, generator mass is of importance to the wind turbine designer, particularly in horizontal-axis wind turbines, where the generator is located at the tower head. The generator mass is influenced considerably by the speed level at a given rated power (Fig. 9.6). The faster the generator rotates, the lighter and, as a rule, more cost-efficient it becomes. With respect to their application in a wind turbine, this does not, however, imply that a generator rotating as fast as possible is the most economical solution. As the generator speed increases, so does the complexity and cost of the gearbox. The task is to find the optimal combination of generator speed and gear ratio.

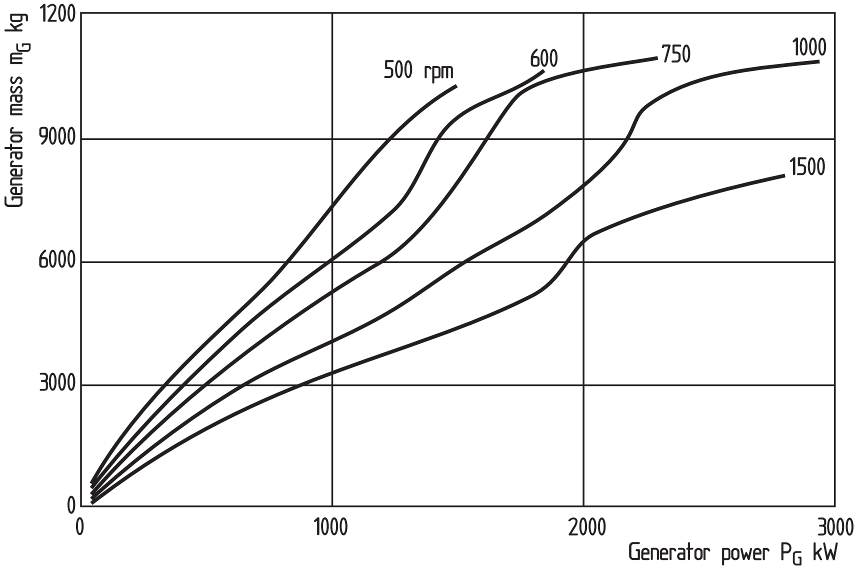


Figure 9.6. Generator mass of synchronous generators [3]

9.1.2
Induction Generator

In the induction machine (or asynchronous machine), an electric field is induced by a relative movement (slip) between the rotor and the rotating stator field which produces a voltage across the rotor winding. The interaction of the associated magnetic field of the rotor with the stator field results in the torque acting on the rotor (Fig. 9.7).

The rotor of an induction generator can be designed as a so-called *squirrel-cage rotor* or, with additional slip rings, as a so-called *slip-ring rotor* (Fig. 9.8). The slip-ring rotor allows the electrical characteristics of the rotor to be influenced from the outside. By changing the electric resistance in the rotor circuit, greater slip can be attained and with it a degree of speed compliance for direct coupling to a fixed-frequency grid. If an inverter is used in the rotor circuit, it is possible to achieve variable-speed operation in parallel grid operation.

Like synchronous generators, induction generators can be operated both as motors and as generators. The induction version is wide-spread among electric motors. Almost all

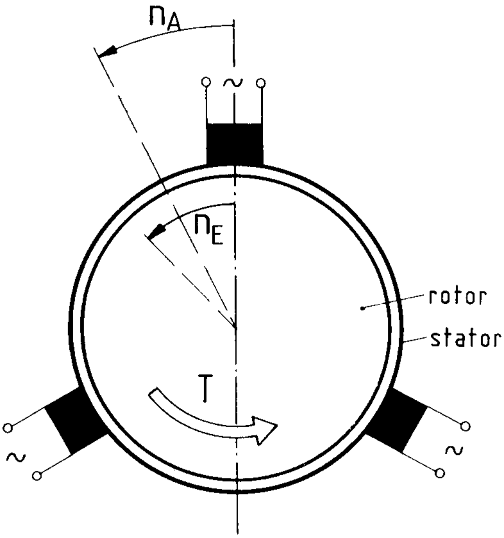
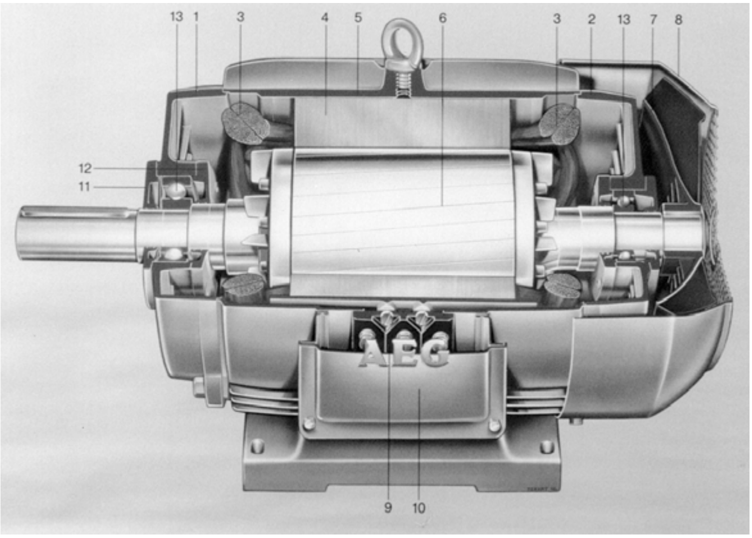


Figure 9.7. Induction generator



1 End shield — input side
2 End shield — non-input side
3 Stator winding
4 Stator laminations
5 Housing
6 Rotor
7 Internal fan
9 Terminal board
10 Terminal box
11 Outer bearing cover
12 Inner bearing cover
13 Rolling bearing

Figure 9.8. Induction generator with squirrel-cage rotor (AEG)

modern electric motors are induction machines. The squirrel-cage versions, in particular, stand out because of their unrivalled robustness and low maintenance requirements. Apart from the rotor bearings, they have practically no rotating, wearing parts and, moreover, their price/performance ratio is advantageous.

In generator technology, the asynchronous design no longer plays a significant role. Large power plant generators are synchronous generators. It is only in connection with smaller hydroelectric turbines that induction generators are occasionally used. For wind turbines, on the other hand, the induction generator is a suitable type of generator, the reasons for which will be discussed later. A look at its basic characteristics is, therefore, indispensable.

For a start, an important fact for operating an induction machine in generator mode is that the rotor must be supplied with a magnetizing current for generating and maintaining its magnetic field. This so-called *reactive-power* demand depends on active power. In parallel grid operation, the reactive power can be taken from the grid. In isolated operation, *power factor compensation* must be provided in the form of capacitors.

The synchronous speed of the rotor of an induction generator depends on the grid frequency and the number of pole pairs:

$$n_{\mathrm{syn}} = \frac{f}{p}$$

where

f = grid frequency in Hz,
p = number of pole pairs, and
n = rotational speed in 1/s.

For two pole pairs, frequently used, a synchronous speed of 1500 r.p.m. is obtained at $f =$ 50 Hz, whereas a 60 Hz grid as in the US requires a generator speed of 1800 r.p.m. In motor operation, the mechanical rotor speed is a few percent below this value and in generator operation a few percent above it, due to the slip.

The slip s is:

$$s = \frac{n_{\mathrm{syn}} - n_{\mathrm{mech}}}{n_{\mathrm{syn}}}$$

The mechanical rotor speed then becomes:

$$n_{\mathrm{mech}} = n_{\mathrm{syn}}(1 - s)$$

The torque of the asynchronous machine is a function of the slip. Accordingly, its torque characteristic is specified in dependence on the slip (Fig. 9.9).

When the slip is $s = 0$ and $s = \infty$, the machine does not produce torque, or cannot absorb torque, respectively. In between, the torque exhibits a maximum, the so-called *pull-out torque*. According to VDE 0530, the ratio between pull-out torque M_K and rated torque M_N must be at least 1.6 in grid operation.

The electrical efficiency of induction generators is a function of the nominal slip. In larger turbines in the megawatt range, the nominal slip is below 1 % (Fig. 9.10). The associated efficiency of approximately 96 to 97 % is not much lower than in a comparable synchronous generator. Due to the absorption of reactive current from the grid, the power factor cos φ is comparatively low and amounts to approximately 0.87. Smaller induction

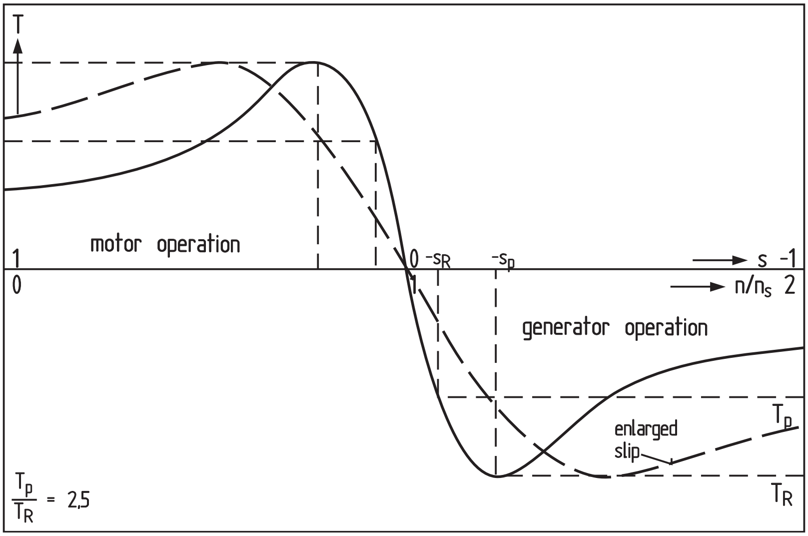


Figure 9.9. Torque characteristic of an induction generator [1]

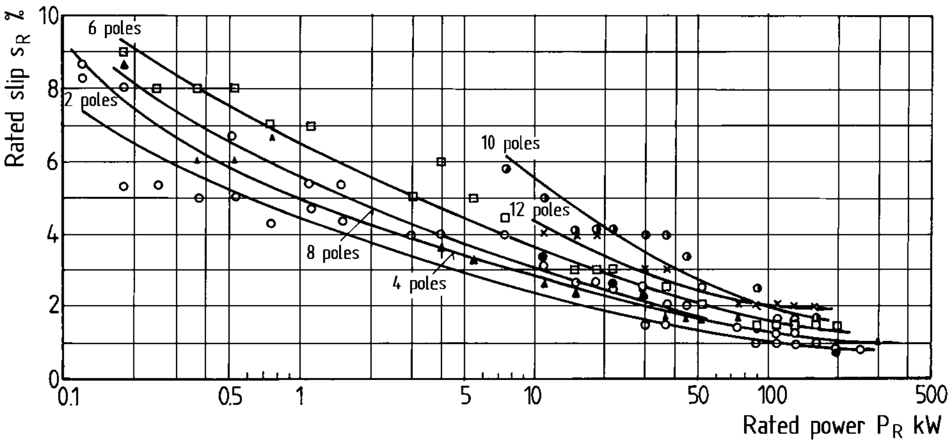


Figure 9.10. Nominal slip of induction generators with increased rated power and varying numbers of poles [3]

generators in the kilowatt power range have a much poorer efficiency, with correspondingly higher values for the nominal slip.

In contrast to a DC machine, it is very difficult to make an induction machine change its speed. It is possible to influence the speed within a very narrow range by increasing the terminal voltage. By connecting external resistors in the rotor circuit, the speed can be varied at least in one direction by increasing slip. This, however, requires a slip-ring rotor. The rotational speed of a squirrel-cage rotor can be changed in steps by means of pole reconnection. This requires the stator winding to have two separate windings with different numbers of pole pairs, a version which is occasionally used in induction generators for wind turbines (Chapt. 9.3.4).

9.2 Assessment Criteria for Electrical Generators in Wind Turbines

The brief discussion of the fundamental properties of synchronous and induction generators shows that both versions can really only be used without problems when they are combined with a drive unit which provides a steady driving torque at a fixed speed. But in a wind turbine rotor this, of all things, is not the case. Apart from simple synchronous or induction generators, variable-speed generator systems with inverters are increasingly used in wind turbines for precisely this reason. These systems can be implemented on the basis of either generator type.

Before discussing the different electrical systems in greater depth, however, it is useful to compile a "catalogue" of assessment criteria which can be used for assessing the different generator systems against the background of the different operating conditions, for example in parallel with the grid or in isolation. As usual, it becomes obvious here that there is not *one* solution, but that different generator systems appear to be advantageous depending on what relative importance is given to the individual properties. The most important assessment criteria to be applied to electric generators or generator systems with respect to their suitability for use in wind turbines can be summarised by means of the following characteristics.

Dynamic response in operation on the fixed-frequency grid

Coupling the generator directly to the fixed-frequency grid forces the generator to run at a constant speed. On the other hand, the wind turbine rotor wants to follow the variations in wind speed. In between there is the mechanical drive train of the wind turbine. High dynamic loads on the mechanical components and severe fluctuations in the electrical power output are the consequences.

Reduction of the dynamic loads can only be achieved by allowing the wind rotor speed a degree of freedom from the grid frequency, regardless of how this is realised, mechanically or electrically. One decisive question is what amount of speed variability is required to decisively reduce the dynamic load level. Answering this question requires the consideration of a whole series of system properties of the wind turbine, such as the aerodynamic rotor design, the pitching rate of the blade pitch control and, if available, generator torque control, to name only the most important. Computer simulations, but also empirical values from practical operation suggest that with a speed "elasticity" of only 2 % to 3 % a lasting improvement can be achieved [1]. A speed elasticity of this magnitude can be achieved via the slip of the induction generator.

Apart from speed coupling, the dynamic behaviour on the grid is also influenced by the damping of any generator speed fluctuation about the grid frequency. Induction generators have much better damping characteristics than synchronous generators. They are, therefore, also dynamically less problematic with respect to their oscillatory response, apart from the speed slip.

In the case where a synchronous generator is used, an additional mechanical device is needed in the drive train, for example a fluid coupling which provides damping and speed compliance (mechanical slip).

Speed range

Although it is true that a speed elasticity of 2 to 3 % is sufficient to distinctly reduce the dynamic loads, this is insufficient to obtain speed variability in the sense of a wind-oriented operation. Based on the background discussed in Chapt. 14, completely wind-oriented operation requires a speed range of approximately 40 to 100 % of the nominal speed. A speed range of this extent can only be achieved with a variable-speed generator and an inverter. However, the inverter costs and decreasing efficiency are factors to be considered.

Controllability

Apart from controlling power output by blade pitching, it is also desirable to have a second control capability on the electrical side. If it is possible to influence the generator torque, a variable-speed mode of operation of the rotor can be implemented in parallel grid operation. This will relieve the comparatively inert aerodynamic blade pitch control and thus improve the overall control characteristics of the turbine. The controlled variable-speed generator/inverter systems almost completely smooth out the electrical power output within the given speed limits (Chapt. 6.6.4).

Reactive power

The reactive-power requirement of the generator system is a central issue primarily in isolated operation, preventing the use of an induction generator, as a rule. In parallel-grid operation the reactive power characteristics cannot be left out of consideration, at least in the case of large turbines or of a large number of turbines. The public utilities charge high fees for supplying reactive power from the grid. With induction generators the reactive-power consumption must be compensated for by connecting capacitors. In synchronous generators the *power factor* "$\cos\varphi$", i. e. the reactive power, can be controlled by regulating the voltage at the terminals. In the case of generator systems with inverter, the reactive-power requirement of the inverter must be taken into consideration.

Grid perturbations

Even drawing reactive power from the grid represents an undesirable perturbation. Furthermore, other interferences with the grid must be noted. Among them are high starting currents when an induction generator is connected, or harmonics in the current fed into the grid. Harmonics such as these can be generated to a small extent by the generator itself, but to a much larger extent they are associated with the use of static converters. The higher-frequency waves can interfere with the ripple control systems in the interconnected grids. However, they can be filtered out more easily than low-frequency oscillations. The harmonics load on the grid was an assessment criterion at least for some of the variable-speed generator systems with older inverter types. Modern inverters generate an alternating current which is almost completely free of harmonics. In Germany, testing newly developed wind turbines for *grid compatibility* in accordance with uniform criteria has been common practice for some years (compare Chapt. 18.5).

Synchronisation

Synchronising the generator with the grid presents entirely different problems for the two generator designs. Synchronising a synchronous generator with the grid poses considerable difficulties for a wind turbine. In practice, it can only be done by using an additional inverter or some speed elasticity and damping in the drive train. Nevertheless, induction generators, too, are connected to the grid by means of a "soft connection" arrangement using thyristors. This is intended to reduce the so-called "switch-on transient" with its momentarily high power import from the grid (compare Chapt. 9.3.2). It is, however, much easier to connect induction generators to the grid.

Load disconnection

A sudden load disconnection, for example due to a failure of the grid or an electrical fault, is always a critical moment for a wind turbine. The loss of the generator torque requires immediate action from the rotor brake systems in order to avoid the rotor from "running away". A generator behaviour which sustains the electric generator torque for a certain period of time even after failure of the grid is therefore desirable. It is relatively easy to implement this "electric braking" in a synchronous generator. After failure of the grid, the turbine merely needs to be switched to an ohmic baking resistance. In principle, this is also possible with induction generators, but then the magnetising current for the rotor must be maintained, for example by means of rotor feedback. This is much more complicated to achieve and is, therefore, not done in most cases.

Efficiency

The difference in the electric efficiency of synchronous generators and induction generators is small, at least when the nominal slip of the induction generators is small. The discussion of the electric efficiency therefore focuses on the question of how the efficiency of the variable-speed generator/inverter systems is related to the direct grid coupling of the generators.

Until recently, it was only possible to build inverter systems with relatively poor efficiency. Modern power electronics, however, have changed this situation over the past ten years. Today, the overall electrical efficiency is only a few percent below that of fixed-speed generators, even including inverters. If the higher aerodynamic rotor efficiency, made possible by the variable-speed operation, is also included in the calculation, the resultant overall efficiency of the wind rotor and generator system is even higher. In the long term, even the higher investment costs can be compensated for. Given this background, the differences in efficiency of the electric generator systems are no longer significant enough to be a deciding factor.

Costs

One of the main criteria for the assessment of generator systems is the investment costs involved. However, the differences in cost of the different generator types are almost completely hidden within the overall cost of the electrical equipment in completed turbines which largely explains the often contradictory statements about the costs of the electrical systems of the wind turbines. This makes it difficult to obtain a precise cost comparison for the various generator systems. In addition, it must be taken into consideration that higher investment costs, for example for a variable-speed generator system with inverter, do not in any way lead to poor economics, i. e. higher power generation costs.

Maintenance and Reliability

Different types of systems have differing maintenance requirements. The controllable variable-speed generators have slip-ring rotors and, therefore, require somewhat more maintenance than smaller induction generators with squirrel-cage rotors. Furthermore, the switching elements of the static converters are components requiring special servicing. On the whole, however, the maintenance work for the electrical system will be less significant than that for the mechanical components of the turbine and will therefore not represent a primary decision criterion.

However, this assessment should not lead one to conclude that the electrical and electronic equipment of a wind turbine is entirely without its problems from the point of view of maintenance and reliability. Past experience shows a different picture, at least for the time being. Electronic faults, mainly due to software 'bugs', account for a disproportionately high number of failures (compare Chapt. 18.9).

9.3 Fixed-Speed Generator Systems

The majority of the smaller, older wind turbines is still equipped with generators which are coupled directly to the grid. In some cases, even today, cost considerations led to a preference for this concept in spite of considerable disadvantages for the aerodynamic operation of the rotor and the dynamic loads on the mechanical drive train components. It is only in recent years that with the progress in static converter technology, the indirect grid coupling with its advantage of variable speed operation of the generator has allowed this solution to become a serious and economically viable alternative.

9.3.1 Synchronous Generator Directly Coupled to the Grid

From the point of view of dynamic behaviour on the grid, coupling a synchronous generator directly to a fixed-frequency grid represents the "hardest" case and is thus an extreme case among the technical possibilities (Fig. 9.11).

The advantages of this solution are its simplicity and compatibility with today's standard generator technology for feeding the three-phase grid. Moreover, the reactive power can be controlled very easily via the direct current excitation of the rotor. Isolated operation of a synchronous generator is possible without any additional equipment for reactive-power compensation. These advantages, however, are balanced by a series of grave disadvantages. Only very small load angles are possible for compensating for the dynamic loads imposed upon the generator by the wind rotor. Large load surges, for example due to strong gusts, can cause a loss of synchronisation. The synchronous generator, in response to even small load peaks (for example tower shadow in the case of a downwind rotor, or even frequency fluctuations on the grid), tends to produce oscillations which are only poorly damped.

It is mandatory to take into consideration the "generator-grid's" characteristic frequencies in the dynamic behaviour of the grid-coupled turbine (compare Chapt. 11.2.2). In addition, difficulties arise with synchronisation to the grid, necessitating complex automatic synchronisation equipment. The stiffness of the direct grid coupling results in a highly uneven power output of the wind turbine. Every wind fluctuation captured by the rotor is passed on to the grid without any smoothing.

In addition to difficult operating characteristics, the direct coupling of a synchronous generator to the grid results in high dynamic loads being imposed on the mechanical drive train. The American wind turbines of the first and second generation (MOD-0, MOD-1 and MOD-2), for example, had synchronous generators which were coupled directly to the grid. The MOD-0A turbines were equipped — in some cases retrofitted — with fluid couplings in the mechanical drive train, in order to achieve better damping and smoother power output (Chapt. 8.9). The torsionally compliant but undamped rotor shaft of the MOD-2 also proved to be inadequate to attain complete mastery over the dynamic problems.

Successful use of a synchronous generator can, therefore, be achieved only with complex compliance and damping arrangements in the mechanical drive train. This requires a torsionally compliant and damped transmission, or, even better, an hydraulic slip coupling between gearbox and generator (see Fig. 8.4).

Apart from those measures in the mechanical drive train an active electrical damping system in the generator itself has been proposed [4]. This requires an extra field winding which would be controlled actively. But in view of the advances made in variable-speed generator systems, coupling a synchronous generator directly to the grid is no longer a serious alternative in wind turbine technology.

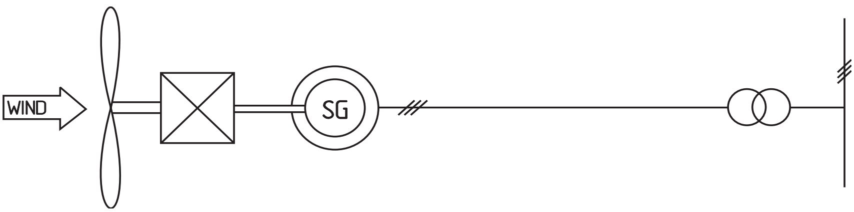


Figure 9.11. Synchronous generator with direct grid coupling

9.3.2 Induction Generator Directly Coupled to the Grid

Induction generators coupled directly to the grid have been successfully used in wind turbines for decades (Fig. 9.12). Particularly in combination with the stall-controlled three-bladed wind rotors of Danish turbines, they initially represented by far the most commonly used electrical concept. The squirrel-cage rotors used in smaller systems are unsurpassed with respect to cost and low maintenance and do not require a complicated blade pitch control arrangement.

Small induction generators have comparatively high nominal slip values which provide sufficient compliance to the grid. They can, therefore, be synchronised to the grid without field excitation and without elaborate synchronisation measures in the range of its synchronous speed.

In larger induction generators without special devices, however, the "inrush current" is in most cases unwanted. More recent turbines, therefore, have "soft grid coupling". After the generator has reached synchronous speed, it is initially connected to the grid via a thyristor controller with *phase-angle control.* This limits the inrush current to about 1.5-times the nominal current. After 1 to 2 seconds, the thyristor controller is bypassed by the line contactor. However, the phase-angle control produces a brief but relatively strong 5th-order harmonic.

The reactive power requirement of an induction generator depends on its power output. The reactive current increases with output, starting from a magnetising current needed for idling. Thus, various stages are required for more or less complete reactive-power compensation depending on the requirements. One set of permanently connected capacitors can only provide static compensation for one operating point. Discrepancies must be made up from the grid or the compensation has to be provided incrementally by means of a set of switchable capacitors.

If the reactive-power consumption is to be kept as low as possible, further improvements can be achieved by special idling compensation. In some cases (isolated operation) a rotating phase shifter, a synchronous machine with voltage or reactive-power control, may be installed.

In large wind turbines in the megawatt power range, however, the use of directly grid-connected induction generators is not undisputed. Large induction generators are designed with a small nominal slip in favour of high efficiency. With respect to its grid-coupled operation, the behaviour of such a generator does not differ much from that of a syn-

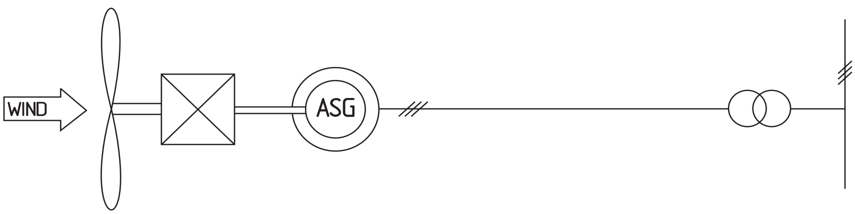


Figure 9.12. Induction generator with direct grid coupling

chronous model. Wind fluctuations are passed on to the grid almost as unsmoothed as with a synchronous generator. Although its oscillatory characteristics are less problematic, the dynamic loads imposed on the wind turbine are also high.

An improvement can only be achieved via a higher nominal slip value. This, however, is in conflict with efficiency, generator weight and cost. Nevertheless, the nominal slip of an induction generator can be manipulated to a certain extent. There are various methods to increase slip. The most obvious possibility is designing the rotor for a higher slip values. The example of an induction generator with a rated power of 1200 kW shows to what extent this affects efficiency (Fig. 9.13). Overall generator mass also increases with increasing nominal slip (Fig. 9.14). Up to a nominal slip of a few percent, the increase in cost is not so serious, if it is kept in mind that the generator itself constitutes only a small part of the cost of the total electrical system.

One disadvantage of induction generators with increased slip which must not be ignored is the problem of heat dissipation. Generator cooling and with it the entire cooling air ducting system in the nacelle must be designed for a higher throughput.

Seen overall, a generator design with a nominal slip of 2 to 3 % should represent a feasible compromise for providing a minimum amount of speed compliance with justifiable additional expenditure and loss of efficiency.

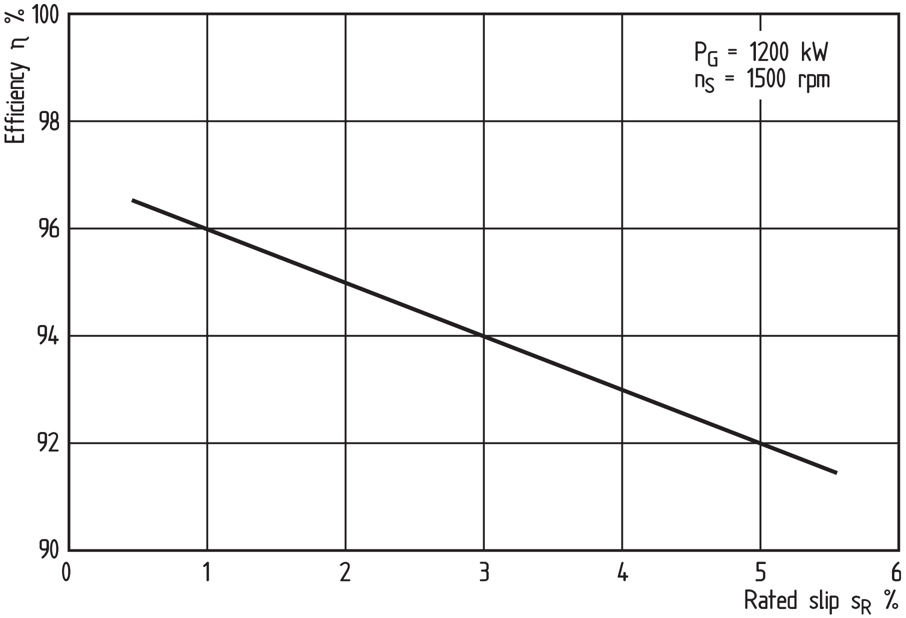


Figure 9.13. Efficiency of an induction generator as a function of rated slip [5]

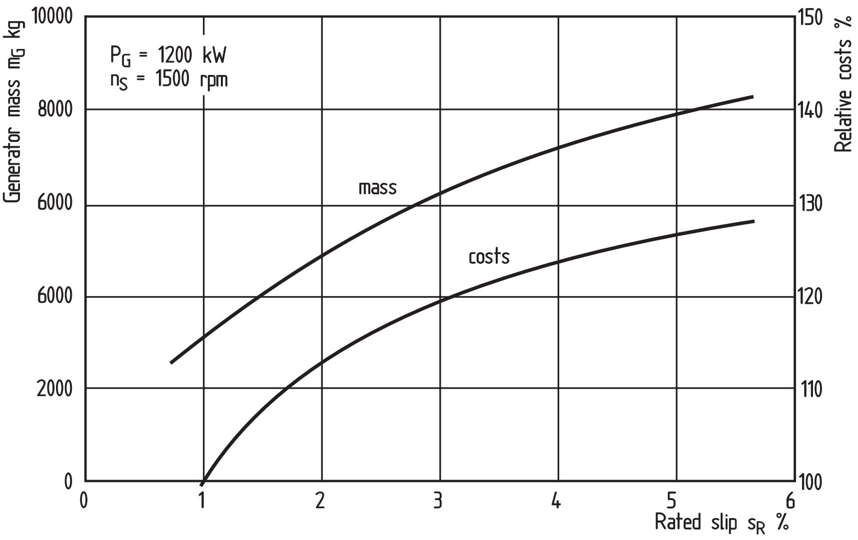


Figure 9.14. Overall mass and relative cost of an induction generator as a function of rated slip [5]

9.3.3
Variable-Slip Induction Generator

The slip of the induction generator provides the opportunity for implementing greater speed compliance. To do this, external resistors can be connected into the rotor circuit which normally requires a slip ring rotor. The external resistors will only be connected in order to produce the desired slip when the load on the wind turbine becomes high. Using external resistors instead of a rotor with higher slip also creates somewhat simpler conditions for cooling the generator (Fig. 9.15).

The more recent Vestas turbines, for example, have such a dynamic slip control system which is offered under the name "Optislip". The resistors are softly connected into the rotor circuit of the induction generator, thus providing for a speed compliance of approximately

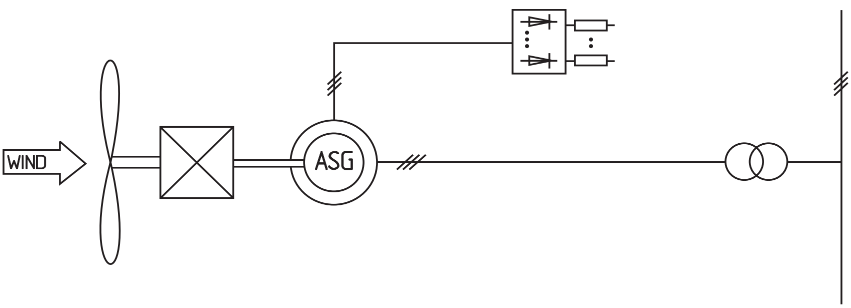


Figure 9.15. Grid-coupled induction generator with external resistors for slip control

10 % under turbulent wind conditions. As a special feature, co-rotating rotor resistors and control unit are mounted on the shaft of the generator which does away with the need for a slip ring rotor (Weier design).

Quite generally, however, these solutions give rise to the question whether it wouldn't be more economic to use a variable-speed generator with inverter. Moreover, the loss of power is to be considered. Although the average loss of electrical efficiency in operation is clearly less than at the maximum point, it is still within a range of 2 to 3 % on average.

9.3.4
Multi-Speed Generator Systems

To obtain an improved adaptation of the rotor speed to the wind speed, multi-speed operation can be considered. Generally, two constant speeds will be chosen, the lower one of which will be used for partial load conditions, i. e. when wind speeds are lower. It is true that this method of speed stepping is no replacement for speed variability, as it does not improve the dynamic characteristics. But with two fixed speeds, the rotor's energy yield can be increased somewhat, and the noise emission of the turbine under partial load operation can be reduced. There are various possibilities of implementing a stepped-speed rotor by electrical means.

Dual generator

Older Danish wind turbines are frequently equipped with two generators, of which the smaller one, with lower speed, is used during low-wind conditions. Apart from the more advantageous rotor speed, an improvement in the electrical efficiency under partial load, and a more favourable power factor, owing to the lower reactive-power requirement of the smaller generator, is achieved (Figs. 9.16 and 9.17). In most cases, the turbines have a three-bladed rotor without pitch control. The second, larger generator is sized to the rated power to meet the requirements of the stall-controlled rotor to provide enough generator torque to keep the generator on the grid (s. Chapt. 5.3.2).

Naturally, the greater expenditure, not only for the two generators and the more complex gearing but also with regard to control and operation, is a disadvantage. In the case of large, aerodynamically controlled turbines, the use of two generators can be justified only if difficult situations involving isolated grid operation have to be coped with. In turbines in the megawatt power range, neither the drop in efficiency under partial load nor the reactive-power requirement are sufficient reason to justify the expense of a dual generator system.

Pole-changing generator

A basically simple solution is the use of a pole-changing induction generator. These generators have two electrically isolated windings in the stator with different numbers of poles. Normally, 4 and 6 poles or 6 and 8 poles are paired. The speed ratio is correspondingly 66.66 % to 100 % or 75 % to 100 %. The generators are much more expensive compared to standard generators, and their efficiency is slightly lower when operating at the lower speed

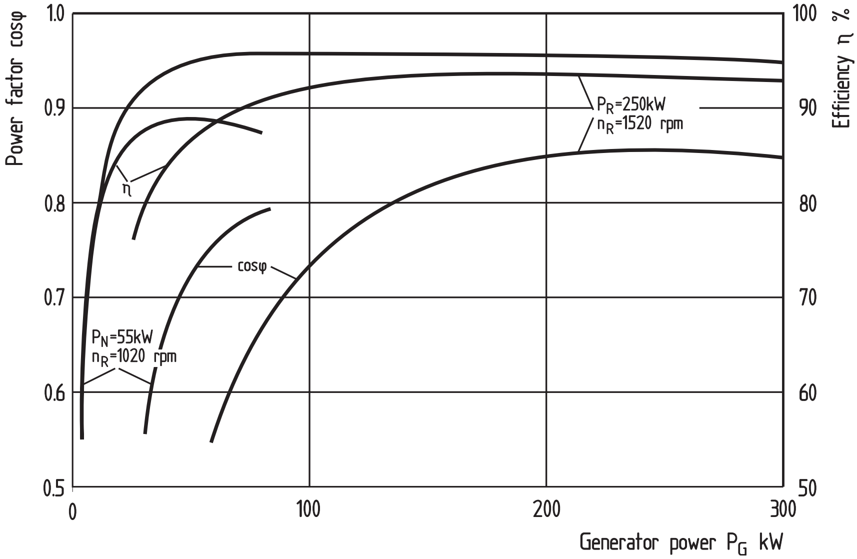


Figure 9.16. Electrical efficiency and power factor of the prototype of a Volund experimental wind turbine with two induction generators [6]

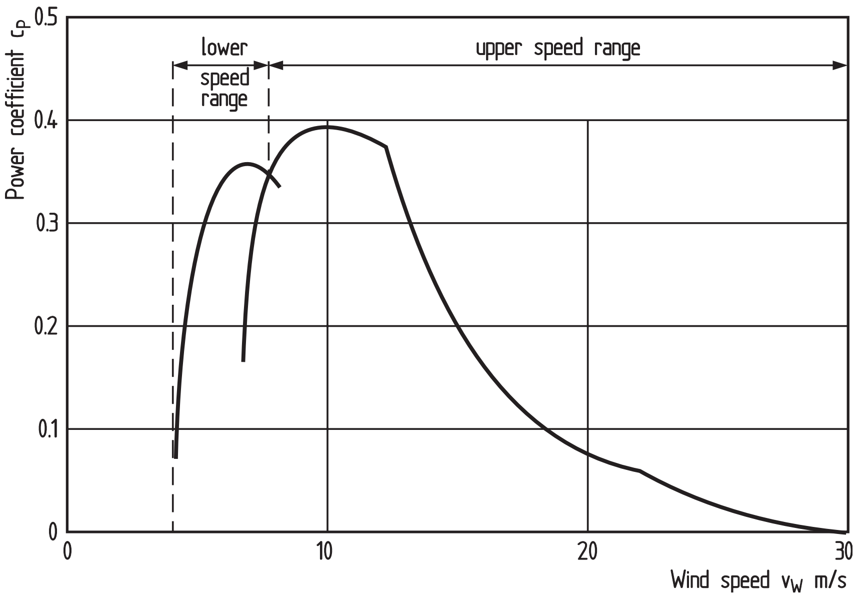


Figure 9.17. Rotor power coefficient of the Volund turbine [6]

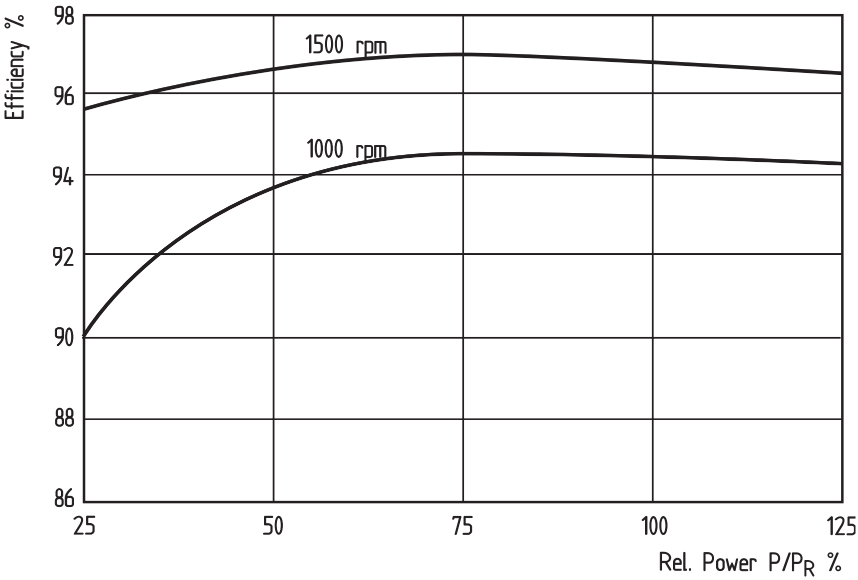


Figure 9.18. Electrical efficiency of a pole-changing induction generator (rated power 750 kW) [7]

(Fig. 9.18). The advantages of stepped-speed operation are, therefore, questionable, even with pole-changing generators, but it might be useful in areas of poor wind conditions.

9.4 Variable Speed Generator Systems with Inverter

Controlled variable-speed operation of a wind rotor is only possible with an electric generator which is operated with a downstream inverter. An Alternator operated with variable speed inevitably generates alternating current with varying frequency. The latter can only be adjusted to the required constant grid frequency by the inverter. Inverter technology is expensive and causes losses of efficiency. But apart from reducing the dynamic loads considerably, it permits an operation of the wind rotor which meets the requirements of its specific aerodynamic properties better than operation at constant speed. Generator-inverter systems are, therefore, used more and more.

Conventional generator technology supplies few models for this. Prime movers such as steam turbines or diesel engines do not require variable-speed generators. Variable-speed generator systems are only used in some special cases of application. In large ocean-going ships variable-speed generators with inverters and driven by a propelling shaft have been in use for about a decade [8]. The use of these "shaft generators" on ships has mainly economic reasons. If the generator is driven by the ship's propelling shaft and thus by the ship's main diesel engine, the electric energy is generated by cheap heavy fuel oil. The speed of the propeller shaft varies, however, especially in ships without variable-pitch propeller, so that the variable-frequency three-phase current generated must be converted to a constant frequency by an inverter for feeding the on-board power system.

In electric drive technology, variable-speed motors, needed for many different purposes, could not be implemented without inverters. In some cases these concepts represent the staring point for the development of variable-speed generator systems for wind turbines.

A variable-speed generator system can be implemented both on the basis of a synchronous generator or by using an induction generator. While in the synchronous generator, all the current generated must be converted, the induction generator offers slip as a starting point. The power loss (slip power) can be fed back into or added to the power output flow from the stator by means of suitable inverters. In this way, only a part of the electric power generated needs to be sent through the inverter. However, this implementation requires a slip ring rotor, which is associated with higher costs and more maintenance.

Today, variable-speed generator systems are the preferred design for large wind turbines, a development which has been made possible by significant advances in the technology of inverters. At first, the inverter designs were based on thyristors. The older 6-pulse systems were still afflicted by the disadvantage of relatively poor replication of the ideal sinusoidal alternating current, with the consequence of a large content of harmonics and a considerable requirement for reactive power. In addition, the efficiency was still comparatively poor. These disadvantages have been eliminated almost completely by changing to 12-pulse systems providing better control. New inverters are based on transistors, using *IGBTs (insulated-gate bipolar transistors)*. Although the efficiency of these inverters is slightly lower, their range of applications with respect to the voltage level is considerably expanded. Moreover, there are no more harmonics.

In most cases, the frequency converter or AC inverter systems are constructed as separate *rectifier* and *inverter* with a *DC link*. This provides for the best type of control. In certain applications, so-called *cycloconverters* operating without DC link are also suitable. The inverter frequency is controlled by the given grid frequency on the grid side (*line-commutated inverters*). In isolated operation, *self-commutated inverters* are required, but these are much more complex and expensive.

9.4.1 Synchronous Generator with Inverter

Variable-speed operation of a synchronous generator is usually effected via an inverter with DC link. The variable-frequency AC from the generator is rectified to DC and then fed into the grid via an AC inverter (Fig. 9.19).

This concept provides for a wide speed range as the DC link circuit results in complete decoupling of the generator speed, and thus of the rotor speed, from the grid frequency. This wide speed range permits an effective wind-oriented rotor operation so that a noticeable increase in its aerodynamics-related energy yield can be achieved. It almost goes without saying that this concept completely eliminates the disagreeable dynamic characteristics of synchronous generators coupled directly to the grid.

The generator torque can be controlled by controlling the DC link circuit. However, this can lead to undesirable low-frequency beat oscillations in the DC link, making it more difficult to control the system. The shaft generators on ships, therefore, frequently have

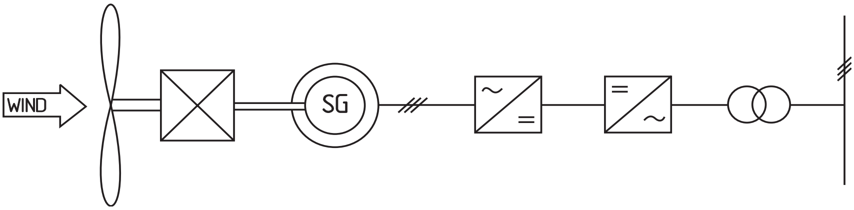


Figure 9.19. Synchronous generator with DC link (rectifier and inverter)

synchronous generators without damper windings, enabling the system to be controlled more rapidly.

The synchronous generator with inverter also offers further operational advantages. Without much additional expenditure, the speed of the wind turbine can be accelerated with the generator used as a motor and decelerated with the generator used as an electrical brake. In contrast to induction generators, electric braking in case of a grid failure can be implemented very easily by means of an ohmic resistor. In addition, there are no problems with grid synchronisation or with inrush current on start-up.

However, in spite of the synchronous generator, the reactive-power requirement of the system is considerable. The power of the inverters necessary for control and commutation is high. Moreover, older and simpler inverters produce unwanted perturbations on the grid due to their harmonic frequencies. If the reactive-power requirement is to be completely compensated for and the harmonic frequencies are to be filtered out, the technical complexity will increase markedly.

Until a few years ago, the most important argument against the synchronous generator with a DC link was, apart from high costs, its poor overall electrical efficiency. As the total electric power output flows via the inverters, efficiency is basically lower than in variable-speed generator designs which use the inverter only in the rotor circuit of an induction generator. However, with advanced inverter technology this argument is no longer so important. Today, inverters with extraordinarily small losses are being built, so that the overall efficiency of this generator system is scarcely lower than, for example, in the dual-feed induction generator. The troublesome harmonics of the older inverters are virtually completely eliminated using pulse-width-modulated inverters.

Regardless of these advantages, the synchronous generator/DC link system is not the system of first choice under current conditions if variable-speed generator systems for wind turbines are considered. Technical solutions based on an induction generator are more cost effective and have a somewhat better efficiency.

A particularly complex development in this field was the electrical system of the WKA-60 wind turbine which was capable of isolated operation (Fig. 9.20). Here, too, a synchronous generator with a static converter, which had been derived directly from the shaft generator of a ship, was used. The turbine was installed on the German island of Heligoland. For the first time, a large wind turbine with a rated power of 1200 kW was operated in the comparatively small island grid with a maximum load of about 3000 kW. The main power source in this grid are two diesel generators each with 1800 kW of power output [8].

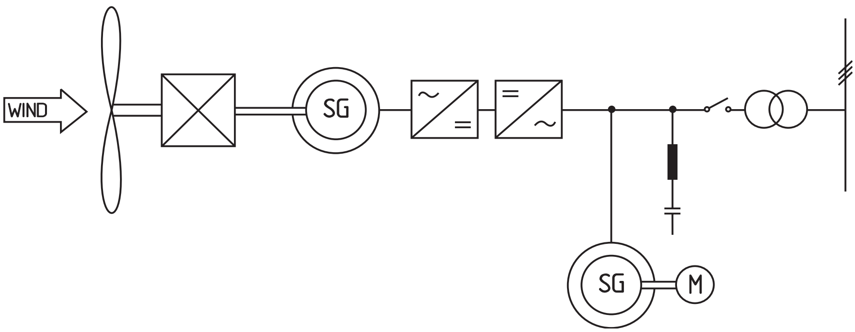


Figure 9.20. Electric generator system of the WKA-60 wind turbine with synchronous generator and static inverter including rotating phase shifter and harmonic frequency filter for use in a weak island grid (AEG system)

The generator system of the wind turbine had been designed for a relatively wide speed range to achieve extensive smoothing of the power output. Smoothing of the power output was necessary to facilitate the control interaction with the diesel generators. In addition, the wind turbine had been equipped with a rotating phase shifter, which provided for complete reactive-power compensation over the whole power output range. The harmonics produced by the inverter were largely filtered out. Thus, the technical complexity and the costs for such a variable-speed generator system with full isolated-operation capability were considerable.

9.4.2
Induction Generator with Oversynchronous Cascade

Another possibility for implementing a variable-speed generator is to influence the slip in the induction generator, as already mentioned. If it is possible to make use of the slip power, normally lost, the turbine can be operated over a larger speed range without great losses in efficiency. Feed-back requires a simple link circuit consisting of an uncontrolled rectifier and a line-commutated AC inverter (Fig. 9.21). This concept, however, only permits power delivery from the rotor via the static converter to the grid, a reverse flow of power is not possible because of the uncontrolled rectifiers. The generator can, therefore, only be operated in the oversynchronous mode. The electric torque can be influenced by changing the current in the DC link. This configuration is known as sub-synchronous converter cascade in electrical drive technology and is used in controlled-speed drive units. In the generator configuration, this is an oversynchronous cascade.

A considerable disadvantage of previous oversynchronous cascades was the high reactive-power requirement. The reactive-power requirement of the converter can be limited by restricting the speed range. The economic speed range is thus restricted to approximately 100 to 130 % of the nominal speed. Another disadvantage of the older systems hitherto built is the relatively high proportion of unwanted harmonics passed on to the grid.

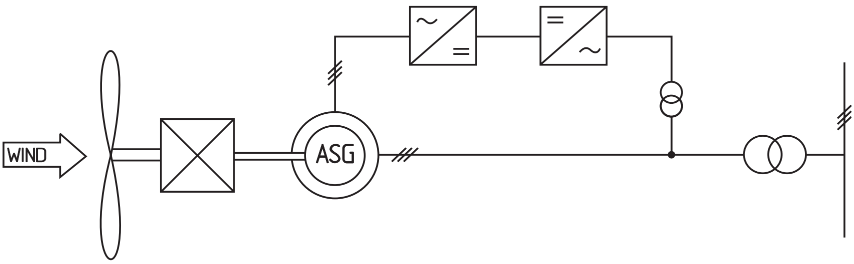


Figure 9.21. Oversynchronous converter cascade for variable-speed operation of an induction generator

Up to now, only one large wind turbine has been equipped with an oversynchronous converter cascade, the Spanish AWEC-60 experimental turbine, which was derived from the German WKA-60 [9].

9.4.3 Double-Fed Induction Generator

The *double-fed induction generator* as a variable-speed system was implemented for the first time in the large experimental Growian wind turbine (Fig. 9.22). In contrast to the oversynchronous converter cascade, the slip power of the induction generator is not only fed into the grid, but, conversely, the rotor is also supplied with power from the grid. In this way, both oversynchronous and subsynchronous operation of the generator is possible.

The frequency generated by the inverter is superimposed on the frequency of the rotating field of the rotor, so that the resulting superimposed frequency remains constant, regardless of the rotor speed. The speed range is determined by the frequency being fed into the rotor. If a cycloconverter is used as inverter, the frequency deviation is restricted to approximately $\pm$ 40 % of the nominal speed. Since inverter power increases with the speed range, a considerably smaller range was selected for Growian. The chosen speed range of

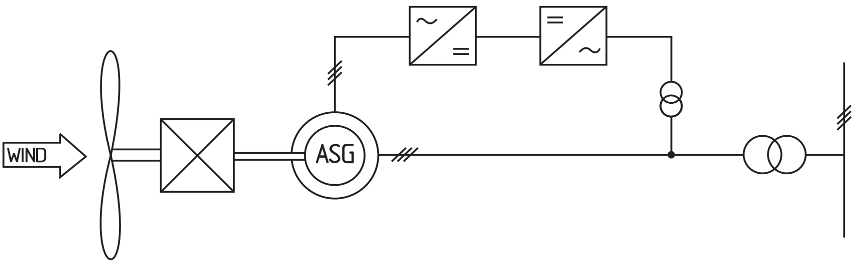


Figure 9.22. Double-fed induction generator with cycloconverter of the experimental Growian wind turbine

± 15 % was primarily intended as "speed elasticity" to reduce the dynamic structural loads on the wind turbine and to smooth out the power.

The double-fed induction generator can be operated in the over- or sub-synchronous speed range, as a motor or as a generator (Fig. 9.23). In the normal operating range, it behaves like a synchronous machine. By controlling the magnitude and phase of the AC in the rotor circuit, any desired reactive or active current can be set, i. e. the generator can be operated with any power factor required.

These different operational modes require a complex control system which is particularly in evidence in the switching and control arrangements for the inverter. On the other hand, the controlled double-fed induction generator combines the operating advantages of both the synchronous and the asynchronous machine. Apart from variable-speed operation, it offers the special advantage of separate active- and reactive-power control. A further advantage of the double-fed generator is associated with the fact that only about a third of the nominal generator power flows via the rotor circuit, i. e. via the inverter. As a result, the inverter becomes much smaller than e. g. in the case of the variable-speed synchronous generator where all the power is converted. This reduces the costs and the loss in efficiency due to the inverter.

The first models of this design (Siemens), for the Growian turbine and somewhat later for the American MOD-5 turbine on the island of Hawaii, were still complicated and correspondingly expensive but the operating experience was good right from the start. For years, however, this electrical concept was not pursued further because of the high costs involved and was only taken up again by a number of generator manufacturers towards the middle nineties.

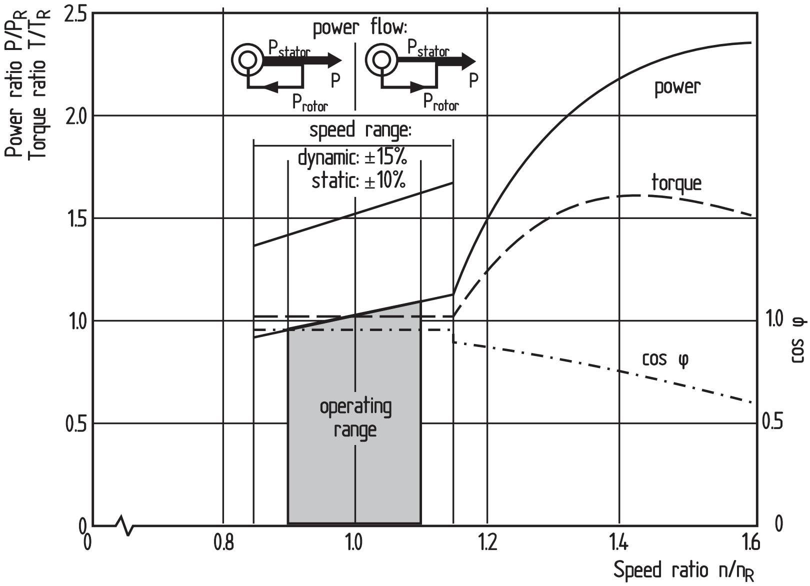


Figure 9.23. Operating modes of the double-fed induction generator of Growian [10]

In recent years, the double-fed induction generator has been developed further and simplified. Today, it is being offered as off-the-shelf generator system and is used in many large wind turbines (Fig. 9.24). Instead of the cycloconverter, a so-called cascade converter with DC link, which is superior to a cycloconverter with respect to its control characteristics and speed range, is used today (Fig. 9.25).

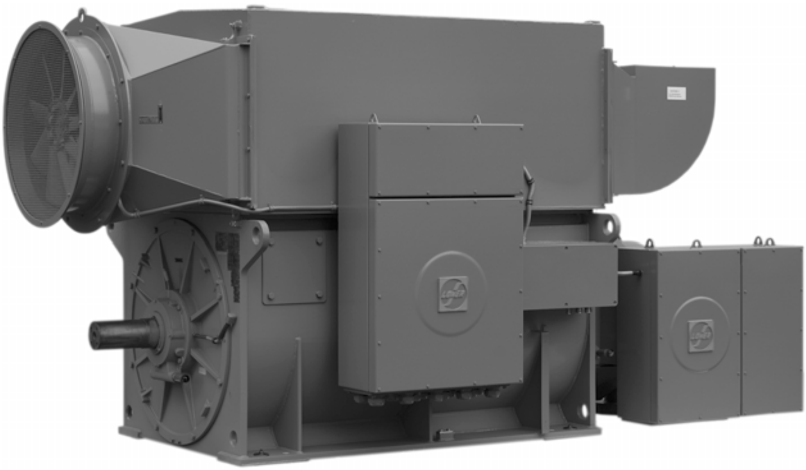


Figure 9.24. Double-fed induction generator with 1.5 MW rated power (Loher)

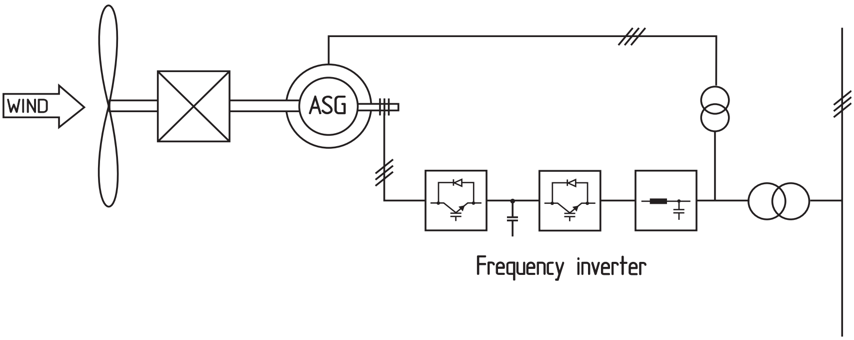


Figure 9.25. Double-fed induction generator with cascade converter (Loher) [11]

9.5 Directly Rotor-Driven Variable-Speed Generators

The idea of driving the electric generator directly from the rotor without intermediate gearbox is as old as modern wind energy technology. However, due to the slow rotor speed in large wind turbines, the generator requires such a large number of poles to reach the grid frequency that the generator diameter and weight assume unacceptable dimensions (compare Chapt 8.1). In the meantime, efficient and cost-effective inverters are available so that the generator itself no longer needs to generate the required grid frequency (Fig. 9.26).

9.5.1 Synchronous Generator with Electric Excitation

The credit for having been the first to successfully implement the design of a direct-drive generator with inverter is due to the German manufacturer Enercon. The generator developed in the mid-nineties for the E-40 type is an electrically excited synchronous machine with 84 poles. Its diameter is approximately 4.8 m (Fig. 9.27). Its nominal power of 500 kW

Figure 9.26. Directly rotor-driven variable-speed synchronous generator with inverter

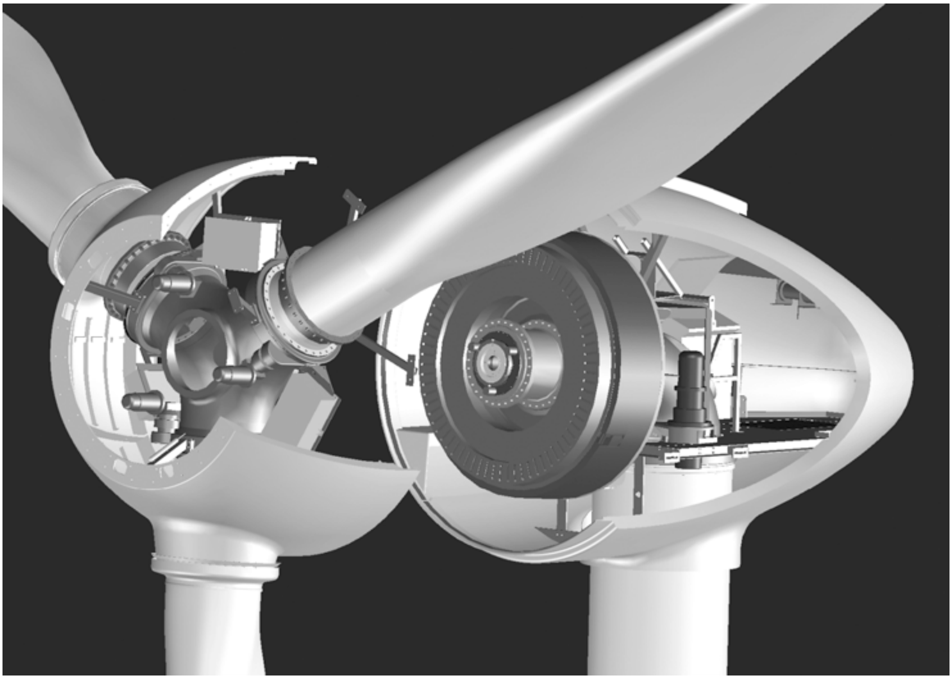


Figure 9.27. Direct-drive multi-pole synchronous generator of the Enercon E-30

is reached at a speed of 38 r.p.m. The usable speed range is between 20–40 r.p.m. The generator generates a frequency of 16⅔ Hz at the nominal operating point, which is then converted to the grid frequency of 50 Hz by the inverter. Electrical efficiency of the generator with inverter is specified as appr. 0.94 at maximum economical rating and is almost constant over the operating range.

The input to the grid is effected via a DC link circuit with an inverter which has virtually no harmonics. The output voltage is already at a medium-voltage level (20 kV) so that no separate transformer is necessary if a medium-voltage system is being fed. The control system offers several adaptive options, which facilitate operation on weak grids. Power limitation depending on grid voltage fluctuations prevents inadmissible voltage peaks in the grid. As in all synchronous generators, reactive-power output, i. e. cos φ, is regulated. In addition, it is possible to set the minimum and maximum frequency for operation on the grid. This grid-voltage- and frequency-controlled operation stabilises the grid frequency, which can be very important with weak feeders.

In the meantime, direct-drive generators of this design are used in all Enercon turbines of up to 4.5 MW. Other manufacturers are also developing gearless drive train concepts for their wind turbines, but in most cases in connection with a permanent magnet generator.

Figure 9.28. Generator production in Enercon's Aurich plant (Enercon)

The concept of a generator driven directly by the rotor has become a serious alternative to the standard design of a high-speed generator with gearbox. Nevertheless, its disadvantages must not be overlooked. As the size of the wind turbine increases, its assembly raises considerable problems. Maintaining an accurate air gap between rotor and stator becomes a problem as the large-diameter stator can only be assembled from several ring segments (Fig. 9.28). Moreover, it is not simple to cool the generator. Closed cooling systems as required for offshore installations are difficult to implement.

The heavy weight as well as the torque loading caused by the slowly rotating generator are of greater importance than the production and assembly problems. Both parameters have unavoidable negative consequences for the entire wind turbine. In comparison with the standard design, it is found that the gearless design still has distinct weight disadvantages, particularly in the 4.5-MW model developed by Enercon (see Fig. 19.8). Thus, with respect to manufacturing costs, the question still remains whether large gearless turbines are competitive against the standard machines in the long term even if these differences are not apparent from the current pricing of wind turbines. On the other hand, the gearless design can claim, that maintenance and probably also service life is more advantageous.

9.5.2
Generators with Permanent Magnets

In drive technology, motors with permanent magnets are widely used in the low-power range. In larger motors, the high specific costs of the materials for the magnets, for example neodymium iron or exotic materials such as samarium cobalt, result in a considerable economic disadvantage in comparison with conventional designs. On the other hand, the technology of permanent magnets in drives is penetrating into the megawatt range, for example in compact shipboard drives. The manufacturers of these drive motors (ABB, Siemens et al.) point out that the costs for these materials can be lowered with increasing quantities so that even generators for wind turbines can be produced economically.

In principle, permanent magnets can be used for all types of electrical machines. Their main advantages are the lack of exciter power, and thus a greater efficiency. The great power density means a reduced mass at a given power, i. e. the construction becomes more compact. This is balanced by poorer controllability because the output voltage cannot be controlled via the exciter frequency. The idling voltage can, therefore, be 30 to 40 % below the rated voltage. The most serious disadvantage to date is, however, the high cost for the material of the permanent magnets and their complicated assembly.

The advantage of the more compact type of construction has induced the developers of direct-drive multi-pole generators for wind turbines, in particular, to make use of the permanent magnet technology. At the beginning of the nineties, the German manufacturer "Heidelberg Magnetmotor" built some vertical-axis turbines with direct-drive generator and permanent excitation [12] but the concept of the wind turbines proved to be unsuccessful, regardless of the generator design, and this development was discontinued

Some years later, permanent magnet technology was proposed for generators of wind turbines, especially by ABB and Siemens. It was ABB, in particular, who pushed ahead with a number of generator developments in this field. Moreover, the ABB generators, derived from similar designs from other applications, are designed as *high-voltage generators* with output voltages of 6 and 30 kV, respectively. The intention was to further reduce the losses up to the grid feed. In 2002, the Dutch company Lagerwey presented a large wind turbine with a permanent magnet generator developed by ABB. Lagerwey had already gained experience with a relatively small turbine with directly driven generator, still with electrical excitation, however (Fig. 9.29).

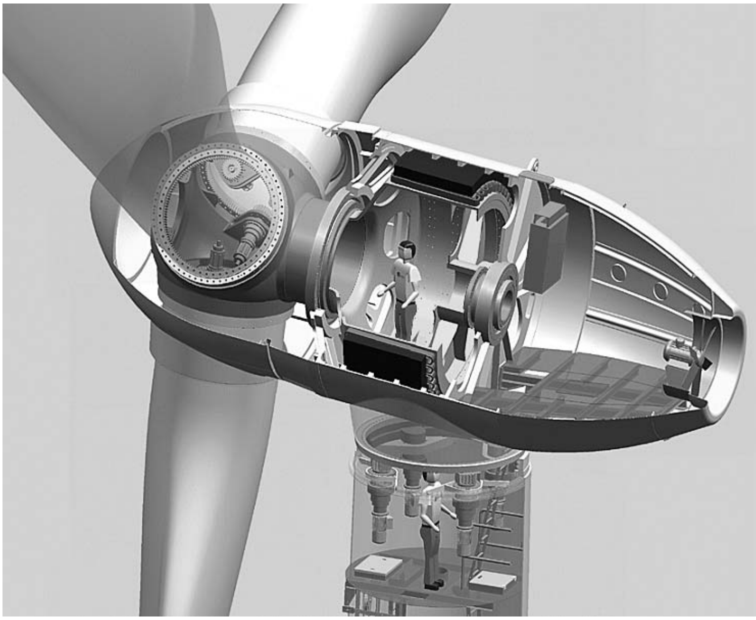


Figure 9.29. Wind turbine concept with permanent-magnet generator (mtorres)

There is no doubt that permanent magnets have the advantage that high power densities can be achieved in a small space and the generators become much more compact as a result. On the other hand, economy apart, there are some disadvantages which must not be overlooked. The generators with permanent magnet excitation have a very poor $\cos\varphi$. This disadvantage must be compensated for by complicated inverter technology or by special filters because the $\cos\varphi$ cannot be controlled as in electrically excited synchronous generators.

9.6 Total Electrical System of a Wind Turbine

From the electrical engineering point of view, wind turbines are electricity generating power plants, like hydroelectric plants or diesel-powered plants. Their electrical systems are similar and must meet the common standards for systems connected to the utility grid. This requirement mainly concerns the technical systems for safety, supervision and power quality. Moreover, the control system must be designed for fully automatic operation.

To connect wind turbines used in interconnected grid operation, there are regulations and requirements which have to be met. On an international basis the IEC has issued the general conditions [13]. The national or local utilities can have more specific requirements. If these regulations are related to connecting induction generators, the following precautions must be taken, in addition to adequate short-circuit and generator protection:

- Prevention of motor operation (reverse-power protection)
- Rapid disconnection of the generator from the grid if the grid voltage or frequency exceeds or drops below certain limits
- Compensation for the reactive-power requirement to a power factor $\cos\varphi = 0.9$
- Connection of the induction generator only within a range of about 95 % to 105 % of the synchronous speed.

In addition, there are regulations covering the monitoring systems to be provided and the accessibility of the electrotechnical equipment.

9.6.1 Large Turbines

The complexity and extent of the complete electrical equipment depends to a certain degree on the generator system and the conditions of use. A turbine with a simple constant-speed induction generator operated in parallel with the grid requires less sophisticated electrical equipment than a turbine with variable-speed generator and inverter which must meet the requirements of isolated operation. Regardless of these differences, there is a certain basic electrotechnical complement as can be shown in the example of a turbine designed for variable-speed operation (Fig 9.30).

Generator

In the example chosen, a series-production synchronous alternator with an output voltage of 690 Volt was selected. The 4-pole alternator has a nominal speed of 1500 rpm.

Inverter

The inverter with AC-DC-AC link also consists of off-the-shelf components but is customised for this special application. The rectifier is in the nacelle and the inverter is in the base of the tower.

Control and supervisory system

The control functions for power and speed control and the control and monitoring systems for the operational sequence are combined in a centralised control unit (compare Chapt. 10). In addition, the generator/inverter system has an internal control system which is integrated in the inverter.

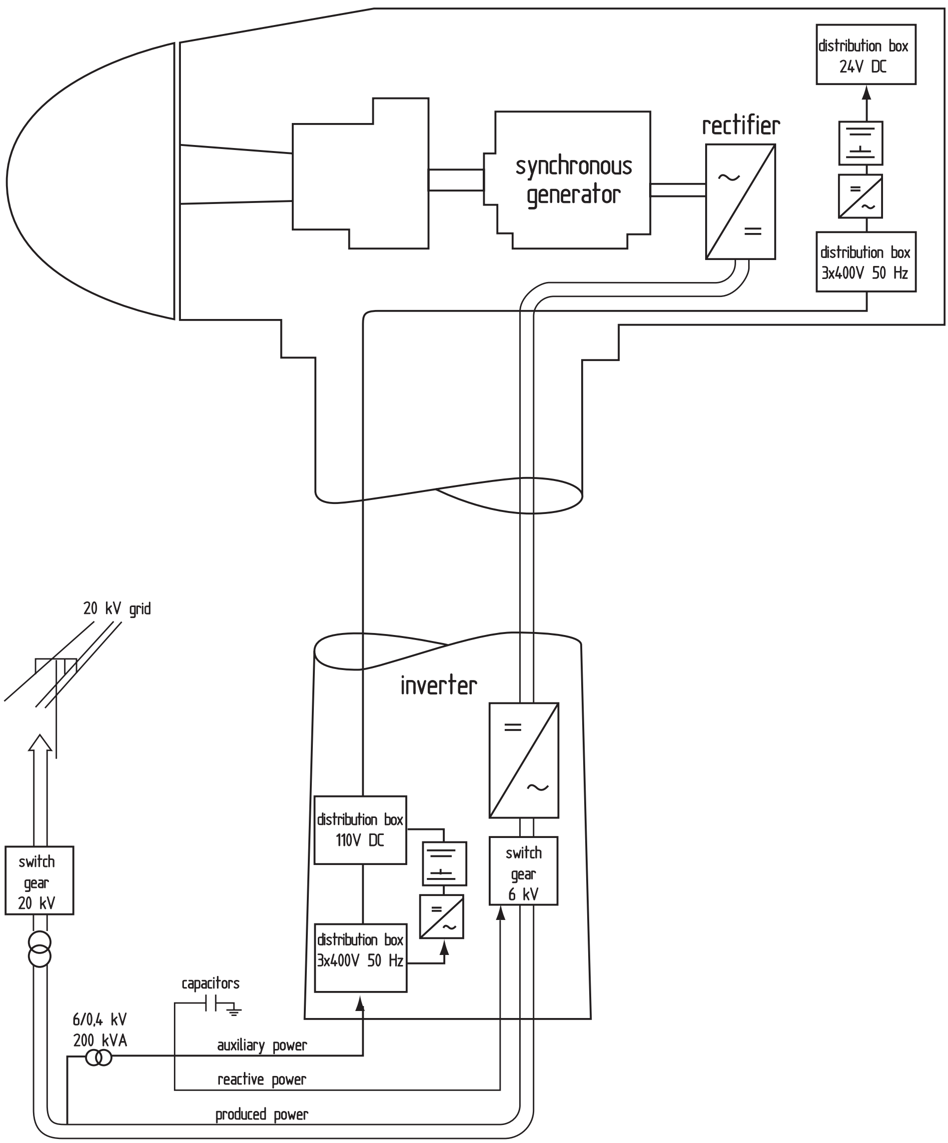


Figure 9.30. Electrical system and equipment of a large wind turbine with synchronous generator and inverter

Power supply for the control system

The instrumentation and control functions require a DC control voltage supply (24 V). There may also be a 220 (110) V AC-voltage distribution system for the generator control system.

Medium-voltage distribution for the auxiliary services

The electrical supply for the numerous auxiliary drive units such as pumps, actuators etc requires its own supply system at low-voltage level, 220/400 V (110/400 V).

Power transmission

In current turbines, freely suspended torsionally flexible cables are used in the upper tower area. Twisting angles of up to 500 or 600 degrees are permissible with the appropriate lengths and fixings. For safety reasons, however, an automatic "untwisting" switch is necessary for when the permissible limit angle is reached.

Transformer

Most of today's commercial wind turbines have their own transformer which changes the generator output voltage (690 V or 6 kV) to medium-voltage level (20 kV). The transformer is accommodated in the base of the tower or in the nacelle.

Reactive-power compensation

In wind turbines with induction generators, reactive power must be compensated for in accordance with the requirements of the relevant utility. This requires the provision of corresponding capacitors in the electrical system. In addition, the inverter emits harmonics which must be filtered out.

Electrical safety devices and lightning protection

The electrical safety devices include primarily the lightning protection system, the aircraft warning lights and a fire detection system. As the size of the wind turbines increased, a comprehensive lighting protection system was found to be indispensable and this is associated with a significant electrical installation. The aircraft warning lights are associated with a certain expenditure. Depending on the siting of the turbine, an ice warning device or even electrical resistance heating for de-icing the rotor blades may also be necessary (compare Chapt. 18.8).

9.6.2 Small Wind Turbines

The electrotechnical equipment of small wind turbines must basically meet the same requirements as large turbines if they are used for feeding into the grid. However, turbines yielding some tens or hundreds of kilowatts commonly have electrotechnical solutions which overall result in much simpler systems. Above all, combining the electrotechnical and control-related equipment in one "switchbox", as is possible in small turbines, creates more favourable conditions for component integration (Fig. 9.31).

Combining the general electrical equipment and electronic control system in compact form reduces the price both of component production as well as of the assembly of the electrical system, a considerable cost factor in large turbines. The switchbox is mounted at the foot of the tower, or also free-standing next to the turbine. The electrical system of a small turbine of the Aeroman type is shown in Fig. 9.32.

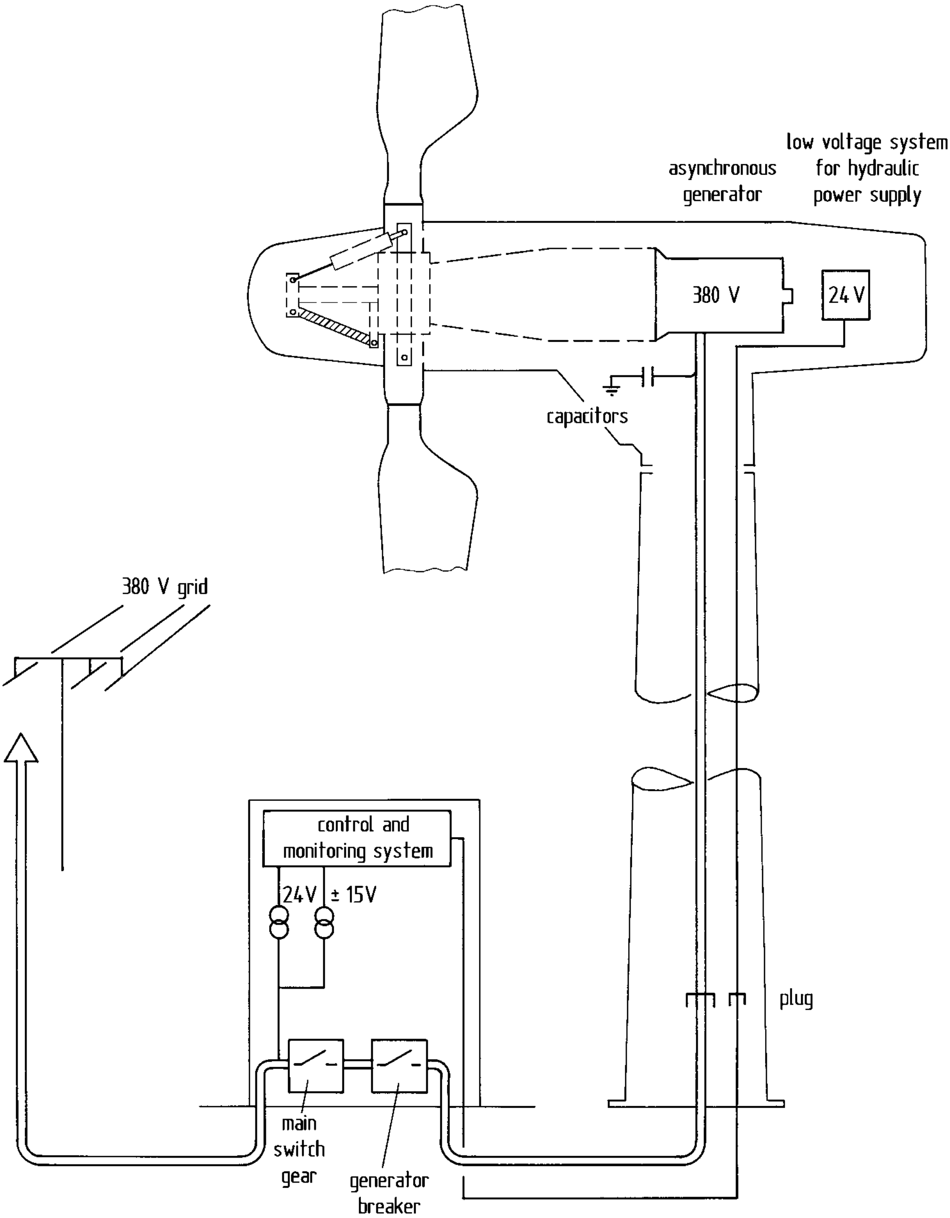


Figure 9.31. Electrotechnical system of a small turbine of the Aeroman type

Figure 9.32. Switchbox of a small Aeroman wind turbine

9.7 Comparison of Electrical Concepts

The different electrotechnical concepts for wind turbines demand a comparison. For several reasons, however, a quantitative comparison is not simple. For one, the advantages and disadvantages of the electrical concepts can only be assessed within the framework of the overall "wind turbine and its applications" system. Moreover, a complex electrical concept may indeed lead to a cheaper overall solution, if it is associated with advantages on the mechanical or operational side. On the other hand, the result of a comparison will depend on the actual technical implementations of a particular power class. Regardless of these difficulties and at the risk of being justifiably contradicted, some basic data are compiled in Table 9.33 in the sense of a comparative overview. However, the problems involved in such a comparison requires some explanatory remarks.

Table 9.33. Electrical efficiencies and approximate cost ratio of electric generator systems of wind turbines in the 0.5–3 MW power range

System	Typical speed range	Maximum efficiency of generator with inverter	Approx. cost ratio
Induction generator (squirrel-cage rotor))		0.965	100 %
– with static reactive-power compensation	100 ± 0.5 %	0.955	
Pole-changing two-speed induction generator	100 ± 0.5 % 66 ⅔ ± 0.5 %	0.965 0.945	110 %
Induction generator with oversynchronous cascade	100 + 30 %	0.95	150 %
– with harmonic frequency filter and reactive-power compensation		0.935	
Double-fed induction generator with static inverter (AC-DC-AC)	100 ± 50 %	0.955	160 %
– with harmonic frequency filter and reactive-power compensation		0.94	
Synchronous generator with static inverter (AC-DC-AC)	100 ± 50 %	0.95	180 %
– with harmonic frequency filter		0.940	
Direct-drive synchronous generator with static inverter (AC-DC-AC) and harmonics filter	100 ± 50 %	0.94	350 %
Direct-drive synchronous generator (permanent magnet excitation) and static inverter (AC-DC-AC)	100 ± 50 %	0.96	450 %
– with harmonics filter and reactive-power compensation		0.94	

The comparison is based on a rated power of approximately 1000 kW. The numerical values should remain valid within a range of from approximately 500 kW to several megawatts. However, they cannot be applied to low outputs of less than 100 kW. At low outputs, it is the electrical efficiency, above all, which is lower.

The assessment of the electric efficiency requires a more differentiated approach, also for other reasons. It is of little use to compare the efficiencies of the different electric generators only by taking data merely from the catalogue. The actual differences will only become apparent in the context of the total electrical system, on the basis of the selected type of generator, but also taking into consideration the entire system.

The overall electrical system is characterised by the chain of efficiency from the generator to the line transformer. The efficiency of the transformer, approx. 98 to 99 %, has been excluded. The figures for reactive power compensation and harmonic frequency filtering have been indicated. If they are required, these two devices will degrade the total efficiency. The following losses of efficiency can be assumed as guide values: static reactive power compensation 0.8 – 1.0 %, harmonics filter appr. 0.5 %.

The speed range of the generator system has a considerable influence on the electrical efficiency and on the cost. In comparison, an "economic" speed range, adapted to the individual concept, has been assumed. Regardless of the efficiency and cost, a wider speed range can be selected. The efficiencies listed in Table 9.34 are to be understood as at rated power. In the range of partial load the efficiency decreases by different amounts depending on the system. The differences are not very great but should not be disregarded either (Fig. 9.34).

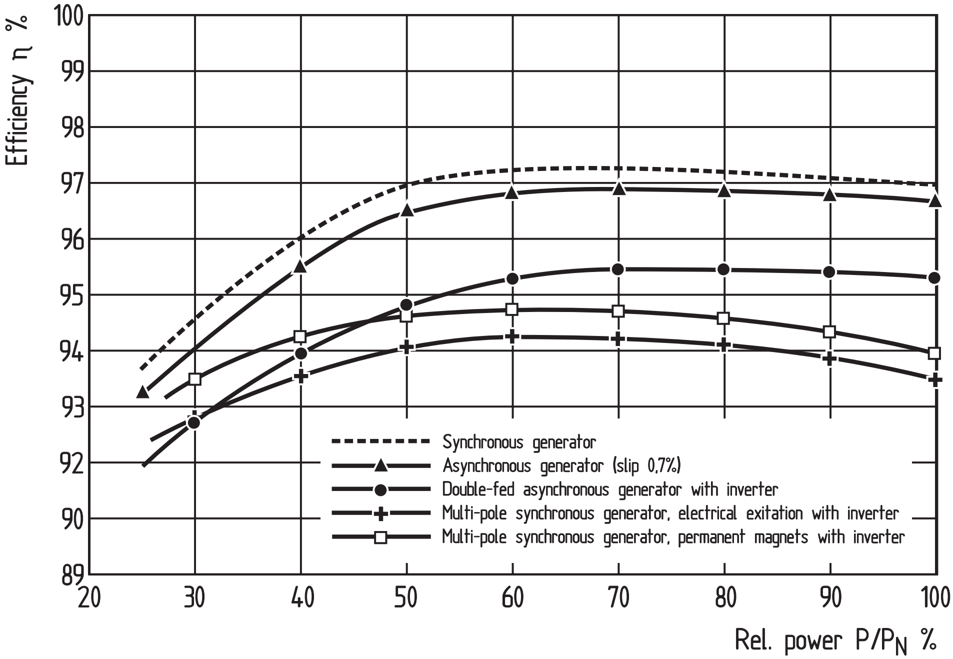


Figure 9.34. Electrical efficiency versus load for various generator/inverter systems

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Chapter 10

Control Systems and Operation Sequence Control

The control systems and sequence control of a wind turbine must primarily ensure its fully automatic operation. Any other approach requiring some manual intervention during normal operation would be entirely unacceptable from an economic standpoint. Moreover, economical considerations demand from the control systems that maximum efficiency be achieved at every point of operation. This does not happen by itself but requires "intelligent" control systems.

Apart from these requirements, there are other tasks which must be fulfilled by the control systems and by the sequence controller. Among these, operational safety is of the highest priority. Technical faults and environmental hazards must be recognised and the safety mechanisms provided must be triggered. In addition, the control system's function is to contribute to minimising the structural loads on the wind turbine.

Not least, the control systems and the sequence controller are expected to be flexible enough to adapt the performance of the turbine to varied operating conditions without extensive technical modifications. Such adaptation can be provided by modern digital control technology through a mere change in the software. Although there is no precise distinction between the terms "control system" and "sequence control" in practice, they do characterise different tasks (Fig. 10.1).

The sequence controller receives external inputs according to the operating conditions and, above all, the wind conditions and the operator's intentions. This information will determine the setpoint values for the control system. The sequence controller monitors operating conditions and functional sequences and makes decisions concerning the mode of operation on the basis of logical deductions. As a rule, it is implemented in a programmable process computer with an associated data acquisition system.

The control system takes care of the internal control processes of the turbine. In a way, it represents the connecting link between the sequence controller and the mechanical and electrical components of the turbine. The control system must, therefore, be matched to the operating characteristics and structural strength limits of the turbine.

In wind turbines with blade-pitch control, the control and supervisory systems control three functional systems: rotor yawing, speed and power control and the operational sequence. Smaller wind turbines which frequently have no blade-pitch control also have no active speed and power control. Instead, passive aerodynamic power limiting and speed

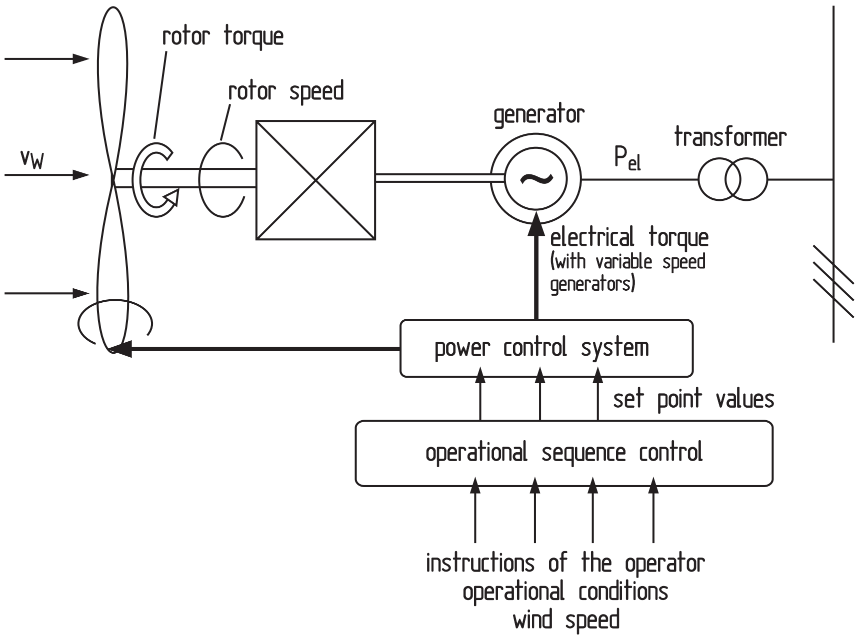

Figure 10.1. Tasks of the control system and sequence control of a wind turbine [1]

control are provided by the grid. But even in this simpler version, a supervisory and sequence control system is necessary for operation monitoring and controlling the operating sequence.

The following discussion of the control problems of wind turbines is conducted with the same assumptions as that of the electric generator systems. The fundamentals of electrical machine control must be known or standard literature consulted [2].

10.1 Wind Measurement System

Sequence control and yawing requires measuring the wind speed and direction, at least in the case of larger turbines. Motorised yawing requires information about wind direction. Control of the operating sequence requires the wind speed information in order to switch between different modes of operation. Small turbines may under some circumstances do without the measurement of these two parameters. The prerequisite for this is a passive, aerodynamic yaw system and an operating mode which uses the electrical power generated as an indicator of wind speed.

In larger turbines, too, power and speed control is carried out without direct wind speed measurement. An attempt to measure wind speed and to use this figure as a direct input value for control leads to considerable problems. Wherever the wind speed is measured, no single value is ever representative of the power generated by a large wind rotor sweeping an area of several thousand square meters. The inevitable consequence would be a wrong response by the rotor speed or power control. To avoid these difficulties, it is better to measure wind speed indirectly by means of the electric power output. The rotor itself is the only representative "wind measuring instrument" of a turbine.

10.1.1 Locality of the Wind Measurement

The locality of the wind measurement needs to be chosen carefully since the air flow in close vicinity of the turbine is influenced considerably by the turning rotor. This means that the "true" wind speed is measured correctly by a sensor close to the rotor plane only when the rotor is at a standstill. If the turbine is started up too early on the basis of this signal, the wind speed is retarded by the rotating rotor and the turbine is switched off again by the sequence controller if the retarded wind speed is then below the cut-in speed again. If the wind speed is just barely above the cut-in wind speed, this process could repeat itself any number of times.

If the measurement of wind speed and direction must not be influenced by the rotor, a point of measurement behind the rotor plane would have to be more than ten rotor diameters away. Apart from the fact that this would require the setting up of a separate mast for wind measurement, it would by no means provide a more accurate wind measurement. One single point of measurement, and at a considerable distance from the turbine at that, does not provide an aerodynamically representative value for the rotor-swept area. Wind measurement in front of the rotor plane does not solve this problem, either. Although the retardation of the air flow by the wind rotor "upwind" is not as perceptible as in the "wake", it is still large enough to corrupt the result in the immediate vicinity.

Considering the above, it is understandable why the operational wind measurement, regardless of the corruption of results in the immediate surroundings of the rotor plane, is usually taken on the roof of the nacelle (Fig. 10.2). In some cases, the anemometer is also mounted on the tower, below the rotor radius. Whichever way, accurate wind speed measurement is not feasible. However, practical operation does not require an accurate wind measurement, as long as the "discrepancy" caused by the rotating rotor is known with some accuracy and is taken into consideration in the processing of the data obtained.

The question arises, therefore, as to what extent the measured values are influenced by the rotor flow. Betz's simple impulse theory provides an initial indication. According to this approach, the free stream velocity is reduced to barely two thirds of the undisturbed value in the rotor plane in an ideal turbine. But this only applies to the ideal power coefficient of 0.593. A real wind turbine with a distinctly lower power coefficient also retards the air flow to a lesser extent. A real rotor with a lower power coefficient also results in less retardation to the air flow.

It can be assumed that a fast modern rotor with a maximum power coefficient of approx. 0.45 retards the wind speed in the rotor plane by approximately 25 % in nominal operation. At a rated wind speed of approximately 12 m/s, wind speed measurements on the nacelle roof will show a discrepancy of 2 to 3 m/s, depending on whether the measurement is carried out in front of or behind the rotor plane. Taking this discrepancy into account in

Figure 10.2. Operational wind measuring system on the nacelle of a Vestas offshore turbine

the distribution of measured values, measuring wind speed on the nacelle roof will provide results which are accurate enough for the operation management of the turbine.

Wind measurement can also be affected by the flow around the nacelle. If the outer shape of the nacelle was designed without any regard to aerodynamics, the sensor must be kept out of the disturbed flow close to the nacelle. The one-sided shadowing effect of the nacelle when the wind flow is at an angle can falsify the measurement of wind speed and wind direction. It is for this reason, but also for reasons of redundancy, that two anemometers are sometimes mounted on large turbines.

10.1.2 Wind Sensors and Data Processing

The wind measuring system basically consists of two main components, the sensor and the data processing system. Sensors for the combined measurement of wind speed and direction are available in numerous forms. As a rule, wind speed is recorded by a cup anemometer (Fig. 10.3). Wind direction is determined with the aid of a small wind vane. In most cases, the speed of the cups and the position of the wind vane are scanned opto-electronically.

The measured data are usually processed electronically, especially if the scanning process is also carried out electronically. The signal processing depends on the requirements of the sequence controller (Chapt. 10.1.3). Above all, a suitable determination of mean values is important, as they are used as the switching signal for the yawing system and for cutting-in

Figure 10.3. Combined wind sensor for measuring wind speed and direction (Thies)

the turbine. The mean values must be determined in such a way that the signals for cutting in the rotor and for yawing are input with the correct delay in order to avoid too much cutting-in and -out or yawing. Programmable instruments which are easily adaptable to the characteristics of the turbine and to the peculiarities of the local wind conditions, are very helpful for this purpose.

10.2 Yaw Control

Control of the yaw motion is characterised by conflicting aims. On the one hand, the deviation of the rotor from the wind direction, the yaw angle, is supposed to be as small as possible to avoid power loss. On the other hand, the yaw control system must not respond too sensitively, to avoid continuous small yaw movements which would reduce the life of the mechanical components. The problem is to find a practicable compromise as it is not possible to set up a general rule. The solution is determined by turbine-specific properties as well as by the local wind conditions.

The situation relating to the WKA-60 turbine will be given as an example, although it is not necessarily a generally valid model. The wind measuring system of the turbine provides a mean value of the wind direction over a period of ten seconds. This value is compared with the instantaneous azimuth position of the nacelle every two seconds. If the deviation remains below 3 degrees, the yaw control system will not be activated. If the yaw angle determined is above this value, the time until correction is determined in accordance with a pre-programmed function. If the yaw angle is small, for example 10 degrees, yawing is carried out within 60 seconds, if it is greater, e. g. 20 degrees, the yaw is accomplished within the subsequent 20 seconds. If the yaw angle determined exceeds a value of 50 degrees, the rotor is yawed immediately. The operating diagram shows the ranges within which the yaw system works (Fig. 10.4).

Yawing starts at rotor standstill at a wind speed of about 4 m/s, i. e. 1 m/s below cut-in speed. If the wind speed exceeds 36 m/s, the rotor will not be yawed. If extreme yaw angles occur at the non-rotating turbine with such extreme wind speeds, the yaw brakes will slip so that the air forces will passively yaw the leeward rotor. The control system and sequence control of the yaw system briefly described on the example of the WKA-60 turbine is typical for a large turbine. In smaller turbines, simpler processes are possible.

Regardless of how the sequence control system of the yaw drive is set up and the control characteristics are determined, temporary deviations of the wind direction from the azimuth angle of the rotor cannot be avoided. An impression of the size of the yaw angles occurring is given by the values plotted in Fig. 10.5. The average yaw angle is of the magnitude of approximately 5 degrees. This involves a certain amount of rotor power loss. As this only becomes noticeable in the partial load range, the loss remains within bearable limits at approximately 1 to 2 % of the annual energy yield [3].

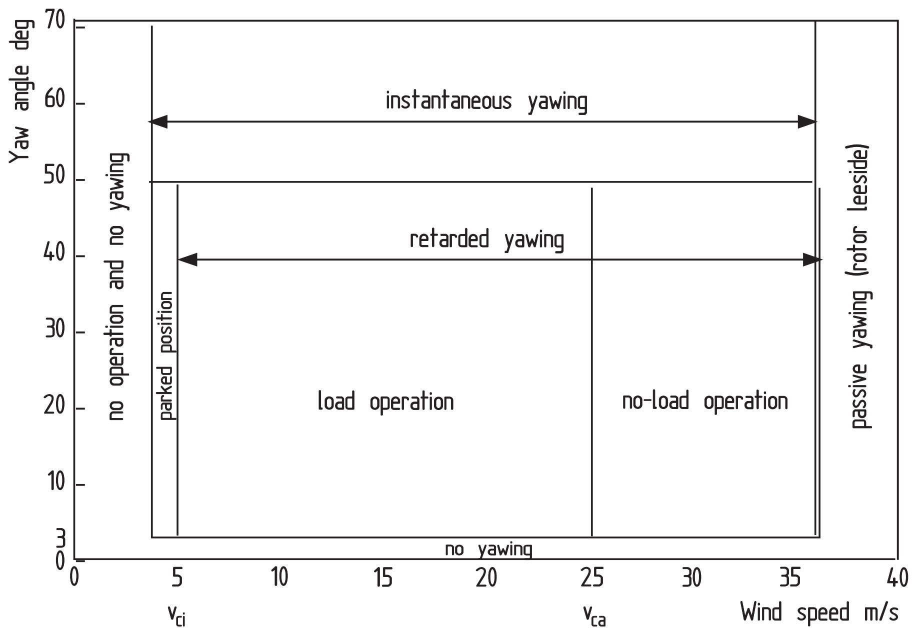

Figure 10.4. Operating diagram of the WKA-60 yaw system

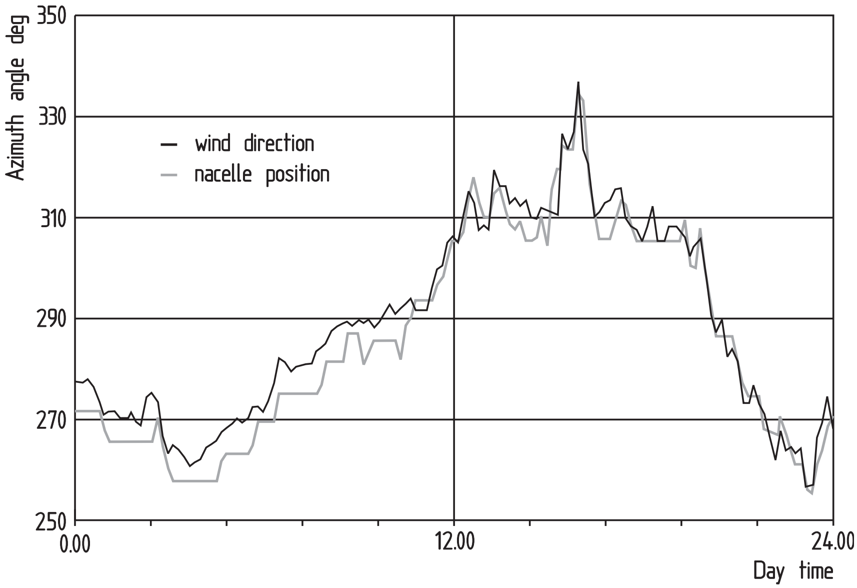

Figure 10.5. Measured azimuth angle of the nacelle and wind direction during operation of the WKA-60 [3]

Apart from trying to keep the mean yaw angle as small as possible, the yawing rate of the rotor is also determined by taking into consideration the gyroscopic moments. The yawing rate is normally about 0.5 degrees per second. At higher rates, the influence of the gyroscopic moments becomes too great (Chapt. 5.6).

10.3 Power and Speed Control by Means of Rotor Blade Pitching

The fundamental problems of power control in a turbine become particularly apparent if the task of control is compared to that of a conventional thermal power station (Fig. 10.6). In a thermal power station, the fuel, or in more general terms the primary energy source, is fed to the steam generator in doses (action A). The steam is then fed into the turbine via an adjustable inlet valve (action B). The turbine drives the electric generator the voltage and reactive power of which can be influenced via the field excitation (action C). Thus, there are three types of control action available to regulate the overall system.

When looking at a wind turbine, it immediately becomes apparent that the first control action, the dosing of the primary energy source, is absent. The "wind turbine" must cope with the random variations of the primary energy source "wind". The primary energy conversion of the rotor can be controlled only by pitching the blades. This control action can be most easily compared with the steam inlet of the turbine. If an appropriate electrical system is used, the generator torque and reactive power can also be controlled in a wind turbine. The main problem with wind turbine control is the fluctuating supply of primary

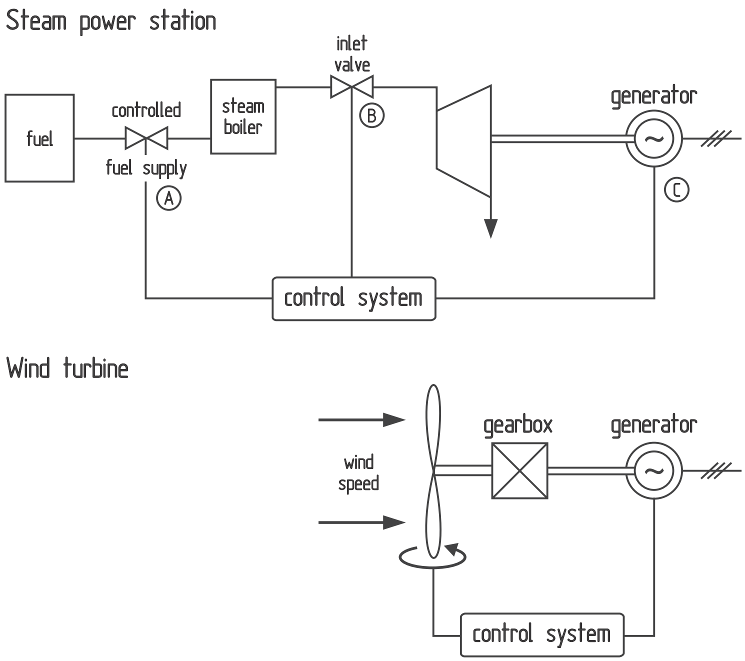

Figure 10.6. Comparison of the control task in a thermal power station and in a wind turbine [1]

energy. These fluctuations in the primary energy source are of greater or lesser significance to the control characteristics depending on the time intervals over which they are effective.

Due to the mass inertia of the rotor blades and actuating elements, extremely brief fluctuations (wind turbulence and gusts) of less than a second cannot be responded to by the blade pitch control. As the control system cannot respond within these periods of time, the resultant loads must be borne by the turbine and the ensuing power fluctuations accepted.

Changes in wind speed within a range of "several-seconds" can be responded to by the control system. This is where the real task of the control system lies. The control system of the turbine can respond with the aid of the two control variables "blade pitch" and, possibly, "generator torque".

The power control system cannot respond to longer-term variations in wind speed. In the minute range, they influence the sequence control of the turbine. Even longer-term fluctuations, over hours up to seasonal changes, pose questions of availability or lead to the problem of energy storage.

With the two control variables of "blade pitch" and, in most larger turbines, the "generator torque", two reference variables of wind turbine operation can be regulated: "rotor speed" and "power output". Speed control becomes indispensable when the speed is not maintained by the grid frequency. This is always the case in isolated operation. But speed control is also necessary in parallel-grid operation of turbines during start-up or when shutting down and in generators with no direct connection to the grid.

Power control is required for protecting the turbine against overloading, or because the power consumption of the generator load requires it. Large turbines are, therefore, equipped with a combined speed/power control system. The interaction of speed and power control, the control structure, is determined by the type of generator system and by the desired sequence control system.

10.3.1
System Characteristics and Controlled Systems

The control structure of a turbine must be matched to the electrical-mechanical energy conversion chain. Within this chain, five areas can be distinguished which can be understood to be controlled subsystems of the overall control structure (Fig. 10.7). These five controlled systems are:

- dynamic characteristics of the blade pitch mechanism
- aeroelastics of blade pitching
- aerodynamic torque of the rotor
- dynamics of the mechanical drive train
- electrical characteristics of the generator.

If operating conditions are difficult, in isolated operation or operation on a weak grid, the characteristics of the grid and sometimes of the generator loads must be added to these.

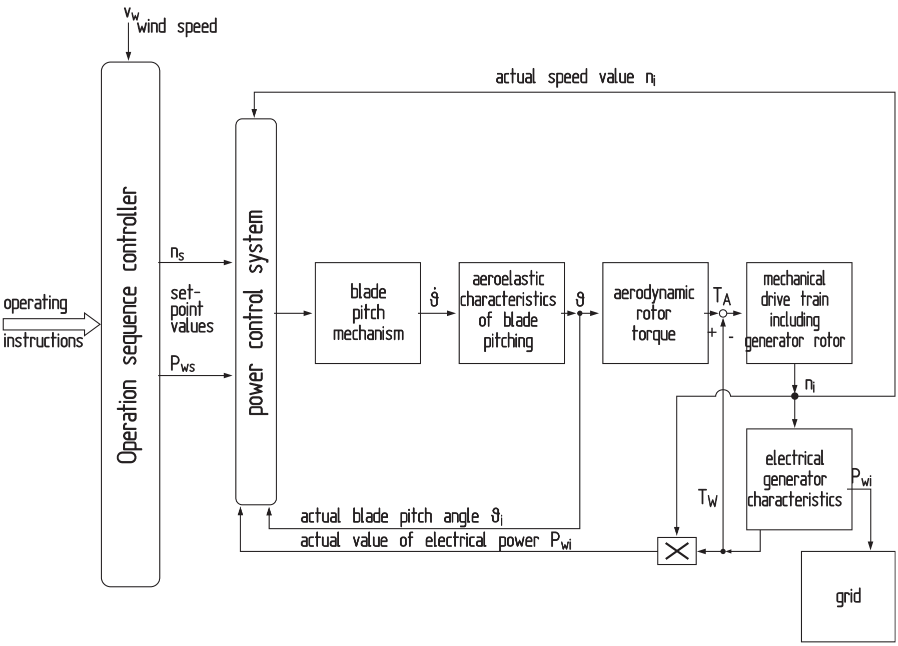

Figure 10.7. Principle of the power and speed control structure of a wind turbine with the essential controlled members and control loops [1]

Characteristics of the Blade pitch mechanism

The blade pitch system for adjusting the blade pitch angle is actually an actuating element, but, due to its complex mechanics, it is also the first controlled system, the physical properties of which are of considerable significance for the control response. The control-related properties differ greatly, depending on the design principle. An electromechanical actuator differs distinctly from the various hydraulic blade pitch mechanisms with regard to its mechanical inertia and its elastic damping properties. It's therefore not possible to make general statements on the control characteristics of the blade pitching mechanism.

Aeroelastics of blade pitching

The magnitude of the pitching moment around the longitudinal axis of the blade, which must be provided by the blade pitch mechanism, is determined by a complex interaction of forces and moments. Apart from the torsional moments resulting from the mass inertia of the blades and the friction in the blade bearings, it is the aerodynamic moments, above all, which become effective to greatly varying degrees depending on the operating conditions. Wind speed, the aerodynamic angle of attack and rotor speed affect these aerodynamic moments to an extraordinary degree.

The forces and moments caused by aeroelasticity have an influence on the control response which is not to be underestimated. The bending of the rotor blades is almost always accompanied by a torsional movement, so that elastic deformations of the rotor blades have a direct influence on the aerodynamic angle of attack. Slender and thus in most cases also flexible rotor blades might be advantageous from the viewpoint of aerodynamic performance, but from a control point of view they are difficult to govern. On closer inspection, difficulties concerning the control system of a turbine frequently turn out to be problems of "controllability", especially with regard to the aeroelasticity of the rotor blades.

Aerodynamic rotor torque

The torque of the rotor depends on the wind speed and the pitch angle of the rotor blades as actuating variable. The steady-state characteristics of this "controlled system" form the family of power characteristics of the rotor and the family of torque characteristics (Chapt. 5.2). Considering the control system, it should be remembered again that the aerodynamic rotor concept, as it is reflected in the power or torque characteristics, has a direct influence on control response. Non-stationary effects during the build-up of the aerodynamic rotor torque may also have to be considered. Apart from the changing wind speed, these can occur when the blade pitching rates are relatively high.

Dynamics of the mechanical drive train

The aerodynamic torque delivered by the rotor is opposed by the moment of resistance of the electric generator. Between these, there is the mechanical drive train. The inertia of these rotating masses, including the generator rotor, the stiffnesses and the damping characteristics, and also the play in the gearbox and couplings, all affect the dynamics of the drive train and must thus be considered as a controlled subsection. Chapter 11.2

discusses the essential parameters from the point of view of vibrational behaviour. Treating the problem from a control engineering point of view permits simplifications.

Electrical characteristics of the generator

The end point of the chain of controlled systems is the electrical part of the generator, which generates the moment of resistance. Each type of generator has different torque characteristics which must be adapted to the control structure of the wind turbine. It is important for the design of the control systems that the electrical processes leading to the formation of the moment of resistance in the generator occur by orders of magnitude more quickly than the mechanical control processes of the blade pitching. Internal generator control can, therefore, be considered independently. Within the context of the overall control structure, the characteristics of the moment of resistance of the generator, similar to the rotor characteristics, appear as a stationary curve or, in complicated generator systems, as a family of curves. The characteristics of the generator are of special significance for the control structure to be selected.

In practice, the control structures are implemented in different variations. The operating conditions or the aerodynamic and mechanical system properties of the wind turbine result in a range of variations. This is above all true for the quality and quantity of the parameters taken into consideration. The control of a large wind turbine with several megawatts must meet different requirements from a turbine in the 50-kW range. Nevertheless, there are certain basic patterns which are of importance for the various generator systems and operating conditions.

10.3.2
Operation with Generators Directly Coupled to the Grid

From the point of view of control, the operation of a wind turbine on a fixed-frequency grid represents the simplest case. In load operation the speed of the electric generator, and hence of the rotor, is determined by the fixed grid frequency, if the generator is directly electrically coupled with its stator winding to the grid. With respect to a wind turbine, the interconnected transmission systems of the public utilities are generally to be considered as having a "fixed frequency". At most feed-in points of the grid, the load changes caused by a turbine feeding into the grid are too small to exert a measurable influence on the frequency, compared with the total load of a large grid. The situation can be different on weak spur lines.

The technical preconditions for parallel-grid operation differ depending on the type of generator installed. These differences are more important, as the practical application is not solely restricted to the synchronised operation on the grid, but also includes other operating modes such as start-up, synchronisation with the grid frequency and rotor braking.

Induction generator

For turbines with blade pitch control, the use of induction generators simplifies the task of controlling. The — albeit slight — power-dependent speed "elasticity" due to generator slip allows speed and power control to be combined. In the typical control structure shown

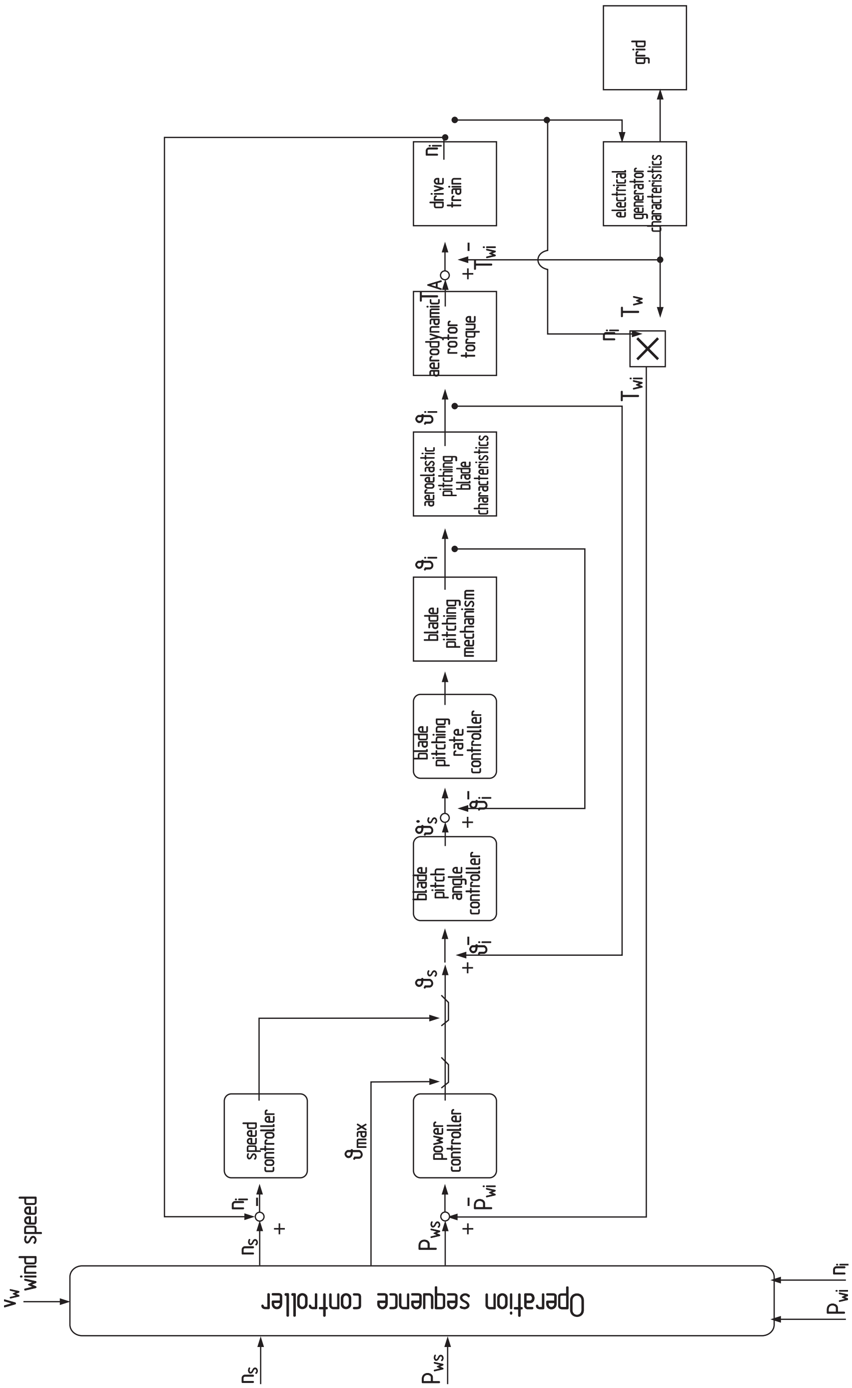

Figure 10.8. Control structure of a large turbine with a directly grid-coupled induction generator [1]

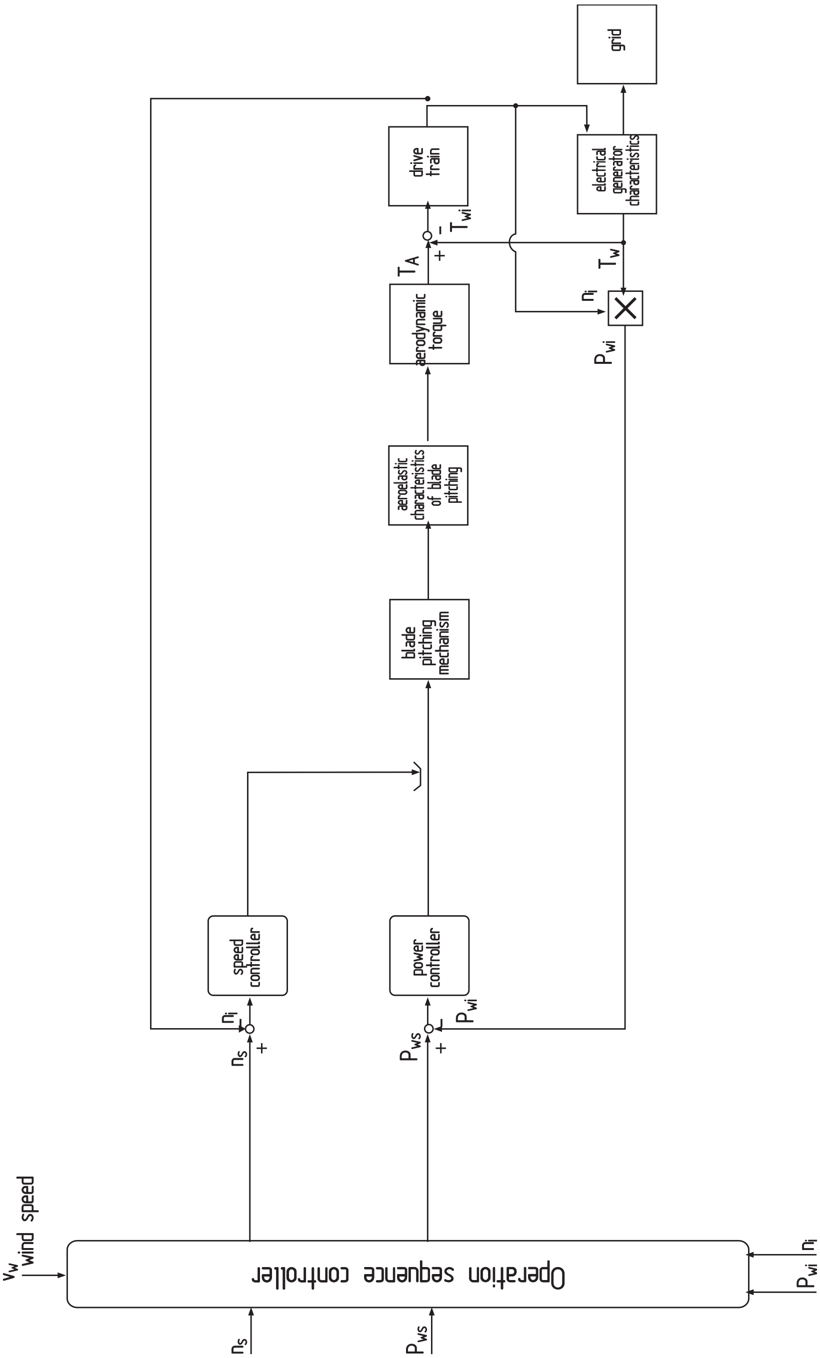

Figure 10.9. Simplified control structure of the small Aeroman turbine with an induction generator directly coupled to the grid without acquisition of the actual blade-pitch angle and without pitching rate control

in Fig. 10.8, the controllers are arranged separately such that the speed controller has a limiting effect on the output of the power controller.

In normal operation, the nominal speed n_S is set several percent higher than the corresponding value of the grid frequency. Apart from start-up and shut-down sequences, the speed control only intervenes in cases of trouble (for example a grid failure). The speed setpoint value can be varied for start-up and shut-down and for preparing for grid synchronisation.

The arrangement shown enables the speed controller to be adjusted to idling and the power controller to be adjusted to grid operation. A secondary blade pitching-rate controller is also included in the blade-pitch control, to improve its stability and dynamic range. This means that the pitching rate is regulated by the setpoint values of the nominal rotor speed in dependence on the gradient of the measured deviation. Allowing for this parameter results in softer blade pitching, a desirable feature in large turbines.

Recording the actual value of the blade pitch angle and the pitching rate requires the transmission of a signal from the rotating rotor. If the two inner control loops are omitted, the power controller then directly acts on the pitch mechanism and no pitch angle information is required. This simple structure provides a sufficiently stable control response even though the adjustment of the controllers is not without problems as far as the stability over the entire range of wind speeds is concerned. Power instabilities can occur, particularly at higher wind speeds. For smaller turbines, however, this simplified structure is often sufficient (Fig. 10.9).

Synchronous generator

When synchronous generators are used, the dynamic behaviour is determined by the speed coupling to the grid frequency being absolutely fixed. The energy captured from the wind must be processed directly by the generator and creates a certain load angle depending on the state of excitation. If the load angle exceeds its maximum value of approximately 90 degrees, the generator loses synchronisation and must be taken off the grid. Moreover, the undamped characteristic of the synchronous generator means that the system's potential for vibration can become a problem.

For reasons of stability, therefore, it must be ensured that in the stationary condition, the mechanical driving torque of the generator has a large enough safety margin with respect to the electrical pull-out torque. In addition, the pull-out torque can be increased by increasing the excitation voltage, thus also improving the stability. At least for large turbines, voltage and reactive power control makes technical sense and may even be necessary. The control structure of a wind turbine with a synchronous generator, meeting the requirements of direct grid coupling as well as of isolated operation, is shown in Fig. 10.10.

The upper section of the diagram shows the speed and active-power control with the blade pitch angle as actuating variable. The lower section shows the current or reactive-power control with the excitation voltage as actuating variable. As the control processes in the electrical system occur much faster than the mechanical actuating movements, the two control systems can be considered as being largely decoupled as far as the dynamics are concerned.

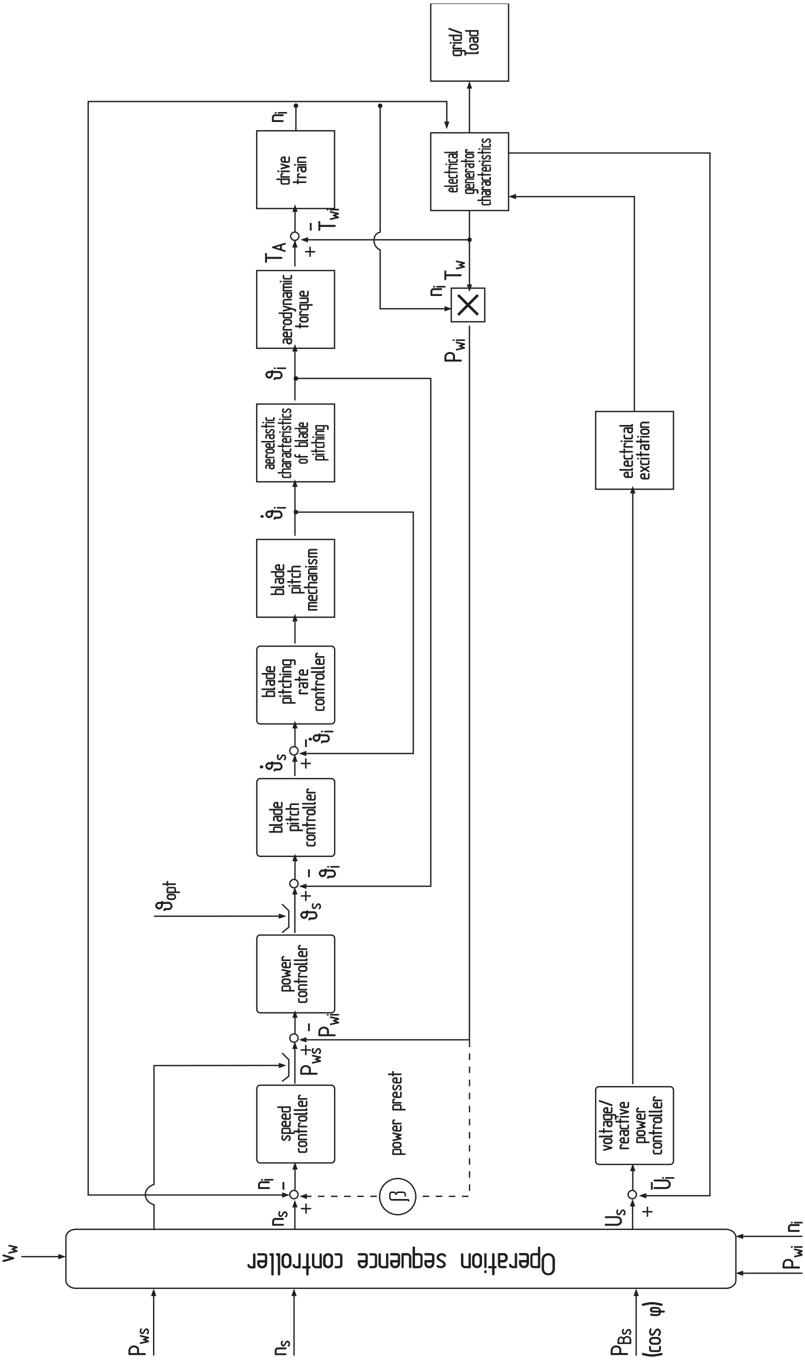

Figure 10.10. Control structure of a large turbine with synchronous generator for parallel grid and isolated operation [1]

The entire structure for speed and active-power output control consists of a speed control loop, with secondary control loops for active-power output, blade pitch and pitching rate. The speed controller, the nominal speed n_S which lies several percent above the grid frequency f_N, is only used in isolated operation.

When operated on the grid, the generator frequency is controlled by the grid, the actual speed n_i remains constant and, because $n_i < n_s$ is maintained, the output of the integrating speed controller tends towards the upper limit. This corresponds to the required maximum active-power output P_{Ws}, preset by the sequence controller as reference value, and is maintained by the blade pitch system if the wind speed is high enough. If the wind speed is not high enough, the setpoint value of the pitch angle is set to the selected constant blade pitch angle for partial load operation.

During idling, i. e. without the rotor speed being governed by the grid frequency, the turbine accelerates up to the n_S speed and the speed controller also becomes active. By inserting reactive current compensation, a power output coupled to the grid frequency can be obtained which corresponds to normal power station control.

Despite the critical stability properties of the synchronous generator in parallel-grid operation, it is technically feasible to control a wind turbine with a synchronous generator operating on a fixed frequency grid. The prerequisite for this is, however, the presence of torsional compliance and damping in the mechanical drive train (s. Chapt. 8.9). Recent research projects suggest improving the critical vibrational behaviour by means of a special damper winding in the synchronous generator [4]. Regardless of these possibilities, coupling a synchronous generator for wind turbines directly to the grid is no longer "state of the art" today (s. Chapt. 9.3.1).

10.3.3
Parallel-Grid Operation with Frequency Converter

Inserting a frequency converter between the generator and the grid enables the rotor to be operated with variable speed. Apart from the aerodynamic advantages, it reduces the dynamic loads on the mechanical drive train and acts to smooth out the electrical output power (s. Chapt. 6.6.4 and 14.4.4). From the point of view of control, the wind turbine thus has two actuating variables:

- The blade pitch angle for controlling the aerodynamically captured power of the rotor and possibly the rotor speed,
- The generator torque for varying the electrical output power independently of rotor speed.

These two actuating variables make the instantaneous electrical power output independent of the aerodynamically captured rotor power.

On the aerodynamic side, coarse power control is carried out by controlling pitch angle, whereas small variations are taken care of by the electrical control, but only within the limits of the permissible speed range. This relieves the mechanical pitching mechanism.

In principle, the control structure according to Fig. 10.11 can be applied to all variable speed generator systems in the form shown. There are, of course, some variations in detail,

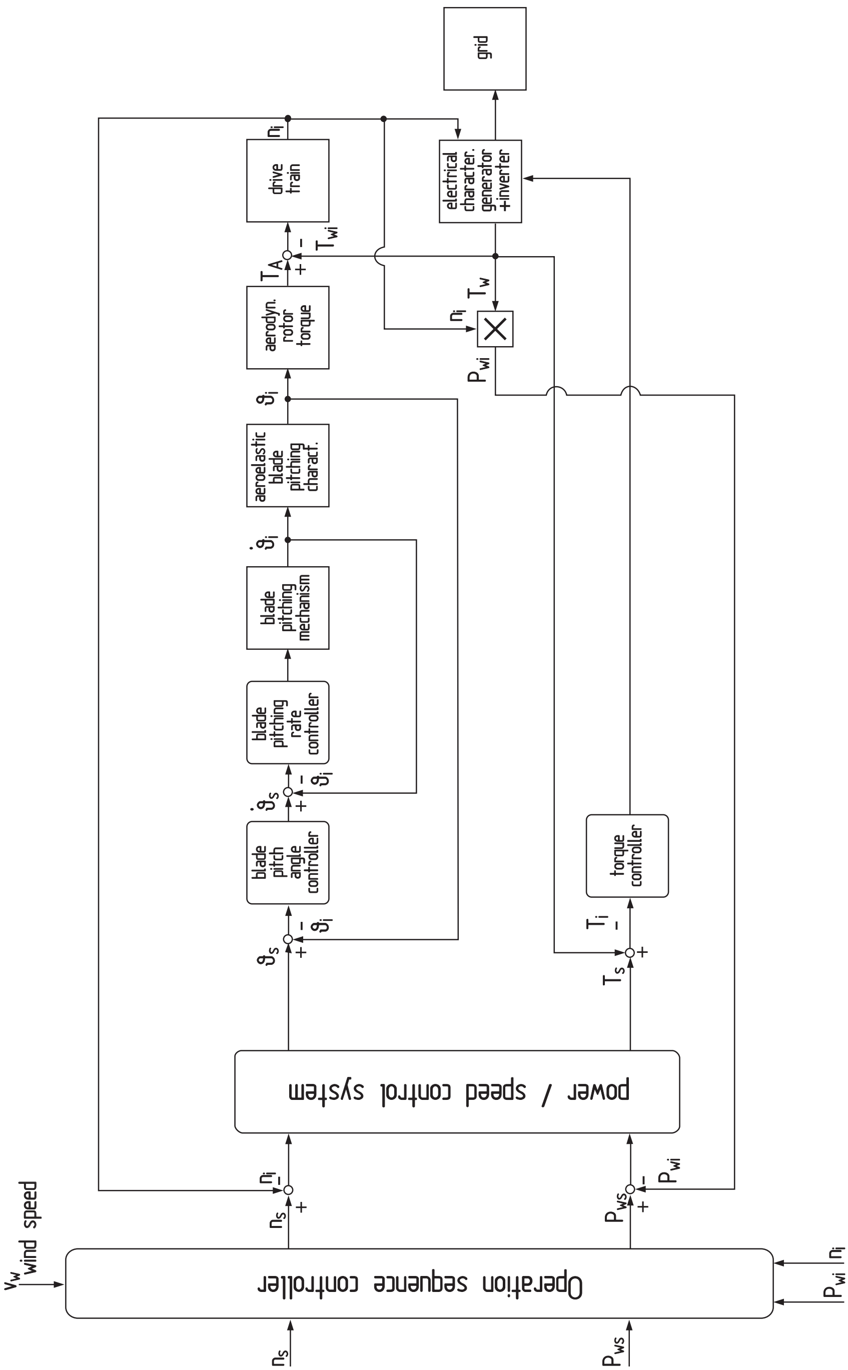

Figure 10.11. Control structure of a wind turbine with variable-speed generator and frequency converter [1]

depending on whether a synchronous generator with an AC-DC-AC link to the grid or a double-fed induction generator is involved.

In full load operation the pitch control is active, so that rotational speed and power can be adjusted to the setpoint values. The speed controller can be provided with a range of insensitivity to reduce the number of pitching operations. At partial load, the power output and rotor speed are controlled exclusively by varying the generator torque. There are no further control operations via the blade pitch angle. When the wind speed drops, rotor speed is reduced in order to maintain the optimal tip-speed ratio of the rotor. Variable-speed rotor operation in the partial-load range presents the problem of having to control the rotor speed in dependence of the wind speed in such a way that the optimal rotor power coefficient is achieved. In principle, there are three different ways of accomplishing this:

- To preset a nominal power characteristic in dependence on the rotational speed. The experimental single-bladed Monopteros turbine was controlled in this way [5].
- Speed control by using wind speed measurements with a given c_p-λ characteristic. The problem is here the measurement of a truly representative wind speed (s. Chapt. 10.1.1).
- The so-called "MPPT" (Maximum Point Power Tracking) process, which has also been applied in other systems, has proven to be more useful for this purpose. The point to which the power maximum is to be set is determined by incremental speed variation, in the form of a search process.

It has been attempted in some turbines to control the rotor power solely by means of rotor speed, i. e. via the generator torque of a variable speed generator system, but the aerodynamically captured rotor power can only be regulated by this means within a much narrower range than is possible with pitch angle control. In principle, this method is an option for rotors without blade pitch adjustment. Present experience has shown that a practical implementation with respect to stable control characteristics encounters considerable problems. It is not really possible to achieve satisfactory power limiting by means of aerodynamic stall with a variable rotor speed.

10.3.4 Isolated Operation

The isolated operation of a wind turbine has an energy supply aspect and a control aspect (Chapt. 16.2). From the control point of view, isolated operation can be defined as the mirror image of parallel-grid operation, as follows:

- The possibility of speed control of the generator by a fixed-frequency grid is not available.
- The instantaneous power output of the turbine is no longer arbitrary, but must be seen and controlled in relation to the instantaneous power consumption of the generator load.

In real-life operation these conditions will apply to a greater or lesser extent. Instead of completely isolated operation, there will be in many cases a "weak grid". The turbine will then have to "keep up with" the grid frequency and to adapt its power output to certain load conditions of the grid.

Speed control via blade pitching is possible only if the power supplied by the wind is greater than the power taken by the generator load. In isolated operation two areas of operation must therefore be distinguished:

- If the energy supplied by the wind is greater than the power demanded by the load (full-load operation), speed and power consumption can be adapted andcontrolled by changing the blade pitch angle.
- If the wind energy is less than the power demanded by the load (partial load operation), the rotor is usually operated with a fixed blade pitch angle. It must then be ensured that the energy taken by the load is reduced accordingly. This has to be done by a "load management" system by which the loads to be supplied are cut in or out of the supply.

In general, effective load management can be organized well if several loads are connected and can be distributed over a number of load circuits (Fig. 10.12). These loads are cut in or out in accordance with pre-determined priorities in dependence on the frequency. In combination with the blade pitch control, this results in a quality of supply which is also satisfactory for the more demanding loads, in electrical terms [6]. In autonomous, isolated operation, the electrical equipment of a turbine will generally have a synchronous generator since it is difficult to provide the exciter current for an induction machine.

Apart from the general case discussed here, isolated operation with small turbines exhibits a number of the most varied special control features depending on the requirements

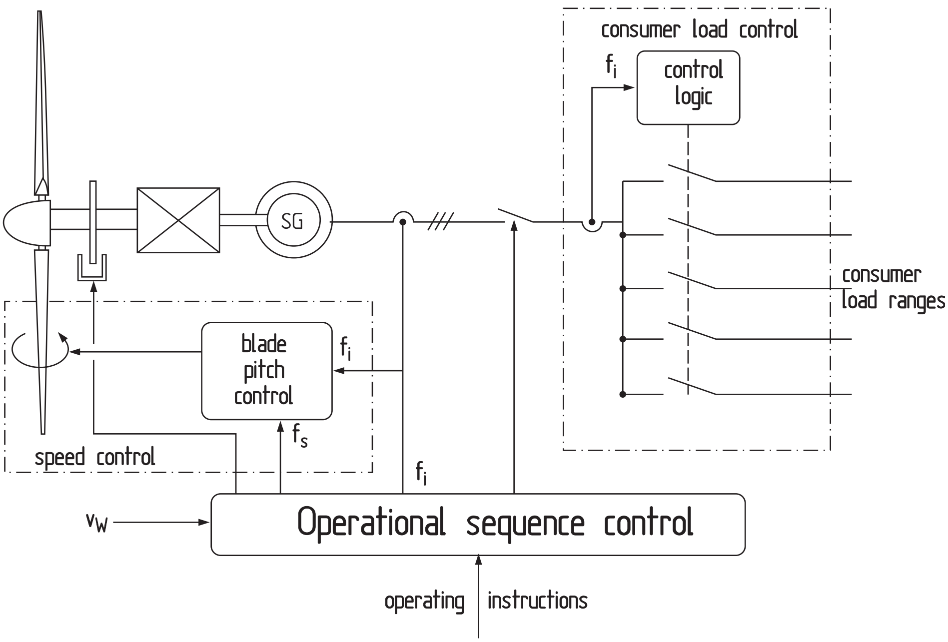

Figure 10.12. Control and load management of a wind turbine with blade pitch control in isolated operation

of the loads connected. Examples of this would be the use of wind turbines for heating applications or for driving electric water pumps. These applications do not require a constant frequency, so that control will be simplified in this respect. Instead, the operating characteristics of the loads (power consumption or torque characteristics as a funtion of rotational speed) must be taken into consideration in the control of the turbine. Under these conditions, the design of the control system must be individually matched to the overall "wind turbine/load" system. It should be noted, that the interaction of the varying load with the varying power output of the turbine caused by unsteady wind conditions can lead to considerable power losses if the control is not optimal.

Variable-speed operation of a generator with downstream frequency converter offers the best control conditions also for isolated operation. However, isolated operation requires the use of a line-independent self-commutated frequency converter but these are much more expensive than line-commutated versions.

10.4 Power Limiting by Aerodynamic Stall

Many smaller turbines do without pitch angle control. Without blade pitching, the possibilities of control are very restricted. If a suitable generator system is chosen, the requirements of parallel-grid operation can be met without great difficulty but isolated operation without blade pitch control is a much more difficult task. The fact that wind turbines without blade pitch control do not have an active speed or power control should not lead to the conclusion that all types of control technology are superfluous. Even in parallel-grid operation, the supervision of important functions such as the triggering of safety systems and the synchronization with the grid require a considerable complexity of electronic system control components.

10.4.1 Parallel-Grid Operation with Passive Stall

Operation on the grid is the main field of application for turbines without blade pitch control. As a rule, the smaller turbines have a rotor with fixed blade pitch angle and aerodynamic blade tip brakes. An active speed/power control system is not required for parallel-grid operation (Fig. 10.13).

The sequence control is restricted to yawing and to the switching signals for controlling the operational sequence in dependence on the wind speed and the operational status of the turbine. If there is enough wind, the mechanical rotor brake is released and the rotor accelerates to the synchronous speed. The automatic synchronizing system connects the generator to the grid and operation under load commences. If the wind speed exceeds the permissible maximum operating value, the rotor is retarded mechanically and, in most cases, simultaneously turned out of the wind (furled). The turbine can survive extreme wind speeds in this position. In case of a grid failure, rotor overspeed will be prevented by releasing the aerodynamic brakes or pitching the rotor blades (s. Chapt.7.7). Apart from controlling the operating cycle described, another task of the sequence controller is the monitoring of safety-related electrical and mechanical parameters such as grid voltage and

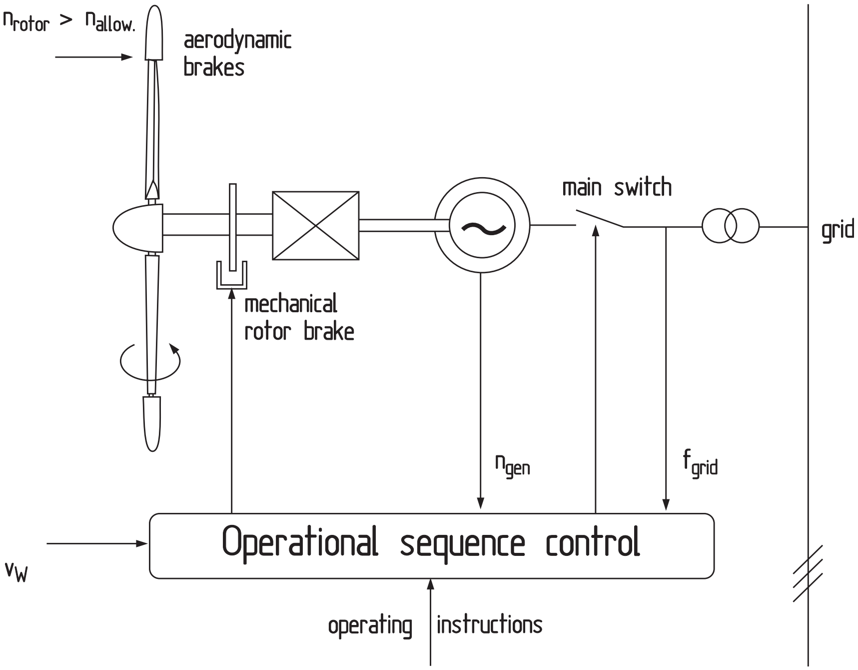

Figure 10.13. Sequence control and supervisory system of a wind turbine without pitch control on the grid

frequency, generator and gearbox oil temperatures, or unacceptable amplitudes of vibration (s. Chapt. 14.6).

10.4.2 Isolated Operation with Passive Stall Rotors

With some technical effort, wind turbines without blade pitch control are also capable of isolated operation. As the power capture of the rotor cannot be controlled, speed or frequency control can only be achieved by changing the generator load. As far as possible, the connected loads are connected to different load circuits for this purpose. However, these load circuits, as switchable load stages, are generally not enough for speed control, so that additional regulating resistors are necessary. Control with a high degree of constancy of frequency requires fast and accurate matching of the load to the wind power fluctuations This requirement is met by tapped, quickly switched resistors ("dump loads"). Semi-conductor switching elements are preferred due to the high switching frequencies (Fig. 10.14). If operating conditions in which the load circuits cannot also be used for control purposes are to be expected, the dump loads must be designed for the maximum power output of the wind turbine.

In principle, using a frequency converter expands the control capabilities also in conjunction with stall-controlled turbines. Apart from the high costs of a self-commutated

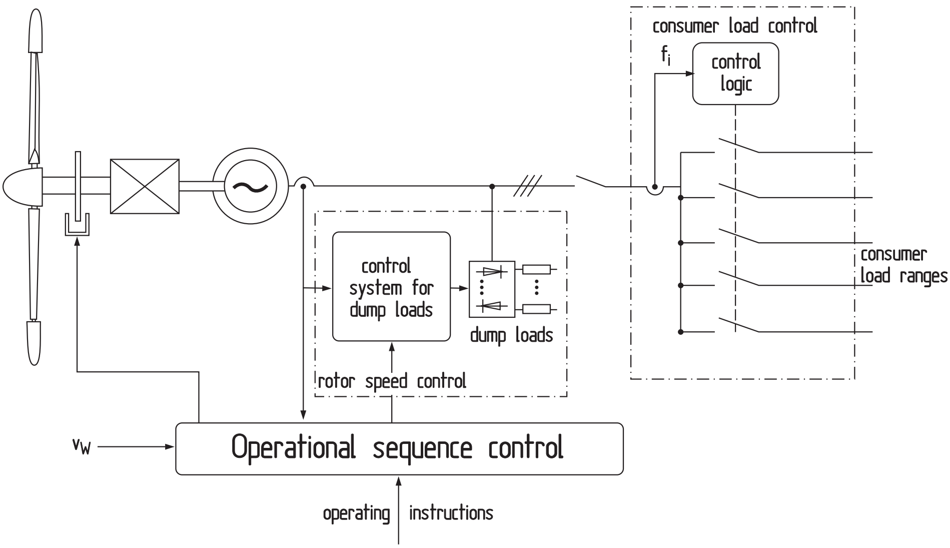

Figure 10.14. Frequency control by load management and dump loads for a wind turbine with fixed-pitch angle in isolated operation [6]

frequency converter, however, the implementation is impeded by the aforementioned technical prolems. The necessity of limiting the speed range over controllable loads remains. In isolated operation, variable-speed operation in conjunction with load limiting by means of aerodynamic stall becomes even more complex because the appropriate rotor speed has to be matched to the stall characteristics of the rotor. It is for these reasons, among others, that no successful applications have become known to the present.

10.4.3 Active Stall Control

In large turbines, it is not possible to achieve a satisfactory operating performance covering all possible operating conditions by providing only one fixed blade pitch angle. Operation involving a number of different blade pitch angles which in eachg case initiate a rotor stall and are preset by the sequence controller of the turbine is called "Active Stall Control" (s. Chapt. 5.3.3).

The blade pitch angle is "controlled" in dependence on a number of parameters, setpoints for power and rotational speed, altitude, temperature, wind velocity and gradients of wind velocity and temperature changes. Strictly speaking, there is no closed control loop of pitch angle and power based on mathematically determined relationships but the term "closed-loop control" is still generally used. In practice, this leads to relatively complex structures as can be seen clearly in the diagram (Fig. 10.15). In the example shown, three control loops are used:

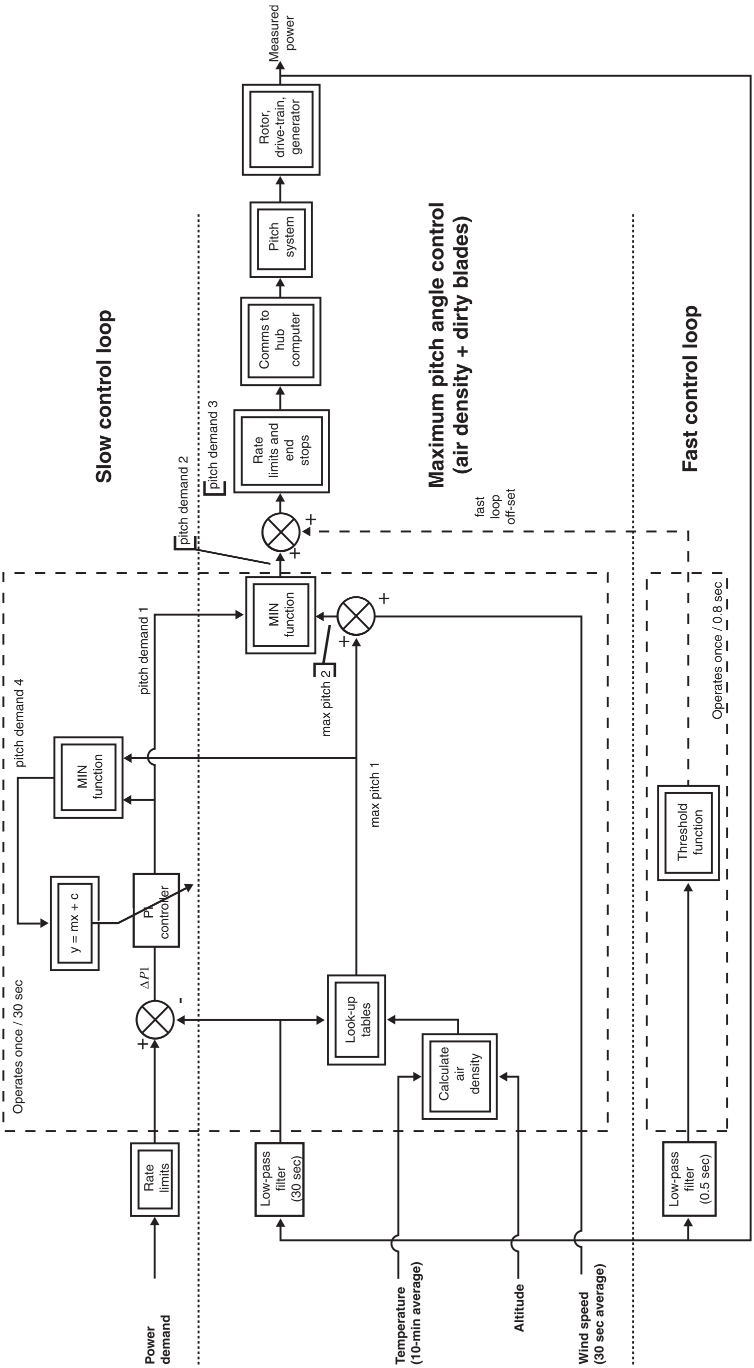

Figure 10.15. Active stall control (courtesy NEG Micon)

- A "slow" control loop is used at wind velocities above the rated wind velocity (15 m/s) for measuring the mean power over a period of 30 seconds and adjusting the blade pitch angle in such a manner that the 10-minute mean of the rated power is kept is kept at 1500 kW.
- A further control loop can be used for adjusting the blade pitch angle with a higher rate of adjustment as a direct response to the 30-second mean if this is required.
- A third, "fast" control loop is provided for an emergency stop of the turbine. The blade pitch angle is adjusted in the direction of the stop position at a rate of 3 degrees/second on the basis of an 0.5-second mean value of the power if this exceeds the value of 1.27-times the rated power.

In all three control loops, the influence of the air density on the temperature measurement and the drop in power due to possible contamination of the rotor blades with respect to the correlation of power to wind velocity is taken into account. This "control logic" shows how an active stall control departs from the original simplicity of power limiting by means of a stall with fixed blade pitch angle.

However, the advocates of this principle point to some advantages such as that, in particular, the rotor blade pitch angle is kept close to the stall position over the entire wind speed range so that only very small pitch angle changes are necessary (Fig. 10.16). Even aerodynamic braking only requires an adjustment by approx. 20 degrees (s. Chapt. 5.3.3).

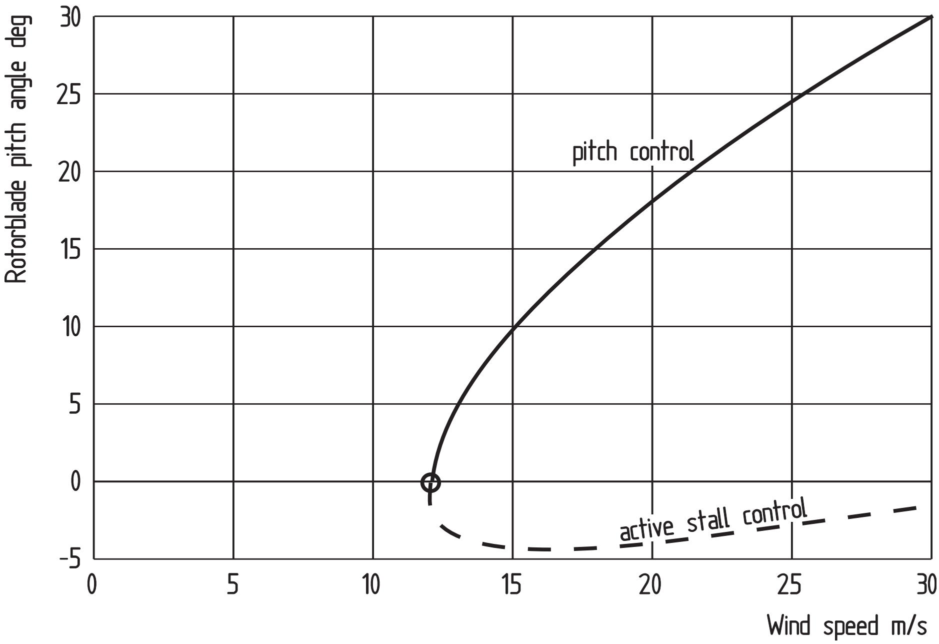

Figure 10.16. Blade pitch angle adjustment range for power control with conventional blade pitch angle control and with active stall control

10.5 Supervisory Control and Operational States

The task of the supervisory control system of a wind turbine is to bring the wind turbine from one operational state to another. It must permit fully automatic operation, it must recognize hazards and activate the corresponding safety systems and it must be able to execute special instructions by the operator. In this respect it acts as replacement for the non-existent operating personnel.

This task requires an all-system data acquisition, monitoring and control system with numerous contact points to almost all components of the turbine itself and its peripheral technical systems. The most important subtasks can be described as follows:

- Acquisition of the input data necessary for controlling the operating sequence. This includes wind speed and wind direction and sometimes also information on the state of the grid to be fed, for example the currently allowed power input or the connection of loads (load control).
- Control of the operating sequence in automatic mode, with manual operation for special cases. These tasks include operating elements and monitoring displays.
- Driving the control system with the setpoint values predetermined by the automatic operating sequence or the operator's instructions.
- Activation of the safety and emergency systems. The emergency shut-down of the rotor is of primary importance here. The sequence controller should guarantee that these "ultimate" safety mechanisms act as directly as possible, without the electronic control system.
- Adaptation to the operating conditions. Not least, the operation management of a turbine should have a certain margin for adapting to various operating conditions. In parallel-grid operation, e. g., different requirements must be met than in isolated operation.

Naturally, the technical complexity of the sequence control and supervisory system depends to a certain extent on the size and the technical concept of the turbine. A 100-kW wind turbine with a simple induction generator for parallel-grid operation cannot be compared to a variable-speed large megawatt turbine as far as sequence control is concerned. This is especially true for the operating and monitoring instruments. However, the operating cycle is similar in all larger wind turbines.

10.5.1 Operational States and Operating Cycle

The sequence control of the experimental WKA-60 will be used as an example of the operating cycle of a larger wind turbine. The automatic operating cycle includes the following states:

- system check
- standstill
- start-up
- running up to speed
- power production

– shutdown
– stopping

The operating states of "standstill" and "operation under load" are stationary states. All others form transitions between the stationary states within an operating cycle.

System check

The operating cycle begins with checking the operational status of the most important systems and components. In large turbines a great number of parameters like voltage, temparature and pressure values are checked. Also the grid status has to be verified before the turbine will start. If no faults are indicated in the "system check" state, a signal will indicate that the turbine is ready for further progress in the operational cycle.

Standstill

If the system check was positive, the yaw system is activated, the rotor still being braked. The turbine is yawed to the wind direction within the permissible limits and it is checked whether the wind speed is within the operating range of 6 to 24 m/s.

Start-up

Start-up begins with pitching of the rotor blades into the starting position (blade-pitch angle approximately 60 degrees). Following this, the mechanical rotor brake is released. The rotor starts to turn.

Running up to speed

When running up to speed, the rotor speed is accelerated up to the synchronization speed of the generator, corresponding to 90 % of the nominal speed. The blade-pitch angle is controlled in accordance with a preset speed variation. Synchronization of the generator with the grid frequency occurs within the speed range of from 88 % to 92 % of the nominal speed.

Power production

Once the connection of the generator to the grid has been established, the turbine begins to output power into the grid. Depending on the existing wind speed, a distinction is made between partial and full load.

The turbine operates at partial load if the wind speed is below the rated value of 12 m/s. Under these conditions, the pitch angle of the blades is set to a fixed value of –1 degree. As much power is extracted from the wind as is possible on the basis of the rotor power characteristics at the fixed blade pitch angle set, which is close to the optimum for this range of wind speeds (Chapt. 14.1.1). More recent control systems operate with a number of blade pitch angles at partial load.

If the wind speed exceeds its rated value, the turbine can operate with full power. The blade pitch angle is then controlled in such a manner that the rated power, which at the same time is the highest permissible continuous output of the generator, is not exceeded. The transitions between partial load and full load operation and the associated other control undertakings are performed automatically by the sequence control and do not require any intervention from outside.

Shut-down

If the wind speed drops below the minimum operational wind speed (cut-out wind-speed) or if operation under load is to be interrupted, the rotor will be brought to the "standstill position" again. During the shut-down process, the rotor blade is pitched in order to achieve a defined speed decrease. The generator must be taken off the grid which takes place within the range of 92 % to 90 % of the rated speed.

Stopping

If the wind speed is no longer sufficient for maintaining operation or if the operation is to be interrupted for a relatively long time, the turbine is returned to its standstill position. Rotor standstill is achieved by setting the speed setpoint value to zero. The rotor blades are pitched to an angle of approximately 80 degrees. This brakes the rotor aerodynamically down to a low residual idling speed. Complete standstill is achieved by applying the mechanical rotor brake. After reaching the "standstill" condition, the turbine is ready for a new operating cycle.

The operating cycle described with the example of the WKA-60 in automatic operation cannot claim to be representative in detail. The sequence of the operating cycle is simpler in smaller turbines. However, the essential operating phases and sequences are similar as long as the turbines have blade pitch control. Even more simple, of course, is the operating cycle in the case of rotors having a fixed pitch angle.

10.5.2 Interaction with the Grid

The basic idea for control systems and sequence control in parallel-grid operation consists in that the grid represents an invariable or rather unlimited situation from the point of view of the wind turbine, both with respect to the electrical parameters, particularly frequency and voltage, and with respect to its capability for absorbing the power fed in. This holds true as long as the wind power fed in is low in comparison with the load-carrying capability of the grid. In the meantime, however, conditions are beginning to change also in the strong interconnected European power system. The wind powers fed in are becoming greater and greater whilst the injection points are located in areas having weak feeders.

As wind energy becomes used more and more widely, the capability of wind turbines to respond to certain restrictions in the interconnected power system is gaining in importance. Some wind turbine manufacturers are already equipping the control system and sequence controller of their turbines in such a way that certain electrical grid parameters or their changes, respectively, are registered and the control and management system of the turbine responds in such a way that not only no unwanted loads on the grid are created but support is also provided for a weak grid. The prerequisite is an electrical and control-related design of the wind turbine which can do this. The best basis for this are variable-speed systems with the capability of cos φ control. Naturally, the interaction of the control system of a wind turbine with the power grid has its limits. Nevertheless, some functions are of importance for operation on weak spurs:

Operation within predetermined voltage and frequency values

When certain predetermmiined limit values of grid voltage or frequency are exceeded in either direction, the wind turbine will disconnect itself from the grid within a few tens of milliseconds. This ensures that power feeding really only takes place within the limits of parallel-grid operation set by the power system ooperator.

Grid-voltage-dependent power feeding

Should there be an increase in voltage, for instance at night due to a decrease in loads, the power output of the wind turbine is automatically reduced.

Connection and disconnection with predetermined power gradient

When the wind turbine or wind farm is connected to the grid, the power fed in is controlled in accordance with a predetermined time gradient in order to avoid short-term voltage peaks which could not be corrected by other means. In some cases, disconnection of the wind turbine from the grid also has to be performed with a predetermined time gradient.

Cos φ control

In certain situatioins, the power system operator has to rely on certain reactive-power characteristics of the loads and power suppliers connected. With a cos φ control of e.g. cos φ = 0.90 (capacitive) to 0.95 (inductive), the wind turbine can make a contribution to balancing the reactive power in the grid.

The functions mentioned by way of example are already facilitating the operation of wind turbines on weak grid operating points to a considerable extent. As the penetration of wind energy power into the interconnected power system increases, the operators of conventional power plants and grids will certainly increase their demands on the operational characteristics of wind turbines in these points.

10.6 Mathematical Simulation and Hardware of Control Systems

The mathematical simulation of the "control systems and sequence controller" complex is one of the most important theoretical tools in the development of wind turbines. Apart from the characteristics of the electrical system, almost all functional characteristics of the aerodynamic and mechanical design are involved. Mastery of this set of problems, therefore, incorporates a large proportion of the system engineering knowledge in wind turbine design.

Exhaustive mathematical simulations and analyses of the fields of "control systems and sequence control" and "generator system control" have been published by the Institute of Electrical Energy Supply Systems of the University of Kassel and the Institute of Control Technology of the Braunschweig Technical University in Germany [1]. Fortunately, the necessity of having to develop unmanageable "mammoth" computer programs is defused by some functional relationships. The main subsystems are not coupled too tightly, making it possible to treat them independently. These main subsystems are:

Aerodynamic rotor modell

The steady-state power characteristics of the rotor (c_p-λ and c_m-λ map) form the basis for the mathematical simulation of the control system (s. Chapt. 5). Non-linear relationships between the c_p and c_m values and the wind speeds, the blade pitch angle and the rotor speed must be linearised in certain subsections.

Mechanical model

As a rule, the rotor blade pitching mechanism will also be described by a linearised model (s. Chapt. 10.3.1) and is virtually independent of the mechanical model of the drive train.

Electrical model

The electrical control of the generator is faster by orders of magnitude than the aerodynamic/mechanical control processes, a fact which permits this area to be dealt with independently. Generator/converter systems, however, are coupled so tightly that they can only be dealt with together. They are inserted into the overall simulation via steady-state characteristics or maps of characteristics of the electrical system.

Practical Implementation

Electronically operated systems are state of the art nowadays. Mechanical control systems will at best be considered for small turbines, even though electronics, with its manifold possibilities, will replace mechanical controllers in this field, too. In the past, the practical implementation of the electronics system was dominated by the question as: to what extent will the entire control system be integrated and thus digitized.

Conventional engineering is based on a largely decentralized structure of the control system for the individual functions. The control algorithms were usually represented in analog form and hard-wired on corresponding circuit boards. For some functions, for example the speed controller with access to the blade pitch angle, analog operation is still applicable and advantageous. The advantage of the decentralization of individual analog control systems was mainly that proven mass-produced components could be used, thus reducing development work. However, the disadvantages could not to be ignored. Joining together a large number of components considerably increases the overall volume and the complexity of the hardware. Moreover, modifications in the control response could only be effected by modifying the hardware. Control systems and sequence controllers of this type were typical of the large, older experimental turbines, where the manufacture of the overall system was based on easily available components.

In today's designs, as many control algorithms as possible are combined in one central processing unit and processed digitally in a processor. This considerably reduces the hardware requirements and thus also the production costs. Changes in the control characteristics merely require a change in the software, i. e. in the computer programs. The hardware can still be used universally, the only disadvantage being the greater amount of work necessary for development. Today, this type of construction is standard for series-produced wind turbines. The supporting industry nowadays offers complete control units for wind turbines, both in hardware and in software (Fig. 10.17) and the leading manufacturers of wind turbines develop their own control systems or have them developed exclusively for themselves.

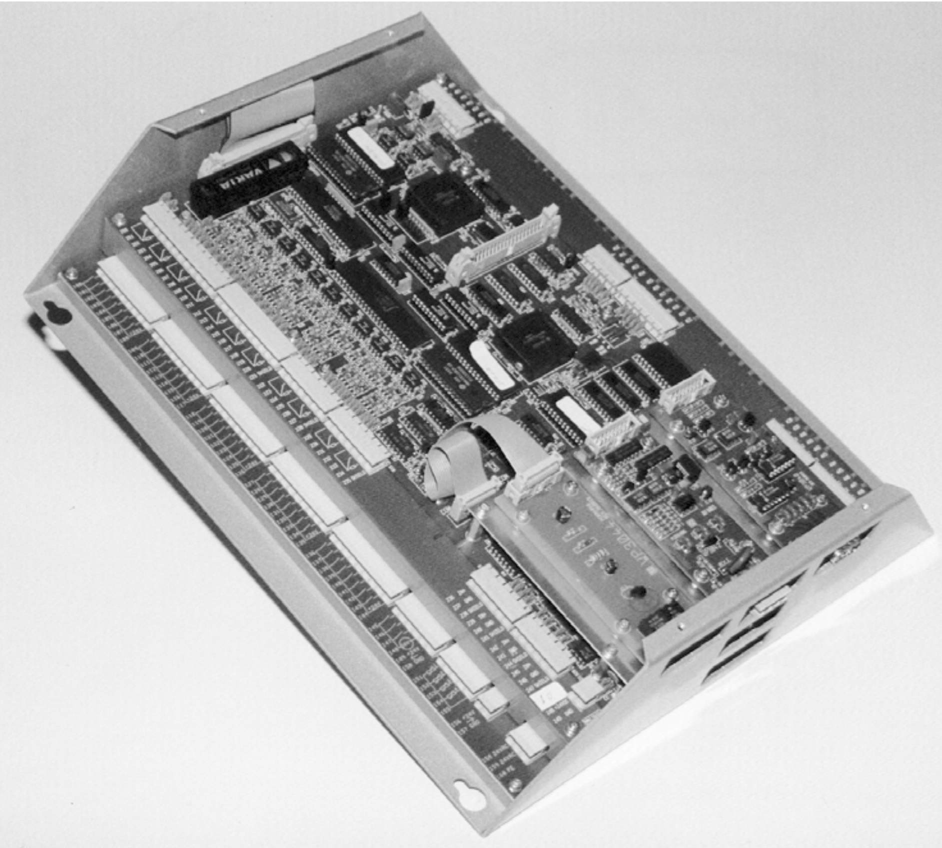

Figure 10.17. Central control unit for a series-produced wind turbine model (Mita)

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Chapter 11

Vibration Problems

Vibration problems in wind turbines are an old phenomenon. Even in the Middle Ages, the post windmill of that time was also called a "rocking mill", as the mounting of the entire millhouse on a trestle led to a rocking motion. This drawback then became the stimulus to continued development, from which evolved the more stable Dutch windmill which ran more smoothly.

Modern wind turbines are of slender and elastic construction, above all the rotor blades and the tower. They are, therefore, structures which are extremely prone to vibration. In addition, there is no lack of excitations as the discussion of cyclically alternating rotor forces has shown. These forces can excite certain subsystems or even the entire turbine to vibrate dangerously. Wind turbines must, therefore, undergo a painstaking analysis of their natural vibrational modes and possible resonance problems, even at the design stage.

This vibration analysis has the aim of verifying the dynamic stability and the absence of resonances within the permissible operating range. Unstable speed ranges, for example with regard to a bending vibration of the tower, or resonances of bending or torsional vibrations of other important structural components, must be avoided, at least in steady-state operating phases. For this reason, the natural frequencies of rotor blades, tower and mechanical drive train components must not be too close to each other, and their clearance from the possible excitation frequencies must not be too small.

This objective of verifying the dynamic stability must not be confused with the task of calculating the increase in dynamic loads resulting from the elastic response characteristics of the structure. It is true that the mathematical approaches and calculation methods are similar, even identical in part, but the formulation of the task is different and hence also the procedure.

Vibration problems in wind turbines are essentially concentrated in four areas:

- The slender rotor blades are subject to aeroelastic influences. To avoid hazardous vibrations, certain criteria of stability must be met.
- The mechanical-electrical drive train is prone to torsional vibrations which can be excited both by aerodynamic influences and by electrical influences.
- The yaw system has its own dynamics which can also lead to undesirable vibrational behaviour.

– Not least, the entire wind turbine, i.e. the rotor/tower-system, can start vibrating. This is caused by the periodic forces caused by the rotor resonating with the tower's natural bending frequency.

Theoretically, these four areas are not independent of one another. But a joint treatment with a comprehensive mathematical model would be both impractical and unnecessary. Generally, the vibrational coupling of these individual processes is not so strong that an independent treatment would be impossible.

11.1 Aeroelastic Stability of Rotor Blades

One of the first prerequisites for avoiding unwanted vibrations and structural failure is that the rotor blades are aeroelastically stable. Aeroelastic instabilities arise when a cumulative interaction develops between the deformations of the elastic structure and the resultant aerodynamic forces. Elements creating lift, such as aircraft wings, are especially prone to this. Calculation methods for detecting aeroelastic instabilities have, therefore, been developed above all in aeronautical engineering and can be applied directly to the rotor blades [1]. Basically, the most varied types of aeroelastic instability phenomena exist, but in this book only the most important ones can be discussed.

Static divergence

A phenomenon known from the behaviour of aircraft wings is the torsional instability of the wing at a certain flying speed. This effect depends on the relative position of the so-called elastic axis, which is the imaginary axis around which the wing twists free of moments, and of the aerodynamic centre. In almost all airfoils, the aerodynamic centre, the point of attack of the lift forces, is located at approximately a quarter of the chord length (Fig. 11.1). If the aerodynamic centre is located in front of the elastic axis, the lift creates a torsional moment which increases the angle of attack. This moment increases with the square of the free-stream velocity. However, the restoring moment resulting from the wing's torsional stiffness is independent of the speed, so that at a certain speed, the "speed of divergence", a torsional instability develops.

In most wind turbine rotor blades, this static divergence does not pose a problem. It should nevertheless be checked in all real cases. It must be noted here that a torsional moment in the sense of a greater angle of attack is not only caused by the aerodynamic lift force, but additionally by a component of the centrifugal force, if the rotor blade is twisted out of the plane of rotation, or when the rotor has a coning angle.

Flutter

A certain type of aeroelastic instability of a wing or a rotor blade is called "flutter". If, for whatever reason, the airfoil is excited into an oscillating motion, a mutual excitation of aerodynamic forces, elastic forces and mass forces can occur. In particular, it is the combined bending-torsional vibration, which is virtually unavoidable in a twisted wing

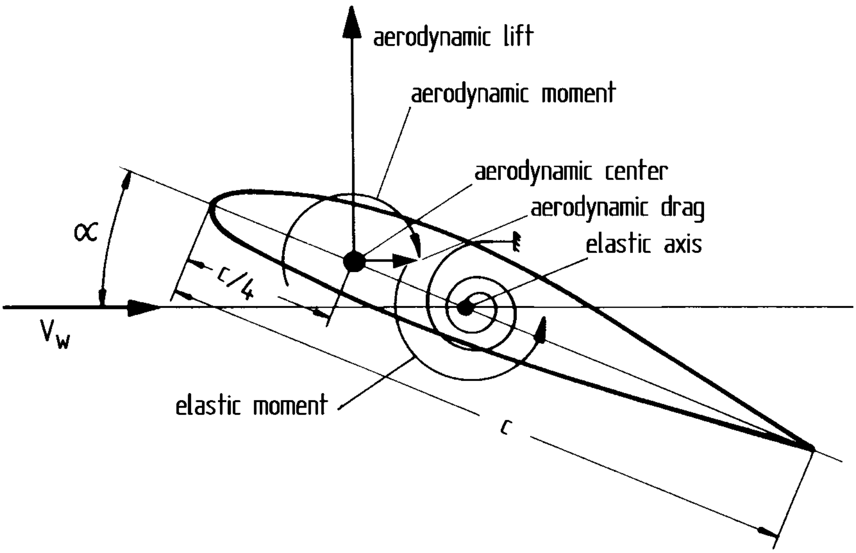

Figure 11.1. Aerodynamic and elastic moments in a wing or rotor blade cross-section

or rotor blade, which represents the classical case of flutter. Since this directly involves the aerodynamic angle of attack and thus the lift forces, this flutter is especially dangerous and can lead to destruction in the shortest period of time.

An effective counter-force is, above all, *aerodynamic damping.* Aerodynamic damping is understood to be the speed-related force resulting from the change in the angle of attack, acting counter to the direction of movement. It is proportional to the speed of the vibrational deflections and is not to be confused with the aerodynamic drag in the direction of the free stream velocity. The aerodynamic damping is much greater in the flapwise direction than in the chordwise direction of the blade. Despite the presence of aerodynamic damping, the vibrational mechanism of the flutter can absorb energy under certain boundary conditions, thus becoming hazardous.

A special case of flutter is the so-called *stall flutter* which is characterised by a periodic change between flow separation and normal flow on the airfoil when the angle of attack is high and close to the critical angle of attack. This stall flutter can represent a danger to rotors which are deliberately operated close to aerodynamic stall at higher wind speeds. As stall is approached, the lift coefficient develops a negative gradient at increasing angles of attack. The aerodynamic damping then also becomes negative and the rotor blades can resonate with exciting frequencies both in the flapwise and the chordwise direction. In particular, chordwise rotor blade vibration was observed in some larger stall-controlled turbines [2].

The tendency of the rotor blades to flutter is determined by a multitude of parameters. The most important ones are the natural frequencies of the blades as regards the direction of flapping, chordwise and torsion motion, the coning angle, the twist, as well as the relative positions of the aerodynamic centre with respect to the centre of mass, and of the elastic axis and the plane of rotation. A first criterion for a possible susceptibility to flutter is the relationship between torsional stiffness and the distance of the elastic axis from the centre of mass. This makes it possible to specify "stability limits" (Fig. 11.2).

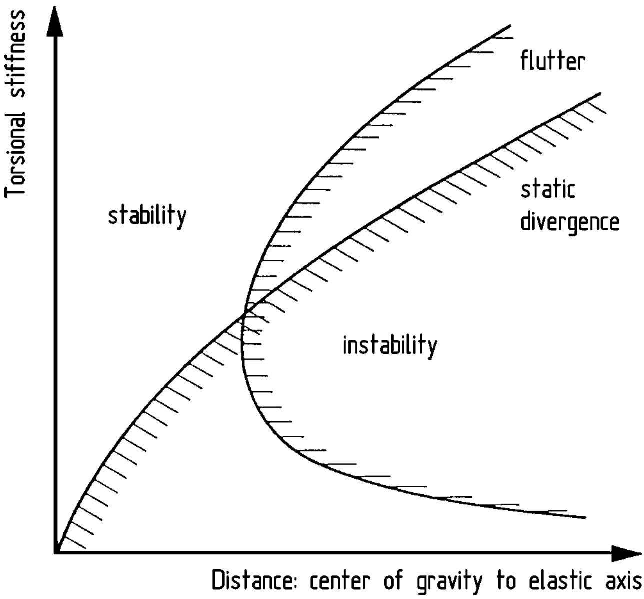

Figure 11.2. Stability limits for the "static divergence" and "flutter" of wings and rotor blades [2]

Apart from considering aeroelastic structural instabilities, the stability characteristics of wind rotor blades must also be considered under an additional aspect. With rotor blades that are pitched around their longitudinal axis, it is not only the torsion of the blade in itself which is of importance, but also the torsional moments around the axis of rotation of the blade. The position of the axis of rotation, which is mostly fixed for constructional reasons, must, therefore, be included in these considerations. The blade pitch mechanism, in combination with the control system, also has its own dynamic characteristics. Interacting with the structurally elastic torsional behaviour of the rotor blades, it can lead to instabilities and vibrations. An elastic element which is capable of vibrating can be formed by hydraulic actuating cylinders.

11.2 Torsional Vibration of the Drive Train

The drive train of a turbine with its rotating masses and torsionally elastic components is a subsystem capable of vibrating. Vibrational modes can also be excited by external influences at both ends of the energy transmission chain. Apart from the stochastic fluctuations of the rotor torque caused by wind turbulence, the rotor also generates cyclic torque variations which represent an ideal source of excitation. At the other end there is the electrical generator with its connection to the grid or to a particular load. In the discussion of the characteristic properties of electrical generators, it has been pointed out that, in particular, the synchronous generator coupled directly to the grid tends to vibrate. However, the problem also occurs in other types of generators.

Against this background, it is absolutely mandatory to deal with the phenomenon of *drive train vibrations* in wind turbines. The most important natural frequencies and modes of vibration must be analysed and tuned to the possible exciting frequencies in such a way so as to avoid resonances. Vibrational resonances in the drive train can exert a considerable influence on the dynamic load of the components, on the quality of the power output and even on the mechanical noise.

The term electrical-mechanical drive train usually includes the elements of the energy transmission chain, without the rotor blades. For dynamic considerations, however, the rotor blades must be included as their share in the rotating masses is by far the largest and, in addition, they have a decisive part in determining the dynamic behaviour due to their bending behaviour in the chordwise direction.

The series-connected components of the drive train such as rotor hub, rotor shaft, gearbox, high-speed shaft, brake and clutches have such diverging dimensions, mass distributions and material properties, that an accurate analysis of vibrations can only be carried out to a limited extent. The most important parameters can, nevertheless, be calculated by means of comparatively simple equivalent mechanical models.

11.2.1 Mathematical Model

The mathematical simulation of the vibrational behaviour of rotating multi-mass systems is widely used in the field of engineering, so that only the basic approaches will be called to mind here [3, 4]. Firstly, the most important natural frequencies and modes of inherent vibrations (modal analysis) are calculated with the aid of an equivalent mathematical vibration model. In a second step, the reactions of the drive train to excitations are examined and critical resonances found.

In a method developed by Lagrange, the kinetic and potential energies of the multi-mass system consisting of torsional masses and torsionally-elastic shaft elements are balanced and the equations of motion are derived by differentiation with respect to time. To solve these equations, all mechanical parameters are "reduced" to a uniform rotational speed. The multi-mass system with different rotational speeds becomes an equivalent system with a uniform speed, taking into consideration the requirement that the total energy be conserved. The vibration equation for this equivalent system can be solved. The solutions of the so-called "characteristic equation" provide the natural frequencies. Inserted into the general solution of the system of differential equations, these, in turn, yield the associated natural vibration frequencies.

The vibration response of a torsional vibration system is determined by three elastomechanical parameters:

- the polar moment of inertia of the rotating masses,
- the torsional stiffness of the elastic shafts and connecting elements
- the torsional damper constants.

These three parameters must be determined from the design and material properties of the drive train components involved. This is where the main difficulty arises.

Apart from the torsional stiffness of the drive train itself, the chordwise bending behaviour of the rotor blades also plays a role, as already mentioned. The antimetrical chordwise elastic deformation of the rotor blades is directly related to the torsional dynamics of the drive train. An equivalent torsional stiffness can be calculated if the first natural bending frequency of the blades in chordwise direction is known.

The torsional damping constants of the mechanical components are generally small. This applies both to structural damping and damping caused by bearing friction. Hence an equivalent mathematical model without damping can be used (conservative system), as long as no special damping elements are used for damping the vibrations in the drive train.

The drive train of a horizontal-axis wind turbine can be composed essentially of two masses: the rotor and the generator rotor. A "two-mass model", therefore, provides a first overview. Occasionally, the rotor hub in connection with the blade roots represents a relatively "soft" link, so that a three-mass model consisting of rotor blades, hub, generator rotor with gearbox and "the rest" represent a suitable equivalent model by means of which the most important natural frequencies and resonances can be recognised. The proportion of the inertial moments of these subsystems contributing to the overall inertial moment of the drive train of wind turbines with widely differing sizes and technical concepts are shown in Table 11.3.

In practice, the mathematical treatment is based on an idealised concept of the drive train (Fig. 11.4 and Fig. 11.5). According to this, the polar mass moment of inertia and the torsional stiffness are referred to the selected "reference speed" for all components involved in the torsional vibration, and are clearly plotted to scale along the drive train (Fig. 11.4).

In this way, an idea of the vibration-related influence of the components involved is obtained, and the suitable "multi-mass model" can be selected for the vibration calculation.

Table 11.3. Proportions of the components contributing to the overall inertia

Wind turbine \ Component	Blades	Hub	Generator	Rest
Aeroman	87 %	2 %	9 %	2 %
WKA-60	91 %	1 %	7 %	1 %
Growian	85 %	8 %	5 %	2 %

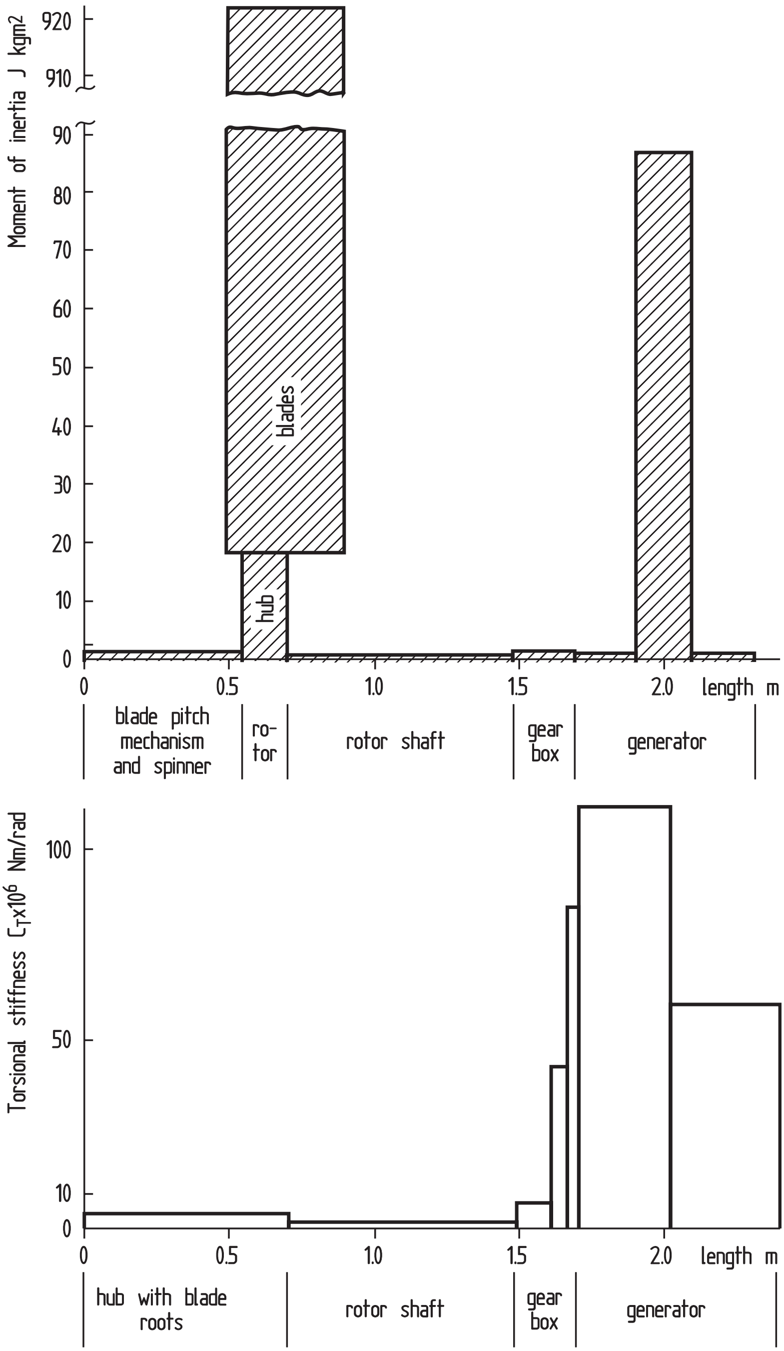

Figure 11.4. Distribution of the polar mass moment of inertia and torsional stiffnesses of the drive train of a small wind turbine

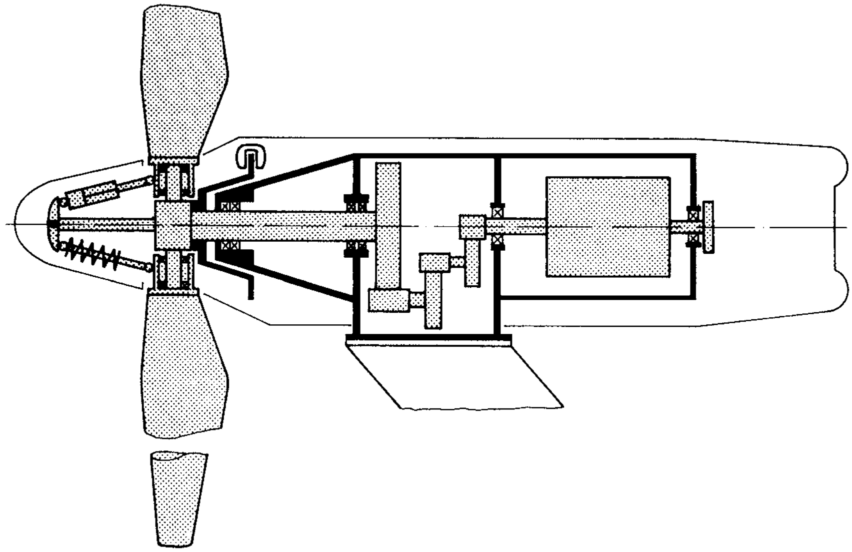

Figure 11.5. Idealised drive train of a small turbine of the Aeroman type

11.2.2
Mechanical Models for the Electrical Grid Coupling

Apart from elastomechanical properties, the dynamics of the drive train are also determined by the electrical aspects. In the discussion of the generator characteristics it was pointed out that the various types of generator behave very differently as far as their dynamic coupling to the grid or the load are concerned. The electrical characteristics can be represented by analogous, equivalent mechanical models (Fig. 11.6). These equivalent models are only valid as far as the vibrational behaviour is concerned, namely for very small deviations around a steady-state point of operation. Any speed variability which may exist is of no consequence.

The synchronous generator is characterised by the dominant torsionally-elastic behaviour. The magnetic coupling between rotor and stator (grid) can be described by a mechanical torsion spring. The damping is so slight that it can be virtually neglected. If the generator operates on a fixed-frequency grid, the torsion spring is clamped to a "solid wall", as it were. In isolated operation the frequency is determined by the instantaneous generator speed. The generator only loads the drive train with the moment of resistance corresponding to the power delivered. In contrast to the induction generator, the magnetic coupling of the synchronous generator is weak when idling, due to the grid-independent excitation of its rotor.

In the induction generator, the slip existing between rotor and stator under load acts as torsional damping, whereas the elasticity is virtually zero. During idling or after a load shedding, the coupling between rotor and stator disappears completely.

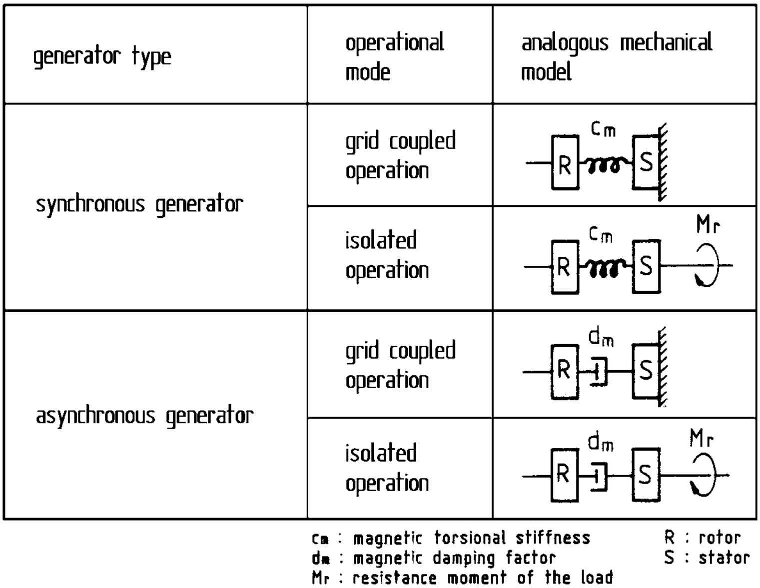

Figure 11.6. Equivalent mechanical models for the electrical coupling of the generator to the grid or the load

The equivalent mechanical models for the electrical grid coupling of the drive train show that, in addition to the generator type, the operational mode, too, must be taken into consideration. This results in different natural frequencies and vibration modes, depending on the load condition.

11.2.3
Natural Frequencies and Vibration Modes

The models and calculation method outlined above provide the natural torsional frequencies and with them the vibration modes (eigenmodes) of the drive train as the most important results. Depending on the type of electrical grid coupling or, in isolated operation, on the type of load characteristics, typical vibration modes are obtained. These are shown in Fig. 11.7 calculated by means of a "three-mass model".

Synchronous generators coupled to the grid

The rotational speed of the generator rotor fluctuates around the grid frequency, the drive train masses vibrate in opposition to one another. Given the usual mass conditions of a horizontal-axis turbine, the following characteristic vibration modes are obtained:

– At the first natural frequency, the entire drive train vibrates in opposition to the fixed-frequency grid.

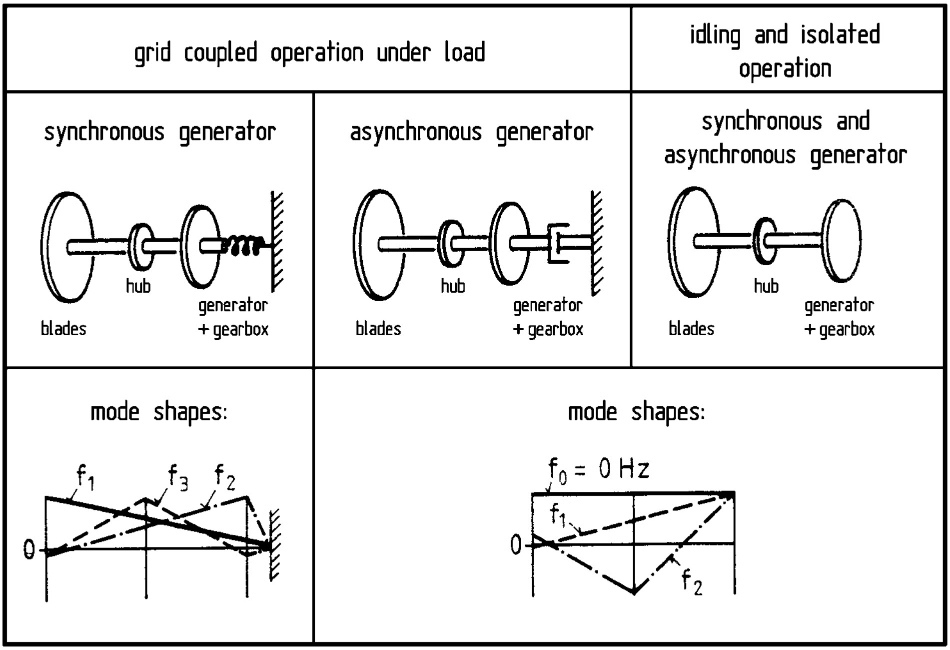

Figure 11.7. Natural vibration modes of the drive train with grid-coupled generator, and with isolated operation

- The second eigenmode is characterised by the vibration of the second largest partial mass, the generator rotor, around the other parts of the drive train.
- At the third natural frequency, the third largest partial mass, the hub, vibrates between the adjacent larger masses.

The magnetic coupling of the generator rotor to the grid frequency is dependent on power, the same as the natural frequencies. This is shown clearly by the example of the American MOD-0 test turbine (Fig. 11.8). This turbine was equipped with a synchronous generator directly coupled to the grid. Strong vibrational resonances, a consequence of the tower shadow excitation, among others, necessitated the subsequent installation of a damping hydraulic coupling in the high-speed shaft (Fig. 11.9).

Grid-coupled induction generator

The slip of grid-coupled induction generators is the reason why the grid does not exert a reversing spring force on the drive train, but merely a damping force. The "zeroth natural frequency" resulting from these conditions is the total rotation of the drive train corresponding to the rotational generator speed, with a zero vibrational frequency. In contrast to the synchronous generator with direct grid coupling, the natural frequencies are not or only slightly dependent on power.

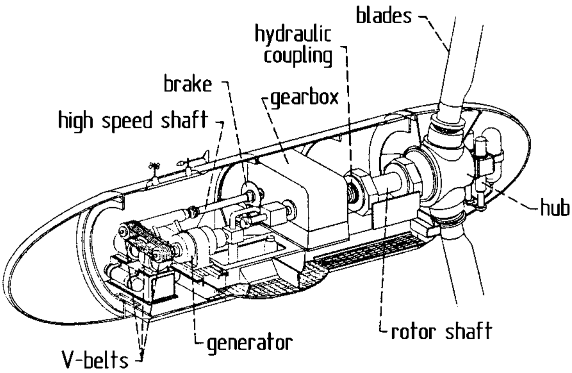

Figure 11.8. Drive train of the experimental MOD-O [5]

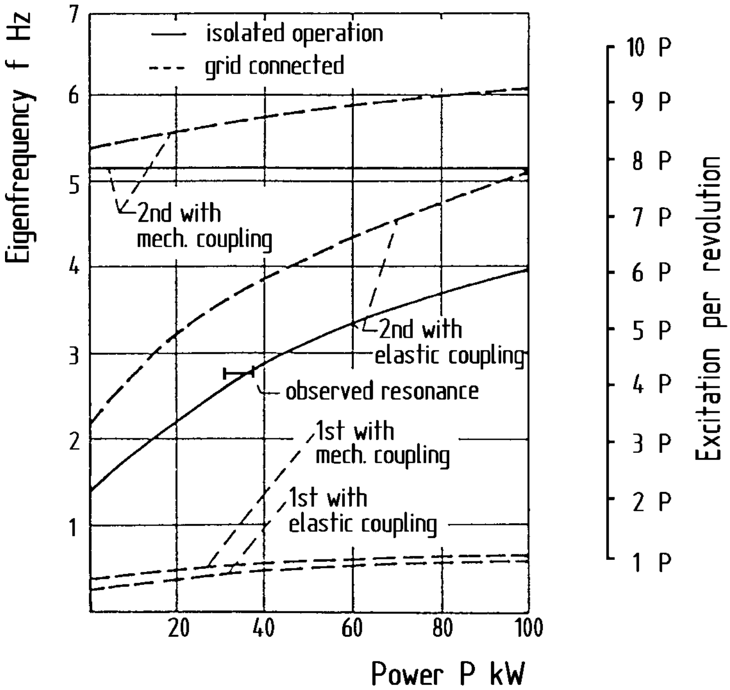

Figure 11.9. Natural frequencies of the drive train of the MOD-o with a synchronous generator directly coupled to the grid [5]

Synchronous and induction generators in idling and isolated operation

When idling and in isolated operation, both generator types behave the same in the same way. The zeroth natural frequency is again the total rotation with zero vibrational frequency.

At the first natural frequency, the drive train vibrates around its largest mass, the rotor blades, whereas the second mode includes the vibration of the partial mass next in size.

11.2.4
Excitations and Resonances

In the second step, the dynamic responses to various sources of excitations can be examined on the basis of the results of the modal analysis, and hazardous resonance points can then be identified. The excitation of vibrations in the drive train of a wind turbine can have its origin in many areas: External excitations can affect the drive train by way of the rotor. This applies mainly to cyclically alternating forces (Chapt. 6.2):

- tower wind shadow or tower dam,
- vertical wind shear,
- cross wind at the rotor due to yaw misalignments or an inclined rotor axis,
- mass imbalance of the rotor blades.

The external excitations occur with multiples of the rotor speed and are therefore characterised by 1 *P*, 2 *P* etc. (Chapt. 14.4.1). On the generator side, attention has to be paid to the following:

- electrical grid oscillations when grid feed lines are excessively long,
- oscillations of the inverters and AC-DC-AC links,
- control influences,
- load feedback in isolated operation.

Apart from these external influences, the drive train vibrations can also have "internal" origins. Possible causes are "mass imbalances" of the rotating parts, and "meshing frequencies" of the gearbox. Which of the excitation sources does indeed lead to hazardous resonances naturally depends on the actual numerical values of the natural and excitation frequencies. Small turbines with drive trains of relatively high stiffness react readily to internal excitation sources (Fig. 11.10). In the example shown, the meshing frequency of the second gear stage excites the fourth natural harmonic of the drive train. In this real example, this fourth natural harmonic is the result of the vibration of the relatively large mechanical centrifugal switch mounted on the high-speed shaft. Strong resonances occurred here during a test operation.

In large wind turbines, the first natural frequencies of the drive train are lower by almost one order of magnitude and range around "a few Hertz". This is the range where the cyclically alternating aerodynamic forces from the rotor, for example the tower shadow interferences or the influence of the vertical wind shear, are located. Hence, there is a greater risk that the excitation frequencies emanating from the rotor will resonate with the drive train torsion, as is clearly shown by Fig. 11.11.

In the example shown, the tower shadow interference excited the first natural torsion frequency of the drive train at the upper edge of the operational speed range. It was, therefore, not possible to utilise the design speed range to its full extent.

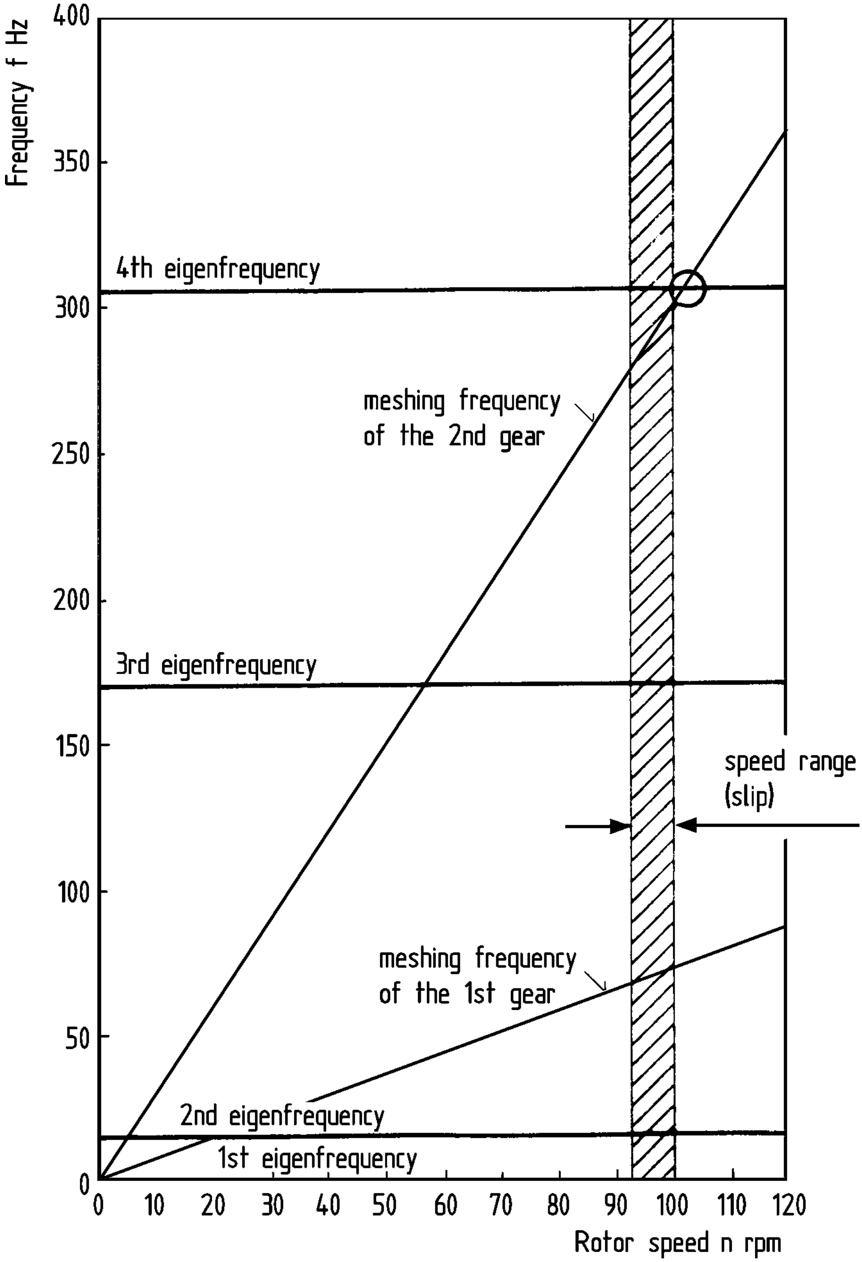

Figure 11.10. Resonance diagram (Campbell diagram) of the Aeroman drive train with a resonant point at the fourth natural harmonic of the drive train, with the meshing frequency of the second gear stage close to rated speed

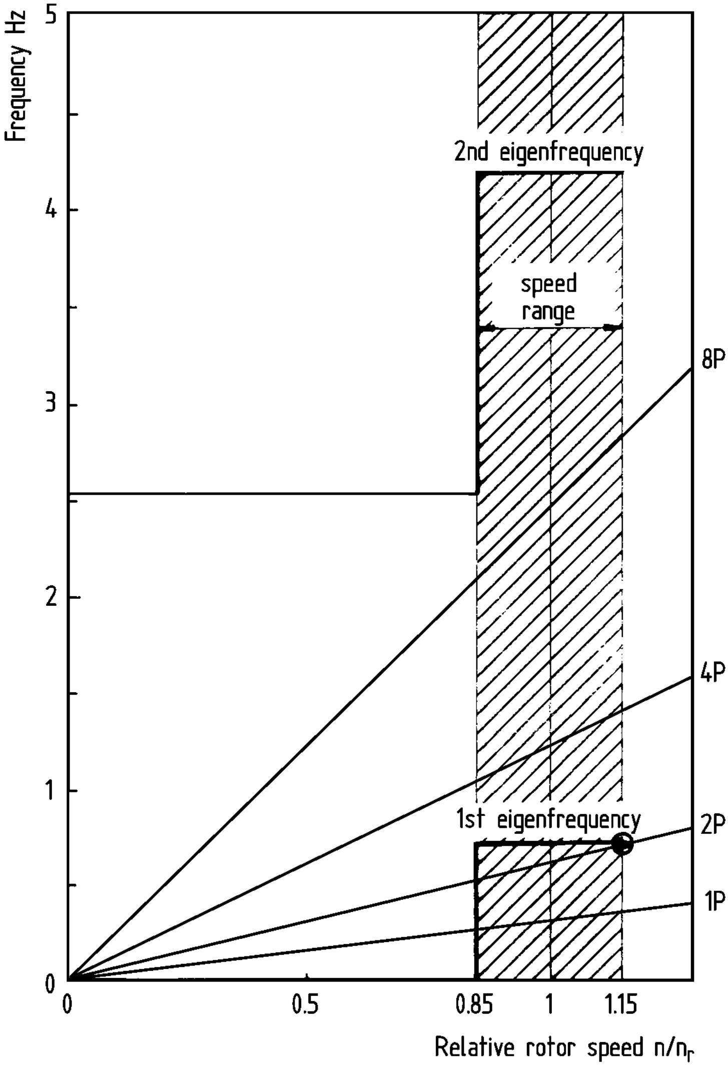

Figure 11.11. Resonance diagram for the Growian drive train. Resonance of the first natural drive train frequency with tower shadow interference (2 P) at a rotor overspeed of 115 %

11.3 Dynamics of the Yaw System

The failure statistics of wind turbines display a conspicuous accumulation in the "yaw system" component. The smaller turbines, in particular, frequently have problems with the life span of the yaw drive system. The reason for this is that the dynamic loads acting on the yaw system are often underestimated. It is, therefore, absolutely imperative that the dynamic load situation and the vibrational behaviour of the yaw drive be analysed. Just like the drive train, the azimuth drive has certain natural frequencies with respect to the yaw oscillation of the tower head. If resonances develop with the cyclically alternating rotational forces of the rotor, destruction of the components is only a matter of time.

11.3.1
Modelling and Moments Around the Yaw Axis

In principle, the mathematical model of the yaw system is very simple (Fig. 11.12). If the tower may be considered as being torsionally stiff, a "one-mass model" with an equivalent mass for the rotor and the nacelle is sufficient in the simplest case. As a rule, this assumption applies to older tubular steel towers of stiff design. Recent, more flexible towers require more accurate calculations which take into account the tower's torsional elasticity.

There is some difficulty in determining the torsional stiffness of the yaw drive from a real example. On the other hand, it is easier to determine the damping moments of friction. With some experience, it is nevertheless possible to determine the numerical values of the

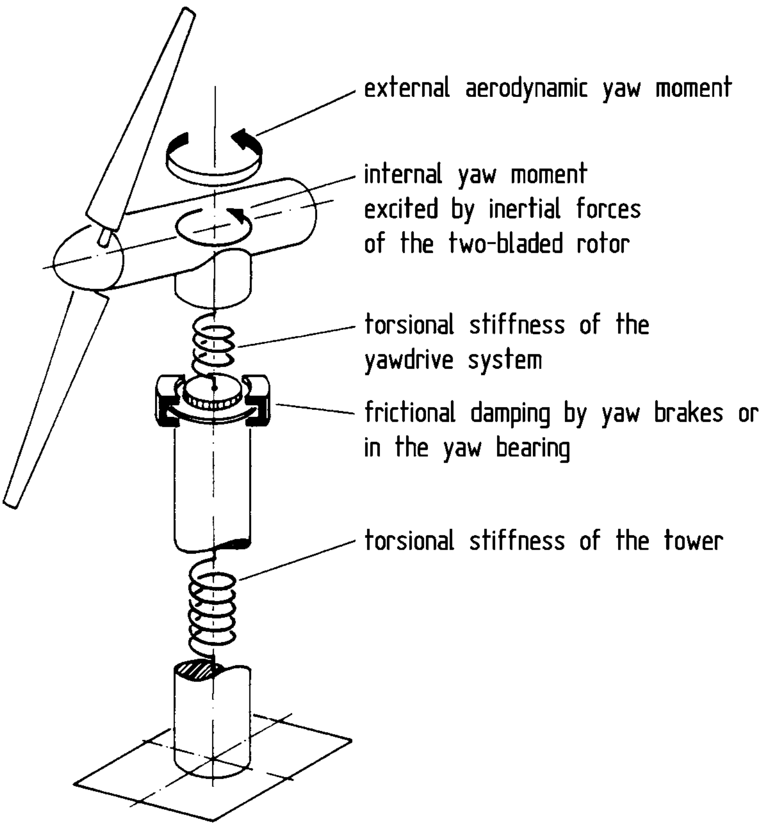

Figure 11.12. Model of the vibrational behaviour of the yaw system

most important first natural frequencies of the yaw vibration. On the basis of this and including the external excitation sources, the analysis of the vibrational behaviour can then be carried out.

The load situation for the yaw system varies greatly depending on the existing design features of the turbine, particularly on the number of rotor blades, the rotor position relative to the tower, the hub type and the distance of the rotor plane from the tower axis. In any case, the changing yaw moments can trigger undesirable torsional vibrations in the yaw system. Hence, the system must be designed with sufficient torsional stiffness. In addition, there must be sufficient frictional damping during the yawing process and, in a fixed azimuth position, suitable arresting forces.

The external excitation forces and moments vary, depending on whether the tower head is standing still or yawing is taking place. When the rotor is rotating during a yawing motion, the following moments are active around the yaw axis:

Aerodynamic moments

Depending on whether the rotor is a down-wind rotor or an up-wind rotor, the aerodynamic yaw moment of the rotor either has an assisting effect or an opposing effect. In both cases, the aerodynamically caused moments around the yaw axis are particularly undesirable, as these cyclic loads fluctuate intensely or even alternate. This is especially true for two-bladed rotors with a hingeless hub. This problem is solved almost completely by a teetering hub.

Gyroscopic moments

Yawing of the rotating rotor causes gyroscopic moments around the pitch axis of the nacelle. In turbines with active yaw drives, these moments only play a subordinate role, since the yawing rate is, as a rule, so slow that only small gyroscopic moments are developed. But problems will arise in smaller turbines with free yawing systems (Chapt. 6). Abrupt changes in wind direction, producing fast yawing movements, can lead to destructive gyroscopic moments.

Components of the rotor torque

If the rotor axis is tilted, a component of the rotor torque develops around the yaw axis. This moment must be taken into account in the balance of moments.

Moment of friction of the yaw bearing

The friction in the yaw bearing and brakes naturally also enters into the balance of moments. This moment is relatively small with the usual roller bearings. However, some turbines which do not have any separate yaw brakes have frictional sliding bearings (so-called sliding blocks) or roller bearings with special damping elements. Electric yaw drive motors with integrated brakes are also used (Chapt. 8.11).

Moment of friction of the yaw brakes

Large turbines which have a number of active yaw brakes will use one or two brakes which are engaged during yawing in order to suppress unwanted yaw vibrations.

11.3.2 Excitation and Resonances

Yaw vibrations of the rotor and nacelle are, above all, excited by aerodynamic forces and moments. The main causes are cyclically fluctuating forces from wind shear or the tower shadow. They represent an ideal source of excitation for the tower head yaw vibration, mainly in combination with the dynamic mass effects of a two-bladed rotor with hingeless hub. The moment of inertia of a two-bladed rotor, which changes with respect to the pitch and yaw axes during one revolution, represents an additional so-called "parametric excitation" (Chapt. 6.6.2).

The natural modes of vibration of the yaw system have a characteristic feature which needs special attention. The yaw drive, i. e. either the driving pinion acting on a gear ring on the nacelle or tower, or the transmission gears of the drive motor, always has some play. If this play comes into effect, for example if the friction brakes are too weak, it will have considerable consequences with respect to the system's natural frequency. The treatment of play-related vibrations is described in the relevant specialist literature [3].

Yawing systems with aerodynamically driven fantail wheels, commonly in use in the past, were particularly subject to this hazard. The small Aeroman turbine had initially been equipped with aerodynamic yawing using a fantail wheel acting on a worm gear (Chapt. 5.6). To ensure that the worm gear was running smoothly, a certain amount of play was necessary which, moreover, increased with increasing operating time. There was also the turbine design with a hingeless two-bladed rotor and the associated large rotor yaw moments around the vertical axis.

In the resonance diagram, the natural frequency range was outside the area of critical excitation, not taking into account the play in the worm gear (Fig. 11.13). As soon as the play in the gears became perceptible after some hundreds of hours of operation, the natural frequency dropped drastically, and a resonance with the exciting aerodynamic moments of the rotor developed. Without considerable frictional damping or a yaw brake, such a vibration will destroy the yaw system after a short period of time. Passive aerodynamic yaw systems with fantail wheels and without yaw damping or brake are, therefore, seldom used today. The small Aeroman turbine, too, had to be retrofitted with an active yaw drive with yaw damping in the azimuth bearing.

Large turbines generally have fewer problems with the dynamic behaviour of the yaw system. The active yaw system, with servo-controlled yaw drives and a number of yaw brakes, can be controlled more precisely and is, above all, protected from resonances by having the brakes applied when it is in the stand-still position. The risk of resonance is, therefore, restricted to the yaw movement. During yawing, however, there is still a risk of an inadmissible vibration. In this condition, the yaw system's natural frequencies must, therefore, be taken into consideration.

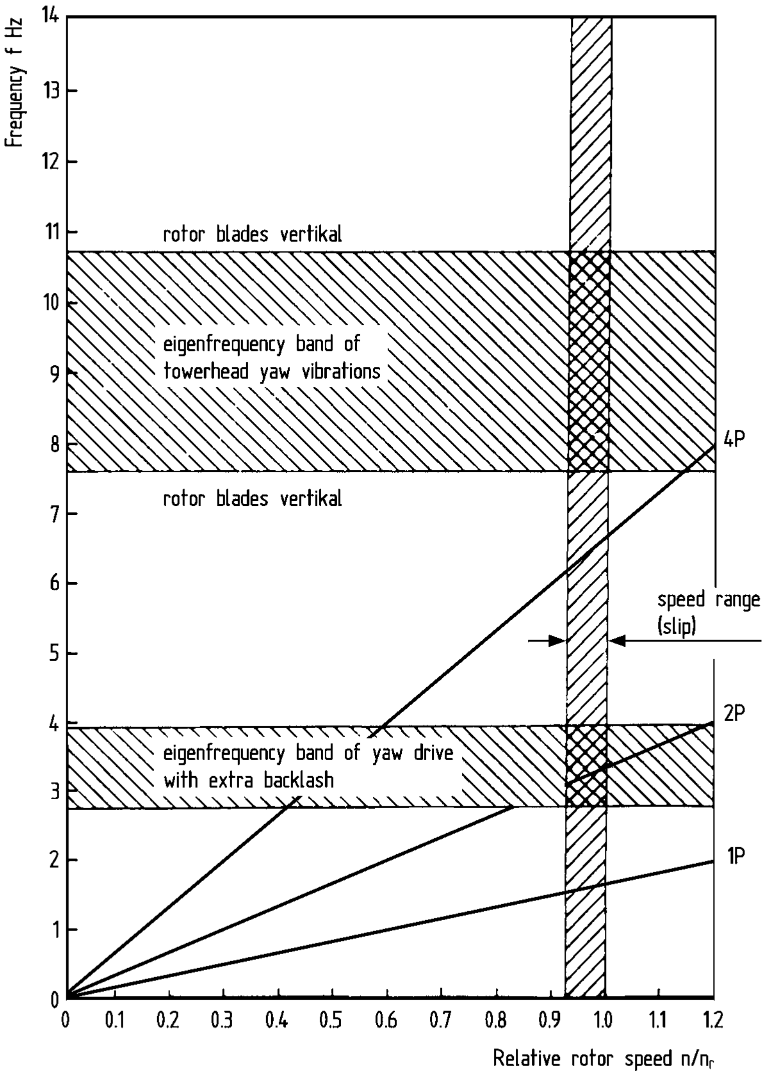

Figure 11.13. Resonance diagram of the yaw motion of Aeroman. Natural frequency ranges with and without play in the worm gear

11.4 Vibration of the Whole Wind Turbine

When speaking of the vibrational behaviour of the turbine as a whole, this refers primarily to the vibrational coupling between the rotor and the tower. The rotor-tower system is continuously subject to the risk of self-excitation. Fig. 11.14 shows the most important degrees of freedom of this system.

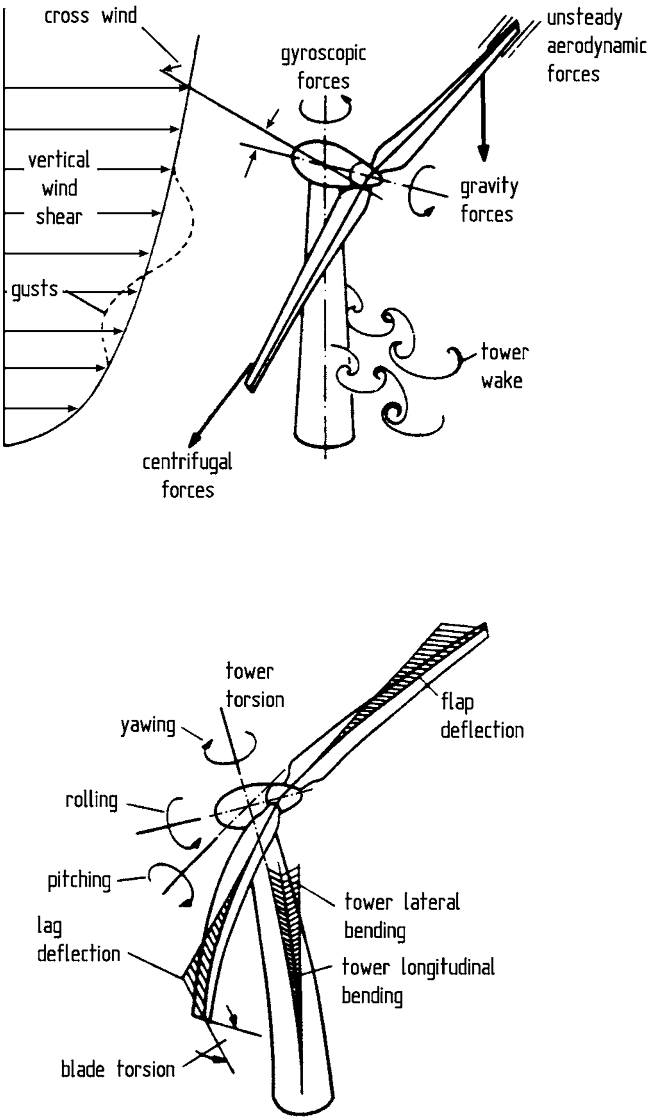

Figure 11.14. Exciting forces and degrees of vibrational freedom of a wind turbine [6]

It is obvious that the exciting forces do not only excite the first tower vibration, but also a multitude of degrees of freedom of other components, which, in addition, interact with each other. This situation could lead one to assume that a vast number of the most varied modes of vibration occurs, and theoretically, this is the case, too. But the dynamic coupling of the individual degrees of freedom in the overall system varies in its extent, so that only a few coupled vibrations are of practical significance, whereas most of the others are more of academic interest.

From the practical point of view, the vibrational behaviour of the turbine as a whole can, therefore, be reduced to a limited number of typical vibrational modes with certain degrees of freedom. The cyclic rotor forces primarily excite the tower bending vibrations. But tower torsion must not be entirely disregarded, even if in most towers the first natural torsion frequency is distinctly higher than the first bending frequency. Above all, it is the yaw moment of the two-bladed rotor, which has already been mentioned numerous times, which can excite a torsional vibration in the tower. As far as vibrations are concerned, a turbine with a hingeless rotor and flexible tower design would, therefore, be an extremely hazardous concept. In the teetering rotor, the rotor yaw and pitch moments are largely decoupled from tower torsion or bending, thus permitting a less stiff and hence more cost-effective tower design to be realised.

In the rotor blades, the flapwise, chordwise and torsional movements with their corresponding natural frequencies are of significance. The first flapwise natural bending frequency of the blades can resonate with the tower bending, whereas the second natural bending harmonic of the blades is, in most cases, so high that it is no longer of concern. The chordwise movement, in particular the antimetric chordwise movement of the blades, must be considered in relation to the vibrational behaviour of the drive train (Chapt. 11.2). As mentioned in Chapter 11.1, chordwise vibrations of the rotor blades can be excited in large stall-controlled wind turbines. Taking into account the stiffness of the blade pitch drive, the torsion frequency of the blades must not be too close to the flapwise frequency, a criterion which is of importance in the flutter tendency of the rotor blades (Chapt. 11.1).

11.4.1 Tower Stiffness

The first and most important requirement for keeping the vibrational behaviour of the turbine as a whole under control is to prevent the exciting rotor forces from resonating with the natural tower bending frequencies. In this case, the natural tower frequencies are meant to be the natural frequencies of the tower with towerhead mass. In common tower designs, the primary risk is that the first natural bending frequency will resonate with the rotor forces. The decisive criterion for vibrational behaviour of the wind turbine is, therefore, the position of the first natural bending frequency of the tower in relation to the exciting frequencies from the rotor. The exciting forces of the rotor can be assigned to two categories:

- Exciting forces occurring with the rotor's rotational frequency. These are primarily forces from mass imbalances;
- Exciting forces occurring with the rotor's rotational frequency multiplied by the number of rotor blades. Among these are the "aerodynamic imbalances", i. e. forces developing as a result of an asymmetrical air flow against the rotor (tower shadow effect, vertical wind shear).

The aerodynamically caused exciting forces are the critical ones, since they cannot be avoided, in contrast to mass imbalances. The position of the tower's first natural bending frequency relative to these exciting frequencies characterises the design of the turbine with respect to its vibrational behaviour. The situation differs depending on the number of rotor blades.

In a turbine with a two-bladed rotor, the aerodynamic frequency of excitation occurs at twice the rotational frequency of the rotor (2 *P*). According to American literature, the frequencies of excitation are called 1 *P*, 2 *P* and 3 *P* (per revolution). Plotted against the rotor speed, they are located along straight lines (Fig. 11.15).

The tower's first natural bending frequency must not under any circumstances coincide with the critical exciting forces. Moreover, care must be taken to ensure that a certain dis-

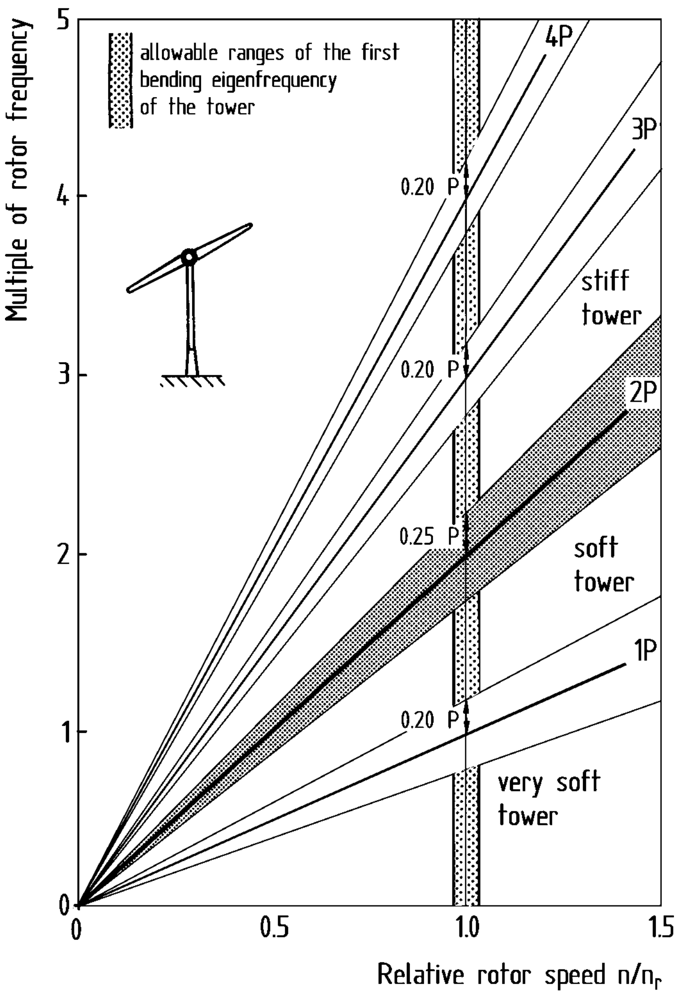

Figure 11.15. Tower stiffness in the resonance diagram of a wind turbine with a two-bladed rotor (Campbell diagram)

tance from the remaining multiples of the rotor frequency is maintained. This distance cannot be generally specified. The distances between frequencies at which excessive vibrations will occur are determined by system damping, i. e. both structural as well as aerodynamic damping. Experience from existing turbines indicates that a safety distance of 0.25 *P* from the dominant frequency of excitation and of 0.15 *P* to 0.20P from the less critical ones is a good guide value.

It has become accepted practice to designate the tower as being "stiff" or "soft" corresponding to the position of the tower's first natural bending frequency relative to the dominant excitation frequency of the rotor. In a tower of stiff design, the natural tower frequency is not encountered during the start-up or shut-down procedures, thus eliminating

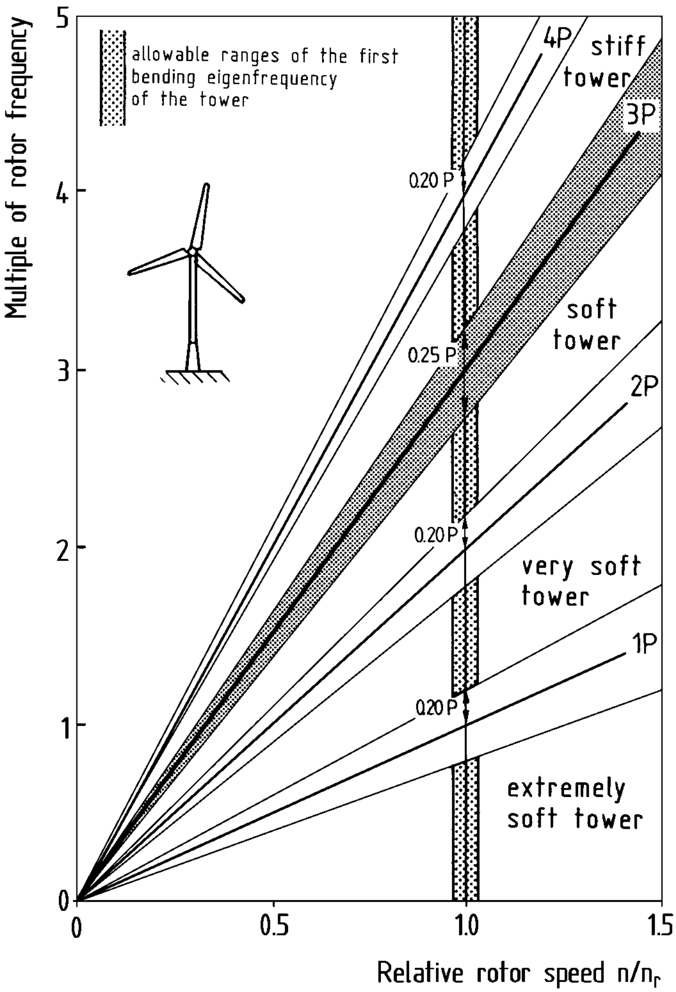

Figure 11.16. Tower stiffness in the resonance diagram of a wind turbine with a three-bladed rotor

the resonance hazard. Conversely, this "encounter problem" with a risk of resonance does exist in the soft tower. At present, the tower stiffness (first natural tower bending frequency) is set below the 1 *P* exciting force. This case is occasionally referred to as the "double soft" or "soft-soft" design.

The same considerations and definitions basically apply to three-bladed rotors (Fig. 11.16). The main difference is that the critical aerodynamic rotor excitation occurs at 3 *P* instead of 2 *P*. For the soft tower design, there is yet another option, namely between 3 *P* and 2 *P*, between 2 *P* and 1 *P* and, theoretically, even below 1 *P*.

In most cases, towers of the first generation were stiff. Resonances developing during the start-up sequence of the rotor were feared. In the course of development, however, almost all manufacturers changed to increasingly more flexible designs. For reasons of economy, the material saved in the process almost became a critical requirement (Chapt. 12.4). Analogous to two-bladed wind turbines, more recent wind turbines with three-bladed rotors therefore have a soft tower design with the tower's first natural bending frequency being located between 2 *P* and 1 *P*, and below 1 *P*.

Apart from the terms "soft" and "stiff" used for the tower design, the terms "supercritical" and "subcritical" design are occasionally mentioned in the literature. As these designations are much less graphic in their descriptive function and as, moreover, it is often not clear which component is super- or subcritical with respect to what, these designations are not used here.

11.4.2
Vibrational Characteristics of Existing Wind Turbines

Designers initially achieved control over the vibrational behaviour of wind turbines by means of various designs. Proponents of the stiff design stood in opposition to those favouring the "soft line". It only emerged in the course of the development that the problematic and risky flexible line became the preferred design. It was found that, particularly with the increasing size of turbines, the weight saving in the tower which could be achieved by the flexible design represents a considerable economic benefit. Since then, the soft tower concept is generally considered to be the more advanced design and is, therefore, almost the only one implemented today. A soft tower design is almost mandatory for large turbines for these reasons.

The following resonance diagrams (called *Campbell diagrams* in English-language literature) can be described as the "dynamic calling cards" of the wind turbines. The numerical values indicated are not highly accurate. The data published by the individual manufacturers are not complete and are also based on not fully comparable preconditions. Partly, the figures may be calculated results from the design stage determined, on the one hand, for isolated components, i. e. rotor blades, and, on the other hand, for subsystems, i. e. the rotating rotor. These values are set against measurement results from operational turbines. Their accuracy is, nevertheless, sufficient to provide an overview of the vibrational characteristics of the individual turbines.

The "first-generation" American MOD-0 and MOD-1 experimental turbines (Fig. 11.17) were representatives of the stiff turbine design [7]. The first natural bending frequency of the tower was located well above the rotor's 2 *P* excitation frequency. Moreover, the lattice steel

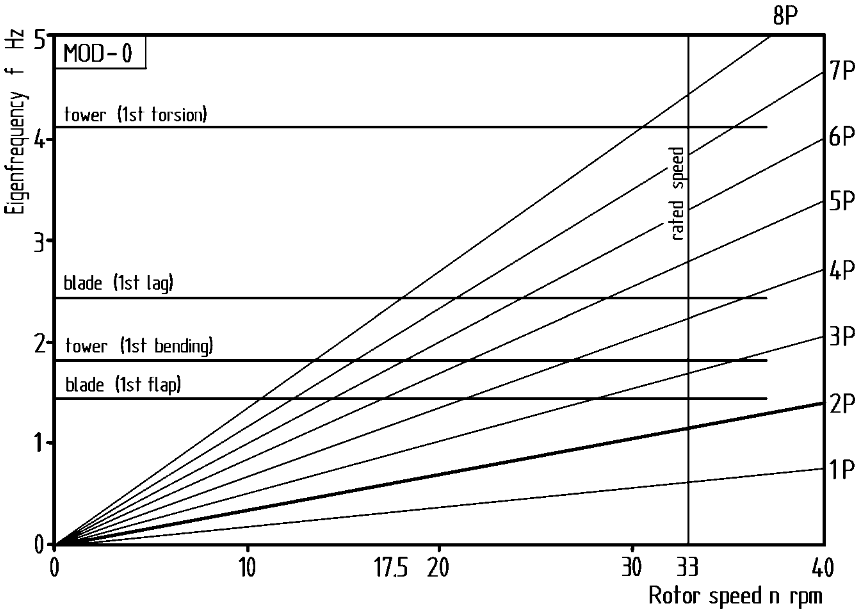

Figure 11.17. Resonance diagram of the MOD-0 with hingeless two-bladed rotor on the down-wind side and lattice tower of stiff design

towers had extraordinary torsional stiffness, a characteristic which was definitely necessary in view of the hingeless two-bladed rotors. The "second-generation" MOD-2 (Fig. 11.18) represented the transition to the flexible design. The first natural bending frequency of the tower was placed between the 1 *P* and 2 *P* excitation frequencies.

A comparison with the large Swedish WTS-75 and WTS-3 turbines and the American WTS-4 sister model is particularly interesting. In a way, they represented the key elements in the wide range of vibrational designs. The WTS-75 stood for the stiff design (Fig. 11.19). However, the consequences were obvious: the concrete tower weighed a colossal 1500 tonnes! The concept of the WTS-3/4 is the exact opposite. In combination with a two-bladed teetering rotor, a soft tower between 1 *P* and 2 *P* was chosen for the Swedish WTS-3 (Fig. 11.20).

The American version WTS-4 even had a "double-soft" tower with a first natural bending frequency below 1 *P*. Experience with the vibrational characteristics of the WTS-4 showed, however, that these extremely flexible tower designs lead to problems at least with this large two-bladed turbine. The tower head's vibration amplitudes were described as extremely unpleasant.

With regard to their vibrational behaviour, turbines with three-bladed rotors are more unproblematic. Above all, there is no strong excitation of the yawing movement with respect to tower torsion, typical of the two-bladed rotor. An example of a turbine with a three-bladed rotor is the Tjaereborg turbine (Fig. 11.21). It is representative of the traditional

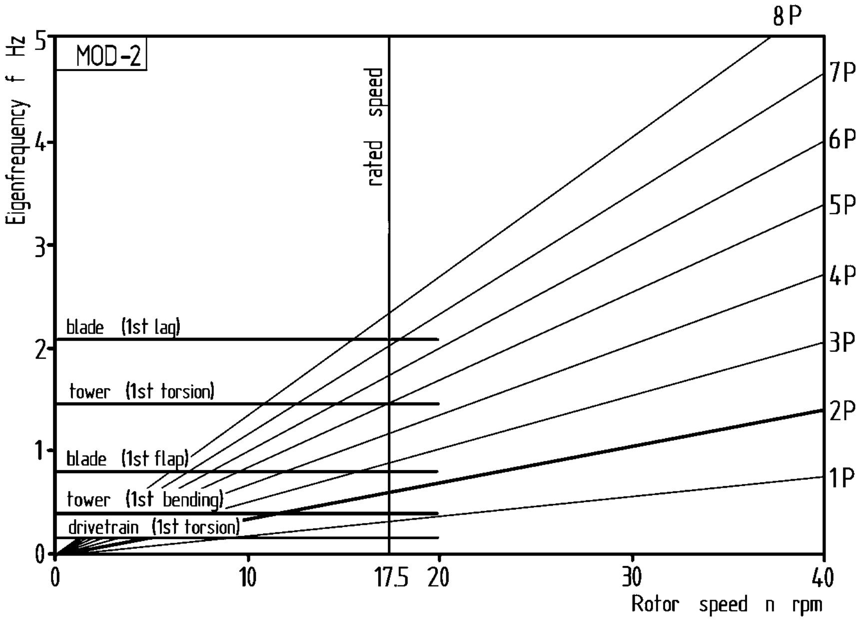

Figure 11.18. Resonance diagram of the MOD-2 with teetering rotor on the up-wind side and steel tube tower of soft design

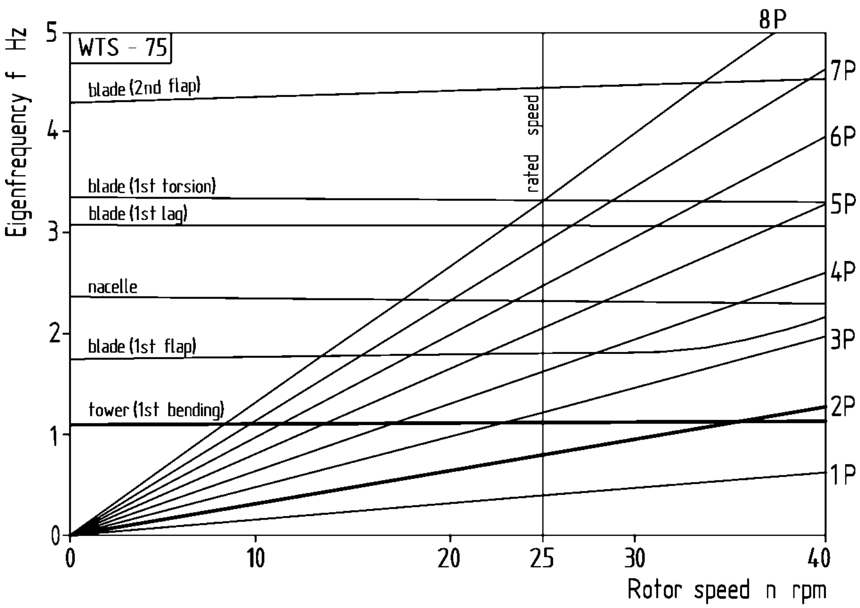

Figure 11.19. Resonance diagram of the WTS-75 with hingeless rotor on the up-wind side and a stiff concrete tower [8]

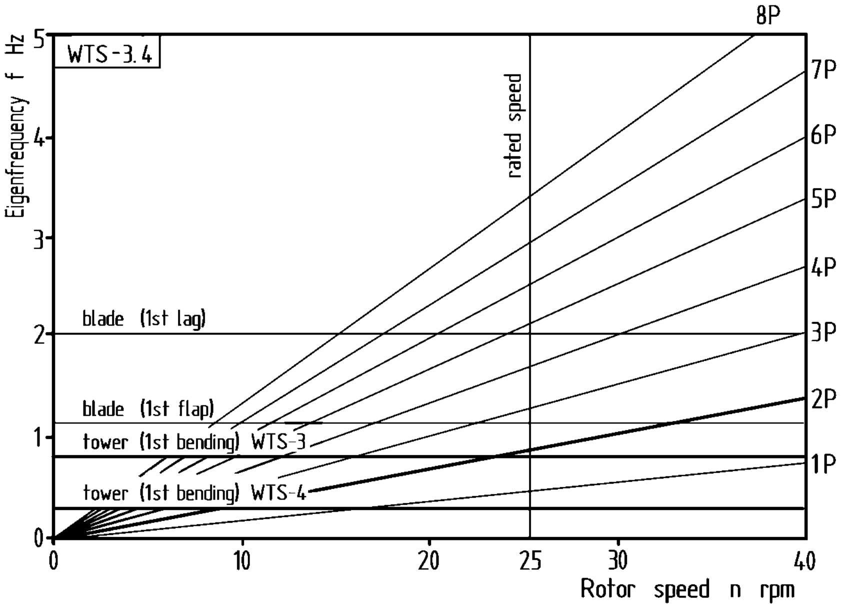

Figure 11.20. Resonance diagram of the WTS-3/4 with two-bladed teetering rotor on the down-wind side and soft tower design (WTS-3) as well as double-soft tower design (WTS-4)

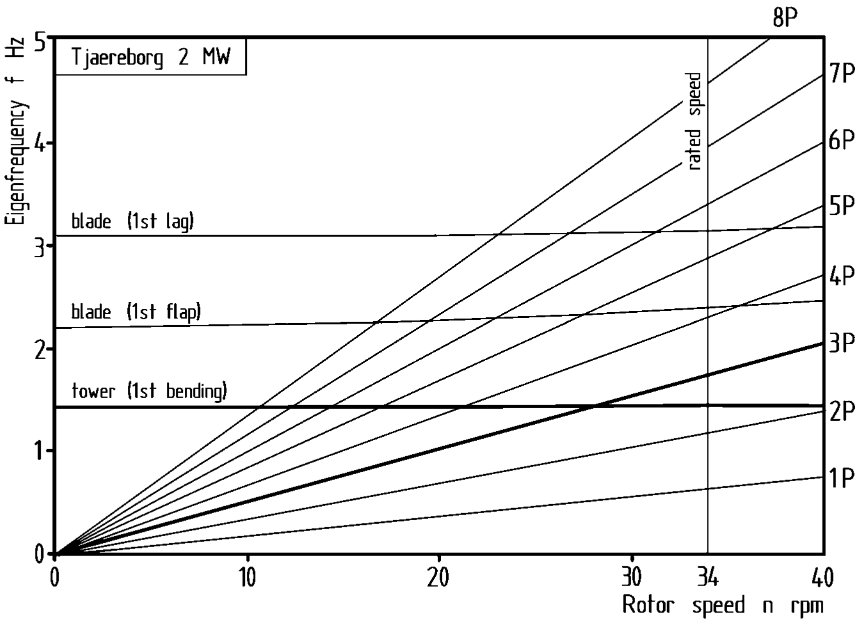

Figure 11.21. Resonance diagram of the Tjaereborg turbine with three-bladed rotor on the up-wind side and soft concrete tower

Danish line. The concrete tower has a "soft" design with respect to the critical 3 *P* excitation, i. e. the rotor passes through the tower resonance during the start-up sequence.

More recent three-bladed turbines with steel towers all have flexible towers with a natural bending frequency between 1 *P* and 2 *P* or even below 1 *P*. As the size of wind turbines increases and they are being economically optimised, the reduction in tower mass thus achieved has clearly become a factor which is no longer negligible. In addition, the vibrational characteristics of wind turbines are increasingly being brought under control so that it is becoming possible to push the design closer to the technical limits.

Avoiding resonances becomes considerably more difficult when the rotor is of the variable-speed type. Either the speed range is restricted by the locations of the relevant natural frequencies, or a critical speed section has to be bridged by the speed control system passing through it quickly and not allowing steady-state operation within it. The first of the two options was chosen for the WKA-60 (Fig. 11.22).

In this turbine, however, the first natural bending frequency of the concrete tower coincided precisely with the 2 *P* excitation at rated speed. Even though these multiples of 1 *P* excitation are basically considered to be less critical in a three-bladed rotor, unpleasant resonances did, nevertheless, develop in practical operation. The *dynamic amplification factor*, i. e. the ratio of the maximum vibrational response to the amplitude of the excitation, shows how the 2 *P* excitation affects the tower's transverse vibration (Fig. 11.23). If resonance occurs, the cyclic transverse force is magnified by an amplification factor of 4, a fact which must be taken into consideration with respect to fatigue life. A peculiarity associated with concrete towers must be mentioned in this context. It is no rare occurrence that the actual

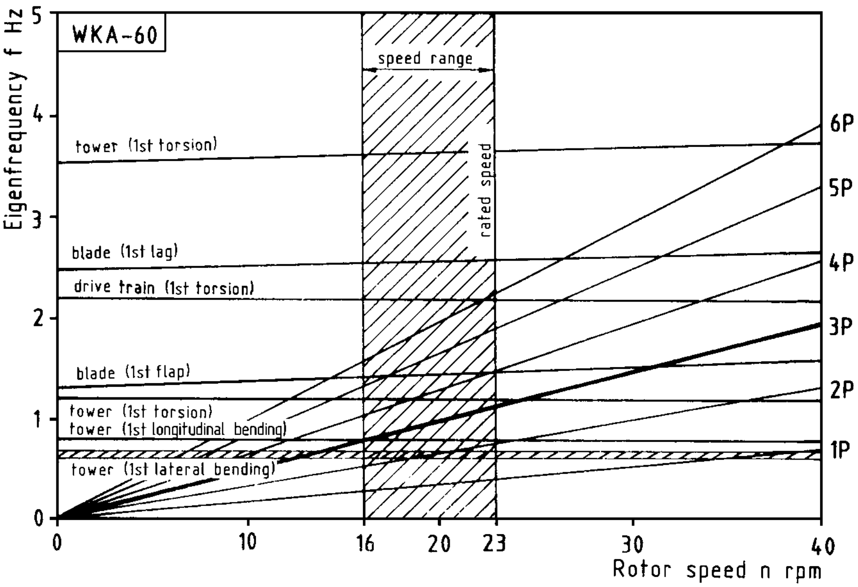

Figure 11.22. Resonance diagram of the WKA-60 with variable speed three-bladed rotor on the up-wind side and soft tower

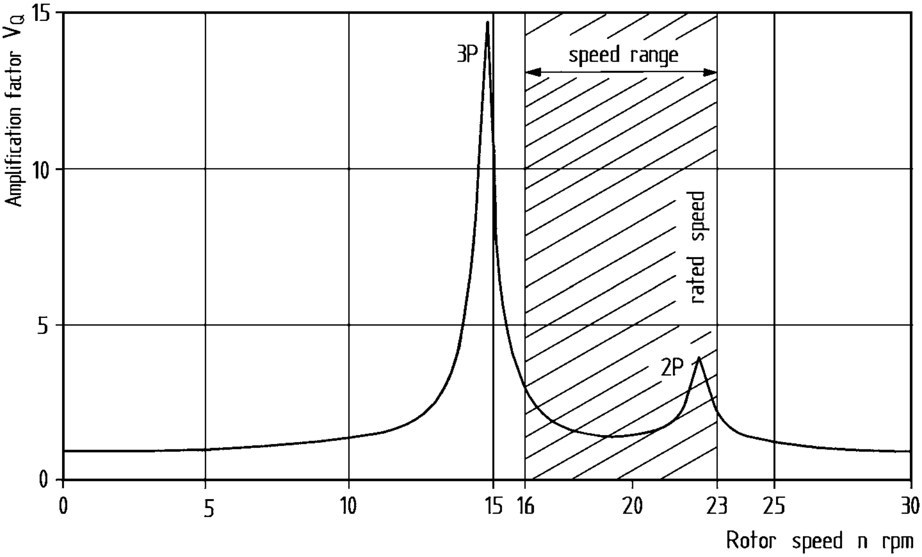

Figure 11.23. Amplification of the static loads exemplified by the transverse force acting on the tower of the WKA-60 in a case of resonance

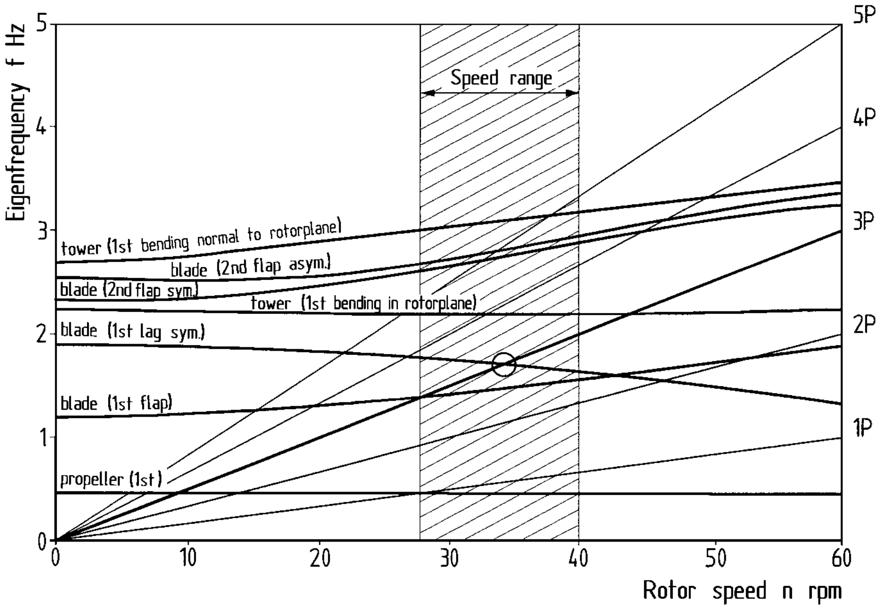

Figure 11.24. Resonance diagram of a Darrieus rotor with two rotor blades [9]

natural frequencies of concrete towers differ considerably from the calculated values. This may be due to a lack of appropriate care and attention during construction.

The same considerations and criteria basically apply to the dynamic behaviour of vertical-axis rotors as do to horizontal-axis rotors (Fig. 11.24). Adapted calculation methods for dynamics analysis are available from published literature [9]. The special characteristics of vertical-axis rotors are based on the fact that the free-stream velocity and the angle of attack of the rotor blades oscillate during the cycle of rotation, resulting in special excitation situations for the vibrational behaviour of the rotor blades. This is influenced mainly by the symmetrical and asymmetrical vibration modes in the rotor plane (in two-bladed rotors).

11.4.3 Mathematical Simulation

Strictly speaking, the vibrational behaviour of a system with several degrees of freedom can only be treated as a total system. This is true, above all, when the dynamic coupling of the excited degrees of freedom is so strong, that complex vibrational coupling modes are produced the natural frequencies of which deviate distinctly from the separate natural frequencies of the components involved. This is basically the situation found in wind turbines. In addition, aerodynamics, gravitational forces, structural and aerodynamic damping and, not least, control characteristics must also be included in the calculation.

Before beginning with a mathematical simulation of such an overall system, it is helpful to find out as much as possible about the basic vibrational character of the turbine or of its design so that the critical vibration modes can be recognised. In most cases, isolated mathematical treatment of the components or of specific subsystems of the turbine is feasible. For this purpose, the first and some higher natural frequencies and the vibration modes of the most important components are isolated and then calculated for a stand-still condition.

The natural frequencies of the subsystem "tower with tower head" can always be calculated with sufficient accuracy when it is assumed that the rotor is at stand-still. The influence of the rotating rotor is small. This only applies to a limited extent to the rotor blades. For one, the natural frequencies of the rotor blades vary greatly depending on the mode of vibration. Moreover, when rotating, the rotor blades behave differently compared to the standstill condition. The centrifugal forces exert a "stiffening" influence. Precise determination of the natural rotor blade frequencies therefore requires a mathematical simulation of the rotating rotor, taking into consideration the degrees of freedom and the stiffness of the hub construction. The resonance diagram determined on this basis already provides reliable information about the resonant behaviour of any reasonable design.

If the vibrational behaviour is assessed as being particularly complex, or even critical, and if shifting of the natural component frequencies is no longer feasible by constructional measures, a mathematical simulation of the coupled total system is unavoidable. Considering the fact that this mathematical simulation of the vibrational behaviour plays an important role in the development at least of large experimental turbines, the basic principles of mathematical simulation techniques will be explained here briefly.

As has been described above, the first step is to determine the natural frequencies of the main components. Based on this, the subsystems "tower with nacelle and rotor mass" are coupled mathematically to the subsystem "rotating rotor", taking into account the kinematic and kinetic constraints. As is common practice in the case of multiple mass systems, further treatment is carried out according to a theory by Lagrange. The kinetic and potential energy, as well as the energy of the external forces (aerodynamic forces), are determined for the subsystems and then coupled according to a modal condition of compatibility, i. e. one relating to the vibration mode. Differentiation of the energy equations yields differential equations (equations of motion) for the variation of the vibrations with time.

For gravitationally-symmetrical rotors, i. e. rotors with three and more blades, these equations are comparatively easy to solve. The mathematical treatment of rotors with two or even only one rotor blade which are not gravitationally symmetrical is much more difficult. Due to the fact that the inertial moment alternates with rotation in relation to the fixed system of axes, the equations of motion contain time-dependent periodic coefficients. This makes the matrix operations applied for solving the equations very complex. The solution is achieved with the aid of the so-called Floquét theory.

As a consequence of the periodic coefficients, the result contains non-sinusoidal natural vibrations of the overall system with components of higher harmonics. To every degree of freedom, several natural frequencies can be assigned. In practice, one natural frequency or vibration mode is almost always distinctly dominant and, moreover, usually lies close to the natural frequency of the subsystem treated in isolation. This holds true at least as long as no resonance occurs (Fig. 11.25).

One of the first mathematical simulation techniques for the vibrational behaviour and the dynamic loads of wind turbines with horizontal-axis rotors has been developed by the Paragon Pacific Institute in the US under the name of Mostas (Modular Stability Derivative Program) [10]. This collection of programs had originally been developed for the treatment of aeroelastic effects of aircraft structures and helicopter rotors and was then adapted for the mathematical treatment of the vibrational behaviour of wind rotors and wind turbines. The theoretical results were verified mainly with the experimental MOD-0 wind turbine. After several stages of development of the theory and the computer programs, consistency with the measured results seems to be satisfactory. Computation methods developed in Germany have also been published in recent years [6].

However, some critical remarks with respect to the mathematical simulation of the vibrational behaviour of wind turbines are necessary. Under the pretext of a comprehensive simulation of vibrational behaviour and dynamic loads or instabilities to be derived from these, veritable "computer orgies" are staged, the practical value of which is frequently inversely proportional to the number of degrees of freedom taken into consideration and of the coefficients in the differential equations.

The more complex the simulation technique, the more input data are required. But this is exactly what is lacking. At the design stage, detailed stiffness and damping parameters of the complex mechanical structures are almost never available. Without reliable input data, however, simulation becomes a pointless formality.

If the technical concept of the wind turbine is feasible, the vibrational coupling between rotor and tower will not be as drastic as may be feared, and if it is, the design must be changed. A vibrationally safe overall technical concept with sensible determination of rotor design and tower stiffness and correct placement of the natural frequencies of the critical components is the only decisive prerequisite for managing the vibrational behaviour of a wind turbine. Mathematical simulation has its justification as a checking tool, but it is no substitute for a vibrationally safe design.

The uncertainties remaining in the mathematical simulation of vibration response have led to occasional efforts of trying to experimentally determine vibrational behaviour by means of model tests in the wind tunnel. These attempts almost always meet with insurmountable difficulties as to observing the necessary laws of similarity which is required for guaranteeing that the model results can be transferred to the original. The problem is that both aerodynamic model laws and model laws concerning structural elasticity must be observed, something which is not possible in practice with small model scales in the available wind tunnels. Nevertheless, these types of experimental investigations can be of use if they are carried out with limited goals and if the results are interpreted correctly, as they improve the basic understanding of the mechanisms at work.

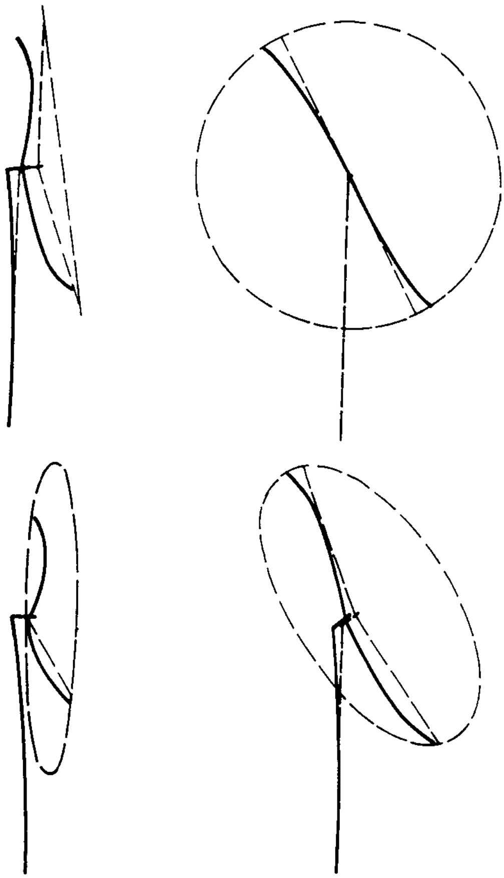

Figure 11.25. Vibration modes of the coupled "rotor-tower" system as a result of a mathematical simulation [6]

During the development of the Growian turbine, the Institute of Aeroelastics of the DLR in Göttingen, Germany, carried out qualitative investigations on an aeroelastic model with a scale of 1:66 [6]. A similar test program was carried out in the US for the MOD-2 turbine, using a model with a rotor diameter of 3.8 m.

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Chapter 12

The Tower

The high tower is an essential component of the horizontal-axis turbine, a fact which can be both an advantage and a disadvantage. The costs, which can amount to up to 20 % of the overall turbine costs, are, of course, disadvantageous. As the height of the tower increases, transportation, assembly and erection of the tower and servicing of the components also become increasingly more difficult and costly. On the other hand, the specific energy yield of the rotor also increases with tower height. Theoretically, the optimum tower height lies at the point where the two growth functions of construction cost and energy yield intersect. Unfortunately, this point of intersection cannot be specified in any generally applicable form. In larger turbines, construction costs rise more rapidly with increasing tower height than in small turbines. An even greater role is played by the choice of site. At inland sites, i. e. in regions with a high degree of surface roughness, the wind speed increases more slowly with height than at shore-based sites. Higher towers will, therefore, show better returns here than, for example, in offshore applications where the reverse effect is found. In inland regions, large wind turbines with tower heights of 80 m and more are a decisive factor for the economic use of the wind potential.

Next to its height, the second most important design parameter of a tower is its stiffness. Establishing the first natural bending frequency in the right way is an important task in the design. This determines the material required and, ultimately, the construction costs. The goal of the tower design is to achieve the desired tower height with the required stiffness at the lowest possible construction cost.

The transportation and the erection procedure is developing into an increasing problem for the latest generation of multi-megawatt wimd turbines. Tower heights of more than 100 m and towerhead weights of several hundred tons require a diameter at the tower base of more than five meters, with the consequence that road transportation will no longer be feasible. This becomes a strong incentive to find innovative solutions in the tower design.

The materials available for the construction are steel or concrete. Designs range from lattice constructions to guyed or free-standing steel tubular towers up to massive concrete structures. The technical requirements posed by the overall system can be met by almost any variant but the economic optimum is only achieved by appropriately matching the selected tower design to the requirements set. This shows clearly that, although the tower of a wind turbine can be seen as a conventional structure when considered by itself, its design also requires a considerable amount of understanding of the overall system and its application.

Apart from these functional aspects, it should not be overlooked that the tower, even more so than the nacelle, determines the outward appearance of a wind turbine. Due attention should, therefore, be accorded aesthetics, even if this implies some additional costs.

12.1 Tower Configurations

The oldest types of "wind turbines", the windmills, had no towers but millhouses. These were low in height in relation to the rotor diameter and of voluminous construction in accordance with their function as a work space, thus also providing for the necessary stiffness. Soon, however, the advantage of increased height was recognised and the millhouses became more slender and more tower-like. But it is only in modern-day constructions, first in the small American wind turbines and then later in the first power-generating wind power stations, that "masts" or "towers" were used, the sole function of which lay in supporting the rotor and the mechanical components of the tower head. As a consequence of this development, designs and materials for towers increased in variety. Steel and concrete took the place of the wood construction of the millhouses. In the early years of the development of modern wind energy technology, the most varied tower designs were tried out and tested but in the course of time, the range has been narrowed down to free-standing designs, mainly of steel and more rarely of concrete.

Lattice Type

The simplest method of building high and stiff tower constructions is as a three-dimensional truss, so-called *lattice* or *truss towers*. Lattice towers were, therefore, the preferred design of the first experimental turbines and in the early years also for smaller commercial turbines (Fig. 12.1). Today, the lattice tower has again become an alternative to the steel tubular tower in the case of the very high towers required for large turbines sited in inland regions.

Concrete Type

In the thirties, steel-reinforced concrete towers were used for the so-called "Aeromotors" in Denmark (Chapt. 2.1). These towers were also characteristic of the earlier large experimental Danish turbines (Fig. 12.2). Later, steel towers became dominant also in the commercial turbines in Denmark. Concrete towers have recently gained favour again for tower heights of more than 80 m.

Free-standing steel tubular towers

The most common tower type currently in use is the free-standing steel tube tower (Fig. 12.3 and 12.5). Mastery of the vibrational behaviour has made it easier to use this type so that steel tubular towers with very low design stiffness can be implemented. It has thus become

Figure 12.1. MOD-1 with lattice tower (1982)

Figure 12.2. Concrete tower of the Tjaereborg test turbine (1986)

possible to lower the structural mass, and thus the costs of the towers, considerably by using "soft" designs (Chapt. 12.5).

Guyed steel tubular towers

Down-wind rotors made it necessary to use slender steel tubular towers in order to keep the tower shadow effect as small as possible. These were anchored with steel cables or in some cases with stiff trusses to ensure the required bending stiffness (Fig. 12.4). Despite their comparatively low overall mass, guyed towers are not very cost-efficient. The guys and the additional anchoring foundations required inflate the total cost. Moreover, the guys are considered a hindrance in agricultural areas.

Special designs

Apart from the prevailing designs, some special tower designs can be found in wind turbines. The Dutch experimental HAT-25 turbine, for example, had a tower of mixed concrete/steel construction (Fig. 12.6). Some Danish wind turbines have towers with a tripod design. In some rare cases, slender lattice or concrete towers are also fitted with guys. Altogether, however, constructions such as these do no longer play an important role. The majority of today's turbines have free-standing lattice, concrete or steel tubular towers.

Figure 12.3. Free-standing steel tubular tower of the MOD-2 (1982)

Figure 12.4. Guyed steel tubular tower of a Carter turbine (1985)

Figure 12.5. Staged steel tubular tower of a Bonus turbine (1985)

Figure 12.6. Steel tower of the Dutch experimental HAT-25 turbine, on a concrete base (1985)

12.2 Free-Standing Steel Tubular Towers

Today, free-standing steel tubular towers are by far the preferred type of construction for commercial wind turbine installations, the main reason being the short on-site assembly and erection time (Fig. 12.7). Small towers with a height of up to 20 m can be fabricated of one piece at the manufacturer's and bolted to the foundation at the site. Higher towers of up to 100 m height are made of several sections which are bolted together so that no on-site welding is required. The preference for steel tubular towers is also buoyed by the very low steel prices in the last twenty years.

12.2.1 Strength and Stiffness Design

The dimensioning of a tower is determined by a number of strength and stiffness requirements. Factors to be considered are the breaking strength required for surviving extreme wind speeds, the fatigue strength required for 20 or 30 years of operation and the stiffness with respect to the vibrational behaviour.

Breaking strength

The static load is determined by the tower-head weight, the tower's own weight, and the aerodynamic rotor thrust. In turbines with blade pitch control, rotor thrust is generally at its highest level when the rotor is running at its rated speed. It can, however, be surpassed by the wind load during rotor standstill at extreme wind speeds. The maximum bending moment distribution at the tower is obtained with rotors without blade pitch control (stall-controlled turbines) or when the worst rotor blade position is demanded for a particular load case. In the standard case, the question of breaking load will be reduced to that of the bending moment acting on the tower base.

Fatigue loading

The dynamic loading caused by the rotor thrust during operation has a definite impact on the fatigue life of slender towers. Additional loads caused by the vibrational behaviour in cases of resonance must also be taken into consideration (Chapt. 11.4.2). Hence a purely static stress analysis, commonly required by the building authorities for conventional buildings, is not appropriate for all tower designs of a wind turbine.

Stiffness

The stiffness requirement is derived from the chosen vibrational concept of the turbine as a whole (Chapt. 11.4.1). It is generally focused on the requirement for a particular first natural bending frequency, even though other natural frequencies, and particularly the natural torsion frequency, must be checked with regard to the dynamics of the yaw system of the turbine.

Figure 12.7. Free-standing tubular towers of GAMESA wind turbines

Buckling strength

One important criterion which plays a role at least for thin-walled steel tubular towers with a low natural bending frequency below the 1 *P* excitation is the resistance to local buckling of the tube wall. As a result of the increasing weight optimisation in modern steel tubular towers, the buckling strength frequently becomes the determining dimensioning factor for the required wall thicknesses.

The example of the MOD-2 clearly illustrates in a real case the consequences of these load cases with respect to the required tower wall thickness (Fig. 12.8). Despite the "soft" tower design, the necessary wall thickness is determined by the stiffness requirement, a result which is typical of almost all comparable modern tower concepts. This becomes even more pronounced when the tower height in relation to the rotor diameter is greater than was the case in the MOD-2. Apart from a few exceptions, the important criterion for dimensioning the tower is, therefore, the stiffness requirement.

Tower stiffness is characterised by several natural frequencies, but only the first and the second natural bending frequency and the first natural torsion frequency are of any practical significance (s. Chapt. 11.4.1). In most towers, the first natural torsion frequency is much higher than the first natural bending frequency. The torsion frequency of free-standing steel tubular towers is approximately three times higher if their diameter/wall thickness ratio lies within normal limits. It is, therefore, sufficient to use the first natural bending frequency for obtaining a rough overview. With a given tower height and head weight, the tower must be designed in such a way that the required first natural bending frequency is reached.

A stiff tower design is always a simpler and safer solution with regard to vibrational behaviour, but the mass of the tower required to achieve this becomes very high. In wind

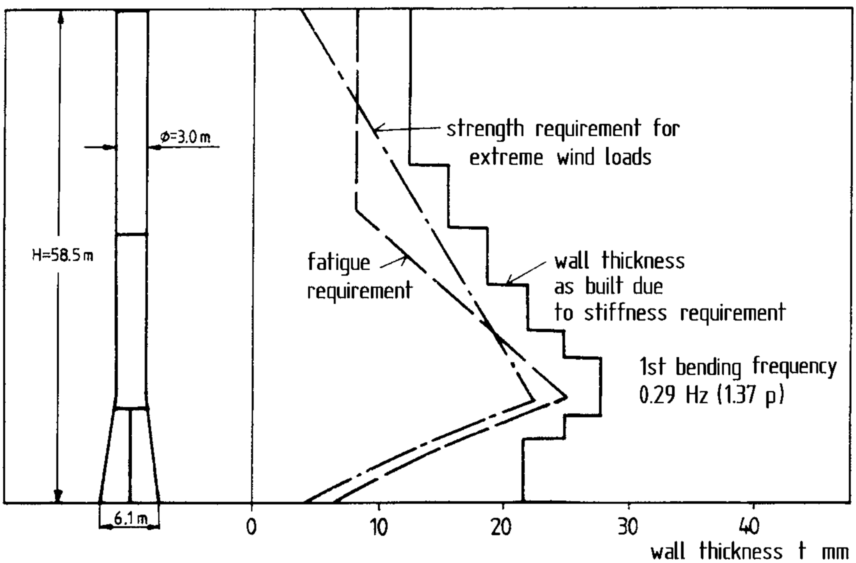


Figure 12.8. Dimensioning criteria of the tower wall thickness in the MOD-2 [1]

turbines with tower heights of more than 80 m, a stiff tower design can, therefore, no longer be realised in practice. For economic reasons, the stiffness should be kept as low as technically feasible.

For simple tower geometries, for example a cylindrical steel tube, dimensioning models were developed which permit the required wall thickness to be calculated by using relatively simple formulae, on the basis of the said load cases with a given height, tower head mass and the chosen stiffness concept of the wind turbine [2]. These models are mainly suited to demonstrating the influence of the dimensioning parameters, thus helping to understand their significance with regard to tower optimisation. In reality, the calculated masses are often lower. Manufacturers increasingly tend to favour more complicated designs such as wall thickness varying in stages with diameter, or weight-optimised tapered shapes to minimise the tower mass and thus the costs.

Figures 12.9 and 12.10 show the specific mass of free-standing steel tubular towers, referred to the rotor-swept area, of various turbine sizes and concepts. The shaded areas in the diagrams are based on various simplifying assumptions. A tower height equal to the rotor diameter has been assumed. For two- and three-bladed turbines, different tower head masses have been assumed as a function of the rotor diameter according to the approaches in Chapt. 19.4. The stiffness requirement, i. e. the tower's first natural bending frequency in relation to the rated rotor speed, has been taken to be 1.5 P and 0.75 P (Chapt. 11.4.1).

The shaded areas of the diagrams show the specific tower mass to be expected with the above assumptions. As anticipated, the lightest towers are to be found with a first natural

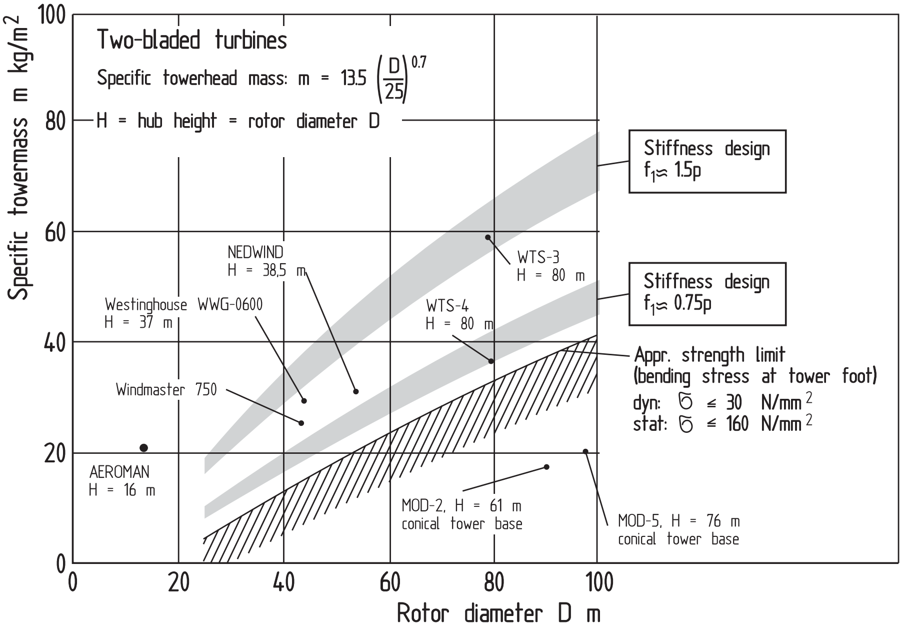


Figure 12.9. Specific overall mass referred to the rotor swept area of free-standing cylindrical steel tubular towers for wind turbines with two-bladed rotor

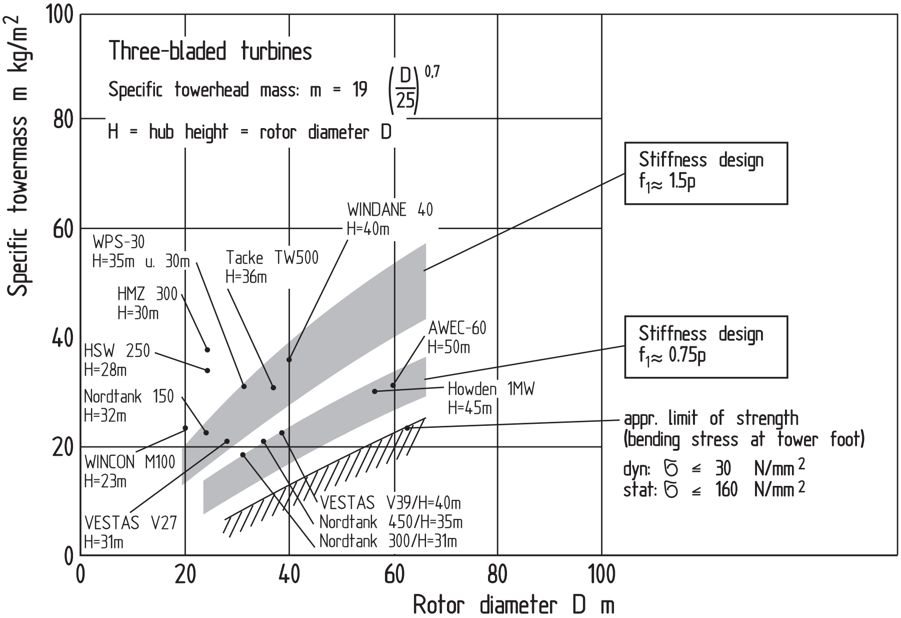


Figure 12.10. Specific overall mass of free-standing cylindrical steel tubular towers for wind turbines with three-bladed rotor

bending frequency below 1 P. Almost all of the more recent turbines tend towards a very soft tower design of approximately 0.7 P. The savings in weight and cost achieved by this concept are obviously considered to be significant by the manufacturers.

In some cases it is noticeable that the overall mass of some existing towers differs considerably from the calculated values. The reasons for this are differently chosen relations of rotor diameter to tower height, but also a more weight-optimised geometry. For example, a conical tower base will increase stiffness or, respectively, decrease the tower mass for a given stiffness. The same effect is achieved with a tapered change in wall thickness. The masses of finished towers will, therefore, be sometimes less than the calculated masses in the diagrams of Figures 12.9 and 12.10.

On the other hand, the tower height is much greater in relation to the rotor diameter, particularly at inland sites. The more recent wind turbines are offered with different tower heights of up to 1.5 times the rotor diameter. In these cases, the specific tower mass becomes very much higher than calculated in the model above.

12.2.2
Manufacturing Techniques and Construction

Almost without exception, the towers of the large turbines of today have a conical shape, with a diameter that diminishes from the base up to the tower head. Compared with a cylindrical geometry, this saves weight for a given required stiffness.

The towers consist of a number of prefabricated sections with a length of up to about 30 m. The sections are produced from sheets of steel plate with a thickness of 10–50 mm. The sheets, which have a width of about 2 m, are rolled into a circular shape on a rolling stand (Fig. 12.11). From these segments, the tower section is welded together. In most cases, automatic welders are used for this. The welding requires special attention in view of the loading situation of the tower. The quality is checked by means of the usual methods such as ultrasonics, X-rays and examination for surface cracks. The tower sheets consist of commercially available St52 grade structural steel plate and, more rarely, St48. Higher-strength material is used for most of the forged joining flanges and the foundation section.

At the ends of each tower section, the internal flanges are welded on (Fig. 12.12). They consist of high-strength steel and occasionally of forged steel. Shaping and welding of the flanges requires some experience since the components can easily become distorted, the consequence being that the flanges will not match during the assembly. The resultant gaps between the tower sections are a quality defect frequently found in steel tubular towers.

As a rule, the tower is joined to the foundation by means of a so-called *foundation section*. This is manufactured separately and incorporated in the foundation when the concrete is poured (Fig. 12.13).

The tower is joined to the nacelle via the *azimuth flange*. It accommodates the azimuth bearing if a roller bearing is used. The azimuth flange is often a cast part.

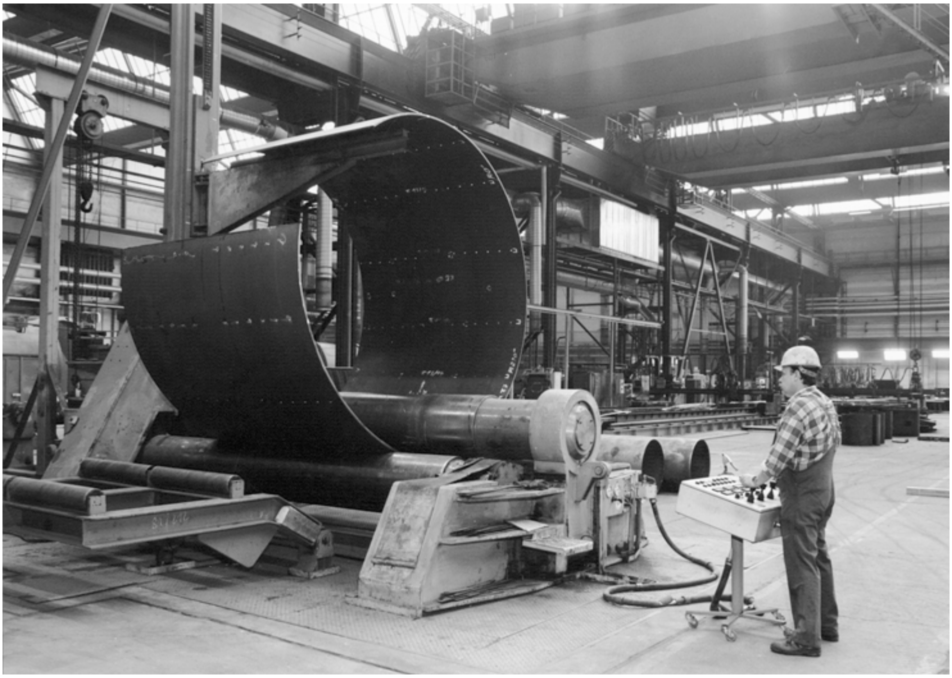


Figure 12.11. Manufacture of tower sections (CAS)

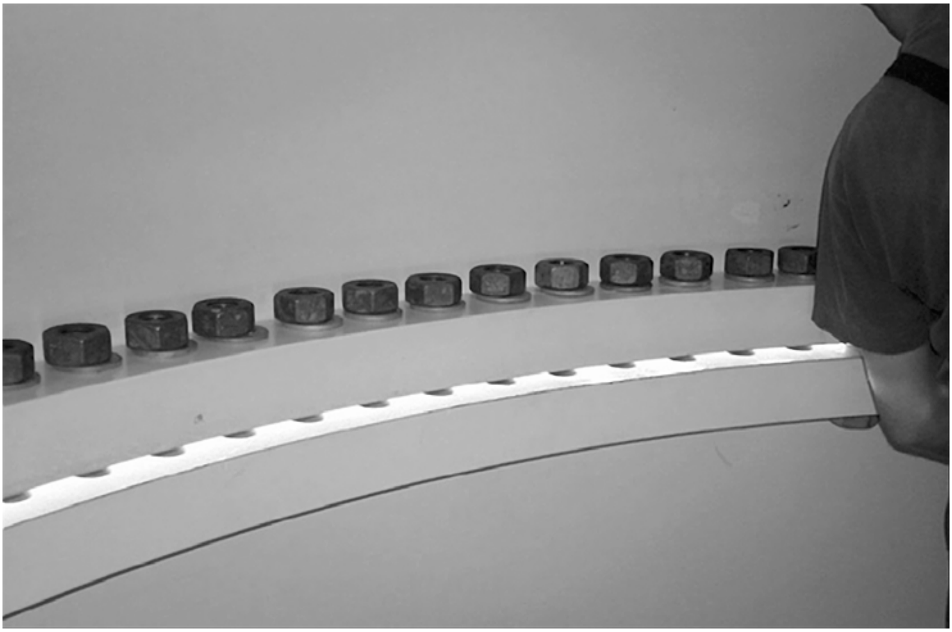


Figure 12.12. Internal flange connection of the bolted tower sections

Figure 12.13. Embedding the foundation section of a steel tubular tower into the foundation

Surface treatment is an important feature regarding the quality of steel towers. Corrosion must be prevented over decades even in an aggressive environment ("sea air"). After some blasting, the tower sections are covered with thermally applied zinc coating. The outer coating consists of at least two and at most three different paint coats. Some countries or regions have regulations regarding the color of the tower.

Manufacturing steel tubular towers with a diameter of up to about 4 m is a conventional technology that does not make any great demands on the equipment of the manufacturers. At heights of more than 90 m, the tower base diameter becomes greater than 4.5 m and the required thickness of the steel exceeds 40 mm. Shaping the steel sheets, i. e. roll-bending them, will then require special machines which are not always available in normal structural steel works. To this is added that, due to the large diameter, the lower tower sections can no longer be transported by road.

12.2.3
Climbing Aids and Internal Installation

The tower must provide for a safe ascent to the nacelle and also contain certain electrical installations, particularly the lead-down of the power transmission cables to the tower base. This requires certain internal installations. Depending on the height, a number of intermediate platforms are normally installed, typically one platform for each tower section (Fig. 12.14). Up to a height of about 60–70 m simple vertical ladders with climbing protection (safety rope or safety rail) are used for the ascent. If required by the operator, simple so-called "climbing lifts" are installed for tower heights above 80 m.

The cables for transmitting the electrical power are hanging free with a running loop in the upper tower section. The mounting elements for introducing the cables into the tower are part of the tower installations (Fig. 12.15). In addition, internal lighting is mandatory for maintenance work in the tower.

In larger turbines, it has become customary to accommodate transformer, switching panel and control lamps for reading of the operating data in the tower. The transformer, in particular, requires considerable space and the installation of a ventilating and cooling system (Fig. 12.16). At the tower base, a secure entry door is required which is usually at an elevated level with respect to the building in order to prevent water from penetrating in the case of bad weather.

For some applications and depending on the internal equipment, i. e. transformers and control systems, the internal climate of the tower has to be controlled. Particularly for offshore applications, air conditioning including dehumidifying and filtering the intake air is necessary in order to avoid corrosion problems on the electrical and electronic equipment.

The towers of small wind turbines are of much simpler construction. In some cases, existing tubular elements from other applications can be used for the manufacture. Up to tower heights of about 15 m, the tower is climbed from the outside (Fig. 12.17). In some countries, special work protection rules and insurance requirements must be observed with respect to an external ascent so that there is a trend to provide a safe internal ascent even in relatively small turbines.

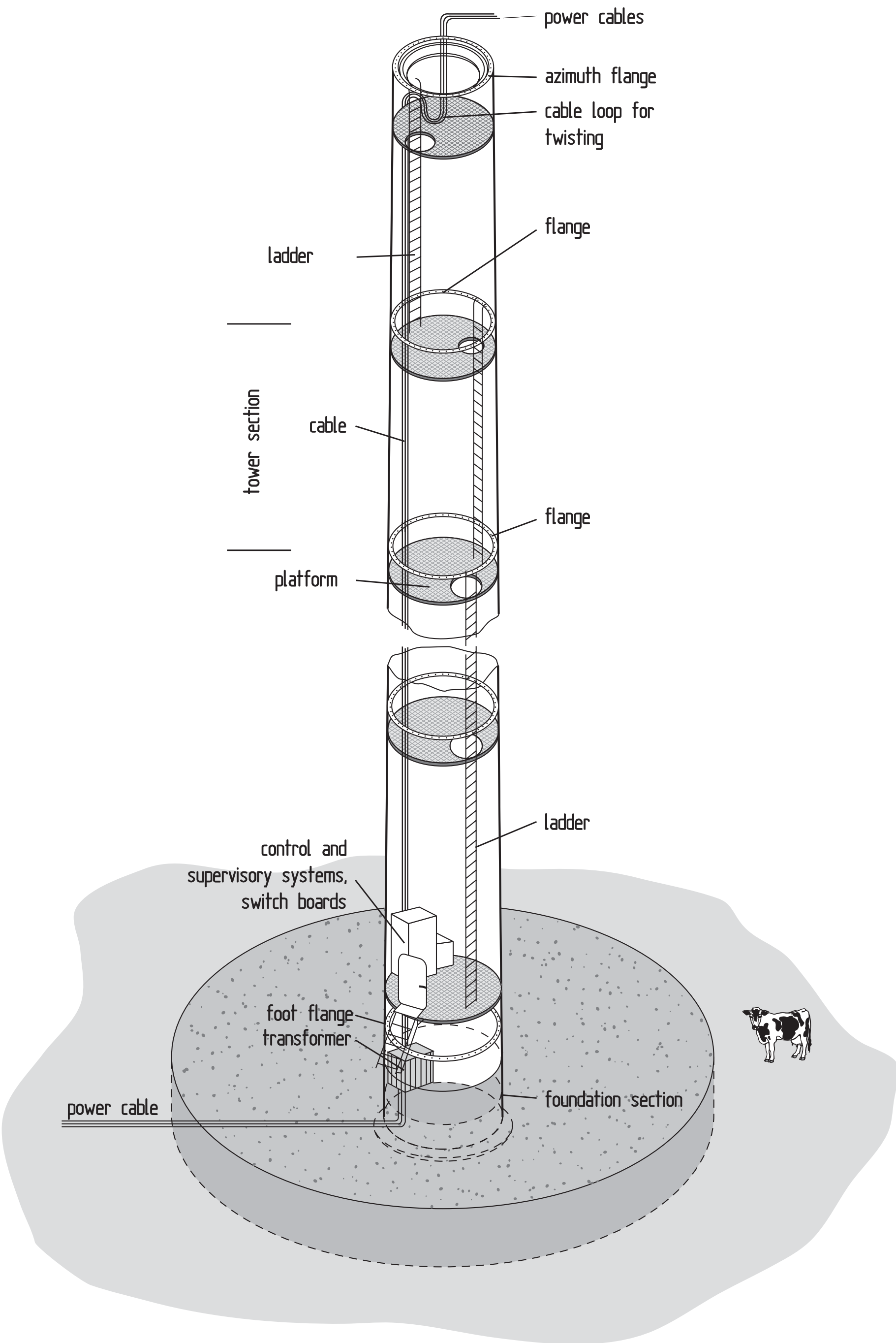


Figure 12.14. Steel tubular tower with installations of a large wind turbine

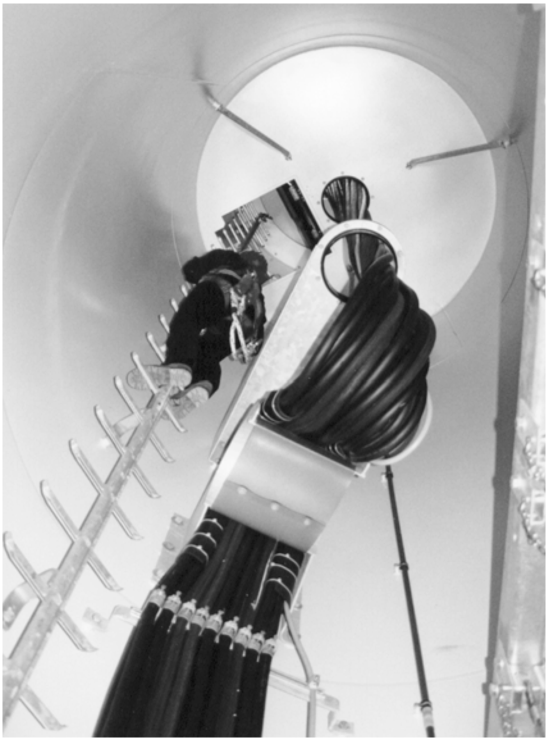


Figure 12.15. Free-hanging power cables in the upper tower area of a Vestas V-66

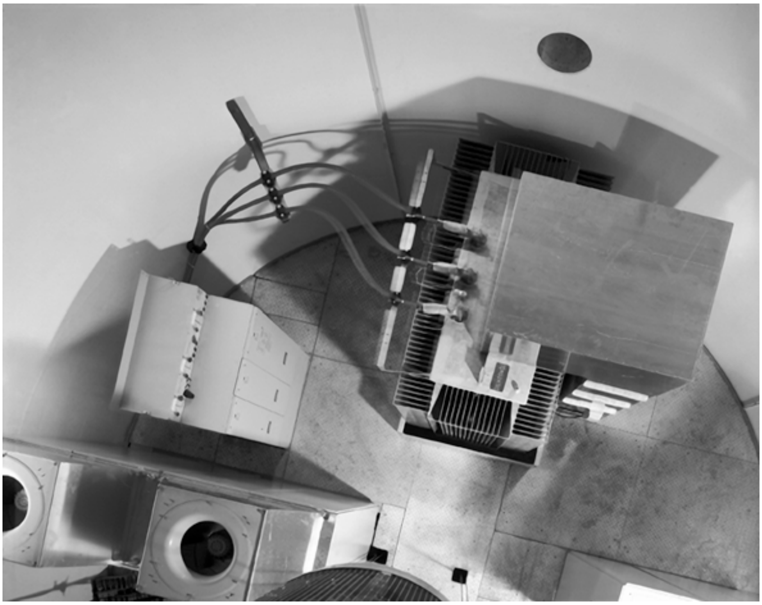


Figure 12.16. Installation of the transformer and of the SF-6 switchgear in the tower base (ENERCON)

Figure 12.17. Steel tubular tower of a small wind turbine (Aeroman) that can be climbed from the outside

12.3 Lattice Towers

In the initial years of commercial wind energy utilisation, lattice towers were widely used in small turbines (Fig. 12.18). As their sizes increased, steel tubular towers increasingly displaced the lattice towers. Recently, the interest in lattice towers has been rekindled, particularly in connection with large turbines with a hub height of 100 m and more.

The main argument used against the lattice towers, which were initially widely used, was the reference to their "ugliness". Considered more objectively, this objection is not as a clear-cut as it appears. Close-up, the lattice structure is not so pleasing to the eye but from a greater distance, the filigree lattice structure becomes much more transparent and begins to merge with the background. Reflection of light, which is much stronger in the case of closed structures (steel tubes), also plays a role (Fig. 12.19). Proponents of lattice towers consider the visual effect from a greater distance to be less obtrusive in the landscape than the tubular towers.

Like high-tension masts, lattice towers can be welded or bolted together from angled sections. Tubular steel struts are sturdier, however, at least for the larger elements subjected to greater loads. Although this type of construction would not be the cheapest for wind turbines, it is the better alternative.

It is an indubitable advantage of lattice towers that with a given height and stiffness, the expenditure of material is less than in the case of tubular towers. The mass of the structure is less by up to 40 % [3]. In spite of the more complex assembly, this results in a considerable cost advantage and, in addition, transportation to the site is much easier in the case of very large towers. Transportation by road has reached its limits with steel

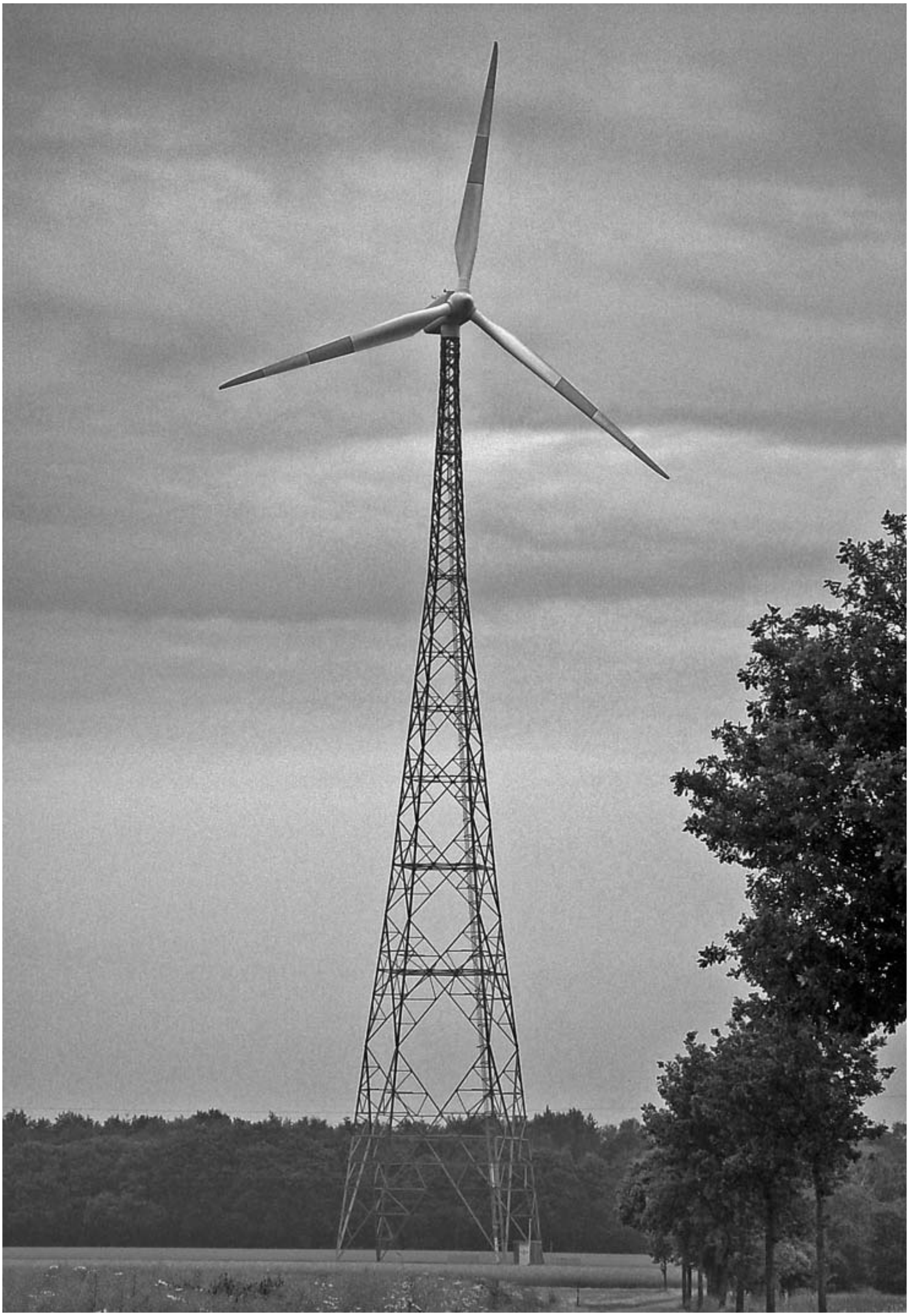


Figure 12.18. Lattice tower of a VESTAS V80 wind turbine (photo Rüth)

Figure 12.19. Wind turbines with lattice towers and with steel tubular tower (photo Sinning)

tubular towers of 100 m length and tubes with diameters of more than 4.5 m. They can no longer be transported by truck on many roads whereas disassembled lattice masts can be moved to any site whatever.

The much longer assembly time on site and the greater expenditure for maintenance are considered as disadvantages of lattice towers. These arguments are certainly valid but the question remains as to what extent this would influence the economic viability of the investment quantitatively. Past experience has not yet provided any reliable values in this regard.

12.4 Concrete Towers

Although the use of concrete for constructing towers of wind turbines has a long tradition, at least in Denmark, the concrete towers, like the lattice towers, have been largely displaced by the steel tubular towers prevailing today. Concrete allows very high towers to be built without this being associated with unsolvable transport problems. The long construction period, too, can be shortened today by means of various methods of using prefabricated parts.

Concrete structures are implemented in various types of construction and static principles. Curing the concrete on site is called *site-mixed concrete.* This is contrasted by the use of prefabricated concrete components that are assembled on site. The static principle is characterised by the fact whether the steel reinforcement is not prestressed or whether the reinforcement is prestressed, sometimes with special tensioning elements with the aid of which the permissible tensile stresses in the concrete can be increased. In the former case, the concrete is "simple" *reinforced* concrete and in the second case it is *prestressed* concrete.

The concrete towers for wind turbines are constructed in accordance with these manufacturing and static methods which in each case have their specific advantages and disadvantages. The decision for which is the best method of construction depends on the site where it is not only the position of the site with regard to accessibility that is of significance but also the availability of an engineering infrastructure. This, too, influences the cost to no minor degree so that cost comparisons between concrete towers should not be made in an abstract manner either with regard to the different types of concrete construction or in comparison with steel tubular or lattice towers. The same also applies to the construction time, which is also a cost factor.

Site-mixed concrete

With the traditional reinforced-concrete type of construction, the concrete is either mixed in liquid form on site or delivered in special vehicles as is done in most cases today. The concrete is poured into a timber form into which the steel reinforcement has first been inserted in the form of a steel wire mat. In this formwork, the concrete hardens so that the required shape emerges when the boarding is removed.

This type of construction, called *site-mixed concrete,* is also used for producing towers of wind turbines. The formwork is pushed upward step by step as climbing or sliding form (Fig. 12.20). Since the lower part must always have set before a new stage can be placed on top, the construction time is very long. In addition, the setting of the concrete is dependent on temperature, which is why it is not possible to work in severe frost conditions in spite of the antifreeze additives used today. In addition, the site-mixed type of construction also requires a corresponding building infrastructure with regard to the production or delivery of the concrete. For this reason, the method is normally not economic for one or only a few turbines. Site-mixed construction can only be an economical alternative for a wind park with a large number of turbines. Nevertheless, the tower of the prototype of the Enercon E-112 with a height of 120 m was built with site-mixed concrete (Fig. 12.21).

Towers with site-mixed concrete can also be constructed as prestressed-concrete towers. The prestressed concrete type of construction originally comes from bridge building and is also used for other concrete components subjected to high dynamic loads. In this process, the steel reinforcement or the special tensioning elements (ropes or steel rods) are introduced into the concrete structure and prestressed, that is to say a compressive stress is generated in the concrete body so that tensile stresses which, for example, are caused by a bending load are largely cancelled. Because of the additional tensioning elements, prestressed concrete structures are comparatively expensive. Their load-bearing capacity is greater than that of normal reinforced concrete and it is also possible to influence stiffness (natural frequency) within certain limits by varying the prestressing.

Figure 12.20. Construction of a tower for an Enercon E-66 with site-mixed concrete (Enercon)

Some large experimental turbines of the 80s were installed on prestressed concrete towers (WTS-75, Aeolus-I and LS-1). For cost reasons, prestressed concrete towers of site-mixed concrete are normally not considered for commercial wind turbines.

Prefabricated concrete towers

To avoid the major disadvantage of the site-mixed type of construction, the long building time, various prefabrication methods have been developed in recent years. This makes it possible to shorten the building time considerably. A further advantage of prefabrication is that this makes it possible to build very high towers without causing insurmountable transportation problems as in the case of steel tubular towers.

Figure 12.21. Prototype Enercon E-112 (rotor diameter 112 m, rated power 4500 kW), with a site-mixed prestressed concrete tower of approx. 124 m (Enercon)

One prefabrication type of construction that is more frequently used for small and medium-sized wind turbines is the use of *centrifugally cast concrete towers* [4]. The tower parts of up to 35 m length and 50 t weight are manufactured on special spinning machines and are also prestressed during this process (Fig. 12.22). The concrete and the reinforcement are introduced into moulds and spun. During this process, the reinforcement can also be prestressed, resulting in a prestressed-concrete type of construction. The effect of the centrifugal forces during the spinning produces very dense concrete structures that are well suited to absorbing dynamic loads. The individual tower segments are transported to the site and placed on top of one another. A tower of, for example, 50 m height consists of two or three segments and smaller towers are made of one piece.

Another method of prefabricating concrete towers is based on segments prefabricated in the factory [5]. The segments of approximately 3.8 m length are produced with conventional formwork in the plant (Fig. 12.23). The segments are then placed on top of one another on site and "bonded" with a concrete/resin mixture. The individual segments are provided with empty tubes distributed over their circumference into which tensioning ropes are inserted during the construction. These are used for additionally fixing and tensioning the segments. This type of prefabricated prestressed-concrete construction is also suitable for very high towers of 100 m and more (Fig. 12.24).

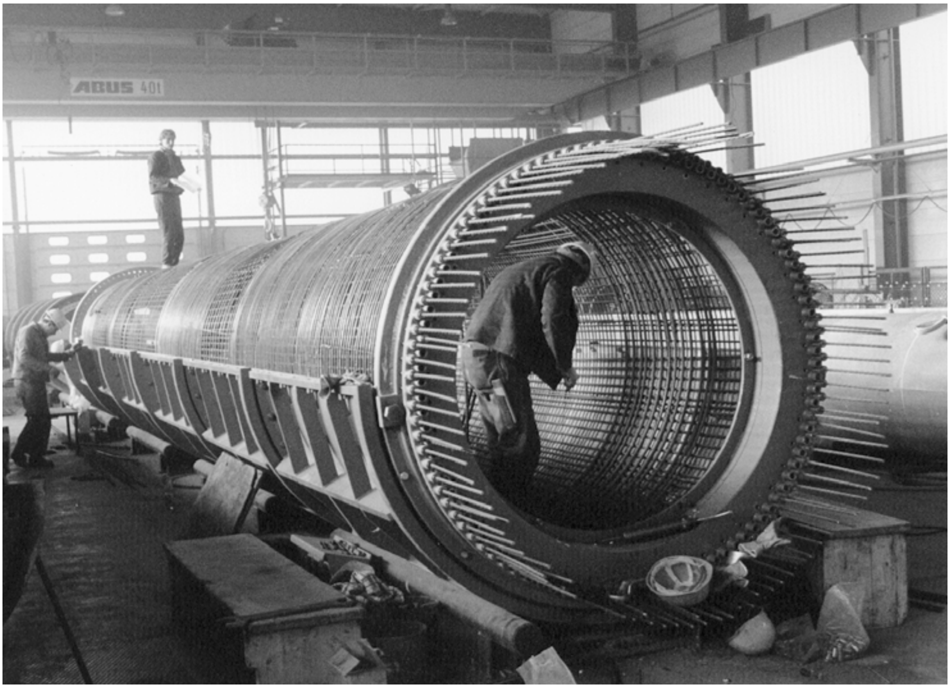


Figure 12.22. Manufacture of centrifugally-cast concrete towers (Pfleiderer)

Figure 12.23. Production of tower segments for a prefabricated prestressed-concrete tower (WEC-Turmbau)

Figure 12.24. Erection of a prefabricated prestressed-concrete tower for an E-66 (WEC-Turmbau)

12.5
Comparison of Different Tower Concepts

The various types of tower design invite a comparison. Even if the most important criterion, the costs of construction, cannot always be assessed in a generally applicable form, the most significant differences will still become apparent in a comparison. The comparison was carried out for the experimental WKA-60 turbine (Table 12.25). The characteristics of this turbine with respect to the tower head mass no longer correspond to current conditions but do not materially affect the differences between tower concepts.

Earlier steel tubular towers are dimensioned as soft towers with a first natural bending frequency of about 1.5 P just like the prefabricated prestressed concrete tower. Site-mixed unstressed concrete towers are designed with a higher stiffness of approx. 2.5 P. Considering more recent tower designs with a bending eigenfrequency of 0.75 P, the tower masses can be reduced, but the relation remains more or less unchanged by comparison.

When the calculated masses are compared, it is found that, although a free-standing cylindrical tube with a constant wall thickness may be simple to manufacture, but it is in no way optimal. With the given height and stiffness requirements, the overall mass can be reduced decisively with other configurations. Broadening the base of a free-standing steel tower conically is obviously helpful in achieving the required stiffness with a reduced overall mass. Free-standing steel tubular towers with this geometry can, therefore, be found in most wind turbines.

Diameter and mass can be reduced significantly when the tower is anchored by guys. The disadvantages of this concept are the cost of the guying cables and the additional foundations. It is, therefore, questionable whether guyed steel tubular towers are in fact an economical solution (Chapt. 12.1). Moreover, their stiffness is not very high with respect to their first natural torsion frequency, since the guys do not have a torsion-stiffening effect.

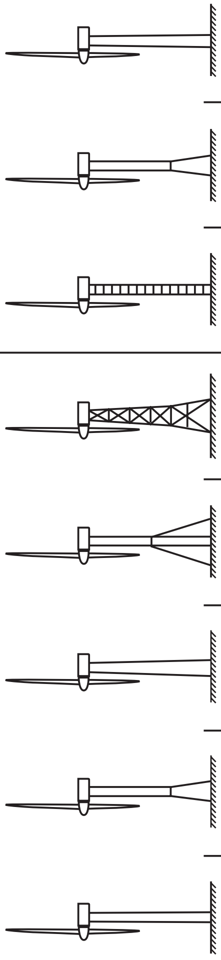
The constructional mass of the tower variants can be calculated with good accuracy whereas the costs of construction can only be estimated roughly. Steel tubular towers can be produced today at a specific cost of less than \$ 1.5/kg. In the case of concrete towers, a considerable cost range of about \$ 250–400/tonne is obtained for the above reasons. The cost relations specified in Table 12.25 show the differences between the calculated variants.

Although the overall mass of concrete towers is four to five times higher than that of steel towers, the differences in construction cost are obviously not serious. In practice, the lower specific material cost of the concrete compensates for the greater overall mass. On the whole, concrete designs are more cost-effective in this comparison. This especially applies when prefabricated concrete tower segments are used. However, concrete constructions are frequently not feasible. When there is no suitable local manufacturer, high costs of transport incurred for the heavy concrete components will cancel out the cost advantage.

The production costs of the calculated lattice tower variant are also comparatively favourable. The costs of the lattice design are up to 20 % less than the costs of a steel tubular tower. However, the higher assembly and maintenance costs must not be overlooked in this comparison.

It should be noted that the results of the cost comparison may change with increasing steel raw-material costs as has been observed since about 2003.

Table 12.25. Comparison of steel and concrete tower designs for the WKA-60 experimental wind turbine



Wind Turbine Rotor: 3 blade Diameter: 60 m Rotor speed: 23 rpm Towerhead mass: 180 t Hub height: 50 m Tower height: 46.6 m		Steel					Concrete		
		cylindrical	cylindrical with conical base	conical	cylindrical with guys	lattice	prefabricated prestressed	reinforced	prestressed
1st bending eigenfrequency	Hz	0.567	0.577	0.570	0.551	0.60	0.65	0.941	0.947
Multiple of rated rotor speed	P	1.48	1.51	1.49	1.44	1.57	1.70	2.45	2.47
Upper diameter	m	3.5	3.5	3.5	2.5	3.5	3.5	3.5	3.5
Lower diameter	m	3.5	7.1	4.4	2.5	11.6	3.5	8.4	5.5
Wall thickness	mm	55 ÷15 staged	25/15 staged	30/15 staged	20/15 staged	16/10	520/250 staged	300	300
Mass									
- Tower structure	t	150	120	111	40	110	465	485	477
- Equipment	t	22	22.5	22.8	20	22.5	21	22.5	22.5
Total mass	t	172	142.5	133.8	60+guys	ca. 120	486	507.5	499.5
Appr. cost relation	%	100	90	85	95	70	60	75	75

12.6 The Foundation

The foundation of the tower is determined by the size of the wind turbine and by local ground conditions. In this respect, it is primarily, the highest loads acting on the wind turbine under stand-still conditions which must be considered. The determining factor is here the highest assumed wind speed, the so-called survival wind speed (Chapt. 6.3). However, the technical concept of the wind turbine also plays a certain role. Turbines with stall control do not provide the option of feathering the rotor blades so that comparatively high stand-still loads can occur with this design, a fact which is of significance in the dimensioning of the foundation and thus in the costing.

A second load case, which must at least be checked, is that involving the highest loads during operation. In operation, the maximum tilting moment for the foundation is determined by rotor thrust. In turbines with blade pitch control, rotor thrust reaches its peak at the rated power, whereas in stall-controlled turbines it continues to increase even after the rated power has been reached (Chapt. 5.3.1).

The *design approval and safety certification* required by the authorities is in most cases based on these static loads (Fig. 12.26). Fatigue life calculations taking into consideration the dynamic load spectrum are normally not requested. Those calculations are carried out under responsibility of the manufacturer.

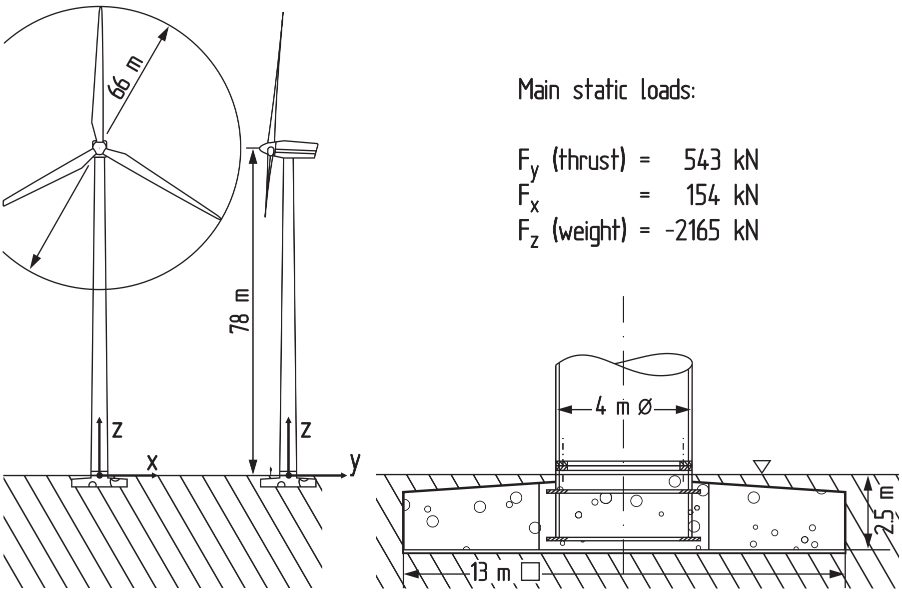


Figure 12.26. Dimension-determining loads and dimensions of the foundations of a large wind turbine

Depending on the geological conditions, either *slab foundations* or *pile foundations* are required. The decisive factor is the depth at which soil layers are found which will absorb the loads imposed.

Slab foundations

The slab foundations, often called the *standard foundation,* are circular or rectangular or polygonal footings. The steel tubular towers are anchored by a foundation section joined to the steel reinforcement of the concrete (Fig. 12.27). The required mass and the dimensions of the slab are determined by the overturning moment of the structure. This is resisted by the weight of the turbine, the tower and the foundation itself. Centrifugally cast prefabricated concrete towers are "cast" into the foundation (Fig. 12.28).

Pile foundations

Pile foundations for weak soils have a bedplate sitting on piles which transfer the loads into load-bearing ground layers. For this purpose, prefabricated "ram piles" are used (Fig. 12.29). Pile foundations are necessary, for example, in the German coastal marshland areas near

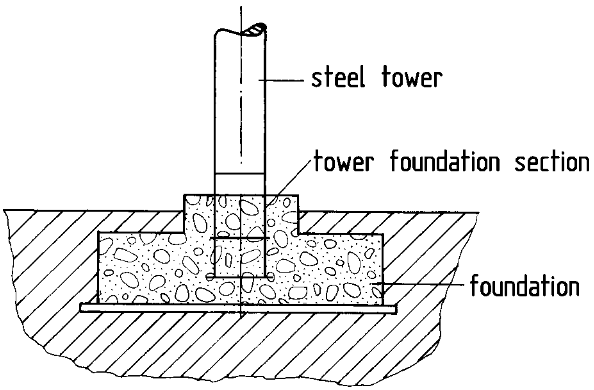


Figure 12.27. Standard foundation (slab foundation) for steel tubular towers

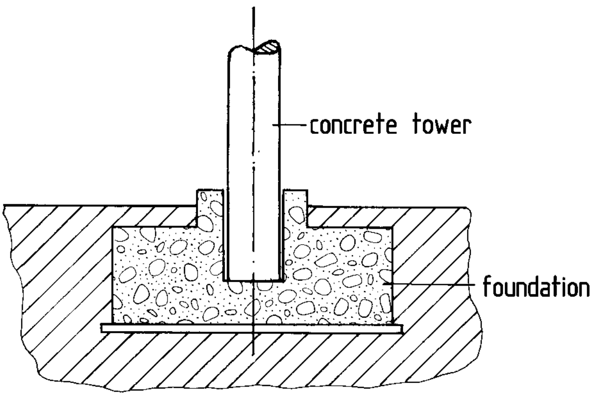


Figure 12.28. Slab foundation with cast-in prefabricated concrete tower

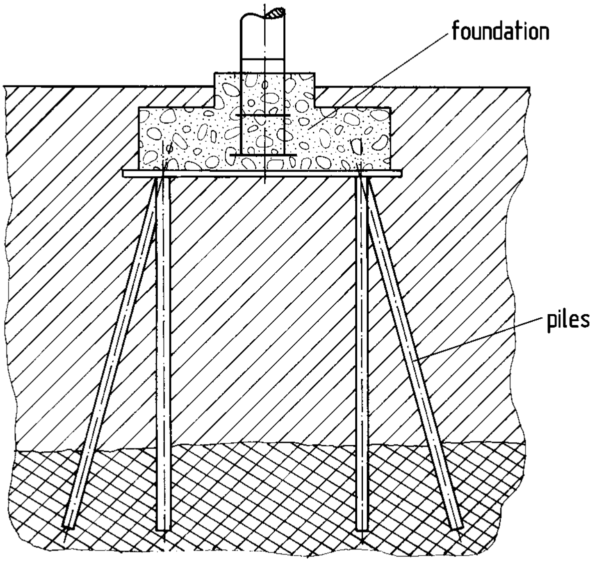


Figure 12.29. Foundation with piles (pile foundation)

Figure 12.30. Construction of the foundation for a large wind turbine

the North Sea. In these areas, the solid sand layers of the continental shelf are in some cases located at a depth of 20 to 25 m. The piles, up to 20 of which are required for a medium-sized turbine, are of corresponding length to ensure the load-carrying capability of the foundation. This increases the costs of the foundation by 30 to 50 %.

As a rule, the foundations of wind turbines are constructed of Category B 25 concrete according to the German classification. As is common practice, a formwork is set up in the foundation pit and the steel reinforcement is plaited before the concrete is poured into the pit (Fig. 12.30).

Integrating the foundation section, to which the bottom flange of the tower is joined, requires some experience. The flange of the foundation section must be placed in a horizontal and level position with only a small tolerance to prevent the tower from slanting. In the foundation of a wind turbine of the 500 kW class with an foundation section flange diameter of approximately 3.6 m, the maximum allowable deviation from the horizontal is in the range of ± 2 mm.

It is obvious that the *soil consistency* or, more precisely, the *"clamped stiffness"* of the tower in the ground, has an influence on the natural bending frequency. This influence is small on solid ground and may be neglected in a first approximation. In very loose soil, however, this does not apply in every case. Using the example of a simple bed plate, Fig. 12.31 shows the order of magnitude of a reduction in the first natural bending frequency of the system to be expected.

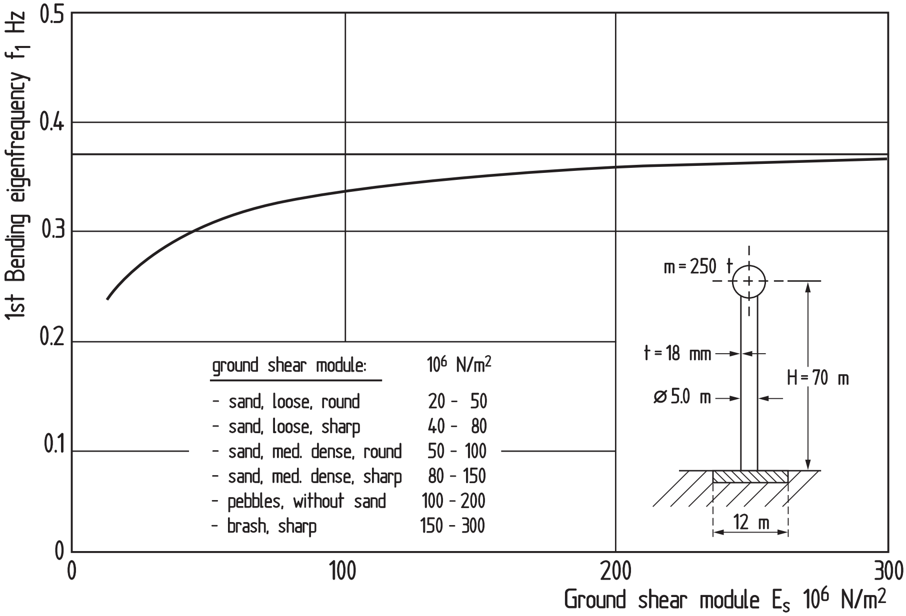


Figure 12.31. Influence of soil consistency on the first natural bending frequency of a tower configuration

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Chapter 13

The Wind Resource

In the past, wind data were measured and evaluated almost exclusively from a meteorological point of view. However, these data are not sufficient when one is considering the commercial exploitation of wind resources by means of wind turbines. The earlier meteorological data do not provide much detailed information about the increase in wind speed with height or the local wind conditions of a particular terrain. It is only in the past two decades that extensive wind measurements have been carried out with consideration of the particular aspects relating to the use of wind turbines. In the meantime, full-coverage wind data are available in the countries in which wind energy utilisation is widespread. A reliable database is provided mainly by the long-term evaluation of the energy supply from existing wind turbines.

Nevertheless, the determination of the wind conditions at the intended site of the wind turbines remains an important task that cannot be solved by means of the available large-scale wind maps alone. Providing reliable wind data must, therefore, be the first step in any planning for the use of wind turbines. Since it is impossible to carry out new, long-term measurements in every case, critical a priori verification of existing data is of particular importance. After that, a wind appraisal is obtained with the aid of the available semi-empirical methods.

Moreover, the value of verbal information provided by the local population and of natural indicators should not be underestimated. Trees clearly growing at an angle, for example, are a reliable indicator of high mean wind speeds. A knowledge of the characteristics of the wind and of some of the laws governing its behaviour with respect to its utilisation is indispensable for a successfully planning of wind energy projects.

13.1
Causes of the Wind and Power in the Wind

The movement of air masses in the atmosphere is perceived as wind and has various causes. The first and most important of these is the heating of the earth by the sun. Wind energy utilisation is, therefore, an indirect form of solar energy utilisation. The radiation from the sun is absorbed by the earth's surface and then returned to the atmosphere above. Since the earth's surface is not homogeneous (land, water, desert, forest, etc.), the absorption of the solar energy varies both with respect to geographic distribution and with respect to the time of the day and the annual distribution. This nonuniform heat absorption produces great differences in the atmosphere with respect to temperature, density and pressure so that the resultant forces will move the air masses from one place to another. Above all, the tropical regions on the earth absorb much more solar energy throughout the year than the polar regions. Since, as a result, the tropical regions become warmer and warmer and the polar regions become increasingly colder, there is a strong convection current flowing between these regions.

Coriolis forces produced by the rotation will deflect the air masses to the right (seen in the direction of flow) in the northern hemisphere and to the left in the southern hemisphere. This process causes the familiar spiral movements of air equalisation known from the cloud pictures of the low pressure regions.

The second effect of earth rotation becomes effective at a medium altitude. Each air particle has an angular momentum that is directed from west to east. If the particle is moving in the direction of the poles, it will approach the axis of rotation of the earth more closely. The law of conservation of momentum causes an increase in the velocity component from west to east as compensation for the increasingly closer approach to the pole. This effect is less in the vicinity of the equator and causes the so-called *west drift* that is opposite to the global wind direction (Fig. 13.1).

Close to the ground, the surface friction produces a decrease in wind velocity, which also reduces the effect of the coriolis forces. For this reason, the wind direction close to the ground is deflected by approx. 30° less than the geostrophic wind in European latitudes. Above the sea where the friction is less because of the relatively smooth surface, the difference in direction with respect to the geostrophic wind is only about 10°. Since the equalisation between the different pressure regions takes place mainly by means of the deflected wind close to the surface, the low-pressure regions, for example, will persist longer over the sea and are also accompanied by higher wind velocities.

Apart from these global movements of air equalisation in the atmosphere, the wind flows are also influenced by small-scale topographic situations. For example, mountain slopes facing the sun are heated more quickly. The heating and cooling of large contiguous forest regions differ from that of water surfaces close by. Specially shaped valley cuttings which follow the main wind direction can cause jet-like effects which locally accelerate the wind velocity. These effects are certainly of significance for the local wind conditions and must be taken into consideration when selecting a site for wind turbines, and can also be utilised to advantage.

At greater altitude, the air moves along lines of equal pressure (*isobars*). This movement of air masses at an altitude of more than about 600 m is called *geostrophic* wind. The airflow can be considered free of surface influences. At lower altitudes the influences of the earth surface can be felt. This part of the atmosphere is known a the *boundary layer.* The principal effects governing the properties of the boundary layer are the strength of the geostrophic wind and, the surface roughness, Coriolis effects and thermal effects.

The influence of the thermal effects are classified in to three categories, stable, unstable and neutral stratification. Unstable stratification occurs when there is a lot of surface heating. The warm air rises and the result is a thick boundary layer with heavy turbulence in the air. If the adiabatic cooling effect causes the rising air to become colder than its

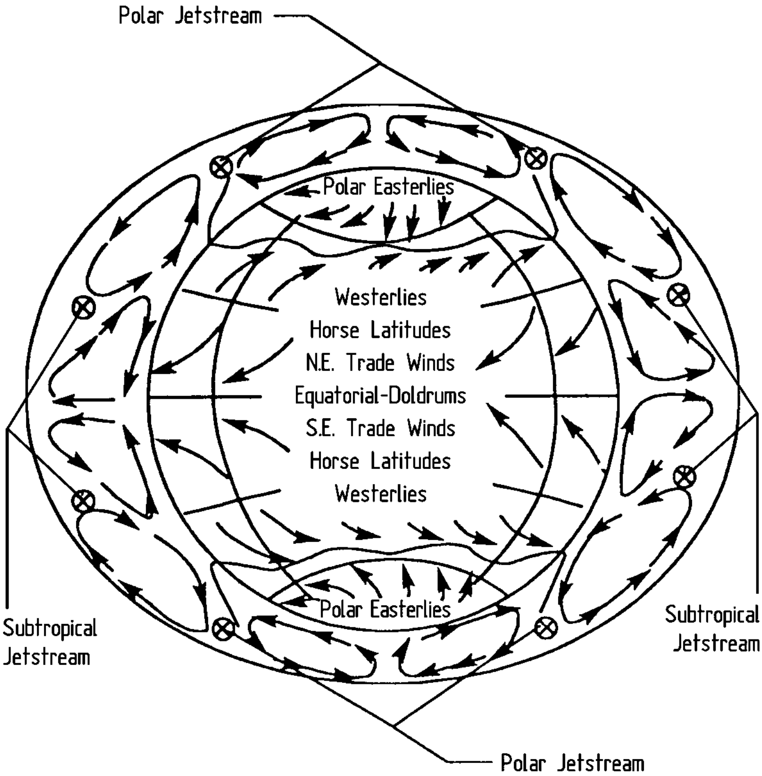


Figure 13.1. Global wind flows [1]

surroundings, its vertical motion will be suppressed. This is called a stable stratification. It occurs at cold nights when the ground surface is cold. In this situation, the movement of the air is dominated by friction with the earth surface and the increase in mean wind speed with height is large. In a neutral atmosphere, adiabatic cooling of the air as it rises is such that it remains in thermal equilibrium with it surroundings. This is often the case with strong winds. For wind energy utilisation, neutral stability is the most important situation to consider at least when calculating the turbulent wind loads on the turbine, but, as mentioned before, unstable atmospheric situations can influence the vertical wind shear exponent (see chapter 13.5.3).

Only about 2 % of the solar energy of 1.5×10^{18} kWh captured annually by the earth's atmosphere is converted into energy of motion of the air envelope. Nevertheless, this results in a calculated power of the wind of about 4×10^{12} kWh. This is one hundred times more than all of the power station output installed on this globe. Of course, such numerical values provide virtually no information about the potential that can be commercially utilised, but nevertheless it is worthwile to be mentioned.

For the purposes of wind energy use and wind turbine design, the wind vector is considered to be composed of a steady wind plus fluctuations about the steady wind. Whereas for designing wind turbines, the steady wind and the wind fluctuations have to be considered, the power and energy obtained from wind can be based only on the steady wind speed.

The power available in the wind varies with the cube of the wind speed. A common unit of measurement is the *wind power density*, or the power per unit of area normal to the wind direction from the wind is blowing:

$$p_\mathrm{W} = \frac{1}{2}\varrho \cdot v_\mathrm{W}^3 \qquad (\mathrm{W/m^2})$$

where:

ϱ = air density at standard atmosphere ($\mathrm{kg/m^3}$)
v_W = wind velocity (m/s)

Due to the fact that the main intention is to extract the energy from the wind and not just producing power, the most important parameter is the mean annual wind power density:

$$\bar{p}_\mathrm{W} = \frac{1}{2}\varrho \cdot \frac{1}{8760}\int\limits_{\text{year}} v_\mathrm{W}^3\, d\,t$$

With respect to the annual wind frequency distribution it can be obtained:

$$\bar{p}_\mathrm{W} = \frac{1}{2}\varrho \cdot v_\mathrm{W}^3\, f(v_\mathrm{W})$$

where $f(v_\mathrm{W})$ is the wind frequency distribution, a Weibull function, as a rule. Instead of integrating the mathematical Weibull function, the mean value of the third power of the wind speeds in appropriate time intervals can also be used. (Not the cube of the mean annual wind speed!)

Wind resource maps often estimate the potential of the wind resources in terms of *wind power classes* referring to the annual wind power density.

13.2 Global Distribution of Wind Resources

The most striking characteristic of the wind resource is its variability. The wind is highly variable, both geographically and temporally. This is amplified due to the cubic relationship of the wind speed to available energy. On a large scale the global variability describes the fact that there are many different climatic regions in the world.

Within one climatic region, there is a great deal of variation on a smaller scale influenced by the physical geography, the size of land and sea, the topography and vegetation on land. Above the open seas, the wind velocities are highest, whereas they rapidly decrease above the land surfaces.

Figure 13.2 provides an overview of the global distribution of the average annual wind velocity. It shows the annual mean wind speed at the usual meteorological measuring height of 10 m, divided into four classes. Only regions with more than 4 m/s at 10 m height can be

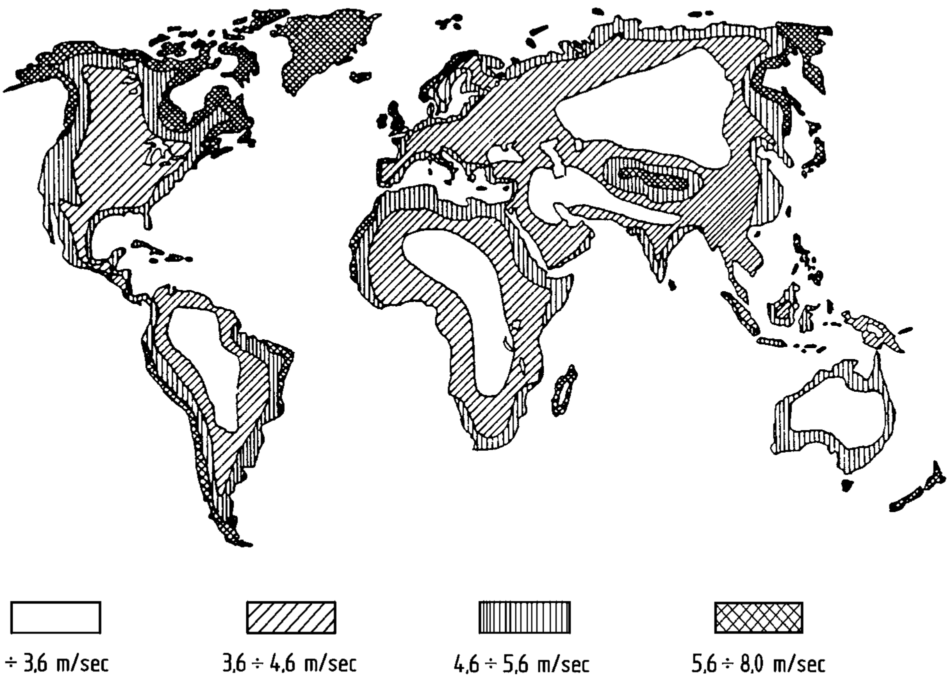


Figure 13.2. Global distribution of the mean annual wind speeds [2]

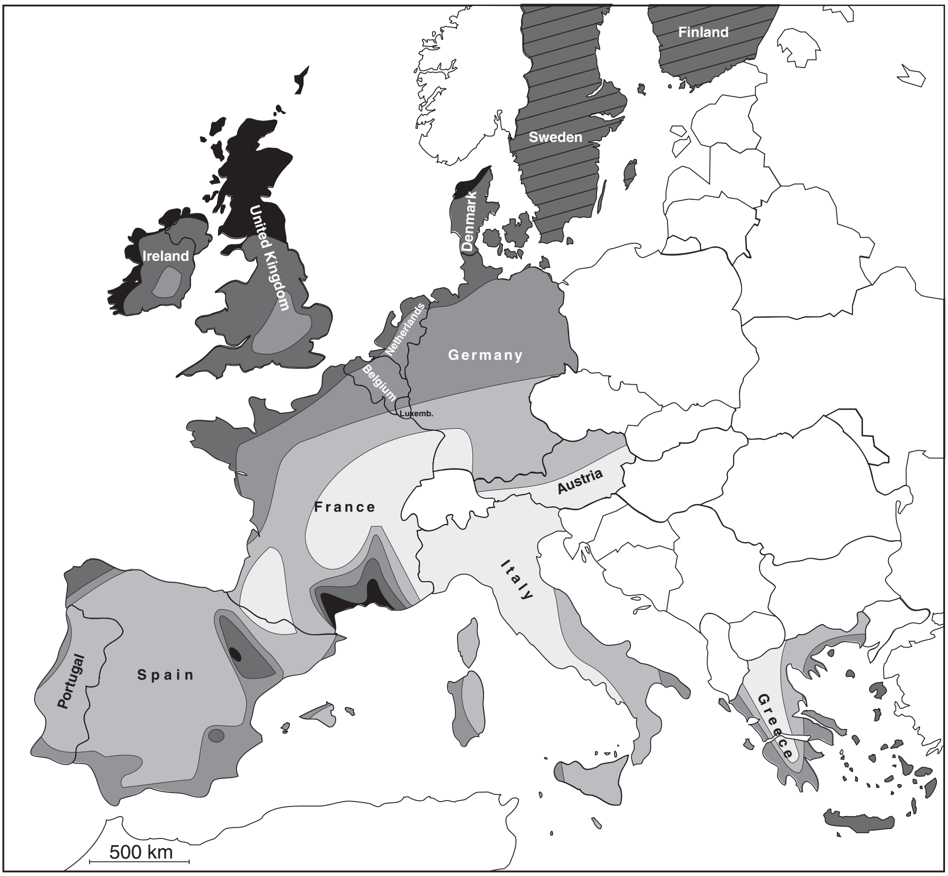
used unreservedly for commercial exploitation. Having regard to the utilisation by wind turbines, the real wind speed is considered as a steady wind speed over a relatively long period of time (mean wind speed) with superimposed fluctuations (wind turbulence). The wind resource maps indicate the spatial distribution of the long-term mean of the wind speed (mean annual wind speed).

13.2.1 Wind Resources in Europe

Like the general climate, the wind conditions in Europe vary from a maritime climate in Northern Europe and the British Isles to the continental climate in Central and Eastern Europe to the Mediterranean climate. With special reference to the wind conditions, there are two different areas:

- the area with distinct maritime low-pressure regions migrating from west to east,
- the area in Southern Europe that is only partly reached by the migrating low pressures and is greatly influenced by the thermal wind streams of the Mediterranean area.

Having regard to utilising the speed of the wind for producing energy, the *European Wind Atlas* has been developed in recent years by the Danish Research Centre of Risø with support by the European Commission [3]. It is based on the evaluation of the data from more than 200 measuring stations and a specially developed mathematical method by means of which the *regional wind climate* is determined in a particular region. From the regional wind data, local "peculiarities" (wind obstacles like buildings, etc., surface roughness and orography) are removed and then the data are specified as wind conditions prevailing in the "region". From these regionally valid wind data, the local wind data at a particular site can be determined (compare Chapt. 13.5.2).



Wind resources iat 50 m elevation (mean wind speed m/s, wind power density W/m)										
	Forest or urban areas		Flat land		Sea shore		Open sea		Mountains	
	m/s	W/m²	m/s	W/m²	m/s	W/m²	m/s	W/m²	m/s	W/m²
(black)	> 6.0	> 250	> 7.5	> 500	> 8.5	> 700	> 9.0	> 800	> 11.5	> 1800
(dark grey)	5.0 - 6.0	150 - 250	6.5 - 7.5	300 - 500	7.0 - 8.5	400 - 700	8.0 - 9.0	600 - 800	10.0 - 11.5	1200 - 1800
(medium grey)	4.5 - 5.5	100 - 150	5.5 - 6.5	200 - 300	6.0 - 7.0	250 - 400	7.0 - 8.0	400 - 600	8.5 - 10.0	700 - 1200
(light grey)	3.5 - 4.5	50 - 100	4.5 - 5.5	100 - 200	5.0 - 6.0	150 - 250	5.5 - 7.0	200 - 400	7.0 - 8.5	400 - 700
(very light)	< 3.5	< 50	< 4.5	< 100	< 5.0	< 150	< 5.5	< 200	< 7.0	< 400

Figure 13.3. European Wind Atlas: Distribution of wind velocities at 50 m altitude [3]

The map from the European Wind Atlas (Fig. 13.3) shows an overview of the regional wind conditions in Europe. The dominance of regions with high wind speeds along the northern European coasts is obvious. However, there are also limited regions with high mean wind velocities in the Mediterranean area, for example in Spain, in Southern France and, above all, on the Greek Isles. In Germany, the wind conditions in the north are dominated by the chain of maritime low-pressure regions. Further inland, topographic situations and particularly the elevation play a decisive role.

The wind resource maps of the European Wind Atlas show the mean annual wind speed at 50 m height, divided into five zones. In addition, the data for five roughness classes from "open sea" to "protected terrain" are specified. Moreover, the wind atlas specifies the mean specific annual energy content in watts per square meter rotor swept area.

13.2.2
Wind Resources in North America

Since the end of the seventies, the wind conditions on the North-American subcontinent have been investigated with regard to wind energy utilisation. The Batelle Institute had a leading position in this investigation. Similar to Europe, the results have been published in the "Wind Energy Resource Atlas of the United States", published for the first time in 1986 [4].

In this document, the area of the United States is divided into 12 regions including Alaska, Hawaii and the US Caribbean islands. The maps include a rating of the average wind speed, certainty ratings and an estimation of the percentage of land area suitable for wind energy development. The complexity of the topography and the availability of reliable measurements determine the certainty rating. The average wind speeds are presented as "wind power density classes", divided into seven classes (Table 13.4). The technical wind energy utilisation is considered to be promising up to class 3. In class 2 only some hot spots are suitable and class 1 areas are generally unsuitable.

In the United States, good to excellent wind conditions exist on the West Coast where the Californian wind farms were installed, and in the States of Oregon and Washington

Table 13.4. Wind Classification based on average wind power density according to [1]

Wind power class	Annual average wind power density (W/m^2)		Equivalent mean wind speed (m/s)	
	10 m elevation	50 m elevation	10 m elevation	50 m elevation
1	0 – 100	0 – 200	0.0 – 4.4	0.0 – 5.6
2	100 – 150	200 – 300	4.4 – 5.1	5.6 – 6.4
3	150 – 200	300 – 400	5.1 – 5.6	6.4 – 7.0
4	200 – 250	400 – 500	5.6 – 6.0	7.0 – 7.5
5	250 – 300	500 – 600	6.0 – 6.4	7.5 – 8.0
6	300 – 400	600 – 800	6.4 – 7.0	8.0 – 8.8
7	400 – 1000	800 – 2000	7.0 – 9.4	8.8 – 11.9

A Rayleigh frequency distribution is assumed.

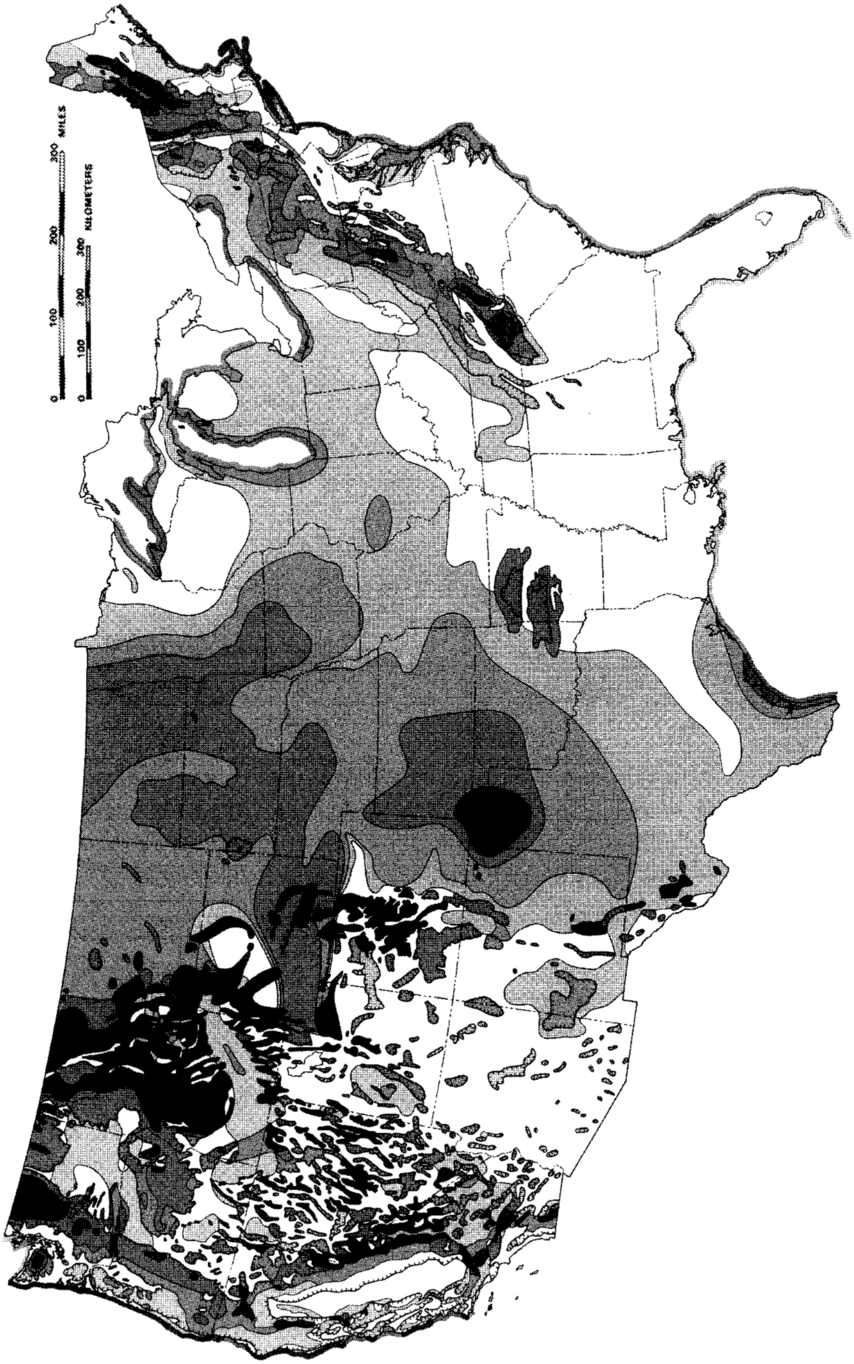


Figure 13.5. Wind Atlas of the United States [4]

adjoining in the North. In addition, good wind conditions are encountered in Mid-Eastern regions in the Great Plains in Kansas and in the surrounding States such as Wyoming, Nebraska, Iowa, Minnesota down to Texas. The South-East of the United States, in contrast, is less suitable for wind energy utilisation (Fig. 13.5).

13.3 Characteristic Parameters

A knowledge of certain parameters and physical laws is of particular importance if the energy of the wind is to be exploited. While the short-term behaviour of the wind, the turbulence, is of significance with regard to the structural strength and the control function of a wind turbine, the long-term characteristics of the wind have relevance with regard to the energy yield. The long-term characteristics of the wind can only be determined by means of statistical surveys over many years. These data are then used for determining the energy yield of a wind turbine (Chapt. 14). At the same time, the discussion of these parameters presents a guide for procuring the required wind data for wind turbine siting.

13.3.1 Mean Annual Wind Speed and Wind Speed Frequency Distribution

The mean annual wind speed, understood to be the "invariable" long-term mean value of the wind speed at one location can only be determined on the basis of measurements taken over decades. Since there are not many reliable measurements available for periods longer than 30 years, the measurements are limited to this period. It is, therefore, quite possible that as the evaluating periods increase, the concepts of the long-term mean have to be revised (s. Chapt. 13.3.3),

Knowing the mean annual wind speed is not enough to provide a precise energy calculation. It also requires information on how frequently the individual wind speeds of the spectrum can be statistically expected. The frequency distribution of the annual wind speeds can be derived from data measured at a given elevation. The mean values for ten minutes are commonly evaluated over one year and are then compiled in defined wind speed classes.

To achieve a sufficiently reliable statistical basis, an evaluation period of at least several years, up to ten years according to meteorologists, is necessary. The frequency distribution is generally specified as *relative frequency distribution,* or as *cumulative frequency* (Fig. 13.6). The relative frequency distribution immediately indicates the occurrence of the most frequent wind speeds. The cumulative frequency indicates as a percentage the period within a year in which the wind speed falls below the value of a certain point on the curve. By using the cumulative frequency, the "mean annual wind speed" can be accurately defined and represented geometrically (Fig. 13.7). Occasionally, the so called *median wind speed* is used in literature. It is defined as the wind speed with a cumulative frequency of 50 % and, as a rule, it is 0.3 to 0.5 m/s lower than the mean wind speed.

In practice, the problem is frequently that insufficient data about the frequency distribution of the wind speeds at a particular location are available. In such a case, there is no alternative but to use a mathematical approximation for the distribution curve. In normal

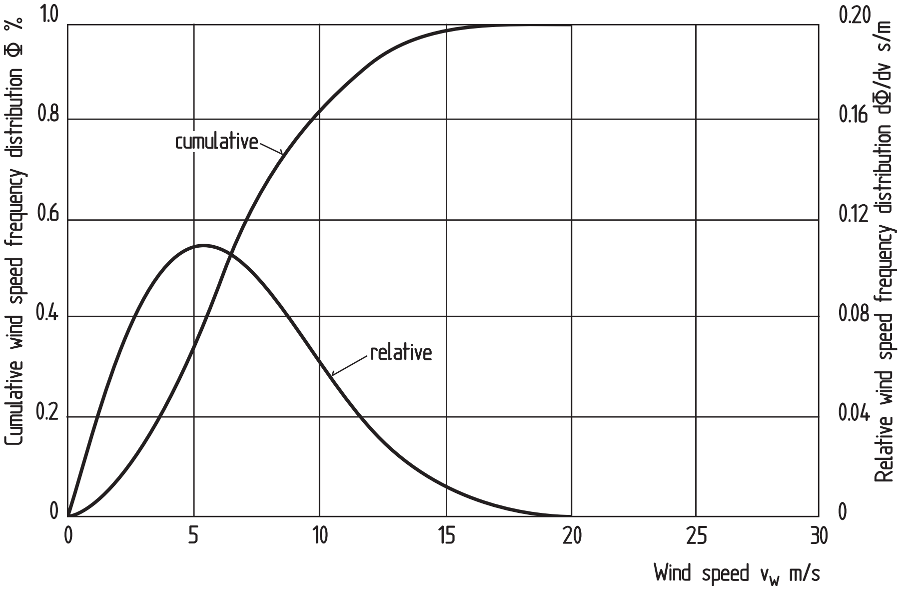


Figure 13.6. Wind speed frequency distribution for the island of Sylt, Germany, measured at an elevation of 10 m

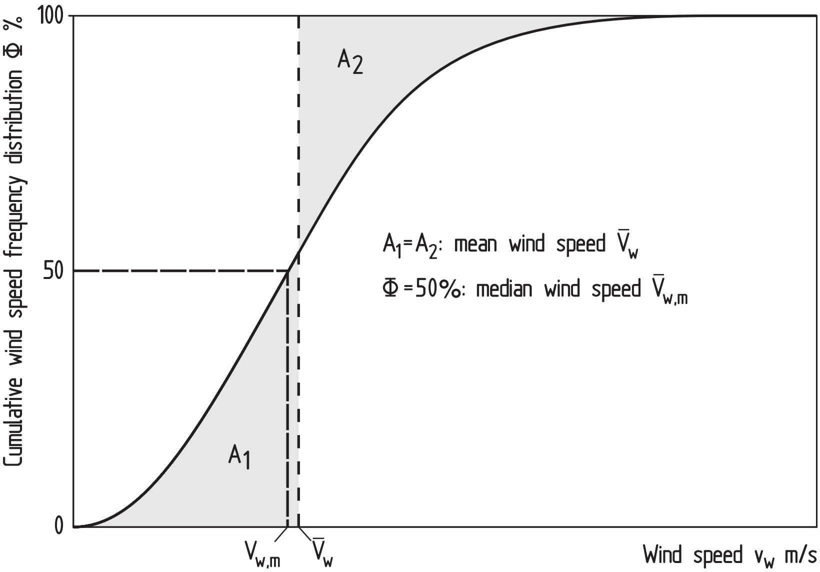


Figure 13.7. Definition of mean annual wind speed and median wind speed

wind regimes, a *Weibull function* will provide a good approximation (Fig. 13.8). The Weibull function is defined as:

$$\Phi = 1 - e^{-\left(\frac{v_W}{A}\right)^k}$$

where:

Φ = distribution function
e = logarithmic base (normally the natural log, $e = 2.781$)
A = scaling factor
k = form parameter

If nothing besides the mean wind velocity is known and an "usual" frequency distribution can be assumed, this is characterised by a form factor of $k = 2$. In this special case, the Weibull distribution is called a *Rayleigh distribution*. The relative frequency is obtained mathematically from the cumulative frequency by differentiating with respect to the wind speed v_W.

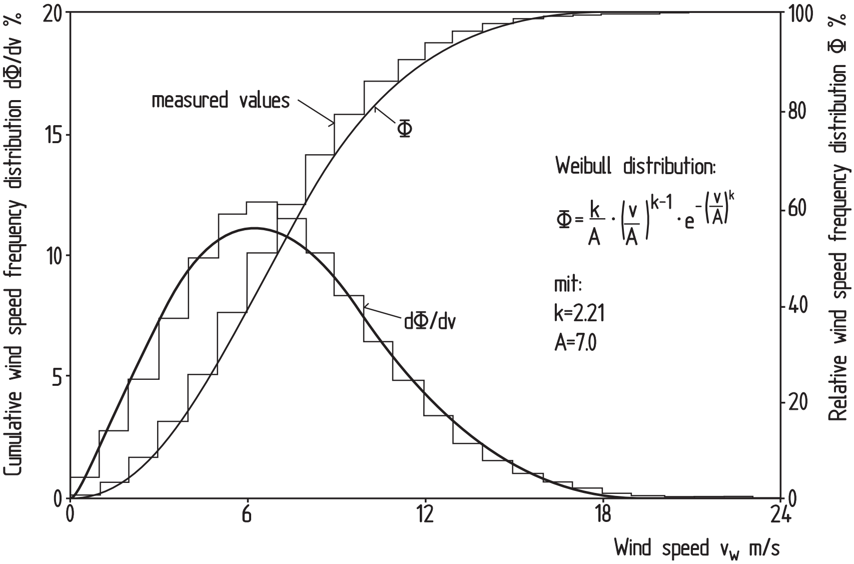


Figure 13.8. Approximation of the measured wind frequency distribution of List on the island of Sylt by a mathematical distribution function according to Weibull

13.3.2 Increase in Wind Speed with Altitude

One of the most important phenomena with respect to the utilisation of wind energy is the increase in wind speed with altitude. The friction of the moving air masses against the earth's surface slows down the wind speed from an undisturbed value at great altitude (geostrophic wind) to zero directly at ground level. Depending on the time of day and atmospheric conditions, the range up to where the wind speed is undisturbed is between 600 and 2000 m above ground and is called the atmospheric boundary layer (Chapt. 13.1).

The area of the boundary layer close to the ground is called the *Prandtl layer.* The flow conditions in this area are dominated by the friction of the air flow against the earth's surface. The height of the Prandtl layer varies with the meteorological conditions. During the nocturnal hours, it is only 10 to 50 m thick whereas during the day, the vertical extent is, as a rule, between 50 and 150 m. Investigations have shown that, for example, a rotor hub height of 60 m is within the Prandtl layer for only about 30 % of the annual hours whereas it is only about 7 % at a hub height of 100 m [7].

The instantaneous increase in wind speed with elevation depends on a number of meteorological factors, e. g., temperature layering and humidity. These largely determine the atmospheric stability. However, the mean value to be expected statistically over a long term at a particular height is largely determined by the roughness of the earth's surface (Chapt. 4.4.7). The roughness of the earth's surface is defined by the so-called *roughness length* z_0 that is specified in metres (Table 13.9).

The increase in wind speed with height can be described as the statistical mean of an assumed steady-state speed distribution. This simplification is adequate with respect to problems based on the long-term statistical mean of the wind speed, that is to say the calculation of the energy delivery of a wind turbine. Naturally, instantaneous fluctuations that can be of significance for certain problems of the strength calculation, for example of the rotor blades, are superimposed on this mean (Chapt. 6).

A conventional approach for describing the increase in wind speed with height is the above-mentioned *logarithmic height formula:*

$$\bar{v}_H = \bar{v}_{\mathrm{ref}} \cdot \frac{\ln \dfrac{H}{z_0}}{\ln \dfrac{H_{\mathrm{ref}}}{z_0}}$$

where:

$\bar{v}_H$ = mean wind velocity at elevation H (m/s)
$\bar{v}_{\mathrm{ref}}$ = mean wind speed at reference elevation H_{ref} (m/s)
H = height (m)
H_{ref} = reference elevation (measuring elevation) (m)
ln = natural logarithm (base $e = 2.7183$)

Strictly speaking, the validity of the logarithmic height formula is restricted to the Prandtl layer close to the ground. There are numerous approaches to improving the accuracy of this formula and taking into consideration, for example, the influence of atmospheric stability or taking into account the fact that the increase in wind speed with altitude also indicates a dependence on the wind speed itself. To be able to handle the more detailed method in practice, however, several parameters, unknown as a rule, must be estimated so that it is questionable whether better results are achieved in every case.

Table 13.9. Roughness lengths and roughness classes for various surface characteristics [3]

z_0 [m]	Types of terrain surfaces	Roughness class
1.00	City Forest	
0.50	Suburbs	
		3
0.30	Built-up terrain	
0.20	Many trees and/or bushes	
0.10	Agricultural terrain with a closed appearance	2
0.05	Agricultural terrain with an open appearance	
0.03	Agricultural terrain with very few buildings, trees, etc. Airports with buildings and trees	1
0.01	Airports, runway Meadow	
$5 \cdot 10^{-3}$	Bare earth (smooth)	
10^{-3}	Snow surfaces (smooth growth)	
$3 \cdot 10^{-4}$	Sand surfaces (smooth)	
		0
10^{-4}	Water surfaces (lakes, fjords and the sea)	

A comparatively simple description of the increasing wind speed with altitude is the power law approximatio according to Hellman. This formula is sufficient for many engineering tasks:

$$\bar{v}_H = \bar{v}_{\text{ref}} \cdot \left(\frac{H}{H_{\text{ref}}}\right)^{\alpha}$$

where:

$\bar{v}_H$ = mean wind velocity at elevation H (m/s)
$\bar{v}_{\text{ref}}$ = mean wind speed at reference elevation H_{ref} (m/s)
H = height (m)
H_{ref} = reference elevation (measuring elevation) (m)
α = Hellmann's exponent (—)

The correlation between Hellman's exponent and the logarithmic formula can be calculated in approximation by using the formula:

$$\alpha = \frac{1}{\ln \dfrac{H}{z_0}}$$

With respect to the calculation of the energy delivered by a wind turbine, attention must be paid to the fact that the logarithmic height formula and, even more so, Hellman's exponent, often supply inaccurate values for greater rotor heights (more than 60 m). As a rule, the mean wind speed is underestimated at greater hub heights. This is particularly important for the assessment of the wind speed on inland sites with higher values of the roughness length (Chapt. 13.5.3).

13.3.3 Steadiness of the Wind

From the beginning, the unsteadiness of the wind has been a frequent argument against the utilisation of wind energy. Indeed, the available wind is less steady than, for example, direct solar irradiation but this has the considerable disadvantage of disappearing virtually completely at night. The variation in wind flow is essentially determined by two factors: the latitude of the site on the globe and the surrounding distribution of land and water.

In medium continental latitudes, the wind fluctuates greatly as the low-pressure regions move through. In these regions, the mean wind speed is higher in winter than in the summer months. The proximity of water and of land areas also has a considerable influence. For example, higher wind speeds can occur in summer in mountain passes or in river valleys close to the coast because the cool sea air flows into the warmer land regions due to thermal effects. A particularly spectacular example are the regions of the passes in the coastal mountains in California through to the lower lying desert-like hot land areas in California and Arizona (compare Chapt. 2.5).

Having regard to the reliability of energy delivery by a wind turbine, it is primarily the long-term fluctuations of wind speed which are of interest as already mentioned. They are expressed as lines of diurnal variations, as seasonal variations and as fluctuations of the mean annual wind speed over relatively long periods.

A distinct, periodic change in wind speed over the diurnal period of 24 hours occurs when thermal effects play a role. Thus, for example, higher wind speeds only occur around noon in the aforementioned regions in California. It takes until the noon hours before the land behind the coastal mountains is heated up. Then the cool air is drawn from the Pacific over the mountain passes. This wind continues until late at night. This diurnal characteristic is of significance if the demand curve follows the power consumption or if it has the opposite characteristic. In California, the prevailing wind matches the characteristic of the power demand quite well which is dominated by room air-conditioning in this area. Under these conditions, the utility companies offer tariffs which vary with the time day and are advantageous at noon in this case. In Northern and Central Europe, on the other hand, there are no such distinct fluctuations in the diurnal wind speed (Fig. 13.10).

The seasonal change in wind speed is a fact which is generally known. As already mentioned, it is highly dependent on the geographic location on the globe. The line of annual variation of the mean monthly values for List/Sylt shows that the winter months to March have the highest wind speeds whereas the second peak in spring is less distinct (Fig. 13.11).

The diurnal and seasonal fluctuations in wind speed are of little significance for grid-coupled wind turbines. The fluctuations in the long-term mean annual wind speed from year to year, on the other hand, are quite important. Wind turbines are investments which must be financed from their income over relatively long periods (up to 20 years) (Chapt. 20).

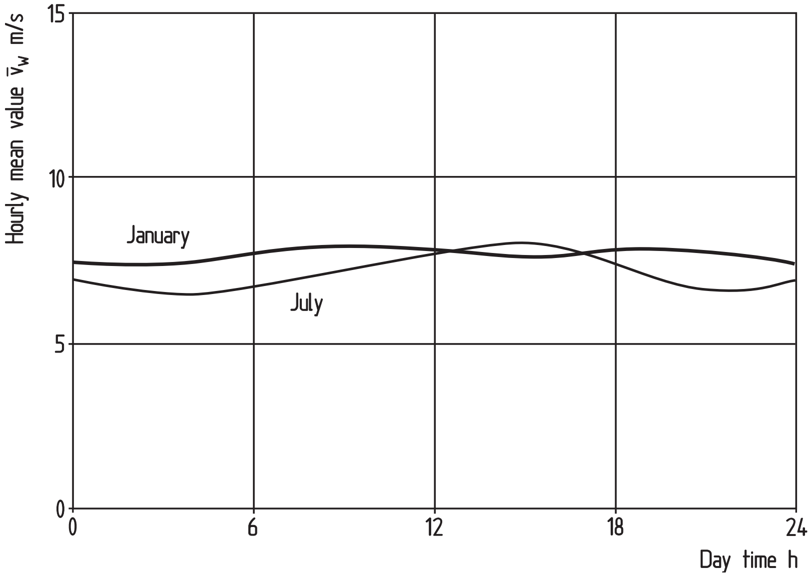


Figure 13.10. Line of diurnal variation (mean hourly values) of wind speed in List/Sylt measured at 12 m height (1971–80) [2]

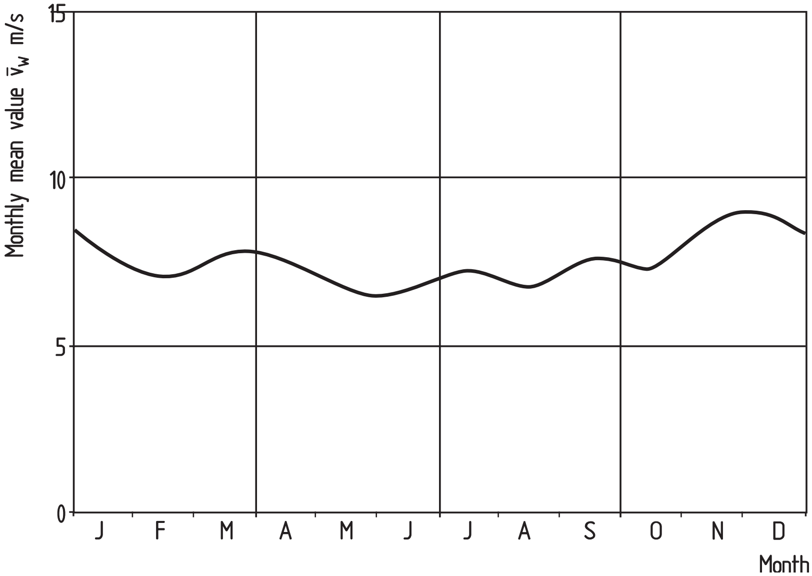


Figure 13.11. Monthly mean values of the wind speed for List/Sylt measured at 12 m height (1971–80), mean annual wind speed 7.1 m/s [2]

The operator, therefore, has to know the long-term mean annual wind speed as accurately as possible as a basis for his calculation of economic viability. But the fluctuations in energy yields from year to year can also cause considerable problems in the financing if liquidity is at a premium.

The energy yield of a wind turbine varies (theoretically) with the third power of the mean wind speed which is why it makes sense to look at the fluctuations of the energy content of the wind. In Germany and Denmark, the energy yield of the past years since about 1990 is being analysed and is defined in a so-called *wind index.* The wind index is the quotient of the delivery of energy from one or more wind turbines in a particular year and the average delivery of energy of the wind turbine(s) over the period of observation. Thus, it is actually an "energy delivery index within a certain period" in which the technical characteristics of the wind turbines assessed play a certain role. In the meantime, *regional wind indices* have been published which are based on a relatively large number of wind turbines evaluated [8]. Since 1993, the wind indices as average values for Germany are:

1993	106 %
1994	115 %
1995	104 %
1996	85 %
1997	92 %
1998	107 %
1999	96 %
2000	99 %

2001	86 %
2002	94 %
2003	80 %
2004	95 %

However, it is emphasised that the results are site-related up a certain degree and are also dependent on the height of measurement. The coast/inland comparison, in particular, shows considerable differences in part. The wind index for Germany has been published regularly for some years, both for Germany overall and for about 25 different regions.

The evaluation of Fig. 13.12 shows a long-term comparison. It shows the energy yield of a 300-kW wind turbine on a coastal site in the period from 1967 to 1997 [9]. For most years, the fluctuations in energy yield about the mean were less than 10 %. However, there are some years with little wind and some years with more wind in which the deviations amount to up to 15 %. The publishers of the European Wind Atlas have concluded that the mean standard deviation from the mean value over an observation period of 22 years is about 13 %. These fluctuations in annual energy yield and the resultant fluctuations in annual income can be quite significant for a detailed calculation of economic viability. Depending on the financing model chosen for the investment, these fluctuations in yields must be taken into consideration in a cashflow prognosis, for example by keeping a reserve account (see Chapt. 20).

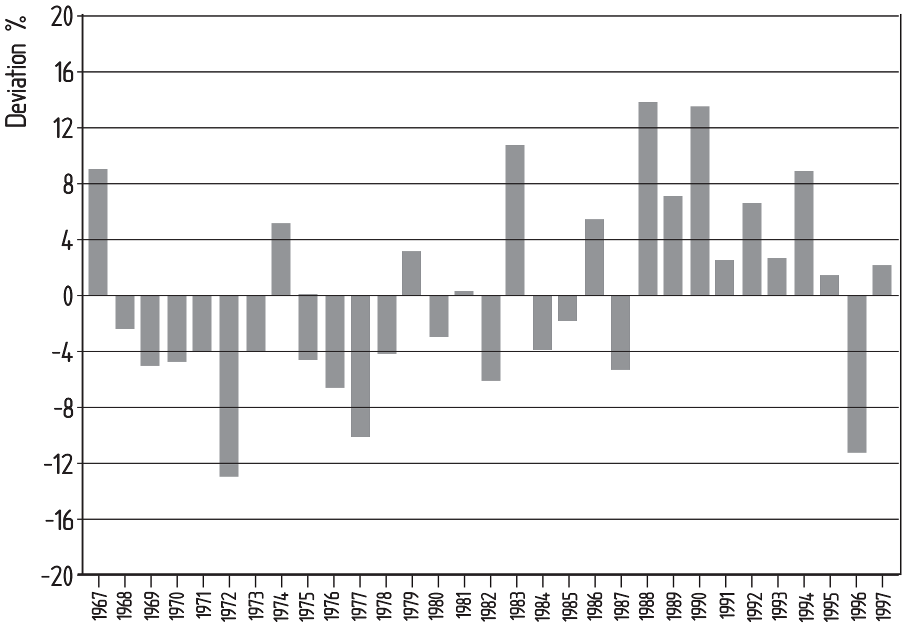


Figure 13.12. Percentage deviations of the annual energy yield from the expected long-term mean, calculated for a 300-kW wind turbine on a site at the North Sea coast [9]

In connection with the observations on the steadiness of the wind, it must also be mentioned that the distribution of wind direction to be expected statistically is also subject to fluctuations [2]. For example, east wind occurs more frequently in one year than in another one. However, apart from exceptional cases, the fluctuations have little influence on the energy yields so that they are not analysed in detail at this point.

13.3.4 Wind Turbulence

The study of a wind speed time history measured with sufficiently high resolution enables its most important parameters to be defined (Fig. 13.13). Ignoring short-term fluctuations, the level of the prevailing wind speed determines the *mean wind speed* $\bar{v}_W$. It is generally averaged over a period of 10 minutes. Using this steady mean wind speed, the instantaneous wind speed at a point in time t can be specified as follows:

$$v_W(t) = \bar{v}_W + v_T(t)$$

The superimposed fluctuating part of the wind speed $v_T(t)$ is caused by the turbulence of the wind. Thus, *turbulence* is the instantaneous, random deviation from the mean wind speed. The extent and characteristics of the turbulence are dependent on a variety of meteorological and geographic factors which are described in the relevant meteorological literature [5].

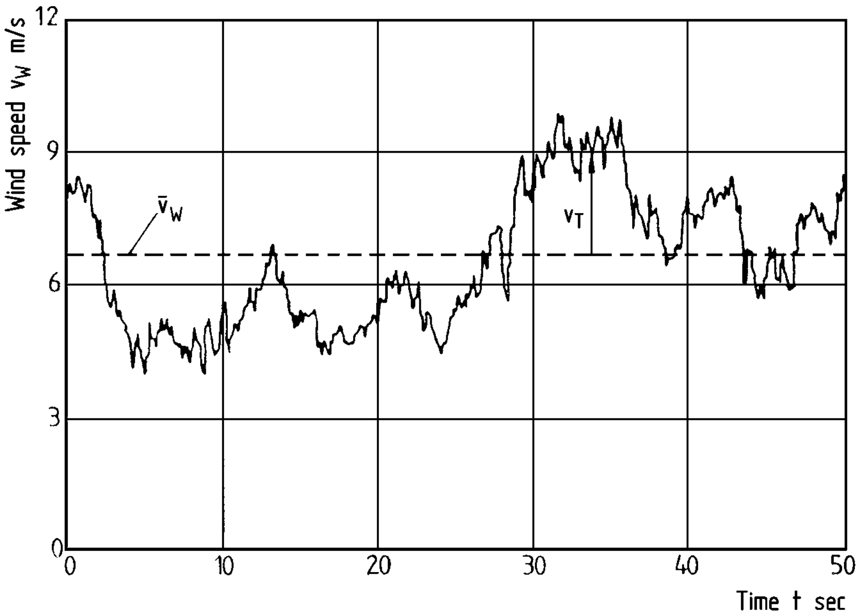


Figure 13.13. Measured time history of wind speed [5]

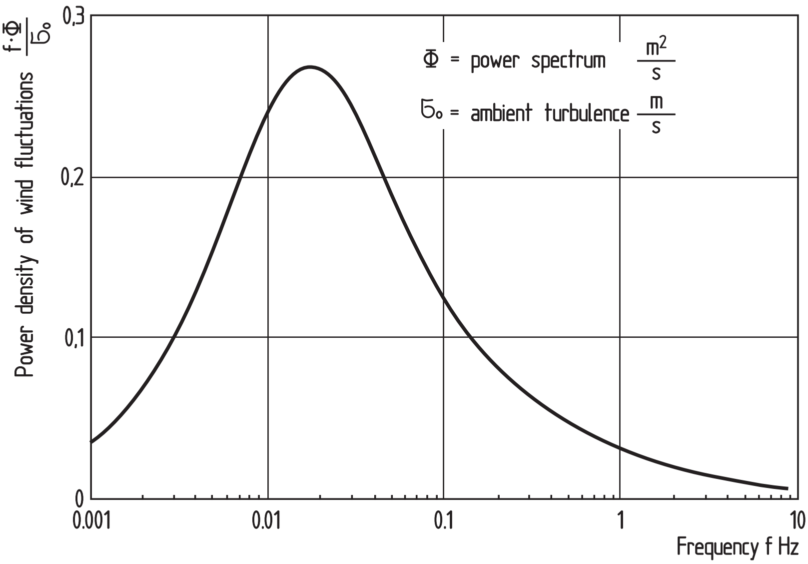


Figure 13.14. Energy spectrum of wind speeds (turbulence spectrum) [6]

Turbulence can be described comprehensively with the aid of a statistically deduced turbulence spectrum (Fig. 13.14). For this, the energy content of the wind speed fluctuation about the mean wind speed is plotted in the form of a spectrum vs. frequency. This spectrum must have been determined from wind speed measurements. Frequently used spectra have been developed for example by Davenport [6].

To characterise the turbulence, the term of *turbulence intensity* is used which is occasionally also called the degree of turbulence. The turbulence intensity σ_o is defined as the ratio of the standard deviation σ_v of the wind speed to the mean wind speed $\bar{v}_W$ in a certain averaging time and is specified in percent:

$$\sigma_o = \frac{\sigma_v}{\bar{v}_W} \qquad (\%)$$

The turbulence intensity changes with the mean wind speed, with the surface roughness, with the atmospheric stability and with the topographic features [5]. The lowest values are measured over the open sea (5 % and less) whereas the highest values (20 % and more) occur over densely settled areas or forest areas. In the load assumptions for wind turbines, values of between 16 and 18 % are assumed depending on *wind turbine classes* (compare Chapt. 6.3.1).

In the open air, the wind turbulence does not occur in the "one-dimensional" form as idealised here. Instead, the wind fluctuations are distributed spatially in all directions. For this reason, meteorology has very complex models for the spatial multi-dimensional turbulence of wind [1]. However, these multi-dimensional turbulence models are of no great significance in wind power technology.

13.4 Topography and Local Wind Flow

When considering global wind resource maps and fundamental laws, it must not be forgotten that at any location, the prevailing wind regime will exhibit local peculiarities which can be of decisive significance to the siting of a wind turbine. The smaller the wind turbine and the more the local topography, including trees and buildings (obstacles), differs from the ideal "flat and obstacle-free terrain", the greater the importance of the local orographic relief of the immediate surroundings. It is, therefore, useful to get an idea of whether the local terrain can be considered to be "obstacle-free".

According to Frost, the terrain in the surroundings of a wind turbine can be considered "flat" if (Fig. 13.15):

- differences in elevation do not exceed 60 m within a radius of 11.5 km,
- the ratio of the maximum level difference h_C to the horizontal distance between these two marked points is less than 0.032 for a distance of 4 km upwind and 0.8 km downwind,
- the height of the rotor relative to the lowest point within a distance of 4 km upwind is at least three times greater than the largest existing level difference h_C.

Naturally, the existence of level differences can also be utilised in a positive sense when a wind turbine is to be located in the area. Wind speeds on mountain ridges with a particularly advantageous shape (slopes of 1:3 to 1:4) can increase to double the value prevailing far away from the ridge [5].

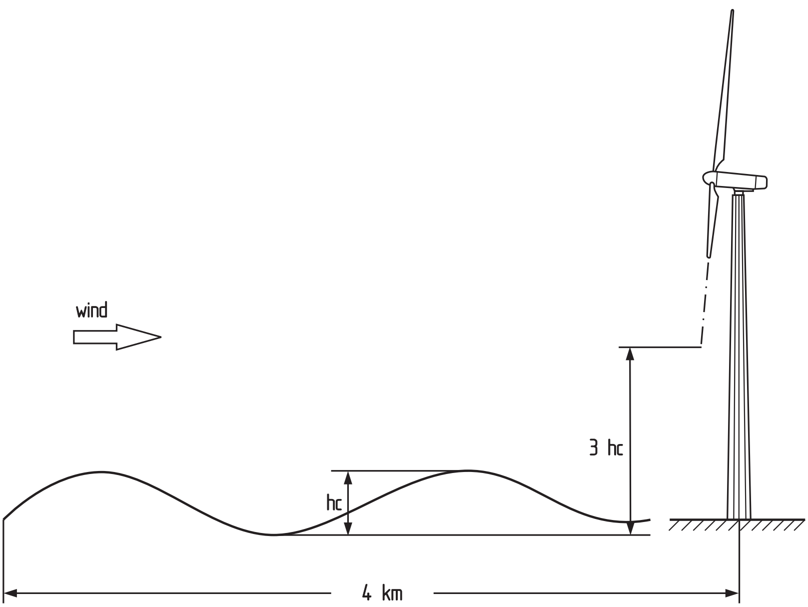


Figure 13.15. Definition of "flat countryside" in the environment of a wind turbine [5]

Apart from differences in elevation in the terrain, the topographical environment of a wind turbine is characterised by the "roughness" of the earth's surface and by the presence of "obstacles". The roughness of the earth's surface is brought about by evenly or randomly distributed surface characteristics, primarily by the type of vegetation (forests, meadows etc.) or by the differences caused by land and water. The European Wind Atlas contains extensive notes and computational methods for determining the roughness length for certain types of surface [3].

While roughness determines the characteristics of the wind regime in a larger area, obstacles only have a limited local significance. Buildings, trees or groups of trees create turbulences which can have highly undesirable consequences for the operation and lifetime of a wind turbine. The flow wake caused by a building is shown in Fig. 13.16. The airflow on the lee-side of such an obstacle is separated to approximately twice the obstacle's height and is more or less turbulent (separation bubble). On the down-wind side the disturbed air flow extends to a distance of up to twenty times the height of the obstacle. If a negative influence on the wind turbine is to be avoided, the rotor should be placed at three times the height of the obstacle and sufficiently far away down-wind.

The relationship between the orography of the environment and the local wind regime is extremely complicated. Numerous attempts have been made to develop theoretical modelling concepts and calculation methods [10] (s. a. Chapt. 13.5.3). Practical experience and observation also play a not inconsiderable role, especially in this field.

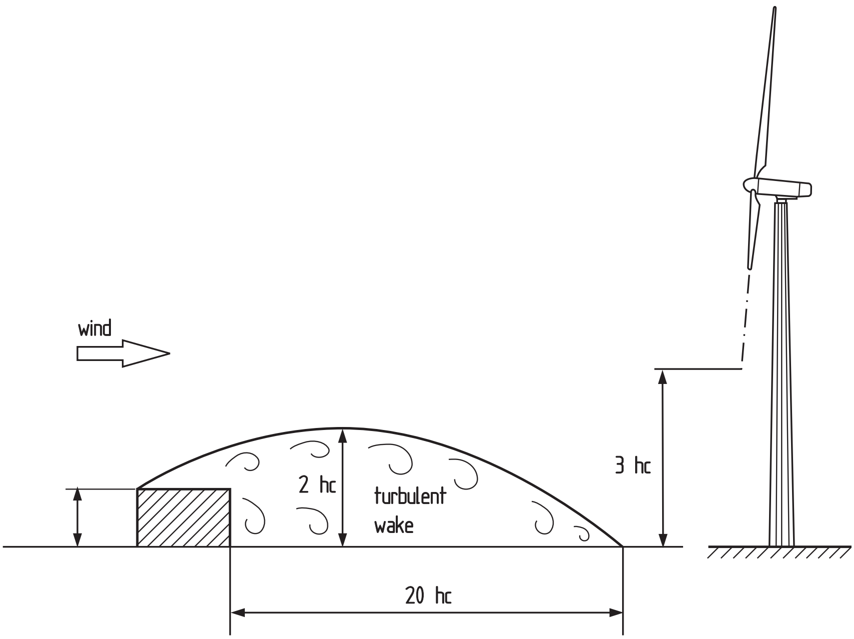


Figure 13.16. Flow wake behind an obstacle [5]

13.5 Determining the Wind Speed

The potential user or planner of a wind turbine is frequently faced with the situation of not having any data on the wind regime at the intended location. There are basically only two possibilities for procuring wind data. Either a theoretical method as described, for instance, in the European Wind Atlas will be applied, or measurements will be taken at the site. It almost goes without saying that, whenever possible, both methods should be used in parallel so that the results can be compared.

13.5.1 Measuring Techniques

Measuring the wind on site is the most reliable method, but frequently the possibilities and results of such measurements are linked with unjustified expectations, or measurements are taken the results of which are insufficient for providing correct and adequate answers to the questions which are really of interest. The question therefore arises: What can the user of a wind turbine achieve by carrying out his own measurements?

The energy yield of a wind turbine can only be predicted with statistically validated values of mean wind speed, wind speed distribution and the vertical wind profile. Statistically reliable values require long-term measurements, though. Generally, specification of a reliable value for the long-term mean annual wind speed requires the mean value taken over at least ten years. This means, however, that the user must rely on the literature published by meteorological institutes and organisations. Measurements taken by oneself over a period of only a few months with simple equipment are not suitable for this purpose.

On the other hand, the areas covered by the wind maps are usually so large that the data are not transferable to specific local situations, particularly not in a *complex terrain* (Fig. 13.17). Mountainous topographies or particular building developments can cause considerable local deviations from large-scale data. These uncertainties can be eliminated by short-term measurements.

Wind measurement over a relatively short period, for instance one year, offers the possibility of comparing these values with the long-term data measured within the same period of time at the closest location at which the long-term mean value is known. This permits verification of whether and to what extent the local value deviates from the value ascertained for the larger area. If, in addition, the wind speed is plotted over time, indications as to the turbulence intensity can be derived from the wind variations. From the point of view of the prudently planning operator, wind measurements having this objective make sense and may even be necessary.

If several wind turbines or even a large wind farm is to be installed, the question of the prevailing wind direction or even the wind direction distribution, arises. Efforts will always be undertaken to situate the wind turbines according to the prevailing wind direction (Chapt. 16.4). However, these measurements are highly time-consuming, so that frequently qualitative information relating to the prevailing wind direction has to be relied on. The growth pattern of trees and shrubs is an especially reliable indicator in this respect (Fig. 13.18).

Figure 13.17. Wind turbines installed in a Spanish mountain region (complex terrain) (Thyssen)

Figure 13.18. Wind-flagged trees as qualitative indicators of the local wind resources

In addition to the planning of the installation of wind turbines, their operation also requires some sort of continuous wind measurement. Although almost all large turbines have their own operational wind measuring system, additional information about the wind speed is still frequently of interest. The operator wants to compare the actual energy yield with the theoretically possible value. This already requires an additional wind measuring system, which must be sufficiently clear of the turbine to remain unaffected by the rotor (Chapt. 10.1.1). In some cases, especially in large wind farms, turbine-independent wind measurement is also used for power output management and supervision. Thus, for example, it is desirable for various reasons to perform the shut-down and start-up sequence in groups. For this purpose, the signals from a turbine-independent measuring point are used.

What instruments and measuring methods are suitable for this type of wind measurement? An instantaneous "measurement" of the wind speed with a conventional cup anemometer by hand may on occasion be quite illustrative, but its value for technical purposes is virtually zero. Usable data can only be obtained by means of measurements over a certain period and recording of the measured values. This requires a stationary measuring system on a mast with a logging device for the measured data. The sensors of a wind measuring system suitably consist of a combination of an anemometer and wind vane or, most recently, of an ultrasonic sensor which has no moving parts (Fig. 13.19).

Time and again, the accuracy of the sensors becomes the subject of discussions about the quality of the measurement data which is why considerable importance must be accorded to the calibration of the anemometers. The anemometers must be checked and

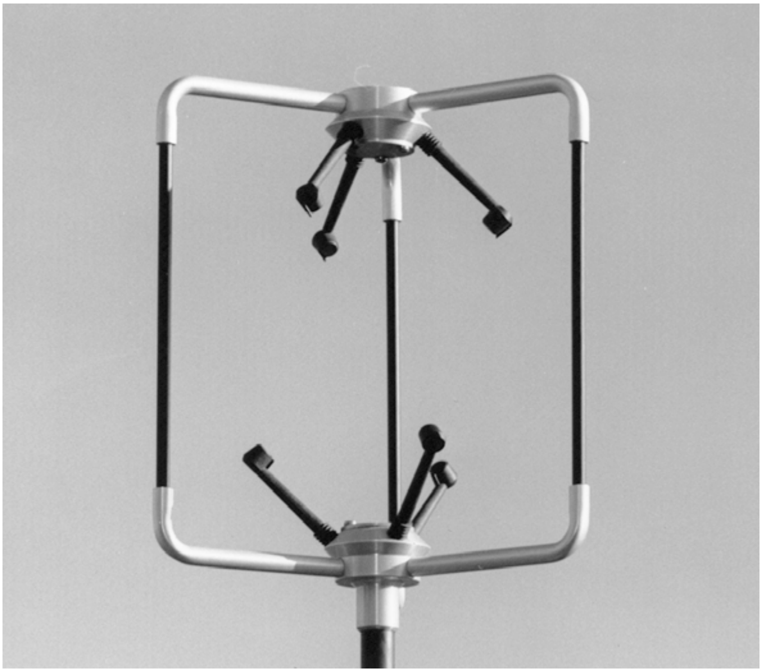


Figure 13.19. Ultrasonic anemometer (Ammonit)

recalibrated at regular intervals. Today, independent institutions will provide anemometer calibrations and an operator is well advised to pay attention to these.

The sensors are mounted on top of or on side arms of a mast or a tower. The mast height depends on the requirements to be met. If only a comparison with the data in the wind maps is intended, then the standard measuring elevation of 10 m is enough. With larger wind turbines, the problem then arises of having to extrapolate the wind speed to the rotor's hub height. If there are too many uncertainties concerning wind shear, nothing remains but to build the wind measuring mast as high as the rotor's hub height. However, a wind measuring mast with a height of fifty or more meters represents a cost factor and may require a building permission (Fig. 13.20).

In the past, mechanical anemographs were used which plotted wind speed and direction on a paper strip. Mean values were determined with the help of an plotting rule. Nowadays, electronic recorders are used almost exclusively where the measured data is stored on tape or in chips. This provides for immediate data evaluation by computer. The manufacturers offer an almost endless variety of suitable storage devices and analysers.

In recent years, specific data loggers, sometimes called *wind classifiers* have been developed especially for wind turbines. They count the duration of the wind speed within certain speed ranges (classes) and thus provide direct information on the wind speed frequency distribution (Fig. 13.21). Moreover, it is possible to obtain additional information on instantaneous wind speed or the average wind speed reached in the past month or the like.

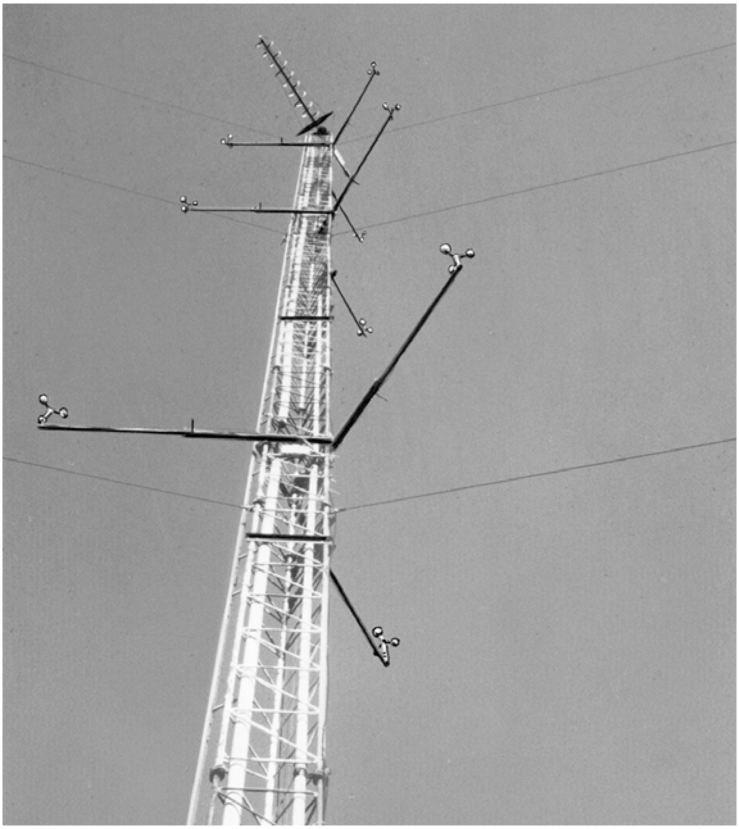


Figure 13.20. Wind measuring mast with sensors (Siggelkow)

Figure 13.21. Data logger for wind speed analysis (Ammonit)

Logging the wind speed distribution, and thus also the average wind speed, over a year by using such a data logger, in combination with long-term wind data which may be available from neighbouring areas, represents a useful basis for obtaining a reliable assessment of the energy yield of a wind turbine. Wind classifiers can thus supply valuable information for a wind turbine operator. However, they are no exclusive substitute for long-term wind statistics.

The wind speed is indicated in meters per second in the SI system of units. Despite this, the *Beaufort scale* of "wind forces" is still widely used in many places, and is perhaps also more graphical (Table 13.22). Above all, the correlation between wind speeds and visible effects is a valuable aid to assessing the wind regime, especially for a wind power technician.

Table 13.22. Classification of wind speed according to the Beaufort Scale

Wind speed m/s from	to	Wind force acc. to Beaufort	Wind force notation	Visible effects inland
0.0	0.2	0	Calm	Smoke rises vertically
0.3	1.5	1	Light air	Smoke indicates wind, wind vanes do not
1.6	3.3	2	Light breeze	Wind perceptible on face, wind vanes move move
3.4	5.4	3	Gentle breeze	Leaves and thin branches move, wind extends pennants
5.5	7.9	4	Moderate breeze	Thin branches move, dust and paper are raised
8.0	10.7	5	Fresh breeze	Small trees begin to sway, white caps form on lakes
10.8	13.8	6	Strong breeze	Thick branches move, telegraph lines whistle
13.9	17.1	7	Moderate gale	Whole trees move, difficult to walk
17.2	20.7	8	Fresh gale	Wind breaks branches off trees
20.8	24.4	9	Strong gale	Minor damage to houses (roof tiles)
24.5	28.4	10	Whole gale	Trees are uprooted
28.5	32.6	11	Storm	Significant damage to houses (very rare inland)
32.7	56	12 – 17	Hurricane	storm damage Widespread devastation

13.5.2 Ascertaining the Wind Data and the Energy Yield from the European Wind Atlas

In recent years, the European Wind Atlas has become one of the most important tools in determining a site for wind turbines and predicting the energy yield to be expected. In European countries, the usual "wind studies" are produced almost exclusively by this method if they cannot be based on the evaluation of measurements at the site itself. The calculations of economic viability, and thus the decision regarding investments for many projects, rely on the information provided by this semi-empirical method. For this reason, some fundamental notes relating to the methods involved and the reliability are indispensable. The correct application of this method is assisted by very good documentation including data sources and calculation methods provided on floppy disks, which are commercially available [3]. It is not difficult to handle but the method is not without risk if it is used in a purely formal way, i. e. without adequate general experience in the field of wind conditions and site factors.

The European Wind Atlas consists of two parts: the first part describes wind conditions in Europe and the second part contains a mathematical method by means of which the wind conditions and the energy yield of one or more wind turbines can be predicted at a particular site from these data.

The first part is based on about 220 measuring stations from which measurement data are available for a relatively long period (essentially from 1970 to 1980). These measurement data, in most cases measured at the standard meteorological measuring height of 10 m, supply the raw data of the atlas. The measurement data include the local co-ordinates of the measuring station, the measuring height, the so-called roughness rose, i. e. the information on environmental roughness in directional sectors and the frequencies of wind speed and wind direction specified in the sectors. In addition, the database contains the diurnal and annual variation in wind speed. From these data, the Weibull parameters A and k have been calculated for each directional sector.

From these raw data, the so-called *"regional wind climatology"* is determined by using the *geostrophic law of friction*. The geostrophic law of friction is a fundamental theoretical approach to describing the wind conditions in the boundary layer of the earth's atmosphere. The forces resulting from the pressure gradients in the atmosphere are brought into equilibrium with the frictional forces of the earth's surface, removing local influences like:

- orography,
- environmental roughness
- obstacles

from the local raw data of the measuring stations and calculating the Weibull parameters (A and k) for "regionally" valid wind data. These data then apply to "flat and even" terrain and "no shading by obstacles" and are calculated for four different roughness classes. They are also specified in directional sectors and, in this form, represent the wind conditions that can be applied for a region of about 200 × 200 km.

The wind atlas provides detailed information on how the measuring stations — and in the second part the sites looked for — can be classified in accordance with the criteria of orography, surface roughness and obstacles. For this purpose, the landscape is divided into five different landscape types and four surface roughness classes are defined. The roughness length z_0 is then determined from, among other things, the so-called "roughness elements" (e.g. large trees, houses, etc.). Using correction factors derived from these, the corrected regional wind data are calculated from the actual measurement data of the stations. The maps show these data for a height of 10 m above ground level. Conversion to other heights of up to 200 m is done on the basis of the logarithmic height formula, taking into consideration correction factors. The wind data for a height of 200 m virtually correspond to the geostrophic wind (Chapt. 13.1).

The second part of the wind atlas, the "*Wind Atlas Analysis and Application Programme" (WASP)* contains descriptions on how the wind data for an actual potential site for a wind turbine can be determined from the regional data. In this method, the calculation of regional data from the basic local raw data of the measuring stations is reversed and the same physical and mathematical models are used. In practice, it is handled in such a manner that a suitable station located in the vicinity of the site is selected from regional wind data and then the site is classified in accordance with the criteria of orography, surface roughness and shading by obstacles and on the basis of this the Weibull parameters at the heights of interest of the site looked for are calculated (Fig. 13.23).

Furthermore, the average achievable power or energy yield is calculated by inputting the power characteristic of the intended wind turbines and the Weibull parameters determined at rotor hub height. The power and energy yield are determined as azimuthal distribution in 12 directional sectors.

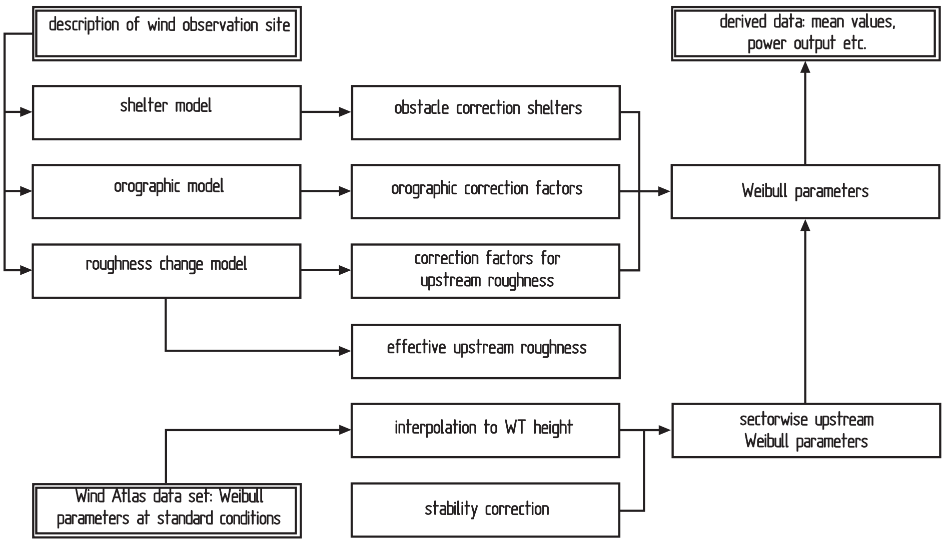


Figure 13.23. Block diagram of the Wind Atlas Analysis and Application Programme (WASP) for calculating the wind data and the energy yield of a wind turbine at a particular site [3]

The WASP computing model is being continuously improved and in its present from has been very successful for open and flat coastal regions and also the level inland regions. The results present problems in mountainous terrain since the classification of the site in accordance with the above criteria becomes very difficult in this case and, moreover, the wind conditions are influenced by microclimatical orographic situations.

A further inaccuracy is found in the calculation of the mean wind speeds at heights of more than 60 m. The basic logarithmic height formula is only reliable in the lower area of the boundary layer of the Prandtl layer which frequently only extends up to a height of 60 m. The mean wind speed at a height of more than 60 m has often been considerably underestimated when using the calculation according to WASP. In recent WASP versions, a special correction factor is used for improving accuracy above 60 m height.

The deviation in the wind data determined is estimated by the publishers of the wind atlas to be approximately 5 %, and the possible error of the mean wind power (energy yield) is approximately 15 %. However, this very cautious statement should not lead to the conclusion that a more comprehensive wind prognosis that also includes comparisons with existing measurements in addition to the calculation according to WASP, must have these error tolerances. In the major regions of wind energy utilisation, for example in Denmark or in the North German lowlands, there are by now so many reference points available due to the increasing selection of wind turbines that wind and yield prognoses can be created with a much greater accuracy than that mentioned above, at least in those areas, if this experience and information is correctly included. This applies at least up to the aforementioned height of about 60 m.

13.5.3
Numeric Models of Three-Dimensional Wind Fields

The penetration of wind energy utilisation into the inland regions with their much more complex topographical conditions in comparison with the open and flat coastal regions has made it clear that a more accurate determination of the wind data is necessary. The widely used method of the European Wind Atlas which is based on the conventional "wind study" or "wind assessment" shows distinct weaknesses at inland sites. These are basically attributable to two reasons:

- The influence of the terrain relief (orography) on the local wind field is reproduced only inadequately.
- The logarithmic height formula for the increase in wind speed with height, used in the WASP method, loses its validity outside the Prandtl layer.

Against this background, numeric simulation models are increasingly used which, although they are much more complex and, as a result, are also associated with high costs, do provide more accurate results. Such models are used in many areas of meteorology such as weather prediction, but also for assessing the spread of pollutants in the atmosphere. The basic concept of these simulation calculations is based on a digital three-dimensional model of the orography including surface features. Onto this model, the wind field of the geostrophic wind is superimposed, which is not influenced by relief and surface features. The result is a three-dimensional wind field which reproduces the influence of the shape of the terrain with its surface characteristics and manages without extrapolating to a greater height the wind speed of measuring stations close to the ground. Similar to the WASP method, a certain lack of certainty is given with the correct estimation of the nature of the surface. For this reason, a certain amount of experience is required when handling these models.

A model that has recently been used successfully for determining wind data, particularly in inland regions, is known by the name "Fitnah" [7]. This is a so-called *mesoscale model* which can be used with a mesh size (spatial resolution) of between 25 and 50 m. Figure 13.24 shows the result of a wind field simulation for a region under examination with a size of 10 × 10 km. The annual mean of the wind speed is represented in a 200 m grid pattern. Using this information, the choice of site for wind turbines can be adapted very precisely to the considerable differences in wind conditions in the field under examination in a complex mountainous terrain, or the differences in energy yield of the individual turbines can be calculated if their sites have already been established.

The more accurate determination of the mean wind speed at rotor hub heights of more than 60 m is an important aspect which speaks for the use of such simulation models. The models do not use the logarithmic height formula and, therefore, are not tied to the validity of this approach being restricted to the Prandtl layer. A comparison with a measurement and a calculation according to WASP shows that considerable differences can occur in individual cases (Fig. 13.25). Generally, however, the differences are not as great. In inland regions, the mean wind speed at 80 to 100 m height can be underestimated by up to 0.5 m/s

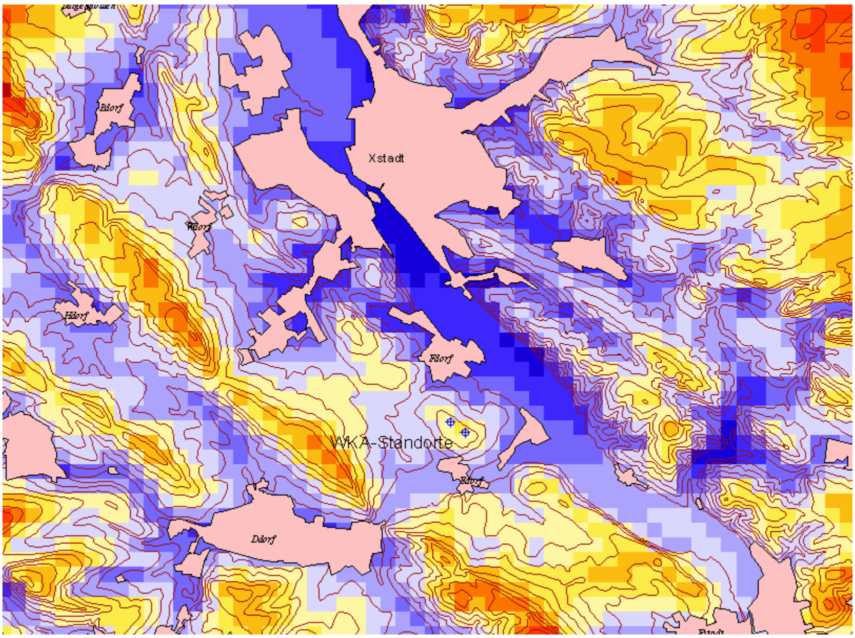


Figure 13.24. Simulated spatial distribution of the annual mean of the wind speed at a height of 98 m above ground level for a mountainous inland site using the Fitnah model [7]

in the application of WASP. But it should be noted that more recent versions of WASP use an improved formula for calculating the increase in wind speed with height, so differences will be smaller.

The economic significance of a precise knowledge of the mean wind speed at heights of more than 60 m for the utilisation of wind energy in inland regions is not to be underrated. The usual rotor hub heights are between 80 and 100 m there and will exceed the 100-m limit with the next generation of large turbines. Underestimating the yield at 100 m hub height by 10 or 20 %, which can occur quite easily in this order of magnitude when using a WASP calculation, may well be the decisive factor in determining whether an enterprise will be economically viable or not.

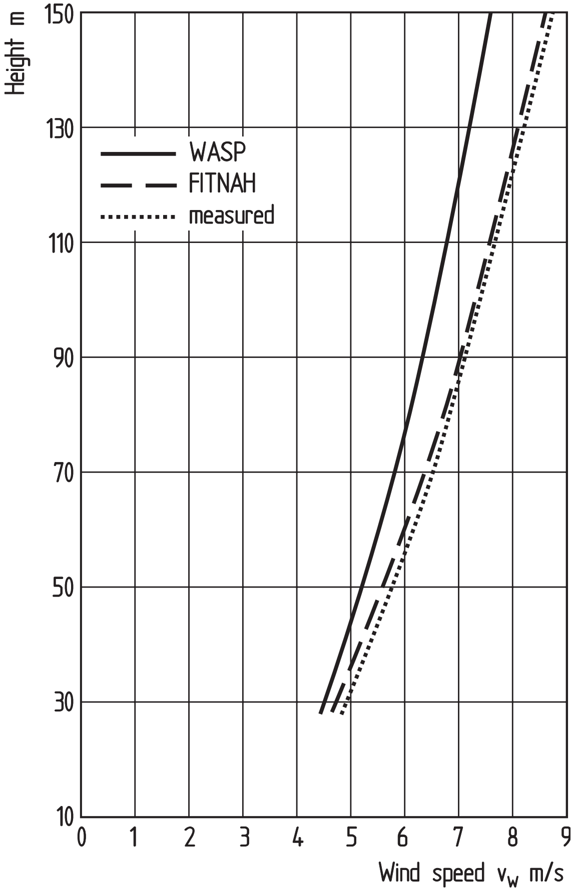


Figure 13.25. Comparison of the vertical profiles of the mean wind velocity calculated by using WASP and Fitnah, and with measurement values taken on an anemometer mast

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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 little 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. 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.

This process results in the power curve, the relationship between electrical power output and wind velocity. It is the most important testimony for the performance of the wind turbine from the point of view of the operator. The power curve forms the basis for the energy yield to be expected under the given wind conditions at a specific site.

Last but not least, it has to be mentioned that the power curve of a wind turbine will be influenced by extraordinary site-related wind climate conditions. These can cause perceptible power losses in complex terrain.

14.1
Principles of Power Optimisation

The power curve of a wind turbine is primarily based on the aerodynamic quality of the rotor and on the individual efficiencies in the mechanical-electrical chain of energy conversion. In addition, however, some operating parameters are of significance which must be determined in dependence on the wind regime and some other site-related conditions. These principles of power optimisation are of less importance to the turbine operator since he is purchasing a turbine with predetermined power curve. On the other hand, the power curve is influenced to a certain extent by the conditions prevailing at the site — also from the point of view of the operator — so that a certain understanding of the principles underlying the power curve is useful. The reliability of the manufacturer's information relating to the power curve is also of special economic significance

14.1.1
Operating Characteristics of the Rotor

The starting point for determining the performance of a wind turbine is the set of aerodynamic characteristics of the rotor. Its origin and significance have been described in Chapter 5. The aerodynamic properties, however, merely describe the rotor's potential power capacity. The actual power used is also influenced by the operating mode of the rotor. In practice, the rotor's mode of operation, i. e. its speed control and blade pitch control, cannot be implemented in such a way that there are no power losses compared with the potential power capacity. There are several constraints preventing the rotor from operating at its theoretical maximum power output:

- 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 maximisation 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. 14.1).
- 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.

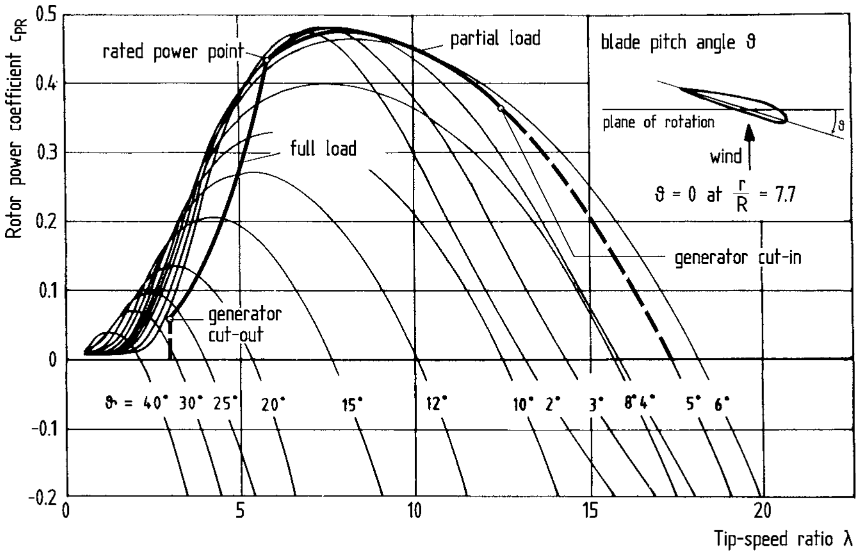


Figure 14.1. Operating characteristics in the c_P-λ chart of the WKA-60 rotor

Given these constraints, the following rotor operating characteristics for partial and full-load operation are obtained (Fig. 14.1).

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).

14.1.2
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, if any,
- Losses in the energy transmission to the grid.

In addition, there is a power demand for operating the auxiliary units which cannot be neglected. These losses must be included in the power balance. Using the WKA-60 as an example, Fig. 14.2 shows the energy flow through the drive train at the rated power.

A loss of 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

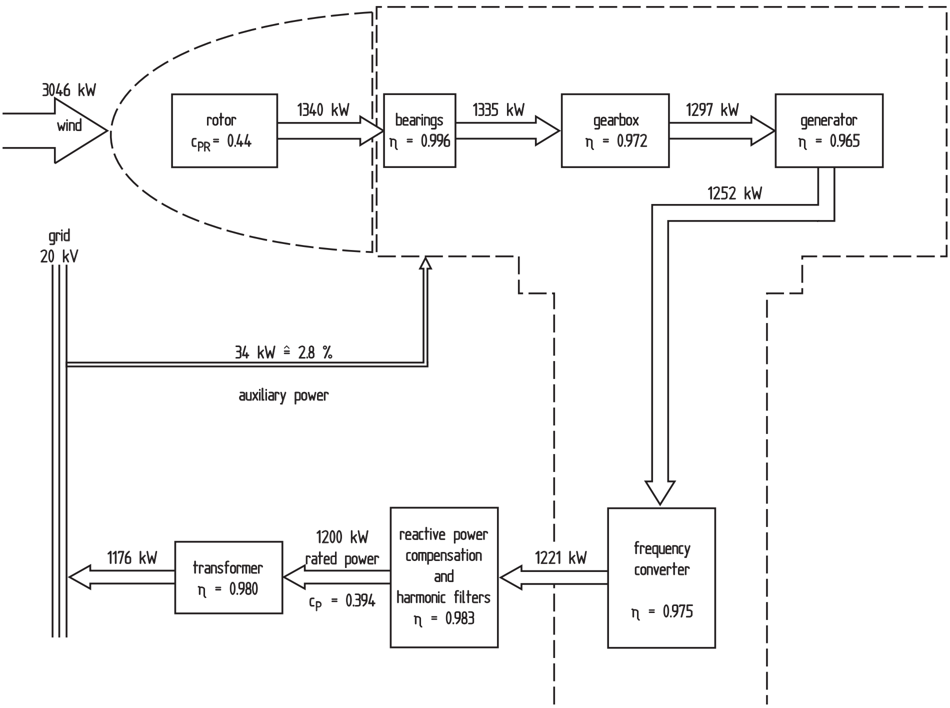


Figure 14.2. Energy flow through the mechanical-electrical energy conversion chain at nominal operating point, for the WKA-60

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.

A graphical overview of the power losses, from the theoretically possible rotor power to the effective electric power output of the wind turbine, is given in Fig. 14.3. The resulting curve of the *turbine power coefficient* constitutes the basis for determining the power curve of the wind turbine.

The discussion of the power losses cannot be concluded without noting some causes of possible wind-turbine related reductions in the delivered electric power:

– The unavoidable lag in rotor yawing is one cause of power reduction. A loss of 1 to 2 % can hardly be avoided, even with a sensitive yawing system (Chapt. 5.7).
– In the course of operation, deteriorating blade surface quality can lead to noticeable power losses. Power specifications are generally based on the assumption of aerodynamically "smooth" airfoils (Chapt. 5.5.4).

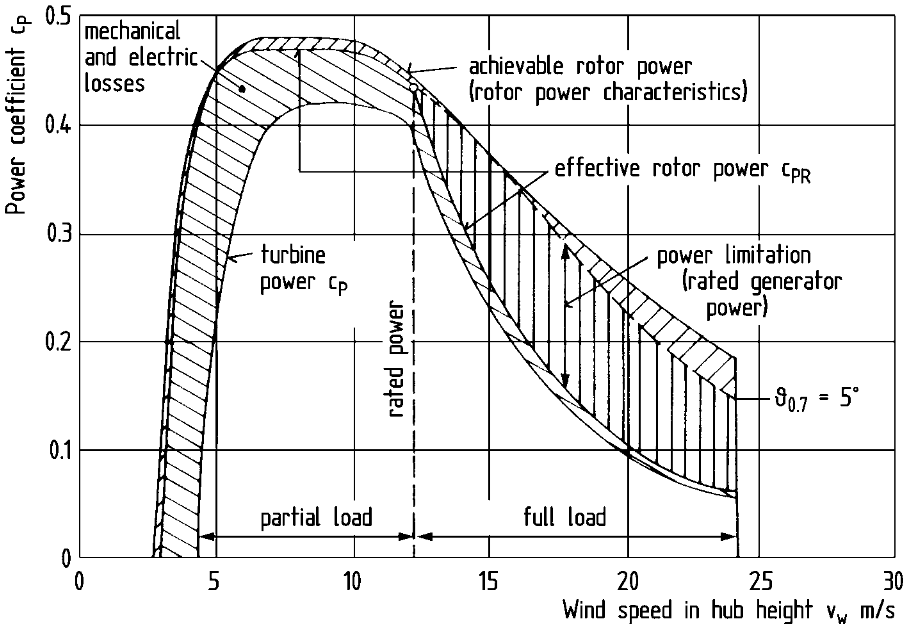


Figure 14.3. Power losses represented in the rotor power characteristics of the WKA-60

– The tower shadow effect in down-wind rotors causes a certain amount of aerodynamic rotor power loss. A loss of 2 to 3 % can be assumed as a reference value (Chapt. 6.2.3).

When assessing these power losses from aerodynamic causes, and the losses in the drive train, it must be considered that they only become effective at partial load. In the full-load range, i. e. at wind speeds above the rated wind speed, there is more than enough wind power available, permitting the wind turbine to deliver the maximum power of its generator virtually independently of its efficiency.

The example considered is a variable-speed turbine with synchronous generator and inverter with AC-DC-AC link circuit. Naturally, other electrical and/or mechanical designs have other types of losses, resulting in a different mechanical-electrical efficiency. The differences existing in currently used technical concepts are primarily determined by variable-speed operation as compared with direct grid coupling of a fixed-speed generator (Fig. 14.4).

The total mechanical-electrical efficiency of the traditional fixed-speed turbine with induction generator with direct grid coupling is more than 93 % at full load. As was to be expected, the peak of the variable-speed system with double-fed induction generator is lower at about 92 % whereas the direct-driven synchronous generator (Enercon) maintains an efficiency of approx. 94 % over almost the full power range. In addition, the variable-speed turbines have the advantage that an additional gain in energy is achieved due to the aerodynamically more efficient operating mode of the rotor (Fig. 14.27).

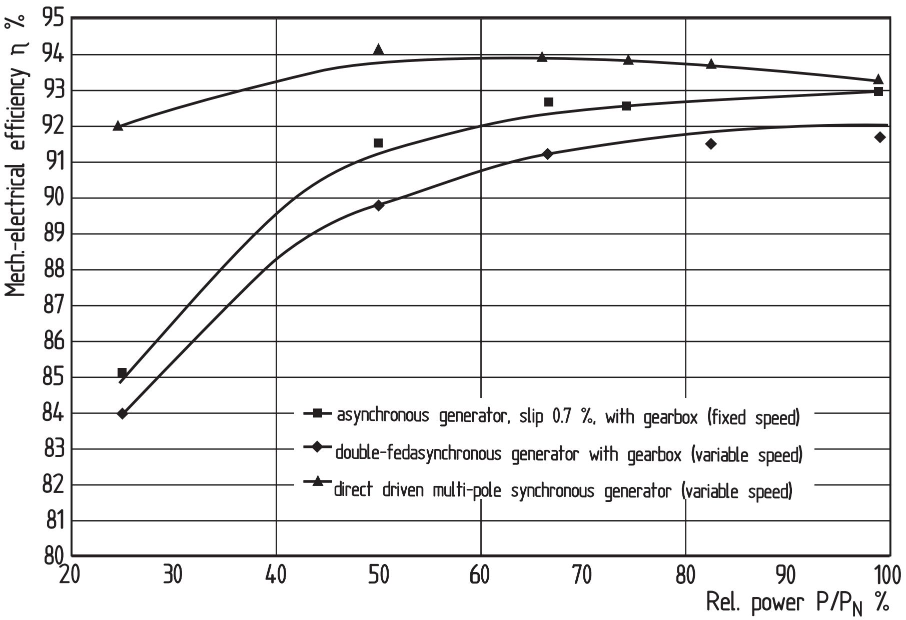


Figure 14.4. Total mechanical-electrical efficiency for different drive train concepts

The differences in efficiency are determined not only by the chosen design of the mechanical-electrical drive train but to some extent also by the power class. Small generators in the power range of some tens of kilowatts have a lower efficiency than units in the megawatt range. Whereas these machines achieve a total efficiency of over 90 %, the maximum mechanical-electrical efficiency of small turbines is about 85 % for fixed-speed systems.

In practice, the power coefficients achieved by present-day wind turbines definitely exhibit significant differences (Fig. 14.5). Apart from the small differences in mechanical/electrical efficiencies of the drive train, the aerodynamic efficiency of the rotor has the dominating effect. The excellent c_P values of the more recent Enercon turbines from 2004 onward are primarily achieved by aerodynamic optimisation of the rotor blades which, in addition to improved airfoils and an optimised blade tip, also takes into consideration the overall flow around the nacelle (s. Chapt. 5.5.2). To achieve this optimum obviously requires consideration of the three-dimensional rotor flow field in conjunction with the nacelle and the radial flow components in the flow around the rotor blade. The example clearly shows the significance of the rotor aerodynamics.

The effect of the variable rotor speed operation can be seen from the flatter curves around the maximum c_P-value. Some c_P-curves show irregularities due to a step-change in the rotor speed at a certain wind speed or a change in the blade pitch control program. This can be observed at wind turbines with two generators or with a pole-changing generator (Chapter 9.3.4).

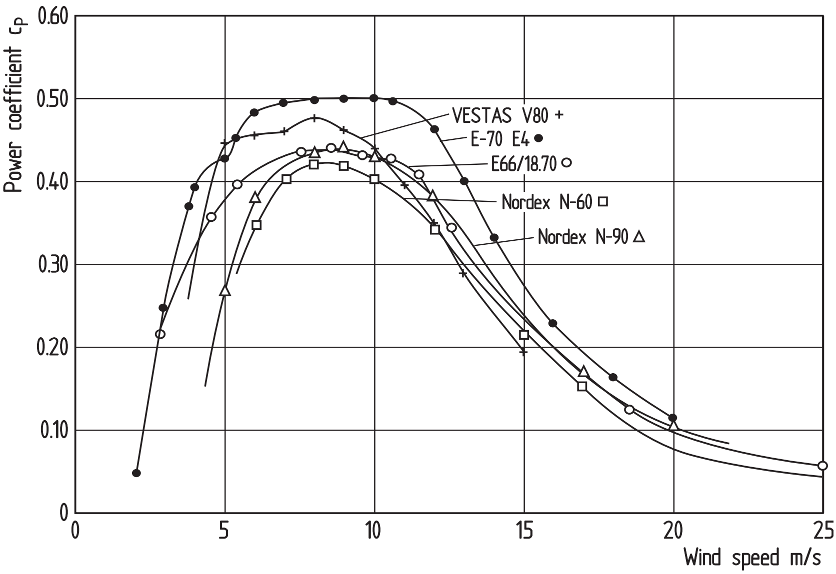


Figure 14.5. Power coefficients of today's wind turbines

When power coefficients are compared, it must be taken into consideration that they are calculated from measured power curves. The same reservations, therefore, apply with regard to the anemometers used (s. Chapt. 14.2.2).

14.1.3
Optimisation of Rotor Speed

The rotor's power characteristics, or more precisely the shape of the c_{PR}-curves, shows that the maximum power coefficient can only be achieved at a certain value of the tip-speed ratio. Plotting the c_{PR}-curves against wind velocity, keeping the rotor speed fixed, it becomes immediately apparent how the variation of the characteristics depends on the wind speed. The peak can be shifted towards lower or higher wider speeds for different rotor speeds (Fig. 14.6). On the other hand, the frequency distribution of the wind speeds at a given site only has its maximum at a certain wind speed.

With the aim of maximising the energy yield, the rotor speed must, therefore, be selected where the widest possible range of the wind speeds expected at the intended site will be exploited with high rotor power coefficients. In other words, the rotor speed must be selected such that the energy yield is maximised. Optimum rotor speed and energy yield are, therefore, calculated as one.

In a real wind turbine, the c_{PR}-curves are limited by the maximum generator power. Thus, the choice of rated power also has a certain influence on the optimum rotor speed. The desired cut-out wind speed represents another restriction whilst the cut-in wind speed is a natural result of the point of intersection of the characteristic with the abscissa with the given aerodynamic rotor design (compare Fig. 14.3).

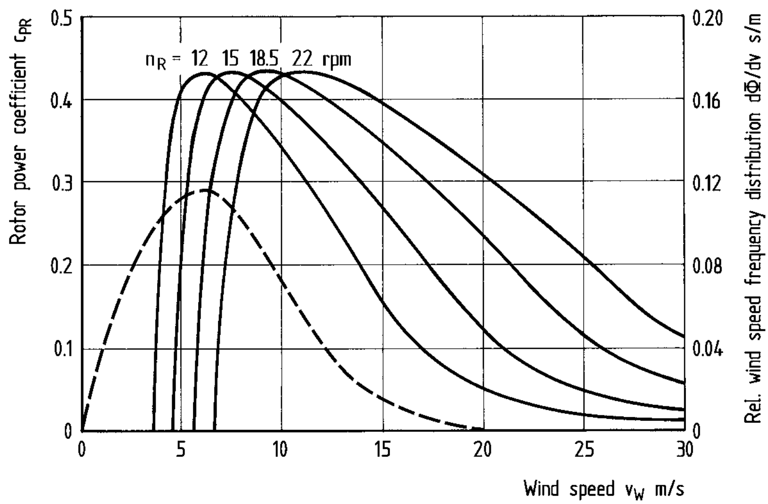


Figure 14.6. Rotor power coefficient against wind speed for different rotor speeds and relative wind speed frequencies at the List site on the island of Sylt, using the Growian experimental test turbine as an example

Using a standard fixed-speed generator confines the rotor to a fixed speed which must be determined carefully. But a variable-speed turbine, too, requires the speed range to be determined so as to maximise the energy yield since the available speed range is limited.

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 c_{PR}-curve vs. wind speed can be determined from the rotor power curves (Fig. 14.7). The mechanical-electrical efficiency provides the wind turbine's power coefficient.

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

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

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

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

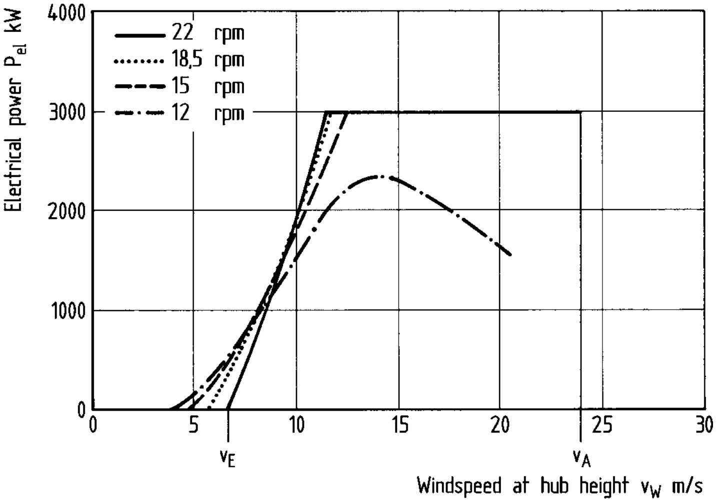


Figure 14.7. Power curves for various rotor speeds in the case of Growian

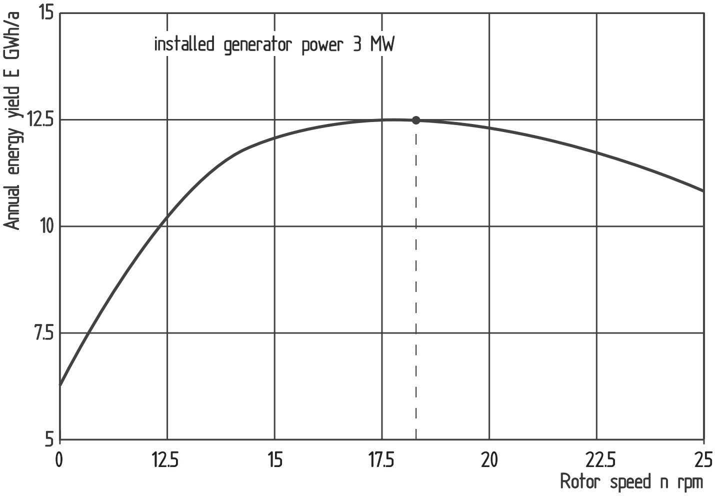


Figure 14.8. Annual energy yield as a function of the rotor speed

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}:

$$E = \sum_{v_E}^{v_A} \Delta E = \sum_{v_E}^{v_A} P_{el}(v_W)\ \Delta t$$

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 vs. the rotor speed shows the maximum energy yield and the corresponding optimum rotor speed (Fig. 14.8). The determination of the optimal rotor speed, 18.5 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.

The flow chart below illustrates the process of calculation with the required parameters and intermediate results (Fig. 14.9). The optimum rotor speed is obtained in an iteration process by maximising the energy yield.

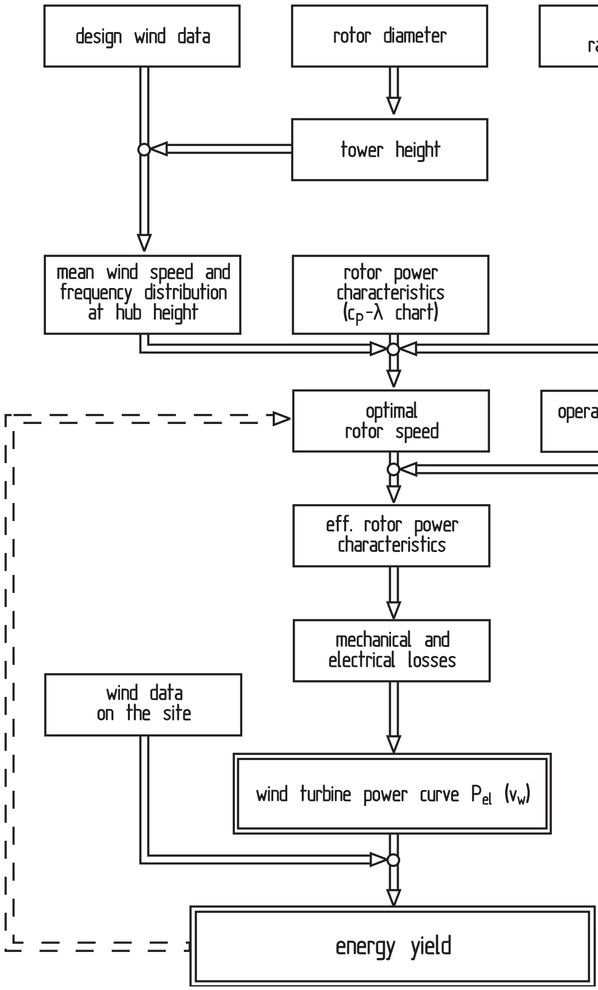


Figure 14.9. Flow chart with parameters for calculating the optimum rotor speed and energy yield

14.2
Power Curve of the Wind Turbine

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 summarises all the essential 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 and Characteristics

The shape of the calculated power curve is determined by three key elements relating power output to wind speed:

- 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.
- 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/m^3 at MSL, temperature 15 °C). The air density, and thus the temperature and the altitude, influence 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).

Since the early eighties, a group of experts of the International Energy Association (IEA) developed recommendations for the definition and determination of the power curve [1]. These were continuously improved and then adopted in a Guideline by the IEC [2]. This standard, IEC 61400-12, is generally accepted as a binding basis for defining and measuring the power curve.

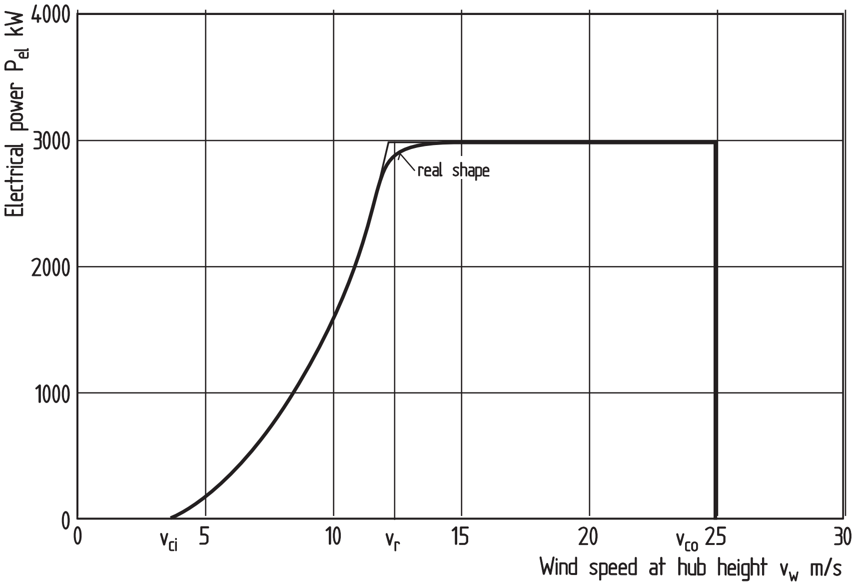


Figure 14.10. Calculated power curve of the experimental Growian turbine

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 table 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 noncorrespondence 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

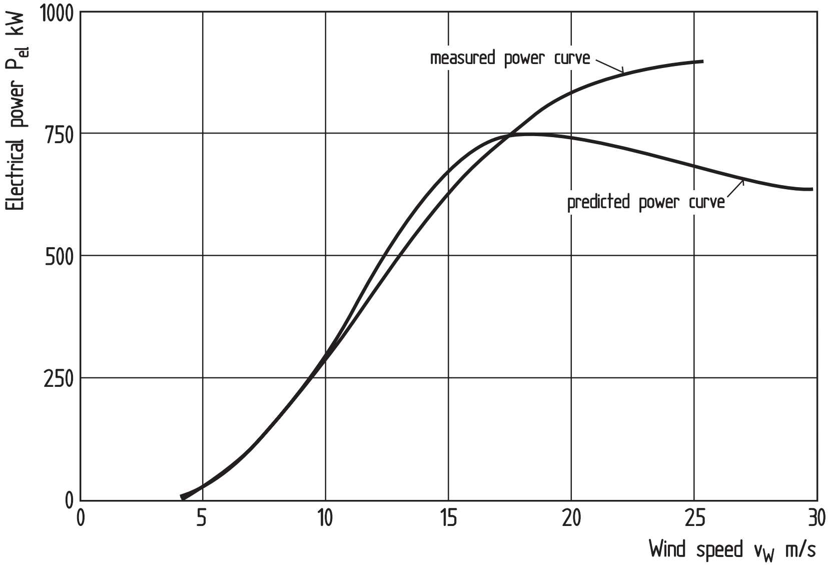


Figure 14.11. Typical deviation of a measured curve from the calculated curve for a stall-controlled turbine

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.

14.2.2
Measuring the Power Curve

Wind turbines having a power curve based only on theoretical calculations are sold only in exceptional cases. As a rule, the power curve of all commercial wind turbines is 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 [3].

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 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 metereological 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 Fig. 14.12.

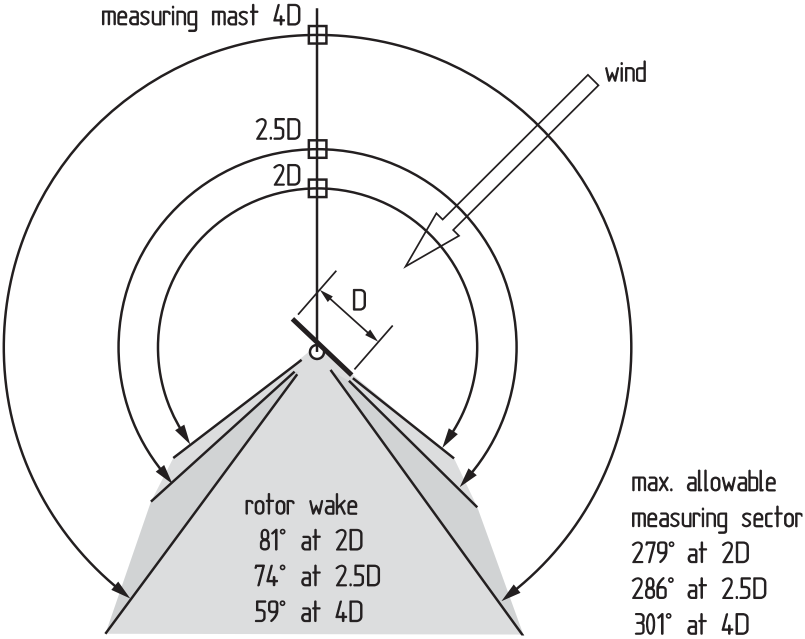


Figure 14.12. Position of the meteorological mast for measuring the power curve of a wind turbine according to IEC 6100-12 [1]. Wind measurement 2 to 4 rotor diameters from the wind turbine (recommended distance 2.5 D)

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 [4]. 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/m^3). 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 normlized 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 result is the "*normalized and averaged power curve*".

Power coefficient

The power coefficient c_p of the wind turbine shall be added to the test results and presented. 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 can not 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 diagramm and in a form of a table. For each wind-speed bin the table shall list (Fig. 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 producion

The annual energy production 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.

A particular problem is the power performance of wind turbines in complex terrain. The distribution of wind turbines to inland sites and mountain regions experienced in several cases significant deviations from the predicted annual energy production, so that doubts about the power curve of the wind turbines were expressed. It is a matter of fact

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**

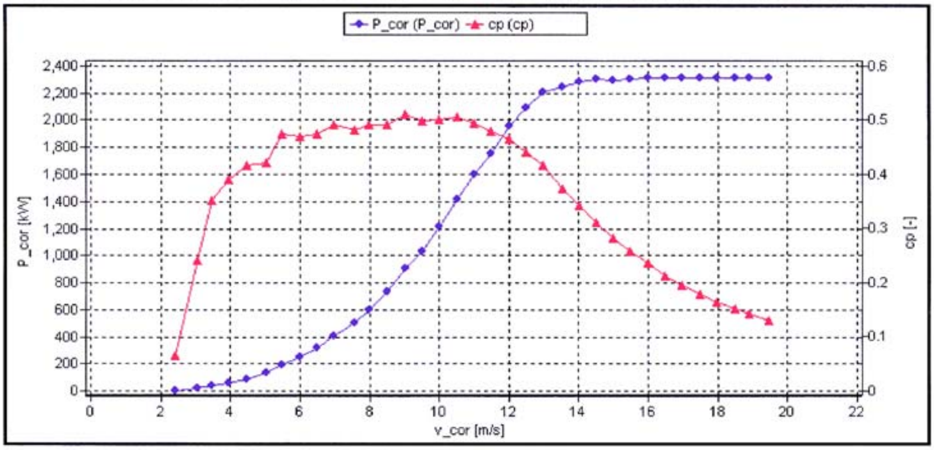
Scope of Measurement and Information about Sensors

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.

Figure 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

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

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

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

Figure 14.14. Measured power curve and calculated annual energy production including standard uncertainities according to IEC 61400-12 (DEWI)

that other wind flow characteristics than the mean wind speed measured over 10 minutes and the air density have an influence on the average power output in a ten minutes period.

These other variables include turbulence fluctuations of wind speed in three directions, the inclination of the flow vector relative to horizontal, scale of turbulence and shear of mean wind speed over the rotor, but also operational characteristics like a certain hysteresis in the cut-in and cut-out behaviour of the wind turbine which, again depends on the turbulence level on the site. Presently, analytical tools offer little help in identification of the impact of these variables and experimental methods encounter equally serious difficulties. The result is that the power curve will vary from one site to the next, but since the other influential variables are not measured and taken into account, the variation in the power curve will appear as uncertainty. Quantification of this apparent uncertainty is difficult. Depending on site conditions and climate, the uncertainty may amount to several percent. In general terms, the uncertainty may be expected to increase with increasing complexity of topography and with increasing frequency of non-neutral atmospheric conditions.

From the user's point of view this means either he has to assess these influences by using his own expertise and experience or he has to include the supplier of the wind turbine in the site assessment and ask for a site-specific power curve.

14.3 Calculation of the Annual Energy Yield

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 (Fig. 14.15 and 14.16). 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:

$$E = \frac{8760}{100} \sum_{v_E}^{v_A} P_{el}\, \Phi \qquad \text{(kWh/a)}$$

where the power output P_{el} is given in kW and the wind frequency distribution Φ in %. The annual energy yield is then obtained by summing from v_E to v_A, the duration of the wind velocity within an interval being given in hours in accordance with the frequency distribution.

It is common practice to specify the energy output of a wind turbine over one year and as annual energy yield. An illustrative graphical representation of the annual power output is given in Fig. 14.17 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

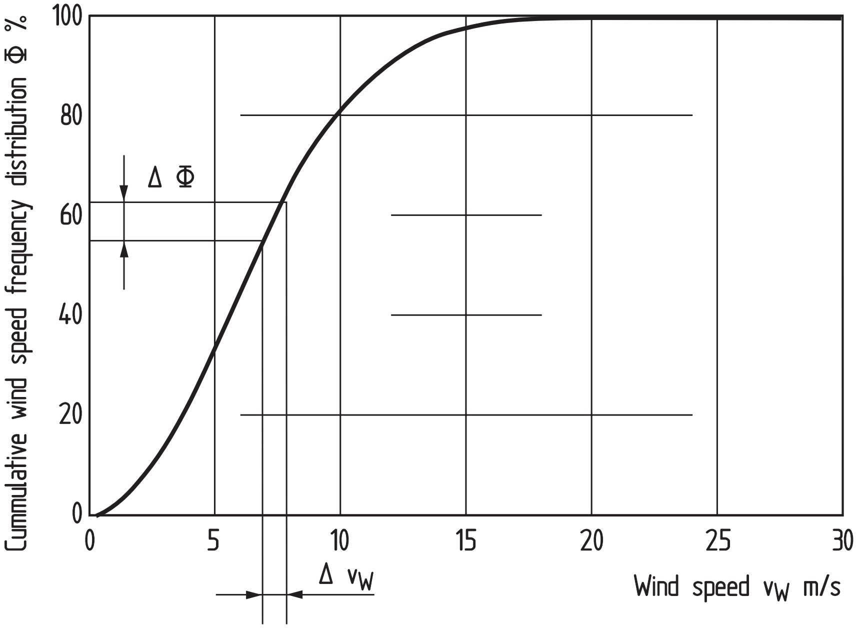


Figure 14.15. Subdividing the frequency distribution of the wind speeds into wind speed intervals (method of bins)

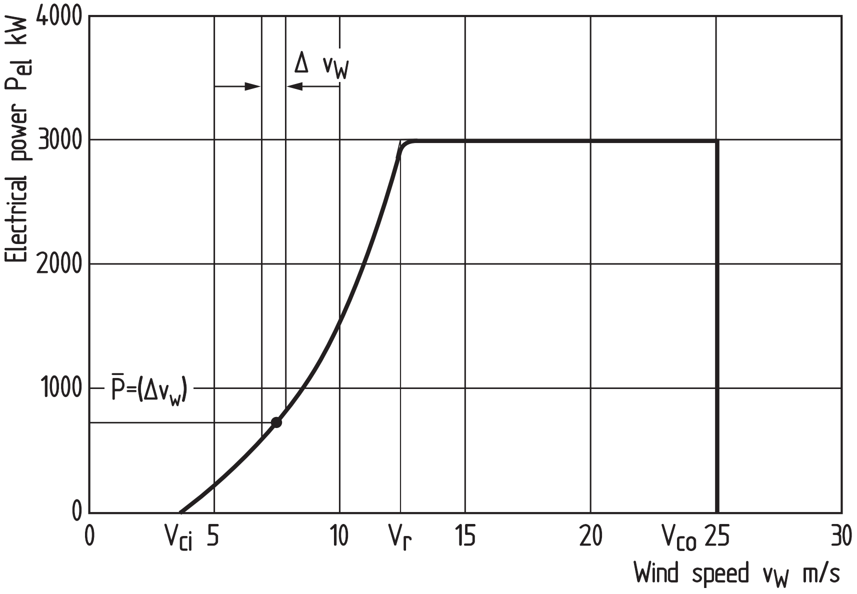


Figure 14.16. Power curve of the wind turbine

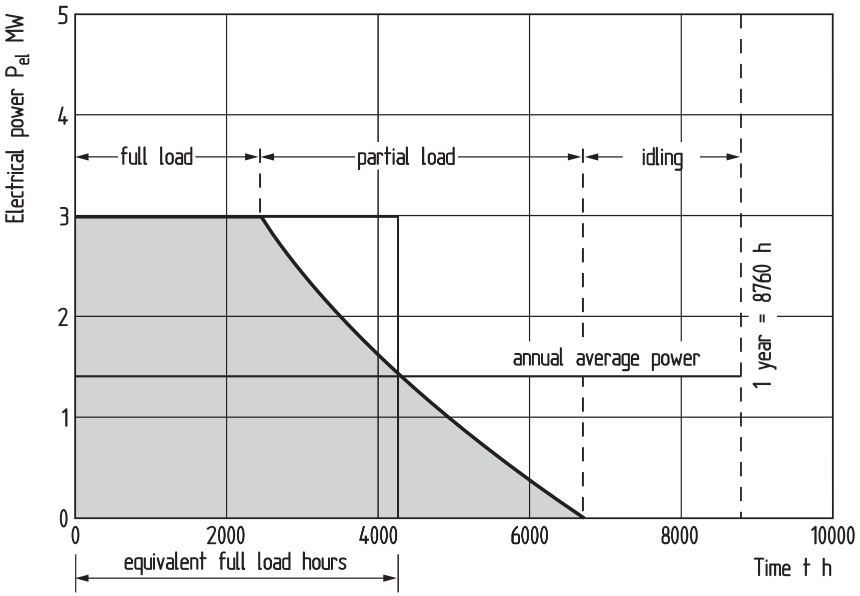


Figure 14.17. Graded annual power output and related technical terms using Growian as the example (wind conditions at List on the island of Sylt)

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. These are of importance especially in the case of calculated values. For this case, too, the IEC 61400-12 has several recommendations [2]:

- 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 of 4–11 m/s at rotor hub height. The frequency distribution of the wind speeds should be assumed as a Weibull function with a form parameter of $\beta = 2$ (Rayleigh distribution).

14.4 Major Influences on the Power Curve and the Energy Yield

At the design stage and to a certain extent when planning the installation of a wind turbine, questions arise as to what extent technical modifications or a different wind regime will influence the energy output. In the discussion of the calculation method, the major influencing parameters already became apparent. But even without the help of a computer, the user should develop a sense of the quantitative significance of these influencing factors. This assessment is important to the user in his search for a suitable site, but also with regard to a possible adaptation of some of the turbine's technical features. 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 influencing variables 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 experimental Growian turbine as an example, using the wind regime of List on the island of Sylt as a basis. These data correspond to the wind conditions at an excellent wind site.

14.4.1 Wind Regime on Site

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 main determining factors for the energy yield are three characteristics of the wind regime: the mean annual wind speed, the frequency distribution of the wind speeds and the shear-wind profile with elevation (Chapt. 13).

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 partial-load/full-load ratio, 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. 14.18).

The frequency distribution of the wind speeds has considerably less influence on the energy output. Figures 14.19 and 14.20 show these relationships for sites with different frequency distributions with an approximately equally high mean annual wind speed.

In most cases, the wind speed at hub height must be extrapolated from the measured values recorded at the usual measuring height of 10 m. This poses the problem of determining the vertical wind shear and the uncertainty can be considerable. Assuming different, but reasonable, values for the wind shear exponent (Hellmann exponent) noticeably changes the mean wind speed at hub height and thus also the energy yield to be expected (Fig. 14.21).

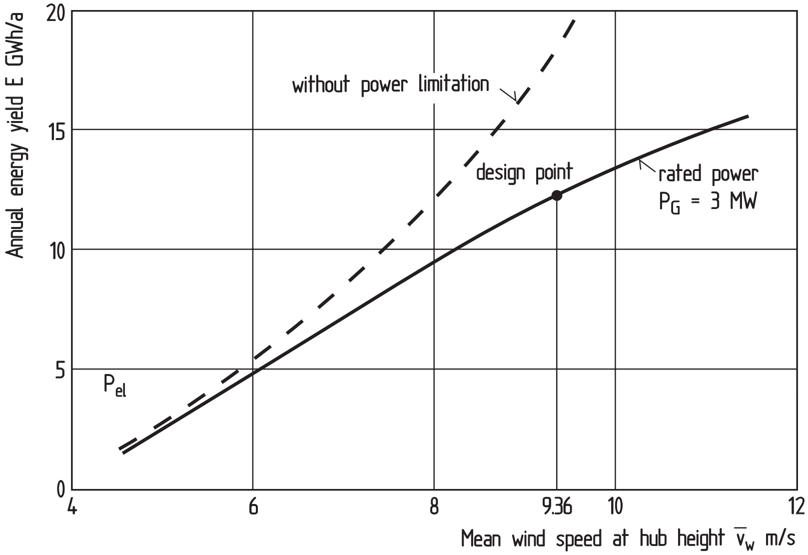


Figure 14.18. Increase in the annual energy yield with increasing mean annual wind speed, for the Growian turbine

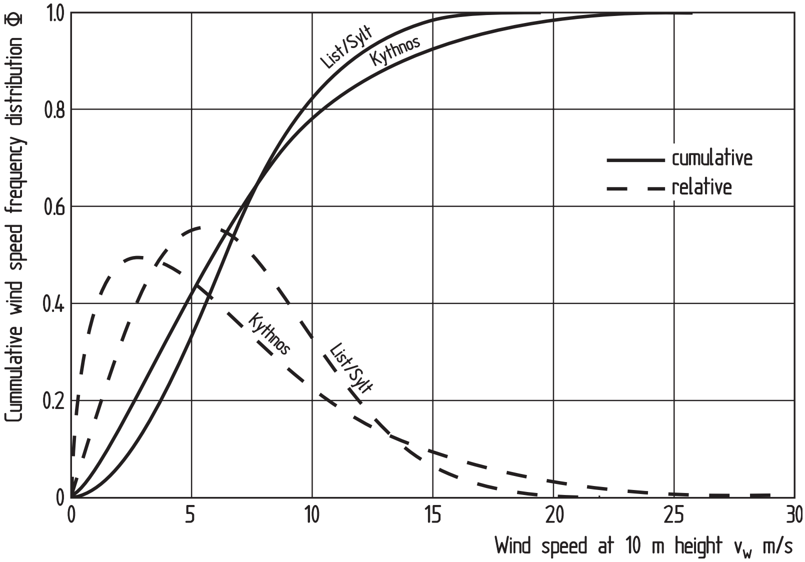


Figure 14.19. Frequency distribution of the wind speed of two sites with approximately the same mean annual wind speed but different frequency distribution of the wind speeds (List on the island of Sylt, and Kythnos in Greece)

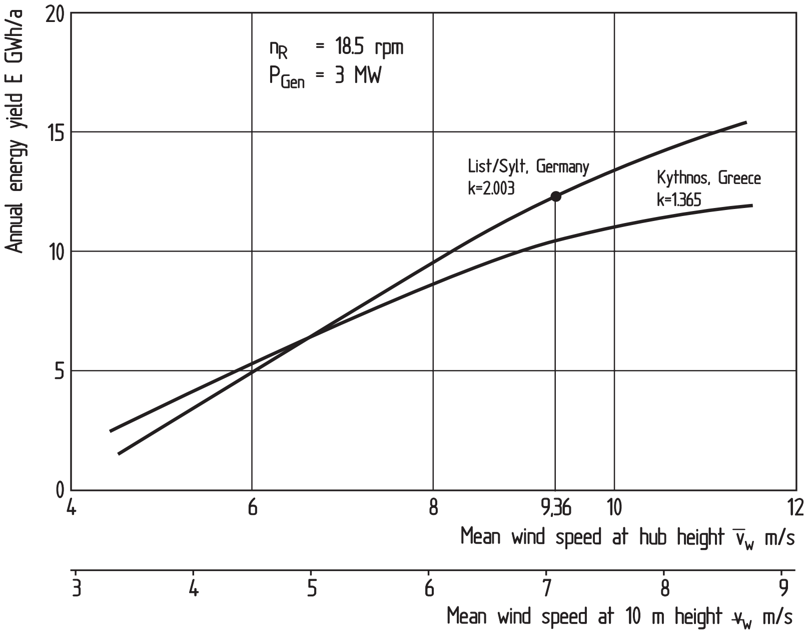


Figure 14.20. Annual energy yield of the Growian turbine for sites with different frequency distributions but the same mean annual wind speed

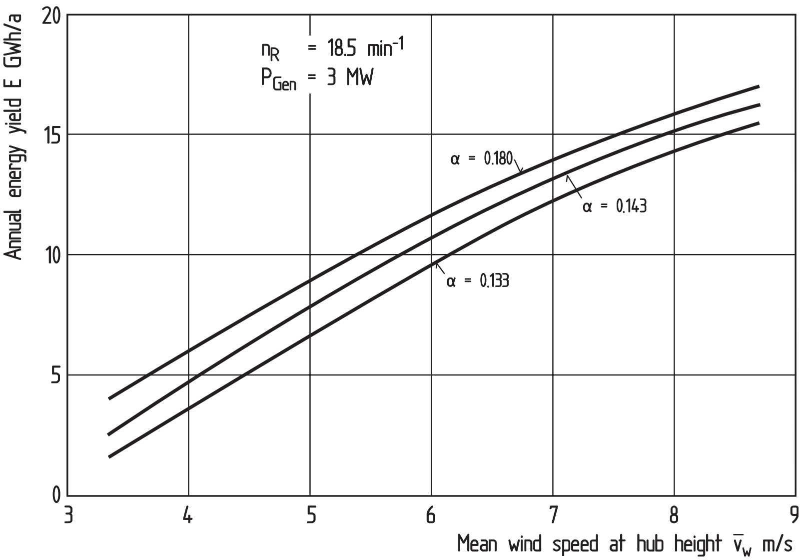


Figure 14.21. Influence of different shear wind profiles (Hellmann exponent) on the energy yield, using the Growian turbine as an example

14.4.2 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.

It is well known that air density decreases with altitude so that 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. 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 ($\varrho_0 = 1.225$ kg/m^3)
T_0 = 288.15 K at 15 °C at MSL
p_0 = air pressure at MSL (p_0 = 1013.3 mbar)
t = temperature at altitude H (°C)

For a stall controlled wind turbine the power corrected to standard condition is:

$$P_H = P_0 \cdot \frac{\varrho_H}{\varrho_0}$$

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. 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.

The power of wind turbines with stall-limited energy absorption is reduced over the entire range of wind speeds. 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. 14.22). 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 Fig. 14.22 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 %

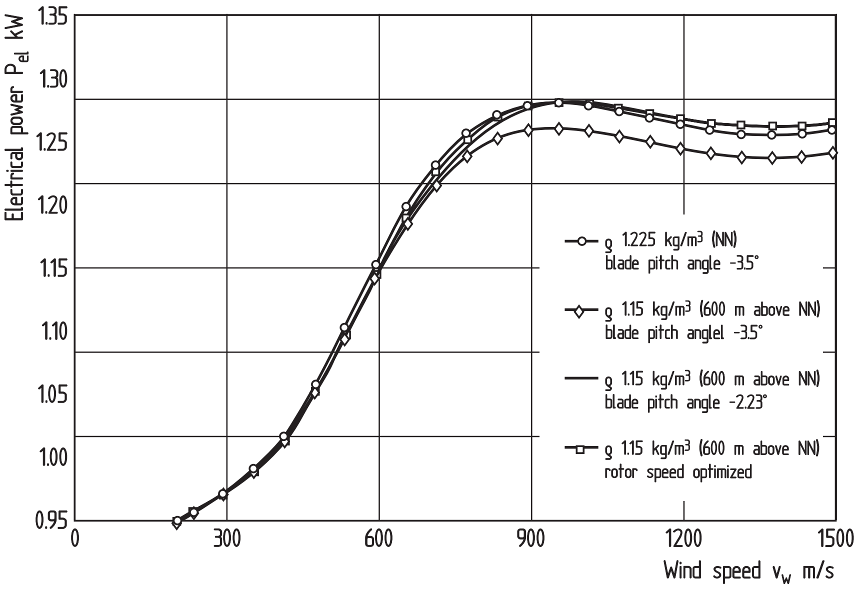


Figure 14.22. Optimization of the power curve of a stall-controlled turbine at an elevation of 600 m above MSL

– 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).

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 the 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. 14.23). An approximate correction is given by the formula:

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

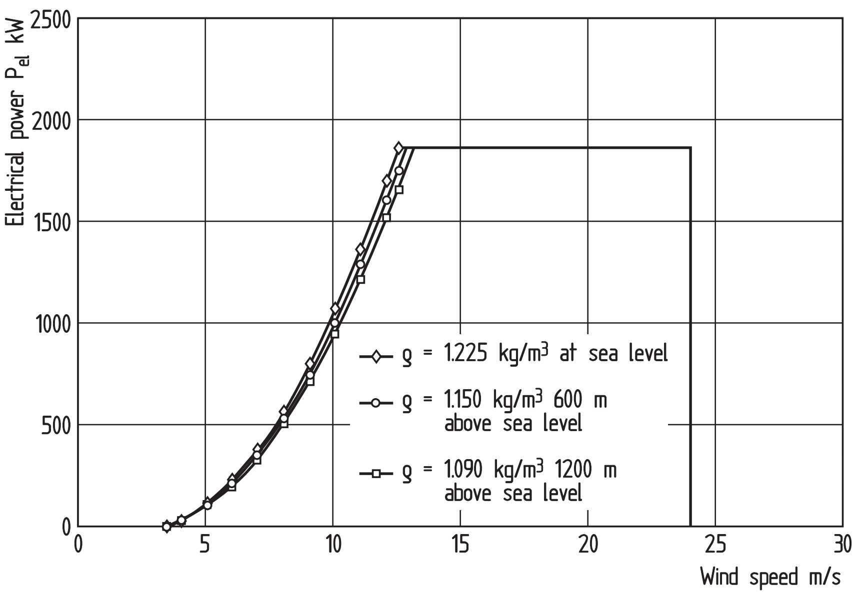


Figure 14.23. Variation of the power curve of a blade-pitch controlled turbine at an installed altitude of 600 m and 1200 m above MSL (without correction of the rotor speed)

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 increases in site elevation but can be operated losslessly optimally with blade pitch angles corrected for changing temperatures.

14.4.3 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. Positive contributions of the higher air density to the power characteristic of a wind turbine are, therefore, observed only in the low-wind speed range [5].

Under practical conditions, a high turbulence intensity has a negative influence on the power performance of the wind turbine in nearly all cases. The control system is not able to respond in an optimal way to the fast and large fluctuations of the wind speed. Moreover, local stall situations can occurs on the rotor blades, an effect which is especially important for stall controlled rotors. The result is that the power curve decreases, particularly near the rated wind speed. Figure 14.24 shows an example of a measurement at different turbulence intensities . It is obvious that, if the power curve is to be measured properly, attention must be paid to adhering to certain limit values of turbulence intensity [6].

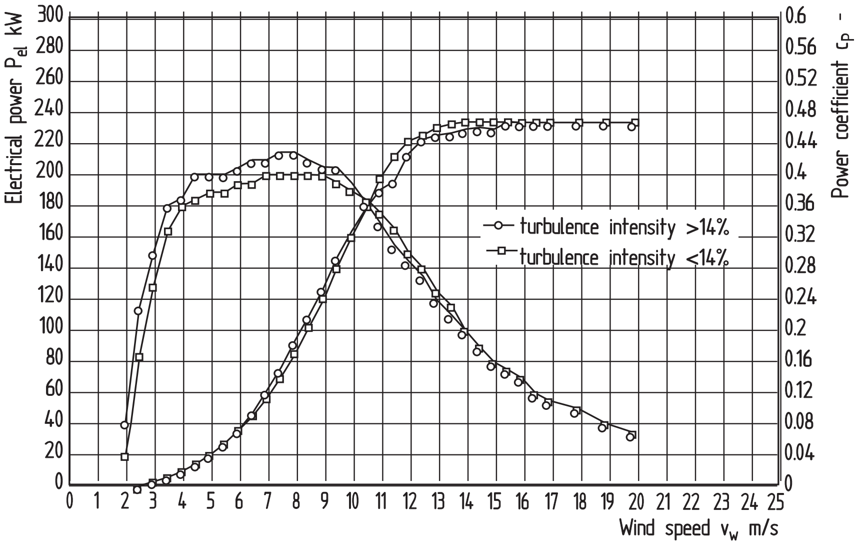


Figure 14.24. Measurements of the power curve at different turbulence intensities on the example of an Enercon E-30 [6]

14.4.4 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 that 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.

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. 14.25).

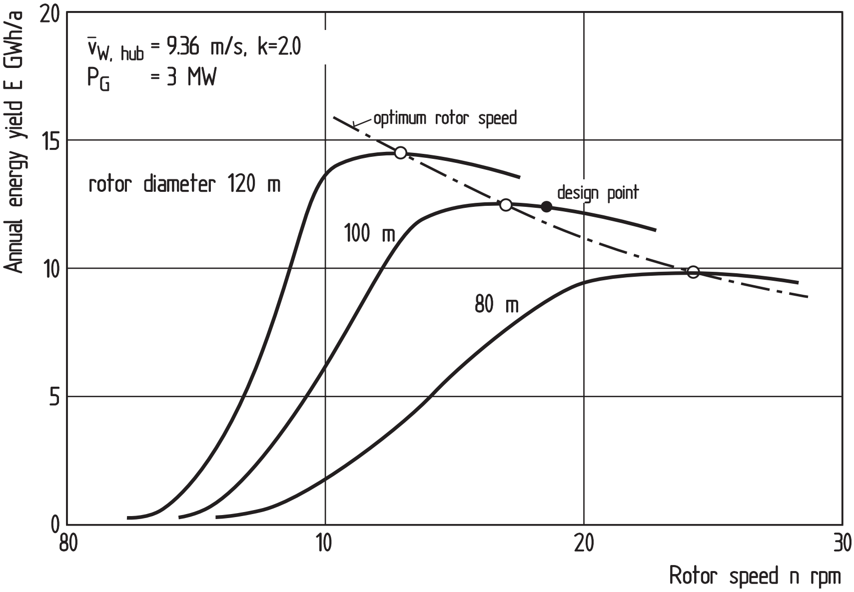


Figure 14.25. Optimum rotor speed for different rotor diameters

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 wind speed, where the power output is limited by the generator maximum power, there is no increase in the energy yield with higher wind speed (see Chapt. 14.4.1). This means a significant gain in energy yield is only achieved with a simultaneous increase in rated generator power.

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 class (Chapt. 6.8).

14.4.5 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 again Growian as an example, Fig. 14.26 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.

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. If possible, it should cover the complete partial-load range, from cut-in speed to rated wind speed. For common values of the rated power per rotor swept area, this means a speed range of 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 % (Fig. 14.27 and 14.28).

In nearly all cases the energy increase due to variable-speed, wind-oriented operation is 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, reduced aerodynamic noise during partial load operation and a smoother power output may possibly count for more than the modest increase in energy yield.

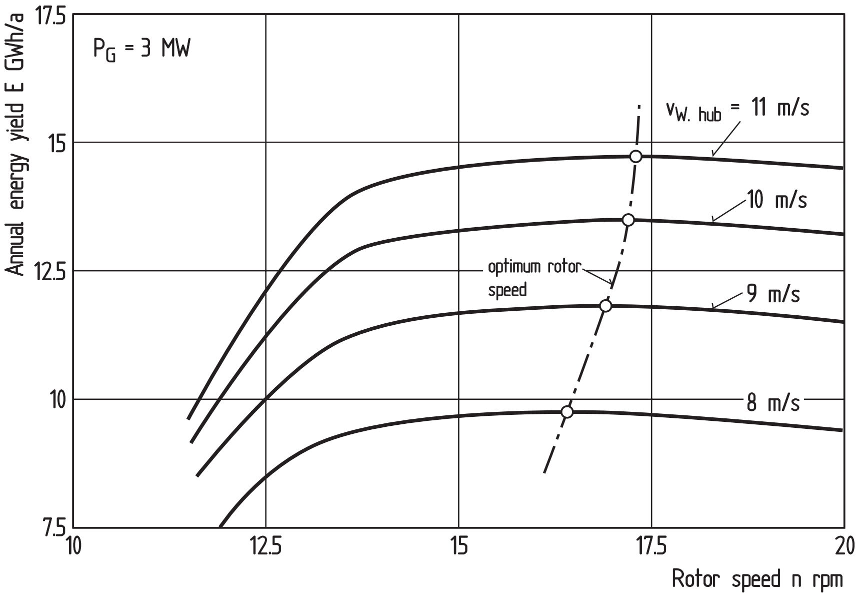


Figure 14.26. Influence of the mean annual wind speed on the optimal rotor speed at the example of Growian

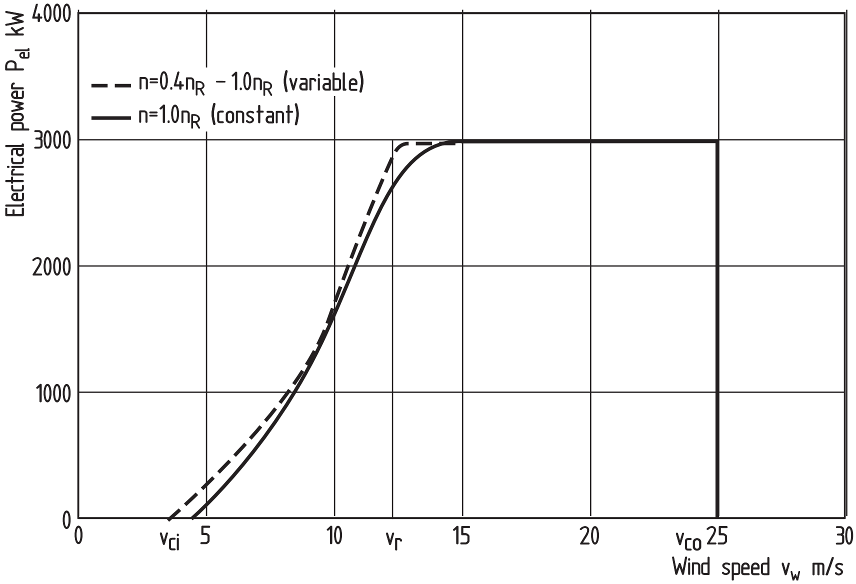


Figure 14.27. Influence of variable-speed operation in the range of 40 to 100 % of the rated speed on the energy yield, for Growian

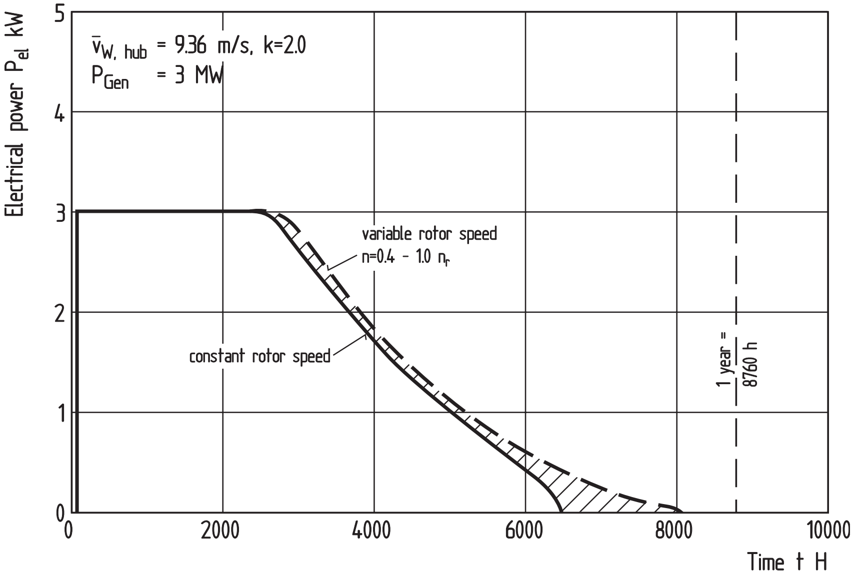


Figure 14.28. Added energy yield due to variable-speed operation shown in the continuous annual energy yield line of the Growian turbine

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. Two fixed rotor speeds provide almost the same energetic yield as 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 (Chapt. 6.6.3).

14.4.6 Power Control

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.

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).

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.

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.

14.4.7 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. 14.29).

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.

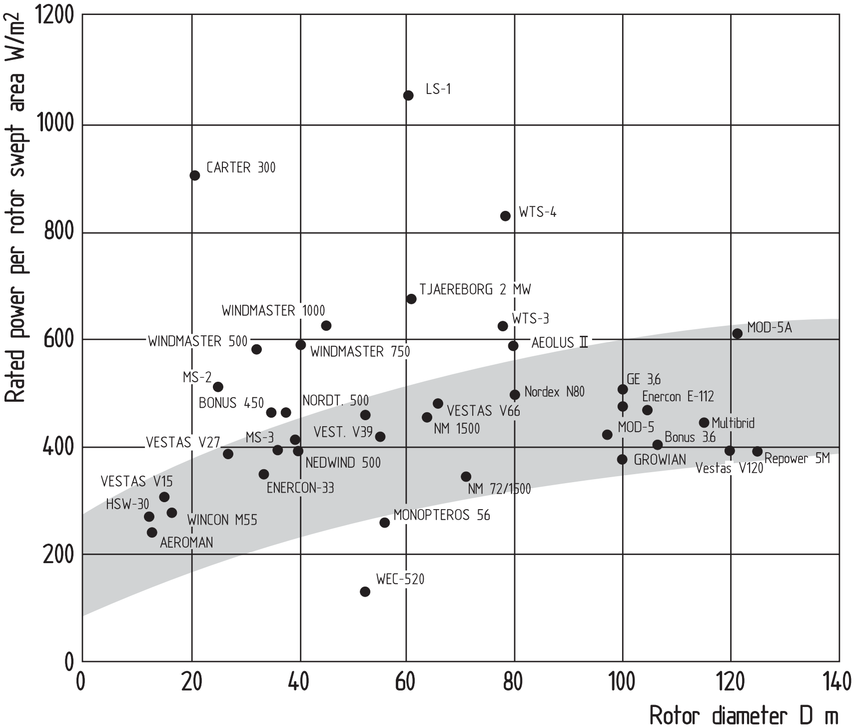


Figure 14.29. Ratio of rated power per rotor swept area of existing wind turbines

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 decisive 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 (Fig. 14.30).

An interesting question would be to what extent the theoretically possible energy capture is exploited by existing wind turbine designs. Table 14.31 shows examples for a site with a high mean annual wind speed of 6 m/s at 10 m hub height. The ratio of rated power to rotor area of the wind turbines is clearly established such that approximately 80 to 95 % of the

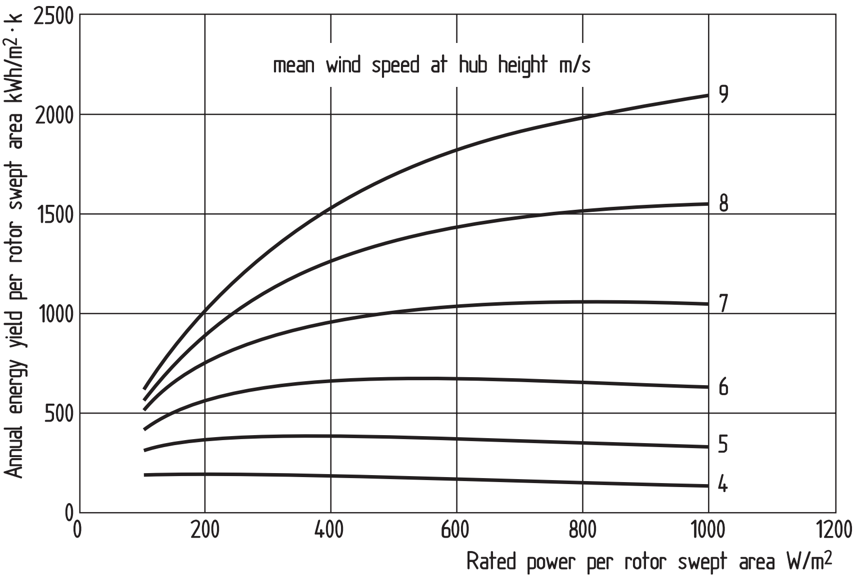


Figure 14.30. Influence of rated power per rotor swept area on the energy yield for various mean annual wind speeds

Table 14.31. Exploitation of the theoretically possible specific energy yield for a site with a mean annual wind speed of 6 m/s at hub height

Parameter / Wind turbine	Ratio of rated power to rotor swept area (W/m^2)	Wind speed at hub height (m/s)	Theoretical possible spec. energy yield (kWh/m^2)	Actual energy yield (kWh/m^2)	$\frac{E_{act.}}{E_{theo.}}$ (%)
Vestas V15 (stall) 15.3 m ∅, 55 kW, $H = 23$ m	294	6.75	950	800	0.84
Bonus 450 (stall) 35 m ∅, 450 kW, $H = 36$ m	467	7.20	1120	980	0.87
Tjaereborg 61 m ∅, 2000 kW, $H = 61$ m	684	7.75	1450	1350	0.93
Westinghouse 600 43.3 m ∅, 600 kW, $H = 36.6$ m	408	7.20	1120	1020	0.91
WTS-3 78 m ∅, 3000 kW, $H = 80$ m	627	8.10	1600	1500	0.93
MOD-5B 97.5 m ∅, 3200 kW, $H = 77$ m	429	8.05	1600	1320	0.82
Monopteros 50 56 m ∅, 640 kW, $H = 60$ m	260	7.75	1380	980	0.71

theoretically possible energy capture is achieved on a good site with a mean annual wind speed of 6 m/s at hub height. As expected, higher values are found in the stall-controlled turbines, whereas the blade-pitch controlled turbines are designed for lower values. These numerical values are possibly a useful compromise for wind turbines of conventional design, avoiding extremely high, cost-ineffective power outputs without, on the other hand, "giving away" an uneconomically high amount of energy.

14.4.8
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, regardless of the question of a building licence Chapt 13.3.2). In general, offshore sites and land sites close to the coast differ from typical inland sites. The increase in wind speed with height is less at inland locations because of the greater roughness of the ground (Fig. 14.32). 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

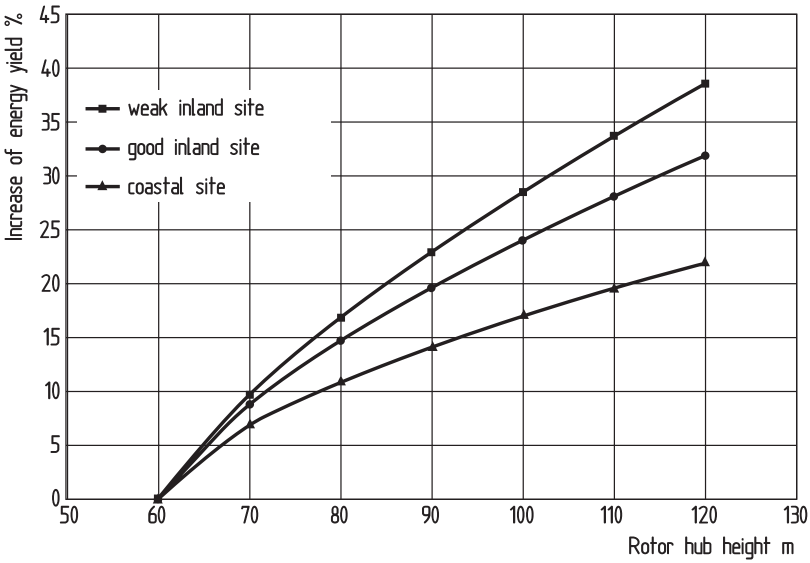


Figure 14.32. Energy yield at different rotor hub height (tower height) for a coastal site and for an inland site

for some years, are a decisive prerequisite for the economic utilisation of wind energy in inland areas.

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. 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 60 m. As explained in Chapter 13.3.2, the approaches used today for determining the increase in mean wind velocity at heights of more than 60 m are not very reliable.

Practical experience has shown that, at least in inland regions with great surface roughness, the increase in wind speed with increasing height above the Prandtl layer is greater than predicted by the conventional methods from the European Wind Atlas (Chapt. 13.5.2 and 13.5.3). For this reason, inland towers with up to 120 m height have been found to be the optimum solution from economic points of view.

14.4.9
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, as a rule 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: using Growian as an example, Fig. 14.33 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.

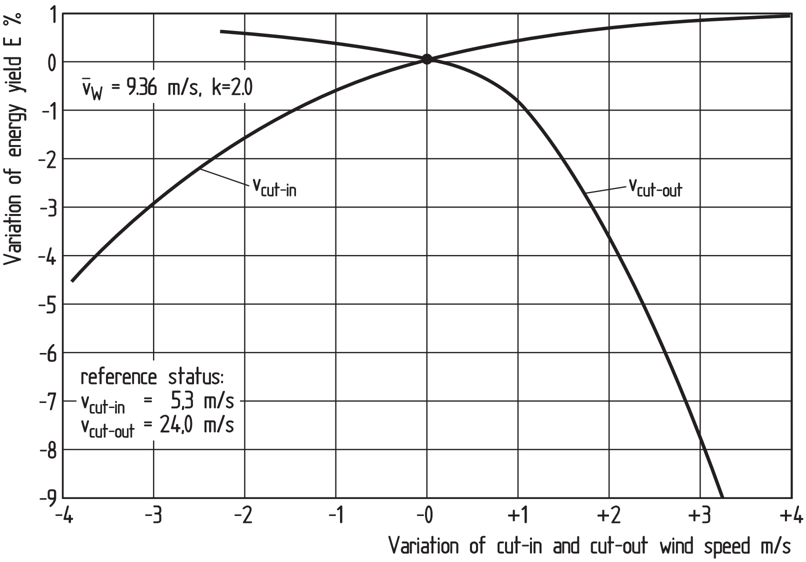


Figure 14.33. Influence of the operational wind speed range on the annual energy yield, using the Growian turbine as an example

14.4.10
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).

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 of the Growian turbine, albeit for a site with high mean wind speed.

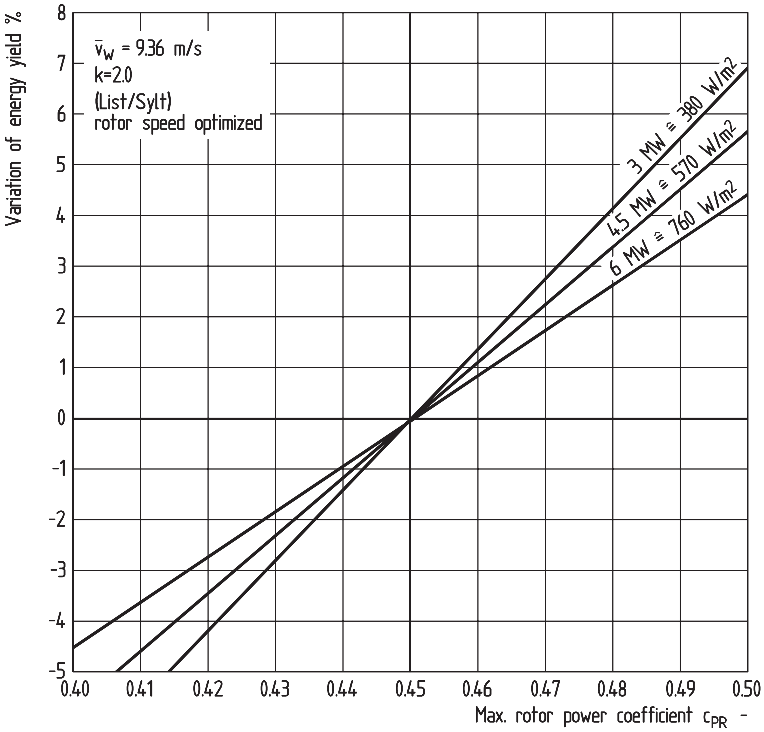


Figure 14.34. Influence of the maximum rotor power coefficient on the energy yield of the Growian turbine at List on the island of Sylt

14.5 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. Figs. 14.35 to 14.37 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. 14.35). 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 [5]. In any case, there is a not inconsiderable fluctuation which becomes visible at a certain temporal resolution (Fig. 14.36), whereas power output becomes almost completely smooth with variable speed operation (Fig. 14.37).

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.

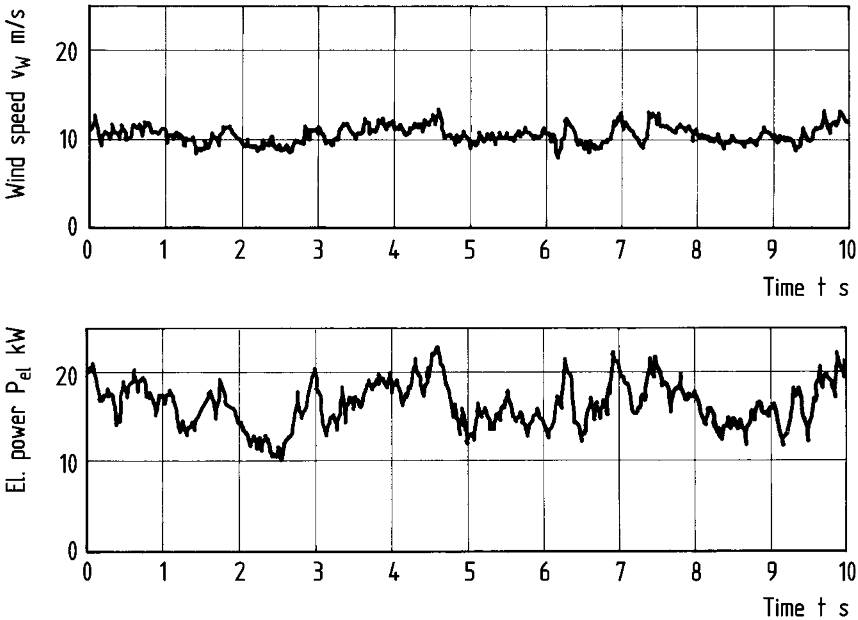


Figure 14.35. Electrical power output of a small wind turbine with fixed blade pitch angle and a grid-coupled induction generator

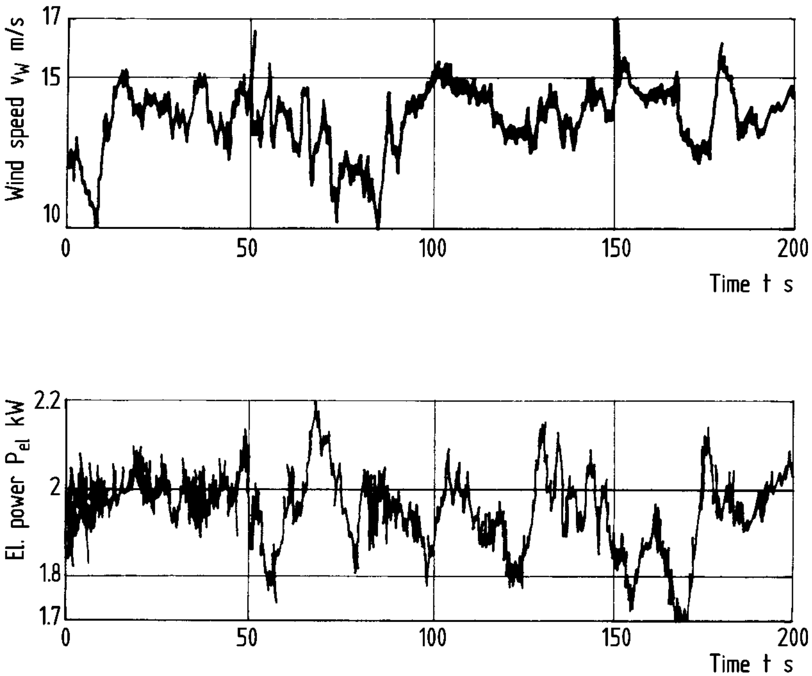


Figure 14.36. Power output of the Tjaereborg wind turbine with blade pitch control and a direct-coupled induction generator (generator slip appr. 2 %) [7]

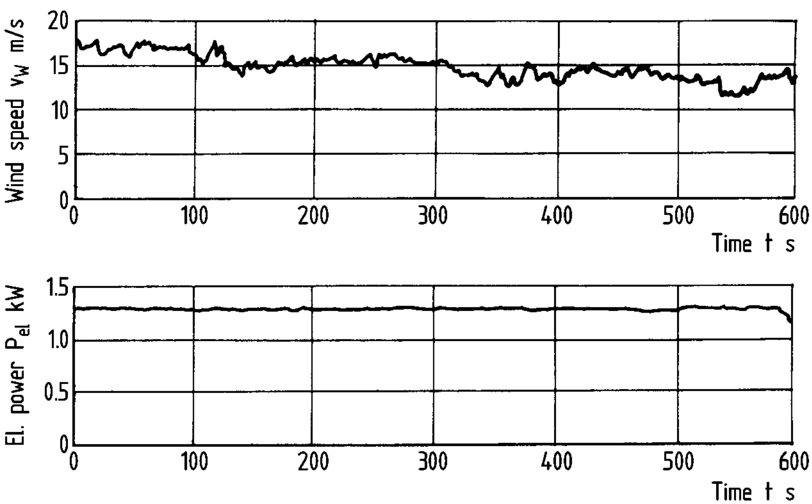


Figure 14.37. Power output of the WKA-60 wind turbine with blade pitch control and variable speed generator system (speed variation ± 15 %) [8]

14.6 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 Fig. 14.38 is intended to serve this purpose.

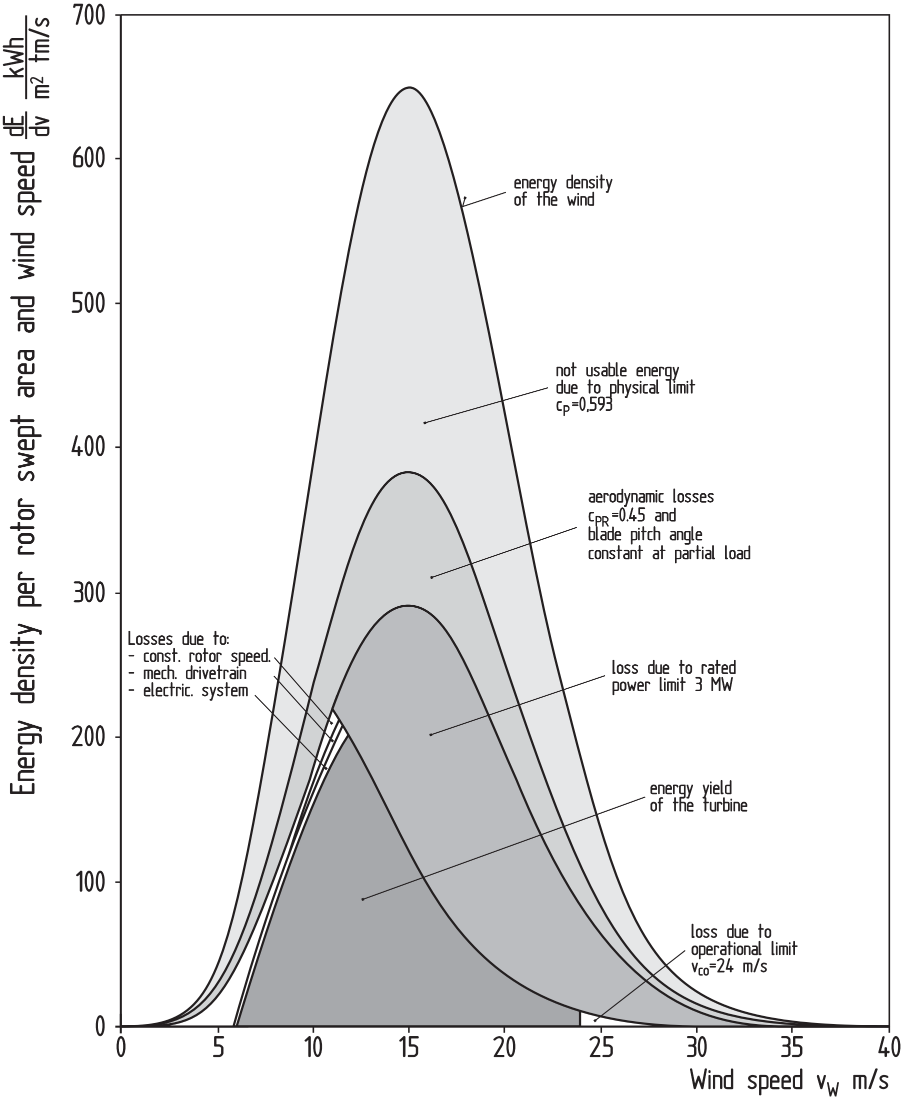


Figure 14.38. The wind turbine as energy converter, using Growian as an example

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.

14.7 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 two- or 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:

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

where:

π = ratio of rated power to rotor-swept area (W/m^2)
ϱ = air density (1.225 kg/m^3 at MSL)
$c_{p\,R}$ = rotor power coefficient at rated power (appr. 0.40 for two-bladed rotors and slightly above for three-bladed rotors)

Figure 14.39 shows that, for some reference turbines, 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.

The accuracy of this 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 blade-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.

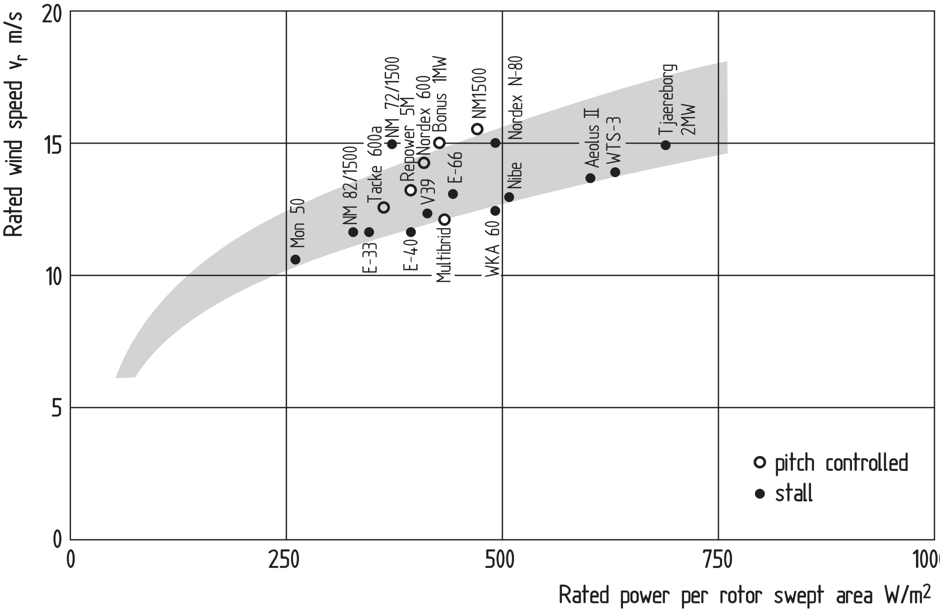


Figure 14.39. Relationship between the rated wind speed and the ratio of rated power to rotor-swept area

In addition, many of these rotors are operated at a lower speed than that which produces optimum results with respect to energy yield (Table 14.31). 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 14.39 and 14.40 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. Fig. 14.40 shows the usage time versus mean annual wind speed at hub height with 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. If the prevailing conditions differ from the average, an accurate calculation must be performed, taking into consideration all the turbine data. 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 optimum speed aerodynamically and thus largely avoid this loss in power. The diagram is also related to the two-bladed rotor of the Growian turbine so that a bonus of about 3 % is justified for the more recent three-bladed rotors.

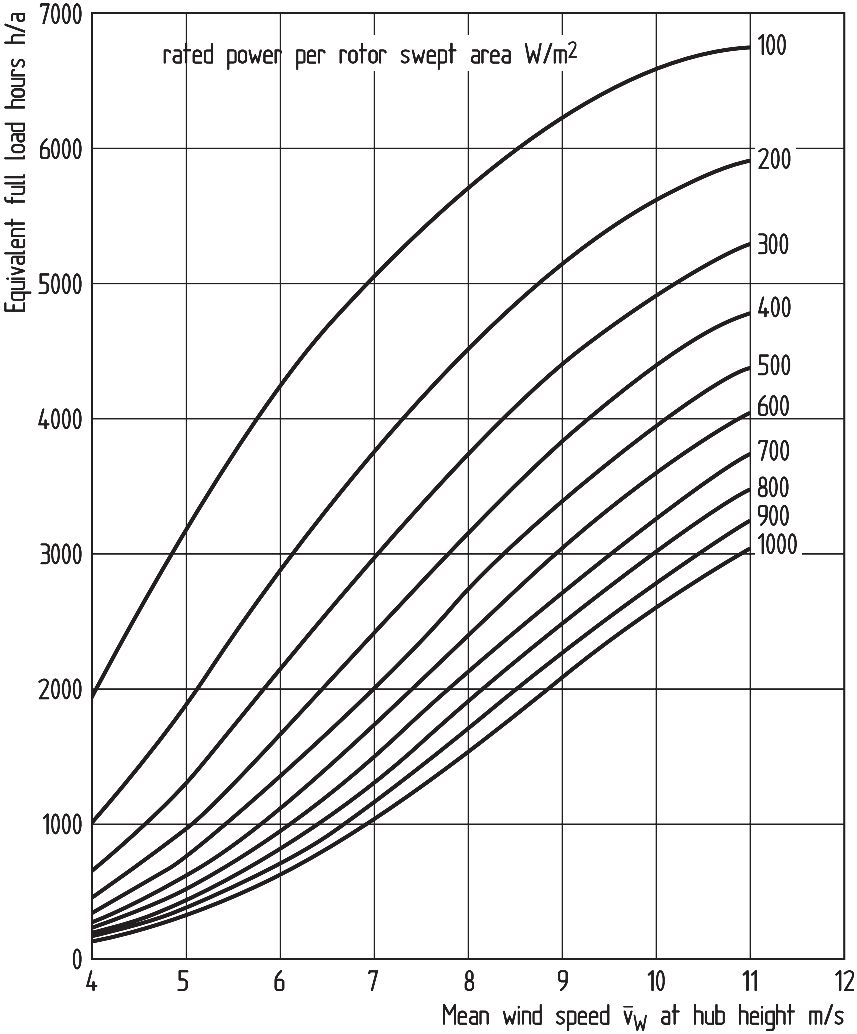


Figure 14.40. Approximate calculation of the full-load hours of a wind turbine as a function of the mean annual wind speed and the rated power per rotor-swept area (assumed technical availability 100 %)

14.8 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 [9]. 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 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 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 turbine 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 [10]:

– 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 important factor in the contractual specifications is the times which are *not* counted as non-availability, e. g.:

- 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)
- "trivial" standstill times for whatever reasons, e. g. of less than 5 hours per year.

An important aspect of the definition of availability is the acquisition and documentation of the above times 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. 14.41). However, the reliability of the turbines increased continuously. For the last ten years, availability values of 98 % and more have been achieved [10]. 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 95 %, achieved by servicing and maintenance costing, e. g. 10 % of the total investment, is a disastrous result. A commercially viable situation requires an availability of at least 95 % with annual maintenance costs of no more than 2 to 3 % of the investment cost.

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 $\overline{P}$, which is output by the wind turbine yields in a calendar year, and the rated power P_R:

$$c = \frac{\overline{P}}{P_R}$$

or it is calculated from the annual energy yield:

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

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

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

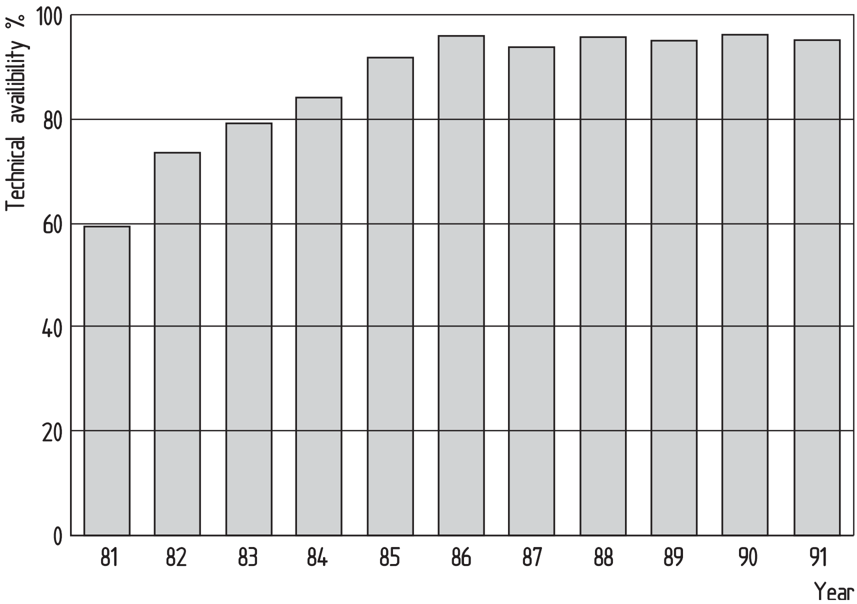


Figure 14.41. Development of the technical availability of the Danish wind turbines over the last ten years [11]

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

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 with 15 m rotor diameter and 55 kW rated power,
  rated power per rotor-swept area 311 W/m²,
  annual energy yield 110 000 kWh,
  capacity factor = 0.23,
  usage time = 2000 hours,
- Large turbine with 60 m rotor diameter and 1200 kW rated power,
  rated power per rotor-swept area 424 W/m²,
  annual energy yield 3.5 million kWh,
  capacity factor = 0.33,
  usage time = 2916 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.

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Chapter 15

Environmental Impact

Discussing the characteristics of energy sources without simultaneously considering the impact they have on the environment is no longer possible these days. Wind turbines do not pollute the atmosphere with carbon dioxide, sulphur or hydrocarbons, nor will they cause problems for present and following generations with regard to the disposal of radioactive waste. The utilisation of wind energy thus unreservedly deserves the attribute "environmentally friendly". All the same, even the operation of wind turbines is not without its effects on the environment.

In contrast to large conventional power plants, the environmental impact of wind turbines only affects their immediate surroundings. This localisation of their impact indicates that it must be seen as site-related and can, therefore, largely be avoided by a sensible choice of site. Even in the densely populated industrial countries, the areas designated for the exploitation of wind energy are not so densely built up so as not to offer even some limited choice. Then again, sites which are entirely unpopulated are indeed an exception. Wind turbines must, therefore, be acceptable with respect to their environmental impact, for instance noise emission, in more or less densely populated areas and their environmental impact must be considered with this in mind.

The most important effects on the immediate environment emanating from wind turbines can be calculated objectively and can today be substantiated by long years of experience. This includes noise emission, shadow effects or possible interference with radio and television signals. Possible effects on plant and animal life, especially with respect to the behaviour of birds, have been researched less thoroughly and lasting changes in these areas, caused by the installation and operation of wind turbines, can only be ascertained over very long periods of time.

The visual effect of a large number of big wind turbines in the landscape is increasingly the subject of controversial discussions, and the assessment of this aspect will always be subjectively tinged. It also reveals a general attitude towards the value of renewable energies. The personal attitude of an individual depends on whether he or she places a higher value on the contribution of wind turbines to the global protection of the environment or on the preservation of a local landscape.

Last but not least one should be aware of the fact that there is no way for power generation employing any source of primary energy to have no impact on the environment.

15.1
Hazards for the Environment

The only possible threat to the surroundings of a wind turbine is posed by parts of the rotor flying off. The danger of the entire turbine toppling over at extreme wind speeds, burying underneath it the people around it, is a possibility in principle but is no more likely than with any other building. The only real danger, at most, is presented by the rotor blades or parts of them breaking off. The question of safety in the environment of a wind turbine, therefore, essentially revolves around the question of how far damaged rotor blades can be flung off and what risk is involved here.

15.1.1
How Far Can a Rotor Blade Fly?

To answer this question, the conditions should be first called to mind under which a rotor blade can self-destruct, and the parameters which influence its trajectory.

As experience has shown, the most frequent cause of rotor blade fracture is rotor "runaway". When all rotor-brake systems fail, the rotor speed can increase up to the limit which is aerodynamically possible. This is reached when the flow velocity in the outer blade area approaches the speed of sound. As is generally known, this results in a steep increase in air drag. The lifting forces acting on the airfoil are balanced by the aerodynamic drag, resulting in an equilibrium speed which is the critical aerodynamic speed.

This speed depends on the aerodynamic properties of the chosen airfoil, on the blade geometry and, not least, on the wind speed. A more detailed discussion would be beyond the scope of this book. Theoretical investigations have shown that with modern rotor blade shapes, the critical aerodynamic speed is approximately three times the design tip-speed ratio [1]. At a constant wind speed, this means three times the rotor speed.

Generally, however, the critical velocity of the rotor blades with respect to their breaking strength is usually below the aerodynamically possible maximum speed. Fracture will occur earlier at least on large rotors, due to the centrifugal forces increasing with the square of the speed. The exact location of this limit is a question of the strength dimensioning and can be precalculated theoretically. Generally, it can be assumed that the strength limit of large rotors is reached at about two- or three times the rated rotor speed value.

Apart from the rotor speed at the time the fracture occurs, the blade‘s rotational position also plays a role. Applying the known principles of simple ballistics immediately shows that a rotor position of 45° from the vertical axis in the direction of rotation will lead to the maximum trajectory length.

Rotor runaway resulting in the loss of rotor blades was a danger mainly in older and smaller wind turbines, even though, statistically, this has also been extremely rare. Modern wind turbines have at least two independent systems for rotor braking including multi-redundancy release mechanisms, so that this hazard is effectively counteracted. Large turbines contain elaborate rotor brake systems, in any case (Chapt. 8.7).

The other conceivable case of rotor-blade fracture can occur as a result of undetected material fatigue. After a certain length of time, an undetected progressive fatigue crack will lead to fracture, even without the rotor blades being subjected to abnormal loading.

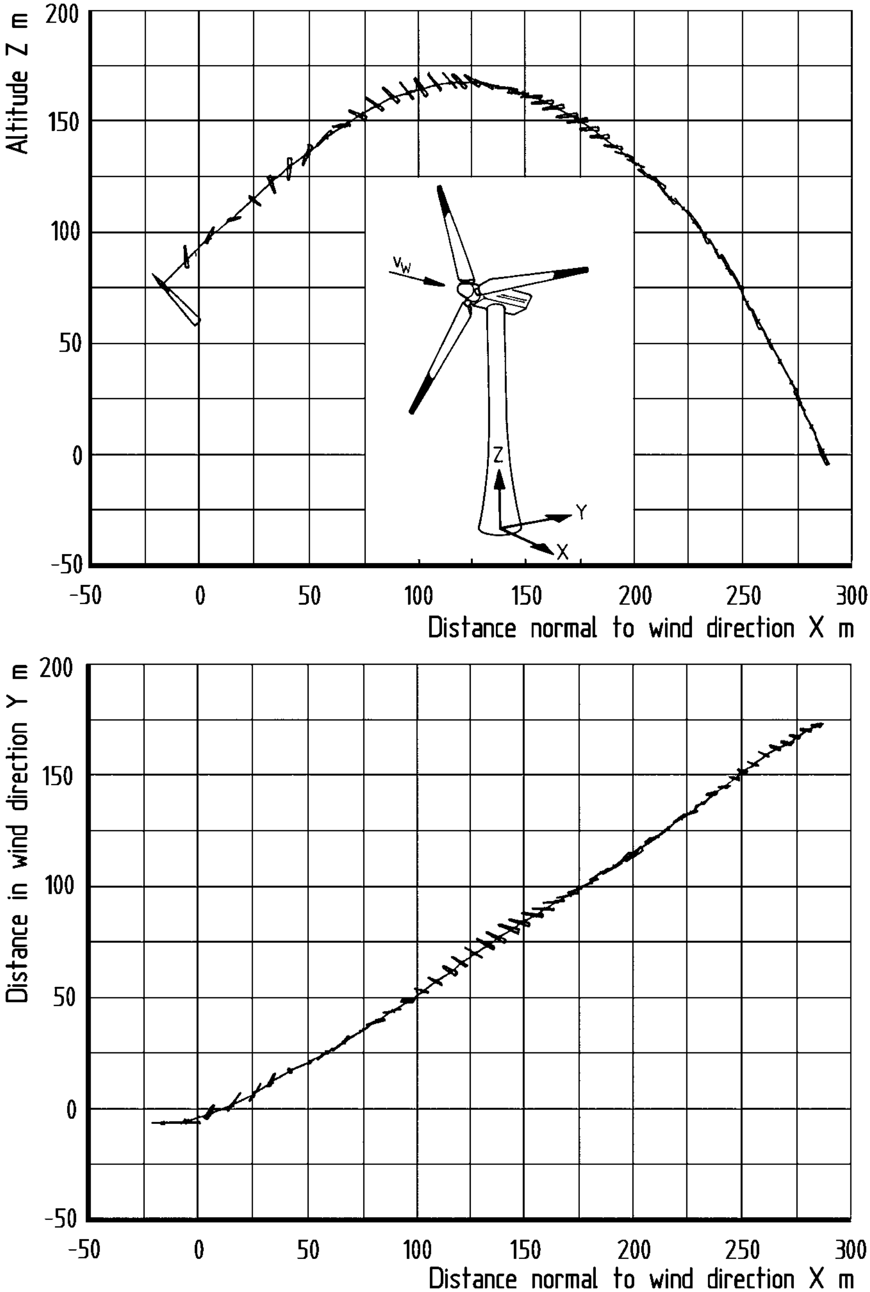

Figure 15.1. Trajectory of the outer third of the rotor blade in the rotor plane, calculated for the Danish Tjaereborg wind turbine (Tower height 60 m, rotor diameter 60 m, blade weight 8 t, initial conditions: blade-tip speed 100 m/s corresponding to 50 % overspeed, wind speed = 10 m/s) [3]

For the wind turbine, this means a possible blade fracture at rated rotor speed, i.e. in normal operation. In the only case so far where a rotor blade has broken off from a large wind turbine and was hurled away, fatigue fracture was indeed the cause. After a three-year operating period, the ageing Smith-Putnam turbine lost one rotor blade, the result of fatigue damage at the blade root (Chapt. 2.3). In that particular incident, the 8-ton rotor blade was propelled over a distance of about 230 m. The designers of this wind turbine must be given credit, however, for having known about this weak point, even though the mechanisms of material fatigue had not yet been researched as widely as they are today. However, no preventive repair had ever been carried out due to a lack of funding and because interest in the project had waned.

It is not very easy to predict the flying characteristics of a broken rotor blade or of a part of it. After all, a rotor blade is an aerodynamically shaped structure generating high lifting forces, as it was designed to do. It would be easy to speculate that a detached rotor blade could, like a glider, cover long distances by gliding. However, this possibility must be discarded upon closer inspection of the flight stability conditions. The position of the centre of gravity in relation to the centre of aerodynamic pressure does not permit a stable flight position.

Firstly, the rotor blade will "tumble" on its trajectory, and then it will fly with its heavy end first. It is, therefore, not to be expected that the aerodynamic lifting forces will increase the trajectory length significantly [2]. The problem is reduced to the question as to what is the effective mean drag coefficient over the trajectory. A theoretical analysis calculating trajectory and trajectory length of an example taking into consideration aerodynamic lift and drag yielded the result that a mean air drag coefficient of $c_W = 0.25$ is to be expected [3].

Rotor speed, the blade's rotational position and the location of the centre of gravity are the main parameters influencing the trajectory length of the rotor blade becoming detached. In addition, the blade pitch angle at the time of fracture and the momentary wind speed have some influence. The orders of magnitude to be expected for the trajectory lengths of a detached rotor blade are illustrated by an example. Due to the ratio between aerodynamic forces and gravitational forces, the outer section of a rotor blade can fly the farthest (Fig. 15.1).

Discussing the hazards caused by parts of the rotor being hurled away, the problem of ice accretion at the rotor blades must be mentioned once more (Chapt. 18.8.2). Observations made on the American MOD-0A experimental wind turbine in Clayton have shown that, indeed, significantly large chunks of ice are flung off over considerable distances. Theoretical investigations relating to this problem have also been published in Denmark [4]. Thus, appropriate precautions must be taken at certain sites. The installation of an ice warning system which would shut down the wind turbine during critical weather conditions is one possibility.

15.1.2 Safety Risks

In view of the possible hazards caused by rotor parts or chunks of ice being flung off, various probability calculations have been carried out with the aim of determining the statistical risk to a person nearby. When looked at closely, the results of such mathematical predictions of safety depend almost exclusively on the possible range of the parameters used. Considering thus their extremely dubious value, one would do better to refrain from using them when dealing with wind turbines. Wind turbine technology does not need such "magical formulae" to prove its harmlessness to the public. Instead, some readily comprehensible remarks about the safety risk of this technology will not go amiss here.

The "dangerousness" of a technology must be seen under two different aspects. Firstly, there is the question of the frequency of accidents and, secondly, the question of the extent of the consequences to be expected with the occurrence of such an accident. The "dangerousness" could be defined as the product of frequency and the severity of its effects.

This may be illustrated by two examples: road traffic with automobiles is characterised by an appalling frequency of accidents. Although the number of people injured annually in road accidents reaches the familiar order of magnitude, it will be found that the effects of each individual event — as painful as they may be to those concerned — remain within calculable limits. This may well be a possible reason why, despite the 6000 fatalities per year for example in Germany alone, this technology is not rejected by society.

With nuclear power technology it is quite the other way round. The probability of an accident occurring is very low — that much must be conceded to the promoters of this technology. But the possible consequences of an accident are practically incalculable. Even though it was a long way from being the "Maximum Credible Accident" (MCA), the reactor accident of Chernobyl made this quite clear for the first time. This is the reason why this technology will always be rejected by a part of society. Does this make motor traffic and nuclear power dangerous technologies? It is not the task of this book to find an answer to this question. It is only intended here to apply this approach also to wind energy technology.

Firstly, it can be stated that in professionally built wind turbines, the frequency of rotor-blade breakage is very low. The probability of a person being hit is even lower. It can, therefore, be said that the frequency of fatal accidents due to self-destructing rotor parts can rightly be classified as extremely low, even when massed clusters of wind turbines are considered.

How, then, about the conceivable extent of a "catastrophe" caused by wind turbines? Even with pessimistic assumptions, a detached rotor blade cannot have the same consequences as, for example, a comparable critical technical failure in a car, or an aircraft. And a comparison with a nuclear power plant need not even be attempted as it is completely inappropriate. Thus, wind power technology can be called decidedly "harmless" as far as both the "frequency" and the "severity" of accidents are concerned. It probably is the altogether least dangerous energy generation technology, at least when considering the megawatt power output range.

15.2 Wind Turbine Noise

Wind turbines do not run completely silently. Their operation generates noise which can be heard at a certain distance. While in the case of the old windmills, this noise was generally not perceived as annoying, some modern wind turbines gave rise to complaints. In the early phase of modern wind-energy utilisation, the American MOD-1, in particular, was much talked about due to the disagreeable and, at the time, inexplicable noises it made. This triggered numerous scientific investigations about the noise emissions by wind turbines, first in the USA and a little later in some European countries.

Today, it can be said that the mechanisms behind the generation of noise emission by wind turbines are known by and large. It is certain technical characteristics that are responsible for a higher or lower noise emission, as is the case with other machines, too. In simple words: there are quiet wind turbines, the noise of which is virtually imperceptible at a short distance away, and there are distinctly noisy turbines which cannot be tolerated in populated areas.

Tackling the problem of noise emission is, therefore, a must both for the designer and for the operator of a wind turbine. If serious mistakes are made in this respect, the turbine's possibilities of application will be restricted to such an extent, that projects will be doomed to fail at many sites.

15.2.1
Acoustic Parameters and Permissible Noise Levels

Before entering into a more detailed discussion of the specific noise sources in wind turbines, it is useful to call the most important parameters of acoustics to mind. Noise is large a question of the criteria of assessment. Unfortunately, the degree of annoyance associated with noise levels is highly subjective. This fact presents a challenge to any objective and quantitative assessment of noise but such assessments are indispensable.

The most important parameter describing the overall noise intensity at the location of perception is the *sound pressure level,* usually indicated as an amplitude-weighted level and then designated by the symbol "dB(A)". Although in some cases levels related to other criteria can also be applied in acoustics, the dB(A) parameter comes closest to the subjective aural impression and so is used most frequently.

For example the German DIN standard 45645-1 suggests various averaging methods for weighting measured sound pressure curves [5]. Among others, it defines a so-called *noise rating level.* This parameter takes into account the experience that highly tonal and impulse-like noises are perceived more intensely. A certain additional amount corresponding to the tonal level and impulse character is added to the continuous sound pressure level.

The nature of the noise is represented by a frequency or third-octave spectrum. This spectrum shows the measured sound pressure levels versus the frequency. The frequency spectra provide information about the sources of the noise. They are thus primarily of interest to the designer of the wind turbine.

The permissible sound pressure level which a noise source may generate as a "continuous nuisance" at a certain location has been prescribed by legislation. Regulations governing these levels vary from country to country. In the Federal Republic of Germany, the standard values are based on the above mentioned DIN standard [5]. The maximum values depend on the nature of the surroundings and on the time of day: The permissible noise levels vary from country to country. Some examples are shown in Table 15.2.

These regulations must also be observed in the operation of wind turbines. One important and necessary aspect must not be ignored: the increase in the natural ambient noise with wind speed. It would not make sense to require the noise of a wind turbine at full load,

Table 15.2. Permissible noise levels for sound pressure levels (dB(A)) in some European countries

Permissible noise level (dB(A))	Germany	Netherlands	Denmark
– Predominantly industrial area			
day:	65		
night:	50		
– Mixed industrial and residential area			
day:	60	50	
night:	45	40	
– Predominantly residential area			
day:	55		
night:	40		
– Exclusively residential area			
day:	50	45	
night:	35	35	40
– Rural area			
day:	40		
night:	30	45	

which generally occurs at wind speeds exceeding 10 m/s, to be 35 dB(A), i. e. lower than the ambient noise. At these wind speeds, the noise of a wind turbine will be masked by the ambient noise. A sensible interpretation of the noise emission standards must, therefore, be based on the "loudness level", that is the noise level which is generated by the wind turbine and which exceeds background noise made by the wind.

The background noise generated by the wind at increasing wind speeds when blowing around obstacles (for example buildings, trees, grass etc.) increases by about 2.5 dB(A) per one m/s wind speed. If measurements of the background noise level are not available, the background sound pressure level can be estimated by using the following formula [6]:

$$L_A = 27.7 \text{ dB} + 2.5 v_w \text{ dB}$$

where:

L_A = sound pressure level (dB(A))
v_W = wind speed (m/s)

Experience has shown that the noise emission of a wind turbine increases by only about 1 dB(A) per m/s wind speed. According to that it follows that, from a certain wind speed on, the noise of the wind turbine will be masked by the background noise. If the background sound level exceeds the calculated noise level of a wind turbine by about 6 dB(A), the latter will no longer contribute to any perceptible increase in the sound pressure level at the location of immission [6].

A noise source is characterised by its *sound power level.* This parameter contains information about the intensity and thus about the sound propagation potential of a sound source. According to definition, measurements would have to be obtained over a spherical surface around the source of the noise. In practice, several methods are normally used. The IEC has elaborated a standard for wind turbines [7]. According to this, the sound pressure levels are measured at five fixed measuring points in a particular geometrical arrangement on an "acoustically inert" plate, and from these measurements the sound power level (L_W) is determined by using the following formula:

$$L_W = L_A + 10 \lg(4\pi R_i^2) \text{ dB(A)} - 6 \text{ dB(A)}$$

where:

L_A = measured sound pressure level (dB(A))
R_i = distance from the point of measurement to the centre of the rotor (m)

The *propagation of sound* can be determined by semi-empirical mathematical methods on the basis of the sound power level of the noise source, which allows the sound pressure level to be calculated at a given location of noise immission. Information on how to calculate sound propagation is given in VDI Standard 2714 "Sound Propagation in the Open" [8]. The propagation of sound is determined by a whole series of factors:

- Properties of the sound source
  (acoustic power emitted, directional characteristics, tonal components)
- Geometry of the sound field
  (height and distance of the sound source from the location of immission)
- Topography
  (topography, vegetation, buildings)
- Weather conditions
  (wind direction, wind speed, humidity, temperature)

Taking into account the above influencing parameters, the sound pressure level (L_A) at the location of immission is determined as follows:

$$L_A = L_W + DI + K_0 - D_S - D_L - D_{BM} - D_D - D_G + D_W$$

where:

L_W = sound power level
DI = factor of directivity
K_0 = steradian factor
D_S = factor of distance
D_L = factor of atmospheric absorption
D_{BM} = factor of ground and meteorological absorption
D_D = factor of vegetational absorption
D_G = factor of absorption by buildings
D_W = influence of wind

Both the VDI Standard cited and related literature contain information as to how these parameters can be derived from the conditions on site. If several sound sources, for example the turbines of a wind farm, contribute to the sound pressure level generated at one location of immission, the noise levels generated by the wind turbines are calculated individually and the acoustic energies are added. The total sound pressure level generated ($L_{1+\ldots n}$) is obtained from the formula:

$$L_{\mathrm{AZ}} = 10 \lg \sum_{i=1}^{n} 10^{0.1\, L_i}$$

where:

n = number of sound sources
L_i = the individual sound pressure level of the sound source i.

15.2.2
Noise Sources in Wind Turbines

The sound power level of a wind turbine is emitted by various sources. The total sound power level measured is determined by aerodynamic noises, primarily emitted by the rotor, and by various types of mechanical noises. The different noise sources must be identified during the development and analysed carefully. Every potential source requires special attention in order to achieve a design with low noise emission overall.

Aerodynamic noise

The primary noise source of a wind turbine is the air flowing around the rotor. The noises caused by this process are, to a certain extent, unavoidable, and cannot be attenuated either. They are thus the actual problem to be dealt with and their mechanisms of generation must be examined more thoroughly.

On closer inspection, various effects are responsible for the generation of aerodynamic noise from a wind rotor. The main causes are the turbulent boundary layer and the formation of vortices at the trailing edge of the blade, and aerodynamic loading fluctuations. Moreover, there are the flow separations, which are also audible and, to a much lesser extent, the turbulence of the rotor wake. A special role is played by the vortices separating from the tip of the rotor blade. The major part of the rotor noise — as well as the rotor power — emanates from the outer 25 percent of the blade and, therefore, the geometry of the blade tips is of special importance (Chapt. 5.5.2). The influence of other vortex-generating edges, gaps or struts should not be underestimated, either. These are the causes of loud aerodynamic noises in many rotors of earlier design.

The flow around the rotor blades generates a sound similar to the flow around an aircraft wing. A low-flying glider with an air speed comparable to that of the rotor blade of a wind turbine generates the same broad "hissing" or "whooshing" sound in the frequency range of about one thousand Hertz (Fig. 15.3).

Apart from the broad aerodynamic whooshing of the rotor in the 1000 Hz range, wind turbines can generate impulsive, low-frequency sound waves. These are generated when the lift forces acting on the rotor blades change rapidly due to discontinuous flow conditions. The main causes of this are rapid changes in the aerodynamic angle of attack and thus of the aerodynamic lift force. Rapid changes in lift are, for example, caused by wind turbulence in gusty wind or by flow separations at the rotor blades. Under these circumstances, stall-controlled rotors without blade pitch adjustment may emit a characteristic

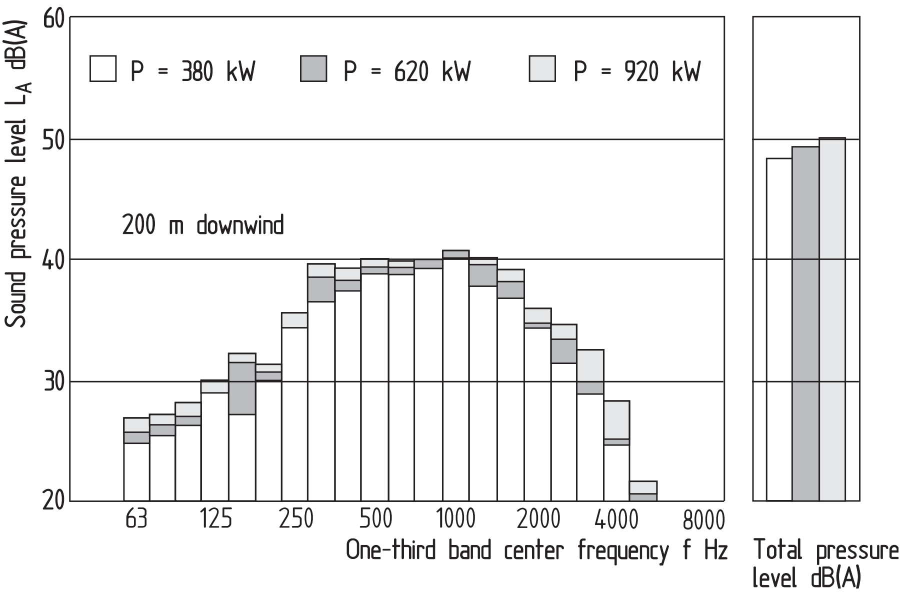

Figure 15.3. Frequency spectrum (amplitude-weighted third-octave spectrum) of the sound pressure level measured 200 m (downwind) from the WKA-60 experimental turbine on the German island of Heligoland [9]

low-frequency sound. From a certain distance, however, these are generally no longer perceived to be annoying.

Conversely, low-frequency noise emission occurring as a result of tower shadow interference in downwind rotors must be assessed quite differently (Fig. 15.4). In the case of the MOD-1 wind turbine in the USA, mentioned earlier, the associated noise turned out to be a major reason for complaints by residents. The turbine's lattice tower created a considerable tower shadow for the downwind rotor mounted at a small distance away. Moreover, the propagation of the sharp pressure impulses generated by the periodic alternation of the rotor lift forces was assisted by the local topography. The oscillations of very low frequency in the inaudible infrasound range additionally triggered resonances in house walls and windows of the lightly built weekend houses in the vicinity. This was the explanation for the mysterious "psi-phenomena" experienced by the residents, such as the clattering of cups in their cabinets and similar events. The situation was thus extremely unfavourable, both with regard to the technical characteristics of the wind turbine and the specific conditions of its location.

Low-frequency sound emissions can be observed in all downwind rotors, but with greatly varying intensity. This problem must, therefore, be paid careful attention to when designing the turbine. Apart from the tower design, the technical parameters mainly responsible for the intensity of the emission are the rotor's clearance from the tower and the rotor speed. Rotor speed is significant as, in the worst case, the frequency of the blades passing through the tower shadow can coincide with the separation frequency of the Kármán

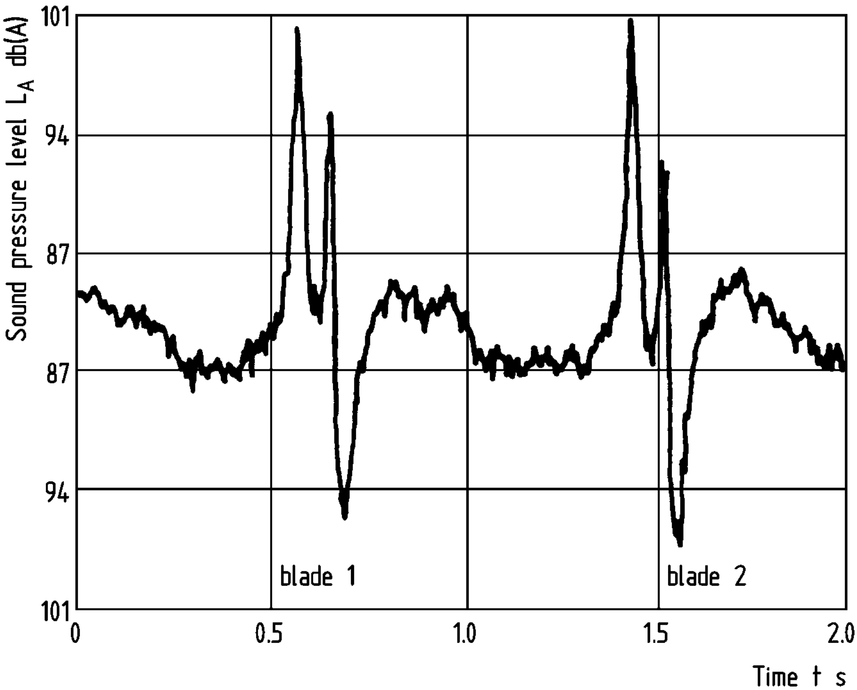

Figure 15.4. Noise pulses generated by the tower shadow effect, measured close to the American MOD-1 wind turbine [10]

vortices at the tower. At certain wind speeds, this may cause a triggering effect for the vortices, thus amplifying the noise further. The frequency of separation of the Kármán vortices can be determined by means of the so-called *Strouhal number,* which is a function of the Reynolds number.

The common denominator for all sounds of aerodynamic origin is that they increase sharply with increasing airflow velocity. Noise emissions increase by about the 5^{th} power (!) of the flow velocity, which, in turn, is essentially determined by the tangential velocity of the rotor blade tips. A reduction in blade-tip speed by 25 % results in a reduction in noise emissions by about 6 dB(A).

A low tip-speed ratio is, therefore, a most important criterion. With regard to this aspect, variable-speed or two-speed rotor operation becomes additionally attractive, particularly at low wind speeds when the ambient noise has not yet been increased by the wind speed and the rotor can be operated at a low speed. Apart from the airflow velocity, aerodynamic noise emission is also influenced by the power output, but to a much lower degree (Chapt. 15.2.3).

The aerodynamically caused sound power level of a wind rotor can be estimated in approximation by means of various mathematical models [11]. The theoretical determination of the frequency spectrum is more difficult and less accurate.

Mechanical noises

In many wind turbines, particularly in smaller ones, the aerodynamic noise is drowned out by mechanical noise sources. Since mechanical noise, in contrast to aerodynamic noise, can be avoided or heavily damped, it must be considered as an indication of poor design. However, avoiding mechanical noise does require a certain amount of care and possibly additional expenses for soundproofing or insulation material for solid-borne noise.

The first priority is to pay attention to the noise emission of the gearbox. There are no silent gearboxes in practice (Chapt. 8.8.2). The sound propagated through the air must, therefore, be intercepted by appropriate sound insulation of the nacelle. Generally, this does not pose any problems. It is much more difficult to prevent noise propagation through solid bodies. For structural reasons, the gearbox must be firmly connected to the supporting nacelle structure which, in turn, must be firmly joined to the tower. Noise is thus transferred to these structures and there may be considerable resonance amplification of the emitted sound. A hollow steel tower or the steel walls of the nacelle are just about the ideal resonating bodies.

Soundproofing of the gearbox and of some other, noise-generating units is, therefore, a must for every modern wind turbine. All kinds of rubber or rubber-like synthetic materials are available for this purpose and are used in mounting the gearbox, in particular, on the supporting structure. All of the more recent wind turbines have constructional elements of this type. What has been said about the gearbox also applies to a certain extent to other noise-emitting units in the nacelle. For example, hydraulic pumps and gear motors represent special noise sources. The generator cooling should not be overlooked either. In some turbines, it is much too noisy even though enough information about the design of quiet ventilation systems is available.

15.2.3 Noise Emission of Current Wind Turbines

The noise emission of wind turbines has been noticeably reduced in the past fifteen years by the constant improvement of design and the optimisation of numerous details. This is true at least of the successful commercial turbines. Experimental wind turbines differing from the common technical concepts are the exceptions to this rule.

By now, the manufacturers have become quite aware of the problem of noise emissions which greatly influence the acceptance of wind turbines. With some wind turbines technical compromises in favour of reduced noise emission have a marked influence on the power output. Frequently, the rotor speed is chosen to be lower than the aerodynamic optimum, but other influencing parameters, too, for example the blade pitch angle at wind speeds around 8 to 10 m/s, are chosen for the least possible noise emission, even if this means sacrificing the last few percent of possible power output.

After the power curve, the sound power level has become the most important technical parameter today. The buyers or operators of wind turbines are well advised to ask for independent certification of the manufacturer's specifications and to demand corresponding guarantees from the manufacturer. The noise accreditation nowadays required for every wind energy project is based on the sound power level of the wind turbine. Even if the sound pressure levels generated are influenced by numerous local influences at a particular site, a low sound power level is still the best basis for adhering to the standards prescribed by law.

As already mentioned, the sound power levels actually reached by wind turbines are determined by numerous aerodynamic and constructional characteristics. As long as the turbines to be assessed are of comparable technical design, for example three-bladed rotors with a tip-speed ratio of 6–7 and a fixed rotor speed, the dominant parameter will be turbine size, so that size-related guide values are possible:

– Small wind turbines up to 20 m rotor diameter / 100 kW	~ 95 dB(A)
– Medium-sized wind turbines up to 40 m rotor diameter / 500 kW	~ 98 dB(A)
– Large wind turbines with 70–80 m rotor diameter / 2000 kW	103–105 dB(A)
– Multi Megawatt wind turbines, 100–120 m rotor diameter	105–107 dB(A)

These recommended values apply to modern turbines which have already been designed with a view towards low noise emission. Earlier wind turbines frequently exceed these values considerably. The first generation of large experimental wind turbines, in particular, produced noise values of up to 120 dB(A) (Fig. 15.5).

The limits within which the sound power level can be influenced by technical or operational parameters are illustrated by the example of an acoustic investigation carried out on a medium-sized wind turbine. The dependence of the sound power level on the wind speed or the electric power output is relatively small (Figs. 15.6 and 15.7). The result

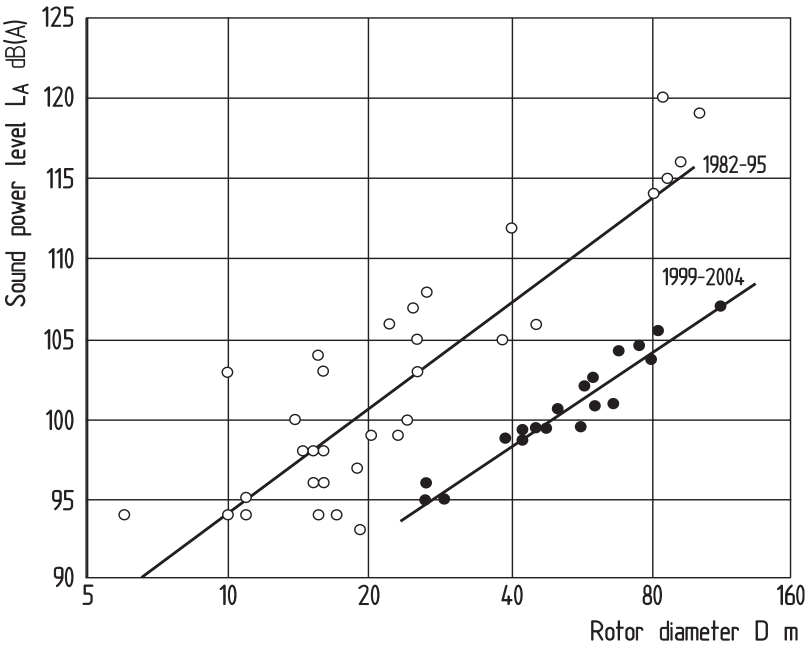

Figure 15.5. Measured sound power level of wind turbines as a function of rotor diameter [12]

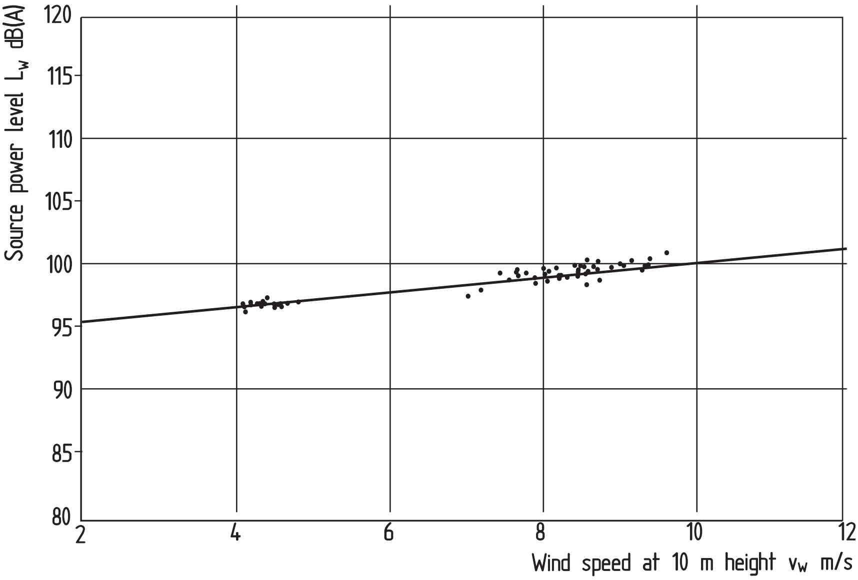

Figure 15.6. Source power level as a function of wind speed, measured on a medium-sized Tacke TW-600 wind turbine, rotor diameter 43 m, rated power 600 kW, rotor speed 18 rpm. [13]

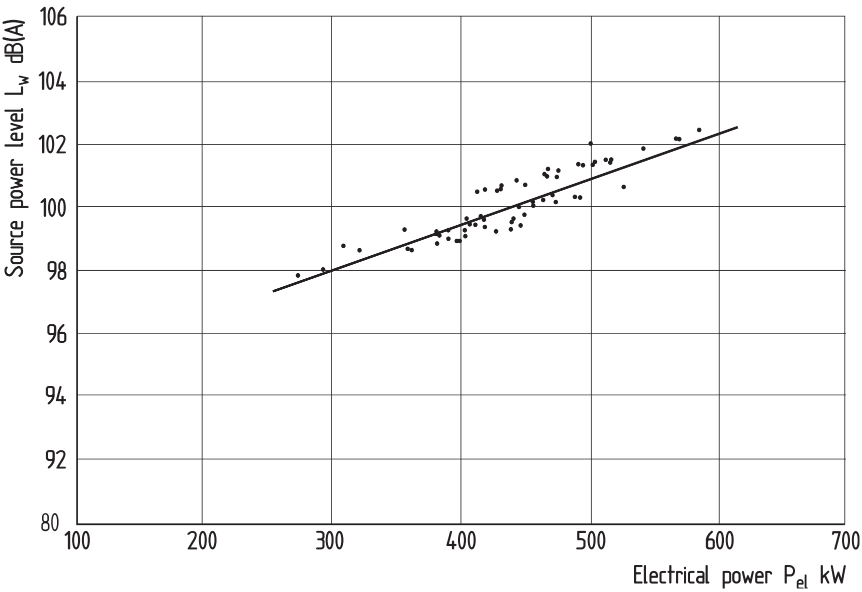

Figure 15.7. Source power level as a function of the power output. (Tacke TW 600) [13]

of a sound propagation calculation, i.e. the expected sound pressure level as a function of distance, for the TW 600, shows that the commonly demanded maximum value of 45 dB(A) is obtained at a distance of about 220 m (Fig. 15.8). In order to remain below the standard acoustic limit value of 45 dB(A), a minimum distance of about 200 m is typical for medium-sized wind turbines in the power class of around 500 kW.

The sound emission of a wind farm is composed of the combined noise emission of the individual wind turbines (Chapt. 15.2.1). Within the framework of the existing building licensing procedure, some institutions produce acoustic assessments which include so-called "noise maps" of the areas subject to noise pollution (Fig. 15.9).

These examples show the state presently reached in noise emission control of wind turbines; further improvements can be expected in the future. However, one should not hope for too much in this respect. The unavoidable aerodynamic noise is largely determined by the rotor speed. Optimising rotor blade shapes, particularly in the blade tip sections, or choosing different aerodynamic airfoils has only a very limited effect. Decreasing rotor speed because of noise emission quickly leads to conflicts with economic aspects. At low speed, the power must be generated by higher torque. This, in turn, has a direct effect on the component masses and thus on manufacturing costs (Chapt. 19.4).

From some manufacturers, turbines with a special operating mode for minimum-noise operation are available for installation on sites with a critical noise situation. For example, the Vestas V-66 turbine can be operated with power-optimised blade pitch angle in the

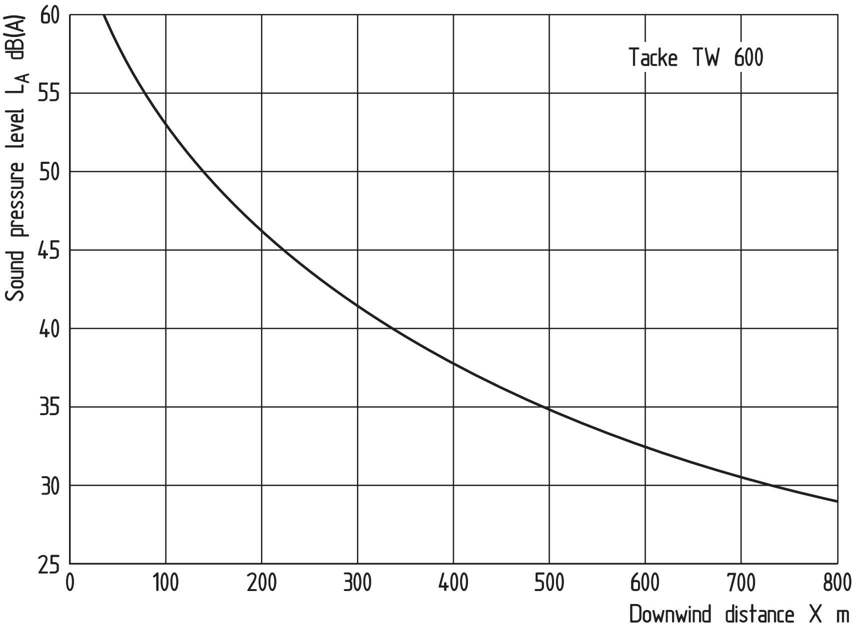

Figure 15.8. Sound propagation calculated on the basis of VDI 2714 for the Tacke TW 600 wind turbine [13]

Figure 15.9. Noise map of the surroundings of a wind farm and of one large individual turbine (sound pressure level of each turbine: 102 dB(A), large turbine: 108 dB(A)) [6]

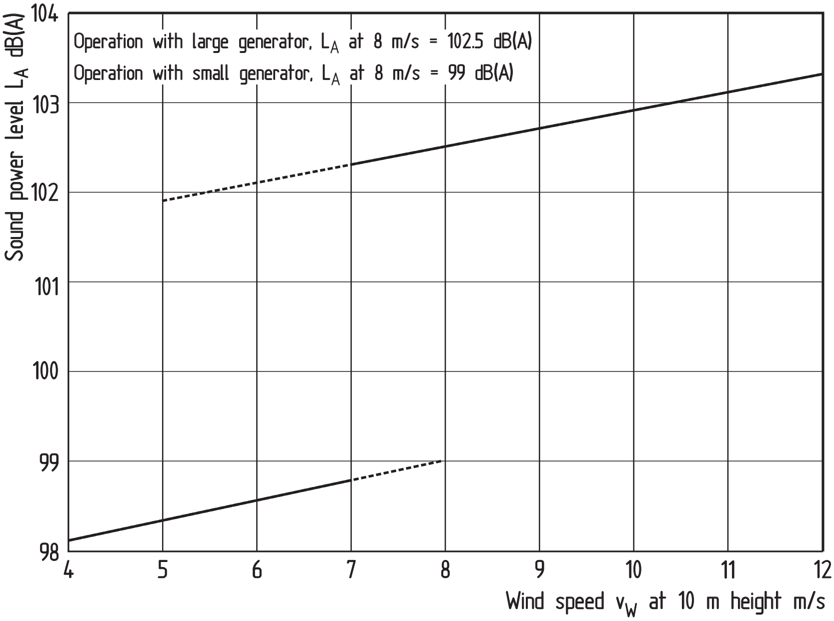

Figure 15.10. Sound power levels of the Vestas V66 wind turbine with two generators for two-speed rotor operation [14]

partial-load range, or with a blade pitch angle which is optimised for minimum noise emission. In the latter case, however, a certain percentage of the possible energy yield is lost. Earlier turbines have two generators, where the smaller generator can be used with a lower rotor speed at lower wind speeds (Fig. 15.10).

15.3 Shadow Effects

Like all large buildings, wind turbines, too, cast their shadow over the surroundings when the sun shines. In contrast to "normal buildings", however, the shadow of a wind turbine has a peculiar feature which can be can be felt to be very annoying under certain conditions.

When the rotor is standing still, the wind turbine casts a stationary shadow just like any other building or like a tree (Fig. 15.11). Due to the rotation of the earth, this shadow moves

Figure 15.11. Shadow cast by a wind turbine near by (photo Oelker)

and stays for only a short time at any particular point (the immission point). Normally, this shadow does not cause any problems and, in any case, only occurs in the immediate vicinity of the turbine.

When the rotor is turning, however, the situation changes. The rotor blades cutting through the sunlight at three times the frequency of rotation of the rotor (in the case of a three-bladed rotor) produce an unpleasant flickering "stroboscopic" or "disco" effect when the shadow falls onto an observer.

If a number of operating turbines simultaneously cast their shadows onto an immission point, this effect is cumulative and occurs at higher frequency. A shadow varying with time like this, *shadow flicker,* is one of those environmental effects of a wind turbine which are considered to be acceptable but only within certain limits.

The shadow can create a disturbance to people inside buildings exposed to such light passing through a narrow window. It is considered to be an issue in Europe, and was also recognized in the operation of traditional windmills. The frequencies that can cause disturbance are between 2.5–20 Hz. The effect on humans is similar to that caused by changes in intensity of an incandescent electric light due to variations in network voltage from a wind turbine (Chapter 18.5). In the case of shadow flicker the main concern is variations in light at frequencies of 2.5–3 Hz which have been shown to cause anomalous EEG (electroencephalogram) reaction in some, but very few cases [16].

In a study conducted in 1999 for the State of Schleswig-Holstein in Germany, shadow flicker, the time-variant shadow cast by rotating wind rotors was thoroughly investigated [15]. The limit values recommended in this study were subsequently adopted by most Federal States as guide values for their licensing procedures. Accordingly, the maximum permissible time that a shadow can be cast at an immission point is 30 hours annually or 30 minutes per day, respectively, based on the astronomically possible maximum period.

The basic mathematical model is firstly based on the astronomically possible "shadow-casting times". The essential geometric quantities used as initial parameters are (Fig. 15.12):

- Angle of direction of the wind turbine clockwise from North, referred to the immission point IP
- Distance of the wind turbine from the immission point
- Height of rotor hub
- Rotor diameter
- Difference in height between rotor hub and immission point
- Geographic latitude and longitude of the wind turbine and the immission point.

Given these parameters, the shadow cast is calculated in accordance with the solar altitude at one or more immission points [17]. The model contains the following simplifications:

- The sun is assumed to be a point source.
- The wind direction corresponds to the azimuth angle of the sun, i.e. the rotor-swept area is perpendicular to the solar irradiation.
- A so-called "occultation component" of the sun with respect to the total rotor-swept area is assumed. This is derived from a normal rotor blade chord, assumed to be constant, with a predetermined rotor diameter (assumed as 20 %). Given this assumption, a shadow cast of 1.5 to 2 km is obtained for a large wind turbine.

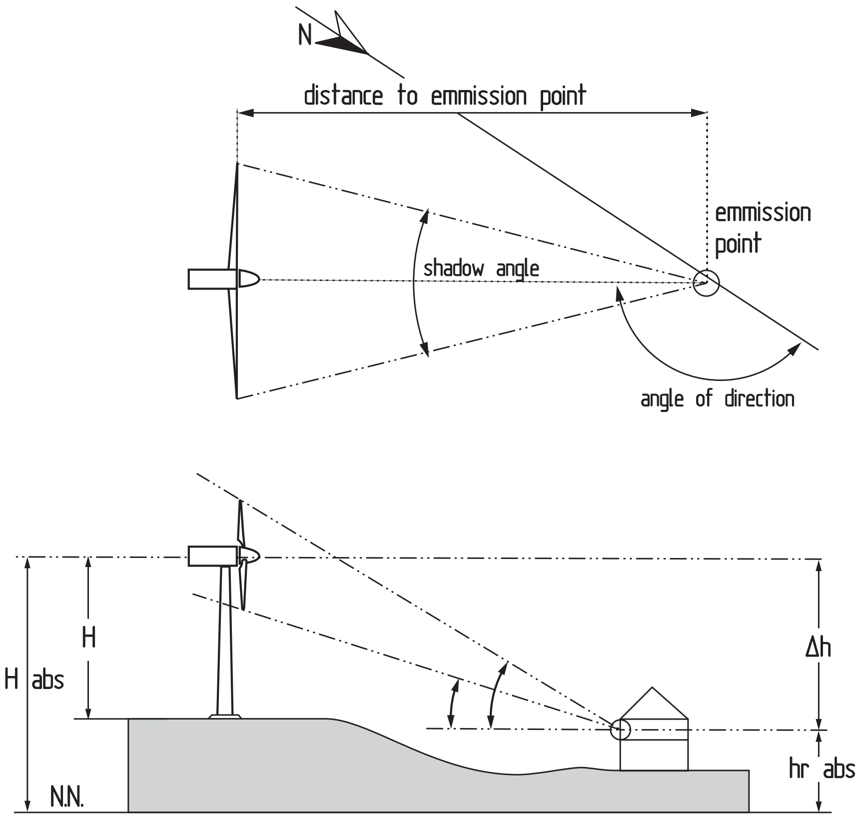

Figure 15.12. Geometric relationships for calculating the time-variable shadow cast by a wind turbine in operation [17]

– A solar altitude (angle of elevation) of less than 3 % is ignored since it is supposed that atmospheric turbidity, surround buildings or vegetation will prevent shadows at such low solar altitudes.

This calculation provides the astronomically possible times of shadow casting for a particular wind park configuration and immission points. The shadow times at the calculated immission points are listed in table form or represented graphically (Fig. 15.13).

Naturally, the astronomically possible duration of shadow casting is considerably reduced in practice by the prevailing weather conditions. Taking into consideration the statistical weather conditions with respect to the frequency distribution of the wind direction and the hours of sunshine, the effective shadow period is reduced to 20 to 30 % of the astronomically possible maximum period at Central European latitudes. Statistically, the permissible 30 hours annually become only 6 to 9 hours per year.

Today's large wind turbines are equipped with an automatic shadow cut-out system. This is programmed with the astronomically possible shadow-casting times and switches off the turbine with the aid of a light sensor as soon as the weather situation allows a

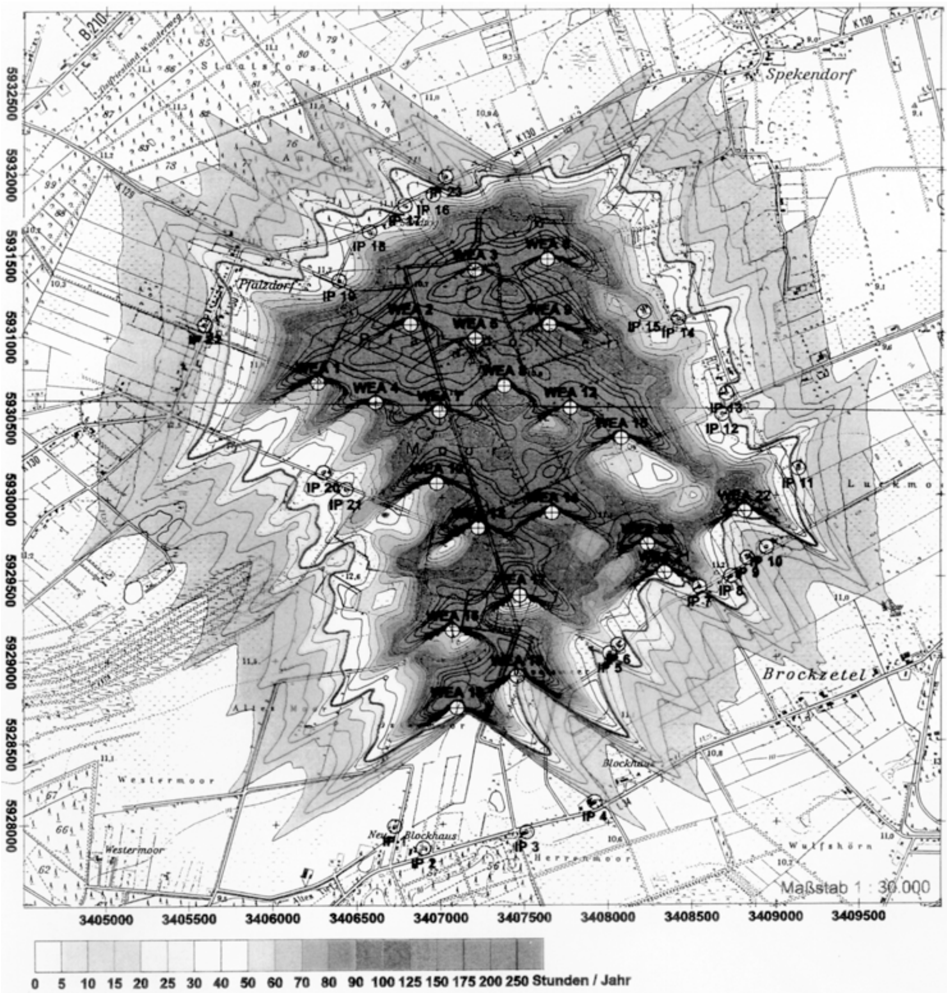

Figure 15.13. Astronomically possible times of shadow casting by a particular wind park configuration [18]

shadow to be cast at a critical point. Keeping in mind the statistically low number of hours involved, the loss in energy yield is virtually negligible. In the worst case, it amounts to one to two percent of the annual energy yield.

Apart from shadow casting there is another effect caused by the sun, which occasionally can be felt annoying. When the sun is shining, the rotor blades can have an unpleasant "flashing effect" when the sunlight is strongly reflected. This phenomenon is counteracted by applying a non-reflective coating which reduces the *degree of glare* as defined in DIN standard DIN 67530.

15.4 Interference with Radio and Television Signals

Like other large buildings, wind turbines can interfere with the transmission of electromagnetic waves. Basically, all types of navigational or communication-related systems are affected by this. As the interference is concentrated on a small area, interference with navigational or directional radio link routes can be avoided by choosing an appropriate site for the turbine. The situation is different with regard to the reception of public radio and television, as these are used virtually everywhere.

In the USA and Sweden, the problem of interference with radio and television has been examined in more detail in recent years. Firstly, observations made with the existing experimental MOD-0 and MOD-2 turbines were systematically evaluated. This revealed that, in contrast to the reception of radio signals, the reception of television signals was indeed disturbed. Experiences with individual wind turbines differed with regard to the intensity of the interference and the distance from the wind turbine.

In the vicinity of the MOD-1 turbine in Boon (North Carolina), about 30 households at distances of up to two kilometres were affected. Less interference was found with the MOD-0 wind turbines, for example on Block-Island near New York. Evaluation of these observations and the subsequent systematic investigations carried out with the experimental NASA MOD-0 turbine in Plum Brook showed that the interference with television signals could essentially be attributed to two causes (Fig. 15.14).

- The direct signal from the television station can be disturbed by the rotating rotor blades if the wind turbine is positioned directly in line with the receiver. This effect is strongest in the UHF band.
- The second, far less significant interference is created by the wind turbine reflecting the direct signal, so that receivers situated at the corresponding angle of reflection receive a second, unwanted signal. This effect, which is also produced by other large buildings, causes the familiar ghost images in analogue television which flicker when the rotor is turning. It also occurs when the rotor is not turning but is absent in digital television.

After this experience with the first large experimental wind turbines, the problem of interference with radio and television signals was examined with numerous other wind turbines. The results differed greatly.

The differing intensities of the interference effects were attributable, on the one hand, to the technical concept of the wind turbines and, on the other hand, to the topography of the individual sites. As for the technical concept, it became apparent that it is mainly the design of the rotor blades which is of significance. Rotor blades totally or partly consisting of steel, as in the case of the MOD-1, caused the highest interference. Rotor blades made of glass-fibre composite material or wood proved to be far less disturbing. During standstill, the rotor's position has a perceptible influence, at least in two-bladed machines.

Based on the empirical results, theoretical models were developed permitting the probable interference with television signals to be calculated in advance. According to Sengupta

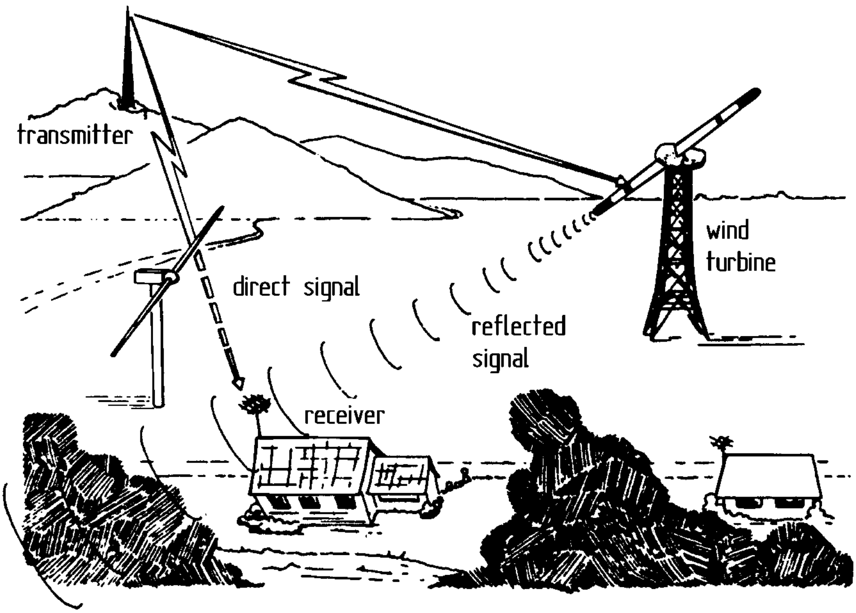

Figure 15.14. Interference with radio and television signals caused by a wind turbine [15]

and Senior, the zone of interference to be expected can be estimated by means of the following formula [19]:

$$r = \frac{c\,\eta\,A}{\lambda\,m_0}$$

where:

A = projection area of the rotor blades (m^2)
η = reflective efficiency of the rotor blades (metal blades 0.7; glass fibre blades 0.3)
λ = wavelength of the television signal
c = constant of the geometric set-up of TV transmitter, receiver and wind turbine ($c = 2$, if wind turbine and receiver are on line of sight with the TV transmitter; $c = 2$ to 5, if wind turbine is below the radio horizon of the TV transmitter)
m_0 = intensity index of the interference (0.15)

Taking the MOD-2 turbine with its steel rotor blades as an example, the formula yields a zone of interference of 2 to 3 kilometres. This formula results in an estimation which is too rough for a specific situation due to its numerous simplifications but it has the benefit of at least identifying the main influencing parameters.

Interference with television signals was also observed in the case of the Swedish WTS-3 wind turbine in Maglarp. Even though its rotor blades entirely consist of glass fibre composite material, distinct interference effects were nevertheless observed. The aluminium webs integrated into the blade structure as a protection against lightning stroke obviously played a perceptible part in this. In the village of Skare, two kilometres away from the wind turbine and directly on the extended line connecting transmitter and wind turbine, interference was observed in some houses. However, television reception was seriously impaired only when the wind turbine was in operation. An auxiliary transmitter with a power of two watts, mounted on the anemometer mast at some distance from the wind turbine, corrected the problem for those television viewers.

Generally, the impact on television reception due to wind turbines is not too much of a problem. Where it occurs, the problem can be solved by relatively simple technical equipment. Experience in the US has shown that in a number of cases, realignment of the existing antennas was enough to correct the problem. Where this was not satisfactory, a small relay transmitter was installed, or the relatively few television viewers affected were supplied via cable. Taking into consideration the progress in digital video broadcasting and the increasing transmission of television signals by cable or via direct reception from geostationary satellites, this problem will disappear in the long run in any case.

15.5 Impact on Bird Life

A question which is frequently raised by animal lovers, which the author definitely considers himself to be as well: Do wind turbines present a special danger to birds? Observations at various turbines have shown that "local" birds quickly learn to identify the obstacle and fly around it. The comparatively slowly turning rotor blades are obviously noticed by them. It is conceivable, though, that birds without local experience, i. e. migratory birds, can come to harm through wind turbines (Fig. 15.15). But flocks of migratory birds rarely fly at altitudes

Figure 15.15. A flock of migrating birds passing close to a wind park (Windkraftjournal)

of less than 200 m, so that this hazard, too, should be a very slight one. In Denmark, the question of wind turbines presenting a possible hazard to migratory birds has been the subject of various investigations. More recently, wind farms near Tarifa in southern Spain were also the object of reports stating that a large number of dead birds had been found, a highly exaggerated figure as it later turned out. In the wind farms in the US, only a very small number of birds killed verifiably by wind turbines have been found to date.

Sometimes there is the argument that the installation of wind turbines will prevent the birds from coming to these regions, particularly if their breeding places are in the area. Naturally, efforts must be made to keep wind turbines away from special breeding places. On the other hand, all kinds of developments have this effect of restricting the living space of birds which used to live there and power generation by wind turbines, too, is involved in this conflict between undisturbed nature and the requirements of a technical civilisation.

15.6 Land Use

Land is becoming ever more scarce. For example, almost 10 % of the territory of the Federal Republic of Germany is already covered with asphalt and concrete for streets, industry and housing. This fact forces the land requirements of a technology to be considered also from the point of view of its environmental impact. What does the situation look like with regard to wind turbines? The minimum area required for erecting a wind turbine is the area needed for the tower and its foundation. Annexes for measuring and test facilities often found with the large experimental wind turbines no longer exist in today's series produced turbines. The equipment needed for operation and grid connection is housed in the tower base in most cases. Central buildings of larger wind farms are hardly significant compared with the number of wind turbines.

Occasionally it is argued that extensive safety zones must be added to the basic area required for tower and foundation so that, for example, rotor blades breaking off do not cause any harm. This argumentation must be opposed rigorously. If such standards were also applied to other technologies, wide, deserted safety zones would also have to be provided alongside every road or below the flight corridors of every airport. In these locations, uninvolved persons are exposed to incomparably greater hazards in cases of catastrophic technical failure. Compared to that, the damage caused by a rotor blade breaking off is relatively minimal. In areas where wind energy utilisation has a tradition, a realistic attitude towards the possible dangers presented by wind turbines is natural, as illustrated in Fig. 15.16.

The cross-sectional area of the tower of even a large wind turbine amounts to only a few square meters. Depending on the type of turbine, the area of its foundation is of the order of about 200 to 400 m². If the installed power of the wind turbine is related to this basic area, a land-area of 240 m²/MW is required for a 500 kW turbine with a foundation area of approx. 120 m².

With this land usage requirement, wind turbines score comparatively well (Fig. 15.17). This value improves even more with increasing wind turbine size. As has been shown by a relevant study, all the other regenerative energy systems have a much higher land

Figure 15.16. Small wind turbine on the premises of a Dutch company

requirement. Wind turbines need the same amount of area as conventional power plants if the gross requirement of the power plant including all annexes for fuel storage and other purposes are included [19].

What is more important than the figure for installed power is the amount of energy to be extracted in relation to the land area. Assuming an annual energy yield of approximately 1.4 million kWh for a 500 kW turbine, this yields a value of 11.7 MWh/m² per year. For a regenerative energy system, this value, too, is extraordinarily high. Wind turbines also score well when being compared with a conventional power plant. A 750 MW coal-fired power station with 4000 hours operating time has a characteristic value of 15 to 20 MWh/m². Hence, the excessive land-use requirement as frequently claimed is not a valid argument against the extensive use of wind energy.

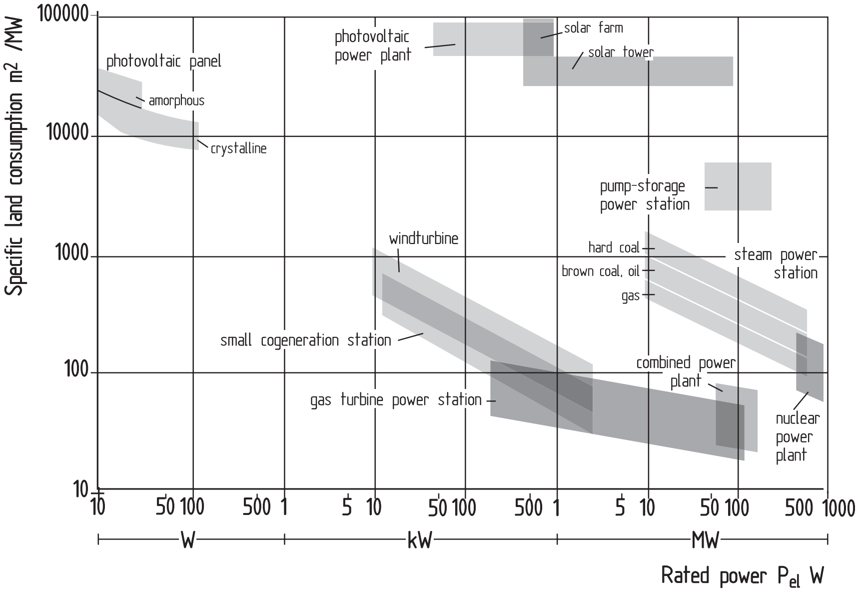

Figure 15.17. Specific land-use requirements of power generation plants [20]

15.7 Visual Impact on the Landscape

Of all the effects on the environment caused by wind turbines, their visual impact on the landscape is the most difficult factor to assess. Accordingly, discussions of this subject are controversial and frequently verge on becoming polemic. In recent years, building application for even the smallest "wind wheels" were occasionally rejected by the authorities with express reference to the unacceptable visual impact on the landscape. Nowadays it is frequently the nature conservation organisations which are raising objections against the visual effect of wind turbines, thus preventing not a few wind power projects (Chapt. 18.2).

The real problem is not presented by individual cases, but rather by the intention of expanding wind energy utilisation to such an extent that it will contribute significantly to the supply of energy. In other words: The visual effect on the landscape is a problem of large numbers. Large numbers of clustered wind turbines existed for the first time in the US in the form of wind farms. Pictures of the Californian wind farms — frequently photographed with exaggerated optical effects — have repeatedly been used as proof of the unacceptable visual impact. It is undoubtedly true that American wind farms, with thousands of small wind turbines crammed in seeming disorder into a very small space, are not a useful model for Europe. There is no doubt that in densely populated Central Europe, accumulations of small wind turbines in this manner would be visually unacceptable. The many recent wind parks in Europe show that there are better solutions.

For this reason, among others, wind energy utilisation in Europe will essentially have to rely on larger wind turbines. The majority of unbiased visitors considers them with a mixture of inquisitiveness, admiration and incomprehension — just like with other technical novelties. Depending on how informed the visitor is, one or the other basic attitude will prevail. Only very few visitors spontaneously react negatively to the appearance of wind turbines. However, it would be difficult to consider an individual wind turbine as "visual pollution" of the landscape, as even the largest turbines look relatively modest as close as 10 rotor diameters away (Fig. 15.18).

The Swedish "National Board of Energy (NE)", responsible for the Swedish wind energy utilisation program, had the question of the visual impact of large wind turbines researched scientifically, using photomontage, among other methods [21]. According to the results of this research, the visual impact is determined by three factors:

- Psychological factors: What does the observer associate with it?
- The type of landscape: The visual impact in open landscapes differs markedly from that in more closed-in areas (with trees or buildings).
- The size of the wind turbine: Turbines with less than 50 m height are usually masked easily in most cultivated and built-up landscapes. Wind turbines with a height exceeding 50 m dominate the landscape over long distances.

The study concludes that the installation of wind turbines in wind parks can be accepted in most landscapes, as long as the distance between the individual turbines is of the order of between 8 to 10 rotor diameters. It is only in a few areas that the visual impact is considered to be so dominating that justifiable objections would have to be expected. The study concedes, however, that the visual impact cannot be completely clarified by available methods and experience, as extensive experience has only been gained with static buildings of this

Figure 15.18. Howden HWP 1000 wind turbine (55 m rotor diameter) from a distance of about 1 km, near a power plant near Richborough (England)

size. The extent to which the turning rotors would trigger a long-term visual annoyance could not be reliably predicted.

A highly critical stance should, therefore, be taken towards the argument that large-scale power generation with wind turbines should not be taken into consideration as their visual impact is completely unacceptable. If similar standards were applied to other technologies, the world would look completely different (Fig. 15.19).

Figure 15.19. Power transmission lines near a large town

On the other hand, the sins of the past cannot be a justification for new errors. The supporters of wind turbines must face up to the critical attitude concerning their visual impact. In some areas, limits will, therefore, have to be set to their spread. They will share this fate, it is to be hoped, with an increasing number of technical structures.

15.8 Effect on the Environmental Climate

Occasionally, fears are uttered that wind turbines could have a negative effect on the environmental climate, as they "slow down the wind". This aspect of any conceivable environmental impact also requires some remarks.

The theoretically optimal reduction of the wind speed by a wind rotor is a third of the undisturbed wind speed in the rotor plane. This physical law should first be called to mind. However, due to the actual power coefficient and the control process, this wind speed reduction is not realised to its full extent in practice. For example, at the rated operating point of a large wind turbine, the wind speed is slowed down by about 25 %. In the entire operational wind speed range from 5.4 to 24 m/s, the wind speed is retarded by only 18 % on average. Referred to the kinetic energy content of the air flow in a local area 1000 m wide and 200 m high, for example, through which the wind blows at a speed of 12 m/s, this amounts to only 0.7 %.

This figure already illustrates that one single wind turbine cannot exert a measurable influence on the environmental climate. Meteorologically caused energy conversion processes achieve quite different orders of magnitudes in the boundary layer of the atmosphere close to the surface. For this reason, a measurable influence on the environmental climate is only conceivable, if at all, with a massed array of large wind turbines. However, it is highly improbable that real negative effects are actually brought about by this means. At wind speeds below about 4 m/s, wind turbines are not in operation, anyway. Due to this, critical weather conditions, where a wind flow would be desirable for mixing up the air, are not affected in any case.

In weather conditions with high wind speeds, i. e. when the wind turbines are in operation, it is not low wind speeds but wind speeds which are too high which pose an environmental problem. In many regions today, increasing dryness and land clearance are leading to highly undesirable soil erosion due to high wind speeds. If there were a measurable wind speed reduction caused by high numbers of wind turbines at all, it is by no means certain that this would have any negative effects on the climate. The opposite is more than likely. Any theoretically conceivable effect of wind turbines on the environmental climate can, therefore, be faced without any worries. The utilisation of wind energy would have to have achieved vast dimensions before this problem becomes relevant, if it should become a problem at all.

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Chapter 16

Commercial Applications of Wind Turbines

The use of wind turbines can be considered from various points of view: The use of the energy generated, the organisational integration into the public energy supply infrastructure, the operational concepts and the geographic location all characterise the range of possible applications. The size of the turbines takes up a significant place in these considerations since he fields of application available for small wind turbines with a power of a few kilowatts differ fundamentally from those for large turbines in the megawatt power range.

In comparison with the past, the pressure for using the wind energy directly on site where it is needed has largely gone nowadays. Apart from a few special cases, wind turbines are now used primarily for the generation of electrical energy. Generating electrical energy means almost unlimited possibilities for the use of the energy captured from the wind. Electrical energy can be transported over long distances and can be used for any purpose. The technical conditions of energy generation are almost completely disconnected from those of energy consumption. This aspect is of the greatest importance for an energy generation system dependent on the environment. The design and location of the wind turbine can be adapted optimally to the wind resource and need not be burdened by additional compromises in order to be matched to the characteristics and the final location of the point of energy consumption.

The main question arising when considering applications is the organisational integration of wind energy into the existing energy-supply infrastructure. Decisive differences and alternatives are to be found here. The range extends from supplying energy to a particular piece of equipment in isolated operation, for example a water pump, or the frequently expressed desire of having a power supply which is largely independent of the public supply, to the efforts of public utility companies to use large wind turbines in their interconnected power station system. These highly diverging aspirations and goals are not contradictory. Wind energy can be utilised in many ways and these should not be considered as being mutually exclusive, but as providing alternative possibilities.

The considerations regarding the application of wind turbines also include the various operational and siting concepts even if these do not open up any independent areas of use. The operation of wind turbines in large wind parks creates different organisational and economic conditions compared to the operation of distributed single turbines. The vision of operating large wind turbines "offshore" in the coastal areas of the sea is also included in these considerations and will be dealt with in a separate chapter because of its significance for the future.

16.1 Stand-Alone Applications

The first attempts of generating electric current with the help of wind energy were almost always directed at providing independent electrical energy in remote areas without connection to the grid. As long as a few hundred watts of direct current were enough to cover this modest need of electrical energy, generally only for lighting, this object could be achieved with comparatively simple technical means by using a small wind turbine and a storage battery (Chapt. 2.1).

Nowadays direct current is not longer used. Even when dwelling and living circumstances are modest, the wide variety of electrical loads requires utility-grade AC power. Self-sufficiency of individual houses thus becomes a comparatively complex technical problem. From an economic point of view a suitable technical configuration can only be justified if it can be achieved by means of relatively large wattages which is the reason why the dream of many to have their own independent power supply with a small wind turbine of only a few kilowatt power cannot be economically realised today. Given the current specific investment costs, an autonomous power supply system comprising a small wind turbine plus a storage battery and an inverter represents a very costly solution and only makes sense if there is no access to the grid.

The fundamental technical problem with the isolated operation of wind turbines is the dependence of the consumers to be supplied on the wind turbine's energy yield. This dependence has two different aspects. On a short-term basis this means that the wind turbine's power output must be matched to the power consumption of the loads. There must be an equilibrium between wind turbine and load at any given moment. This power balance either requires that the wind turbine can be controlled accordingly or that the power consumption of the load can be adapted to the output of the turbine (Chapt. 10).

Moreover, even stand-alone operation frequently requires current with a constant frequency. This requirement can be met to a limited degree of accuracy by wind turbines with blade pitch control, and wind turbines with fixed blade pitch have to be equipped with adjustable electrical load resistors, so-called dump loads. Where this is not precise enough, the only solution is a self-commutating frequency converter (Chapt. 10.4). In a long-term operation, the dependence of the load on the wind turbine leads to the question of *security of supply (firm power)*. Due to the nature of the wind, independent and firm power cannot be realised by means of wind turbines alone. It requires an overall supply concept which includes at least an energy storage system. In some special cases of isolated operation the question of energy storage can be solved cost-efficiently where water is used as the medium for energy storage. In almost all other cases expensive batteries must be used, otherwise security of supply can only be guaranteed by means of a hybrid system including a conventional energy-supply unit, a diesel generator in most cases, as back-up unit.

16.1.1
Autonomous Power Supply and Storage Problems

A power supply in an isolated situation can only meet present-day requirements if a certain degree of security of supply is guaranteed. To put it more simply: Even if the wind does not blow, the lights must not go out. If wind is the sole source of energy, a means of energy storage is imperative.

All efforts in striving for an autonomous energy supply system with the aid of renewable energy sources always end up with the problem of energy storage. The search for cost-effective energy storage is a theme pervading the whole range of these technologies. To exaggerate, one might say that as soon as an economically viable solution of storing energy has been found, all energy problems concerning the utilisation of renewable energy sources, i. e. with solar energy, can be solved. However, there is no such technology of energy storage in existence at present. All storage methods which can be used in practice today have a very limited storage capacity and are very expensive. Moreover, they require complex conversion systems, as the energy is mostly stored in a form which is not suitable for the end user.

Attempting to provide an overview of all possible methods of energy storage would be useless. The range of methods, patents and ideas relating to this subject is almost inexhaustible. However, there are some energy storage methods which are frequently discussed in connection with wind energy utilisation and these will be described in greater detail here.

A wind turbine is a two-fold energy conversion system: Firstly, the rotor converts the kinetic energy of the moving air into mechanical energy, and secondly, the electrical generator converts the latter into electrical energy. There are, therefore, basically two ways of tackling the problem of energy storage. For one, it may be attempted to store the mechanical energy directly, which has the advantage of not requiring any further high-loss energy conversion. However, the choice of mechanical energy storage methods is narrow.

It may be possible to store greater amounts of mechanical energy in flywheels. Flywheels have been tested intensively in the eighties [1]. New technologies such as high-speed flywheel rotors made of fibre-reinforced composite material, suspended magnetically in a vacuum and thus rotating virtually frictionlessly, gave rise to great hopes. Flywheels with a very high energy density, capable of absorbing large amounts of energy and of storing this energy over long periods of time virtually without any losses, are thus technologically feasible. However, the technical implementation of this technology proved to be far more difficult than expected, which effectively removes this possibility from present consideration.

In contrast, flywheels of more conventional design, made of steel and with conventional bearings, lose much more energy and thus become unsuitable for long-term storage. Moreover, project studies of steady-state flywheel systems showed unexpectedly high construction costs, the reason for these being, among other factors, that a continuously variable speed and torque conversion system — electrical or mechanical — is required for transferring the mechanical energy into the flywheel [2]. Coupling the wind rotor to the storage flywheel via a continuously variable transmission is technically feasible, but disproportionately complex and also subject to losses. The situation is different when a flywheel is used as short-term storage for smoothing the power output of a wind turbine, a purpose to which it is much better suited. This idea was implemented as early as 1950 in a small wind turbine in the former Soviet Union [3].

Recently, Enercon has developed a flywheel storage system which is offered for stand-alone applications and for operation in small grids (Fig. 16.1). The flywheel has a mass of 2.5 t and is connected to an asynchronous motor/generator [4].

The second possibility for energy storage is offered by the electrical energy generated. The capacity of storing electrical energy in conventional batteries is very limited. The storage capacities of even advanced batteries, for example nickel/cadmium- or silver/zinc-based batteries, are not enough to meet the electrical demand of some ten or even hundred kilowatts over a period of days. The economical use of batteries is therefore restricted to that as short-term buffer storage batteries. For the more distant future, the continued advance in the development of the fuel cell gives rise to new hopes for a suitable long-term storage device.

As long as there is no suitable storage device, however, conventional generator sets must be used in addition to the wind turbine. An autonomous supply system of this type, consisting of a wind turbine, storage battery with frequency converter, load management and an additional emergency generating set, represents a considerable technical investment (Fig. 16.2). Such a complex and expensive system is economically justified only when the fuel costs for a supply provided exclusively by a diesel generator are extremely high.

An indirect possibility of storing energy which is increasingly coming into the focus of interest and also of research in connection with solar energy and particularly with photovoltaics, is the electrolytic generation of hydrogen. It is highly probable that hydrogen will become an important element in the energy and traffic technology of the future as a storage medium and — which may be even more significant — as an alternative, environmentally

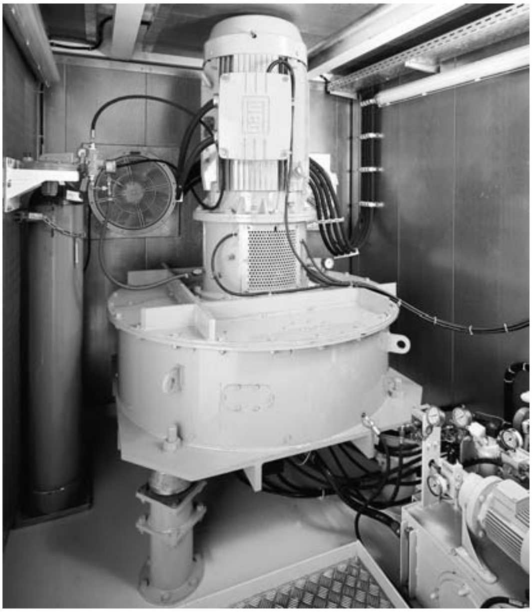

Figure 16.1. Flywheel storage system developed by Enercon

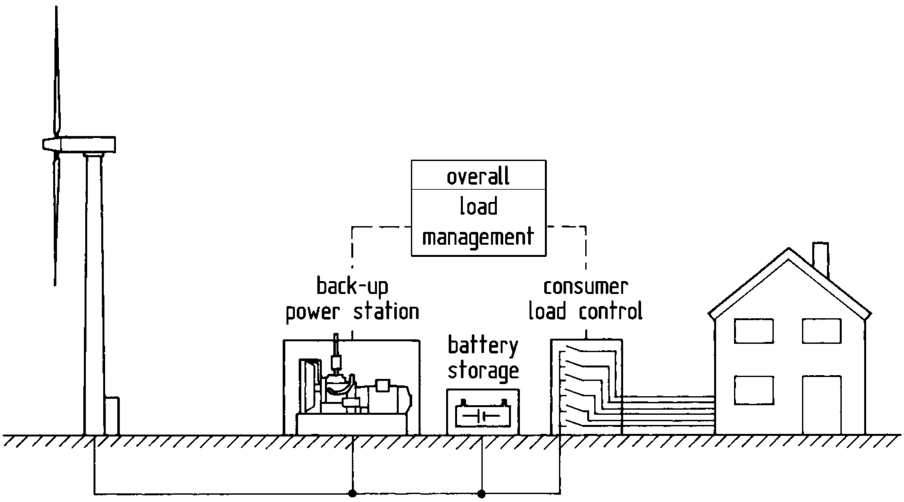

Figure 16.2. Autonomous power supply system with wind turbine, battery storage and a back-up diesel power unit

friendly fuel for vehicles. Naturally, the electrical energy generated by wind turbines can also be used to produce hydrogen.

Hydrogen can either be stored unpressurised at low temperatures, chemically adsorbed into a suitable medium or pressurised as a gas. It is an excellent, environmentally benign fuel and propellant the use of which is not restricted to the generation of electricity, but extends to numerous other applications. Therein lies the special appeal of this energy storage method, which can be technically implemented without problems. Unfortunately, however, the electrolytic production of hydrogen and its storage has to date not yet achieved a high enough level of economy for large-scale applications. The production of one standard cubic meter of hydrogen requires an energy input of approximately 4 to 5 kWh. As wind power can, by no means, be captured free of charge, it is easy to see how economical this process would be. The not inconsiderable costs of the storage technology required must also be included.

Nevertheless, the production and storage of hydrogen with the aid of solar technology is the technology for the future. The significance of regenerative energy sources will always remain a peripheral issue without the possibility of economic long-term energy storage and thus also of transporting energy from its generating site to the consumer without the need for power lines. Hence, solar hydrogen technology represents less of an inevitable technological symbiosis, but rather a comprehensive "energy option" [5]. From the standpoint of wind energy, all that remains is to wait for the development of hydrogen technology until an economical application becomes feasible. When this is the case, new perspectives will also open up for wind energy.

In the search for suitable energy storage methods for wind turbines, the question remains of whether there is not at least one method which can be realised economically by the technical means currently available. From the technological point of view, the answer is disappointing. The fact is that the oldest method of energy storage is also the only one today which can be used economically under certain circumstances. A water reservoir for energy storage offers the best preconditions for storing wind energy economically over a longer period of time.

If water is used as energy storage medium, several applications such as water pumps, sea-water desalination or room heating can be realised in stand-alone situations. Large-scale concepts are also conceivable, if the topographical conditions are favourable. Figure 16.3 shows an interesting proposal from Holland, which could be realised economically, in this way or in a similar form, due to the natural circumstances and already existing reservoirs. The proposal includes a pumped storage basin in the Ijsselmeer, on the dam walls of which a large number of wind turbines are to be accommodated [6].

There is the occasional suggestion of implementing pumped storage power stations, as they are in use by utilities as peak-load power stations, in combination with wind turbines.

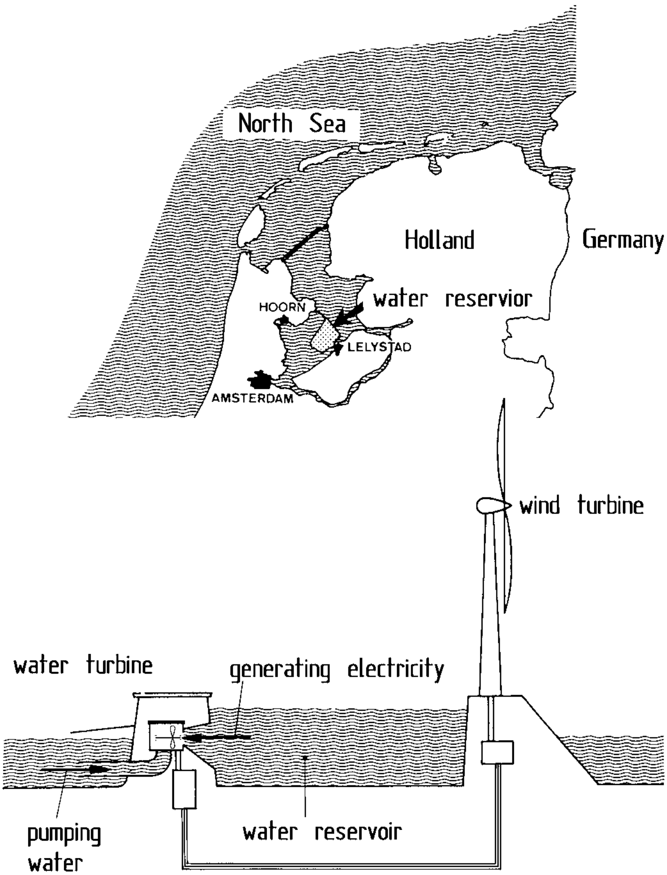

Figure 16.3. Proposal for the use of large wind turbines in combination with a pumped storage basin in the Ijsselmeer [6]

However, building pumped storage plants only to improve the utilisation of wind power is entirely out of the question from an economic point of view. Pumped storage plants have specific investment costs of more than 5 000 $/kW. In other words: under current conditions even water is an economical energy storage medium only if the preconditions are particularly favourable, or if the wind energy can be integrated into a supply concept which includes the storage of water in any case.

16.1.2
Residential Heating

There is a number of reasons why wind energy should be used for residential heating. Possibly the most important argument emerges when one looks at energy consumption patterns, for example for a country like Germany. With approximately 45 %, the "households and small consumers" sector represents the highest percentage of overall primary energy consumption. About 6 % of the energy requirement of this group is met by coal, about 16 % by gas and about 60 % by oil (1994) [6]. An overwhelming proportion of the energy consumed by this group is used for space heating. It accounts for 80 % of the energy demand of a private household. This proportion is contrasted by only approximately 5 % for lighting and power and approximately 15 % for process heat (hot water for domestic use). Using a wind turbine for home heating would, therefore, replace the primary energy sources of petroleum and natural gas particularly effectively.

Another argument, relating more to energy politics, puts stress on the fact that the utilisation of wind energy in the privately organised "heat supply market" could be handled much less restrictively than power generation involving feeds into the public grid. Heating energy is not produced and distributed by large electricity syndicates. Against this background, market penetration could be achieved much more easily, an argument which can certainly not be dismissed completely.

Not least, there is the argument emphasising the simpler and cheaper equipment when wind turbines are used for heating purposes. For resistance heating, constant frequency and voltage are of secondary importance. However, it remains to be proven to what extent the resultant lower requirements as to the wind turbine's control system will actually be reflected in lower investment costs. It must be kept in mind, that, for reasons of economy, the power which is not used must be fed into the grid, thus necessitating utility-grade AC power.

All in all, there are thus several arguments for using wind energy for residential heating. Hence, a somewhat more intensive discussion of this possibility is necessary. In Germany, several technical and economic analyses relating to this subject have been carried out in the years when heating oil was expensive [7].

The heat consumption of the space heating system of a private home is composed of the consumption of heat convection and of transmission. These are usually calculated according to the German DIN regulation 4701. The convection heat, i.e. the heat flow required in order to heat the outside air coming in through leaks, such as window gaps, and outside doors, depends on the wind speed and wind direction. According to the German DIN 4701, this parameter is generally only considered with a very rough estimate, if at all (Fig. 16.4).

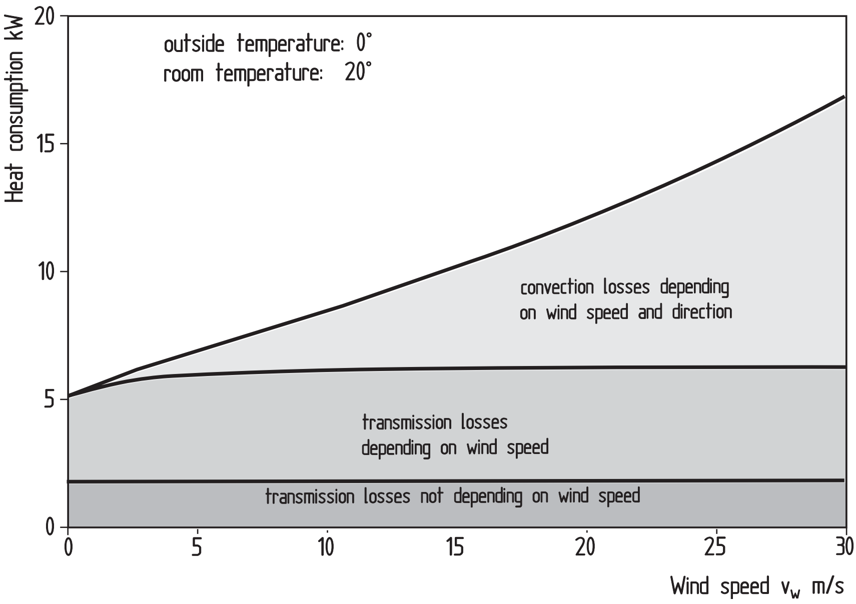

Figure 16.4. Heat losses of a family home (140 m² floor area) as a function of the wind speed [8]

The influence of the wind speed essentially means that the heat transfer coefficient increases with wind speed. Thus, the times of abundant energy availability coincide with those of increased demand, in contrast to heating systems based on the direct utilisation of solar power.

The extent to which the demand for heating power can be met by wind energy has been examined in a concrete case by a computer simulation [8]. For this purpose, the performance characteristics of the small Aeroman wind turbine with a rated power of 11 kW were assumed for supplying a family home with a floor area of 140 m². For the assumed site of List on the German island of Sylt, off the North Sea coast, 77 % of the heat requirement could be covered whereas 32 % of the power generated by the wind turbine could not be utilised (Fig. 16.5).

A look at the time correlation between wind energy supply and heating demand shows that it is not possible to cover the demand with the wind turbine alone. Surplus wind energy can only be utilised with the help of storage, which would decouple energy supply and demand in time. Theoretically, by using an energy store, the total annual heat demand of the house could be more than covered with the given size of wind turbine. The computer simulation shows, however, that a store permitting complete coverage over the entire heating season by wind power alone, would become uneconomically large.

For this reason, the economic solution is a hybrid system: a wind turbine combined with a conventional heating system. The overall system could consist of a separate electric heating system or of electrical resistance heating which would be integrated into the water cycle of a thermal heating system. The second possibility is more suitable for retrofitting

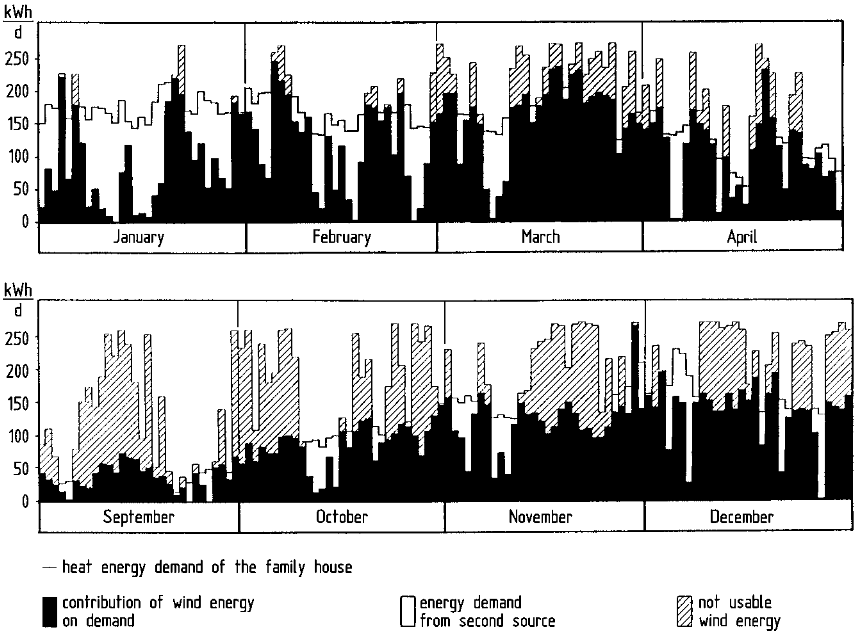

Figure 16.5. Computer simulation of a small Aeroman wind turbine heating a family home (floor area 140 m^2),assumed location List on the island of Sylt, mean annual wind speed $v_W = 6.8$ m/s at 10 m height [8]

to an existing central heating system. For this, a small additional energy store can be quite economical, so that at least a certain proportion of the otherwise unusable wind energy can be stored and utilised. In the example shown, wind energy could cover about 90 % of the heating demand.

Quite generally, the economics of using wind energy for heating purposes should be seen without illusion. Heating energy from a conventional gas or oil heating system currently (in 2003) costs approximately 3 Cents/kWh. Roughly speaking, this is too little by a factor of two to be able to amortise a wind turbine within a sensible period of time. Even if wind turbines could be technically simplified for the special application of for resistance heating, there would still be the additional costs of the conventional system. It is only if this equipment is already installed and could be shared that the investment costs can be kept within justifiable limits.

The utilisation ratio of wind energy should be near to 100 % for economical reasons. In nearly all cases this is only possible if the energy which is not used can be fed into the public grid. This, however, eliminates the possibility of introducing technical simplifications into the wind turbine. Due to these circumstances, "heating with wind" does not yet have an economical chance at the current oil or gas prices. Very small wind turbines which can be integrated into existing heating systems are most likely to be successful here, especially if the prices of oil and gas increase in the future.

16.1.3 Pumping Water

Pumping water is one of the most ancient applications of wind power. From the last decades of the nineteenth century until today, the American (and Australian) wind turbine with its mechanically driven piston pump has become the second symbol for the utilisation of wind energy, next to the European windmill. This technology is particularly well-suited to areas with moderate wind speeds and for the pumping of small amounts of water from a great depth, primarily for providing drinking water. For this application, the American wind pump has remained virtually unbeatable in its simplicity and reliability.

However, modern irrigation technology has different requirements, especially in the agriculture of many developing countries. Here, large amounts of water are needed to be pumped, often from shallow depths. Moreover, it is frequently not possible to locate wind turbine and water pump in the same place. Under these circumstances, a conventional wind turbine for driving electrical water pumps becomes increasingly attractive, even though this technology is far more complicated. In many cases, the wind turbine is again set up as a hybrid system in combination with a diesel generator, or is integrated into an existing system. Its economic efficiency must then derive from the fuel saved in the diesel set.

In principle, the wind turbine can be operated in combination with a piston pump or a centrifugal pump. Piston pumps have a high efficiency of approximately 80 to 90 %, even at reduced rotational speeds. The efficiency of centrifugal pumps is lower, approximately 50 to 75 %, and it drops rapidly with decreasing speed. The pumping characteristics and thus power consumption relative to speed also differ greatly. Piston pumps raise a volume flow which is proportional to the rotational speed and almost independent of the delivery head, i. e. the depth of the well. Moreover, a certain delivery head requires a minimum rotational speed.

A comparison of the operating characteristics of the two types of pumps with the power characteristic of a high-speed wind turbine shows that the operating characteristics of the water pump can be matched more easily to the power characteristics of a wind rotor if it is a centrifugal pump (Fig. 16.6). The simple reason is that the characteristics of the two "fluid flow machines", wind rotor and centrifugal pump, are a better match [9]. Although the electrical transmission of power from wind turbine to water pump involves a twofold energy conversion, with corresponding losses of altogether about 30 %, this loss is more than compensated for in many cases by the optimal siting of the wind turbine.

A modern concept of a wind/pump system is shown in Fig. 16.7. An Aeroman wind turbine is equipped with a synchronous generator of 14 kVA and supplies the two submerged electric pumps in the well via a three-phase low-voltage line. Depending on the wind power on offer, the electric control system switches on one or both pumps and thus roughly adapts pump power consumption to the available wind power. The pumps operate at the frequency dictated by the wind turbine's synchronous generator. This frequency varies between 40 and 50 Hz., with the power consumption of the pumps ranging from 50 to 100 % of the rated power.

The frequency limits are the control criteria for switching the pumps on or off. As the wind speed increases, the blade pitch control of the wind turbine helps to maintain the upper frequency limit. If the wind speed is lower so that the power provided by the wind

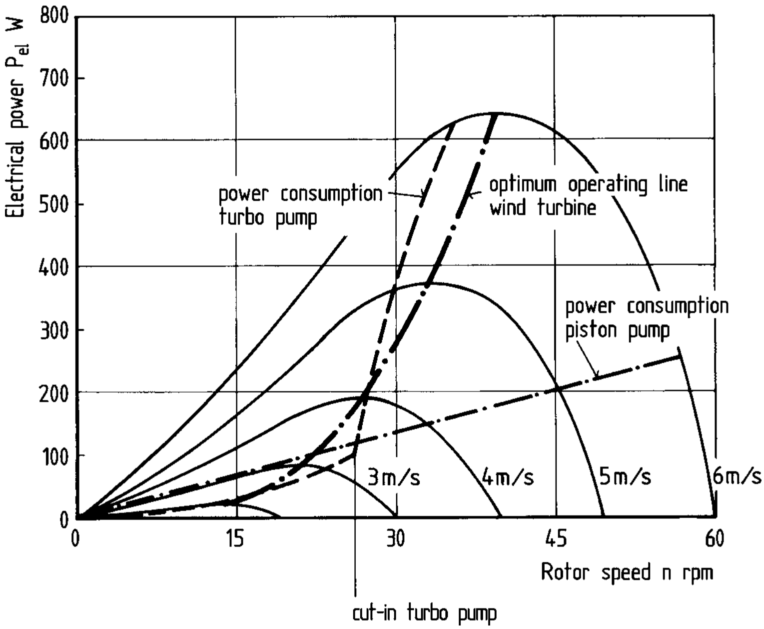

Figure 16.6. Power consumption of a piston pump and a centrifugal pump compared to the optimal power characteristics of a wind turbine [9]

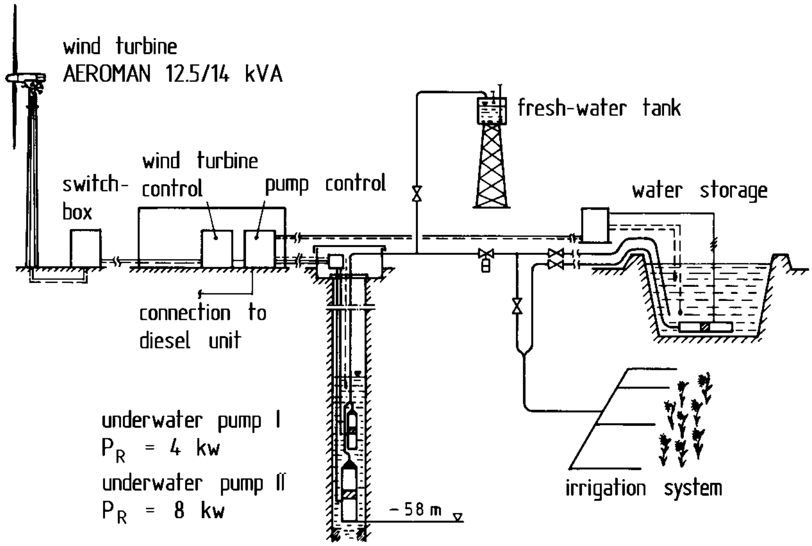

Figure 16.7. Wind-supported irrigation system with an Aeroman wind turbine and two underwater electric well pumps [10]

turbine is below the maximum power demand of the pumps, there will be operating points within the variable frequency range which correspond to a power equilibrium between wind turbine and pumps. In this range, the blade pitch control of the wind turbine is not active. In principle, the wind pump system can start up without an auxiliary power source, since the wind turbine is started by a battery-powered hydraulic control system and accelerates up to a generator speed where the generator voltage guarantees the supply of the electronic control system. The dynamic interaction between the wind turbine's variable power output and the power consumption of the water pumps requires a finely tuned control system and load management, if severe power losses are to be avoided.

Naturally, the pumping capacity of the wind pump system described depends on the wind regime and the delivery head. For a site with a mean annual wind speed of 5.5 m/s and a delivery head of 50 m, the water volume pumped annually amounts to approximately 130 000 m^3. As soon as the investment costs, which are still too high at present, can be lowered via higher production numbers, wind-driven water pumps of this or similar concepts are projected to have very good chances of being used widely in the Third World.

16.1.4 Desalination of Sea Water

Quite a few experts predict that there will be a catastrophic world shortage of drinking water long before there will be a real energy crisis. This prediction is not so far-fetched for some Third World countries and it may even have become reality already in some regions. The only global solution seems to be the utilisation of sea water for drinking water.

Technical methods of sea-water desalination for use on board ships were developed as early as the 19th century. On land, sea-water desalination plants for supplying drinking water have only been in use for some decades. Desalination processes based either on distillation or on the separation of water and salt by semi-permeable membranes, have achieved practical significance.

Distillation provides for almost complete desalination of sea water. The specific energy requirement is largely independent of the salt concentration. The processes mainly require thermal energy. Currently, distillation plants using the so-called multi-stage flash evaporation process, with a daily output of drinking water of 30 000 to 40 000 m^3 are being built. The power requirement of a plant of this size is approximately 150 Megawatts.

Lately, the membrane methods, electrodialysis and reverse osmosis, are increasingly being used. With the ready availability of modern membrane materials, interest has focused particularly on reverse osmosis (RO). It is based on the different permeability of semi-permeable membranes for salt and water. The structure of a reverse osmosis plant resembles an osmotic cell. A receptacle contains a salt-water cell and a fresh-water cell separated by a membrane (polyamide or cellulose acetate). Salt water is continuously fed into this cell with a pressure higher than the osmotic pressure of the saline solution. Part of the water diffuses through the membrane into the fresh-water cell and from there into a storage tank. The remaining, more concentrated salt solution is drained from the cell.

The energy requirement (all that is needed is the mechanical or electrical energy for driving the pumps) increases with the salt concentration of the available sea water. For this reason, this method is to date predominantly being used for desalinating sea water with a low salt content (brackish water). With modern membranes, however, drinking water with a residual salt content of 0.5 g/kg can be produced even with sea water with a salt content of 35 g salt per kg water (North Sea). The energy demand for this salt concentration amounts to 10 to 15 kWh electrical energy for the desalination of one cubic meter of salt water. However, the reverse osmosis method requires extensive pre-conditioning of the sea water. Suspended organic particles and various minerals must be filtered out to prevent premature clogging of the membranes.

Reverse osmosis provides favourable conditions for being operated in combination with a wind turbine, as the energy required for driving the pumps is electrical energy. Moreover, water desalination has the general advantage of all water treatment and supply methods, namely that of simple storage methods for water. Continuous production with constant volume is not mandatory. Utilising wind energy for desalinating sea water by means of reverse osmosis is, therefore, considered to be a promising application. A series of small test plants has already been built and plans for larger installations are about to be implemented.

A small test plant was taken into operation in 1984 on the German North Sea island of Süderoog [11]. A small Aeroman wind turbine was used to drive an RO-plant. With a mean annual wind speed of approximately 7 m/s, the average daily capacity amounted to

Figure 16.8. Wind-driven desalination plant on the island of Rügen, using a Tacke TW 300 wind turbine and a pressurised evaporation plant (Thyssen/SEP)

3 m³ of drinking water. The maximum production volume was achieved at wind speeds in excess of 8.5 m/s with one cubic meter per hour. Another test installation has been in operation since 1995 on the island of Rügen (Fig. 16.8).

Based on the experience of the test plant on Süderoog, more evolved concepts with higher performance were developed (Fig. 16.9). In the concept shown, the power consumption of the RO-plant is matched to the wind turbine by switching the individual modules on or off. From sea water with a salt concentration of 36 g/kg and with a mean annual wind speed of 7 m/s, the average daily production amounts to approximately 13 m³ of drinking water.

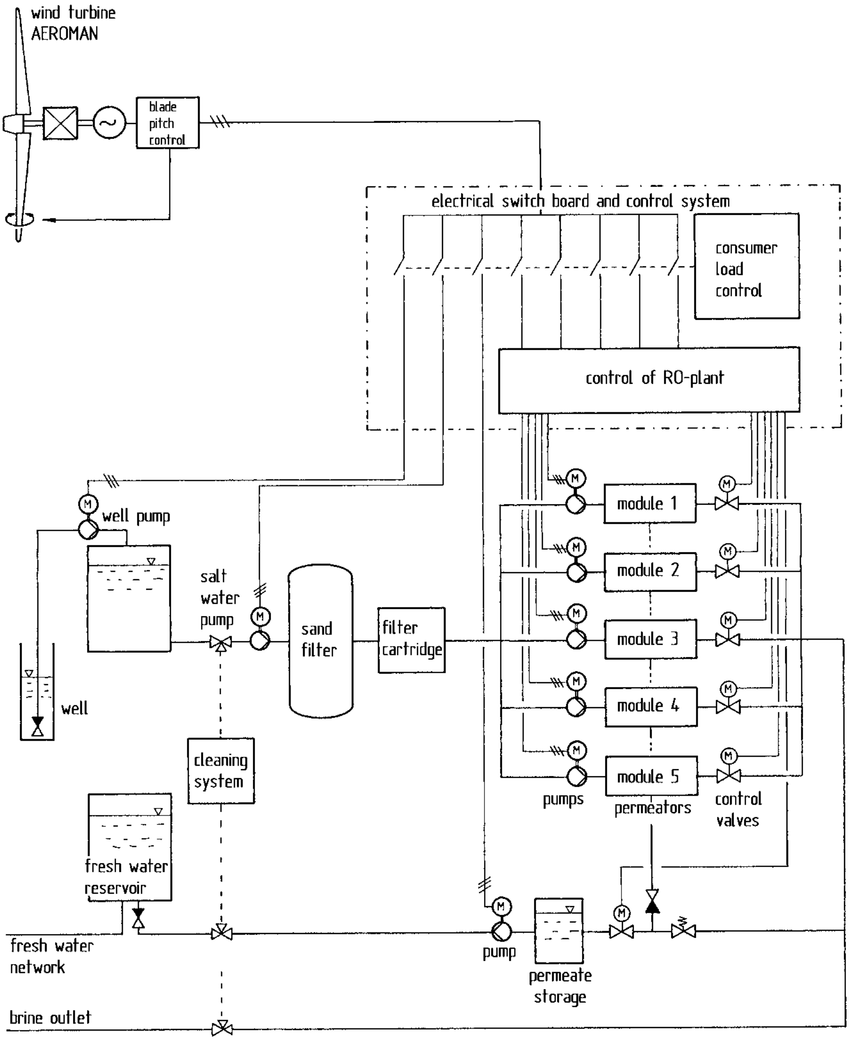

Figure 16.9. Concept of a wind-driven sea-water desalination plant based on the RO-method [12]

Some test installations have been built by Enercon since middle of the nineties. On the islands of Tenerife (Spain), Syros and Chios (Greece) and in India some plants (reverse osmosis) are being tested. Enercon has announced to offer a modular concept ready for series production. The plants shall be suitable for private consumers as well as for industrial applications or hotels etc.

The economics of drinking-water production by wind power and RO-methods are, as usual, determined by the investment costs. At present, these are still very high in the case of the test plants described here. The costs of servicing and maintenance can not be ignored either, especially with RO-plants. One fact already emerges clearly, however, namely that in remote, windy locations, water-production costs are competitive when compared to plants driven by diesel generators [12].

16.2 Small grids with Diesel Generators and Wind Turbines

Under current conditions, an energy supply system relying exclusively on renewable energy sources does not lead to a really practicable solution, except in a few individual cases. It will remain this way, too, for the foreseeable future, unless the energy storage problem can be solved in an economic way. The path to a wider application of renewable energy sources, therefore, lies via a hybrid supply system. It is based on the idea of running the renewable energy system as far as the energy source allows, and to use an additional conventional system to meet the requirement for security of supply. To this end, both systems must be controlled in such a way that switching from one system to the other is possible without interruption or, as in most cases, the systems are operated parallel. A combination which could be used widely in the future is the energy supply by a diesel power station combined with one or several wind turbines working as "fuel savers", called *wind-diesel systems* for short by the professionals.

Diesel power stations are used in many countries, especially in the Third World. Frequently these are generators with a maximum power of several hundred kilowatts up to a few megawatts, supplying surrounding consumers via a local grid. But this technically simple and reliable concept is increasingly afflicted by high fuel costs. Cheaper heavy oil can be used in large diesel engines, but smaller diesel units up to one megawatt need the far more expensive light diesel oil. Using a wind turbine is especially attractive under these conditions. In locations with good wind conditions, the fuel consumption of such an electricity supply system can be reduced to a fraction and at the same time the environmental pollution caused by the diesel exhaust gases is reduced. Operating a wind turbine in a local grid fed by a diesel generator is *the* essential isolated application. More precisely, this should be called small or isolated grid operation.

In the recent years, the oil prices have increased dramatically. The economic attraction of wind-diesel systems has naturally increased in the same way. In 2005 the electricity production price of light oil has doubled since the late Eighties, when the described experimental plants have been built. So a new economic approach for the wind-diesel applications has more chances now.

In the first period of modern wind energy use wind-diesel electricity supply systems have been constructed as test systems in various countries. As early as 1979, NASA operated one of the four MOD-0A test turbines on Block Island in the USA in combination with a diesel power station. In Canada, several wind-diesel systems with Darrieus turbines in a power range of up to 250 kW were tested [13]. In Europe, an isolated wind-diesel system was installed on the Greek island of Kythnos [14].

The largest and technically most sophisticated wind-diesel system so far was built on the German North Sea island of Heligoland. The energy and water supply of the island of Heligoland with its population of approximately 2000 was completely reorganised between 1988 and 1990 [15]. The supply system is based on two diesel generators with 1800 kW each, the waste heat of which was recovered for the local district heating system. In addition, a large WKA-60 type wind turbine was used as a "fuel saver" for the diesel engines. In times when the wind energy exceeded the instantaneous load in the grid, the electrical energy was used for powering a sea-water desalination plant and the drinking water produced there was stored. In this way, the overall system also had an, albeit limited, energy storage capacity (Fig. 16.10).

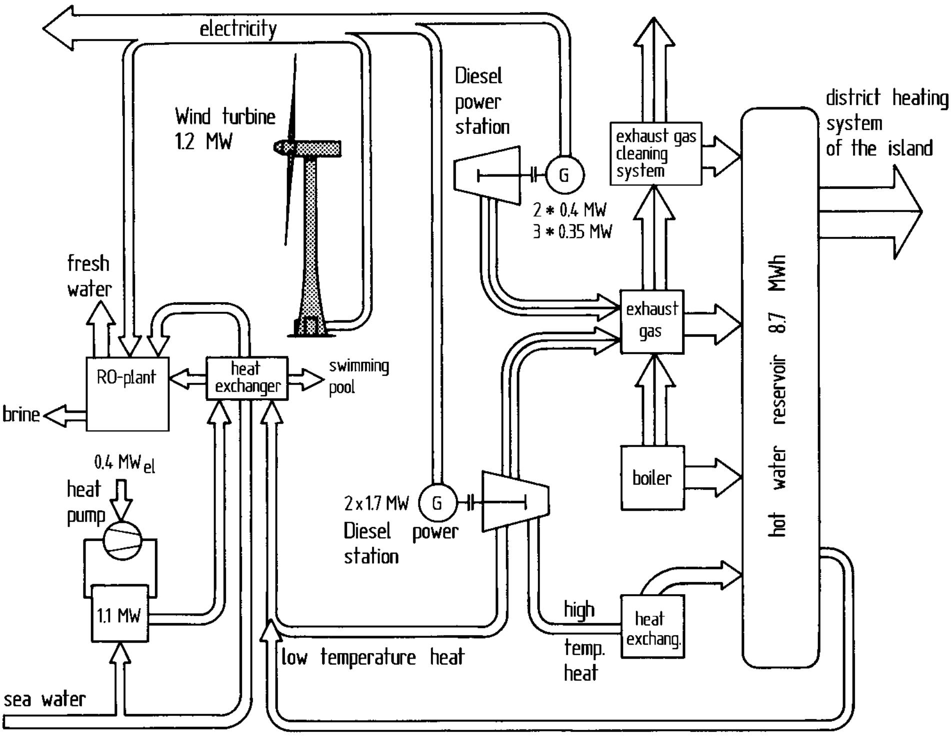

Figure 16.10. Energy and water supply system on the German island of Heligoland, with a large wind turbine of the WKA-60 type (Krupp/MaK)

A wind turbine of the WKA-60 type was modified especially for this application. The turbine's synchronous generator with a static frequency converter was operated at variable speed over a relatively wide range of speeds. Considering the high wind-power input in the small, isolated grid, the resultant smoothed power output was an essential precondition for overall system control interaction with the diesel generators. Moreover, the wind turbine was equipped with an autonomous reactive power supply, a synchronous generator in parallel operation, and the harmonic frequencies produced by the inverter were largely filtered out (s. Chapt. 9, Fig. 9.20).

The wind turbine was operated on Heligoland from 1988 to 1995. However, the practical experience gained was not satisfactory. The overall load management of the island's grid gave preference to the diesel generators to such an extent that the wind turbine could not be used to its full potential. The wind turbine itself was damaged considerably several times by lightning strikes so that the local utility removed the turbine from operation in 1995 and had it dismantled not much later.

Designing wind-diesel systems, or integrating a wind turbine into an already existing small grid creates a number of system-related problems. Firstly there is the question of the wind turbine's maximum permissible power, measured as the installed power of the diesel units, or of the grid load. For reasons of energy economy, the largest possible wind turbines will be given preference in most cases. However, the operational interaction between diesel unit and wind turbine limits the "wind power" in the grid.

The higher the proportion of wind power in the grid, the greater the influence of the wind turbine on the grid frequency, taking into consideration the instantaneous conditions. It is obvious that the control system of the wind turbine plays a decisive role in this context. A wind turbine with blade pitch control can itself contribute to the frequency stability, thus making it possible to achieve a higher proportion of wind power content than with a turbine without blade pitch control, which must be controlled completely by the grid frequency. The second factor limiting the size of a wind turbine has to do with the behaviour of the diesel generator at partial load. If diesel engines are run at less than approximately 25 % of their rated power, their efficiency drops sharply, resulting in an increase in the specific fuel consumption.

Some further problems arise with regard to the operational sequence control. In principle, alternating operation of diesel generator and wind turbine is possible but is difficult to implement, as, in this case, the grid frequency must be maintained by the wind turbine alone from time to time. In a simpler case, the wind turbine will be run only in parallel with the diesel generator the power of which is restricted in dependence on the power input by the wind turbine. Operating the wind turbine and diesel unit in parallel also has the advantage that the diesel unit, which is usually equipped with a synchronous generator, can control the grid frequency as well as provide the excitation current for the wind turbine. The latter can then be equipped with the usual induction generator.

The technical problems of isolated grids are simplified if several diesel units are available. This is usually the case, anyway, for reasons of redundancy. It permits individual units to be switched on and off instead of having to drastically reduce power, which is undesirable. It must be ensured, though, that excessively frequent warm-up phases of the diesel engines should be avoided, as they cause high fuel consumption. The frequently voiced concern that increased non-steady operation of a diesel engine in combination with a wind turbine could unfavourably affect fuel consumption has not been confirmed. Compared with cold runs, these influences proved to be negligible [16].

Figure 16.11 shows the technical concept of a wind-diesel system which also meets more complex requirements. The system consists of a number of small wind turbines which are equipped with electro-hydraulic blade-pitch control. The turbines are fitted with induction generators. The synchronous generator of the diesel unit is connected to the engine via a switchable clutch. In addition, there is a storage battery which can be charged and discharged by an inverter or rectifier.

Being equipped in this way, the system can operate completely autonomously in both parallel and alternating modes of operation. When the wind turbines are operating without

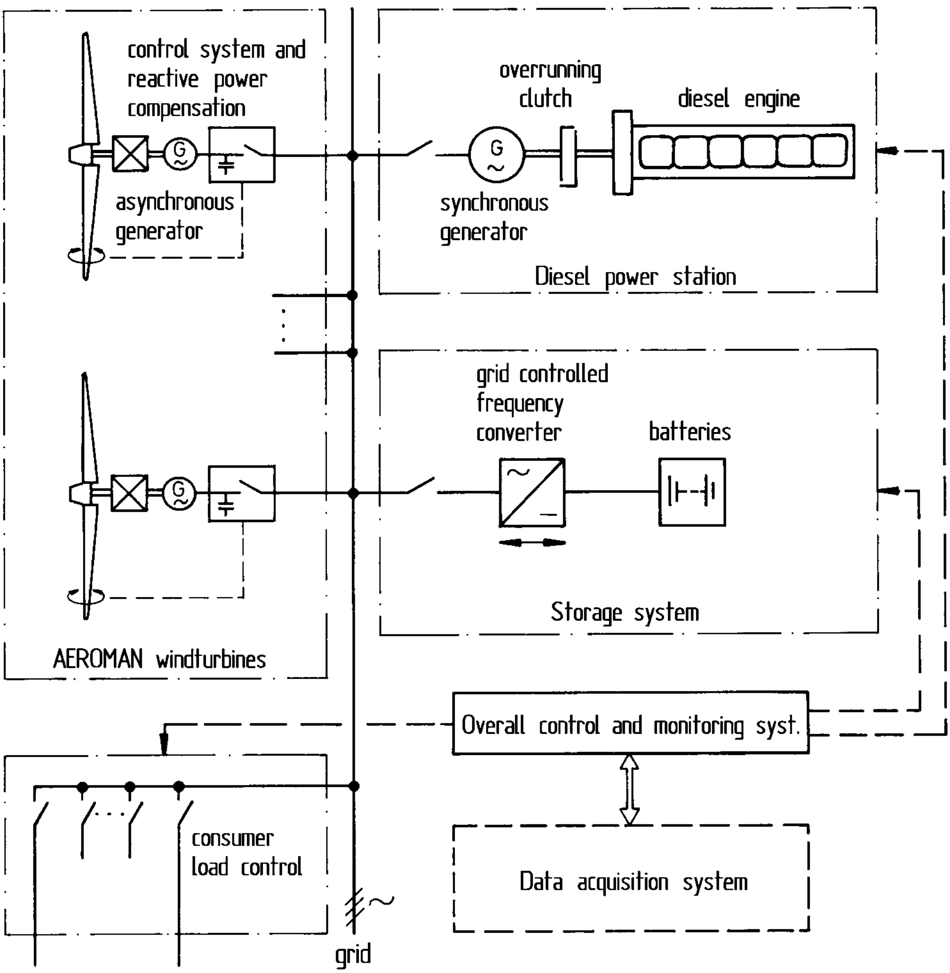

Figure 16.11. Concept of an autonomous wind-diesel system for alternating and parallel operation of wind turbines and diesel units [17]

the diesel generator, the grid frequency is held within an acceptable range by the rotors' speed control. Decoupled from the diesel engine, the synchronous generator works as a rotating phase shifter and takes care of voltage control in the grid. The storage battery, the capacity of which is designed for approximately 30 minutes of operation at rated power, can bridge short periods of low winds, thus avoiding excessively frequent start-ups of the diesel generator. In addition, the back-up battery can be used for smoothing out the load variations for the diesel engine, so that it can be kept within an advantageous operating range. Control of the overall system is handled by an overall load management system using the instantaneous grid frequency as reference variable.

In 1987, a wind-diesel system which largely corresponds to the concept described above was installed on the Irish island of Cape Clear. Unfortunately, the experience gained during its operation was not favourable enough for an economical operation to be kept up over a longer period of time. It was found in this case, too, that these as yet rather improvised systems require intensive technical servicing which cannot be guaranteed in remote sites. The implementation of "wind-diesel systems" which are really commercially viable is obviously still a task for the future.

16.3 Wind Turbines Interconnected with Large Utility Grids

By far more than 95 % of the worldwide wind energy capacity is connected to large utility grids. The operation on a large grid has several important advantages with respect to the characteristics of wind power generation. The power output of the wind turbines needs not be controlled in accordance with the instaneous power demand of a specific consumer. The lack of firm power delivered by the wind turbines is compensated by the conventional power stations. Last but no least, the frequency of the large grid is held by the power stations and can be used to control the rotor speed of the wind turbines. Against this background, the operation of wind turbines in parallel with the grid is technically not as complicated as in stand-alone applications.

16.3.1 Distributed Wind Turbines Operated by Private Consumers

The operation of a single wind turbine or of a few wind turbines by private or industrial consumers of electric power was the first field of application which achieved commercial status. It is primarily in Denmark that private customers, mostly with farms, small businesses and in recent years also communities have been buying wind turbines and have been operating them interconnected with the public grid since approximately 1978. This development was made possible by Danish legislation and by initially high public subsidies for electricity generation from wind energy. The technical experience in constructing and operating small wind turbines existing in Denmark also played quite a significant role (s. Chapt. 2.5).

Since about 1990, wind turbines have also found wider application in other countries. Particularly in Germany, wind turbines became widespread. The so-called "Einspeisegesetz für Strom aus regenerativen Energien" (Law Concerning the Infeeding of Power from

Regenerative Energy Sources) from 1990 created a reliable basis for paying for power from wind energy. Today (2004), about 15 000 wind turbines are operated singly or in wind parks in parallel with the grid in Germany. A similar development took place a few years later in several other European countries, such as the United Kingdom, the Netherlands and Spain. Depending on the geographical conditions, the wind turbines are used more in large wind parks as, for example in Spain, or more as single installations or in relatively small groups.

The distributed installation of wind turbines is relatively easy from a technical standpoint. The wind turbines are operated almost exclusively in parallel with the grid. This means that the systems are directly electrically coupled to the fixed-frequency grid, so that the grid is handling the speed control. In this way, wind turbines without blade pitch control can be operated on the grid without any control problems (Chapt. 10.3.2).

Initially, small single wind turbine installations could be connected to the public grid in various ways. Today, the power supplied by the turbine is fed directly into the grid via a meter in the same way as large wind parks. The consumer continues to keep his regular grid connection via the existing meter (Fig. 16.12). Billing by the proper utility company is handled via separate meters for injected power and for received power. It is only in rare cases that a consumer is connected directly, for instance with an electrical resistance heating system, so that only the excess energy is being fed into the grid.

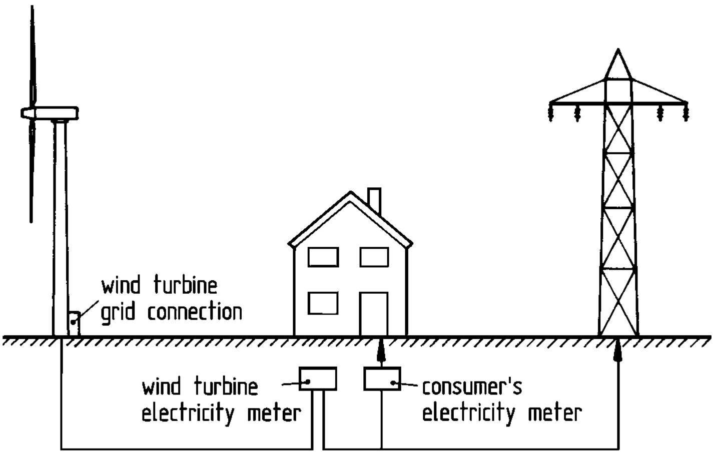

Figure 16.12. Wind turbine at private consumer's interconnected with the public grid

16.3.2 Wind Park Installations

Even when considering today's largest wind turbines with a rated power of several megawatts, the power output of one single wind turbine is a small amount when compared to the power of a conventional power station. If the share of wind power in the overall energy supply is to become worth mentioning, the problem becomes one "numbers". The distributed installation of wind turbines according to the maxim: "Every consumer with his own wind turbine!" quickly meets its limits in more densely populated countries. As much as a completely decentralised supply structure on the basis of other technologies would have undeniable advantages, there is a number of reasons why this wouldn't work with wind turbines. In most countries, areas with technically usable wind speeds are restricted to certain regions. This creates the necessity of concentrating as many wind turbines as possible in these regions, regardless of the local energy demand.

Concentrating several or even many wind turbines in one area also offers considerable advantages technically. Operating one single wind turbine involves a comparatively large amount of work. From an economic point of view, it is much more cost-effective to provide the required lifting and assembly equipment for a larger number of wind turbines in close proximity to each other.

A further economic aspect relates to the costs for grid connection. Long distances to a suitable infeed point can only be justified for a relatively large number of turbines which can also be combined electrically.

In 1982, the first large wind-turbine arrays were set up in the American state of California. They initially consisted of comparatively small turbines with maximum power outputs of between 20 and 100 kW, in most cases of US manufacture. The Danish manufacturers of wind turbines soon recognised their chances and the further growth of the Californian "wind farms" rapidly became based on Danish imports. The development came to a halt in 1985/86 when the tax incentives for the investors largely disappeared (s. Chapt. 2.5).

In Europe it was the Danes who, in addition to their numerous distributed installations, emulated the American model with their first "wind parks", although on a much smaller scale. Because of the limited space available, however, further development has been greatly retarded in recent years in Denmark.

In Germany, the introduction of the so-called "Einspeisegesetz" (Law Concerning Power Infeeding) in 1990 created the economic preconditions for the construction of larger wind parks. The utilisation of wind energy in Germany has been based on large turbines right from the start (Fig. 16.13). Whereas in the initial years, wind turbines had been erected almost exclusively in the immediate vicinity of the coast, wide inland regions have also been opened up for the utilisation of wind energy in recent years. Today, wind parks with up to several hundred megawatts output form a part of the energy supply in many countries which can no longer be overlooked. In Europe, this applies especially to Spain, but wind parks are also increasingly being erected in nearly all other European countries and in all parts of the world (Fig. 16.14 and 16.17).

The terms *wind farm* or *wind park* denote the concentration of several wind turbines into a spatially and organisationally interconnected cluster, the operation of which is, as a rule, commercially organised. There is no mandatory technical connection between the individual turbines. Although the turbines are connected to the grid via internal cabling and a joint substation of the utility company, the turbines are operated completely autonomously in parallel with the grid. This will not result in an independent concept for the technical use of wind turbines but in a special organisational form of application.

The two terms "wind farm" and "wind park" are used interchangeably. In American and international usage the term "wind farm" has become established. But there are possibly indications of a differentiation between the two terms. The European "wind parks" consist of a much smaller number of wind turbines, usually sited in a more geometric arrangement.

The wind park thus differs from the more or less disorderly massed array of turbines in the Californian wind farms of the eighties. In the meantime, large and carefully planned "wind parks" are also being erected in the United States, of course.

Figure 16.13. Windpark Altenheerse with Fuhrländer wind turbines in Germany (Fuhrländer)

Figure 16.14. Wind park La Muela with NEG Micon 750 kW turbines in Spain (Renerco)

Figure 16.15. Wind park Qingdao in China with Nordex N62 wind turbines (Nordex)

Figure 16.16. Wind park with Vestas V80 turbines in Australia (Babcock & Brown)

16.4 Technical Layout of Wind Park Installations

The technical layout and design of wind park installations is an important part of wind power engineering. This task — unfortunately — can not be solved by technical optimisation alone, because it is strongly associated with economic, legal, environmental and social aspects. Nevertheless the optimal technical concept should be used as a guideline to be followed as closely as possible.

16.4.1 Wind Turbine Spacing

When dealing with the installation of a number of wind turbines concentrated in an array, the first technical problem which arises is the issue of spacing. Apart from the fact that in the real-world, many factors must be considered when determining the geometry of the array — in many cases the topography of the terrain will be the decisive factor — this question will first be considered from an aerodynamic point of view to avoid unjustifiably high power losses due to mutual turbine shielding. A minimum clearance between the wind turbines must be guaranteed, otherwise power losses will be so high that the wind park will operate uneconomically from the start.

Aerodynamic Array Efficiency

The problem of aerodynamic interference of wind turbines in a geometric array was first examined in the US when the first wind farms were being built. The power loss from aerodynamic causes due to the mutual shading of the turbine is expressed as the so-called *aerodynamic array efficiency*. It is defined as the energy yield of the entire wind farm in relation to the sum total of the energy yield which would be delivered if the wind turbines were operating as single units and without interference. On a real site, the array efficiency is always less than 100 %, as the mutual aerodynamic interference is noticeable a distance of up to 20 rotor diameters or more.

This array efficiency must be determined for a given array geometry, or the geometric arrangement of the array must be chosen such that the array efficiency of the wind farm is as high as possible. The array efficiency can be determined with the aid of theoretical models which have a similar structure to the rotor power calculation described in Chapt. 5.1, but which additionally include the mutual interference of the rotor wake (s. Chapt. 5.4).

The power output of a single wind turbine can be calculated without knowing the wind direction characteristics of the site. Since the wind turbine is yawed into the wind, the power output is only dependent on the wind speed. The power output of an array of turbines, however, behaves quite differently. Depending on the wind direction, the distances of the individual wind turbines both in the direction of the wind and at an angle to the wind will differ, so that losses caused by shading can be smaller or greater. In addition to the frequency distribution of the wind speed, the calculation of the energy yield of a wind turbine array, therefore, also requires the annual distribution of the wind direction.

The decisive parameters determining the aerodynamic efficiency are the number of turbines and the array geometry, the turbine characteristics (thrust coefficient), the turbulence intensity on site and the frequency distribution of the wind direction.

Figures 16.17 and 16.18 show the order of magnitude of array efficiencies based on theoretical model calculations. The conclusion that can be drawn from these results is that, from an aerodynamic point of view, a turbine spacing of 8 to 10 rotor diameters in the prevailing wind direction and 3 to 5 rotor diameters across the main wind direction represents a reasonable array geometry. Under such conditions, the array efficiency reaches approximately 90 %. This result has also been confirmed by practical experience.

The aerodynamic array efficiency is essentially determined by the following parameters:

- Number of wind turbines and array geometry,
- Wind turbine characteristics (rotor thrust coefficient),
- Wind turbulence intensity on site,
- Frequency distribution of wind direction.

It is not only the energy yield of an array which differs from the sum of interference-free single turbines, but also the power curve. When the wind reaches cut-in speed, the wind turbines of the first row will start up first, but the turbines behind these will not run yet due to the retarded flow. Progressively, all wind turbines will start up until, from a certain wind speed on, all turbines are in operation. From this speed on, which lies above the rated wind speed specified for a single wind turbine, all units will operate at rated power and

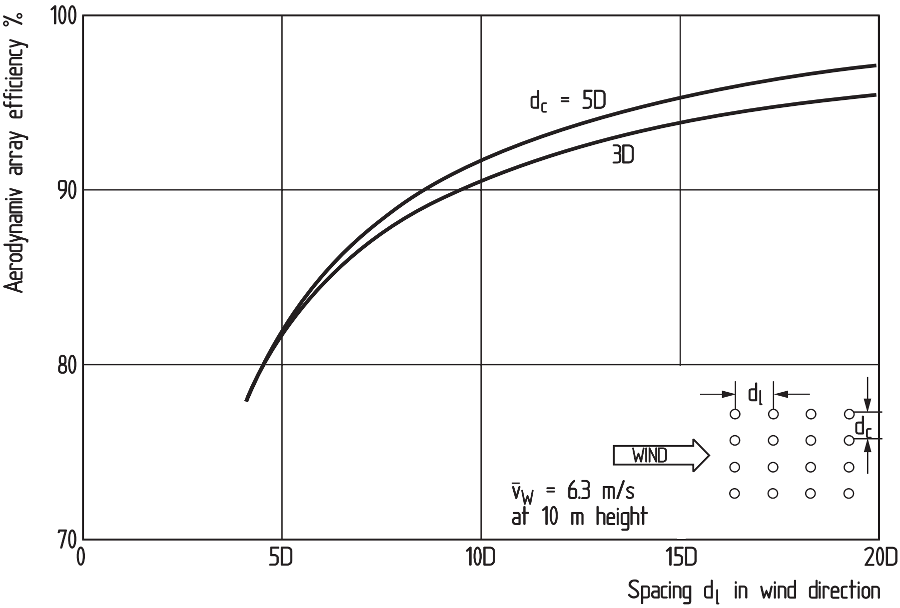

Figure 16.17. Aerodynamic array efficiency as a function of rotor distance in the wind direction, calculated for an array of 16 turbines [18]

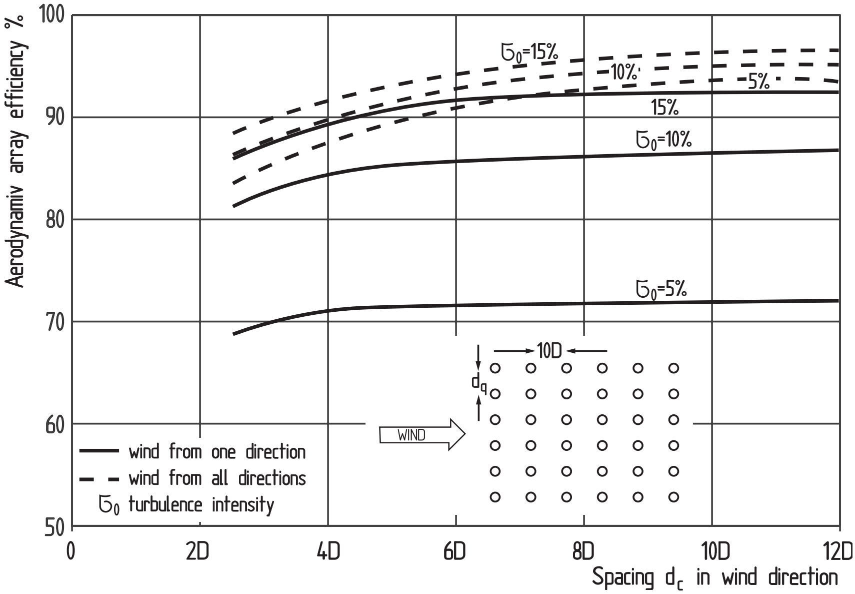

Figure 16.18. Aerodynamic array efficiency as a function of rotor distance across the wind direction and of the degree of turbulence [18]

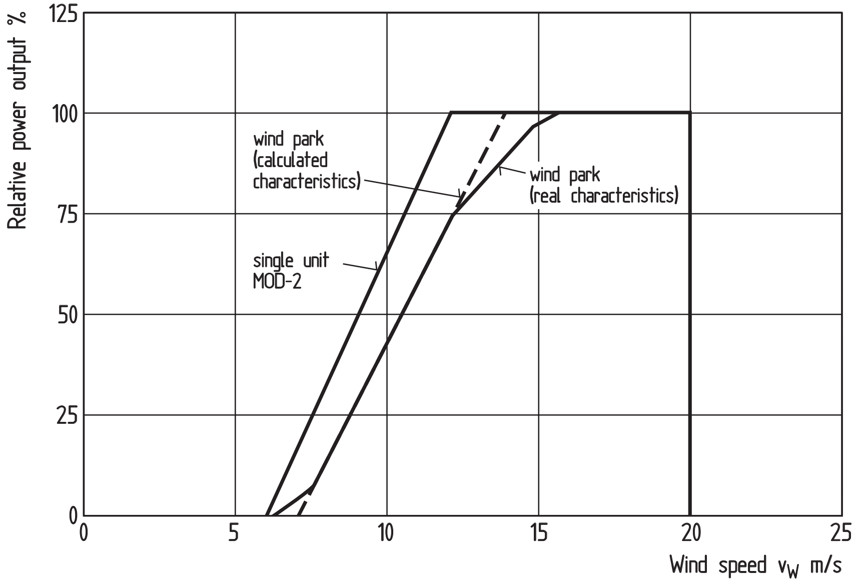

Figure 16.19. Power curve of an undisturbed single turbine and of a wind park [18]

the array efficiency is then 100 %. These effects lead to a difference in the power curves between the interference-free single wind turbine and the turbine array. In addition, the array power curve also depends on the wind direction (Fig. 16.19).

Induced Turbulence

In addition to its positive effect of replenishing the wake more rapidly, the turbulence caused in the array by the wind turbines also has the negative effect of increasing the turbulence intensity by a not inconsiderable amount with regard to the fatigue load spectrum. This "induced" turbulence generated by the wind turbines themselves is added to the "natural" turbulence on the site. As already mentioned in Chapt. 5.4, this effect essentially depends on the distance from the rotor, i. e. on the spacing of the turbines of a wind park array, apart from the turbine characteristics. With a given turbulence intensity on the site, therefore, there is a fundamental risk that the total turbulence may exceed the "design turbulence" used as a basis in the load assumptions for the individual turbines.

On the other hand, a lower mean wind velocity is applied to the wind turbine located in the wake flow of the upwind turbine so that the mean load level is reduced. It is, therefore, not possible to decide a priori whether the overall load level will increase for the turbines in the array or not. Some manufacturers have adopted the approach — possibly as a precaution — to prescribe a minimum spacing for erecting their turbines in an array. Other manufacturers are assuming that the load level will not increase even with narrower spacing (Fig. 16.20).

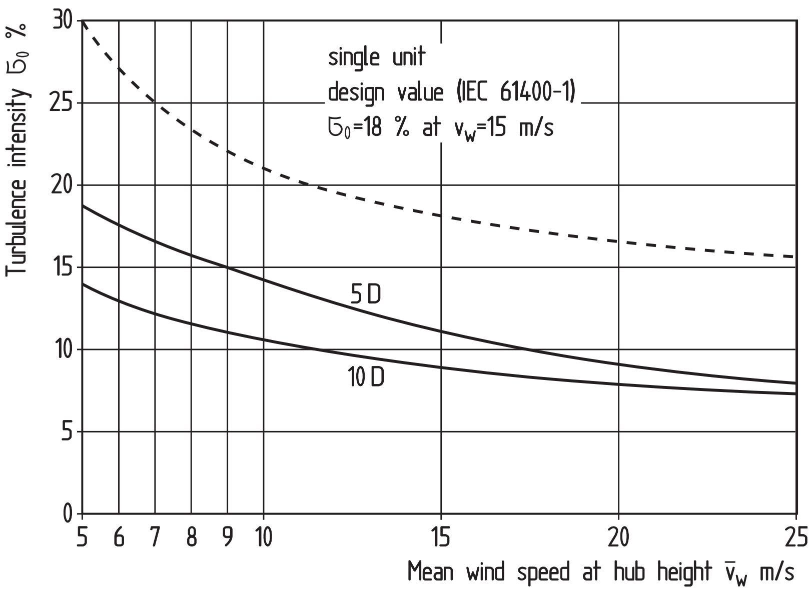

Figure 16.20. Relationship between turbulence intensity and mean wind velocity and the mean turbine spacing for an offshore site [19]

16.4.2 Electrical Cabling and Connections

The electrical infrastructure of a wind park is determined by two aims, firstly to keep the costs as low as possible, and secondly to minimise the electrical transmission losses whilst at the same time ensuring high fault tolerance. In the case of buried cables, the fault tolerance is twice or three-times that of overhead lines. Among the parameters available for selection, the cable lengths are largely predetermined by the size of the wind park and the distance from the grid infeed point. This leaves only the voltage level and the cable cross-sections as design variables. To a certain degree, it is also possible to minimise the number of switchgear sections required and of any interstage transformers by way of the geometric layout.

The transmission losses in a three-phase cable are determined by the familiar ohmic relationship between current intensity and line resistance:

$$P_L = U_D\, I \;= R\, I^2$$

The electrical power dissipation P_L can be reduced by means of larger line cross-sections, i. e. a reduction in the ohmic resistance R or — much more effectively — by a higher voltage which is accounted for via the current intensity squared:

$$P_L = \frac{3\, l\, I^2}{\varkappa\, q}$$

where:

P_L = power dissipation (W)
U_D = voltage drop (V)
I = current intensity (A)
l = cable length (m)
$\varkappa$ = electrical conductivity (S/m)
q = conductor cross-section (mm^2)

For practical reasons, and from the point of view of costs, care should be taken not to exceed a certain value of the line cross-sections. If this point is reached, it is then advisable for economic reasons to change to the next higher voltage level. On the other hand, a certain minimum cross-sectional area is required for preventing thermal overloading of the cable (Fig. 16.21).

Internal Cabling

The internal cabling of the wind park is first of all a geometric problem. The sites for the wind turbines have now been established and the task is to interconnect them in such a way that the cable lengths and the number of switchgear sections and of any interstage transformers which may be required is minimised. In most cases, the substation containing the switchgear and, if necessary, a transformer for raising the level of the voltage to that at the grid infeed point is located at one of the wind turbines.

One further task is the choice of the correct voltage level. The generators of smaller wind turbines operate with low voltage (400 volts) and can be connected to a low-voltage cable. In

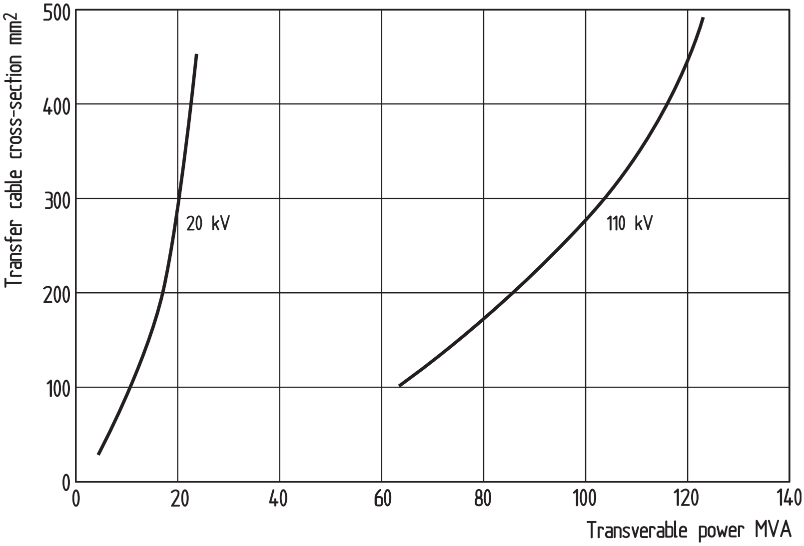

Figure 16.21. Required conductor cross-section of a copper cable as a function of the transmission power [20]

wind parks with the turbines of 500 kW rated power and more used nowadays, however, the internal cabling is almost always at medium-voltage level in order to minimise the electrical transmission losses. A number of turbines with the usual generator output voltage of 690 Volts will be connected to a 20-kV medium voltage rail via interstage transformers. Before it reaches the substation, the feeder is also conducted to the grid infeed point of the medium voltage system at this voltage level (Fig. 16.22).

Wind parks with megawatt-class turbines are always cabled at medium-voltage level. Most large turbines have their own built-in transformer and the turbines are connected individually to the 20-kV lines. The medium-voltage lines are connected to the substation in several rows (Fig. 16.23).

The electrical losses in the turbine array are an immediate result of the electrical connection layout chosen. The important parameters are: voltage level, cable lengths, cable cross-sections and number of transformers. Even in larger wind farms, the power transmission losses up to the grid should not exceed 2 %.

Grid Connection

Small wind parks are almost always connected to the medium-voltage power system, usually 15 to 30 kV. Wherever possible, this is the most cost-effective solution. On the one hand, switchgear and transformers are much more inexpensive than those for high-voltage use and, on the other hand, the distances up to the grid infeed point are generally limited to a few kilometres in industrialised countries.

Large wind parks with total power outputs of more than 20 MW can no longer be connected to the medium-voltage system. The power system stability at medium-voltage

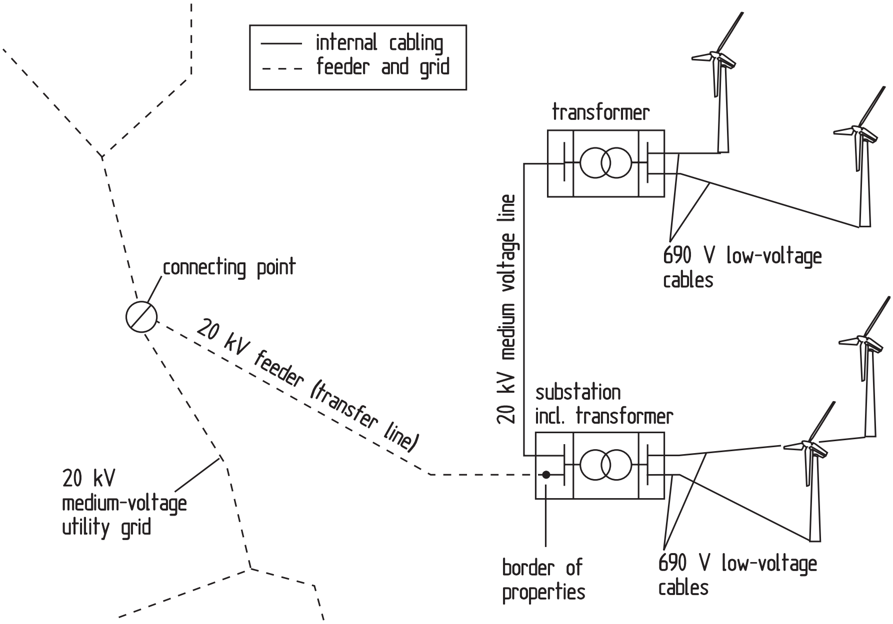

Figure 16.22. Internal cabling of a small wind farm and grid connection to the medium-voltage system

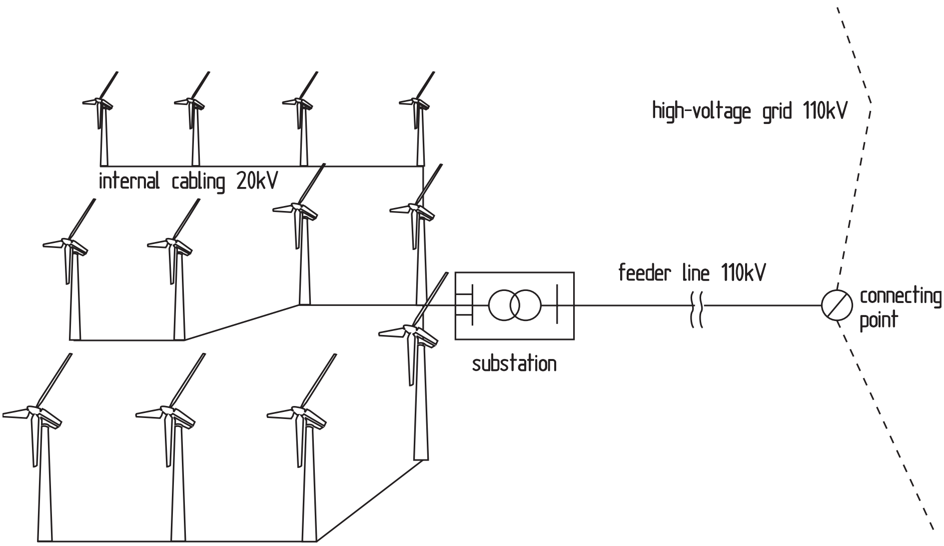

Figure 16.23. Internal cabling of a large wind park and connection to the high-voltage system

Figure 16.24. 20/110 kV transformer substation (photo Oelker)

level does not allow such powers to be injected from a point source, given the specific characteristics of wind power generation (s. Chapt. 18.5). For this reason alone, there is no other choice but to install the more expensive connection to the high-voltage power system with 110 or 220 kV which in most cases requires the construction of a new transformer substation. (Fig. 16.24). In addition, suitable grid infeed points are generally farther distant since the high-voltage power system is much more widely spaced apart. The costs for connecting a large wind park to the high-voltage grid are thus considerable. On the other hand, the costs for high-voltage switchgear and transformers have dropped in recent years so that this is no longer an insurmountable economic impediment if the wind park is of a certain minimum size.

16.5 Integrating Wind Turbines into the System of Interconnected Power Stations of the Utilities

If wind power utilisation is to take a significant share in the overall supply of electricity, a number of questions arise in relation to the interaction of a large number of wind turbines with conventional power stations. The problems are essentially focused on two aspects attributable to the same particular characteristic of power generation by means of wind power, namely the unpredictable, fluctuating way in which power is fed into the public utility grid.

First, this could result in control problems in interaction with the conventional power stations. In the high-capacity interconnected grids of the industrial countries, this will become relevant only when wind power has attained a noticeable share of the system load. Nevertheless, it is a problem. Secondly, the unpredictable nature of the wind power infeed leads to the basic question of whether and to what extent wind turbines can replace other power stations.

These two questions suggest that large-scale wind power utilisation is conceivable only as an integrated component of the conventional energy supply system. This directly concerns the power producers, the utility companies. In the long term, they will have to incorporate wind energy generation into the capacity planning for their generation system of conventional power stations

These problems have been dealt with in various theoretical investigations in the past. In Germany, it was Jarras who first carried out extensive mathematical simulations in 1981, with the aim of showing the possibilities and limits of the integration of wind turbines into the German public electricity supply system [21]. As has always been the case in such investigations, the results are dependent on many kinds of assumptions, and thus are not undisputed in some of the details. However, this subject is of decisive significance for the long-term prospects for wind energy utilisation and in some areas of Europe it is becoming an issue even today. For this reason, several essential aspects will be discussed here which will, however, require a small excursion into the technical organisation of public electricity supply systems.

16.5.1 Operational Strategies and Control Issues

In Europe, the pool of power stations feeding a supraregional utility grid forms an interconnected international electricity supply system, which is usually divided into three levels:

- *Base-load power stations* with high capacity, permanently operated at their rated power regardless of the instantaneous grid load. Nuclear power stations and large thermal power stations are typical base-load power stations. They achieve more than 6000 full-load hours per year. Their power output is regulated only over periods of days.
- *Medium-load power stations* which can be operated and controlled in accordance with the demand curve of expected daily requirements. For this purpose, medium-sized power station units, with power outputs of around 300 MW and 3000 to 4000 full-load hours, are used. The preferred fuel is coal. Control periods are in the range of several hours.
- *Peak-load power stations* for compensating for short-term variations in the grid load. These much smaller units are operated with gas, oil or water power. Control periods are very short. The power output of hydroelectric plants, for example, can be regulated within only a few minutes.

In order to meet the power demand, power station pools of this structure are used by the utilities in accordance with the following strategy: The operation for the following day is planned on the basis of statistical experience, trend analyses and by including the weather forecast. The goal is to use the various power station types in such a way that the resulting power generation costs are minimised, seen from an overall perspective. The "on-line control" has to respond to the instantaneous load variations in the grid. An increasing load in the grid firstly extracts the required energy from the kinetic energy of rotation of the generators. Their speed starts to drop until the torque of the prime mover can be adjusted. As this can take up to one minute, the generators must be run with a so-called *spinning reserve* so that voltage and frequency can be maintained during this period. Conversely, a certain non-loaded capacity must be available in order to be able to respond to a sudden drop in load. "Spinning reserve" and "non-loaded capacity" together constitute the so-called *control capacity* of the power-station pool.

Feeding power from wind turbines into the utility grid on a large scale presents an increased challenge, both for the planning of next day's operation and for the on-line control capacity. An example from a Swedish computer simulation study showed the extent to which this could be the case [22]. The mathematical simulation is based on the assumption of a total power of 3000 MW supplied by 1500 individual wind turbines. The wind turbines are distributed over a wide area. Taking into account the statistical wind conditions in this area, the following variations in the power output of the wind turbines were obtained:

– over 8 hours	100 %
– over 1 hour	10 – 20 %
– over 10 minutes	2 %

These results showed that short-term fluctuations of a few seconds or minutes are levelled out in the interconnected power system itself by the large number of distributed wind turbines. These short-term fluctuations thus do not present a problem. On the other hand, the power output may cease altogether over a period of one or several days. In southern Sweden, for example, the wind may die down almost completely over large areas so that any technical utilisation becomes impossible. Relatively great fluctuations in the output power will thus obviously occur in the hours range.

If these results are assessed with regard to the interaction with the conventional power-station pool, it is immediately apparent that the load compensation must be effected primarily by the medium-load power stations. The higher its share of medium load within an interconnected system of power-stations, the more wind power can be integrated into the grid. In Germany, for example, the use of wind power would save mainly coal as a fuel. The ideal power stations for compensating for the "wind power" in the grid are, of course, the fast-response hydroelectric plants which, for example, contribute approximately 60 % of the power generation capacity in Sweden. In other countries the medium-sized coal or gas fired power stations are concerned.

The question of whether, and to what extent, the control capacity of the power station in operation would have to be increased in order to ensure the frequency and voltage stability in the grid in the minute range with its relatively small fluctuations cannot be answered in such an unambiguous manner. It may only be possible to solve this problem reliably by gaining practical experience in this matter. The results of theoretical analyses indicate that a wind power of up to about 20 % of the grid load can be handled without great control problems [23]. First practical experience from the Danish utility company Elsam shows that this limit is exceeded at certain times of the day without causing any significant control problems.

16.5.2 Can Wind Turbines Replace Conventional Power Stations?

The integration of wind turbines into existing interconnected power station systems brings up a question repeatedly asked with regard to the technical utilisation of wind energy: "Can wind turbines replace conventional power stations?". Hasty answers such as: "Wind is unpredictable and when one needs it it's not available and that's why there's no way they can replace conventional power stations", are of little help. The problem is much more complex and requires both unprejudiced discussion and a qualified answer.

An energy supply system consisting of a pool of power-plants of various types provides so-called *firm power*. Firm power is the minimum power which is available at the point in time of the maximum annual load with a given probability (*security of supply*). With a given maximum annual load, the installed total power needed for achieving security of supply must be just enough for its firm power to cover the maximum annual load. The difference between installed and firm power is the required *reserve power*. Each individual power station contributes to the firm power. The magnitude of this contribution depends on the installed total power of a power station pool and on the availability of the individual power station. The availability of one single power station is the probability with which its power is available. A power station pool comprises individual power stations of different types and thus, inevitably, of different individual availabilities.

Wind turbines have a certain availability, as does any other power station, even if the availability of wind turbines is much lower when compared to conventional thermal power stations. The availability of wind turbines is a product of the wind-related availability and technical availability. For example, a large wind turbine in the coastal area of North Germany achieves the about 3000 equivalent full-load hours. This corresponds to a wind-related availability of 34 %. If this is multiplied by a technical availability of 95 %, a total availability of 30 % is obtained. This value is called the *capacity factor* in American literature (Chapt. 14.8).

The firm power of a power-plant pool is determined by a formula based on the individual availabilities [24]. To this end, it is irrelevant how the individual availabilities are achieved. The probability theory does not differentiate between the random non-availability of conventional power stations and that of wind turbines. Thus, wind turbines, like conventional power stations, do contribute to the firm power of a power-plant pool, even if their contribution is much lower.

The proportion of firm power contributed by wind turbines within the power station pool, the *capacity value* of wind power, basically depends on two parameters:

- The availability of the wind turbine,
- The ratio of injected wind power to the standard deviation of the power output of the existing power station pool. (The standard deviation, in turn, is a function of the number, the size and the availabilities of the individual power stations.)

For small percentages of wind power in the overall power station output — which will almost always be the case with the wind turbines feeding into a large interconnected power system — the contribution to the firm power approximately corresponds to the value of availability [25].

This result is illustrated by an example. With a mean annual wind speed of 6 m/s at 30 m height, a medium-sized wind turbine (60 m rotor diameter, 1200 kW rated power) achieves 2750 equivalent full-load hours per year. Assuming a technical availability of 95 %, this corresponds to a total availability, or a capacity factor, of 30 %. When feeding into the public grid, which provides only a very small contribution of wind power to the power output of conventional power stations, it contributes about 30 % of its rated power, namely 400 kW, to the firm power. In other words: in this example 1 kW wind power replaces 0.30 kW of conventional power-plant power. If the economic value of wind power utilisation is to be assessed objectively, this effect must be taken into consideration. Thus, the economic value of a wind turbine is measured not only by the fuel saved in the conventional power stations, but also by the contribution to the firm power of the interconnected supply system.

It is occasionally pointed out in the literature that, although the relationships outlined are applicable to the injection of wind power in principle, they do not always meet local conditions. This effect should be taken into consideration in areas where the annual wind speed distribution is negatively correlated with the annual distribution of grid loading. For example, the observation would be applicable to the coldest winter days. The estimate of the contribution of the wind turbines to the firm power station output should, therefore, be lowered since it is especially in those days that the wind to be expected would be below average [26].

16.6 Market Development and Wind Energy Potential

The technical feasibility and reliability of power generation by wind energy can no longer be seriously questioned today. At sites with suitable annual wind speeds the economics are also no longer an issue. Today, these facts must be acknowledged even by the critics of wind energy utilisation.

Supporters of a practically unchanged continuation of the traditional energy-supply structures, therefore, increasingly use the supposed lack of macro-economic perspective of wind energy, and of renewable energy sources as a whole, as an argument. The renewable energy technologies are praised for their usefulness in certain market niches only to explain in the same breath that, of course, "wind and sun" could under no circumstances replace the reliable, conventional coal and nuclear power stations. The contribution of the "renewables" would basically remain restricted to "a few percent".

Against this background, the question of the potential of wind energy arises, particularly in the political discussions about future energy sources. This is essentially of no importance to individual users. They will use a technology which works, as has been proven, and is economic, regardless of whether its potential is high or low, as long as the overall economic conditions give them a chance of acting within a useful economic margin. In power economics in particular, however, structural conditions have been set from political points of view and they decide about the economic scope for action by the individual consumer.

Before presenting some thoughts on the potential for exploitation of wind energy, the development of wind energy utilisation in the past twenty years will first be illustrated with the help of some plain figures. These are at least facts which can be verified by statistics and are, therefore, indisputable.

16.6.1 Wind-Energy Utilisation Since the Eighties and Market Forecasts

Commercial utilisation of wind energy for the generation of power started in Denmark in about 1980. At the beginning, the number of wind turbines increased only slowly: In 1980, there were only about 50 wind turbines with a total power output of about 2 megawatts until public subsidies pushed the application of wind turbines more effectively. In the US, federal support of wind-power utilisation was introduced in California via the well-known tax credits in 1982. Within a few years, by about 1985/'86, the Californian wind farms, with about 16000 wind turbines, had emerged, providing a total power output of 1500 megawatts (Chapt. 2.5). As a result of this first "boom" of wind energy utilisation in the United States, the Danish wind turbine industry developed, and was able to supply about 40 % of the capacity installed in California.

After the tax credit legislation had run its course in California and due to the slump in the American market, the focus of development shifted to Europe. Due to the expansion of industrial capacities in Denmark, and to a much smaller extent in Germany, Belgium and the Netherlands, manufacturers increasingly looked for markets in Europe. The numbers of wind turbines in Denmark rose rapidly. In the meantime, wind turbine prices had dropped to such low levels that wind energy utilisation at good sites had become economically viable without massive subsidies, at least for the consumer.

In Germany, the economic conditions improved due to the "Einspeisegesetz" (Law Concerning the Infeeding of Power from Regenerative Energy Sources) passed in 1990 and the subsidies offered in the "250 MW Wind" program, so that here, too, a market developed. This home market formed the basis of some medium-sized German companies which relatively successful developed wind turbines in competition to the Danish manufacturers and were able to sell a considerable number of units. Most other European countries also established subsidy programs in the late eighties. Increasingly, initiatives and subsidies by the Commission of the European Union supported research and application in the field of wind energy [27]. Against this background, the number of wind turbines in Europe has increased rapidly since 1990

The German *Einspeisegesetz* was replaced in 2000 by the "Law Concerning the Priority of renewable Energy Sources" (Erneuerbare-Energien-Gesetz (EEG)) [28] which again improved the economic conditions for the utilisation of wind energy. This law, which was confirmed in its essential points one year later by the Commission of the EU in spite of considerable opposition, also created the necessary legal basis for the financing of the investments. Similar laws were passed in other European countries so that, after Denmark and Germany, the basic economic conditions required for the utilisation of wind energy on a broad basis were also created first in Spain and then in Italy and recently also in France.

In the late nineteen-nineties and first years of 2000, the growth rates in Germany reached values of up to 3000 MW per annum so that Germany became the leading country in wind energy utilisation in the world. At the end of 2003, 13 000 MW of wind power were installed in Germany, followed by Spain with 4 800 MW and Denmark with 2 300 MW. In

Table 16.25. Installed wind power capacity throughout the world, end of 2003 [29]

Europe	(MW)
Germany	12 001
Spain	4 830
Denmark	2 889
Italy	785
Netherlands	683
United Kingdom	552
Sweden	328
Greece	302
Portugal	194
France	147
Austria	139
Ireland	137
Norway	97
Poland	58
Belgium	46
Ukraine	44
Finland	41
Latvia	23
Turkey	19
Luxembourg	16
Russia	7
Switzerland	5
Estonia	5
Tchechia	3
Hungary	1
Romania	1
Total	3 357
Middle East and Africa	
Egypt	69
Morocco	54
Iran	11
Israel	8
South Africa	2
Jordan	2
Total	146
Asia	
India	1 702
China	468
South Korea	8
Sri Lanka	3
Taiwan	3
Total	2 184

United States	(MW)
California	1 772
Texas	1 105
Iowa	432
Minnesota	336
Washington	228
Oregon	220
Wyoming	140
Kansas	113
Colorado	58
Wisconsin	53
New York	49
Pennsylvania	34
Nebraska	15
Vermont	6
North Dakota	5
Michigan	3
South Dakota	3
Hawaii	2
Tennessee	2
Alaska	1
Massachusetts	1
New Mexico	1
Total	4 579
Canada	
Canada	236
Total	236
Central and South America	
Costa Rica	71
Argentina	26
Brazil	22
Caribbean	13
Mexico	5
Chile	2
Total	139
Pacific Region	
Japan	384
Australia	103
New Zealand	37
Total	524
World Total	31 165

the countries of the European Union, a total power output of more than 23 000 MW was generated at the end of 2003 (Table 16.25), i. e. before the enlargement of the European Union in May 2004.

In other parts of the world, too, the development accelerated. In the United States, where wind energy utilisation had come to a virtual standstill at the end of the nineteen-eighties, the installed wind energy power increased to about 6 500 MW by the end of 2001. In the Third World, India was the leading country with 1 700 MW capacity by the end of 2003.

Since 2003, the growth rate of wind power in countries such as Germany and Denmark has been declining, mainly due to a shortage of suitable sites. On the other hand, the forecasts for the next few years are extremely favourable for many other countries. The development in the near future can be predicted with relative certainty from the actual planning and project developments in hand for such periods in large wind parks. Extrapolation over longer periods, e. g. up to 2020, is naturally subject to greater uncertainties but is, nevertheless, based on careful trend analyses. The annual report "Wind Energy Development — World Market Update" issued by BTM Consult in Denmark contains comprehensive and carefully researched market analyses and forecasts [29]. It is expected that the growth rates of the on-land installations in Germany and in some other European countries will slow down after 2003. On the other hand, for the time after 2005, the offshore wind energy capacity will become a more important driver. For the next decade, the worldwide installations will overtake the European wind energy capacity by far (Fig. 16.26).

Electricity generation by wind energy has already achieved a certain economic importance in the European Union, at least in some regions. This is especially true for Denmark.

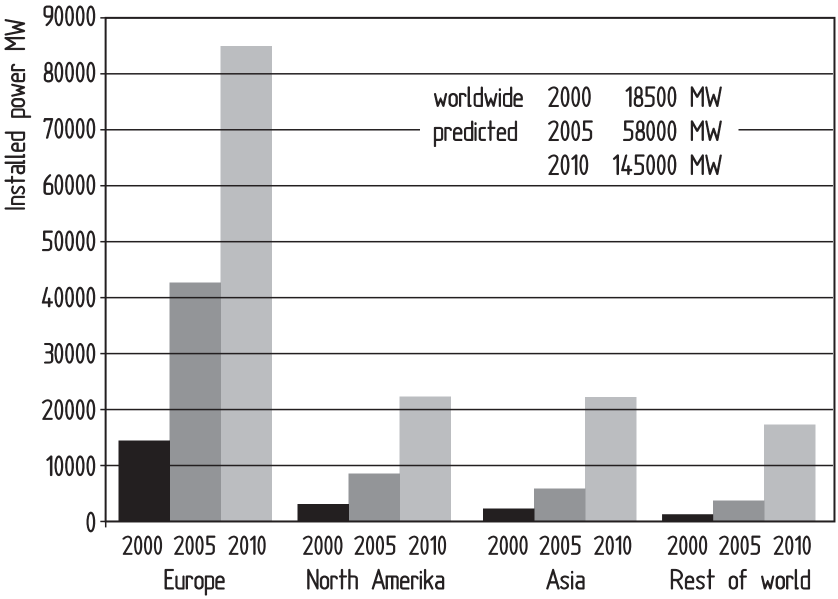

Figure 16.26. Global wind energy development [29]

In 2003, the installed power contributed about 6 % of the total energy consumed in Denmark. It must be taken into account in this respect that the majority of the wind turbines installed there are small, ten-years old 50-kW turbines. In Germany, the proportion of power generated from wind energy was about 5 % in 2003. Regionally, about 29 % of the energy consumption were generated from wind power in the state of Schleswig-Holstein, whereas it was about 23 % in Sachsen-Anhalt, 21 % in Mecklenburg-Vorpommern and about 14 % in Lower Saxony and Brandenburg.

16.6.2 The Wind Turbine Industry

Wind turbines were first manufactured on an industrial scale in the early eighties when the number of wind turbines being erected in Denmark rapidly increased and the Californian wind farms were installed in the US. In the initial years, there were numerous small manufacturing companies, mainly in Denmark but also in the US and the Netherlands, producing small series of wind turbines in the power range of up to about 100 kW.

In many cases, these small Danish companies had a manufacturing background of agricultural machinery and implements, as in the example of Vestas, Nordtank et al. They built conventional three-bladed turbines, following examples developed back in the forties, but only produced in small numbers (see Chapt. 2.7). In the US, it was more the technologically motivated small companies and newly establishes firms which considered power generation from wind energy as a technological challenge and often pursued unconventional solutions with a great amount of engineering effort. Among these were US Windpower, Flowind, Fayette and ESI — names which are forgotten today.

Apart from these relatively small companies, wind turbines were also being manufactured by large corporations mainly at home in the field of mechanical and electrical engineering and aviation. Companies like General Electric, Boeing and Westinghouse in the US, McAlpine in the UK or MAN and MBB (now EADS) in Germany were all busy with this technology. They built the first large experimental turbines from the end of the seventies until the beginning of the eighties — albeit with massive state subsidies, drawing on their own financial resources to only a limited extent for this purpose. The first large experimental turbines were developed and built almost exclusively by these companies (see Chapt. 2.3).

It is actually quite interesting to analyse in retrospect which approach had been the more successful one. The large corporations, which were expected to pave the way to success for this new type of power generation, all failed to do so. Their involvement diminished to the same extent to which the sources of state finance dried up. Even though it would certainly have been possible to overcome the technical problems associated with the construction and operation of the first megawatt-rated turbines, their most serious handicap was the lack of access to a market which had evolved contrary to expectations. They were exclusively focused on selling their power plant products to large electricity generating concerns which, however, were only interested to a limited extent. The large undertakings did not have any proven sales channels — and thus no knowledge of the market — for the sale of, at first, small turbines to private customers. At the beginning of the boom in wind power utilisation they had almost without exception turned their backs on this technology and concentrated again on other products, of which there were many alternatives in large concerns.

The smaller companies in the US were able to produce turbines in considerable numbers in the initial phase of the Californian wind farms. Their technical concepts, which were often innovative, were not very reliable, however, and not thought through thoroughly in many cases. And they were unable to bear the financial burden of warranty and service. When the focus of wind energy utilisation moved from California to Europe with the end of the tax credits, they also lost their markets at their doorsteps. The leap to Europe was too far for them.

As is known, industrial and commercial success fell to the Danish manufacturers. Their turbines, which were of conventional design, achieved the necessary reliability right from the beginning and their products could be manufactured relatively quickly and cost-effectively in increasing numbers. At the end of the eighties, almost half of the wind turbines installed in California were of Danish origin, making it possible to set up corresponding production capacities in Denmark but the end of the boom in California also created great problems for the Danish manufacturers, with the consequence of numerous insolvencies. However, the Danish bankruptcy laws supported well established manufacturers well enough to enable them to continue operating on a de facto basis. In contrast to the large concerns, the smaller companies were able to use their traditional access to private customers in the agricultural area, providing them with an excellent jumping-off position at the beginning of the European boom in the early nineties.

Where the Californian wind farms were still somewhat of an experiment, it now became possible for a real industry to develop against the background of the European market. Fur-

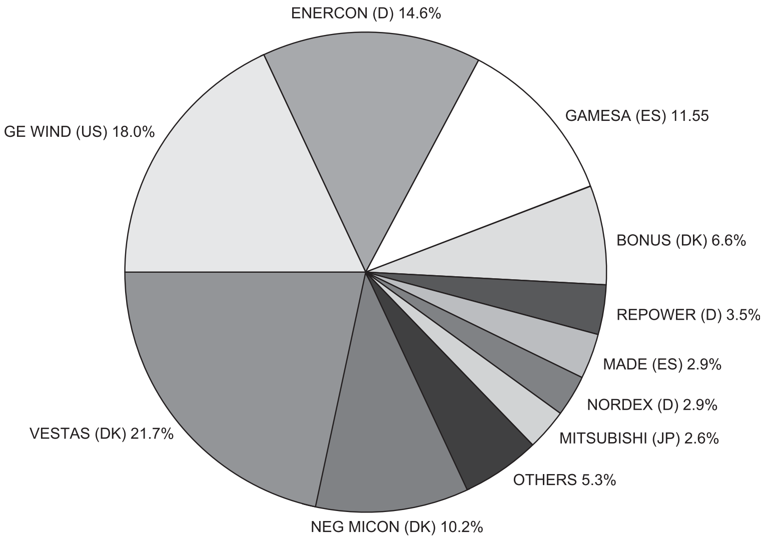

Figure 16.27. The ten leading wind turbine manufacturers and their market shares in 2003 [29]

ther successful manufacturing companies became established in the nineties in Germany — the foremost wind energy market for a long time — and slightly later in Spain.

The wind turbine industry today is very impressive, indeed. In Germany, some 50 000 people are employed directly in the wind energy industry, of which more than 8 000 are working in the turbine manufacturing plants themselves. To these are added further places of employment in the numerous ancillary industries and in servicing. In 2003, the turnover of the wind turbine manufacturers was about $US 8 billion world-wide. At the end of 2003, there were about 25 wind turbine manufacturing companies, not counting the makers of small wind wheels. The leading 10 manufacturers share between them 95 % of the market so that the others are not very significant, by comparison (Fig. 16.27). The most successful companies are from Denmark, Germany and Spain, and from Japan and the United States.

Vestas/NEG Micon *(Denmark)*

One of the oldest and largest manufacturers of wind turbines is the Danish company Vestas. It had its origins in a factory for agricultural machinery. Vestas Wind Systems A/S builds technologically sophisticated wind turbines with blade pitch control and variable-speed generators. All the major components such as rotor blades and control systems — but not the electrical generators and converters — are developed and built by Vestas themselves.

The second largest Danish manufacturing company NEG Micon, was the result of a merger between Nordtank and Micon, The technology taken over from these firms served as basis for building relatively simple turbines with stall control and fixed generator speed up to a power of about 2 MW. It has only been recently that NEG Micon changed to a turbine design with blade pitch control and variable-speed generators with the development of, among other things, a 4.2 MW turbine with a rotor diameter of 110 meters. In contrast to Vestas, NEG Micon largely depends on outside suppliers for important components such as rotor blades, control systems etc.

In 2003, Vestas and NEG Micon negotiated a merger which, in fact, amounted to a take-over of NEG Micon by Vestas. The new Vestas Group became by far the largest manufacturer of wind turbines world-wide. Like all the large manufacturers, Vestas manufactures not only in Denmark but also in many other countries of Europe and overseas. A turnover of about $US 2.5 billion was achieved with about 9 000 employees. Vestas has been listed on the stock market as a limited company for some years now.

Enercon *(Germany)*

The German company Enercon was founded in 1984 in Aurich in East Frisia and owes its rise into the ranks of leading wind turbine manufacturers to the rapid growth of the market in Germany after 1990 and to the special technical design of their wind turbines. Initially, Enercon built rather conventional wind turbines in relatively small numbers until their E-40 model introduced an innovative concept without transmission gears between rotor and generator at the beginning of the nineties. This gearless model proved to be a success right from the start. About 4 000 of these turbines have been produced to date. On the basis of this success, a range of exclusively gearless turbines of various sizes with rated powers of up to 2 MW have been developed. About 2 200 E-66/70s were produced by the middle of 2004. The latest model, presented in 2002, is the E-112 with 4.6 MW rated power and a rotor diameter of 114 m and is based on the same technical design.

Like Vestas, Enercon develops and produces all the key components (even the electrical system) in house in order to gain a technical advantage over their competitors. The Enercon group employs about 5 000 people, mainly in Germany and in production sites in Sweden, Brazil, India and Turkey. The company is not listed on the stock market and to the present day is largely controlled by its founder Alois Wobben.

GE Wind Energy *(USA, Germany)*

The production of wind turbines in the large American concern of General Electric (GE) has its origin with the German manufacturer Tacke. Tacke originally produced gear boxes. In the late Eighties it started to develop several types of wind turbines, achieving up to 1.5 MW rated power in the nineties. The company was taken over at the end of the nineties by the American company Enron who had previously already bought up the two American wind turbine manufacturers US Windpower and Zond. After Enron collapsed, General Electric took over the German production site and has been running it under the name of GE Wind Energy since 2002.

GE Wind Power has been very successful in recent years and, as an American/German manufacturer, has been able to profit from a reinvigorated market in the United States. In particular, large numbers of the 1.5-MW turbine were produced for the US market. The success on the US market has also been made possible through ownership of a certain US patent. Since the days of the US company Kenetec, which was taken over by Zond Energy Systems, a patent about variable-speed wind turbines couched in very general terms has existed in the US. According to European patent law, this patent would not have any validity. According to applicable US law, however, it was enough to keep other manufacturers of variable-speed turbines away from the US market. A number of attempts at contesting the patent by legal means, including attempts by Enercon, were unsuccessful for many years. It wasn't until 2004 that a patent agreement was reached between GE and Enercon.

Gamesa *(Spain)*

Gamesa Eólica is a part of the Spanish Gamesa concern which is active in the aerospace and energy generation fields. Its wind turbine manufacturing branch, founded in 1994, has evolved out of producing Vestas turbines under licence in Spain and is an independent manufacturer of wind turbines today. The Spanish market proved to be a particularly good basis for fast growth. Today, Gamesa is a competitor also in other countries. Next to Vestas/NEG Micon and Enercon Gamesa achieved the third largest market share worldwide (see Fig. 16.27). The wind turbines in the range of 660 kW to 3 MW rated power offered still largely correspond to the earlier Vestas models. In 2003, Gamesa took over the smaller Spanish manufacturer Made.

Siemens Wind Power/Bonus *(Denmark)*

Bonus is the oldest manufacturer of wind turbines in Denmark and is thus able to look back on a tradition comparable to that of Vestas. Although Bonus did not participate in the growth of the nineties to the extent of its competitors, but it still possesses considerable market shares in Denmark. The Bonus wind turbines are considered to be rugged and reliable, if somewhat conservative in design (stall controlled). In 2003, Bonus attracted attention by supplying wind turbines for the second largest offshore wind farm in Denmark (Nysted). With the latest development of 2.3 and 3.6 MW wind turbines Bonus adopted the technology of pitch controlled, variable speed wind turbines.

At the end of 2004, Bonus was taken over by the German electrical concern Siemens. The new company is named Siemens Wind Power A/S. The headquarter of the new company shall remain in Denmark.

REpower *(Germany)*

The German manufacturer REpower Systems AG emerged from the merger and take-over of some smaller German wind energy companies (Jacobs, Pro Und Pro, Husumer Schiffswerft, Aerodyn). REpower is listed as limited company on the stock market. Its production is essentially concentrated on a model of the 1.5–2.0 MW class (MD70/82) with blade pitch control and variable-speed generator. In October 2004, REpower installed the prototype of a 5-MW turbine with a rotor diameter of 125 m near Bremerhaven in the North of Germany, the largest wind turbine in the world in 2005.

Nordex *(Germany)*

The German company Nordex AG, also listed on the stock exchange since 2001, arose out of the take-over of a smaller Danish manufacturer named Nordex by the German Babcock corporation. After Babcock had been largely dissolved, the manufacture of wind turbines was continued in the form of a limited company as "German" Nordex including former Südwind company, which has been taken over. Nordex produces turbines in the range from 1.3 MW to 2.5 MW rated power. The Nordex/Südwind model S70/77 based on the same design as the REpower MD-70/77 turbine.

Dewind *(UK, Germany)*

The German manufacturer Dewind AG was founded in 1985 and converted into a limited company in 2001. In 2002, the majority of the stock was taken over by the British financial group FKI so that Dewind became a British manufacturer of wind turbines also with respect to its production sites. The range of FKI/Dewind wind turbines includes models of up to 80 m rotor diameter and 2 MW power. Their overall market share is small but Dewind is represented well in some regions such as Austria. End of 2004 FKI announced its withdraw from the wind energy business, so that the future of Dewind is open. About 500 Dewind wind turbines have been produced.

Fuhrländer *(Germany)*

The Fuhrländer AG company in Germany had its start in the mid-eighties when they built some Danish turbines under licence. Today, Fuhrländer mainly produces a 1.5 MW turbine, apart from other types with 30 to 2 700 kW rated power. The type made under licence is largely of the same design as the corresponding turbines by Nordex (S70/S77) and REpower (MD70/MD77).

Made *(Spain)*

Until it was taken over by Gamesa in 2003, the Spanish company Made was a relatively small manufacturer of wind turbines founded more than 15 years previously. Made never achieved the breakthrough to become one of the "great". They had a modest market share in Spain with models in the 600 to 1 200 kW range.

Ecotèchnia *(Spain)*

Ecotèchnia, a member of a large industrial group, manufactures wind turbines in Spain. Ecotèchnia has been on the market since about 1970 and is developing solar systems and wind turbines. In 2004, their production ranges from turbines of 750 to 1 670 kW rated power but their market share has remained very modest.

Lagerwey *(Netherlands)*

The Dutch company Lagerwey is one of the oldest manufacturers of wind turbines altogether. However, Lagerwey did not emulate the rapid development to ever larger turbines taking place in the nineties so that their market share remained largely restricted to Holland where many small two-bladed turbines in the range of 80–250 kW are being operated. In 2000, Lagerwey ran into financial problems and had to cease production. Adopting the name Zephyros,Lagerwey attempted to promote the development of a 2 MW turbine with permanent-magnet generator in a newly founded company with new partners but this development has remained limited to one prototype up to 2004. In 2005 Zephyros run into bankruptsy and the technology has been sold to a Japanese company.

Mitsubishi *(Japan)*

Mitsubishi, one of the largest industrial corporations in the world, is one of the few large concerns producing wind turbines. The first wind turbines built by Mitsubishi were already installed in the Californian wind farms in the mid eighties. The company has been producing wind turbines since then but has not been able to acquire a larger share of the market. Mitsubishi's wind turbines are of conventional design in the power range of up to 1.5 MW.

Suzlon *(India)*

The investor's group Suzlon started with service activities for Vestas wind turbines on the Indish market. Some years ago it began with the production of its own wind turbines and has achieved a certain market share on the rapidly growing Indian market. Suzlon produces turbines with power ratings from 550 kW to 2 MW, mainly for the domestic market and other markets in Asia.

Nordic Windpower *(Sweden/UK)*

Nordic Windpower AB was a joint venture of AF Industriteknik AB and Hägglunds Component AB. It has the distinction to be engaged in the development of light-weight, two-bladed wind turbines since 1990 (Chapt. 19, Fig. 19.11). It started with a 1 MW model, but only few prototypes have been produced. In 2004 Nordic Windpower produced a small series of a 2.3 MW units, which were exported to Canada. Larger prototypes for offshore-siting are under development. The majority of Nordic Windpower was taken over by the British company Parson Peebles.

Apart from the wind turbine manufacturers, the wind energy industry also supports a large variety of suppliers. Roughly 50 % of the business associated with the production of wind turbines is carried out by the suppliers of components. Among the parts supplied there are wind-specific components which belong to the wind energy technology in a wider sense, but many parts are common commodities in the mechanical and electrical industry. It should be noted that technical progress will be driven not only by the wind turbine manufactures but that the suppliers of the wind-specific key components, or better subsystems, like variable speed generator systems or rotor blades also contribute a great deal to the technical development.

Rotor Blades

The by far most important suppliers to the wind turbine manufacturers — or at least for many of them — are the independent manufacturers of rotor blades. About half of all rotor blades are developed and produced by the wind turbine manufacturers themselves. The other half is supplied by independent manufacturing companies, among which the Danish company LM Glasfiber A/S takes first place.

After having taken over a small Danish manufacturer producing rotor blades for the wind turbines of the day under the name Aerostar, the traditional boat and yacht builder LM began to produce rotor blades in large numbers in the mid eighties. Today, in 2004, LM Glasfiber employs about 3000 persons and have numerous smaller production sites in several other countries, in addition to their main site in Denmark.

Apart from LM, there are some other manufacturers of rotor blades such as Abeking & Rasmussen and NOI in Germany, Tecsis in Brazil and Euros in Poland but these only have small shares of the market.

Electrical Generator Systems

The electrical systems play a special role in the technological development of wind turbine technology. In the initial phase, standard generators and inverters from the production ranges of the large electrical manufacturers were used. As the variable-speed systems were developed which could no longer be supplied from existing series production lines, the electrical companies also had to involve themselves in wind turbine technology. Here, too, it was firstly the smaller generator manufacturers like Loher or Weiher in Germany who were the first ones to be able to deliver cost-effective variable-speed generator systems.

Today, variable-speed generator systems as well as conventional fixed-speed generators are available from all the larger electrical companies like Siemens, ABB etc.

Gearboxes

One of the key components supplied for wind turbines from outside is the gearbox. There have been service life problems in this area which are still persisting. The development of durable gearboxes for wind turbine operation will only be successful in close co-operation with the wind turbine manufacturer as overall system developer.

Flender, Winergy, Renk, Lohmann & Stoltrerfoht, Jahnel + Kestermann, Eickhoff in Germany, Hansen in Belgium or Metso in Finland are among the leading manufacturers of gearboxes for wind turbines.

Other Components

The entire supply industry for the production of wind turbines is as varied as the components of the product "wind turbine". Almost all types of engineering components and electrical equipment are being supplied by the relevant industry. As has always been the tradition, German suppliers have been maintaining a leading position but there has recently been a trend to procure more and more vendor parts from "cheaper" countries for cost reasons. In not a few cases, however, the "cheaper" components proved to be not the bargain expected by the customers.

The further development of the wind turbine industry is naturally a matter of speculation. However, some trends are already apparent. In Germany, the great significance accorded to the market by the manufacturers in the last fifteen years is diminishing. In the United States, the situation is characterised by ups and downs and thus by uncertainty. Luckily, a number of new markets opened up throughout the world. All manufacturers are forced to react to the much-quoted globalisation of markets and those who cannot — e. g. by building up a world-wide sales and services network — will disappear from the market.

The second challenge for the manufacturers, apart from the globalisation of the market and of the production sites, is the unbroken trend towards largeness. The successful development of wind turbines with rotor diameters of more than 120 meters and rated powers of up to 5 MW requires resources of personnel and of finance which does not appear to have been appreciated by manufacturers.

This situation is exacerbated further by the special requirements of future offshore operations. The manufacturers have two options: Either they grow to the required size on their own or they will be taken over sooner or later by those who are already "big". At present, the large concerns still need some coaxing; many still remember their false start in the early eighties. But those days are long past.

16.6.3 The Wind Energy Potential

In the physical sense, potential — the ability to perform work — is a state variable which can be accurately described and thus does not need to be interpreted. In the case of wind energy it has been pointed out that about 2 % of the solar energy captured by the earth's atmosphere is converted into motion of the air masses. Mathematically, this yields a power (power because the energy is quantifiable only over a certain period of time) of approximately 4×10^{12} kW. This is one hundred times more than the total power-plant capacity installed on earth (s. Chapt. 13.1). Naturally, the exploitable potential is very much smaller, but all other restrictions are firstly of a technical nature and then of an economic nature, and are ultimately a question of the social consensus about the importance to be accorded wind energy utilisation. Apart from the basic physical value mentioned, all other figures about the potential of wind energy thus always amount to saying *"if it is assumed that … then a potential of … is obtained"*. Controversies are caused less by the results than by the assumptions on which they are based.

Before discussing this problem in any greater detail, the results of several studies on the potential of wind energy, published in recent years, will be quoted. The investigations and assessments are restricted to the territory of the European Union.

The first attempt at gauging the strength of the potential of wind energy in the territories of the European Union dates back to 1980–'86 [30]. With certain assumptions and preconditions, the comprehensive study "Potential of Wind Energy in the EC" estimated an installable capacity of approximately 560 000 megawatts, not including the offshore potential. This figure was widely criticised as being much too high, without, however, being able to back this up in detail.

In 1990, the European Wind Energy Association (EWEA) carried out an updated study on the wind energy potential in the area of the EU [31]. In the meantime, more precise estimates of potential were available for some countries, as well as improved wind data in the form of the "European Wind Atlas". Apart from adequate wind conditions, a wind energy infeed of 15 % of the total energy consumption of a state was assumed as the second restricting factor. Theoretical studies point out that infeeding of wind energy into a large interconnected grid would be possible up to this point without causing serious technical problems. Under these conditions, a potential wind energy capacity of 67 000 MW on land was predicted. Including a certain offshore capacity, a goal of 100 000 MW wind energy by the year 2030 was formulated. With this, wind energy could contribute about 10 % to the overall electricity generation in the EU.

A further comprehensive estimate as to potential was published in 1994 by Eurosolar [32]. Again, the most recent national estimates and a new estimate of the offshore potential in the EU were included. Taking into account the offshore potential, which was assessed to be higher than the potential on land, a figure of the order of 200 000 MW was obtained for the European Union.

In 1999, Greenpeace published an estimate of potential which, however, looks more like a programme study of energy economics. Under the title "Wind Force 10", the proposed aim is to cover 10 % of the world's electricity demand by means of wind energy. The calculated wind energy required to achieve this is 181 000 MW [33]

The quoted studies about wind-energy potential all arrive at the result that under realistic conditions, the wind energy potential has the order of magnitude of "hundreds of thousands of megawatts". However, one cannot expect unambiguous and reproducible results from these investigations. One must be aware that, as has been mentioned before, the technically usable wind-energy potential is not a physically defined state variable and hence precise and undisputed figures cannot be expected. The assumptions on which the numerical values are based allow a wide range of results. Thus, an assessment of these figures can only be carried out by evaluating the assumptions made. By comparison, gaps still existing in the data on the wind regimes are of much lesser significance. Regionally, unreliable wind data can quite easily lead to an erroneous assessment of the wind's potential, but this has no significant influence on the global results.

The attempt to compile the results of the estimates in conjunction with the preconditions on which they were based in an overview produced the following categories concerning the potential of wind energy:

The atmospheric wind-energy potential

As mentioned earlier, the atmospheric potential of wind energy exceeds the globally installed power-plant capacity by two orders of magnitude. It is true that, from an economic point of view, this fact is not of interest, nevertheless it should not be completely ignored. This energy potential does indeed exist and if it were possible to use even less than one percent of it, all energy problems with respect to the generation of power would be solved.

Basically, there are neither physical nor technical obstacles precluding the utilisation of this potential. For example, the exploitation of wind energy at an altitude of one thousand meters above the open sea is no further away from current technological reality than the utilisation of nuclear fusion by commercial utilities. The decisive difference as to why vast sums of dollars are being invested in the research into nuclear fusion and not, e. g., wind power is probably only due to the fact that the established scientific and technical lobby for nuclear physics and its attendant industry has enough political influence to force through these immense expenditures.

The economically usable wind-energy potential

The currently available technology can only be used for exploiting the atmospheric wind-energy potential economically on land and in shallow coastal waters of the seas where the mean annual wind speeds exceed 4 m/s at 10 m height, and where the generated electricity does not need to be transported to the consumer over continental distances. Moreover, wind energy utilisation is only feasible up to a rotor hub height of 100 or 150 meters. In other words, technical and economical utilisation is only possible at sites where wind turbines of currently known designs and dimensions can be set up.

According to this criterion alone, the usable wind-energy potential of the European Union is still immense. The installable power is definitely of the order of several hundred thousand megawatts, corresponding to a generated energy volume of the order of one billion kWh. This is more than half the total energy consumption of the EU in 1991 (approx. 1.8 billion kWh).

It is possible to extract such quantities of energy from the wind from a technical point of view alone. The economic aspects are by no means utopian, either. In areas with wind speeds exceeding 5 m/s, the costs of power generation are of the level of current production costs of conventional power stations. Economically viable power costs are still achieved in areas with weaker wind regimes.

Utilising wind energy to such an extent would, of course, not be possible without profound changes in the structure of the technical energy production of today. The problem of a firm power supply would have to be solved. Without a highly sophisticated combination of the most varied solar generation units and possibly even retaining considerable sections of conventional generation plants, firm power could only be guaranteed by an extremely expensive storage technology, given the current state of technology. In the long run, energy storage via hydrogen generation could represent an economically viable solution to this problem.

From the point of view of the energy politics of the utility world, the scenario described is, of course, nothing short of a revolution, but it is far from being technologically utopian, however frequently this is asserted. What is utopian are not the technical possibilities, but breaking with outdated traditional priorities in the energy industry and politically accepted concessions to technological and economic developments.

The politically acceptable wind-energy potential

All "serious" estimates of the potential of wind-energy start out by listing areas where the annual mean wind speed reaches the minimum value considered necessary economically, and then continue with a long enumeration of restrictions preventing the siting of wind turbines as, for example:

- Regions of residential settlement
- Landscape conservation areas
- Wildlife reserves
- Traffic routes
- Protected biotopes
- Regions of special tourist interest
- Transmission lines
- Microwave links, transmitters and directing lights
- etc.

According to the presentations of the relevant interest groups, these regions should remain free of wind turbines and, moreover, large "safety distances" maintained, if possible. The areas remaining are considered acceptable for the siting of wind turbines and on this basis, the "wind energy potential" is then calculated, including the technically required minimum clearances between the turbines. It is amazing that even in densely populated areas, there is still considerable remaining potential, but this is naturally only a fraction of the technically usable potential. In other words: all existing claims on land utilisation are considered permanent and immutable. The utilisation of wind energy is relegated to what niches remain.

What if these standards had also been applied to the extension of traffic routes, especially road construction, or to the exploitation of conventional primary fuels? Coal mining did not only spoil entire landscapes but, in the case of open-cut brown coal mining, completely destroyed them. The resettlement of entire villages is only one of the more humane side-effects in this context. The quality of life of the people living in the mining districts has been quite poor for more than a century, a fact which has been and still is tolerated and accepted by society as the unfortunate but necessary tribute to be paid for a technical civilisation.

Whosoever demands even the relocation of a microwave radio link for the benefit of wind energy utilisation is regarded as a starry-eyed dreamer. This illustrates the status which society is willing to grant an ecologically oriented energy supply system. Verbal declarations cannot obscure the fact that emission-free and sustainable energy generation occupies the last place on the "list of priorities". It is only when all other fields of interest remain untouched, from the optimal position of microwave radio links to the preservation of a "natural" landscape, that society as represented by the vested interests is prepared to permit the installation of wind turbines.

The decision about how much wind-energy potential is available is reached virtually without considering other aspects, only these. The natural preconditions and the technical and economical feasibility do not impose any real limits on the development of wind-energy utilisation. Neither do uneconomically high costs present an obstacle to wind-energy utilisation. It is important to keep these facts in mind. The statement by H. Scheer on the utilisation of solar energy can be applied equally to wind energy [34]: "*The question, frequently asked, of how high a percentage of the supply of energy could be contributed by solar-energy utilisation really does not make sense: as the potential of solar energy is more than enough for the energy requirements of humankind, there is also no limit to the usable proportion of solar-energy. The magnitude of the proportion of solar-energy is a question of »input« alone: the more political initiatives and economic investments there are, the higher the proportion.*"

What positive conclusions can then be drawn from this situation? It would certainly be wrong to demand a "hard approach" to utilising the wind energy potential. But it should not be lost from sight as an option for cases of emergency. If crises develop due to the continuation of today's energy politics, the only solution in the long run will be to push ahead with the utilisation of wind energy in this way. Wind energy is the only emission-free source of energy which could come to the rescue with currently available technology and at economically justifiable costs.

But this situation does not as yet exist. Continuing exploitation of the wind-energy potential will therefore only be pursued within socially accepted limits. However, a totally restrictive approach is to be rejected. Intentionally or naively, it is a strategy for maintaining outdated, traditional structures to the disadvantage of the ecology and for the benefit of the protagonists of the current line of energy politics. Wind energy must be granted a certain priority. In the individual case, it must not be thwarted because lines of microwave radio links will not be relocated or because of the mere suspicion that certain bird species might avoid the sites of wind turbines.

If the education of the public in these matters is consistently continued, basic legislation for the benefit of wind-energy utilisation will certainly be understood and accepted. This would clear the way for supplying quite a considerable proportion of the energy requirement with power provided by wind energy. This proportion will undoubtedly not be restricted to "a few percent" of the energy requirement. Whether the wind-energy potential to be exploited in the course of the coming century — for example in the European Union — will amount to one hundred thousand or two hundred thousand megawatts, can be safely left to the future. The decisive fact is rather that the wind-energy potential is high enough to cover a significant part of the power generation.

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Chapter 17

Offshore Wind Energy Utilisation

In recent years, utilising the wind energy offshore, that is to say siting wind turbines at sea off the coasts, has evolved from a one-time vision of the wind pioneers into reality. In this area, too, the utilisation of wind energy is progressing in leaps and bounds — regardless of all the sceptics. What are the motives behind this development?

On the face of it, it is often alleged that the necessary area required for further development of wind energy on land would limit this development within the foreseeable future. This is certainly so for some countries such as, for example, Holland, Denmark or Germany. In general, however, this argument certainly does not hold water. In many countries, including some in Europe, the land areas suitable for wind energy utilisation have still not been utilised to their full extent by far. Exploiting the wind energy potential on land will remain dominant, therefore, for a long time (see Chapt. 16.6.1).

Another argument for the offshore siting of wind turbines is the higher wind speeds available over the open sea. This argument, too, is correct and important but still not the decisive motive. According to present-day findings, the higher specific offshore energy yield is balanced by the higher construction and operating costs so that the economic perspectives do not necessarily have to be better.

A third argument for offshore wind energy utilisation is gaining increased significance in public discussions and appears to be becoming the actual engine for development. Siting wind turbines at sea promotes the tendency to "size" for several reasons. The wind turbines suitable for offshore wind energy utilisation are becoming larger and larger and the projects are planned with wind farms of the magnitude of 1000 megawatts and more. Thus, offshore wind energy utilisation will reach an order of magnitude similar to power stations even in individual projects. This outlook is now also attracting the established electricity supply industry. In contrast to wind energy utilisation on land, which has been driven by private power consumers until the present, offshore utilisation appears to be becoming a domain of the "large players" again. The question whether this development will have consequences for the acceptance of wind energy utilisation in society will not be discussed here. However, it can be noted in this connection that, if the potential of offshore wind energy utilisation is exploited resolutely — and technical problems will certainly not be the cause of failure in this respect — the future offshore wind parks will represent a real alternative to some of the present-day conventional large power stations. This argument should be taken into consideration when weighing the ecological and economic arguments.

17.1 Offshore Wind Energy in the North Sea and the Baltic Sea

Most of the countries in which wind energy utilisation on land is already playing a role today are countries bordering on the North Sea and the Baltic Sea. This is, therefore, where the offshore technology for siting wind turbines is being primarily developed. Naturally, there are numerous other coastal areas throughout the world that are also suitable for the offshore utilisation of wind energy but it is here that the initial phase of offshore wind energy utilisation is taking place.

The offshore areas of the North Sea and Baltic Sea provide different conditions with respect to wind energy utilisation so that the development of the offshore wind energy utilisation also proceeds at a different rate in the individual regions.

17.1.1 Oceanographic Conditions and Wind Resources

The offshore siting of wind turbines is initially determined by oceanographic and meteorological conditions. Depending on the available state of the art, they are decisive for the technical and economical feasibility of a project. Licensing procedures taking into consideration ecological and competitive economic interests are subject to other considerations.

Depth of the water

Water depth is the most important oceanographic parameter of influence. Resting on the continental shelf, both the North Sea and the Baltic Sea are very shallow in the coastal areas. The depth of the North Sea does not exceed 40 m. At short distances from the coast, a depth of 10 to 20 m is the norm. The tidal range must also be taken into consideration, reaching maximum values of 4.5 m in some areas near the coast. However, there are the tidal shallows covering mud-flats off the German North-Sea coast where wind turbines cannot be erected for ecological reasons. For this reason, large projects can only be implemented at long distances from land and thus also at greater depth of water (20 to 40 m) in the German North-Sea area. Figure 17.1 shows the increase in water depth with distance from the coast [1]. The water depth of the Baltic Sea only reaches maximum values of approx. 20 m. In addition, there are no tidal shallows there so that the immediate coastal area, only a few metres deep, could be utilised. It is particularly the Danish offshore projects that profit from this situation. In the area of the Danish waters of the Baltic Sea, it is possible to implement even very large offshore wind farms in water depths of 10 to 15 m.

There is virtually no tide in the Baltic Sea but a much greater part of the sea freezes in winter. The heights of the waves to be expected are as significant as the water depth. The North Sea and the Baltic Sea differ considerably in this respect. Whereas in the Baltic Sea, the maximum wave height is about 7 m, a maximum wave height of 20 m must be expected in the North Sea (so-called "wave of the century").

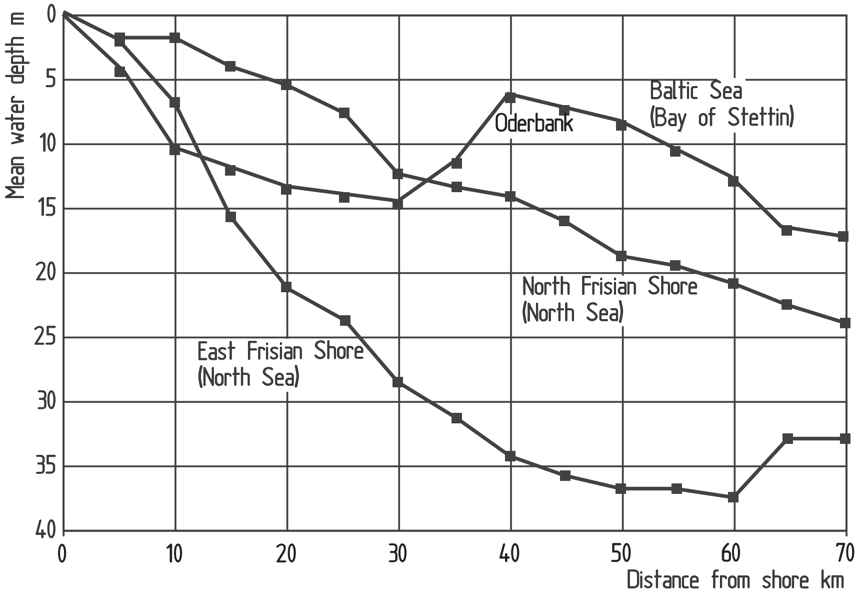


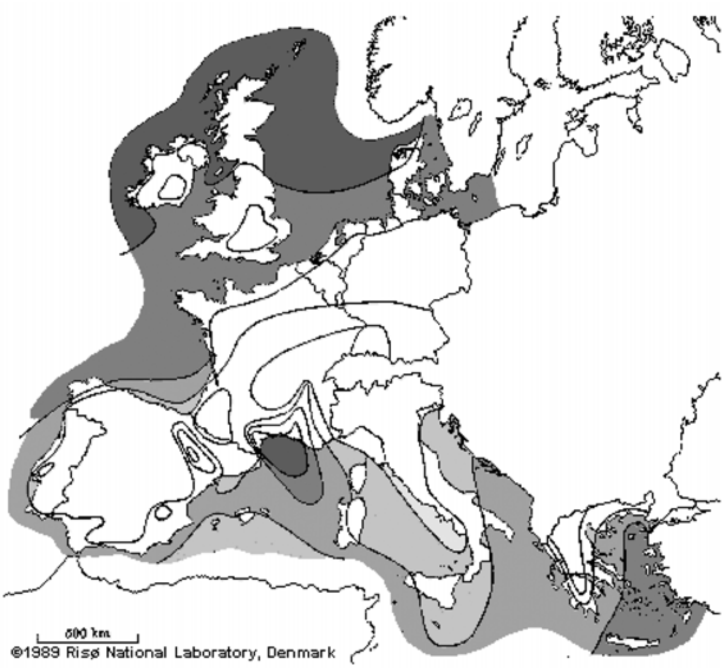
Figure 17.1. Increase in water depth with distance from the coast in the German Bight (North Sea) and in the "Stettiner Bucht" (Baltic Sea) [1]

Wind resources

The higher wind speeds above the sea and the almost unrestricted space available are essential incentives for the offshore siting of wind turbines. Figure 17.2 provides an overview of the wind conditions off the coasts of Europe. At a distance of more than 10 km from the North Sea coast, mean annual wind speeds of more than 8 m/s at a height of 60 m are specified in the southern region. In the north, the mean wind speeds are approximately 1 m/s above this value [2]. Above the Baltic Sea, the mean wind speed is generally somewhat less. It increases from west to east and off the Baltic countries it reaches similar values as in the southern region of the North Sea.

The immediate area off the coast up to a distance of about 10 km into the sea requires special attention with respect to the wind conditions. More recent investigations show that it is in this region that the transition from the wind conditions on land, particularly with the gradient of the increased in wind speed with height, to the conditions prevailing over the open sea takes place [4]. In other words: the wind turbines must be sited at this distance from the land in order to be able to exploit the offshore wind as effectively as possible. It is only then that an energy yield of 30 to 40 % higher than that on land can be expected. This finding is of special significance for the Baltic Sea coast since offshore sites directly off the coast are possible due to the absence of tidal shallows and mud flats.

The frequency distribution of the wind speed can be described according to a Weibull distribution with a scaling factor of k = 2.0 to 2.2. Depending on position, the prevailing wind direction varies between Southwest and Northwest. Because of the lower surface roughness, the wind speed increases more rapidly with height than on land. The average roughness length is only about 0.003 m. The corresponding Hellmann exponent is within a range from 0.11 to 0.12. The gain in energy yield with increasing height is thus less than



	Wind resources over open sea (more than 10 km offshore) for five standard heights				
	10m ms^{-1}/Wm^{-2}	25m ms^{-1}/Wm^{-2}	50m ms^{-1}/Wm^{-2}	100m ms^{-1}/Wm^{-2}	200m ms^{-1}/Wm^{-2}
	> 8.0 > 600	> 8.5 > 700	> 9.0 > 800	> 10.0 > 1100	> 11.0 > 1500
	7.0-8.0 350-600	7.5-8.5 450-700	8.0-9.0 600-800	8.5-10.0 650-1100	9.5-11.0 900-1500
	6.0-7.0 250-300	6.5-7.5 300-450	7.0-8.0 400-600	7.5-8.5 450-650	8.0-9.5 600-900
	4.5-6.0 100-250	5.0-6.5 150-300	5.5-7.0 200-400	6.0-7.5 250-450	6.5-8.0 300-600
	< 4.5 < 100	< 5.0 < 150	< 5.5 < 200	< 6.0 < 250	< 6.5 < 300

Figure 17.2. Wind conditions off the coast of the European Union at a distance of more than 10 km from the coast for various heights [2]

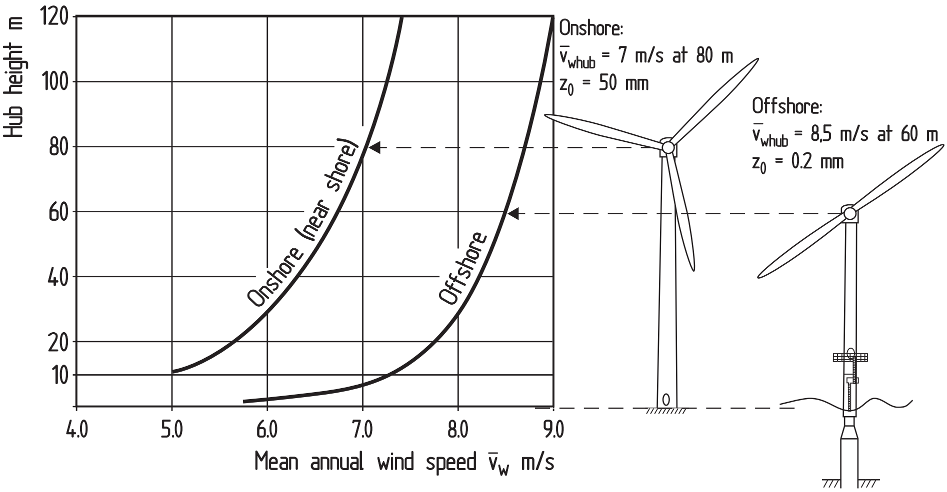


Figure 17.3. Logarithmic profiles of increasing wind speed with height for typical land at offshore sites [3]

on land, with the consequence that the economic tower heights of the wind turbines are lower (Fig. 17.3) (Chapter 14.4.8).

Turbulence intensity is another important characteristic parameter. Whereas the turbulence intensity over land is within a range of between 10 and 20 %, a turbulence intensity of less than 10 % is measured above the open sea. Typical values are about 8 % at a height of 60 to 70 m [5]. As a result of this lesser turbulence intensity, the fatigue loads on the wind turbines, resulting form the wind turbulence, are less, on the one hand, but, on the other hand, the wake behind the rotor "fills up" less rapidly. For this reason, the distances between the turbines must be greater than with siting on land in order to achieve the same aerodynamic array efficiency (Chapters 5.4 and 16.4.1).

Sea bottom

The nature of the sea bottom is of importance for building the foundation of a wind turbine. In the area of the North Sea and Baltic Sea, the major part of the sea bottom consists of fine sand. This is interspersed with areas with coarser sand and relatively large accumulations of stones. If monopile foundations are used, the strength of the ground plays a role in the vibrational characteristic of the wind turbine [3] (Chapter 17.3.2).

In connection with the nature of the sea bottom, oceanic currents must be considered which cause considerable displacements of the ground material in the case of a sand bottom and *scouring* in the case of obstacles (e. g. foundations). These effects can have considerable influence on the stability of the foundation. For these reasons, careful soil testing is an absolute requirement for any planning.

17.1.2
The First Offshore Wind Parks

With the availability of mature wind turbines in the 500/600 kW class at the end of the eighties, the first small offshore test units were started up for demonstration purposes. In 1991, Denmark took into operation the first offshore wind farm near Vindeby off the coast of Lolland (Fig. 17.4). This small wind farm consists of 11 turbines sited in water 3 to 4 metres deep, each with a power output of 450 kW. The maximum distance from the coast is approx. 3 km. The cost of construction is stated as being 76.2 million DKr [6]. According to the builders, the investment costs were about twice the amount required for a location on land.

In the following ten years, further, relatively small demonstration projects were implemented in Denmark, Holland and Sweden (Table 17.5). Their main features are very similar:

- slightly modified wind turbines of the 500/600 kW class
- water depth 3 to 10 m
- distance from the coast up to 6 km

Figure 17.4. Offshore wind farm near Vindeby off the cost of Lolland (Denmark), 1991

Table 17.5. Offshore demonstration projects from 1990 to 1998

Location	Commis-sioned	Wind turbines	Water depth m	Distance from the coast km	Spec. In-vestment costs US$/kW
Vindeby, Baltic (DK)	1991	11 × Bonus with 450 kW	3–5	1.5	2015
Lely, Ijsselmeer (NL)	1994	4 × Nedwind with 500 kW	5–10	1	2360
Lely, North Sea (NL)	1994	4 × Nedwind with 500 kW	5–10	6	2600
Tunø Knob, Baltic (DK)	1995	10 × Vestas with 500 kW	3–5	6	1935
Dronten, North Sea (NL)	1996	28 × Nordtank with 600 kW	5	0.2	1500
Bockstigen, North Sea (S)	1998	5 × Wind World with 500 kW	5–6	4.5	2040

These demonstration projects were thus not subject to the requirements encountered by an offshore technology that can be used commercially, with much greater water depth and distance from the shore. The construction costs were also too high for achieving an economic efficiency comparable to siting on land. On the other hand, the experience was encouraging enough so that now almost all the countries bordering on the North Sea and the Baltic Sea are building large commercial offshore wind farms or at least have plans to do so.

The first steps in direction of commercial offshore wind energy utilisation were taken at the end of the 90s. By now, tried and tested wind turbines of the megawatt class were available. Given this turbine size, it was possible to go to greater depths of water (Table 17.6). The first projects implemented under commercial aspects were the wind farms of Utgrun-

Table 17.6. The first commercial offshore wind farms up to 2001

Location	Commis-sioned	Wind turbines	Water depth m	Distance from the coast km	Spec. In-vestment costs US$/kW
Utgrunden, North Sea (S)	2000	7 × GE Wind 1.5 MW	7–10	8	1800
Blyth, North Sea (GB)	2000	2 × Vestas 2.0 MW	6	1	1600
Yttre Stengrund, North Sea (S)	2001	5 × NEG Micon 2.0 MW	9	5	1480
Middelgrunden, Baltic (DK)	2001	20 × Bonus 2.0 MW	3–6	3	1220

Figure 17.7. Offshore wind farm Utgrunden off the southern Swedish North-Sea coast (7 GE wind turbines of 1.5 MW ea.) (GE Wind Energy)

Figure 17.8. Wind farm Yttre Stengrund in the Baltic Sea off Gutland in Sweden (5 NEG Micon turbines of 2.0 MW ea.) (NEG Micon)

den off the southern Swedish North-Sea coast, Yttre Stengrund (Sweden), Middelgrunden (within sight of the harbour of Copenhagen, Denmark) and Blyth off the British North Sea coast (Figures 17.7 to 17.9). Middelgrunden, with 20 Bonus wind turbines with a power of 2.0 MW each provides a first indication of the dimensions of future offshore wind farms.

Figure 17.9. Offshore wind farm Middelgrunden off the Danish coast near Copenhagen (20 Bonus 2 MW wind turbines) (photo Oelker)

17.1.3 Commercial Installations

At the same time as the first projects are being implemented, there is a race for the future sites in almost all areas of the North Sea and Baltic sea, which is driven by numerous private project initiators — often with the support of the large turbine manufacturers [7]. Attempts are being made by the relevant countries to control the development by providing overall guidelines.

Denmark

The most advanced planning has been produced for Danish waters. Applying some pressure, the Danish government has managed to interest the energy supply undertakings Elsam and Elkraft in its offshore projects so that, in the meantime, there exists a very solid and well-ordered plan for exploiting the offshore potential in Denmark. It is intended to install at least 4000 MW of wind energy power at various offshore sites by the year 2030. The Danish plan "Energie 21" is essentially based on five sites for which extensive suitability studies have been carried out in recent years (Fig. 17.10).

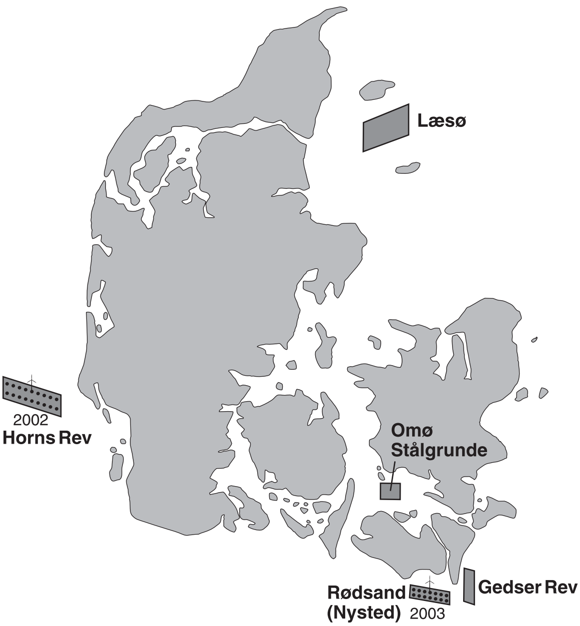


Figure 17.10. Major sites for the planned development of the offshore wind energy utilisation in Denmark [8]

These sites are to be built up with about 150 MW in each case in the first phase and, after the experience gained has been evaluated, extended step-by-step until the year 2030 when they reach the planned capacity which provides for over 1000 MW per site (Table 17.11). If this goal is achieved, Denmark would be able to cover 40 to 50 % of the national power consumption from offshore wind energy utilisation alone. The first two projects, started in 2002, are located at the sites of Horns Rev in the North Sea and Rødsand in the Baltic. Horns Rev was completed in the autumn of 2002 (Figures 17.12 and 17.13). The operational experiences revealed some severe technical probems. Generators and transformers did not withstand the salty environment, requiring a comprehensive retrofitting program.

Table 17.11. Planning data for the five offshore sites in the Danish "Energie 21" plan

Location	Water depth m	Distance from the coast km	1st construction phase	Commissioning	Spec. investment costs US$/kW	Owner
Horns Rev	6–14	14	80 × 2 MW Vestas 160 MW	2002	1690	Elsam, Eltra
Rødsand/Nysted	6–9	12	72 × 2.3 MW Bonus 166 MW	2003	1600	EnergiE2 Sydkraft
Gedser Rev		12		after 2005	—	—
Læsø Syd	6–9	20		after 2005	—	—
Omø Stålgrunde	4–12	10		after 2005	—	—

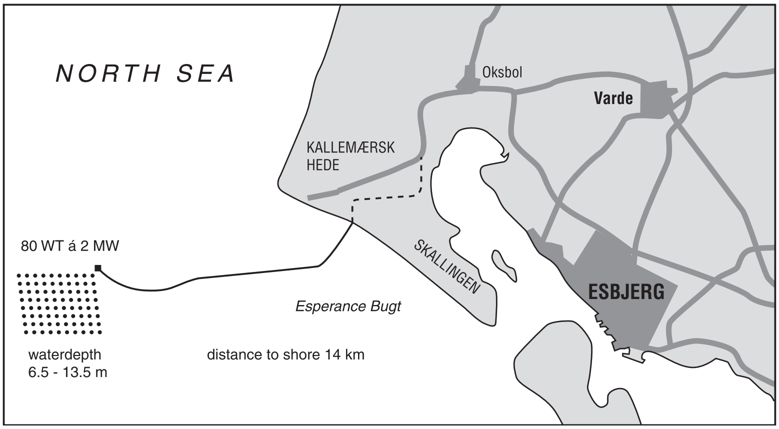


Figure 17.12. Horns Rev offshore wind farm with 160 Vestas V-80 wind turbines of 2 MW each [9]

Figure 17.13. Horns Rev offshore wind park (Vestas)

The second large offshore wind farm Rødsand/Nysted was erected in the summer of 2003 in a record time of two months (Fig. 17.14). It consists of 72 Bonus wind turbines, the rated power of 2.3 MW of which is limited by an active stall control system. The foundations were constructed as concrete caissons. These gravity type foundations have proved to be

Figure 17.14. Offshore wind park Rødsand/Nysted with 160 2.3-MW Bonus wind turbines (Siemens Windpower)

relatively expensive in the builders' estimation. Although the total costs of constructing the wind farm are said to be US$ 270 million, the specific value of 1 485 US$/kW is better than the comparable Horns Rev project with approximately 1 690 US$/kW. Figure 17.15 shows how the construction costs are attributed to the major systems.

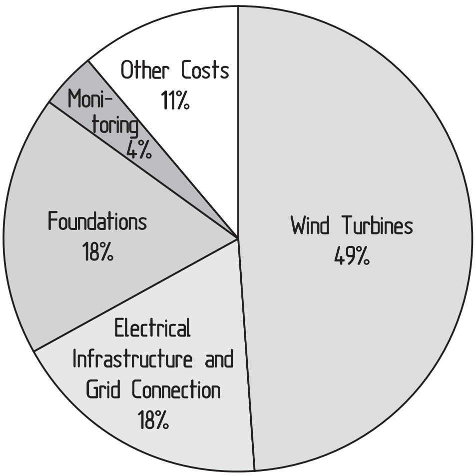


Figure 17.15. Distribution of the construction costs over the major systems in the Nysted wind farm [10]

Great Britain

In Great Britain, it is also intended to generate about 10 % of the power consumption from renewable energies by the year 2010. Investigations of suitable offshore sites have been carried out for some years (Fig. 17.16). Since 2003, developments have been accelerating very rapidly in this field.

The British Department of Trade and Industry (DTI) has initially licensed about 15 sites in its so-called "Round 1". These sites are located within the 12-mile zone in relatively shallow waters. On the sites, about 30 turbines each are installed, the capacity of which will be between 60 and 100 MW depending on turbine size. Overall, about 450 MW will be installed in Round 1. The first project, North Hoyle, with 30 2-MW Vestas turbines, was taken into operation in November 2003 (Fig. 17.17). Scroby Sands, Kentish Flats and Gunfleet Sands are built in 2004/2005. Also in 2003, Arklow Bank off the coast of Ireland was built, consisting of 7 GE-Wind 3.6 MW wind turbines.

At the end of 2003, further 15 sites were licensed in "Round 2". These sites are located outside the 12-mile zone in deeper waters and at a greater distance from the coast. They have a capacity of 5 000–7 000 MW which will be achieved essentially by about 2010.

The projects are pushed ahead by numerous planning groups which are backed by many notable European energy supply undertakings such as RWE (D), E-on (D), EdF (F), Energi E-2 (DK), and also by Shell and Total.

Figure 17.16. Planned offshore sites off the British coast [9]

Figure 17.17. Offshore wind park in North Hoyle, UK

Germany

In comparison with the countries mentioned above, the realisation of offshore projects has been delayed in Germany. The conditions in the North-Sea region are characterised by the fact that all serious projects beyond the mud flats, that is to say in relative great depth of water and distance from the coast, are being pursued (Fig. 17.18). In some cases, regions considered to be suitable are outside the territorial waters, the 12-mile zone. For this reason, the strategy pursued is slightly different from, for example, that in Denmark. The location of the sites requires advanced technology if the requirements for economic feasibility are to be met. The wind turbines must be larger, preferably in the range of 4 to 5 MW, as must be the projects overall. Distances of over 60 or 70 km from the coast require technical expenditure for link-up with the grid which is only economically supportable for very large projects. In addition, this also raises the question of how much power the grids on land can accept at the available in-feed points. In the area of the North Sea and the Baltic Sea, there are only a very few extra-high voltage rails of 220 or 380 kV. Therefore the implementation of large wind farms off the German coast will not be possible without a certain expansion of the grids close to the coast.

More than 20 projects are in different stages of planning. In 2004, the authorities granted a licence for implementing offshore projects for two sites in 2004: Butendiek and Borkum West in the North Sea area. Meanwhile, some more permits are granted, but in nearly all cases objections from environmental groups are subject to court cases.

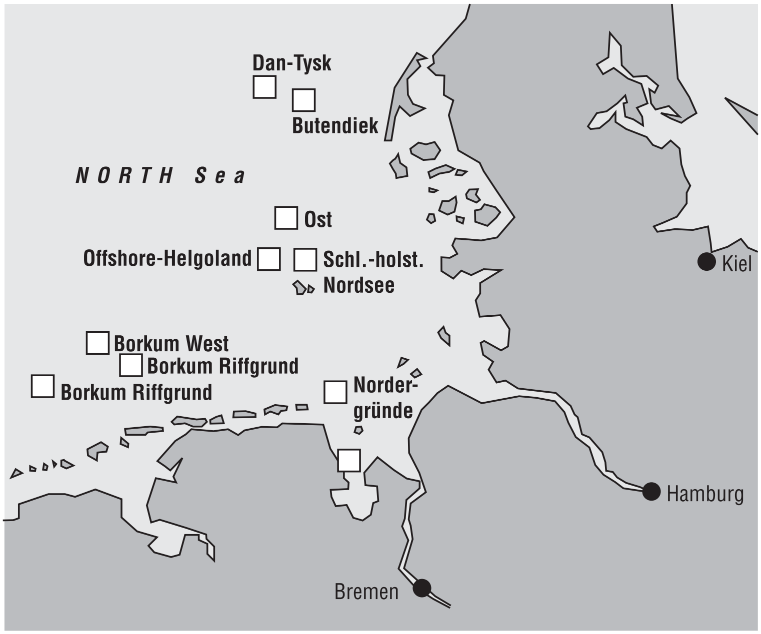


Figure 17.18. Planned sites for large offshore wind farms off the German North-Sea coast (status as of the end of 2001) [11]

Figure 17.19. Planned offshore sites in the area of the German Baltic coast (status as of the end of 2003) [11]

The German area at the Baltic coast is comparatively modest (Fig. 17.19). Although the conditions close to the coast are more advantageous than at the North Sea coast since there are no mud flats in the Baltic Sea, it is impossible to see that there is enough space for large wind farm projects. For this reason, only the area beyond the 12-mile zone is available for large projects so that here, too, one has to take rather a long-term view with respect to implementation in comparison with other countries.

Other countries

In the other countries with coasts on the North Sea or Baltic Sea, planning is not as advanced as in Denmark. In the Netherlands, there is a plan to cover 10 % of the national energy consumption with renewable energy sources, including 1250 MW from wind energy, by the year 2020. One project "Egmond am Zee" at a distance of about 10 km from the coast will have a capacity of 100 MW. This project is called a "near-shore wind park" in Holland. The subsequent projects are much farther out in the open sea.

The countries adjoining the North Sea also include Belgium. There, two offshore sites, intended to generate in each case about 100 MW in a first phase, are being investigated more thoroughly. The Knokke and Wenduine sites are located at a distance of 7 to 12 km off the Belgian coast.

In Sweden, where the Utgrunden project already represents a step into commercial offshore wind energy utilisation, a number of other sites are being examined. According to the Swedish plans, it is intended to achieve an offshore capacity of several hundred megawatts within the next ten years. Two of the projects implemented in 2002 are the projects in Lillegrund and Klasården.

17.2 Licensing Procedure

At the beginning of the discussion about siting wind turbines at sea, the prevailing opinion was that on the "open sea" one could also escape from the constraints of the licensing procedures delimiting wind energy utilisation on land. After the first plans became known and public discussion began, it immediately became clear that this was a mistaken hope. The doubts and objections and even tumultuous protests show that the interests of the people with claims in the coastal regions of the countries are in conflict with one another in the same way as on land. At sea, too, numerous people with claims immediately spoke up who saw their interests being affected. The familiar experience that something new can only arise when all existing claims remain untouched obviously also applies at sea.

The situation is certainly different from one country to another. The situation in the offshore areas of Denmark and Great Britain is not as complex as in the German part of the North Sea. Here the ecological area of the "Wattenmeer" is more or less untouchable so that only the more distant offshore areas are suitable for offshore siting of wind turbines. In the meantime, the discussion has become more objective and the criteria, whether ecological or economic, which must be observed in the context of a licensing procedure have become clearer [12]. Apart from the geographic and environmental conditions, the legal situation is also different from one country to another.

17.2.1
Legal Situation

The legal situation with respect to licensing is primarily determined by whether the relevant maritime region is located within the area of the territorial waters, that is to say within the 12-mile zone, or beyond this boundary. All states bordering the North Sea and the Baltic Sea are claiming a region beyond the 12-mile zone in which they exclusively pursue their economic interests. The boundaries of this "exclusive economic zone" were last established contractually in 1994 in an agreement by the neighbouring states.

Naturally, the legal regulations are different in the different countries. Any concrete project planning must, therefore, deal in detail with the national regulations. The general problems described in the following sections primarily relate to the German area of the North Sea and the Baltic Sea. In principle, however, the situation is comparable to that in other countries.

Territorial waters

In some countries, for example in the Federal Republic of Germany, the same planning and licensing prerequisites as on land apply, "in principle", in the territorial waters. The coastal provinces authorise the sites as part of their area planning and are using as a basis the same licensing criteria and legal principles as on land. This means that the environmental compatibility check is carried out as on land. At the same time, the European guidelines for "flora/fauna habitats" (FFH) and the "important bird areas" (IBA) must be observed. The regional authorities issuing building permits are formally responsible in the same way as for sites on land. For constructional undertakings on the bottom of the sea (laying sea cables), the Federal Mining Statutes and regulations must be observed.

Exclusive economic zone

The legal situation in the *exclusive economic zone* is much less unambiguous and leads to a discussion of the principles of international law, independently of the siting of wind turbines. Strictly speaking, all national and European laws end at the boundaries of the territorial waters. In Germany, for example, the permissible procedures in the exclusive economic zone are specified in the "Decree Relating to Maritime Installations" (Seeanlagenverordnung) of the Federal German Office for Navigation and Hydrography (BSH — Bundesamt für Seeschiffahrt und Hydrographie) and are based on the regulations of the "International Maritime Law". This legal situation results in the necessity that all national rules must be "harmonised" with the international maritime law. It goes far beyond the bounds of this book to explain in detail the resultant problems of legal principles or method steps.

From a pragmatic point of view, there is a tendency, at least in the Federal Republic of Germany, that the licensing criteria applicable in national waters are also extended "voluntarily" to the exclusive economic zone. In other states bordering the North Sea and the Baltic Sea, this may be handled differently in detail. Some countries tend to allow a simplified licensing method in the exclusive economic zone. The discussion of this question is not yet finished by a long shot.

17.2.2
Licensing Criteria

The criteria according to which the licence application for the installation of wind turbines in the territorial waters — and also in the exclusive economic zone, is examined extend to the following:

- Traffic safety for waterborne and airborne traffic
- Ecological effects
- Infringement of the economic interests of third parties

The licence application must be made with the usual project documents at the relevant authorities, depending on whether the site is within the territorial waters or outside the 12-mile zone. The authorities will then ask the responsible offices and associations affected by the above criteria for a first comment. During the examination for environmental compatibility, the applicant has to obtain the required assessments and examinations by recognised persons or institutions. On the basis of this situation, the responsible authority will decide on the licence application and, if the decision is positive, will grant a building permit according to the valid building laws.

Unfortunately, this plain and brief description of the basic sequence of the procedure does not correspond to the real situation. Reality is characterised by a multiplicity of complex situations for which the scientific and sometimes also the legal foundations often do not yet exist or are at least contested. On this objective situation, a power struggle of the most varied associations of interest and persons with claims in the matter is superimposed. Against this background, licensing procedures lasting years and having an uncertain end are the unavoidable consequence.

A detailed discussion of the problems underlying these licensing criteria will go far beyond the bounds of this book. Instead, it is only possible to list the criteria for the licence in key words at this point but even this listing alone — the completeness of which cannot be guaranteed by the author — clearly shows the complexity of the basic considerations used for arriving at decisions.

Traffic safety for waterborne and airborne traffic

Through almost all regions of the North Sea and the Baltic Sea close to the coast, shipping routes pass. Attention must be paid not only to civil waterborne traffic: the military also use certain regions for exercises or communications facilities. Civil aviation is less problematic in this context, but requirements possibly for height restriction and always for visual and electronic warning signals must be heeded.

Ecological effects

This area is by far the most extensive one and without contest also the most important one. The key words under which the ecological effects are discussed are:

- Birds: bird migration, collisions with birds, breeding areas, food sources for birds, etc.

- Sea mammals (small whales, seals): disturbances of the animals by submarine sound emission and possibly by electrical and magnetic fields emanating from the wind turbines.
- Fish: influence on the breeding sites and feeding areas, changes in oceanic currents and the nature of the sea bottom due to the offshore foundations and their influence on the behaviour of the fish.
- Small forms of life in the sea bottom (Benthos): adverse effects on this biotope are feared particularly during the building work.
- Landscape conservation: visibility of the turbines from land.

In the meantime, the "visibility from land" aspect, which was emphasised particularly by nature conservationists and the tourist industry, appears to be assessed largely uniformly. In Denmark, a minimum distance of 6 km and a desirable distance of 12 km from the coast is stipulated for the large commercial wind farms. From this distance, visibility is minimum and is only a factor when the view is very clear. The ideas are similar in Germany. It should be noted in this connection that due to the curvature of the earth, the wind turbines will disappear below the horizon at a distance of 20 to 30 km, in any case.

Economic interest

When a new field of utilisation appears, it must be delimited against existing economic interests. Particular cases are:

- Obstruction to fishing
- Impeding any possible exploitation of mineral wealth
- Observing existing infrastructural facilities (oil and gas pipelines, maritime electrical cables, etc.)

These spheres of interest cannot always be clearly differentiated from one another in individual cases. Loudly voiced objections that the offshore wind turbines could have a negative influence on the fishing industry appear to have economic reasons rather than ecological ones when looked at more closely. Naturally, structures at sea such as offshore wind turbines will present obstacles to the fishing technique using bottom-trawling nets, often criticised, with which even the last small plaice are being caught today.

A further problem is that many ecological aspects, which are raised in the discussions, have the nature of "suppositions" or must first be seen in their correct dimension. The assumption that the electrical fields which may emanate from the underwater cables of the wind turbines could have an adverse effect on the well-being of the loveable small creatures in the sea bottom can be considered, on the one hand, as a stimulus for interesting research work never performed and one can wait for the results — which, unfortunately, will only be forthcoming in long-time trials — or one is forced to weigh up the economical pros and cons.

All the same, the future offshore utilisation of wind energy will provide the probably most significant contribution for an ecologically effective energy supply for the foreseeable future.

17.3 Technology of Offshore Siting

There have been offshore structures in large numbers for more than 50 years, particularly platforms for extracting oil and natural gas. In extreme cases, oil drilling platforms are standing in water depths of several hundred meters. The technical problems associated with the transportation, erection and operation of such structures are well known, as is a multiplicity of suitable technical solutions. Nevertheless, the offshore siting of wind turbines raises new questions, especially because the economic boundaries are much tighter than, for example, in the case of the drilling platforms mentioned which represent investments of millions and are also operated by a large operating team. Although the techniques that can be used for erecting wind turbines offshore can be largely "borrowed" from the familiar offshore technology, the operation of large offshore wind farms without operating personnel represents a completely new, technically oriented challenge.

17.3.1 Technical Requirements for the Wind Turbines

The first prerequisite for utilising wind energy successfully offshore is a suitable design and the technical equipment of the wind turbines themselves. Existing wind turbines were designed for siting on land. A wind turbine located at sea is typically subjected to different external conditions that must be taken into consideration in the design.

Tower height

To make use of high wind speeds, the towers of wind turbines sited offshore do not need to be as high as those on inland sites. The wind speed profile has more of a bulge so that lower tower heights are sufficient for attaining the optimum economic value. The tower height is also determined by the oceanographic conditions in relation to the rotor diameter. Factors to be taken into consideration are the normal water depth above sea bottom, the tidal range, the maximum wave height to be expected and sufficient clearance to the rotor. Figure 17.20 shows the proposed minimum height for a large wind turbine with a rotor diameter of 100 m for an assumed water depth of 20 m and the water level conditions of the North Sea.

Load spectrum

The loads to be taken into consideration in the strength and stiffness design of the structure in offshore use differ considerably from those "on land" in a few points:

- The mean wind speed is higher.
- The turbulence intensity above the open sea is less but a higher induced turbulence can be expected in the array depending on the turbine spacing selected (see Chapter 5.4).
- The wave motion of the water is a new significant loading influence. This applies both to the extreme loads resulting from the so-called "wave of the century" and to the dynamic response of the structure to the periodic wave loads.

- The motion of the ice at sea can lead to very high extreme loads, particularly in the Baltic. In addition ice accretion on the turbine must also be taken into consideration.
- The change in sea level height due to the tides may have an influence on the load spectrum.
- In some maritime regions, the currents can be so strong that they play a role in the load spectrum.
- The "scouring" of the sea bottom behind the foundations that is associated with the currents can influence the stiffness of the foundation structure.
- Not lastly, the increased corrosion — if it is not prevented by appropriate protective measures — plays a considerable role in the fatigue strength of the components of the structure.

An important aspect is the superimposition of wind and wave loads in the load spectrum. It plays a role with regard to the fatigue strength in the dynamic design of the structure. This affects primarily the tower structure and the foundation whereas the wind loads as before almost exclusively affect the rotor and the mechanical drive train. Similar to wind turbulence, the wave loading is taken into consideration in the design of the structure in accordance with the method of variation with time or spectral method. The approaches by Pierson-Moskovitz or Gonswap are frequently used frequency spectra [2]. It is noteworthy

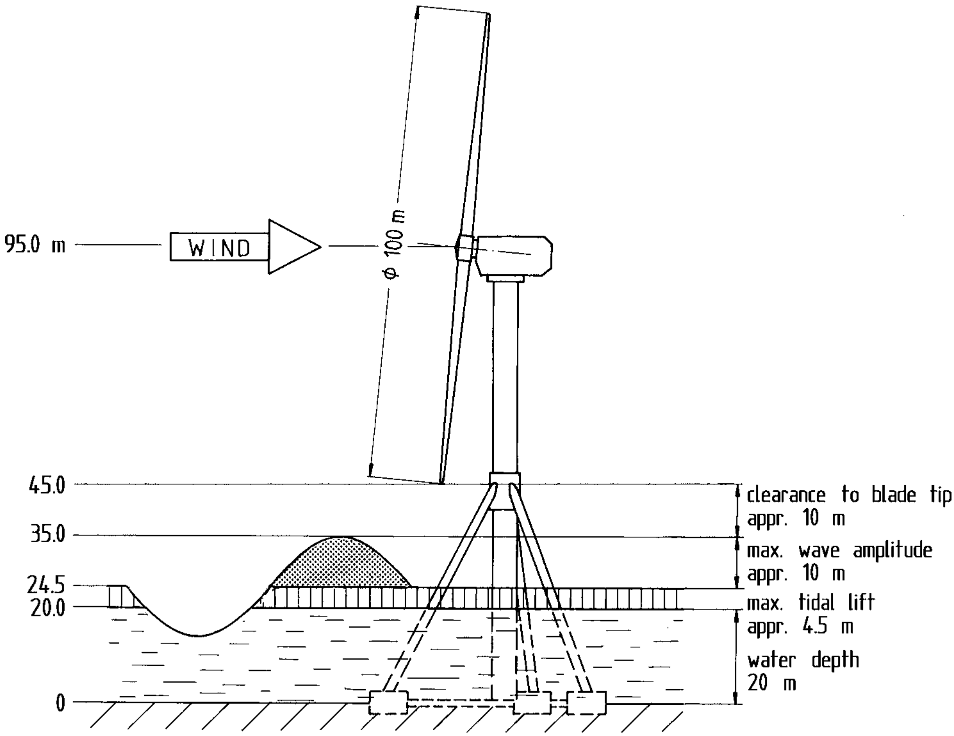


Figure 17.20. Water levels in the North Sea with regard to the tower height of a wind turbine [13]

that the sum of the superimposed load spectra of wind and waves can be less than when the individual observations are added together independently. The reason lies in the aerodynamic damping of the running rotor that damps the excitation due to the wave motion similarly to the way in which the sails of a sailing vessel damp the motion of the ship when there are waves [3, 14].

In 1995, Germanische Lloyd issued the first recommendations for the design of offshore wind turbines [15]. In Denmark, design guidelines for offshore wind turbines were also published in 2000 [16]. These standards are being continuously updated within the framework of IEC 61400-2 [17].

Turbine equipment

Compared to locations on land, the offshore siting of wind turbines makes much higher demands on their technical equipment. For example, it is not clear at present to what extent the redundancy of certain functions must be increased in order to achieve the required reliability that is an economic necessity in view of the more difficult accessibility. The measures necessary for ease of maintenance in offshore use will only become known in prolonged use. The first generation of offshore turbines differs from the on-land versions especially in the following features:

- Much more corrosion protection on almost all structural components
- Nacelles with better sealing
- Closed generator cooling system
- Monitoring and control systems that can be reprogrammed from land
- On-board crane in the nacelle for facilitating maintenance and repair work
- Special lifting tools in the nacelle and in the tower for heavy components and loads
- Docking platforms for maintenance boats with special docking aids and mountings for accessibility in rough seas
- Illumination in accordance with the rules at sea

The complete technical equipment of the wind turbines must be developed as an integral component of a comprehensive logistics and maintenance concept for the commercial offshore wind farms (see Chapter 17.3.4).

17.3.2
Foundation on the Sea Floor

The most far reaching adaptation demanded by offshore siting is associated with the tower design and its foundation on the sea floor. This structure, although it is generally called a foundation, is much more than a simple foundation as is found on a land site. At greater water depths, the required building work represents a significant component of the cost and may have considerable influence on the vibrational characteristic of the overall installation.

From general offshore technology, a large number of designs are known which have their advantages and disadvantages depending on the depth of the water and the size of the structure resting on them. An attempt to provide a complete overview does not help much and is not required, either, since the technical solutions suitable for erecting wind turbines are restricted to a few designs.

The basic static principle of the foundation is characterised by whether the stability is guaranteed from the mass of the foundation body, i. e. where there is a gravity foundation, or whether the structure is positively anchored in the sea floor, i. e. whether this is a deep foundation. There are today essentially three basic designs that are considered.

Gravity-type foundation with caissons

This type of construction has long been used for shallow water. A concrete caisson fabricated on land is floated and towed to the site where it is submerged and brought to the required weight by means of filling material (sand or gravel) (Fig. 17.21). The mass of a caisson for a 2-MW turbine is about 1500 t (Middelgrunden) plus the mass of the filling material. Because of the high weight of the concrete structures, the use of steel boxes is occasionally also considered. In maritime regions with much ice motion (Baltic Sea), the part protruding out of the water should have a conical shape that is more advantageous with respect to the pressure of the pack ice.

Caisson foundations are the most cost-effective solution in shallow water with a few metres depths. There is a rule of thumb which says that the mass — and thus also the cost — increases almost as a square of the water depth. For this reason, their use is restricted to a maximum water depth of 10 m. A further disadvantage is that the sea floor must be levelled and possibly reinforced so that more extensive underwater work is required.

With regard to the vibrational characteristics, gravity-type foundations are "stiff". For this reason, the aerodynamic damping of the rotor cannot contribute much to a softer response of the structure so that the load spectrum remains relatively hard with respect to

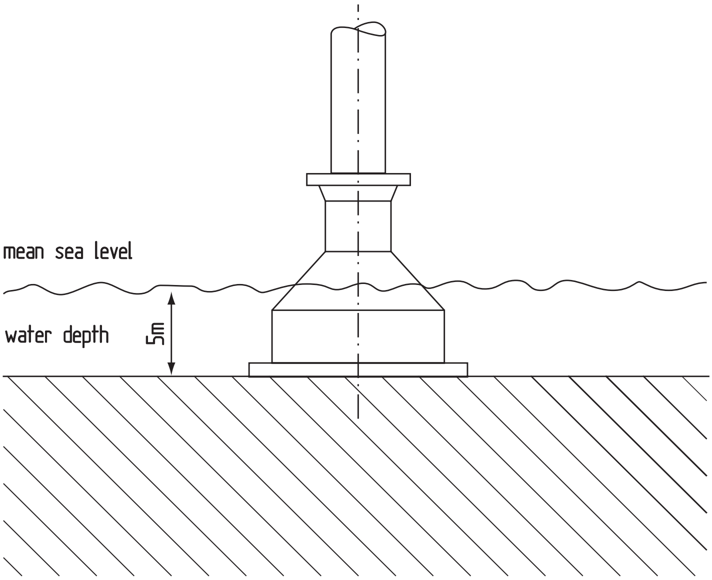


Figure 17.21. Gravity-type foundation with a conrete caissons

the fatigue strength. A further environment-related aspect is the fact that the foundation can be removed without much effort, in contrast to the deep foundations.

Monopile

A foundation with a free-standing steel pipe which is rammed into the sea floor is called a "monopile foundation" (Fig. 17.22). This comparatively simple solution is preferred wherever the external conditions are suitable, especially for cost reasons.

A monopile foundation requires virtually no preparation of the sea bed but the sea bottom must consist of sand or gravel in order to avoid expensive drilling work. Depending on the foundation soil, the steel pipe is rammed into the sea floor to a depth of 10 to 20 m with a hydraulic hammer from a floating platform. This type of heavy assembly equipment must be available for this purpose.

From the point of view of vibrational characteristics, a monopile foundation is a "soft" system. The natural frequencies of the tower of the wind turbine can only be determined in the overall "tower with monopile" system. The soft response of the structure effectively reduces the fatigue load spectrum. Since this design is capable of vibration, however, the

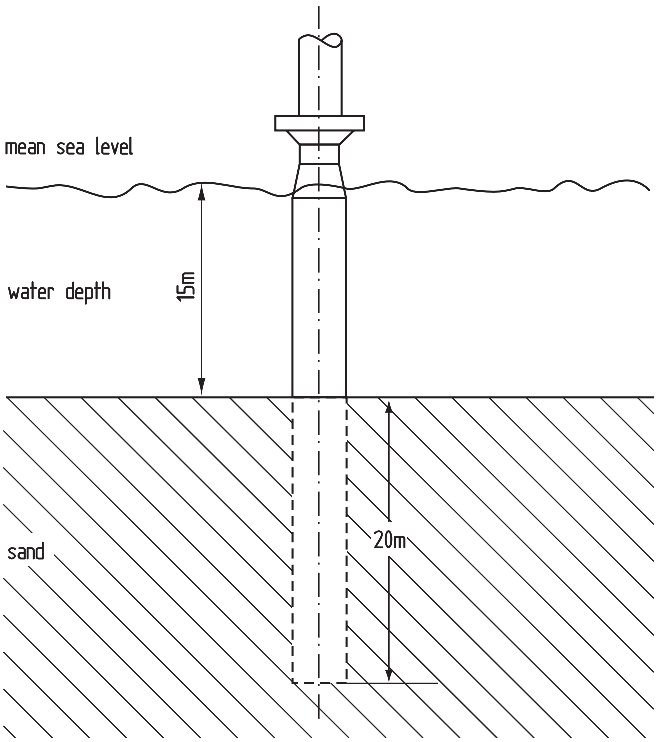


Figure 17.22. Monopile foundation

length, and thus the range of application, is also restricted with regard to the depth of the water to a maximum of 25 m according to current opinion.

Tripod

A central steel tube supported by three legs is called a tripod (Fig. 17.23). Such a design — which occasionally also has supports — can be designed as a comparatively light-weight and stiff structure. It is, therefore, suitable for greater water depths. As a rule, the three support points are anchored in the sea floor by means of thinner steel tubes (approximately 0.9 m diameter). The depth of penetration can be up to 20 m depending on the foundation soil. The stability is thus very high, even on an uneven sea floor.

This type of foundation requires a limited amount of preparatory work on the sea floor. In principle, a tripod foundation can also be constructed on caissons as gravity-type foundation. Because of the greater expenditure, however, this solution is usually avoided. The essential disadvantage of the tripod design is the high production expenditure on land and the difficulty in transporting it. According to current opinion, however, the tripod foundation is a suitable solution for greater water depth, for example in the North Sea.

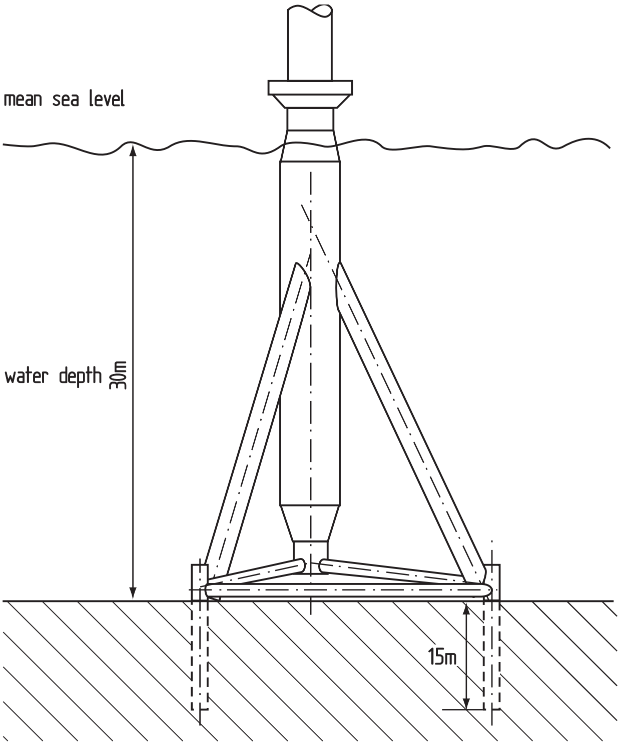


Figure 17.23. Tripod foundation

Floating platforms

Occasionally, floating platforms on the high seas are also proposed for offshore wind energy utilisation. Such platforms, which are attached to the sea floor by means of lines, are known in offshore technology. They are not an economic alternative for wind turbines in the water depths currently seriously considered for offshore wind energy utilisation. It remains to be seen whether in the far distant future, wind energy will also be utilised at great distance from the coast and thus in water depths which can only be exploited by means of floating platforms.

17.3.3
Electrical Infrastructure

In large offshore wind farms, the electrical infrastructure forms an independent and comparatively complex system, much more so than the cabling and the grid connection of wind turbines on land. Although the same electro-technical considerations apply as on land, the special requirements demand other technical solutions and in some cases new ones. There are three aspects, in particular, which must be taken into consideration much more than on land:

- The reliability of the systems and, in consequence, their redundancy
- The higher costs both of the components and of the assembly and installation in the sea
- The much greater distance for transporting the energy to the land

Under these conditions, unconventional solutions will also be considered, for example for transmitting the electrical energy generated to the land over a greater distance. The electrical infrastructure can be subdivided into four areas:

- Internal electricity system of the wind farm
- Offshore transformer station
- Sea-cable connection to the land
- Link-up with the interconnected grid on land

There are different technical solutions to these four subsystems, but these can always be selected and assessed only in the context of the overall system, taking into consideration the electrical concept of the wind turbines.

Internal electrical system

For the current projects, the internal cabling of an offshore wind farm is a medium-voltage three-phase system with a voltage range of from 20 to 40 kV. The sea cables are 3-core cables with integrated fibre-optical signal conductor. There are so-called "XLPE" cables with a round cross section and "flat-type" cables in which the three conductors are next to one another in one plane.

The cost of current plastic-sheathed sea cables is about 20 to 40 % above that of comparable land cables. The laying amounts to about 50 to 80 % of the costs so that one metre of laid medium-voltage sea cable costs US$ 100 to 150. High-voltage cables (110 to 150 kV) cost approx. US$ 250 per metre, including the laying. They are laid by means of specially equipped cable-laying ships. According to an often-used method, the cables are driven into the sea bottom to a depth of about one metre by means of a water jet.

The wind turbines are connected to a central transformer substation via their own transformer. On an offshore site, ring connections are suitable for a certain number of wind turbines up to about 30 to 40 MW per connecting ring according to the maximum transmission capacity of the cable cross sections selected. Ring connections have the advantage that in the event of a break in the cable, the wind turbines "behind it" are not lost but can be switched over via the ring, in contrast to the daisy chain connection normally used in wind farms on land (Fig. 17.24).

In principle, an internal DC power system is also conceivable. However, this only makes sense if every wind turbine is connected by means of a regulated rectifier and the connection to the land is also constructed as DC transmission line. This option may become interesting in future in the case of wind turbines operated with variable speed, which have a DC link circuit, and if the wind farm is located at a great distance from the coast.

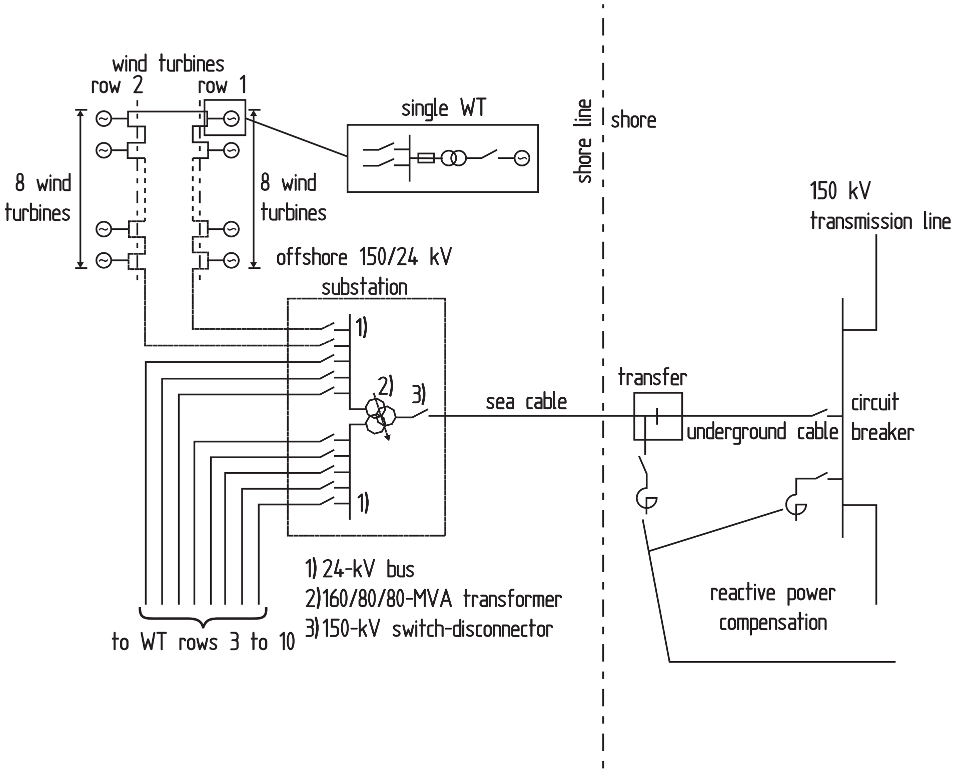


Figure 17.24. Electrical infrastructure of the Horns Rev offshore wind farm [18]

Offshore substation

At greater distances and with higher powers, the energy must be transmitted to the mainland at high-voltage level. This requires a transformer substation at the wind farm site. In this substation, the lines from the wind turbines are brought together at a central point and the energy is transformed to high voltage.

Apart from this task, the substation contains the necessary switching panels and other electrical facilities such as, for example, power-factor correction systems. The high-voltage

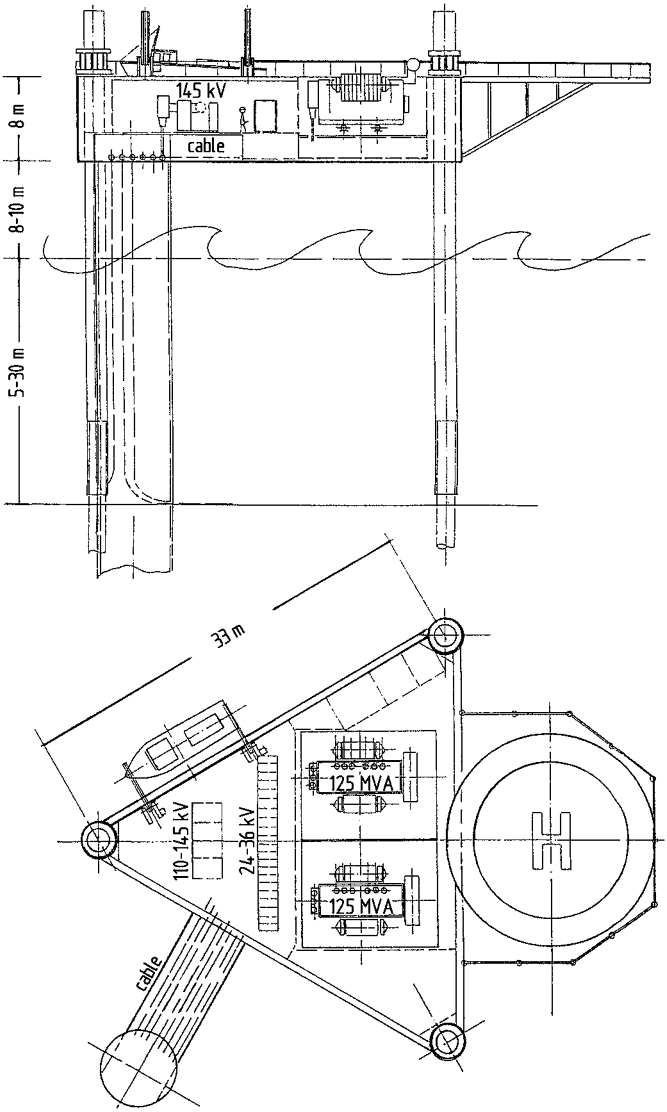


Figure 17.25. Concept of an offshore transformer substation that is also used as the central service platform [19]

transformers are normally oil-cooled. The switching panels must be gas-insulated (SF_6). Figure 17.25 shows the layout of a central offshore transformer substation. The substation rests on three monopile foundations and is used at the same time as service station for the wind farm with a boat docking facility and a helicopter landing platform.

A somewhat different layout of the substation has been conceived for the Nysted Rødsand offshore wind park (Fig. 17.26). This has resulted in an impressive styling concept of the containment.

Sea cable link to the land

If the distances and powers are greater, as is required for transporting energy to the grid on land, a medium-voltage cable link is no longer adequate. The voltage must be transformed to the next higher level (110 to 150 kV). High-voltage three-phase cables are generally available and their structure does not differ from medium-voltage sea cables (Fig. 17.27 and Table 17.28). Laying the cables needs a special equipment, but is "state of the art" for many sea-cable transmission lines (Fig. 17.29).

However, transmitting alternating current over long distances presents its own problems. The cables act like a large capacitor, that is to say electrically they exhibit capacitive characteristics. Above a certain distance (about 100 km), the permanently required charging current (reactive power) is of such a magnitude that virtually no more active power can be transmitted. The only remedy can be provided by parallel-connected choke coils that compensate for the reactive current.

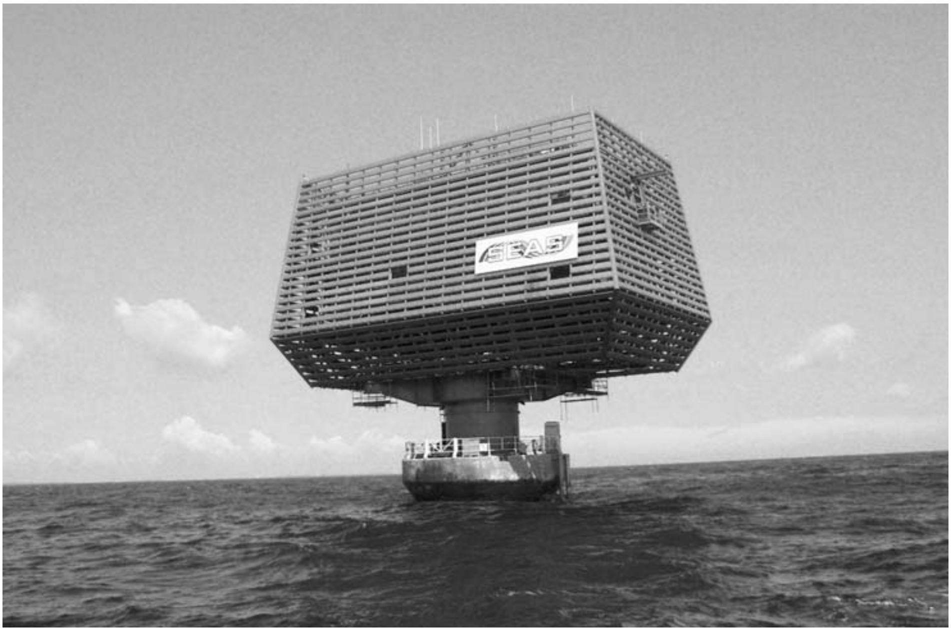


Figure 17.26. Offshore substation of the Rødsand/Nysted wind park (VfU)

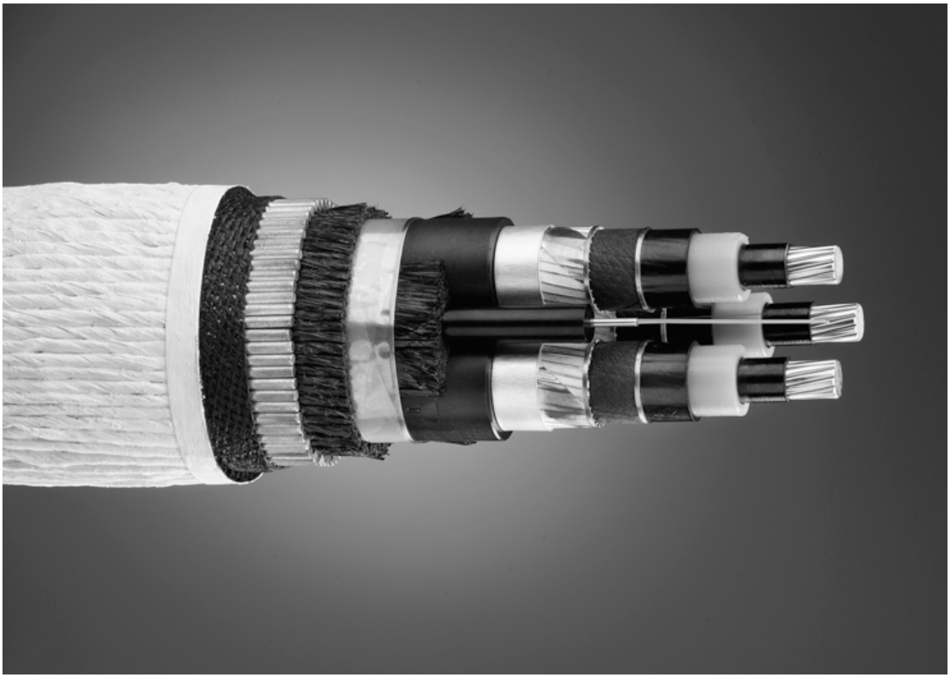


Figure 17.27. Underwater three-phase cable with integrated fibre-optical signal line (Nexans)

Table 17.28. Technical data of a 145-kV sea cable (Nexans/Alcatel)

Rated voltage	145 kV
Type	XLPE
Number of cores	3
Rated current per core	900 A
Transmission capacity	205 MVA
Copper cross section per phase	630 mm²
Ohmic resistance per phase	0.0641 Ω/km
Inductive impedance per phase	0.1162 Ω/km
Capacity per phase	0.185 μF/km
Charging current per phase	4.7 A/km
Losses per phase	52 W/km
Outside diameter	200 mm

Figure 17.29. Laying of a 110 kV cable at the construction of wind park Ittre Stengrund (NEG Micon)

Since the required reactive power increases as the square of the voltage level, it makes sense to limit the voltage level to, e.g. 110 to 150 kV. In the case of high powers, it may be necessary to lay a number of lines in parallel — which also provides redundancy. The voltage drop over this distance and the associated loss in efficiency are quite considerable. The transmission efficiency of a 145 kV three-phase marine cable is given as follows [13]:

Length:	Transmission efficiency:
20 km	0.88
50 km	0.70
100 km	0.40

These disadvantages are having the result that the economic efficiency of transmitting three-phase current is being questioned for a distance or more than about 50 km and high-voltage DC transmission (HVDCT) is being considered as an alternative. HVDCT avoids the disadvantages associated with power factor compensation and the decrease in efficiency. However, all the systems and components such as switches etc. are much more expensive in this case. A further disadvantage consists in that in the case of direct current, the change to a different voltage level cannot be accomplished by direct means. Transformation is only possible via an expensive and lossy inverter followed by later rectification.

In current HVDCT systems, thyristor inverters are used. These have the disadvantage that, for connecting wind farms with an internal alternating-voltage power system, the reactive power cannot be regulated. The inverters can only be used as line-commutated inverters so that a separate isolated AC power system must be set up in the wind farm. Thyristor inverters also generate harmonics that require special filtering.

The disadvantages of thyristor technology can be avoided by using IGBT inverters. These are used in connection with a voltage-controlled converter instead of a current-controller converter. These so-called "HVDCT light systems" are already used in some cases [19].

From the current point of view, HVDCT can only be considered if the overall concept of the wind farm, that is to say the generator technology, the internal cabling and the energy transmission to the land, can be realised as a direct-current design throughout, or the distance from the land is greater than 50 km. The first generation of offshore wind farms does not yet meet these requirements so that alternating-current transmission is the more economic solution for the foreseeable future.

Linking up with the interconnected grid on land

The first offshore wind farms with powers of 100 or 200 MW can still be fed into the relatively closely-meshed high-voltage grid on land (i. e. 110 kV) (compare Fig. 17.19). The future large offshore wind farms with powers of 1000 MW, however, need to be linked to the extra-high voltage grid (220 to 380 kV). At present, overhead extra-high voltage transmission lines can only be found close to the large power stations or the large power consumers, in large cities or centres of industry. In the area of the German North-Sea and Baltic-Sea coast, for example, only six possible points of coupling to the extra-high voltage grid are mentioned [20].

If the offshore wind energy utilisation advances into these power ranges, an extension of the high-voltage and extra-high voltage grids will becomes necessary. Naturally, this is associated with considerable investments. Critics who wish to use this fact as a reason for the "impossibility" of utilising wind energy in this dimension should remind themselves that the erection of the large power stations on land also required a corresponding extension of the grids. If in future, the flow of energy comes from a different direction for a number of good reasons, the same will naturally apply.

17.3.4 Transportation, Installation and Maintenance

The installation and the operation of wind turbines at sea makes special demands on the concept of transportation and assembly and the later operation of the turbines, as it does for all offshore structures. The associated problems and costs acquire a completely different significance from those of the utilisation of wind energy on land.

The first difficulties occur at the latest when the future large turbines of 4–5 megawatts are being transported. It is difficult to imagine that the tower sections and rotor blades with lengths of more than 50 m can still be transported long distances over land. This also applies to the offshore foundation, for example if more complex structures are used such as, e. g. tripod foundations. For economic reasons, efforts will be made to prefabricate the turbines and components on land as much as possible in order to avoid the expensive assembly at sea with its uncertainties with respect to time and weather. If, for example, there are delays in the assembly due to bad weather, the necessity of storing the components immediately arises at the manufacturing site and this can be a problem given the existing dimensions (Fig. 17.30).

The extent of the assembly works at sea and the equipment required for this are determined by the type of foundation, among other things. Monopile foundations require heavy hydraulic hammer works in order to ram the steel pipes with 4 m diameters into the sea bottom to a depth of about 20 m (see Chapter 17.3.2). The assembly of tripod foundations requires less heavy equipment. However, the transportation of the tripod structure prefabricated on land is more complex. Weather is a considerable risk factor for assembly. All currently known assembly techniques can only be carried out when the sea is quiet. The most important criterion is the wave height in this connection. Work becomes extremely

Figure 17.30. Loading the preassembled rotor (70 m diameter) in Yttre Stengrund for assembly in the offshore wind farm (NEG Micon)

difficult or impossible with wave heights of more than one metre so that a temporary interruption of the work has to be included in the calculations of the logistics.

Transportation to the site generally takes place on a floating assembly platform. For this purpose, so-called *jack-up platforms* are used. These have support feet that can be lowered to the sea floor for the assembly work.

During transportation, the supports are pulled up and the platform is towed by a tow boat (Fig. 17.31 and 17.32).

A considerable problem of the offshore siting of wind turbines, which became apparent for the first time in the Bockstigeen wind farm approximately 12 km off the Swedish west coast, is that of reaching the wind turbines in a rough sea. Docking the maintenance boat proved to be extremely difficult even at a wave height of little over one metre. The consequence was long stand-still times due to relatively minor defects which could have been eliminated within a few hours on a turbine situated on land.

This problem can have fatal economic consequences and is, among other things, a criterion for exclusion with respect to insurability against loss of income (service interruption insurance) unless a satisfactory solution can be found.

After this experience, a wide variety of concepts for guaranteeing that the turbines can be reached are being developed for commercial offshore projects. For example, the use of submarine vehicles is being considered with the aid of which the maintenance personnel can enter the tower underwater in diver's suits. Similar work is required in any case during the assembly of the wind turbines (Fig. 17.33). An alternative is accessibility from the air by

Figure 17.31. Transportation of the components to the Yttre Stengrund site (NEG Micon)

Figure 17.32. Assembly of the wind turbines in the Yttre Stengrund wind farm (NEG Micon)

means of helicopters. This would require that, at the least, each wind turbine is equipped with a platform on the nacelle suitable for dropping personnel and equipment (Fig. 17.34). For very large turbines, a helicopter landing platform may be feasible. It is doubtful, however, whether this would provide satisfactory accessibility. If the sea is rough and the weather is bad, the mission capabilities of helicopters are also greatly restricted. The next few years will show what methods are most successful in practice.

To limit the complex and expensive maintenance work to an economically sustainable measure, preventative maintenance is allotted central significance. Primarily, it is still necessary to reduce the requirement for maintenance and susceptibility to failure of the turbines compared with the current state of the art. Early fault detection is just as important as a strategy of preventative maintenance so that this work can be performed when the weather conditions are favourable. The aim must be to maximise the "MTBF" (mean time between failures). Strategies and technical measures suitable for this purpose must still be introduced in the wind energy industry.

More far-reaching ideas provide for the use of "telecontrol systems". It is hoped that this technology will make it possible to carry out at least simple maintenance and adjustment work from land. In any case, the overall logistical concept will be of decisive significance for the commercial utilisation of offshore wind energy.

Figure 17.33. Maintenance work in the Yttre Stengrund wind farm (NEG Micon)

Figure 17.34. Offshore wind turbine with helicopter supply platform in the Horns Rev wind farm (Vestas)

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Chapter 18

Wind Turbine Installation and Operation

Implementing turnkey projects for the utilisation of wind energy means much more than purchasing a wind turbine. Generating electrical energy from wind energy represents an intervention into the existing power supply infrastructure and even more so into the immediately surrounding environment. It is thus inevitable that it will encounter resistance from those who do not consider this intervention to be necessary or do not want it for some other reasons. The planning of wind energy projects falls right into this area of tension and is thus less of a technical problem than one of striving, as a rule over long periods, to achieve a balance between the various interests until an equitable consensus is found.

The formal procedure for obtaining the building permit for a wind turbine or a wind farm follows a broadly similar process to that of any other power generation project. The procedure itself has thus been officially regulated for some time and is a routine matter. The range of procedural steps required and of expert assessments depends on the magnitude of the project. A simple building permit issued by the local authorities is not sufficient for larger wind farm projects. In most countries, there are higher-level regional planning and licensing regulations in force such as the Federal Antipollution Law (BImSchG) in Germany [1].

Erecting a wind turbine of small to medium size with a tower height of 40 to 50 meters does not present a technical problem as long as the site is accessible to common transport and hoisting equipment. The erection of large turbines, however, is a separate problem. The most varied solutions have been developed and tried out in recent years.

The operation of a wind turbine is ruled by the unavoidable necessity of having to manage without permanent operating personnel. For an energy generation system with a maximum power output of several megawatts, automatic operation is absolutely imperative for economic reasons. Control and supervisory systems are, therefore, accorded special significance in wind turbines. From a technical point of view, therefore, the operation of a wind turbine consists primarily of the organisation of the servicing and maintenance work. Major repairs and maintenance procedures are normally carried out by the manufacturer under the provisions of a maintenance contract, but the routine monitoring of the installation remains the responsibility of the operator. This task is made easier by remote monitoring systems utilising a simple PC and data communications via a modem and the telephone network, a method which has become widespread in recent years.

18.1 Project Development

The planning of a project for wind energy utilisation begins with the search for a suitable site. Naturally, adequate wind velocities take first place in the considerations but other criteria are also becoming increasingly more important. In densely settled areas such as Germany, Denmark or the Netherlands, space plays a decisive role with respect to population density. To find a suitable area which is also large enough for a large wind farm and conflicting interests can be resolved is almost as important today as good wind conditions. In less densely settled countries, connection to the grid often represents a major obstacle since in many cases, the power systems must be extended first before it becomes possible to connect a wind farm with 50 or 100 MW power to the grid.

Once a suitable site has been found, the next problem is that of the contractual agreements with the property owners for erecting the wind turbines. Since the utilisation of wind energy has become a "business", the potential operators are competing for every contract of use with the owners of the land. The communities are attempting to intervene in a regulatory capacity and are in some cases identifying "priority areas" for wind energy utilisation and excluding other areas. Naturally, these regional planning measures will not be undisputed since the criteria are often assessed quite differently depending on the prevailing ideological point of view. The potential operator will, therefore, have to deal both with the private property owners and with the representatives of the local community. The advantage of all this is, however, that in this phase, it is often already decided in fact whether the project will be given the green light later.

The formal procedure for obtaining a building permit is clearly regulated in most countries today. The problem lies in achieving a balance between the conflicting interests behind the formal licensing procedure. The project planners have the task of attempting to actively control this process and to accelerate it, if possible. This is the main cause of the long planning periods. As they are obliged to procure the environmental assessments required for the building permit, their role is mandatorily prescribed for them.

At the same time as planning for the licensing, the question of the connection to the grid must also be discussed with the relevant power system operator. Even though the power system operators have a "duty to connect", the problems of technical feasibility and distribution of costs if grid reinforcement measures are required have not yet been solved in every individual case. Large wind farm projects require separate transformer substations and apart from a building permit, this also requires financing. In many cases, these costs cannot be borne by one wind farm project alone, requiring joint planning with neighbouring projects.

As with all large enterprises, the financing of these project is a separate subject (s. Chapt. 20). Solving this problem represents a significant part of the project development. If the means are not available, either from credits or from equity capital, it will not be possible to sign a binding delivery contract for the wind turbines without which, in turn, the manufacturers cannot commit themselves to a delivery date. The last and decisive prerequisite not only for the scheduling but for the overall project implementation is, therefore, an established financing model.

For large wind farm projects, the interdependent planning tasks outlined above require professional knowledge and experience — and they severely test the endurance and patience of the project developers. From the first site inspection until the delivery contract for the wind turbines is finally signed now generally takes three to four years and often even longer. Shorter planning periods are an exception which is becoming more and more rare.

18.2 Planning and Building Permits

The formal legal procedures for erecting wind turbines have evolved over the last ten to twenty years. In the initial years, the procedures differed in the individual regions and had an air of improvisation which often presented the potential operator with considerable problems. Since the late nineteen-nineties, the licensing procedures have been legally restructured in most countries of the EU, the US and other major countries and require compliance with a large number of laws and public regulations, the most important of which are:

Regional framework

In some regions maps have been in use for some years which designate certain areas for wind energy utilisation. These designations set up important boundary conditions. To fit the projects into this framework it is very important and requires close contacts to the responsible authorities. But the regional approvals cannot replace the individual permit procedure on the community level.

Building permit

Building permits normally come within the powers of the local building authorities which are a part of the local community administration or cooperate closely with the relevant community.

In most countries the existence of a so-called *type approval* (s. Chapt. 6.8) is of particular significance for obtaining the legal building permit. As a rule, there will be one already for a series-production turbine. A type-approved turbine does not require any technical tests and the building permit can be obtained much quicker and much more inexpensively. Turbines which are not type-approved, for example home-built machines, require a *single licence* which can be associated with considerable costs.

The application for the building permit basically includes the following documents:

- Siting plan with the location of the individual wind turbines and peripheral equipment and facilities including cables and access roads.
- Three-sided view of the type of wind turbine used.
- Drawings of other facilities.
- Static calculations for verifying the stability of the tower and its foundation.
- Technical assessments of the mechanical engineering parts of the turbine (rotor and nacelle) or official type approval certification.

Assessment studies of environmental impact, safety aspects and economic effects, typically including:

- noise emission,
- shadow flicker,
- interference with telecommunication systems,
- aircraft safety,
- hydrological assessment,
- archaeological and historical assessment,
- ecological assessment regarding the impact on local flora and fauna, in particular bird life, including measures to be taken in order to minimise and compensate for the effects,
- visual impact on the landscape,
- economic effects on the local economy (required in some countries).

Apart from the obligatory check by the authorities, the sections of the licensing procedure provide for a public exposition and a date for a public discussion, providing an opportunity for third parties to voice any objections to the granting of a permit.

The subject of permits cannot be concluded without some important general comments. The licensing process is becoming an increasingly difficult hurdle to the continued development of wind power utilisation. It is not so much technical, or in a narrower sense, administrative obstacles which play a role here, but rather the growing resistance of nature and landscape protection organisations. Their representatives increasingly obstruct the installation of wind turbines and decisively influence public acceptance of wind power utilisation.

The problem of wind energy utilisation as seen from this aspect can be characterised as follows. The global ecological advantages of wind power utilisation are obvious and are vigorously substantiated by all interest groups. The disadvantages of wind turbines, however, their visual impact on the landscape and possible noise pollution, make themselves felt right on the doorstep of the local residents. The citizen is thus forced to put up with these incursions into his immediate surroundings for the benefit of global advantages which he cannot directly experience. This leads to the well-known attitude: "Wind power, yes — but not on my doorstep, please". It is too simple to dismiss this attitude as "narrow-minded" and it does, indeed, present a problem.

Great efforts will have to be made in the future to make the public aware of the fact that an ecologically oriented power supply does require certain sacrifices if long-term damage to the overall ecology is to be avoided: The negative consequences would otherwise have immediate and much more severe effects at one's doorstep. At a time of general retreat into one's private sphere this is no easy task as it basically runs counter to the current trend in society. However, this somewhat pessimistic assessment must not be an excuse not to try everything to increase public awareness.

Regulations for connecting turbines to the electrical grid

In many countries, the power system operator is legally obliged to accept or to distribute power from renewable energy sources in their grids. However, there is also a number of technically based requirements for connecting power feed units into the grid which must be met in detail. In the case of large wind farms, there is also the problem of the capacity of the respective grid connection point. In many cases, lengthy negotiations with the power system operator about the enlargement of the grid and about who will meet the costs are unavoidable.

18.3 Transportation Problems

Transporting smaller turbines is more an economic problem than a technical one. To keep transportation costs low, the maximum component sizes are an important factor in the design of the turbine (Fig. 18.1). The age of container traffic prescribes maximum dimensions which must not be exceeded if a drastic rise in transportation cost is to be avoided. With overseas shipping, in particular, the question arises whether transporting the tower makes economic sense or whether it might not be cheaper to have the tower manufactured by a local company.

When large wind turbines with rotor diameters exceeding 50 m are to be moved, the transportation problem also shifts into a higher dimension. Only in the rarest of cases will there be a rail connection so that road transportation by truck remains as the only option.

Figure 18.1. Loading Aeroman turbines into a ship container for shipment to California (MAN)

The transportation problem is also determined by the wind turbine's technical design and by its method of erection. There are two mutually opposed aims in evidence. On the one hand, the assembly should be carried out as much as possible at the factory site, to save time and cost-intensive assembly work at the site; and on the other hand, there are the problems of transporting the entire nacelle and mounting it on the tower.

Up to a size of 2 to 3 MW, complete nacelles can still be transported by road (Fig. 18.2). Even the complete tower can be moved by means of a road vehicle (Fig. 18.3). Transporting the tower becomes more problematic if a height of 80 meters is exceeded. Steel tubular towers with a height of 100 m have a diameter of approx. 5 m at the base. Transporting the tower in several sections does not solve the problem of having to transport a "tube" with a diameter of 5 m on a low-loader over narrow streets and especially through underpasses and under road bridges. It is not least for this reason that very high towers are today again being manufactured as concrete structures or as lattice towers (s. Chapt. 12.3 and 12.4).

The transportation and assembly of turbines will acquire a completely new dimension with the next generation of turbines of the 4 to 5 MW class. The technical design will have to be increasingly assessed and determined from the point of view of transportability and erectability on site. The location of the production sites in relation to the final location of the turbines will also play a role. The only possiblity of transporting the complete nacelle is by ship (Fig. 18.4). The tower diameter at the base is nearly 6 m, reaching the limits of transportability on the road (Fig. 18.5).

Figure 18.2. Transportation of a Nordex N-80 nacelle on the road (Nordex)

Figure 18.3. Transportation of the complete WTS-3 tower to the site (1982) (Swedyard)

Figure 18.4. Transportation of the REpower 5 M nacelle on the Kiel Canal (REpower)

Figure 18.5. Transportation of the tower base section for the REpower 5 M (REpower)

Under current conditions, the problem of transportation and erection on site is considered as essential criteria for the economic use of wind turbines in less developed areas, i. e. mainly in the Third World. In complex terrain such as a mountainous region, this determines the upper economic limit to the size of a wind turbine. However, one should be aware of the fact that the conditions that are valid today will change with the increasing use of wind turbines. Access roads and large hoisting equipment become economically feasible as their scope of application becomes wider with increasing numbers of turbines.

18.4 Erection on the Site

Firstly, the erection of a wind turbine requires a suitable foundation for the tower. The type of foundation required primarily depends on the geological conditions and, to a certain extent, on the tower design (Chap. 12.5). There are various methods of erecting a turbine. Decisive criteria as to which method is used are the tower height, the weights to be lifted and the available hoisting equipment. The accessibility of the wind turbine site to heavy vehicles also plays role.

18.4.1 Small and Medium-Sized Turbines

For small and medium-sized turbines with a tower height of up to 50 m, the erection procedure is primarily chosen from the point of view of economy. Only in rare cases will it be necessary to manage without suitable hoisting equipment. A mobile crane will almost always be available (Fig. 18.6).

Figure 18.6. Erection a small Vestas V-39 wind turbine with a mobile crane

Figure 18.7. Erection of a Bonus 2 MW turbine (from top left):
- Assembly of the three tower sections
- Pulling up the nacelle
- Mounting the complete rotor

(Siemens Windpower)

The current commercial wind turbines with a size of up to 80 m rotor diameter can be erected in a few steps. The usual steel tubular tower is assembled from a number of sections and screwed together. The nacelle and the completely preassembled rotor can be pulled up "in one piece" and mounted. This only requires cranes with up to 500 t lifting capacity (Fig. 18.7). It is then possible to carry out the entire assembly process within one day, given good preparations and appropriate weather conditions.

In some locations, mainly in the Third World, the availability of even light hoisting equipment is not guaranteed. Some wind turbines were, therefore, designed for assembly without external hoisting equipment. Instead of using a mobile hoisting crane, the turbine was pulled to an upright position by an hydraulic pulling device (Fig. 18.8). If necessary, hydraulic power could be replaced by pure muscle action. It must be noted, however, that such methods of assembly are not without effect on the design of the turbine. From an economic point of view, therefore, they can only be justified if normal hoisting equipment is not available.

Nevertheless, the design of wind turbines which can be erected without extensive hoisting equipment is certainly justified for special sites. Apart from the example shown, the most diverse solutions have been proposed for this purpose, including telescoping towers. As wind turbines become more widely used in remote regions of the Third World, such erecting methods, used only with experimental turbines at present, may well become popular.

Figure 18.8. Pulling of the experimental Voith WEC-520 wind turbine to an upright position with a hydraulic pulling device (1982) (Voith)

In the Californian wind farms, the feverish construction activities of the years 1982 to 1986 were sometimes carried out with unconventional methods. Even transport and erection with a helicopter can be economically justifiable in impassable terrain (Fig. 18.9).

Figure 18.9. Transportation and erection of Aeroman turbines with a crane helicopter on a US wind farm (1986) (MAN)

18.4.2 Large Wind Turbines

The development and trial of methods for erecting wind turbines with tower heights of up to 100 m and corresponding tower head weights of up to 400 t (Growian) was an important task in the construction of the large first-generation experimental turbines. It is, therefore, important to look at the methods used then because with the next generation of commercial turbines with rotor diameters and tower heights of more than 100 m and nacelle weights of up to 500 t, such assembly methods are gaining prominence again. The mobile hydraulic cranes normally used today are no longer adequate under these conditions. The largest cranes of this type available (500-t to 600-t cranes) are no longer capable of hoisting the complete nacelles onto towers of 100 m height and more.

A considerably more complex crane set-up was used for erecting the Swedish WTS-3 turbine. Using a portal crane, it was possible to lift the nacelle plus rotor and the prefabricated tower in one single lifting operation (Fig. 18.10). Its American sister turbine WTS-4 was erected in Medicine Bow, Wyoming, using a different method (Fig. 18.11). Instead of a portal crane, a tiltable swinging crane was used.

Figure 18.10. Erection of the nacelle plus rotor and tower of the Swedish WTS-3 turbine with a portal crane, 1982

Figure 18.11. Erection of the WTS-4 using a swinging crane in Medicine Bow, Wyoming, 1984

The assembly of these turbines was facilitated by the fact that the large experimental turbines of those years almost without exception had two-bladed rotors. On the other hand, the hoisting equipment used was not really selected from the point of view of costs. The fact that it was possible to carry out the assembly successfully technically, an undertaking without many models, was considered a success in itself.

In two of the large test turbines, the crane function was integrated into the wind turbine design so that they could be erected without large external cranes. The outsides of the concrete towers of the Swedish/German test turbines of the Aeolus II type were fitted with sliding rails. This had already been done in its forerunner, Aeolus I. In this system, a cradle carrying the completely assembled nacelle plus rotor slid up the tower. This was done by means of an hydraulic pulling device which slowly lifted the weight of over 160 t to the 90-m high tower top over a period of approximately 20 hours (Fig. 18.12). This erection method requires the solid concrete tower to carry the rail system and the pulling device. It also considerably affects the turbine design, which in turn involves additional costs, in particular for the heavy prestressed concrete tower which has to be constructed completely on the site.

An extraordinary erection procedure was used for the largest wind turbine at the time, Growian (Fig. 18.13). The tower height of 100 m and a tower head mass of approximately 380 t precluded conventional erection methods with common cranes. At a very early design stage, a concept was, therefore, adopted where the tower passed through the nacelle during

Figure 18.12. Pulling up the nacelle on sliding rails on the concrete tower of the Aeolus-II turbine (MBB)

Figure 18.13. Lifting the nacelle of Growian on October 20, 1982 (MAN)

the lifting procedure. The nacelle plus rotor could thus be moved up and down on the tower by means of an hydraulic pulling device fixed at the top of the tower. This method was made possible by using a slender steel tubular tower with a diameter of 3.5 m.

The assembly method chosen for the Growian turbine, even more than in the case of the Aeolus II, had a considerable influence on the design of its nacelle (s. Fig. 2.26). The generator and the gearbox had to be moved far forward in order to make room for the tower to pass through the nacelle, resulting in a distinct overhang of the nacelle with its mechanical drive train and gearbox. The later failure of the very large welded-steel rotor hub structure was at least indirectly related to this method of construction.

An assembly method which follows on from the erection methods of the earlier experimental turbines was used in the assembly of a Vestas V-66 turbine on a 117-m-high lattice tower. The tower itself, topped with the appropriate assembly extension, was used as hoist (Fig. 18.14). A similar method, using an auxiliary crane on the 80-m-high tower, was also used for the prototype of the Lagerwey-Zephyros turbine (Fig. 18.15).

Figure 18.14. Assembly of a Vestas V-66 on a 117-m-high lattice tower, using a top crane extension

Figure 18.15. Erection of the Lagerwey-Zephyros turbine, using a top crane extension on the 80-m-high steel tube tower and an additional mobile crane

The erection procedures selected for the latest 5 MW-prototypes are still of an experimental nature. For the largest wind turbine so far, the REpower 5 M, the nacelle and the drive train had to be assembled on site, because the complete nacelle of approximately 300 t could not be hoisted up in one piece (Fig. 18.16).

The most difficult assembly of a turbine to date has been the erection of the Enercon E-112 turbine. The technical design of the E-112 is the same as that of the smaller Enercon turbines. Because of its extraordinary dimensions, however, the assembly had to be arranged somewhat differently. The individual subsystems were preassembled on the ground (Fig. 18.17). The heavy rotor of the large annular generator was delivered in two halves. The assemblies were mounted by using two cranes operating in tandem (Fig. 18.18). The rotor blades had to be assembled individually (Fig. 18.19).

Figure 18.16. REpower 5 M (rotor diameter 126 m, tower height 120 m, rated power 5 MW) (REpower)

Figure 18.17. Preassembly of the Enercon E-112 nacelle (Enercon)

Figure 18.18. Mounting the generator of the Enercon E-112 using two cranes (Enercon)

Figure 18.19. Mounting the rotor blades at the Enercon E-112 (rotor diameter 112 m, tower height 120 m, rated power 4.5 MW) (Enercon)

The erection method used for the prototype of the E-112 turbine approaches the limits of what is technically feasible and especially the limits of what is economically justifiable. This applies both to the availability of suitable hoisting gear and to the time taken for the erection, taking into consideration also the weather conditions. It remains to be seen whether today's standard technical design and the resultant erection method can be an economic alternative to the turbines of two or three megawatts for the future wind turbines of the power range of the E-112.

18.5 Grid Connection

The public grids of most countries are operated with three-phase current at a frequency of 50 Hz (Europe) or 60 Hz (US). It is arranged in three voltage levels:

- High-voltage, e. g.: 380 kV, 220 kV, 110 kV,
- Medium-voltage: 30 kV, 20 kV, 10 kV,
- Low-voltage: 400 V.

The low-loss transportation of large amounts of electric energy at the *high-voltage and extra-high-voltage level* is carried out in Europe by interconnected grid, intended to be fed by large, centralised power stations. Large wind farm projects with more than 10 to 15 MW power must normally be connected to the high-voltage grid (110 kV). In some rare cases, connection to the extra-high-voltage system (380 kV) will also be necessary. Connection to the high-voltage system means in many cases that the wind farm will require a new transformer substation.

Starting from the higher high-voltage level, the *medium-voltage* grid handles the regional distribution of the electric energy. Commonly, its voltage level is 20 kV. Grid density and transmission capacity decrease from conurbations to rural areas which is why the branches of the medium-voltage grid in the regions of the North Sea and Baltic Sea coasts with the most wind are frequently not designed for taking large power volumes from decentralised power stations. Nevertheless, the medium-voltage grid was initially the most important voltage level with regard to the use of wind energy.

The local *low-voltage* or *urban grids* supply households and other small consumers such as trade buildings, farms etc. Only relatively small wind turbines with a power of up to approximately 100 kW and in some exceptional cases a little above this value can be connected to the low-voltage grid. Connecting relatively small wind turbines to the low-voltage grid, occasionally called "house service", is especially simple and inexpensive.

The technical equipment and with it the cost of the grid connection are determined by four factors:

- Distance of the wind turbine from the grid,
- Voltage and transmission capacity of the grid,
- Power control and electrical equipment of the wind turbine,
- Technical requirements of the utility for power stations operated in parallel with the grid (Chapt. 9.2).

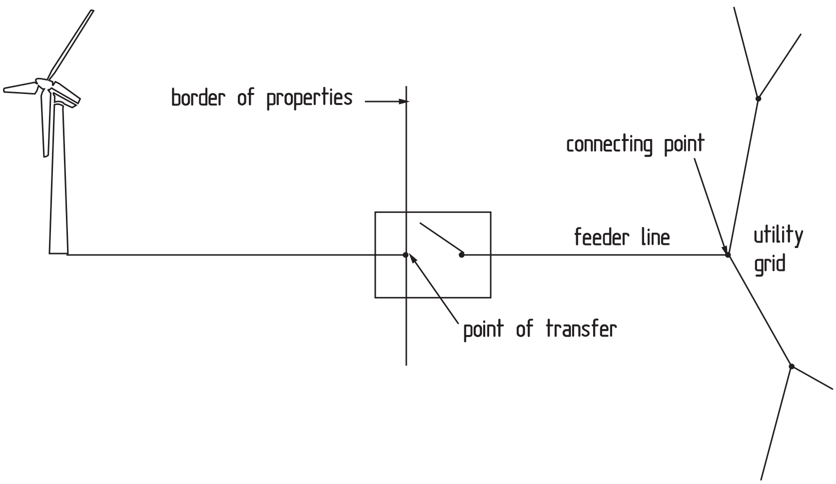

Figure 18.20. Scheme for connecting wind turbines to the public grid

The choice of grid connecting point is determined not only by the site and the power of the wind turbine but also to a considerable extent by the state of the grid and the power system perturbation caused by the wind turbine. The distance to a suitable connecting point at which these perturbations can be handled by the system may increase with their severity.

Before going into detail about these factors, a more precise definition of the position of the turbine in relation to the public utility is of use (Fig. 18.20). In this context, several terms must be clarified:

Connecting point C

The connecting point C is defined as the point in the public utility grid at which power is fed in (Fig. 18.21).

Figure 18.21. Grid connection to a 20 kV medium-voltage grid with mast-mounted circuit breakers

Point of transfer T

The point where the extended utility grid begins and with it the responsibility of the utility company. The point of transfer is marked by a prescribed isolating point which must be accessible to the utility at any time. In Germany, for example, all facilities between the point of transfer (property boundary) and the connecting point become the property of the utility. As a rule, the operator must bear all costs up to the connecting point in the form of a non-repayable contribution to building costs. This regulation is disputed in some cases but it is common practice.

The technical implementation of the point of transfer and of the connecting point is relatively simple and does not differ from the facilities also used by other small power stations of comparable power output. The electrical industry provides so-called kiosk substations or "head stations" as transfer point. The switchgear and, if necessary, the (690 V/20 kV) transformer are accommodated in a compact weathertight housing which also contains the necessary monitoring instruments (Fig. 18.22).

With this legal situation as background, a number of technical criteria must be observed when connecting a turbine to the public grid. The resultant consequences and the

Figure 18.22. Transformer and medium-voltage switchgear in a "compact substation"

responsibility for the ensuing costs lie partly with the operator of the wind turbine and partly with the public utility, depending on the spheres of responsibility and the property boundaries of each individual case. It is obvious that there can be a not inconsiderable potential for conflict with the utility in this situation.

Transmission capacity

Apart from the possible effects on the grid caused by wind turbines, the primary requirement to be met is that the equipment (power lines, transformers, switches etc.) used for transferring the generated energy must not be overloaded thermally. A common underground cable with 150 mm² aluminium conductors can transport the following approximate powers:

- Low voltage: ca. 200 kW
- 20 kV medium voltage: ca. 10 MW
- 110 kV high voltage: ca. 150 MW

Apart from this requirement, it is desirable to keep the power losses (line losses) in the cables to a minimum. For example, given an acceptable voltage loss of 5 % (the power loss then also amounts to 5 %), the following so-called "power lengths" are obtained for a feeder from the wind turbine to the grid connecting point, with the above-mentioned 150 mm² aluminium cables:

- Low-voltage grid: 34 kW km
- 20 kV medium-voltage grid: 85 MW km

Accordingly, a 150 kW turbine connected at low voltage should not be farther than approximately 230 m when the above cable is used. The connecting distance of an 8-MW wind farm at medium voltage level should accordingly be restricted to about 10 km. If the transmission capacity is low, or if the conduction losses of the cable are too high, several power lines can be run in parallel but this will increase cable costs.

Short-circuit power

The *short-circuit power* of a grid indicates the degree to which it can compensate for interfering current impulses. An increase in the short-circuit power at the point of connection leads to a corresponding drop in the grid impedance so that the interfering currents emitted will generate only slight voltage variations. Hence, a wind turbine's perturbations of the grid will decrease with higher short-circuit power at the connecting point. On the other hand, the short-circuit power in the grid decreases with increasing distance from the next higher voltage level, i. e. the transformer substation.

Voltage fluctuations

Feeding power into the grid, which takes place in the opposite direction to the normal flow of energy from decentralised power stations, leads to an increased operating voltage at the point of grid connection. The control parameters of the controlled bus bars in the medium-voltage grid must be matched to the non-steady operating and performance characteristics of wind turbines to such an extent that the voltage fluctuations can be compensated for. In certain situations, this can cause problems like, e. g. *flicker,* which is perceptible to the human eye in the electric lighting (Chapt. 9.3.2). In particular, the high inrush currents which occur with synchronisation of the wind turbine to the grid, especially with induction generators directly coupled to the grid, must be taken into consideration. Today's induction generators in wind turbines are, therefore, equipped with a thyristor-controlled "soft" grid synchronisation system (Chapt. 9.3.2).

Harmonic frequencies

Some years ago, the harmonic frequencies caused by wind turbines were the subject of heated discussions with the grid operators. Due to the non-sinusoidal currents of the inverter, variable-speed turbines with frequency converters generate harmonics in the grid. The earlier 6-pulse inverters especially, although not state-of-the-art today, have a high proportion of harmonics. More recent 12-pulse inverters provide a much smoother sine-wave voltage. As a result of recent developments in power electronics, for example pulse-width modulated inverters, quasi-sinusoidal currents can also be generated by variable-speed generators (Chapt. 9.5.1).

Reactive power

Importing reactive power from the grid, required to a certain extent for technical reasons, represents an undesirable effect on the grid from the point of view of the grid operator (s. Chapt. 9.2). The turbine operator must, therefore, pay for this, a fact which, in severe cases, can present quite an economic handicap for the operation of a wind turbine. The technical requirements of connection to the grid usually demand a compensation for the reactive power requirement for a $\cos\varphi$ of 0.9 capacitive and 0.8 inductive. This is achieved by wind turbines with induction generators directly coupled to the grid and equipped with progressive static reactive power compensation, which can be adapted to one or several operating points.

Nowadays possible impacts of the electrical properties of a wind turbine on the grid are evaluated by a *grid compatibility test.* At least in Germany, this test has been common practice for a number of years. It is carried out as part of the certification procedures for new wind turbines [3]. In addition to the effects mentioned above, the quality of the power output of the turbine is assessed. Power peaks, as instantaneous values (averaged over approximately 8 grid periods) and mean values over one and ten minutes are measured. Among other things, the flicker effect is evaluated which can be caused by cyclic power dips and corresponding voltage fluctuations, e. g. due to tower dam or tower shadow effects.

For a general assessment of the perturbations caused in the grid it should be taken into consideration that the grid's insensitivity to perturbing effects, i. e. the short-circuit power and the transmission capacity, can be enhanced by the utility by introducing appropriate reinforcements at the respective voltage level. Investments are continuously required for replacement and extension in any case so that public grid is permanently in a state of change. In Germany, for example, the medium-voltage power system is to be completely converted to 20-kV underground cabling in the long term. It is up to the utilities to include distributed power generating plants in such planning. The German Renewable Energies Law (EEG — Erneuerbare-Energien-Gesetz) obliges the grid operators in principle to further extend the grids in favour of the infeeding of energy from renewable energy sources. This would considerably improve the preconditions for parallel wind turbine operation on the medium-voltage grid, particularly for regions with a weak infrastructure but with a lot of wind. The present grid situation should, therefore, not be considered as being absolutely unchangeable.

On the other hand, wind turbines, too, are becoming increasingly more grid compatible. With each new turbine generation, controllability with respect to power infeeding and maintaining certain parameters specified by the grid is becoming better.

18.6 Commissioning

Like all complex technical installations, wind turbines must be "commissioned" before they can be handed over to the operator. In the context of this discussion, commissioning is the period from when the turbine has been installed to when it is handed over to become the operator's exclusive responsibility. It thus goes beyond the actual technical process of taking the units into operation The procedure is not without its problems from the legal point of view, either. To avoid later disputes, it is of importance to clearly define the individual phases and the associated results.

18.6.1 Commercial Wind Turbines

The commissioning of wind turbines, which usually forms part of the handover of a wind farm to the operator, is a relatively long process requiring close co-operation between the manufacturer and the operator. The details of the procedure involved and of the criteria to be applied are in most cases regulated by a "General Work Contract" for the installation of the wind farm. The purchase contract for the wind turbines itself usually does not contain adequate regulations in this respect. An operator who is building a wind farm by himself would be well advised to negotiate corresponding additional agreements with the supplier of his turbines, in addition to his purchase contract. The commissioning process generally includes a number of separate phases.

Functional check

Checking the assembly and activating the electrical and hydraulic units and the electronics systems after the wind turbine has been erected is entirely the manufacturer's responsibility. Test reports of the checks made are produced and handed to the operator. After a successful conclusion of these tests, the installation is released for operation by the manufacturer. The operator should be notified in writing of the beginning of trial operations.

Test operation

It is customary and useful to agree a test operation of the turbines with the manufacturer. To date there are no binding rules regarding the duration of such an operation and the associated success criteria to be applied. Usually, a period of, for example, 250 hours (corresponding to about 10 days) is agreed. The criterion for success consists in that, in this period, the turbine not be unavailable for more than, for example, 6 to 7 hours for technical reasons residing in the turbine itself, or, in accordance with the contractually defined technical availability, achieve a minimum availability value of, for example, 95 %. It is in the operator's own interest to check that the trial operation is successful so that this phase already requires the involvement of the operator with regard to the evaluation of the operating data.

Independent technical assessment

It is common wisdom, and in the operator's or, more precisely, the buyer's own interest, to obtain an independent assessment of the technical status of the turbine before it is handed over. Faults in the assembly or defects in the turbine, for example any corrosion which may already have begun, can result in damage and thus expenses even after the warranty period has elapsed. For this reason, the operators ask recognised technical experts to assess the constructional condition of the wind turbines on behalf of the buyer. This can be a somewhat time-consuming procedure in the case of large wind farms since every individual turbine must be inspected and assessed in detail. As a rule, this results in a so-called "List of Defects" containing all complaints still to be rectified by the manufacturer.

Acceptance and handover

After the trial operation and the technical assessments by an independent expert, the "Acceptance" is agreed by the operator. The prerequisite for this is that the trial operation has been successful and that it is found that the wind turbine no longer has any "significant" defects. All facts relevant to operational reliability and safety and to the power generation are considered to be "significant". Appropriate deadlines are agreed for eliminating the remaining defects in the list. Once the signature is at the bottom of the acceptance report, the wind turbine becomes the property of the operator (buyer). From the legal point of view, this means "Passage of Title" or, in other words "Transfer of Benefits and Burdens". This handover to the operator is followed by the warranty period and regular operation under the responsibility of the operator.

18.6.2
Experimental Turbines and Prototypes

The commissioning of a prototype or of a large experimental turbine is quite a different task from that of a commercial project based on previously developed and proven, series-production units. Commissioning here includes not only the testing of the turbine's basic functions but also the measuring of its detailed operational characteristics and performance data. Thus, the commissioning procedure evolves into a longer operating phase which can only be carried out in several stages. In the first stage, efforts will be made to check component functions as extensively as possible with the turbine at standstill. After this general "check-out" of the mechanical and electrical equipment, the wind turbine's anemometer will be checked and, if necessary, calibrated. This provides the basis for testing the operational sequence of the yaw control system. The operation of the mechanical rotor brake and of the blade pitch mechanism can also be checked with the rotor at standstill.

In the second phase, the operational characteristics of the running wind turbine without being connected to the grid will be checked. Rotor speed will then be increased incrementally and the rotor's speed control will be tested. Rotor start-up and shut-down can also be tested. The emergency shut-down of the rotor by fast pitching of the rotor blades, or with the aid of the aerodynamic brakes, will initially be triggered by hand and will subsequently be left to the automatic safety system.

The last phase of commissioning begins by synchronising the generator to the grid. When this function is satisfactory even during a gusty wind regime, operation under load can be started. Power will be increased incrementally up to the rated power and operation is then extended up to maximum operating wind speed. At this early stage of loaded operation, extensive reliance will already be placed on the automatic systems especially since, in any case, power control only works with the automatic systems. In this phase, the rotor emergency stop must be verified at maximum power and higher wind speeds. Some points on the power curve will also be measured as far as possible within the available time.

Table 18.23. Agreed acceptance tests of the MOD-2 wind turbines for delivery to the Bonneville Power Administration in the US

Required tests	Number of tests
Start-up sequences and shut-down sequences	
at low v_W (6.3 – 8.9 m/s)	5
at medium v_W (8.9 – 17.0 m/s)	4
at high v_W (17.0 – 19.7 m/s)	2
at any v_W	4
Emergency shut-down	2
Operation	
$v_W = 6.3 – 8.9$ m/s, min. of 2 hrs	2
$v_W = 8.9 – 17.0$ m/s, min. of 1 hrs	2
$v_W = 17.0 – 19.7$ m/s, min. of 30 minutes	2
$v_W =$ any, min. of 10 minutes	9
Remote operation	
8. test by the Dittmer remote control station	1
Power curve $P = f(v_W)$	1
100-hr. run	1
General demonstration of operation and control	4

Generally, a prototype will be commissioned during the development of a new type of turbine under the responsibility of the manufacturer alone. In the case of very large turbines, however, it may be necessary to hand over immediately to an operator. In addition, the certifying organisations and the licensing authorities are involved. Table 18.23 shows the acceptance tests agreed for the delivery of the experimental MOD-2 turbines to the Bonneville Power Administration in the United States.

18.7 Operation and Monitoring

All wind turbines are designed for automatic operation. It is a "must" for commercial applications. With a power output of a few megawatts at the most, labour costs for permanent operating staff would be economically prohibitive. Although a certain amount of operator intervention is still required, e. g. for the commissioning, for monitoring and for maintenance purposes, the automatic monitoring systems are of special importance with respect to operational reliability because the wind turbines are normally being run without operating personnel.

18.7.1 Monitoring of Operation and Performance

Wind turbines are equipped with a control and monitoring unit with operating keys and a small display screen which is normally mounted in the tower base and is easily accessible (Fig. 18.24). This information and operating panel is primarily used by the maintenance

Figure 18.24. Monitoring display of a commercial wind turbine (Vestas)

personnel for the acquisition of data characterising the instantaneous operating status, and for the retrieval of measurement values about the status of the most important units. In addition, certain operations required for maintenance can be performed "manually". In principle, this information can also be accessed by the operator. However, numerous internal data concerning the technical state of the of the units and error messages are encrypted so that only limited information is available to the operator.

Usually, the information from the monitoring units of the individual wind turbines can be sent to any other location using a telephone modem so that *remote monitoring* of the wind turbines is possible. In the case of wind farms containing a number of turbines, the data must be combined and transmitted serially. They can then be interrogated individually by the remote monitoring station. Certain operations can also be performed from these stations. Thus it is possible, for example, to isolate the turbines from the grid and to start them again. This type of remote monitoring is standard practice today with all modern wind turbines. The corresponding software package is included in the turbine delivery. In the case of large wind farms, higher-level operating data are now often also being fed into the Internet and can be retrieved from there.

The technical monitoring requires an appropriate data acquisition system in the turbine and, if possible, also the acquisition of data from the environment, for example wind and weather information from an external anemometer station or the acquisition of certain parameters from the grid. In the wind turbine, the required measurement data are acquired from sensors on the mechanical and electrical components (Fig. 18.25).

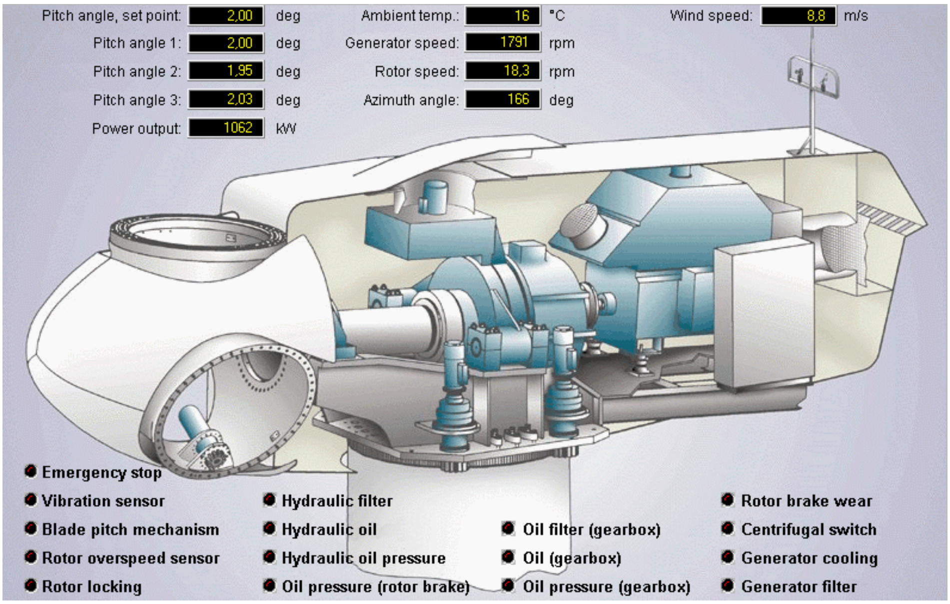

Figure 18.25. Data acquisition in the nacelle of a GE-1.5S turbine for monitoring its mechanical components (GE-Wind)

The electrical data and information about the operating state are taken from the data flow from the control system. Naturally, this data acquisition system must not interact with the control system if there is an error in the monitoring system. The data are stored over relatively long periods and can be evaluated from the most varied aspects and edited in table form or graphics. Depending on the degree of user friendliness of the software, this information can be retrieved directly on the turbine or on-line by remote monitoring, or it will have to be stored on a data medium and evaluated by using special computer programs. The turbine monitoring system commonly has a menu-structure with different levels and options. Besides the wind turbine identification data and general operational information, the main menu shows, for example, the following parameters on the display (Fig. 18.26):

- Wind velocity
- Electric power output
- Generator revolutions
- Rotor speed
- Pitch angle
- Voltage
- Frequency
- Current intensity

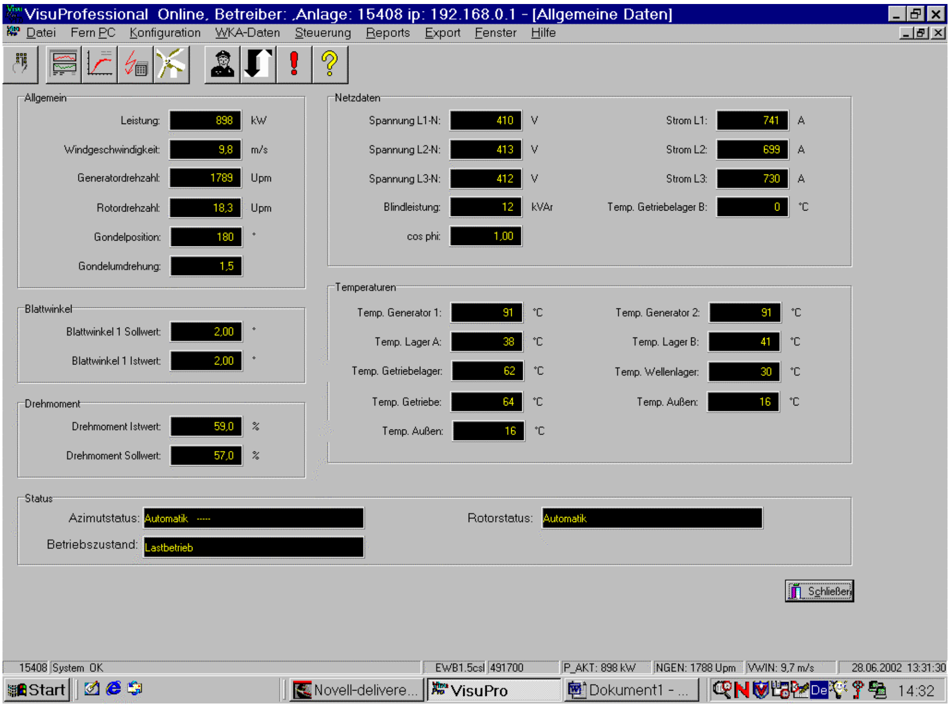

Figure 18.26. Main remote monitoring menu of a GE-1.5S turbine (GE-Wind)

Below this level there is a level of sub-menu options, for example referring to the complete wind and weather data or to a more detailed overview of the electrical parameters such as cos φ, current and voltage for all three phases etc.

Apart from this instantaneous information relating to the operating conditions, the monitoring parameters provide the possibility of calling up and/or printing out long-term data evaluations in a statistical or graphical form, for example power and availability statistics of the current operating year, or also as a "short-time graph" of the variation of wind speed, rotor speed and electrical power over the period of some minutes (Fig. 18.27).

The software also provides for a statistical analysis of the electrical output power in dependence on wind velocity over a relatively long period. However, the "power curve" thus generated must be treated with caution. In most cases, the wind velocity used as a basis in this case is not correct. When the rotor is running, the wind speed measurement taken on the nacelle is incorrect and must be corrected in dependence on power in order to obtain the true, unaffected wind speed as a reference basis. These relationships should be accurately known before far-reaching conclusions are drawn from these "power statistics" (Chapt. 14.2.2).

For some time, *early fault detection* methods have been developed which use so called *condition monitoring systems* [4]. The aim is to be able to predict from certain criteria the occurrence of damage in order to avoid unexpected stand-stills. This is considered to be

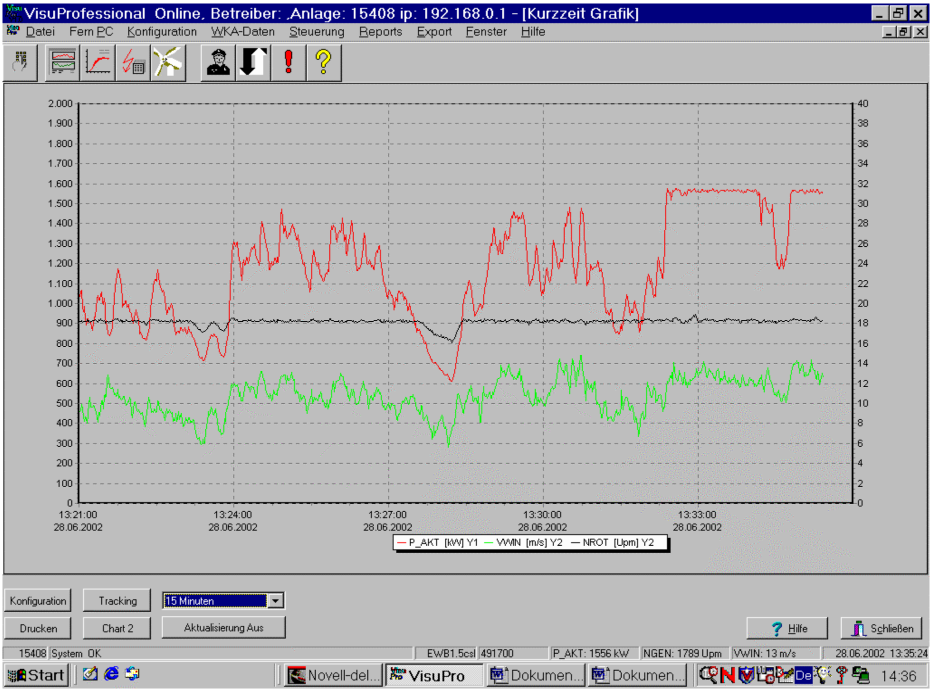

Figure 18.27. Short-time graph (15 minutes) of wind velocity, rotor speed and electrical power output of a TW-1.5S turbine (GE-Wind)

of importance particularly in relation to the offshore installation of wind turbines. These systems are based on the acquisition of certain characteristic properties of the components, for example their vibrational behaviour, the structural sound radiation or the analysis of the power output. The analysis of these data is intended to reveal damage which has already occurred (cracks or abnormal wear phenomena). These systems are particularly important for offshore wind turbines.

18.7.2 Monitoring of Large Wind Farms

Operating a larger wind farm with twenty wind turbines or more imposes additional requirements on the operational organisation, apart from the functioning of the individual turbines. If all turbines are operated in parallel with the grid, an overall monitoring system is actually not required. Just like a stand-alone wind turbine, each individual turbine, with its autonomous control and monitoring system, is capable of automatically stepping through the entire operating cycle, involving all required operating conditions from standstill to emergency shut-down, without any overall control system. Economic reasons, however, suggest a central monitoring where there is a larger number of turbines involved. In a wind farm comprising fifty wind turbines, it is not rare to find that distances of up to ten kilometres must be overcome from the first to the last wind turbine due to the minimum distances between turbines required for aerodynamic reasons. A central monitoring system is extremely useful under such circumstances.

To monitor and control the operational sequence of large wind farms, special monitoring and data evaluation systems were developed which combine the data of the individual turbines in a suitable manner. This makes it possible to display the power characteristics of the entire wind farm, and also to exercise a type of higher-level sequence control. The aim is to optimise the power generation and energy delivery of the entire wind farm under various external boundary conditions, for example due to restrictions with regard to grid infeeding. The data are evaluated from the most varied aspects which also include industrial management aspects like, for example, the accounting for the electricity infeed with different tariffs at different times of the day. A software package tailored to these tasks has been on offer under the name of SCADA for more than ten years and is being used in numerous wind farms[5].

Large, older wind farms often still have a large visual monitoring board of the type provided in conventional power stations (Fig. 18.28). A large mimetic diagram represents the spatial arrangement of the wind farm. Visual indicators enable the operating state of the turbines to be assessed at one glance. This monitoring board is usually accommodated in an operating building together with other operational equipment and a minimum of comfort for the staff.

It is certain that the higher-level sequence control and management of large wind farms and possibly even the operational combination of all wind turbines in a particular region will gain greater importance in the future. As soon as the utility companies are ready to take into consideration the generation of power from wind energy in their application planning for the conventional power stations, higher-level sequence control will become

Figure 18.28. Central monitoring board of a wind farm inside the operations building (Mita)

indispensable (the so-called "virtual power station"). In Denmark, the first beginnings of this can be seen already in the area of the Elsam electricity supply undertaking.

On the other hand, the individual control systems of the wind turbines are becoming more and more "intelligent" so that the wind turbines themselves can respond to external events or states of the grid without any central control system (s. Chapt. 10.5.2)

18.8 Safety Aspects

The operation of a wind turbine is associated with safety aspects which are both general and turbine-related. The issue of safety must be seen from two different angles. For one, there is the problem of functional dependability of the wind turbine itself. For an unmanned system, this requirement is primarily a question of reliability and thus, ultimately, of economy. It is only during servicing and repair work that this has an immediate effect on humans. On the other hand, the question arises as to the extent to which a functional failure of the turbine will pose a threat to the surrounding area.

18.8.1 Structural Strength and Operational Safety

The first safety requirement must be that neither its structural strength nor its operational sequence will result in a wind turbine presenting safety risks which exceed the unavoidable minimum. This could be called the inherent technical reliability and is the manufacturer's responsibility. It is also one of the tasks of the independent certification process to guarantee that this minimum is not exceeded. The most important safety aspects are:

Structural strength of the rotor blades

Monitoring of component functions in the section of the mechanical-electrical drive train can be carried out relatively easily and reliably by means of the usual indicators, such as oil pressures and temperatures. These procedures are state-of-the-art for any complex technical system. It is much more difficult to monitor structural strength. In wind turbines, a possible structural failure of the rotor blades presents a special risk.

The frequently voiced fear that rotor blades will break when exposed to strong storms is quite unfounded in the case of wind turbines. Breaking loads at high wind speeds can be calculated highly accurately and are accordingly included in the load cases. However, rotor blades being hurled away or even toppling turbines are a real hazard in the case of small, non-professional wind turbines which are frequently built in do-it-yourself fashion without sufficient theoretical bases of calculation. On the other hand, it is extremely rare today that large modern wind turbines are destroyed by a storm. Rather, the danger lies in material fatigue as a consequence of the high dynamic loads experienced in operation.

Fatigue damage, for instance as a consequence of a local stress concentration or in combination with progressive corrosion, can never be entirely discounted in steel components. An undiscovered and progressive fatigue crack, for instance in the area of the metal connecting structure or of the rotor hub, involves the inherent danger of the rotor blades suddenly breaking off without the rotor emergency shut-down having had a chance to take effect.

To counter this danger the allowable stress level in the material is set so low that a "safe life" can be guaranteed (safe-life design) with regard to fatigue, taking into consideration the operational strength theories. Moreover, manufacturing quality, particularly with regard to the welding seams, is subjected to the strictest controls. Despite these quality control measures and tests during production, regular checks during operation are nevertheless indispensable.

Rotor blades made of composite fibre material prove to be less critical than steel components with regard to cracking. If a structural failure does occur in composite fibre material, the blades as a rule do not break off abruptly but rather "fray out". With rotor blades made of composite fibre material, the danger of a sudden breakage is, therefore, concentrated on the metal connecting structures and on the interface between the connecting flange and the fibre structure. Design and quality control during manufacture are, therefore, of special significance for the operating safety in this area.

Rotor stop

No other safety system determines the safety during operation of a wind turbine as much as its capability to bring the rotor to a stop within the shortest period of time, with the greatest possible reliability and under all conceivable circumstances. It is true that, on the one hand, rotor runaway represents a specific safety hazard to a wind turbine, but on the other hand, fast braking of the rotor provides an additional safety factor which can compensate for numerous other risks (fail-safe design).

A system's ability to shut-down immediately is by no means a matter of course, particularly in energy generation systems. Thermal power stations, for instance, cannot be switched off by the "push of a button" when a fault occurs. In a wind turbine, really catastrophic consequences of a defect can only occur if the rotor emergency shut-down fails. The rotor braking system is, therefor, the dominating safety system of a wind turbine.

By pitching the rotor blades quickly towards feathered position, wind turbines with blade pitch control can brake the rotor aerodynamically and can bring it to a standstill within only a few seconds. Blade pitching must start immediately with a high pitching rate to prevent rotor overspeed. When the electric generator loses synchronisation, the entire rotor power becomes available for accelerating the rotor. Without immediate "braking", the rotor speed would increase very rapidly and within seconds the rotor would be destroyed by the centrifugal forces. On the other hand, there are limits set to the pitching rate so that the bending moments developing at the blades during the aerodynamic braking do not become too great (Chapt. 6.3.3).

Rotors without blade pitch control are almost always equipped with aerodynamic brakes (Chapts. 5.3.2 and 10.4). These are usually triggered by a centrifugal switch at a certain rotor overspeed and are then deployed by a pre-tensioned spring (fail-safe design). More recent turbines also have hydraulically actuated, aerodynamic blade-tip brakes, which have the advantage of being retractable without manual intervention at the rotor blades. This is an operational advantage at sites with frequent grid outages necessitating rotor braking (Chapt. 7.7).

Ensuring the reliability of aerodynamic rotor braking requires redundant release mechanisms and, if economically justifiable, also redundant actuators and energy supply systems for the actuating elements (Chapt. 8.5.5). In addition to the aerodynamic brakes, small turbines can be stopped by using a mechanical brake. In large turbines, the mechanical brake between gearbox and generator is only designed to act as an arresting brake (Chapt. 8.7).

Vibrational instability

The vibrational behaviour of a wind turbine has been discussed extensively in Chapt. 11. The occurrence of resonances in the rotor blades, in the tower or in the entire turbine must, therefore, be counted among the specific safety risks. The monitoring system, therefore, contains a special vibration detection system. It consists of several accelerometers which are mounted at critical locations in the wind turbine.

In smaller wind turbines, simple mechanical vibration detectors are frequently used. They consist of a steel ball which is connected to a switch via a chain and which rests in a shallow depression or bore hole. When strong vibrations develop the ball is shaken out of its position and its fall triggers the rotor braking system. Larger wind turbines have more complex, electronic vibration detection systems. The signals from different sensors such as strain gauges and accelerometers are evaluated by a processor and the safety system is activated whenever preset threshold values are exceeded.

Safety of electrical equipment

A wind turbine generates electrical power at a voltage level similar to that of a power station. The safety regulations provided for this technology must, therefore, be strictly adhered to. Where national codes are not used, the IEC publications are to be taken as a basis. The relevant regulations prescribe in detail the safety measures to be included in the design and which regulations are to be observed by the operating or maintenance personnel. With regard to the electrical safety measures, small turbines generating power at the low-voltage level are less complex than large turbines where the electrical systems operate in the medium-voltage range.

18.8.2 Environmental Effects

Apart from any turbine-related technical safety aspects, external effects can result in safety risks. These are primarily meteorological phenomena but can also include effects caused by the "technical environment" (e. g. air traffic) since wind turbines are "buildings" which protrude above the skyline of the rest of the buildings.

Lightning stroke

A reliable protection against lightning is an important feature for a wind turbine (Fig. 18.29). In level terrain, high, slender structures perfectly attract lightning strikes. The lightning

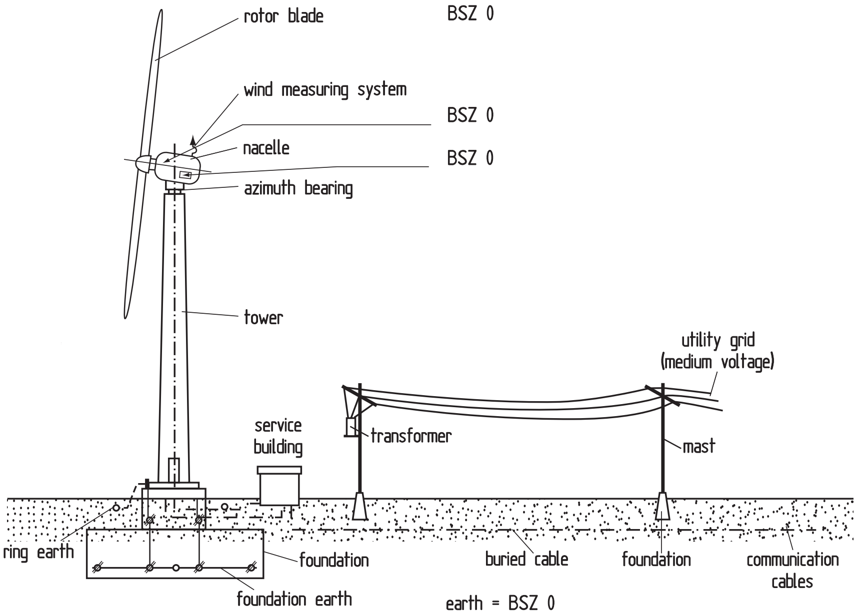

Figure 18.29. Lightning protection system and earthing of a wind turbine [6]

protection system must protect the mechanical components from damage as well as ensure that the electrical and electronic components are not destroyed or subjected to excessive voltage.

The components primarily affected by a lightning strike are the rotor blades. If the blades or their spars are made of steel, they will form an ideal lightning conductor and do not need any further lightning protection devices. In the past, rotor blades made of glass fibre material were manufactured without providing special lightning protection components. However, with the increasing use of wind turbines the number of cases of damage due to lightning strikes rose steeply. The frequency of such cases has assumed a prominent place in insurance statistics, creating economic pressure to limit this type of damage. More recent rotor blades thus have special lightning protection equipment (Chapt. 7.8). It consists of, among other things, "lightning arresters" (copper brushes and flexible copper strips) at the critical interfaces where they discharge the lightning into the earthing system of the foundations (Chapt. 9.7).

Icing

One environmental effect which can also lead to impairment of the operational safety is ice accretion on the rotor blades under certain weather conditions. The danger of icing is greatest at temperatures around freezing and high humidity at the same time. The frequency of such conditions depends greatly on the location of the site. Apart from the fact that, naturally, this affects only Northern countries, it can be said that such weather conditions occur more rarely at the coastal sites than those in the low mountain ranges further inland. Measures against ice accretion on wind turbines have hitherto been taken only very rarely but the problem is being taken more seriously as the turbines are spreading.

Ice can form on all parts of a wind turbine. It is a particular nuisance at ventilation inlets and other openings and at the anemometer (Fig. 18.30). In most cases, the anemometer system on the nacelle roof is the first one to be taken out of action unless icing is prevented by heating. This type of icing can critically affect the operability of the system, especially if the system has been out of action for some time and is to be started again.

One disadvantageous consequence of the formation of ice on the rotor blades is that this will considerably worsen the aerodynamic airfoil characteristics. The risk of icing is much greater when the rotor is turning than when it is standing still. The typical ice accretion at the leading edge of the airfoil reduces the generation of lift and increases drag (Fig. 18.31 and 18.32). The result is a deteriorating power curve which, in turn, can considerably reduce the energy output. Up to 30 % of the annual energy delivery can thus be lost at sites with a particularly high risk of icing [7].

Fears that ice accretion on the rotor blades will lead to an unacceptable load on the blades or on the entire wind turbine are unfounded. The deformation of the rotor blade airfoil due to ice deposits degrades its aerodynamic properties to such an extent that rotor performance is reduced and with it the aerodynamic loads [7].

The potential danger of ice accretion lies in fact that lumps of ice of considerable weight can be hurled away by the rotating rotor over distances of several hundred meters. Investigations of the ranges of lumps of ice hurled away have arrived at the recommendation that the safety distance should be 1.5 times the sum of tower height and rotor diameter [7].

Figure 18.30. Icing of the anemometer on the nacelle roof (photo: Seifert)

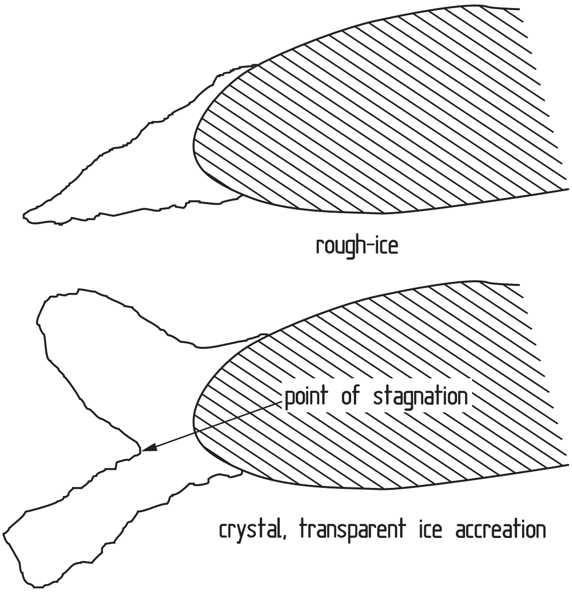

Figure 18.31. Ice accretion on the leading edge of a rotor blade

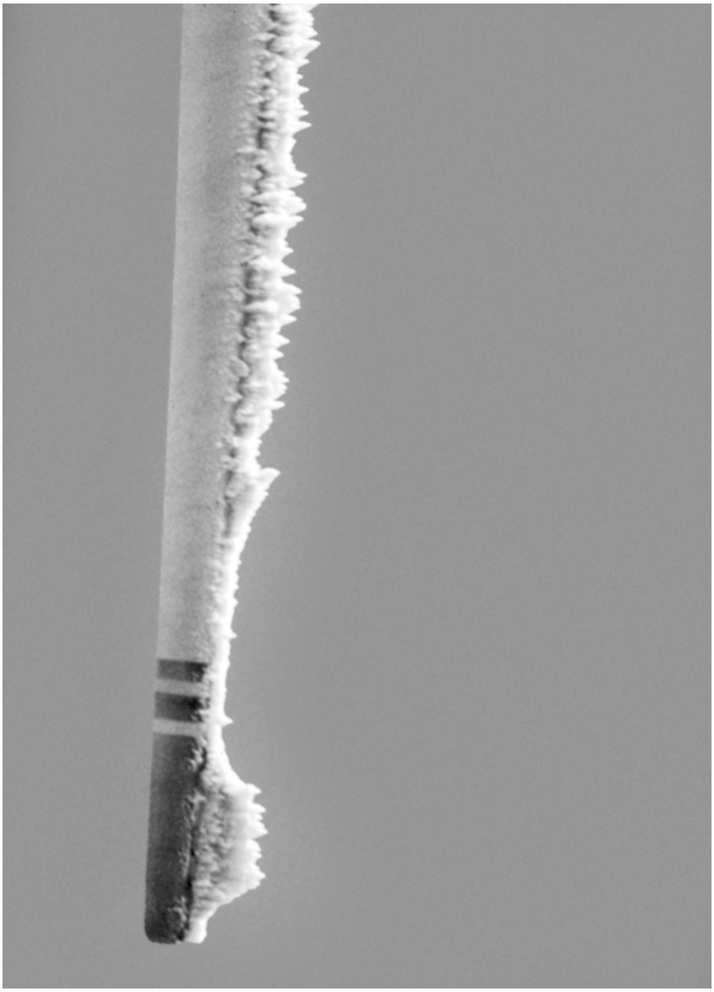

Figure 18.32. Ice accretion on a rotor blade (photo: Seifert)

The protective measures against the hazard of flying chunks of ice simply consist of an ice warning system which automatically switches off the turbine if ice accretion is to be expected due to the prevailing weather conditions. Such systems are being offered by the turbine manufacturers as supplementary equipment. De-icing systems on the rotor blades would be much more expensive but are available from some rotor blade manufacturers as an optional extra (Chapt. 7.9).

An idea of the practical value of de-icing systems can be gained from an investigation according to which rotor blade de-icing at a site at which one third of the total annual energy output would be lost due to icing consumes only 3 % of the annual energy output [7].

Air traffic

Large turbines, like all large buildings projecting above the skyline of their surroundings, require warning markers for air traffic. The relevant regulations are passed by the appropriate national aviation authorities. In Germany, for example, this is the Ministry for Traffic and Civil Engineering. According to the latest status, the following measures are required:

The so-called *daytime marking* consists of a coat of red warning paint on the outer sections of the rotor. This is specified outside of towns and densely settled regions when the height of the building exceeds 100 m above the ground level. The marking consists of two stripes of red paint, one at the tip of the rotor blade and a second one closer in (Fig. 18.33). For a time, the authorities allowed the installation of a "flashing white rotating-lens beacon" on the roof of the nacelle which is why some turbines do not have red markings on the rotor blade tips.

Night-time marking is not so easy to implement. It would be necessary to illuminate the highest points of the wind turbine, i. e. the rotor blade tips. For one, this represents a technical difficulty as common light bulbs cannot easily withstand the high centrifugal forces acting on the rotating blade tips. Moreover, the visual effect at night would certainly not be uncontroversial. Rotating circles of light in the night sky would not meet with undivided approval in the long run. The hazard-warning lights used for night-time marking are generally either "red flashing omnidirectional beacons" or also rotating "flashing lights" (Fig. 18.34). For the reasons mentioned above, special procedural regulations have been

Figure 18.33. Daytime markings on the rotor blades of a Dewind D-6 turbine

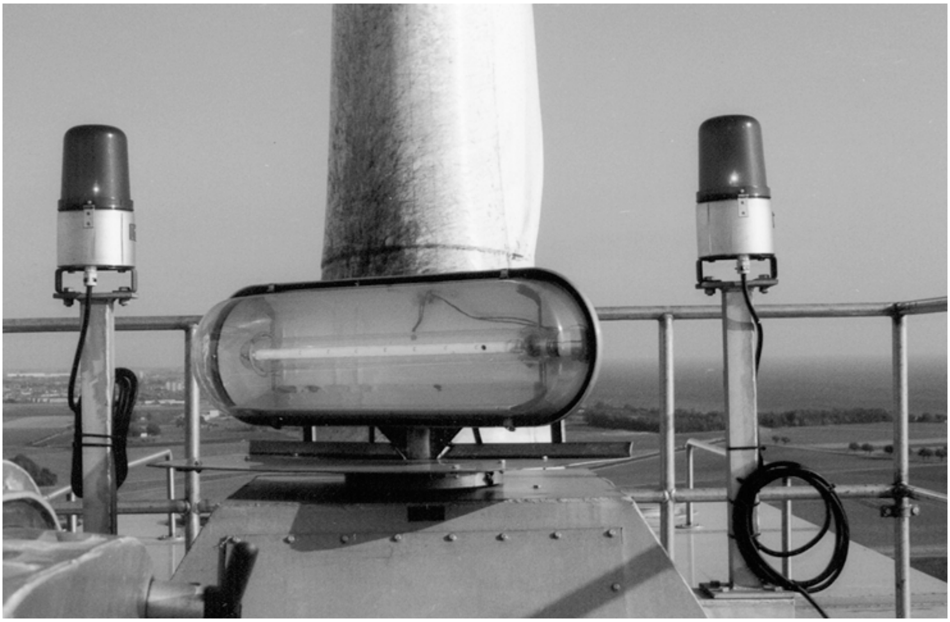

Figure 18.34. Safety lights (night-time markers) on the WTS-3 in Maglarp with omnidirectional beacons or also rotating flashing lights (Sweden)

issued for wind turbines. These specify that hazard-warning lights are only required on the nacelle roof. It is only when the rotor blade tip projects past a maximum height of 150 m that day-time marking in the form of the red/orange markers on the blade tips is required.

18.9 Maintenance and Repair

Just like any other technical system, wind turbines must be serviced regularly and, in the case of defects, repaired. In wind turbines the conventional components of mechanical-electrical energy conversion such as shafts, bearings, gears and generator require maintenance similar to that with other technical systems. The type and interval of maintenance work required should be contained in the turbine manual. The general question is whether wind turbines require an extraordinary level of maintenance or whether they are often in need of repair. There are two reasons why this could be so:

The ambient conditions of a wind turbine are unusually tough. Not only are wind turbines exposed to "wind and weather" over a service life of at least 20 years, but their preferred sites close to the coast where the air is salty also provide ideal conditions for corrosion on all metal components. A further reason is the comparatively high number of operating hours achieved by a wind turbine over the period of its service life. The effective operating period of a wind turbine at a good site is about 5000 hours annually, corresponding to a full-load operating time of 2500 hours. This amounts to 100 000 hours running time over the turbine's design life of 20 years. By comparison, a motor car travelling an assumed 20 000 km annually at an average speed of 80 km/h will achieve just 5000 operating hours.

The extremely high dynamic loading on the components is of special significance. The load fluctuations by themselves already lead to high cyclic loads on the components. Combined with the high number of operating hours, load alternations of an order of magnitude of 10^7 to 10^8 are obtained over the service life of the turbine (Chapt. 6.2.3 and 6.4). Material fatigue, therefore, requires special attention and there is also corrosion to be dealt with. For many materials, there are no verified empirical values available about the fatigue strength with 10^7 to 10^8 load alternations.

However, it would be wrong to conclude from these conditions that the requirements for servicing and maintenance are particularly high. Experience has shown that it is possible, nevertheless, to operate wind turbines with an economically justifiable amount of servicing and maintenance. This statement can be verified with statistical data for a period of almost 20 years. Naturally, there are fewer reliable data available for the second half of the economic life of a turbine.

The precondition for achieving economically supportable maintenance and repair expenditure is that the aggravated environmental and operating conditions be considered carefully in the design and the selection of materials . For example, corrosion is much more a problem of product quality than of the more or less severe conditions on-site. This has been proven by the experience gained with other technical products, for instance automobiles. The design and construction of a technical system must allow for the aggravated ambient and operating conditions to such an extent that the work required for maintenance remains within economically justifiable limits.

Thus, the maintenance work required is primarily a problem of investment cost. In the case of wind turbines, increased manufacturing costs for the benefit of a construction with lower-maintenance will be the more economical solution, as repairs are comparatively expensive due to the complex on-site servicing work requiring heavy transportation and lifting equipment. This situation will change only if wind turbines can be produced with much lower cost in the future. In conditions such as these, "expendable structures" could be more economical but such a development looks unlikely at the present time, particularly for energy generating equipment intended for a long service life.

At present, all efforts are aimed at designs which are increasingly more maintenance-free. The impending commercial offshore use of wind turbines, in particular, requires an extension of maintenance intervals for economic reasons (Chapt. 17). In addition, there are still problems with the service life of certain components (gearboxes, bearings etc.) so that further design improvements are still required, the aim being that all components achieve a continuous service life of at least 20 years.

18.9.1 Routine Maintenance

Apart from a low-maintenance design, the second basic prerequisite for minimising the repair costs and for achieving a high degree of availability is a regular check and the associated performance of prescribed routine maintenance work. Wind turbines are no exception in comparison with other complex technical systems.

The manufacturer's manuals contain descriptions of the components and of the procedures for the checks to be carried out at fixed intervals. These details are only of interest to the operator if he wants his own personnel to perform the maintenance work, something which, to date, is done in only a few exceptional cases. As a rule, the basic pattern of the routine maintenance consists of a half-yearly check of the important components and functions. Comprehensive inspections are provided for in cycles of one or two years. The routine maintenance covers the following areas:

- Checking the major components, e. g. visual inspection of the rotor blades. shafts, gearboxes, servomotors etc. and checking the most important flange joints (tightening torques of the screws)
- Oil change in gearbox and hydraulic components, half-yearly if required
- Operating tests (blade pitching mechanism, hydraulic pressure, emergency shut-down)

This work is billed at flat rates in the completed maintenance contract (Chapt. 20). Small repairs (e. g. up to $100) and small expendable parts are included in the flat rate. The appropriate details and additional costs accrued for travel by the technicians to and from the site etc. are regulated in the maintenance contract. The maintenance contract generally comes into force after the normal warranty period of two years has elapsed. The manufacturers will almost always tie an extension of the warranty period to e. g. 5 years to a demand for the conclusion of a long-term maintenance contract and frequently also to a higher purchase price for the turbines.

18.9.2
Causes of Damage and Repair Risks

A certain amount of technical defects and damage is unavoidable even with a high-quality construction and careful maintenance. In almost all cases, the operator will attempt to cover any resultant risks of repair costs by means of *mechanical-breakage insurance.* In practice, however, the repair costs will no always be handled by the insurance so that there will always be a certain risk incurred by the operator. Correctly estimating this risk, in association with the provision of corresponding reserves, is of fundamental importance to the economic viability of a wind farm project (Chapt. 20). Before discussing the available experience in relation to this complex of problems, some important terms and basic relationships between the causes of damage must be explained. In principle, damage occurring in operation on a technical system is attributable to two different causes:

- Wrong assessment of the loads acting on the system, inadequate dimensioning of the components or faulty interaction between the components in a complex system can lead to design-related excessive loading of the material in a component. Such a "systematic" fault will cause damage or a fracture in every individual device of a series of the same type of construction. The insurance companies call this *series-product damage.* They are not prepared to pay for the repair or the failure of a complete production series.
- The second cause of damage lies in the individual faults of a component with respect to the material used, the manufacture or also the assembly, something which can never be

avoided completely statistically. Such individual faults cannot be avoided one hundred percent, however careful the quality control and it is this type of damage which is covered by mechanical breakage insurance.

In practice, it is often not possible to distinguish between these two causes in an individual case so that the costs for the repair are not infrequently divided between insurer and operator in a compromise. During the warranty period, the manufacturer will pay, naturally. After the end of the warranty period, a certain risk of repair costs will remain with the operator for the above-mentioned reasons, even if he has taken out mechanical breakage insurance. If the damages are numerous and occur over a long period and are paid for by the insurance companies, their premiums will rise, thus lastly affecting the operator again.

In principle, the components and systems of a wind turbine are designed for a given minimum service life (safe-life design) which is at least twenty or thirty years. That is to say, the fatigue load spectra are specified, both with respect to the mean level and with respect to the number of load alternations for the dynamic load components, such that they cover the entire calculated service life. At the same time, the permissible material stresses are limited to this "endurance limit" which is synonymous with the "fatigue strength" in most materials. This design philosophy applies to all essential components with the exception of some small expendable parts such as transmission belts, filters etc.

For this reason, there is no mandatory requirement for "replacement investments" in wind turbines, a fact which is often misrepresented because practical experience teaches otherwise. On the other hand, it must be admitted that, regardless of the "safe-life" design, certain doubts are justified in the case of at least some components of a wind turbine. Comprehensive damage statistics have, therefore, been collected in recent years on behalf of the insurance industry and technical/scientific institutes have been commissioned to conduct investigations into the causes of damage [8]. In the investigations, the following main areas and causes of damage are identified:

- Rotor bearings
- Bearings and gearing in the gearbox
- Gear oil
- Clutch
- Roller bearings in generators
- Yaw drive
- Nacelle mounting
- Rotor blades
- Rotor shaft
- Electronics

It is pointed out that damage occurs most frequently in gearboxes, followed by roller bearings and generators. In some areas mainly wind turbines with stall control are affected. The most doubts are reported with regard to the safe-life design of gearing and roller bearings and it is pointed out that, given the current state of the art, it cannot be assumed that the full service life of a wind turbine will be achieved without having to replace components in these areas [7].

18.9.3
Background Experience and Long-Term Forecasting

Data on the causes of faults and repairs of wind turbines have been systematically collected and analysed since the beginning of the eighties. From the first ten years of wind energy utilisation, there are primarily analyses from Denmark and from the United States. In Germany, the operational results of a representative number of wind turbines have been collected since 1990 in a "Scientific Measuring and Evaluation Program" (WMEP — Wissenschaftliches Meß- und Evaluierungsprogamm) and evaluated from the most varied points of view [8]. It covers the causes and effects of faults and the reference to the components affected in the wind turbine (Fig. 18.35 and 18.36). Evaluation of the fault causes shows that, apart from the "system control" area, the "component defect", not specified in greater detail, causes about two thirds of all faults.

This evaluation highlights the operational reliability of wind turbines but does not provide any information about the actual repair risks. For example, malfunctions in the "electrical" and "control" area can often be eliminated by very simple measures and frequently even by the mere "push of a button". The real repair risk only becomes apparent on evaluation of the repair costs (Chapt. 19).

On this basis, some institutes produced in 1999 some long-term forecasts for the operating costs and, in particular, for the repair costs to be expected. In its survey, the German Wind-Energy Institute (DEWI — Deutsches Windenergie-Institut) suggests that 65 to 70 % of the mechanical parts by value must be replaced, i. e. exchanged or repaired within a service life of twenty years [10]. This value is generally considered to be too high since the prognosis was made in favour of the wind turbine operators during the discussion about

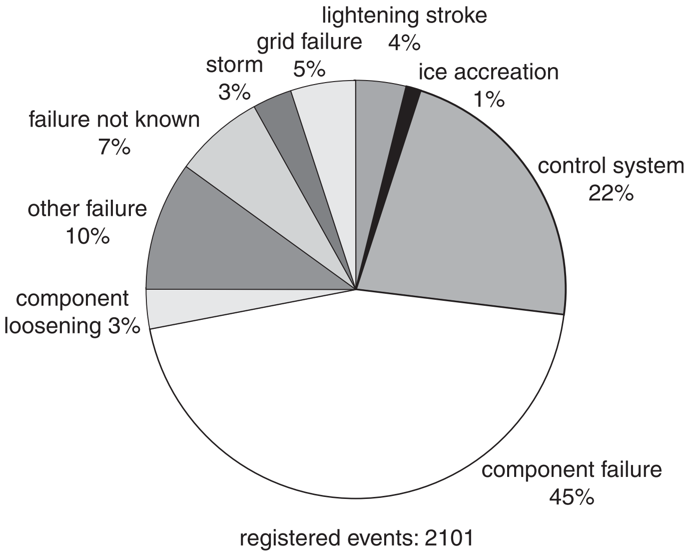

Figure 18.35. Frequency percentages of the fault causes, ISET (WMEP), 2001 [9]

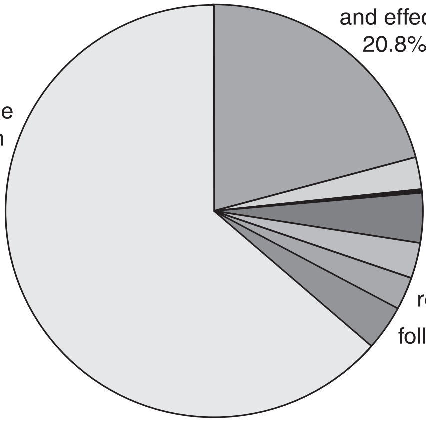

Figure 18.36. Frequency percentages of the fault effects [9]

payment for power before the Renewable Energies Law was passed. Other experts predict a requirement for replacement of "30 % of the machine costs" [11] after the tenth year of service.

Assuming, for instance, the rotor blades, the gearbox and the blade bearings have to be replaced after ten years, this will result in about 30 % of the machine costs. Calculating further repair expenditure of about one percent of the turbine costs per annum over the entire life of twenty years, this comes to a proportion of about 50 % by value of the turbine costs. This order of magnitude comes closer to reality and reflects the state of the art which has been achieved at present. It must be taken into consideration, however, that the existing stock of installed turbines also includes many older and smaller turbines. After what has been said before, the replacement of rotor blades, gearboxes and blade bearings is not at all mandatory and will become more and more improbable in future as the technology matures.

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Chapter 19

Wind Turbine Costs

The basis for all economic considerations regarding systems utilising solar energy is the manufacturing cost of the energy converters. The low density of the energy source requires large surface areas of the energy collectors which are thus expensive to produce. The central question is, therefore: whether the specific manufacturing costs are too high so that the generation of energy becomes uneconomical, despite the fuel savings? This fate is still shared by most regenerative energy generation systems.

At present, commercial, series-produced wind turbines are available in a power range of up to about 3000 kW. During the last fifteen years, enormous progress has been made towards lower production costs of wind turbines. The early large experimental wind turbines of the eighties were extremely expensive, individually manufactured prototypes, with the cost focus on the associated extensive research and development programs. The first series-produced, relatively small wind turbines installed in Denmark and at American wind farms shortly in the mid-eighties were produced for more than 5 000 $US per kW rated power. Today, series-produced commercial wind turbines are available for less than 1 000 $US per kW. This price level allows the economic use of wind energy even in the lower inland wind regimes.

One central problem with respect to future economics is the cost reduction potential of wind turbines which is still available. Expectations with regard to lowering the manufacturing costs are essentially based on two factors. On the one hand, the technical state of development achieved to date still offers some scope for more cost-effective solutions. This is true both for more sophisticated technical concepts and for design refinements on existing wind turbines. One main goal is to develop simpler and lighter structures and thus lastly also cheaper machines. The large wind turbines will certainly still make considerable progress in this regard.

The second decisive factor for lowering the manufacturing costs is, of course, the production of a greater number of units. Measured against today's costs, large wind turbines will again profit from this to a disproportionate amount. However, one should not harbour exaggerated hopes in this respect. Wind turbines will probably never come off the assembly line like automobiles. The achievable cost reduction potential will be restricted to runs of a few hundred units, or maybe a few thousand units per year in the case of small turbines.

Prices are not necessarily identical with costs. Naturally, this elementary economic rule also applies to wind turbines. Manufacturers consider the market situation when setting their sales prices so that their profit margins vary depending on time and location. The long-term stabilisation of the market is, therefore, of considerable importance in arriving at a reliable cost calculation, both for the manufacturing companies and for the users who will rediscover the "price ex factory" of the wind turbines as "costs" in their profitability calculation. The costs of the wind turbines themselves form the main component of the investment costs for turnkey projects for utilising wind energy. However, the other cost components must also not be underestimated. There are two main trends with regard to this aspect: On the one hand, the planning periods for large wind farms are increasing considerably, and with them the costs. On the other hand, the costs for the technical implementation of buildings and electrical infrastructure are tending to fall.

19.1 Specific Costs and Significant Reference Parameters

For systems of various size and power output, an analysis comparing manufacturing costs and sales prices can only be carried out with the aid of specific cost figures. Thus, one immediate question is: Which system parameter must the costs be referred to in order to provide an objective picture, which will not distort the comparison of competing systems?

Dealing with renewable energy systems requires a new approach also in this case. When comparing conventional energy generation systems, the rated power is used as the significant parameter for indicating the specific performance of a system as a matter of course. Indeed, manufacturing and operating costs as well as the energy yield of reactors, turbines and motors are primarily dependent on the rated power. Accordingly, "cost per kilowatt" is the appropriate parameter for assessing profitability.

The situation is different with renewable energy systems. These systems must first capture a "fuel" with an extremely low density, i. e. solar radiation or wind, before they can convert it into usable energy. To a certain extent, this is also true of the conventional renewable energy source of "water power", if the buildings for collecting and concentrating water, the reservoirs, are included. This means, however, that the costs are determined by the size of the "energy collector". The dimensions of the collector also determine the energy generation. A high rated power of the energy converter is only of benefit if the energy collector is capable of delivering the required volume of energy.

Thus, relating the manufacturing costs to the rated power of the energy converter says little about the economic potential of renewable energy systems and may even be misleading in some cases. Instead, the size of the energy collector is the decisive reference parameter. Therefore, a wind turbine is characterised by the rotor-swept area or the rotor diameter, respectively. This is primarily what determines the manufacturing costs and the energy yield. If meaningful specific costs are to be specified, they must be related to the dimensions of the rotor.

On the other hand, the manufacturing costs and the energy yield are not exclusively determined by the rotor diameter. The tower height and the installed generator power play a certain role (Chapt. 14.4). The tower height is necessarily correlated with the rotor diameter. In a first approximation, the influence of the tower height is therefore included when referring to the rotor diameter. If the installed power per rotor swept area (W/m^2) is within normal limits, the influence of the installed generator power can be neglected for the first approximation.

The parameters of a wind turbine determining the manufacturing costs can thus be arranged in the following order according to their significance: firstly rotor-swept area, then rated generator power and then tower height. An all-in estimate of the specific manufacturing costs can only be justified on the basis of "costs per square meter rotor-swept area".

Admittedly, this fact makes a comparison with conventional energy systems more difficult. There is always the temptation of thinking and comparing on the basis of "costs per kilowatt". This will probably not change much in the future either. A comparison with conventional systems on this basis only makes sense if the "annual utilisation time" is comparable. This situation exists, for example, when a large wind turbine at a very good windy site is compared with a medium-load thermal power station. In both cases, the utilisation times of about 3000 to 4000 full-load hours per year are of similar magnitude. Under these conditions, a comparison of the specific manufacturing costs with reference to the rated power is justified.

When comparing wind turbines against one another, the characteristic value of "$/kW" makes sense only if the specific installed power per rotor-swept area "W/m^2" is approximately comparable. If the conditions differ greatly, the specific cost values must be corrected accordingly or the specific costs per square meter rotor-swept area must be used.

The specific costs per rotor-swept area figure is, however, not meaningful enough for exact economic calculations. Ultimately, it is the investment related to the energy yield, commonly the annual energy production, which is the valid measure. This is, of course, site-related or, more precisely, it depends on the power characteristics of the wind turbine *and* the wind regime.

The performance of an actual project can, therefore, be characterised by the parameter "investment cost per kilowatt-hour per year" ($/kWha). Using this parameter, the profitability of the investment "wind turbine at a certain site" can be assessed with high accuracy. The basis certainly has to be the turnkey investment costs, i. e. the costs of the wind turbine including all site-related additional costs. Compared with the sales prices for power generation from wind energy, for example approximately 0.09 $US/kWh (in Germany 2003) this value must not exceed 0.5 $US/kWha by much if an economically acceptable repayment period of about 12 years is to be achieved.

A stock taking of the costs and prices of wind turbines can only ever provide a snapshot survey. It is based on the current state of the art and the currently used production processes. The overall economic conditions are also of importance. Even if the indicated price figures are no longer completely valid after only a few years, an analysis of the state currently achieved is; nevertheless; important. A forecast of any future development can only be based on the present situation. The economic course of the development of wind energy technology will become clearer by first taking a look into the past, at the first trials of modern wind turbines.

19.2 Costs of Previous Experimental Turbines and Prototypes

In the first phase of wind power technology, countries interested in this technology in most cases tended to support projects involving very large experimental units. These projects were financed by massive federal subsidies, built by large companies and operated by public utilities as experimental turbines. These projects were in all cases additionally supported by accompanying research and development projects (Chapt. 2.5).

Under these conditions, it was not easily possible to separate the costs of research and development from those for construction or operation and the published cost figures were inaccurate and frequently contradictory for this reason alone [1]. Moreover, the preconditions for implementing these projects differed to a high degree. Cost components listed explicitly in one project were hidden behind a different organisational structure in others, for example those of research institutions which were financed by other sources. In addition, cost budgets were exceeded considerably in almost all cases. In some cases these were absorbed by the companies involved and hence did not show up in the published cost figures. There was often a considerable difference between official budget proposals and the costs actually expended.

There were also technology-related differences influencing the assessment of the costs. These were mainly due to the uncertain design criteria and quality requirements in the first generation of the large experimental turbines. If, for example, the American MOD-2 turbine is compared with the Swedish or German designs, there is an obvious difference: the design of the former was characterised by efforts to keep the overall structural mass, and thus production costs, low virtually "at any price", whereas the others were oriented more to standards valid in common power plant technology and still applicable today.

With many reservations and regardless of the difficulties mentioned and the uncertain reliability of the figures, Table 19.1 lists some published cost figures of the most important large experimental wind turbines of the years 1980 to 1987. The project costs include development and manufacturing costs of the turbines and, in some cases, also peripheral research costs. The figures for the manufacturing costs of the turbine mostly arose from a repeat estimation for a "second-unit manufacture". In general, it can be assumed that the figures relate to the costs of the turnkey, installed wind turbine, including the site-related costs.

If specific cost figures are derived from the data listed here, manufacturing costs range between 2200 and 2800 $US/m² rotor-swept area or 2200 to 5500 $US/kW. The specific construction costs of the large experimental wind turbines were on average more than two times higher than the ex-factory prices of the first smaller commercial series-produced wind turbines of that time.

These extraordinarily high costs of the first large wind turbines were the subject of conflicting discussions about the future prospects of this technology. It was not until the smaller commercial wind turbines had come along that the general assertions about the costs of power generated from wind energy based on the costs of these experimental turbines could be refuted. Much greater importance had to be accorded to the argument that, for physical and technical reasons, the technical complexity of a wind turbine would increase with increasing wind turbine size to such a degree that large wind turbines would "on principle" remain more uneconomic than smaller turbines, even after having achieved commercial development and production status (Chapt. 19.4.1).

Table 19.1. Total project costs and approximate manufacturing costs of large experimental wind turbines from 1980 to 1987

Project \ Costs	Published total project costs	Approximate installed costs of the wind turbine
Growian (100 m/3000 kW), DE, 1982	90 Mio DM	30 Mio DM
Monopteros (48 m/370 kW), DE, 1982	35 Mio DM	n.k.
3×MON-50 (56 m/640 kW), Jade wind farm, DE, 1989	30 million DM	8 million DM
WKA-60 (60 m/1200 kW), Helgoland, DE, 1989	20 million DM	9 million DM
Aeolus II (80 m/3000 kW), DE, S, 1990	35 million DM	24 million DM
Nibe A und B (40 m/630 kW), DK, 1980	35 million DKr	9.4 million DKr
Tjaereborg 2 MW (60 m/2000 kW), DK, 1987	70 million DKr	40 million DKr
LS-1 (60 m/3000 kW), GB, 1987	10.5 million £	n.k.
HWP-1000 (55 m/1 000 kW), GB, 1989	app. 2.8 million £	2.1 million £
WTS-3 (78 m/3 000 kW), S, 1982	265 million SKr	30 million SKr
WTS-75 (Aeolus) (75 m/2000 kW), S, 1982		28 million SKr
Awec-60 (60 m/1 200 kW), E, DE, 1989	930 million Pts	app. 600 million Pts
MOD-2 (91 m/2 500 kW), USA, 1981	n.k.	5.3 million US$
WTS-4 (78 m/4 000 kW), USA, 1982	n.k.	5.5 million US$
MOD-5 (98 m/3 200 kW), USA, 1987	65 million US$	n.k.
Aéole (64 m/4000 kW), CAN, 1987	35 million Can$	n.k.

19.3 Sales Prices of Commercial Wind Turbines

Wind turbines have currently achieved commercial status up to a power of about 3000 kilowatts and in some cases even higher. There is industrial series production up to this power class, but the numbers in the upper power range are still relatively small.

The most successful manufacturer, the Danish Vestas company, the largest producer world-wide after their merger with NEG Micon, had produced about 15 000 wind turbines by the year 2003, followed by GE Wind Energy (US) with about 5 000 and Enercon (Germany) with about 8 000 manufactured units. For example, one of the most frequently sold models, the Enercon E66, achieved production figures of about 2 000 units. About 95 % of all wind turbines sold were delivered by about 10 manufacturers. While Vestas had about 9000 employees in different factories world-wide in 2003 and Enercon had 5000 employees, the other manufacturers are much smaller (see Chapt. 16.6.2).

If the manufacturing costs of the presently series-produced wind turbines are discussed, they must be considered against the background described above. The scale of production can best be described as "large-batch production", on a production line similar to that used in aircraft manufacture. This method still has a long way to go until real assembly-line type production is achieved.

The specific prices of the wind turbines offered commercially in 2002/2003 are shown in Fig. 19.2. The figures come from official price lists of the manufacturing companies for the "ex-factory" price. Experience has shown that when a relatively large number of units is purchased, for example in the case of orders for the larger wind farms, a volume discount is granted. 5 to 10 % discount is quite common, so that in the individual case the costs may be lower than indicated in the statistics. Furthermore, it has to be considered that the sales prices are also "market prices". For example, the prices are higher in markets with better economic conditions for wind energy, for example in Germany. The indicated prices are average prices on the "world market".

The mean value of the specific ex-factory price per square meter rotor-swept area is about 350 \$US/m². Differences due to the technical concept are not discernible. However,

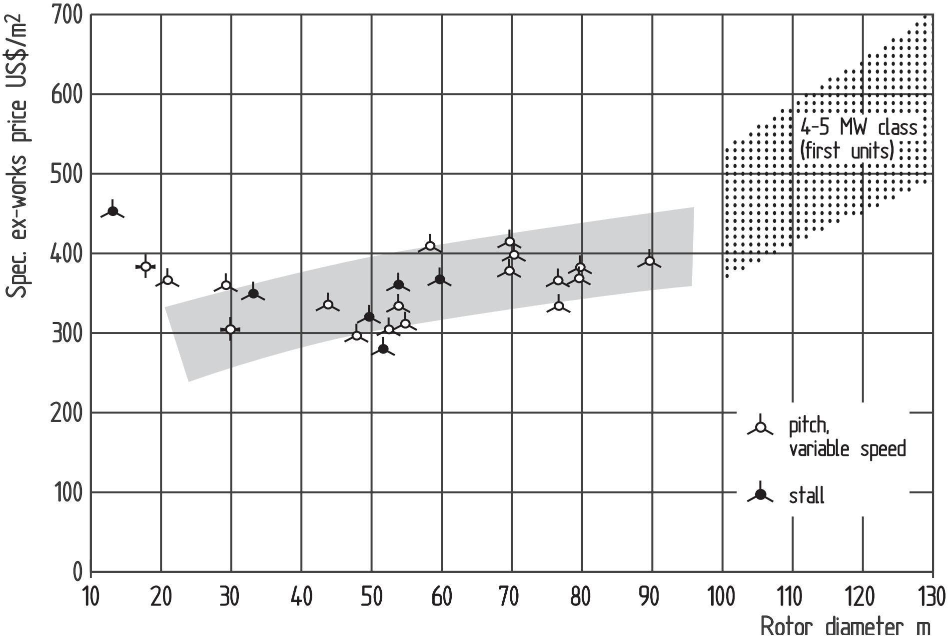

Figure 19.2. Specific ex-works prices per rotor-swept area of commercially available wind turbines in 2002/2003

a tendency of the specific prices rising with increasing wind turbine size in large turbines with rotor diameters of more than 50 m can be detected.

As already mentioned, the specific price of wind turbines generally increases with increasing size (Chapt. 19.4). Up to a size of about 50 m in rotor diameter it has been possible to a certain extent in practice to absorb this increase in specific construction costs, which has its basis in physical facts, by means of technical improvements, more efficient production methods and possibly also more accurate calculation

In spite of all the reservations, Fig. 19.3 shows the prices based on the rated power, to facilitate a comparison with conventional power generation plants. As expected, the range is wider and the result is less easy to interpret. It is at least apparent that the majority of the power-related, specific prices lies within a range of about 700–800 $US/kW. This is remarkably low, even when being compared with the production costs of conventional power plants.

When comparing wind turbines with conventional power plants, it must be considered that a large wind turbine with 70 m rotor diameter and 1500 kW rated power, at a good wind site (mean annual wind speed 5.5 m/s at 10 m height), achieves about 2500 equivalent full-load hours. Even if this figure is related to that of conventional systems, a specific price of 800 $US/kW is still comparatively reasonable. Conventional medium-load power plants are operated at scarcely more than 3000 to 4000 full-load hours per year. Their specific construction costs of 1000–1500 $US/kW are almost twice as high as those of wind turbines at good sites.

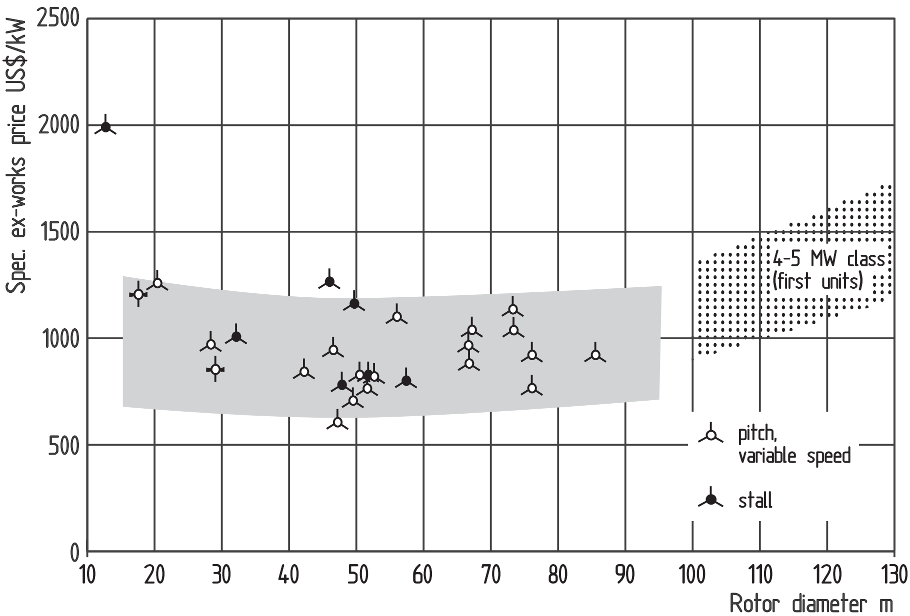

Figure 19.3. Specific ex-works prices per rated power of commercially offered wind turbines in 2002/2003

19.4
Cost Structure and Manufacturing Costs of Wind Turbines

A product's cost structure is primarily determined by the product itself — this goes without saying. Some other factors which affect the overall costs and their composition, albeit to a small extent, are not so much a matter of course.

The influence of the production environment where the product is manufactured should not be underestimated. Initially, new products are almost always afflicted by the handicap of being manufactured in a production structure which was developed for other products. In other words, wind turbines can only be manufactured really economically in a wind turbine factory. Factories are built for products and not the other way round. This simple fact does not seem to be obvious to many supporters of a "diversification" in outdated fields of production. There is no other possible explanation for those attempts where a new product frequently enough turns out to be apparently "uneconomic".

Another important factor is the production status that the product has achieved. The cost structure of an individually manufactured prototype is different from that of a series-produced product. This is mainly due to the fact that certain components become considerably cheaper when produced in larger numbers, whereas costs of other components can hardly be lowered. Rotor blades, for example, can be manufactured considerably more cheaply in series, whereas gears, bearings and other conventional machine components hardly become cheaper even if the wind turbine is produced in series, since these components are taken from other series in any case.

19.4.1
Cost Breakdown to Subsystems and Components

Like with other products, too, the cost structure of a wind turbine can be broken down with respect to different aspects. For a commercial cost calculation, a breakdown into material, vendor parts, labour costs and additional items for overhead costs is important. However, this type of analysis says little about the technology. A breakdown according to components or subsystems is much more informative. This provides a direct insight into the technology from a technical/economic perspective. Above all, the starting points for further developments towards a more cost-effective concept become visible. The structure of the production costs with respect to the main components of a wind turbine is illustrated in two examples (Table 19.4).

Here, the reference parameters are the so-called "component costs" (Chapt. 19.3.3). Although these two wind turbines are of different technical concepts and sizes, their cost structure basically does not differ very much. Furthermore, it becomes evident that there is obviously no single subsystem which dominates the cost of a wind turbine. From this, it follows that efforts at lowering the production costs will only be successful if they succeed in making the complete wind turbine system more inexpensive.

Statements of general validity are difficult to make when the cost breakdown is very detailed as in the examples above. The more detailed the breakdown, the more product-specific it must be. Thus, the following examples show the cost structure of wind turbines of various designs, sizes and origin at the level of the main subsystems (Fig. 19.5).

Table 19.4. Cost breakdown into main subsystems and components of a medium-sized and a large wind turbine (with respect to the sum of "component costs")

Wind turbine / Components	Medium-sized turbine 750 kW (stall-controlled) Proportion %	Large turbine 1500 kW (variable-speed controlled) Proportion %
Rotor blades	34.0 %	21.0 %
Rotor hub	2.0 %	2.1 %
Blade bearings	—	3.1 %
Hydraulic blade-pitch system	0.8 %	4.0 %
Rotor shaft	2.7 %	2.6 %
Rotor bearings with housings	1.0 %	1.7 %
Gearbox	12.5 %	13.6 %
Load-bearing nacelle structure	8.7 %	4.7 %
Yaw drive (includes. azimuth bearing)	2.4 %	3.4 %
Nacelle fairing	2.0 %	1.6 %
Miscellaneous (rotor brake, generator shaft, clutches, heat exchanger etc.)	5.0 %	3.2 %
Generator (and inverter in the large turbine)	7.5 %	10.9 %
Control system and monitoring equipment	5.0 %	7.4 %
Tower	16.4 %	20.7 %
Component costs	100.0 %	100.0 %
Assembly (in the factory)	5.0 %	5.0 %

Looking at these pie charts, it is immediately obvious that the cost proportions of the subsystems thus defined differ only insignificantly. There is no apparent tendency of a general shift of the cost proportions towards certain components with increasing wind turbine size. For example, the opinion, sometimes stated, that rotor blades take up an ever-higher proportion of the cost of larger wind turbines cannot be verified by these examples. Nor does the different production status, single-unit manufacturing or series production, lead to any obviously significant differences. For changes in the cost structure to become obvious, differences in the production methods will probably have to diverge to a much greater degree.

Upon closer inspection, however, some interesting details show up with regard to the technical concepts of the turbines. In the Danish standard turbines, the cost share of the rotor blades is relatively high. The fact that these are three-bladed rotors equipped with an aerodynamic brake is reflected in the cost breakdown. The proportion of costs of the mechanical drive train and nacelle consistently amounts to about 40 to 50 % of the production cost.

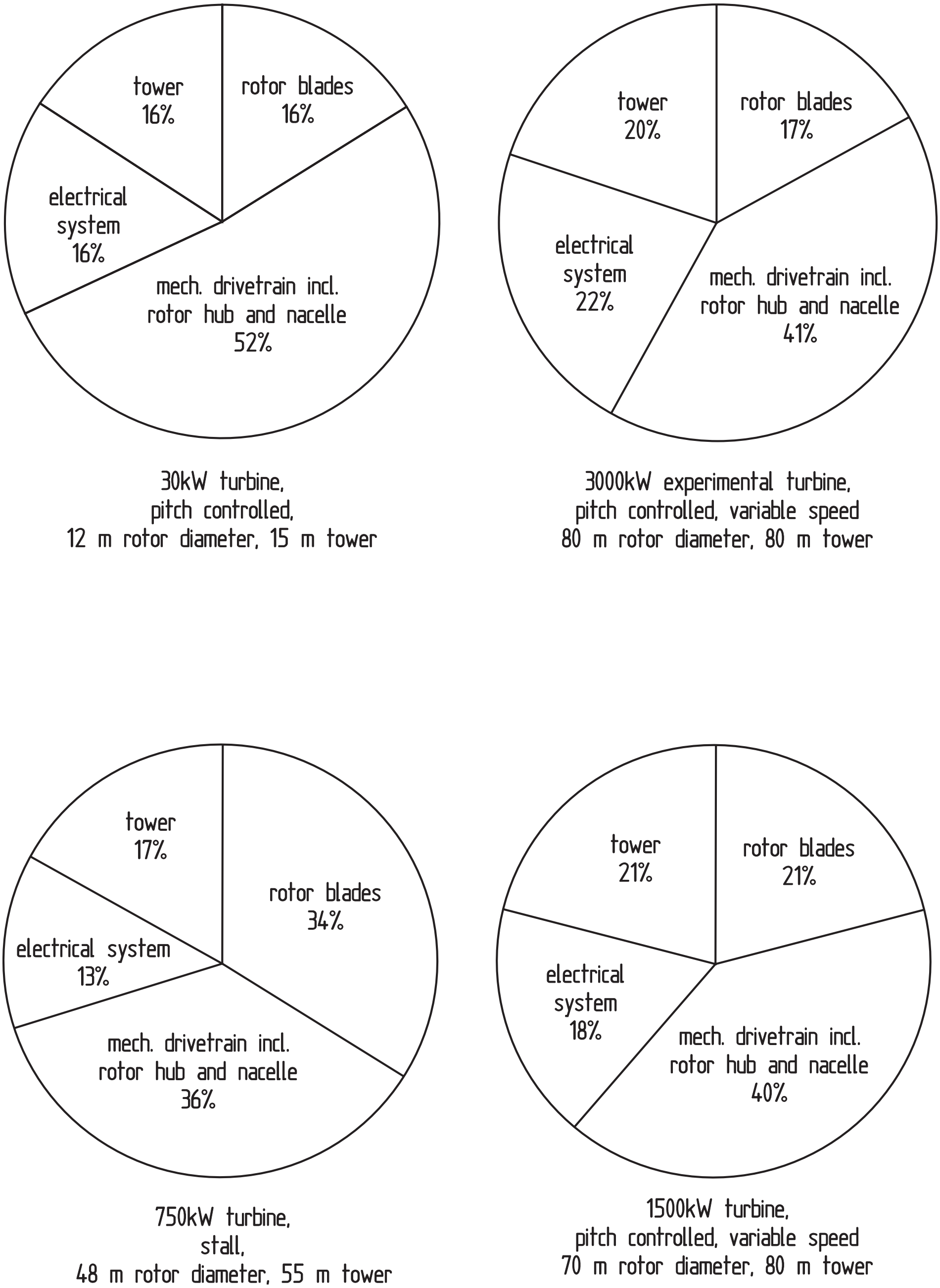

Figure 19.5. Breakdown of the manufacturing costs into the main subsystems of wind turbines (component costs)

The proportion of costs of the electrical system reflects a considerable difference between the simple, fixed-speed induction generators of the older turbines and the more complex variable-speed generator systems with frequency converters. The overall electrical equipment based on a simple induction generator can be limited to a cost share of about 13 % whereas the cost share of a variable-speed system can amount to up to 20 % (Table 19.4).

In current turbines, the cost fraction of the electrical system is lower. The additional costs for a variable-speed system based on a double-fed induction generator are no longer quite as important in the cost breakdown. Although the variable-speed electrical system itself is more expensive by 30 to 40 %, the difference compared to a fixed-speed generator is only 3 to 5 % with respect to the sum of the component costs.

Occasionally it is asserted that wind turbines with blade-pitch control were considerably more expensive than comparable machines with a fixed blade pitch angle. Table 19.6 shows a direct comparison with the example of a relatively small wind turbine which was designed and calculated with both blade-pitch control and fixed blade pitch angle [2]. According to this analysis, introduction of a blade-pitch control system only increases the cost of a wind turbine by about 4 %.

Basically, it is doubtful whether it is necessary at all for wind turbines with blade-pitch control to be more expensive than fixed-blade machines. The reduced loads due to the blade-pitch control must result in lower masses of the rotor blades and the associated mechanical components and structural components. This applies at least when the turbines are operated with variable speed as is customary today. In the implementation it must be assumed that the load assumptions take this fact into account and that the designer fully exploits these opportunities when dimensioning the components. The relationship between the technical features of the turbine and the resultant load spectra of the components does not appear to have been grasped reliably enough, at least in some areas. These differences are more apparent in the case of large turbines. Large, stall-controlled machines with fixed rotor blades are much heavier compared with blade pitch controlled turbines. With fixed

Table 19.6. Cost breakdown of a wind turbine with 25 m rotor diameter and 200 kW rated power, both with and without blade-pitch control [2]

Variant / Component	With blade-pitch control	With fixed blades
Rotor (three-bladed)	20 %	24 %
Blade-pitch mechanism	6 %	—
Mechanical drive train	18 %	20 %
Nacelle	15 %	18 %
Electrical system	19 %	16 %
Control and monitoring system	9 %	4 %
Tower	12 %	18 %
Relative total costs	104 %	100 %

blades, the "extreme wind velocity" case of loading, in particular, will lead to higher loads and thus also to much heavier and expensive foundations, among other things.

The general conclusion to be drawn from the above and other examples can be summarised in the following statements:

Rotor blades

The cost fraction of the rotor blades amounts to between 16 and 34 % of the production costs. The higher value is for stall-controlled three-bladed rotors with integrated, hydraulically reset aerodynamic brakes and the lower value is for wind turbines with two-bladed rotors. The material also plays a role, naturally. Rotor blades made of glass/epoxy are generally more expensive than glass/polyester blades, despite their lower weight.

Mechanical drive train and nacelle

The mechanical drive train and nacelle (it would be difficult to consider these two components separately) have a cost share of about 40 to 50 % of the total component cost. A considerable fraction is contributed by the yaw system. In more recent models with very compact nacelle and integrated drive train design, the proportion of drive train and nacelle costs to total costs is tending to decrease.

Electrical and control system

This cost fraction ranges between 13 and 20 %. The lower value applies to simple systems with fixed-speed induction generators. The higher value of 20 % characterises a variable-speed system, with synchronous generator and frequency converter.

Tower

The cost proportion of the tower shows a much wider range compared to other subsystems in dependence on the type of construction selected and on the height in comparison with the rotor diameter. The share of the production costs ranges between 12 and 20 %. In more recent wind turbines designed for inland application, in some cases with very high towers, the proportion can be even higher.

19.4.2 Economy of Scale in Series Production

An important factor in lowering the costs, which takes effect when a product is manufactured repeatedly, is the learning effect. This is achieved by labour time being saved due to work cycles becoming routine, as well as by minor improvements effected in the course of repeated production. The "*learning curve*" is a forecast of manufacturing cost reduction with an increasing number of produced units. It presupposes that the product is produced repeatedly without major modifications and that the production equipment and processes remain essentially the same.

A common approach for the economy of scale of industrial products in series production is:

$$P_n = B\, n^{\ln T_f / \ln 2}$$

where:

P_n = the costs of the n^{th} unit
n = the number of units
B = the costs of the first unit
T_f = the technology factor.

The technology factor of industrially manufactured products is mostly between 0.85 and 0.95. Here are some examples:

Ford Model T: $T_f = 0.95$
Aircraft: $T_f = 0.80 - 0.90$
Building cranes: $T_f = 0.96$

Figure 19.7 shows the cost reduction resulting from different technology factors as a function of the number of units. But due to the difficulty of having to estimate the technology factor of a new product, prognoses based on the learning curve are associated with relatively large uncertainties.

Up to now, reliable evaluations with regard to the technology factor in the series-production of wind turbines have as yet to be published. On the basis of comparisons with

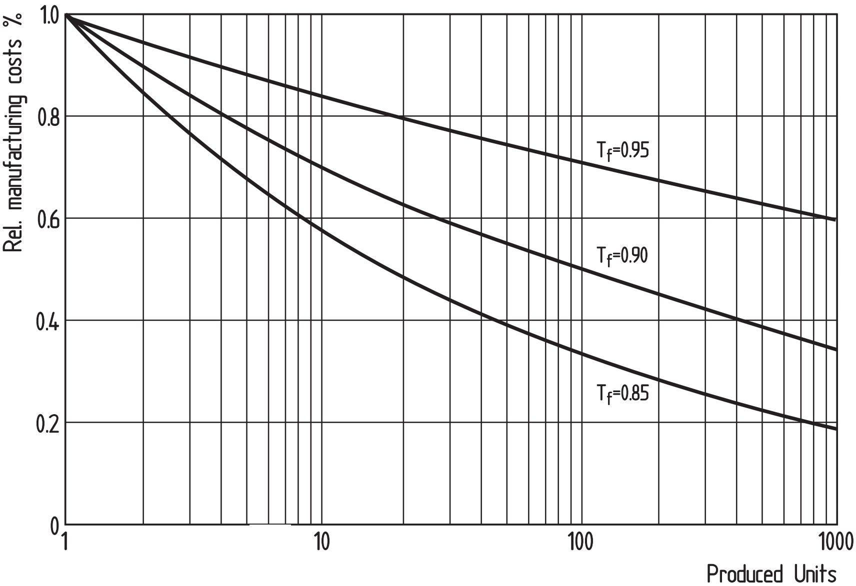

Figure 19.7. Reduction of the manufacturing costs in series-production as a function of the technology factor (learning curves)

similar products, it can be expected that the costs per unit will have dropped by 40 to 50 % by the 100th unit. This corresponds to a technology factor between 0.90 and 0.95. The prerequisite for this is, of course, a continuous production, which means that the production rate (number of units per time) must not be too low. On the other hand, it must be taken into consideration that wind turbines largely consist of components which already include the economy of scale factor due to mass production. The learning factor thus only relates to the turbine-specific components like rotor blades etc. For this reason, only a much lower cost reduction from prototype to one-hundredth unit can be expected.

Mass production with a very high number of units, for example several thousand units per year, is not economical without a qualitative change in the production equipment. Thus, it is no longer the learning curve alone which determines the economy of scale, but also the investments in production equipment. The range of existing production equipment is extremely wide. At present, the pinnacle is represented by the almost fully automated assembly line production used in the automobile industry. Making general statements with regard to the production costs of wind turbines is hardly possible under these conditions. Entrepreneurial considerations become relevant. The manufacturer will invest more or less in the production equipment depending on his expectations with regard to future sales.

Automated production methods will not be of great significance in the manufacture of wind turbines within the foreseeable future. However, one should not be blind to the fact that industrial production in small numbers also requires certain investments into production equipment and an adaptation of the production structures to the product. Economical production always requires a holistic consideration of the product and of the production method.

19.4.3 Costs and Price Calculation in Production

Manufacturing costs are not the same as sales prices. The difference is not only the profit. In the commercial calculation involving industrial products, things are not quite so simple. It is especially the term "production costs" which requires more explanation.

The manufacturers normally define different cost stages in their cost calculation. A common method first calculates the production costs of all components individually. For vendor-supplied parts, the purchase price plus a surcharge of 5–15 % for procurement is normally used. The parts manufactured in-house are calculated with all overhead costs required for their production. This is the only way a decision can be reached between the economic options of "buying in" and "manufacturing in-house".

The manufacturers of wind turbines pursue highly varying policies in this regard. Many manufacturers try to purchase as many parts as possible from outside vendors. Their own vertical range of manufacture is extremely small. Thus, they benefit from price competition and the technical knowledge of the vendor industry. Other manufacturers prefer to bet on their own production. Above all, they want to push ahead the integrated development of the system with all its important components, thus nosing ahead of the competition. They put up with certain cost disadvantages caused by the non-specialised company production of certain components.

Adding up the component costs is the first important step in the pricing of the system. These "component costs" cannot be decreased without a modification of the technical concept, of the production method or a change of supplier.

A commercial enterprise aiming at a long-term and stable market position, including not only the production side but also a global product management, must include a number of other cost factors in its pricing calculations:

- Assembly at the factory (system integration)
- Material procurement, storage,
- Quality assurance and control,
- Contingency reserves for liabilities,
- Insurance,
- Administrative overhead,
- Marketing costs,
- R & D costs,
- Shipment and packing,
- Commissioning,
- Profit.

These cost factors which, considered individually, make up only a few percent of the component costs, normally add up to a total percentage of between 40 and 50 %. This high surcharge of "soft costs" on top of the "hardware" may surprise the reader unfamiliar with industrial cost pricing, but experience has shown that no manufacturers who, in their initial euphoria, believe that "they can make it a lot cheaper", have been successful competitors in the long run. The sales price must contain sufficient reserves for new developments — and possibly associated set-backs, more serious cases of liability which are not always covered by insurance, and much more. The following cost analyses are, therefore, based on the sum of the component costs and assume a surcharge of 45 % in order to arrive at the "ex-factory" sales price. The order of magnitude of these overheads has been confirmed by sampling the cost calculation of some series-produced wind turbines.

19.5 Wind Turbine Weight and Manufacturing Costs

In the mid-eighties, experience gained with the extremely high construction costs of large experimental wind turbines, which amounted to up to 3 000 $US per square meter rotor-swept area or 5–6 000 $US/kW, led to controversial discussions about the economic perspectives of large wind turbines in the megawatt power range. The high manufacturing costs could not be explained by the mere fact that these large turbines were manufactured individually. The effect was considered in principle that, for physical reasons, the specific overall masses of wind turbines become worse with increasing size, due to unfavourable scaling effects. In the simplest case it has been argued that, due to its volume, the overall mass increases with the third power of the dimensions whereas the energy yield only increases with the square of the rotor diameter, which is why the economic efficiency deteriorates with increasing wind turbine size. On the other hand, the progressive development of commercial wind turbines showed that these turbines did not in any way lose their economic efficiency with increasing size. To answer these questions, which were of importance for research and development tasks, numerous theoretical investigations relating to this subject were carried out, among them a comprehensive study on behalf of the Commission of the European Union [3].

Both the theoretical investigations and practical experience revealed the significance of the overall mass to the manufacturing costs. As is the case in other fields of machinery or vehicle production, it was found that in series production, the weight of the components becomes the decisive cost factor. In other words, as long as there are no large differences in technology, for example due to the use of particularly expensive materials or an especially complex manufacturing method, the manufacturing costs of a product are primarily proportional to its mass.

19.5.1 Development of Specific Mass with Turbine Size

The result of a statistical analysis of past and current wind turbines with regard to their specific tower-head mass, which is the weight of rotor and nacelle referred to the rotor-swept area, is shown in Fig. 19.8. Leaving out some runaway values, various bands can be seen which characterise particular turbine concepts. The figure also clearly shows the relationship between specific mass and turbine size.

Earlier Danish turbines and large three-bladed experimental turbines

With their low tip-speed ratio and heavy construction, the smaller stall-controlled three-bladed wind turbines in sizes of 15 to 20 m rotor diameter had a specific tower-head mass of between 25 and 35 kg/m². The large experimental turbines of Danish origin (Nibe, Windane, Tjaereborg) built in the eighties or those in the Danish style like WKA-60 and Awec-60 showed the highest-values of more than 60 kg/m². In these wind turbines, several weight-enhancing factors come together: heavy rotor blades, huge nacelles with drive-train components on a heavy bedplate and a comparatively high ratio of rated power to rotor-swept area (Tjaereborg: 700 W/m²). However, some distinctly lighter designs could already be found among the earlier large three-bladed turbines. Particularly the three-bladed machines by the British manufacturer Howden, the HWP-750 and HWP-1000, had comparatively advantageous values of about 35 kg/m².

More recent three-bladed wind turbines

A considerable reduction in specific mass has been achieved in the more recent wind turbine types. Commercial wind turbines with rotor diameters of about 40 m achieve values of about 20 kg/m² and in some cases even lower. As expected, this value rises slightly with increasing size. With a rotor diameter of 80 m, the specific tower head mass is between 20 and 30 kg/m². The prototypes of the largest turbines to date, the Enercon E-112, attain a value of approx. 50 kg/m² with a rotor diameter of 114 m whereas in the 5-MW REpower with a rotor diameter of 126 m, the specific tower head mass could be limited to 28 kg/m². It is difficult to differentiate between tower head masses by turbine design. The trend shows

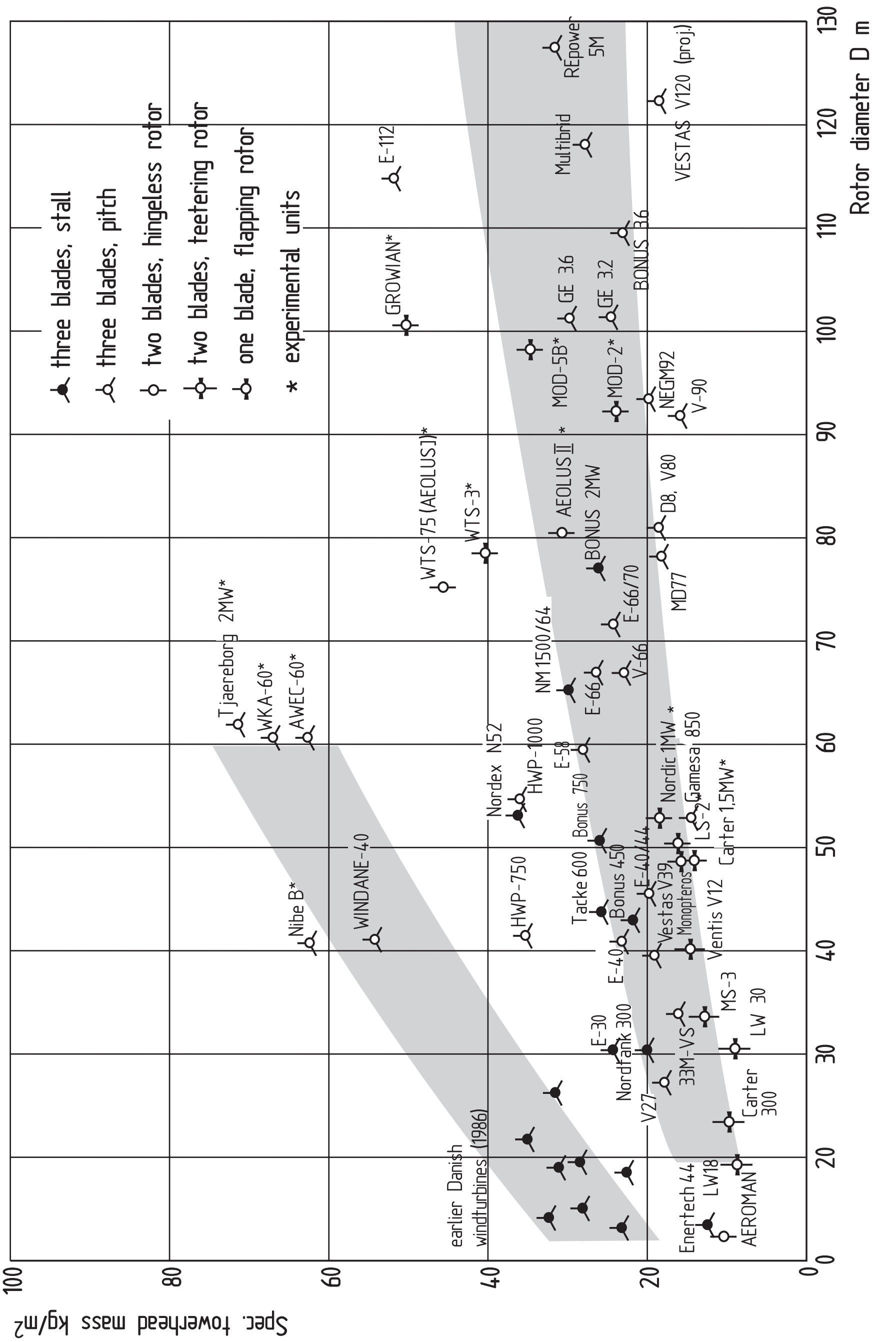

Figure 19.8. Development of specific tower-head weight with rotor diameter for wind turbines of various technical concepts

that stall-controlled turbines and turbines with directly driven slow-speed generator are at the upper limit of the bandwidth.

Wind turbines with two-bladed rotors

The earlier large two-bladed turbines with hingeless rotors are difficult to evaluate with respect to their specific tower-head mass. Some of these turbines had components with poor weight characteristics such as heavy steel rotor blades on the MOD-1 and WTS-75. On the other hand, the monocoque nacelle structures, for example of the Newecs-45 and the WTS-75, exhibited favourable weight characteristics. In any case, their tower-head mass was markedly below that of the large three-bladed wind turbines of the day. The two-bladed wind turbines with teetering hubs (MOD-2, MOD-5B, Growian) provided the best basis for low specific overall masses. Even the largest planned wind turbine to date, the MOD-5A project, remained below 40 kg/m². The more recent two-bladed wind turbine Nordic 1 MW has a particularly low specific tower-head weight of approx. 19 kg/m² with a rotor diameter of 54 m.

Single-bladed wind turbines

Compared to the two-bladed turbines with teetering hubs, the weight characteristics of the experimental single-bladed wind turbines of the Monopteros series were not any better. In addition, this concept, with its high tip-speed ratio and the associated noise problems was found to be unsuitable for practical application.

If the statistical plot of the tower-head masses, as shown in Fig. 17.8 is analysed from these points of view, an empirically based tendency can be indicated for the more recent light-weight design of the three-bladed turbines and for two-bladed turbines with teetering hubs. The absolute mass of the tower head increases with the power of 2.6 to 2.7 in dependence on the rotor diameter. The specific overall mass thus follows the following growth function:

$$m_1 = m_2 \left(\frac{D_2}{D_1}\right)^{0.6 \text{ to } 0.7}$$

The increase in the specific mass with rotor diameter can be demonstrated not only empirically, but can also be derived from physically based relationships. In recent years, this problem has been dealt with by various technical-scientific investigations [3]. Detailed mass models of wind turbines were developed and "scaling laws" were derived for every component, taking into consideration the main loads. These scaling laws can be used with good results by extrapolating upward, starting with a certain size where the masses are known. The prerequisite for this is that the technical concept essentially remains unchanged.

A mass model for a wind turbine requires taking into consideration the dimensioning load assumptions and knowledge of the strength and stiffness values of the materials and components used. Since the load cases for the entire system are very complex and additionally differ for the individual components, it is only by applying numerous idealisations and simplifications that the computing effort can be kept within tolerable limits. Experience and a certain amount of sensitivity are indispensable assets in this. The rotating parts such as rotor shaft and gearbox are almost exclusively dimensioned for power or, respectively, the torque to be transmitted whereas other components such as rotor blades or the tower are directly loaded by aerodynamic forces.

The development of the tower-head mass and the manufacturing costs versus rotor diameter was calculated for two basic technical concepts, applying certain simplifying assumptions (Fig. 19.9). Typical representatives of these two basic concepts are, for example, the NEG Micon NM-1500 and the Nordic 1 MW (Figs. 19.10 and 19.11).

The empirical trend is verified by theoretical analysis. Both the specific tower-head mass and thus lastly also the specific manufacturing costs related to the rotor-swept area increase with increasing rotor diameter.

As expected, the increase is greater in the conventional, heavier concept range. However, this increase is by no means as steep as was initially expected after the experience with the first large wind turbines. These wind turbines, with their specific tower-head mass of over 60 kg/m² had simply not been designed correctly! Using more modern and weight-optimised designs, the increase in specific mass can be limited to such an extent that economic viability is not lost with increasing size. This has been proven by the new generation of commercial turbines of this size range. Although the mass model calculated on the basis of the design features did not reflect the component design in detail, it was possible to detect the difference between stall-controlled turbines and those with blade pitch control, the latter having a weight advantage of about 20 % of the tower head mass.

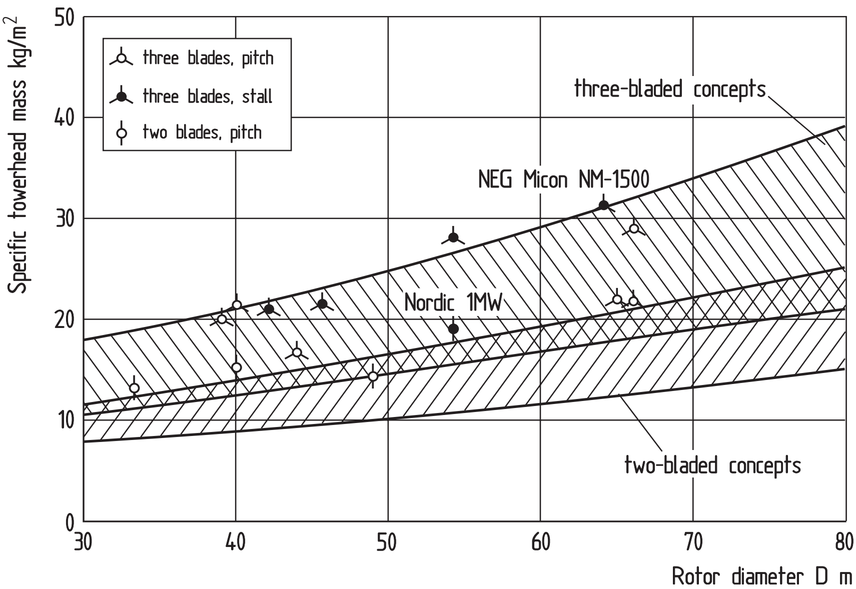

Figure 19.9. Development of the specific tower head mass versus rotor swept area with the rotor diameter [3]

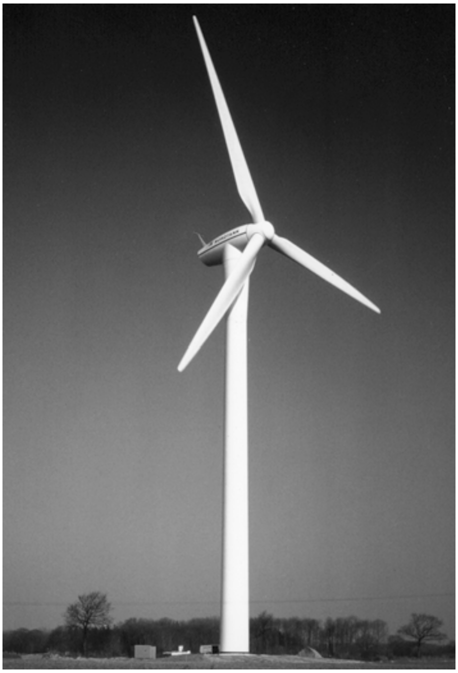

Figure 19.10. NEG Micon 1500 kW, rotor diameter 64 m (stall), specific tower-head weight: 32 kg/m^2

Figure 19.11. Nordic, 1000 kW, rotor diameter 53 m, specific tower-head weight: 19 kg/m^2

It is true that the few examples of the lighter two-bladed line are not entirely within the expected range, being heavier than predicted by theory. One reason for this could be the simplifying assumptions (load cases) in the theoretical model which still exhibited many features of improvisation in its developmental stage. Another reason could be, that the two-bladed wind turbines also do not fully exploit their design potential for weight reduction. In some turbines of this line, moreover, the combination of their design features was in no way convincing. Thus, for example, the prototype of the Nordic 1 MW was built with variable-speed generator system and stall control, as a result of which the problems were already pre-programmed. The project was abandoned in 1998.

However, this experience, which is not very encouraging, should not lead one to draw any hasty conclusions to the effect that the two-bladed turbine concept is finished once and for all and for all conditions of use, e. g. in offshore applications or other areas where noise pollution is not a problem. The two-bladed rotor with its lighter weight has the greater potential for further reduction in the production costs even though the development costs for a reliable two-bladed rotor with teetering hub do present a hurdle. The larger the turbines, the more obvious are the advantages of lower production costs and simple assembly

19.5.2
Manufacturing Cost Calculation on the Basis of Mass-Related Cost Figures

Calculating the manufacturing costs with the aid of specific mass and cost figures provides reliable results only when the components or subsystems are defined in such a way that they are technically homogenous and can be characterised by one single specific cost figure. Moreover, the correct reference parameter must be selected. Manufacturing costs of structural components and machinery can be determined quite well by mass-specific cost figures but mass is not significant where electrical components are concerned. In this case, power is the better reference.

If a "mass model" is available for the wind turbine, i. e. an analytical or statistical relationship between the component masses and the turbine's most important parameters (rotor diameter, rated power, tower height etc.), the manufacturing costs can be estimated with the help of specific cost figures [3]. "Mass/cost models" such as these are used with good results in aeronautics and space technology. With regard to the technical homogeneity of the subsystems, the following areas which can be characterised by a specific cost value can be defined.

High-strength lightweight composite structures

Only the rotor blades can be classified under this term, not the entire rotor. Design and manufacturing of rotor blades represent a technology similar to aircraft engineering. The manufacturing costs can be specified in weight-related terms in \$/kg. However, it is not the mass-related costs that are relevant with wind turbines, but the costs related to the rotor-swept area, so that the parameter "\$/m^2" plays a role in the cost model of the wind turbine. It is for this reason that two-bladed rotors already have a cost advantage.

Mechanical equipment

In wind turbines, traditional mechanical equipment is represented by the mechanical drive train including the rotor hub, blade bearings and blade-pitch mechanism. The yaw drive is also a mechanical-engineering component which in most cases is integrated into the nacelle structure and is often included in the cost component of the load-bearing nacelle structure (steel or casting).

Steel structures

Steel structures comprise the load-bearing structure of the nacelle and the tower (if this is a steel tower). With regard to the specific costs, however, there is a difference. The labour-intensive steel structure of the nacelle involves higher specific costs than the tower. Moreover, the nacelle includes complex systems and equipment, such as the yaw drive, the oil supply and the cooling system, as well as the non-load-bearing nacelle housing, which are frequently made of non-metallic materials. Thus, the specific cost value of the nacelle's structure relates to a rather heterogeneous subsystem. Added to this is that cast steel is increasingly being used for load-bearing structural components. However, machined cast steel belongs to the category of traditional engineering and must be classified differently from welded steel constructions with respect to its specific manufacturing costs.

Electrical and control system

The electrical system consists of the generator, the frequency converter if installed, and the general electrical equipment with cabling and the control systems for control and operations management (Chapt. 9.7). In contrast to the mechanical components, it is more telling to relate the specific costs of this subsystem to power than to weight. The specific costs are thus given in "\$/kW". There is a distinct trend for the electrical components to become specifically more inexpensive with increasing size (rated power).

If the components of a wind turbine are arranged in accordance with the defined areas, this can be used to develop a usable cost model. Naturally, there can be considerable deviations in the individual components in some cases depending on the individual design-related differences but overall, the cost breakdowns given in Tables 19.12 and 19.13 provide a picture of the cost structure of a wind turbine corresponding to the current state of the technology.

The specific manufacturing costs of wind turbines only become meaningful if they are compared with similar products. This requires a certain amount of caution. The product used for comparison should not only be comparable with regard to its design, i. e. material and structural complexity, but the stress level and service life should also not deviate very much. Not least, the production status is also highly significant. An automobile, for example, would be a completely unsuitable "reference product". With certain reservations, material and structural complexity could just barely be compared. The required service life, however, which amounts to only a few thousand hours in a car, and the production status, which is characterised by a largely automated assembly-line production, are completely incompatible. Under these conditions, the specific manufacturing costs are on completely different levels.

Table 19.12. Specific manufacturing costs calculation of a series-produced medium-sized wind turbine, rotor diameter 48 m, 750 kW rated power (stall-controlled), rotor hub height 55 m

Component	Mass kg	Spec. costs \$US/kg	Costs \$US	Proportion %
Rotor blades (glass/polyester, with tip brakes)	3 × 3 100	11	102 300	34.05
Hub, machined	3 000	2.0	6 000	
Blade bearings	—	—	—	
Blade pitch mechanism	—	—	—	
Spinner and small parts	500	—	2 500	
Rotor, total	12 800		110 800	
Front rotor bearing and case	600	5.0	3 000	37.06
Rotor shaft	2 300	3.5	8 050	
Gearbox	4 700	8.0	37 600	
Nacelle bedplate	6 500	4.0	26 000	
Yaw drive with tower head bearing	900	8.0	7 200	
Nacelle fairing	1 200	5.0	6 000	
Miscellaneous (rotor brake, clutch, generator shaft, hydraulics, external cooling)	1 500		15 000	
Mechanical drive train and nacelle	17 700		102 850	
Generator	3 450	30 \$US/kW	22 500	
Inverter with control system and switchgear	—	—	—	
Control system		—	10 000	
Cabling and other electrical components	1 000	—	5 000	
Electrical system, total	4 450		37 500	12.41
Tower head mass	34 950			
Tower (incl. Foundation section)	38 000	1.3	49 400	16.48
Component costs			300 550	100
Surcharge for overheads (45 %)			135 247	
Expected sales price			435 797	

Table 19.14 shows a selection of reference products which can be allocated to the various subsystems of a wind turbine. Naturally, individual points are open to discussion as to whether the product does indeed provide a reliable reference value for the specific manufacturing costs of a wind turbine. However, by comparing several products and by discussing existing differences and incompatible points, a reliable picture of the costs to be expected can be obtained.

The comparison with the specific production costs of the wind turbine analysed in Table 19.12 and 19.13, shows that the wind turbines produced in larger numbers are being produced today with comparatively low specific costs. Even if the number of units produced were to be increased, no further significant cost reduction can be expected with

Table 19.13. Wind turbine, rated power 1500 kW, rotor diameter 70 m, hub height 80 m, blade pitch control, double-fed induction generator

Component	Mass kg	Spec. costs \$US/kg	Costs \$US	Proportion %
Rotor blades (glass/polyester, with tip brakes)	3 × 5 500	12	198 000	21.03
Hub, machined	10 000	2.0	20 000	
Blade bearings	3 × 1 200	8.0	28 800	
Blade pitch mechanism	2 500	12.0	30 000	
Spinner and small parts	1 500	5.0	7 500	
Rotor, total	34 100		284 300	
Front rotor bearing and case	3 200	5.0	16 000	
Rotor shaft	7 000	3.5	24 500	39.92
Gearbox	16 000	8.0	128 000	
Nacelle bedplate	11 000	4.0	44 000	
Yaw drive with tower head bearing	4 000	8.0	32 000	
Nacelle fairing	3 000	5.0	15 000	
Miscellaneous (rotor brake, clutch, generator shaft, hydraulics, external cooling)	2 000	—	30 000	
Mechanical drive train and nacelle	46 200		289 500	
Generator	7 500	35 \$US/kW	52 500	
Inverter with control system and switchgear (appr. 500 kW)	—	100 \$US/kW	50 000	
Control system	—	—	30 000	
Cabling and other electrical components	1 000	—	10 000	
Transformer, 20 kV (in tower)	—	20 \$US/kW	30 000	
Electrical system, total	8 500		172 500	18.33
Tower head mass	88 800			
Tower (incl. Foundation section)	150 000	1.3	195 000	20.72
Component costs			941 300	100
Surcharge for overheads (45 %)			423 585	
Expected sales price			1 364 885	

these turbines. A further drop in the manufacturing costs can, therefore, only be achieved by a more advanced technical concept and a thoroughly "value-engineered" component design.

As discussed in Chapter 19.4.1, the specific tower-head weight increases with increasing rotor diameter. Using the mass-related specific cost figures as a basis, the specific manufacturing costs must also increase with the rotor diameter. In the theoretical analysis quoted, a rise in specific manufacturing costs ($US/m²) with a power of between 0.5 and 0.6 was determined [3].

$$K_2 = K_1 \left(\frac{D_2}{D_1} \right)^{0.5 \text{ to } 0.6}$$

This theoretical result is not quite confirmed at the calculated level by current price statistics (Fig. 19.2). The 40-m turbines have a specific price of about 300 $/m² whereas about 380 $/m² have to be paid for the turbines with 80 m diameter. This corresponds to a rise to the power of about 0.4 in specific costs referred to the rotor diameter. The explanation

Table 19.14. Specific ex-factory prices of products from the sectors of lightweight structures, engineering, steel structures, vehicles and electrical equipment (Cost situation in 1995)

Sector	Product	Production status	Spec. costs $US/kg
Simple lightweight structures	Container (40 ft), steel	Large series	1–2.5
	Oil tank (20 m^3), steel	Large series	1.5
	FRP-tank (2 m^3), GFK	Large series	3
	FRP-hull of a boat	Series	5–6
High-strength lightweight structures	Glider plane (FRP/CFRP)	Series	100
	Aircraft and aerospace structures (CFRP)	Single piece	500
	Large aircraft (Duraluminium)	Series	150–250
Engineering (vehicles) (Fahrzeugbau)	Diesel engine, 77 kW	Assembly line	13
	Diesel engine, 1800 kW	Series	28
	District heating power plant 4.4 MW, unit type	Small series	15
	Hydraulic excavator	Series	5–8
	Tractors	Large series	6–100
	Passenger vehicle (VW Golf)	Assembly line	15–20
	Gearbox (1 MW)	Small series	15–20
	Gearbox (20 — 100 kW)	Series	8–12
	Large roller bearings	Series	8–15
Electrical equipment	Synchronous generator (1 MW)	Series	30–50
	Induction generator (20–100 kW)	Large series/ assembly line	30–60
	Frequency converter (1 MW)	Series	40–60
Complex steel structures	Power plant boiler (20 MW)	Single piece	10
	Pressurised bottles (200 bar)	Large series	4–6
Simple steel structures	Ship (tanker)	Single piece	2–2.5
	Steel masts (latticed)	Series	1.5–2

is that the new 80-m turbines are more advanced with respect to their component design compared with the earlier 40-m class of turbines.

An interesting question with regard to these basic cost calculations is whether the rise in the specific costs can be compensated for by the rotor's specific energy yield, which also increases with wind turbine size (tower height). Assuming that the tower height is the same as the rotor diameter, the specific annual energy yield can be specified for a given wind regime in dependence on the rotor diameter. Assuming that the vertical wind shear gradient can be described by the Hellman exponent of 1⁄7, the specific energy yield per square meter rotor-swept area increases with the rotor diameter according to the following formula:

$$E = \left(\frac{D_2}{D_1}\right)^{0.44} \qquad (\mathrm{kWh/m^2})$$

With this increase in mean wind velocity with height, the rise in specific costs is nearly balanced. However, it must be pointed out here that the specific energy yield (wind velocity) increases more rapidly with tower heights of more than 60 m, particularly on inland sites (Chapt. 13.3.2).

One should be careful not to overrate the accuracy of these findings. The underlying mass-cost model, arrived at partly by theoretical and partly by empirical means, was derived with numerous simplifications. Even a slight shift in the assumptions, for example the supposition that for some components the specific manufacturing costs improve with increasing turbine size, will change the figures. Hence, the purpose of this idealised mass-cost model is not so much to accurately determine the manufacturing costs but rather to represent the basic interrelationships of the achievable manufacturing costs with a particular technical design and turbine size. The problem thus addressed is in no way only a backward look at the first "dinosaurs" of wind turbine technology but is of fundamental importance with respect to the question of how far the construction of wind turbines can be developed further and still remain economically viable. Offshore installation forces the development of wind turbines with dimensions which considerably exceed those of the first experimental megawatt turbines.

Moreover, it must be noted that the costs for the wind turbine itself are not the only criterion for the economic efficiency of an actual application project. A complete overall picture of the economics also requires other factors such as operating costs, land requirements, etc. to be included (Chapt. 20).

19.6 Lowering Costs through Further Technical Development

Wind turbines of current design have by no means reached the final stage in their technical development. How could a complex system, which has been the object of systematic research and development work for not even twenty years, have reached the limit of its potential for development? The existing potential for development will be utilised not only for increasing the efficiency and service life of wind turbines, but also for a further reduction of their manufacturing costs. In small and medium-sized wind turbines, the potential for further development with respect to reducing the manufacturing costs appears to be relatively limited. However, it is noticeable that the price minimum of about 300 $US per square meter rotor-swept area is shifting towards ever larger wind turbines whilst at the same time rising only slightly. In the mid-eighties, only the Danish wind turbines with about 15 m rotor diameter and 50 to 60 kW rated power achieved this value. Only three years later, wind turbines with 20 m rotor diameter and about 150 kW were already available at these specific prices. At present, wind turbines of up to 2 000 kW are produced in series at an only slightly higher price level.

The main reason for this development has been the consistent continued weight optimisation of the components within the past fifteen years (Chapt. 19.4.1). It was possible to reduce the weight of the rotor blades considerably by means of improved composite-fibre designs, which also created the preconditions for the weight optimisation of the subsequent components. Another step, already implemented in recent years, was the transition from distributed, large and heavy drive train designs to compact designs, in some cases with integrated components (Chapt. 8.6). The progress achieved especially in this sector may be even more important than that of the rotor blades. The weight-optimised design of the mechanical drive train and of the load-bearing nacelle structures has been considerably improved in comparison with the wind turbines of earlier years. Apart from reducing the component weights, the further technical development will also be aimed at constructional simplifications. Gearless drive trains with the electric generator driven directly by the rotor are already competing with conventional concepts and could become the more cost-effective solution in the future. Another weight-saving and cost-reducing measure is the increased use of cast components. One the other hand, the cost of raw material, particularly steel, has been rising in recent years and the general expectation is that this trend will continue.

Looked at overall, advancing the design- and component-specific development of wind turbines still offers a variety of starting points for improvement with regard to lowering production costs. The larger the wind turbine, the greater the potential which can be exploited. However, the development costs and time involved should not be underestimated. Evolutionary development moves in small steps and only becomes effective when every detail is included.

19.7 Alternative Technical Concepts and Achievable Costs

One hope of utilising wind energy more efficiently is based on technical concepts and systems other than those currently represented by conventional horizontal-axis wind turbines with two or three rotor blades. Naturally, it is not possible to predict what innovations the future will bring. Producing technological prophecies is a thankless business also in the field of wind-energy technology. But even without anticipating coming events, there are a number of alternative technical concepts which could be developed to maturity in the foreseeable future. The question is, therefore: Can a qualitative change in the cost level be expected from these technical alternatives to the current horizontal-axis wind turbines?

Innovative drive train concepts

The current standard design, with mechanical transmission gears between rotor and electrical generator, is complex and requires maintenance. The solution of having the electrical generator connected directly to the rotor, which has been attempted on several occasions in the history of wind power technology, is becoming increasingly attractive due to progress made in the field of frequency converters. The variable output frequency of a generator connected directly to the rotor or integrated into the rotor hub can be adapted to the required grid frequency without great expenses or efficiency losses by means of advanced and cost-effective frequency converters. Although a generator operated at low speed and high torque is heavier, the greatly simplified mechanical drive train design represents a definite advantage.

This concept, which was produced for the first time by Enercon with the E-40 series, has proved itself in the meantime as an economical alternative to the standard design and is also being adopted by other manufacturers. Whether it will ultimately be an economically superior design will only become apparent after a long period of probation with large numbers being produced and with long operating times. Large numbers are necessary because it is only by being mass-produced that such a special type of generator construction can compete economically with the standard generators and gearboxes with respect to production costs. Long-term operation is necessary to show whether the lower maintenance costs due to the omission of the gearbox really show up in the costs. In any case, the comparatively great mass of wind turbines with directly driven generator of the "Enercon concept" will remain to be a disadvantage. One way out of this situation is the more compact permanent magnet generator. So far, the material costs of the magnets are high but there is a realistic chance that the costs will reach an economic level in the forseenable future.

Rotors with fewer than three blades

The manufacturing costs of the rotor are clearly determined by the number of rotor blades. Roughly speaking, the share of one rotor blade in the total costs of a wind turbine amounts to roughly 5 to 6 %. It is, therefore, an obvious thought to manage with the fewest number of rotor blades as possible. Unfortunately, however, the rotor power coefficient drops with a decreasing number of blades (Chapt. 5.4.1). The cost advantage achieved by omitting a rotor blade is thus virtually cancelled out. On the other, turbines with two-bladed rotors can be built with lower weight and thus also with lower manufacturing costs. As already discussed in Chapt. 19.4.1., such turbines have a basic inherent potential for lowering costs in comparison with the three-bladed rotors commonly used today.

Single-bladed rotors have even more unfavourable dynamic properties than two-bladed ones. It is for this reason, and others, that wind turbines of the one-bladed Monopteros series were dimensioned for a very low specific power loading (approx. 300 W/m^2). A concept with one rotor blade would, therefore, only lead to an economically superior wind turbine, if significantly lower manufacturing costs could be achieved. From the present point of view, however, this appears to be more than improbable, at least in comparison with two-bladed rotors.

Vertical-axis rotors

In principle, the same considerations apply to the numerous rotor concepts with a vertical axis of rotation. Even the best aerodynamic rotor designs with vertical axes, the Darrieus rotor and the H-rotor (Chapt. 5.8), do not achieve the power coefficients of horizontal-axis rotors. With maximum power coefficients of about 0.40, they are at least 10 % lower. The aerodynamic properties with respect to the loading are more unfavourable in all vertical-axis rotors (Chapt. 6.2). In the case of the Darrieus rotor, there is the additional factor that the manufacturing costs of the rotor itself are also higher than those of a horizontal-axis rotor. The comparatively long rotor blades with their complex geometry, exposed to high dynamic loads, are very costly to manufacture (Chapt. 7.3). Even more decisive is the circumstance that all vertical-axis models have a distinctly lower optimum tip-speed ratio than horizontal-axis rotors (Chapt. 5.8). The equivalent power output must be generated by higher torque. This fact considerably affects overall mass and thus manufacturing costs. This is shown clearly in a comparison between the weights of current vertical-axis turbines with conventional horizontal-axis designs.

These disadvantages of lower aerodynamic efficiency, greater overall mass, unfavourable aerodynamic loading and high rotor blade costs must be compensated for by simplifying the remaining components. The absence of a yawing system and of the tower is not enough, especially since the lack of a tower also entails a lower energy yield at the same wind speed. There are, therefore, as yet no vertical-axis wind turbines which are economically competitive with their horizontal-axis counterparts. Overall mass and manufacturing costs are about a third higher, with lower energy yield. If vertical-axis turbines are to become an economic alternative to the horizontal-axis turbines currently prevailing, they will definitely require a longer period of development.

Nevertheless, there is an argument which speaks for the vertical-axis type of construction under certain conditions. The rotor blades' own weight will not result in perceptible alternating bending moments during rotation as in the case of propeller-like rotors. This could be an advantage for the vertical axis concept in the case of very large dimensions.

Conclusion

The general question of whether alternative technical concepts can reduce the manufacturing costs of wind turbines can be answered as follows: The alternatives to the standard design which are currently available, namely the horizontal-axis wind turbines with three rotor blades, will have a difficult task in competing with the standard concept. This does not exclude the possibility that some innovative concepts could improve their cost situation in the long run. These improvements will be of an order of magnitude which will provide for competition between the different concepts, but they do not point to a qualitatively different level in the manufacturing costs of a wind turbine. Hopes with regard to the general economic situation should, therefore, not be based on alternative technical concepts for the time being. For the foreseeable future, the realistic potential for reducing costs and improving economic efficiency lies in the evolution of the current systems.

19.8
On the Development Costs of Wind Turbines

An analysis of the production costs of wind turbines cannot be concluded without some remarks about the research and development (R & D) costs. From the business point of view, R & D costs must be apportioned to the sales price. The magnitude of this surcharge on the production costs naturally depends on the anticipated number of units produced. In most cases, however, it will not be possible to charge significantly more than 5 to 10 % of the sales price for the amortisation of the R & D costs. The currently produced number of wind turbines thus still only represents a very narrow basis for the industry for amortising the R & D costs. Without public funding of these costs and related research projects, technical progress can only be achieved very slowly and in very small steps.

It is practically impossible to indicate generally valid figures on the level of development costs to be spent on a new project. The various conditions used as basis by the individual "developers" influence these costs at least as much as the product itself. Nevertheless, there are some reference values from comparable fields of technology and also some empirical values from wind turbine development itself.

A correct interpretation of these empirical values first requires an exact definition of the term "R & D costs". Today, it is largely common practice to refer to the costs of research and development in one breath. Upon closer examination, however, technological research is a different matter from engineering development with the goal of producing a specific product. The latter is based on available technologies and with these a new or optimised technical product is developed. Although these two tasks overlap, they should not be lumped together without differentiation.

The development and construction of wind turbines does not actually require any research in the field of new technologies, which does not mean that wind turbines do not profit from technological progress, for example in the field of materials research or electronics. The actual objective of the development of a wind turbine is the development of its system engineering, the component design and the manufacturing. In the text which follows, the term "development costs" is intended to mean expenses without technological research. This is the only way in which development costs can be estimated.

If a complex system such as a larger wind turbine has to be developed with experience and resources being available to the developer from a technically similar forerunner project, development costs at least twice as high as the manufacturing costs of the first experimental unit must be expected. For example, this situation is reflected in the development costs of the first generation of the large wind turbines of the megawatt class. These units were developed almost without exception on the basis of technically similar precursors of the 500-kW class.

However, it would be naive to think that the development work for a commercially mature project would be complete with the building of a prototype. An entirely new system usually requires three design stages to achieve a status mature enough for the market. The first stage of the process is largely experimental, in the second stage reasonably reliable systems with survival potential are achieved, but it is only in the third stage of development, when the technical design principles are known in detail that there is a movement towards cost reduction and value engineering. It is only this final step in the development work which creates the basis for cost-optimised series manufacture and it is in this final phase where the production structures must be included in the development process.

The development of a new generation of wind turbines also passes thorough these development phases and thus requires an investment of some ten millions of dollars.

Altogether, the costs of research and development for a reliable and cost-effective wind power technology will ultimately reach the order of billions of dollars — just as with other technologies, too. Whether this is too much for introducing a new environmentally benign energy supply system, which has the additional advantage of already generating electrical energy today at acceptable costs, should be assessed in comparison with other large-scale technical projects.

19.9 Investment Costs for Turn-key Installations

The total investment costs required for a turnkey system, i.e. for an operable system or a wind farm with all associated structures and technical facilities, form the basis for determining its economic viability. In technical terms, the investment costs for installing an operable, turnkey wind turbine or a wind farm are called *installed costs*. The realisation of a project frequently spans a period of several years from the first idea to the day of starting operation and, therefore, firstly entails considerable planning costs which are frequently underestimated at first glance.

19.9.1 Project Development

The engineering issues of a wind turbine project, once a site has been found, basically comprise the selection of a suitable turbine, constructing the foundation and access roads and connecting the wind turbines to the grid. Planning this work is not too complex. However, the planning work necessary for wind turbine projects today is determined less by technical planning but rather by the increasingly more complicated licensing procedures. Although more and more communities are allocating so-called "wind priority regions", multiple revisions in the planning, caused by numerous objections and the resulting requirements set by the approving authorities, are almost the rule. It is difficult to put a figure on the costs of planning up until the building permit is issued. In the case of large wind farm projects, total costs for project development up to "close of financial business" amount up to 5 % of the investment costs.

The following reference values for the important individual assessments and required planning activities can be used as a costing basis for a medium-sized wind farm project with perhaps 10 large turbines and investment costs of approx. $US 20 M:

– Wind resource assessment (at least two independent assessments)	3 000–4 000 $US
– Geological studies	20 000–30 000 $US
– Noise emission assessment	3 000–5 000 $US
– Shadow casting assessment (if required)	1 000–3 000 $US

– Environmental compatibility study	100 000–200 000 $US
– Micro-siting	20 000–50 000 $US
– Building permit (varies regionally)	100 000–200 000 $US
– Ecological compensation measures (sometimes required)	100 000–200 000 $US
– Personnel costs (for professional staff)	250 000–500 000 $US

Referred to the above investment costs of approx. $US 20 M, the project development costs amount to between 3 and 6 % of the investment costs.

19.9.2 Foundations and Civil Works

The costs for civil works on the site vary very much with the local situation. Obviously, the price levels of the local civil construction firms play a considerable role in dependence on the prevailing local competitive situation. Experience has shown that the costs for the foundations of wind turbines drop with increasing experience of the construction firms involved. This is particularly evident when comparing the prices in various countries. For example, in 1992/93, the costs of wind turbine foundations in Denmark were about one third below the level in Germany.

Foundations

The costs of the foundations are firstly determined by the wind turbine's size and then by the geological composition of the ground. In addition, the technical concept of the turbine

Table 19.15. Typical foundation costs for wind turbines

Wind Turbine	Foundation	Costs in $US	
Small wind turbine	Standard foundation	4 550	(60 $US/kW)
15.6 m rotor diameter	Excavation work	450	
75 kW (pitch controlled)	Concrete	2 300	
	Steel	1 800	
Medium-sized wind turbine	Standard foundation	27 600	(55 $US/kW)
40 m rotor diameter	Excavation work	600	
500 kW (stall control)	Concrete	14 000	
	Steel	13 000	
	Foundation with piles	37 000	(74 $US/kW)
	Foundation base	26 000	
	8 piles, 14 m each	11 000	
Large wind turbine	Standard foundation	61 000	(37 $US/kW)
66 m rotor diameter	Foundation with piles	83 000	(50 $US/kW)
1650 kW (pitch controlled)	(20 m)		
Large wind turbine	Standard foundation	75 000	(50 $US/kW)
64 m rotor diameter	Foundation with piles (20 m)	100 000	(67 $US/kW)
1500 kW (stall controlled)			

plays a certain role. Stall controlled wind turbines with fixed rotor blades, in particular, generate much greater loads at extreme wind speeds when they are standing still than pitch-controlled turbines which can set their rotor blades to the feathered position in this case, and, therefore, require more expensive foundations compared to pitch-controlled turbines. (Chapt. 12.6). The costs for a standard foundation for stall-controlled turbines are up to 50 % higher than those for pitch-controlled turbines (Table 19.15).

In some coastal areas, for example in northern Germany, the foundation costs are influenced significantly by the necessity for a pile foundation (Chapt. 12.6). In some regions, piles going down to a depth of 25 m are required, which entails about an increase of 30 to 40 % in costs compared to a "standard foundation" in solid ground.

Access roads and civil works

In connection with the costs for foundations, costs are also incurred for other civil works, particularly of access roads. Road building and ground stabilisation for heavy building equipment (cranes) are a significant cost factor in the case of wind farms. Up to 5 % of the ex-factory price of wind turbines is used for this, as is shown by relevant examples of large wind parks. In an easily accessible terrain, an average value can be considerably lower, though.

This cost factor almost never shows up with smaller or single wind turbines. Nevertheless, certain expenses are necessary here as well. However, expenses incurring here are frequently included in the foundation or installation costs and are not listed separately. They cannot, therefore, be quantified easily.

19.9.3
Electrical Infrastructure and Grid Connection

The costs for connecting a wind turbine to the grid are essentially determined by two factors: The distance to the *connecting point* and the local voltage level of the grid (Chapt. 18.5). The costs arising are allocated in proportion to the property boundaries of the turbine operator and the electricity utility. Up to the point of transfer (substation) which, as a rule, also constitutes the boundary, the owner of the wind turbine must pay for all electrical installations himself (s. Fig. 18.20). In the case of wind parks, this electrical infrastructure also includes the internal electrical cabling and any intermediate transformers for matching the existing voltage level.

The utility grid begins after the point of transfer. Apportioning of costs from here to the next possible connecting point to the existing grid is very often the subject of controversy and discussions, at least in Germany. One side argues that the utility must provide the grid and must thus also bear the full costs, and the utilities, on the other hand, hold against this that, especially in extreme cases, a small wind turbine with a few kilowatts of power requires may require a long feeder and it would not be in their general interest to take care of such a completely uneconomic investment. In practice, a compromise is frequently agreed upon, i.e. the wind turbine owner pays a "lost building-cost contribution" to the utility, which covers a part of the costs for the feeder (Chapt. 18.5).

It goes without saying that it is impossible to indicate generally valid guide values for the costs for the grid connection which can be applied directly to an individual case. Local conditions have a much too strong an influence on that. Instead, typical grid-connection costs will be illustrated by means of two examples (Tables 19.16 and 19.17). Extreme situations cannot be taken into account here. Costs which are part of the grid connection are indicated as "turbine-related costs" to permit easier generalisation. This means that the costs which are not determined by the power of the wind turbine to be connected, but are merely caused by the cable length from the transfer point to the connecting point, are listed separately as "distance-related costs".

A statistical evaluation of the grid-connection costs of wind turbines set up in Germany up until 1992 during the "250 MW Wind" programme revealed a range of about 110 to 170 $US/kW. This value also includes the costs of the internal cabling required in small wind parks [4]. According to a study by the German Wind Energy Institute (DEWI), the grid-connection costs amounted to an average of between 130 and 150 $US/kW for wind turbines connected after 1995 [5]. For single turbines, an average of 12 % with respect to the ex-factory costs of the wind turbine is mentioned, and 13 to 14 % for wind farms.

Table 19.16. Grid connection costs for a single wind turbine

	Costs in $US
Wind turbine	
Rotor diameter 40 m, rated power 500 kW, induction generator coupled directly to the grid, stall control, operating voltage 400 volts	
Ex-works price	400 000
Grid connection	
Distance to connecting point 200 m, (feeder line)	
Medium-voltage grid 20 kV	
Electrical infrastructure	
– Transformer housing incl. transportation	9 000
– Low-voltage switchboard with safety isolators, transducer and meters	6 000
– 0.4/20 kV transformer 500 kVA	8 000
– 20 kV medium-voltage switchgear in SF_6-design with two sections, safety circuit breaker for transformer, circuit breaker with grounding for cable outlet	7 000
– Cable connections, electrical material and assembly	2 500
– Connection of the feeder line	3 500
Total of turbine-related costs	36 000
Distance-related costs	
– Feeder line, 20 kV ground cable (200 m at 55 $US/m)	10 000
Grid connection and feeder line	46 000
Specific costs (total)	92 $US/kW
Specific costs (without feeder line)	72 $US/kW
Percentage of the ex-works price of the wind turbine	9.0 %

Table 19.17. Electrical infrastructure and grid connection costs of a small wind park (built in 1992)

	Costs in $US
Wind park	
7 Vestas V27 wind turbines, 27 m rotor diameter, 225 kW rated power, 400-volt induction generator,	
2 Vestas V39 wind turbines, 39 m rotor diameter, 500 kW rated power,	
690-volt induction generator (incl. 20-kV transformer),	
Total power installed 2 575 MW	
Ex-works price of the wind turbines	1 945 000
Grid connection	
Feeder line 1500 m	
20-kV medium-voltage grid	
Electrical infrastructure (Turbine-related costs)	
– Substation with transformer № 1, 0.4/20 kV, 1000 kVA, 1 medium-voltage section	55 000
– 4 kiosk substations with transformers № 2, 3, 4 and 5 with 0.4/20 kV, 630 kVA, 4 medium-voltage sections each	70 000
Electrical fittings, civil works	20 000
– Cable ditch (1100 m with 15 $US/m)	17 000
– Low-voltage cable (1000 m with 40 $US/m)	38 000
– Medium-voltage cable (1000 m with 45 $US/m)	40 000
Total	240 000
Feeder line (Distance-related costs)	
– Feeder line, 20 kV underground cable, (1500 m at 55 $US/m)	75 000
Grid connection and feeder line	315 000
Specific costs (total)	122 $US/kW
Specific costs (without feeder line)	93 $US/kW
Percentage of the ex-works price of the turbines	12.3 %

More recent projects point towards lower specific grid connection costs of less than 10 % in some cases (see Tables 19.19 and 19.20). As a rule, large wind farms with a total power of more than 15 MW will need to be connected to the high-voltage grid (Chapt. 18.5). Since this requires a separate substation to be built, grid connection becomes correspondingly more expensive. A 20/110-kV-substation for a power range of 200 to 500 kVA costs up to 60 to 70 $US/kW.

19.9.4
Other Cost Factors

When wind-energy projects are carried out on an all-inclusive basis, other costs may be incurred the level of which can differ widely and which should in any case be considered in the planning as items to be kept in mind.

Transportation, erection and commissioning

Transportation to the site as well as the erection and commissioning are considerable cost factors with larger wind turbines. In the case of series-produced commercial wind turbines, these costs are normally included in the purchase price. In the case of the costs of transportation, this is only true if the manufacturing companies are not too far away from the installation sites ("a few hundreds of kilometres"). They do not, therefore, appear under the "site-related costs" item of the manufacturer even though, in their essence, they do of course belong in this class. However, this general rule does not mean that some manufacturers do not try to claim for additional costs for these items from their customers. Thus, costs of this type can be found on the operator side, too, in a number of projects. Disregarding remote and relatively inaccessible sites, these costs will, however, not materially alter the general cost pattern.

Operational monitoring of larger wind parks

All modern wind turbines, without exception, are designed for fully automated parallel operation on the grid (Chapt. 18.7.2). Nevertheless, a central monitoring system still makes sense in larger wind parks for practical reasons. As a rule, this is accommodated in an operations building which also contains equipment for wind turbine maintenance and facilities for the comfort of the maintenance staff.

The costs of a central supervision system organised from economic points of view are difficult to assess in a generally valid way. These expenses depend on the size of the wind park and the intentions of the operator. According to the few existing empirical values, a usable central monitoring system for a small wind park with 20 or 30 wind turbines can be realised with a budget of $US 80 000 to 100 000. Of this, about $US 30 000 to 50 000 are accounted for by the signal transmission from the individual turbines to the central station. About $US 55 000 must be allocated for a modest operations building. Moreover, remote data transmission via modem to a remote location (next power plant, if the utility is involved, or to the manufacturing factory of the wind turbines) is increasingly popular. Some wind turbine manufacturers offer systems which are optimised for their turbines.

"One-off" financing expenses

The costs for financing a project are frequently only assessed as interest and debt repayments within the framework of current expenses. However, commercial banks increasingly demand arrangement fees as "bank charges". Technical investment projects with their specific risks require a lot of effort for examination on the side of the bank, a fact which is used for explaining the necessity of such charges. The class of non-recurring financing costs also includes an agreed discount which must be covered by the financing scheme. Nowadays, the "financial planning" or "financial engineering" of large-scale projects is a separate planning task, which can scarcely be mastered without expert advice. Sounding out all possibilities and obtaining reduced-interest credits, subsidies for investment costs and other aids and optimising the income, the expenses and last, but not least the dividend payments to the investors over the economic life of the project require the active assistance from the banks or other financial experts.

The interest for bridging loans during the building phase until the project yields its first income is also part of the one-off financing costs. With a small wind park with an investment total of e. g. $US 10 million, it takes about one year from the time when the first payments have to be made to the time of commissioning. To this is added the advance financing of the legally required value-added tax. Depending on the speed with which the taxman pays back the expenditures, which can be considered as pre-tax expenditures, another financing gap of up to one year is thus created. Given this condition, the total financial expenditure for bridging finance amounts to between $US 55 000 and 120 000 for a wind park project of the size mentioned

19.9.5 Total Investment Costs — Selected Examples

The total investment costs for turnkey installations can only be illustrated by some typical examples. The examples listed were selected such that both typical applications and the currently common range of plant costs are illustrated. The basis is the ex-works price of the wind turbine. The remaining cost proportions are indicated in percent of the ex-works price.

Single wind turbines on low- and medium-voltage grids

The installation of a single small wind turbine in a power range of about 20 to 30 kW by a private consumer requires comparatively low site-related expenses. The prerequisite for this is that the grid connection can be carried out without extensive modification of the electrical house installation and that there are no expenses for the land (Table 19.18).

Table 19.18. Investment costs of two turnkey installed wind turbines. Small wind turbine on a low-voltage grid and medium-sized wind turbine on a medium-voltage grid

	Small wind turbine 15.7 m rotor diam./75 kW		Medium-sized wind turbine 40 m rotor diam./500 kW	
Wind turbine	$US	%	$US	%
Ex-factory price incl. transport, erection and commissioning	80 000	100	400 000	100
Site-related costs				
Planning and permissions	480	0.60	25 000	6.25
Civil works	—	—	12 000	3.00
Foundation	4 500	5.63	25 000	6.25
Cabling and grid connection	6 000	7.30	46 000	11.5
	House connection		200 m 20 kV cable to the grid	
Miscellaneous	3 000	1.90	5 000	1.25
Total	13 980	15.30	113 000	27.25
Total investment costs	93 980	117.50	513 000	128.30

The installation of a single wind turbine for operation on a medium-voltage grid which can in most cases only be reached at a relatively great distance, already requires distinctly higher site-related costs. These range between 25 and 35 % of the ex-works price. The lower values can only be attained with the transformer being incorporated in the wind turbine (Table 19.18).

Wind parks

The specific investment costs of wind park installations are of the same order of magnitude as those of single turbines. Although the internal cabling produces additional costs, some other costs do no increase proportionally to the number of turbines so that, overall, the specific total costs remain at the same level.

Geographical conditions and the grid connection naturally also have an influence on the investment costs. Small wind parks with a total power output of up to about 15 MW can still be connected to the medium-voltage grid. Since this is closely meshed in densely settled regions, the distances to be bridged are not too great on average. Under favourable conditions, i. e. firm ground for standard foundations, grid connecting point nearby within a few kilometres, connection to the medium-voltage system or to an existing transformer substation, wind turbines with 20-kV transformers already incorporated, the site-related "balance of plant costs" can be limited to about 20 % of the wind turbine costs (Table 19.19).

The conditions are different with large wind farms with total power outputs of more than 15 MW. Wind farms of this size in most cases have to be connected to the high-voltage grid (110 or 220 kV). The distances to be covered by the feeder are greater which increases the costs for the grid connection. In many cases, a completely new transformer substation needs to be built and financed. If there are other cost-increasing factors such as a necessity for pile foundations, the site-related costs can rise to up to 40 % of the ex-factory price (Table 19.20).

It has to be noted that the costs are also affected by the organisational concept of project execution. Large wind parks are in most cases developed and built by commercial single-project organisations. These companies develop the project, construct and operate the wind park or they act as general contractors and sell shares in the project to institutional or private investors (Chapt. 20.1). Therefore, the "soft costs" for planning, financing, warranties and liabilities are high. This expenditure is reflected in the investment and operating costs. Where the projects are implemented by institutional investors or utilities, the financing costs and also some other costs are considerably lower. It is then possible to achieve specific investment costs for turn-key installations of 1 000 $/kW.

In contrast to these professionally managed large-scale projects, there are numerous smaller wind parks which are built and operated by local private initiators. These projects are realised with a lot of personal commitment and without counting and accounting for every working hour. Thus, the cost structure of such projects is much more favourable.

As already mentioned in Chapter 19.8.1, the planning costs for large wind farm projects play quite an important role. The planning periods are becoming longer and longer, automatically increasing the costs for "site development". Large wind farm project frequently require planning periods of four or five years.

Table 19.19. Investment costs of a large wind park on an inland site, connected to the medium-voltage system, financed by a limited partnership company

Wind park 13 wind turbines 1 MW, 60 m rotor diam., 68 m height Total power 13 MW	Costs $US	Proportion %
Wind turbines		
Ex-works price incl. 20 kV transformers, transportation, erection and commissioning	12 100 000	100
Site-related costs		
Foundations	460 000	3.80
Civil works, access roads, fences, gates	130 000	1.08
Electrical infrastructure: Internal cabling 20 kV (5.5 km) Switchgear (20 kV)	270 000	2.23
Grid connection (110 kV grid): Modification to existing transformer substation, utilities substation, 6 km feeder	510 000	4.21
Remote monitoring	12 000	0.10
Land lease during construction	27 000	0.22
Environmental compensation fee	130 000	1.07
Expert reports	40 000	0.33
General contractor: planning, management and guarantees	900 000	7.43
Purchase of the lease contracts, preliminary planning with building permit	630 000	5.22
Bridging loan	290 000	2.40
Financing and legal costs, bank fees	230 000	1.90
Total site-related costs	3 629 000	29.99
Total investment costs	15 729 000	129.99
Specific investment costs	1210 $US/kW	

Considering these examples in general, the range of specific investment costs including the financing costs for the turnkey installation of wind parks amounts to between 130 to 140 % of the ex-works price of the wind turbines. A value of about 130 % represents a usable first reference value.

These costs include the technical investment, the project financing and organisation in a "single purpose company" for building and operating the wind park. The examples shown also include the construction by a general contractor which amounts to about 5 % of the project costs. Not all these cost factors are necessary in each individual case but they are typical of large commercial wind parks. With a "lean" organisational and financial frame a specific investment figure of approximately 1000 $US/kW can be reached.

Tabelle 19.20. Investment costs of a large wind park, connected to the high-voltage system, financed by a limited partnership company

Wind park 32 wind turbines 1.5 MW, 64 m rotor diam., 80 m height Total power 48 MW	Cost $US	Proportion %
Wind turbines		
Ex-works price incl. 20 kV transformers, transportation, erection and commissioning	41 600 000	100
Site-related costs		
Foundations	2 460 000	5.91
Civil works, access roads, fences, gates	1 060 000	2.55
Electrical infrastructure: 32 Intermediate transformers and internal cabling	2 390 000	5.75
Grid connection (20 kV): Substation, include. 20/110-kV transformer Feeder (5 km)	2 490 000	5.99
Remote monitoring	180 000	0.43
Aircraft warning lights	160 000	0.38
Land lease during construction	300 000	0.72
Environmental compensation fee	700 000	1.68
Expert reports and permissions	770 000	1.85
General contractor: planning, management, and guarantees	2 230 000	5.36
Purchase of land lease contracts and building permit	1 990 000	4.78
Bridging loan	900 000	2.16
Financing and legal costs, bank fees	1 300 000	3.13
Total site-related costs	16 930 000	40.69
Total investment costs	58 530 000	140.69
Specific investment costs	1219 $US/kW	

19.10 Operating and Maintenance Costs

Wind turbines do not consume any fuel, but neither can they work completely without operating costs. Maintenance and repairs, insurance and several other expenses cause recurring operating costs. With some reservations, the level of these expenses can be indicated in a generally valid form. A private owner operating a small wind turbine next to his house and who does the occasional repair work himself, has a different view of operating costs than the commercial operator of a large wind park or an electricity supply undertaking. Up to a certain extent, an accurate operating-cost calculation will always have to be an individual calculation.

19.10.1 Maintenance and Repairs

Not too long ago, the costs required for the maintenance of a wind turbine were one of the largest uncertainty factors for the long-term economic calculation of power generation with wind energy. The obvious reason was the early stage of development of this technology. In the early phase of a new technology, routine and unscheduled maintenance work is encumbered by numerous technical breakdowns and failures. The costs incurred by this were in fact late development costs. In numerous cases, these costs made any economic calculation look absurd. This was especially true of the operation of the first large wind turbines, which were operated predominantly for research and development purposes.

This situation has changed drastically in the meantime. With regard to the costs of maintenance and repair, reliable information is today available from the operation of several ten thousands of commercially operated wind turbines, even if it is taken into consideration that the calculated life of the turbines, twenty years or more, has only just been reached by a few turbines. After all, the oldest commercial wind turbines have already operated for twenty years.

The statistically recorded commercial operation of wind turbines had its beginning approximately in the year 1978 in Denmark and in 1982 in the US with the wind turbines of California. In Denmark, the "Association of the Danish Wind Turbine Manufacturers" and the wind turbine test station in Risø evaluate the experience gained in operation and publish it regularly [6]. The progress in technical maturity of the wind turbines achieved within this period is illustrated by the fact that in 1979, 50 % of the wind turbines still suffered one "severe defect" per year, while in 1984 this failure rate had already been reduced to 5 %. In the meantime it is the insurance companies, above all, who carry out detailed statistical surveys and analyses about the susceptibility of wind turbines to failure. Insurance rates to insure against machine breakage are thus a clear indicator of the frequency and level of defects of a certain type. Today, the wind turbines of the latest generation already achieve a degree of reliability which is equal to that of any comparable technology. This finding also applies against the background that in recent years there has been increasingly damage in gearboxes and bearings which have not reached their expected service life (Chapt. 18.9).

Maintenance contracts and warranties

Almost all manufacturers offer maintenance and service for the wind turbines they supply. These contracts contain various services. In the simplest case, only routine maintenance, prescribed at certain intervals, is agreed upon. However, manufacturers also offer "all-inclusive" maintenance contracts in combination with an availability guarantee and taking care of any repair costs up to a period of five years after commissioning.

Thus, service contracts are closely linked to the manufacturer's *warranty* for the product. Unfortunately, there are no harmonised regulations as yet. A warranty period of one year, formerly common practice in mechanical engineering, is no longer customary today. Today, most manufacturers offer a warranty of two years. In some cases, when a comprehensive maintenance contract has been concluded, some manufacturers also go beyond this period. Negotiating a favourable "package" including purchase price, warranty and service contract is left to the skill of the customer. He is well advised to display a certain tenacity and, above all, to be well informed about the offers of other competitors.

The cost of the maintenance contracts depends on the services agreed upon. In 2000, the costs of the maintenance contracts comprising all routine maintenance work prescribed for wind turbines of the following size amounted to:

– 200 – 300 kW:	2000 – 4000 $US/year
– 500 kW:	5000 – 6000 $US/year
– 1500 kW:	10 000 – 15 000 $US/year

Operating materials and large spare parts are additionally charged, unless they are included in the warranty. Referred to the ex-works price of the turbine, this amounts to a percentage of between 0.8 and 1.0 % per year.

Repair reserves

Since the maintenance contracts generally do not cover more extensive repairs and the insurance does not account for every type of damage, the operator will not be able to avoid keeping back a certain annual reserve for larger repairs. To a certain extent these costs are exchangeable for the costs of an insurance against machine breakage. This means that on condition that such insurance has been taken out, the reserve can be fixed at a relatively small amount. (Chapt. 18.9.2). The length of the warranty period also plays a certain role.

In view of the fact that there is as yet no statistically relevant experience about a service life of twenty or more years, the actual amount of any appropriate repair reserve is still in dispute, as discussed in Chapter 18.9.3. Many commercial operators base their calculations on one percent of the ex-factory price of the wind turbines. They are obviously assuming that the greater proportion of the repair costs to be expected will be met by the turbine insurance company. This percentage may be too low for certain turbine types from the production years of 1995 to about 2000.

19.10.2 Insurances

The operator of a wind turbine will normally try to cover the financial risks associated with operating the turbine as far as possible with insurances. Insurance coverage plays an important role and requires some expert knowledge, particularly with a technology which yet has to prove its long-term reliability. At present, the operating risks of wind turbines are covered by the following insurances:

Liability insurance

This almost indispensable insurance covers the risks against damage claims by third parties, both with regard to persons and property, which can be caused by the operation of the wind turbine. It entails only low costs of about 100–150 $US/year for a medium-sized wind turbine.

Insurance against machine breakage

Coverage against major repairs has largely become common practice. However, it cannot be expected that insurance will endlessly cover all repairs in case of an unusual accumulation of claims for damages. Insurance conditions list a number of exemption clauses, particularly with regard to so-called "domino claims" (Chapt. 18.9). The costs of insurance against machine breakage are approx. 0.5 % of the ex-works price of the wind turbine. In view of the increase in damage to gearboxes and bearings in recent years, the insurance premiums will rise again, at least until the turbines of the last few years of production have demonstrated that, with proper design, the components affected can attain their required service life.

Loss-of-profit insurance

A so-called loss-of-profit insurance is taken out for commercially operated energy generation plants. In cases of doubt, private owners of wind turbines can do without it. This insurance covers the loss of revenue in times of a standstill which was caused by a technical defect or an interruption of operation not attributable to the operator. The costs are about 0.5 % per year of the annual revenue from the sale of power, which corresponds to approximately 0.05 % of the ex-works price of the wind turbine.

Insuring the operation of wind turbines competently requires special knowledge of the risks and characteristics of power generation in general, and turbine technology in particular. For this reason, some insurance brokers have specialised in the insurance of wind power plants and turbines [7]. They offer independent consultation on conclusion of the contract and are also helpful in the regulation of damage claims.

19.10.3 Other Operating Costs

Apart from the costs of maintenance and repair and the required insurances, there are other operating costs which must be considered in any complete operating cost calculation. These costs vary greatly in some cases and are "operator-specific" which is why the figures below can only be reference values for average conditions.

Land leasing

Unless the operator does not own the land himself, a land lease must be paid for the site where the wind turbines are set up. In most cases this is agreed with the property owner, who usually runs a farm, in the form of a "secondary usage" agreement. The prices for land use have steadily risen in recent years. They depend on the local circumstances, on wind turbine size and on the prevailing wind regime. For example in Germany at good sites close to the coast, the prices for site leases in 2000 were as follows for turbines in the following size categories:

– 500 bis 1000 kW: 3000 bis 4 000 $US/year
– 1000 bis 2000 kW: 6000 bis 10 000 $US/year

In the weaker inland wind regions, at the limits of economically viable wind energy utilisation, the lease payments asked for are lower. Some landowners will not agree any fixed lease payments but ask for a share in the income to the amount of the above-mentioned leasing costs. This is usually, for example, 5 % of the annual income from the sale of power.

Basically, it would also be possible to purchase land for the installation of wind turbines. A simple rough estimate shows, however, that even with very low prices per square-meter, a purchase does not make economic sense, unless the wind turbine operator himself arranges for further use of the remaining land, thus providing a second source of income.

In connection with the lease payments to the property owner, there are frequently also payments to be made to the local community. The communities demand certain compensation payments for inconvenience during the construction phase or for the use of paths and roads during operation. It is not really possible to express these payments in figures but, as a rule, the costs are of such an order of magnitude that they do not put in question the viability of the projects.

Taxes

Increasing commercialisation of wind-power utilisation also yields profits for which taxes must be paid. Usually, a commercial wind park operator must pay tax on the profit gained. It is obviously not possible to indicate generally valid reference values here. However, the operator should understand clearly that considerable taxes will have to be paid, at the latest after his credits have been paid off.

Administration

The operation of a technical installation with an investment volume of more than one million dollars, whether it is only a simple one-megawatt turbine or, even more so, a large wind park, is not possible without a certain amount of administrative effort. Compiling financial balances and, in the case of commercial operating companies, determining the distribution of dividend payments, external services such as tax and legal consulting etc. incur costs. Commercially organised wind-park companies calculate about 0.5 to 1 % of the investment costs per year for this type of expense.

19.10.4 Total Annual Operating Costs

The total annual running costs for the operation of a commercial wind turbine or wind parks, as a percentage of the ex-factory price of the turbine, can be added up as follows:

– Routine maintenance (service and maintenance contract) 0.8–1.0 %
– Repair reserves after warranty period 1.0–1.5 %

– Insurances		0.5–0.8 %
– Land lease		0.5–1.0 %
– Monitoring and administration		0.7–1.0 %
	Total costs	3.5–5.3 %

Assuming a specific wind regime, the annual running costs can be related to the energy yield or the income from the sale of power of a wind turbine. At the reference site with a mean wind velocity of 5.5 m/s at 30 m height, a 1 500-kW turbine with a rotor diameter of 70 m provides an annual amount of energy of 3.5 million kWh (see Table 20.3). The average operating costs of 4.3 % of the ex-factory price of the turbine are thus approx. 60 000 $US. Assuming, for example, a sales price of 9 $USCent/kWh, the turbine produces an income from power to the amount of 315 000 $US. The annual operating costs accordingly amounts to about 19 % of the income from power or are approx. 1.7 $USCent/kWh referred to the annual energy yield.

In a statistical evaluation of wind power projects in the US and in Denmark, it was concluded that 0.8 to 1.2 $USCent/kWh were paid for "Operation and Maintenance" [8]. These data included the costs for maintenance, insurances and administration (operation), but apparently no reserves for major repairs. In addition, they relate to relatively small turbines of earlier design and thus cannot be compared with the more recent large turbines.

19.11 Offshore Projects

The costs and economic viability of offshore projects for utilising wind energy are a separate chapter — even in this book. They differ from wind farms on land in at least three points: The investment costs are higher, the usable wind velocities are also higher and the operating costs are still of a speculative nature for the time being.

The first offshore projects built after 1990 as small demonstration projects do not yet have the decisive features which determine the costs of today's commercial offshore wind farms (Chapt. 17.1.2). Nevertheless, the specific investment costs provide at least some indications. The construction costs were within 1 900 to 2 300 $US/kW. A comparison with a corresponding inland site was made for the Vindeby project in Denmark. The result showed that the investment costs were about twice as high, but with the comment that, on the basis of the experience gained, it was possible to lower the costs to 1.5-times those of a comparable land site in a fictitious further project [8].

The next generation of offshore projects, which is already much closer to future commercial projects especially with regard to the size wind turbines used, Yttre Stengrund (Sweden), Utgrunden (Sweden) and Middelgrunden (Denmark), is exhibiting a relatively wide range of specific construction costs from more than 1 200 $US/kW (Utgrunden) down to a relatively low 1 400 $US/kW for Middelgrunden. The reason for this lies in the different site conditions. Utgrunden is located 14 km away from the shore in 10 m depth of water whereas Middelgrunden is close to the shore in a few meters depth (Fig. 17.9).

The first offshore projects exhibiting nearly all the features of future commercial offshore projects are the Danish wind farms Horns Rev and Nysted/Rødsand with a total power of 160 MW each and consisting of wind turbines of the 2-MW class (Chapt. 17.1.2).

The specific investment costs quoted for this project are 1 650 $us/kW for Horns Rev and 1 600 $us/kW for Nysted/Rødsand. This would be the benchmark figure for the offshore projects of the next few years.

The cost structure of this first generation of commercial offshore wind farms is clearly apparent in an actual project planning schedule as listed in Table 19.21. The project, with a

Table 19.21. Investment costs of a projected large offshore wind park

		Cost $us	Proportion %
Wind park			
120 wind turbines, rated power	2.5 MW		
Rotor diameter	80 m		
Hub height	70 m		
Distance from land	approx. 30 km		
Depth of water	12–17 m		
Mean wind speed at hub height	9.0 m/s		
Wind turbines			
Single ex-works price incl. erection	1 950 000 $us		
	120 units	234 000 000	54.4
Foundations (tripod/steel tube)			
Production cost per unit	350 000 $us		
Transport and erection per unit	350 000 $us		
	120 units	84 000 000	19.55
Electrical infrastructure			
Internal power system (24 kV), 85 km cable run (260 $us/m)		22 100 000	
Offshore substation (24/110 kV), include erection		18 000 000	
30 km 110 kV marine cable run (460 $us/m)		13 000 000	
30 km 110 kV overhead line on land (400 $us/m)		12 000 000	
Substation on land (110 kV/220 kV)		6 000 000	
	Total	71 000 000	16.73
Remaining infrastructure and logistics			
Maintenance ship, pontoons etc.		5 000 000	
Operations building		1 000 000	
Remote monitoring, measuring and control		2 000 000	
Anemometer system (4 masts 70-m high)		1 800 000	
	Total	9 800 000	2.28
Project development			
Technical planning and project management		15 000 000	
Geological, traffic engineering and environmental investigations		10 000 000	
Other investigations, permits		5 000 000	
	Total	30 000 000	6.98
Technical investment costs		429 700 000	100
Specific investment costs		1432 $us/kW	

total power of 300 MW, is planned for erection in the Baltic Sea at a distance of about 30 km from the coast at a water depth of approx. 15 m. This example clearly shows the differences with respect to wind farm projects on land. The wind turbines themselves now represent only slightly more than one half of the construction costs. The foundation costs amount to about 20 % and the electrical infrastructure is 17 %. The calculated specific investment costs of 1 433 $US/kW are higher by about 50 % than the specific investment costs "on land", using as a reference scale the investment costs of approx. 1 000 $US/kW widely used internationally. To this must be added the costs of financing, quite a considerable factor especially with these long-term projects.

The extremely long planning and licensing periods present a considerable hurdle to implementing large offshore wind farms, a hurdle which is also of great significance in the costing. The project development costs to be found, which must be considered to be typical "risk capital" before the final building permit is granted, are completely out of proportion compared with anything previously experienced in wind energy utilisation.

In the more remote future, when greater depths in the North Sea are made accessible for offshore wind energy utilisation, the cost pattern evident here may change. The distances from the coast will be greater, which will increase the costs not only for the foundations but also for the electrical link to the mainland. On the other hand, there will be a new generation of larger offshore wind turbines in the 4 to 5 MW power class so that the cost structure will also change in this respect.

The greatest uncertainty factor are the operating costs of the offshore wind farms because of the lack of experience. For the reasons mentioned above, it is not really possible to use any empirical values hitherto obtained from the smaller demonstration projects. There are empirical values about maintenance, repair and service life available from other offshore technologies for the foundations, but the actual point in question are the operations and maintenance costs for operating the wind turbine in the open sea, and the resulting technical availability.

The costs for maintenance and repairs will depend decisively on the extent to which it will be possible to make the future offshore wind turbines easy to maintain in their critical functional areas such as, e. g. all the sensors, the control systems and the monitoring of operations, and to introduce redundancy wherever possible, so that, with the restricted accessibility "on the high seas", the number of maintenance and repair trips required becomes as low as possible.

The logistics, too, will be of decisive significance for the operating costs. If the problem of accessibility in rough seas is not solved in a satisfactory manner, even the smallest defects will diminish the availability of the turbines to such an extent that economic operation becomes questionable (Chapt. 17.3.4).

On the basis of the investment costs outlined and considering the higher operational risks, the economics of offshore wind energy will not likely to be better compared to land installations, but offshore wind energy has a large potential for the future (see Chapt. 20.2.2).

It should be noted that the calculated specific investment costs of 1430 $US/kW do not include any financing costs. This has to be considered when comparing this figure with the examples of wind park costs in Tables 19.19 and 19.20.

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Chapter 20

Wind Turbine Economics

When considering the negative effects of conventional fuels on the environment and their limited availability, or the safety questions associated with the use of nuclear energy, renewable energies must not be looked at from an economic point of view only. However, this does not mean that the utilisation of renewable energy sources makes sense "at any price". Exorbitant energy prices are not acceptable to industry or to the economy in general. Profitability from a business management point of view and profitability for the national economy are, however, two different aspects entirely.

Regardless of any macroeconomic significance, it is the duty of an operator operating as a business, and also his right, to demand cost effectiveness. However, the business results are also influenced by numerous macroeconomic conditions. Particularly in energy generation, it is political conditions which determine to a large extent what proportion of the costs is passed on to the community as a whole and which costs really enter into balance sheet of the energy producer. These factors affect both the energy prices and the competitiveness of the various energy sources.

Economic viability in the sense of being cost effective for the investor, therefore, always means whether or not the system is cost effective "within the framework provided by the relevant energy policy". Whether this framework is indeed concerned with the interest of the public is a different question. This is a political task and not the responsibility of an operator working as a business. The latter can only be economically active under the existing macroeconomical conditions.

The current economic situation of wind energy has two faces. On one hand, there is its application at the consumer end. Measured against the consumer prices of electrical energy, not only for the end user, but also for communal or regional power distributors, the generation of electricity from wind energy is economical, provided the site has appropriate wind conditions.

On the other hand, there is the electricity generation by the utilities. In this case, the power-generation costs of the large power plants set the economic standard. From the standpoint of the utilities, these much "tougher" economic conditions do not yet allow a profitable utilisation of wind energy. However, the development potential of wind turbines indicates that the chances for power generation from wind energy to become competitive with conventional power plants are quite good. This will apply, above all, when the utilities are prepared to integrate wind turbines into the organisation of their existing pool of power plants in such a way that power generation from wind energy can be allowed to make some contribution to the firm power station capacity, apart from the energy generated.

Calculating the specific economics of an investment project is not realistic without including the conditions of financing. Even if the economical assessment deals primarily with the economic potential of the technology, the financial aspect has to be considered. Innovative and courageous "financial engineering" frequently provides the decisive impulse for helping new ideas to achieve a breakthrough and this also applies to the success of wind energy.

20.1 Financing

The capital required for implementing a wind-turbine project is firstly determined by the overall investment costs. However, the method by which the funds are raised, that is how the investment is financed, is not without influence on the recurring and non- recurring costs. The financing method, in turn, is itself influenced by the legal form of the "owner" or "operator" (legal entity) of the wind turbines. If, for example, a financing company, the "project company", carries out the investment, other forms of financing are possible than in those cases where wind turbines are purchased and operated by private individuals. Analysing the economics thus requires that the legal form of the owner, and the associated possibilities for financing, are taken into consideration. It is, therefore, impossible to make a completely abstract and generally valid statement about the economic viability which will always remain subject to the individual situation to a certain degree.

Commonly, the investment will be largely financed by bank credits (borrowed capital), thus predetermining the interest and repayment service. If the investment is completely financed by equity in exceptional cases, an operator thinking in business terms will calculate a return for his investment, which will provide for a return of the equity within a given period and for a minimum interest rate. This calculatory service of the equity is of the same magnitude as for the borrowed capital so that there is no difference between equity and borrowed capital as far as obtaining a rough estimate of the economics involved is concerned.

Banks grant credits only with certain securities which must be provided by the borrower. Traditional bank financing is secured by so-called "real securities", that is mortgages or the transfer of ownership of buildings and assets. An increasing number of banks has been venturing into so-called *project financing* where the loans are no longer secured with real securities [1]. The borrower commits himself to allocate the revenue from his project predominantly to servicing his debt to the bank. The bank's security thus rests exclusively on their faith in the long-term security of the income, i. e. the technical and organisational stability of the project and its economic viability.

This type of financing practice is widely used for larger investment projects. It goes without saying that under these conditions banks demand a very detailed technical and economic examination of the projects and ultimately also exert influence on the investment decision itself. As an additional security, the banks demand a minimum share of equity in order to reduce their credit risks.

In some countries, i. e. Germany or Denmark, bank loans for investment projects in the energy and environment sector are provided at cheaper prices. For example, loans paid out via the commercial banks are available at lower interest rates for various refunding programs supported by state-owned banking organisations. These credits are requested from the commercial banks for the investment project to be financed and are then available to them as refinancing means. Most wind-turbine projects in Germany were financed in this way in recent years. The average interest rate was about 1.5 to 2 % below the direct loans provided by the commercial banks.

Apart from bank financing, direct public grants also played a role in the field of renewable energies in the past. A variety of direct and indirect funding programs is available in most countries. A complete overview of the various subsidising programs and their frequently highly complicated conditions is virtually impossible and would not make sense within the scope of this book. Public grants provided an important impulse in the early phase of wind-energy utilisation, but lost their importance with the improvement of wind-energy economics. Today, public grants only play a role in research and development projects.

Financing an investment project requires a legal framework on the owner's side. In the simplest case, when the owner is a natural person, he or she will register a business, unless this is already the case. The liabilities towards the creditor bank for the credits as well as the tax assessment are basically the same as in any other trade or business. With larger projects, a special company which owns the project legally will be established, particularly when external investors are involved. In this case there are several options with regard to the legal form:

Private company

A private company is the most uncomplicated legal form and can be formed by a number of persons (at least two). The tax advantages (writing off the operating losses) can be taken advantage of directly by the individual person. All partners in the company are personally liable for up to the total sum of obligations

Limited company

In the case of the limited company, the liability is theoretically restricted to the nominal capital. In real life, however, banks demand a personal liability or other real securities for loans to small limited companies. Tax advantages with regard to depreciations remain within the limited company and cannot be used by the individual partners. Larger projects can be handled better by a limited company than by a private company since a manager must be appointed and an annual account must be kept.

Limited partnership

This legal form is mainly used in the form of limited company & limited partnership. This complicated construction has the advantage that the "unlimited partner" who otherwise is personally fully liable can be replaced by a company with limited liability. In the limited partnership, capital can be obtained to a greater extent through any number of "limited partners" who are only liable with their capital invested. In addition, the limited partners can use the tax losses of the company. Numerous wind farms are operated by such a combined limited company & limited partnership. This legal form is of significance with respect to the economic viability of wind energy utilisation since the nominal return on one's own capital can be comparatively low. The investors (limited partners) will achieve a higher effective return "after tax" due to tax advantages. Their own capital thus becomes cheaper for project financing. This legal form of wind park financing is of great importance particularly in Germany. In other countries, limited partnerships are relatively unknown, depending on the tax laws in force.

Joint-stock company

The joint-stock company, typically the legal form of large companies, does not yet play an important role in wind-energy utilisation. It is not possible to generate any personal tax advantages for the shareholders in a joint stock company. However, the basis for raising capital by issuing shares is very large. Stock companies are subject to strict supervision under the provisions of the Shares Law and must regularly publish their business report. It is conceivable that future large-scale projects such as offshore wind parks will be financed and operated on this basis.

An accurate analysis of the economics involved must take into consideration the characteristics of these legal forms, particularly the tax effects. Companies, for example in the form of the limited company & limited partnership, are frequently called "tax-shelter companies" somewhat condescendingly. However, critics are obviously not aware of the fact that all reputable companies will make use of their tax advantages as extensively as possible. The only difference between them and the "tax-shelter companies" is that these publish their tax advantages and dividend payments for the investors in brochures, as prescribed by law and are, therefore, regarded as objectionable. Whether or not these tax laws are "just" is quite a different issue and belongs exclusively into the realm of politics. At any rate, any individual calculation of economic viability which does not take into account the tax effects is unrealistic from the point of view of a professional operator.

20.2 Estimating Electricity Costs and Repayment Period

How much does wind power cost? Any discussion about the economics of wind turbines will ultimately return to this point. It is important to recall first the order of priority of the parameters influencing electricity generation costs:

- The mean annual wind speed at the site.
- The performance characteristics of the wind turbine, in particular the power curve.
- The investment costs
- Sufficiently high technical availability of the wind turbine.
- The running costs, essentially for operation and maintenance.

As soon as specific figures are available for these parameters, a simple "static" calculation of the achievable power-generation costs should mark the beginning of every analysis of the economics. This is the only way to show the objective potential of the technology to be assessed. More complicated "dynamic" calculations of the economics are indispensable for long-term investment decisions, but they necessarily introduce numerous speculative elements into the calculation. The result is then determined not only by the economic potential of the investment itself, but also by the assessment of certain overall economic conditions and their evolution over a relatively long period.

In many cases, the problem of economics is not one of direct inquiry into the costs of power generation but of calculating the repayment or amortisation period of the investment with a given revenue from power generation. This situation exists almost always when the energy produced is fed into the grid. Calculations must then be based on existing electricity rates stipulated by legal regulations or power purchase contracts. The calculation of economics is the same as in the case of calculating power-generation costs, except that the repayment period is derived indirectly from predetermined power payments.

The repayment time granted for the capital invested can be considered from various perspectives. There are many good reasons why, from a socio-economic point of view, a wind turbine could be granted a repayment time corresponding to its life time. But from the point of view of a commercial investor, a payback period of twenty or more years for an investment sum of some hundreds of thousands of dollars is unrealistic. Capital recovery periods exceeding 10 years run counter to good market practices, particularly for small turbines bought by private users. A private investor who accepts an amortisation time of ten years for a small wind turbine does so with quite a lot of idealism.

It is a different story with wind park projects including large wind turbines of the megawatt power range. The public utilities are used to having to write off large conventional power stations over twenty or more years. Moreover, a wind turbine in the megawatt power range will certainly have a longer life expectancy than a small 50 kW turbine. For these reasons, there would be some justification in granting longer repayment periods to larger wind turbines.

The capital raised for an investment; in particular the bank loans, will in many cases be redeemed by regular repayments over a certain period of time, called the redemption or amortisation time or better, the capital repayment time. The constant repayment rate comprising interest and repayment is called "annuity". It represents the capital costs to be raised annually. The annuity can be calculated in dependence on the period of capital repayment and the interest rate by using the familiar formula:

$$A = p + \frac{p}{(1+p)^n - 1}$$

where:

A = annual capital costs, (annuity in % of the capital invested)

p = interest rate (%)

n = period of capital repayment (years)

Figure 20.1 shows the annuity with sufficient accuracy for rough estimates without using a calculator.

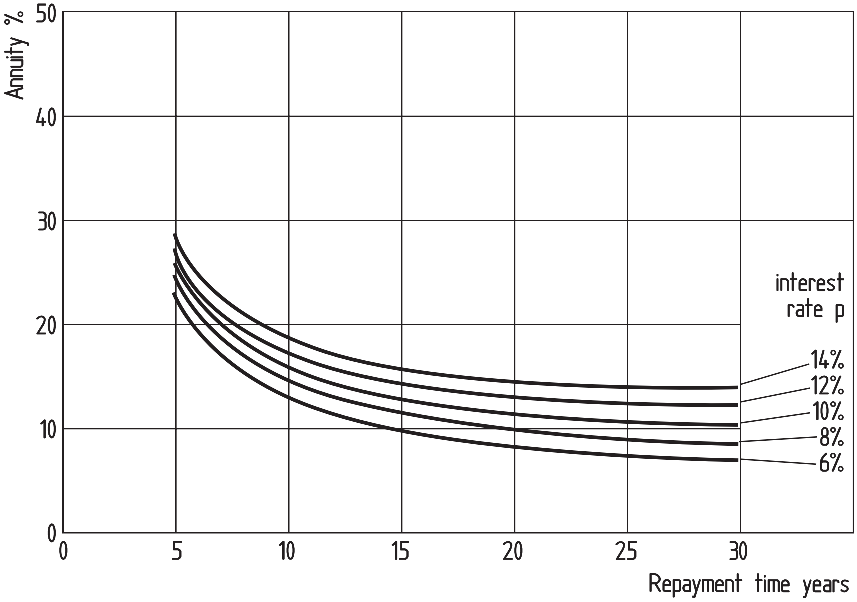

Figure 20.1. Annuity as a function of the interest rate and the period of capital repayment

20.2.1 Selected Examples

The costs of generating electricity from wind energy can be demonstrated on the example of a medium-sized wind turbine in the power range of 500 kW and of a large wind turbine with 1 500 kW rated power. The calculation is based on a site with a mean annual wind speed of 5.5 m/s at 30 m height. These wind data characterise a good inland site at some distance from the coast.

The second most important factor after the wind conditions is the service of capital for the investment costs. Usually, a relatively small proportion of the means for the investment is raised using the investor's own capital and the greater proportion is financed through bank credits. Depending on the economic stability of the project as estimated by the banks, the latter usually demand equity of between 20 and 30 %.

In calculating the required service of capital, no distinction has been made between equity capital and bank loan in the example. In a first approximation, an investor will expect at least the same interest rate for his own capital as for the bank loan. Professional investors will generally expect a shorter repayment time for their equity capital used.

If the calculation is based on a service life of the wind turbine of 20 years, the power generation costs amount to only about 0.06 $US/kWh (Table 20.2). This is considerably below the level of the price which must be paid by an electricity consumer under current tariffs. If it were technically possible to use the generated power oneself, i. e. directly on the consumer side, wind power would be an almost unrivalled economical power source. Even

Table 20.2. Calculation of the electricity-generation costs of a medium-sized wind turbine (rotor diameter of 40 m, 500 kW rated power, mean annual wind speed 5.5 m/s at 30 m height)

Investment costs	
Ex-works price of the wind turbine	400 000 $US
Planning, installation, infrastructure and financing (30 % of ex-works price)	120 000 $US
Total investment costs	520 000 $US
Annual costs	
Maintenance, insurance, land lease	16 000 $US
(4 % of ex-works price)	
Service of capital (6 % interest rate p.a.,), repayment period within	
– 10 years (annuity = 13.59 %)	70 668 $US
– 20 years (annuity = 8.72 %)	45 344 $US
Site	
Mean annual mean wind speed at 30 m height	5.50 m/s
Roughness length z_0	0.1 m
Mean wind speed at hub height (50 m)	6.00 m/s
Annual energy yield	
at 98 % technical availability	950 000 kWh
Specific investment costs with respect to annual energy yield	0.55 $US/kWh
Power-generation costs	
– with repayment in 10 years	0.091 $US/kWh
– with repayment in 20 years	0.065 $US/kWh

if a practical repayment period of 10 years is used as a basis, the power-generation costs are still favourable at about 0.09 $US/kWh.

In practice, however, the real situation for the operator of a wind turbine is determined by the income he receives when the electricity generated is fed into a large interconnected power system. Assuming that the price for the power generated is 0.08 $US/kWh, this amounts to a repayment time of about 11 to 12 years. From the point of view of a commercial operator, this value is quite acceptable for a long-term investment, or the development of wind energy utilisation would not have been quite as meteoric. This time also corresponds to a usual credit period for the investment credits for financing wind energy projects.

The characteristic figure "invested capital per kilowatt-hour generated annually", which is 0.55 $US/kWh in the example calculated, can be used as criterion for the economic viability of the project (Chapt. 19.1). Under the assumed conditions of payment for electricity, this value must not be significantly higher than 0.5 $US/kWh if it is to be used for achieving an economic situation "wind turbine at a particular site". The prerequisite for the validity of this criterion is, however, that the operating costs are at the normal level (Chapt 19.9).

With the introduction of commercial wind turbines in the megawatt power class, the economic situation of wind-power utilisation has moved forward another step. Although the power generation costs are no cheaper than with smaller wind turbines (in the sample calculation the levels are about the same (Table 20.3), large wind turbines with tower heights of 80–100 m have advantages at sites with weaker wind regimes so that the economic area of application of wind energy utilisation is clearly extended geographically

Apart from these economic figures, the fact also plays a role that scarce sites in densely settled areas are becoming more and more valuable. It will always be attempted, therefore, to utilise these sites with the largest turbine possible, an argument which has a decisive influence on the trend to use turbines of ever-increasing size.

When considering these figures, one should never lose sight of the significance of the mean wind speed at the site. Figure 20.4, therefore, shows the relationship between power generation costs and the mean annual wind velocity for the example shown in Table 20.3.

Taking into consideration the total wind speed spectrum available in most countries, the power generation costs of a medium-sized or large wind turbine can be assessed as follows: At a good site (5.5 m/s at 30 m height), power-generation costs of about 0.05 $US/kWh can be achieved, if the entire service life of a wind turbine is granted as depreciation period for the capital investment. This value would be of significance if wind turbines were to be used

Table 20.3. Calculation of power-generation costs of a large wind turbine. (rotor diameter 70 m and 1500 kW rated power, mean wind velocity 5.50 m/s at 30 m height)

Investment costs	
$US Ex-works price of the wind turbine	1 400 000 $US
Planning, infrastructure and financing, (30 % of ex-factory price)	420 000 $US
Total investments costs	1 820 000 $US
Annual costs	
Maintenance and repairs, insurance, land lease	56 000 $US
(4 % of ex-factory price)	
Service of capital (6 % interest p.a.)	
– 10 years (ave. annuity 13.59 %)	247 738 $US
– 20 years (ave. annuity 8.72 %)	158 704 $US
Site	
Mean annual wind speed at 30 m height	5.50 m/s
Roughness length z_0	0.1 m
Mean wind speed at hub height (80 m)	6.50 m/s
Annual energy yield	
at 98 % technical availability	3 500 000 kWh
Specific investment costs with respect to annual energy yield	0.52 $US/kWh
Power-generation costs	
– with repayment in 10 years	0.087 $US/kWh
– with repayment in 20 years	0.061 $US/kWh

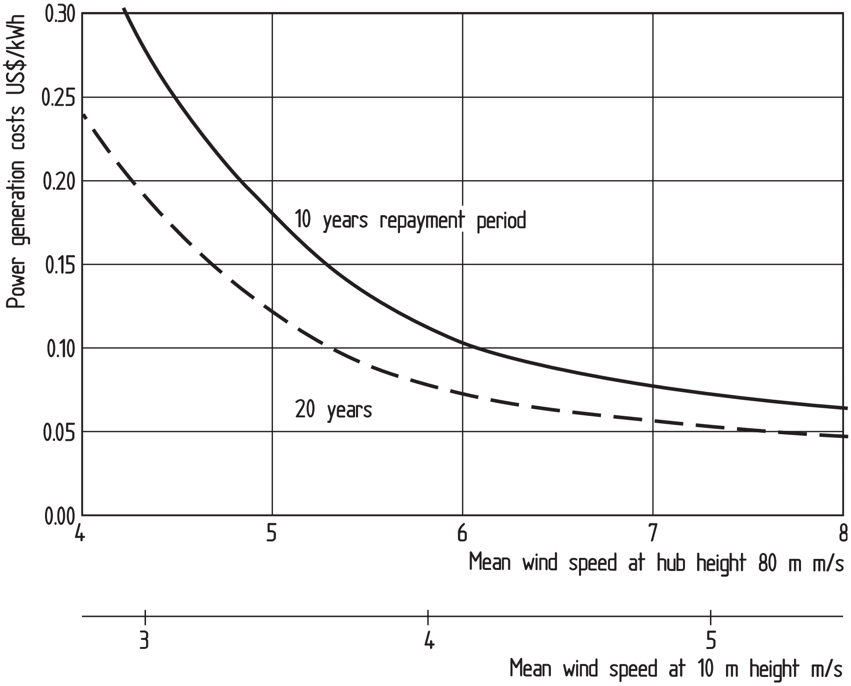

Figure 20.4. Power generation costs for a large wind turbine, 70 m rotor diameter and 1 500 kW rated power, as a function of the mean annual wind velocity at rotor hub height (80 m) and at 10 m height (increase in wind speed with height according to log. formula with $z_0 = 0.1$ m)

in competition with conventional power stations by the electricity producers. An operator who must assess the economic feasibility of the investment by means of the payment for feeding electricity into an interconnected system, can achieve an economically acceptable situation at a mean annual wind speed of above 6.0 m/s at rotor hub height. For large wind turbines with rotor hub heights of 80 m and more, this means that regions with mean wind speeds above about 4.0 m/s measured at 10 m height can be used economically.

20.2.2 Offshore Wind Parks

The economic viability of offshore siting of wind turbines will firstly be judged by whether it can stand a comparison with a land site. On the one hand, there are higher investment costs and greater expenditure for maintenance and repairs and on the other hand there is the increased energy yield due to the higher wind velocities.

The investment costs are manageable, at least in those offshore areas used for the first generation of offshore wind farms. Operating costs are a bigger question. The planned annual operating costs for the first, still relatively small, offshore projects are stated to be in the range of 4 to 7.6 % of the price of the wind turbines or 2.5 to 5 % of the total investment costs. From today's point of view, it can be assumed that the annual operating costs will be at least one third higher than with a land installation. In the static calculation of the power generation costs of a planned offshore wind farm in the Baltic Sea in Chapt. 19.10, the total operating costs including all additional costs (like, e. g. lease payments) were set at 5 % of the technical investment costs.

The calculation of the power generation costs in Table 20.5 shows that, with comparable financing conditions and repayment period, the power generation costs per kilowatt-hour are at the same level as in the examples of land-sited wind farms. The increase in investment costs (about one third) has been virtually cancelled out by the increased energy yield at a mean wind velocity of 9.0 m/s at a hub height of 70 m.

There is no clear answer to the question whether offshore wind energy utilisation is more economic in the long term than on land. Among other things, it is a matter of what sites are used for the comparison. Land sites are known to exhibit a wide range of mean wind velocities from the coast to the inland regions.

Table 20.5. Power-generation costs of a projected 300-MW wind park in the Baltic Sea (Chapt. 19.10, Table 19.21)

Investment costs	
120 WKA at 2.5 MW ea., ex-factory price	234 000 000 $US
Project development and techn. infrastructure	195 700 000 $US
Technical investment costs	429 700 000 $US
Financing and additional costs (5 % of investment costs)	21 485 000 $US
Total project costs	451 185 000 $US
Annual costs	
Maintenance and repairs, insurance, land lease, management (5 % of investment costs)	21 485 000 $US
Service of capital (6 % interest p.a.)	
– 20 years (ave. annuity 8.72 %)	38 490 080 $US
Site	
Mean annual wind speed at 30 m height	8.40 m/s
Roughness length z_0	0.000 2 m
Mean wind speed at hub height (70 m)	9.0 m/s
Annual energy yield	
at 95 % technical availability	
8 000 MWh/a per unit	960 000 MWh
Specific investment costs	
referred to annual energy yield	0.47 $US/kWh
Power-generation costs	
with repayment in 20 years	0.062 $US/kWh

It may also be assumed that wind energy technology will make further advances with respect to lower investment costs, and thus lower power generation costs, both on land and offshore at sea.

One thing can be said with certainty, however: There is no other renewable energy conversion technology with which it would be possible within the foreseeable future to achieve power outputs which are comparable to conventional power stations and, at the same time, achieve power generation costs which are economically compatible in today's energy economy — even if they are still higher than the generation costs in conventional power stations. The future offshore wind parks thus open up new perspectives in energy economics.

20.3 Power Generation Costs of Wind Turbines in Competition with Conventional Energy Sources

In principle, the economic viability of electricity generation from wind energy on the basis of the calculated power generation costs can be assessed under three different frames of reference:

- The electricity price to be paid by a user who is able to use the wind power himself,
- the income received by an operator of a wind turbine on feeding the current into the public grid,
- the power generation costs of an electricity producer who wants to generate electricity from wind energy as an alternative to other power stations.

For the reasons discussed in Chapter 16.3, the self-use of wind energy is restricted to a few exceptions and, therefore, virtually of no significance in wind energy utilisation. Today, wind turbines are operated almost without exception for the purpose of feeding the generated power into the grid. The legal conditions for feeding into the grid are subject to regulations in almost all European countries. The decisive question is, therefore, what price is offered to the operator of a wind turbine for one kilowatt-hour of electricity fed in. In some countries, there are legal or semi-legal regulations for payment for feeding-in power (such as Germany, Denmark, Spain, Greece, France). In other countries, particularly in the United Kingdom, the turbine operator must negotiate the electricity price with the utility or compete with others. Table 20.6 shows the payments made for wind power in some countries of the European Union in recent years.

In many cases, the costs of generating electricity from wind energy are derived from average values of the general electricity prices. The increasing liberalisation of the electricity market in the EU has resulted in a continuous movement in the electricity prices in recent years which also affect the payments for electricity fed in from renewable sources so that the current payments for supply must be ascertained with respect to the present day. However, in Germany, the Renewable Energies Law has resulted in the link between payment for supply and the general electricity prices being broken as was intended politically. It is a different matter that this regulation, which is quite advantageous for the development of renewable energies, is not undisputed at the European level but a uniform regulation for

Table 20.6. Prices paid for wind energy in some member states of the European Union (€Cent/kWh) and in the US ($usCent/kWh), 2003

Country	Payment	Basis
Germany	8.7	Law (EEG), 2000
Denmark	7.5	Law
Netherlands	7–8 (expected)	Certificates Dealing
France	8.38	Law since 2002
Italy	8–10 (expected)	Certificates Dealing
Spain	6.30	Law since 1997
Portugal	6–7	Law
Greece	6–7	Law
UK	5–7	Tendering
Sweden	5–6	—
US	4.86 + 1.7	purchase price + tax refund

the production of electricity from renewable energies can be expected also at European level within the foreseeable future.

It is certain that, in future, wind energy will also be utilised by the electricity utilities. In Denmark and Great Britain, the course is already set in this direction with the construction of the first large offshore wind farm. As wind farms increase in size, this development will gain momentum not only in the offshore areas but also in other countries. Seen from this perspective, the comparison with the power generation costs of the existing power stations is the decisive reference. This should, however, not be confused with the extremely low short-term "so-called power-generation costs". Excessive capacities built up in the days of the monopolies and in some cases over-hasty liberalisation of the electricity market towards the end of the nineties have led to extremely low electricity production or market prices in some countries. Excess power from power stations written off is being offered prices of 2–3 Cents and less per kilowatt-hour. No conventional power station can generate electricity at these prices if genuine complete cost accounting is used as a costing basis.

The reference for future power generation costs is the complete cost accounting for new power stations. A serious business calculation will show that power cannot be generated for less than 3 to 3.5 Cents/kWh even with the most cost-efficient gas and steam power stations today. Coal-fired power stations using imported coal have power generation costs of at least 4.5 Cents/kWh (Table 20.7). Taking into account the distribution costs, the electricity costs are approximately 5 Cents/kWh at the 110-kV level. This is the only level to use for an economically correct comparison of power generation from wind energy. It must be emphasised at this point that this is a purely "business" calculation. It does not take into consideration the much-quoted "external costs" of power generation from fossil fuels or from nuclear energy (see Chapt. 20.7). The power generation costs from different types of power plants on a European basis are summarised in Table 20.6 [2].

It is of interest in this connection to cast a glance at the composition of the electricity prices from the producer through to the industrial or private end-user. Even if the figures

Table 20.7. Electricity generation costs from different types of power plants [2]

Fuel (Technology)	Specific investment costs $us/kW	Capital costs $us/kWh	Fuel costs $us/kWh	Operating costs incl. admin. and profits $us/kWh	Total generating costs $us/kWh
Coal	1000–1200	1.8–2.0	1.5–4.5	1.3–2.0	4.6–8.5
Nucl. power	1200–1800	2.0–2.3	0.8–1.0	1.0–1.3	3.8–4.6
Gas	450–600	1.0–1.3	1.5–1.8	0.5–0.8	3.0–3.9

can only be taken as a rough guide — it is a well-known fact that the utilities never disclose their figures — their order of magnitude should be correct. In 2004, the following typical picture from the point of view of a private power user was obtained in Germany:

– Power generation costs	3.5 Cent/kWh
– Transmission costs	
Extra high voltage (380/220 kV)	0.9
High voltage (110 kV)	1.5
Medium voltage (20 kV)	2.5
Low voltage (400 V)	3.0
– Licence fee (municipalities)	1.0 (variable, up to 2.0)
– Environmental tax	1.8
– Value-added tax (16 %)	2.0
Total:	16.2 Cent/kWh

A mixed electricity price of payment for demand and energy consumption price of approximately 16 Cent /kWh is thus an end-user price which, with honest complete cost accounting, can not be lowered, at least not under the currently prevailing conditions. To this, profits and other costs have to be added. A cost factor which frequently raises controversy concerns are the transmission costs. In many countries, for example in Germany, they are considered to be far too high. It can be expected that these costs will come down with thorough liberalisation of the electricity market.

Large industrial consumers often get their electricity at the 110-kV level and, therefore, only have to pay for the production costs and the EHV distribution costs. Neither do they have to pay electricity and value-added taxes. These users were offered electricity at prices in the range of 4 to 5 Cent/kWh.

Since 2002, however, the electricity prices have been rising again. It seems that the utilities have also recognised that market prices on this level are not a lasting basis for successful business. The margin between the payments made today for power from renewable energy sources and the business costs incurred in the energy industry will thus become less by itself.

It is important to have knowledge of these relationships when assessing the economic viability of generating power from wind energy. The further evolution of payments for power from renewable energies cannot be considered in complete detachment from the business costs in the electricity industry, even if it is necessary to pay a bonus for environmental friendliness as is only right.

20.4 Dynamic Calculation of Economic Viability

The static calculation of power-generation costs conveys only a momentary picture of the economics. A long-term investment decision requires a more far-reaching perspective. This means that a "dynamic" approach must include the anticipated development of certain economic conditions in the investment period. This unavoidably introduces speculative elements into the calculation of economic viability, but a long-term investment decision without this uncertainty is impossible anyway.

These speculative elements include the general inflation rate and the increase in electricity prices. These two factors have been the issue of many contentious discussions. Regardless of developments in recent years, it can be assumed, according to the opinion of the majority of economic experts, that inflation will amount to several percent per annum in the long-run and that the prices of electricity from fossil fuels will rise much more quickly than the remaining costs rising at the rate of inflation. Not least, there will be increasing expenses for the environmental compatibility of conventional power generation which will contribute to rising electricity prices.

20.4.1 Present-Value or Discounted Cash-flow Analysis Method

Calculation methods which consider the dynamic development of the relevant economic factors are based on the *present-value* or *cash-value* method [3]. It is characteristic of this method that the different times of the occurrence of costs and income are taken into account regardless of whether the money has been or will be paid or received in the past or in the future. This is done by deduction of unaccrued interest (discounting) of all payment flows to a common reference time. The value of the payment flows at the respective time is called the *present value*. The sum of all present values is called the *net present value (NPV)*. Comparing the return flows discounted to a time with the value of the initial investment provides a picture of the profitability of the project.

The net present value is calculated as follows:

$$c_0 = \sum_{i=1}^{n} \frac{E_i - K_i}{q^i} - \frac{R_l}{q^l} + \frac{S_n}{q^n} - I_0$$

where:

c_0 = capital value (present value)
n = economic life of the investment in years
E_i = revenue in the year i
K_i = expenses in the year i
q = $(1 + p)$ with the discount interest rate p
S_n = residual value of the investment in year n
R_l = renewals investment in year l
I_0 = initial capital investment

The net present value (NPV) can be calculated for any point in time of the economic operating period. It evolves from negative values at the beginning of the operating period to positive values at the end of the economic operating period. An investment is economic when the NPV added together over the period of investment, is positive. A negative value indicates an uneconomic investment. For the example shown in Tables 20.3 the NPV varies with respect to the economic operating period of 20 years as shown in Fig. 20.8.

Repayment period

Besides the net present value, which provides a criterion for the investment's economics, the repayment (amortisation) period is an important further criterion. Formally, this is the period where the difference between costs and earnings is equal to the initial investment. This also means that the repayment period occurs at the time at which the net present value becomes equal to zero. This occurs in year ten in the example considered (Fig. 20.8).

Average power generation costs in the investment period

Utilities often calculate for their investment projects (power stations) the average cost of power generation calculated over the lifetime of the investment and compare this with an alternative in order to find out which is the economically more advantageous project. Naturally, both investments must be calculated by using the same method and under no circumstances must the actual power generation costs be compared with those calculated by

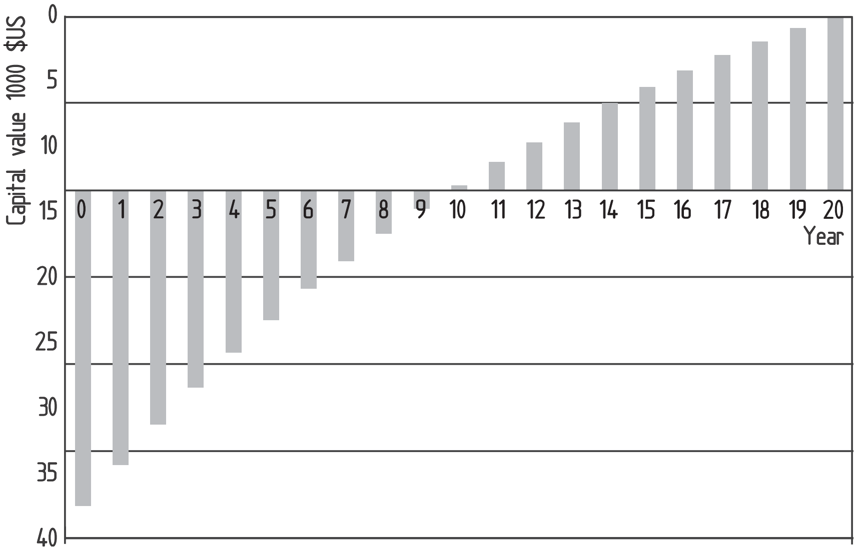

Figure 20.8. Evolution of the net present value (NPV) with respect to the economic life, using the financing of a large wind turbine as an example (Table 20.3)

the discounted cash-flow analysis method. The average power generation costs according to the present-value method can be obtained by the formula:

$$K_w = \frac{1}{n\,E} \sum_{i=1}^{n} \frac{I_o f_w + K_i}{(1+p)^i}$$

where:

K_w = average power generation costs over the economic life
n = economic life of the investment in years
E = annual energy yield
I_o = initial capital investment
f_w = recovery factor
K_i = expenses in the year i
p = discount interest rate

The factor f_w contained in the formula is called *annuity* or *recovery factor:*

$$f_w = \frac{(1+p)^n p}{(1+p)^n - 1}$$

For the example of Table 20.3 and Table 20.7, average power generation costs of K_W= 3.69 Cent/kWh are obtained. The recovery factor (annuity) is $f_w = 8.72\,\%$.

By themselves, these figures do not provide much information. They are of significance when several different investments are compared using these criteria as reference. This is the case with large utilities where a often a number of alternatives are compared with respect to technology and site. Such choice is usually not available for wind energy utilisation which is why cash flow calculation is more informative for large wind energy projects. This is described in the next chapter.

20.4.2 Cash-Flow Projection

Today, large investments are assessed economically almost exclusively by applying a cash flow calculation over the economic service life of the investment object. This method is generally called a *cash-flow calculation.*

The cash-flow method is based on an accounting "spreadsheet" that is a year-by-year listing of revenue income and expenses over the service life of the project, taking into consideration such dynamic factors as price increases, variable tax payments etc. The result of the continuous comparison of earnings and expenses is the so-called *cash flow.* Unfortunately, the term "cash flow" is not clearly defined in the relevant literature. One widely used definition is that cash flow is the difference between income and object-related expenses including interest payments. Accordingly, cash flow is the money available before depreciation, redemption, tax payments and profits. In other words, these are the liquid means generated which are available for repayment, taxes and dividend payments.

The cash flow calculation thus provides a complete formal overview of the most important economic figures of the investment object in its assumed lifetime. As always, however, the truth is much more complex. Only a slight change in the input data, for example in the indices of price and cost increase, will dramatically alter the numerical values after a few years. It could also be said that, with the appropriate input data in one's calculation, any investment can be made to appear to blossom or to wilt. Moreover, the profitability criteria derived from the cash flow calculation, e.g. the *internal interest rate,* can be altered considerably by formal manipulation, for example by changing the period of observation.

Regardless of these doubts, today no profitability analysis of investments is complete without cash flow calculation. Like all complex methods, it must be generated responsibly and used with the necessary care. It also provides valuable service by revealing the influence of certain factors in the sense of a "best case" and "worst case" consideration by means of "sensitivity analyses". This throws light on the economic stability of the investment with changes in technical and economic parameters.

The example of a wind farm consisting of 10 wind turbines of 1.5 MW rated power each in Tables 20.9 and 20.10 shows the results of a cash-flow projection. Table 20.9 provides the necessary input data for the calculation. Table 20.10 shows the development of income and expenses over an operational period of twenty years. The relative order of magnitude of the cash flows becomes quite clear in the graphical representation of Fig. 20.11. The predominating significance of the service of capital over the assumed credit period of 12 years is immediately obvious. Within this period, the result for the investor is quite modest, and it is only after the credit has been repaid that the project really becomes attractive from an economic point of view. With the assumed electricity revenue of 9 Cent/kWh, the repayment period for the equity used will be reached in ten years.

The so-called *internal rate of return* (IIR) provides information on the profitability of the equity used. The value depends to a certain extent on the assumed times of supply and withdrawal of payments so that the exact method of how it was determined should always be specified [5]. In the example calculated, the internal rate of return is 10.1 % over the term of 20 years. This value does not quite meet the expectations of so-called "institutional investors" who generally expect a return of about 15 % on their capital investment and a shorter term. For many private investors, however, who initially can still link their investment to tax advantages, the fact that after the loans have been repaid, the available cash flow becomes very high, acts as an incentive for this type of investment.

From the point of view of the banks providing finance, the *debt service cover ratio (DSCR)* is a measure of the economic stability of the project. It indicates the amount by which the available cash flow exceeds the payments for interest and repayments of loans. The banks often demand a DSCR of at least 1.3.

In real cases, professional cash-flow projections for large investments projects are carried out in much more detail, as in the example of Table 20.10. In particular, it contains variable interest payments and repayment rates, different durations of various bank loans and more detailed tax payments.

Overall, cash flow projections are an indispensable tool in the development of complex financing models. Large investment projects can no longer be realised without them today. The risk inherent in long-term investments can generally only be managed by means of a combination of equity capital and outside capital and by very careful distribution of the risks.

Table 20.9. Input data and economic conditions for the cash-flow projection for the operation of a wind farm

Wind farm	
10 wind turbines of 1.5 MW rated power each	
Rotor diameter 70 m, Tower height 80 m	
Investment costs	
Ex-works price of wind turbines include. transport and erection	14 000 000 $US
Planning, techn. infrastructure and financing	
(30 % of ex-factory price)	4 200 000 $US
Total investment costs	14 820 000 $US
Annual costs	
Maintenance and repairs	80 000 $US
Reserves for repairs (after 2 years' warranty)	234 000 $US
Insurances	67 500 $US
Administration, operation	126 000 $US
Land lease	100 000 $US
Misc., e. g. restoration reserves	20 000 $US
Financing	
Equity 30 % of investment	5 646 000 $US
Loan 70 % of investment (interest rate 6 %, 10 years term)	13 174 000 $US
Depreciation	
Book depreciation 16 years (linear)	1 176 000 $US
Variations	
Cost increase	2.0 % p.a.
Electricity sales price increase	0.0 p.a.
Energy yield	
Mean wind speed at hub height	6.5 m/ s
Net energy production (98 % availability, losses due to park efficiency,	
electrical transmission and safety deduction)	30 000 MWh
Electricity sales price	0.09 $US/kWh

A specific risk which has to be pointed out is the variability of income due to the unsteadiness of the mean annual wind speed from one year to the next (compare Chapt. 13.3.3). The cash flow projection as the basis for the project financing is based on the long term average of the wind speed, but the experience is that several successive years of lower wind speed can occur. If this happens, the project runs into liquidity problems if no financial reserves are available. In many single-purpose companies based on project financing and on the cash flow projection described this situation can cause severe problems.

Table 20.10. Cash-flow projection for the operation of a wind farm

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
A. Income Statement																				
Revenues																				
energy sales revenues	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700	2700
interest earned on reserve account	0	8	16	19	21	24	26	28	29	30	31	26	21	16	9	2	7	8	8	7
Total revenues	2700	2708	2716	2719	2721	2724	2726	2728	2729	2730	2731	2726	2721	2716	2709	2702	2707	2708	2708	2707
Expenses																				
maintenance contract	0	0	80	82	83	85	87	88	90	92	94	96	98	99	101	103	106	108	110	112
insurances	67	69	70	72	73	75	76	78	79	81	82	84	86	87	89	91	93	94	96	98
land rent	100	102	104	106	108	110	113	115	117	119	122	124	127	129	132	135	137	140	143	146
repair reserves	0	0	105	107	109	111	114	116	118	121	302	308	314	320	327	333	340	347	354	361
administration	126	129	131	134	136	139	142	145	148	151	154	157	160	163	166	170	173	176	180	184
other costs	20	20	21	21	22	22	23	23	23	24	24	25	25	26	26	27	27	28	29	29
Total operating costs	313	320	511	521	532	542	553	564	576	587	778	793	809	825	842	859	876	893	911	930
Depreciations	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176	1176				
Net Income																				
earnings before interest and taxes (EBIT)	1211	1212	1028	1021	1013	1005	996	987	977	967	777	757	736	714	691	667	1832	1814	1796	1778
interest payments	790	756	720	682	642	599	554	505	454	400	343	282	218	149	77					
earnings before tax	421	456	308	339	371	406	443	482	523	567	434	475	518	565	614	667	1832	1814	1796	1778
tax paid (35%)	147	160	108	119	130	142	155	169	183	198	152	166	181	198	215	234	641	635	629	622
Net income	274	296	200	220	241	264	288	313	340	368	282	309	337	367	399	434	1190	1179	1168	1156
B. Cash-Flow Statement																				
debt service reserve account	0	262	523	622	711	792	862	921	969	1005	1028	882	714	524	310	72	249	262	260	242
net income + depreciation	1450	1472	1376	1396	1418	1440	1464	1489	1516	1545	1458	1485	1513	1543	1576	1610	1190	1179	1168	1156
debt repayments	566	600	636	674	715	757	803	851	902	956	1014	1074	1139	1207	1280					
cash-flow available for dividend payments	666	666	666	666	666	666	666	666	666	666	666	666	666	666	666	1581	1581	1581	1581	1788
in % of equity	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	28%	28%	28%	28%	32%
Debt Service Cover Ratio (DSCR)	1.68	1.68	1.56	1.56	1.55	1.54	1.53	1.53	1.52	1.51	1.38	1.37	1.35	1.33	1.32					

Internal Rate of Return (IRR), 20 years: 10.1%

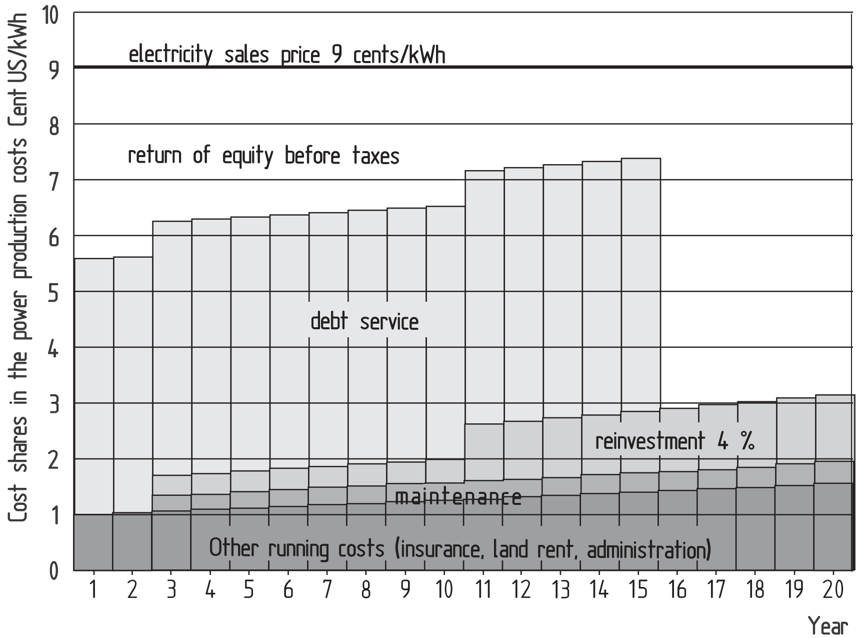

Figure 20.11. Cash-flow components in the cash-flow projection for the operation of a wind farm

20.5 Energy Recovery of Wind Turbine Production and Operation

In discussions of renewable energy systems the question is frequently asked of whether the energy required for manufacturing the equipment is not greater than the energy yielded during the service life of the system. Quite generally, this can be countered with the argument that when an energy-generating system has a fairly acceptable commercial capital recovery time, its energy recovery period will in any case be shorter since the energy costs constitute only a fraction of the manufacturing costs. Even if the manufacturing costs are greater by one order of magnitude than what is required for achieving commercial redemption, the system repays itself from an energy point of view.

When determining the energy requirement of the manufacturing process, attention must be paid to the fact that an assessment is made of the different types of energy used. Due to their conversion efficiencies of 0.3 to 0.4, the value of electrical and mechanical energy must be rated about three times higher than thermal energy. Owing to its high conversion efficiency of 0.8 to 0.9, the amount of thermal energy obtained can be considered as equal to the primary energy used, in a first approximation.

Table 20.12 shows the energy recovery time of a medium-sized wind turbine. The specific primary energy values listed indicate the energy required for semi-finished production and processing. Accordingly, the primary energy requirement amounts to 2 million kWh for the manufacture of the wind turbine. The primary energy equivalent of the annual elec-

Table 20.12. Energy requirement for manufacturing a medium-sized wind turbine with 53 m rotor diameter and 1000 kW rated power. Annual energy yield 2.4 million kWh

Material	Masse (kg)	Specific primary energy requirement (kWh/kg)	Primary energy requirement (kWh)
Steel (nacelle structure, tower)	105 000	15.5	1 627 500
Copper (generatorwindings, cables)	2 700	25.0	67 500
Glass-fibre composite (rotor blades, nacelle)	9 600	28.0	268 000
Concrete (foundation)	100 000	0.5	56 000
Total requirement			2 013 800

trical energy yield of 2.4 million kWh amounts to 6.85 million kWh. Thus, the resultant energy redemption time is 34 months. If a wind turbine has an assumed life of 20 years, a *recovery factor* of 70 is achieved. Compared to conventional power plants, this value is very good. Relevant literature indicates a recovery value of 20 to 30 for conventional power plants [4].

20.6 Effect of Wind Energy Utilisation on Employment

An important question in the context of every new technology is its effect on employment. The concern that the introduction of a new technology will turn into a "job-killer", or the hope that it will create new jobs concerns an ever-increasing number of people. In the European Union, more than 100 000 persons were employed in the wind energy industry in 2004, including outside vendors. In the actual assembly factories, which themselves frequently carry out only a limited amount of actual production, the number of employees amounted to about 60 000. These figures can be derived from the empirical value that in the mechanical engineering industry, a turnover of approximately 60 000 $US creates an employment effect of one job, including all pre-production stages leading up to the final product. Looking at the future, the question arises: If the utilisation of wind energy were to expand until it makes a significant contribution to the energy supply, what effect on employment would this have?

In a study by the "European Wind Energy Association", carried out on behalf of the EU Commission, a scenario for increasing wind energy utilisation within the European Union was suggested [5]: The first goal of achieving a capacity of 4000 MW by 2000 had already been exceeded by 1998 so that the Commission of the EU, in their "White Book", is now using the following figures as a basis [6].

- 40 000 MW by 2010
- 100 000 MW by 2020

In 2004, the installed wind energy power in the EU was approx. 23 000 MW. In order to achieve these goals, the production of the European wind turbine industry would have to remain at about 5 000 MW/year in the period indicated above. Using the production value of 1 million \$US/MW installed, this would equal a turnover of 5 billion \$US/year. Based on the above empirical value of 60 000 \$US turnover for one job, about 80 000 jobs are created for the production of wind turbines. If the annual production of new units would be of the same order of magnitude as the production of replacement units, the number of employees could be kept at the same level. Maintenance, repairs and other services on the installed wind-turbine capacity require an annual expenditure of about 4 % of the investment costs. The operation of 100 000 MW, therefore, calls for another 67 000 jobs.

Judging from the development of recent years, the expected growth and energy capacity including the increasing export of wind turbines will probably be much greater. It is, therefore, not unlikely that employment in the industry will double or more in comparison with the figures quoted above.

It should be noted in this context that the production of wind turbines, even of very large wind turbines, does not mean employment for heavy industry only. Apart from a few aspects in research and development, wind turbines are not "large-scale high-tech products" like nuclear power plants or aircraft. Neither are they "do-it-yourself" kits which can be put together in a bright green world by the operators themselves in an attempt at self-realisation. Wind turbines are industrial products of medium-level technology, the production of which can be handled both by relatively small companies and by large companies.

20.7 Macroeconomics and Renewable Energies

From the point of view of a commercially oriented investor, profitability of an investment is a demand which cannot be waived. Renewable energy systems must also meet this demand. Arguments for the utilisation of renewable energy sources other than economic ones — as important as they may be — can, therefore, not be addressed to the operator. The higher-order economic aspects must be reflected in the macroeconomic conditions. Drafting these in the interest of public welfare is a political task.

As is generally known, the economic action of the individual is determined by numerous macroeconomic conditions. Among these are the tax treatment of investments and profits, direct subsidies, but also less visible aids such as funding for research and development which benefit a particular branch of the economy but are paid out of public funds. This applies to almost any branch of the economy, but particularly to the energy industry.

In this way, the competition between the various primary energy sources such as coal, oil, gas, nuclear power and hydro-electric power is to a considerable extent controlled by macroeconomic considerations. In many countries, the use of domestic coal, for example, is supported by public funds and, as in Germany, the contractual obligation for the utilities to use domestic coal.

The utilisation of nuclear power, too, was, and still is, being considerably subsidised with public funds. Without the double-figure billion-dollar subsidies for research and development which have been paid within the past 50 years, there would be no commercial nuclear power stations, or the electricity from nuclear energy would be considerably more expensive if these sums had to be raised out of private pockets.

These two examples, and many more could have been named, show that free competition between primary energy sources in the sense of a free market, does not exist and has never existed. It would also be wrong to demand such a condition. The energy supply, particularly of an industrialised country, is of such great significance to its general economy and social life, that it cannot be left to the accountants of profit-oriented companies alone to decide on this matter.

In the past, most countries set their policies with respect to energy supply targets only from strategic and economic points of view and also based the macroenconomic conditions for the energy industry on these considerations. But the times have changed. The requirements to be set for the supply of energy must also be re-evaluated. Attempts at self-sufficiency in energy supply cannot succeed, in any case. At the most, the dependence on a primary energy supply can be eased by diversification. A new awareness has grown with respect to the interrelationship between energy generation and ecology. Solving this problem may possibly be one of the question of survival of the human race, if survival in an environment suitable for human life is meant.

Moreover, an increasing number of people are disturbed by the hazards which may be presented by the utilisation of nuclear energy. An energy form which in principle involves the risk of a catastrophe for humanity, will always be rejected by a part of the population, despite all safety precautions. And even if the technical safety measures were as perfect as has always been maintained by its supporters, the risk factor of "human error" will always remain. In order to eliminate this risk, for example in times of political instability, the entire energy cycle must be kept under surveillance. Many see in this an inevitable route to a "police state". In other words, after strategic independence and economic efficiency, "environmental compatibility" and "social compatibility" are also aspects which must play a role in formulating the contemporary political boundary conditions for the energy supply.

And what about the demand for inexpensive energy? Are not low energy costs the precondition for the economic power of an industrialised country? The question is, what is cheap for whom? Surely not for the utilities alone, acting under specific political conditions. This would mean confusing cause and effect. Ultimately, it is only the "value for money" which can be the valid measure, considering all economical and ecological effects. This requirement must be met by all forms of energy supply including the utilisation of regenerative energy sources.

If all cost-related factors are included in the energy supplied, starting with the research about the processing of the fuel, e. g. coal mining, the investment costs of power plants, fuel costs, waste disposal and, not least, consequential ecological damage as well as expenses for public safety, the assessment of the competing primary energy sources becomes a very difficult issue to address. Despite many commendable approaches attempting a quantitative assessment, a generally accepted answer to this question is yet to be found. One thing can be said right from the start, however: The utilisation of renewable energy sources can not possibly fail to impress in such a comparison [7].

What remains is the question of security of supply (firm power) for the consumer. An argument frequently used against renewable energy sources, above all against wind energy utilisation, is that it is unpredictable by its nature, and thus unsuitable. The answer to this is simple: No reasonable person would think of basing his energy supply on the utilisation of wind power alone. Wind power will always be only a part of the overall power supply system. The required availability, with or without wind turbines, will always be borne by the entire system of interconnected power stations. The comparatively low availability of wind turbines is reduced to the purely technical question as to what extent they can contribute to the firm power of system of interconnected power stations and thus becomes an economic problem, at most.

An attempt to draw a conclusion from all these macroeconomic considerations, and to derive from them requirements to be set for future energy supplies, could be summarised in four central points:

- Secure in the sense of firm power based on the total combined power supply system and not dependent on imported sources only,
- Economically acceptable costs including all cost-related factors from the primary energy source generation to waste disposal to environmental effects.
- As ecologically beneficial as possible according to the state-of-the-art. In case of doubt, always opt for the solution with better ecological impact,
- Socially compatible with respect to the hazards inherent in the technology.

Political conditions which take these contemporary requirements into account will create fair chances for the utilisation of renewable energy sources. Moreover, they will be indispensable for a future energy industry which will again be based on a broad consensus in society.

In the end, however, it will not be laws which will guarantee a lasting change in the energy economy but a rethinking by every individual and, hand in hand with this, a change in values as perceived in our society.

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