European Commission
Directorate-General for Energy

WIND ENERGY - THE FACTS

Volume 2

COSTS, PRICES AND VALUES

EXECUTIVE SUMMARY

1 INTRODUCTION

No single value can be assigned to the price of wind energy. The same is true of energy prices for thermal plant. It is important to distinguish between the cost of plant (such as wind turbines and wind farms) and the price of the electrical energy they produce. Capital costs are primarily a function of the size of the installation (due to economies of scale). Energy prices depend on wind speeds and institutional factors, and have two components:-

- Capital charges, including depreciation and interest charges
- Operating costs

The calculation of wind energy generation prices follows procedures which are reasonably standardised across the power industry. "Real", i.e. net of inflation, interest rates (test discount rates) - are used. National interest rates and repayment periods vary widely across the EU, but reference energy prices may be derived provided the levels are quoted.

Institutional factors account for most of the apparent variations in quoted wind energy prices. In Denmark, for example, the costs of grid reinforcement for wind installations are not always charged to the developer.

2 WIND ENERGY PRICES

Price trends: The cost of wind energy wind plant has fallen substantially during the last fifteen years, and this trend is continuing. Energy prices have fallen even faster, due to lower wind turbine costs, higher efficiency and availability, and lower operation and maintenance costs. Wind turbine prices fell by a factor of at least three from 1981 to 1991, and energy prices have halved in the last 9-10 years.

Current energy prices: The price of modern turbines around the 45 m diameter mark is around 700 ECU/kW. It may be noted that the "most economic size" has changed over the years and is still moving upwards. The larger the machines the fewer are required for a given capacity. This brings savings in site costs and in operation and maintenance costs. Overall, balance of plant costs add between 15 and 40% to wind turbine costs, depending on the number and size of machines in the wind farm, and the location. The windiest sites - on hilltop sites, often remote from a grid connection, or coastal locations where deep piling into silt is needed, tend to incur costs above average. Operational costs vary between countries and between wind farm sites; they range from around 25 ECU/kW/yr for 200 kW machines, falling to around 15 ECU/kW year for 500 kW machines.

Current energy prices corresponding to a mid-range wind farm cost of 850 ECU/kW are 9.6 cECU/kWh at 5 m/s, declining to 3.4 cECU/kWh at 10 m/s. (All wind speeds refer to hub height). These assume a 7.5% test discount rate and depreciation over 20 years.

National institutional frameworks influence discount rates and depreciation periods, and vary across the EU. Local wind speeds also vary widely across the European Union.

The best resources are in the upland regions of Ireland, Britain and Greece, parts of southern France, Spain and the Canary Islands, where average wind speeds (at hub height) may be around 8-10 m/s. In Western Denmark, speeds range up to about 8 m/s, while the coastal regions of north Germany range up to about 7.5 m/s. Elsewhere winds are lower, with speeds decreasing further inland.

Offshore wind has the potential to deliver substantial quantities of energy - at a price which is cheaper than most of the other renewable energies. Wind speeds are generally higher offshore than on land, although the upland regions of the British Isles, Italy and Greece, do yield higher speeds.

3 ENERGY PRICES FROM COMPETING FUELS

The electricity generation prices from thermal plant in the EU vary widely. Government support for the nuclear and coal industries may mean that the real generation prices are higher than is apparent. Comparisons between the price of wind energy and of electricity from the thermal sources ignore the fact that, in many instances, renewable technologies deliver energy closer to consumer demand than centralised generation.

Electricity prices for thermal plant, moreover do not include the so-called "external costs" of electricity generation - those associated with damage to health and the environment.

4 FUTURE PRICE TRENDS

There are a number of factors which are causing a steady fall in the cost of wind energy systems:-

- The trend towards larger wind turbines
- Falling infrastructure costs
- Possible reductions in the cost of raw materials

Data from the European Renewable Energy Study (TERES II)(DG XVII), indicate that wind may become one of the cheapest renewable energy sources, with prices within the range of those of the thermal sources. Energy prices from the thermal sources are, however, subject to uncertainty.

5 CONCLUSIONS

Wind plant costs and wind energy prices have been falling steadily and there are strong indications that this trend is continuing. No single figure can be assigned to price of wind energy, as wind speeds, interest rates, amortisation periods and plant costs vary across the EU, but on best sites, current wind prices are within ranges quoted for thermal plant.

- External costs of thermal plant need to be taken into account when making comparisons with wind energy prices. Some external costs, like the cost of coal support in Germany, are irrefutable. Others more difficult to quantify, but nonetheless real.

- Wind energy must also be credited with additional value, as it is usually injected into low voltage distribution networks, enabling utilities to save on transmission and other costs.
- Offshore wind energy prices are now moving down rapidly and will probably continue to do so, as new installations are commissioned.
- There is considerable scope for future price reductions.

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1 INTRODUCTION

There are no absolutes in energy prices. No single number can be assigned to the price of wind energy. The same is true of energy prices for thermal plant. Unless all the relevant assumptions are clearly set out, single numbers are virtually meaningless.

This paper includes a brief summary of past trends in wind plant costs and energy prices. It then examines current price levels, and the influence of capital costs, wind speeds, operation and maintenance costs, interest rates and other institutional factors such as capital depreciation periods.

Price comparisons with coal, gas, nuclear and other renewable energies are also included, and "system integration" issues are examined, including energy and capacity credits, how the value of wind energy in utility networks is affected by its variability, and the value of distributed generation.

The paper concludes with a review of published forecasts of future price trends.

2 DEFINITIONS AND CALCULATION METHODS

2.1 Definitions

To the layman, costs are what must be paid to acquire items and prices are the amount for which items are sold or offered. Value is the worth of an item to the recipient. The context must therefore be clear. Manufacturers incur costs when building wind turbines, and sell them at a price which includes their profit. From the perspective of a wind energy developer, however, he will incur costs throughout the lifetime of the project, which include the turbines, and sell the energy at a price which includes his profit. Inputs are therefore costs, and the output is a price. This is the perspective used in this paper.

Economic theory yields different definitions, and the economist's perspective includes wider and more complex issues, not relevant to this paper. The focus is more on the role of costs and profits as determinants of decision-making in organisations concerned with allocating resources to particular activities. "Economic opportunity cost" considers the value of the next best thing which could have been produced with the same resources, and takes into account the opportunity cost of capital, land and time (**1**). The relevant interest rates, however, vary with time, place and activity, and tend to be lower than the reference levels used in many energy price calculations. The use of reference levels, however, (typically 5 or 10%), makes no assumption about profit levels, which may be positive or negative, but the price levels clearly do not necessarily equate to the economic costs. Procedures for calculating economic costs may be found in standard texts on energy policy, and a detailed review may be found in reference (**2**).

Cost inputs: There are two cost inputs to a wind developer or owner. The capital, or installed, costs of the plant are most frequently quoted in terms of investment cost per installed kilowatt, or ECU/kW, and, broadly speaking, are primarily a function of the size of the installation (due to economies of scale). Operating costs are the second input, and, similarly, depend on size, and may be dependent also on capacity or energy yield.

Energy prices: These depend on installed costs, wind speeds, test discount rates and capital repayment periods, and are simply the sum of the capital cost element and the operating costs, and are usually expressed in cECU/kWh, although ECU/MWh is also used.
The term “reference price” is used in this paper to denote energy prices calculated using standard procedures, with fixed interest rates. These must be distinguished from prices relevant to particular EU states, which use appropriate levels of interest rate and repayment period; these are given the generic name “national prices”.

2.2 Price calculation methods

The basic procedures for setting selling prices for electricity are set out in standard textbooks, e.g. (2). The first step is to calculate the annual capital charge, which depends on the project interest rate, or “test discount rate” and repayment period. An "annual charge rate" is used, which expresses the fraction of capital cost which needs to be charged each year in order to yield the required rate of return over the specified period.

The annual capital charge includes capital depreciation and interest charges, and is divided by the annual energy output to yield the capital element of energy price. The energy output of wind plant is primarily dependent on the wind regime, i.e. on its geographical location, and on the performance of the wind turbines.

Institutional factors arguably account for most of the apparent variations in quoted wind energy prices. These factors may also influence the exact make-up of capital and operating costs. In Denmark, for example, the costs of grid reinforcement for wind installations are not always charged to the developer. Similarly, utilities in Denmark and elsewhere may not always charge their overheads to "operating costs", whereas in Britain, by contrast - where wind developments are undertaken by private developers - all costs are included.

2.3 Recommended Practices

The calculation of wind energy generation costs follows procedures which are reasonably standardised across the power industry. The International Energy Agency has published guidelines in the form of a "Recommend Practice" (**3**) for wind energy, and these are similar to those used for other renewables and for thermal plant. The IEA document advocates the use of "real", i.e. net of inflation, interest rates - more accurately, test discount rates - for the calculations, which is also common practice.

The following items are included in energy price calculations:-

- planning costs)
- capital cost of plant) <u>Capital</u>
- construction costs)
- interest during construction)
- land costs (either as part of the capital or as annual leasing payments)
- fuel costs - zero for renewable energy plant
- operating costs (O & M), including labour, materials, rents, taxes and insurance

- decommissioning

The IEA document recommends that capital costs are amortised over the technical life of the plant and that standard test discount rates are used. While this may produce useful data for comparative purposes, actual interest rates and amortisation periods are controlled by regulatory or institutional frameworks, as noted above. Each of these parameters needs, therefore, to be considered in more detail.

A useful parameter which reflects the dependence of energy cost on wind speed is the "cost per annual unit of output", simply obtained by dividing installed cost by annual output, and expressed in ECU/Annual MWh. This is useful for comparative purposes, as it does not depend on interest rates or depreciation periods.

2.4 Interest rates

Public sector companies use test discount rates set by Government. These vary in the EU, generally between 5% and 8%. Private companies set their own rates. In practice, many projects are financed using a mixture of loan and equity funding. A typical ratio is 80/20. If the loan interest rate is, say 6%, and the equity return is 25%, the equivalent test discount rate is 10%. The reference energy prices in this paper, which are not specific to particular states, use sample discount rates of 5 and 10% - in line with conventions for thermal plant, **(3,4)**.

2.5 Amortisation periods

Amortisation and depreciation periods also vary, and are not necessarily as long as the life of the plant. This is rarely used outside the public sector. The IEA Recommended Practice notes that “20 years is commonly used for proven grid connected wind turbines” and is used in this paper as a default value.

2.6 Typical interest rates and repayment periods

Table 1 shows sample European data and Figure 1 illustrates how repayment periods and interest rates influence energy prices, for wind and combined cycle gas turbine plant (CCGT). Energy prices for CCGT plant are less sensitive to these factors, as the capital element of the energy price is lower. The data used in Figure 1 are set out in Table 2.

It should be noted that the data in Table 1 can alter. To quote an example - before privatisation, in the UK it was assumed that capital was repaid over the life of the plant. Later, capital had to be repaid within about six years for most projects in the second round of the Non Fossil Fuel Obligation (NFFO), since premium prices ran out at the end of 1998. Later rounds of the NFFO offered contracts for 15 years, but this did not necessarily define the amortisation period. The technology at that time was seen as fairly new, so bank loans were limited to around 10/12 years (**5**). More recently this period has been extended.

Location	Interest rate, % real	Repayment period	Reference
Denmark	7	20	4
Germany	Varies, 5 upwards	10	4
The Netherlands	5		4
Portugal	10		4
United Kingdom	Developer's choice	15	

Table 1 Interest rates and repayment periods used for wind plant

Technology	Wind	Gas
Capital cost, ECU/kW	1000	724
Build time, year	0.5	1
Load factor, %	0.26	0.8
Fuel cost, cECU/kWh	0	3.3
O & M cost. cECU/kWh	1	0.6

Table 2 Plant data used to illustrate effects of interest rates and repayment periods

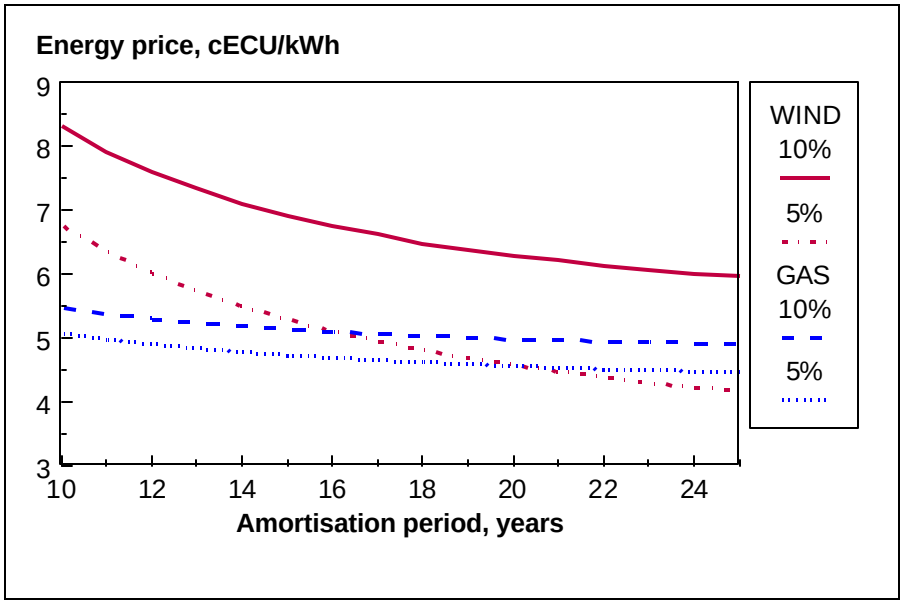


Figure 1 Energy prices - influence of interest rates and repayment periods

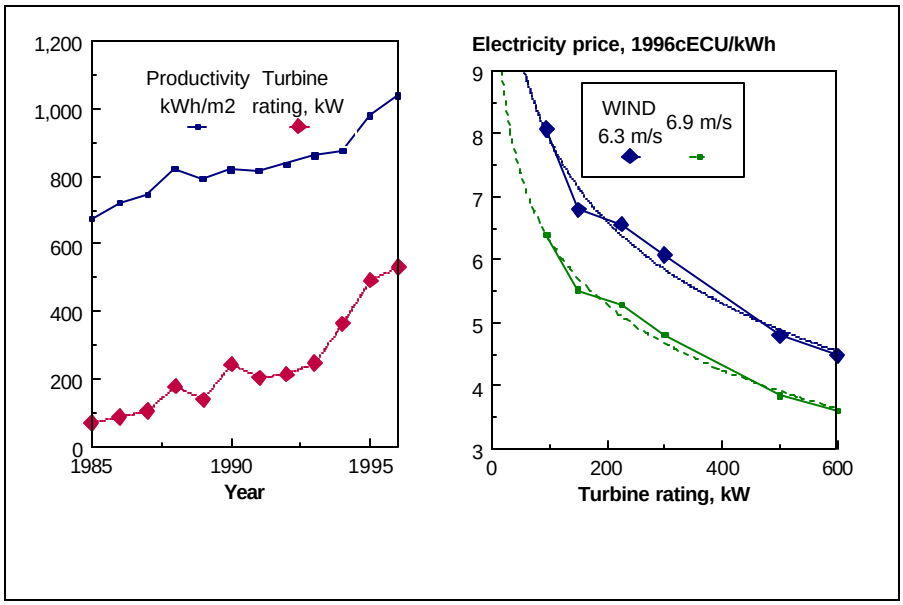
3 HISTORICAL SUMMARY

The cost of wind plant has fallen substantially during the last fifteen years, and this trend is continuing. The reduction in energy prices has been greater and is due to:-

- Lower wind turbine prices
- The turbines are larger, with taller towers (so the wind speeds intercepted by the rotors have increased). Most machines installed in the 1980s were around 50 kW in size whereas modern wind farms use 600 to 750 kW machines.
- Better understanding of the technology and improved production methods
- Efficiency and availability have improved.
- Operation and maintenance costs have fallen.

Several studies have reported these movements in prices. The results differ, since they depend on the precise way the data were collated, but there is broad agreement that wind turbines prices fell by a factor of at least three from 1981 to 1991, and energy prices by a factor of about 4. Prices have halved in the last 9-10 years **(6).**

The way in which machine sizes and productivity have increased in shown in Figure 2. The average size of wind turbines installed in Denmark increased from 71 kW in 1985 to 523 kW in 1996. The productivity of new machines increased from 673 kWh/sq m in 1985 to 1037 kWh/sq m in 1996. (7). The link between turbine sizes and energy prices has also been analysed (6), indicating a 44% reduction from the early 95 kW machines to the 600 kW size. This is shown in Figure 3. The overall trend in Danish wind energy costs over the last 10 years, assuming a 6.3 m/s site, 5% interest rate and 20 year life, is illustrated in Figure 4, which shows an 8% per annum fall in prices.



Figures 2 and 3 Danish wind turbine sizes, productivity and energy prices

The minimum bid prices for wind energy in the UK NFFO are also shown in Figure 4, and show a similar rate of fall. The appropriate wind speeds and interest rates are not known; minimum bid prices are shown as these are not influenced by the size of the NFFO orders.

This summary of historical trends is intended to give a broad picture of price movements; the energy prices quoted are comparable as far as possible but the all-important question of wind speeds, test discount rates and depreciation periods need to be taken into account when making more detailed comparisons between costs, particularly across national boundaries.

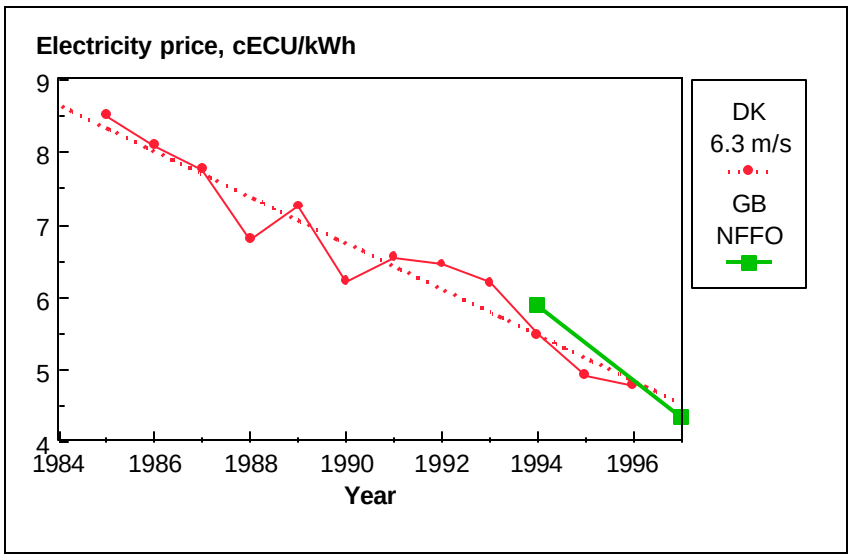


Figure 4 Energy price trends

4 CURRENT PLANT COSTS

4.1 Methods of presentation

Wind turbine and wind farm costs are often quoted on the basis of a price per unit of installed capacity (ECU/kW), but such data can be misleading as manufacturers have differing design philosophies - there is no fixed relationship between rotor size and rating. A 40m machine, for example, may have a rating anywhere between 350 kW and 500 kW. The price of a machine with a high rating, relative to its size, will therefore tend to appear low when compared with one which has a low rating for its size. More reliable comparisons may be made by comparing prices on the basis of price per unit swept area (ECU/sq m). However, although this may be more rigorous it is probably less readily understood. Both methods of presentation are used in this paper, with comparisons on the basis of the rated output being preferred, provided it does not lead to ambiguity.

The analysis of current energy prices uses data for machines around 500-600 kW rating, as these are currently being deployed in large numbers around the EU and generally give the lowest energy prices.

4.2 Key factors

4.2.1 Installed costs

Turbine prices: Danish wind turbine prices are representative of EU levels, and published price lists facilitate analysis. Price data are shown in Figure 5. There is no clear link between price per unit swept area and size, and the price of turbines around the 45 m diameter mark is around 300 ECU/sq m. It may be noted that the "most economic size" has changed over the years and the relationship between size and price is discussed in Appendix A.

Balance of plant costs: Wind turbine prices, discussed above, vary little with size, but there are sound reasons for pursuing the development of large machines. The use of large machines means fewer are required for a given capacity, and a number of items in the "balance of plant" cost category decrease with machine size, or machine numbers, especially:-

- Foundation costs
- Electrical interconnection costs
- Access tracks

Analytical studies have shown that the contribution of balance of plant costs to overall energy costs can be reduced by around 25% by moving from machines of the 300 kW size range to 1 MW size machines **(9)**. These trends are explored further in Appendix A

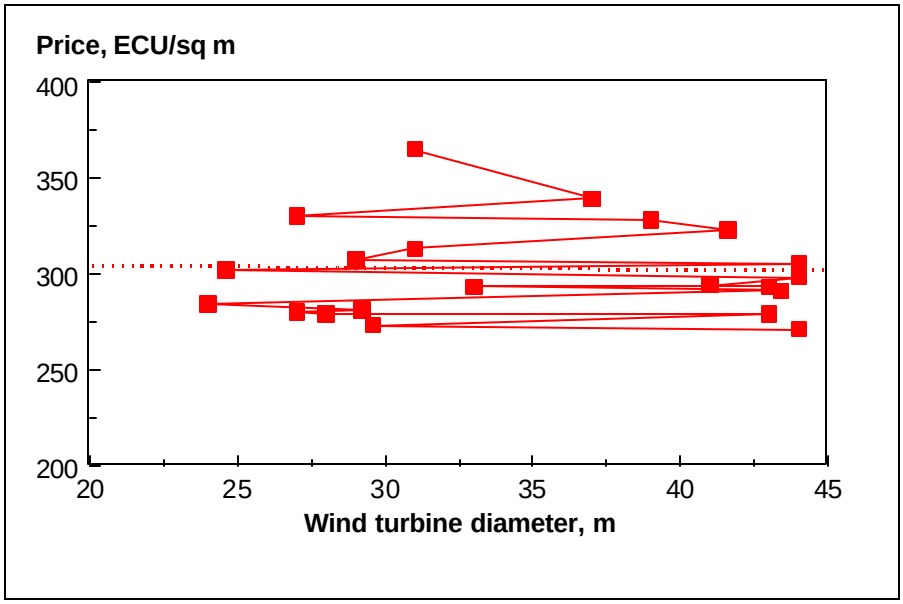


Figure 5 Turbine prices - Denmark

Balance of plant costs add between 15 and 40% to wind turbine costs, depending on the number and size of machines in the wind farm, and the location. The windiest sites - on hilltop sites, often remote from a grid connection, or coastal locations where deep piling into silt is needed, tend to incur costs above average. Table 3 summarises the components of “balance of plant costs”, and shows typical values (**10-12**). National institutional factors affect the precise mix of items; “land purchase”, for example, reflects German practice, whereas landowners tend to be paid a rent in Britain. If the turbine owner also owns the land, however, there is unlikely to be a rental charge.

Item	Costs, % turbine price

	Range
Foundations	5-11
Electrical connections	5-11
Land purchase	0-5.7
Planning costs	1.5-3
Approvals	3-8
Infrastructure	2-4
Management	3-6
Miscellaneous	2-4
Grid connection	7.5-15
TOTAL	15-40

Table 3 Wind farm balance of plant costs

4.2.2 Installed costs and wind speeds

Installed costs tend to rise with increasing wind speed, as noted in the previous section. This reflects the fact that developers can afford higher costs, if they get a higher yield. Increasing the wind speed e.g. from 8 to 9 m/s at hub height will typically increase output from a wind turbine by 10 per cent. The link between prices and winds has been examined for Britain **(13, 14)** and Germany, and similar trends found, see Appendix A. A further factor which influences this correlation is that tall towers are often used in Germany to obtain higher wind speeds, but at increased turbine cost. For the purpose of this analysis, it is assumed that costs increase linearly by 8% per m/s increase in wind speed, above 7 m/s at hub height.

4.2.3 Operational Costs

Operational costs vary between countries and wind farms. As some elements are fixed annual sums, wind farms on high wind speed sites may have lower costs. Table 4 shows the main components and the usual basis of charging is underlined. Some costs are size-dependent (see Appendix A), but entries relate to machines in the 500-750 kW range. Total costs are around 25 ECU/kW/yr for 200 kW machines, falling to around 15 ECU/kW year for 500 kW machines.

Item	ECU/kW/year, or other cost basis	cECU/kWh (approx)
Service contract	4-8, or based on output	0.15-0.6
Administration	Cost basis varies	0.1-0.3
Insurance	4-7	0.15-0.5
Land rent	0-4, 1-2% of revenue, if charged	0-0.4
Local rates	0-5	0-0.2
Electricity usage	Standard tariffs	0.05-0.2
Reactive power	Up to 0.4 kVArh	0-0.1
TOTAL	Up to 24 ECU/kW/year	0.6-1.5

Table 4 Operational costs - 500 kW turbines

Not all utilities charge for reactive power - and not all machines need it. Land rent may be an explicit cost if a developer builds on land he does not own, but may not appear if the wind farm operator owns the land. In the latter case the cost of the land may be included in the overall capital cost, or the owner may simply receive remuneration from the overall profit.

4.2.4 Size of wind farm

The size of a wind farm influences its cost, as large developments:-

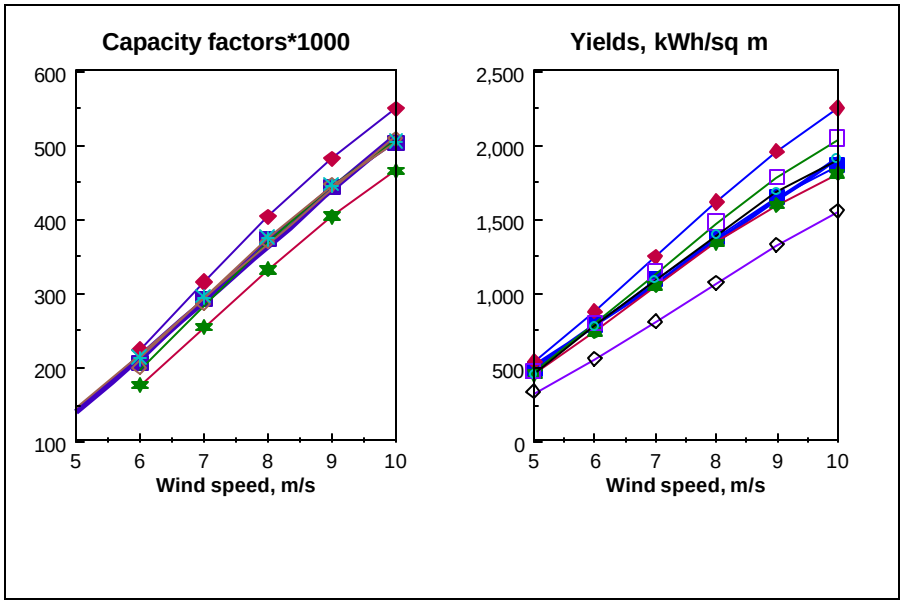
- may attract discounts from wind turbine manufacturers
- enable site infrastructure costs to be spread over a number of machines, reducing the unit cost
- may enable more effective use of maintenance staff

These issues are examined further in Appendix A

5 WIND ENERGY PRICES

5.1 Influence of wind speed

Wind energy prices are critically dependent on site wind speeds, so links between wind speed and machine productivity (in kWh/sq m and kWh/kW) need to be established for the purposes of generalised analyses. Energy yield data for a number of modern machines were collated and these show that capacity factors are typically around 0.2 at 6 m/s, rising to 0.45 at 9 m/s (at hub height). Yields are typically around 750 kWh/sq m at 6 m/s, rising to 1600 kWh/sq m at 9 m/s. These data are shown in Figures 6 and 7.



Figures 6 and 7 Capacity factors and yields for modern machines (500-750 kW)

Wind speeds vary widely across the European Union. The best resources are in the upland regions of Ireland, Britain and Greece, parts of southern France, Spain and the Canary Islands, where average wind speeds (at hub height) may be around 8-10 m/s. In Western Denmark, speeds range up to about 8 m/s, while the coastal regions of north Germany range up to about 7.5 m/s. Elsewhere winds are lower, with speeds decreasing further inland. Information on wind speeds is given in the European Wind Atlas (**8**).

5.2 Reference prices

Although wind energy prices, as noted earlier, depend on national institutional frameworks, reference values may be calculated, using the IEA "Recommended Practice". The wide range of interest rates and other factors must be acknowledged and so indicative low, average and high prices are used. The assumptions are set out in Table 5, and the data apply to machines in the size range 600-750 kW. It is assumed that installed costs increase with wind speed above 7 m/s by 8% per m/s, as noted earlier. Energy production has been derived assuming that array, availability and other losses account for 10% of the gross energy. (Actual losses may be less, as availability levels of 98% and above are achieved by many turbines, but the guaranteed level is usually 95%. This is normally the basis of investment decisions). The energy prices corresponding to the mid-range costs are 9.6 cECU/kWh at 5 m/s, declining to 3.4 cECU/kWh at 10 m/s. The data are shown in Figure 8.

Price parameter	Low	Average	High
Installed cost, ECU/kW, at 7 m/s (hub height)	700	850	1,000
Real interest rate, %	5	7.5	10
Construction period, years	0.5	0.5	0.5
Amortisation, years	20	20	20
Running costs, fixed, ECU/kW/yr	12	18	24
Running costs, variable, cECU/kWh	0.2	0.3	0.4

Table 5 European reference wind energy prices - summary

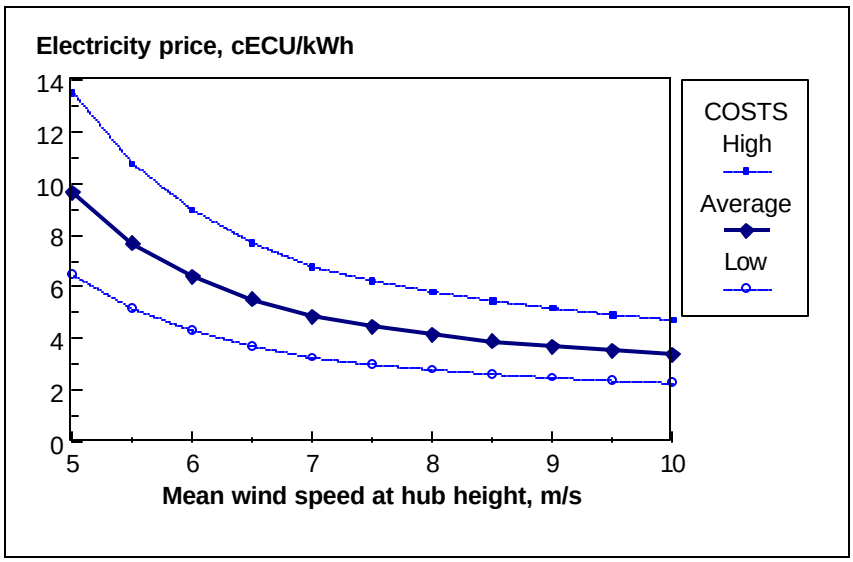


Figure 8 European reference wind energy prices

5.3 National wind energy prices

National institutional frameworks control actual electricity price levels, as noted earlier, and these vary across the EU**(27)**. In practice, also, renewable energy plant are often supported by specific price mechanisms.

The financing of German wind farms, for example, is complex, but a recent appraisal **(15)** suggests that an effective real interest rate of 6.5% and an amortisation period of 10 years is currently used to derive energy prices. The strong dependence of energy price on wind speed has been examined by the German Wind Energy Institute - DEWI **(16)** and recent estimates are shown in Figure 9.

The length of contracts under the British Non-Fossil Fuel Obligation also influences prices. This is set at 15 years, and as all developments are undertaken by private companies, the test discount rate is unlikely to be less than 7.5%. Wind farm prices in the UK are in line with the "Maximum" levels in Table 5. Energy price estimates based on these assumptions are shown in Figure 9, for comparison with the German data. It may be noted that few wind farms in Germany have winds above 7.5 m/s, and few in Britain have winds below 7.5 m/s.

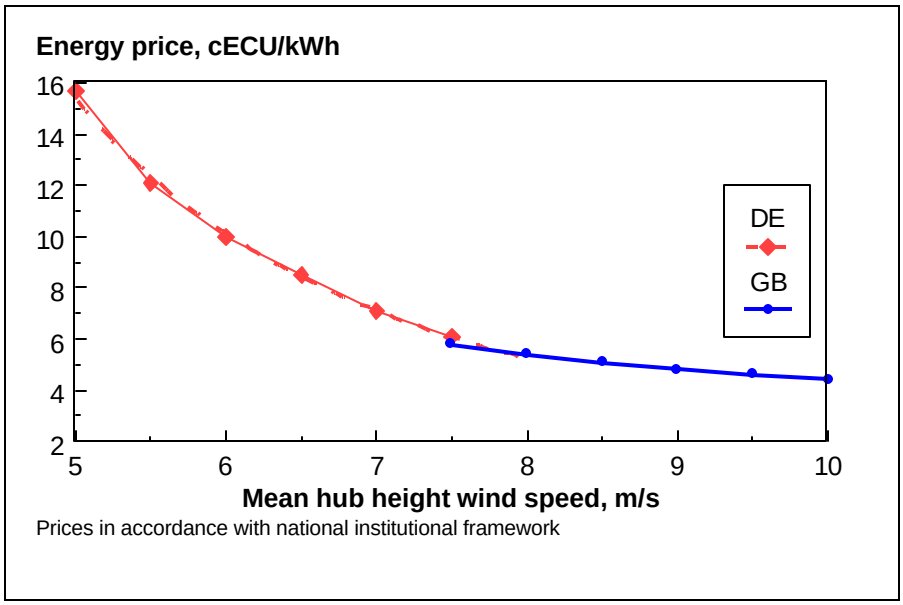


Figure 9 Typical wind energy prices

Table 6 shows wind plant installation costs and other data from across the European Union **(17-21)**, but it should be noted that fewer data are available outside Denmark, Germany and Britain, so the figures in the Table are only samples. Plant costs, wind speeds and energy prices are mostly within the ranges discussed in the analysis of Danish, British and German data, although the important influence of wind speeds and test discount rates in defining energy prices needs, again, to be emphasised. It should also be noted that methods of paying for wind energy vary (**22**), and remuneration may be linked to electricity tariffs rather than the price of wind energy. The Netherlands is a case in point. Similarly, investment subsidies may influence energy prices, and hence the price data in Table 6 may not necessarily derive from rigorous application of the procedures discussed in this paper.

Location (Reference)	Location	Machines (Number/type/kW)	Installed Cost	Energy price (cECU/kWh)
France **(17)**	General analysis	Minimum energy price at 800 kW	28% above turbine cost	5 at 7.5 m/s (15 yr life, 8% tdr)
Greece **(18)**	General analysis	Not specified	1000-1330 ECU/kW	2, winds/tdr not quoted
Netherlands **(19)**	Gronigen area	40/Lagerwey/80	4.83 MECU (1510 ECU/kW)	5.8 (paid by utility)
Norway **(20)**	Central Norway, general data	500 kW, effect of machine numbers on cost of wind farms	997 ECU/kW for 1, falling to 990 for 10 machines	4-8, winds 6-7.9 m/s, 7% tdr, 20 yr life
Spain **(20)**		67/Ecotecnia/225	15.9 MECU (1055 ECU/kW)	
Sweden **(18)**	General analysis	400-500 kW	932 ECU/kW	3.6-4.3, with 2200 kWh/kW (5% tdr, 25 yr)

Table 6 European wind farm data

6 OFFSHORE WIND ENERGY

Offshore wind has the potential to deliver substantial quantities of energy - at a price which is cheaper than most of the other renewable energies, but more costly than onshore wind. Offshore wind energy has the added attraction that it has minimal environmental effects and, broadly speaking, the best European resources are reasonably well located relative to the centres of electricity demand.

Wind speeds are generally higher offshore than on land, although the upland regions of the British Isles, Italy and Greece, do yield higher speeds. In the UK, for example, onshore winds at hilltop sites range up to 9 m/s at hub height - higher in some instances - whereas offshore winds at, say, 5 km from the East Coast are around 8 to 8.5 m/s. Offshore wind power is therefore most attractive in locations such as Denmark and the Netherlands where windy hill top sites are simply not available. In these areas offshore winds - which increase with distance from land - may be 0.5 to 1 m/s higher than onshore, depending on the distance offshore.

Several offshore wind farms have now been built, so it is possible to assess the economics in the light of operational experience. This analysis is carried out in Appendix B.

7 ENERGY PRICES FROM COMPETING FUELS

The electricity generation prices from coal, gas, hydro, oil and lignite - the fuels most commonly used across the EU - vary widely. There is no single price that can be assigned to any source of generation, as discussed in section 2. The institutional arrangements which influence discount rates and amortisation periods are, again, frequently the dominant factor in setting energy prices from thermal and hydro plant, but variations in plant and fuel costs also play a part. Government support for the nuclear and coal industries also means that the real generation costs are higher than is apparent.

For example, the pithead price of coal in Germany is more than three times the world market price, so the *true* generation price from coal there is over 9 cECU/kWh (The utilities do not actually pay the higher price, as an annual subsidy of 7400 million DM is paid by the taxpayer to the coal industry. This is a classic example of a "hidden", or "external" cost - a concept discussed in Appendix C).

Capital costs for large combined-cycle gas turbine (CCGT) plant are falling as the "dash for gas", in Britain and elsewhere, leads to intense competition. Gas prices, however are moving upwards. All future coal plant is likely to be fitted with flue gas desulphurisation plant and increasingly stringent controls on emissions may raise plant costs. "Clean coal" technology is being explored, but dramatic changes in generation prices in the short term are unlikely.

The price and costs of nuclear power are the subject of much debate. One key issue is the difference between "mature" plant costs for a series of Pressurised Water Reactors (the most popular option) and "first of a kind" costs, which are inevitably higher. With the exception of France, "production runs" of nuclear plant are rare. Further uncertainty arises from the treatment and precise level of decommissioning costs. Nuclear generation price estimates therefore span a wide range and a UK government review of 1995 quoted 5.2-8.5 1995cECU/kWh (rebasing the prices from the 1990 levels used). Nuclear prices may also exclude hidden external costs: accident risks, for example, are often borne by governments, relieving utilities of the need to pay insurance premiums..

The status and costs of thermal plant are summarised in Table 7. The energy prices have been derived using a 5% discount rate - to correspond with one set of wind price estimates. This yields lower prices for nuclear than those which stem from systems which have been privatised. These prices are compared with wind energy prices in Figure 10.

Plant	**Capital cost, ECU/kW**	**Fuel cost, cECU/kWh**	**O&M cost, cECU/kWh**	**Total cost, cECU/kWh**
Gas	450-700	1.7-2	0.4-0.6	3.1-4
Coal	1000-1300	1.8-2.3	0.7-1	3.7-5.5
Nuclear	1200-2000	0.7-0.9	0.8-1	3.3-8

Table 7 Thermal plant data - current levels

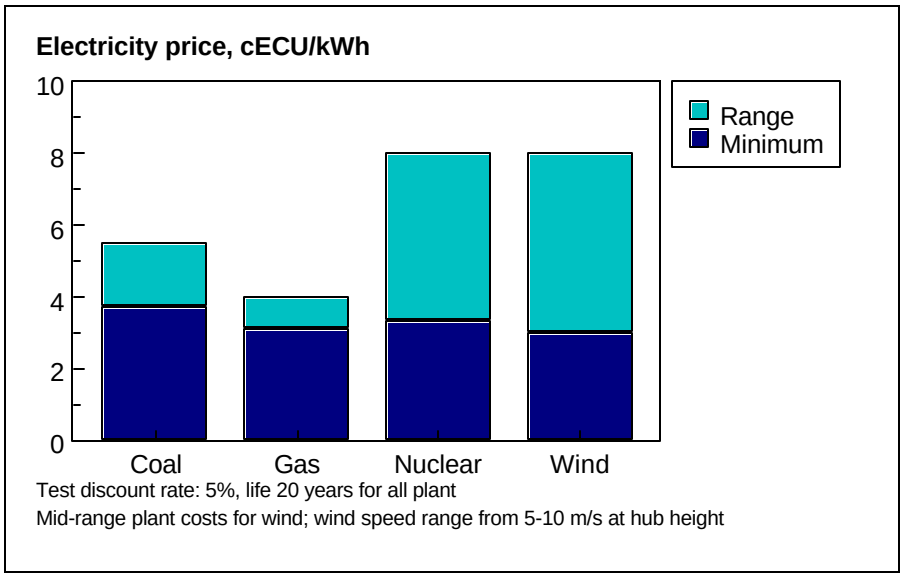


Figure 10 Current electricity prices

8 THE VALUE OF WIND ENERGY

Direct comparisons between the price of wind energy and of electricity from the thermal sources ignores the fact that, in many instances, renewable electricity-generating technologies deliver energy closer to consumer demand than centralised generation. It substitutes for electricity which has accrued a higher selling price than the generation costs of large thermal plant, due to its passage through the network. This rising level of "value" with reducing voltage is reflected in higher charges for customers connected at lower voltage levels. These concepts are illustrated in Figure 11, which includes typical selling prices for electricity at various stages in the system.

Small-scale generation of this kind is classified as "embedded". An alternative term for plant of this kind is "distributed generation" and there is a growing interest in the possible benefits, which may include reduced grid losses, a role in stabilising the supply in areas remote from generation and deferment of the need for main transmission reinforcement. It is argued that the value of the energy is greater than simple "generation substitution" when these benefits are taken into account. This issue is explored in more detail in Appendix D.

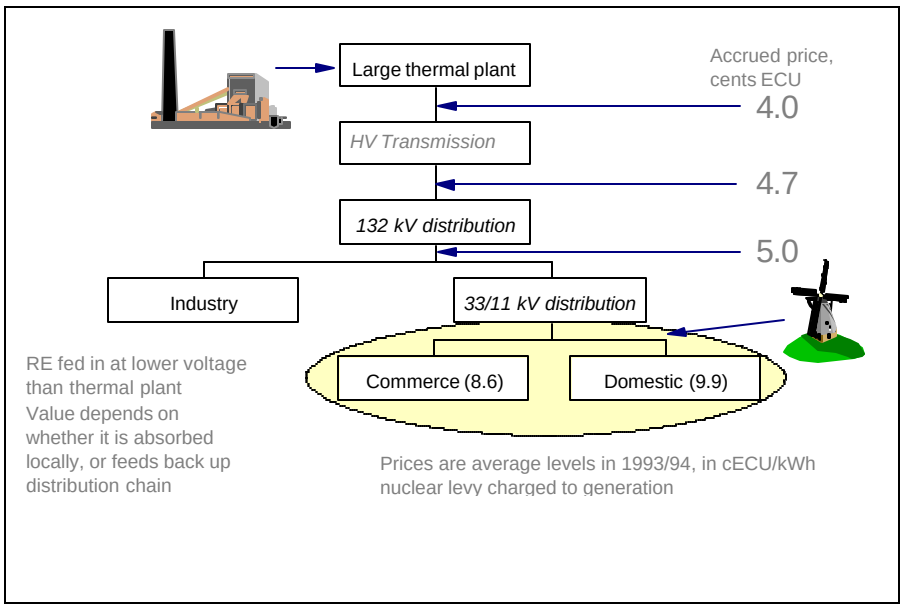


Figure 11 Electricity distribution and renewable energy

9 EXTERNAL COSTS

9.1 Introduction

The electricity prices quoted in Section 5 do not include the so-called "external costs" of electricity generation - those associated with damage to health and the environment. These are not borne by the electricity generator or consumer, and are not included in the price of electricity. External costs may be difficult to quantify accurately, and this is used as a reason for preserving the status quo, but there is increasing awareness that this is unsatisfactory.

Although there is general agreement as to the broad definition of external costs - costs attributable to an activity that are not borne by the party involved in that activity - there are widespread variations in defining the boundaries. There is an argument, for example, that the maintenance of petrol stocks for strategic reasons adds approximately one third to the price of fuel due to costs incurred in storage, extra transport and security. Therefore, this ‘shadow’ cost should be regarded as an "external cost" of oil.

9.2 Cost categories

External costs, or at least some elements, are difficult to quantify, but they are nonetheless real. If the enormous costs of cleaning up after the Chernobyl nuclear disaster had been taken into account when the plant was constructed, it clearly would never have been built. Arguments for the external costs attributable to oil fired generation range from supertanker spillages to a substantial proportion of western defence budgets. For simplification they can be divided into three broad categories (**23,24**).

- hidden costs borne by governments, including energy industry subsidies and research and development costs
- costs of the damage caused to health and the environment by emissions other than CO2

- the costs of global warming attributable to CO_2 emissions

The second category is costs due to emissions which cause damage to the environment or to people. These include a wide variety of effects, including damage from acid rain and health damage from oxides of sulphur and nitrogen emitted from coal fired power stations. An EU-funded study has recently examined these in some detail (25). Other costs in this category are power industry accidents, whether they occur in coal mines, on offshore oil or gas rigs, or in nuclear plant. The probability of a nuclear accident in Western Europe might be extremely low, but should a catastrophic failure occur the costs would be undeniably huge. Multiplication of a number close to zero (the probability of a nuclear accident) by a number close to infinity (the cost of such an accident), does not necessarily give a meaningful result.

The third category is by far the largest: external costs due to greenhouse gas emissions which cause global warming - with all its associated effects. This is the most contentious area of the external costs debate. The range of estimates for the possible economic implications of global warming is huge. Costs associated with climate changes, flooding, changes in agricultural patterns and other effects all need to be taken into account.

9.3 External cost values

Despite the difficulties in assessing external costs there is a some measure of political agreement in the EU about the level of a carbon tax, and the EU's proposed carbon taxes would have reflected this rough consensus. This would eventually have added around 1.6 cECU/kWh to the price of coal-fired generation, 0.8 cECU/kWh to gas, and 0.7 cECU/kWh to nuclear. The latest proposals for energy taxation are more modest, and are not a good reflection of external costs.

10 FUTURE PRICE TRENDS

A number of factors are causing a steady fall in the cost of wind energy systems:-

- The trend towards larger wind turbines
- Falling infrastructure costs
- Possible reductions in the cost of raw materials

Manufactured items which are produced in quantity benefit from increased production, due to improved manufacturing and assembly techniques. The way in which costs fall as a depends on the product, and is a function of the relative inputs of material and labour. For wind turbines it has been estimated that the price is likely to fall by 8% for each doubling of production. Given that other factors, such as better understanding of wind loads and materials properties, also contribute to cost reduction, this figure may be improved. As wind turbines are relatively small in output - in power generation terms - the need for significant numbers of machines enhances their prospects for cost reduction.

The energy price trends shown in Figure 4 do not give any indication that the trend in price reductions is slackening. The recently-completed European Renewable Energy Study (TERES II)

reaches a similar conclusion. It also expects that further R&D will enable technological advances to be made.
By 2020 capital costs are expected to be 50-75% of present levels, allowing financially viable wind energy production on high and medium wind regime sites. Data from the study, shown in Figure 12, indicate that wind may become one of the cheapest renewable energy sources**.**

Energy prices from the thermal sources are, however, subject to uncertainty. Demand for gas in Western Europe and the United States which will influence its price, as it is in relatively short supply. Coal is plentiful, but the growing demand from the third world - especially India and China - may raise the world coal price between now and the year 2000. Estimates for coal prices on the world market in 2000 range from 2.7 ECU/GJ to 3.5 ECU/GJ.

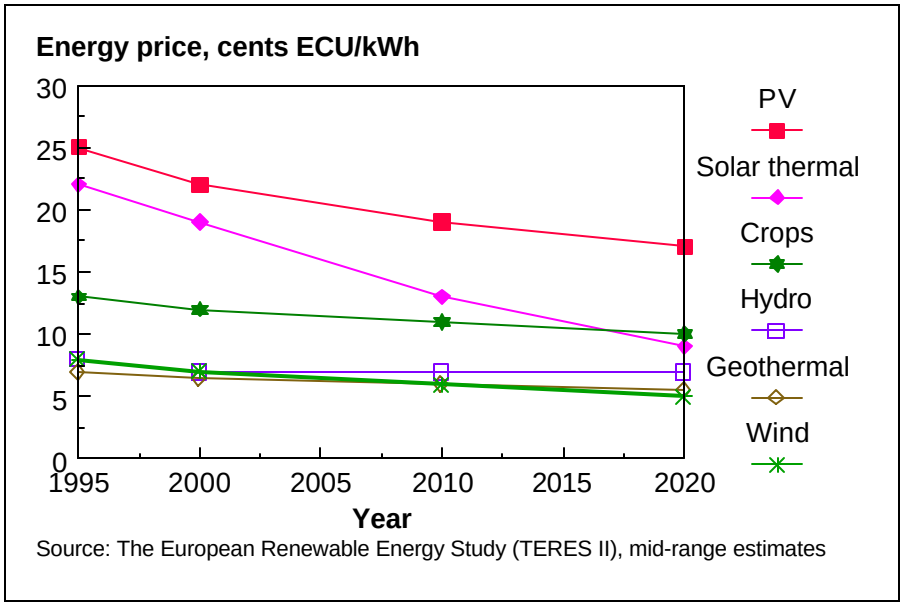


Figure 12 Forecasts for unit costs - centralised generation

With these provisos, Table 8 sets out energy price estimates for fossil sources for the year 2000. As there are a wide range of plant and other costs, two authoritative data sources, only, have been used; the UNIPEDE study **(4)**, and a recent EU assessment **(23).** The range of electricity prices has been derived after rebasing the UNIPEDE data to ECU1995. Two ranges are quoted:-

1. Using UNIPEDE central plant and fuel cost estimates, with 5% and 10% discount rates.
2. Taking into account, in addition, the spread of fuel cost estimates.

It must be emphasised that this Table adheres to the EU/UNIPEDE estimates and that a wider spread of price estimates would result from an examination of country-specific data.

As wind energy prices below 4 cECU/kWh have already been realised in the latest round of the UK NFFO**,** the prospects for wind energy are bright.

	Gas (CCGT)	Coal	Nuclear
Plant cost, 1992ECU/kW	694-754	1185-1293	1478-1740
Plant life, years	25	30	30
Fuel cost, cECU/kWh	3.3, +/- 0.6	1.9, +/- 0.3	0.8, +/- 0.1
O & M costs, cECU/kWh	0.4	0.7	0.8
1. Electricity price, cECU/kWh	5.0-5.5	4.4-5.6	4.0-5.7
2. Electricity price, cECU/kWh	4.4-6.1	4.1-5.9	3.9-5.8

Table 8 Thermal plant costs, year 2000

11 CONCLUSIONS

There is a very large variation of wind speeds, plant costs, test discount rates and other factors which influence wind energy prices across the European Union. Currently, an average EU-wide installed cost of 1000 ECU/kW may be taken as a typical value. German plant costs are slightly higher and Danish levels are slightly lower. A direct comparison between wind energy prices and those of thermal plant is misleading, as wind has lower external costs and often has a higher value. Nevertheless, wind becomes competitive with gas at the 5% discount rate, if both use amortisation periods of 20 years; at the 10%, gas is cheaper. Given that wind prices are falling, its competitive position is expected to improve.

In practice wind speeds vary widely across the EU, and wind prices at sites with winds higher than 6.5 m/s will clearly be lower. When the external costs of other fuel sources and system benefits of wind are taken into account, it is clear that wind's competitive position is becoming ever stronger.

More specific conclusions must be country-specific. The German wind prices shown in Figure 9, for example, must be set alongside the high price of generation from coal (there are very few gas-fired generation plant), and the massive subsidy given to the coal industry. As Danish utilities use discount rates around 6%, this works in favour of wind energy and several Danish studies have shown that the costs are similar to those of thermal plant. In Britain, however, gas prices are low, yielding low generation prices, but wind prices, based on the latest NFFO bids, are only slightly higher, due to the high wind speeds.

The key conclusions may therefore be summarised:-

- Wind plant costs have been falling steadily and this trend is likely to continue.
- Wind energy prices are falling faster, as machines become more reliable and efficient.
- No single figure can be assigned to price of wind energy, as wind speeds, interest rates, amortisation periods and plant costs vary across the EU, but -
- On best sites, current wind prices are within ranges quoted for thermal plant.
- External costs of thermal plant need to be taken into account when making comparisons with wind energy prices. Some external costs, like the cost of coal support in Germany, are irrefutable. Others more difficult to quantify, but nonetheless real.
- Wind energy must also be credited with additional value, as it is usually injected into low voltage distribution networks, enabling utilities to save on transmission and other costs.
- Offshore wind energy prices are moving down rapidly.
- There is considerable scope for future price reductions, supported by several studies.

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APPENDIX A

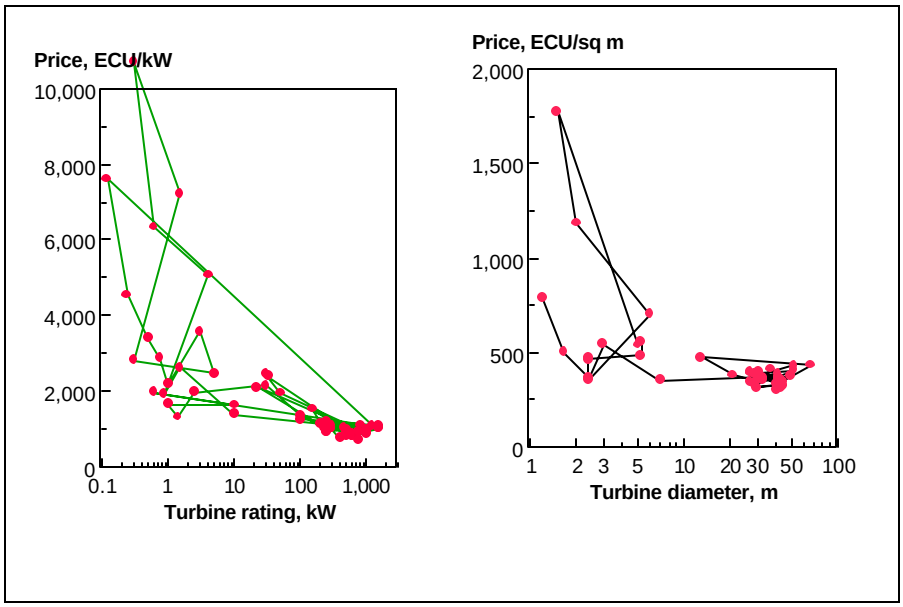
WIND PRICE SENSITIVITIES

A1 COST/SIZE TRENDS

A1.1 Introduction

A number of analyses of wind energy prices have shown that wind turbine economics improve with increase of size. Rehfeldt et al, for example **(1)**, show that the price per annual kWh falls by over 25% as rotor diameter increases from the 16/22 m range to the 32/45 m range. The Danish data plotted in Figure 3 shows a similar trend.

A study of wind turbine prices, however, shows that wind turbine prices fall with increasing size up to a certain point beyond which the price rises. The reasons for this trend have been explored in some detail (2). The very small machines cannot easily make the best use of material; bearings and generators tend to assume a higher proportion of the cost than at the larger scales. At the very large sizes, however, the influence of weight - which must inevitably tend to increase as the cube of the size - may make the economics less attractive. These trends can be seen in Figures A1 and A2. Figure A1 shows prices, in ECU/kW plotted as a function of turbine rating; this graph exhibits more scatter than the analysis in terms of ECU/sq.m against diameter (Figure A2). Despite the scatter on both graphs the overall trends are clear. At the 1 kW size, prices are around 2500 ECU/kW, falling to around 800 ECU/kW around the 500 kW region. A more detailed examination of larger machines shows that prices move upwards from a minimum value around 350 ECU/sq m as size increases towards 70 m diameter (Figure A3). The "most economic size" has changed over the years and may continue to change, but the fundamental design laws mean that the price - size curve will always tend to have a similar form.



Figures A1 and A2 German wind turbine prices

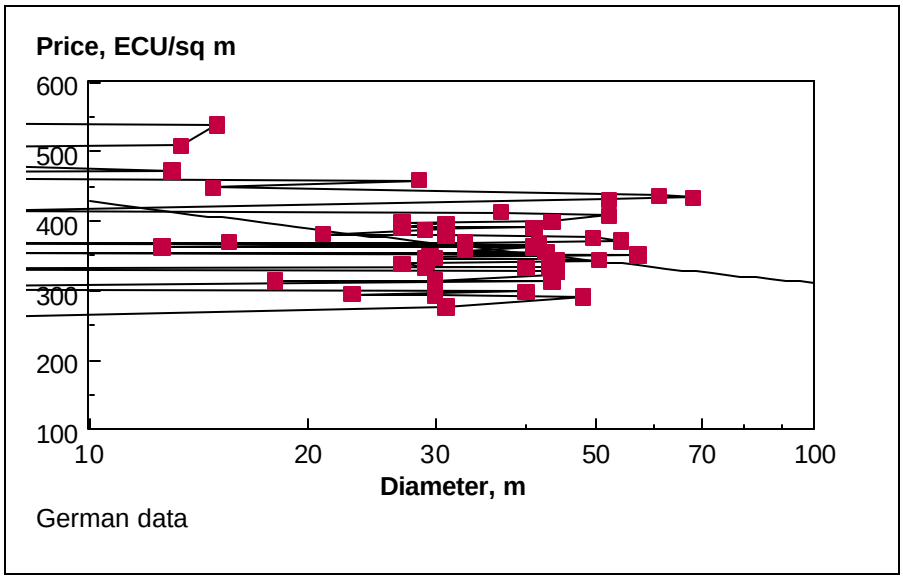


Figure A3 Price and diameter - larger wind turbines

A1.2 Balance of plant costs

Although wind turbine prices may increase at the large size ranges, there are nevertheless sound reasons for pursuing the development of such machines. A number of items in the "balance of plant" costs decrease with size of machine and/or machine numbers such as:-

- Foundation costs
- Electrical interconnection costs
- Access tracks

The way in which foundation costs decrease with increasing size is illustrated in Figure A4. Analytical studies have considered these issues in more detail and shown that the contribution of balance of plant costs to overall energy costs can be reduced by around 25% by moving from machines of the 300 kW size range to 1 MW size machines.

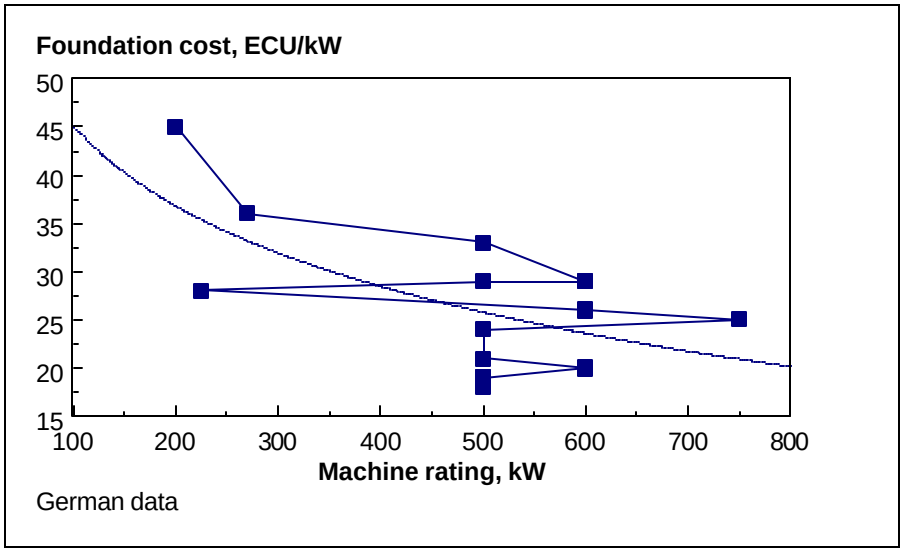


Figure A4 Foundation costs

A1.3 Operational Costs

Operational costs also fall with increase of turbine size. Analysis of data from German wind installations (**3**) shows that the price of insurance and guarantees both halve, approximately as ratings increase from 200 to 600 kW (figure A5). Total costs fall from around 38 ECU/kW/yr at the 200 kW size to around 15 ECU/kW/yr at 600 kW.

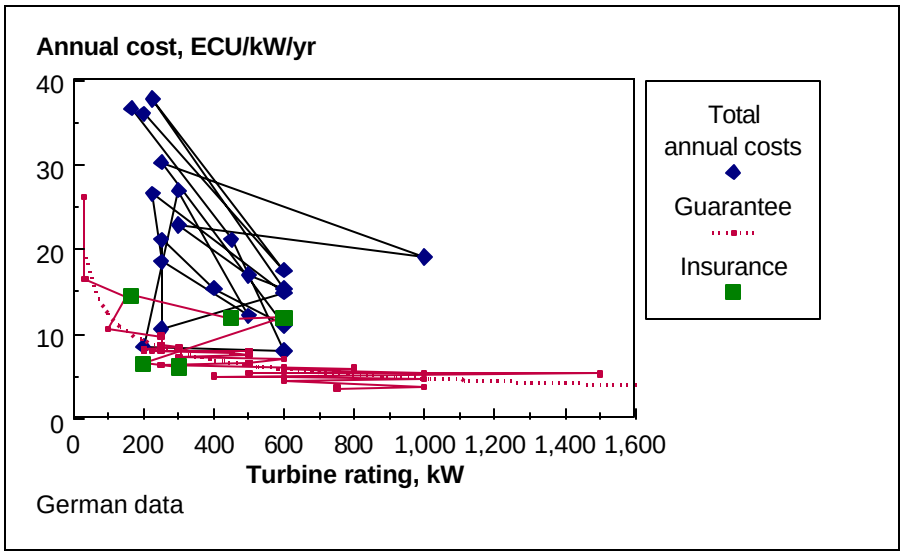


Figure A5 Cost of operations

A2 PRICE AND MACHINE NUMBERS

Wind farm prices decrease weakly with increasing numbers of machines. (Figure A6). Prices average around 1300 ECU/kW with one machine, falling below 1200 ECU/kW with 20 machines. Although conventional wisdom indicates that this trend should be stronger there are so many factors which influence wind farm prices that frequently the trend is obscured. This does not invalidate the general hypothesis that, at a given site, construction of a wind farm rather than a single machine will generally be the cheaper option **(4)**.

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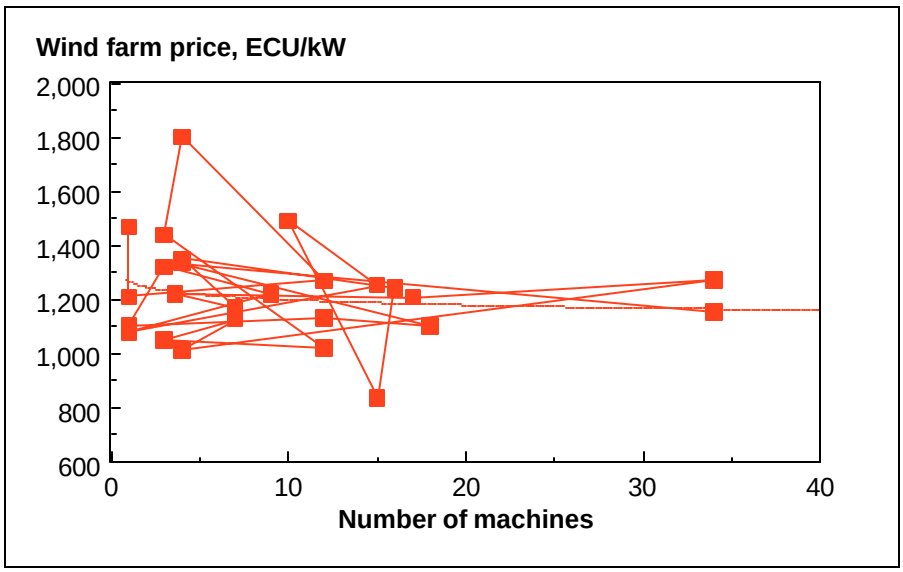

Figure A6 Effect of numbers on wind farm price

A3 PRICE CHANGES OVER TIME

Data from German and British wind farms confirms the Danish trends discussed in Section 3. British prices fell by about 35% and German prices by about 16%., as shown in Figure A7. Given the strong trend, discussed in Section 3, for turbine prices to fall, a more significant rate of decrease may have been expected. However, the more accessible - and cheaper - sites in Germany were used up in the early years of the wind programme and later construction has had to use more expensive sites.

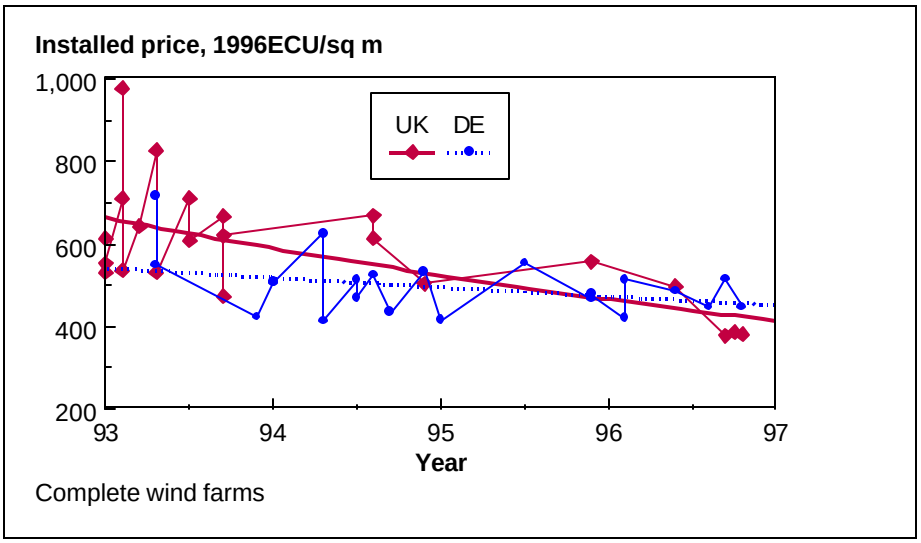

Figure A7 Price changes with time

A4 PRICE AND YIELD

The link between for prices and energy yields is examined in Figure A8 and a weak, but discernible increase of price with yield is evident, in Britain and Germany. This is probably due to the fact that

the higher yields in Germany may be found at coastal sites, where foundation costs are frequently higher due to the necessity of piling into the silt. A further factor which may influence this correlation is that tall towers are often deployed to give access to higher wind speeds, but at increased turbine cost. In Britain, the high wind speed sites tend to be in remote areas, with higher construction costs.

Prices have been correlated with energy yield, as wind speed data are not always available or reliable. However 400 kWh/sq m corresponds to around 4.5 m/s (installed cost around 400 ECU/sq m) and 1300 kWh/sq m is around 8 m/s (installed cost around 550 ECU/sq m).

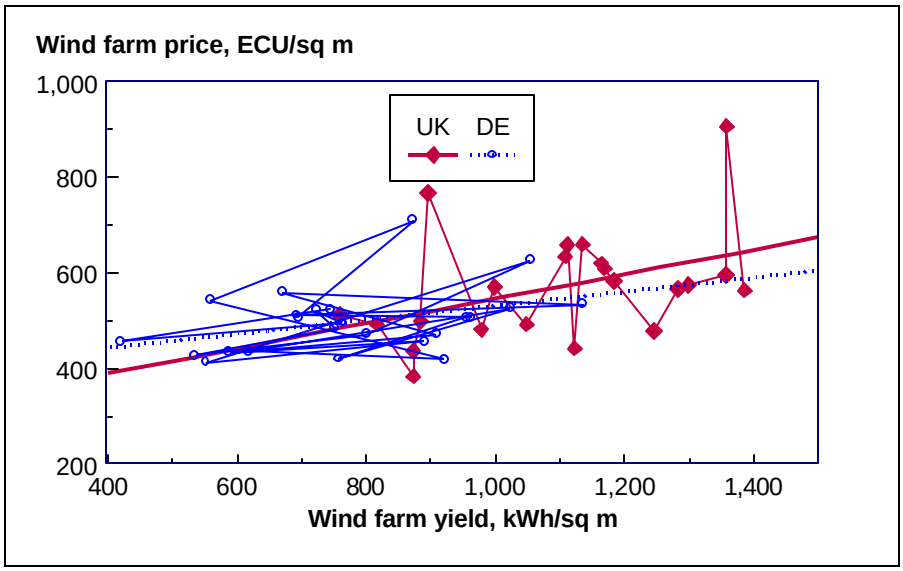

Figure A8 Wind farm costs and yield

A5 REFERENCES

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APPENDIX B

OFFSHORE WIND ENERGY

B1 INTRODUCTION

Offshore wind has the potential to deliver substantial quantities of energy - at a price which is cheaper than most of the other renewable energies, but not yet competitive with the conventional thermal sources - nor with onshore wind. Offshore wind energy has the added attraction that it has minimal environmental effects and, broadly speaking, the best European resources are reasonably well located relative to the centres of electricity demand.

An additional attraction of offshore wind power is that wind speeds are generally higher offshore than on land, although the upland regions of the British Isles, Italy and Greece, do yield higher speeds. In the UK, for example, onshore winds at hilltop sites range up to 9 m/s at hub height - higher in some instances - whereas offshore winds at, say, 5 km from the East Coast (where the utility PowerGen is contemplating a wind farm) are around 8-8.5 m/s. Offshore wind power is therefore, most attractive in locations such as Denmark and the Netherlands where pressure on land is acute and where windy hill top sites are simply not available. In these areas offshore winds - which increase with distance from land - may be 0.5 to 1 m/s higher than onshore, depending on the distance offshore.

B2 OPERATIONAL EXPERIENCE AND ECONOMICS

A number of factors combine to push up the cost of offshore wind farms relative to their onshore equivalents:-

- the cost of the cable connection from the wind farm to the shore.
- the need for more expensive foundations, where a number of options have been examined:-
    - gravity-based structures, simple, but heavy
    - piled structures
    - tethered, floating structures, which support individual turbines or groups

- operation and maintenance costs are increased with the risk of lower availability due to difficulties in obtaining access to the wind turbines during bad weather.
- the need to "marinise" the wind turbines, to protect them from the corrosive influence of salt spray

Several offshore wind farms have now been built, so it is possible to assess the economics in the light of operational experience. To do so, data from the two experimental Danish installations, Vindeby and Tuno Knob (**1**), may be compared, and set alongside other recent cost assessments, including the pilot Dutch farm in the Ijselmeer (**2**). Table B1 summarises the principal operational data for these early wind farms together with a proposed installation by PowerGen off the East coast of England (**3**), and recent proposals for large farms off the Coast of the Netherlands and Denmark (**2,4**).

Although the cost of the Vindeby wind farm was 85% higher than the cost of an onshore installation the anticipated energy yield was 20% higher. (Production statistics show that the energy production is higher than expectations, so concerns about lower availability offshore - due to problems of access - have not been realised).

PowerGen's proposals for Scroby Sands were for a much larger wind farm, comprising 25 63m 1.5 MW wind turbines. The site is 3 km off the Norfolk coast near Yarmouth and the initial estimate of the project was around 44 MECU, bringing costs per annual megawatt hour to about half that of Vindeby - due partly to continuing maturity of the industry and partly to the use of larger machines.

Location	Date	Turbines	Capacity	Wind	Output	Cost		
		No.*kW	MW	m/s	GWh	MECU	ECU/MWh	ECU/kW
Vindeby, DK	1991	11x 450	4.95	7.9*	11.2	9.6	857	1939
(Comparable onshore farm)				7.2*	10	5.3	530	1071
IJsselmeer, NL	1994	4 x 500	2		3.8	3.8	1000	1900
Tuno, DK	1995	1 0 x 500	5	7.4*	12.5	10.6	848	2120
Gotland, SW	1997	4 x 500	2			2.8		1400
Scroby, UK	Planned	25 x 1500	37.5	8.2*	102*	44	429*	1173
IJmuiden, NL	Planned	100 x 1000	100		275	225	818	2250
Laeso, DK	Planned	400 x 1500	600		2028	934	461	1560

*Author's estimate

Table B.1 Offshore wind farm performance and costs

B3 FUTURE OFFSHORE TRENDS

The PowerGen project did not secure a contract in the competitive bidding for the Non-fossil Fuel Obligation (NFFO), but two other offshore proposals did succeed. One is a two-machine cluster, one kilometre from Blyth, in Northumberland, the second a 30 MW project off Clacton, in Essex. No details of costs are available, but one may have a grant from the EU demonstration programme.

The two major utilities, Elkraft and Elsam, have recently announced their intention to build 750 MW of offshore wind, and there are also plans for a 30/40 MW scheme near Copenhagen. Two major utilities in the North of Holland, ENW and NUON have proposed a windfarm in the shallow waters along the 35 kilometre long "Afsluitdijk" between the Provinces of Friesland and Noordholland. The line of 57 MW-sized turbines (two-bladed 60/1.750) will be sited at 500 metres from the dike and 500 metres apart from each other. The project is budgeted at 114 MECU (about 875 ECU/sq m rotor area) and could be build within three years**.**

An analysis of energy prices has recently been carried out for the Danish utilities (**5**). This showed that the use of larger wind turbines - up to 1500 kW rated output - would realise substantial savings. Assuming a wind farm is sited around 6 km from the coast, in a water depth of 5-6 m, the electricity price may be expected to fall from around 6 cECU/kWh (at Tuno) to around 3.8 cECU/kWh.

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APPENDIX C

EXTERNAL COSTS

C1 INTRODUCTION

The so-called "external costs" of electricity generation - those associated with damage to health and the environment - are currently borne by those who must rectify this damage (not usually the polluter); they are not made transparent in the market price of electricity. The fact that external costs are difficult to quantify accurately is used an argument for preserving the status quo, but there is increasing awareness that this is unsatisfactory. This section draws upon a review undertaken for the journal *Windpower Monthly* **(1)**.

C2 KEY ISSUES

Although there is general agreement as to the broad definition of external costs - costs attributable to an activity that are not borne by the party involved in that activity - there are widespread variations in defining the boundaries. There is an argument, for example, that a substantial proportion of Western defence budgets should be regarded as an "external cost" of oil - for fairly obvious reasons.

External costs - or at least some - may be difficult to quantify, but they are real. If the enormous costs of the clean-up operation after the Chernobyl nuclear disaster had been taken into account when the plant was constructed, it is unlikely it would have been built. The task facing energy policy makers is how best to go about the job of reducing pollution in electricity generation when, in most countries, external costs are not reflected in the market price of the end product. If they were, fossil fuel and nuclear energy prices would rise, making wind energy one of the cheapest technologies.

In Europe, regulation of the fuel mix for electricity generation, as a way of reducing pollution has not been generally accepted. The problem is how to include external costs as an element of competitive electricity markets - without interfering with market forces. Not all governments are following this route, but there is a clear trend in that direction.

At one end of the spectrum is Denmark, determined to bring about a 20% cut in carbon dioxide emissions. It has an efficient distribution system and plenty of renewables - promoted by carefully designed energy taxes. Britain, at the other end of the spectrum - at least until the recent change of government - had an unambitious target for carbon dioxide reductions, with consideration of external costs sidelined. There are now indications that this may change.

C3 COST CATEGORIES

There are widespread variations in defining the boundaries. Arguments for the external costs attributable to oil fired generation range from supertanker spillages to a substantial proportion of western defence budgets. For simplification, however, they can be divided into three broad categories.

- hidden costs borne by governments
- costs of the damage caused to health and the environment by emissions other than CO2
- the costs of global warming attributable to CO2 emissions

The first category includes the cost of regulatory bodies and pollution inspectorates (generally small) and the cost of energy industry subsidies and research and development programmes. These are larger. In the analysis of external costs published in 1988, Hohmeyer **(2)** calculated that support to the German coal industry added DEM 0.002/kWh to the price of electricity. He also assigned a cost of DEM 0.0235/kWh for nuclear R&D, compared to around DEM 0.004 DM/kWh for wind.

The second category is costs due to emissions which cause damage to the environment or to people. These include a wide variety of effects, including damage from acid rain and health damage from oxides of sulphur and nitrogen emitted from coal fired power stations. In a recently released European study, ExternE **(3)**, the costs of damage to health were estimated by calculating the loss of earnings and costs of hospitalisation of people susceptible to respiratory diseases.

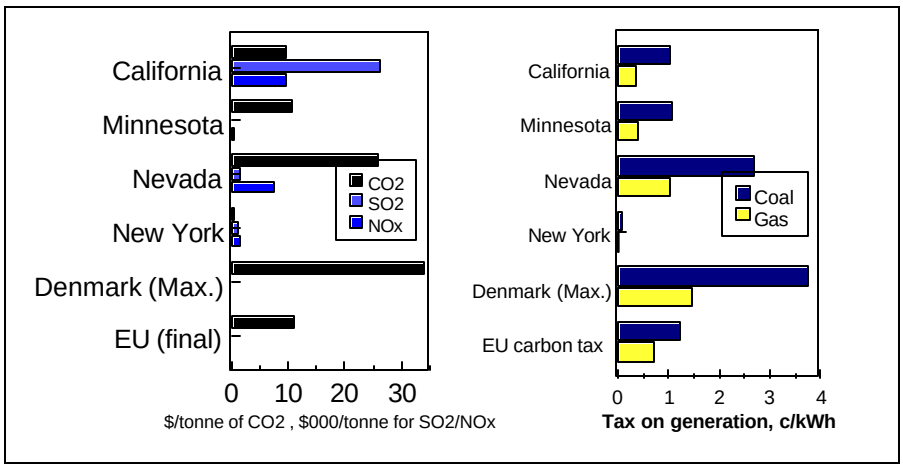
Other costs in the damage and health category are power industry accidents, whether they occur in coal mines, on offshore oil or gas rigs, or in nuclear plant. The probability of a nuclear accident in Western Europe might be extremely low, but should a catastrophic failure occur the costs would be undeniably huge. Multiplication of a number close to zero (the probability of a nuclear accident) by a number close to infinity (the cost of such an accident), does not necessarily give a meaningful result.

The third category is by far the largest: external costs due to greenhouse gas emissions which cause global warming. This is the most contentious area of the external costs debate. The range of estimates for the possible economic implications of global warming is huge. Costs associated with climate changes, flooding, changes in agricultural patterns and other effects all need to be taken into account.

C4 PRICE ESTIMATES

Hohmeyer **(2),** ExternE **(3),** and others looked at damage potentials on health and the environment, assigning a cost penalty to each generating technology, depending on the fuel. This approach enables the difference in external costs between, say, coal and wind, to be easily compared. Another approach calculates costs per pollutant, as different fuels generate different amounts of pollutant. Typically these penalties, as proposed by some American states, are around $10/tonne for CO2, and up to $25,000/tonne for SO2 (Figure C1). Since the quantities of each pollutant, per kWh, are known for each fuel, these costs enable calculation of the external cost of each unit of electricity. Coal-fired generation produces the most pollutants - about 1 kg of CO2 per kWh, plus SO2 and other pollutants. It therefore attracts the highest penalties (Figure C2).

Despite the wide variety of approaches, the external cost assigned to coal-fired generation is often reckoned to add about 1 cent (US)/kWh to each kWh. Gas, on the other hand attracts a lower penalty - around half this figure.



Figures C1 and C2 Taxes on emissions and fossil generation

C5 MARKET MECHANISMS

Once monetary values are assigned to the extra cost of energy from differing technologies, the next step is to find a mechanism for "internalising" them in market prices. There is, however, a debate on the best way to apply external costs - if at all. At one end of the spectrum are the free marketeers, who argue against any interference; at the other are those who feel that there are imbalances in energy pricing which need to be rectified. The Netherlands and Denmark, amongst others, have acted and introduced so-called carbon taxes.

The European Union's original proposals for a carbon tax would have altered the balance between coal, gas, nuclear and wind significantly, adding around 1.5 cECU/kWh to coal-fired generation prices, and 0.8 cECU/kWh for nuclear. The levy included an "energy" element as well as a "carbon" component, which is why nuclear is penalised. The tax was intended to be "fiscally neutral", with tax revenue supposedly to lead to tax reductions elsewhere; reliefs were proposed for energy-intensive industries. Several EU states were concerned that higher energy taxes would reduce the competitiveness of their industries in global markets.

Nevertheless, some EU states have gone ahead and introduced carbon taxes. Denmark has recently implemented a wide range of measures aimed at encouraging the energy industries to become more efficient and to reduce harmful emissions. The taxes are applied to fuels and to electricity, but also focus on consumption, with space heating, for example, attracting the highest tax rates.

An alternative approach to the problem of reflecting external costs - and one which possibly causes less economic disturbance - is to assign the renewable energies "environmental credits." This is the basis of the 1.6 cent "production tax credit" currently available to wind power in the United States. This has the merit of simplicity and has a marginal effect on energy costs, but it is not a true integration of external costs into market prices. The taxpayer pays, not the electricity consumer.

C6 INTEGRATED RESOURCE PLANNING

A third approach - favoured by many American states - is to use "integrated resource planning" (IRP) to assess future generating plant needs. The beauty of IRP is that, in complying with government mandates to consider all energy supply options, the regulatory body simply assumes that external costs are to be applied, without actually imposing them. This approach does away with the need to agonise over how to calculate the monetary value of pollution in electricity generation. It also helps to ensure that power plants are built in the right place and that the electricity network operates efficiently. The result is a competitive market operating under guidelines aimed at long term economic responsibility.

Recent studies in California and elsewhere, however, indicate that the result of this approach is simply to shift the utility plant mixes in favour of gas, which is currently cheap and has low external costs. Renewables profit, but the additional market share remains relatively small. It is important to remember, however, that gas is unlikely to remain so cheap indefinitely.

C7 EXTERNAL COSTS of RENEWABLE ENERGIES

No-one claims that renewable energies have zero external costs. The recent EU study, for example, examined the external costs of wind energy under nine headings (nv: not valued):-

1. Noise
2. Visual Intrusion
3. Accidents during manufacture and operation
4. Accidents to public
5. Impacts wind turbines on birds (nv)
6. Impacts on local ecosystems (nv)
7. Electro-magnetic interference (nv)
8. Acid rain damage - from energy used in construction in case of wind
9. Global warming effects

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The range of cost estimates - for two specific British sites - lay in the range 0.2-0.4 cECU/kWh. This is consistent with other studies, which generally show lower external costs for wind than either PV or biomass, although all are small. The analysis was very thorough and included estimates of external costs incurred during the manufacturing processes, as well as operation of the plant. Nevertheless, the overall conclusion from the EU study was that the highest estimate of external costs for wind was below the minimum estimate of the external costs for coal. Excluding global warming, the latter were between 0.5 and 1.5 cECU/kWh.

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APPENDIX D

THE VALUE OF WIND ENERGY

D1 INTRODUCTION

Most utility studies which have studied the effect of installing wind plant on interconnected networks have shown that operation of the system is unaffected by the variability of wind - provided the amounts of wind energy on the system are modest. "Modest" in this context implies energy penetrations below about 10%.

Early studies assigned a fuel-saving value, only, to wind energy. More recently, it has been argued that wind energy should be assigned a higher value as it is injected into low voltage distribution networks and does not incur high voltage transmission costs and resistive losses. This hypothesis is implicitly recognised in some National remuneration schemes - such as those operated in Denmark and Germany - where wind energy is paid a proportion of consumer selling prices. Although studies in America and elsewhere, point to the fact that renewable energy may have a high value in certain locations, this point is generally not accepted within EU utilities, most of whom continue to assign wind energy a value based on its fuel saving capability.

D2 THE CONCEPT OF EMBEDDED GENERATION

In many instances renewable electricity-generating technologies deliver energy closer to consumer demand than centralised generation. It substitutes for electricity which has accrued a higher selling price than the generation costs of large thermal plant, due to its passage through the network. This rising level of "value" with reducing voltage is reflected in higher charges for customers connected at lower voltage levels. These concepts are illustrated in Figure 12, which includes typical selling prices for electricity at various stages in the UK system.

Small-scale generation of this kind is classified as "embedded". In England and Wales, for example, there are currently some 1500 MW of embedded generation although most of this is not renewable plant. An alternative term for plant of this kind is "distributed generation" and there is a growing interest in the possible benefits, which include system support in areas remote from generation and deferment of the need for main transmission reinforcement. It is argued that the value of the energy is greater than simple "generation substitution" when these benefits are taken into account.

D3 BACKGROUND TO ELECTRICITY PRICING

The cost, price, and hence the value of electricity varies on a geographical basis. Above-average costs are incurred when energy has to be transmitted long distances from the generating plant. The need to supply remote locations increases the costs of the distribution network and, in addition, electrical losses are incurred in feeding the energy to the extremities of the system.

Electricity utilities do not attempt to ascribe exact costs to account for all geographical and temporal factors. Tariffs build in cost averaging so that blocks of consumers with similar requirements and locations pay similar rates. A further factor which complicates an analysis of value is that accounting

procedures vary and political considerations may be imposed in pursuit of particular objectives. These tend to distort accurate assessments of value. Examples of such political overlays are requirements by many Governments that all domestic consumers should be treated equally.

D4 SYSTEM COSTS

As part of an EU-funded study (1), an analysis of the cash flows through the electricity network in England and Wales has been carried out to aid a study of value. The data are being compared with information from tariffs, and with other case studies in Europe and the United States. The cash flow data enable average levels of electricity price to be established at key points in the distribution chain:-

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- At the busbars of large thermal plant
- At exit from the high voltage transmission system
- at delivery to the consumer

Conventional terminology assigns three stages between the production of electricity and its delivery to the consumer:-

- generation
- high voltage transmission (often abbreviated to "transmission")
- distribution

For each of these stages of in the supply chain, costs can be allocated under 4 headings:-

- Fuel, (fuel cost purchases for generators and power losses in transmission and distribution)
- Operating, reflecting all operating costs including overheads
- Depreciation of capital assets
- Profit on a historic cost basis

The cash flow analysis was carried out for 1993/94 as additional data were available from privatisation prospectuses to aid the segregation of costs. Costs in nominal money vales were very similar in 1996/97.

The results of the cashflow analysis are shown in Summary form in Table D1.

	Generation	Control	Transmission	Distribution	Supply	TOTAL
FUEL	2.03	0	0.08	0.31	0	2.42
OPERATING	1.28	0.14	0.11	0.8	0.26	2.59
DEPRECIATION	0.35	0.01	0.16	0.42	0.01	0.95
PROFIT	0.35	0.03	0.17	0.58	0.13	1.26
TOTAL	4.01	0.18	0.52	2.11	0.4	7.22

Table D1 UK electricity price breakdown (cents ECU/kWh)

Although the constituent elements of electricity price, tabulated in Table D1, define its "value" at any given point in the system - in average terms - it does not follow that electricity which is injected at

that same point will be credited with that same value by the generator or utility. A brief summary of current attitudes to value follows:-

- **Fuel** - most studies accept that fuel savings are a component of the value of Renewable Energy. With the intermittent sources, the value declines as the amount of intermittent capacity increases, for reasons discussed in Section D5.
- **Operating Costs** - These include "Fixed" and "Variable" components. The variable costs of generation are part of the value of RE, but the variable costs of transmission and distribution are more contentious issues. Acceptance of the Fixed component of these costs as a component of value depends on whether it is accepted that RE, particularly the intermittent sources has a "capacity credit". This is considered in more detail in Section D6.
- **Depreciation** - the crucial point is whether the introduction of RE on to a system enables plant savings to be made (section D6). Most studies which have addressed generation plant savings, but more recent work addresses transmission and distribution savings.
- **Profit** - The question of profit as an element of value has not explicitly been addressed. In a deregulated system, where no single generator or distributor has exclusive rights, it would seem valid to allow its inclusion, at least partially, in value assessments.

The price elements shown in Table D1 apply to the system as a whole. Regional variations occur for many reasons, primarily the proximity of a locality to sources of generation.

The average delivered price of energy from the HV network in England was 4.7 cECU/kWh in 1993/94. Beyond this point, savings realised by RE plant such as wind farms will vary, but an average level has been estimated by assuming that one-half of the distribution losses are avoided. However, for every unit of electricity which passes through the distribution system, a mark-up (profit) of 0.6 cECU/kWh is added, and it appears both logical and fair that this profit should not remain wholly with the distributor. If half this profit element is assigned to the wind energy generator then an average value of wind energy on the English system is 5.6 cECU/kWh. Regional variations in prices mean this level may lie between 5 and 6.4 cECU/kWh.

At the European level, comparisons of English cost levels with those elsewhere indicates that this range of values is relevant to most mainland systems.

It must be emphasised that these are average values and particular installations may have higher or lower values, depending on their location within the network.

Particular technologies may also have higher or lower value, depending on their seasonal and diurnal generation profiles and the match (or otherwise) with demand. Assessments for wind and solar in England, based on typical seasonal variations, indicate that wind energy's fuel saving value is 3% higher than the mean and that of solar is 5% below the mean. The principal reason for temporal variations in electricity cost is the changing demand on the system. As the load rises, more plant must be brought into use and, as this plant does not operate at base load, its operating costs are higher.

D5 EXTRA OPERATING COSTS

Operation of European supply systems with small amounts of wind plant poses no problems whatsoever. The systems are able to cope with the sudden loss of a large generator or the effects of thunderstorms (which can cause trips on the transmission network). Nevertheless, increasing amounts of wind might require a change in operating procedures and a preliminary assessment of the extra operating costs has recently been made **(2)**, updating an earlier study for England and Wales. The costs arise if additional plant needs to be held on part load to compensate for possible fluctuations in the level of wind generation.

The additional part-loading costs can be derived by noting that plant which is part-loaded operates at a lower efficiency and that the part-load energy loss is equivalent to 15% of the full load heat rate (**3**). This energy penalty, in turn, can be converted to a monetary value by assuming an appropriate coal cost. Using a level of 1.55 ECU/GJ - roughly the delivered cost, based on the world market price - the extra costs as a function of energy penetration may be derived. (Figure D1). This shows the extra cost is below about 0.05 cECU/kWh with 1% energy penetration, rising to about 0.1 cECU/kWh at 10% penetration

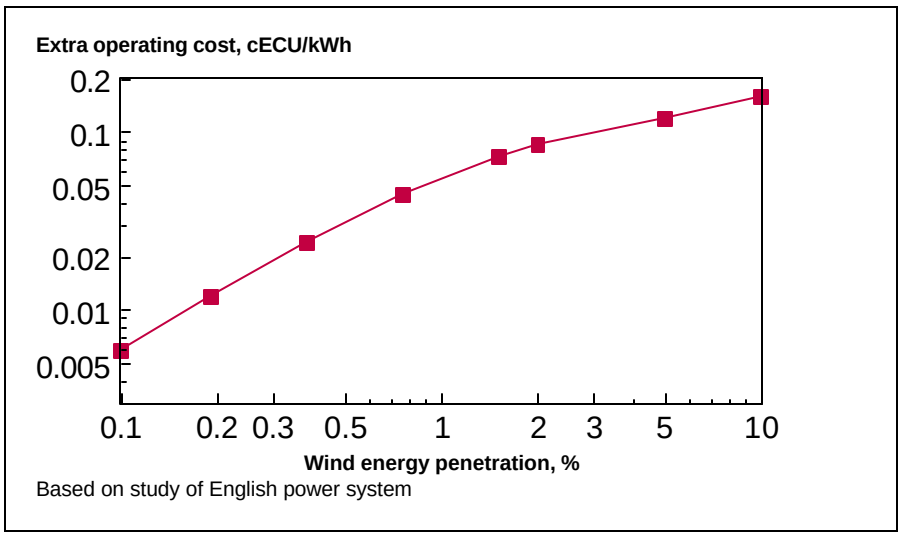

Figure D1 Extra operating costs incurred with rising wind energy use

D6 CAPACITY CREDITS

An important element of value is the capacity credit of renewable plant. If plant has a capacity credit, then some of the depreciation cost can be included in the value assessment.

The capacity credit of power plant may be defined, in general terms, as a measure of the ability of the plant to contribute to peak demands of a power system. Utilities quantify this in different ways, so numerical values of capacity credit are not necessarily comparable.

Data from ten utilities who examined the impact of wind on utility networks for the European Commission study have been collated (4) and compared to determine underlying patterns in assessments of capacity credits. It was found that:-

- Capacity credits increase with annual capacity factor

- Although capacity credits are often derived from summations of LOLP over a full year, the result is very strongly influenced by values near the time of peak demand. (Since LOLP decreases very rapidly away from the peak). It follows that -
- An examination of the long-term expectation of generation at times of peak demand enables credits to be established with reasonable accuracy

It should be noted, however, that the overall value of capacity to an electricity network is usually modest. The EC-funded studies yielded a range between 5 and 38% of generation costs. The accounts of the UK generators show that depreciation accounts for about 10% of the selling price.

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