WIND ENERGY - THE FACTS

VOLUME 2

COSTS & PRICES

Acknowledgments

This volume was compiled by Poul Erik Morthorst, Senior Research Specialist at Risø National Laboratory, Denmark. Our thanks also to the national wind associations around Europe for their contributions of data, and to the other project partners for their inputs.

VOLUME 2 - COSTS & PRICES: TABLE OF CONTENTS

1 INTRODUCTION

From a European, as well as a global perspective, wind power is undergoing rapid development. Within the past 10 years the global installed capacity of wind power has increased from approximately 2.5 GW in 1992 to a little below 40 GW at the end of 2003, with an annual growth rate of around 30%. However, only at few sites with high wind speeds can wind power compete economically with conventional power production at present.

This section focuses on the cost structures of a wind power plant, including the lifetime of the turbine and operation and maintenance costs. Finally, it analyses how the costs of wind power have developed in previous years and how they are expected to develop in the near future.

Wind power is used in a number of different applications, including both grid-connected and stand-alone electricity production, as well as water pumping. This section analyses the economics of wind energy primarily in relation to grid-connected turbines which account for the vast bulk of the market value of installed turbines.

2 COST AND INVESTMENT STRUCTURES

The main parameters governing wind power economics include the following:

- Investment costs, including auxiliary costs for foundation, grid-connection, and so on.
- Operation and Maintenance (O&M) costs.
- Electricity production/average wind speed.
- Turbine lifetime.
- Discount rate.

Of these, the most important parameters are the wind turbines' (WT) electricity production and their investment costs. As electricity production is highly dependent on wind conditions, choosing the right site is critical to achieving economic viability. The following sections outline the structure and development of capital costs and efficiency trends of land based WTs.

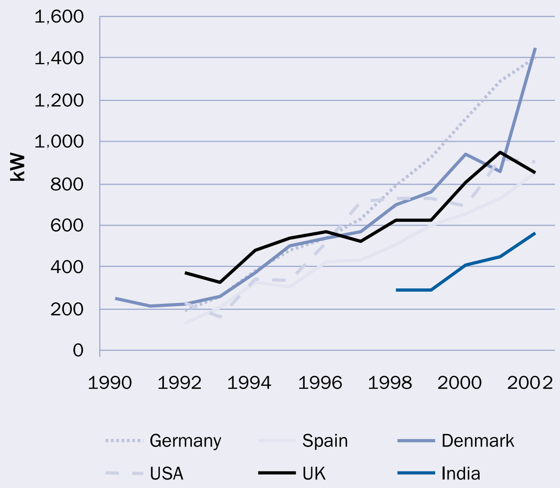
In general, three major trends have dominated the development of grid-connected WTs in recent years:

- The WTs have grown larger and taller – thus, the average size sold has increased substantially.
- The efficiency of WT production has increased steadily.
- In general, investment costs per kW have decreased.

Figure 2.1 shows the growth in average size of WTs sold each year in a number of the most important wind power countries. The annual average size has increased significantly within the last 10-15 years, from approximately 200 kW in 1990 to almost 1.5 MW in Germany and Denmark in 2002. But, as shown, there is quite a difference between the individual countries. In Spain, the US and the UK, the average size installed in 2002 was approximately 850-900 kW, significantly below the levels of Denmark and Germany of 1,450 kW and 1,400 kW respectively. The large increase in Denmark from 2001 to 2002 was mainly caused by the Horns Reef offshore wind farm which came onstream in 2002 equipped with 80 WTs of 2 MW each.

In 2002, the best-selling WTs had a rated capacity of 750-1,500 kW and a market share of more than 50%. But WTs with capacities of 1,500 kW and above had a share of 30% and have been increasing their market shares. By the end of 2002, WTs with a capacity of 2 MW and above were becoming increasingly important, even for on-land sitings.

Figure 2.1: Development of the Average Wind Turbine Size Sold in Different Countries



Source: BTM Consult

The wind regime at the chosen site, the hub height of the WTs and the efficiency of production mainly determine power production from the WTs. Thus, increasing the height of the WTs has, by itself, yielded a higher power production. Similarly, the methods for measuring and evaluating the wind speed at a given site have improved substantially in recent years, thus improving the siting of new WTs. In spite of this, the fast development of wind power capacity in countries such as Germany and Denmark implies that most of the good wind sites are, by now, taken. Therefore, any new on-land turbine capacity has to be erected at sites with a marginally lower average wind speed. It should be added, however, that the replacement of older and smaller WTs with new ones is getting increasingly important, especially in countries that have taken part in wind power development for a long time, as is the case for Germany and Denmark. In 2002, a successful re-powering scheme in Denmark had a substantial impact on market development.

The development of electricity production efficiency owing to better equipment design, measured as annual energy production per swept rotor area (kWh/m^2) at a specific reference site, has correspondingly improved significantly over the last few years. Taking into account all the three mentioned issues of improved equipment efficiency, improved turbine siting and higher hub height, overall efficiency has increased by 2% to 3% annually over the last 15 years.

Capital costs of wind energy projects are dominated by the cost of the WT itself (ex works[1]). Table 2.1 shows the cost structure for a medium sized turbine (850 kW to 1,500 kW) sited on land and based on a limited data-selection from the UK, Spain, Germany and Denmark. The WTs share of total cost is typically a little less than 80%, but, as shown in Table 2.1, considerable variations do exist, ranging from 74% to 82%.

Table 2.1: Cost Structure for a Typical Medium Sized Wind Turbine (850 kW – 1500 kW)

	Share of Total Cost %	Typical Share of Other Costs %
Turbine (ex works)	74-82	-
Foundation	1-6	20-25
Electric installation	1-9	10-15
Grid-connection	2-9	35-45
Consultancy	1-3	5-10
Land	1-3	5-10
Financial costs	1-5	5-10
Road construction	1-5	5-10

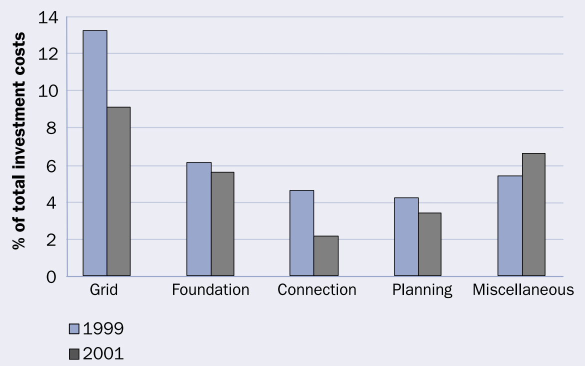
Based on data from Germany, Denmark, Spain and UK for 2001/02.

Of other cost components, dominant ones are, typically, grid-connection, electrical installation and foundation, but other auxiliary costs such as road construction could represent a substantial proportion of total costs. There is considerable variation in the total level of these auxiliary costs, ranging from approximately 24% of total turbine costs in Germany and the UK to less than 20% in Spain and Denmark. The costs depend not only on the country of installation, but also on the size of the turbine.

Typical ranges of these other cost components as a share of total additional costs are also shown in Figure 2.2. As seen, the single most important additional component is the cost of grid-connection which in some cases can account for almost half the auxiliary costs, followed, typically, by lower shares for foundation costs and the cost of the electrical installation. Thus, these three issues might add significant amounts to the total cost of the WT. Cost components such as consultancy and land rental normally account for only a minor share of additional costs.

In Germany, the development of these additional costs has been further investigated in a questionnaire carried out by Dewi (2002), looking at the actual costs for wind turbines installed in 1999 and 2001 (Figure 2.2). As shown, all additional cost components tend to decrease over time as a share of total WT costs, with only one exception. The increase in the share of miscellaneous costs is mostly on account of increasing prefeasibility costs. The level of auxiliary costs in Germany has, on average, decreased from approximately 31% of total investment costs in 1999 to approximately 28% in 2001.

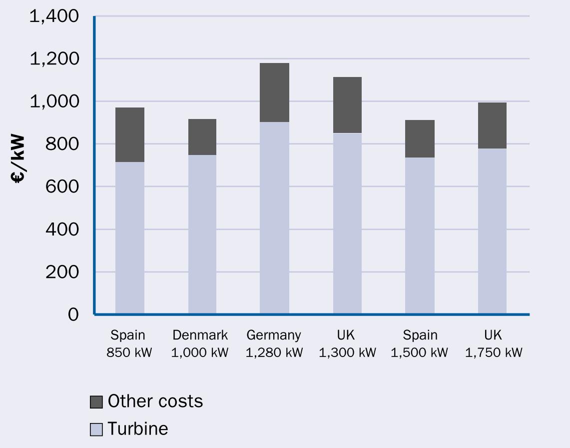
Figure 2.2: Development of Additional Costs (Grid-Connection, Foundation, etc.) as a Percentage of Total Investment Costs for German Turbines



Source: Dewi (2002).

The total cost per installed kW of wind power capacity differs significantly between countries, as exemplified in Figure 2.3. The cost per kW typically varies from approximately 900 €/kW to 1,150 €/kW. As shown in Figure 2.3, the investment costs per kW were found to be almost at the same level in Spain and Denmark, while the costs in the data-selection were approximately 10% to 30% higher in the UK and Germany. However, it should be noted that Figure 2.3 is based on limited data.

Figure 2.3: Total Investment Cost, Including Turbine, Foundation, Grid-Connection, etc., Shown for Different Turbine Sizes and Countries of Installation (€/kW)



Based on reported data from Germany[2], UK, Spain and Denmark.

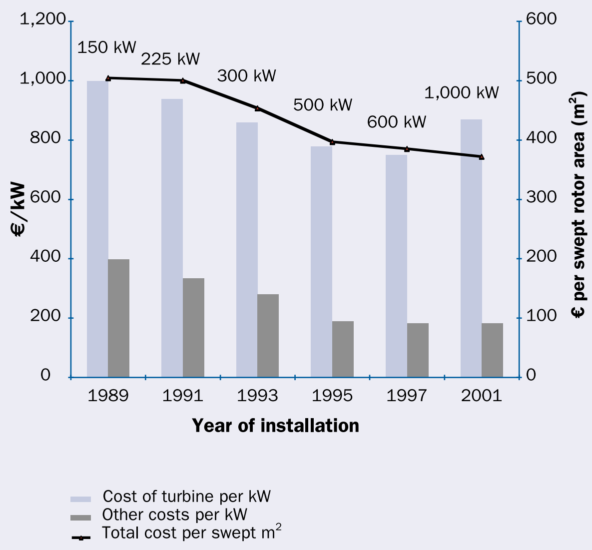
Figure 2.4 shows how investment costs have developed, exemplified by the case of Denmark for the period 1989 to 2001. The data reflect turbines installed in the particular year shown[3]. All costs at the right axis are calculated per swept rotor area, while those at the left axis are calculated per kW of rated capacity.

Swept rotor area is a good proxy for the turbines' power production and this measure is therefore a relevant index for cost development per kWh. As shown in the figure, there has been a substantial decline in costs per unit swept rotor area in the period under consideration and for all turbines. Thus, overall investment costs by swept rotor area have declined by almost 3% per annum during the period analysed, corresponding to a total reduction in cost of approximately 30% over the past 12 years.

Looking at the cost per rated capacity (per kW), the same decline is found in the period 1989 to 1997. Surprisingly, however, investment costs per kW have increased from the 600 kW machine to the considerably larger 1,000 kW turbine. The reason is to do with the dimensioning of the turbine. With higher hub heights and larger rotor diameters, the WT is equipped with a relatively smaller generator although it produces more electricity. It is particularly important to be aware of this when analysing WTs constructed to be used in low and medium wind areas, where the rotor diameter is dimensioned to be considerably larger compared to the rated capacity.

Another reason for the increase in capacity costs is that, in 2001, the 1,000 kW machine was fairly new. It is usually the case that, due to economies of scale, a reduction in price is seen over time.

Figure 2.4: The Development of Investment Costs, Exemplified by the Case of Denmark for the Period 1989 to 2001



Right axis: Investment costs divided by swept rotor area (€/m² in constant 2001 €).
Left axis: Wind turbine capital costs (ex works) and other costs per kW rated power (€/kW in constant 2001 €).

Also, the share of other costs as a percentage of total costs has decreased. In 1989, almost 29% of total investment costs were related to costs other than the turbine itself. By 1997, this share had declined to approximately 20%. The trend towards lower auxiliary costs continues for the last vintage of turbines shown (1,000 kW), where other costs amount to approximately 18% of the total.

3 OPERATION AND MAINTENANCE COSTS OF WIND POWER

O&M costs constitute a sizeable share of the total annual costs of a WT. For a new machine, O&M costs might easily have an average share over the lifetime of the turbine of approximately 20%-25% of total levellised cost per kWh produced – as long the WT is fairly new, the share might constitute 10%-15% increasing to at least 20%-35% by the end of its life. Thus, O&M costs are increasingly attracting the attention of manufacturers seeking to develop new designs requiring fewer regular service visits and less out-time.

O&M costs are related to a limited number of cost components:

- Insurance
- Regular maintenance
- Repair
- Spare parts
- Administration

Some of these cost components can be estimated with relative ease. For insurance and regular maintenance, it is possible to obtain standard contracts covering a considerable portion of the WT's total lifespan. On the other hand, costs for repair and related spare parts are much more difficult to predict. Although all cost components tend to increase, costs for repair and spare parts are particularly influenced by turbine age, starting low and increasing over time.

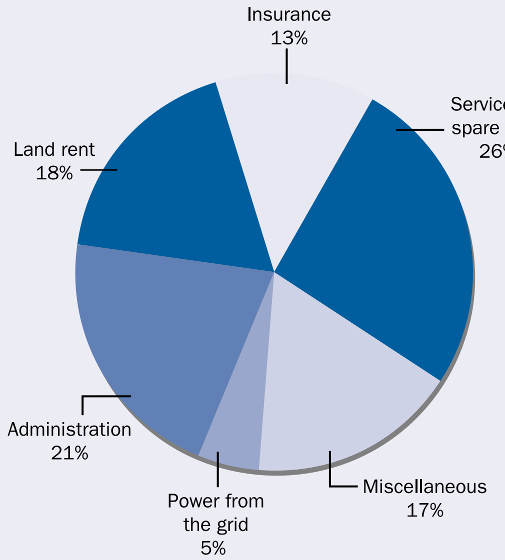
Due to the newness of the wind energy industry, only a limited number of WTs have existed for their expected lifespan of 20 years. Compared to the average size WTs commercially available nowadays, these older WTs are nearly all small and have, to a certain extent, been constructed using more conservative, less stringent design criteria than that used today. Some cost data can be gleaned from existing older WTs, but estimates of O&M costs should nevertheless be considered highly uncertain, especially around the end of a turbine's lifetime.

Based on experiences from Germany, Spain, the UK and Denmark, O&M costs are, in general, estimated to be at a level of approximately 1.2 to 1.5 c€/kWh of produced wind power seen over the total lifetime. Data from Spain indicate that a little less than 60% of this amount goes strictly to O&M and installation, with this proportion split into approximately half for spare parts and the rest equally distributed between labour costs and fungibles. The remaining 40% is almost equally split between insurance, rental of land[4] and overheads.

In Germany, a questionnaire by Dewi (2002) also looked into the development and distribution of O&M costs for German installations. For the first two years of its life, a WT is normally covered by the manufacturer's warranty. Thus, in the German study, O&M costs for the first two years were fairly low at 2%-3% of total investment costs, corresponding to approximately 0.3-0.4 c€/kWh. After six years, total O&M costs had increased to constitute a little less than 5% of total investment costs, which is equivalent to approximately 0.6-0.7 c€/kWh. These figures are in line with calculated O&M costs for newer Danish turbines (see below).

Figure 3.1 shows an average over the period 1997 - 2001 of how total O&M costs were split into six different categories based on the German data from Dewi. The cost of buying power from the grid and land rental (as in Spain) are included in the O&M cost calculation for Germany.

Figure 3.1: O&M Costs for German Turbines as an Average over the Period 1997-2001



Source: Dewi (2002).

Figure 3.2: O&M Costs Reported for Selected Sizes and Types of Wind Turbines

Source: Jensen *et al.* (2002).

A recent study in Denmark has analysed the development of O&M costs, insurance costs, etc., including the economic and technical lifetime of WTs. Based on a survey of national wind organisations and an existing database, time series for O&M cost components were established going back to the early 1980s. Relevant O&M costs were defined to include reinvestments – for example, replacement of blades or gears – if any. Due to the industry's evolution towards larger WTs, O&M cost data for old WTs exist only for relatively small units, while data for younger WTs relate primarily to larger units. In principle, the same sample should have been followed throughout successive years. However, due to the appearance of new WTs, the scrapping of older ones, and general uncertainty about the statistics, the sample is not constant over time, particularly for the larger WTs. Some of the key results are shown in Figure 3.2.

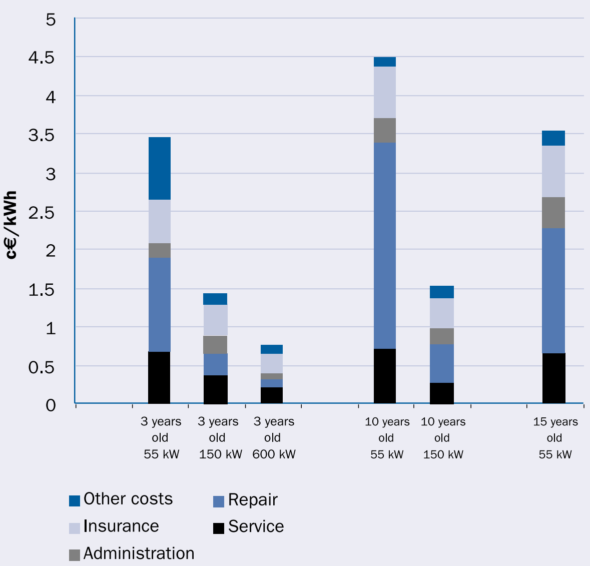
The figure shows the development of O&M costs for selected sizes and types of turbines since the beginning of the 1980s. The horizontal axis represents the age of the WT while the vertical axis is the total O&M costs stated in constant 1999 €. As seen, the 55 kW WTs now have a track record close to 20 years, implying that the first serial-produced machines are now reaching the end of their life. The picture for the 55 kW machine is patchy, showing rapidly increasing O&M costs right from the start, and reaching a fairly high but stable level of approximately 3-4 c€/kWh after five years.

Furthermore, the figure shows that O&M costs decrease for newer and larger WTs. The observed strong increase for the 150 kW WTs after 10 years represents only a very few machines; therefore, it is not known at present if this increase is representative of the 150 kW type or not. For turbines with a rated power of 500 kW and more, O&M costs seem to be under or close to 1 c€/kWh. What is also interesting is that the 225 kW machine over its first 11 years has O&M costs at around 1-1.3 c€/kWh, closely in line with estimated O&M costs in Germany, Spain, the UK and Denmark.

Thus, the development of O&M costs appears to be strongly correlated with turbine age. In the first few years, the manufacturer's warranty[5] implies a low level of O&M expenses for the owner. After the 10th year, however, larger repairs and reinvestments should be expected: from experience with the 55 kW machine, these are the dominant O&M costs during the last 10 years of the turbine's life.

Figure 3.3 shows the total O&M costs as found in the Danish study and details how these are distributed among the different O&M categories, according to the type, size and age of the turbine. Thus, for a three-year-old 600 kW machine, which was fairly well represented in the study[6], approximately 35% of total O&M costs are for insurance, 28% for regular service, 11% for administration, 12% for repair and spare parts, and 14% for other purposes. In general, the study found that expenses for insurance, regular service and administration were fairly stable over time, while, as mentioned above, costs for repair and spare parts fluctuated heavily. Finally, in most cases, other costs were of minor importance.

Figure 3.3: O&M Costs as Reported for Selected Types and Vintages of WTs



Source: Jensen *et al.* (2002).

Figure 3.3 clearly shows the trend towards lower O&M costs for new and larger machines. Thus, for a three-year-old turbine, O&M costs have decreased from approximately 3.5 c€/kWh for the old 55 kW machine to less than 1 c€/kWh for the newer 600 kW. The figures for the 150 kW WTs are almost at the same level as the O&M costs identified in the three countries mentioned above.

That O&M costs increase with turbine age is, again, fairly clear, although not to the same extent as shown in Figure 3.2.

With regard to the future development of O&M costs, care must be taken in interpreting the results of Figure 3.3. Firstly, as WTs exhibit economies of scale in terms of declining investment costs per kW with increasing turbine capacity, similar economies of scale may exist for O&M costs. This means that a decrease in O&M costs will, to a certain extent, be related to up-scaling of the WTs. Secondly, the newer, larger WTs are more optimised with regard to dimensioning criteria than the old ones, implying an expectation of lower lifetime O&M requirements than the older, smaller machines. This might, however, imply that newer WTs are not as robust as older ones and are less capable of dealing with unexpected events.

Taking this reasoning into account, the O&M cost percentage for a 10-15 year old 1,000 kW WT could be expected not to rise to the same level as seen today for a 55 kW WT of the same age. Most likely, the O&M costs for newer turbines will be significantly lower than those experienced to date for the 55 kW WTs. How much lower future O&M costs go will also depend on whether the existing trend of up-scaling continues.

4 THE COST OF ENERGY GENERATED BY WIND POWER

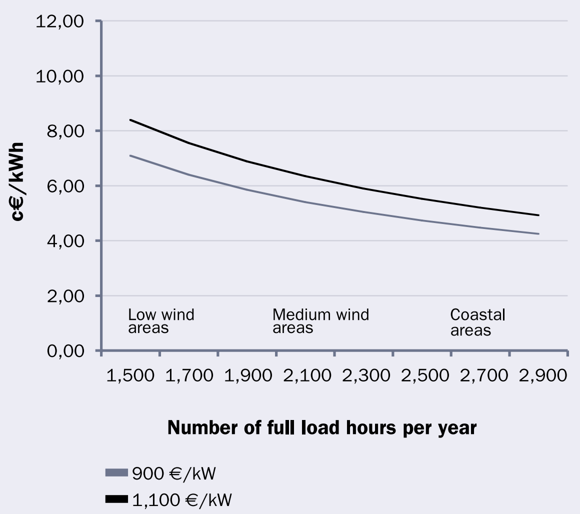
The total cost per produced kWh (unit cost) is traditionally calculated by discounting and levelising investment and O&M costs over the lifetime of the WT, divided by the annual electricity production[7]. The unit cost of generation is thus calculated as an average cost over the lifetime. In reality, actual costs will be lower than the calculated average at the beginning of the life, due to low O&M costs, and will increase over the period of WT use.

The production of power is the single most important factor for calculating the cost per generated unit of power. Turbines sited at good wind locations are likely to be profitable, while those at poor locations may run at a loss. In this section, the cost of wind-produced energy will be calculated based on a number of assumptions. Due to the importance of the power production, this parameter will be treated on a sensitivity basis. Other assumptions include the following:

- The calculations relate to a new land-based medium-sized WT of 850-1,500 kW, which could be erected today.
- Investment costs reflect the range given in section two, i.e. a cost per kW of 900 to 1,100 €/kW. These costs are based on data from Spain, UK, Germany and Denmark.
- O&M costs are assumed to be 1.2 c€/kWh as an average over the lifetime of the WT.
- The lifetime of the WT is 20 years, in accordance with most technical design criteria.
- The discount rate is assumed to range within an interval of 5% to 10% a year. In the basic calculations, an annual discount rate of 7.5% is used, and a sensitivity analysis of the importance of the interest range is performed.
- Economic analyses are carried out as simple national economic ones. No taxes, depreciation, risk premia, etc. are taken into account. Everything is calculated at fixed 2001 prices.

The calculated costs per kWh wind power as a function of the wind regime at the chosen sites are shown in Figure 4.1 below[8]. As shown, the cost ranges from approximately 6-8 c€/kWh at sites with low average wind speeds to approximately 4-5 c€/kWh at good coastal positions[9]. In Europe, coastal positions such as these are mostly to be found in the UK, Ireland, France, Denmark and Norway. Medium wind areas are generally found at inland terrain in mid- and southern Europe in Germany, France, Spain, Holland, Italy, but also at inland sites in Sweden, Finland and Denmark. In many cases, local conditions significantly influence the average wind speed at the site. Therefore, strong fluctuations in the wind regime are to be expected, even for neighbouring areas.

Figure 4.1: Calculated Costs per kWh Wind Power as a Function of the Wind Regime at the Chosen Site (Number of full Load Hours)

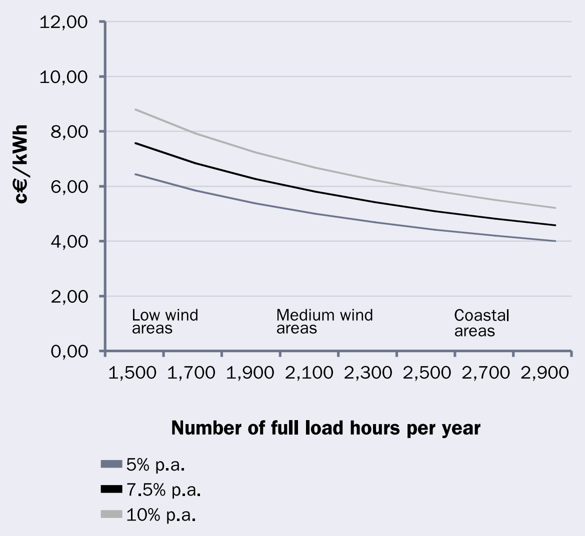


For assumptions: see above.

Approximately 75% of total power production costs for a WT are related to capital costs, i.e. costs for the WT itself, foundation, electrical equipment and grid-connection. Thus, WTs are a so-called capital-intensive technology compared with conventional fossil fuel-fired technologies such as a natural gas power plant, where as much as 40%-60% of total costs are related to fuel and O&M costs. For this reason, the cost of capital (discount or interest rate) is an important factor for calculating the cost of wind power; cost of capital varies substantially between individual EU member states. In Figure 4.2, the costs per kWh wind power are shown as a function of the wind regime and the discount rate, where the latter varies between 5% and 10% a year.

As shown in Figure 4.2, costs range between approximately 5 and 6.5 c€/kWh at medium wind positions, indicating that a doubling of the interest rate induces an increase in production costs of 1.5 c€/kWh. In low wind areas, the costs are significantly higher, 6.5-9 c€/kWh, while production costs range between 4 and 5.5 c€/kWh in coastal areas.

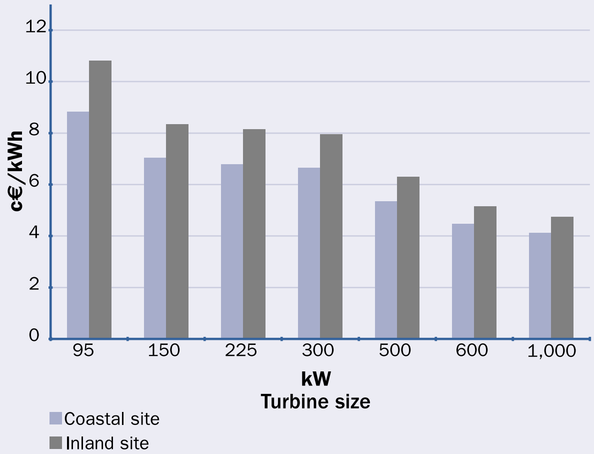
Figure 4.2: The Costs of Wind Power as a Function of Wind Speed (Number of Full Load Hours) and Discount Rate



5 DEVELOPMENT OF THE COST OF WIND POWER

The rapid European and global development of wind power capacity has had a strong influence on the cost development of wind power within the past 20 years. To illustrate the trend towards lower production costs of wind power, a historical case showing the production costs for different sizes and vintages of WTs has been constructed. Due to limited data, it has only been possible to construct this case for Denmark, though a similar trend was observed in Germany at a slightly slower pace.

Figure 5.1: Total Costs of Wind Power (c€/kWh, Constant 2001 Prices) by Turbine Size



For assumptions on wind speed, see endnote 10.

Figure 5.1 shows the calculated unit cost for different sizes of turbines based on the same assumptions as used in the previous section. Thus, a 20-year lifetime is assumed for all turbines in the analysis and an annual discount rate of 7.5% is used. All costs are converted into constant 2001 prices. Electricity production is estimated for two wind regimes, a coastal and an inland medium wind position, respectively. The starting point for the analysis is the 95 kW machine that was mainly installed in Denmark during the mid 1980s, followed by successively newer WTs (150 kW, 225 kW, etc.), ending with the most recent - the 1,000 kW turbine typically installed around year 2000. It should be noted that WT manufacturers, as a rule of thumb, expect the production cost of wind power to decline by 3%-5% for each new generation of WTs that they add to their product portfolio. Further cost reductions are therefore likely to have occurred with the longer production series of WTs over 1,000 kW. Note that the calculations are performed for the total lifetime (20 years) of the WTs, which means that calculations for the old WTs are based on track records of up to 15 years (average figures), while newer WTs might have a track record of only a few years. Thus, the newer the WT, the more uncertain the calculations.

In spite of this, Figure 5.1 clearly illustrates the economic consequences of the trend towards larger WTs and improved cost-effectiveness. For a coastal position, for example, the average cost has decreased from approximately 8.8 c€/kWh for the 95 kW WT (mainly installed in the mid-1980s) to approximately 4.1 c€/kWh for a fairly new 1,000 kW machine – an improvement of more than 50% over a 15 year period at constant 2001 prices.

6 FUTURE DEVELOPMENT OF THE COST OF WIND POWER

In this section, the future development of the economics of wind power is illustrated by the use of experience curve methodology. The experience curve approach was developed back in the 1970s by the Boston Consulting Group. Its main feature is that it relates the cumulative quantitative development of a product with the development of its specific costs (Johnson, 1984). Thus, if the cumulative sale of a product is doubled, the estimated learning rate gives you the achieved reduction in specific product costs.

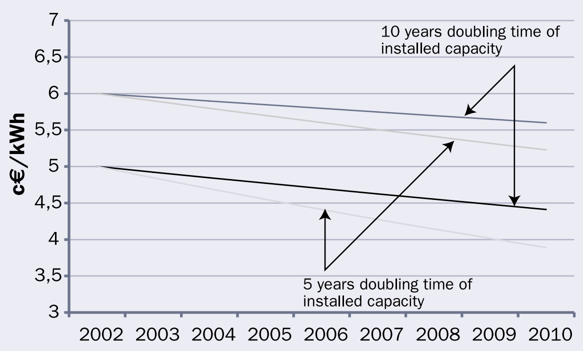
The experience curve is not a forecasting tool based on estimated relationships. It merely points out that if existing trends are to continue, then we might see the proposed development. It converts the effect of mass production into an effect on production costs, but other casual relationships are not taken into account. Thus, changes in market development and/or technological break-through within the field might considerably change the picture.

For a number of projects, different experience curves have been estimated[10], but, unfortunately, most used different specifications, which means that they cannot be directly compared. To get the full value of the experiences gained, not only should the price-reduction of the WT (€/kW-specification) be taken into account, but the improvements in efficiency of the WTs production should be included too. The latter requires the use of an energy specification (€/kWh) which excludes many of the mentioned estimations (Neij, 1997 and Neij *et al.*, 2003). Thus, using the specific costs of energy as a basis (costs per kWh produced), the estimated progress ratios in these publications range from 0.83 to 0.91, corresponding to learning rates of 0.17 to 0.09. That is, when total installed capacity of wind power is doubled, the costs per produced kWh for new turbines are reduced by between 9% and 17%. In this way, both the efficiency improvements and embodied and disembodied cost reductions are taken into account in the analysis.

Wind power capacity has developed very rapidly in recent years, on average approximately by 30% per year during the last 10 years. Thus, at present, total wind power capacity is doubled every three years. The EU has set a target of 40,000 MW of wind power by year 2010, compared to approximately 23,500 MW installed in the EU at the end of 2002. The European Wind Energy Association (EWEA) has recently published a target of 75,000 MW for Europe by 2010. The EU target implies an annual growth rate of approximately 7% (a doubling time of a little more than 10 years), while the EWEA target requires an annual growth rate of almost 16% (a doubling time of 4.8 years). In Figure 6.1 below are shown the consequences for wind power production costs according to the following assumptions:

- A learning rate between 9% and 17% is assumed, implying that each time the total installed capacity is doubled, then the costs per kWh wind power is reduced by 9%-17%.
- The growth rate of installed capacity is assumed to double cumulative installations every 5th, respectively every 10th year.
- The starting point for the development is the cost of wind power as observed today, i.e. in the range of 5 to 6 c€/kWh produced for an average medium sized turbine (850-1,500 kW) sited at a medium wind regime (average wind speed of 6.3 m/s at a hub height of 50 m).

Figure 6.1: Using Experience Curves to Illustrate the Future Development of Wind Turbine Economics until 2010



Costs illustrated for a turbine installed in a medium wind regime with a present day production cost of 5 to 6 c€/kWh.

The consequences of applying the above-mentioned results for wind power are illustrated in Figure 6.1. At present, the production costs for a medium sized WT

(850-1,500 kW) installed in an area with a medium wind speed is approximately 5-6 c€/kWh produced power. If a doubling time of total installed capacity of 10 years is assumed, the cost interval in 2010 would be approximately 4.4 to 5.6 c€/kWh. A doubling time of five years only would imply a cost interval in 2010 of 3.9 to 5.2 c€/kWh. If the WT is located in a coastal area with a higher wind speed (average wind speed of 6.9 m/s at a height of 50 m), the costs per kWh produced in 2010 could be as low as 3.1 to 4.4 c€/kWh in the case of a five-year doubling time of total installed capacity.

7 COSTS OF CONVENTIONAL POWER PRODUCTION

The cost of conventional electricity production is determined by three components:

- Fuel cost
- O&M costs
- Capital cost

When conventional power is substituted by wind power, the avoided cost depends on the degree to which wind power substitutes each of the three components. It is generally accepted that implementing wind power avoids the full fuel cost and a considerable portion of O&M costs of the displaced conventional power plant. The level of avoided capital costs depends on the extent to which wind power capacity can displace investments in new conventional power plants and is thus directly tied to the capacity credit of wind plant.

The capacity credit will depend on a number of different factors: among these is the level of penetration of wind power and how the wind capacity is integrated into the overall energy system and market. In general, for marginal levels of wind penetration, the capacity credit for WTs is close to the annual average capacity factor. Thus, 25% is considered to be a reasonable capacity credit for wind power when the volume of wind electricity is less than 10% of total electricity production[11]. This capacity credit declines as the proportion of wind power in the system increases; but even at high penetrations a sizeable capacity credit is still achievable if the management and future development of grid infrastructure are conducted with a view to the expected increase in distributed generation from wind power and other renewable energy sources.

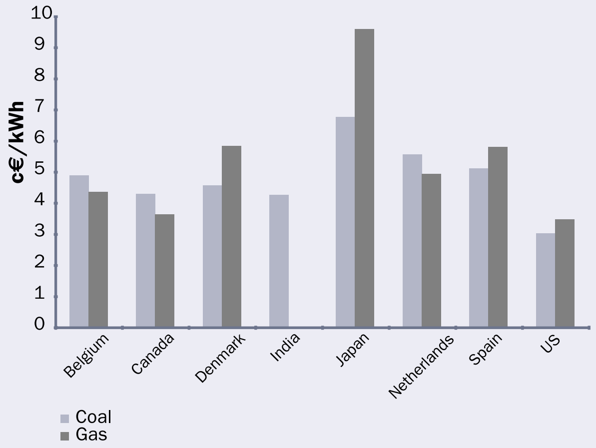
The capacity credit of wind power depends heavily upon the structure of power markets. Studies of the Nordic power market, NordPool, show that the cost of integrating intermittant wind power is, on average, approximately 0.3-0.4 c€/kWh wind power at the present level of wind power capacity (20% in Denmark). Under existing transmission and market conditions, and as in the case of capacity credit, these costs are supposed to increase with higher levels of wind power penetration.

To get a comparable picture, *"Projected Costs of Generating Electricity - Update 1998"* (OECD/IEA, 1998)[12] has projected the costs of electricity generation with state-of-the-art coal-fired and gas-fired base load power plants, given the following common assumptions:

- Plants are commercially available for commissioning by the year 2005
- Costs are levellised using a 5% real discount rate and a 40-year lifetime[13]
- 75% load factor
- Calculations are carried out in constant 1996 US$, converted to € 2001 prices

The OECD/IEA calculations were based on data made available by OECD member countries. Costs related to electricity production, pollution control and other environmental protection measures were included in the calculated generation costs, while general costs, such as central overheads, transmission, and distribution costs were excluded. Losses in transmission and distribution grids were also not taken into account. Fuel price developments were projected in accordance with national assumptions. Figure 7.1 shows the costs of conventional power as projected by OECD/IEA, updated to 2001 € prices.

Figure 7.1: Projected Costs of Conventional Power (2001 c€/kWh)



Source: OECD/IEA (1998), updated to 2001 € prices.

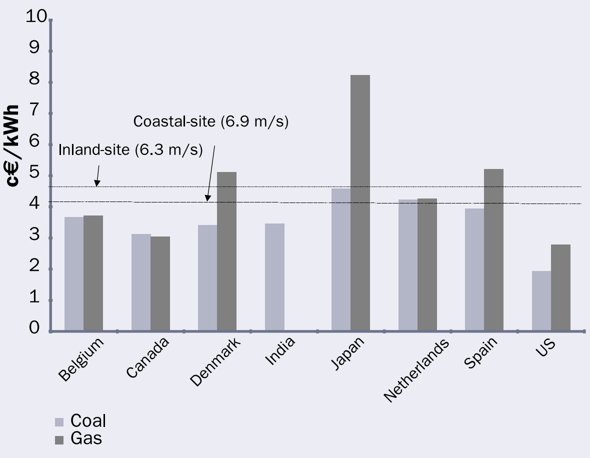
The figures are based on the above cost data from OECD/IEA (1998) for a selected number of countries and power technologies. The costs for the conventional technologies were originally stated in 1996 US$, but at the aggregate level converted to 2001 € prices. Thus, considerable uncertainty exists for the costs shown owing to changes in exchange rates, national differences in inflation rates and different national assumptions on fuel price development. Finally, although no major changes are expected, investment costs for conventional power plants may have changed quite substantially since 1998.

Figure 7.2 shows those costs of conventional power which are avoidable through wind electricity, assuming that all conventional fuel and O&M costs are avoided and that wind power is assigned a capacity credit of 25%. For example, in Spain, for each kWh of electricity generated by wind power which displaces a kWh of gas power, approximately 5.2 c€/kWh are saved in gas fuel, O&M costs and displaced capital costs. Therefore, if a wind turbine could be installed in Spain at an average cost below 5.2 c€/kWh, this would make wind power economically competitive in comparison with new gas-fired power plant in Spain. For comparative purposes, the estimated total costs (including capital costs and calculated using an annual discount rate of 5%) for a medium sized on-land turbine at average coastal and inland sites are also shown (4.2 and 4.8 c€ per kWh, respectively[14]). As shown in Figure 7.2, under the assumption of a 25% capacity credit for wind energy, a medium sized turbine is actually approaching competitiveness in terms of direct costs in a number of countries, compared to technologies based on coal and gas.

Of course, if a higher capacity credit for wind than 25% is assumed, this would raise the avoided costs of conventional technologies and thus improve wind's competitiveness. Similarly, if a lower capacity credit were assumed, this would make wind power less economically competitive.

Capital costs are more important for coal based power than for natural gas fired plants, and therefore assumptions about wind's capacity credit are particularly important regarding coal plants, as shown above. However, this importance may change in the future as

Figure 7.2: Projected Avoided Costs of Conventional Power Compared to Costs for Wind Electricity (2001 c€/kWh), Assuming 25% Capacity Credit for Wind Power



Source: OECD/IEA (1998), updated to 2001 € prices.

electricity markets increasingly move away from centralised generation planning and towards increased competition. Much of wind energy's future competitiveness will depend on short-term wind predictability and on the specific conditions which develop for bidding into short-term forward and spot markets at the power exchange.

Finally, it should be stressed that the above-mentioned costs of conventional generation are based upon national assumptions on the development of fossil fuel prices which, of course, are subject to significant uncertainties. As discussed by Awerbuch (2003), these uncertainties relating to future fossil fuel prices imply a considerable risk for future generation costs of conventional plants, while the costs per kWh generated by wind power are almost constant over the lifetime of the turbine when first installed. Thus, although wind power today might be more expensive than conventional power technology per kWh, it may nevertheless take up a significant share in investors' power plant portfolios, taking on the role of hedging against unexpected rises in future prices of fossil fuels. Thus, the constancy of wind power costs justifies a relatively higher cost per kWh compared to the more risky future costs of conventional power.

8 EXTERNAL COSTS OF POWER PRODUCTION

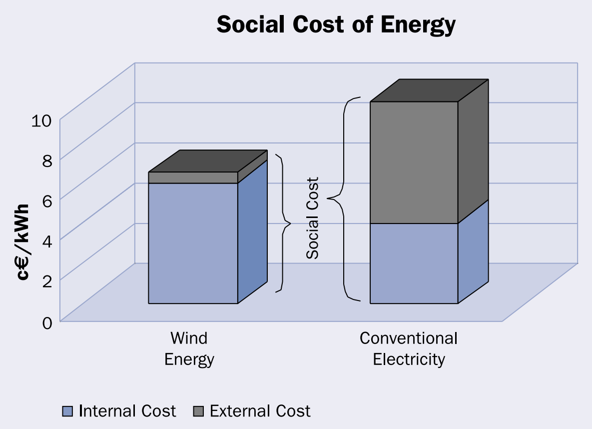
The competitiveness of wind power is dependent on the particular market conditions where wind developments are placed. Figure 7.2 shows that wind costs are marginally higher than conventional power technologies such as coal and natural gas. However, it is generally appreciated that wind energy and other renewable energy sources have environmental benefits when compared to conventional electricity generation. But are these benefits fully reflected in the market prices of electricity? And, on the other hand, is conventional power generation charged for the environmental damage caused by polluting emissions?

This section deals with these questions in order to estimate the hidden benefits/costs of the different electricity production activities not taken into consideration by the existing pricing system. To establish a fair comparison of the different electricity production activities, all internal and external costs to society need to be taken into account.

Hence, it is important to identify external effects of different energy systems and to monetise their costs, especially if these are of a similar order of magnitude as the internal costs of energy and if the external costs vary substantially between competing energy systems such as conventional electricity generation and wind energy. The question arises whether the inclusion of external costs – the externalities – in the pricing system (internalisation) could have an impact on the competitive situation of different electricity generating technologies. Results from different studies are shown in Figure 8.1. The external costs of conventional power systems make these technologies less competitive in comparison with wind energy as the externalities are included to take account of the social cost of energy production. The internal cost of wind energy is practically unchanged by including the externalities.

Volume 4 'Environment', presents a more detailed analysis of the external cost of energy as well as the latest results obtained for different generation technologies. In addition, an analysis focusing on the avoidable external costs of wind energy for European member states, along with an estimation of the total avoided external costs, are also introduced.

Figure 8.1: An Illustrative Example of the Social Cost of Energy



Endnotes

1 "Ex works" means that no site work, foundation, or grid connection costs are included. Ex works costs include the turbine as provided by the manufacturer, including the turbine itself, blades, tower, and transport to the site.

2 For Germany, an average figure for the installed capacity in 2001 is used.

3 All costs are converted to 2001 euros.

4 In Spain the rental of land is seen as an O&M cost.

5 In the Danish study, only the costs to be borne by the wind turbine owner are included, i.e. costs borne by the manufacturer in the warranty period and subsequently by the insurance company are not taken into account.

6 The number of observations was, in general, between 25 and 60.

7 The cost of wind energy should not be confused with the price of wind power. The latter relates to the amount per kWh the wind turbine owner receives for the power he/she sells.

8 In the figure, the number of full load hours is used to represent the wind regime. Full load hours are calculated as the turbine's average annual production divided by its rated power. The higher the number of full load hours, the higher the wind turbine's production at the chosen site.

9 In this context, a coastal position is defined as a site with an average wind speed of 6.9 m/s at a height of 50 m above the ground. Correspondingly, the medium and low wind sites have average wind speeds of 6.3 and 5.4 m/s at a height of 50 m.

10 See, for instance, Neij (1997), Neij (1999), Milborrow (2003) or Neij *et al.* (2003).

11 EPRI (1997) suggests that wind turbines located in highly windy areas could achieve capacity factors of 40%-45% by 2005.

12 This seems to be the most recent update of the projected costs of generating electricity available.

13 National assumptions on plant lifetime might be shorter, but calculations were adjusted to 40 years.

14 Average wind power production costs calculated using an annual 5% discount rate as shown in chapter 4.