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THE EUROPEAN WIND ENERGY ASSOCIATION

The Economics of Wind Energy

A report by the European Wind Energy Association

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In memory of Dr. Shimon Awerbuch (1946-2007)

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Executive Summary

One of the most important economic benefits of wind power is that it reduces the exposure of our economies to fuel price volatility. This benefit is so sizable that it could easily justify a larger share of wind energy in most European countries, even if wind were more expensive per kWh than other forms of power generation. This risk reduction from wind energy is presently not accounted for by standard methods for calculating the cost of energy, which have been used by public authorities for more than a century. Quite the contrary, current calculation methods blatantly favour the use of high-risk options for power generation. In a situation where the industrialised world is becoming ever more dependent on importing fuel from politically unstable areas at unpredictable and higher prices, this aspect merits immediate attention.

As is demonstrated in this publication, markets will not solve these problems by themselves because markets do not properly value the external effects of power generation. Governments need to correct the market failures arising from external effects because costs and benefits for a household or a firm who buys or sells in the market are different from the cost and benefits to society. It is cheaper for power companies to dump their waste, e.g. in the form of fly ashes, CO_2, nitrous oxides, sulphur oxides and methane for free. The problem is that it creates cost for others, e.g. in the form of lung disease, damage from acid rain or global warming. Similarly, the benefits of using wind energy accrue to the economy and society as a whole, and not to individual market participants (the so-called common goods problem).

This report provides a systematic framework for the economic dimension of wind energy and of the energy policy debate when comparing different power generation technologies. A second contribution is to put fuel price risk directly into the analysis of the optimal choice of energy sources for power generation.

Adjusting for fuel-price risk when making cost comparisons between various energy technologies is unfortunately very uncommon and the approach is not yet applied at IEA, European Commission or government level. This report proposes a methodology for doing so. The methodology should be expanded to include carbon-price risk as well, especially given the European Union's December 2008 agreement to introduce a real price on carbon pollution (100% auctioning of CO_2 allowances in the power sector) in the EU.

1. Basic cost of wind energy

Approximately 75% of the total cost of energy for a wind turbine is related to upfront costs such as the cost of the turbine, foundation, electrical equipment, grid-connection and so on. Obviously, fluctuating fuel costs have no impact on power generation costs. Thus a wind turbine is *capital-intensive* compared to conventional fossil fuel fired technologies such as a natural gas power plant, where as much as 40-70% of costs are related to fuel and O&M. Table 0.1 gives the price structure of a typical 2 MW wind turbine.

TABLE 0.1: **Cost structure of a typical 2 MW wind turbine installed in Europe (€ 2006)**

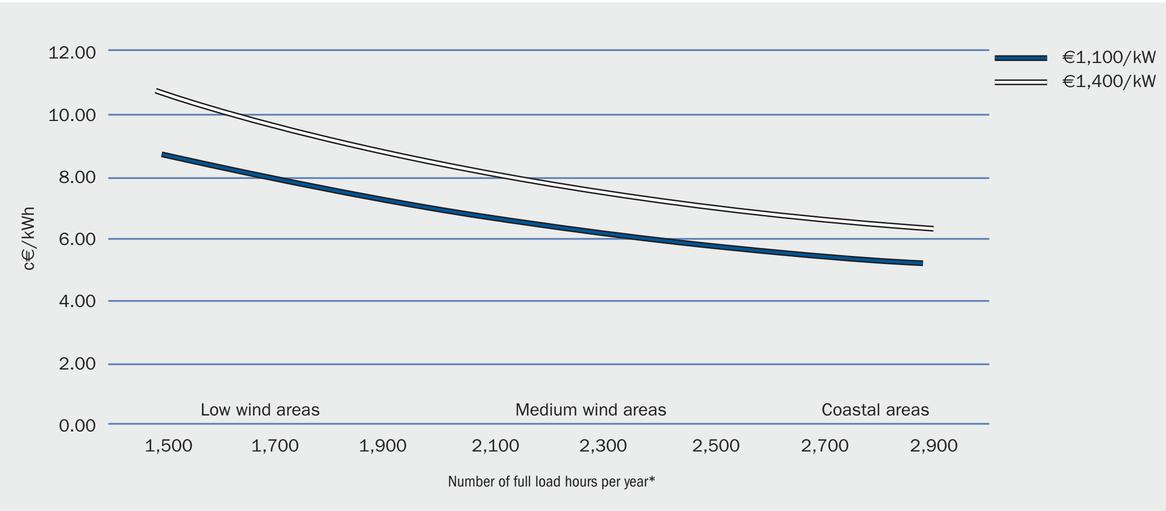
	INVESTMENT (€1,000/MW)	SHARE OF TOTAL COST %
Turbine (ex works)	928	75.6
Grid connection	109	8.9
Foundation	80	6.5
Land rent	48	3.9
Electric installation	18	1.5
Consultancy	15	1.2
Financial costs	15	1.2
Road construction	11	0.9
Control systems	4	0.3
TOTAL	**1,227**	**100**

Note: Calculated by the author based on selected data for European wind turbine installations

Operation and maintenance (O&M) costs for onshore wind energy are generally estimated to be around 1.2 to 1.5 c€ per kWh of wind power produced over the total lifetime of a turbine. Spanish data indicates that less than 60% of this amount goes strictly to the O&M of the turbine and installations, with the rest equally distributed between labour costs and spare parts. The remaining 40% is split equally between insurance, land rental and overheads.

The costs per kWh of wind-generated power, calculated as a function of the wind regime at the chosen sites, are shown in Figure 0.1 below. As illustrated, the costs range from approximately 7-10 c€/kWh at sites with low average wind speeds, to approximately 5-6.5 c€/kWh at windy coastal sites, with an average of approximately 7c€/kWh at a wind site with average wind speeds. The figure also shows how installation costs change electricity production cost.

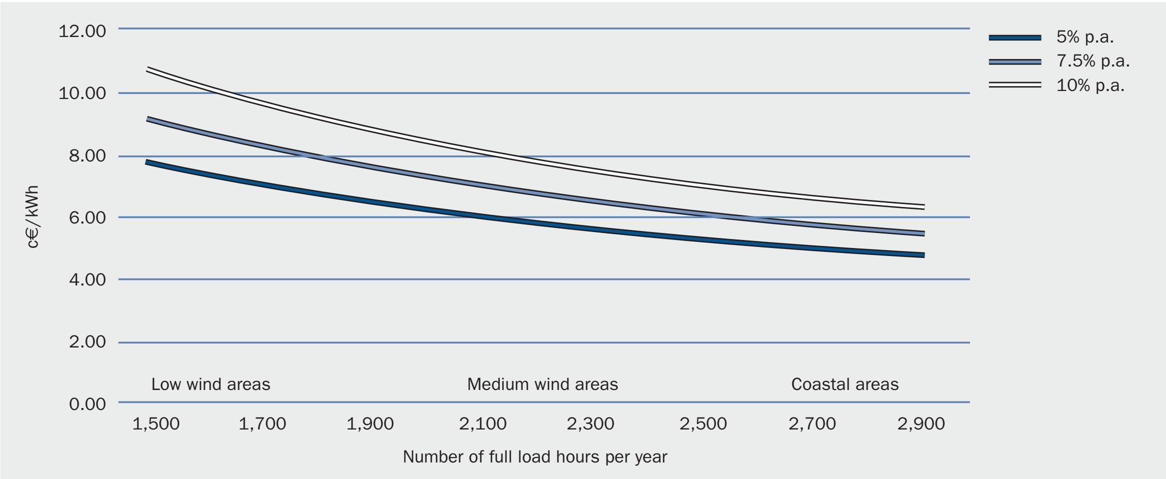
FIGURE 0.1: **Calculated costs per kWh of wind generated power as a function of the wind regime at the chosen site (number of full load hours).**



* Full load hours are the number of hours during one year during which the turbine would have to run at full power in order to produce the energy delivered throughout a year (i.e. the capacity factor multiplied by 8,760).

Source: Risø DTU

FIGURE 0.2: **The costs of wind produced power as a function of wind speed (number of full load hours) and discount rate. The installed cost of wind turbines is assumed to be 1,225 €/kW.**



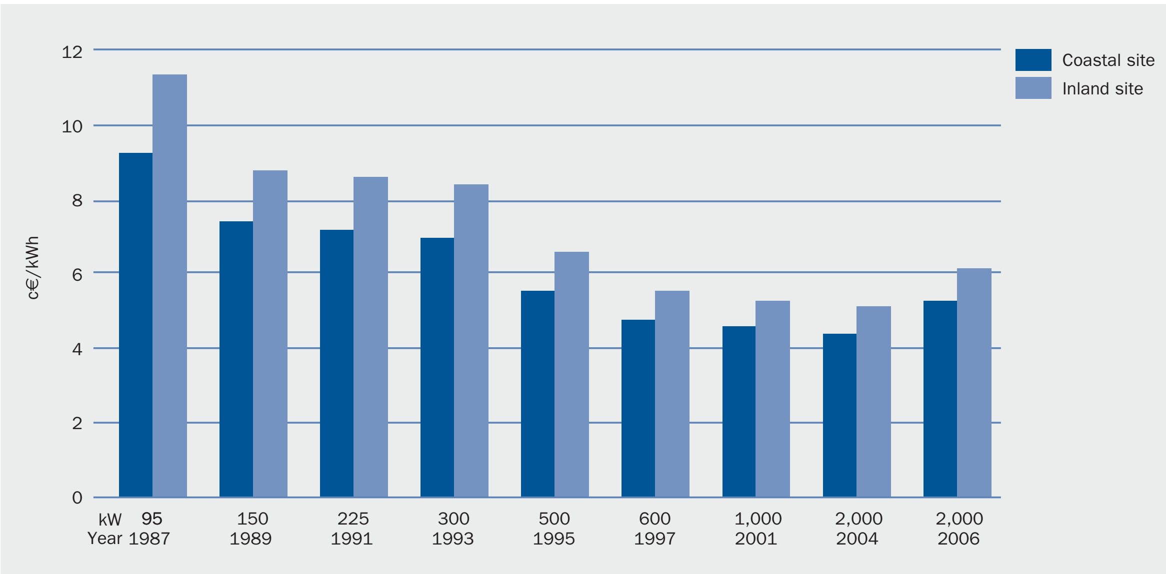
Source: Risø DTU

Figure 0.2 shows how discount rates affect wind power generation costs.

The rapid European and global development of wind power capacity has had a strong influence on the cost of wind power over the last 20 years. To illustrate the trend towards lower production costs of wind-generated power, a case (Figure 0.3) that shows the production costs for different sizes and models of turbines is presented. Due to limited data, the trend curve has only been constructed for Denmark, although a similar trend (at a slightly slower pace) was observed in Germany.

The economic consequences of the trend towards larger turbines and improved cost-effectiveness are clear. For a coastal site, for example, the average cost has decreased from around 9.2 c€ /kWh for the 95 kW turbine (mainly installed in the mid 1980s), to around 5.3 c€ /kWh for a fairly new 2,000 kW machine, an improvement of more than 40% (constant €2006 prices).

FIGURE 0.3: **Total wind energy costs per unit of electricity produced, by turbine size (c€/kWh, constant €^{2006} prices), and assuming a 7.5% discount rate.**



Source: Risø DTU

Using the specific costs of energy as a basis (costs per kWh produced), the estimated progress ratios range from 0.83 to 0.91, corresponding to learning rates of 0.17 to 0.09. That means that when the total installed capacity of wind power doubles, the costs per kWh produced for new turbines goes down by between 9 and 17%.

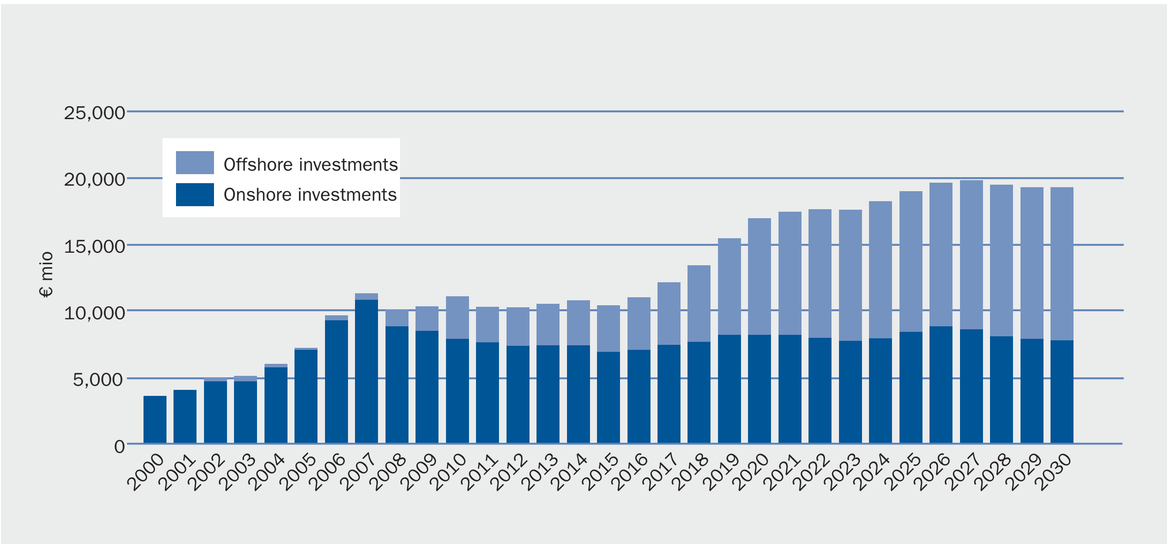
Offshore wind currently accounts for a small amount of the total installed wind power capacity in the world – approximately 1%. The development of offshore wind has mainly been in northern European counties, around the North Sea and the Baltic Sea, where about 20 projects have been implemented. At the end of 2008, 1,471 MW of capacity was located offshore.

Offshore wind capacity is still around 50% more expensive than onshore wind. However, due to the expected benefits of higher wind speeds and the lower visual impact of the larger turbines, several countries – predominantly in European Union Member States - have very ambitious goals concerning offshore wind.

Although the investment costs are considerably higher for offshore than for onshore wind farms, they are partly offset by a higher total electricity production from the turbines, due to higher offshore wind speeds. For an onshore installation utilisation, the energy production indicator is normally around 2,000-2,500 full load hours per year, while for a typical offshore installation this figure reaches up to 4,000 full load hours per year, depending on the site.

Figure 0.4 shows the expected annual wind power investments from 2000 to 2030, based on the European Wind Energy Association's scenarios up to 2030[1]. The market is expected to be stable at around €10 billion/year up to 2015, with a gradually increasing share of investments going to offshore. By 2020, the annual market for wind power capacity will have grown to €17 billion annually with approximately half of investments going to offshore. By 2030, annual wind energy investments in EU-27 will reach almost €20 billion with 60% of investments offshore. It should be noted that the European Wind Energy Association will adjust its scenarios during 2009, to reflect the December 2008 Directive on Renewable Energy, which sets mandatory targets for the share of renewable energy in the 27 EU Member States.

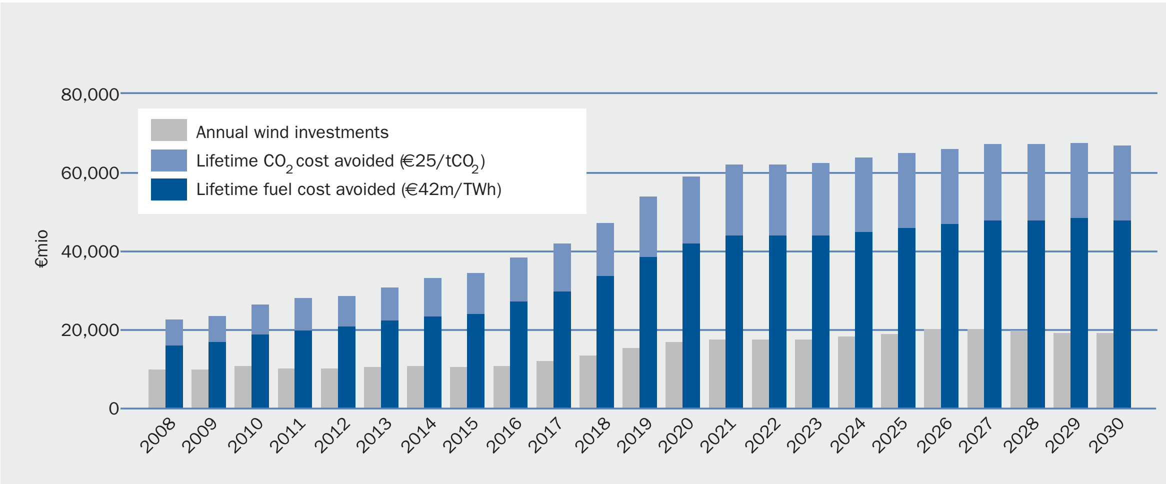
FIGURE 0.4: **Wind energy investments 2000-2030 (€ mio)**



Source EWEA, 2007

[1] European Wind Energy Association, April 2008: Pure Power: Wind energy scenarios up to 2030. www.ewea.org.

FIGURE 0.5: **Wind investments compared with life time avoided fuel and CO_2 costs (Oil – \$90/barrel; CO_2 – €25/t)**



Source EWEA, 2007

Figure 0.5 shows the total CO_2 costs and fuel costs avoided during the lifetime of the wind energy capacity installed for each of the years 2008-2030, assuming a technical lifetime for onshore wind turbines of 20 years and for offshore wind turbines of 25 years. Furthermore, it is assumed that wind energy avoids an average of 690g CO_2/kWh produced; that the average price of a CO_2 allowance is €25/t CO_2 and that €42 million worth of fuel is avoided for each TWh of wind power produced, equivalent to an oil price throughout the period of \$90 per barrel.

COST OF WIND POWER COMPARED TO OTHER TECHNOLOGIES

The general cost of conventional electricity production is determined by four components:

1. Fuel cost
2. Cost of CO_2 emissions (as given by the European Trading System for CO_2, the ETS)
3. O&M costs
4. Capital costs, including planning and site work

In this report, fuel prices are given by the international markets and, in the reference case, are assumed to develop according to the IEA's World Energy Outlook 2007, which assumes a crude oil price of \$63/barrel in 2007, gradually declining to \$59/barrel in 2010 (constant terms). As is normally observed, natural gas prices are assumed to follow the crude oil price (basic assumptions on other fuel prices: Coal €1.6/GJ and natural gas €6.05/GJ). Oil prices reached a high of \$147/barrel in July 2008. Note that, in its 2008 edition of the World Energy Outlook, the IEA increased its fuel price projections to €100/barrel in 2010 and \$122/barrel in 2030 (2007 prices).

Figure 0.6 shows the results of the reference case, assuming the two conventional power plants are coming online in 2010. Figures for the conventional plants are calculated using the Recabs model and the IEA fuel price assumptions mentioned above (\$59/barrel in 2010), while the costs for wind power are recaptured from the figures for onshore wind power arrived at earlier in this study.

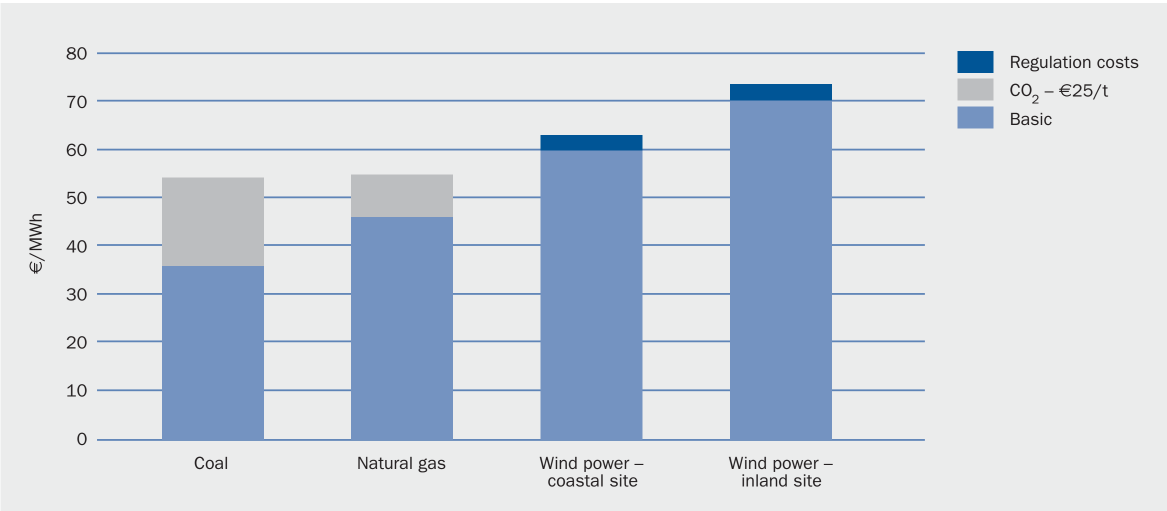
At the time of writing, (September 2008), the crude oil price is \$120/barrel, significantly higher than the forecast IEA oil price for 2010. Therefore, a sensitivity analysis is carried through and results are shown in Figure 0.7.

In Figure 0.7, the natural gas price is assumed to double compared to the reference equivalent to an oil price of \$118/barrel in 2010, the coal price to increase by 50% and the price of CO_2 to increase to 35€/t from 25€/t in 2008. As shown in Figure 0.7, the competitiveness of wind-generated power increases significantly with rising fuel and carbon prices; costs at the inland site become lower than generation costs for the natural gas plant and around 10% more expensive than the coal-fired plant. On coastal sites, wind power produces the cheapest electricity of the three.

The uncertainties mentioned above, related to future fossil fuel prices, imply a considerable risk for future generation costs of conventional plants. The calculations here do not include the macro-economic benefits of fuel price certainty, CO_2 price certainty, portfolio effects, merit-order effects and so on.

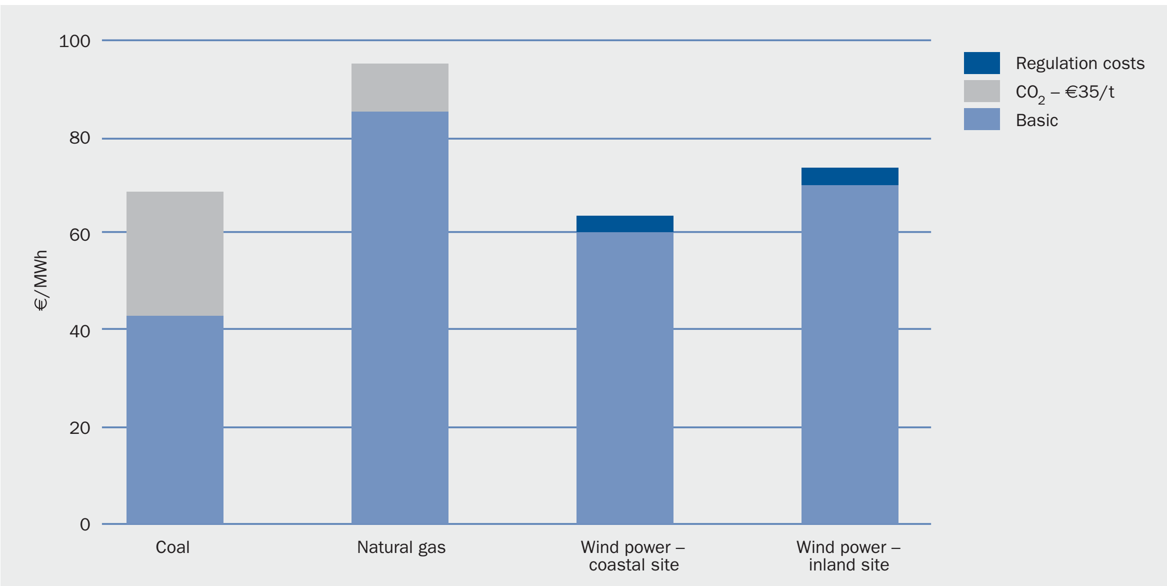
Even if wind power were more expensive per kWh, it might account for a significant share in the utilities' portfolio of power plants since it hedges against unexpected rises in prices of fossil fuels and CO_2 in the future. According to the International Energy Agency (IEA), a EU carbon price of €10 adds 1c€/kwh to the generating cost of coal and 0.5c€/kWh to the cost of gas generated electricity. Thus, the consistent nature of wind power costs justifies a relatively higher price compared to the uncertain risky future costs of conventional power.

FIGURE 0.6: **Costs of generated power comparing conventional plants to wind power, year 2010 (constant €^{2006})**



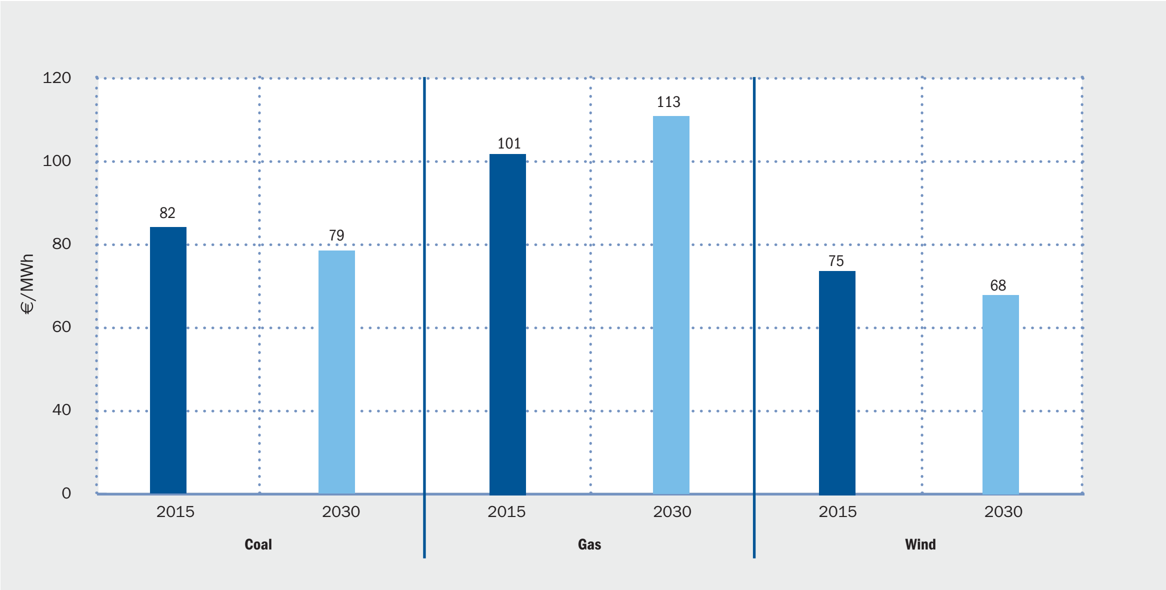
Source: Risø DTU

FIGURE 0.7: **Sensitivity analysis of costs of generated power comparing conventional plants to wind power, assuming increasing fossil fuel and CO_2 prices, year 2010 (constant €^{2006})**



Source: Risø DTU

FIGURE 0.8: **Electricity generating costs in the European Union, 2015 and 2030**



€/$ Exchange rate: 0.73

Source: IEA World Energy Outlook 2008

In its 2008 edition of World Energy Outlook, the IEA revised its assumptions on both fuel prices and power plant construction cost. Consequently, it increased its estimates for new-build cost. For the European Union, it also assumed that a carbon price of $30 per tonne of CO_2 adds $30/MWh to the generating cost of coal and $15/MWh to the generating cost of gas CCGT plants. Figure 0.8 shows the IEA's assumption on future generating cost for new coal, gas and wind energy in the EU in 2015 and 2030. It shows that the IEA expects new wind power capacity to be cheaper than coal and gas in 2015 and 2030.

2. The price of wind energy

The price of wind energy is different from the cost of wind energy described above. The price depends very much on the institutional setting in which wind energy is delivered. This is a key element to include in any debate about the price or cost of wind energy, and it is essential in order to allow for a proper comparison of costs and prices with other forms of power generation.

In this report we distinguish between the production costs of wind, and the *price* of wind, that is, what a future owner of a wind turbine will be able to bid per kWh in a power purchasing contract tender – or what he would be willing to accept as a fixed-price, fixed premium or indexed-price offer from an electricity buyer.

There is thus not a single price for wind-generated electricity. The price that a wind turbine owner asks for obviously depends on the costs he has to meet in order to make his delivery, and the risks he has to carry (or insure) in order to fulfil his contract.

Wind power may be sold on long-term contracts with a contract term (duration) of 15-25 years, depending on the preferences of buyers and sellers. Generally speaking, wind turbine owners prefer long-term contracts, since this minimises their investment risks, given that most of their costs are fixed costs, which are known at the time of the commissioning of the wind turbines.

Compared to traditional fossil-fuel fired thermal power plant, generation from wind (or hydro) plants gives buyers a unique opportunity to sign long-term power purchasing contracts with fixed or largely predictable, general price level indexed prices. This benefit of wind power may or may not be taken into account by the actors on the electrical power market, depending on institutional circumstances in the jurisdiction.

Governments around the world regulate electricity markets heavily, either directly or through nominally independent energy regulators, which interpret more general energy laws. This is true whether we consider jurisdictions with classical electricity monopolies or newer market structures with 'unbundling' of transmission and distribution grids from wholesale and retail electricity sales, allowing (some) competition in power generation and in retail sales of electricity. These newer market structures are often somewhat inaccurately referred to as 'deregulated' markets, but public regulation is necessary for more than just controlling monopolies (such as the natural monopolies of power transmission and distribution grids) and preventing them from exploiting their market position. Regulation is also necessary to create efficient market mechanisms, e.g. markets for balancing and regulating power. Hence, liberalised or deregulated markets are no less regulated (and should be no less regulated) than classical monopolies, just as stock markets are (and should be) strongly regulated.

As a new and capital-intensive technology, wind energy faces a double challenge in this situation of regulatory flux. Firstly, existing market rules and technical regulations were made to accommodate conventional generating technologies. Secondly, regulatory certainty and stability are economically more important for capital-intensive technologies with a long lifespan than for conventional fuel-intensive generating technologies.

Unregulated markets will not automatically ensure that goods or services are produced or distributed efficiently or that goods are of a socially acceptable quality. Likewise, unregulated markets do not ensure that production occurs in socially and environmentally acceptable ways. Market regulation is therefore present in all markets and is a cornerstone of public policy. Anti-fraud laws, radio frequency band allocation, network safety standards, universal service requirements, product safety, occupational safety and environmental regulations are just a few examples of market regulations, which are essential parts of present-day economics and civilisation. As mentioned, in many cases market regulation is essential because of so-called *external effects*, or spill-over effects, which are costs or benefits that are not traded or included in the price of a product, since they accrue to third parties which are not involved in the transaction.

As long as conventional generating technologies pay nowhere near the real social (pollution) cost of their activities, there are thus strong economic efficiency arguments for creating market regulations for renewable energy, which attribute value to the environmental benefits of their use. Although the economically most efficient method would theoretically be to use the polluter pays principle to its full extent – in other words, to let all forms of energy use bear their respective pollution costs in the form of a pollution tax – politicians have generally opted for narrower, second-best solutions. In addition to some minor support to research, development and demonstration projects – and in some cases various investment tax credit or tax deduction schemes – most jurisdictions have opted to support the use of renewable energy through regulating either price or quantity of electricity from renewable sources.

In regulatory price-driven mechanisms, generators of renewable energy receive financial support in terms of a subsidy per kW of capacity installed, a payment per kWh produced and sold or a fixed premium above the market price.

In quantity-based market schemes, *green certificate models* (found in the UK, Sweden and Belgium, for example) or *renewable portfolio standard models* (used in several US states) are based on a mechanism whereby governments require that an increasing share of the electricity supply be based on renewable energy sources.

Neither of the two types of schemes can be said to be more *market-orientated* than the other, although some people favouring the second model tend to embellish it by referring to it as a 'market-based scheme'.

3. Grid, system integration and markets

Introducing significant amounts of wind energy into the power system entails a series of economic impacts - both positive and negative.

At the power system level, two main aspects determine wind energy integration costs: balancing needs and grid infrastructure. It is important to acknowledge that these costs also apply to other generating technologies, but not necessarily at the same level

The additional *balancing cost* in a power system arises from the inherently variable nature of wind power, requiring changes in the configuration, scheduling and operation of other generators to deal with unpredicted deviations between supply and demand. This report demonstrates that there is sufficient evidence available from national studies to make a good estimate of such costs, and that they are fairly low in comparison with the generation costs of wind energy and with the overall balancing costs of the power system.

Network upgrades are necessary for a number of reasons. Additional transmission lines and capacity need to be provided to reach and connect present and future wind farm sites and to transport power flows in the transmission and distribution networks. These flows result both from an increasing demand and trade of electricity and from the rise of wind power. At significant levels of wind energy penetration, depending on the technical characteristics of the wind projects and trade flows, the networks must be adapted to improve voltage management. Furthermore, the limited interconnection capacity often means the benefits coming from the widespread, omnipresent nature of wind, other renewable energy sources and electricity trade in general are lost. In this respect, any infrastructure improvement will bring multiple benefits to the whole system, and therefore its cost should not be allocated only to wind power generation.

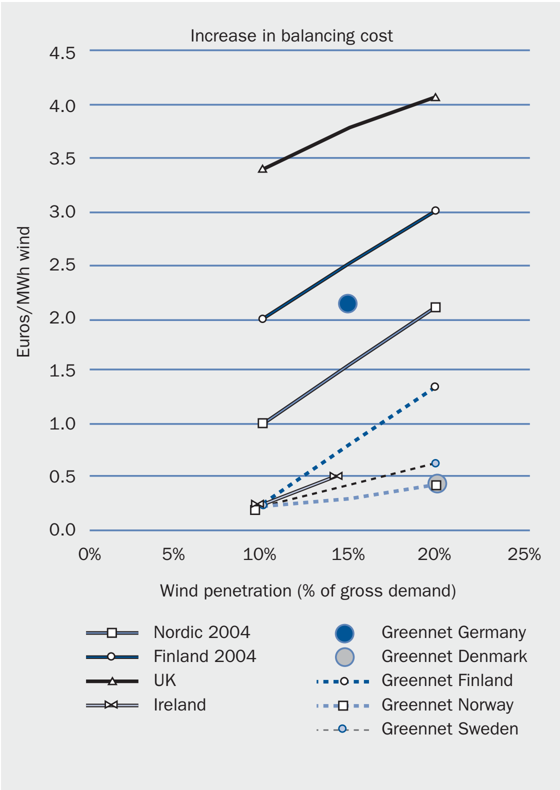
Second to second or minute to minute variations in wind energy production are rarely a problem for installing wind power in the grid, since these variations will largely be cancelled out by the other turbines in the grid.

Wind turbine energy production may, however, vary from hour to hour, just as electricity demand from electricity costumers will vary from hour to hour. In both cases this means that other generators on the grid have to provide power at short notice to balance supply and demand on the grid.

Studies of the Nordic power market, NordPool, show that the cost of integrating variable wind power in Denmark is, on average, approximately 0.3-0.4 c€/kWh of wind power generated, at the current level of 20% electricity from wind power and under the existing transmission and market conditions. These costs are completely in line with experiences in other countries. The cost of providing this balancing service depends both on the type of other generating equipment available on the grid and on the predictability of the variation in net electricity demand, that is demand variations minus wind power generation. The more predictable the net balancing needs, the easier it will be to schedule the use of balancing power plants and the easier it will be to use the least expensive units to provide the balancing service (that is, to regulate generation up and down at short notice). Wind generation can be very reliably forecast a few hours ahead, and the scheduling process can be eased and balancing costs lowered. There are several commercial wind forecasting products available on the market, usually combined with improved meteorological analysis tools.

At wind energy penetrations of up to 20% of electricity demand, system operating costs increase by about 1-4 €/MWh of wind generation. This is typically 5-10% or less of the wholesale value of wind energy. Figure 0.9 illustrates the costs from several studies as a function of wind power penetration. Balancing costs increase on a linear basis with wind power penetration; the absolute values are moderate and always less than 4 €/MWh at 20% level (more often in the range below 2 €/MWh).

FIGURE 0.9: **Results from estimates for the increase in balancing and operating costs, due to wind power**



Holttinen, 2007

Note: The currency conversion used in this figure is 1 € = 0.7 GBP = 1.3 USD. For the UK 2007 study, the average cost is presented; the range for 20% penetration level is from 2.6 to 4.7 €/MWh.

Large balancing areas offer the benefits of lower variability. They also help decrease the forecast errors of wind power, and thus reduce the amount of unforeseen imbalance. Large areas favour the pooling of more cost-effective balancing resources. In this respect, the regional aggregation of power markets in Europe is expected to improve the economics of wind energy integration. Additional and better interconnection is the key to enlarging balancing areas. Certainly, improved interconnection will bring benefits for wind power integration. These are quantified by studies such as TradeWind.

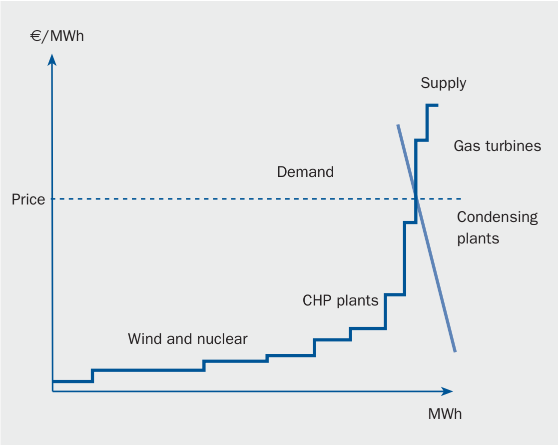
The consequences of adding more wind power into the grid have been analysed in several European countries. The national studies quantify grid extension measures and the associated costs caused by additional generation and demand in general, and by wind power production. The analyses are based on load flow simulations of the corresponding national transmission and distribution grids and take into account different scenarios for wind energy integration using existing, planned and future sites.

It appears that additional grid extension/reinforcement costs are in the range of 0.1 to 5€/MWh - typically around 10% of wind energy generation costs for a 30% wind energy share. Grid infrastructure costs (per MWh of wind energy) appear to be around the same level as additional balancing costs for reserves in the system to accommodate wind power.

In the context of a strategic EU-wide policy for long-term, large-scale grid integration, the fundamental ownership unbundling between generation and transmission is indispensable. A proper definition of the interfaces between the wind power plant itself (including the "internal grid" and the corresponding electrical equipment) and the "external" grid infrastructure (that is, the new grid connection and extension/reinforcement of the existing grid) needs to be discussed, especially for remote wind farms and offshore wind energy. This does not necessarily mean that the additional grid tariff components, due to wind power connection and grid extension/reinforcement, must be paid by the local/ regional customers only. These costs could be socialised within a "grid infrastructure" component at national or even EU level. Of course, appropriate accounting rules would need to be established for grid operators.

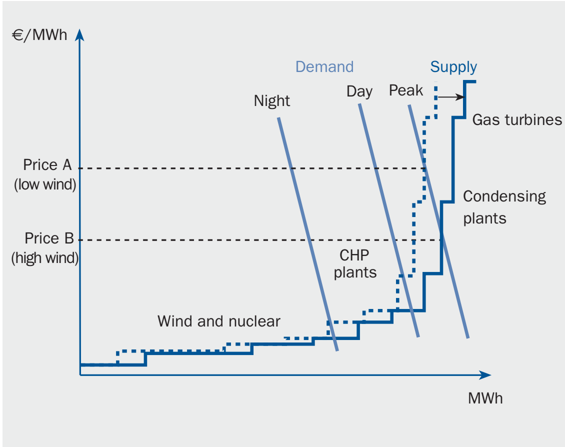
Figure 0.10 shows a typical example of electricity supply and demand. As shown, the bids from nuclear and wind power enter the supply curve at the lowest level, due to their low marginal costs (zero fuel cost), followed by combined heat and power plants, while condensing plants/gas turbines are those with the highest marginal costs of power production. Note that hydro power is not identified on the figure, since bids from hydro tend to be strategic and depend on precipitation and the level of water in reservoirs.

FIGURE 0.10: **Supply and Demand Curve for the NordPool Power Exchange**



Source: Risø DTU

FIGURE 0.11: **How wind power influences the power spot price at different times of day**



Source: Risø DTU

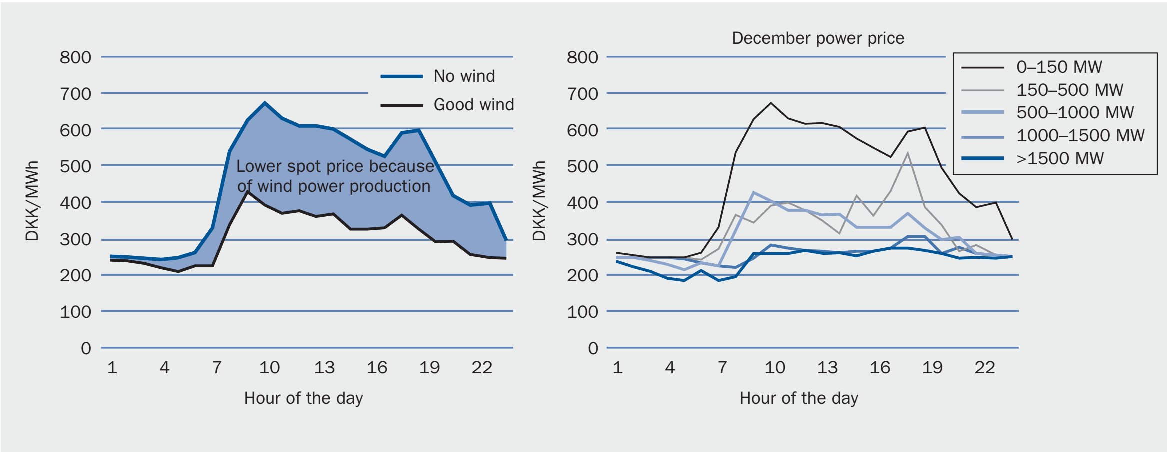
Wind power is expected to influence prices on the power market in two ways:
Wind power normally has a low marginal cost (zero fuel costs) and therefore enters near the bottom of the supply curve. This shifts the supply curve to the right (see Figure 0.11), resulting in a lower power price, depending on the price elasticity of the power demand. In Figure 0.11, the price is reduced from Price A to Price B when wind power production increases during peak demand. In general, the price of power is expected to be lower during periods with high wind than in periods with low wind. This is known as the 'merit order effect'.

As mentioned, there may be congestions in power transmission, especially during periods with high wind power generation. Thus, if the available transmission capacity cannot cope with the required power export, the supply area is separated from the rest of the power market and constitutes its own pricing area. With an excess supply of power in this area, conventional power plants have to reduce their production, since it is generally not economically or environmentally desirable to limit the power production of wind. In most cases, this will lead to a lower power price in this sub-market.

When wind power supply increases, it shifts the power supply curve to the right in Figure 0.11. At a given demand, this implies a lower spot price at the power market, as shown. However, the impact of wind power depends on the time of the day. If there is plenty of wind power at midday, during the peak power demand, most of the available generation will be used. This implies that we are at the steep part of the supply curve in Figure 0.11 and, consequently, wind power will have a strong impact, reducing the spot power price significantly (from Price A to Price B). But if there is plenty of wind-produced electricity during the night, when power demand is low and most power is produced on base load plants, we are at the flat part of the supply curve and consequently the impact of wind power on the spot price is low.

This is illustrated in the left-hand graph in Figure 0.12, where the shaded area between the two curves approximates the value of wind power in terms of lower spot power prices in west Denmark (which is not interconnected with east Denmark). In the right-hand graph in Figure 0.12, more detail is shown with figures from the west Denmark area. Five levels of wind power production and the corresponding power prices are depicted for each hour of the day during December 2005. The reference is given by the '0-150 MW' curve, which thus approximates those hours of the month when the wind

FIGURE 0.12: **The impact of wind power on the spot power price in the west Denmark power system in December 2005**



Note: The calculation only shows how the production contribution from wind power influences power prices when the wind is blowing. The analysis cannot be used to answer the question 'What would the power price have been if wind power was not part of the energy system?'

Source: Risø DTU

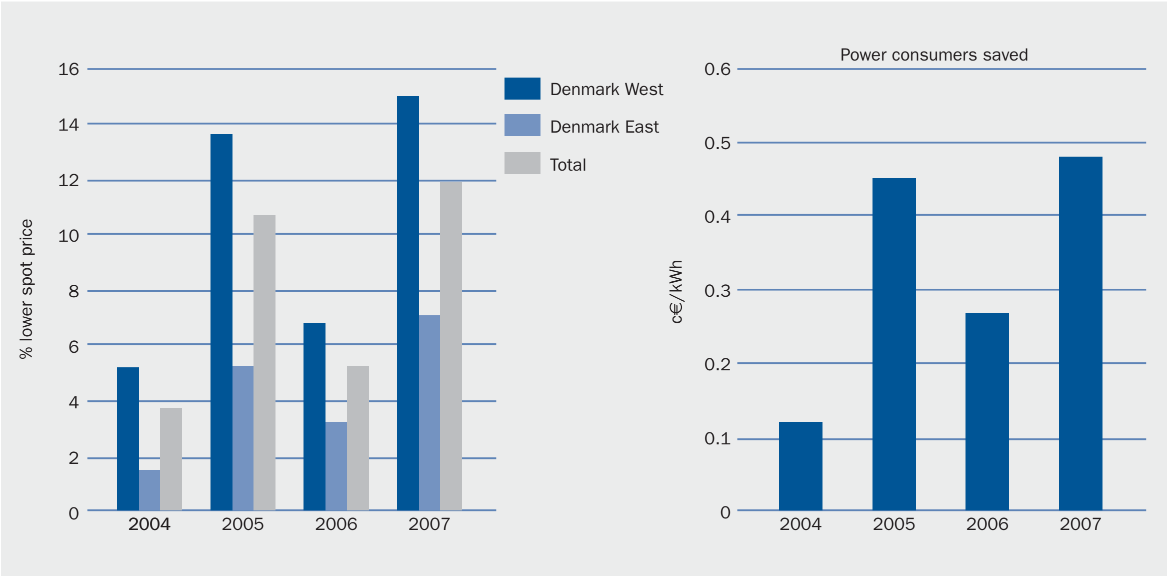
was not blowing. Therefore, this graph should approximate the prices for an average day in December 2005, in a situation with zero contribution from wind power. The other curves show increasing levels of wind power production: the 150-500 MW curve shows a situation with low wind, increasing to storms in the >1,500 MW curve. As shown, the higher the wind power production, the lower the spot power price is in this area. At very high levels of wind power production, the power price is reduced significantly during the day, but only falls slightly during the night. Thus there is a significant impact on the power price, which might increase in the long term if even larger shares of wind power are fed into the system.

When wind power reduces the spot power price, it has a significant influence on the price of power for consumers. When the spot price is lowered, this is beneficial to all power consumers, since the reduction in price applies to all electricity traded – not only to electricity generated by wind power.

Figure 0.13 shows the amount saved by power consumers in Denmark due to wind power's contribution to the system. Two calculations were performed: one using the lowest level of wind power generation as the reference ('0-150 MW'), in other words assuming that the power price would have followed this level if there was no contribution from wind power in the system, and the other more conservative, utilising a reference of above 500 MW. For each hour, the difference between this reference level and the levels with higher production of wind power is calculated. Summing the calculated amounts for all hours of the year gives the total benefit for power consumers of wind power lowering spot prices of electricity. Figure 0.13 shows how much higher the consumer price would have been (excluding transmission tariffs, taxes and VAT) if wind power had not contributed to power production.

In general in 2004-2007, the cost of power to the consumer (excluding transmission and distribution tariffs, taxes and VAT) would have been approximately 4-12% higher in Denmark if wind power had not contributed to power production. Wind power's strongest impact is estimated to have been for west Denmark, due to the high penetration of wind power in this area. In 2007, this adds up to approximately 0.5 c€/kWh saved by power consumers, as a result of wind power lowering electricity prices. Although wind power in the Nordic countries is mainly established in Denmark, all Nordic power consumers benefit financially due to the presence of Danish wind power on the market.

FIGURE 0.13: **Annual percentage and absolute savings by power consumers in western and eastern Denmark in 2004-2007 due to wind power depressing the spot market electricity price**



Source: Risø DTU

4. Energy policy and economic risk

Industrialised countries – and European countries in particular – are becoming increasingly dependent on fossil fuel imports, more often than not from areas which are potentially politically unstable. At the same time global energy demand is increasing rapidly, and climate change requires urgent action. In this situation it seems likely that fuel and carbon price increases and volatility will become major risk factors not just for the cost of power generation, but also for the economy as a whole.

In a global context, Europe stands out as an energy intensive region heavily reliant on imports (54% of the EU's primary demand). The EU's largest remaining oil and gas reserves in the North Sea have already peaked. The European Commission (EC 2007) reckons that, without a change in direction, this reliance will be as high as 65% by 2030. Gas imports in particular are expected to increase from 57% today to 84% in 2030, and oil imports from 82% to 93%. The European Commission estimates that the EU countries' energy import bill was €350 billion in 2008, equal to around €700 for every EU citizen.

In turn, the International Energy Agency predicts that global demand for oil will go up by 41% in 2030 (IEA, 2007a), stating that "the ability and willingness of major oil and gas producers to step up investment in order to meet rising global demand are particularly uncertain". Even if the major oil and gas producers were able to match the rising global demand, considerable doubt exists concerning the actual level of accessible remaining reserves.

The use of fossil fuel fired power plants exposes electricity consumers and society as a whole to the risk of volatile and unpredictable fuel prices. To make matters worse, government energy planners, the European Commission and the IEA have consistently been using energy models and cost-of-energy (COE) calculation methods that do not properly account for fuel and carbon price risks.

The oil and gas price hikes of the supply crises of the 1970s had dramatic effects on the world economy, creating inflation and stifling economic growth for a decade. Fossil fuel prices, which are variable and hard to predict, pose a threat to economic development. The vulnerability of an economic system to oil price was empirically formulated by J.K. Hamilton in 1983 and relevant literature refers to it as the "oil-GDP effect".

In 2006, Awerbuch and Sauter estimated the extent to which wind generation might mitigate oil-GDP losses, assuming the effect of the last 50 years continues. They found that by displacing gas and, in turn, oil, a 10% increase in the share of renewable electricity generation could help avert €75 to €140 billion in global oil-GDP losses.

The Sharpe-Lintner 'Capital Asset Pricing Model' (CAPM) and Markowitz's 'Mean Variance Portfolio Theory', both Nobel Prize-winning contributions, proved that an optimum portfolio is made up of a basket of technologies with diverse levels of risk. This is the so-called 'portfolio effect', whereby the introduction of risk-free generating capacity, such as wind, helps to diversify the energy portfolio, thereby reducing overall generating cost and risk. The introduction of the portfolio theory has been slow in energy policy analysis, given the divergence between social and private costs, and the ability of power producers to pass hikes in fossil fuel price onto the final consumer, thus transferring the risk from the private company to society as a whole.

The higher capital costs of wind are offset by very low variable costs, due to the fact that fuel is free, but the investor will only recover those after several years. This is why regulatory stability is so important for the sector.

5. A new model for comparing power generating cost – accounting for fuel and carbon price risk

Wind, solar and hydropower differ from conventional thermal power plant in that most of the costs of owning and operating the plant are known in advance with great certainty. These are *capital-intensive* technologies - O&M costs are relatively low compared to thermal power plants since the energy input is free. Capital costs (interest and depreciation) are known as soon as the plant is built and financed, so we can be certain of the future costs. Wind power may thus be classified as a *low-risk technology* when we deal with cost assessments.

The situation for thermal power plants is different: These technologies are *expense-intensive* technologies – in other words, they have high O&M costs, with by far the largest item being the fuel fill. Future fuel prices, however, are not just *uncertain* – they are highly *unpredictable*. This distinction between *uncertainty* and *unpredictability* is essential.

If fuel prices were just uncertain, you could probably buy insurance for your monthly fuel bill (much as you can insure your wind generation if the insurance company knows the likely mean generation on an annual and seasonal basis). Since there is a world market for gas and oil, most of the insurance for predictable, but (short-term) uncertain fuel prices could probably be bought in a world-wide financial futures market for oil and gas prices, where speculators would actively be at work and thus help stabilise prices. But this is not how the real world looks.

In the real world, you can neither simply nor safely buy a fossil-fuel contract for delivery 15 or 20 years ahead, the long-term futures market for fuels does not exist and it never will; the risks are too great for both parties to sign such a contract because fuel prices are not just uncertain – they are too unpredictable. But you cannot sensibly deal with real risk in an economic calculation by assuming it does not exist. The unpleasant corollary of this is that the 'engineering-economics cost calculations' (levelised-cost approaches), widely used by governments and international organisations, simply do not make sense because future fuel prices - just like stock prices - are both uncertain and highly unpredictable.

Likewise, investors in power plants – or society at large – should be equally rational and choose to invest in power plants with a possibly lower, but predictable rate of return rather than investing in power plant with a possibly higher, but unpredictable rate of return. The way to analyse this in financial economics is to use *different discount rates depending on the risks involved*. Unpredictable income has to be discounted at a higher rate than predictable income, just as for financial markets.

What does this analysis tell us about the way the IEA, governments and the European Commission currently calculate the cost of energy from different sources? It tells us that when these institutions apply a single rate of discount to all future expenditure, they pretend that fuel prices are riskless and predictable. Fuel prices are thus discounted too heavily, which under-estimates their cost and over-states their desirability relative to less risky capital expenditure. In other words, current calculation practice favours conventional, expenditure- intensive fuel-based power generation over capital-intensive, zero carbon and zero fuel-price risk power generation from renewables such as wind power.

Traditional, engineering-economics cost models were first conceived a century ago, and have been discarded in other industries (because of their bias towards lower-cost but high risk *expense-intensive* technology. In energy models, they continue to be applied widely. In the case of electricity cost estimates, current models will almost always imply that risky fossil alternatives are more cost-effective than cost-certain renewables. This is roughly analogous to telling investors that high-yielding but risky "junk bonds" or stocks are categorically a better investment than lower yielding but more secure and predictable government bonds.

If our power supply consisted of only oil, gas and coal technology, the engineering cost approach would not be too much of a problem. This was true for most of the last century but is no longer the case. Today, energy planners can choose from a broad variety of resource options that ranges from traditional, risky fossil alternatives to low-risk, passive, capital-intensive wind with low fuel and operating cost risks.

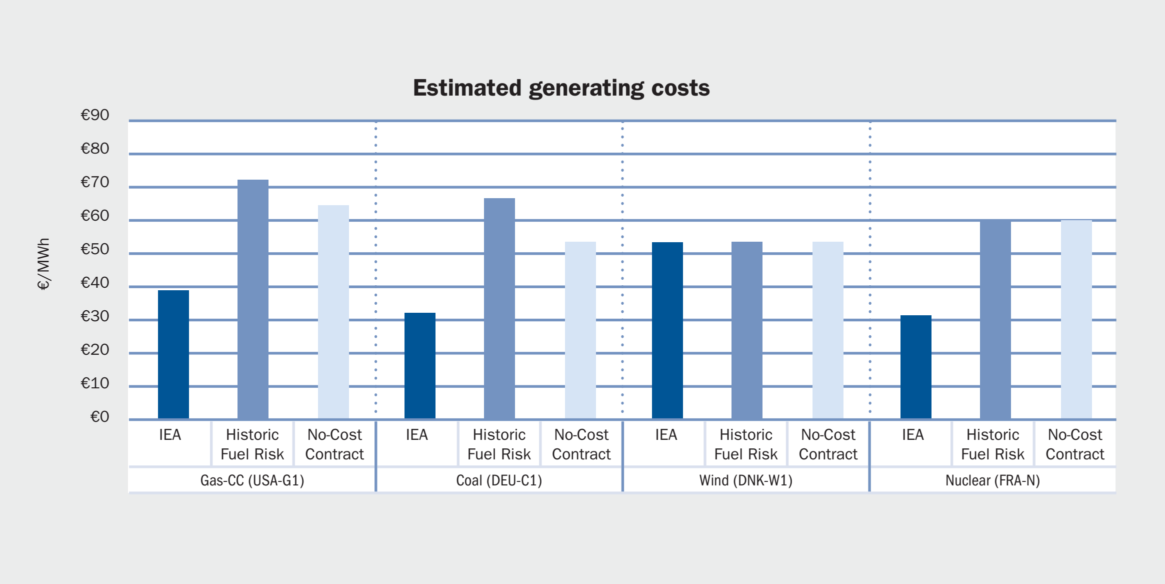
Current energy models assumes away the fuel cost risk by using different discount rates (sensitivity analysis). But as explained above, this method does not solve the problem of comparing different technologies with different fuel requirements – or no fuels, as it is the case for wind energy. Rather than using different risk levels, and applying those to all technologies, the IEA should use differentiated discount rates for the various technologies.

In contrast to the previous sections, this section describes a market-based or financial economics approach to COE estimation that differs from the traditional engineering-economics approach. It is based on groundbreaking work by the late Shimon Awerbuch. He argued that comparing the costs of wind and other technologies using the same discount rate for each gives meaningless results. In order to make meaningful COE comparisons we must estimate a reasonably accurate discount rate for generating cost outlays – fuel and O&M. Although each of these cost streams requires its own discount rate, fuel outlays require special attention since they are much larger than the other generating costs on a risk-adjusted basis.

By applying different methods for estimating the discount rates for fossil fuel technologies we find that the present value cost of fossil fuel expenditure is considerably greater than those obtained by the IEA and others who use arbitrary (nominal) discount rates in the range of 8% to as much as 13%.

In Figure 0.14 we use two different methods for establishing the differentiated discount rates and apply the Capital Asset Pricing Model to data covering a range of power plants. Interesting results are obtained:
In the IEA 2005 report "Projected costs of generating capacity, 2005", a typical natural gas power plant is assumed to have fuel costs of $2,967 at a 10% discount rate, equivalent to $0.049 per kWh (around 3.9 c€/kWh). However, if a historical fuel price risk methodology is used instead, fuel costs go up to $8,018, equal to $0.090 per kWh (approx. 7.2 c€/kWh). With an assumed no-cost 40 Year Fuel purchase contract, the figures would have been $7,115 or $0.081 per kWh (6.48 c€/kWh).

FIGURE 0.14: **Risk-adjusted power generating cost of gas, coal, wind and nuclear.**



Source: Shimon Awerbuch

Something similar happens for coal plants, which are also covered in the IEA report. In the central case, with a discount rate of 10%, the fuel costs of a coal power station (DEU-C1, chapter 3) are equal to $1,234 or $0.040 per kWh (around 3.2 c€/kWh). If the historical fuel price risk methodology is preferred, the fuel costs peak at $5,324 or $0.083 per kWh (6.64 c€/kWh). Finally, when the no-cost 40 Year Fuel purchase contract is assumed, the figures appear as $3,709 and $0.066 per kWh respectively (approx. 5.28 c€/kWh).

In both cases the fuel costs and subsequently the total generating costs more than double when differentiated discount rates are assumed. As can be observed from the graph, wind energy cost remains unchanged because the technology carries no fuel price risk. It should be noted that the onshore wind energy cost calculated above are based on IEA methodology, which gives a wind energy generating cost of 5.3 c€/kWh. In Chapter 2 of the report, we find that the levelised cost of onshore wind energy range between 6 c€/kWh at a discount rate of 5% to 8 c€/kWh at a discount rate of 10% at a medium wind site.

Shimon Awerbuch carried out this analysis based on an IEA Report on electricity generating cost published in 2005 when the average IEA crude oil import price averaged $51/barrel. Results would obviously be very different if fuel prices were equivalent to the $150/barrel reached in mid 2008. Although only an example, the figures reflect how the relative position of wind energy vis-à-vis other technologies will substantially vary if a different – and more rational – COE estimate is used. Wind energy would appear even more cost competitive if carbon price risk had been included in the analysis.

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Introduction

This report is the result of an effort by the European Wind Energy Association to assemble a team of professional economists to assess the costs, benefits and risks associated with wind power generation. In particular, the authors were asked to evaluate the costs and benefits to society of wind energy compared to other forms of electricity production. In the present context of increasing energy import dependency in industrialised countries as well as the volatility of fuel prices and their impact on GDP, the aspects of energy security and energy diversification have to be given particular weight in such an analysis.

The research team responsible for this report consists of:

Søren Krohn, CEO, Søren Krohn Consulting, Denmark (editor)
Dr. Shimon Awerbuch, Financial Economist, Science and Technology Policy Research, University of Sussex, United Kingdom.
Poul Erik Morthorst, Senior Researcher, Risoe National Laboratory, Denmark

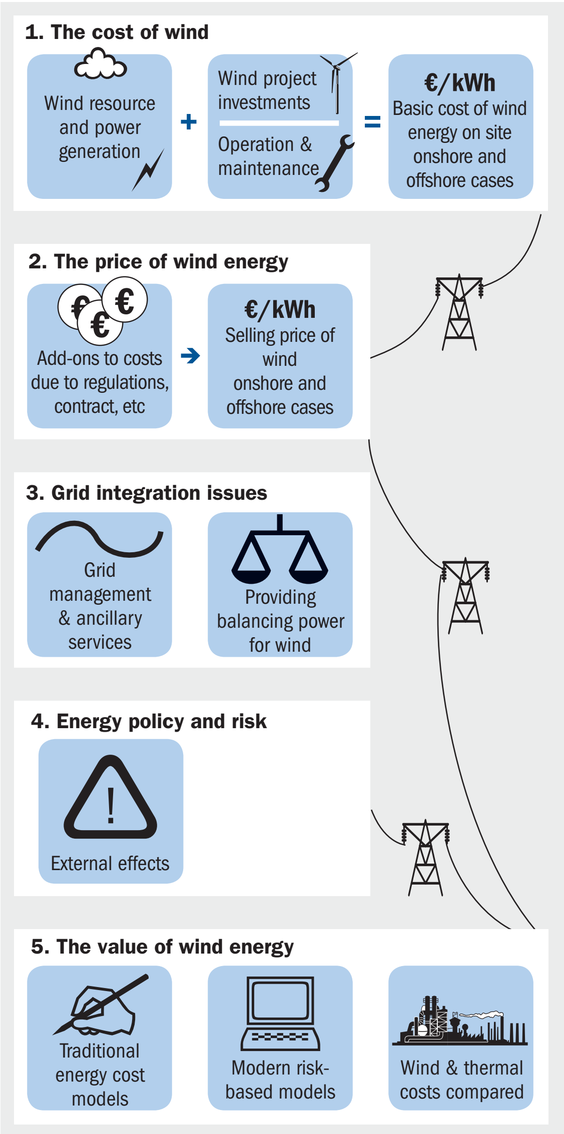
In addition, Dr. Isabel Blanco, former Policy Director, European Wind Energy Association, Belgium; Frans Van Hulle, Technical advisor to the European Wind Energy Association and Christian Kjaer, Chief Executive, European Wind Energy Association (EWEA), have made substantial contributions to the report.

Other experts have contributed to specific sections.

Figure A shows the structure of this publication:

Chapter 1 examines the basic (riskless) cost components of wind energy, as it leaves the wind farm, including some international comparisons and a distinction between onshore and offshore technologies.
Chapter 2 illustrates other costs, mainly risks that are also part of the investment and thus have to be incorporated in the final price at which electricity coming from wind can be sold in the markets. The chapter discusses why the electricity market for renewable energy sources (RES) is regulated and how different support systems and institutional settings affect the final cost (and hence, price) of wind power.
Chapter 3 discusses how the integration of wind energy is modifying the characteristics and management of the electrical system including grids, and how such modifications can affect the global price of electricity.
Chapter 4 analyses how the external benefits of wind energy, such as its lower environmental impact and the lower social risk it entails can be incorporated into its valuation
Chapter 5 develops a methodology for the correct economic comparison of electricity costs coming from wind and from fuel-intensive coal and gas power generation. Chapter 5 uses as a starting point the methodology currently applied by the International Energy Agency and improves it by incorporating some of the elements described in the previous sections.

FIGURE A: **Report structure**



The report shows that wind energy can become a valuable component in the electricity supply of Europe and other continents in the years ahead, if energy policy makers apply a consistent and comprehensive economic analysis of the costs, benefits and risks associated with the different power generation technologies available at this time.

One of the most important economic benefits of wind power is that it reduces the exposure of our economies to fuel price volatility. This benefit is so sizable, that it could easily justify a larger share of wind energy in most European countries, even if wind were more expensive per kWh than other forms of power generation. But this risk reduction from wind energy is presently not accounted for by standard methods for calculating the cost of energy, which have been used by public authorities for more than a century. Quite the contrary, current calculation methods blatantly favour the use of high-risk options for power generation. In a situation where the industrialised world is becoming ever more dependent on importing fuel from politically unstable areas, this aspect merits immediate attention. As is demonstrated in this publication, markets will not solve these problems by themselves without Governments creating the proper framework, since the benefits of using wind accrue to the economy and society as a whole, and not to individual market participants (the so-called common goods problem).

A major contribution of this report is to provide a systematic framework for the economic dimension of the energy policy debate when comparing different power generation technologies. This framework for discussion may also prove useful for insiders of the wind industry. A second contribution is to put fuel price risk directly into the analysis of the optimal choice of energy sources for power generation. Adjusting for fuel-price risk when making cost comparisons between various energy technologies is unfortunately very uncommon and the approach is not yet applied at IEA, European Commission or government level. Chapter 5 proposes a methodology to do so. With the European Union's December 2008 agreement to introduce a real price on carbon pollution (100% auctioning of CO_2 allowances inthe power sector), adjusting for carbon-price risk is equally important.

Like all other sources of power generation wind energy has its own unique technical, economic and environmental characteristics, as well as a distinctive risk profile. It is important to understand them, also when it applies to the electricity grid, in order to make a proper assessment of the costs and benefits of each technology.[1]

[1] To illustrate the point in a different area, it would hardly be reasonable to discuss the costs and benefits of air transportation solely by assessing the cost per tonne km or the cost per passenger mile compared to container liners, ferries, city buses, trains and cars. Each one of these means of transportation provides different services to cover different needs. Likewise, each means of transportation has to be seen in the context of the infrastructure required to support the vehicles, be it air control systems, highways, ports or rescue services. In addition, capacity or congestion problems are important dimensions of an analysis of transportation economics. Offhand it may seem that discussing wind in the electricity supply is less complex, but that is not necessarily the case.

But even on a more elementary level there is much confusion in the debate about the economics of wind power, even within the wind industry itself:

- Firstly, many participants in the energy policy debate fail to realise that the economics of wind power is fundamentally different from, say, the economics of gas turbine generation units. A gas turbine plant converts a storable, dispatchable and costly energy source into electrical energy. Wind turbines convert a fluctuating and free energy source, into electricity. The extraction rate at a given site is determined by fairly stable statistical distribution functions. The underlying economics of wind energy is also different from classical hydropower economics, because hydro energy is inherently storable – at a cost – and thus dispatchable. If anything, the economics of wind mostly resembles the economics of photovoltaics or – to a limited extent – the run-of-the-river hydropower. Conventional measures of technical efficiency or capacity factors are frequently misleading or even meaningless in this debate, particularly if the figures are compared to other generating technologies.

- Secondly, when discussing costs, debaters frequently forget to mention which point in the *value chain* of power generation they refer to, i.e. are we talking about kilowatt-hours delivered at the location of the turbine, at the electricity outlet or somewhere in between; what is the voltage level; to which extent are we talking about firm or statistically predictable delivery including or excluding *ancillary grid services*; and who pays for grid connection and grid reinforcement?

- Thirdly, basic *costs* and final *prices* are frequently mixed up in the debate. In the following discussion we will distinguish between the production *costs* of wind, i.e. the operation, maintenance and capital expenditure undertaken by the owner of a wind turbine and the *price* of wind, i.e. what a future owner of a wind turbine will bid per kWh in a power purchasing contract tender – or what he would be willing to accept as an offer from an electricity buyer. The difference between the two concepts of costs and price covers a number of concepts that are present in every investment decision: risk adjustment, taxes and what the economic theory calls normal profit for the investor.

- Fourthly, and given that the electricity market is heavily regulated, *legal and institutional provisions* will have a large impact on investment risk, on total costs and on final prices. Even simple administrative rules on the deadline for submitting bids on the electricity market in advance of delivery, the so-called *gate closure times,* will substantially affect the final figure. This situation partly explains why the total cost for wind energy can substantially differ in the different countries, even with the same level of wind resource.

  Another institutional – and thus political – issue is how to allocate the cost of adapting the grid and the electricity system to accommodate sustainable energy forms such as renewable energy, which rely on decentralised power generation and which have variable output.[2] The present structures of both the electricity grid and power markets are to a large extent the result of historical circumstances and were designed by government-owned, vertically-integrated monopolies that were generators, transporters, distributors and commercial agents at the same time. The grid and the markets that we have today are the result of such decisions and thus not optimum for the introduction of new and decentralised generation units, including wind. In planning for the future, the requirements and possibilities inherent in distributed and sustainable power generation will likely change the structure of both.

- Fifthly, the cost per kWh of electricity is far too simple a measure to use when comparing different portfolios of generating technologies. Different generating technologies have very different capital intensities and very different fuel cost risks. A prudent utility, a prudent society or a prudent energy policy maker would choose generating

[2] This subject is extensively dealt with in EWEA's 2005 publication *Large Scale Integration of Wind Energy in the European Power Supply: Analysis, Issues and Recommendations*, Brussels, 2005 and TradeWind's 2009 publication: *Integrating Wind: developing Europe's power market for the large-scale integration of wind power*. Both are available at www.ewea.org.

technologies, which provide both low costs and low risks for energy consumers. In the terminology of an economist, we would say that the cost of a risk-adjusted portfolio has to be minimised (which implies correcting the price per kWh of each technology by the risk of higher prices/ reduced supply, etc. This is normally made in the form of a probability attached to each technology). To use an analogy from the capital markets: pension fund managers could invest in junk bonds or in loans denominated in weak currencies, instead of government bonds in strong currencies, to obtain high prospective interest rates. They could invest in long-term bonds instead of short-term bonds to get higher prospective yields. But a prudent pension fund manager would also attempt to minimise risk and not just maximise prospective yields. A generating portfolio containing substantial amounts of wind energy will reduce the risks of future volatile and higher energy costs by reducing society's exposure to price volatility and price increases for fossil fuels.

The higher likelihood of oil price increases and volatility will translate into a decrease of the economic activity, a higher inflation and unemployment rates and a reduction of the economic value of other assets. This is the so-called Oil-GDP effect, which has been reported in the academic literature for a quarter of a century, although it received little attention from energy policy makers prior to the recent oil, gas, coal and uranium price spikes. The Oil-GDP effect is sizeable and can be mitigated by wind and other fuel free generation. This oil-GDP is quite substantial, and – like environmental benefits – it should be taken into account when taking decisions on energy policies for electrical power generation.

- Sixthly, the value to society of wind energy and other renewables cannot be estimated solely on the basis of direct electricity prices. Wind energy entails important environmental benefits that are not taken into account by the market; it also has a positive impact in terms of employment creation[3] and in terms of revitalisation of rural and declining areas[4].

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The analysis presented in this publication focuses mainly on the economics of large, grid connected wind turbines within a market setting dominated by fossil fuel fired power stations, such as it exists in the European Union and many other economies around the world.

[3] For more information on wind energy's contribution to job creation, see EWEA's January 2009 report, 'Wind at Work: wind energy and job creation in the EU', available on www.ewea.org.

[4] This effect depends on whether the new activity/job displaces a previous one, or whether it is additional employment and economic activity that is being created. Such effects are difficult to state on a global basis and have to be judged on a case-by-case approach. Generally speaking though, unless the country is at its production frontier level and there is full employment, the net impact will be positive.

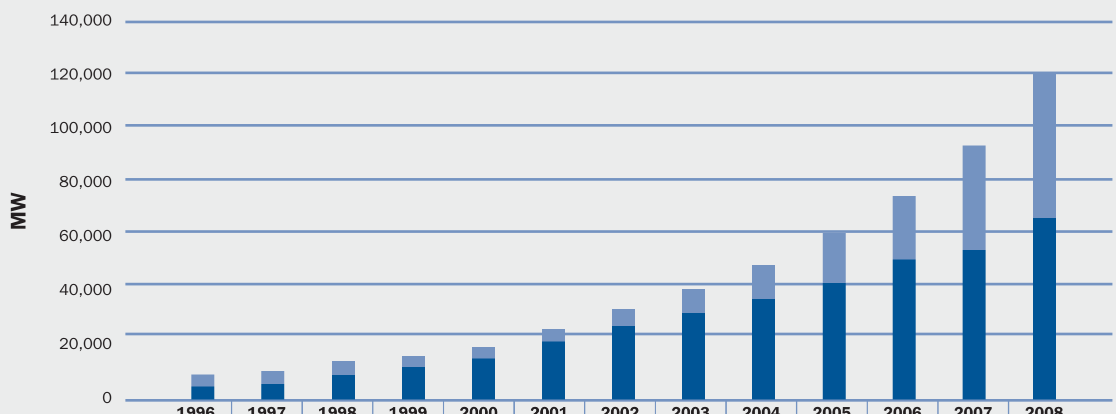
1. **Basic cost components of wind energy**

1.1. Overview of main cost components

Both in Europe and worldwide, wind power is being developed rapidly. Within the past ten years the global installed capacity of wind power has increased from approximately 1.7 GW in 1990 to pass the 100 GW mark in December 2008. From 1997 to 2008, global installed wind power capacity increased by an average of 35% per year and the annual market has grown from 1.5 GW to 20.1 GW at the end of 2008,[5] an average annual growth rate of some 29%.

In 2008, global wind turbine investments totalled more than €36.5 billion of which €11 billion (bn) was invested in the EU-27.

FIGURE 1.1: **Global cumulative wind power capacity 1996-2008 (in MW)**

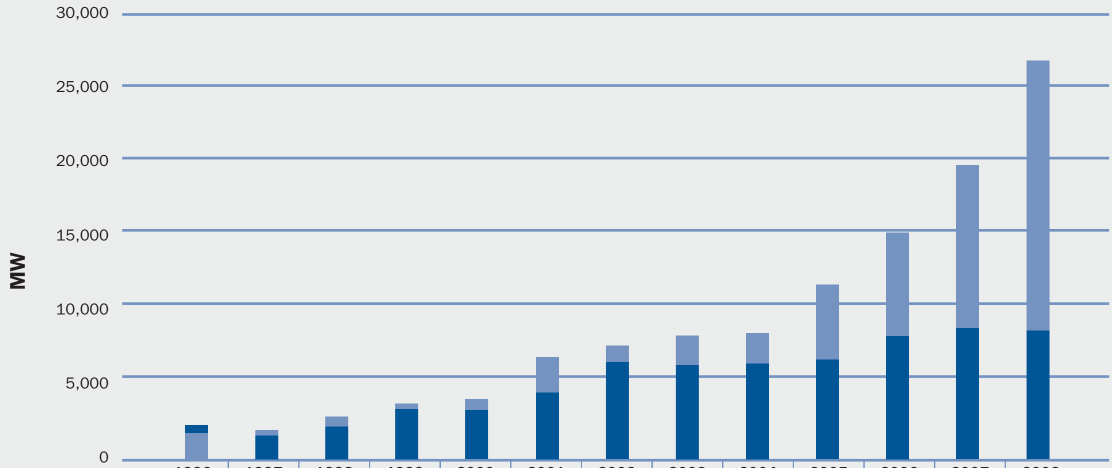


	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
World	6,100	7,600	10,200	13,600	17,400	23,900	31,100	39,431	47,620	59,091	74,052	93,823	120,791
EU	3,476	4,753	6,453	9,678	12,887	17,315	23,098	28,491	34,372	40,500	48,031	56,517	64,935

Source: GWEC/EWEA

[5] Pure *Power – Wind Energy Scenarios up to 2030*; European Wind Energy Association, March 2008. www.ewea.org

FIGURE 1.2: **Global annual wind power capacity 1996-2008 (in MW)**



	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
World	1,280	1,530	2,520	3,440	3,760	6,500	7,270	8,133	8,207	11,531	15,245	19,865	27,056
EU	1,979	1,227	1,700	3,225	3,209	4,428	5,913	5,462	5,838	6,204	7,619	8,535	8,484

Source: GWEC/EWEA

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 report analyses the economics of wind energy primarily in relation to grid-connected turbines, which account for the bulk of the market value of installed wind turbines.

The chapter focuses on the basic generation costs of a wind power plant, both upfront (including the lifetime of the turbine) and variable costs, which are mainly for operation and maintenance, since the fuel is free. It analyses how these costs have developed in previous years and how they are expected to develop in the near future, making a distinction between the short and the long term. Variables such as developer profit, risk premiums, taxes and institutional arrangements, which also affect investments, will be added in successive chapters in order to calculate the final price for wind energy.

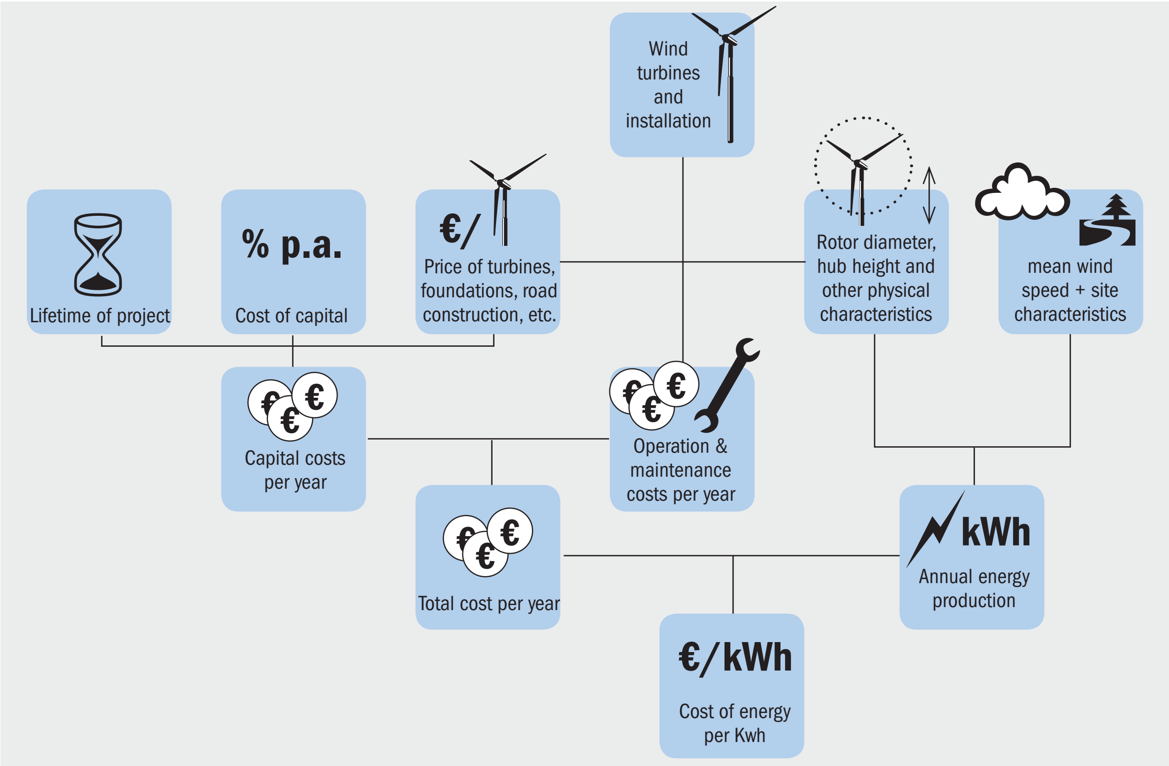
For purposes of clarity, we distinguish between the investment cost of the wind farm in terms of capacity installed (addition of upfront/capital costs plus variable costs) and the cost of wind per kWh produced, which incorporates energy production. This report focuses on the second (cost in €/kWh produced), because it allows comparisons to be made between wind and other power generating technologies, as in Chapter 5.

The key elements that determine the basic costs of wind energy are shown in detail below:

- Upfront investment costs, mainly the turbines
- The costs of wind turbine installation
- The cost of capital, i.e. the discount rate
- Operation and maintenance (O&M) costs
- Other project development and planning costs
- Turbine lifetime
- Electricity production, the resource base and energy losses

Approximately 75% of the total cost of energy for a wind turbine is related to upfront costs such as the cost of the turbine, foundation, electrical equipment, grid-connection and so on. Obviously, fluctuating fuel costs have no impact on power generation costs. Thus a wind turbine is *capital-intensive* compared to conventional fossil fuel fired technologies such as a natural gas power plant, where as much as 40-70% of costs are related to fuel and O&M.

FIGURE 1.3. **The cost of wind energy**



1.2 Upfront/capital costs

The capital costs of wind energy projects are dominated by the cost of the wind turbine itself (ex works). Table 1.1 shows the typical cost structure for a 2 MW turbine erected in Europe. The average turbine installed in Europe has a total investment cost of around €1.23 million/MW. The turbine's share of the total cost is, on average, around 76%, while grid connection accounts for around 9% and foundation for around 7%. The cost of acquiring a turbine site (on land) varies significantly between projects, so the figure in Table 1.1 is to be taken as an example. Other cost components, such as control systems and land, account for only a minor share of total costs.

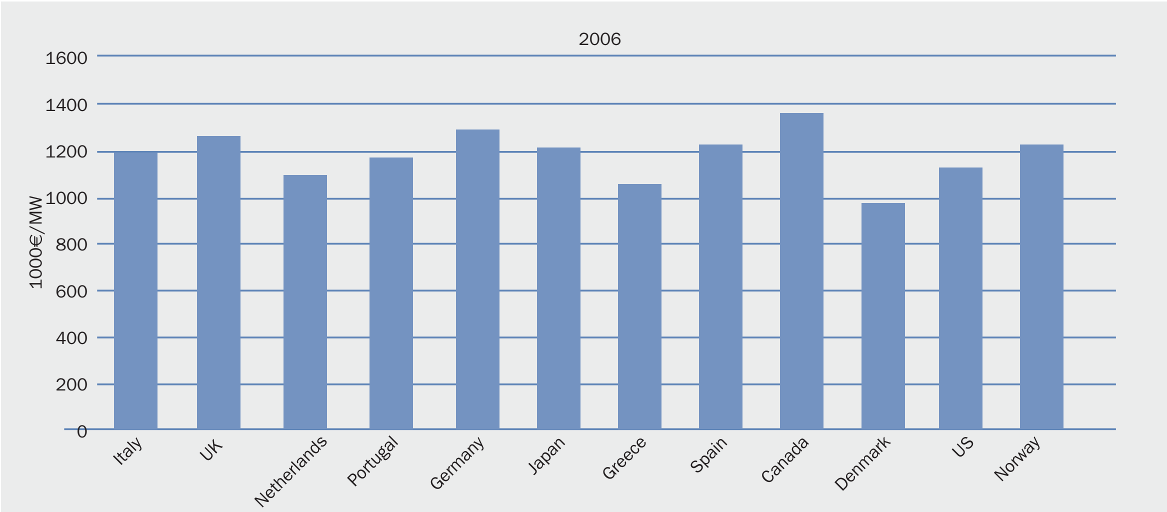
TABLE 1.1: **Cost structure of a typical 2 MW wind turbine installed in Europe (€ 2006)**

	INVESTMENT (€1,000/MW)	SHARE OF TOTAL COST %
Turbine (ex works)	928	75.6
Grid connection	109	8.9
Foundation	80	6.5
Land rent	48	3.9
Electric installation	18	1.5
Consultancy	15	1.2
Financial costs	15	1.2
Road construction	11	0.9
Control systems	4	0.3
TOTAL	**1,227**	**100**

Note: Calculated by the author based on selected data for European wind turbine installations

Of the other cost components, the main ones are typically grid connection and foundations. Also land rent,

FIGURE 1.4: **Total investment cost, including turbine, foundation and grid connection, shown for different turbine sizes and countries of installation. Based on data from the IEA.**



Source: Risø DTU

electric installation, consultants, financial cost, road construction and control systems add to the investment cost.

The total cost per kW of installed wind power capacity differs significantly between countries, as shown in Figure 1.4. The cost per kW typically varies from around €1,000/kW to €1,350/kW. As shown in Figure 1.4, the investment costs per kW were found to be the lowest in Denmark, and slightly higher in Greece and the Netherlands. For the UK, Spain and Germany, the costs in the data selection were found to be around 20-30% higher than in Denmark. However, it should be observed that Figure 1.4 is based on limited data, so the results might not be entirely representative for the countries mentioned.

Also, for "other costs", such as foundation and grid connection, there is considerable variation between countries, ranging from around 32% of total turbine costs in Portugal, to 24% in Germany, 21% in Italy and only 16% in Denmark. However, costs vary depending on turbine size, as well as the country of installation, distance from grids, land ownership structure and the nature of the soil.

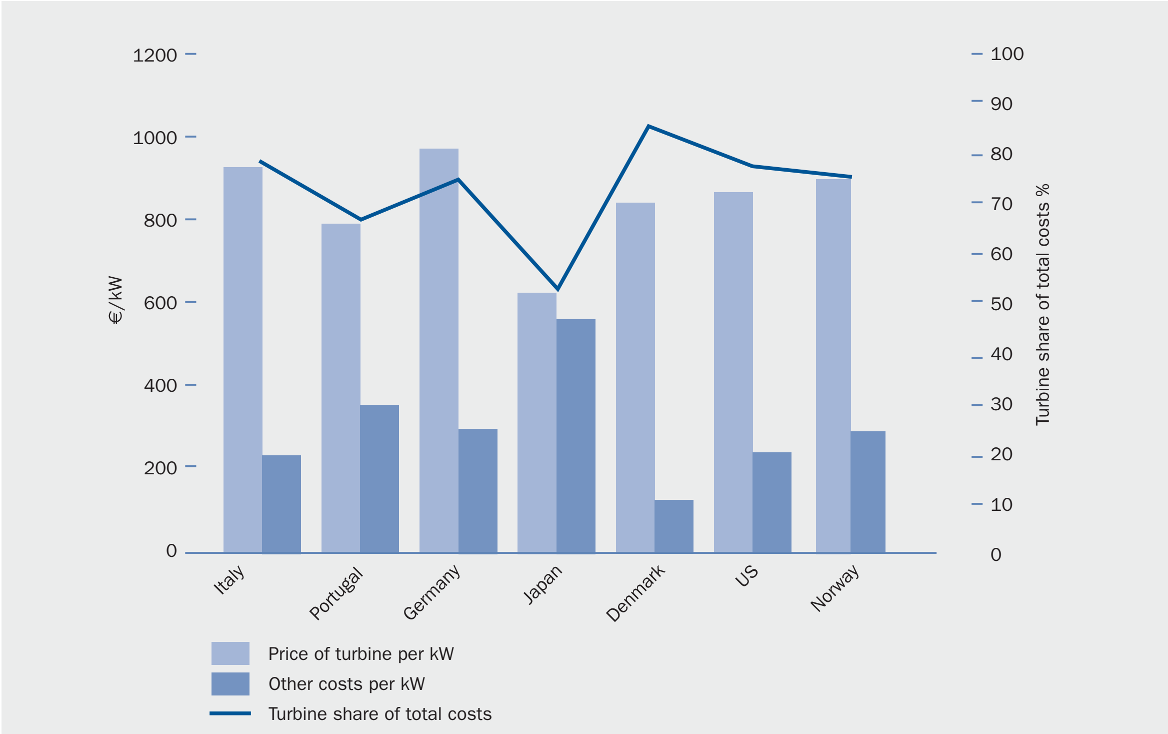
The typical ranges of these other cost components as a share of the total additional costs are shown in Table 1.2. In terms of variation, the single most important additional component is the cost of grid connection that, in some cases, can account for almost half of the auxiliary costs, followed by typically lower shares for foundation cost and cost of the electrical installation. Thus, these auxiliary costs may add significant amounts to the total cost of the turbine. Cost components such as consultancy and land, usually only account for a minor share of the additional costs.

TABLE 1.2: **Cost structure for a medium-sized wind turbine**

	SHARE OF TOTAL COST (%)	TYPICAL SHARE OF OTHER COST (%)
Turbine (ex works)	68-84	-
Grid connection	2-10	35-45
Foundation	1-9	20-25
Electric installation	1-9	10-15
Land	1-5	5-10
Financial costs	1-5	5-10
Road construction	1-5	5-10
Consultancy	1-3	5-10

Note: Based on a selection of data from Germany, Denmark, Spain and the UK adjusted and updated by the author

FIGURE 1.5: **Price of turbine and additional costs for foundation and grid connection, calculated per kW for selected countries (left axes), including turbine share of total costs (right axes.).**



Source: Risø DTU

Note: The different result for Japan may be caused by another split by turbine investment costs and other costs, as the total adds up to almost the same level as seen for the other countries.

Grid connection can in some cases account for almost half of auxiliary costs, followed by typically lower shares for foundation cost and cost of the electrical installation. These three items may add significant amounts to the total cost of the projects. Cost components such as consultancy and land normally account for only minor shares of the additional costs.

For a number of selected countries, the turbine and auxiliary costs (foundation and grid connection) are shown in Figure 1.5.

1.3 Wind Energy Investments in EU-27 up to 2030

One of the significant benefits of wind power is that the fuel is free. Therefore, the total cost of producing wind energy throughout the 20 to 25-year lifetime of a wind turbine can be predicted with great certainty. Neither the future prices of coal, oil, gas or uranium, nor the price of carbon, will affect the cost of wind power production.

In order to calculate future wind energy investments in the EU, it is necessary to make assumptions regarding the future development of investment costs and installed capacity. For some years, it was assumed as a rule of thumb that installed wind power capacity cost approximately €1,000 / kW. That is probably still a valid rule of thumb. However, since 2000 there have been quite large variations in the price (not necessarily the cost) of installing wind power capacity.

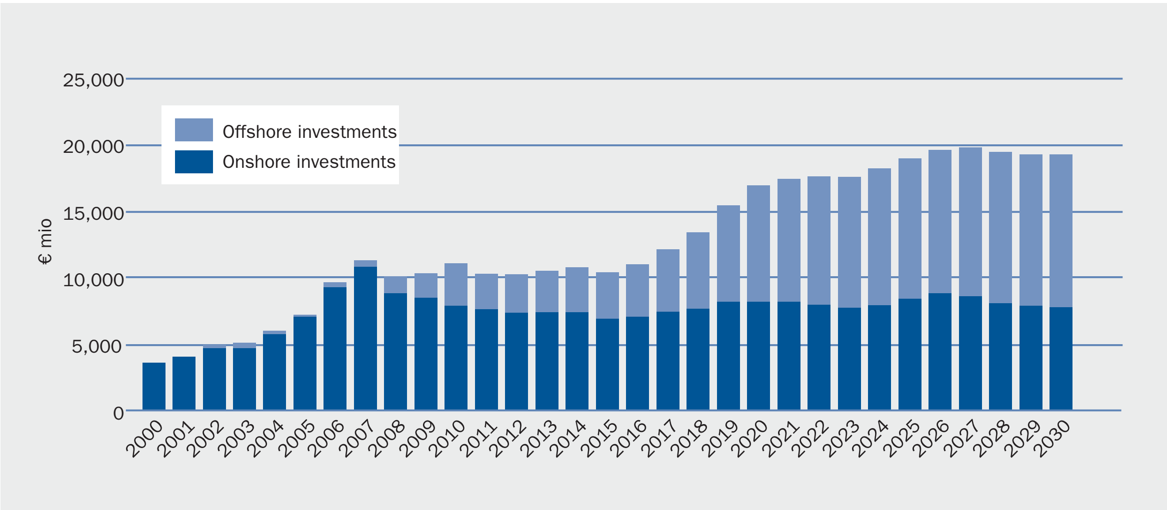
In the period 2001 to 2004, the global market for wind power capacity grew less than expected (see Section 1.1) and created a surplus in wind turbine production capacity. Consequently, the price of wind power capacity went down dramatically – to as low as €700-800 / kW for some projects. In the four years from 2005 to 2008 the global market for wind turbines increased by 30-40% annually, and demand for wind turbines surged. This, combined with increasing raw material prices up until mid-2008, led to increases in wind farm prices.

The European Commission, in its 'Renewable Energy Roadmap', assumes that onshore wind energy cost €948/kW in 2007 (in €2006 prices). It assumes that costs will drop to €826/kW in 2020 and €788/kW in 2030. That long term cost curve may still apply for a situation where there is a better balance between demand and supply for wind turbines than at present.

For reference, Figure 1.7 shows the European Commission's assumptions on the development of onshore and offshore wind power capacity costs up to 2030. However, this section will use figures for future capacity cost that we believe better reflect the effect of demand and supply on wind turbine prices in recent years, based on the assumptions above, that is onshore wind farm prices starting at €1,300/kW in 2007 (€2006 prices) and offshore prices of €2,300/kW. The steep increase in offshore cost reflects the limited number of manufacturers in the offshore market, the current absence of economies of scale due to low market deployment and bottlenecks in the supply chain.

To estimate the future investments in wind energy, we assume EWEA's reference scenario[6] (180 GW in 2020 and 300 GW in 2030) for installed capacity up to 2030 and wind power capacity prices estimated above, starting with €1,300 / kW in 2007. Figure 1.6 shows the expected annual wind power investments from 2000 to 2030, based on the cost development described. The market is expected to be stable at around €10 billion/year up to 2015, with a gradually increasing share of investments going to offshore. By 2020, the annual market for wind power capacity will have grown to €17 billion annually with approximately half of investments going to offshore. By 2030, annual wind energy investments in EU-27 will reach almost €20 billion with 60% of investments offshore.

FIGURE 1.6: **Wind energy investments 2000-2030 (€ mio)**



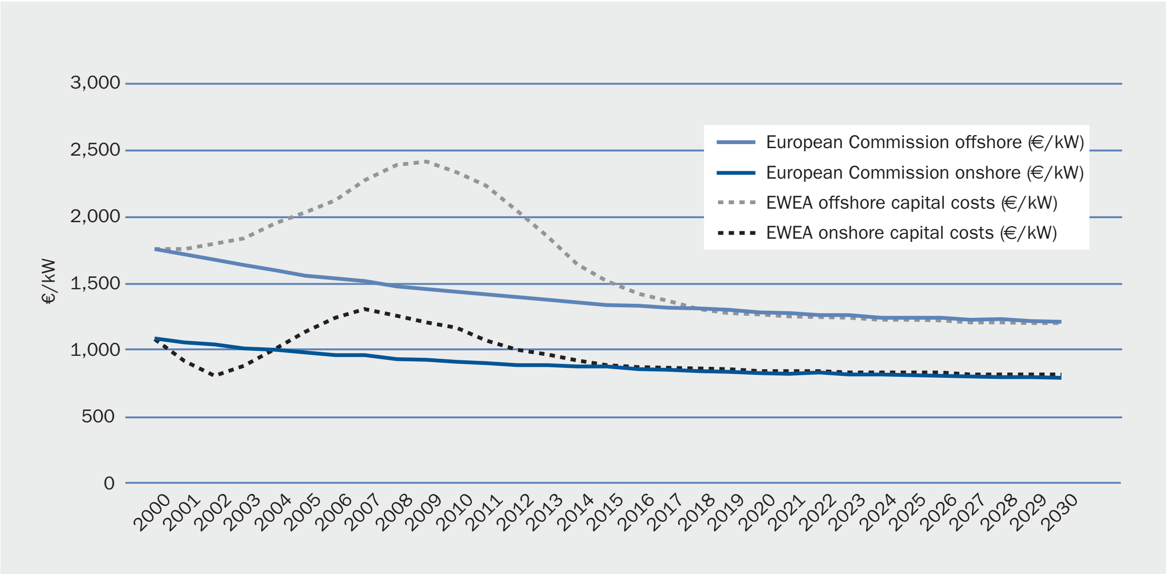
Source EWEA, 2007

[6] This section is based on *Pure Power – Wind Energy Scenarios up to 2030*; European Wind Energy Association, March 2008. www.ewea.org

Cumulative investments in wind energy over the three decades from 2000 to 2030 will total €390 billion. According to EWEA's reference scenario, between 2008 and 2030 approximately €340 billion will be invested in wind energy in the EU-27 - €31 billion in 2008-2010; €120 billion in 2011-2020; and €188 billion in 2021-2030.

The International Energy Agency (IEA, 2008) expects $1,505 billion (€1,150 billion) of investment in electricity generating capacity to be needed for the period 2007 to 2030 in the OECD Europe. According to the EWEA reference scenario, €351 billion – or 31% - of that would be wind power investments[7].

FIGURE 1.7: **Cost of onshore and offshore wind (€/kW) European Commission/EWEA assumptions**



Source EWEA, 2007

[7] Note that the IEA uses "OECD Europe", while this report uses EU-27.

1.4. Wind energy investments and total avoided lifetime cost

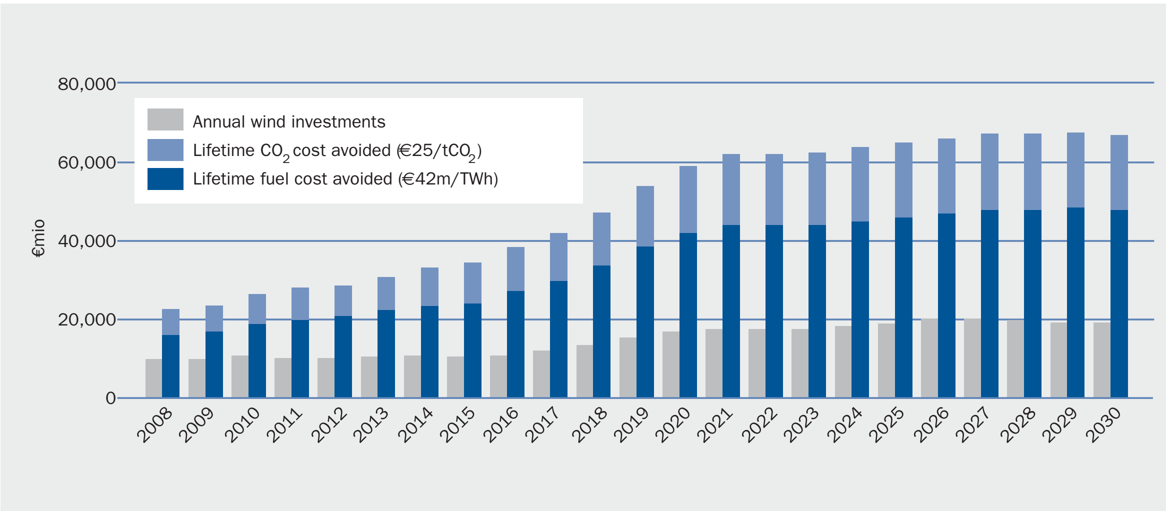
In order to determine how much CO_2 and fuel cost are avoided from wind power investments made in a given year over the entire life-time of the capacity, it is important to remember that investments in wind energy capacity in a given year will continue to avoid fuel cost and carbon cost throughout the 20 to 25 year lifetime of the wind turbines. For example, wind farms installed during the year 2030, will continue to avoid cost up to and beyond 2050.

Figure 1.8 shows the total CO_2 costs and fuel costs avoided during the lifetime of the wind energy capacity installed for each of the years 2008-2030, assuming as per EWEA's reference scenario a technical lifetime for onshore wind turbines of 20 years and for offshore wind turbines of 25 years. Furthermore, it is assumed that wind energy avoids an average of 690 g CO_2/kWh produced; that the average price of a CO_2 allowance is €25/t CO_2 and that €42 million worth of fuel is avoided for each TWh of wind power produced, equivalent to an oil price throughout the period of $90 per barrel.

For example, the 8,554 MW of wind power capacity that was installed in the EU in 2007 had an investment value of €11.3 billion, will avoid CO_2 emissions worth €6.6 billion throughout its lifetime and fuel costs of €16 billion throughout its lifetime, assuming an average CO_2 price of €25/t and average fuel prices (gas, coal and oil) based on $90/barrel of oil.

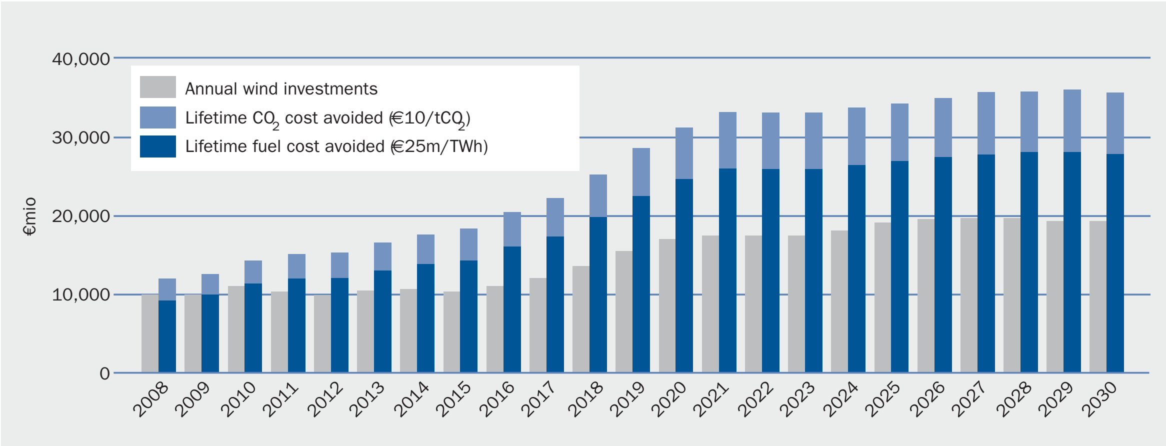
Similarly, the €152 billion of investments in wind power between 2008 and 2020 will avoid €135 billion worth of CO_2 and €328 billion in fuel cost under the same assumptions. For the period up to 2030, wind power investments of €339 billion will avoid €322 billion in CO_2 cost and €783 billion worth of fuel.

FIGURE 1.8: **Wind investments compared with life time avoided fuel and CO_2 costs (Oil – $90/barrel; CO_2 – €25/t)**



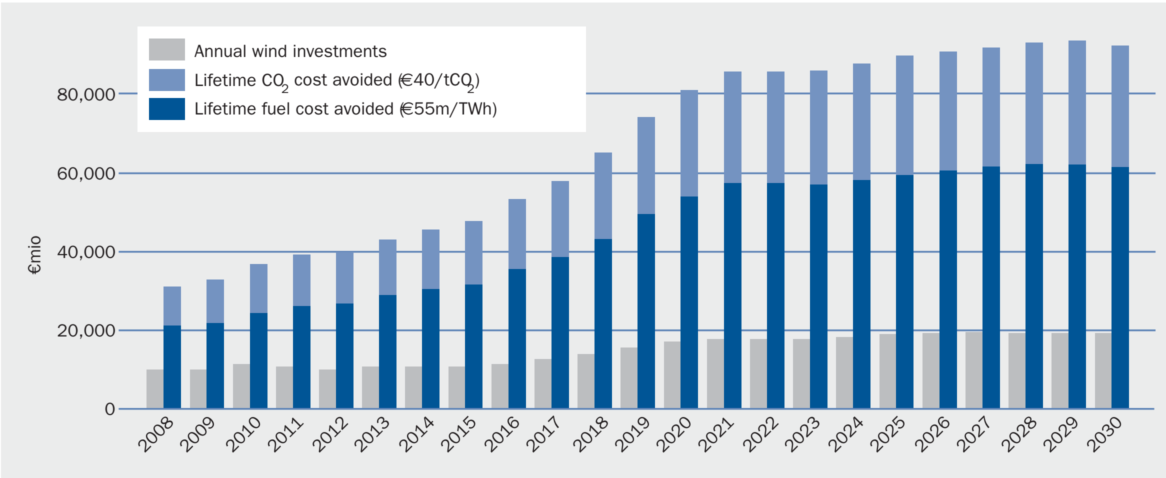
Source EWEA, 2007

FIGURE 1.9: **Wind investments compared with life time avoided fuel and CO_2 costs (Oil – $50/barrel; CO_2 – €10/t)**



Source EWEA, 2007

FIGURE 1.10: **Wind investments compared with life time avoided fuel and CO_2 costs (Oil – $120/barrel; CO_2 – €40/t**



Source EWEA, 2007

It is important to note that these calculations only compare the capital cost of wind energy to avoided CO_2 and fuel cost. The operation and maintenance cost (low because the fuel is free) has not been taken into account. In addition, it would be reasonable to assume that some components of the wind turbine would need replacing during their technical lifetime. This has not been taken into account either. The purpose is to compare the investment value in an individual year with the avoided fuel and CO_2 cost over the lifetime of the wind turbines.

As can be seen from Figures 1.8, 1.9 and 1.10, changing the CO_2 and fuel price assumptions has a dramatic impact on the result. With low CO_2 prices (€10/t) and fuel prices (equivalent of $50/barrel of oil) throughout the period, the wind power investments over the next 23 years avoid €466 billion instead of €783 billion. With high prices for CO_2 (€40/t) and fuel (equivalent to $120/barrel of oil) wind power would avoid fuel and CO_2 costs equal to more than €1 trillion over the three decades from 2000 to 2030.

Figures 1.8-1.10 show the different savings made depending on the price of fuel and CO_2 (per tonne).

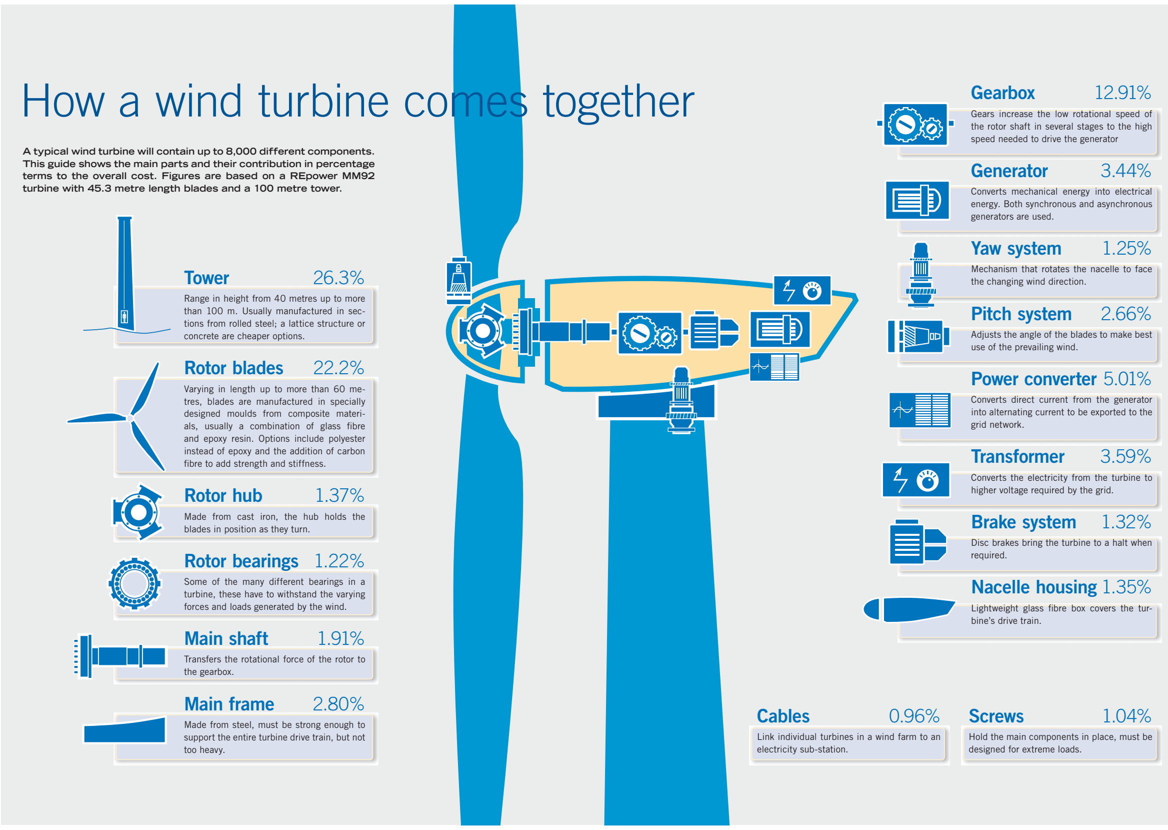
1.4.1 THE WIND TURBINE

Wind turbines, including the costs associated with blades, towers, transportation and installation, constitute the largest cost component of a wind farm, typically accounting for around 75% of the capital cost (see Table 1.2 on page 29).

Wind turbines tend to be type-certified for clearly defined external conditions. This certification is requested by investors and insurance companies, and states that wind turbines will be secure and fit for their purpose for their intended lifetime of around 20 years for onshore projects and 25 years for offshore.

Figure 1.11 illustrates the main sub-components that make up a wind turbine, and their share of total wind turbine cost. Note that the figure refers to a large turbine in the commercial market (5 MW as opposed to the 2 to 3 MW machines that are commonly being installed). The relative weight of the sub-components varies depending on the model.

FIGURE 1.11. **Main components of a wind turbine and their share of the overall turbine cost for a 5 MW wind turbine.**



Source: Wind Directions, January/February 2007

Wind turbines are priced in proportion to their swept rotor surface area and generally speaking in proportion to roughly the square root of their hub height. The size of the generator of a wind turbine plays a fairly minor role in the pricing of a wind turbine, even though the rated power of the generator tends to be fairly proportional to the swept rotor area.

The reason for this is that for a given rotor geometry and a given tip speed ratio,[8] the annual energy yield from a wind turbine in a given wind climate is largely proportional to the rotor area. In relation to tower heights, the production increases with the hub height roughly in proportion to the square root of the hub height (depending on the roughness of the surrounding terrain).[9]

It should be noted that the generator size of a wind turbine is not as important for annual production as the swept rotor area of the turbine. This is because on an optimised wind turbine, the generator will only temporarily be running at rated (peak) power. It is therefore not appropriate to compare wind turbines with other power generation sources purely on the basis of the installed MW of rated generator power.[10] One has to keep in mind that the energy of a wind turbine comes from the swept rotor area of the wind turbine. The swept rotor area is thus in some sense the *field* from which the energy of the wind is harvested.

Wind turbines built for rougher climates, cold temperatures, in deserts or for offshore conditions are generally more expensive than turbines built for more clement climates. In addition, stricter technical requirements from transmission operators in recent years have added to the technology cost.

The sub-sections below explain some of the key features of wind turbines, which allow a better understanding of the level and trend of costs of wind turbines. They refer to the lifetime of the wind turbines onshore and offshore, the continuous increase of the turbine size, improvements in the efficiency of turbines and the cost decreases that have been achieved by m^2 of swept rotor area.

TECHNICAL LIFETIME OF WIND TURBINES

Wind turbines from the leading international wind turbine manufacturers are usually type-certified to withstand the vagaries of a particular local wind climate class safely for 20 years, although they may survive longer, particularly in low-turbulence climates.

Wind conditions at sea are less turbulent than on land, hence offshore sites are type certified to last 25-30 years on offshore sites. In view of the substantially higher installation costs at sea, life extension is a possibility.

Most of the wind turbines that were installed in the 1980s are either still running or were replaced before the end of their technical life due to special repowering incentives. An investor will be very concerned with the pay-back time, that is, how long it takes for a wind turbine to pay back the initial investment. Usually banks and finance institutions require a pay-back of 7-10 years. After the investment is paid off, the cost of producing electricity from wind energy is lower than any other fuel-based technology and, hence, generally lower than the electricity price. The longer the wind turbine runs after the pay-back time the more profitable the investment. As we learned previously, wind energy is a capital intensive technology. Once the investment is covered, the income from selling the electricity only has to be higher than the (very low) O&M cost, for the turbine to keep running.

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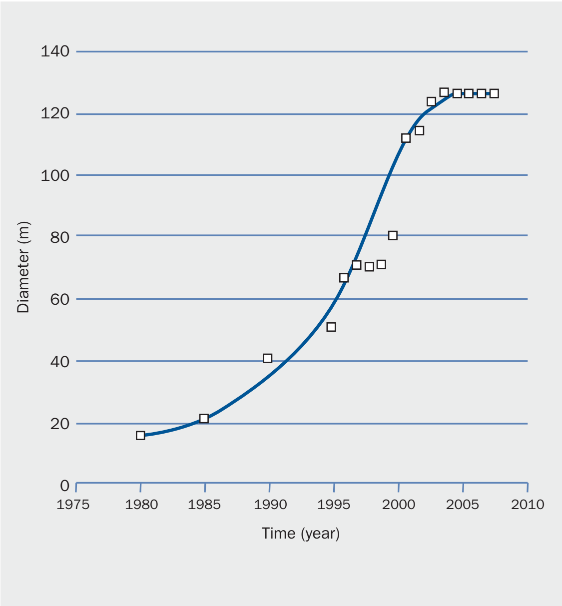
[8] The tip speed ratio is the ratio between the speed of the wing tip and the speed of the wind blowing towards the wind turbine. Turbine owners generally prefer high tip speed ratios in order to increase energy production, but turbine manufacturers limit tip speeds to about 75 m/s to limit noise.

[9] A logarithmic regression analysis of the data for 50 wind turbine models ranging from 150 kW to 2500 kW available on the Danish market from Vestas, Neg-Micon, Bonus and Nordex in September 2001 gives the following result: Annual production in roughness class 1 under Danish standard conditions in kWh/year = 124.33 x A1.0329 x h0.4856, where A is the swept rotor area in m^2 and h is the hub height in m. This equation explains 99.4% of the variation in production between wind turbines. The corresponding equation for price in DKK is = 304.51 x A1.1076 x h0.3107. This equation explains 98.9% of the price variation between wind turbines. Detailed production and price information for the Danish wind turbine market is not available in the public domain after the date mentioned above.

[10] The issue is explained in more detail on Section 1.6.1. on wind turbine capacity factors.

FIGURE 1.11: **Turbine diameter growth with time**



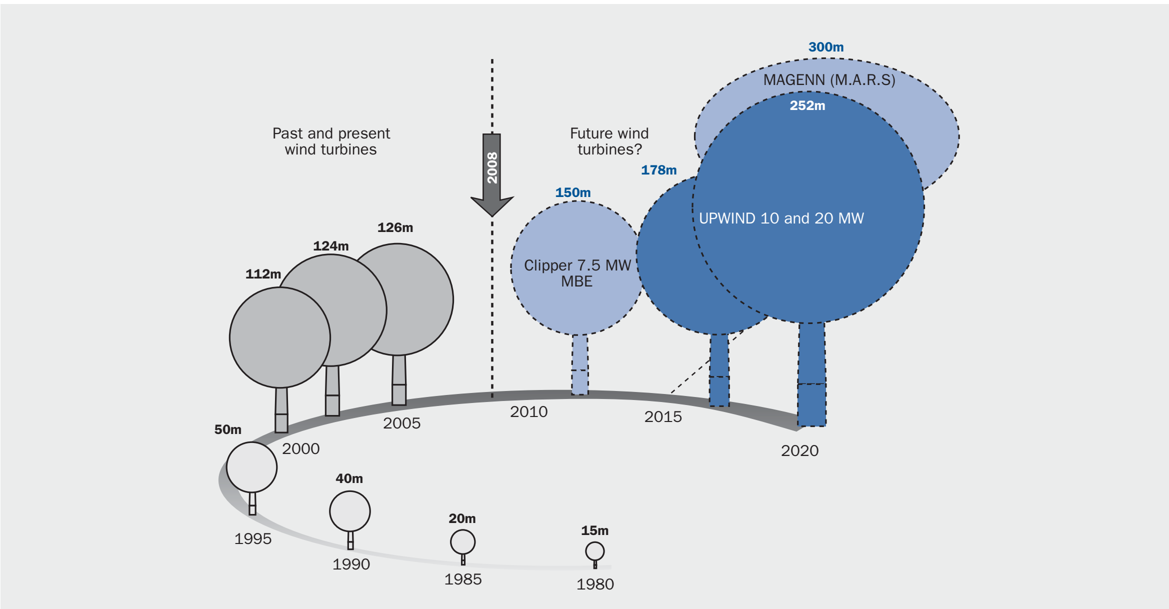
Source Garrad Hassan

INCREASE IN TURBINE SIZE

Figure 1.11 shows trends by year of the typical largest turbine sizes targeted for mainstream commercial production. Megawatt turbines existed in the 1980s but almost all were research prototypes. An exception was the Howden 1 MW design (erected at Richborough in the UK), a production prototype, which was not replicated due to Howden withdrawing from the wind business in 1988. Although there is much more active consideration of larger designs than indicated in Figure 1.11, no larger turbines have appeared since 2004.

Up until around 2000 an ever-increasing (in fact mathematically exponential) growth in turbine size over time had taken place among manufacturers and was a general industry trend. In the past three or four years, although there is still an interest in yet larger turbines for the offshore market, there has been a slowdown in the growth of turbine size at the centre of the main, land-based market and a focus on increased volume supply in the 1.5 to 3 MW range.

FIGURE 1.12: **Growth in size of commercial wind turbine designs,**



Source Garrad Hassan

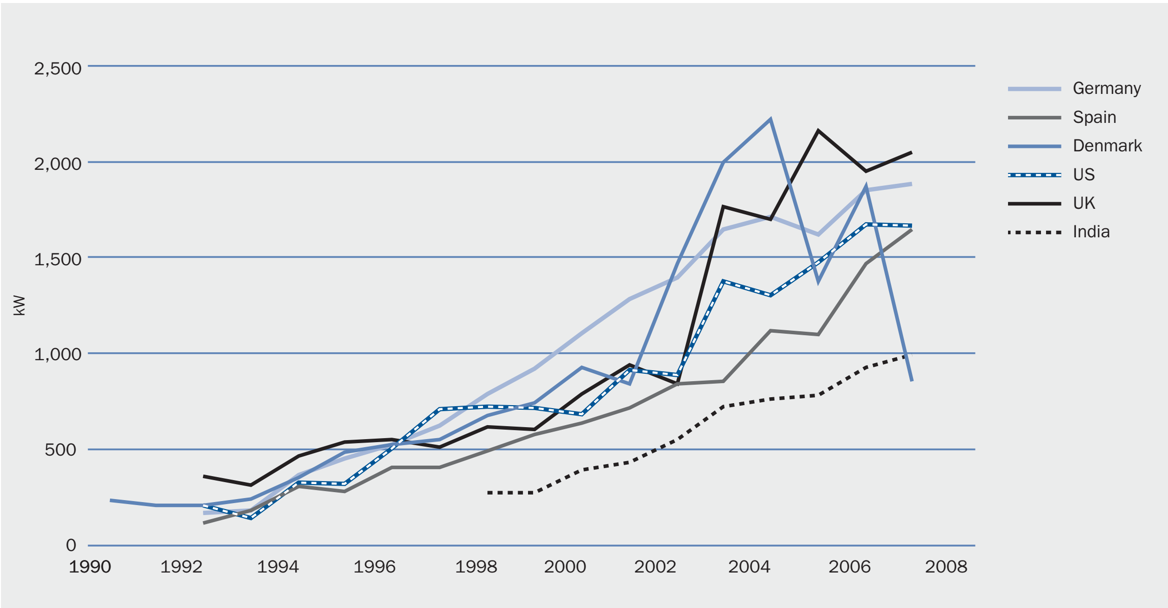
The early small sizes, around 20-60 kW, were very clearly not optimum for system economics. Small wind turbines remain much more expensive per kW installed than large ones, especially if the prime function is to produce grid quality electricity. This is partly because towers need to be higher in proportion to diameter in order to clear obstacles to wind flow and escape the worst conditions of turbulence and wind shear near the surface of the earth. But it is primarily because controls, electrical connection to grid and maintenance are a much higher proportion of the capital value of the system in small turbines than in larger ones.

Onshore technology is now dominated by turbines in the 1.5 and 2 MW range. However, a recent resurgence in the market for turbines of around 800 kW is interesting and it remains unclear, for land-based projects, what objectively is the most cost-effective size of wind turbine. The key factor in continuing quest for size into the multi-megawatt range has been the development of an offshore market. For offshore applications, optimum overall economics, even at higher cost per kW in the units themselves, requires larger turbine units to make up for the proportionally higher costs of infrastructure (foundations, electricity collection and sub-sea transmission) and number of units to access and maintain per kW of installed capacity.

Figure 1.13 shows the development of the average-sized wind turbine for a number of the most important wind power countries. It can be observed that the average size has increased significantly over the last 10-15 years, from approximately 200 kW in 1990 to 2 MW in 2007 in the UK, with Germany, Spain and the USA not far behind.

As shown, there is a significant difference between some countries: in India, the average installed size in 2007 was around 1 MW, considerably lower than in the UK and Germany (2,049 kW and 1,879 kW, respectively). The unstable picture for Denmark in recent years is due to the low level of turbine installations.

FIGURE 1.13: **Development of the average wind turbine size sold in different countries (in KW).**



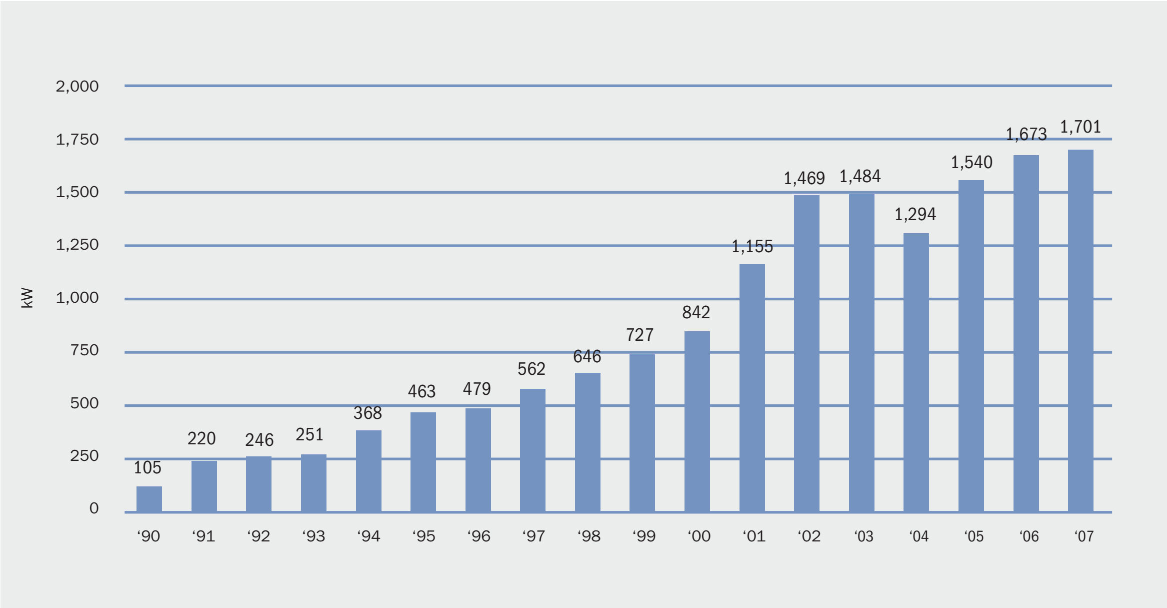
Source: BTM Consult, 2008

In 2007, turbines of the MW-class (with a capacity of over 1 MW) had a market share of more than 95%, leaving less than 5% for the smaller machines. Within the MW-segment, turbines with capacities of 2.5 MW and upwards are becoming increasingly important, even for onshore sites. In 2007, the market share of these large turbines was 6%, compared to only 0.3% at the end of 2003.

5,000 wind turbines were installed in the EU during 2008. That means that, on average, 20 wind turbines were installed for every working day of 2008 in the EU. EWEA estimates that 61,000 wind turbines were operating in the EU by the end of 2008, with an average size of 1,065 kW.

As can be seen from Figure 1.14, the average size of wind turbines installed in a given year in the EU has increased from 105 Kw in 1990 to 1,701 kW in 2007.

FIGURE 1.14: **Average size of wind turbines installed in a given year in the EU (1990-2007)**



Source: BTM Consult, 2008.

IMPROVEMENT IN EFFICIENCY

The development of electricity production efficiency, measured as the annual energy production per square metre of swept rotor area (kWh/m^2) at a specific reference site, has improved significantly in recent years owing to better equipment design.

Taking into account the issues of improved equipment efficiency, improved turbine siting and higher hub height, overall production efficiency has increased by 2-3% annually over the last 15 years.

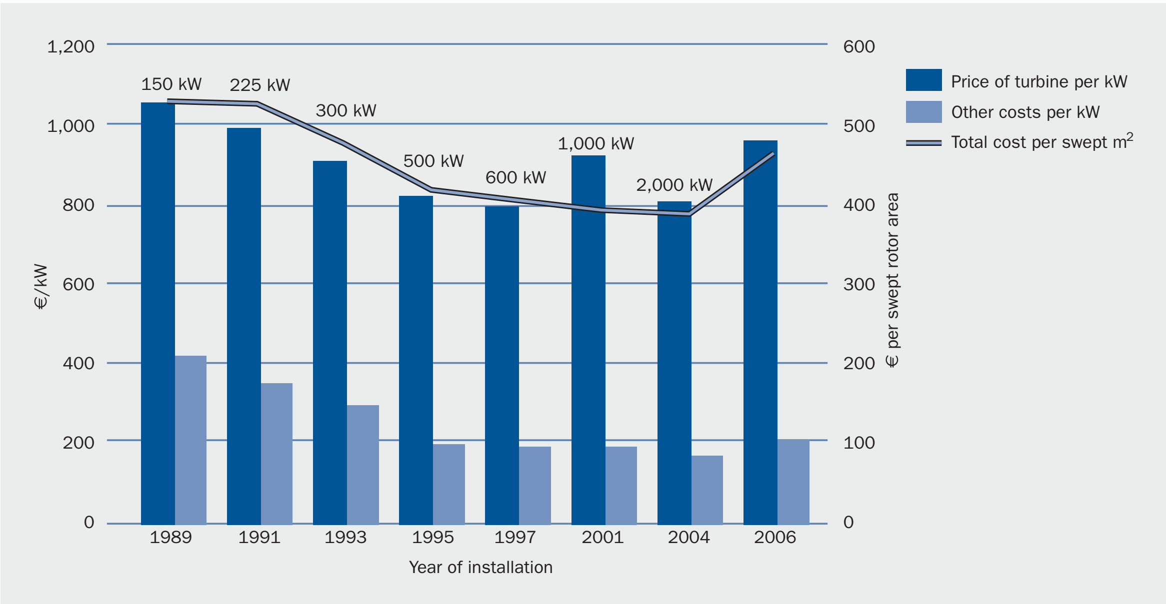
The swept rotor area, as we have already stated, is a better indicator of the production capacity of a wind turbine than the rated power of the generator. Also, the costs of manufacturing large wind turbines are roughly proportional to the swept rotor area. In the context of this paper, this means that when we (correctly) use rotor areas instead of kW installed as a measure of turbine size, we would see somewhat smaller (energy) productivity increases per unit of turbine size and a larger increase in cost effectiveness per kWh produced.

Figure 1.15 shows how these trends have affected investment costs as shown by the case of Denmark, from 1989 to 2006. The data reflects turbines installed in the particular year shown (all costs are converted to €^{2006} prices) and all costs on the right axis are calculated per square metre of swept rotor area, while those on the left axis are calculated per kW of rated capacity.

The number of square metres covered by the turbine's rotor – the swept rotor area - is a good indicator of the turbine's power production, so this measure is a relevant index for the development in costs per kWh. As shown in Figure 1.15, there was a substantial decline in costs per unit of swept rotor area in the period under consideration, except during 2006. So from the late 1990s until 2004, overall investments per unit of swept rotor area dropped by more than 2% per annum, corresponding to a total reduction in cost of almost 30% over the 15 years. But this trend was broken in 2006, when total investment costs rose by approximately 20% compared to 2004, mainly due to a significant increase in demand for wind turbines, combined with rising commodity prices and supply constraints. Staggering global growth in demand for wind turbines of 30-40% annually, combined with rapidly rising prices of commodities such as steel, kept wind turbine prices high in the period 2006-2008.

Looking at the cost per rated capacity (per kW), the same decline is found in the period from 1989 to 2004, with the exception of the 1,000 kW machine in

FIGURE 1.15: **The development of investment costs from 1989 to 2006, illustrated by the case of Denmark.**



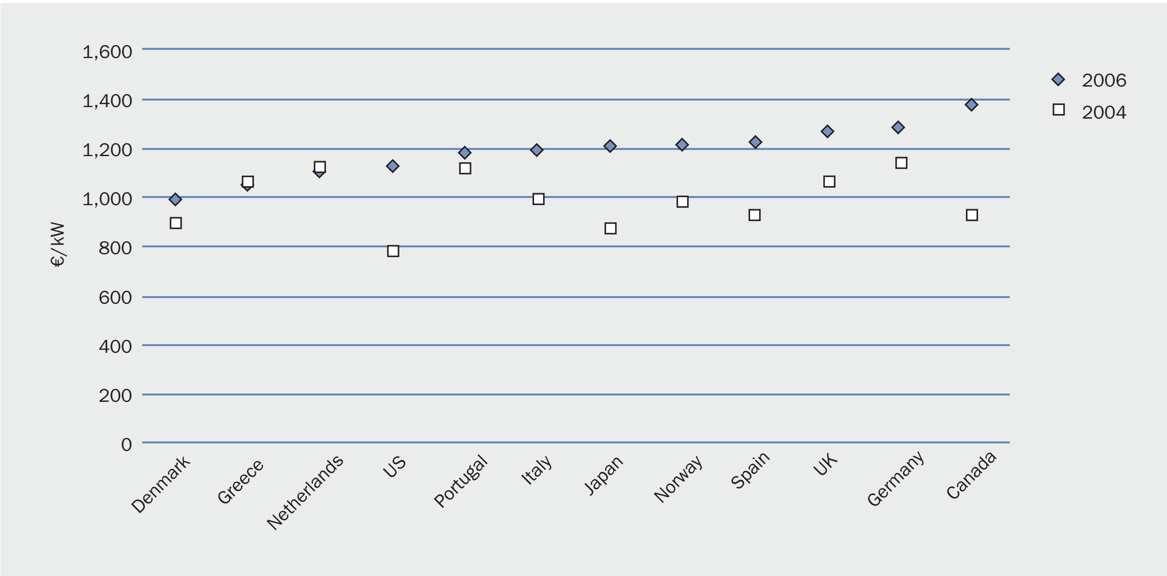
Right axis: Investment costs divided by swept rotor area (€/m^2 in constant 2006 €). Left axis: Wind turbine capital costs (ex works) and other costs per kW rated power (€/kW in constant 2006 €).

Source: Risø DTU

2001. The cause is related to the size of this specific turbine; with higher hub heights and larger rotor diameters; the turbine is equipped with a slightly smaller generator, although it produces more electricity. This fact is particularly important when analysing turbines built specifically for low and medium wind areas, where the rotor diameter is considerably larger in comparison to the rated capacity. As shown in Figure 1.15, the cost per kW installed also rose by 20% in 2006 compared to 2004.

The recent increase in turbine prices is a global phenomenon, which stems mainly from a strong and increasing demand for wind power in many countries, as well as constraints on the supply side (not only related to turbine manufacturers but also resulting from a deficit in sub-supplier production capacity of wind turbine components, caused by the staggering increase in demand) and rising raw material cost. The general price increases for newly installed wind turbines in a number of selected countries are shown in Figure 1.16. There are significant differences between individual countries, with price increases ranging from almost none to a rise of more than 40% in the US and Canada. Towards the end of 2008, market intelligence suggested a reversal to continued cost reductions in wind farm projects, mainly as a result of a large decrease in the cost of raw materials.

FIGURE 1.16: **The increase in turbine prices from 2004 to 2006 for a selected number of countries.**



Source: IEA, 2007

1.4.2 WIND TURBINE INSTALLATION AND OTHER UPFRONT COSTS

The costs of wind turbine installation include notably:

- Foundations
- Road construction
- Underground cabling within the wind farm
- Low to medium voltage transformers
- medium to high voltage substation (sometimes)
- Transport, craning
- Assembly and test
- Administrative, financing and legal costs

As mentioned, these cost elements typically account for some 16%-32% of total investments in a wind project. The geography in terms of site accessibility and the geotechnical conditions on the site of the wind farm obviously plays a crucial role in determining the cost of road construction, cabling and so on.

Generally speaking, there are *economies of scale* in the construction of wind farms, both in terms of the *total size of the wind farms* (the number of turbines sharing a common substation and sharing development and construction costs) – and in terms of the size of turbines. Larger turbines generally have comparatively lower installation costs per swept rotor areas, and the cost of a number of wind turbine components such as electronic controllers, foundations and so on varies *less than proportionately with the size of the wind turbine.*

ELECTRICAL GRID CONNECTION

Large wind farms are generally connected to the high voltage electrical transmission grid (usually 60 kV and above), whereas individual wind turbines or clusters of turbines are generally connected to the distribution grid (8-30 kV). If the local grid is already saturated with other electrical equipment, there may be the additional costs of upgrading the grid to accommodate the wind turbines.

Our discussion of costs assumes that the wind turbines are connected to the distribution voltage grid (8-30 kV) through low to medium voltage transformers. In some jurisdictions, the wind turbine owner pays this part of grid connection costs, in other they are socialised and paid by the transmission company. The remaining cost items related to grid connection will be discussed in Chapter 3.

OTHER PROJECT DEVELOPMENT AND PLANNING COSTS

Development costs for wind farms may be quite high in some jurisdictions due to stringent requirements for environmental impact assessments, for example, which quite often are more costly than, say, wind resource mapping. As Chapter 2 will discuss, the institutional setting, notably spatial planning and public permitting practices, has a significant impact on costs (also on whether or not the wind farm is built), but even in the most favourable cases they can range between 5 to 10% of the total. To give an example, if there is administrative or regulatory uncertainty or a vast number of agencies involved, any of which factors may ultimately derail a project, wind developers may have to undertake development costs for several alternative sites in order to be able to have a single project succeed.

Generally speaking there is a *learning curve* for each jurisdiction in which wind projects are developed. This is because early projects are often very time-consuming to establish, and it usually takes several years to adapt regulatory and administrative systems to deal with these new challenges. Grid connection procedures or multi-level spatial planning permission procedures tend to be both inefficient and unnecessarily costly in new wind energy markets. In many jurisdictions there is consequently a substantial potential for productivity increases for wind energy by adapting regulatory and administrative systems to wind power development. Experience from some of the developed markets suggests that this *administrative learning curve* is quite steep for the first 1,000 MW installed in a country. Hence, it can take many years – even decades – to install the first 1,000 MW in a particular jurisdiction. Once authorities and grid operators have the experience and are used to the procedures, development can happen very fast. As of December 2008, ten EU Member States had more than 1,000 MW of installed wind energy capacity.

1.5 Variable costs

1.5.1 OPERATION AND MAINTENANCE COSTS (O&M) AND OTHER VARIABLE COSTS

Wind turbines – like any other industrial equipment – require service and maintenance (known as operation and maintenance, or O&M), which constitute a sizeable share of the total annual costs of a wind turbine. However, compared to most other power generating costs, they are very low. In addition, other variable costs (for example, related to the energy output) have to be included in the analysis.

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

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

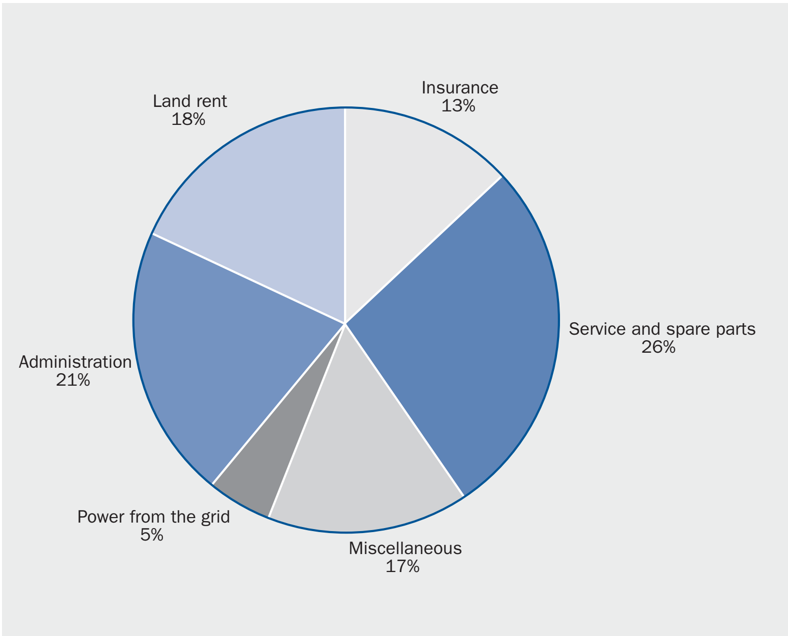
Some of these cost components can be estimated relatively easily. For insurance and regular maintenance, it is possible to obtain standard contracts covering a considerable share of the wind turbine's total lifetime. Conversely, costs for repair and related spare parts are much more difficult to predict. And although all cost components tend to increase as the turbine gets older, costs for repair and spare parts are particularly influenced by turbine age, starting low and increasing over time.

Due to the relative infancy of the wind energy industry, there are only a limited number of turbines that have reached their life expectancy of 20 years. These turbines are much smaller than those currently available on the market and, to a certain extent, the design standards were more conservative in the beginning of the industrial development, though less stringent than they are today. Estimates of O&M costs are still uncertain, especially around the end of a turbine's lifetime; nevertheless a certain amount of experience can be drawn from existing, older turbines.

Based on experiences in Germany, Spain, the UK and Denmark, O&M costs are generally estimated to be around 1.2 to 1.5 eurocents (c€) per kWh of wind power produced over the total lifetime of a turbine. Spanish data indicates that less than 60% of this amount goes strictly to the O&M of the turbine and installations, with the rest equally distributed between labour costs and spare parts. The remaining 40% is split equally between insurance, land rental and overheads.

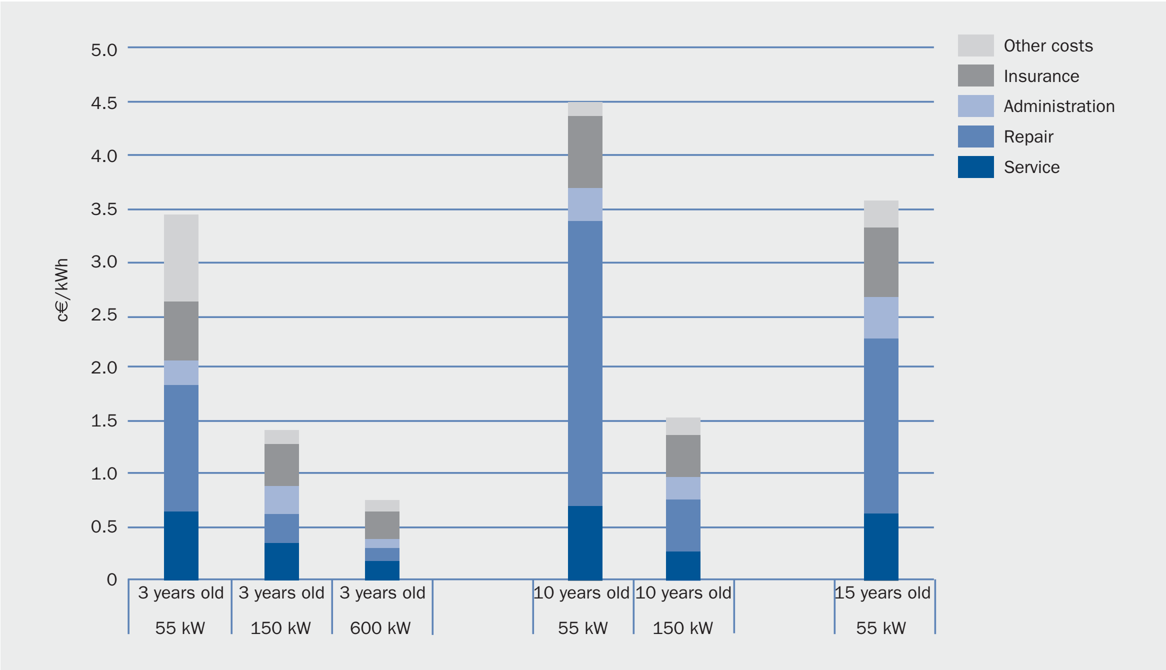
Figure 1.16 shows how total O&M costs for the period between 1997 and 2001 were split into six different categories, based on German data from DEWI. Expenses pertaining to buying power from the grid and land rental (as in Spain) are included in the O&M costs calculated for Germany. For the first two years of its lifetime, a turbine is usually covered by the manufacturer's warranty, so in the German study O&M costs made up a small percentage (2-3%) of total investment costs for these two years, corresponding to approximately 0.3-0.4 c€ /kWh. After six years, the total O&M costs increased, constituting slightly less than 5% of total investment costs, which is equivalent to around 0.6-0.7 c€/kWh. These figures are fairly similar to the O&M costs calculated for newer Danish turbines (see below).

FIGURE 1.16: **Different categories of O&M costs for German turbines, averaged for 1997-2001**



Source: DEWI

FIGURE 1.17: **O&M costs as reported for selected types and ages of turbines (c€/kWh)**



Source: Jensen et al. (2002)

Figure 1.17 shows the total O&M costs resulting from a Danish study, and how these are distributed between the different O&M categories, depending on the type, size and age of the turbine. So, for a three-year-old 600 kW machine, which was fairly well represented in the study, approximately 35% of total O&M costs covered insurance, 28% regular servicing, 11% administration, 12% repairs and spare parts, and 14% other purposes. In general, the study revealed that expenses for insurance, regular servicing and administration were fairly stable over time, while the costs for repairs and spare parts fluctuated considerably. In most cases, other costs were of minor importance.

Figure 1.17 also shows the trend towards lower O&M costs for new and larger machines. So, for a three year old turbine, the O&M costs decreased from around 3.5 c€/kWh; for the old 55 kW turbines, to less than 1 c€/kWh for the newer 600 kW machines. The figures for the 150 kW turbines are similar to the O&M costs identified in the three countries mentioned above.

With regard to the future development of O&M costs, care must be taken in interpreting the results of Figure 1.17. Firstly, as wind turbines 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 be related, to a certain extent, to turbine up-scaling. Secondly, the newer and larger turbines are better aligned with dimensioning criteria than older models, implying reduced lifetime O&M requirements.

Based on a Danish survey, time series for O&M-cost components have been established going back to the early 1980s. Relevant O&M costs were defined to include potential reinvestments (such as replacing turbine blades or gears). Due to the industry's evolution towards larger turbines, O&M cost data for old turbines exist only for relatively small units, while data for the younger turbines are concentrated on larger units. In principle the same sample (cohort) of turbines should have been followed throughout the successive sampling years. However, due to the entrance of new turbines, the scrapping of older ones, and the general uncertainty of the statistics, the turbine sample is not constant over the years, particularly for the larger turbines. Some of the major results are shown in

Figure 1.18 below, which clearly shows that O&M costs increase with the age of the turbine.

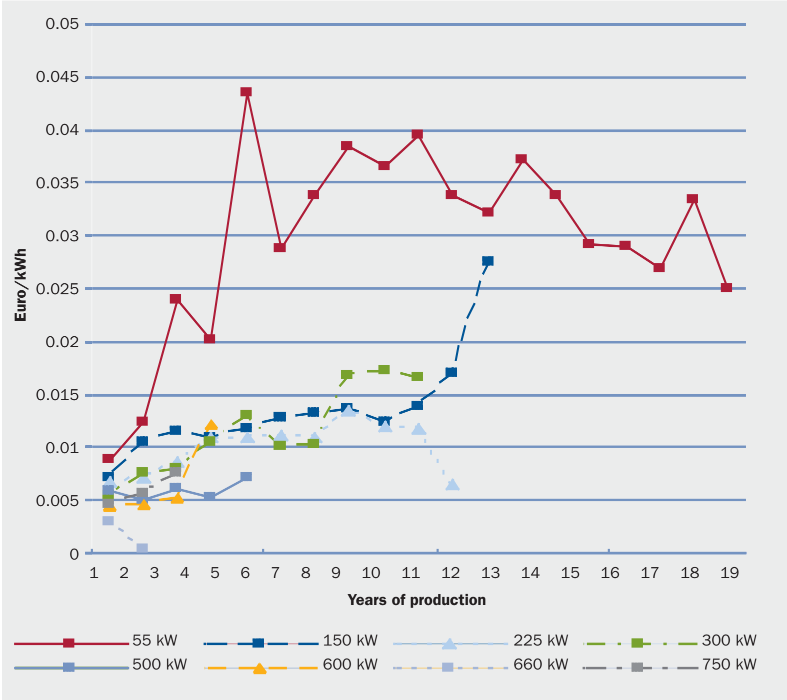
The figure illustrates the development in O&M costs for selected sizes and types of turbines since the beginning of the 1980s. The horizontal axis shows the age of the turbine while the vertical axis measures the total O&M costs stated in constant €1999. We may observe that the 55 kW turbines now have a track record of close to 20 years, implying that the first serial-produced wind turbines now are coming close to their technological design lifetime. The picture for the 55 kW machine is very scattered, showing rapidly increasing O&M-costs right from the start, reaching a fairly high but stable level of approximately 3-4 c€/kWh after five years.

Furthermore, Figure 1.18 shows that the O&M costs decrease for newer and larger turbines. The observed strong increase for the 150 kW turbine after ten years represents only a very few turbines, and therefore at present it is not known if this increase is representative for 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 to see is that for the first 11 years, the 225 kW machine has O&M costs of around 1-1.3 c€/kWh, closely in line with the estimated O&M costs in Germany, Spain, the UK and Denmark.

Thus, the development of O&M costs appears to correlate closely with the age of the turbines. During the first few years the warranty[11] of the turbine implies a low level of O&M expenses for the owner. After the 10th year, larger repairs and reinvestments may begin to appear, and from the experiences of the 55 kW machine these are in fact the dominant O&M costs during the last ten years of the turbine's life.

However, with regard to the future development of variable (notably O&M) costs we must be careful when interpreting the results of Figure 1.18. First, as wind turbines exhibit economies of scale in terms of declining investment 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 the up-scaling of turbines.

FIGURE 1.18: **O&M costs reported for selected sizes and types of wind turbines (c€/kWh)**



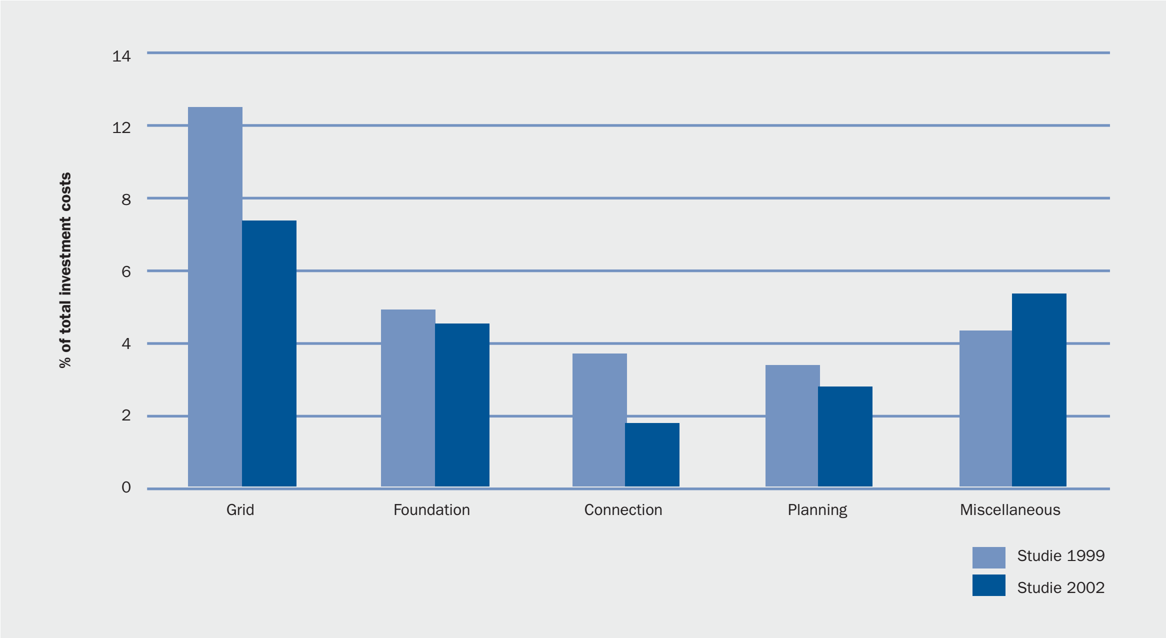
Source: Jensen et al. (2002)

Second, the newer and larger turbines are more optimised with regard to dimensioning criteria than the old ones, implying that lower lifetime O&M requirements are expected for them than for the older, smaller turbines. But this in turn might have an adverse effect, in that these newer turbines may not be as robust in the face of unexpected events as the old ones.

In Germany the development of additional costs has been further investigated in a survey carried out by DEWI, looking at the actual costs for wind turbines installed in 1999 and 2001 (Figure 1.19). As can be seen from the figure, all the additional cost components tend to decrease over time as a share of total wind turbine costs with only one exception. The increase in the share of miscellaneous costs is mostly on account of increasing prefeasibility development 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.

[11] In the Danish study only the costs that are 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.

FIGURE 1.19: **Development of additional costs (grid-connection, foundation, etc.) as a percentage of total investment costs for German turbines**



Source: Dewi, 2002

Nevertheless, following this line of reasoning is can be expected that the O&M cost percentage for a 10-15 year-old 1,000 kW turbine will not rise to the level seen today for a 55 kW turbine of the same age. It is more likely that the O&M cost for newer turbines will be significantly lower than those experienced until now, judging by the 55 kW turbine. But how much lower the future O&M costs will be will also depend on whether the size of the turbines continues to increase.

1.5.2.LAND RENT

A developer of a wind farm has to compensate land owners for siting a wind turbine on their land which can be used for other purposes, such as farming. Generally speaking this cost is quite small, since wind farms usually only use about 1-2% of the land area of a wind farm for installation of turbines, transformers and access roads. This rental cost of land may either be included in the O&M costs of a wind farm or capitalised as an up front payment once and for all to the landowner.

If the amount paid to a landowner for locating a wind turbine on his terrain exceeds the value of the agricultural land (and the inconvenience of having to take account of the turbines and roads when farming the land), then economists refer to the excess payment as land rent.

Such payments of rent may accrue to landowners, who own areas with particularly high wind speeds, which are close to transmission lines and roads. In that case the landowner may be able to appropriate part of the profits of the wind turbine owner (through a bargaining process).

Land rent is not considered a cost in socioeconomic terms, but is considered a transfer of income, that is to say a redistribution of profits, since the rent can obviously only be earned if the profits on that particular terrain exceed the normal profits required by an investor to undertake a project. When calculating the generating cost of electricity from wind it is therefore not correct to include land rent in the socioeconomic generating cost, but it should be considered part of the profits of the project. (However, it is correct to include the inconvenience costs of using the agricultural land).

1.6. Wind resource and power generation

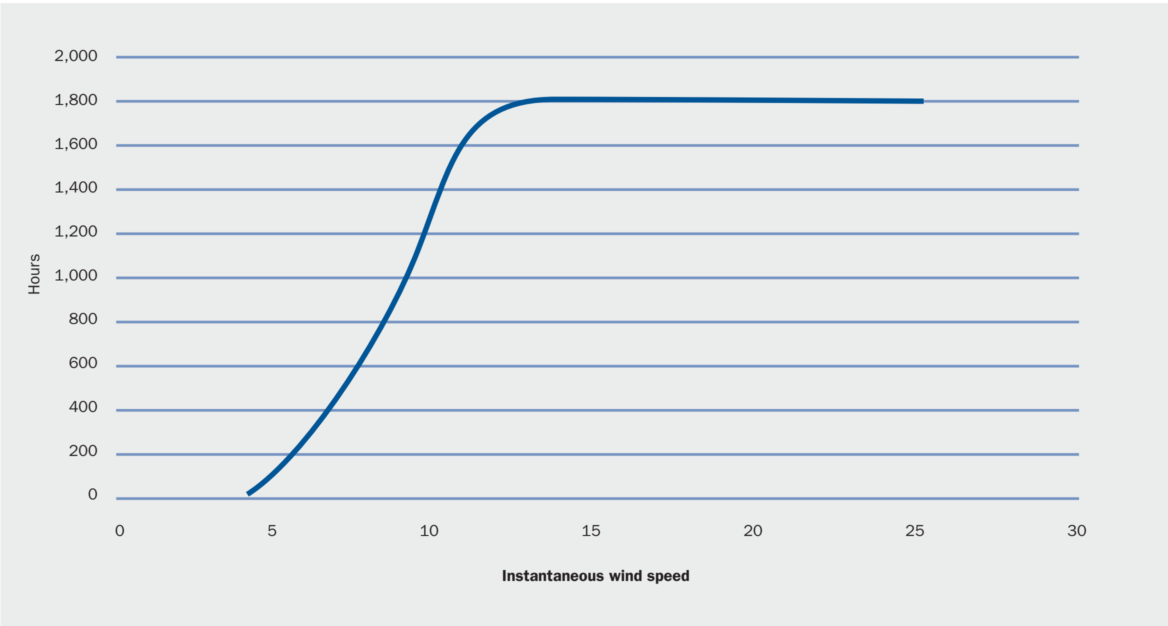
1.6.1. WIND SPEEDS AND WIND POWER GENERATION – A PRIMER

Wind is an extractive industry, that is to say a wind turbine extracts part of the kinetic energy of the wind blowing through the swept surface area of a wind turbine rotor. The amount of energy that can be harvested at a given location depends on the local wind climate. The local wind climate tends to be relatively constant over time. In other words, the energy content of the wind tends to vary less from year to year than, say, agricultural production. Typically, inter-annual wind energy production from a turbine varies with a standard deviation of around 10% of mean energy.

The energy in the wind varies with the third power of the wind speed; hence a doubling of the wind speed gives an eightfold increase in the available energy in the wind. In practice, wind turbines are not equally efficient at all wind speeds, and wind turbines have a generator of a finite size.

Wind turbines are usually optimised to extract the maximum share of the energy at wind speeds of around 8 m/s. Turbines are built to ensure that when the electricity output approaches the rated power of the generator, the turbine automatically limits the power input from the rotor blades, so that at high wind speeds it will produce at exactly the rated power of the generator. This feature is called *power control*.[12]

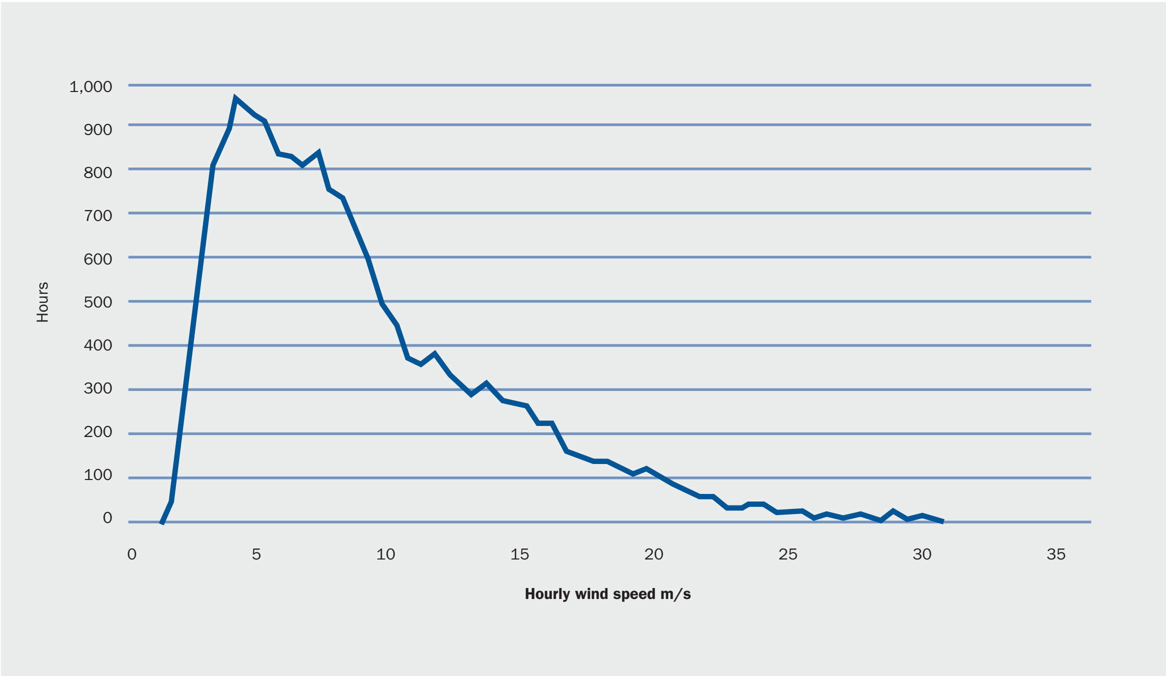
FIGURE 1.20: **Power curve for wind turbine**



Source: Dewi, 2002

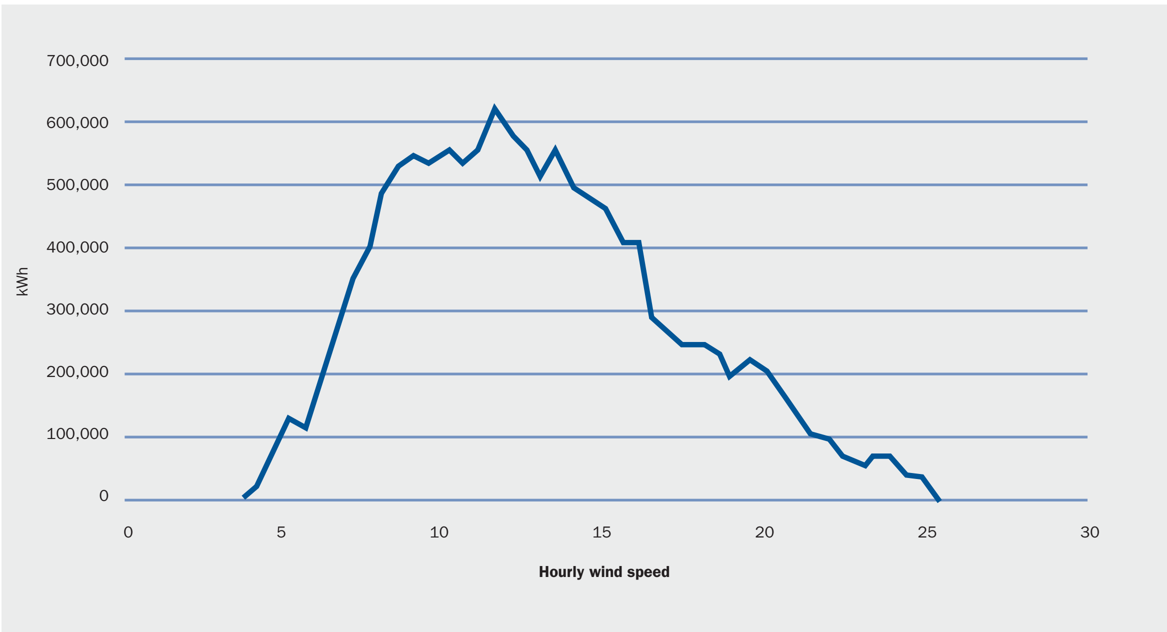
[12] Power control is automatic, but the power output from wind farms as well as ramping rates can be curtailed remotely by the operator of the electrical transmission grid (the TSO) in some jurisdictions.

FIGURE 1.21: **Frequency of different wind speeds at typical wind farm site**



Source: Dewi, 2002

FIGURE 1.22: **Energy produced at various wind speeds at typical site**



Source: Dewi, 2002

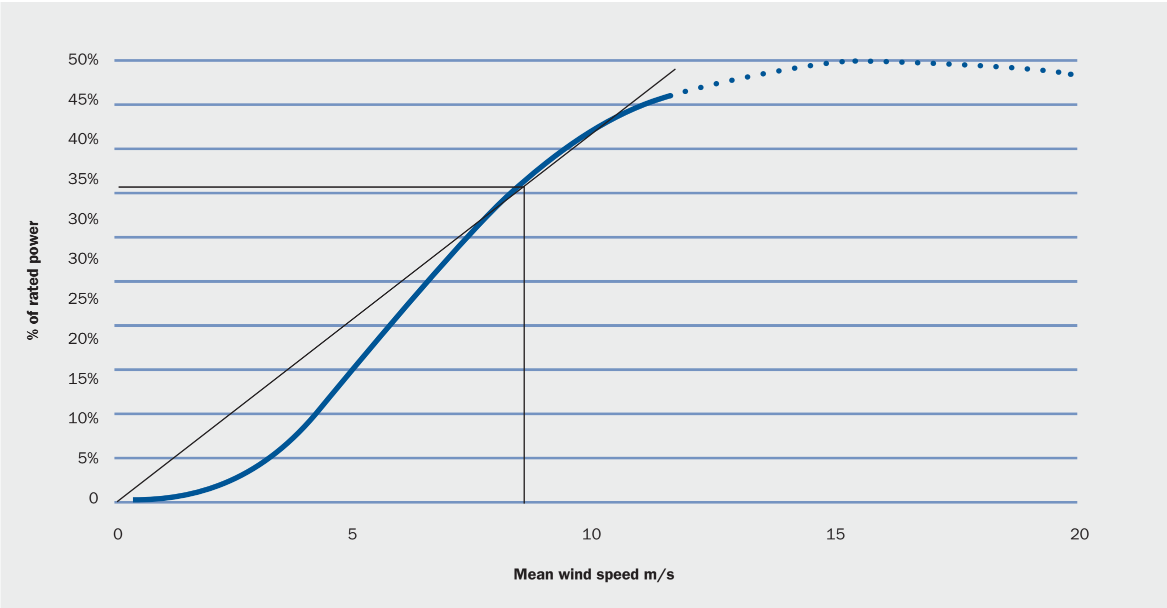
Figure 1.20 shows us a *power curve* for a 1.8 MW wind turbine. The *power curve* tells us how much power the turbine will produce for each instantaneous wind speed.[13]

The power curve does *not* tell us the annual wind energy production of a wind turbine. In order to find that, we would also have to know the number of hours per year during which the wind turbine will be encountering each different instantaneous wind speed.

Wind speeds at a given site fluctuate, and they are unevenly distributed as shown in the second graph (Figure 1.21) from a typical wind turbine site. Most of the time there are weak winds and occasionally there are strong winds. As this graph shows, about 14% of the time the wind is too weak to make the wind turbine produce any energy (below 4 m/s), and roughly 60% of the time it is below the mean wind speed at the wind turbine hub height. Only rarely will the turbine produce at the rated power of the generator.[14] With the power curve we showed previously this only occurs at wind speeds between 13.5 m/s and 25 m/s. This means that in this case the turbine will produce the maximum rated power of the generator 18% of the time. At wind speeds of above 25 m/s the turbine stops to protect itself and its surroundings from potential damage.

If we wish to know how much energy is produced at various wind speeds during a certain time interval, we multiply the number of hours at each wind speed with the power from our power curve, that is to say, we use the data from the two previous graphs to obtain Figure 1.22.

FIGURE 1.23: **Capacity factor in % of rated power**



Source: Dewi, 2002

[13] The exact power curve depends on the particular wind turbine model and is generally published for a standard temperature of 15°C and 10% turbulence intensity. If the weather is cold (high air density) the turbine will have a slightly higher output at all wind speeds. If there is high turbulence intensity (that is, very rapid shifts in wind speed and direction, typically in rugged terrain) power output will be lower at all wind speeds.

[14] The fact that wind turbines rarely run at full generator capacity is not a design problem. On the contrary, wind turbines are equipped with fairly large generators in order to take advantage of high winds when they occur – even if it is a fairly rare occurrence. It is efficient to design wind turbines this way, because the additional cost of a larger generator is fairly small. In this sense, wind turbines always have 'oversized' generators. This means that they are deliberately designed to be running with rather low *capacity factors*, as we explain later.

We can see from the graph that usually about half of the annual energy production will occur at wind speeds of above 1.5 times the mean wind speed of the site. These hours account for some 21% of the hours of the year in this typical example.

In any case, the local wind climate is the most important factor in determining the cost of wind energy.[(15)] In order to be cost-effective, each individual turbine has to be sited very carefully, taking account of not just local wind climate measurements, but also of nearby *obstacles* to the wind, such as woodland and buildings. Also, the roughness and ruggedness of the landscape play an important role in determining local wind speeds. Likewise the *orography* - that is, the varied curvature of the terrain surface - is essential. Generally speaking, wind turbines on rounded hilltops will produce more electricity than turbines located in valleys or rugged terrain, and turbines at sea or close to a shore will produce more energy than turbines located inland.

As mentioned above, we cannot determine the annual wind energy output from the power curve alone, we also have to know the distribution of different wind speeds as we showed in Figure 1.21 above. The key factor determining annual energy production is the mean wind speed at the hub height of the wind turbine rotor. The statistical distribution of wind speeds around the mean wind speed plays a somewhat minor role in determining annual wind energy production.

The next graph (Figure 1.23) shows the hypothetical annual wind energy production from a wind turbine located at various sites in the neighbourhood of the location, where we measured the wind speed at hub height for the graph in Figure 1.21. Each wind turbine location will have a different mean annual wind speed depending on the number and size of the wind obstacles in the neighbourhood and the roughness of the surrounding terrain - whether we have a smooth water surface in the predominating wind direction, which slows down the wind very little, or whether we have dense woodland or a cityscape, which will slow down the wind much more.

At the site in our example, with a mean annual wind speed of 8.4 m/s, a typical 1.8 MW wind turbine will on average be producing 5.6 GWh of electrical energy per year, corresponding to on average 35.5% of its rated power.[(16)]

The final part of the curve is irrelevant, since there are hardly any sites in the world with mean wind speeds of, say 12 m/s. The reason why capacity factors for wind turbines will never reach 50% is that with extremely high mean wind speeds and the characteristic distribution of wind speed frequencies we saw in Figure Y above, the wind turbines will frequently stop due to winds which exceed the *cut-out wind speed* of the wind turbine.[(17)]

---

(15) The term *wind climate* includes not just wind speeds, but also *turbulence intensity, wind shear* (i.e. the difference in wind speeds between the lower and upper part of the rotor surface) and *extreme winds and gusts*. The final three elements have a very important impact on the tear and wear on a wind turbine structure, (fatigue loads and extreme loads), and thus on the expected lifetime of a wind turbine. Turbines designed for harsh climates (frequently found in rugged, mountainous areas) have to be built to more demanding design criteria, and are more costly than turbines built for relatively steady, laminar wind flows such as they occur above water surfaces or smooth or gently rolling terrain.

(16) We have subtracted 14% energy loses from the theoretical figure obtained from the power curve of the wind turbine, as explained in the next section.

(17) The cut-out wind speed is usually set at 25 m/s in order to protect the turbine and its surroundings.

Another interesting aspect of Figure 1.23 can be seen by looking at how the curve for the capacity factor almost coincides with the line drawn from the origin in the graph, when we look at the typical mean wind speeds at hub height of 7-10 m/s. This implies that within a typical wind climate, annual production of wind farms will be roughly proportional to the mean wind speed at the site. [18] The issue of capacity factors for wind turbines is discussed in more detail in the next section.

Given a known statistical distribution of wind speeds at a site, the mean annual wind energy production is generally highly predictable, with a small margin of error of around 5% at the point of measurement. There may be greater uncertainty in cases where wind turbines are located in so-called *complex terrain*. In that case it is more difficult to extrapolate wind speeds from a single or a few anemometer masts to the wind turbines on the site.[19] If measurements were made by a third party there may be additional uncertainty surrounding the quality of measurements, including whether high quality, well calibrated anemometers were used and properly mounted, and whether the complexity of the surrounding terrain, roughness characteristics and wind obstacles were adequately taken into account.

1.6.2. UNDERSTANDING WIND CAPACITY FACTORS: WHY BIGGER IS NOT ALWAYS BETTER

The *capacity factor* of a wind turbine or another electricity generating plant is the amount of energy delivered during a year divided by the amount of energy that would have been generated if the generator were running at maximum power output throughout all the 8,760 hours of a year.[20]

The wind turbine we used in our examples in Section 1.6.1. is technically and economically optimised for use on typical wind turbine sites, yet many people are very concerned that typical capacity factors for wind turbines are 'only' around 20-35%, compared to capacity factor around 60% for some other forms of power generation.

In general it is of course an advantage to place wind turbines on very windy sites in order to obtain low costs per kWh of energy produced. But in this section we will explain why it is not an aim in itself of the wind industry to obtain higher capacity factors for wind turbines.

Wind turbines are built to extract the kinetic energy of the wind and convert it into electricity. The key design criterion for designers of large grid-connected wind turbines is to *minimise the cost per kWh of energy output* from wind turbines, given the local climate, energy transport and policy constraints imposed by nature, power grid availability and regulators.

It is not important to maximise the amount of energy extracted from the flow of zero-cost kinetic energy moving though a given rotor surface area. Since the wind is free, it is not important to draw more or less energy out of it. In theory, if we could capture 1% more of the energy in the wind through a different rotor blade design for example, a wind turbine designer would only do so if this would add less than 1% to the cost of operating the turbine throughout its lifetime. Conversely, a turbine designer could easily sell a design change that would lower the technical efficiency of the turbine by 1% if the lifetime cost savings exceeded 1%.

[18] The fact that the energy of the wind varies with the third power of the wind speed, and that the relationship between the instantaneous wind speed and power production is described by the generally very steep power curve gives rise to much confusion among non-professionals, who debate wind energy. They tend to miss the point, that one cannot discuss annual wind energy production without also taking the very skewed distribution of wind speeds into account, as we did above. In the debate one therefore sometimes sees that people believe that 10% additional mean wind speed will give an additional 30% of energy. That is untrue. In our typical wind climate used in the example, 10% additional mean annual wind speed gives us some 10.5% of additional annual energy output.

[19] Complex terrain means any site where terrain effects on meteorological measurements may be significant. Without being exhaustive, terrain effects include: steep terrain where excessive flow separation occurs, aerodynamic wakes, density-driven slope flows, channelling and flow acceleration over the crest of terrain features.

[20] Sometimes the same concept is explained by calculating the number of 'full load hours' per year, i.e. the number of hours during one year during which the turbine would have to run at full power in order to produce the energy delivered throughout a year, (i.e. the capacity factor multiplied by 8,760).

In the initial design phase, wind turbine designers are *not* particularly concerned whether they are using more or less of the power generating capacity of the generator in the turbine, that is, whether they obtain a low or a high capacity factor. They are – once again – concerned with minimising the cost per kWh of energy delivered by the turbine.

By changing the size of the generator relative to the size of the rotor area a designer can really change the capacity factor of the wind turbine very much at will (for a given annual wind speed pattern). Let us redesign the turbine we used in Section 1.6.1. to prove this point.

When we discussed the frequency of wind speeds at a typical wind farm site, we noted that on that particular site our 1.8 MW turbine would only be producing at maximum rated power during 18% of the hours of the year. During those hours, however, the turbine would be producing 43% of annual energy output. Now, if we downgrade our generator with, say one tenth, our turbine becomes a 1.62 MW wind turbine. This is equivalent to putting a ceiling on our power curve in Figure 1.20 of 1.62 MW. The annual energy output from the turbine will drop by 4.5%, but since we downgraded the generator even more, by 10%, our capacity factor will increase from 35.5% to 37.7%.[21]

Will the wind turbine owner be happier with this larger capacity factor? No, obviously not, because his annual energy sales dropped by 4.5%, and the cost savings from using a 10% smaller generator are likely to be only around 0.5% of the price of the wind turbine.

Hence, we see that differences in capacity factors for wind turbines are useless as indicators of the profitability of wind farms.

It should be pointed out that, economically speaking, the ideal ratio between rotor area and generator size depends on the wind climate, hence the above example depends somewhat on the local wind conditions. In general it is best to use fairly large generators for a given rotor diameter (or smaller rotors for a given generator size) the higher the mean wind speed at the site. Unusually large capacity factors may indeed be a danger sign that a turbine is not optimised for the wind climate in which it is operating, as our example proved.

The confusion in the debate about capacity factors in the wind energy sector arises from the fact that with most other power generation technologies, the potential annual energy sales are roughly proportional to the size of the generators in MW. With wind technology, the annual output varies more according to the *swept rotor area* than the generator size, hence wind turbines are generally priced according to swept rotor area and not according to rated power in MW, as explained in Section 1.1.3.

A final remark on capacity factors (or the relationship between rotor size and generator size) is relevant, however. In our example above, the cost savings on the turbine from using a 10% smaller generator was very small, in the order of 0.5%. If the wind turbine owner pays for the reinforcement of the electrical grid (and the substation) in proportion to the installed power of the wind turbines, then the cost savings on grid reinforcement will be significant when using relatively smaller generators.

If grid connection costs 20% of the price of turbines including installation, then the total cost savings will be around 2.5% when decreasing generator size by 10%. Although this does not change the conclusions in our previous example, it does imply that the optimal ratio between rotor size and generator size and the optimal capacity factor not only vary with the wind climate, but also with the regulatory framework for grid connection and grid reinforcement. In this context it is worth noting that the relatively high capacity factors seen in wind farms in North America are mostly caused by relatively small generators per unit swept rotor area rather than by relatively high wind speeds at the sites in question.

[21] It will increase by (1-0.045) / (1-0.1) = 1.06111, i.e. 6.11%. In practice we may make a slightly larger gain, since a smaller generator is 'easier to turn' and therefore be more productive than a large generator at low wind speeds. (Although the overall efficiency of generators decreases with the size of the generator in kW).

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1.6.3. WIND CLIMATE AND ANNUAL ENERGY PRODUCTION [22]

The local wind resource is by far the most important determinant of the profitability of wind energy investments. Just as an oil pump is useless without a sizable oilfield, wind turbines are useless without a powerful wind field.

The correct micro-siting of each individual wind turbine is therefore crucial for the economics of any wind energy project. In fact, it is beyond dispute that during the infancy of the modern wind industry in 1975-1985 the development of the European Wind Atlas methodology was more important for productivity gains than advances in wind turbine design.[23] Boundary layer meteorology is consequently an essential part of modern wind energy technology. Wind turbines are sited after careful computer modelling based on local topography and local meteorology measurements.

The quality of wind resource assessments is often the most important economic risk element in the development of wind power projects. Financiers of large wind farms will therefore often require a due diligence reanalysis of the resource assessment, usually in the form of a second opinion on the conclusions to be drawn from the available data.

1.6.4. ENERGY LOSSES

When a wind farm developer undertakes a project, they will initially look at the wind climate and the power curve of the turbines, as explained in Section 1.6.1. In practice, however, power generation will be reduced by a number of factors, including

- *Array losses*, or park effects, which occur due to wind turbines shadowing one another in a wind farm, leaving less energy in the wind downstream of each wind turbine. These losses may account for 5-10% of the theoretical output described by the power curves, depending on the turbine rotors, the layout of the wind farm and the turbulence intensity.
- *Rotor blade soiling* losses. Soiled blades are less efficient than clean ones – typically 1-2%.
- *Grid losses* due to electrical (heat) losses in transformers and cabling within the collection grid inside the wind farm, typically 1-3%.
- *Machine downtime* may occur in case of technical failures. If the wind turbines are difficult to access, for example when they are placed offshore, the machines may stand idle for a certain time before they can be repaired. In general, however, modern wind turbines are extremely reliable. Most statistics report availability rates of around 98%. That means that energy losses due to maintenance or technical failure will generally be at around 2%.[24]
- *Other losses* due to wind direction hysteresis, for example (rapidly changing wind direction) may not be tracked infinitely rapidly by the yaw mechanism of the wind turbines. Generally speaking these other losses are very small, usually around 1%.

Usually, the developers calculate energy losses in the order of magnitude of 10-15% below the theoretical power curves provided for the wind turbines. In the primer on *wind speeds and power generation* in the previous section we assumed a 14% energy loss.

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[22] Readers who are interested in more technical detail should consult a standard introductory text on wind energy such as www.windpower.org/en/tour (by Søren Krohn).

[23] The European Wind Atlas method developed Erik Lundtang Petersen and Erik Troen was later formalised in the WAsP computer model for wind resource assessment by Risø National Laboratory in Denmark.

[24] Different institutions and different manufacturers define availability rates differently. The most common definition is to use the amount of energy actually produced relative to a situation where the turbine is ready to run at all times.

1.7. The cost of onshore wind

Below, we present the cost per kWh of onshore wind energy. We will also make a distinction between the unit costs at land and those at the sea, which turn out to be rather different.

The total cost per kWh produced (unit cost) is calculated by discounting and levelising investment and O&M costs over the lifetime of the turbine, and then dividing them by the annual electricity production. The unit cost of generation is thus calculated as an average cost over the turbine's lifetime. In reality, actual costs will be lower than the calculated average at the beginning of the turbine's life, due to low O&M costs, and will increase over the period of turbine use, as explained in Section 1.5.1.

The turbine's power production is the single most important factor for the cost per unit of power generated. The profitability of a turbine depends largely on whether it is sited at a good wind location. In this section, the cost of energy produced by wind power will be calculated according to a number of basic assumptions. Due to the importance of the turbine's power production on its costs, a sensitivity analysis will be applied to this parameter. Other assumptions include the following:

- Calculations relate to new land-based, medium-sized turbines (1.5-2 MW) that could be erected today.
- Investment costs reflect the range given in Section 1.2 - that is, a cost per kW of 1,100-1,400 €/kW, with an average of 1,225 €/kW. These costs are stated in 2006 prices.
- O&M costs are assumed to be 1.45 c€/kWh as an average over the lifetime of the turbine.
- The lifetime of the turbine is set at 20 years, in accordance with most technical design criteria.
- The discount rate is assumed to range from 5 to 10% per annum. In the basic calculations, a discount rate of 7.5% per annum is used, and a sensitivity analysis is also performed.
- Economic analyses are carried out on a simple national economic basis. Taxes, depreciation and risk premiums are not taken into account and all calculations are based on fixed 2006 prices.

The costs per kWh of wind-generated power, calculated as a function of the wind regime at the chosen sites, are shown in Figure 1.24 below. As illustrated, the costs range from approximately 7-10 c€/kWh at sites with low average wind speeds, to approximately 5-6.5 c€/kWh at windy coastal sites, with an average of approximately 7c€/kWh at a wind site with average wind speeds.

In Europe, the best coastal positions are located mainly on the coasts of the UK, Ireland, France, Denmark and Norway. Medium wind areas are mostly found inland in central and southern Europe - Germany, France, Spain, Holland and Italy; and also in northern Europe in Sweden, Finland and Denmark. In many cases, local conditions significantly influence the average wind speeds at a specific site, so significant fluctuations in the wind regime are to be expected even for neighbouring areas.


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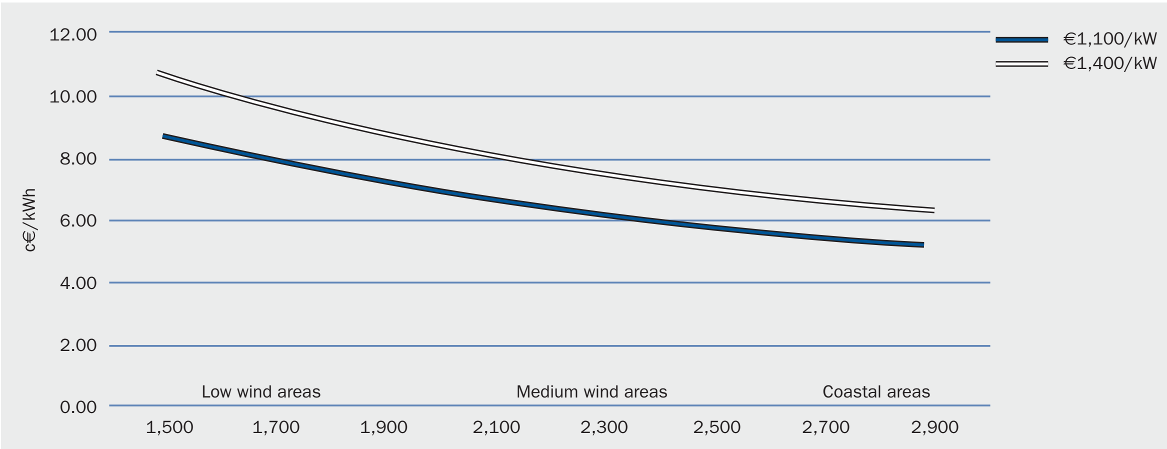
FIGURE 1.24: **Calculated costs per kWh of wind generated power as a function of the wind regime at the chosen site (number of full load hours).**



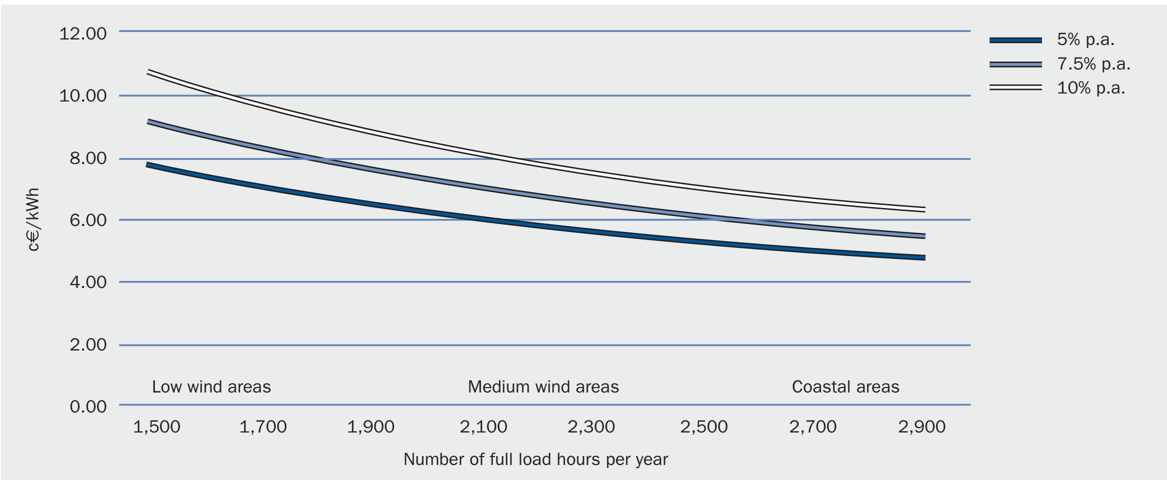
Source: Risø DTU

Note: In this 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 power production at the chosen site.

Approximately 75-80% of total power production costs for a wind turbine are related to capital costs – that is the costs of the turbine, foundation, electrical equipment and grid connection. Thus, a wind turbine is capital-intensive compared with conventional fossil fuel-fired technologies, such as natural gas power plants, where as much as 40-60% of the total costs are related to fuel and O&M costs. For this reason, the costs of capital (discount or interest rate) are an important factor for the cost of wind generated power; a factor which varies considerably between the EU member countries.

In Figure 1.25, the costs per kWh of wind-produced power are shown as a function of the wind regime and the discount rate (which varies between 5 and 10% per annum).

FIGURE 1.25: **The costs of wind produced power as a function of wind speed (number of full load hours) and discount rate. The installed cost of wind turbines is assumed to be 1,225 €/kW.**



Source: Risø DTU

As illustrated, the costs ranges between around 6 and 8 c€/kWh at medium wind positions, indicating that a doubling of the interest rate induces an increase in production costs of 2 c€/kWh or 33%. In low wind areas, the costs are significantly higher, at around 8-11 c€/kWh, while the production costs range between 5 and 7 c€/kWh in coastal areas for various levels of discount rate.

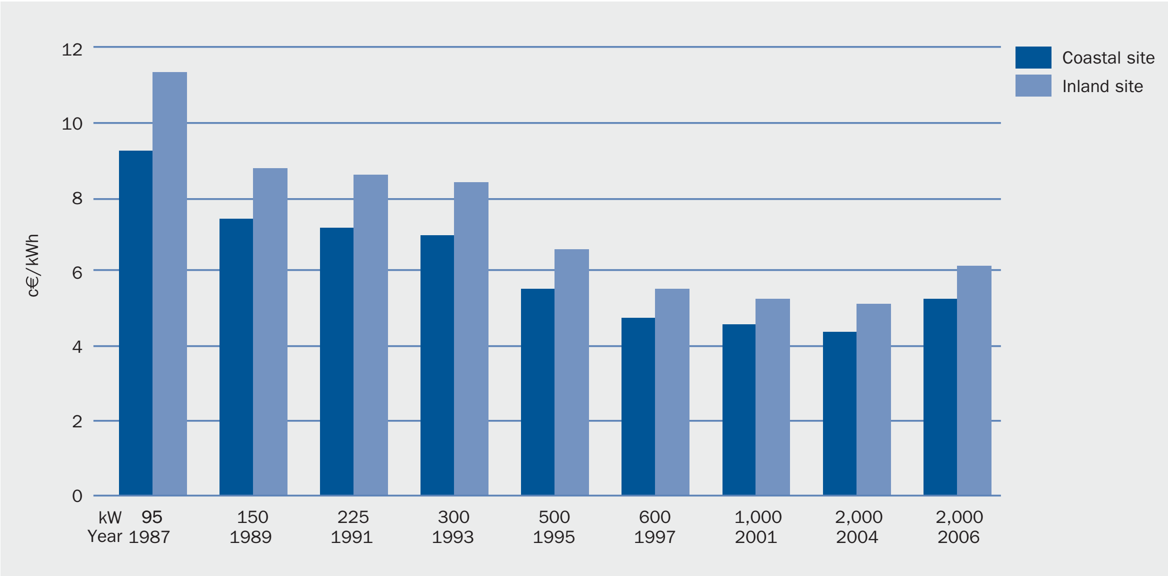
HISTORIC COST DEVELOPMENT OF ONSHORE WIND ENERGY OVER TIME

The rapid European and global development of wind power capacity has had a strong influence on the cost of wind power over the last 20 years. To illustrate the trend towards lower production costs of wind-generated power, a case (Figure 1.26) that shows the production costs for different sizes and models of turbines is presented below. Due to limited data, the trend curve has only been constructed for Denmark, although a similar trend (at a slightly slower pace) was observed in Germany.

Figure 1.26 shows the calculated unit cost for different-sized turbines, based on the same assumptions used previously: a 20-year lifetime is assumed for all turbines in the analysis and a real discount rate of 7.5% per annum is used. All costs are converted into constant €^{2006} prices. Turbine electricity production is estimated for two wind regimes - a coastal and an inland medium wind position.

The starting point for the analysis is the 95 kW machine, which was installed mainly in Denmark during the mid 1980s. This is followed by successively newer turbines (150 kW, 225 kW), ending with the 2,000 kW turbine, which was typically installed from around 2003 onwards. It should be noted that wind turbine manufacturers generally expect the production cost of wind power to decline by 3-5% for each new turbine generation they add to their product portfolio. The calculations are performed for the total lifetime (20 years) of a turbine, which means that calculations for the old turbines are based on track records of more than 15 years (average figures), while newer turbines may have a track record of only a few years; so the newer the turbine, the less accurate the calculations.

FIGURE 1.26: **Total wind energy costs per unit of electricity produced, by turbine size (c€/kWh, constant €^{2006} prices).**



Source: Risø DTU

The economic consequences of the trend towards larger turbines and improved cost-effectiveness are clearly shown in Figure 1.26. For a coastal site, for example, the average cost has decreased from around 9.2 c€ /kWh for the 95 kW turbine (mainly installed in the mid 1980s), to around 5.3 c€ /kWh for a fairly new 2,000 kW machine, an improvement of more than 40% (constant €^{2006} prices).

FUTURE COST DEVELOPMENT OF ONSHORE WIND ENERGY

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

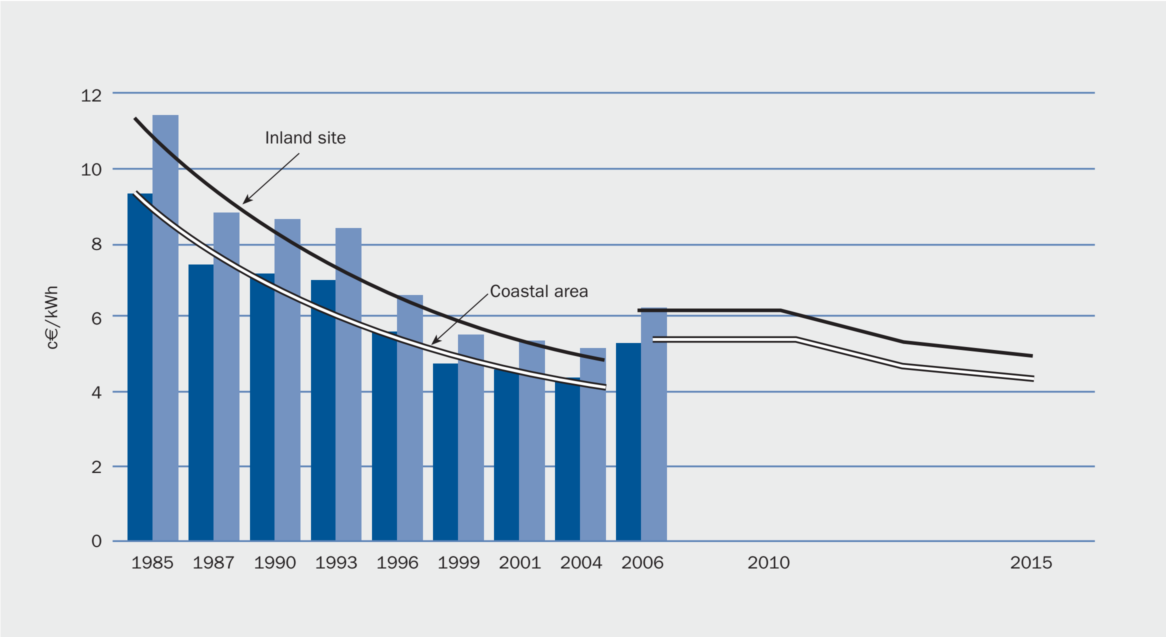
The experience curve is not a forecasting tool based on estimated relationships. It merely shows that if the existing trends continue in the future, the proposed development may be seen. It converts the effect of mass production (economies of scale) into an effect upon production costs without taking other causal relationships into account, such as the cost of raw materials or the demand-supply balance in a particular market (seller's or buyer's market). Thus, changes in market development and/or technological breakthroughs within the field may change the picture considerably, as would fluctuations in commodity prices such as those for steel and copper and changes in an industry's production capacity relative to global demand for the product.

Different experience curves have been estimated for a number of projects (see for example Neij, 1997, Neij, 2003 or Milborrow, 2003). Unfortunately, different specifications and assumptions were used, which means that not all of these projects can be compared directly. To obtain the full value of the experiences gained, the reduction in turbine prices (€/KW-specification) should be taken into account, as well as improvements in the efficiency of the turbine's production (which requires the use of an energy specification (€/kWh), as done by Neij in 2003). Thus, using the specific costs of energy as a basis (costs per kWh produced), the estimated progress ratios range from 0.83 to 0.91, corresponding to learning rates of 0.17 to 0.09. That means that when the total installed capacity of wind power doubles, the costs per kWh produced for new turbines goes down 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 it has increased by 25-30% per year over the last ten years. So, at present the total wind power capacity doubles approximately every three to four years. Figure 1.27 shows the consequences for wind power production costs, based on the following assumptions:

- The 2006 price-relation is retained until 2010; the reason why no price reductions are foreseen in this period is due to a persistently high demand for new wind turbine capacity, and sub-supplier constraints in the delivery of turbine components.
- From 2010 until 2015, a learning rate of 10% is assumed, implying that each time the total installed capacity doubles, the costs per kWh of wind generated power decreases by 10%.
- The growth rate of installed capacity is assumed to double cumulative installations every three years.
- The curve illustrates cost development in Denmark, which is a fairly cheap wind power country. Thus, the starting point for the development is a cost of wind power of around 6.1 c€/kWh for an average 2 MW turbine, sited at a medium wind regime area (average wind speed of 6.3 m/s at a hub height of 50 m). The development for a coastal position is also shown.

FIGURE 1.27: **Using experience curves to illustrate the future development of wind turbine economics until 2015.**



Costs are illustrated for an average 2 MW turbine installed either at an inland site or at a coastal position. Source: Risø DTU

In 2006, the production costs for a 2 MW wind turbine installed in an area with a medium wind speed (inland position) are around 6.1 c€ per kWh of wind-produced power. If sited at a coastal position, the costs are around 5.3 c€/kWh. If a doubling time of total installed capacity of three years is assumed, in 2015 the cost interval would be approximately 4.3 to 5.0 c€/kWh for a coastal and inland site, respectively. A doubling time of five years would imply a cost interval, in 2015, of 4.8 to 5.5 c€/kWh. As mentioned, Denmark is a fairly cheap wind power country, so for more expensive countries the cost of wind power produced would increase by 1-2 c€/kWh.

As an example the power company Hydro-Québec in Canada has made contracts with wind developers to install a total of 1,000 MW of wind power in the period 2006-12 at an average tariff of 4.08 c€/kWh (in 2007-prices indexed with the Canadian CPI) over a 20 year lifetime. Observe that this tariff has to cover not only the costs of investments and O&M, but also the risk premium for the developer (as explained in the next chapter). Thus, the costs of the turbine installation and maintenance should be well below the 4 c€/kWh in fixed 2007 prices[25] at the specific sites in Canada. The Hydro-Québec deal was signed at a time when wind turbine prices were at their lowest level ever and in a period of excess manufacturing capacity and relatively low commodity prices. As such, the project probably constitutes a historic low in wind farm development prices and, as such, serves as a reference point for future cost reductions.

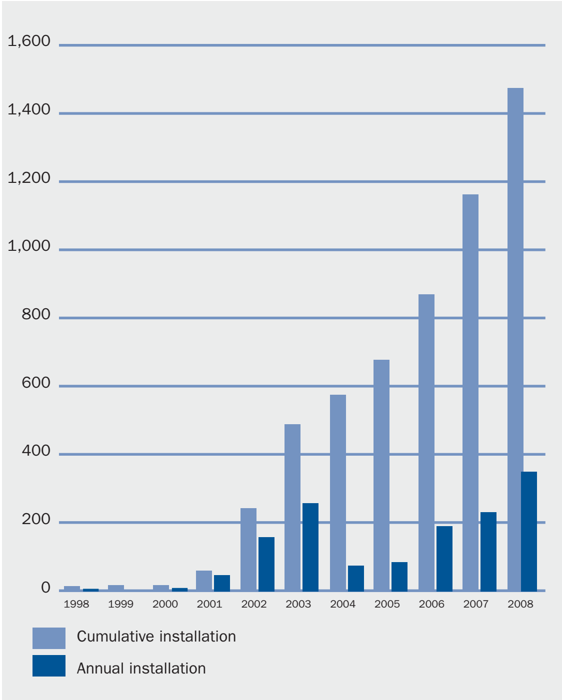
[25] The power purchasing contracts in the Québec tenders for wind energy may be indexed to a number of indices, as explained in Section 2.1. Indexed contracts are more valuable than fixed price contracts for the wind turbine investor, assuming positive inflation rates in the future.

1.8. The cost of offshore wind energy

Offshore wind currently accounts for a small amount of the total installed wind power capacity in the world – approximately 1%. The development of offshore wind has mainly been in northern European countries, around the North Sea and the Baltic Sea, where about 20 projects have been implemented. At the end of 2008, 1,471 MW of capacity was located offshore (Figure 1.29).

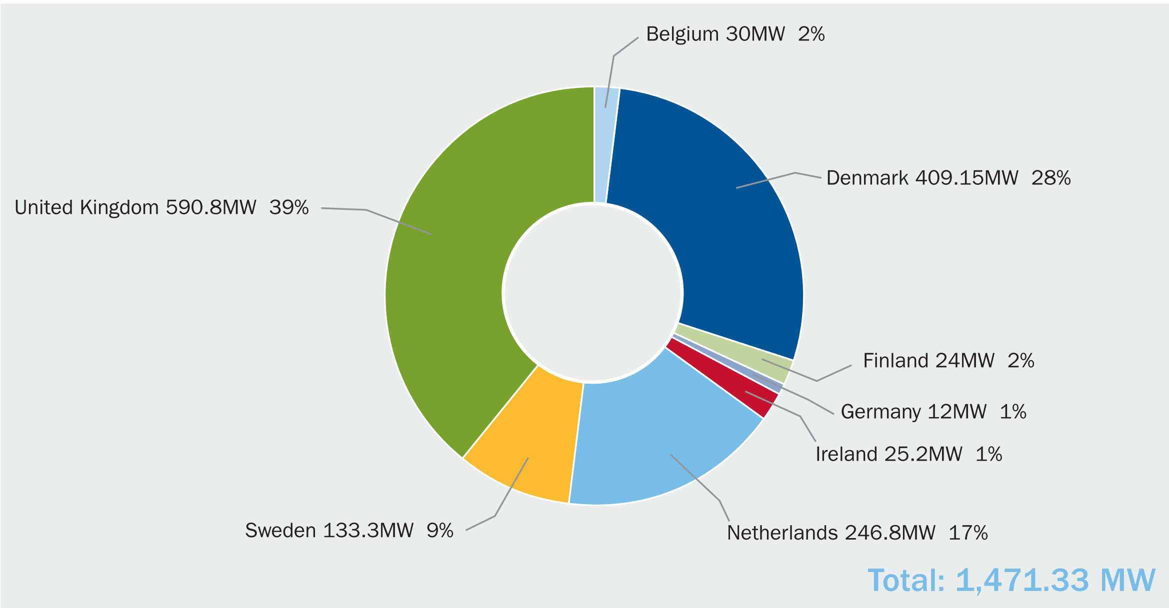
Nine countries have operating offshore wind farms: Belgium, Denmark, Finland, Germany, Ireland, Italy, the Netherlands, Sweden and the UK, as shown in Figure 1.28 and Table 1.3. In 2007, the Swedish offshore wind farm, Lillgrunden was installed with a rated capacity of 110 MW. Most of the capacity has been installed in relatively shallow waters (under 20m water depth), no more than 20 km from the coast, in order to minimise the extra costs of foundations and sea cables.

FIGURE 1.28: **Development of offshore wind power in the EU 1998-2008, EWEA**



Source: EWEA

FIGURE 1.29: **Total offshore wind power installed by end 2008, EWEA**



Source: EWEA

TABLE 1.3 **Installed offshore capacity in offshore wind countries.**

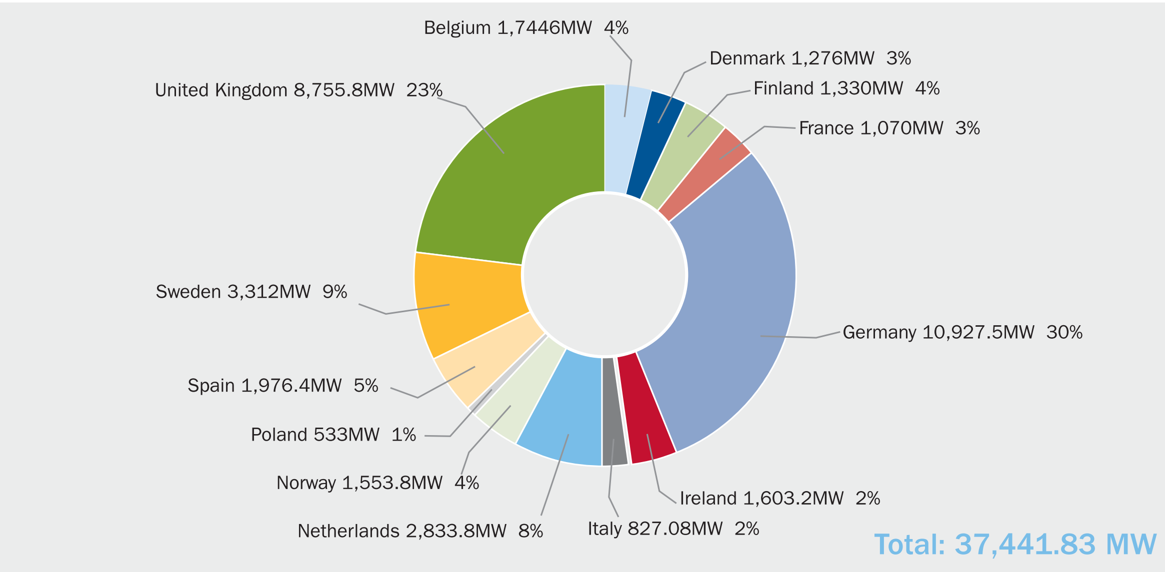
COUNTRY	MW INSTALLED IN 2007	ACCUMULATED MW END 2007	MW INSTALLED IN 2008	ACCUMULATED MW END 2008
Belgium	0	0	30	30
Denmark	0	409	0	409
Finland	0	0	24	24
Germany	0	0	5	12
Ireland	0	25	0	25
Italy	0	0	0.08	0.08
The Netherlands	0	108	120	246.8
Sweden	110	133	0	133
The United Kingdom	100	404	187	591
TOTAL GLOBAL	**210**	**1105**	**366.08**	**1471**

Source: EWEA

Offshore wind capacity is still around 50% more expensive than onshore wind. However, due to the expected benefits of higher wind speeds and the lower visual impact of the larger turbines, several countries – predominantly in European Union Member States - have very ambitious goals concerning offshore wind.

The total capacity is still limited, but growth rates are high. Offshore wind farms are usually made up of many turbines - often 100-200. Currently, higher costs and temporary capacity restrictions in manufacturing, as well as in the availability of installation vessels cause some delays. Even so, several projects will be developed within the coming years, as seen from the tables below.

FIGURE 1.30: **Operating and planned offshore wind farms in Europe as of 31 December 2008.**



Source EWEA

INVESTMENT COST OF OFFSHORE WIND ENERGY

Offshore costs depend largely on weather and wave conditions, water depth and distance from the coast. The most detailed cost information on recent offshore installations comes from the UK, where 90 MW were added in 2006 and 100 MW in 2007; and from Sweden with the installation of Lillgrunden in 2007.

Table 1.4 gives information on some of the recently established offshore wind farms. As shown, the chosen turbine size for offshore wind farms ranges from 2 to 3.6 MW, with the newer wind farms being equipped with the larger turbines. The size of the wind farms also varies substantially, from the fairly small Samsø wind farm of 23 MW, to Robin Rigg with a rated capacity of 180 MW, the world's largest offshore wind farm. Investment costs per MW range from a low of 1.2 million €/MW (Middelgrunden) to 2.7 million €/MW (Robin Rigg) - see Figure 1.31.

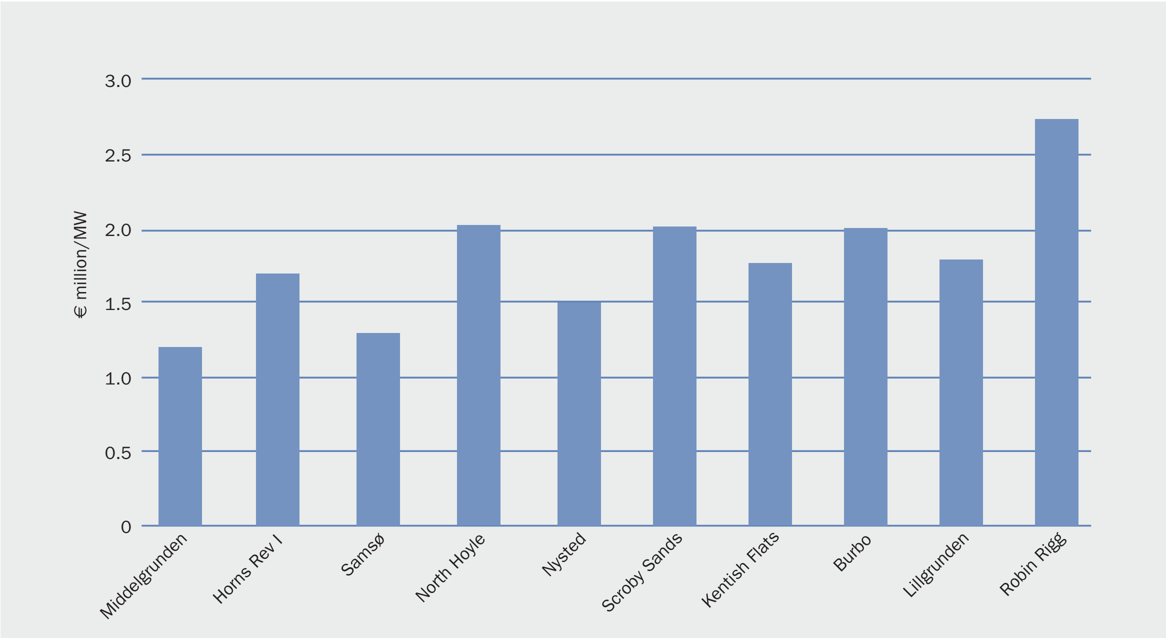
TABLE 1.4: **Key information on recent offshore wind farms.**

	IN OPERATION	NUMBER OF TURBINES	TURBINE SIZE	CAPACITY MW	INVESTMENT COSTS € MILLION
Middelgrunden (DK)	2001	20	2	40	47
Horns Rev I (DK)	2002	80	2	160	272
Samsø (DK)	2003	10	2.3	23	30
North Hoyle (UK)	2003	30	2	60	121
Nysted (DK)	2004	72	2.3	165	248
Scroby Sands (UK)	2004	30	2	60	121
Kentish Flats (UK)	2005	30	3	90	159
Barrows (UK)	2006	30	3	90	-
Burbo Bank (UK)	2007	24	3.6	90	181
Lillgrunden (S)	2007	48	2.3	110	197
Robin Rigg (UK)	2008	60	3	180	492

Source: Risoe

The higher offshore capital costs are due to the larger structures and complex logistics of installing the towers. The costs of offshore foundations, construction, installations and grid connection are significantly higher than for onshore. For example, offshore turbines are generally 20% more expensive and towers and foundations cost more than 2.5 times the price of a similar onshore project.

FIGURE 1.31: **Investments in offshore wind farms, million €/MW (current prices).**



Source: Risø DTU

In general, the costs of offshore capacity have increased up to mid-2008, as is also the case for onshore turbines, and these increases are only partly reflected in the costs shown in Figure 1.31. As a result, the costs of future offshore farms may be different. On average, investment costs for a new offshore wind farm are in the range of 2.0 to 2.2 million €/MW for a near-shore, shallow water facility.

To illustrate the economics of offshore wind turbines in more detail, the two largest Danish offshore wind farms can be taken as examples. The Horns Rev project, located approximately 15 km off the west coast of Jutland (west of Esbjerg), was finished in 2002. It is equipped with 80 machines of 2 MW, and has a total capacity of 160 MW. The Nysted offshore wind farm is located south of the island of Lolland. It consists of 72 turbines of 2.3 MW and has a total capacity of 165 MW. Both wind farms have their own on-site transformer stations, which are connected to the high voltage grid at the coast through transmission cables. The farms are operated from onshore control stations, so staff are not required at the sites. The average investment costs related to these two farms are shown in Table 1.5.

TABLE 1.5: **Average investment costs per MW related to offshore wind farms in Horns Rev and Nysted.**

	INVESTMENTS 1000 €/MW	SHARE %
Turbines ex works, including transport and erection	815	49
Transformer station and main cable to coast	270	16
Internal grid between turbines	85	5
Foundations	350	21
Design and project management	100	6
Environmental analysis	50	3
Miscellaneous	10	<1
TOTAL	**1,680**	**~100**

Source: Risoe

In Denmark, all of the cost components above are covered by the investors, except for the costs of the transformer station and the main transmission cable to the coast, which are covered by transmission system operators (TSOs) in the respective areas. Similar legislation has recently been passed in Germany for offshore wind farms. The total costs of each of the two offshore farms are around €260 million.

The main differences in the cost structure between onshore and offshore turbines are linked to two issues:

- Foundations are considerably more expensive for offshore turbines. The costs depend on both the sea depth and the type of foundation being built (at Horns Rev monopiles were used, while the turbines at Nysted are erected on concrete gravity foundations). For a conventional turbine situated on land, the foundations' share of the total cost is normally around 5-9%. As an average of the two projects mentioned above, this percentage is 21% (see Table 1.5), and thus considerably more expensive than for onshore sites. However, since considerable experience will be gained through these two wind farms, a further optimisation of foundations can be expected in future projects.
- Transformer stations and sea transmission cables increase costs. Connections between turbines and the centrally located transformer station, and from there to the coast, generate additional costs. For Horns Rev and Nysted wind farms, the average cost share for the transformer station and sea transmission cables is 21% (see Table 1.5), of which a small proportion (5%) goes on the internal grid between turbines.

Finally, a number of environmental analyses, including an environmental impact investigation (EIA) and graphic visualisation of the wind farms, as well as additional research and development were carried out. The average cost share for these analyses accounts for approximately 6% of total costs, but part of these costs is because these are pilot projects, and the analyses are not expected to be repeated for future offshore wind farm installations in Denmark. In other countries, the cost of environmental impact assessments (EIAs) can be very significant.

OFFSHORE WIND ELECTRICITY GENERATION COST

Although the investment costs are considerable higher for offshore than for onshore wind farms, they are partly offset by a higher total electricity production from the turbines, due to higher offshore wind speeds. For an onshore installation utilisation, the time is normally around 2,000-2,500 full load hours per year, while for a typical offshore installation this figure reaches up to 4,000 full load hours per year, depending on the site. The investment and production assumptions used to calculate the costs per kWh are stated in Table 1.6.

TABLE 1.6: **Assumptions used for economic calculations.**

	IN OPERATION	CAPACITY MW	MILLION€/MW	FULL LOAD HOURS PER YEAR
Middelgrunden	2001	40	1.2	2,500
Horns Rev I	2002	160	1.7	4,200
Samsø	2003	23	1.3	3,100
North Hoyle	2003	60	2.0	3,600
Nysted	2004	165	1.5	3,700
Scroby sands	2004	60	2.0	3,500
Kentich Flat	2005	90	1.8	3,100
Burbo	2007	90	2.0	3,550
Lillgrunden	2007	110	1.8	3,000
Robin Rigg	2008	180	2.7	3,600

In addition, the following economic assumptions are made:

- Over the lifetime of the wind farm, annual operation and maintenance costs are assumed to be 16 €/MWh, except for Middelgrunden where these costs based on existing accounts are assumed to be 12 €/MWh for the entire lifetime.
- The number of full load hours is given for a normal wind year and corrected for wake effects within the farm, as well as unavailability and losses in transmission to the coast.
- In some countries, wind farm owners are responsible for balancing the power production from the turbines. According to previous Danish experiences, balancing costs are around c€ 0.3/kWh in a system where wind covers over 20% of national electricity demand. However, balancing costs are also uncertain, and depend greatly on the regulatory and institutional frameworks and may differ substantially between countries.
- The economic analyses are carried out on a simple national economic basis, using a discount rate of 7.5% per annum, over the assumed lifetime of 20 years. Taxes, depreciation, profit and risk premiums are not taken into account.

Figure 1.32 shows the total calculated costs per MWh for the wind farms listed in Table 1.6.

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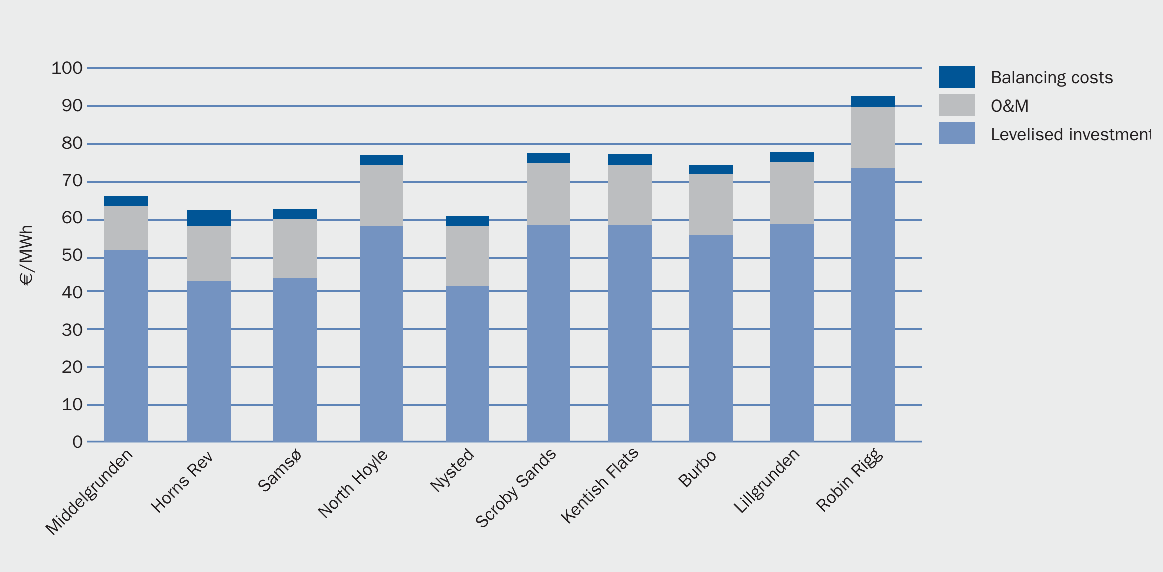
FIGURE 1.32: **Calculated production cost for selected offshore wind farms, including balancing costs (2006-prices).**



Source: Risø DTU

It can be seen that total production costs differ significantly between the illustrated wind farms, with Horns Rev, Samsø and Nysted being among the cheapest, and Robin Rigg in the UK being the most expensive. Differences can be related partly to the depth of the sea and distance to the shore, and partly to increased investment costs in recent years. O&M costs are assumed to be at the same level for all wind farms (except Middelgrunden) and are subject to considerable uncertainty.

Costs are calculated on a simple national economic basis, and are not those of a private investor. Private investors have higher financial costs and require a risk premium and, obviously, a profit. So the amount a private investor would add on top of the simple costs would depend, to a large extent, on the perceived technological and political risks of establishing the offshore farm and on the competition between manufacturers and developers. That is why the production cost of wind energy for onshore and offshore, calculated above, does not give an indication about the levels of national feed-in tariffs or premiums, for example, as no investor would accept zero profits. This chapter looks exclusively at cost whereas Chapter 2 addresses prices – that is, the amount of money paid to investors, which relates to the development of national financial frameworks and payment mechanisms. In Appendix II there is a case-study on the price of offshore wind energy in Denmark. In Appendix III there is a case-study of offshore wind power development in Denmark.

COST OF FUTURE OFFSHORE WIND ENERGY

Until 2004, the cost of onshore wind turbines generally followed the development of a medium-term cost reduction curve (learning curve), showing a learning rate of approximately 10% - namely, that each time wind power capacity doubled, the cost went down by approximately 10% per MW installed. This decreasing cost trend changed in 2004-2006, when the price of wind power in general increased by approximately 20-25%. This was caused mainly by the increasing costs of raw materials and a strong demand for wind capacity, which implied larger order books at manufacturers and scarcity of wind power manufacturing capacity and sub-supplier capacity for manufacturing turbine components.

A similar price increase can be observed for offshore wind power, although a fairly small number of finished projects, as well as a large spread in investment costs, make it difficult to identify the price level for offshore turbines accurately. On average, the expected investment costs for a new offshore wind farm are currently in the range of 2.0 to 2.2 million €/MW.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In the following section, the medium-term cost development of offshore wind power is estimated using the learning curve methodology. However, it should be noted that there is considerable uncertainty over the use of learning curves, even for the medium term, and results should be used with caution.

The medium-term cost predictions for offshore wind power are shown in Table 1.7 under the following conditions:

- The existing manufacturing capacity constraints for wind turbines will continue until 2010. Although there will be a gradual expansion of industrial capacity for wind power, a prolonged increase in demand could continue to strain the manufacturing capacity. A more balanced demand and supply, resulting in unit reduction costs in the industry, is not expected to occur before 2011.
- The total capacity development of wind power is assumed to be the main driving factor for the cost development of offshore turbines, since most of the turbine costs are related to the general development of the wind industry. Thus, the growth rate of installed capacity is assumed to be a doubling of cumulative installations every three years.
- For the period between 1985 and 2004, a learning rate of approximately 10% was estimated (Neij, 2003). In 2011, this learning rate is again expected to be achieved by the industry up until 2015.

Given these assumptions, minimum, average and maximum cost scenarios are reported in Table 1.7.

As shown in Table 1.7, the average cost of offshore wind capacity is expected to decrease from 2.1 million €/MW in 2006 to 1.81 million €/MW in 2015, or by approximately 15%. There will still be a considerable spread of costs, from 1.55 million €/MW to 2.06 million €/MW. A capacity factor of constant 37.5% (corresponding to a number of full load hours of approximately 3,300) is expected for the whole period. This covers increased production from newer and larger turbines, moderated by sites with lower wind regimes, and a greater distance to shore, which increases losses in transmission of power, unless new High Voltage DC grid technology is applied.

TABLE 1.7: **Estimates for cost development of offshore wind turbines until 2015, constant 2006-€.**

	INVESTMENT COSTS, MILLION €/MW			O&M	CAP. FACTOR
	Min	Average	Max	€/MWh	%
2006	1.8	2.1	2.4	16	37.5
2015	1.55	1.81	2.06	13	37.5

1.9 Cost of wind power compared to other technologies

In this section, the cost of conventionally-generated power is compared with the cost of wind-generated power. To obtain a comparable picture, calculations for conventional technologies are prepared utilising the Recabs-model, which was developed by the IEA in its Implementing Agreement on Renewable Energy Technology Deployment. The general cost of conventional electricity production is determined by four components:

- Fuel cost
- Cost of CO_2 emissions (as given by the European Trading System for CO_2, the ETS)
- O&M costs
- Capital costs, including planning and site work

Fuel prices are given by the international markets and, in the reference case, are assumed to develop according to the IEA's World Energy Outlook 2007, which assumes a crude oil price of $63 /barrel in 2007, gradually declining to $59 /barrel in 2010 (constant terms). Oil prices reached a high of $147/barrel in July 2008. As is normally observed, natural gas prices are assumed to follow the crude oil price (basic assumptions on other fuel prices: Coal €1.6/GJ and natural gas €6.05/GJ). As mentioned, the price of CO_2 is determined by the EU ETS market; at present the CO_2 price is around 25 €/t.

Here, calculations are carried out for two state-of-the-art conventional plants: a coal-fired power plant and a combined cycle natural gas combined heat and power plant, based on the following assumptions:

- Plants are commercially available for commissioning by the year 2010
- Costs are levelised using a 7.5% real discount rate and a 40-year lifetime (national assumptions on plant lifetime might be shorter, but calculations were adjusted to 40 years.)
- 75% load factor
- Calculations are always carried out in €^{2006}

When conventional power is replaced by wind-generated electricity, the avoided costs depend on the degree to which wind power substitutes for each of the four components. It is generally accepted that implementing wind power avoids the full costs of fuel and CO_2, as well as a considerable portion of the O&M costs of the displaced conventional power plant. The level of avoided capital costs depends on the extent to which wind power capacity displace investments in new conventional power plants, and thus is directly tied to how wind power plants are integrated into the power system.

Studies of the Nordic power market, NordPool, show that the cost of integrating variable wind power in Denmark is, on average, approximately 0.3-0.4 c€/kWh of wind power generated, at the present level of 20% electricity from wind power and in the existing transmission and market conditions. These costs are completely in line with experiences in other countries. Integration costs are expected to increase with higher levels of wind power penetration.

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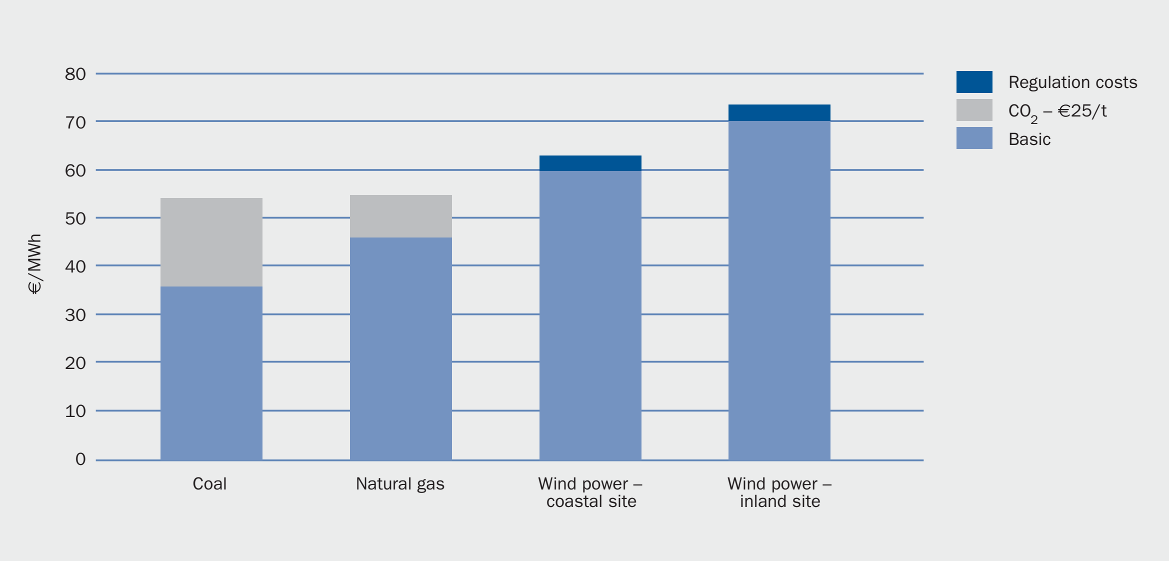
Figure 2.5 shows the results of the reference case, assuming the two conventional power plants are coming online in 2010. As mentioned, figures for the conventional plants are calculated using the Recabs model, while the costs for wind power are recaptured from the figures for onshore wind power arrived at earlier in this study.

FIGURE 2.5: **Costs of generated power comparing conventional plants to wind power, year 2010 (constant €[2006])**



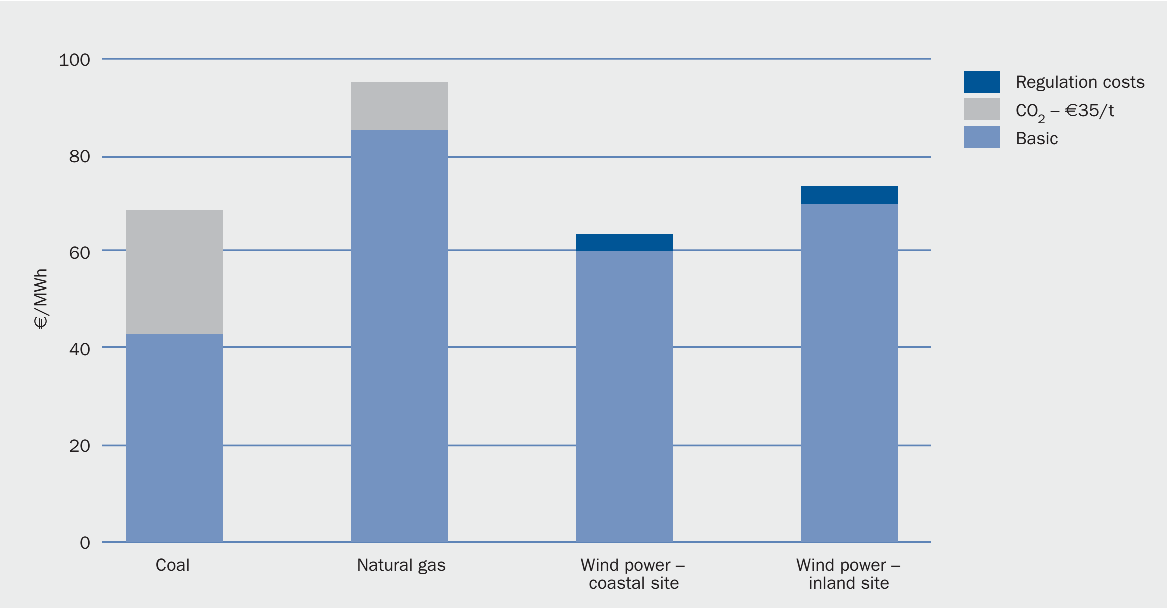
Source: Risø DTU

As shown in the reference case, the cost of power generated at conventional power plants is lower than the cost of wind-generated power under the given assumptions of lower fuel prices. When comparing to a European inland site, wind-generated power is approximately 33-34% more expensive than natural gas- and coal-generated power.

This case is based on the World Energy Outlook 2007 assumptions on fuel prices, including a crude oil price of $59/barrel in 2010[26]. At the time of writing, (September 2008), the crude oil price is $120/barrel. Thus, the present price of oil is significantly higher than the forecast IEA oil price for 2010. Therefore, a sensitivity analysis is carried through and results are shown in Figure 2.6

[26] Note that this analysis was carried out on the basis of fuel price projections from the 2007 edition of the IEA's World Energy Outlook, which projected oil prices of $59 in 2010 and $62 in 2030 (2006 prices). In its 2008 edition of the World Energy Outlook, the IEA increased its fuel price projections to €100/barrel in 2010 and $122/barrel in 2030 (2007 prices).

FIGURE 2.6.: **Sensitivity analysis of costs of generated power comparing conventional plants to wind power, assuming increasing fossil fuel and COs-prices, year 2010 (constant €^{2006})**



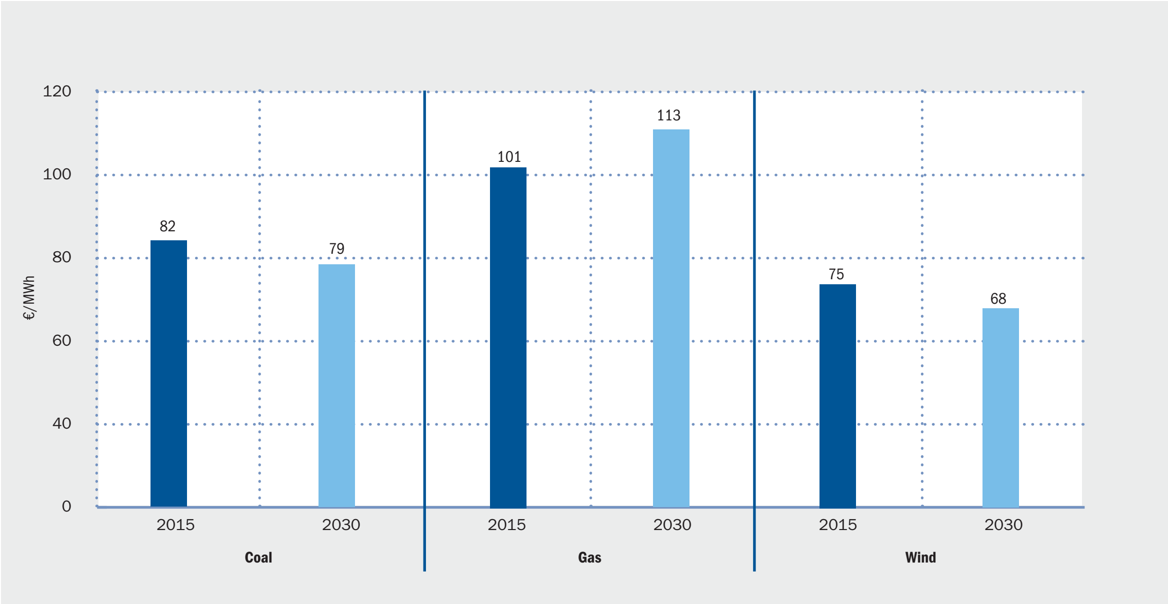
Source: Risø DTU

In Figure 2.6, the natural gas price is assumed to double compared to the reference equivalent to an oil price of $118/barrel in 2010, the coal price to increase by 50% and the price of CO_2 to increase to 35€/t from 25€/t in 2008. As shown in Figure 2.6, the competitiveness of wind-generated power increases significantly; costs at the inland site become lower than generation costs for the natural gas plant and only around 10% more expensive than the coal-fired plant. On coastal sites, wind power produces the cheapest electricity of the three.

Finally, as discussed in Awerbuch, 2003 and as we shall see in Chapter 5, the uncertainties mentioned above, related to future fossil fuel prices, imply a considerable risk for future generation costs of conventional plants. The calculations here do not include the macro-economic benefits of fuel price certainty, CO_2 price certainty, portfolio effects, merit-order effects and so on that will be discussed later in this study. Conversely, the costs per kWh generated by wind power are almost constant over the lifetime of the turbine once it is installed as the fuel cost is known with 100% certainty (it is zero). Thus, even if wind power were to be more expensive per kWh, it may account for a significant share in the utilities' portfolio of power plants since it hedges against unexpected rises in prices of fossil fuels and CO_2 in the future. According to the International Energy Agency (IEA), a EU carbon price of €10 adds 1c€/kwh to the generating cost of coal and 0.5 c€/kWh to the cost of gas generated electricity. Thus, the consistent nature of wind power costs justifies a relatively higher price compared to the uncertain risky future costs of conventional power. We will discuss this further in Section 4.3.

In its 2008 edition of World Energy Outlook, the IEA revised its assumptions on both fuel prices and power-plant construction cost. Consequently, it increased its estimates for what new-build will cost.. As mentioned above, for the European Union, it also assumed a that a carbon price of $30 per tonne of CO_2 adds $30 / MWh to the generating cost of coal and $15/MWh to the generating cost of gas CCGT plants. Figure 2.7 shows the IEA's assumption on generating cost for new coal, gas and wind energy in the EU in 2015 and 2030. It shows that the IEA expects new wind power capacity to be cheaper than coal and gas in 2015 and 2030.

FIGURE 2.7: **Electricity generating costs in the European Union, 2015 and 2030**



€/$ Exchange rate: 0.73

Source: IEA World Energy Outlook 2008

2. The price of wind energy

2.1 Price determinants for wind energy

The price of wind energy depends very much on the institutional setting in which wind energy is delivered. This is a key element to include in any debate about the price or cost of wind energy, and it is essential in order to allow for a proper comparison of costs and prices with other forms of power generation.

In this report we distinguish between the production costs of wind as explained in Chapter 1, and the *price* of wind, that is, what a future owner of a wind turbine will be able to bid per kWh in a power purchasing contract tender – or what he would be willing to accept as a fixed-price or indexed-price offer from an electricity buyer.

When we discussed the cost of wind energy in the previous chapter, we referred to the amount of (fluctuating) wind energy produced by a wind turbine at distribution grid voltage level (usually 8-30 kV), after having accounted properly for energy losses within the wind farm. This is what we might call the cost of wind energy at the factory gate.

In this chapter we introduce a number of cost elements that enter into the value chain between the cost of wind energy at the factory gate and the point where wind energy is delivered. In addition we deal with the profitability requirements of wind turbine owners. The dividing line between the costs mentioned in the previous chapter and the additional costs in this chapter is simply a practical one, since there is a great variation in the way wind energy is traded in different jurisdictions.

When a wind farm owner sells the electricity produced by a wind farm, his power purchasing agreement (PPA) will usually specify the time frame for delivery, the point of delivery, and the voltage level for delivery. The power purchasing agreement may be a fixed-price contract, an indexed price contract (indexed with the consumer price index) or simply give access to the local, regional or national spot market or a power pool market for electricity. Depending on the jurisdiction in question and the contracts involved, the wind farm owner will need to bear some risks, while the electricity purchaser will bear other risks.

There is thus not a single price for wind-generated electricity. The price that a wind turbine owner asks for obviously depends on the costs he has to meet in order to make his delivery, and the risks he has to carry (or insure) in order to fulfil his contract.

It should be kept in mind that the institutional setting in which wind energy is traded has not developed out of nowhere. Present day electrical power markets have been shaped by more than 100 years of experience with the properties of conventional power generation technologies and by the history of electrical utilities regulation. Present-day electrical grid infrastructures, power purchasing contracts, the *gate closure times* of markets and competition rules have likewise been shaped by the possibilities and limitations of existing technologies.

The distribution of risks between power suppliers and purchasers have largely been dictated by this technical setting – that the duration (term) of the power purchasing contract and the possibilities of price adjustments mean that *fuel price risks* are to a large extent borne by final power purchasers rather than power suppliers. It would therefore not be surprising if current market conditions and energy policy frameworks appeared to be skewed in favour of conventional power generation technologies, when viewed from the perspective of new renewable electricity sources, that is, non-hydro renewables.

2.1.1. PROJECT DEVELOPMENT RISKS: SPATIAL PLANNING AND OTHER PUBLIC PERMITTING

Regulatory systems for land use, such as spatial planning procedures may have a considerable impact on wind development costs, as discussed in Section 1.4.2. Developers who invest in the planning of a wind project run the risk of failing to obtain their final planning permission or a construction permit.

This type of risk makes it particularly difficult to organise tenders for wind power efficiently, particularly if the majority of the permitting process takes place after the winning bids have been awarded and many projects fail to get permission.[27] In that case the tendering process may fail to provide the required amount of installed power.

Every risk, including those which are managed by wind developers, has a cost attached to it. However, public authorities may limit the risks if they use a coordinated planning procedure that offers advance screening of areas suitable for wind power development, for example. There are many good examples around the world of such well coordinated planning systems, whether they are combined with wind power purchasing contract tenders or fixed price (standard offer) systems.[28]

2.1.2 PROJECT TIMING RISKS

One of the problems facing power generation project developers and power purchasers alike is that it takes time to develop and build power generation projects. Between the moment when a power purchasing contract has been awarded and the moment the wind farm has been built and starts delivering electricity, the prices of required investments (such as steel prices) or the interest rate may change.

These risks cannot be avoided, but they can be mitigated (and the costs of meeting the risks thus reduced) by sharing the risks appropriately between developers and power purchasers. Depending on the regulatory framework, the least costly solution may be to let electricity consumers bear part of the risk by inserting appropriate indexation clauses in the power purchasing agreement. If there is a market for hedging the index, this can be done quite transparently and at a known cost (such as is the case for interest rate futures) already at the time the power purchasing contract is signed.[29]

Traditionally transmission system operators (TSOs) dimension their interconnections using a conservative assumption of a trough in local power consumption, coinciding with all wind farms producing at peak power output. Since this event will be extremely rare in real life, grid reinforcement costs can be reduced substantially and more wind power can be accommodated economically in a transmission-constrained area if one allows the power generation of wind farms and other

(27) This was one of the major problems in most tendering systems.

(28) A set aside policy for pre-developing land or sea areas, which can be used for wind power development has been implemented in the spatial planning process by local authorities in both Denmark and Germany. In Québec the Ministry of Natural Resources developed a system of non-exclusive letters of intent to wind developers requesting to use public land for siting wind farms in connection with the 2003-2004 1,000 MW wind power tender and the subsequent 2,000 MW tender. An environmental pre-screening of potential sites for offshore wind farms has been used in connection with the Danish offshore wind programme.

(29) Such systems of indexation have been used e.g. in the Québec 2003-2004 tender for 1,000 MW and in the 2005-2007 tender for 2,000 MW of wind power.

power capacity to be curtailed by the TSO during the periods of high winds. The power plant owner should be compensated for such curtailment. Alternatively, for higher penetration levels, a cheap means of creating optional electricity demand rapidly within the area could be dump loads such as remote-controlled electrical heaters in district central heating (cogen) systems within the area. This policy is obviously most cost-effective when dealing with a substantial area containing several geographically dispersed wind farms, thus there are clearly economies of geographically dispersion.

In order to find the optimal installed capacity for a given transmission link capacity, one has to quantify the mean long-term losses from curtailing or dumping excess power generation. These potential losses can be found by matching historical local demand load data on an hourly basis with a simulation of power generation in the hourly time domain. It is essential that such simulations to the extent possible take account of geographical wind farm dispersion, the expected turbulence at wind sites and the mean travelling speed of weather patterns in the area.(30) If in addition to wind there is dispatchable local power generation within the transmission-constrained area, such actions may require coordination between wind and other power sources, such as gas, coal, hydro and co-generation plants.(31)

2.1.3 THE VOLTAGE LEVEL

Depending on the size of a wind project, it may either be connected to the distribution grid (8 to 30 kV) or the regional transmission grid, (above 30 KV). The cost of a local substation (including transformers and circuit breakers) to connect the wind farm to the grid will vary with the voltage level required.

2.1.4 CONTRACT TERM AND RISK SHARING

Wind power may be sold on long-term contracts with a contract term (duration) of 15-25 years, depending on the preferences of buyers and sellers. Generally speaking, wind turbine owners prefer long-term contracts, since this minimises their investment risks, given that most of their costs are fixed costs, which are known at the time of the commissioning of the wind turbines.

The ideal length of a contract depends on the expected technical performance of the wind farm over its lifetime. O&M costs, including reinvestment in the replacement of major turbine components will increase over the lifetime of a project, as turbines are gradually worn down, as shown in the previous section. It may be advantageous for both seller and buyer to have the option of decreasing the quantity of energy delivered towards the end of the lifetime of a project, since it may be uneconomic to do major repairs shortly before the project termination.

O&M costs, which contain both manpower and components costs, will vary with the development of the price level, thus the wind turbine owners will generally prefer a power purchasing contract, which is partially indexed to the general price level. Whether it is feasible to do indexed contracts depends on the traditions in the local institutional system.

Compared to traditional fossil-fuel fired thermal power plant, generation from wind (or hydro) plants gives buyers a unique opportunity to sign long-term power purchasing contracts with fixed or largely predictable, general price level indexed prices. This benefit of wind power may or may not be taken into account by the actors on the electrical power market, depending on institutional circumstances in the jurisdiction.

(30) For such a method, see e.g. Nørgaard & Holttinen (2004).

(31) John Olav Tande: Planning and Operation of Large Wind Farms in Areas with Limited Power Transfer Capacity. SINTEF Energy Research, Norway, 2006.

2.2 Electricity tariffs, quotas or tenders for wind energy

2.2.1 ELECTRICITY REGULATION IN A STATE OF FLUX

Governments around the world regulate electricity markets heavily, either directly or through nominally independent energy regulators, which interpret more general energy laws. This is true whether we consider jurisdictions with classical electricity monopolies or newer market structures with 'unbundling' of transmission and distribution grids from wholesale and retail electricity sales, allowing (some) competition in power generation and in retail sales of electricity. These newer market structures are often somewhat inaccurately referred to as 'deregulated' markets, but public regulation is necessary for more than just controlling monopolies (such as the natural monopolies of power transmission and distribution grids) and preventing them from exploiting their market position. Regulation is also necessary to create efficient market mechanisms. Hence, liberalised or deregulated markets are no less regulated than classical monopolies, just as stock markets are (and should be) strongly regulated.

When regulating electricity markets, governments have a vast number of somewhat conflicting concerns ranging from economic efficiency (low cost electricity generation and distribution) through to social equity (achieved through uniform electricity prices), competitiveness concerns (cross-subsidising energy use for large industrial costumers) and environmental concerns (ensuring energy savings and the use of renewable energy sources and CO_2).

Regulatory reforms have swept through electricity markets everywhere during the past couple of decades, leaving significant imbalances. In industrialised countries, these imbalances often manifest themselves as (temporary) excess generating capacity from conventional power plants and numerous special stranded cost provisions.[32]

As a new and capital-intensive technology, wind energy faces a double challenge in this situation of regulatory flux. Firstly, existing market rules and technical regulations were made to accommodate conventional generating technologies. Secondly, regulatory certainty and stability are economically more important for capital-intensive technologies with a long lifespan than for conventional fuel-intensive generating technologies.

Although many governments and regulators strive to ensure some degree of transparency in rulemaking and in the interpretation of existing rules, the regulatory reform process tends to resemble a traditional political market or game where incumbent and new market participants struggle for their economic interests when economic or technical regulations are being made. If in addition one considers other market distortions, such as transmission system bottlenecks, subsidies to coal mining, nuclear energy and other fuels (80% of the total energy subsidies in the EU-15 is paid to fossil fuels and nuclear energy according to the Environmental Energy Agency), electricity markets everywhere are still quite far from a textbook-type of free market.

New grids as well as reinvestment in the existing transmission grid and its maintenance and operation are generally financed through the standard transmission tariff system in each jurisdiction. The introduction of new technologies such as modern wind energy means that the grid structure will have to be adapted to this – in the case of wind in order to provide access to the wind resource base. In the past such major adaptions of the grid to new technologies were paid for by the vertically integrated public utilities, that is, ultimately financed though electricity tariffs. Nevertheless, in the present regulatory regime of many jurisdictions it is alleged that wind generation should be charged a special contribution to, say, grid reinforcement, when calculating the cost of energy, whereas no such requirement has been put on (or accounted for in relation to) conventional power generation technologies. This logic seems far from convincing, hence when considering market schemes for wind energy as we do in the next section, it should be borne in mind that wind power capacity is often subjected to additional costs, which are not charged specifically to conventional power generation technologies, or to cross-subsidisation within vertically-integrated companies.

[32] *Stranded costs* refers to costs incurred under previous regulatory schemes, where lawmakers consider it just or reasonable to compensate e.g. owners of old power plant for the impact of new regulatory schemes.

2.2.2 MARKET SCHEMES FOR RENEWABLE ENERGY[33]

Unregulated markets will not automatically ensure that goods or services are produced or distributed efficiently or that goods are of a socially acceptable quality. Likewise, unregulated markets do not ensure that production occurs in socially and environmentally acceptable ways. Market regulation is therefore present in all markets and a cornerstone of public policy. Anti-fraud laws, radio frequency band allocation, network safety standards, universal service requirements, product safety, occupational safety and environmental regulations are just a few examples of market regulations, which are essential parts of present-day economics and civilisation.

In many cases market regulation is essential because of so-called *external effects*, or spill-over effects, which are costs or benefits that are not traded or included in the price of a product, since they accrue to third parties which are not involved in the transaction. This is discussed in greater detail in Section 4.2 of this report. Typical examples are air pollution, greenhouse gas emissions or (conversely) environmental benefits from renewable power generation.

As long as conventional generating technologies pay nowhere near the real social (pollution) cost of their activities, there are thus strong economic efficiency arguments for creating market regulations for renewable energy, which attribute value to the environmental benefits of their use.

Although the economically most efficient method would theoretically be to use the polluter pays principle to its full extent – in other words, to let all forms of energy use bear their respective pollution costs in the form of a pollution tax – politicians have generally opted for narrower, second-best solutions.

In addition to some minor support to research, development and demonstration projects – and in some cases various investment tax credit or tax deduction schemes – most jurisdictions have opted to support the use of renewable energy through regulating either price or quantity of electricity from renewable sources. In general, *price* or *quantity* regulations are applied only to the supply side of the electricity market rather than the end consumer. This means that the supplier of wind energy is either paid an above-market price for the energy and the market determines the quantity, or the supplier is guaranteed a share of the energy supply (or installed power) while the market determines the energy price.

Neither of the two types of schemes can be said to be more *market-orientated* than the other, although some people favouring the second model tend to embellish it by referring to it as a 'market-based scheme'. Since both classes of schemes are market-based in relation to either price or quantity, they are referred to as such in the text below. In practice several jurisdictions (such as Denmark and Spain) operate both types of schemes.

REGULATORY PRICE-DRIVEN MECHANISMS

Generators of electricity from renewable sources (RES-E) usually receive financial support in terms of a subsidy per kW of capacity installed, or a payment per kWh produced and sold. The major strategies are:

- Investment-focused strategies: financial support is given by investment subsidies, soft loans or tax credits (usually per unit of generating capacity)
- Generation-based strategies: financial support is a fixed regulated feed-in tariff (FIT) or a fixed premium (in addition to the electricity price) that a governmental institution, utility or supplier is legally obligated to pay for renewable electricity from eligible generators.

The difference between fixed FITs and premiums is the following: for fixed FITs, the total feed-in price is fixed, for premium systems, the amount to be added to the electricity price is fixed. For the renewable plant owner, the total price received per kWh in the premium scheme (electricity price plus the premium), is less predictable than under a feed-in tariff, since this depends on a volatile electricity price.

[33] This section is a simplified representation of the four main types of market schemes used for wind energy in the European Union and North America. In practice, most schemes are somewhat more complex than described here. It is useful to consider these simplified versions for analytical purposes, however. Readers who are interested in a more detailed analysis should consult EWEA's publications on renewable energy support schemes – RE-Xpansion - available on www.ewea.org or consult the Wind Energy - The Facts publication and website: www.wind-energy-the-facts.org.

In principle, a mechanism based on a fixed premium/environmental bonus that reflects the external costs of conventional power generation could establish fair trade, fair competition and a level playing-field between renewable energy sources and conventional power sources in a competitive electricity market. From a market development perspective, the advantage of such a scheme is that it allows renewables to penetrate the market quickly, if their production costs drop below the electricity price plus premium. If the premium is set at the 'right' level (theoretically at a level equal to the external costs of conventional power), it allows renewables to compete with conventional sources without the need for governments to set 'artificial' quotas. Together with taxing conventional power sources in accordance with their environmental impact, well-designed fixed premium systems are theoretically the most effective way of internalising external costs.

In practice, however, basing the mechanism on the environmental benefits of renewables is challenging. Ambitious studies, such as the European Commission's ExternE project, which investigates the external costs of power generation, have been conducted in both Europe and America, illustrating that establishing exact costs is a complex matter. In reality, fixed premiums for wind power and other renewable energy technologies, such as the Spanish model, are based on estimated production costs and the electricity price rather than on the environmental benefits of RES.

Fixed price systems have been operating in countries such as Germany, Denmark, Spain and France for a substantial amount of time.[34] Typically, they order the grid operator to buy renewable electricity at a politically determined price, for example a percentage of the retail price of electricity. Provided the tariff is high enough to make wind projects profitable (given the local wind resource), the system is very popular with wind project developers, who have a long-term certainty of the sales price for their energy. The size and accessibility of the local wind resource and the capital costs and profitability requirements of the investors determine the quantity of investment (number of MW installed). Political uncertainty may cloud the picture, however, if developers are not given signed power purchasing agreements (PPA), which are enforceable in a court of law. Most present-days systems are financed by sharing the additional costs of the scheme on the energy bill of all electricity costumers in the jurisdiction.

Towards the end of the 1990s most of the preferential tariff schemes were modified to diminish their rent-creating[35] potential. From a public policy point of view this was deemed an undesirable effect, hence the schemes were patched up with limits on the *length of the time period or the number of full load hours*, for projects eligible for the preferential tariff. Another frequent modification was the differentiation of tariffs in relation to the size of the wind resource or the actual production on each site. These modified systems are sometimes referred to as 'advanced tariff' schemes. In general, most of these schemes are differentiated so that different sources of renewable energy receive different tariffs. This differentiation can be useful to limit the rent-creating potential and to allow more than a single type of renewable energy (the most profitable, given local resources) to enter the market.

Fixed premium mechanisms (found in Denmark, Spain, Canada and the USA, for example) have properties very similar to fixed price systems in that renewable energy is paid a fixed premium above the market price for electricity. In Europe these schemes are usually financed by a levy on the energy bill of all electricity costumers in the jurisdiction. In the case of the United States, the so-called PTC premium is given as a federal tax credit, whereas the Canadian WPPI scheme is a straight payment from the federal government. When comparing the level of European and Canadian bonus schemes

[34] In reality, schemes in Belgium and Italy, for example, are much the same, since lawmakers have fixed the price of so-called green certificates for the energy.

[35] *Economic rent* is a payment in excess of what is necessary to undertake a transaction. Loosely speaking, if a developer could live with a profit of x on his wind project, but he is able to make x+y, then the y is the economic rent of the project. From a public policy point of view economic rent income is similar to a windfall capital gain in that it does not affect the allocation of resources in the economy, but they do have an impact on the income distribution.

with the American PTC scheme, it should be kept in mind that a tax rebate is worth more than a taxable benefit after tax. For instance, with a marginal tax rate of 30%, the pre-tax value of a 1 cent tax credit is worth 1 / (1-0.3) = 1.43 cents of pre-tax revenues.[36]

In any price-based marked scheme the politicians cannot control the quantity of renewable energy brought to the market. Just like fixed-price schemes, investment (number of MW installed) and the quantity of energy flowing from wind projects will essentially depend on the renewable energy resource base (size and wind speeds on available sites and their accessibility) and on capital market conditions, that is, the cost of capital and required profitability compared to project costs.[37]

QUANTITY-BASED MARKET SCHEMES

Green certificate models (found in the UK, Sweden and Belgium, for example) or *renewable portfolio standard models* (used in several US states) are based on a mechanism whereby governments require that an increasing share of the electricity supply be based on renewable energy sources.

The desired level of RES generation or market penetration – a quota or a Renewable Portfolio Standard – is defined by governments. The most important systems are:

- Tendering or bidding systems: calls for tender are launched for defined amounts of capacity or electricity. Competition between bidders results in contract winners that receive a guaranteed tariff for a specified period of time.
- Tradable certificate systems: these systems are better known in Europe as Tradeable Green Certificate (TCG) systems, and in the US and Japan as renewable portfolio standards (RPS).

In such systems, the generators (producers), wholesalers, distribution companies or retailers (depending on who is involved in the electricity supply chain) are obliged to supply or purchase a certain percentage of electricity from RES. At the date of settlement, they have to submit the required number of certificates to demonstrate compliance. Those involved may obtain certificates:

- from their own renewable electricity generation;
- by purchasing renewable electricity and associated certificates from another generator; and/or
- by purchasing certificates without purchasing the actual power from a generator or broker, that is to say purchasing certificates that have been traded independently of the power itself.

The price of the certificates is determined, in principle, according to the market for these certificates (for example, NordPool).

The obligation is usually directed to electricity suppliers in the jurisdiction and accompanied by a penalty system in case of non-compliance. All electricity costumers finance the schemes, since electricity suppliers ultimately have to pass on their costs to electricity consumers.

Under this system wind developers are paid a variable premium above the market price of electricity. Notionally, wind turbines produce two products: Electricity, which is sold in electricity markets and green certificates, which are sold in a market for fulfilling the political obligation to supply renewable energy. The marketability of the renewables obligation and whether it can be separated from energy sales by the turbine owner varies very much between different jurisdictions. A basic problem in some schemes is that the certificate price may be highly volatile, e.g. due to political uncertainty surrounding the size of future renewable energy obligations (or potential opening of certificate markets between different jurisdictions). High prices can also be the result of planning and grid bottlenecks.

Renewable energy tenders are used in a number of jurisdictions (Denmark for offshore and formerly in France, Ireland and the UK). In this case a politically determined quantity of renewable energy is ordered for the electricity supply, and the cost is shared among

[36] This assumes that the tax credit can be offset from taxable profits or carried forward. If this is not the case, there is usually a potential to obtain the same effect through a leasing scheme.

[37] The Canadian WPPI scheme has a total budget cap, which essentially means that projects are granted support on a first come first serve basis.

electricity consumers. In general, the arrangement takes the form of a tender for long-term (15-25 year) power purchasing contracts, where prices per kWh are either fixed in nominal terms or partly or wholly indexed to a general price index.[38] Renewable energy tenders have a very bad track record in Europe, since early attempts (in the UK, Ireland and France) suffered from possibilities of »gaming the system« (partly due to lack of penalty for non-delivery) plus long project lead times combined with complex spatial planning procedures, which in the end could scupper winning projects completely.[39] A few tenders outside Europe (in North America and developing countries) have been more successful, particularly in jurisdictions, which normally handle electricity supply through public tendering systems.

VOLUNTARY APPROACHES

This type of strategy is mainly based on the willingness of consumers to pay premium rates for renewable energy, due to concerns over global warming, for example. There are two main categories:

- Investment focused: the most important are shareholder programmes, donation projects and ethical input
- Generation based: green electricity tariffs, with and without labelling

INDIRECT STRATEGIES

Aside from strategies which directly address the promotion of one (or more) specific renewable electricity technologies, there are other strategies that may have an indirect impact on the dissemination of renewables. The most important are:

- environmental taxes on electricity produced with non-renewable sources;
- taxes/permits on CO_2 emissions, e.g. the EU's Emissions Trading System, and
- the removal of subsidies previously given to fossil and nuclear generation.

There are two options for the promotion of renewable electricity via energy or environmental taxes:

- Exemption from taxes (such as energy, CO_2 and sulphur taxes)
- If there is no exemption for RES, taxes can be partially or wholly refunded

Both measures make RES more competitive in the market and are applicable for both established (old) and new plants.

Indirect strategies also include the institutional promotion of the deployment of RES plants, such as site planning and easy connection to the grid, and the conditions for feeding electricity into the system. Firstly, siting and planning requirements can reduce the potential opposition to renewable power plants if they address issues of concern, such as noise and visual or environmental impacts. Laws can be used, for example setting aside specific locations for development and/or omitting areas that are particularly open to environmental damage or injury to birds.

Secondly, there are complementary measures which concern the standardisation of economic and technical connection conditions. Interconnection requirements are often unnecessarily onerous and inconsistent and can lead to high transaction costs for project developers, particularly if they need to hire technical and legal experts. Safety requirements are essential, particularly in the case of interconnection in weak parts of the grid. However, unclear criteria on interconnections can potentially lead to higher prices for access to the grid and use of transmission lines, or even denial of transmission access. Therefore, it is recommended that authorities clarify the safety requirements and the rules on the burden of additional expenses.

Finally, rules must be established governing the responsibility for physical balancing associated with the variable production of some technologies, in particular wind power.

Regardless of the mechanisms chosen, a national (or international) support mechanism should be designed in a way that meets certain criteria. EWEA

[38] For example, the jurisdiction's consumer price index (which is also used for the adjustment of the American PTC).

[39] A number of preconditions are necessary for the success of such a system, see e.g. the analysis in Joanna I. Lewis and Ryan H. Wiser: *Supporting Localization of Wind Technology Manufacturing through Large Utility Tenders in Québec: Lessons for China.* Center for Resource Solutions for the Energy Foundation's China Sustainable Energy Program, Washington D.C., 2006.

has developed a list of criteria to keep in mind when designing mechanisms:

1. Simple and transparent in design and implementation, implying low administration costs
2. Accommodate the high diversity of the various technologies being supported
3. Encourage high investor confidence
4. Encourage lower manufacturing costs
5. Capable of reducing the price for power consumers
6. Ensure a high market uptake
7. Conform with the power market and with other policy instruments
8. Facilitate a smooth transition from the existing system
9. Help the benefits of wind power and other renewables to be felt at local and regional level
10. Increase public acceptance of renewable technologies
11. Able to internalise external costs - a central EU policy objective laid down in the EC Treaty.

A comprehensive analysis on designing market mechanisms for wind energy and other renewables energy technologies can be found in the report: *Support Schemes for Renewable Energy – A comparative analysis of payment mechanisms in the EU*.[40]

Regardless of whether a national or international support system is concerned, a single instrument is usually not enough to stimulate the long-term growth of electricity from renewable energy sources (RES-E). Since, in general, a broad portfolio of RES technologies should be supported, the mix of instruments selected should be adjusted according to each particular mix. Whereas investment grants are normally suitable for supporting immature technologies, feed-in tariffs are appropriate for the interim stage of the market introduction of a technology. A premium, or a quota obligation based on tradable green certificates (TGC), is likely only to be a relevant choice when:

- markets and technologies are sufficiently mature;
- the market size is large enough to guarantee competition among the market actors; and
- there is a well functioning power market with a liquid long term contract market (with a duration of at least ten years).

A mix of instruments can be supplemented, for example by tender procedures, which are sometimes useful for very large projects, such as for offshore wind.

2.2.3 OVERVIEW OF THE DIFFERENT RES-E SUPPORT SCHEMES IN EU-27 COUNTRIES

Figure 2.1 shows the evolution of the different RES-E support instruments from 1997-2007 in each of the EU-27 Member States. Some countries already have more than ten years' experience with RES-E support schemes.

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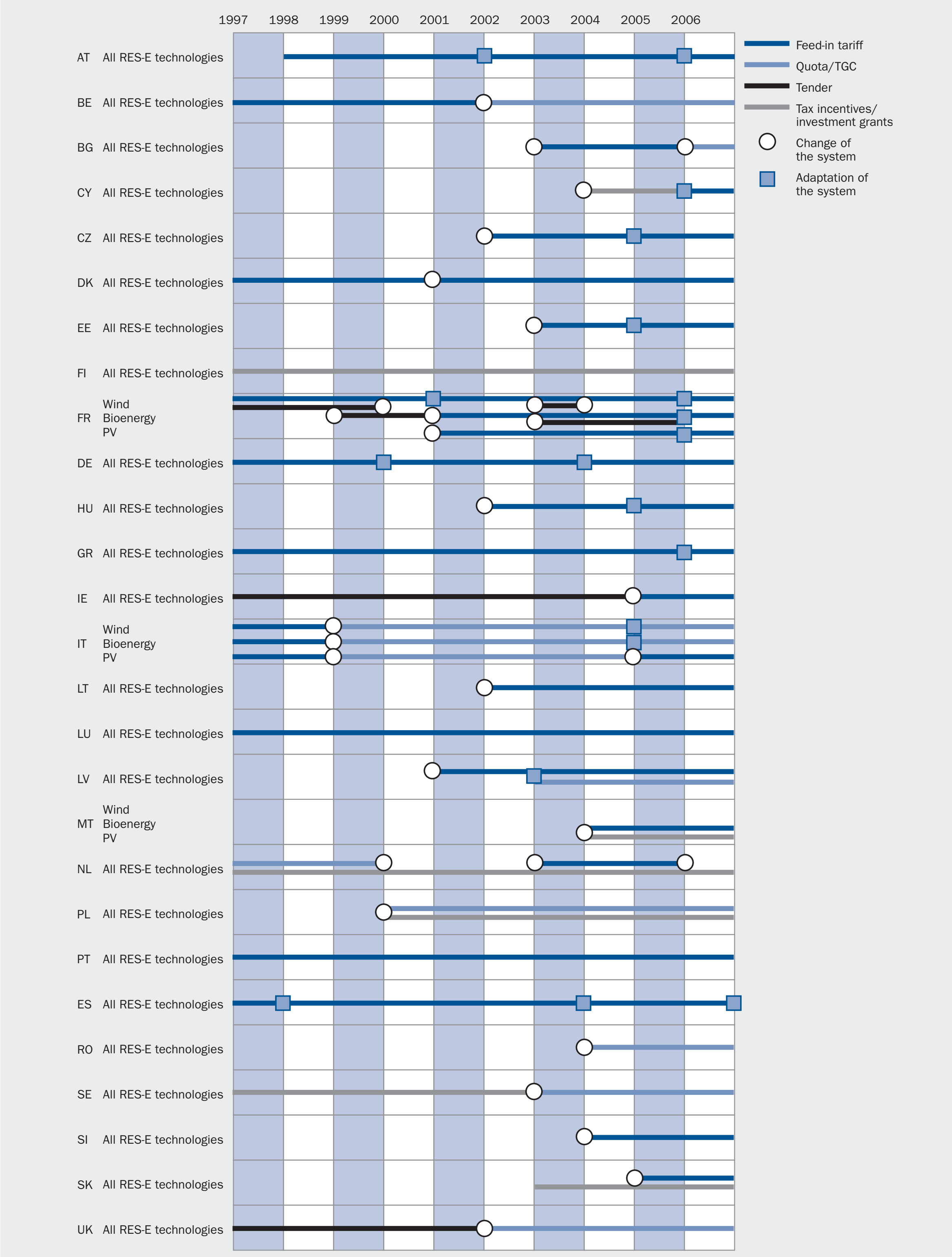
[40] The report can be downloaded from www.ewea.org.

FIGURE 2.1: **Evolution of the main policy support schemes in the EU-27**



Source: Ragwitz et al. (2007)

Initially, in the 'old' EU-15, only eight out of the 15 Member States avoided a major policy shift between 1997 and 2005. The current discussion within EU Member States focuses on the comparison between two opposing systems - the FIT system and the quota regulation in combination with a tradable green certificate (TGC) market. The latter has recently replaced existing policy instruments in some European countries, such as Belgium, Italy, Sweden, the UK and Poland. Although these new systems were not introduced until after 2002, the announced policy changes caused investment instabilities prior to this date. Other policy instruments, such as tender schemes, are no longer used as the main policy scheme in any European country. However, there are instruments, such as production tax incentives and investment incentives, that are frequently used as supplementary instruments; only Finland and Malta use them as their main support scheme.

Table 2.1 gives a detailed overview of the main support schemes for wind energy in the EU-27 Member States.

For more information on the EU Member States' main support schemes for renewables, and detailed country reports, see the Appendix.

TABLE 2.1: **Overview of the Main RES-E Support Schemes for Wind Energy in the EU-27 Member States as Implemented in 2007**

COUNTRY	MAIN SUPPORT INSTRUMENT FOR WIND	SETTINGS OF THE MAIN SUPPORT INSTRUMENT FOR WIND IN DETAIL
Austria	FIT	New fixed feed-in tariff valid for new RES-E plants permitted in 2006 and/or 2007: fixed FIT for years 1-9 (76.5 €/MWh for year 2006 as a starting year; 75.5 €/MWh for year 2007). Years 10 and 11 at 75 per cent and year 12 at 50 per cent.
Belgium	Quota obligation system with TGC; combined with minimum price for wind	Flanders, Wallonia and Brussels have introduced a quota obligation system (based on TGCs). The minimum price for wind onshore (set by the federal government) is 80 €/MWh in Flanders, 65 €/MWh in Wallonia and 50 €/MWh in Brussels. Wind offshore is supported at the federal level, with a minimum price of 90 €/MWh (the first 216 MW installed: 107 €/MWh minimum).
Bulgaria	Mandatory Purchase Price	Mandatory purchase prices (set by State Energy Regulation Commission): new wind installations after 01/01/2006 (duration 12 years each): (i) effective operation >2250 h/a: 79.8 €/MWh; (ii) effective operation <2250 h/a: 89.5 €/MWh.
Cyprus	FIT	Fixed feed-in tariff since 2005: in the first five years 92 €/MWh based on mean values of wind speeds; in the next ten years 48-92 €/MWh according to annual wind operation hours (<1750-2000h/a: 85-92 €/MWh; 2000-2550h/a: 63-85 €/MWh; 2550-3300h:/a 48-63 €/MWh).
Czech Republic	Choice between FIT and Premium Tariff	Fixed feed-in tariff: 88-114 €/MWh in 2007 (duration: equal to the lifetime); Premium tariff: 70-96 €/MWh in 2007 (duration: newly set every year).

COUNTRY	MAIN SUPPORT INSTRUMENT FOR WIND	SETTINGS OF THE MAIN SUPPORT INSTRUMENT FOR WIND IN DETAIL
Denmark	Market Price and Premium for Wind Onshore; Tendering System for Wind Offshore	Wind onshore: Market price plus premium of 13 €/MWh (20 years); additionally, balancing costs are refunded at 3 €/MWh, leading to a total tariff of approximately 57 €/MWh. Wind offshore: 66-70 €/MWh (i.e. Market price plus a premium of 13 €/MWh); a tendering system is applied for future offshore wind parks, balancing costs are borne by the owners.
Estonia	FIT	Fixed feed-in tariff for all RES: 52 €/MWh (from 2003 - present); current support mechanisms will be terminated in 2015.
Finland	Tax Exemptions and Investment Subsidies	Mix of tax exemptions (refund) and investment subsidies: Tax refund of 6.9 €/MWh for wind (4.2 €/MWh for other RES-E). Investment subsidies up to 40 for wind (up to 30 for other RES-E).
France	FIT	Wind onshore: 82 €/MWh for ten years; 28-82 €/MWh for the following five years (depending on the local wind conditions). Wind offshore: 130 €/MWh for 10 years; 30-130 €/MWh for the following 10 years (depending on the local wind conditions).
Germany	FIT	Wind onshore (20 years in total): 83.6 €/MWh for at least 5 years; 52.8 €/MWh for further 15 years (annual reduction of 2 is taken into account). Wind offshore (20 years in total): 91 €/MWh for at least 12 years; 61.9 €/MWh for further eight years (annual reduction of 2 taken into account).
Greece	FIT	Wind onshore: 73 €/MWh (Mainland); 84.6 €/MWh (Autonomous Islands). Wind Offshore: 90 €/MWh (Mainland); 90 €/MWh (Autonomous Islands); Feed-in tariffs guaranteed for 12 years (possible extension up to 20 years).
Hungary	FIT	Fixed feed-in tariff (since 2006): 95 €/MWh; duration: according to the lifetime of technology.
Ireland	FIT	Fixed feed-in tariff (since 2006); guaranteed for 15 years: Wind > 5MW: 57 €/MWh; Wind < 5MW: 59 €/MWh.
Italy	Quota obligation system with TGC	Obligation (based on TGCs) on electricity producers and importers. Certificates are issued for RES-E capacity during the first 12 years of operation, except biomass which receives certificates for 100 per cent of electricity production for first eight years and 60 per cent for next 4 years. In 2005 the average certificate price was 109 €/MWh.

COUNTRY	MAIN SUPPORT INSTRUMENT FOR WIND	SETTINGS OF THE MAIN SUPPORT INSTRUMENT FOR WIND IN DETAIL
Latvia	Main policy support instrument currently under development	Frequent policy changes and short duration of guaranteed feed-in tariffs (phased out in 2003) result in high investment uncertainty. Main policy currently under development.
Lithuania	FIT	Fixed feed-in tariff (since 2002): 63.7 €/MWh; guaranteed for ten years.
Luxemburg	FIT	Fixed feed-in tariff: (i) <0.5 MW: 77.6 €/MWh; (ii) >0.5 MW: max. 77.6 €/MWh (i.e. decreasing for higher capacities); guaranteed for ten years.
Malta	No support instrument yet	Very little attention to RES-E (also wind) support so far. A low VAT rate is in place.
Netherlands	Premium Tariff (0 €/MWh since August 2006)	Premium feed-in tariffs guaranteed for ten years were in place from July 2003. For each MWh RES-E generated, producers receive a green certificate. Certificate is then delivered to feed-in tariff administrator to redeem tariff. Government put all premium RES-E support at zero for new installations from August 2006 as it believed target could be met with existing applicants.
Poland	Quota obligation system. TGCs introduced end 2005 plus renewables are exempted from excise tax	Obligation on electricity suppliers with RES-E targets specified from 2005 to 2010. Poland has an RES-E and primary energy target of 7.5 per cent by 2010. RES-E share in 2005 was 2.6 per cent of gross electricity consumption.
Portugal	FIT	Fixed feed-in tariff (average value 2006): 74 €/MWh; guaranteed for 15 years.
Romania	Quota obligation system with TGCs	Obligation on electricity suppliers with targets specified from 2005 (0.7 per cent RES-E) to 2010 (8.3 per cent RES-E). Minimum and maximum certificate prices are defined annually by Romanian Energy Regulatory Authority. Non-compliant suppliers pay maximum price (i.e. 63 €/MWh for 2005-2007; 84 €/MWh for 2008-2012).
Slovakia	FIT	Fixed feed-in tariff (since 2005): 55-72 €/MWh; FITs for wind are set that way so that a rate of return on the investment is 12 years when drawing a commercial loan.
Slovenia	Choice between FIT and premium tariff	Fixed feed-in tariff: (i) <1MW: 61 €/MWh; (ii) >1MW: 59 €/MW. Premium tariff: (i) <1MW: 27 €/MWh; (ii) >1MW: 25 €/MWh. Fixed feed-in tariff and premium tariff guaranteed for 5 years, then reduced by 5 per cent. After ten years reduced by 10 per cent (compared to original level).

COUNTRY	MAIN SUPPORT INSTRUMENT FOR WIND	SETTINGS OF THE MAIN SUPPORT INSTRUMENT FOR WIND IN DETAIL
Spain	Choice between FIT and premium tariff	Fixed feed-in tariff: (i) <5MW: 68.9 €/MWh; (ii) >5MW: 68.9 €/MWh; Premium tariff: (i) <5MW: 38.3 €/MWh; (ii) >5MW: 38.3 €/MWh; Duration: no limit, but fixed tariffs are reduced after either 15, 20 or 25 years, depending on technology.
Sweden	Quota obligation system with TGCs	Obligation (based on TGCs) on electricity consumers. Obligation level of 51 per cent RES-E defined to 2010. Non-compliance leads to a penalty, which is fixed at 150 per cent of the average certificate price in a year (average certificate price was 69 €/MWh in 2007).
UK	Quota obligation system with TGCs	Obligation (based on TGCs) on electricity suppliers. Obligation target increases to 2015 (15.4 per cent RES-E; 5.5 per cent in 2005) and guaranteed to stay at least at that level until 2027. Electricity companies which do not comply with the obligation have to pay a buy-out penalty (65.3 €/MWh in 2005). Tax exemption for electricity generated from RES is available.

Source: Auer (2008)

In Appendix I, a more detailed overview is provided on implemented RES-E support schemes in the EU-27 Member States in 2007, detailing countries, strategies and the technologies addressed. In the EU-27, FITs serve as the main policy instrument.

For a detailed overview of the EU Member States' support schemes, please refer to Appendix I.

2.2.4. EVALUATION OF THE DIFFERENT RES-E SUPPORT SCHEMES (EFFECTIVENESS AND ECONOMIC EFFICIENCY)

In reviewing and evaluating the different RES-E support schemes described above, the key question is whether each of these policy instruments has been a success. In order to assess the success of the different policy instruments, the most important criteria are:

- Effectiveness: Did the RES-E support programmes lead to a significant increase in deployment of capacities from RES-E in relation to the additional potential? The effectiveness indicator measures the relationship of the new generated electricity within a certain time period to the potential of the technologies.
- Economic efficiency: What was the absolute support level compared to the actual generation costs of RES-E generators, and what was the trend in support over time? How is the net support level of RES-E generation consistent with the corresponding effectiveness indicator?

Other important performance criteria are the credibility for investors and the reduction of costs over time.

However, effectiveness and economic efficiency are the two most important criteria - these are discussed in detail in the following sections.

EFFECTIVENESS OF POLICY INSTRUMENTS

When analysing the effectiveness of RES-E support instruments, the quantities installed are of particular interest. In order to be able to compare the performance between the different countries, the figures are related to the size of the population. Here we look at all new RES-E in total, as well as wind and PV in detail.

Figure 2.2 depicts the effectiveness of total RES-E policy support for the period 1998 to 2005, measured in yearly additional electricity generation in comparison to the remaining additional available potential for each EU-27 Member State. The calculations refer to the following principal:

Effectiveness indicator for RES technology 'i' for the year n Existing electricity generation potential by RES technology in year 'n'

Additional generation potential of RES technology 'i' in year 'n' until 2020 Total generation potential of RES technology 'i' until 2020

It is clearly indicated in Figure 2.2 that countries with FITs as a support scheme achieved higher effectiveness compared to countries with a quota/TGC system or other incentives. Denmark achieved the highest effectiveness of all the Member States, but it is important to remember that very few new generation plants have been installed in recent years. Conversely, in Germany and Portugal there has been a significant increase in new installations recently. Among the new Member States, Hungary and Poland have implemented the most efficient strategies in order to promote 'new' renewable energy sources.

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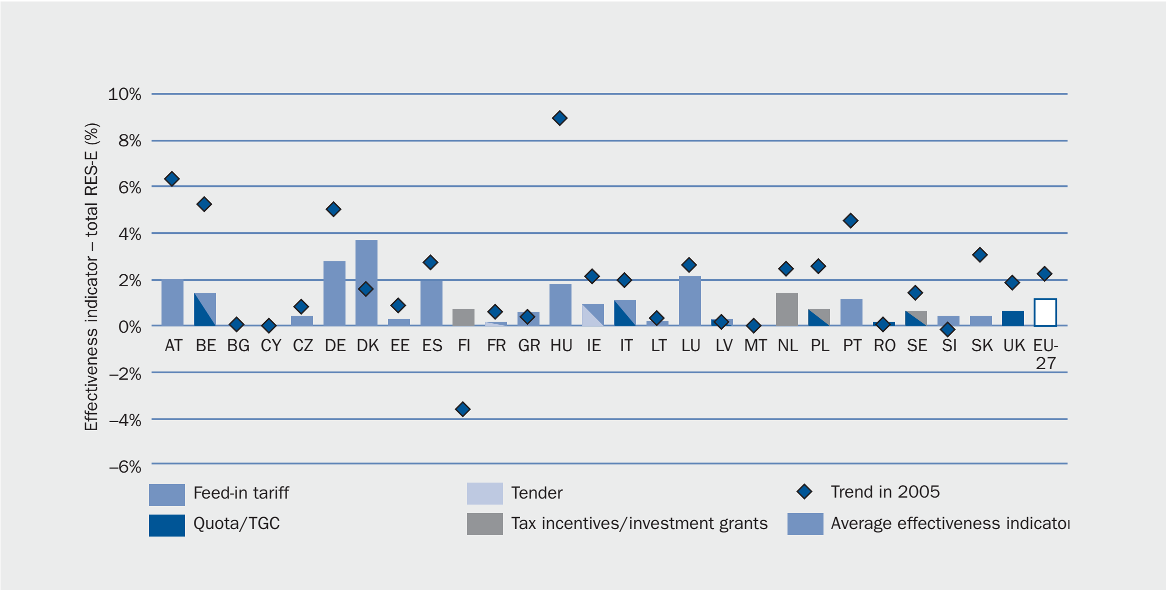
FIGURE 2.2: **Policy effectiveness of total RES-E support for 1998-2005 measured in annual additional electricity generation in comparison to the remaining additional available potential for each EU-27 Member State**



Source: EUROSTAT (2007)

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ECONOMIC EFFICIENCY

Next we compare the economic efficiency of the support programmes described above. In this context, three aspects are of interest:

1. Absolute support levels;
2. Total costs to society; and
3. Dynamics of the technology.

Here, as an indicator, the support levels are compared specifically for wind power in the EU-27 Member States.

Figure 2.3 shows that the support level and generation costs are almost equal. Countries with rather high average generation costs frequently show a higher support level, but a clear deviation from this rule can be found in the three quota systems in Belgium, Italy and the UK, for which the support is presently significantly higher than the generation costs. The reasons for the higher support level, expressed by the current green certificate prices, may differ; but the main reasons are risk premiums, immature TGC markets and inadequate validity times of certificates (Italy and Belgium).

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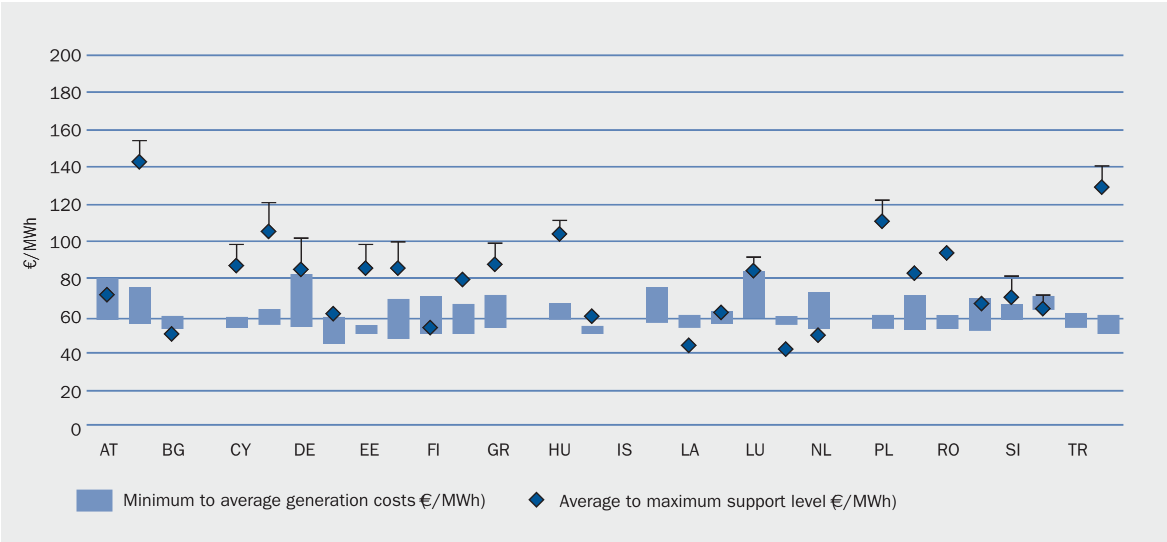
For Finland, the level of support for onshore wind is too low to initiate any steady growth in capacity. In the case of Spain and Germany, the support level indicated in Figure 2.3 appears to be above the average level of generation costs. However, the potential with fairly low average generation costs has already been exploited in these countries, due to recent market growth. Therefore, a level of support that is moderately higher than average costs seems to be reasonable. In an assessment over time, the potential technology learning effects should also be taken into account in the support scheme.

FIGURE 2.3: **Onshore wind: support level ranges (average to maximum support) in EU countries in 2006 (average tariffs are indicative) compared to the long-term marginal generation costs (minimum to average costs).**



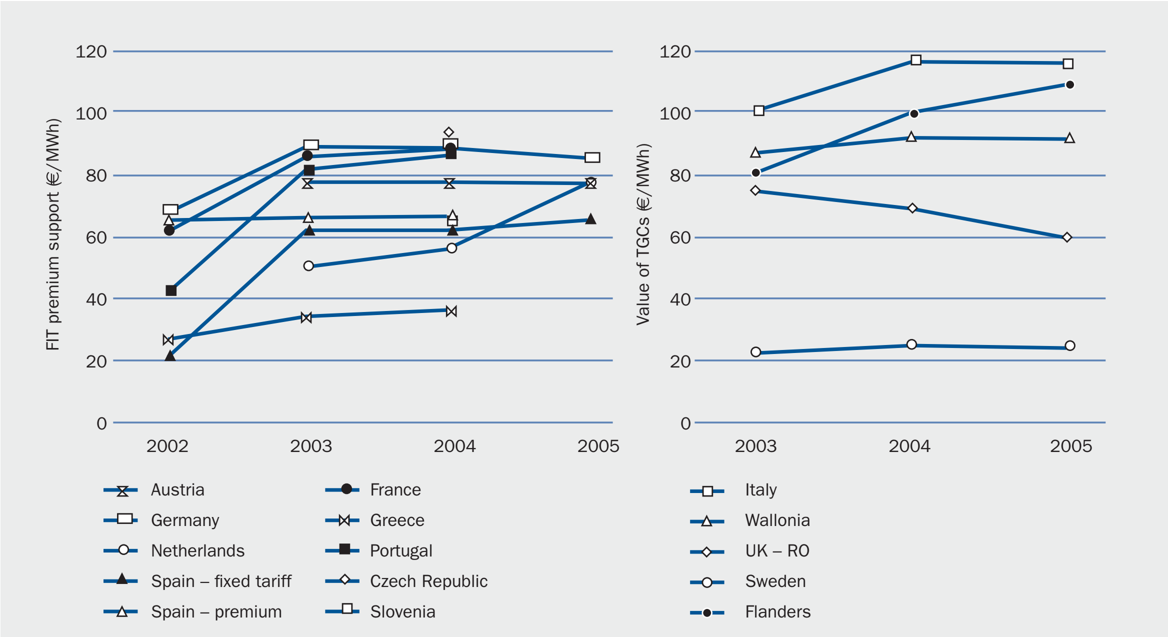
Note: Support level is normalised to 15 years

Source: Adapted from Ragwitz et al (2007).

Figure 2.4 illustrates a comparative overview of the ranges of TGC prices and FITs in selected EU-27 countries. With the exception of Sweden, TGC prices are much higher than those for guaranteed FITs, which also explains the high level of support in these countries, as shown in Figure 2.4.

For more information on offshore wind development in Denmark and its price, see the Appendix.

FIGURE 2.4: **Comparison of premium support level: FIT premium support versus value of TGCs. The FIT premium support level consists of FIT minus the national average spot market electricity price.**



Source: EEG

© Airtricity

3. Grids, markets and system integration

Introducing significant amounts of wind energy into the power system entails a series of economic impacts - both positive and negative.

Looking at the power system level, two main aspects determine wind energy integration costs: balancing needs and grid infrastructure.

- The additional *balancing cost* in a power system arises from the inherently variable nature of wind power, requiring changes in the configuration, scheduling and operation of other generators to deal with unpredicted deviations between supply and demand. Here, we demonstrate that there is sufficient evidence available from national studies to make a good estimate of such costs, and that they are fairly low in comparison with the generation costs of wind energy and with the overall balancing costs of the power system.

- *Network upgrades* are necessary for a number of reasons. Additional transmission lines and capacity need to be provided to reach and connect present and future wind farm sites and to transport power flows in the transmission and distribution networks. These flows result both from an increasing demand and trade of electricity and from the rise of wind power. At significant levels of wind energy penetration, depending on the technical characteristics of the wind projects and trade flows, the networks must be adapted to improve voltage management. Furthermore, the limited interconnection capacity often means the benefits coming from the widespread, omnipresent nature of wind, other renewable energy sources and electricity trade in general are lost. In this respect, any infrastructure improvement will bring multiple benefits to the whole system, and therefore its cost should not be allocated only to wind power generation.

The cost of modifying the power system increases in a more or less linear way as the proportion of wind power rises, and it is not easy to identify its 'economic optimum' as costs are accompanied by benefits. With the studies done so far, and by extending their results to higher wind energy penetration levels it can be seen that it is clearly economically (as well as environmentally) beneficial to integrate over 20% wind power into the EU power system. Moreover, a 20% wind power share of EU electricity demand is not an upper limit, since the many benefits of wind energy must be considered, including the contribution that it makes to the environment, security of supply and the other benefits that were laid out in Section 2.2.2 of this report.

3.1 Grid losses, grid reinforcement and grid management

Wind power is often generated in remote areas of the electricity grid, which means that wind power may contribute to reducing grid losses. On the other hand, wind farms may also be located in remote areas with low population density and consequently a weak electrical grid. This may mean additional costs for reinforcement of the regional transmission grid (usually below 400 kV) and possibly the bulk transmission grid (usually above 400 kV). Additionally, serial electrical compensation equipment may be required to stabilise the grid (depending on grid characteristics and the electrical properties of the wind turbines).

3.2 Intelligent grid management

A key constraint facing wind energy development internationally is bottlenecks in the electrical transmission grid. One reason is that good wind resources (just like oil, gas and coal) are frequently found in remote, sparsely populated areas with (thermally) limited transmission capacity to other parts of the electrical grid, where electricity is consumed.

For a given wind climate, cost minimisation per kWh usually implies a capacity factor of around 30%. But since wind speeds statistically follow a skewed distribution (see Section 1.6.1), high wind speeds occur only very rarely, whereas low wind speeds are very frequent. This means that if electrical interconnections are dimensioned to meet the maximum power output of wind farms, they will be used relatively inefficiently.

Furthermore, when several wind farms are sufficiently geographically dispersed within a transmission-congested area, their peak production will almost never coincide.

Finally, wind power generation in temperate climates often fits well with local power demand, which will to a certain extent diminish the amount of transmission capacity that is needed.

3.3 Cost of ancillary services other than balancing power

Ancillary services is a term generally used for various safety mechanisms which have been built into the generating units in the electrical grid. These services ensure an efficient transfer of energy through the grid (in the case of reactive power control) or provide stabilising mechanisms, which serve to avoid catastrophic grid collapse (blackout) so that errors in a single grid component or influence from lightning strikes do not cascade though the electrical grid.

In the past, when wind turbines were only intended to provide a small part of total generation, wind turbines were designed as passive components, that is, if a wind turbine control system detected that grid voltage or grid frequency was outside a permitted range, the turbine would cut itself off from the grid and stop turning. With large amounts of wind power on the grid, this is not an appropriate reaction, since it may exacerbate the initial grid instability problem, in the case of a collapse in voltage for example.

Modern wind turbines are therefore designed as active grid components, which contribute to stabilising the grid in case of electrical grid errors. This is the case for reactive power control, voltage and frequency control as well as 'fault ride though' capabilities of wind turbines.

The costs of these features, which meet the local grid connection requirements, are usually included in the turbine price.

3.4 Providing balancing power to cope with wind variability

Second to second or minute to minute variations in wind energy production are rarely a problem for installing wind power in the grid, since these variations will largely be cancelled out by the other turbines in the grid.

Wind turbine energy production may, however, vary from hour to hour, just as electricity demand from electricity costumers will vary from hour to hour. In both cases this means that other generators on the grid have to provide power at short notice to balance supply and demand on the grid.

The cost of providing this balancing service depends both on the type of other generating equipment available on the grid and on the predictability of the variation in net electricity demand, that is demand variations minus wind power generation. The more predictable the net balancing needs, the easier it will be to schedule the use of balancing power plants and the easier it will be to use the least expensive units to provide the balancing service (that is, to regulate generation up and down at short notice).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As mentioned previously, wind generation in temperate climates usually fits well with electricity demand, thus wind generation will generally reduce the hour-to-hour variability of net electricity demand compared to a situation with no wind power on the grid.

Wind generation can be reliably forecast a few hours ahead, so the scheduling process can be eased and balancing costs lowered. There are several commercial wind forecasting products available on the market, usually combined with improved meteorological analysis tools.

3.4.1 SHORT-TERM VARIABILITY AND THE NEED FOR BALANCING

For a power exchange, two kinds of markets are important: the spot market and the balancing market. On the *spot market*, demand and supply bids have to be submitted typically 12-48 hours in advance and by equalising demand and supply the spot prices are found for a 24-hour period. If forecast production and actual demand are not in balance, the regulating or *balancing market* has to be activated. This is especially important for wind-based power producers.

When bids have to be submitted to the spot market 12-36 hours in advance as is the case in a number of power markets in Europe, it will not be possible for wind producers to generate the amount that was forecast at all times. Thus, when wind power cannot produce according to the production forecasts submitted to the power market, other producers have to increase or reduce their power production in order to ensure that demand and supply of power are equal (balancing). However, other actors on the spot market may also require balancing power due to changes in demand, power plants shutting down and so on. If the balancing demand from other actors is uncorrelated with wind (or negatively correlated with wind), the ensuing increase in demand for power regulation will be less than one would estimate by looking at wind power in isolation and disregarding other balancing requirements.

3.4.2 ADDITIONAL BALANCING COST

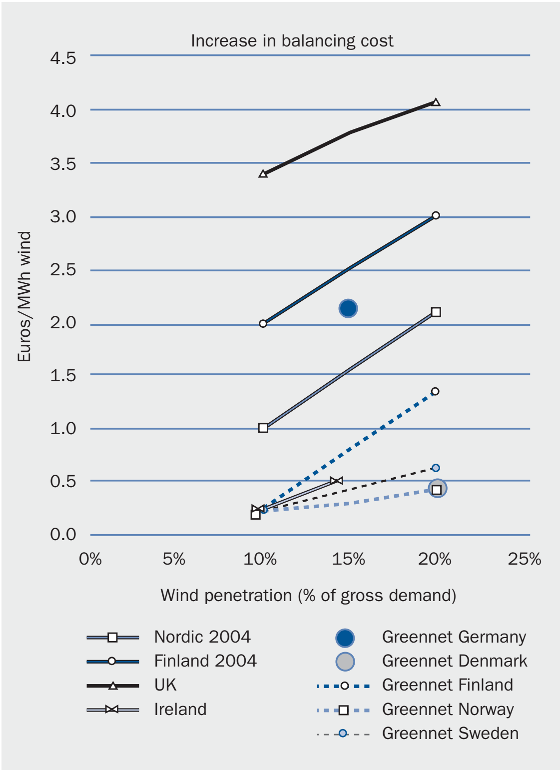
Additional balancing requirements in a system depend on a whole range of factors, including:

- the level of wind power penetration in the system, as well as the characteristic load variations and the pattern of demand compared with wind power variations;
- geographical aspects such as the size of the balancing area, the geographical spread of wind power sites and aggregation;
- the type and marginal costs of reserve plants (such as fossil and hydro);
- costs and characteristics of other mitigating options present in the system, such as storage;
- the possibility of exchanging power with neighbouring countries via interconnectors; and
- the operational routines of the power system, for example, how often the forecasts of load and wind energy are updated (gate-closure times) and the accuracy, performance and quality of the wind power forecast system used.

At wind energy penetrations of up to 20% of gross demand, system operating costs increase by about 1-4 €/MWh of wind generation. This is typically 5-10% or less of the wholesale value of wind energy.

Figure 3.1 illustrates the costs from several studies as a function of wind power penetration. Balancing costs increase on a linear basis with wind power penetration; the absolute values are moderate and always less than 4 €/MWh at 20% level (more often in the range below 2 €/MWh).

FIGURE 3.1: **Results from estimates for the increase in balancing and operating costs, due to wind power**



Holttinen, 2007

Note: The currency conversion used in this figure is 1 € = 0.7 GBP = 1.3 USD. For the UK 2007 study, the average cost is presented; the range for 20% penetration level is from 2.6 to 4.7 €/MWh.

Larger areas: Large balancing areas offer the benefits of lower variability. They also help decrease the forecast errors of wind power, and thus reduce the amount of unforeseen imbalance. Large areas favour the pooling of more cost-effective balancing resources. In this respect, the regional aggregation of power markets in Europe is expected to improve the economics of wind energy integration. Additional and better interconnection is the key to enlarging balancing areas. Certainly, improved interconnection will bring benefits for wind power integration, and these are presently quantified by studies such as TradeWind.

Reducing gate-closure times: This means operating the power system close to the delivery hour. For example, a re-dispatch, based on a 4–6 hour forecast update, would lower the costs of integrating wind power, compared to scheduling based on only day-ahead forecasts. In this respect, the emergence of intra-day markets is good news for the wind energy sector.

Improving the efficiency of the forecast systems: Balancing costs could be decreased if the wind forecasts could be improved, leaving only small deviations to the rest of the power system. Experience from different countries (Germany, Spain and Ireland) has shown that the accuracy of the forecast can be improved in several ways, ranging from improvements in meteorological data supply to the use of ensemble predictions and combined forecasting. In this context, the forecast quality is improved by making a balanced combination of different data sources and methods in the prediction process.

3.4.3 ADDITIONAL NETWORK COST

The consequences of adding more wind power into the grid have been analysed in several European countries (see Table 3.1). The national studies quantify grid extension measures and the associated costs caused by additional generation and demand in general, and by wind power production. The analyses are based on

load flow simulations of the corresponding national transmission and distribution grids and take into account different scenarios for wind energy integration using existing, planned and future sites.

It appears that additional grid extension/reinforcement costs are in the range of 0.1 to 5 €/MWh,- typically around 10% of wind energy generation costs for a 30% wind energy share. As for the additional balancing costs, the network cost increases with the wind penetration level. Grid infrastructure costs (per MWh of wind energy) appear to be around the same level as additional balancing costs for reserves in the system to accommodate wind power.

wind power is produced in a whole range of partial load states, wind farms will only utilise the full rated power transmission capacity for a fraction of the time. In some cases, where there is adjustable power production (such as hydro power with reservoir), the combination of wind and hydro can use the same transmission line.

The need to extend and reinforce the existing grid infrastructure is also critical. Changes in generation and load at one point in the grid can cause changes throughout the system, which may lead to power congestion. It is not possible to identify one (new) point of generation as the single cause of such difficulties, other than it being 'the straw that broke the camel's back'. Therefore, the

TABLE 3.1: **Grid upgrade costs from selected national system studies.**

COUNTRY	GRID UPGRADE COSTS€/KW	INSTALLED WIND POWER CAPACITY GW	REMARKS PORTUGAL 53 – 100 5.1 ONLY ADDITIONAL COSTS FOR WIND POWER
Portugal	53 – 100	5.1	Only additional costs for wind power
The Netherlands	60 – 110	6.0	Specifically offshore wind
United Kingdom	45 – 100	8.0	
United Kingdom	85 – 162	26.0	20% wind power penetration
Germany	100	36.0	Dena 1 study

SOURCE: Holtinnen et al, 2007

The costs of grid reinforcement due to wind energy cannot be directly compared, as circumstances vary significantly from country to country. These figures also tend to exclude the costs for improving interconnections between Member States. This subject has been investigated by the TradeWind project (www.trade-wind.eu), which investigates scenarios up to 2030.

There is no doubt that the transmission and distribution infrastructure will have to be extended and reinforced in most EU countries when large amounts of wind power are connected. However, these adaptations are necessary to accommodate wind power and also to connect other electricity sources to meet the rapidly growing European electricity demand and trade flows.

However, the grid system is not currently used to its full capacity and present standards and practices of transmission lines by TSOs are still largely based on the situation before wind energy came into the picture. As

allocation of costs required to accommodate a single new generation plant to one plant only (for example, a new wind farm) should be avoided.

In the context of a strategic EU-wide policy for long-term, large-scale grid integration, the fundamental ownership unbundling between generation and transmission is indispensable. A proper definition of the interfaces between the wind power plant itself (including the "internal grid" and the corresponding electrical equipment) and the "external" grid infrastructure (that is, the new grid connection and extension /reinforcement of the existing grid) needs to be discussed, especially for remote wind farms and offshore wind energy. This does not necessarily mean that the additional grid tariff components, due to wind power connection and grid extension/reinforcement, must be paid by the local/regional customers only. These costs could be socialised within a "grid infrastructure" component at national or even EU level. Of course, appropriate accounting rules would need to be established for grid operators.

3.5 Wind power reduces power prices

In a number of countries, wind power now has an increasing share of total power production. This applies particularly to countries such as Denmark, Spain and Germany, where the share of wind in terms of total power supply are currently (2008) 21%, 12% and 7% respectively. As such countries demonstrate, wind power is becoming an important player on the power market and such high shares can significantly influence prices.
Different power market designs have a significant influence on the integration of wind power. In the following section, short descriptions of the most important market designs within the increasingly liberalised European power industry are presented, as well as more detailed descriptions of spot and balancing markets. Finally, the impacts of Danish wind power on the Scandinavian power exchange, NordPool's Elspot, which comprises Denmark, Norway, Sweden and Finland, are discussed in more detail.

3.5.1 POWER MARKETS

As part of the gradual liberalisation of the EU electricity industry, power markets are increasingly organised in a similar way, where a number of closely related services are provided. This applies to a number of liberalised power markets, including those of the Nordic countries, Germany, France and the Netherlands. Common to all these markets is the existence of five types of power market:

- **Bilateral electricity trade or OTC (over the counter) Trading:** Trading takes place bilaterally outside the power exchange, and prices and amounts are not made public.
- **The day-ahead market (spot market):** A physical market where prices and amounts are based on supply and demand. Resulting prices and the overall amounts traded are made public. The spot market is a day ahead-market where bidding closes at noon for deliveries from midnight and 24 hours ahead.
- **The intraday market:** Quite a long time period remains between close of bidding on the day-ahead market, and the regulating power market (below). The intraday market is therefore introduced as an 'in between market', where participants in the day-ahead market can trade bilaterally. Usually, the product traded is the one-hour long power contract. Prices are published and based on supply and demand.
- **The regulating power parket (RPM):** A real-time market covering operation within the hour. The main function of the RPM is to provide power regulation to counteract imbalances related to day-ahead operation planned. Transmission System Operators (TSOs) alone make up the demand side of this market and approved participants on the supply side include both electricity producers and consumers.
- **The balancing market:** This market is linked to the RPM and handles participant imbalances recorded during the previous 24-hour period of operation. The TSO alone acts on the supply side to settle imbalances. Participants with imbalances on the spot market are price takers on the RPM/balance market.

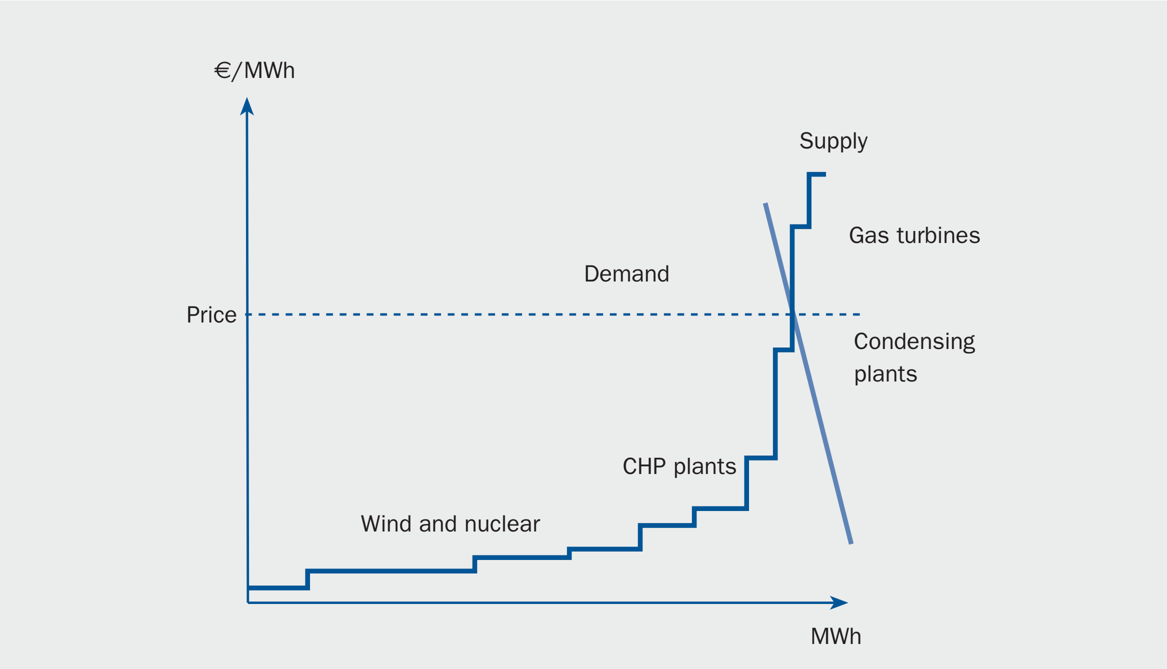
The day-ahead and regulating markets are particularly important for the development and integration of wind power in the power systems. The Nordic power exchange, NordPool, will be described in more detail in the following section as an example of these power markets.

THE NORDIC POWER MARKET - NORDPOOL SPOT MARKET

The NordPool spot market (Elspot) is a day-ahead market, where the price of power is determined by supply and demand. Power producers and consumers submit their bids to the market 12 to 36 hours in advance of delivery, stating the quantities of electricity supplied or demanded and the corresponding price. Then, for each hour, the price that clears the market (balancing supply with demand) is determined at the NordPool power exchange.

In principle, all power producers and consumers can trade at the exchange, but in reality, only big consumers (distribution and trading companies and large industries) and generators act on the market, while the smaller companies form trading cooperatives (as is the case for wind turbines), or engage with larger traders to act on their behalf. Approximately 45% of total electricity production in the Nordic countries is traded on the spot market. The remaining share is sold through long-term, bilateral contracts, but the spot price has a considerable impact on prices agreed in such contracts. In Denmark, the share sold at the spot market is as high as 80%.

FIGURE 3.2: **Supply and Demand Curve for the NordPool Power Exchange**



Source: Risø DTU

Figure 3.2 shows a typical example of an annual supply and demand curve. As shown, the bids from nuclear and wind power enter the supply curve at the lowest level, due to their low marginal costs, followed by combined heat and power plants; while condensing plants are those with the highest marginal costs of power production. Note that hydro power is not identified on the figure, since bids from hydro tend to be strategic and depend on precipitation and the level of water in reservoirs.

In general, the demand for power is highly inelastic (meaning that demand remains almost unchanged in spite of a change in the power price), with mainly Norwegian and Swedish electro-boilers, and power intensive industry contributing to the very limited price elasticity.

If power can flow freely in the Nordic area - that is to say, transmission lines are not congested, then there will only be one market price. But if the required power trade cannot be handled physically, due to transmission constraints, the market is split into a number of sub-markets, defined by the pricing areas. For example, Denmark splits into two pricing areas (Jutland/Funen and Zealand). Thus, if more power is produced in the Jutland/Funen area than consumption and transmission capacity can cover, this area would constitute a sub-market, where supply and demand would balance out at a lower price than in the rest of the NordPool area.

THE NORDIC POWER MARKET - THE REGULATING MARKET

Imbalances in the physical trade on the spot market must be levelled out in order to maintain the balance between production and consumption, and to maintain power grid stability. Totalling the deviations from bid volumes at the spot market yields a net imbalance for that hour in the system as a whole. If the grid is congested, the market breaks up into area markets, and equilibrium must be established in each area. The main tool for correcting such imbalances, which provides the necessary physical trade and accounting in the liberalised Nordic electricity system, is the regulating market.

The regulating power market and the balancing market may be regarded as one entity, where the TSO acts as an important intermediary or facilitator between the supply and demand of regulating power. The TSO is the body responsible for securing the system functioning in a region. Within its region, the TSO controls and manages the grid, and to this end, the combined regulating power and balancing market is an important tool for managing the balance and stability of the grid. The basic principle for settling imbalances is that participants causing or contributing to the imbalance will pay their share of the costs for re-establishing the balance. Since September 2002, the settling of imbalances among Nordic countries has been done based on common rules. However, the settling of imbalances within a region differs from country to country. Work is being done to analyse the options for harmonising these rules.

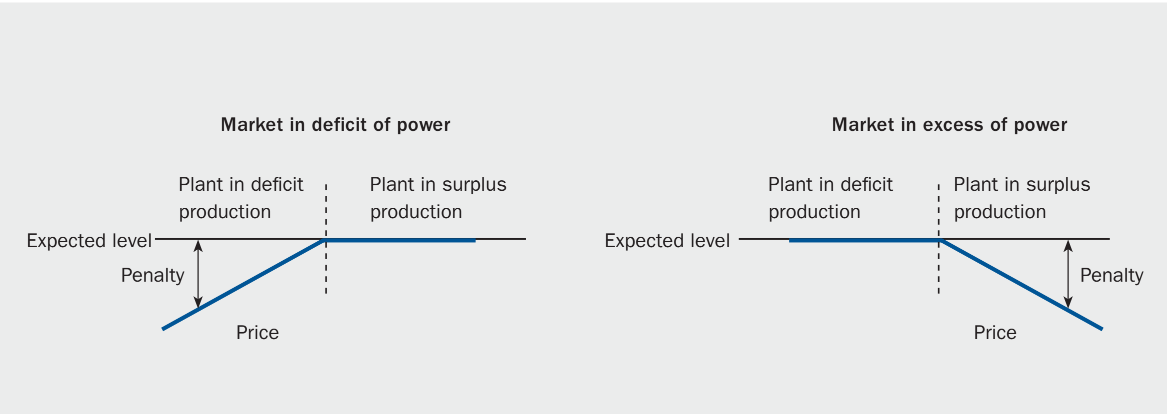
If the vendors' offers or buyers' bids on the spot market are not fulfilled, the regulating market comes into force. This is especially important for wind electricity producers. Producers on the regulating market have to deliver their offers 1-2 hours before the hour of delivery, and power production must be available within 15 minutes of notice being given. For these reasons, only fast-response power producers will normally be able to deliver regulating power.

It is normally only possible to predict the supply of wind power with a certain degree of accuracy 12-36 hours in advance. Consequently, it may be necessary to pay a premium for the difference between the volume offered to the spot market and the volume delivered. Figure 3.3 shows how the regulatory market functions in two situations: a general deficit on the market (left part of the figure) and a general surplus on the market (right part of figure).

If the market tends towards a deficit of power, and if power production from wind power plants is lower than offered, other producers will have to adjust regulation (up) in order to maintain the power balance. In this case, the wind producer will be penalised and get a lower price for his electricity production than the spot market price. The further off-track the wind producer is, the higher the expected penalty. The difference between the regulatory curves and the stipulated spot market price in Figure 3.3 illustrates this. If wind power production is higher than the amount offered, wind power plants effectively help to eliminate market deficit and therefore receive the spot price for the full production without paying a penalty.

If the market tends towards an excess of power, and if power production from the wind power plant is higher than offered, other producers will have to adjust regulation (down) in order to maintain the power balance. In this case, the wind producer will be penalised and get a lower price for his electricity production than the spot market price. Again, the further off track the wind producer, the higher the expected premium. However, if wind power production is lower than the bid, then wind power plants help to eliminate surplus on the market, and therefore receive the spot price for the full production without paying a penalty.

FIGURE 3.3: **The functioning of the regulatory market**



Source: Risø DTU

© Acciona

Until the end of 2002, each country participating in the NordPool market had its own regulatory market. In Denmark, balancing was handled by agreements with the largest power producers, supplemented by the possibility of TSOs buying balancing power from abroad if domestic producers were too expensive or unable to produce the required volumes of regulatory power. A common Nordic regulatory market was established at the beginning of 2003 and both Danish areas participate in this market.

In Norway, Sweden and Finland, all suppliers on the regulating market receive the marginal price for power regulation at the specific hour. In Denmark, market suppliers get the price of their bid to the regulation market. If there is no transmission congestion, the regulation price is the same in all areas. If bottlenecks occur in one or more areas, bids from these areas on the regulating market are not taken into account when forming the regulation price for the rest of the system, and the regulation price within the area will differ from the system regulation price.

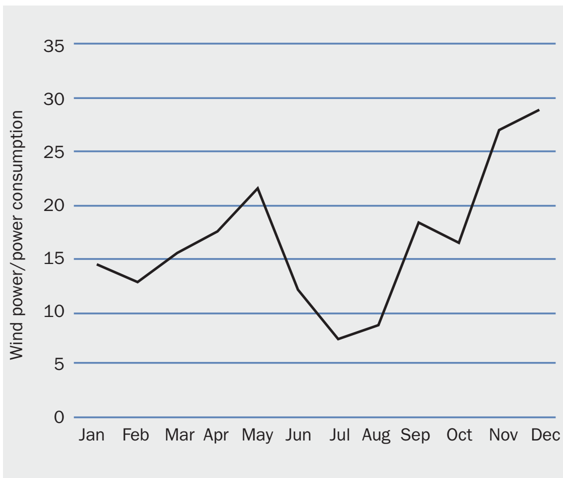
In Norway, only one regulation price is defined and this is used both for sale and purchase at the hour when settling the imbalances of individual participants. This implies that participants helping to eliminate imbalances are rewarded even if they do not fulfil their actual bid. Thus if the market is in deficit of power and a wind turbine produces more than its bid, then the surplus production is paid a regulation premium corresponding to the penalty for those plants in deficit.

3.5.2 WIND POWER'S IMPACT ON THE POWER MARKETS – AN EXAMPLE

Denmark has a total capacity of a little more than 3,200 MW of wind power - approximately 2,800 MW from land turbines and 400 MW offshore. In 2007, around 20% of domestic power consumption was supplied by wind power, which makes Denmark the leading country in terms of wind power penetration (followed by Spain, where the share of wind as a total of electricity consumption is 12%.

Figure 3.4 shows wind power's average monthly coverage of power consumption in Denmark. Normally, the highest wind-generated production is from January to March. However, as 2006 was a bad wind year in Denmark, this was not the case. The contribution during the summer is normally at a fairly low level.

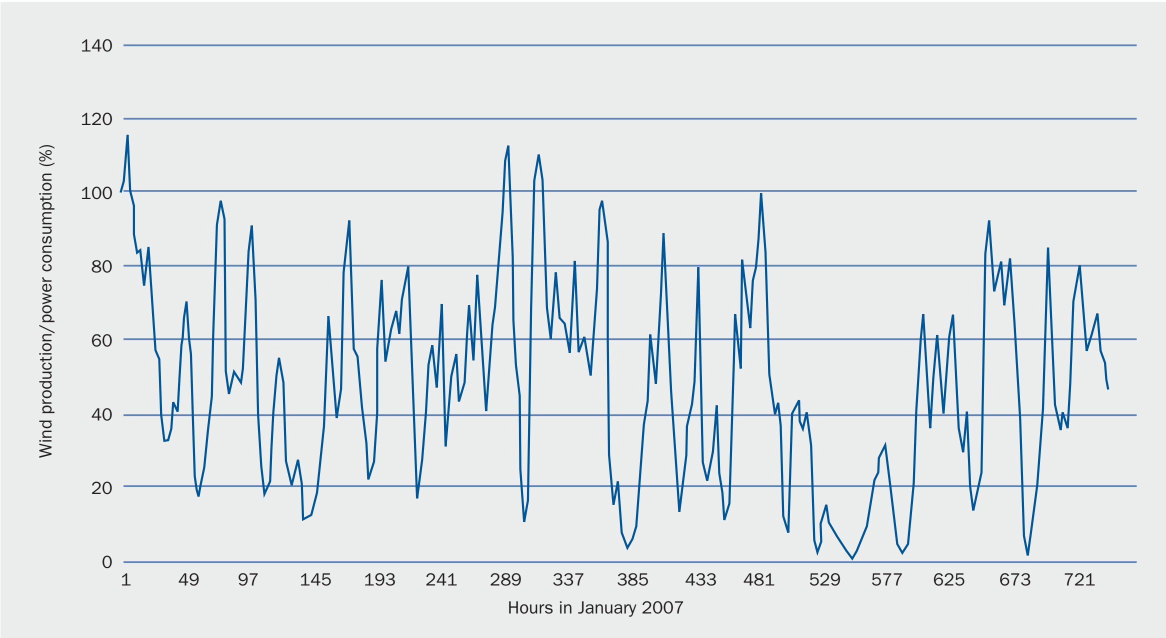
FIGURE 3.4: **The share of wind power in power consumption calculated as monthly averages for 2006, Denmark**



Source: Risø DTU

Considerable hourly variations are found in wind power production for western Denmark, as illustrated in Figure 3.5. January 2007 was a tremendously good wind month, with an average supply of 44% of power consumption in western Denmark, and, as shown, wind-generated power exceeded power consumption on several occasions. Nevertheless, there were also periods with low and no wind in January. In such cases, wind power can significantly influence price determination on the power market. This will be discussed in more detail in the following section.

FIGURE 3.5: **Wind power as a percentage of domestic power consumption in January 2007, hourly basis**



Source: Risø DTU

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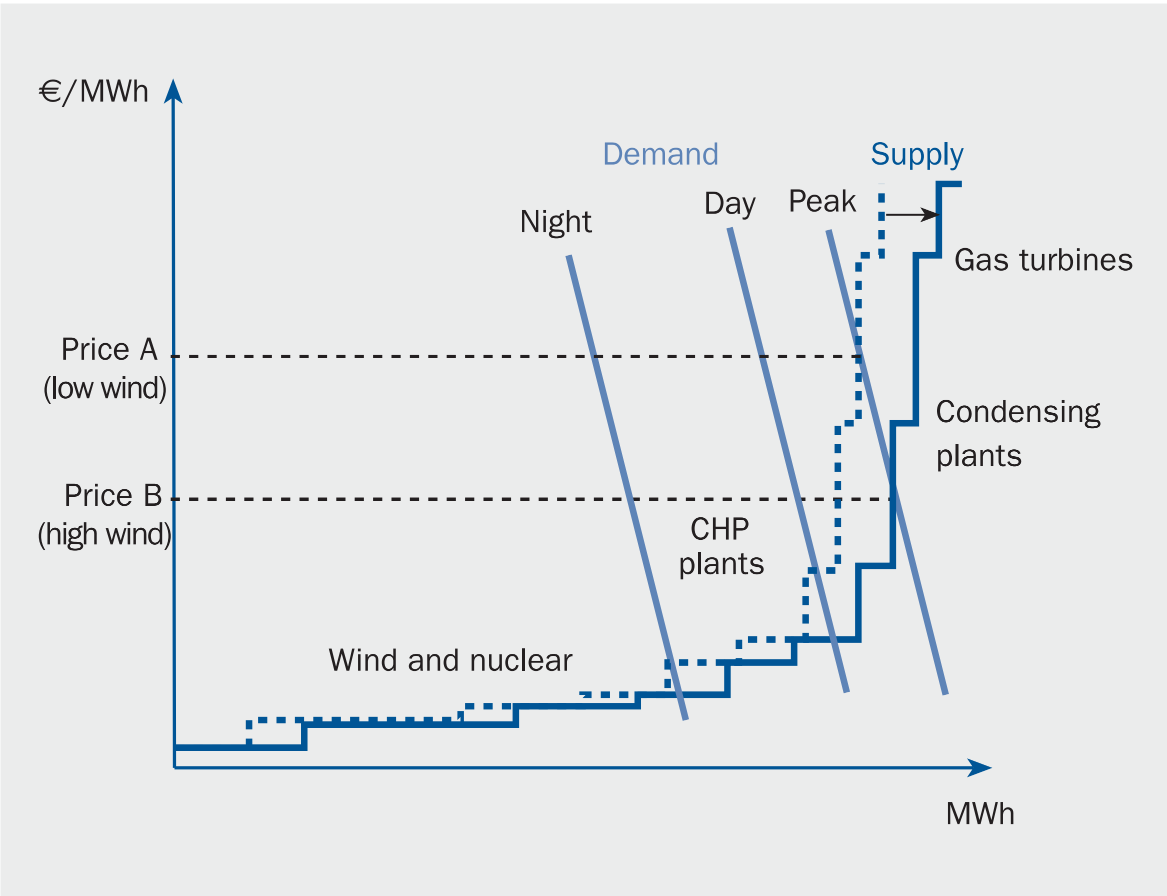
How does wind power influence the power price on the spot market?

Wind power is expected to influence prices on the power market in two ways:

- Wind power normally has a low marginal cost (zero fuel costs) and therefore enters near the bottom of the supply curve. This shifts the supply curve to the right (see Figure 3.6), resulting in a lower power price, depending on the price elasticity of the power demand. In the figure below, the price is reduced from Price A to Price B when wind power decreases during peak demand. In general, the price of power is expected to be lower during periods with high wind than in periods with low wind. This is called the 'merit order effect'.
- As mentioned above, there may be congestions in power transmission, especially during periods with high wind power generation. Thus, if the available transmission capacity cannot cope with the required power export, the supply area is separated from the rest of the power market and constitutes its own pricing area. With an excess supply of power in this area, conventional power plants have to reduce their production, since it is generally not economically or environmentally desirable to limit the power production of wind. In most cases, this will lead to a lower power price in this sub-market.

FIGURE 3.6: **How wind power influences the power spot price at different times of day**

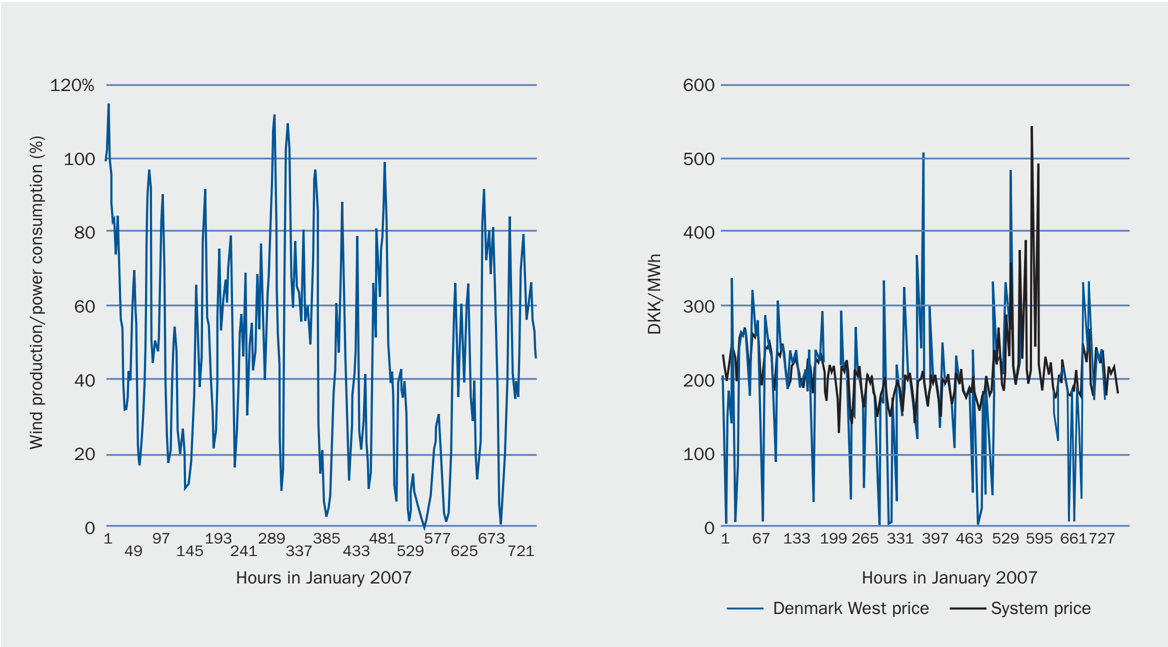


Source: Risø DTU

The way in which wind power influences the power spot price due to its low marginal cost is shown in Figure 3.6. When wind power supply increases, it shifts the power supply curve to the right. At a given demand, this implies a lower spot price at the power market, as shown. However, the impact of wind power depends on the time of the day. If there is plenty of wind power at midday, during the peak power demand, most of the available generation will be used. This implies that we are at the steep part of the supply curve (see Figure 3.6) and, consequently, wind power will have a strong impact, reducing the spot power price significantly (from Price A to Price B in Figure 3.6). But if there is plenty of wind-produced electricity during the night, when power demand is low and most power is produced on base load plants, we are at the flat part of the supply curve and consequently the impact of wind power on the spot price is low.

The congestion problem arises because Denmark, especially the western region, has a very high share of wind power, and in cases of high wind power production, transmission lines are often fully utilised.

FIGURE 3.7: **Left - wind power as percentage of power consumption in western Denmark; right - spot prices for the same area and time period**



Source: Risø DTU

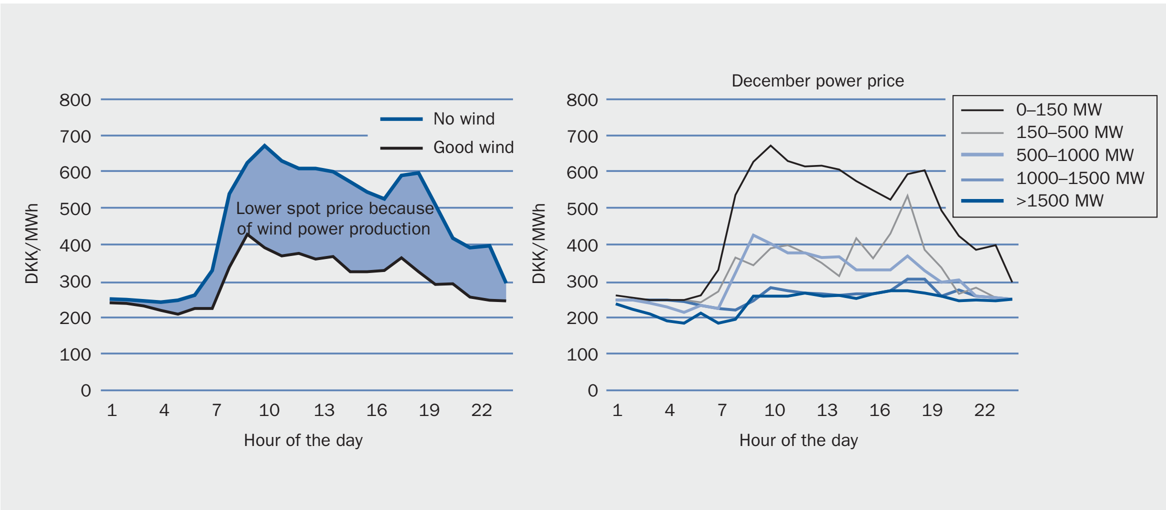
In Figure 3.7, this congestion problem is illustrated for January 2007, when the share of wind-generated electricity in relation to total power consumption for west Denmark was more than 100% at certain periods (Figure 3.7 left part). This means that during these periods, wind power supplied more than all the power consumed in that area. If the prioritised production from small, decentralised CHP plants is added on top of wind power production, there are several periods with a significant excess supply of power, part of which may be exported. However, when transmission lines are fully utilised, there is a congestion problem. In that case, equilibrium between demand and supply needs to be reached within the specific power area, requiring conventional producers to reduce their production, if possible. The consequences for the spot power price are shown on right graph of Figure 3.7. By comparing the two graphs in Figure 3.7, it is can be seen clearly that there is a close relationship between wind power in the system and changes in the spot price for this area.

The consequences of the two issues mentioned above for the west Denmark power supply area are discussed below. It should be mentioned that similar studies are available for Germany and Spain, which show almost identical results.

Impact of wind power on spot prices

The analysis entails the impacts of wind power on power spot prices being quantified using structural analyses. A reference is fixed, corresponding to a situation with zero contribution from wind power in the power system. A number of levels with increasing contributions from wind power are then identified and, relating to the reference, the effect of wind power's power production is calculated. This is illustrated in the left-hand graph in Figure 3.8, where the shaded area between the two curves approximates the value of wind power in terms of lower spot power prices.

FIGURE 3.8: **The impact of wind power on the spot power price in the west Denmark power system in December 2005**



Note: The calculation only shows how the production contribution from wind power influences power prices when the wind is blowing. The analysis cannot be used to answer the question 'What would the power price have been if wind power was not part of the energy system?'

Source: Risø DTU

In the right-hand graph in Figure 3.8, more detail is shown with figures from the West Denmark area. Five levels of wind power production and the corresponding power prices are depicted for each hour of the day during December 2005. The reference is given by the '0-150 MW' curve, which thus approximates those hours of the month when the wind was not blowing. Therefore, this graph should approximate the prices for an average day in December 2005, in a situation with zero contribution from wind power. The other curves show increasing levels of wind power production: the 150-500 MW curve shows a situation with low wind, increasing to storm in the >1,500 MW curve. As shown, the higher the wind power production, the lower the spot power price is in this area. At very high levels of wind power production, the power price is reduced significantly during the day, but only falls slightly during the night. Thus there is a significant impact on the power price, which might increase in the long term if even larger shares of wind power are fed into the system.

Figure 3.8 relates to December 2005, but similar figures are found for most other periods during 2004 and 2005, especially in autumn and winter, owing to the high wind power production in these time periods. Of course, 'noise' in the estimations does exist, implying 'overlap' between curves for the single categories of wind power. Thus, a high amount of wind power does not always imply a lower spot price than that with low wind power production, indicating that a significant statistical uncertainty exists. Of course, factors other than wind power production influence prices on the spot market. But the close correlation between wind power and spot prices is clearly verified by a regression analysis carried out using the West Denmark data for 2005, where a significant relationship is found between power prices, wind power production and power consumption.

When wind power reduces the spot power price, it has a significant influence on the price of power for consumers. When the spot price is lowered, this is beneficial to all power consumers, since the reduction in price applies to all electricity traded – not only to electricity generated by wind power.

Figure 3.9 shows the amount saved by power consumers in Western and Eastern Denmark due to wind power's contribution to the system. Two calculations were performed: one using the lowest level of wind power generation as the reference ('0-150 MW'), in other words assuming that the power price would have followed this level if there was no contribution from wind power in the system, and the other more conservative, utilising a reference of above 500 MW. For each hour, the difference between this reference level and the levels with higher production of wind power is calculated. Summing the calculated amounts for all hours of the year gives the total benefit for power consumers of wind power lowering spot prices of electricity.

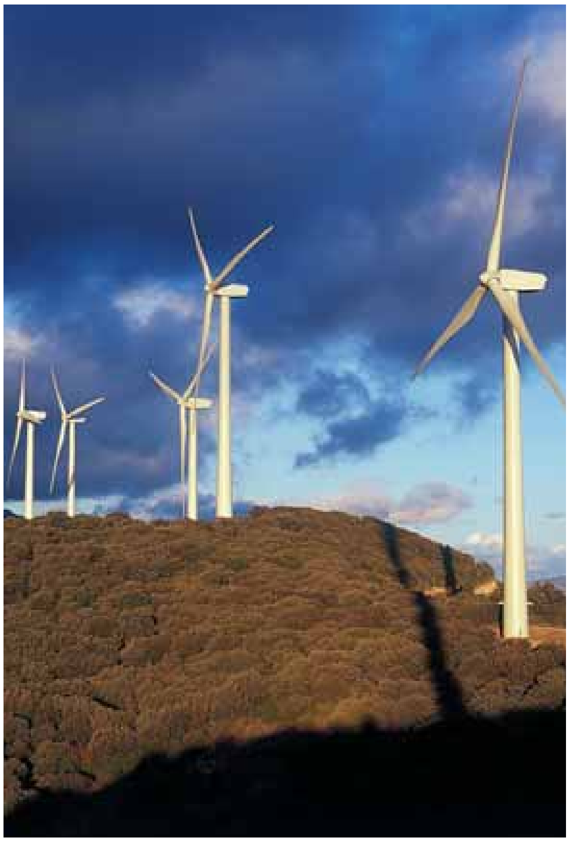


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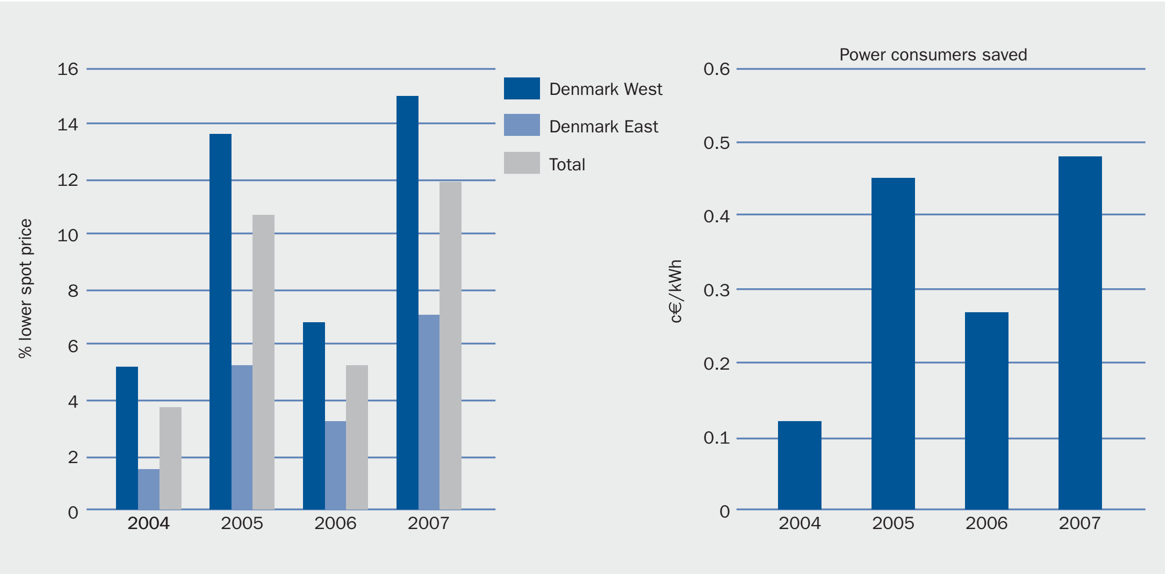
Figure 3.9 shows how much higher the consumer price would have been (excluding transmission tariffs, taxes and VAT) if wind power had not contributed to power production.

FIGURE 3.9: **Annual percentage and absolute savings by power consumers in western and eastern Denmark in 2004-2007 due to wind power depressing the spot market electricity price**



Source: Risø DTU

In general in 2004-2007, the cost of power to the consumer (excluding transmission and distribution tariffs, taxes and VAT) would have been approximately 4-12 per cent higher in Denmark if wind power had not contributed to power production. Wind power's strongest impact is estimated to have been for Western Denmark, due to the high penetration of wind power in this area. In 2007, this adds up to approximately 0.5 c€/kWh saved by power consumers, as a result of wind power lowering electricity prices, compared to the support given to wind power as FITs of approximately 0.7 c€/kWh. Thus, although the expenses of wind power are still greater than the financial benefits for power consumers, a significant reduction of net expenses is certainly achieved due to lower spot prices.

Finally, though having a smaller impact, wind power clearly reduces power prices, even within the large Nordic power system. Thus although wind power in the Nordic countries is mainly established in Denmark, all Nordic power consumers benefit financially due to the presence of Danish wind power on the market.

Is wind responsible for the recent increases in the electricity bill?

In 2005, the European Commission released a communication on the support of electricity from renewable energy sources (EC, 2005). The communication calculated the additional cost that renewable energy systems impose on the EU Member States due to the application of EC Directive 77/2001 on the promotion of electricity produced with renewable energy sources. The communication asserted that such cost is of between 4% and 5% of the electricity bill in Germany, Spain and the United Kingdom and of around 15% in Denmark. Wind supplies 7% of the electricity in Germany, 9% in Spain and 20% in Denmark. Note that the cost to which the Commission refers is for all renewables, not only wind energy.

In the same way, these percentages do not take into account the reduction in the electricity bill as a consequence of the merit order effects, described above. What is more, the percentage of cost attributable to wind and other renewables will appear inflated because once wind reduces the kWh price and thus the global electricity bill, the remuneration of wind as a percentage of a (now lower) bill will have a greater weight.

Independent calculations made by the Spanish authorities (IDAE, 2005) show that the financial impact of RES-e support is very modest: the support system for RES-e accounted for around 6% of the total electricity service cost in 2003, and supplied around 6% of the electricity consumed that year.

In Germany, the Ministry of the Environment (BMU, 2007b) states that renewable energies do not bear the main responsibility for the recent increase in German electricity prices (and in the rest of the EU). 17% of the rise in the electricity price between 2004 and 2005 can be attributed to the Renewable Energy Sources Act. The lion's share of that increase (83%) was due to conventional generation and transmission and the Heat-Power Generation Act.

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3.5.3 EFFECT THAT REACHING THE EU 2020 TARGETS COULD HAVE ON POWER PRICES

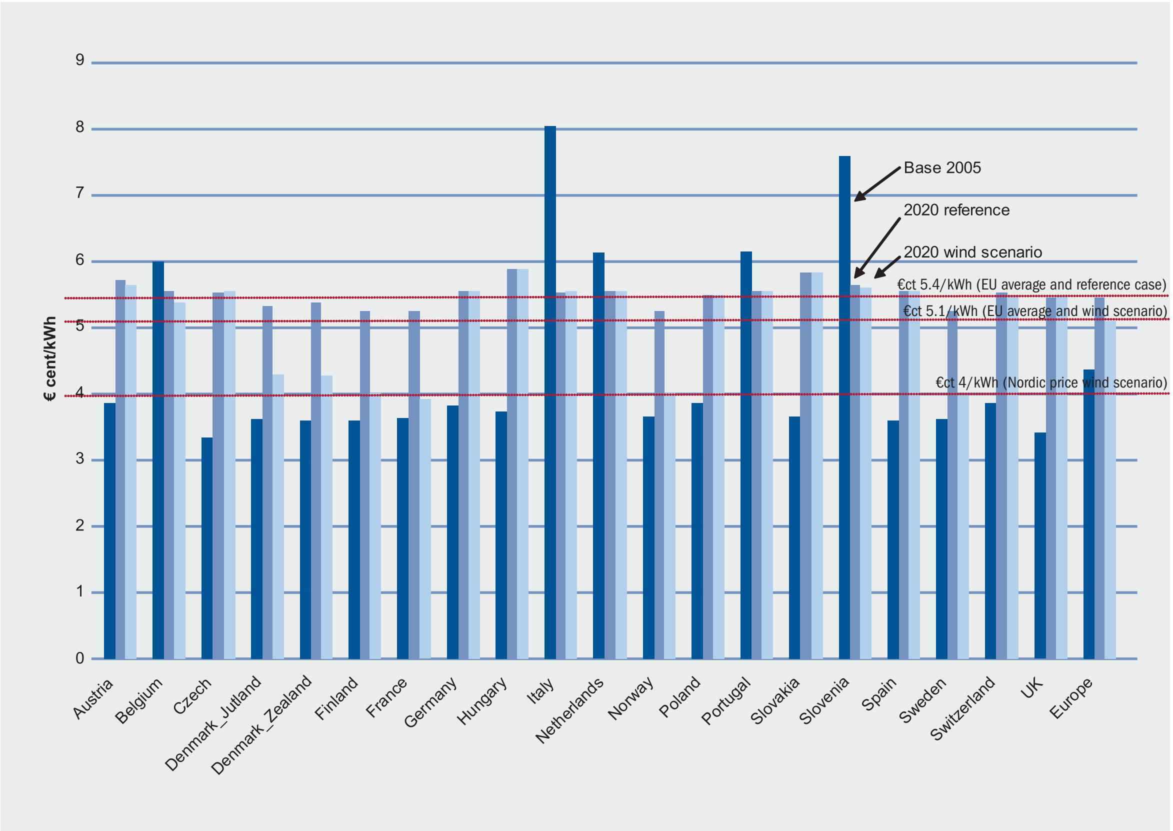
In a 2008 study[41], Econ Pöyry used its elaborate power model to investigate the electricity price effects of increasing wind power in Europe to 13% in 2020.

In a business as usual scenario, it is assumed that the internal power market and additional investments in conventional power will more or less level out the power prices across Europe up to 2020 (reference scenario). However, in a large-scale wind scenario (wind covering 13% of EU's electricity consumption) this might not be the case.

In areas where power demand is not expected to increase very much and in areas where the amount of new deployment of wind energy is larger than the increase in power demand, wind energy will substitute the most expensive power plants. This will lower the price levels in these areas, the study shows.

In the EU, the expected price level is around 5.4 cent €/kWh on average in 2020 for the reference case (Figure 3.11) with a slightly higher price at the continent than in the Nordic countries, but with smaller price differences than today.

FIGURE 3.11: **Price levels – in 2005, in the reference and wind scenarios 2020.**



Source: Econ-Pöyry

[41] Implication of Large-scale Wind Power in Northern Europe; Econ-Pöyry; March 2008

In the wind scenario in Figure 3.11, the average price level in the EU decreases from 5.4 to 5.1 cent €/kWh compared to the reference scenario. However, the effects on power prices are different in the hydropower dominated Nordic countries than in the thermal based countries at the European continent.

In the wind scenario, wind energy is reducing power prices to around 4 cent €/kWh in the Nordic countries. Prices in Germany and the UK remain at the higher level. In other words, a larger amount of wind power would create larger price differences between the (hydro-dominated) Nordic countries and the European continent.

One implication of price decreases in the Nordic countries is that conventional power production becomes less profitable. For large-scale hydropower the general water value decreases. In Norway, hydropower counts for the major part of the power production. However, large-scale implementation of wind creates a demand for flexible production that can deliver balancing services – opening up a window of opportunities for flexible production such as hydropower.

3.5.4 EFFECT ON POWER PRICES OF BUILDING INTERCONNECTORS

With large amounts of wind in the system, there will be an increased need for interconnection. This is also confirmed by the fact that, in the Econ-Pöyro model runs, with 13% wind in the system compared to the reference scenario, the congestion rent (that is, the cable income) increases on most transmission lines. This is also something one would expect: with more volatility in the system, there is a need for further interconnection in order to be better able to balance the system.

In order to simulate the effect of further interconnection, Econ-Pöyro therefore repeated the same model runs as above - the Wind and the Reference Scenario, but this time with a 1,000 MW inter-connector between Norway and Germany in place, the so-called *NorGer* Cable.[42] When running the Wind Scenario, Econ-Pöyro found that the congestion rent on such a cable would be around €160 million in the year 2020 in the Reference Scenario, while it would be around €200 million in the Wind Scenario.

With the cable in place it should first be observed that such a cable would have a significant effect on the average prices in the system, not only in Norway and Germany, but also the other countries in the model. This is illustrated by Figure 3.12. In the Nordic area the average prices increase – the Nordic countries would import the higher prices from northern continental Europe - while in Germany (and the Netherlands) they decrease. This is because, in the high peak price hours, power flows from Norway to Germany. This reduces the peak prices in Germany, while it increases the water values in Norway. In the off-peak low price hours, the flow reverses, with Germany exporting to Norway in those hours where prices in Germany are very low. This increases off-peak prices in Germany and decreases water values. However, the overall effect is higher prices in Norway and lower prices in Germany, (compared to the situation without a cable). Although such effects are to be expected, this does not always have to be the case. In other cable analysis projects Econ-Pöyro found that an interconnector between a thermal high price area and a hydro low price area may well reduce prices in both areas.

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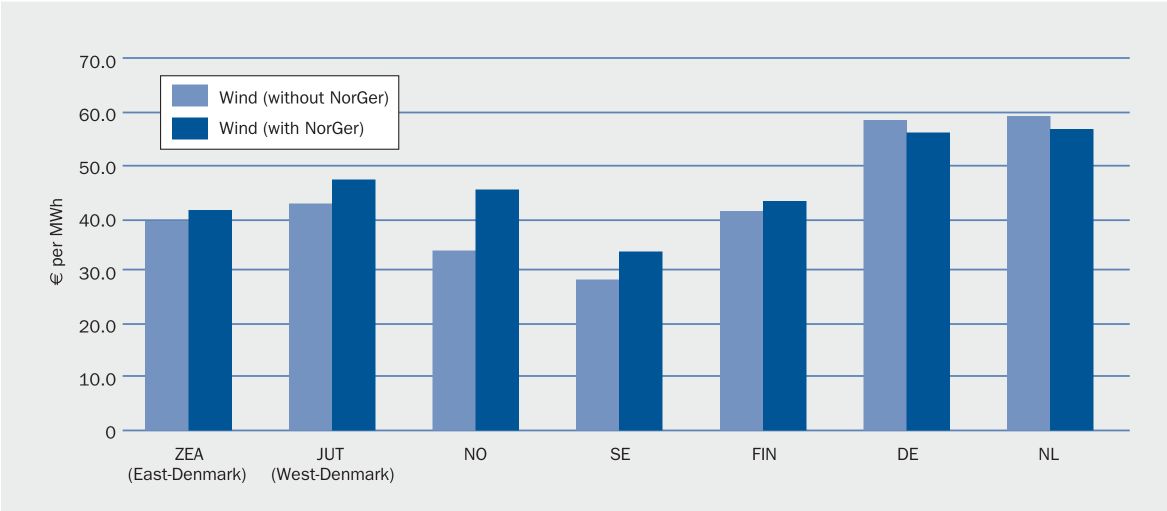
[42] Please note that, in order to find the right amounts of investments for 2020, we also repeated the Classic model runs with a NorGer Cable in place in order to obtain investment figures, and in order to be consistent in our methodology and approach. In this respect it should be noted that the NorGer cable does not have a too pronounced effect on investment levels. Regarding the size of the cable, this has not been decided yet, but a 1,000 MW cable is probably a fair estimate in this respect and sufficient in order to simulate the effects of further inter-connections.

FIGURE 3.12: **Average prices in the Wind Scenario - with and without the NorGer cable**



Source: ECON study

Up to a wind power penetration level of 25%, the integration costs have been analysed in detail and are consistently low. The economic impacts and integration issues are very much dependent on the power system in question. Important factors include the:

- structure of the generation mix and its flexibility;
- strength of the grid;
- demand pattern;
- power market mechanisms; and the
- structural and organisational aspects.

Technically, methods that have been used by power engineers for decades can be applied to the integration of wind power. But for large-scale integration (penetration levels typically higher than 25%), new power system concepts may be necessary, and it would be sensible to start considering such concepts immediately. Practical experience with large-scale integration in a few regions demonstrates that this is not merely a theoretical discussion. The feasibility of large-scale penetration has already been proved in areas where wind power currently meets 20%, 30% and even 40% of consumption (Denmark and regions of Germany and Spain).

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3.5.5 OPTIONS FOR HANDLING LONG-TERM VARIABILITY

The problem of long-term variability may be more difficult to cope with than short-term variability. If the wind does not blow for a week when we are close to the annual peak power demand, this might lead to a very tight capacity balance on the power system, implying at least high prices if not technical problems.[(43)] Moreover, if no capacity is left in the system, only investment in new capacity, new interconnectors or lower demand for power can save the situation. There is a need for investment in new infrastructure and interconnectors and reserve biomass, gas or similar plants, which are cheap in terms of investments but expensive in terms of variable costs, particularly fuel costs.

Another possibility is using energy storage facilities such as batteries for direct power storage although today this is an expensive option. One option is using hot water heating storage as a buffer for power balancing in an optimised heat and power system. It may also be possible to use demand side management to lower demand for power in specific situations with lack of capacity, but interruptions of power demand for several hours up to days may be difficult to implement without major discomfort to the power consumers. However, investments in new capacity or long term options of flexible power demand are not only to be used in situations of wind power shortage, but can in practice be a general and efficient part of management of the electrical power system.[(44)] Thus, the problem of long-term variability interacts closely with the long-term development of the power system, including solutions that may benefit not only wind power but also the operation of the total system.

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(43) It is consequently useful to examine the statistical correlation between wind power generation and electricity demand in order to ascertain the need for additional balancing power or other remedial action. Since wind generation tends to be high during winter and low during summer, and high during the day and low at night in temperate climates, there is frequently a good, positive correlation between electricity demand and wind generation. In the case of Québec, for example, the introduction of 1,000 MW of wind power into the system will actually reduce the hourly variability of net demand, i.e. electricity demand minus wind generation – as per the report, *Études sur la valeur en puissance des 1000 MW d'Énergie éolienne achetés par Hydro-Québec Distribution,* submitted to Régie de l'énergie, June 2005.

(44) An example of demand management: In the province of Québec, Canada, resistive electrical heating is used by the vast majority of households and by industry. This means that the annual peak power demand of currently some 35,000 MW is a major investment determinant for the power company, Hydro-Québec. The company consequently offers residential costumers the option of a so-called Domestic Dual-Energy Rate (early 2006 figures): Instead of paying 0.0633 CAD/kWh = 0.0448 EUR/kWh, costumers can opt for a tariff of 0.0367 CAD/kWh = 0.0273 EUR/kWh when the outside temperature is above -12°C or -15°C depending on the climate zone, and 0.1646 CAD/kWh = 0.1225 EUR/kWh when the temperature is below this limit. In order to qualify for the tariff it is required that the household has a fuel furnace (using heating oil or gas), which automatically takes over when the temperature drops below the limit. The Dual-Energy Rate option has been chosen by some 115,000 households, (nearly a third of which use heat pumps instead of resistive electrical heating).

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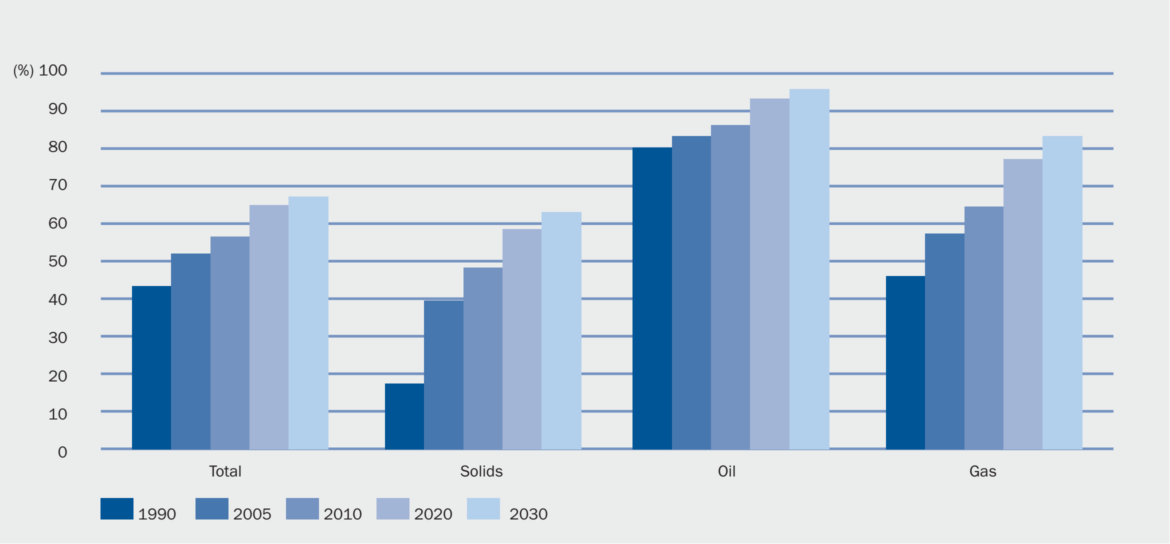
4. Energy policy and economic risk

4.1 Current energy policy risk

Industrialised countries – and European countries in particular – are becoming increasingly dependent on fossil fuel imports, more often than not from areas which are potentially politically unstable. At the same time global energy demand is increasing rapidly, and climate change requires urgent action. In this situation it seems likely that fuel price increases and volatility will become major risk factors not just for the cost of power generation, but also for the economy as a whole.

In a global context, Europe stands out as an energy intensive region heavily reliant on imports (more than 50% of the EU's primary demand). The EU's largest remaining oil and gas reserves in the North Sea have already peaked. The European Commission (EC 2007) reckons that, without a change in direction, this reliance will be as high as 65% by 2030. Gas imports in particular are expected to increase from 57% today to 84% in 2030, and oil imports from 82% to 93%. Figure 4.1, taken from the Commission's report, illustrates these trends.

FIGURE 4.1: **EU-27 Development of import dependency up to 2030.**



Source: EC, 2007

In turn, the International Energy Agency predicts that global demand for oil will go up by 41% in 2030 (IEA, 2007a), stating that "the ability and willingness of major oil and gas producers to step up investment in order to meet rising global demand are particularly uncertain". Even if the major oil and gas producers were able to match the rising global demand, considerable doubt exists concerning the actual level of accessible remaining reserves.

An additional problem is the concentration of suppliers in a few, often unstable geographical regions. Most of our oil comes from the Middle East and virtually all of our gas from just three countries: Russia, Algeria and Norway. Russia has already cut off gas supplies to the EU on several occasions, such as in the beginning of 2009 where no Russian gas reached the Member States for several weeks. 50% of the EU's gas imports come from Russia. The EU's difficulties in signing a new Energy Protocol with Russia, the troubles that the Middle East is experiencing and the uncertain conditions of Spain's gas supply from Algeria demonstrate the possible consequences of this dependency.

Our economy thus depends on the ready availability of hydrocarbons at affordable prices. As the price of oil and gas remained fairly static during the 1990s, many policy makers were lulled into a false sense of security. In 2008, oil prices reached $150 but fell back below $50 as a consequence of the global financial and economic crisis, beginning in the second half of 2008. The price of fuel has certainly come down from its 2008-peak. Nevertheless, a few years back few would think it possible that oil could be priced at €50 per barrel in the middle of the worst economic recession the world has seen since the 1930s.

Price forecasts vary depending on the source, but none of them foresee oil and gas returning to their previous levels: for the European Commission (EC, 2007) oil could reach $100 per barrel in 2030 (a level already attained on 7 January 2008), meaning an increase in the import bill of around €170 billion; the conservative IEA puts the cost of an oil barrel at $100 in 2010 – 11.15 MBtu for natural gas (IEA, 2008); No matter the institution, the EU's dependency on imported fossil fuels will worsen both in terms of quantity needed and of price paid.

When addressing these problems, wind energy is able to make a double contribution: it can provide an abundant, free and indigenous resource, and can do so at a known risk-free price.

4.2 External effects

Electricity markets (or tarification policies in regulated utility markets) do no not properly value the *external effects* of power generation. External effects are also called *spill over effects*. They occur when the costs and benefits for a household or a firm who buys or sells in the market are different from the cost and benefits to society. The problem with leaving external effects out of decisions in the market is that too much or too little is produced or consumed, thus creating costs or loss of benefits to society as a whole. External effects can be subdivided into *external costs* and *external benefits*.

An example of *external costs* are pollution costs. It is clearly cheapest and most convenient for a household or a firm to dump its waste for free anywhere out of sight, and in the power sector companies can be more competitive if they can dump waste such as fly ash, CO_2, nitrous oxides, sulphur oxides and methane for free. The problem with such behaviour is obviously that it creates costs for others, be it in the form of lung disease, damage from acid rain or global warming. The way governments normally deal with such problems is by outlawing, limiting or pricing (taxing) such anti-social behaviour. To the extent that the problems can be reduced through taxation, the ideal tax rate would generally be equivalent to the marginal damage to society from the activity. This is the well-known *polluter pays* principle.

An example of *external benefits* is obviously the use of pollution control equipment. There is no economic incentive to buy hybrid cars if they are more expensive than conventional automobiles, and the car user does not pay for polluting the atmosphere. One way many governments encourage the use of hybrid cars is to reduce car taxes for this type of vehicle. Thus governments can reduce the negative impacts of external effects through taxes or subsidies.

4.3 Fuel price volatility: a cost to society

The use of fossil fuel fired power plants exposes electricity consumers and society as a whole to the risk of volatile fuel prices. To the extent that gas generation increasingly dominates new capacity in the power generation market, gas generators may have sufficient market power to shift fuel price risks onto consumers. Due to overcapacity in the European power market, the adjustment of the generation mix is a slow process. To make matters worse, government's energy planners, the European Commission and the IEA have consistently been using calculation methods that do not properly account for the fuel price risks when assessing alternatives for future power generation, hence the bulk of growth in new European power generation capacity in later years has been in natural gas. This tendency is recognised by the European association of the electricity industry, Eurelectric, which writes:

A rational basis - the one generally used in the past - for selecting the most economic investment choice is to calculate what will be the lifetime-levelised cost, per kWh, for different investment options. But competition has certainly increased investment risk - specifically, the risk that the consumers who initially buy the output of your new plant may not remain customers in the future. This risk has led directly to greater focus on minimising initial capital investment (with less regard to fuel costs over subsequent years) and the time required for construction (i.e. before the investment can begin to be recouped). This has worked directly in favour of gas plants, and against low- (or zero-) fuel cost technologies such as hydro and nuclear and also coal.[45]

In other words, in the face of uncertainty in power markets, it is a relative disadvantage to wind, hydro and nuclear that they have high capital intensity compared to gas and coal. You tie up a lot of capital in them, and you have large fixed costs, even if the price of electricity drops, and you are thus stuck with stranded interest costs and depreciation. Of course, the main disadvantages of gas and coal – apart from the environmental ones – are that the future cost of fuel is uncertain and the future cost of carbon is uncertain. But they will have a cost (from 2013, all power plants in the EU will be obliged to buy emission allowances to be allowed to release CO_2 into the atmosphere).

The argument is really equivalent to saying that you should not invest all of your wealth in bonds, which may in fact be true. A diversified portfolio of stocks and bonds may give a better balance between risk and income. But the present point of departure in the power generation sector in Europe is exactly the opposite: Europe relies on relatively low capital intensity fossil-fuel fired power plants, with a very high risk component in the form of very volatile and unpredictable fuel prices. As we shall explore in the next chapter, a diversified generating technology portfolio containing more capital intensive and low-risk wind power may indeed be a wiser choice for society than relying on fuel intensive high-risk fossil technology.

But the basic problem remains that there is little incentive for power generating companies to introduce wind power or other risk-mitigating policies unless governments use taxes or subsidies to rectify the market distortion due to the otherwise ignored external cost and external benefits of power production. In this case, the external benefit to society of using stable cost wind energy to displace volatile cost fossil-fuel fired power generation cannot easily be sold in the market, because the major beneficiary of such a policy change is society at large. In this sense renewable energy benefits are far more difficult to sell on the market (and hence the case for government intervention is more pronounced) than for, say, air bags in cars, where a larger part of the benefit is *individualised*, that is, accrues to the user of the car (in addition to society's savings on health care costs).

Note that when we are talking ownership of, say, hybrid cars or wind turbines, the owner cannot capture or sell any of the *external benefits* of his product in the market to finance his acquisition. The rest of the members of society are basically *free riders*, who enjoy less pollution and reduced fuel cost risk without paying for these external benefits.

[45] http://public.eurelectric.org/Content/Default.asp?PageID=503

4.4 The oil-GDP effect

The oil and gas price hikes of the supply crises of the 1970s had dramatic effects on the world economy, creating inflation and stifling economic growth for a decade. Although the impacts of the latest oil and gas price increases have been less dramatic, there is no doubt that the economic losses due to volatile fossil fuel prices have a significant effect on the real economy, comparable in magnitude to the effects of the EU single market.

Fossil fuel prices, which are variable and hard to predict, pose a threat to economic development. This is because energy is essential for manufacturing most commodities and a key driver of price formation: the four last global recessions have been triggered by oil price rises. By relying on a source that can be produced domestically and at knowable prices[46], the system is reducing the overall risk and cost of the economy.

The vulnerability of an economic system to oil price was empirically formulated by J.K. Hamilton in 1983 and relevant literature refers to it as the "oil-GDP effect". Further studies from Sauter (2005), Awerbuch (2005 and 2006) and Dillard *et al* (2006) among others have gone deeper into its rationale and consequences.

These authors argue that the divergence between private and social interests adds risk to our economies. Commercial companies pursue benefit maximisation or cost minimisation without taking into account the global risk of the economy in which they operate. This often leads to a sub-optimal mix of electricity generation technologies. In 2006, Awerbuch and Sauter estimated the extent to which wind generation might mitigate oil-GDP losses, assuming the effect of the last 50 years continues. They found that by displacing gas and, in turn, oil, a 10% increase in the share of renewable electricity generation could help avert €75 to €140 billion in global oil-GDP losses.

The Sharpe-Lintner 'Capital Asset Pricing Model' (CAPM) and Markowitz's 'Mean Variance Portfolio Theory', both Nobel Prize-winning contributions, proved that an optimum portfolio is made up of a basket of technologies with diverse levels of risk. This is the so-called 'portfolio effect', whereby the introduction of risk-free generating capacity, such as wind, helps to diversify the energy portfolio, thereby reducing overall generating cost and risk. The introduction of the portfolio theory has been slow in energy policy analysis, given the divergence between social and private costs, and the ability of large power producers to pass hikes in fossil fuel price onto the final consumer, thus transferring the risk from the private company to society as a whole.

The tendency to select technologies that are less capital-intensive and riskier than wind energy can be exacerbated by the lack of financial resources at the time of making the investment. As we explain in Chapter 1, the upfront/capital costs of a wind farm constitute around 80% of the total outlay, while for other technologies they remain in the range of 40% to 60%. If the financial market is not well informed about the benefits of wind and about the uncertainty of the alternative options, obtaining the financial resources needed at the initial stage of the project can be difficult and will favour less capital-intensive technologies.

The variables mentioned above put wind energy projects at a disadvantage. The higher capital costs of wind are offset by very low variable costs, due to the fact that fuel is free, but the investor will only recover those after several years. This is why regulatory stability is so important for the sector. The (apparently) higher wind energy prices have to be compared with the opportunity to plan the economic future of Europe on the basis of known and predictable costs, derived from an indigenous energy source free of all the security, political, economic and environmental disadvantages that we currently face.

These aspects are tackled in more detail in the next chapter.

[46] Fossil fuel costs are zero and variable costs are low; this means that the capital cost accounts for most of the amount that the investor will have to face during the life-time of the investment, and this is known at the time of starting the project.

5. The value of wind energy versus conventional generation

This chapter deals with the value of wind energy as seen from the point of view of the purchaser of wind energy or from the point of view of society as a whole, that is, we look at the *social cost* of wind energy and how it compares with the value of other forms of electrical power generation.

Issues about the point of delivery, the required voltage level, ancillary services such as balancing power and transmission costs were discussed in Chapter 3, so that we assume we are dealing with a well defined, homogeneous product. By this we mean that when we compare wind power and other forms of power generation, we should always refer to the same voltage level and location and have the same level of ancillary services included in the comparison. But even if wind energy in this perspective seems much like any other type of power generation, it differs economically from conventional thermal generation as we shall explore in this chapter.

In this chapter we use the term *the cost* of wind energy even when we talk about value, since we are seeing the price from the point of view of the purchaser of the energy.

Comparing costs of low and high risk power generating technologies

Wind, solar and hydropower differ from conventional thermal power plant in that most of the costs of owning and operating the plant are known in advance with great certainty. These are *capital-intensive* technologies - O&M costs are relatively low compared to thermal power plants since the energy input is free. Capital costs (interest and depreciation) are known as soon as the plant is built and financed, so we can be certain of the future costs. O&M costs generally follow the prices of goods and services in the economy in general, so a fairly broadly based price index such as the consumer price index (or the implicit GDP deflator) will generally track these costs fairly well. Wind power may thus be classified as a *low-risk technology* when we deal with cost assessments.

The situation for thermal power plants is different: These technologies are *expense-intensive* technologies – in other words, they have high O&M costs, with by far the largest item being the fuel fill. Future fuel prices, however, are not just *uncertain* – they are highly *unpredictable*. This distinction between *uncertainty* and *unpredictability* is essential:

Uncertainty: an unreal world

It would be less of a problem to adapt the conventional engineering-economics analysis of costs, (which we have used in the previous chapters) to *uncertainty*. Let us hypothetically assume we have a solid forecast for the development of mean oil and gas prices in two to twenty year's time, that is, that prices are somewhat predictable (or at least moving in step with the general price level), but we know that prices will fluctuate from day to day around the predicted mean. In this case oil and gas prices are *uncertain* but statistically their mean is *predictable*.

If this were the case, we could in principle make simplified cost calculations using future predicted mean oil and gas prices. If we want to compare oil or gas fired generation with wind generation, where the cost pattern over time is different, we could just discount all our costs to the same point in time (as explained in the next section) using the interest rate on our debt (or the opportunity cost in terms of fore-gone profits from other investments) when we do our computations. In fact, this is the way most governments, the European Commission and the IEA make their cost calculations for electricity generation. One reason why this could hypothetically be a sensible approach is that with predictable mean prices, you could probably buy insurance for your monthly fuel bill (much as you can insure your wind generation if the insurance company knows the likely mean generation on an annual and seasonal basis). Since there is a world market for gas and oil, most of the insurance for predictable, but (short-term) uncertain fuel prices could probably be bought in a world-wide financial futures market for oil and gas prices, where speculators would actively be at work and thus help stabilise prices. But this is not how the real world looks.

In the real world, you can neither simply nor safely buy a fossil-fuel contract for delivery 15 or 20 years ahead, the long-term futures market for fuels does not exist and it never will; the risks are too great for both parties to sign such a contract because fuel prices are simply too unpredictable. But you cannot sensibly deal with real risk in an economic calculation by assuming it does not exist. The unpleasant corollary of this is that engineering-economics cost calculations simply don't make sense because future fuel prices - just like stock prices - are both uncertain and highly unpredictable.

Unpredictability: dealing with economic risk in the real world

Just like fuel markets, markets for stocks, bonds and foreign exchange have volatile and unpredictable prices. The financial markets are very important for dealing with (and distributing) risk, and they have many of the instruments that are missing in the fossil fuel market such as futures markets for stocks and bonds, where investors can hedge and trade their risks.

There are economic analysis tools that deal with risks in financial markets. The next section is devoted to showing how these tools from financial theory can be used to analyse investment in a portfolio of generating technologies. Using these methods, we can rectify the key errors of the classical analysis techniques used by governments, the IEA, the European Commission and others, which we described above.

The key element of the correct method explained in the next section is to realise that bond investors are willing to pay more for relatively low, but predictable income from government bonds than for potentially higher, but unpredictable and uncertain income from junk bonds. Likewise, investors in power plant – or society at large – should be equally rational and prefer investing in power plant with a possibly lower, but predictable rate of return rather than investing in power plant with a possibly higher, but unpredictable rate of return.

The way to analyse this in financial economics is to *use different discount rates depending on the risks involved*. Unpredictable income has to be discounted at a higher rate than predictable income, just as for financial markets. Unpredictable expenditures have to be discounted at a lower rate of discount than predictable expenditure. And even better, we will not use arbitrary discount rates. The discount rates we need to use in the different cases are not subjective, but they can either be determined logically or estimated in the market, as explained in the appendices.

What does this analysis tell us about the way the IEA, governments and the European Commission currently calculate the cost of energy from different sources?

It tells us that when these institutions apply a single rate of discount to all future expenditure, they pretend that fuel prices are riskless and predictable. Fuel prices are thus discounted too heavily, which under-estimates their cost and over-states their desirability relative to less risky capital expenditure. In other words, current calculation practice favours conventional, expenditure-intensive fuel-based power generation over capital-intensive, zero carbon and fuel-price risk power generation from renewables such as wind power.

5.1 Value of wind compared to gas generation: a risk-adjusted approach

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Cost-of-electricity (COE) estimates for various generating technologies are widely used in policy-making and in regulation. Managers and public policy makers want a simple means of determining what it will cost to generate a kilowatt-hour (kWh) of electricity using, for example, a wind turbine, over the next 20 years, as compared to generating a kWh of electricity using a combined-cycle gas turbine. Such information helps governments shape various tax incentive policies, as well as R&D policy and other measures. For example, the European Commission, apparently recognising the importance of the cost measurement issue, has suggested a few years back that it will examine COE estimation methods prior to setting additional renewables targets. The EU adopted new mandatory 2020 targets for the share of renewable energy in the 27 Member States in December 2008, but the European Commission's COE methodology remains unchanged. These sections will present valuation issues the European Commission, the IEA and governments should include as it grapples with the issues of how to properly value wind and other renewables and how to compare their cost to other forms of power production.

In traditionally regulated jurisdictions, kWh cost comparisons provide the basis under which utilities and regulators establish investment plans under so-called 'least cost' procedures that are used in many EU countries and the rest of the world. These procedures presume that if every new capacity addition is chosen through a 'least cost' competition, the resulting total generation mix will also be 'least cost'.

This section describes an *investment-orientated* approach to estimating the COE of wind and gas generation. This approach, described in any finance textbook (such as Brealey and Myers' 'Principles of Corporate Finance', McGraw Hill, any edition) reflects market risk,[47] which deals with the variability of the operating cost streams associated with each generating technology. For example, fuel outlays for a fossil-based project are riskier than the outlays for fixed maintenance. Technologies that require large fossil fuel outlays therefore create a risk that must be borne by either the producer or its customers.

Discounting Basics
Present Value Analysis— what is it?

- Procedure by which future cost streams are 'brought back' or 'collapsed' to the present
- Allows cost streams with different time-shapes to be properly compared
- Discounting basics: at a 10% rate of interest:
  €1.10 paid one year from today is worth €1.00 today
  Present Value = Future Value / (1+discount rate)
  = €1.10 / (1 + 0.10) = $1.00

5.1.1 TRADITIONAL ENGINEERING-ECONOMICS COST MODELS

Traditional, engineering-economics cost models widely used by many EU countries and elsewhere were first conceived a century ago, and have been discarded in other industries[48] because of their bias towards lower-cost but high risk *expense-intensive* technology[49]. In the case of electricity cost estimates, engineering models will almost always imply that risky fossil alternatives are more cost-effective than cost-certain renewables, which is roughly analogous to telling investors that high-yielding but risky "junk bonds" or stocks are categorically a better investment than lower yielding but more secure and predictable government bonds.

[47] The analyses presented here assume a world of no income taxes, although income taxes do not affect all technologies uniformly. Because of the value of tax depreciation deductions (depreciation tax shelters) income taxes reduce the generating cost of capital-intensive technologies such as wind (and nuclear) relatively more than gas and other expense intensive technologies.

[48] They were discarded by US manufacturers primarily on the basis of hindsight: i.e. only after global competitive pressures, beginning in the 1970s, clearly exposed their woeful inability to reflect the costs savings – by then obvious – of CIM (computer integrated manufacturing) and other innovative, capital-intensive process technologies. In prior decades, when American manufacturers still enjoyed greater global market power, they generally relied on inappropriate and misleading investment procedures, which according to some (e.g. Kaplan – 198_, *HBR*) contributed to their loss of pre-eminence.

[49] Expense-intensive is the opposite of capital-intensive, i.e. an expense-intensive investment has relatively high current variable costs, e.g. fuel costs. The magnitude of these variable costs is more uncertain than the size of capital costs (interest and depreciation).

The analogy works as follows. Consider two bond investment alternatives: a low-grade corporate debt obligation (a so-called 'junk bond') that promises to pay 8% interest and a high-grade government bond that promises 4% interest. A €1,000 investment in junk bonds produces a contractually promised annual income of €80. To obtain the same income from government bonds requires twice the investment, or €2,000, since they pay only 4%. (€2,000 × 4% = €80). Indeed, if we compare the two bond investments using the engineering-based COE concepts that energy planners apply to fossil and renewable electricity, we conclude that government bonds are twice as costly as junk-bonds -.it requires twice the investment to produce the same promised annual income stream. Yet government bonds routinely trade at approximately the same cost as junk bonds that pay twice as much interest. The costs are similar because investors obviously understand the risk differentials involved. These same ideas must be applied when wind is compared to natural gas and other fossil fired generation.

Engineering cost models worked reasonably well in previous technological eras that were characterised by technological stability and homogeneity – that is, in a static technological environment where technology alternatives all have similar financial characteristics and a similar mix of operating and capital costs over their lifetimes.[50] If our power supply consisted of only oil, gas and coal technology, the engineering-cost approach would not be too much of a problem. This was true for most of the last century but is no longer the case. Today, energy planners can choose from a broad variety of resource options that ranges from traditional, risky fossil alternatives to low-risk, passive, capital-intensive wind with low fuel and operating cost risks.

Engineering-cost models are still widely used in electricity planning, both at macro-economic and micro-economic level. As generally applied, they ignore risk differentials among alternative technologies — a crucial shortcoming which systematically biases cost calculations in favour of gas and other risky expense-intensive fossil technologies. These engineering cost models rely on arbitrary discount rates that produce results with no economic interpretation.

5.1.2 A MODERN, MARKET-BASED COSTING METHOD FOR POWER GENERATION

In contrast to the previous section, this section describes a market-based or financial economics approach to COE estimation that differs from the traditional engineering-economics approach. Both approaches 'discount' projected future operating outlays of a generating technology into a "present value". However, finance theory uses the term *present value* in a strict economic or market-orientated sense: it represents the *market value* of a future stream of benefits or costs. In the case of the junk bond and government bond illustration, the present value of the future annual interest and principal payments is directly observable: it is the price at which each of these bonds trades in the capital markets.

This unique value is obtained analytically only when the correct risk-adjusted discount rate is used (Table 5.1). Discounting the yearly proceeds of both bonds at the same rate (Table 5.1, Panel A) produces misleading results that erroneously suggest that the junk bond has a greater value because no risk has been considered. In today's market, there are many low-grade bonds with yields similar to those in Table 5.1. They generally trade at or above safe government bonds that yield only half as much because the market attaches different levels of risk to the cash-flow from the two types of investment.

[50] S. Awerbuch, "The Surprising Role of Risk and Discount Rates in Utility Integrated-Resource Planning," *The Electricity Journal*, Vol. 6, No. 3, (April) 1993, 20-33.

TABLE 5.1: **Valuing two five-year bond investments**

YEAR	8% Junk Bond	4% Government Bond
	Yearly Proceeds per €1000 Investment	
1	€ 80	€ 40
2	€ 80	€ 40
3	€ 80	€ 40
4	€ 80	€ 40
5	€ 1,080	€ 1,040
A. Assumed Discount	6.0%	6.0%
(Incorrect) Present Value of Proceeds	€ 1,084	€ 916
B. Assumed Discount	8.0%	4.0%
(Correct) Present Value of Proceeds	€ 1,000	€ 1,000

Bond prices represent the risk-adjusted current value of their future payment stream. This current value can be obtained only by discounting or 'collapsing' the future interest and principal payments at the bond's risk-adjusted discount rate - in this case, 8% for the junk bond and 4% for the corporate bond. Evaluating the two investments by applying the same discount to each will incorrectly show that the proceeds of the government bond are worth less (Table 5.1, Panel A).

In the same way, wrong decisions are made when the generating costs of wind and gas (and other technologies) are discounted at the same rate because risk is ignored. If the financial markets acted according to the way governments analyses the power markets, there would be no demand for government bonds, except perhaps those issued by very unstable regimes.

5.1.3 RISK-ADJUSTED COE ESTIMATES FOR ELECTRICITY GENERATING TECHNOLOGIES

The current value of a 20-year stream of fuel outlays (or maintenance) has an economic interpretation directly analogous to that of the bond price: it is the price at which a contract for future fuel purchases would trade if a market for such contracts existed. Bond markets offer investors tens of thousands of risk-reward opportunities, with maturities ranging from as little as one day up to 30 or 40 years.

Fossil fuel futures are more thinly traded and generally do not extend for more than five or six years, making it impossible to directly observe the current value of a 25+ year fuel purchase obligation. Where efficient capital markets do not exist, as in the case of future outlays for fuel and O&M, estimating the present value of a particular cash flow stream entails estimating its market-based or risk-adjusted discount rate.

The previous section demonstrated the idea that underlies proper COE estimation procedures. The present value of two financial investments with different market risks cannot be compared unless the *benefits* are discounted at a particular rate, which gives us the market price of the asset. In much the same way, two generating alternatives can likewise be compared only if projected yearly *cost* streams are each discounted at their own risk-adjusted rate, which gives us the market price of the liability we undertake. In the case of the two bond investments it is simple to tell if the discount rate is correct since the price of both bonds is readily observable.

The notion of market risk as it applies to future generating costs seems more difficult for people to grasp, although the underlying principles are identical. Comparing the costs of wind and other technologies using the same discount rate for each gives meaningless results. In order to make meaningful COE comparisons we must estimate a reasonably accurate discount rate for generating cost outlays – fuel and O&M. Although each of these cost streams requires its own discount rate, fuel outlays require special attention since they are much larger than the other generating costs on a risk-adjusted basis.

How do we estimate a discount rate for gas and other fossil fuels? A number of researchers (Awerbuch, 1995a, b; 2003; Bolinger and Wiser, 2002; Bolinger *et* *al*, 2003; Kahn and Stoft, 1993; Roberts, 2004) have estimated the historic risk of fossil fuel outlays using the Capital Asset Pricing Model (CAPM) described in any finance textbook. The first step consists in finding the so called "ß" parameter, which measures an asset's risk. "ß" can be derived by quantifying the correlation between changes in the stock price of a fuel company (for example natural gas) and changes in the price of that fuel (for example natural gas). In the case of natural gas, the value is thought to be negative, in the range of -0.2 to -0.78. One then works out the discount rate that is used in different international markets for long-term bonds (30 to 40 years) plus a long-term premium to take into account the uncertainty of future outlays. Under these premises, the empirical analyses invariably suggest that an appropriate (nominal) rate for such outlays lies in the range of 1% to 3%.(51) This implies that the present value cost of fossil fuel expenditure is considerably greater than those obtained by the IEA and others who use arbitrary (nominal) discounts in the very high range of 8% to as much as 13%. When expenditure is discounted at a high rate, the resulting cost of energy is under-stated, making the technology appear cheaper (see Table 5.2).

The IEA assumes away the fuel cost risk by using different discount rates (sensitivity analysis). But as explained above, this method does not solve the problem of comparing different technologies with different fuel requirements – or no fuels, as it is the case for wind energy. Rather than using different risk levels, and applying those to all technologies, the IEA should use differentiated discount rates for the various technologies.

It is possible that the historic risk of natural gas and coal prices is not an accurate predictor of the future. In this case, we can evaluate generating costs using an alternative set of assumptions. We could presume, for example, that generators can purchase fuel during the life of their investment (usually taken as 25 to 40 years) at the prices currently projected, and that fuel suppliers will contractually guarantee these prices. Indeed this is probably the most optimistic scenario imaginable, given current gas and oil market trends.

TABLE 5.2: **Present value of projected fossil fuel costs estimated at various discount rates.**

YEAR	PROJECTED FUEL PRICE ($USD/GIGAJOULE)*/	
2010	4.58	
2020	4.97	
2030	4.97	
2040	4.97	
2050	4.97	
Scenario for Discounting	**Nominal Discount Rate**	**Present value of fuel outlays ($/MWh)**
IEA-high discount	13%	$166
IEA-low discount	8%	$301
Historic Gas Price Risk	4%	$579
Assumed 40-Year Contract	3.5%	$702

SOURCE: *IEA Projected Costs of Generating Electricity 2005*, (USA-G1), adjusted for 3% inflation.

(51) Discount rates in this section are generally presented in nominal terms. This means that they include inflation expectations and are hence directly comparable to rates observed in the capital markets. Nominal rates can be converted to *real* or constant-currency rates through the relationship: kreal = $(1 + k_{nominal}) / (1 + p) - 1$, where p represents the expected inflation rate. For relatively small rates this relationship is approximated by: $k_{real} = k_{nominal} - p$.

Such fixed contracts are easy to value. They represent an obligation to the generator, which has a risk very similar to the risk on the generator's debt payments. As long as the generator has sufficient income to cover its obligations, it will be legally required to make its interest payments and also fulfill its contractual fuel purchase obligations. In finance terminology, a long-term fuel contract is a debt-equivalent obligation, whose value is determined by discounting at a rate equal to the firm's debt costs. To get an idea of this value, consider a hypothetical investment grade firm that issues bonds whose risk is rated in the range of single-A to BBB in the US market. The current[52] rate on such obligations is in the range of 5% to 6% nominal.

When we apply the Capital Asset Pricing Model to data covering a range of power plants, interesting results are obtained (see Figure 5.1): in the IEA 2005 report "Projected costs of generating capacity, 2005", a typical natural gas power plant[53] is assumed to have fuel costs of $2,967 at a 10% discount rate, equivalent to $0.049 per kWh (around 3.9 c€/kWh[54]). However, if a historical fuel price risk methodology is used instead, fuel costs go up to $8,018, equal to $0.090 per kWh (approximately 7.2 c€/kWh). With an assumed no-cost 40 Year Fuel purchase contract, the figures would have been $7,115 or $0.081 per kWh (6.48 c€/kWh).

Something similar happens for coal plants, which are also covered in the IEA report. In the central case, with a discount rate of 10%, the fuel costs of a coal power station (DEU-C1, chapter 3) are equal to $1,234 or $0.040 per kWh (around 3.2 c€/kWh). If the historical fuel price risk methodology is preferred, the fuel costs peak at $5,324 or $0.083 per kWh (6.64 c€/kWh). Finally, when the no-cost 40 Year Fuel purchase contract is assumed, the figures appear as $3,709 and $0.066 per kWh respectively (approx. 5.28 c€/kWh).

In both cases the fuel costs and subsequently the total generating costs more than double when differentiated discount rates are assumed, be it the risk-adjusted discount rate or the no-cost 40 Year Fuel purchase contract.

As can be observed from the graph, wind energy cost remains unchanged because the technology carries no fuel price risk. It should be noted that the onshore wind energy cost calculated above are based on IEA methodology, which gives a wind energy generating cost of 5.3 c€/kWh. In chapter two, we found that the levelised cost of onshore wind energy range between 6 c€/kWh at a discount rate of 5% to 8 c€/kWh at a discount rate of 10% at a medium wind site[55].

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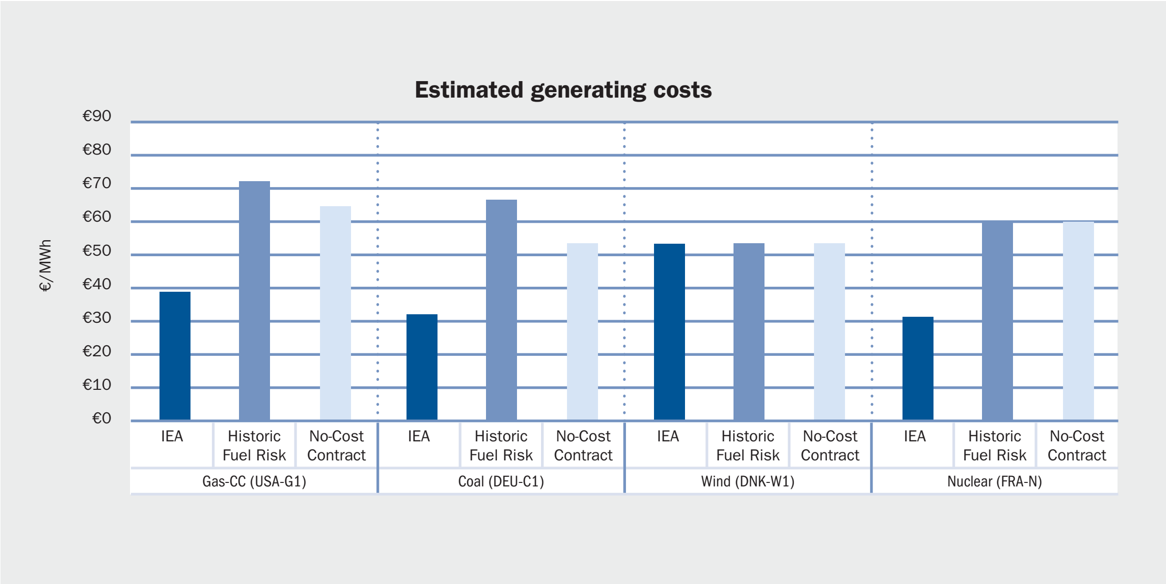
(52) June 2006.

(53) USA-G1, chapter 3.

(54) At an exchange rate USD/ Euro of 1.25.

(55) Shimon Awerbuch carried out this analysis based on an IEA Report on electricity generating cost published in 2005 when the average IEA crude oil import price averaged $51/barrel. Results would obviously be very different if fuel prices were equivalent to the $150/barrel reached in mid 2008. Although only an example, the figures reflect how the relative position of wind energy vis-à-vis other technologies will substantially vary if a different – and more rational – COE estimate is used. The figures would be even more positive for the wind energy sector if carbon prices were included in the analysis.

FIGURE 5.1: **Risk-adjusted power generating cost of gas, coal, wind and nuclear.**



Source: Shimon Awerbuch

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Appendix

Appendix I - Detailed country reports

AUSTRIA

MARKET STRUCTURE

With a share of 70% RES-E of gross electricity consumption in 1997, Austria was the leading EU Member State for many years. Large hydropower is the main source of RES-E in Austria. More recently, a steady rise in the total energy demand has taken place, and a decrease in the share of RES-E has been noted.

MAIN SUPPORTING POLICIES

Austrian policy supports RES-E through Feed-in tariffs (FIT) that are annually adjusted by law. The responsible authority is obliged to buy the electricity and pay a FIT. The total available budget for RES-E support was decreased in May 2006, and tariff adjustments that are adjusted annually have been implemented. Within the new legislation, the annual allocated budget for RES support has been set at €17 million for "new RES-E" up to 2011. This yearly budget is pre-allocated among different types of RES (30% to biomass, 30% to biogas, 30% to wind, 10% to PV and the other remaining RES). Within these categories, funds will be given on a "first come – first served" basis.

TABLE A1: **Feed in Tariffs (valid for new RES-E plants permitted in 2006 and / or 2007):**

Technology	Duration	2006-2007
	fixed years	fixed €/MWh
Small hydro	Year 10 and 11 at 75% and year 12 at 50%	31.5-62.5
PV systems		300- 490
Wind systems		76.5 (2006) 75.5 (2007)
Geothermal energy		74 (2006) and 73 (2007)
Solid biomass and waste with large biogenic fraction Note: Expressed values refer to "green" solid biomass (such as wood chips or straw). Lower tariffs in case of sawmill, bark (-25% of default) or other biogenic waste streams (-40 to -50%)		113-157 (2006);
111- 156.5 (2007)		
64(2006) 63 (2007) - max 50% for hybrid plants		
Biogas		115- 170 (2006) 113-169.5 (2007)
Sewage and landfill gas		59.5 – 60 (2006) ; 40.5-41 (2007)
Mid-scale hydro power plants (10-20 MW) and CHP-plants receive investment support of up to 10% of the total investment costs.		

At present, a new amendment is verified, suggesting an increase in the annual budget for support of "new RES-E" from €17 to 21 million. Consequently, the duration of FIT fuel-independent technologies might be extended to 13 years (now 10 years) and fuel-dependent technologies to 15 years (now 10 years), on behalf of the Minister of Economics. Moreover, investment subsidies of small hydro plants (>1MW) up to 15 % are implemented. The emphasis is laid on 700 MW wind power, 700 MW small hydro power and 100 MW biomass.

FUTURE TARGETS

The RES-E target to be achieved in Austria by 2010 is 78.1% of gross electricity consumption. In 2004, the share of renewable energy in gross electricity consumption reached 62.14%, compared to 70% in 1997.

BELGIUM

MARKET STRUCTURE

With a production of 1.1% RES-E of gross electricity consumption in 1997, Belgium was at the bottom of the EU-15. National energy policies are implemented separately among the three regions of the country, leading to different supporting conditions and separate, regional markets for green certificates. Policy measures in Belgium contain incentives to use the most cost-effective technologies. Biomass is traditionally strong in Belgium, but both hydro power and onshore wind generation have shown strong growth in recent years.

KEY SUPPORT SCHEMES

Two sets of measures are the key to the Belgian approach to RES-E:

**Obligatory targets have been set (obligation for all electricity suppliers to supply a specific proportion of RES-E) and guaranteed minimum prices or 'fall back prices' have been foreseen. In the Walloon region, the CWaPE (Commission Wallonne pour l'Energie) has registered an average price of 92 €/MWh per certificate during the first three months of 2006. In Flanders, the average price during the first half of 2006 has been around 110 €/MWh (VREG – Regulator in Flanders). In all three of the regions, a separate market for green certificates has been created. Due to the low penalty rates, which will increase over time, it is currently more favourable to pay penalties, than to use the certificates. Little trading has taken place so far.

**Investment support schemes for RES-E investments are available. Among them is an investment subsidy for PV.

TABLE A2

			Flanders	Walloon	Brussels	Federal
Target	%		2010: 6%	2007: 7% RES-E & CHP	2004: 2.00% 2005: 2.25% 2006: 2.50%	
Duration	years		10	10		
Min price[1] (fixed)	€/MWh	Wind offshore	n.a.	n.a.	n.a.	90
	€/MWh	Wind onshore	80	65 all RES-E		50
	€/MWh	Solar	450			150
	€/MWh	Biomass and other	80			20
	€/MWh	Hydro	95			50
Penalty	€/MWh		€125 (2005-10)	€100 (2005-07)	€75 (2005-06) €100 (2007-10)	

[1] Min. prices: for the Federal State the obligation to purchase at a minimum price is on the TSO, for the regions the obligation is on the DSO.

[2] Wind, first 216 MW installed capacity: 107 €/MWh

FUTURE TARGETS
For Belgium, the target for RES-E has been set at 6% of gross electricity consumption by 2010. Nationally, the target for renewable electricity is 7% by 2007 in the Walloon region, 6% by 2010 in Flanders, and 2.5% by 2006 in Brussels.

BULGARIA

MARKET STRUCTURE
Bulgaria is approaching its RES-E target for 2010. Large-scale hydro power is currently the main source of RES-E, but its technical and economic potential is already fully exploited. Good opportunities exist for biomass, since 60% of land consists of agricultural land, and about 30% is forest cover. Bulgaria's RES-E share of gross electricity consumption increased from 7.2% in 1997 to 9.28% in 2004.

KEY SUPPORT SCHEMES
RES-E policy in Bulgaria is based on the following key mechanisms:
** Mandatory purchase of electricity at preferential prices will be applied until the planned system of issuing and trading Green Certificates comes into force (expected by 2012).
** A Green Certificate Market is planned to be put in place from 2012. A regulation will determine the minimum mandatory quotas of renewable electricity that generation companies must supply as a percentage of their total annual electricity production. Highly efficient CHP will also be included under the tradable green certificate scheme. Under the green certificate scheme there will still be a mandatory purchase of electricity produced for production up to 50 MW.

TABLE A3: **Actual mandatory purchase prices, determined by the State Energy Regulation Commission:**

Technology	Duration	Preferential price 2008*[3]
Wind Plants with capacity up to 10 MW for all installation committed before 01.01.2006	12 years	61.4 EUR/MWh
Wind new installations produced after 01/01/2006 effective operation > 2250 h/a	12 years	79.8 EUR/MWh
Wind new installations produced after 01/01/2006 effective operation < 2250 h/a	12 years	89.5 EUR/MWh
Hydro with top equaliser	12 years	40.9 EUR/MWh
Hydro <10 MW	12 years	43.6 EUR/MWh
Solar PV < 5kW	12 years	400 EUR/MWh
Solar PV > 5kW	12 years	367 EUR/MWh
Other RES	12 years	40.6 EUR/MWh

*VAT not included

[3] Currently, the Bulgarian Government is considering whether to keep such differentiated levels of support for the different renewable resources, or to set a uniform preferential price for all types of RES.

FUTURE TARGETS

The RES-E target to be achieved in 2010 is about 11% for electric energy consumption. The goal of Bulgaria's National Programme on Renewable Energy Sources is to significantly increase the share of non-hydroelectric RES in the energy mix. A total wind power capacity of around 2,200 – 3,400 MW could be installed. Solar potential exists in the East and South of Bulgaria, and 200 MW could be generated from geothermal sources.

CYPRUS

MARKET STRUCTURE

In Cyprus, an issue regarding policy integration has been observed, since investments in a new fossil fuel power plant creating excess capacity are under way. Until 2005, measures that proactively supported renewable energy production, such as the New Grant Scheme, were not very ambitious. In Cyprus, targets are not being met. In 2006, a New Enhanced Grant Scheme was agreed upon. The leading RES in Cyprus is PV; wind power has a high potential.

KEY SUPPORT SCHEMES

RES-E policy in Cyprus is made up of the following components:

- New Grant Scheme, valid from 2004 until 2006. A tax of 0.22 c€/kWh on every category of electricity consumption is in place. The income generated by this tax is used for the promotion of RES.
- The New Enhanced Grant Scheme was installed in January 2006. Financial incentives (30-55% of investments) in the form of government grants and FITs are part of this scheme.
- Operation state aid for supporting electricity produced by biomass has been suggested, and forwarded to the Commission for approval.

TABLE A4: **The FITs are as follows:**

Technology	Capacity restrictions	Duration	2005	2006	Note
		fixed years	fixed €/MWh	fixed €/MWh	
Wind	No limit	First 5 yrs	92	92	Based on mean annual wind speed
		Next 10 yrs	48-92	48-92	Varies according to annual operation hours: <1750-2000 h 85-92 €/MWh 2000-2550 h 63-85 €/MWh 2550-3300 h 48-63 €/MWh
Biomass, landfill and sewage gas	No limit	15	63	63	A more generous scheme is currently being developed for biomass electricity. Up to 128 €/MWh is expected, depending on the category of investment
Small hydro	No limit	15	63	63	
PV	Up to 5 kW	15	204	204	
	Without investment subsidy	15	x	337-386	Households receive higher tariff than companies.

Note: Exchange rate 1€ = 0.58 CYP

FUTURE TARGETS

The Action Plan for the Promotion of RES determines that the contribution of RES to the total energy consumption of Cyprus should rise from 4.5% in 1995 to 9% in 2010. The RES-E target to be achieved in 2010 from the EU Directive is 6%. In Cyprus, the RES share of total energy consumption decreased from 4.5% in 1995 to 4% in 2002.

CZECH REPUBLIC

MARKET STRUCTURE

The Czech Republic's legislative framework in relation to renewable energy sources has been strengthened by a new RES Act adopted in 2005, and a Government Order regulating the minimum amount of biofuels or other RES fuels that must be available for motor fuel purposes. Targets for increasing RES in total primary energy consumption have been set at national level. The use of biomass in particular is likely to increase as a result of the new legislation.

KEY SUPPORT SCHEME

In order to stimulate the growth of RES-E, the Czech Republic has decided on the following measures:

- A feed-in system for RES-E and cogeneration, which was established in 2000.
- A new RES Act, adopted in 2005, extending this system by offering a choice between a FIT (a guaranteed price) or a "green bonus" (an amount paid on top of the market price). Moreover, the FIT is index-linked whereas an annual increase of at least two percent is guaranteed.

TABLE A5:

Technology	Duration	2006		2006		2007	
	fixed years	premium years	fixed €/MWh	fixed €/MWh	premium €/MWh	fixed €/MWh	premium €/MWh
Wind energy	Equals the lifetime	Set annually	87	85	70	88 - 114	70 - 96
Small hydro (up to 10MW)			68	81	49	60-85	23 - 48
Biomass combustion			84	79 - 101	46 - 68	84 - 121	44 - 81
Biomass co-firing with fossil fuels			17	x	19 - 41		–9 - 55
Biogas			81	77-103	44 - 69	81 - 108	41 - 69
Geothermal electricity			117	156	126	161	125
PV			201	456	435	229 - 481	204 - 456

* ERO can not reduce this by more than 5% each year Note: Exchange rate 1€ = 27,97 CZK

FUTURE TARGETS

A 15-16% share of RES in total primary energy consumption by 2030 has been set as a target at national level. For RES-E, the target to be achieved is 8% in 2010. The Czech Republic's RES percentage of total primary energy consumption is currently approximately 3%. A very gradual increase can be observed in the RES-E share of gross electricity consumption (3.8% in 1997, 4.1% in 2004).

DENMARK

MARKET STRUCTURE

Due to an average growth of 71% per year, Danish offshore wind capacity remains the highest per capita in Europe (409 MW in total in 2007). Denmark is at present close to reaching its RES-E target for 2010. Two new offshore installations, each of 200 MW, are planned. RES, other than offshore wind, are slowly but steadily penetrating the market supported by a wide array of measures such as a new re-powering scheme for onshore wind.

KEY SUPPORT SCHEME

In order to increase the share of RES-E in the overall electricity consumption, Denmark has installed the following measures:

- A tendering procedure has been used for two new large offshore installations. Operators will receive a spot price and initially a settling price as well. Subsequent offshore wind farms are to be developed on market conditions.
- A spot price, an environmental premium (€13/MWh) and an additional compensation for balancing costs (€3/MWh) for 20 years is available for new onshore wind farms.
- Fixed FITs exist for solid biomass and biogas under certain conditions.
- Subsidies are available for CHP plants based on natural gas and waste.

TABLE A6:

Technology	Duration	Tariff	Note
Wind onshore	20 years	Market price plus premium of 13 €/MWh	Additionally balancing costs are refunded at 3 €/MWh, leading to a total tariff of approx. 57 €/MWh
Wind offshore	50.000 full load hours afterwards	66-70 €/MWh spot market price plus a 13 €/MWh premium	A tendering system was applied for the last two offshore wind parks; balancing costs are paid by the owners
Solid biomass and biogas	10 years following 10 years	80 €/MWh 54 €/MWh	New biogas plants are only eligible for the tariff if they are grid connected before end of 2008.
Natural gas and waste CHP plants	20 years 20 years	Individual grant, depending on previous grants Three-time tariff	Above 10 MW only; annual, non-production related grant. 5-10 MW can choose the support scheme, below 5 MW only Three-time tariff
PV	Not determined	200-250 €/MWh	"Meter running backwards" principle applied in private houses

FUTURE TARGETS

In Denmark, the RES-E target from the EU Directive is 29% of gross electricity consumption by 2010. With an increase from 8.7% RES-E in 1997 to 26.30% in 2004, Denmark is nearing its target of 29% RES-E of gross electricity consumption in 2010.

ESTONIA

MARKET STRUCTURE

Estonia has extensive fossil fuel reserves, including a large oil shale industry. However, the average annual growth rate for RES-E, stands at 27%. Estonia's largest RES potential is to be found in the biomass sector, but possibilities also exist in the areas of wind power, biogas electricity and small hydro power.

KEY SUPPORT SCHEMES

Estonian legislation relevant to RES-E includes:

- An obligation on the grid operator to buy RES-E providing that the amount "does not exceed the network losses during the trading period" which came into force in 2005.
- A voluntary mechanism involving green energy certificates was also created by the grid operator (the state-owned Eesti Energia Ltd.) in 2001.

Renewable electricity is purchased for a guaranteed fixed price of 81 EEKcents/kWh (5.2 c€/kWh). Before, the EMA prices were linked to the sales prices of the two major oil-shale based power plants.

TABLE A7:

Technology	Duration	2003 - present
	fixed years	fixed €/MWh
All RES	Wind: 12	
Current support mechanisms will be terminated in 2015	52	

The EMA states that the preferential purchase price for wind electricity is guaranteed for 12 years, but all current support mechanisms will be terminated in 2015. There is no information on legislation planned to replace this after 2015.

FUTURE TARGETS

In Estonia, the share of electricity produced from renewable energy sources is projected to reach 5.1% in 2010. For RES-E, an average annual growth rate of 27% has been registered between 1997 and 2004. Estonia's share of RES-E stood at 0.7% in 2004, compared to 0.2% in 1997. Dominant sources of RES-E in Estonia are solid biomass and small-scale hydro power.

FINLAND

MARKET STRUCTURE

Finland is nearing its RES-E target for 2010, and continues to adjust and refine its energy policies in order to further enhance the competitiveness of RES. Through subsidies and energy tax exemptions, Finland encourages investment in RES. Solid biomass and large-scale hydropower plants dominate the market, and biowaste is also increasing its share. Additional support in the form of FITs based on purchase obligations or green certificates is being considered for onshore wind power.

KEY SUPPORT SCHEMES

Finland has taken the following measures to encourage the use of RES-E:

- Tax subsidies: RES-E has been made exempt from the energy tax paid by end users.
- Discretionary investment subsidies: New investments are eligible for subsidies up to 30% (40% for wind).
- Guaranteed access to the grid for all electricity users and electricity-producing plants, including RES-E generators (Electricity Market Act – 386/1995).

TABLE A8:

Technology	2003 - present Tax reimbursement
	€/MWh
Wind and forest chip	6.9
Recycled fuels	2.5
Other renewables	4.2

FUTURE TARGETS

By 2025, Finland wants to register an increase in its use of renewable energy by 260 PJ. With regard to RES-E, the target to be met is 31.5% of gross electricity consumption in 2010. With figures of 24.7% in 1997 and 28.16% in 2004, Finland is progressing towards its RES-E target of 31.5% in 2010.

FRANCE

MARKET STRUCTURE

France has centred its RES approach around FITs on the one hand, and a tendering procedure on the other. Hydro power has traditionally been important for electricity generation, and the country ranks second when it comes to biofuel production, although the biofuels target for 2005 was not met.

KEY SUPPORT SCHEMES

The French policy for the promotion of RES-E includes the following mechanisms:

- FITs (introduced in 2001 and 2002, and modified in 2005) for PV, hydro, biomass, sewage and landfill gas, municipal solid waste, geothermal, offshore wind, onshore wind, and CHP.
- A tender system for large renewable projects.

TABLE A9:

Technology	Duration	Tariff	Note
Wind onshore	10 years	82 €/MWh	
	following 5 years	28 – 82 €/MWh	Depending on the local wind conditions
Wind offshore	10 years	130 €/MWh	
	following 10 years	30 – 130 €/MWh	Depending on the local wind conditions
Solid biomass	15 years	49 €/MWh	Standard rate, including premium up to 12 €/MWh
Biogas	15 years	45 – 57.2 €/MWh	Standard rate, including premium up to 3 €/MWh
Hydro power	20 years	54.9 – 61 €/MWh	Standard rate, including premium up to 15,2 €/MWh
Municipal solid waste	15 years	45 – 50 €/MWh	Standard rate, including premium up to 3 €/MWh
CHP plants		61 – 9.,5 €/MWh	
Geothermal	15 years	120 €/MWh	Standard rate
	15 years	100 €/MWh	In metropolis only Plus and efficiency bonus up to 30 €/MWh
PV	20 years	300 €/MWh	In metropolis
	20 years	400 €/MWh	In Corsica, DOM and Mayotte Plus 250 €/MWh respectively 150 €/MWh if roof-integrated

FUTURE TARGETS

The RES-E target from the EU Directive for France is 21% RES-E share of gross electricity consumption in 2010. France's share of RES-E decreased from 15% in 1997 to 12.64% in 2004. France has vast resources of wind, geothermal energy and biomass, and wind power and geothermal electricity have shown growth. In addition, there is potential in the area of solid biomass.

GERMANY

KEY ISSUES

Germany is an EU leader in wind utilisation, PV, solar thermal installations and biofuel production. Its onshore wind capacity covers approximately 50% of the total installed capacity in the EU. A stable and predictable policy framework has created conditions favourable to RES penetration and growth. FITs for RES-E have proven a successful policy, leading to a very dynamic market for RES.

KEY SUPPORT SCHEMES

With the aim of promoting RES-E, Germany has introduced the following schemes through its Renewable Energy Act of 2004:

- FITs for onshore wind, offshore wind, PV, biomass, hydro, landfill gas, sewage gas and geothermal.
- Large subsidised loans available through the DtA (Deutsche Ausgleichsbank) Environment and Energy Efficiency Programme.

TABLE A10:

Technology	Duration	Tariff	Note
Wind onshore	20 years	83.6 €/MWh	For at least 5 years
		52.8 €/MWh	Further 15 years, annual reduction of 2% is taken into account.
Wind offshore	20 years	91 €/MWh	For at least 12 years
		61.9 €/MWh	Further 8 years, annual reduction of 2% is taken into account.
		30 – 130 €/MWh	
Solid biomass and biogas	20 years	81.5 – 111,6 €/MWh	Annual reduction of 1.5%
	20 years	64.5 – 74.4 €/MWh	Annual reduction of 1.5%
		additional 20 €/MWh	In CHP applications only
Hydro power up to 5 MW	30 years	66.5 – 96.7 €/MWh	Lower FITs also for hydro plants up to 150 MW
Geothermal	20 years	71.6 – 150 €/MWh	Annual reduction of 1% from 2010 on
PV	20 years	406 – 568 €/MWh	Annual reduction of 6.5%; prices vary depending on the location.

FUTURE TARGETS

Overall, Germany would like to register a 10% RES share of total energy consumption in 2020. The RES-E targets set for Germany are 12.5% of gross electricity consumption in 2010, and 20% in 2020. Substantial progress has already been made towards the 2010 RES-E target. Germany's RES-E share in 1997 was 4.5%, which more than doubled in 2004 (9.46%).

GREECE

MARKET STRUCTURE

Hydro power has traditionally been important in Greece, and the markets for wind energy and active solar thermal systems have grown in recent years. Geothermal heat is also a popular source of energy. The Greek Parliament has recently revised the RES policy framework, partly to reduce administrative burdens on the renewable energy sector.

KEY SUPPORT SCHEMES

General policies relevant to RES include a measure related to investment support, a 20% reduction of taxable income on expenses for domestic appliances or systems using RES, and a concrete bidding procedure to ensure the rational use of geothermal energy. In addition, an inter-ministerial decision was taken in order to reduce the administrative burden associated with RES installations.

Greece has introduced the following mechanisms to stimulate the growth of RES-E:

- FITs were introduced in 1994 and amended by the recently approved Feed-in Law. Tariffs are now technology specific, instead of uniform, and a guarantee of 12 years is given, with a possibility of extension to up to 20 years.
- Liberalisation of RES-E development is the subject of Law 2773/1999.

TABLE A11:

RES-E Technology	Mainland	Autonomous islands
	€/MWh	€/MWh
Wind onshore	73	84.6
Wind offshore	90	90
Small Hydro (< 20MW)	73	84.6
PV system (≤100 kWp)	450	500
PV system (>100 kWp)	400	450
Solar Thermal Power Plants (≤ 5 MWp)	250	270
Solar Thermal Power Plants (> 5 MWp)	230	250
Geothermal	73	84.6
Biomass and biogas	73	84.6
Others	73	84.6

FUTURE TARGETS

According to the EU Directive, the RES-E target to be achieved by Greece is 20.1% of gross electricity consumption by 2010. In terms of RES-E share of gross electricity consumption, the 1997 figure of 8.6% increased to 9.56% in 2004.

HUNGARY

KEY ISSUES

After a few years of little progress, major developments in 2004 brought the Hungarian RES-E target within reach. Geographical conditions in Hungary are favourable for RES development, especially biomass. Between 1997 and 2004, the average annual growth of biomass was 116%. Whilst environmental conditions are the main barrier to further hydro power development, other RES such as solar, geothermal and wind energy are hampered by administrative constraints (for example, the permit process).

KEY SUPPORT SCHEMES

The following measures exist for the promotion of RES-E:

- A feed-in system is in place. It has been using technology-specific tariffs since 2005, when Decree 78/2005 was adopted. These tariffs are guaranteed for the lifetime of the installation.

- A green certificate scheme was introduced with the Electricity Act (2001, as amended in 2005). This act gives the government the right to define the start date of implementation. At that time, FITs will cease to exist.

Nevertheless, from 2007, subsidies for co-generation power and RES will be decreased, since national goals of production from RES were already achieved in 2005.

FUTURE TARGETS

The Hungarian Energy Saving and Energy Efficiency Improvement Action Programme expresses the country's determination to reach a share of renewable energy consumption of at least 6% by 2010. The target set for Hungary in the EU Directive is a RES-E share of 3.6% of gross electricity consumption. Progress is being made towards the 3.6% RES-E target. Hungary's RES-E share amounted to 0.7% in 1997, and 2.24% in 2004.

TABLE A12:

Technology		Duration fixed years	2005 fixed Ft./kWh	2005 fixed €/MWh	2006 fixed Ft./kWh	2006 Fixed €/MWh
Geothermal, biomass, biogas, small hydro (<5 MW) and waste	Peak	According to the lifetime of the technology	28.74	117	27.06	108
	Off-peak		16.51	67	23.83	95
	Deep off-peak		9.38	38	9.72	39
Solar, wind	Peak		n.a.	n.a.	23.83	95
	Off-peak		n.a.	n.a.	23.83	95
	Deep off-peak		n.a.	n.a.	23.83	95
Hydro (> 5 MW), co-generation	Peak		18.76	76	17.42	69
	Off-peak		9.38	38	8.71	35
	Deep off-peak		9.38	38	8.71	35

Exchange rate used 1 Ft. = 0.004075 Euro (1 February 2005) and 1 Ft. = 0.003975 Euro (1 February 2006) from FXConverter http://www.oanda.com/convert/classic

IRELAND

MARKET STRUCTURE

Hydro and wind power make up most of Ireland's RES-E production. Despite an increase in the RES-E share over the past decade, there is still some way to go before the target is reached. Important changes have occurred at a policy level. Ireland has selected the Renewable Energy Feed-In Tariff (REFIT) as its main instrument. From 2006 onwards, this new scheme is expected to provide some investor certainty, due to a 15-year FIT guarantee. No real voluntary market for renewable electricity exists.

KEY SUPPORT SCHEMES

Between 1995 and 2003, a tender scheme (the Alternative Energy Requirement – AER) was used to support RES-E. Since early 2006, the REFIT has become the main tool for promoting RES-E. €119 million will be used over 15 years from 2006 to support 55 new renewable electricity plants with a combined capacity of 600 MW. FITs are guaranteed for up to 15 years, but may not extend beyond 2024. During its first year, 98% of all the REFIT support has been allocated to wind farms.

TABLE A13:

Technology	Tariff duration	2006
	fixed years	fixed €/MWh
Wind > 5 MW plants	15 years	57
Wind < 5 MW plants		59
Biomass (landfill gas)		70
Other biomass		72
Hydro		72

FUTURE TARGETS

The RES-E target for Ireland, set by the EU Directive to be met by 2010, is 13.2% of gross electricity consumption. The country itself would like to reach an RES-E share of 15% by that time. The European Energy Green Paper, published in October 2006, sets targets over longer periods. In relation to Ireland, it calls for 30% RES-E by 2020. Ireland is making some modest progress in relation to its RES-E target, with 3.6% in 1997 and 5.23% in 2004.

ITALY

KEY ISSUES

Despite strong growth in sectors such as onshore wind, biogas and biodiesel, Italy is still a long way from the targets set at both national and European level. Several factors contribute to this situation. Firstly, there is a large element of uncertainty, due to recent political changes and ambiguities in the current policy design. Secondly, there are administrative constraints, such as complex authorisation procedures at local level. Thirdly, there are financial barriers, such as high grid connection costs.

In Italy, there is an obligation on electricity generators to produce a certain amount of RES-E. At present, the Italian government is working out the details of more ambitious support mechanisms for the development and use of RES.

KEY SUPPORT SCHEMES

In order to promote RES-E, Italy has adopted the following schemes:

- Priority access to the grid system is guaranteed to electricity from RES and CHP plants.
- An obligation for electricity generators to feed a given proportion of RES-E into the power system. In 2006, the target percentage was 3.05%. In cases of non-compliance, sanctions are foreseen, but enforcement in practice is considered difficult because of ambiguities in the legislation.
- Tradable Green Certificates (which are tradable commodities proving that certain electricity is generated using renewable energy sources) are used to fulfil the RES-E obligation. The price of such a certificate stood at 109 €/MWh in 2005.
- A FIT for PV exists. This is a fixed tariff, guaranteed for 20 years and adjusted annually for inflation.

TABLE A14:

Technology	Capacity	Duration	2006
		fixed years	fixed €/MWh
Solar PV	<20 kW	20	44.5*
	≤50 kW		46
	50<P <1000 kW		49
Building integrated PV	<20 kW		48.9*
	≤50 kW		50.6
	>50 kW		max 49 + 10 %

*From February 2006, these tariffs are also valid for PV with net metering ≤20 kW

FUTURE TARGETS

According to the EU Directive, Italy aims for a RES-E share of 25% of gross electricity consumption by 2010. Nationally, producers and importers of electricity are obliged to deliver a certain percentage of renewable electricity to the market every year. No progress has been made towards reaching the RES-E target. While Italy's RES-E share amounted to 16% in 1997, it decreased slightly to 15.43% in 2004.

LATVIA

MARKET STRUCTURE

In Latvia, almost half the electricity consumption is provided by RES (47.1% in 2004), with hydro power being the key resource. The growth observed between 1996 and 2002 can be ascribed to the so-called double tariff, which was phased out in 2003. This scheme was replaced by quotas that are adjusted annually. A body of RES-E legislation is currently under development in Latvia. Wind and biomass would benefit from clear support, since the potential in these areas is considerable.

KEY SUPPORT SCHEMES

The two main RES-E policies that have been followed in Latvia are:

- Fixed FITs, which were phased out in 2003.
- A quota system, which has been in force since 2002, with authorised capacity levels of installations determined by the Cabinet of Ministers on an annual basis.

The main body of RES-E policy in Latvia is currently under development. Based on the Electricity Market Law of 2005, the Cabinet of Ministers must now develop and adopt regulations in 2006 to deal with the following areas:

- Pricing for renewable electricity.
- Eligibility criteria to determine which renewable energy sources qualify for mandatory procurement of electricity.
- The procedure for receiving guarantees of origin for renewable electricity generated.

FUTURE TARGETS

According to the EU Directive, the RES-E share that Latvia is required to reach is 49.3% of gross electricity consumption by 2010. Between 1997 and 2004, the Latvian RES-E share of gross electricity consumption increased from 42.4% to 47.1%.

LITHUANIA

MARKET STRUCTURE

Lithuania depends, to a large extent, on the Ignalina nuclear power plant, which has been generating 75-88% of the total electricity since 1993. In 2004, Unit 1 was closed, and the shut down of Unit 2 is planned before 2010. In order to provide alternative sources of energy, in particular electricity, Lithuania has set a national target of 12% RES by 2010 (8% in 2003). The implementation of a green certificate scheme was, however, postponed for 11 years. The biggest renewables potential in Lithuania can be found in the field of biomass.

KEY SUPPORT SCHEMES

The core mechanisms used in Lithuania to support RES-E are the following:

- FITs: in 2002, the National Control Commission for Prices and Energy approved the average purchase prices of green electricity. The tariffs are guaranteed for a fixed period of 10 years.

- After 2010, a green certificate scheme should be in place. The implementation of this mechanism has been postponed until 2021.

TABLE A15:

Technology	Duration fixed years	2002 - present fixed €/MWh
Hydro		57.9
Wind	10	63.7
Biomass		57.9

FUTURE TARGETS

At national level, it has been decided that the RES share of Lithuania's total energy consumption should reach 12% by 2010. The RES-E EU Directive has fixed a RES-E target of 7% of gross electricity consumption by 2010. In 2003, RES accounted for about 8% of the country's energy supply. Between 1997 and 2004, an increase of 0.41% in the RES-E share of consumption was noted (3.71% in 2004 compared to 3.3% in 1997).

LUXEMBOURG

MARKET STRUCTURE

Despite a wide variety of support measures for RES and a stable investment climate, Luxembourg has not made significant progress towards its targets in recent years. In some cases, this has been caused by limitations on eligibility and budget. While the electricity production from small-scale hydro power has stabilised in recent years, the contribution from onshore wind, PV, and biogas has started to increase.

KEY SUPPORT SCHEMES

The 1993 Framework Law (amended in 2005) determines the fundamentals of Luxembourgian RES-E policy.

- Preferential tariffs are given to the different types of RES-E for fixed periods of 10 or 20 years. The feed-in system might be subject to change, due to further liberalisation of the sector.
- Subsidies are available to private companies that invest in RES-E technologies, including solar, wind, biomass and geothermal technologies.

TABLE A16:

Technology	Tariff duration	2001 to September 2005		From October 2005	
	fixed years	Capacity	Tariff fixed €/MWh	Capacity	Tariff fixed €/MWh
Wind	10	Up to 3000 kW	25	<501 kW	77.6
Hydro					
Biomass				<501 kW	102.6 (77.6 + 25 for biomass)
Biogas (including landfill and sewage)					
Wind	10	x	x	500 kW to 10.001 kW	max 77.6 Lower for higher capacities
Hydro					
Biomass					
Biogas (including landfill and sewage)				500 kW to 10.001 kW	max 102.6
PV – municipalities	20	Up to 50 kW	250	No capacity restriction	280
PV– non-municipalities			450 - 550		560

FUTURE TARGETS

The RES-E target to be achieved in 2010, as set by the EU Directive, is 5.7% of gross electricity consumption. A slight increase in Luxembourg's RES-E share can be noted. In 2004, the RES-E share amounted to 2.8% of gross electricity consumption, compared to 2.1% in 1997.

MALTA

MARKET STRUCTURE

The market for RES in Malta is still in its infancy, and at present, penetration is minimal. RES has not been adopted commercially, and only solar energy and biofuels are used. Nevertheless, the potential of solar and wind is substantial. In order to promote the uptake of RES, the Maltese government is currently creating a framework for support measures. In the meantime, it has set national indicative targets for RES-E lower than those agreed in its Accession Treaty (between 0.31% and 1.31%, instead of 5%).

KEY SUPPORT SCHEMES

In Malta, RES-E is supported by a FIT system and reduced value-added tax systems.

TABLE A17:

Technology	Support system	Comments
PV < 3.7 kW	46.6 €/MWh	Feed in
Solar	5 – 15 %	VAT reduction
A framework for measures to further support RES-E is currently being examined		

FUTURE TARGETS

The RES-E target set by the EU Directive for Malta is 5% of gross electricity consumption in 2010. However, at national level, it has been decided to aim for 0.31%, excluding large wind farms and waste combustion plants; or for 1.31% in the event that the plans for a land-based wind farm are implemented. The total RES-E production in 2004 was 0.01 GWh and, therefore, the RES-E share of gross electricity consumption was effectively zero percent.

THE NETHERLANDS

MARKET STRUCTURE

After a period during which support was high but markets quite open, a system was introduced (in 2003) that established sufficient incentives for domestic RES-E production. Although successful in encouraging investments, this system (based on premium tariffs), was abandoned in August 2006 due to budgetary constraints. Political uncertainty concerning renewable energy support in the Netherlands is compounded by an increase in the overall energy demand. Progress towards RES-E targets is slow, even though growth in absolute figures is still significant.

MAIN SUPPORTING POLICIES

RES-E policy in the Netherlands is based on the 2003 MEP policy programme (Environmental Quality of Power Generation), and is composed of the following strands:

- Source-specific premium tariffs, paid for ten years on top of the market price. These tariffs were introduced in 2003 and are adjusted annually. Tradable certificates are used to claim the FITs. The value of these certificates equals the level of the FIT. Due to budgetary reasons, most of the FITs were set at zero in August 2006.
- An energy tax exemption for RES-E was in place until 1 January 2005.
- A Guarantee of Origin system was introduced, simply by renaming the former certificate system.

The premium tariffs are given in the table below:

TABLE A18:

Technology	Duration	1 July to 31 December 2004	1 January 2005 to 30 June 2006	Since August 2006
	years	premium €/MWh	premium €/MWh	premium €/MWh
Mixed biomass and waste	10	29	29	0
Wind onshore		63	77	0
Wind offshore		82	97	0
Pure biomass large scale > 50 MW		55	70	0
Pure biomass small scale < 50 MW		82	97	97*
PV, tidal and wave, hydro		82	97	0

*Only for installations using biogas from manure digestion and having a capacity below 2 MW. Total premium is limited to €270 million for the complete duration period.

FUTURE TARGETS

In its climate policy, the Netherlands set a global target of 5% renewable energy by 2010, and 10% by 2020. According to the EU Directive, the RES-E share of the Netherlands should reach 9% of gross electricity consumption in 2010. Between 1997 and 2004, progress was made towards the RES-E target. In 1997, the RES-E share was 3.5%, and by 2004, had risen to 4.60%.

POLAND

MARKET STRUCTURE

Progress towards the RES-E target in Poland is slow and the penalties designed to ensure an increased supply of green electricity have not been adequately used. Regardless a high potential of hydro power plants, they have not been fully used to date; biomass resources (in the form of forestry residues, agricultural residues and energy crops) are plentiful in Poland, and landfill gas is also promising.

MAIN SUPPORTING POLICIES

The Polish RES-E policy includes the following mechanisms.

- Tradable Certificates of Origin introduced by the April 2005 amendment of the Law on Energy (1997).
- The Obligation for Power Purchase from Renewable Sources (2000, amended in 2003) involves a requirement on energy suppliers to provide a certain minimum share of RES-E (3.1% in 2005, 3.6% in 2006, 4.8% in 2007 and 7.5% in 2010). Failure to comply with this legislation leads, in theory, to the enforcement of a penalty; in 2005, this was not adequately enforced.
- An excise tax exemption on RES-E was introduced in 2002.

FUTURE TARGETS

Poland has a RES-E and primary energy target of 7.5% by 2010. Steady but modest progress is being made with regard to the RES-E target, since the RES-E share of gross energy consumption was about 2.6% in 2005, compared to 2.20% in 2004 and 1.6% in 1997. The potential of hydro power, biomass and landfill gas is high in Poland.

PORTUGAL

MARKET STRUCTURE

The measures adopted so far in Portugal in relation to renewable energy constitute a comprehensive policy mix, complete with monitoring system. Between 1997 and 2004, Portugal has moved further away from its RES-E target. Due to the fact that this target is not entirely realistic, since it was based on the exceptional hydropower performance of 1997, Portugal is not expected to reach its target, even if measures are successful.

KEY SUPPORT SCHEMES

In Portugal, the following measures have been taken to stimulate the uptake of RES-E:

- Fixed FITs per kWh exist for PV, wave energy, small hydro, wind power, forest biomass, urban waste and biogas.
- Tendering procedures were used in 2005 and 2006 in connection with wind and biomass installations.
- Investment subsidies up to 40% can be obtained.
- Tax reductions are available.

The Decreto Lei 33-A/2005 has introduced new FITs as listed below:

ROMANIA

MARKET STRUCTURE

In terms of RES of gross electricity consumption, Romania is on target. In 2004, the majority of all RES-E was generated through large-scale hydro power. To a large extent, the high potential of small-scale hydro power has remained untouched. Between 1997 and 2004, both the level of production, and the growth rate of most RES has been stable. Provisions for public support are in place, but renewable energy projects have so far not been financed.

KEY SUPPORT SCHEME

Romania introduced the following measures to promote RES-E:

- A quota system, with tradable green certificates (TGC) for new RES-E, has been in place since 2004. A mandatory quota increase from 0.7% in

TABLE A19:

Technology		Duration	2004	2006 [4]
		fixed years	fixed €/MWh	fixed €/MWh
Photovoltaics	< 5kW		450	450
Photovoltaics	> 5kW		245	310
Wave			247	n.a.
Small hydro	< 10 MW	15	78	75
Wind			90 [5]	74
Forest biomass			78	110
Urban waste			70	75
Biogas			n.a.	102

FUTURE TARGETS

The RES-E target to be achieved by Portugal in 2010 is 39% of gross electricity consumption. Portugal, which nearly met its RES-E target for 2010 in 1997, has now moved further away from this target. A sharp decline between 38.5% in 1997 to only 23.84% 2004 was observed.

2005 to 8.3% in 2010-2012. TGCs are issued to electricity production from wind, solar, biomass or hydro power generated in plants with less than 10 MW capacity.

- Mandatory dispatching and priority trading of electricity produced from RES since 2004.

[4] Stated 2006 tariffs are average tariffs. Exact tariff depends on a monthly correction of the inflation, the time of feed-in (peak/ off peak) and the technology used

[5] Tariff only up to 2000 full load hours; 2006 tariff for all full load hours

TABLE A20:

The quota is imposed to power suppliers, trading the electricity between the producers and consumers.	
Period	**Penalties for non compliance**
2005-2007	63 €/CV
2008-2012	84 €/CV

FUTURE TARGETS

In Romania, the RES target to be achieved is 11% of gross energy in 2010. The RES-E target was set on 33% of gross electricity consumption in 2010. The RES-E share of gross electricity consumption has decreased from 31.3% in 1997 to 29.87% in 2004.

SLOVAKIA

MARKET STRUCTURE

In the Slovak Republic, large-scale hydro energy is the only renewable energy source with a notable share in total electricity consumption. Between 1997 and 2004, this market share stabilised. The share taken up by small-scale hydro energy has decreased by an average of 15% per year over the same period. An extended development programme, with 250 selected sites for building small hydro plants has been adopted. The government has decided to use only biomass in remote, mountainous, rural areas, where natural gas is unavailable. Between 1997 and 2004, the Slovak republic moved further away from its RES target.

KEY SUPPORT SCHEME

RES-E policy in the Slovak Republic includes the following measures:

- A measure that gives priority regarding transmission, distribution and supply was included in the 2004 Act on Energy.
- Guarantees of origin are being issued.
- Tax exemption is granted for RES-E. This regulation is valid for the calendar year in which the facility commenced operation and then for five consecutive years.
- A system of fixed FITs has been in place since 2005.
- Subsidies up to €100.000 are available for the (re)construction of RES-E facilities.

Decree No. 2/2005 of the Regulatory Office for Network Industries (2005) set out the fixed FITs available for RES-E.

TABLE A21:

Technology	**2006**		**2007***	
	fixed SKK/MWh	**fixed €/MWh**	**fixed SKK/MWh**	**fixed €/MWh**
Wind	2800	75.1	1950 - 2565	55 - 72
Hydro <5 MW	2300	61.7	1950 - 2750	55 - 78
Solar	8000	214.6	8200	231
Geothermal	3500	93.9	3590	101
Biogas	x	x	2560 - 4200	72 - 118
Biomass combustion	2700	72.4	2050 - 3075	58 - 87

* Note: Exact level of FIT depends on the exchange rate. Here 1€ = 35,458 SKK

The prices have been set so that a rate of return on the investment is 12 years when drawing a commercial loan. These fixed tariffs will be inflation adjusted the following year.

FUTURE TARGETS

In terms of its primary energy consumption, the Slovak Republic has fixed the target of 6% renewable energy consumption by 2010. The target set by the EU Directive for RES-E is 31% in 2010. Currently, renewable energy represents about 3.5% of the total primary energy consumption in the Slovak Republic. Between 1997 and 2004, the share of RES-E decreased from 17.9% to 14.53% of gross energy consumption. In the Slovak Republic, the highest additional mid-term potential of all RES lies with biomass.

SLOVENIA

MARKET STRUCTURE

Slovenia is currently far from meeting its RES targets. Solid biomass has recently started to penetrate the market. Hydro power, at this time the principal source of RES-E, relies on a large amount of very old, small hydro plants; and the Slovenian government has made the refurbishment of these plants part of the renewable energy strategy. An increase in capacity of the larger-scale units is also foreseen. In Slovenia, a varied set of policy measures has been accompanied by administrative taxes and complicated procedures.

KEY SUPPORT SCHEMES

In Slovenia, the RES-E policy includes the following measures:

- RES-E producers can choose to receive either fixed FITs or premium FITs from the network operators. A Purchase Agreement is concluded, valid for 10 years. According to the Law on Energy, the uniform annual prices and premiums are set at least once a year. Between 2004 and 2006, these prices stayed the same.
- Subsidies or loans with interest-rate subsidies are available. Most of the subsidies cover up to 40% of the investment cost. Investments in rural areas with no possibility of connection to the electricity network are eligible to apply for an additional 20% subsidy.

TABLE A22:

<table>
<tr><th>Technology</th><th>Capacity</th><th colspan="2">Duration</th><th colspan="4">2004 – present</th></tr>
<tr><th></th><th></th><th>fixed
years</th><th>premium
years</th><th>fixed
SIT/MWh</th><th>premium
SIT/MWh</th><th>fixed
€/MWh</th><th>premium
€/MWh</th></tr>
<tr><td rowspan="2">Hydro</td><td>Up to 1 MW</td><td rowspan="13">After 5 years tariff reduced by 5%. After 10 years tariff reduced by 10%.</td><td></td><td>14.75</td><td>6.75</td><td>62</td><td>28</td></tr>
<tr><td>1-10 MW</td><td></td><td>14.23</td><td>6.23</td><td>59</td><td>26</td></tr>
<tr><td rowspan="2">Biomass</td><td>Up to 1 MW</td><td></td><td>16.69</td><td>8.69</td><td>70</td><td>36</td></tr>
<tr><td>Over 1 MW</td><td></td><td>16.17</td><td>8.17</td><td>68</td><td>34</td></tr>
<tr><td rowspan="2">Biogas (landfill and sewage gas)</td><td>Up to 1 MW</td><td></td><td>12.67</td><td>-</td><td>53</td><td>-</td></tr>
<tr><td>Over 1 MW</td><td></td><td>11.71</td><td>-</td><td>49</td><td>-</td></tr>
<tr><td>Biogas (animal waste)</td><td>-</td><td></td><td>28.92</td><td>-</td><td>121</td><td>-</td></tr>
<tr><td rowspan="2">Wind</td><td>Up to 1 MW</td><td></td><td>14.55</td><td>6.55</td><td>61</td><td>27</td></tr>
<tr><td>Over 1 MW</td><td></td><td>14.05</td><td>6.05</td><td>59</td><td>25</td></tr>
<tr><td>Geothermal</td><td>-</td><td></td><td>14.05</td><td>6.05</td><td>59</td><td>25</td></tr>
<tr><td rowspan="2">Solar</td><td>Up to 36 kW</td><td></td><td>89.67</td><td>81.67</td><td>374</td><td>341</td></tr>
<tr><td>Over 36 kW</td><td></td><td>15.46</td><td>7.46</td><td>65</td><td>31</td></tr>
</table>

FUTURE TARGETS

At national level, a target to increase the share of RES in total primary energy consumption from 8.8% in 2001 to 12% by 2010 has been set. The RES-E target to be achieved in 2010, as a result of the EU Directive, is 33.6% in Slovenia. At present, the contribution of RES to the national energy balance is about 9%. In 2004, the Slovenian RES-E share of gross electricity consumption was 29.9%. The potential of solid biomass is high, with over 54% of land covered by forests.

SPAIN

MARKET STRUCTURE

Spain is currently far from its RES-E target. In 1997, a strong support programme in favour of RES was introduced. In 2004, hydro power still provided 50% of all green electricity, while onshore wind and biomass had started penetrating the market. PV energy is also promising, with an average growth rate of 54% per year.

Proposed changes to the FITs and the adoption of a new Technical Buildings Code (2006) show increased support for biomass, biogas, solar thermal electricity, and solar thermal heat.

KEY SUPPORT SCHEMES

RES-E in Spain benefits from the following support mechanisms:

- A FIT or a premium price is paid on top of the market price. The possibility of a cap and floor mechanism for the premium is being considered. In the draft law published 29 November 2006, reduced support for new wind and hydro plants and increased support for biomass, biogas and solar thermal electricity were proposed.
- Low-interest loans that cover up to 80% of the reference costs are available.

Fixed and premium FITs for 2004, 2005 and 2006 are shown in the table below:

TABLE A23:

Technology	Duration	2004		2005		2006	
	both years	fixed €/MWh	premium €/MWh	fixed €/MWh	premium €/MWh	fixed €/MWh	premium €/MWh
PV < 100 kWp	No limit, but fixed tariffs are reduced after either 15, 20 or 25 years depending on technology	414.4	x	421.5	x	440.4	x
PV > 100 kWp		216.2	187.4	219.9	190.6	229.8	199.1
Solar thermal electricity		216.2	187.4	219.9	190.6	229.8	199.1
Wind < 5 MW		64.9	36.0	66.0	36.7	68.9	38.3
Wind > 5 MW		64.9	36.0	66.0	36.7	68.9	38.3
Geothermal < 50 MW		64.9	36.0	66.0	36.7	68.9	38.3
Mini hydro <10 MW		64.9	36.0	66.0	36.7	68.9	38.3
Hydro 10-25 MW		64.9	36.0	66.0	36.7	68.9	38.3
Hydro 25-50 MW		57.7	28.8	58.6	29.3	61.3	30.6
Biomass (biocrops, biogas)		64.9	36.0	66.0	36.7	68.9	38.3
Agriculture + forest residues		57.7	28.8	58.6	29.3	61.3	30.6
Municipal solid waste		50.5	21.6	51.3	22.0	53.6	23.0

FUTURE TARGETS

The Spanish "Plano de Energías Renovables 2005-2010" sets the goal of meeting 12% of total energy consumption from RES in 2010. The target to be achieved in 2010, under the RES-E Directive, is 29.4% of gross electricity consumption. The revised "*Plano de Energías Renovables*" of 2005 sets capacity targets for 2010, which include wind (20,155 MW), PV (400 MW), solar thermal (4.9 million m^2), solar thermal electric (500 MW) and biomass (1,695 MW). In Spain, the RES-E share of gross electricity consumption was 19.6% in 2004, compared to 19.9% in 1997.

SWEDEN

MARKET STRUCTURE

Sweden is moving away from its RES-E target. In absolute figures, RES-E production decreased between 1997 and 2004, mainly due to a lower level of large-scale hydro production. However, other RES, such as biowaste, solid biomass, off-shore wind and PV have shown significant growth. In Sweden, a comprehensive policy mix exists with tradable green certificates as the key mechanism. This system creates both an incentive to invest in the most cost-effective solutions, and uncertainty for investment decisions due to variable prices.

KEY SUPPORT SCHEMES

Swedish RES-E policy is composed of the following mechanisms:

- Tradable Green Certificates were introduced in 2003. The Renewable Energy with Green Certificates Bill that came into force on 1 January 2007, shifts the quota obligation from electricity users to electricity suppliers.
- The environmental premium tariff for wind power is a transitory measure and will be progressively phased out by 2009 for onshore wind.

FUTURE TARGETS

The RES-E target from the EU Directive for Sweden is 60% of gross electricity consumption by 2010. The Swedish Parliament decided to aim for an increase in RES by 10 TWh between 2002 and 2010, which corresponds to a RES-E share of around 51% in 2010. This deviates from the target originally set by the Directive. In June 2006, the Swedish target was amended to increase the production of RES-E by 17 TWh from 2002 and 2016. The Swedish share of RES-E for gross electricity consumption decreased from 49.1% in 1997, to 45.56% in 2004, and approximately 38% at the present time.

UNITED KINGDOM

MARKET STRUCTURE

In the United Kingdom, renewable energies are an important part of the climate change strategy and are strongly supported by a green certificate system (with an obligation on suppliers to purchase a certain percentage of electricity from renewable energy sources) and several grants programmes. Progress towards meeting the target has been significant (electricity generation from renewable energies increased by around 70% between 2000-2005), although there is still some way to go to meet the 2010 target. Growth has been mainly driven by the development of significant wind energy capacity, including offshore wind farms.

KEY SUPPORT SCHEMES

The United Kingdom's policy regarding renewable energy sources consists of four key strands:

- Obligatory targets with tradable green certificate (ROC) system (Renewables Obligation on all electricity suppliers in Great Britain). The non-compliance 'buy-out' price for 2006-2007 was set at £33.24/MWh (approx 48.20 €/MWh), which will be annually adjusted in line with the retail price index.
- Climate Change Levy: RES-E is exempt from the climate change levy on electricity of £4.3/MWh (approx. 6.3 €/MWh)
- Grants schemes: funds are reserved from the New Opportunities Fund for new capital grants for investments in energy crops/biomass power generation (at least £33 million or €53 million over three years), for small-scale biomass/CHP heating (£3 million or €5 million), and planting grants for energy crops (£29 million or €46 million for a period of seven years). A £50 million (€72.5 million) fund, the Marine Renewables Deployment Fund, is available for the development of wave and tidal power.
- Development of a regional strategic approach for planning/targets for renewable energies.

Annual compliance periods run from 1 April one year to 31 March the following year. ROC auctions are held quarterly. In the April 2006, auction over 261,000 ROCs were purchased at an average price of £40.65 (the lowest price for any lot was £40.60).

TABLE A24:

<table>
<tr><th>Year</th><th>Targets</th><th colspan="2">Non-compliance buyout price</th><th>Amount recycled England and Wales</th><th colspan="2">Total "worth" of ROC (England and Wales) (buyout + recycle)</th></tr>
<tr><th></th><th>% supply of consumption target</th><th>£/ MWh</th><th>€/ MWh*</th><th>£/MWh</th><th>£/MWh</th><th>€/MWh*</th></tr>
<tr><td>2002-03</td><td>3</td><td>x</td><td>x</td><td>x</td><td>x</td><td>x</td></tr>
<tr><td>2003-04</td><td>4.3</td><td>30.51</td><td>44.24</td><td>22.92</td><td>53.43</td><td>77.47</td></tr>
<tr><td>2004-05</td><td>4.9</td><td>31.39</td><td>45.52</td><td>13.66</td><td>45.05</td><td>65.32</td></tr>
<tr><td>2005-06</td><td>5.5</td><td>32.33</td><td>46.88</td><td rowspan="11" colspan="3">Not yet known</td></tr>
<tr><td>2006-07</td><td>6.7</td><td>33.24</td><td>48.20</td></tr>
<tr><td>2007-08</td><td>7.9</td><td rowspan="9">Increases in line with retail price index</td><td></td></tr>
<tr><td>2008-09</td><td>9.1</td><td></td></tr>
<tr><td>2009-10</td><td>9.7</td><td></td></tr>
<tr><td>2010-11</td><td>10.4</td><td></td></tr>
<tr><td>2011-12</td><td>11.4</td><td></td></tr>
<tr><td>2012-13</td><td>12.4</td><td></td></tr>
<tr><td>2013-14</td><td>13.4</td><td></td></tr>
<tr><td>2014-15</td><td>14.4</td><td></td></tr>
<tr><td>2015-16</td><td>15.4</td><td></td></tr>
<tr><td>Duration</td><td colspan="6">One ROC is issued to the operator of an accredited generating station for every MWh of eligible renewable electricity generated with no time limitations.</td></tr>
<tr><td>Guaranteed duration of obligation</td><td colspan="6">The Renewables Obligation has been guaranteed to run until at least 2027. Supply targets increase to 15.4% in 2015, and are guaranteed to remain at least at this level until 2027.</td></tr>
</table>

The following limits have been placed on biomass co-firing within the RO:
**From compliance period 2009-10, a minimum of _25% of co-fired biomass must be energy crops
**2010-11 minimum_ of 50% of co-fired biomass must be energy crops
**2011-16 _minimum of _75% of co-fired biomass must be energy crops
**After 2016 co-firing will not be eligible for ROCs

FUTURE TARGETS

The RES-E target to be achieved by the UK in 2010 is 10 % of gross electricity consumption. An indicative target of 20% for RES-E for 2020 has been set. After a relatively stable share in the early 2000s, growth over the past couple of years has been significant. In 2005, the share of renewable sources in electricity generation reached 4.1%, in comparison with the 2010 target of 10%.

Appendix II - Price of Wind Energy Offshore: Feed-in Tariffs for Offshore Wind in Denmark

Poul Erik Morthost, Risø National Laboratory

The purpose of this section is to illustrate the prices of electricity from offshore wind farms, i.e. what is economically feasible under market conditions (as of 2006).

Onshore turbines in Denmark are currently subject to an environmental premium system whereby the turbine owners are paid the power spot price (approximately 3.4 c€/kWh) plus a premium of 1.3 c€/kWh. In general, the turbine owners themselves are responsible for balancing the power production from the turbines. Though the actual balancing is left to the TSO or another company responsible for balancing, the balancing costs are borne by the turbine owners, which receive 0.3 c€/kWh in addition to the above-mentioned amounts in compensation. The additional costs of wind power compared to conventional power, that is, the environmental premium and the balancing compensation are passed on to the Danish power consumers.[6]

Most of the existing Danish offshore capacity has been established in accordance with an agreement between the Danish government and the power companies. This goes for the two largest offshore wind farms erected so far, Horns Reef I and Nysted I. The owners of these two wind farms are paid a feed-in tariff of 6.1 c€/kWh, including compensation for balancing of 0.3 c€/kWh for 42,000 full load hours. When the number of full load hours has been reached, the turbine owners receive the spot price, plus the premium of 1.3 c€/kWh plus the balancing compensation of 0.3 c€/kWh until the wind farm is 20 years old. Following that, only the spot price will be paid for the power production from the wind farms.

The privately established offshore wind farms, Middelgrunden and Samsø have fairly similar although not identical economic conditions. These wind farms are paid a feed-in tariff of 6.1 c€/kWh, including compensation for balancing of 0.3 c€/kWh, for the first ten years of operation. From the 11th year the turbine owners receive the spot price, plus the premium of 1.3 c€/kWh[7], plus the balancing compensation of 0.3 c€/kWh until the wind farm is 20 years old. Following that, only the spot price will be paid for the power production from the wind farms.

For the Horns Reef II offshore wind farm, which is currently at the planning stage, an agreement on economic conditions has been reached between the Danish government and the consortium of developers that won the tender. According to this agreement, a feed-in tariff of 7.0 c€/kWh is paid for 50,000 hours of full load operation, including a compensation for balancing of 0.3 c€/kWh. After the number of full load hours has been reached, the turbine owners will only receive the spot price, plus the balancing compensation of 0.3 c€/kWh until the wind farm is 20 years old. Following that only the spot price will be paid for the power production from the wind farm.

In Denmark, offshore wind farms are thought of as part of the power system infrastructure. This implies that the costs of the offshore transforming substation, the transmission cables to the shore and any reinforcement of onshore power infrastructure are covered by the Danish TSO and not by the company investing in the wind farm. Finally, for new offshore farms the Danish Government selects the sites where the wind farms are to be constructed, and these sites

[6] It should be noted that practically no new turbines are being erected under the current Danish tariff regime (2006). All new development is being done under a supplementary premium system, which supports repowering, that is, the removal of old wind turbines with a rated power up to 450 kW. The purpose of the scheme is to clear the landscape of many smaller turbines, which contribute relatively little to total Danish wind energy production. Under the scheme, the owner of the smaller turbines which are removed receives a marketable certificate for twice the rated power of the removed turbine. The replacement turbines are generally placed in different areas which are deemed suitable for modern large-scale wind development. The scheme gives an additional incentive of 1.6 c€/kWh for the first 12,000 full-load hours of production, (the rated turbine power in kW times 12,000h).

[7] With a maximum of 4.8 c€/kWh. If the spot price plus the premium exceeds 4.8 c€/kWh the premium is lowered. Balancing compensation is added on top of the maximum of 4.8 c€/kWh.

are environmentally pre-screened, which minimises the risks of investors of not getting approval for the considered project, before the site is sold via a call for tenders. Nevertheless the final environmental impact assessment (EIA) has to be carried out and financed by the investor, because the EIA is tied to the actual project.

Appendix III - Offshore Wind Power Development in Denmark

by Poul Erik Morthorst, Risø National Laboratory

Denmark was one of the early movers in establishing offshore wind farms. The first offshore farm was installed in 1991. Since then a great deal of planning effort has been devoted to developing offshore wind energy further. At the end of 2008, approximately 1,471 MW offshore capacity was installed worldwide, and of this approximately 409 MW were sited in Danish waters (28%). Currently, seven offshore wind farms are in operation in Denmark:[8]

- Vindeby was established in 1991 as the first offshore wind farm in the world. It consists of 11 x 450 kW turbines with a total capacity of 4.95 MW.
- Tunø Knob with ten turbines of 500 kW each was installed in 1995, with a total capacity of 5 MW.
- Middelgrunden, east of Copenhagen, was put in operation in 2001. Total capacity is 40 MW consisting of 20 x 2 MW turbines
- Horns Reef I, situated approximately 20 km off the west coast of Jutland was established in 2002. It consists of 80 x 2 MW turbines, with a total capacity of 160 MW.
- Samsø offshore wind farm is situated south of the island of Samsø. It was put into operation at end of 2002 and beginning of 2003 and consists of ten x 2.3 MW turbines, total capacity 23 MW.
- Rønland offshore wind farm, situated in Nissum Bredning in north-west Jutland. It was put into operation early in 2003 and consists of four x 2.3 MW turbines and four x 2 MW turbines, with a total capacity of 17 MW.
- Frederikshavn offshore wind farm was established in 2003 and consists of two x 2.3 MW units and one 3 MW, with a total capacity of 8 MW.
- Nysted/Rødsand I close to the island of Lolland was put into operation in 2003 and consists of 72 x 2.3 MW units and a total capacity 165.6 MW.

In addition two new offshore farms have been tendered by the Danish government: The contract for Horns Reef II and Nysted II have both been signed, and the wind farms are expected to come online in 2009.

In Denmark, as in other countries, a number of different interest groups are struggling for rights to the sea. Among these are the fishing industry, the navy, nature conservancy associations and marine archaeologists. Thus an important part of the Danish strategy for developing offshore wind power was to reach an appropriate trade-off between the interests of these different parties balancing the benefits and barriers for installing turbines at a number of possible offshore sites. The strategy included the following steps:

In mid 1990s, the Danish government set up an interdepartmental committee to investigate the possibilities for utilising shallow waters for siting offshore turbines. In total an area of around 1,000 square kilometres was allocated, corresponding to the siting of 7,000-8,000 MW of wind power capacity. Most of the areas are located at around 15-30 kilometres from the coast and at a water depth of 4-10 metres [9].

In collaboration between the Danish Utilities and the Danish Energy Agency an action plan was put forward. Two of the main recommendations of the action plan were to concentrate offshore development within a few areas at a specific distance from the coast and to carry out a large-scale demonstration programme.

In September 1997 the Danish government and the utilities agreed to establish a large-scale demonstration programme. The objective was to investigate economical, technical and environmental matters, to speed up offshore development and to open up the selected areas for future wind farms. Due to

[8] Offshore Wind Power – Danish Experiences and Solutions, Danish Energy Authority, October 2005.

the special status of the demonstration programme, a comprehensive environmental measurement and monitoring programme was initiated to investigate the effects on the environment before, during and after the completion of the wind farms.

In 2002 a committee was set up by the government to study the possibilities and conditions of tendering future offshore wind farms in Danish waters. Competition among the bidders will be ensured by applying a tendering procedure and the most cost-effective offshore turbine developments will be undertaken.
In agreement with the recommendations from the tendering committee, a pre-screening of appropriate offshore sites was carried out in autumn 2003. Four areas were selected as relevant for the tender.

The Danish tendering strategy is therefore characterised by the strong planning procedure behind those offshore areas found suitable for tendering. Specific areas are pre-screened and allotted to offshore wind farms. In this way the risks and cost of the investors are decreased, because it is related to the specific project. The capacity of the wind farm is predetermined in the tendering requirements, while the size of the turbines is chosen by the winning investor. Thus technical improvements, such as the utilisation of larger turbines, can be fully exploited by the investor. A minimum expertise concerning the necessary technical and financial capacity of applicants is required. For the two large offshore wind farms, Horns Reef I and Nysted I, a comprehensive environmental monitoring programme had to be carried out as part of the demonstration projects. The results of these projects have made Denmark an international leader in this aspect of the marine environment and have attracted considerable international interest.

Appendix IV - TABLE A25: **Overview of the Main RES-E Support Schemes in the EU-27 Member States as Implemented in 2007**

COUNTRY	MAIN ELECTRICITY SUPPORT SCHEMES	COMMENTS
Austria	FITs combined with regional investment incentives	Until December 2004, FITs were guaranteed for 13 years. In November 2005 it was announced that from 2006 onwards full FITs would be available for ten years, with 75 per cent available in year 11 and 50 per cent in year 12. New FIT levels are announced annually and support is granted on a first-come, first-served basis. From May 2006 there has been a smaller government budget for RES-E support. At present, a new amendment is tabled, which suggests extending the duration of FIT fuel-independent technologies to 13 years (now ten years) and fuel-dependent technologies to 15 years (now ten years).
Belgium	Quota obligation system/TGC combined with minimum prices for electricity from RES	The federal government has set minimum prices for electricity from RES. Flanders and Wallonia have introduced a quota obligation system (based on TGCs) with the obligation on electricity suppliers. In all three of the regions, including Brussels, a separate market for green certificates has been created. Offshore wind is supported at the federal level.
Bulgaria	Mandatory purchase of renewable electricity by electricity suppliers for minimum prices (essentially FITs) plus tax incentives	The relatively low level of incentives makes the penetration of renewables particularly difficult, since the current commodity prices for electricity are still relatively low. A green certificate system to support renewable electricity developments has been proposed, for implementation in 2012, to replace the mandatory purchase price. Bulgaria recently agreed upon an indicative target for renewable electricity with the European Commission, which is expected to provide a good incentive for further promotion of renewable support schemes.
Cyprus	FITs (since 2006), supported by investment grant scheme for the promotion of RES	An Enhanced Grant Scheme was introduced in January 2006, in the form of government grants worth 30-55 per cent of investment, to provide financial incentives for all renewable energy. FITs with long-term contracts (15 years) were also introduced in 2006.

COUNTRY	MAIN ELECTRICITY SUPPORT SCHEMES	COMMENTS
Czech Republic	FITs (since 2002), supported by investment grants	Relatively high FITs with a lifetime guarantee of support. Producers can choose fixed FITs or a premium tariff (green bonus). For biomass cogeneration, only green bonus applies. FIT levels are announced annually, but are increased by at least 2 per cent each year.
Denmark	Premium FIT for onshore wind, tender scheme for offshore wind, and fixed FITs for others	Duration of support varies from 10-20 years, depending on the technology and scheme applied. The tariff level is generally rather low compared to the formerly high FITs. A net metering approach is taken for photovoltaics.
Estonia	FIT system	FITs paid for 7-12 years, but not beyond 2015. Single FIT level for all RES-E technologies. Relatively low FITs make new renewable investments very difficult.
Finland	Energy tax exemption combined with investment incentives	Tax refund and investment incentives of up to 40 per cent for wind, and up to 30 per cent for electricity generation from other RES.
France	FITs plus tenders for large projects	For power plants < 12 MW, FITs are guaranteed for 15 or 20 years (offshore wind, hydro and PV). From July 2005, FIT for wind is reserved for new installations within special wind energy development zones. For power plants > 12 MW (except wind) a tendering scheme is in place.
Germany	FITs	FITs are guaranteed for 20 years (Renewable Energy Act) and soft loans are also available.
Greece	FITs combined with investment incentives	FITs are guaranteed for 12 years with the possibility of extension up to 20 years. Investment incentives up to 40 per cent.
Hungary	FIT (since Jan 2003, amended 2005) combined with purchase obligation and grants	Fixed FITs recently increased and differentiated by RES-E technology. There is no time limit for support defined by law, so in theory guaranteed for the lifetime of the installation. Plans to develop TGC system; when this comes into effect, the FIT system will cease to exist.
Ireland	FIT scheme replaced tendering scheme in 2006	New premium FITs for biomass, hydropower and wind started in 2006. Tariffs guaranteed to supplier for up to 15 years. Purchase price of electricity from the generator is negotiated between generators and suppliers. However, support may not extend beyond 2024, so guaranteed premium FIT payments should start no later than 2009.

COUNTRY	MAIN ELECTRICITY SUPPORT SCHEMES	COMMENTS
Italy	Quota obligation system with TGC Fixed FIT for PV	Obligation (based on TGCs) on electricity producers and importers. Certificates are issued for RES-E capacity during the first 12 years of operation, except for biomass, which receives certificates for 100 per cent of electricity production for the first eight years and 60 per cent for the next four years. Separate fixed FIT for PV, differentiated by size, and building integrated. Guaranteed for 20 years. Increases annually in line with retail price index.
Latvia	Main policy under development. Quota obligation system (since 2002) no TGCs, combined with FITs (phased out in 2003)	Frequent policy changes and short duration of guaranteed FITs result in high investment uncertainty. Main policy currently under development. Quota system (without TGCs) typically defines small RES-E amounts to be installed. High FIT scheme for wind and small hydropower plants (less than 2 MW) was phased out as from January 2003.
Lithuania	FITs combined with purchase obligation.	Relatively high fixed FITs for hydro (<10 MW), wind and biomass, guaranteed for ten years. Closure of Ignalina nuclear plant, which currently supplies the majority of electricity in Lithuania, will strongly affect electricity prices and thus the competitive position of renewables, as well as renewable support. Good conditions for grid connections. Investment programmes limited to companies registered in Lithuania. Plans exist to introduce a TGC system after 2010.
Luxembourg	FITs	FITs guaranteed for 10 years (20 years for PV). Also investment incentives available.
Malta	Low VAT rate and very low FIT for solar	Very little attention to RES support so far. Very low FIT for PV is a transitional measure.
Netherlands	FITs (tariff zero from August 2006)	Premium FITs guaranteed for ten years have been in place since July 2003. For each MWh RES-E generated, producers receive a green certificate from the issuing body (CERTIQ). Certificate is then delivered to FIT administrator (ENERQ) to redeem tariff. Government put all premium RES-E support at zero for new installations from August 2006 as believed target could be met with existing applicants. Premium for biogas (<2 MWe) immediately reinstated. New support policy under development. Fiscal incentives for investments in RES are available. Energy tax exemption for electricity from RES ceased 1 January 2005.

COUNTRY	MAIN ELECTRICITY SUPPORT SCHEMES	COMMENTS
Poland	Quota obligation system. TGCs introduced from end 2005, plus renewables are exempted from the (small) excise tax	Obligation on electricity suppliers with targets specified from 2005 to 2010. Penalties for non-compliance were defined in 2004, but were not properly enforced until end of 2005. It has been indicated that from 2006 onwards the penalty will be enforced.
Portugal	FITs combined with investment incentives	Fixed FITs guaranteed for 15 years. Level dependent on time of electricity generation (peak/ off peak), RES-E technology, resource. Is corrected monthly for inflation. Investment incentives up to 40 per cent.
Romania	Quota obligation with TGCs, subsidy fund (since 2004)	Obligation on electricity suppliers with targets specified from 2005 to 2010. Minimum and maximum certificate prices are defined annually by Romanian Energy Regulatory Authority. Non-compliant suppliers pay maximum price. Romania recently agreed on an indicative target for renewable electricity with the European Commission, which is expected to provide a good incentive for further promotion of renewable support schemes.
Slovak Republic	Programme supporting RES and energy efficiency, including FITs and tax incentives	Fixed FIT for RES-E was introduced in 2005. Prices set so that a rate of return on the investment is 12 years when drawing a commercial loan. Low support, lack of funding and lack of longer-term certainty in the past have made investors very reluctant.
Slovenia	FITs, CO_2 taxation and public funds for environmental investments	Renewable electricity producers choose between fixed FITs and premium FITs. Tariff levels defined annually by Slovenian Government (but have not changed since 2004). Tariff guaranteed for five years, then reduced by 5 per cent. After ten years, reduced by 10 per cent (compared to original level). Relatively stable tariffs combined with long-term guaranteed contracts makes system quite attractive to investors.
Spain	FITs	Electricity producers can choose a fixed FIT or a premium on top of the conventional electricity price. No time limit, but fixed tariffs are reduced after either 15, 20 or 25 years depending on technology. System very transparent. Soft loans, tax incentives and regional investment incentives are available.

COUNTRY	MAIN ELECTRICITY SUPPORT SCHEMES	COMMENTS
Sweden	Quota obligation system with TGCs	Obligation (based on TGCs) on electricity consumers. Obligation level defined to 2010. Non-compliance leads to a penalty, which is fixed at 150 per cent of the average certificate price in a year. Investment incentive and a small environmental bonus available for wind energy.
UK	Quota obligation system with TGCs	Obligation (based on TGCs) on electricity suppliers. Obligation target increases to 2015 and guaranteed to stay at that level (as a minimum) until 2027. Electricity companies that do not comply with the obligation have to pay a buy-out penalty. Buy-out fund is recycled back to suppliers in proportion to the number of TGCs they hold. The UK is currently considering differentiating certificates by RES-E technology. Tax exemption for electricity generated from RES is available (Levy Exemption Certificates which give exemption from the Climate Change Levy).

Source: Ragwitz et al. (2007)

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