VLEEM – Very Long Term Energy Environment Modelling

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ANNEX 3

Monograph: Learning and diffusion for wind and solar power technologies

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Abstract

This study focuses on learning and diffusion for onshore wind, offshore wind, and photovoltaic power (PV, solar panels). The process is driven by the amalgam of technological development and increasing sales. The study addresses the development of onshore wind in Western Europe and the world at large, as well as the current state-of-the-art with respect to technology and cost. It also shows a possible development in the next ten years. An analysis is presented of the potential of cost reduction through 2030, based on a deployment scenario for onshore wind and learning effects that are deemed achievable both from the perspective of progress ratios determined for the last decades and of engineering judgements about future cost reductions.

A similar view is presented for near-shore and offshore wind. Data are presented of near-shore and offshore windfarms that have been realised or are in various stages of preparation. The potential for cost reduction is analysed based on scenarios for deployment until 2030 and learning effects for components of near-shore and offshore windfarms.

At last, a view is presented on the development of photovoltaic power in OECD countries, the status of PV, and potential cost reductions through 2035 based on a deployment scenario for PV and 'progress ratios' for several components of a PV system, partly based on past experience.

CONTENTS

SUMMARY

This study gives an analysis of the potential of cost reduction for wind and photovoltaic power. The process is driven by the amalgam of technological development and increasing sales.

Wind energy has developed fast in Western Europe (the EU-15, Switzerland, and Norway). Reasons for sluggish growth are planning issues, lengthy approval procedures, and sometimes lack of financial incentives taking into account the difference in production cost between wind power and conventional power production. However, there is scope for improvement. Also, the upcoming offshore wind market offers new perspectives. Although Europe has the lead, non-European countries – the USA, China and India – are crucial as well, because of their sheer dimensions, population, wind climate, and electricity demand.

Cost reduction for wind turbines is based on a number of factors. In case of onshore wind, the experience with cost reduction as a function of cumulative installed capacity may be used for predictions of future cost reductions. So-called 'progress ratios' are determined for key components of onshore wind turbines, viz. firstly the rotor & nacelle, secondly the tower, and thirdly civil work, infrastructure, and grid connection. Fairly modest learning effects for wind turbine components are attributed to:

- Rather modern wind turbines with capacities from 500 kW to 2.5 MW.
- Limited potential for further upscaling, one of the main drivers for cost reduction so far.
- Small learning effects for towers that are more and more sourced from local manufacturers.
- Minor learning effects for civil work, infrastructure, and grid connection.
- Cost reductions of 10-34% for production volumes ranging from 1,000 to 30,000 turbines.

The view of Enron Wind Corp on the market potential until 2020 and a corresponding potential of cost reduction is used as a yardstick for future cost reductions. The result is a scenario for onshore wind until 2030. Application of the progress ratios for turbine components gives an investment cost decreasing from $ 900/kW in 2000 to € 590/kW (*default*) or € 560/kW ('*low'*) in 2030. In this scenario, the utilisation of the economic potential from a study by the British consultant Garrad Hassan and Partners a cut-off level of 6¢/kWh is fairly modest, viz. around 30% for Europe. Further growth towards 2100 is not so much limited by wind potential but by economic and other considerations (preservation of landscape).

Data have been assembled of offshore wind farms that have been realised, or are in various stages of preparation. A distinction is made between near-shore and offshore windfarms.

The cumulative capacity of near-shore wind could increase from 0.09 GW in 2000 to 69 GW in 2030 (nearly 10 doublings). Based on progress ratios for turbine components, and an initial cost of € 1,375/kW in 2000, the specific investment cost could come down to € 885/kW (*default*) or possibly € 755/kW ('*low'*) in 2030. Near-shore wind could become nearly as competitive as onshore wind, due to its relatively high capacity factor compared to onshore wind (approximately 36% vis-à-vis ~ 24%).

The cumulative capacity of offshore wind is assumed to increase from 0.16 GW in 2002 to approximately 205 GW in 2030 (more than 10 doublings). The specific investment cost could come down from € 1,700/kW in 2002to € 1,140/kW (*default*) or possibly € 970/kW ('*low'*) in 2030. Offshore wind will remain more costly than onshore wind. Its higher capacity factor (about 40% vis-à-vis ~ 24%) is not sufficient to outweigh the higher specific investment cost.

The principle of photovoltaic power (PV) is straightforward, and it offers a very large potential for small- and large-scale application due to its modular character. The challenge is to make PV an economically viable option. The efficiency of solar cells may be increased substantially. Also, the lifetime may be prolonged by prevention of significant degradation. Furthermore,

consumption of materials – high-grade silicon, precious metals – may be reduced to low and ‘sustainable’ levels. Finally, advanced large-scale production processes will make PV more and more competitive in the long term.

Application of a progress ratio of 0.8 for modules (based on past experience), and more modest ones for other components (inverter, cabling) and installation, to a scenario from the European Photovoltaic Industry Association (EPIA) suggests that the specific investment cost of grid-connected PV systems may come down by a factor 5 to 7 from € 5,400/kW in 2000 to € 950/kW (*default*) or possibly € 790/kW (‘*low*’) in 2035.

A cost reduction of this order of magnitude is confirmed by another study on learning effects for various energy technologies. This scenario presumes a co-ordinated policy from governments and industry. The scenario implies more than 10 doublings of the cumulative installed capacity compared to 2000. The growth of PV capacity after 2035 is limited by economic factors and by the intermittent nature of a renewable option like PV, rather than by its technical potential.

1. INTRODUCTION

Several 'renewables' are in different stages of commercialisation, e.g. onshore wind, offshore wind, and solar (photovoltaic) power. The database of the specific investment costs (e.g. €/kW or $/kW) as a function of the installed capacities of these technologies is increasing. Therefore, projections of future specific investment costs may be made with more accuracy than before. However, the patterns of cost reduction in the past may not be simply extrapolated to the future. For instance, the database may be limited in terms of cumulative installed capacity. This is particularly relevant in case of PhotoVoltaic power (PV). For onshore wind the database is much larger, although differences in definition – (dollar) exchange rates, cost ex-works or installed wind turbine cost – may give problems. So, one should be aware of possible pitfalls.

First of all, one needs an analysis of the characteristics of a technology, its costs in several stages of development subdivided for basic components, and engineering judgements about the potential for cost reduction. Secondly, the specific investment cost is related to the cumulative installed capacity of a technology during a certain period. This is what in the literature is called an 'experience curve' or 'learning curve'. The two units that are compared are the price (or cost) of a technology – in some currency, e.g. €/kW of the year 2000[1] – and its cumulative installed capacity. The corresponding change in price is referred to as the *progress ratio*. A progress ratio (PR) of 0.8 is tantamount to a cost reduction of 20% for each doubling of the cumulative capacity. Experience curves and PR's have been determined for onshore wind and photovoltaic power. A curve with a PR of 0.96 from L. Neij for Danish turbines of 55 kW and more during the period 1982-1997, quoted in a recent IEA study[1], is shown in Figure 1.1.

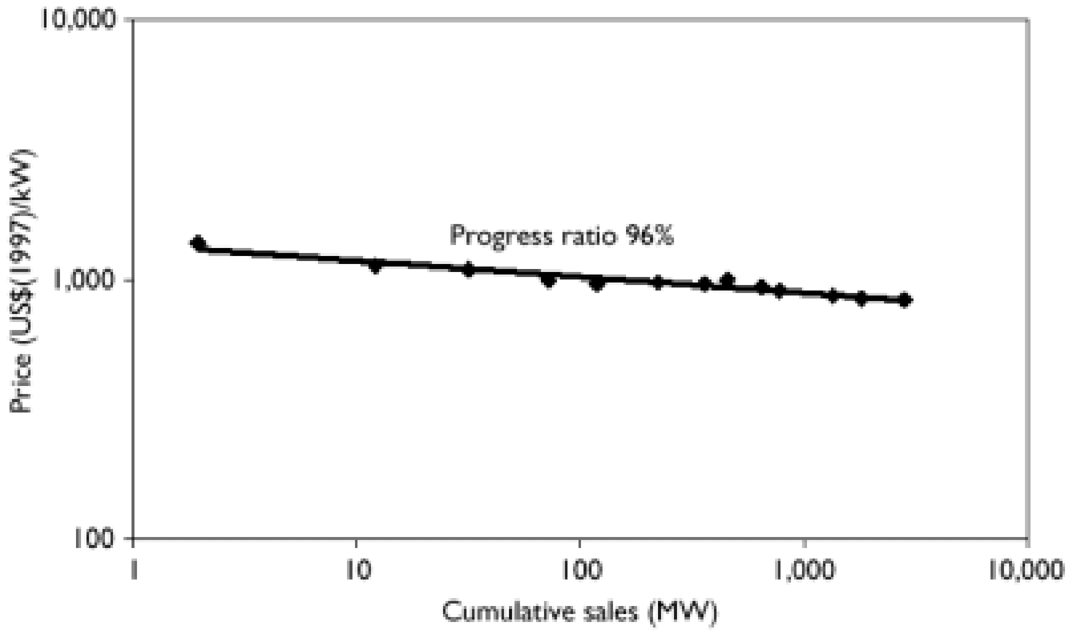


Figure 1.1 *Experience curve for wind turbines from Danish manufacturers (L. Neij)*
Sources: IEA: Experience curves for energy technology policy, 2000, and L. Neij (1999).

[1] Cost figures in this study are in Euro's of 2000, unless otherwise stated.

Although this curve if often referred to and it shows a reasonable fit for the period considered, the progress ratio of ~ 0.96 is not so 'firm' as one might expect. For various reasons one has to be careful in simply adopting a progress ratio of such an order of magnitude:

- The PR of 0.96 is based on Danish turbines produced from 1982 with a capacity of 55 kW and more, exclusive of smaller turbines from other manufacturers than the 'big five'.
- The first few years of the 1980s were characterised by large shipments of Danish turbines to the US in the period of the Californian 'wind boom'. This may have caused a distortion.
- In the 1990s, Germany and Spain showed steeply increasing wind turbine capacities that are generally not reflected by the learning curve, except for turbines originating from Denmark.

The learning curve shown in Figure 1.1 may prove to be not exactly the right yardstick for learning in case of wind turbines in the past decades, despite its nice fit at first glance. A more pronounced learning effect, a PR of say 0.9, as reported by others could be just as probable.

A much more encompassing view of 'technological learning' is provided in [2] for numerous technologies in different periods of time and different world regions. This study is based on a long-term commitment to in-depth analysis of technological development and technological learning within IIASA and other institutes and organisations in the world. Therefore, the view on technological learning has deepened during the last few decades.

The process at the root of cost reductions for wind power and PV is driven by two main factors, viz. the amalgam of technological development and increasing sales on the market. In case of wind energy the development of the market has not been steady in terms of a constant percentage growth of installed capacity per year. Also, sales of PV systems do not show a constant percentage growth, particularly if the analysis focuses on specific countries. The learning process is a complex result of e.g. ongoing R&D in industry and laboratories (e.g. Risø, Denmark, in case of wind energy), demonstration projects, financial incentives, etc. Commercialisation of technologies is intimately linked with RD&D. Clas-Otto Wene says in the aforementioned IEA study: "The cycle reinforces itself; it is a 'virtuous cycle'. There is a double boost form the sales on the market and from the improvement of knowledge through R&D".

This study focuses on learning and diffusion for onshore wind, offshore wind, and PV. In Chapter 2 the development of onshore wind in Western Europe and the world at large is addressed, as well as the current state-of-the-art with respect to technology and cost. It also shows a possible development in the next ten years. Finally, Chapter 2 presents an analysis of the potential of cost reduction through 2030, based on a deployment scenario for onshore wind and learning effects that are deemed achievable both from the perspective of progress ratios determined during the last decades and of engineering judgements about future cost reductions.

Chapter 3 gives a similar view of the development of offshore wind, or more specifically near-shore and offshore wind.

Chapter 4 focuses on photovoltaic power (PV) in OECD countries, the status of PV, and potential cost reductions through 2035 based on a deployment scenario for PV and progress ratios for several components of a PV system, partly based on past experience.

Chapter 5 contains a number of conclusions from the preceding Chapters.

2. ONSHORE WIND

2.1 Introduction

During the last two decades wind energy has become one of the most important 'new' renewables. In the early 1980s, wind turbines were small (55 kW), rather inefficient, prone to mechanical problems, and relatively costly. Today, wind turbines are large (up to 2.5 MW), efficient, reliable, and nearly competitive compared to conventional power generation options.

The wind turbine industry has profited from the favourable RD&D climate and the willingness to pay for the higher cost of wind compared to other power generation options. A growing number of countries have consistent and favourable financial incentives. Also, the process of planning and approval has become accountable. It is no wonder that wind energy has become popular in many countries. Yet, there is still a long way to go before wind will generate 10% of the world's electricity, the target of Greenpeace, European Wind Energy Association (EWEA), and the Danish Forum for Energy and Development (FED) for 2020[3].

Although the deployment of wind turbines is still in its infancy compared to for instance hydropower, wind power is evolving from a regional into a world market. Simultaneously, wind power technology is getting more and more mature. Several wind turbine manufacturers have experience with relatively large numbers of identical turbines, even of Megawatt scale.

An important question is whether wind will capture a large share of the power generation market due to further technological development and cost reduction. In general, it is difficult to estimate the (ultimate) potential of wind energy and the possible cost reduction of wind turbines. Therefore, projections may be based on experience gathered from the last few decades.

A number of issues will be highlighted in this chapter. Sections 2.2 and 2.3 shortly address the development of onshore wind in Western Europe and the world respectively. In Section 2.4 the current state-of-the-art with respect to technology and cost is described briefly. Section 2.5 gives a perspective for the next ten years. Finally, Section 2.6 gives insight in the drivers for further cost reduction, viz. technological development and mass production, and the effect they may have on the production cost of wind energy in a strongly growing market.

2.2 Development in Western Europe

Wind energy has developed fast in Western Europe – the EU-15, Switzerland, and Norway. Table 2.1 shows the installed capacity of onshore wind in the period 1990-2000 according to the Danish BTM Consult ApS[45]. The main markets for onshore wind in Western Europe are Germany (45% of the installed capacity), Spain (21%), and Denmark (17%).

In Denmark, wind energy attained a market share in power generation of 15% in 2000. The Danish government intends to treble this percentage in 2030. Therefore, wind energy may indeed capture a substantial share if conditions are favourable.

The consequence of a higher penetration of wind energy is that the limits imposed by integration into the power generation mix become prevailing. Options to deal with system integration vary from raising the power exchanges with neighbouring countries – at some economic loss – to adding power storage systems or (if all other options fail) curtailing the power generated by wind turbines to prevent conditions endangering the stability of the grid.

Table 2.1 *Installed onshore wind capacity Western Europe [MW]*

	1990	1995	1997	1998	1999	2000
Austria	-	-	20	25	34	69
Belgium	5	7	9	10	11	19
Denmark	343	609	1,106	1,410	1,728	2,291
Finland	1	2	12	18	39	39
France	1	2	13	21	25	63
Germany	31	1,133	2,081	2,874	4,442	6,107
Greece	1	28	29	55	158	274
Ireland (Rep.)	-	7	53	64	74	122
Italy	2	23	103	197	277	424
Luxembourg	-	-	3	5	6	6
Netherlands	39	252	310	360	414	454
Norway	1	4	4	9	13	13
Portugal	1	9	38	51	61	111
Spain	4	114	512	880	1,812	2,836
Sweden	6	49	122	176	220	252
Switzerland	-	-	2	3	3	3
UK	7	195	328	338	362	421
Total	453	2,432	4,745	6,496	9,679	13,504

Source: BTM Consult ApS.

To put the most recent development of onshore wind energy into perspective, Figure 2.1 shows the cumulative installed capacity of the five countries on top of the European list in 2000.

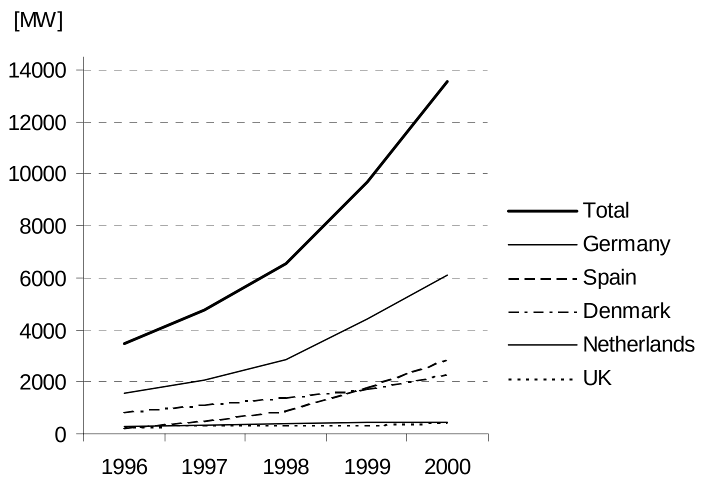


Figure 2.1 *Installed onshore wind capacity in countries of Western Europe*

It is noteworthy that Germany, Spain, and Denmark are also front runners on a global scale.

What do these figures mean in terms of annual growth? Is the current growth of the 'front runners' sustainable? Could other countries copy the spectacular growth rates? Figure 2.2 shows the growth of installed capacity of the countries on top of the 'European wind league'.

In Germany, growth of installed capacity was about 40%/a. Spain and Italy appear to be in the 'take off' stage, with particularly high growth rates of 60 to 80%. Denmark, once the cradle of modern wind energy and now a mature onshore wind market, grows with 30%/a. The Netherlands and the UK show much lower growth rates. Although the Netherlands was once a pioneer of wind energy, it is now lagging far behind. Reasons for sluggish growth are planning issues, lengthy approval procedures, and sometimes lack of financial incentives. However, there is scope for improvement. Also, the upcoming offshore wind market offers new perspectives.

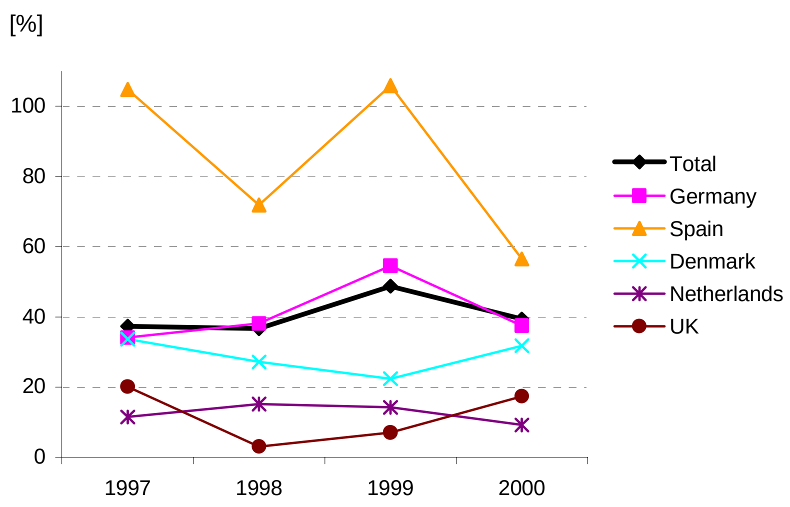


Figure 2.2 *Growth of installed onshore wind capacity, Western Europe 1996-2000*

2.3 Global development

As wind energy has got a very good start in Western Europe and most wind turbines manufactured during the last few decades originate from this region (mainly from Denmark, Germany, and Spain), Europe compares favourably to the rest of the world (Table 2.2).

Table 2.2 *Development of world wide installed wind capacity [MW]*

	1996	1997	1998	1999	2000
America		1,634	2,292	2,667	2,847
Europe		4,787	6,553	9,737	13,630
OECD-Asia		11	37	50	70
Asia		1,077	1,224	1,376	1,728
Other continents		36	37	37	37
Cumulative installed	6,070	7,554	10,153	13,932	18,449
Annual installed	1,292	1,484	2,599	3,779	4,517

Source: BTM Consult ApS.

In order to make a comparison between European countries and the rest of the world, Figure 2.3 shows the cumulative installed capacity of the seven countries on top of the global list in 2000.

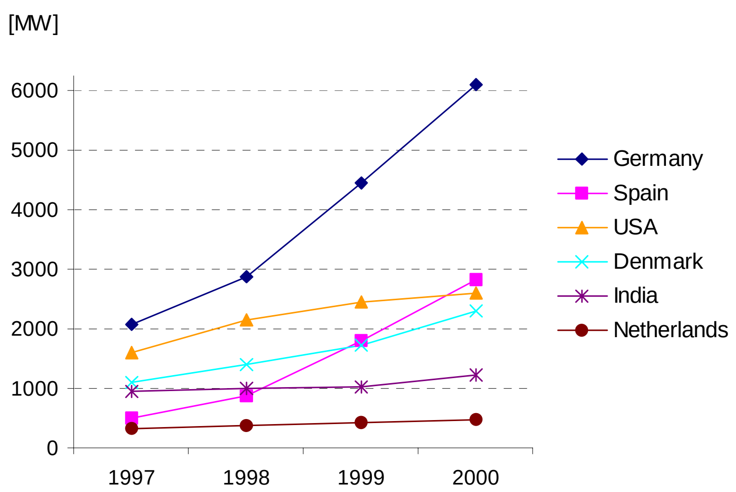


Figure 2.3 *Total installed wind capacity 'Global top seven' 1997-2000*

Although Europe has the lead, non-European countries – the USA, China and India – are crucial because of their sheer dimensions, population, wind climate, and electricity demand.

2.4 Current technology and cost

BTM Consult ApS (2001) attributes cost reduction to the following main factors:

- A better understanding of how loads affect the turbine and thereby the possibility to calculate closer to the physical limits of materials, resulting in a lower weight.
- Better and new materials e.g. for the blade profiles (Advanced Composites) can reduce the weight of the rotor (a compromise between strength/stiffness and dampening properties).
- Optimisation of drive-train – direct drive by use of multipole Synchronous Generator or traditional drive-train-gearbox, couplings and Asynchronous Generator. Control of blades (pitch/adjustment) and control of rotor revolution speed enables the designer to reduce torque peaks in the transmission; hence, lower component prices may be realised.
- Lower loads on rotor and transmission leave room for weight reduction of support structures: machine-frame and tower.
- Advanced control of 'vibration cycles' from the rotor/tower and machinery makes it possible to design advanced and 'light-weight designs', including the variable speed feature.

Table 2.3 shows the relation between weight, capacity and swept area of large wind turbines. Today, the class of 600-900 kW shows the lowest level of weight per square meter swept area.

Table 2.3 *Weight, capacity, and swept area of large commercial wind turbines*

	Country of origin	Rated power [kW]	Weight rotor & nacelle [kg]	Weight/capacity ratio [kg/kW]	Weight/swept area ratio [kg/m^2]
Bonus 600 kW Mk IV	DK	600	36,675	61.1	24.1
Bonus 1 MW		1,000	62,000	63.0	27.5
Enercon E-40[2]	D	500	29,000	59.0	23.1
Enercon E-66/1500		1,500	99,590	66.4	29.1
NEG NM-900/52	DK	900	40,000	44.4	18.9
NEG NM-1500C64		1,500	75,000	50.0	23.3
NEG NM-2000-72		2,000	114,000	57.0	28.0
NEG NM-2000-78		2,000	116,000	59.0	23.8
Nordex N-43/600	DK/D	600	35,500	59.2	24.5
Nordex N-54/1000		1,000	69,800	69.8	30.5
Nordex N-60/1300		1,300	68,000	52.3	24.0
Tacke TW 600	US (Enron)	600	38,500	64.2	26.5
Tacke TW 1.5		1,500	74,000	49.3	23.7
Vestas V47-660	DK	660	27,600	41.8	15.9
Vestas V66-1650		1,650	78,000	47.3	22.8
Average sub MW		643	34,545	53.7	21.7
Average MW		1,494	84,043	56.2	26.5

Source: BTM Consult ApS.

The Spanish industrial engineering firm M Torres is developing the first 1.5 MW variable speed wind turbine with a multipole generator and without a gearbox in Spain[6]. M Torres also uses its aeronautical experience with a lightweight rotor. The first prototype installed at the company's Pamplona factory has glass fibre blades. A second machine will be equipped with blades developed by M Torres based on carbon fibre. A carbon fibre central beam, or cone, will run the length of the blade, while the blade shells are made of glass fibre. Carbon fibre enables a large weight reduction: from 5,500 kg for a standard rotor of 72 m diameter to 2,500 kg.

[2] Recently, Enercon stopped production of the 500 kW machine due to a much higher demand for larger turbines.

A study from Greenpeace and Deutsches Windenergie Institut (DWI)[7] provides data of the specific investment cost of wind turbines in Germany from 1990 to 1999 (Figure 2.4).

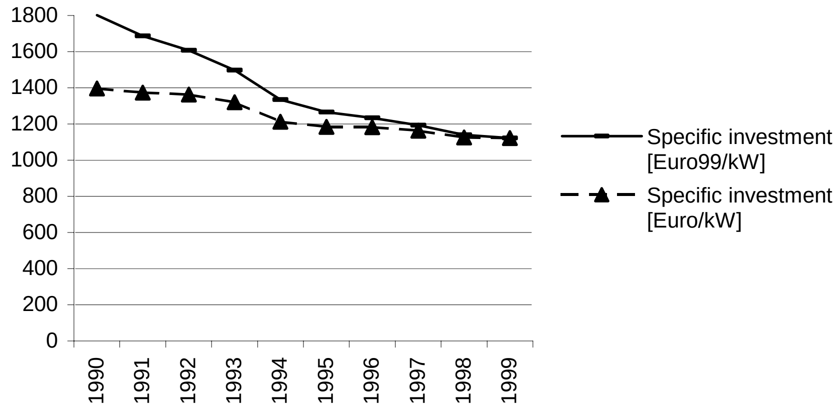


Figure 2.4 *Average specific investment cost of wind turbines in Germany, 1990-1999*
Source: Greenpeace/Deutsches Windenergie Institut: North Sea Offshore wind – A powerhouse for Europe, 2000.

The specific investment cost decreases in *nominal Euro's* from €1,400/kW in 1990 to €1,120/kW in 1999 (bottom line Figure 2.4). Correction for inflation (upper line) using the EU consumer price index suggests a reduction of the specific investment cost in real terms of 35%.

The specific investment cost depends on the capacity of the turbine[8] (Figure 2.5).

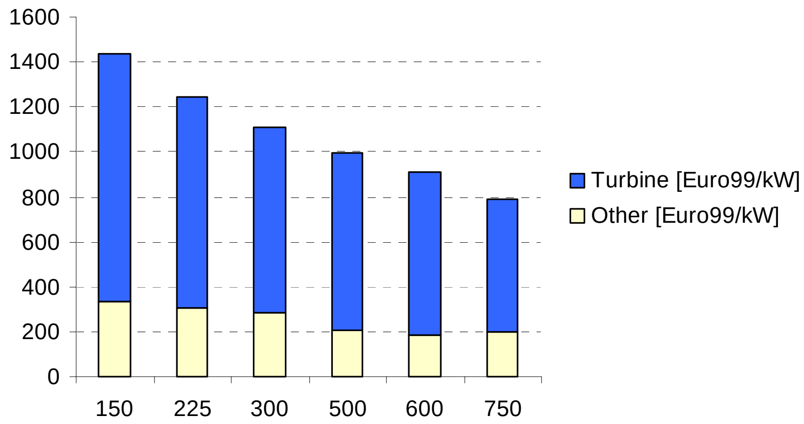


Figure 2.5 *Specific investment cost of Danish wind turbines as a function of capacity*
Source: Wind power in Denmark. Technologies, policies and results. September 1999.

The effect of installation of larger wind turbines in Denmark is pronounced. The substitution of relatively small wind turbines (55+ kW) around 1990 by more economic turbines of 600 and 750 kW accounted for 35% reduction of the specific investment cost during the period 1990-1998. The data on which Figure 2.5 is based reflect the optimum size of Danish turbines in 1998 (750 kW). In the meantime the optimum turbine size has shifted to 900 kW and more.

L. Neij shows that wind energy has mainly benefited from upscaling of turbines and not so much from mass production[9][10]. Still, turbines within a specific class, e.g. 600 kW, have been performing better and better due to continuous improvements (e.g. more advanced blades) during the period in which the turbines were produced (Figure 2.6).

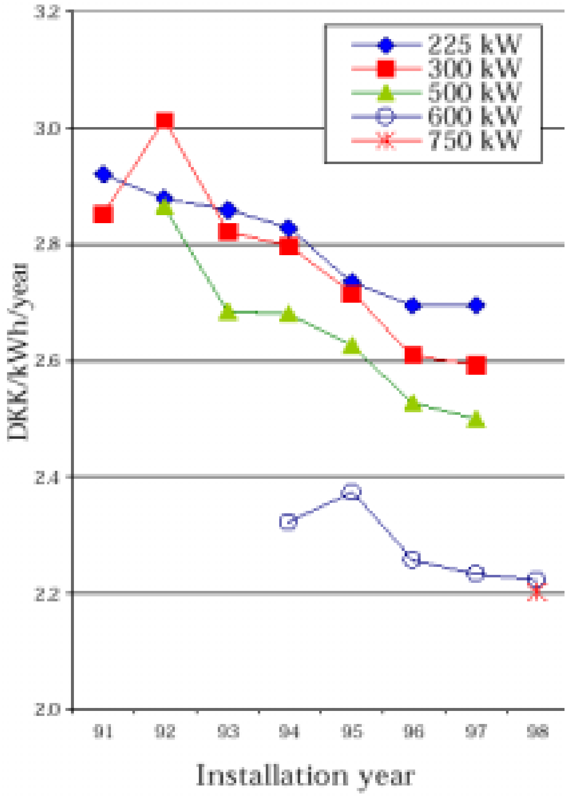


Figure 2.6 *Specific investment defined as ex-works Danish turbine price divided by annual production; roughness class 1; list prices of leading manufacturers (DKK$_{1999}$)*
Source: Wind power in Denmark. Technologies, policies and results. September 1999.

2.5 The next ten years

Technological development is one of the drivers for cost reduction. Simultaneously, the wind turbine market may be quadruplicated in terms of MWs sold within ten years from now, as will be shown in this section. Both effects may entail a substantial cost reduction of wind turbines.

Wind turbines need to be integrated in the electrical network. With rising penetration, the availability of wind turbines and the influence on the network becomes an issue. Fluctuations in the power output, caused by wind gusts, may affect the power quality of the network[11]. A reduction of short-term power fluctuations may be achieved using variable-speed operation. Short-term power variations may be absorbed by the immediate storage of energy in the rotating masses of the drivetrain. Hence, a smoother power output is achieved than with strongly grid-coupled turbines. There is a tendency to apply direct drive and multipole Synchronous Generator as well as variable-speed operation for MW turbines. Also limited variable-speed turbines with Induction Generators with variable slip may reduce power fluctuations due to wind gusts and the tower shadow effect.

Wind turbines become more and more cost effective due to ongoing technological development and rising annual sales (mass production). However, the economies of scale in terms of higher capacities are limited. Today, 2.5 MW turbines are available, but this may be about the limit for onshore application. MW turbines are preferred for their economic use of land area in Germany and other countries. Large turbines capture the wind at higher altitudes (tower height 80 m and more). Also, in a number of countries room for additional wind farms at favourable sites is scarce, taking into account demands from conservation of landscape. However, MW turbines may pose specific requirements with respect to transport and installation on site, e.g. cranes.

According to Gamesa, one of the market leaders in wind turbines, a wind farm of 37 660 kW turbines would cost € 22 million, or €900/kW. This is in agreement with the range of € 800-900/kW for similar Danish turbines (Figure 2.5). Wind farms installed by Spanish utilities were put at € 840-930/kW[12]. And wind farms planned in the province Guadalajara for 2003 with a combined capacity of 482 MW would cost € 400 million, or € 830/kW[13].

A very important factor for cost reduction is the size of the future wind market (Figure 2.7).

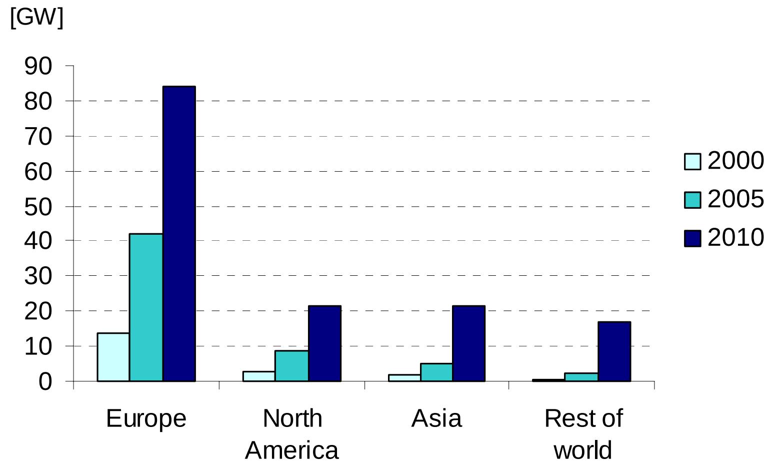


Figure 2.7 *Projection of global installed wind turbine capacity, 2000-2010 [GW]*
Source: BTM Consult ApS.

BTM Consult (2001) projects an increase of the global capacity from 18.45 GW in 2000 to 58.2 GW in 2005 and 144 GW in 2010, or a growth of the capacity of 26%/a until 2005 and 20%/a for the period 2005-2010. Corresponding growth rates for Europe are 25 and 15% respectively.

2.6 The next thirty years and beyond

What is the potential of cost reduction of wind turbines due to technological development and mass production? The relation between the amalgam of technological development and cost reduction may be characterised by an 'experience curve' or 'learning curve': the price of a wind turbine declines due to 'technological learning' as a function of the installed capacity[14]. This relation is analysed for the period of commercialisation that started in the early 1980s. Commercialisation has been accompanied by ongoing R&D in industry and laboratories (e.g. Risø, Denmark) and demonstration projects, ranging from one-of-a-kind or prototype turbines, twin turbines with different modes of blade control (pitch/adjustment or stall), to complete wind farms. So, commercialisation appears to be intimately linked with RD&D.

The relation between the price and installed capacity of wind turbines has been analysed for Danish wind turbines, based on data of annual sales and output (in MW) of wind turbines (from the Danish Wind Turbine Manufacturers Association's Internet site)[15]. Prices in the currency DKK per kW have been corrected for inflation using the Danish consumer price index. Based on data for 1982, 1987, 1990-1991 (Germany), and 1992-1999, the authors find a progress ratio of 0.87: a price reduction of 13% for each doubling of capacity.

Progress ratios of 0.87-0.93 in ECN studies[16] seem to be useful. However, possible pitfalls are the incompleteness of the database – only data from a single German manufacturer of (small) wind turbines for the year 1990-1991 – and distortion of turbine prices in the early 1980s by the Californian 'wind rush' (windfall profits that were used for intensified R&D). At that time US Kenetech installed 100 kW machines at the Altamont Pass at a cost of about $2,200/kW[17]. When Zond (Enron Wind Corp) completed its first wind project in 1981, the cost to purchase and install a wind turbine was $4,000/kW[18]. Junginger gives an example of a hypothetical case of wind turbines originating from Denmark with a 'measured' PR of 0.92 that are exported in declining numbers to the US with a 'perceived' PR of 0.88. Finally, outsourcing of components is a source of errors. Towers represent the component that is most difficult to transport. On Vestas' recent 700-turbine order from the US Florida Power&Light (FPL), the latter sourced its towers from a local manufacturer.

For these various reasons it seems reasonable to limit the use of PR's to a range of 0.9 to ~ 0.96 (the latter determined by L. Neij for Danish turbines of 55 kW and more during 1982-1997).

Table 2.4 presents disaggregated costs for a 600 kW turbine, based on data from BTM Consult. The price level of € 900/kW is used as the starting point for projections for the next decades.

Table 2.4 *Breakdown of investment cost of wind turbine (~600 kW)*

	[$\$_{1998}$/kW]	[$€_{2000}$/kW]	% total machine cost
Machine frame incl. ring	52.7	52.7	8.6
Blades	106.3	123.8	17.3
Hub including main shaft	48.3	56.3	7.9
Gear including clutch	134.0	156.0	21.8
Generator/controller	73.0	85.0	11.9
Tower including painting	96.6	112.5	15.7
Hydraulics including hoses	19.3	22.5	3.1
Yaw gear	14.5	16.9	2.4
Nacelle cover	27.7	32.2	3.1
Insulation/cables etc.	22.3	26.0	4.5
Estimated assembly cost	19.3	22.5	3.1
Total machine cost	*614*	*715*	*100*
Civil works, infrastr.& grid connection		185	26
Total investment cost		*900*	*126*

Sources: BTM Consult ApS, January 1998, and Dresdner Kleinwort Wasserstein, January 2001.

Another important parameter is the development of the global wind turbine market (Figure 2.8).

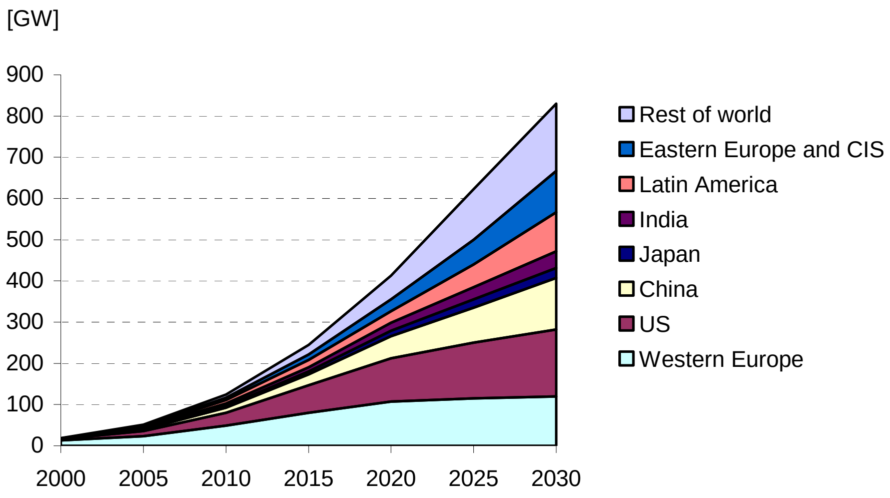


Figure 2.8 *Capacity of onshore wind based on extrapolation of an Enron estimate*

The capacity installed from 2000 to 2020 is put at 400 GW in 2020, based on an estimate from Enron Wind Corp (Table 2.5). The total capacity may rise to about 830 GW in 2030. The annual installed capacity could rise to 48 GW/a in 2025, ten times the current level of installation. It is for sure that the uncertainty of the future development of onshore wind increases with time.

Table 2.5 *Wind turbine capacity according to Enron Wind Corp [MW]*

	1997	2000	2005	2010	2015	2020	Total
US							
Installed capacity	1,564	2,841	12,789	31,675	67,234	101,966	
Incremental capacity		1,277	9,948	18,886	35,568	34,722	100,402
Western Europe							
Installed capacity	4,707	11,208	25,557	57,549	95,563	104,216	
Incremental capacity		6,501	14,349	31,992	35,014	11,564	99,509
China							
Installed capacity	200	500	3,705	12,279	26,044	51,789	
Incremental capacity		300	3,205	8,574	13,765	25,744	51,689
Japan							
Installed capacity	15	75	1,211	3,972	7,238	12,661	
Incremental capacity		60	1,136	2,761	3,266	5,423	12,646
India							
Installed capacity	910	1,242	2,710	5,881	10,420	19,384	
Incremental capacity		332	1,468	3,171	4,539	8,964	18,474
Latin America							
Installed capacity	45	244	2,956	8,991	17,503	26,619	
Incremental capacity		199	2,712	6,035	8,512	9,166	26,574
Eastern Europe & CIS							
Installed capacity	57	305	1,141	4,874	13,013	27,799	
Incremental capacity		248	836	3,733	8,139	14,787	27,742
Rest of the world							
Installed capacity	58	613	3,392	8,001	23,650	56,049	
Incremental capacity		555	2,779	4,609	15,648	32,339	55,991
Total world							
Installed capacity	7,556	17,028	53,461	133,223	257,674	400,483	
Incremental capacity		9,472	36,433	79,762	124,451	142,809	392,927

Source: Dresdner Kleinwort Wasserstein, January 2001 (based on data from Enron Wind Corp).

Based on a brief analysis of learning (progress ratios of 0.90-0.96), the figure of € 900/kW as the starting point for projections of the investment cost (Table 2.4), and the assumed growth of the global capacity (Figure 2.8), two 'learning profiles' have been determined (Table 2.6).

Table 2.6 *'Learning profiles' for investment cost of onshore wind turbines (2000-2030)*

	Period	Progress ratio Rotor & nacelle	Progress ratio tower	Progress ratio civil work, infrastructure, and grid connection
Default	2000-2030	0.90	0.96	0.98
Low	2000-2030	0.90	0.93	0.96

The *'default' learning profile* is based on a Progress Ratio (PR) for rotor and nacelle of 0.9. For this component – € 602.5/kW in 2000 (Table 2.4) – learning is assumed to remain significant. For the tower more modest learning is assumed, viz. a PR of 0.96 starting from € 112.5/kW in 2000. This is because the tower does not provide so much learning potential due to 'regional' manufacturing. At last, for the remaining part of the plant – civil work, infrastructure and grid connection at € 185/kW in 2000 – a really modest learning rate is assumed (PR = 0.98).

The *learning profile 'low'* (low ultimate investment cost in 2030) is based on a PR of 0.9 for rotor and nacelle, just like in the case *default*. The learning potential for the tower is assumed to be somewhat larger than in case of *default*, viz. PR is 0.93. Finally, learning for civil work, infrastructure, and grid connection, is also somewhat more pronounced, viz. PR is 0.96.

Figure 2.9 gives a comparison between the learning profiles and a cost estimate from Enron Wind Corp. As a matter of fact, Enron reported in Dollars, but their cost figures (e.g. $ 900/kW in 2000) suggest parity between Euro and Dollar. The *default* learning profile, bottoming out at € 590/kWin 2030, is a good yardstick for long-term modelling. D. van de Reepe suggests a similar price (€ 595/kW) for 2040[19]. The learning profile *'low'*, ending up at € 560/kWin 2030, is deemed to be useful for sensitivity analysis.

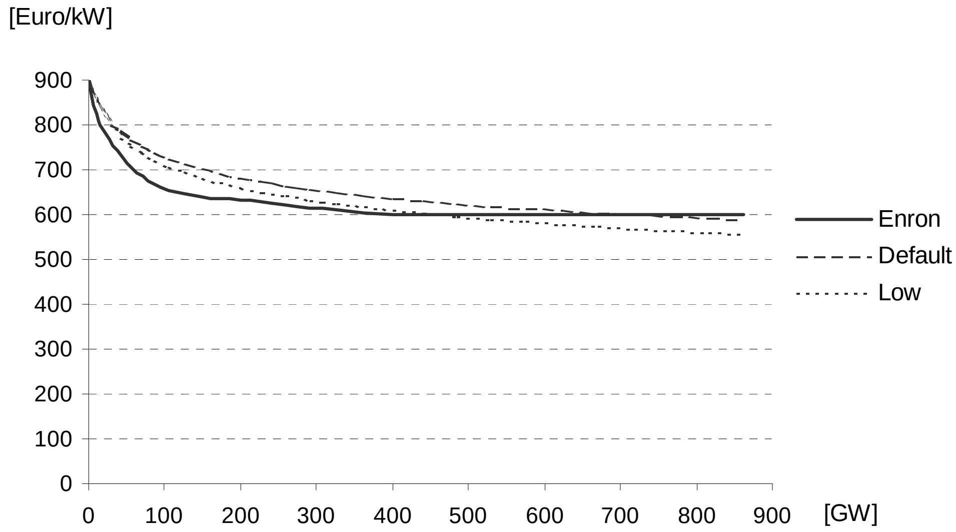


Figure 2.9 *Specific investment cost of onshore wind vis-à-vis cumulative installed capacity*

Figure 2.10 shows the same two learning profiles and Enron's estimate as a function of time.

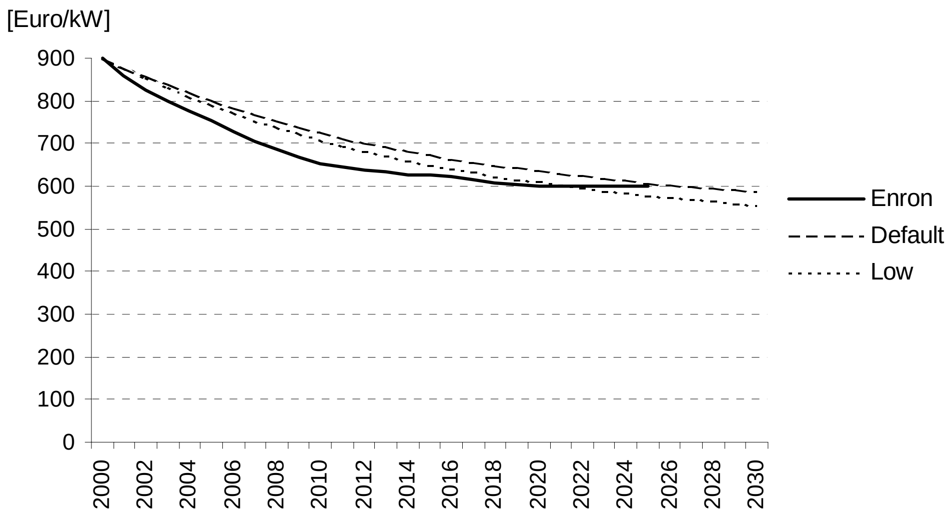


Figure 2.10 *Specific investment cost of onshore wind turbines, 2000-2030*

The default learning profile with PRs ranging from 0.9 for rotor and nacelle to 0.96 for the tower and 0.98 for the balance of plant gives a good approximation of Enron's specific investment cost estimate. Learning effects of this order of magnitude are somewhat higher than reported by Neij (PR is ~ 0.96 for Danish wind turbines ≥55 kW ex-works, 1982-1997).

Fairly modest progress ratios applied for wind turbine components may be attributed to:

- Rather modern wind turbines with capacities from 600 kW to 2.5 MW.
- Limited potential for further upscaling, one of the main drivers for cost reduction so far.
- Small learning effects for towers that are more and more sourced from local manufacturers.
- Minor learning effects for civil work, infrastructure, and grid connection.

- Cost reductions of 10-34% for production volumes ranging from 1,000 to 30,000 turbines reported by Princeton Economic Research Inc. in December 1995[20].

Operation and maintenance costs of 600 kW turbines have been reported by Dresdner Kleinwort Wasserstein, both with respect to replacement costs (Tables 2.7) and annual costs (Table 2.8).

Table 2.7 *Replacement cost for major components on 600 kW turbines*

	[Thousand €$_{2000}$]	[€$_{2000}$/kW]
Entire blade set	~100	~167
Individual blade	~36	~60
Gearbox	>50	>83
Generator	Up to 18	Up to 30

Source: Dresdner Kleinwort Wasserstein, January 2001 (based on data from Allianz).

Table 2.8 *Estimated maintenance cost over 15 years for a 600 kW turbine*

	Cost over 15 years [Thousand €$_{2000}$]	Annual costs [€$_{2000}$/kW/a]
Maintenance including consumables	54	6.0
Oil change	15	1.7
Blade maintenance	33	3.7
Gearbox maintenance	51	5.7
Generator maintenance	10	1.1
Other	23	2.6
Insurance	41	4.6
Total	228	25.0

Source: Dresdner Kleinwort Wasserstein, January 2001 (based on data from Allianz).

The average maintenance cost for new turbines is around 0.6-1.0 €ct/kWh, rising to 1.5-2.0 €ct/kWh after the first 10 years of operation. It is assumed that the future maintenance cost will be 0.6 €ct/kWh for the first 10 years and 0.9 €ct/kWh after that, or 0.7 €ct/kWh on average.

Table 2.9 summarises the projections for the global cumulative installed capacity of onshore wind turbines (Figure 2.8), as well as for the specific investment cost and the maintenance cost.

Table 2.9 *Specific investment cost and maintenance cost for onshore wind turbines based on two learning profiles and an estimate from Enron Wind Corp*

	Unit	2000	2005	2010	2015	2020	2025	2030
Assumed installed cap.	[GW]	18.36	51	124	245	413	623	830
Investment cost								
Enron Wind Corp	[€$_{2000}$/kW]	900	750	650	625	600	600	600
Default	[€$_{2000}$/kW]	900	801	726	674	637	609	589
Low	[€$_{2000}$/kW]	900	791	708	650	609	579	557
Maintenance & insurance	[€$_{2000}$/kW/a]	25	22	20	19	18	17.5	17

The *default* learning profile and the profile according to Enron Wind Corp suggest a reduction of the specific investment cost of 35% through 2030, and 2020 respectively. The maintenance cost could fall by the same percentage. Enron's data or the *default* learning profile could be used for long-term modelling. Whether the costs will decline along these lines remains uncertain. It is noted that the range in PRs reported is still pretty high. Will the cumulative installed capacity indeed be around 880 GW in 2030? Will onshore wind profit from further technological innovation and mass production to the presumed extent? This is all difficult to predict.

With respect to the learning profile '*low*', it is reiterated that this learning profile is very ambitious (perhaps too ambitious). However, considering the range of historical progress ratios reported it has some probability. So, it seems appropriate to use it for sensitivity analysis.

Finally, the presumed development of onshore wind through 2030 is compared to estimates of the potential of onshore wind in different world regions by Garrad Hassan and Partners in a study on behalf of the IEA Greenhouse Gas R&D Programme. The study contains supply curves for both the capacity and the power generation potential as a function of the generation cost. In order to facilitate comparison, the potentials have been corrected for the anticipated reduction of the specific investment cost, viz. some 35% in 2020 compared to 2000 (Table 2.10).

Table 2.10 *Potential dependent on cut-off generation cost for large onshore wind farms from Garrad Hassan's study with correction for investment cost (€ 590/kW)*

	Potential capacity [GW]			Potential generation [TWh]		
Cut-off generation cost	4 ¢/kWh	6 ¢/kWh	8 ¢/kWh	4 ¢/kWh	6 ¢/kWh	8 ¢/kWh
US	100	740	985	350	1,600	2,070
European Union	230	385	465	800	1,170	1,280
China	375	980	1,160	1,000	2,750	3,070
India	20	60	175	60	150	300
Latin America	655	1,230	1,780	2,150	3,100	4,000
Eastern Europe & FSU	2750	5,300	6,100	9,000	13,400	13,700
Africa	365	1,585	4,000	1,200	4,000	9,000
Middle East	670	1,105	1,425	2,200	2,800	3,200
Australia	10	80	270	30	200	600
Rest of Asia	275	535	640	900	1,350	1,430
Total world	5,500	12,000	17,000	17,690	30,520	38,650

Garrad Hassan and Partners present a division in world regions that differs from Enron Wind Corp's projection (Table 2.5). Therefore, only corresponding regions are compared. Figure 2.10 compares the onshore wind potentials from Enron Wind Corp (Figure 2.8) to the corresponding potentials of world regions in Table 2.11 with a cut-off level for the generation cost of 6 ¢/kWh.

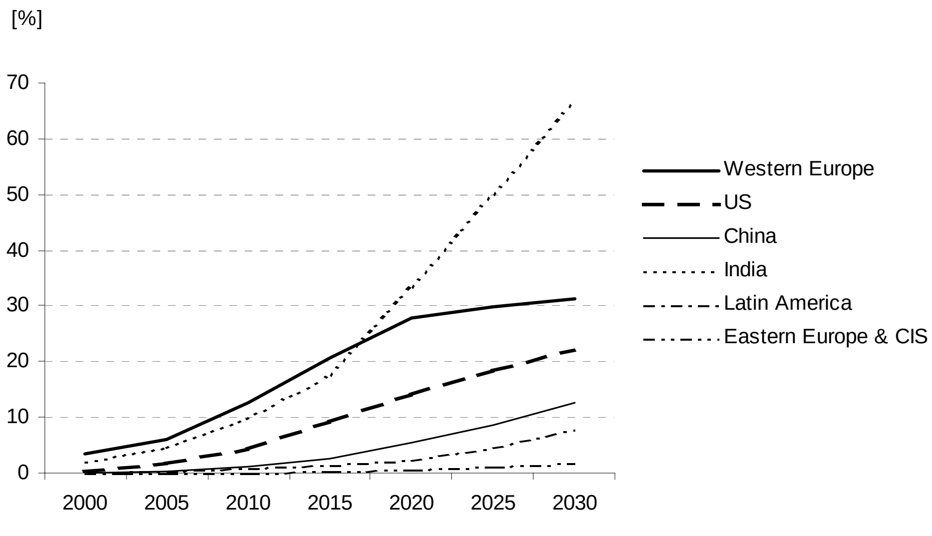


Figure 2.11 *Percentage utilisation in 2030 of onshore wind potential with cut-off at 6 ¢/kWh (based on an assessment by Garrad Hassan and Partners)*

The utilisation of the economic potential at a cut-off level of 6 ¢/kWh is modest, except for India. The development of onshore wind shown in Figure 2.8 is not curtailed by the economic potential of wind, presumed that the anticipated cost reduction will materialise. However, an increasing share of wind power in the power generation mix might necessitate measures to prevent conditions endangering the stability of the grid (power exchanges with neighbouring countries, adding power storage systems, or limiting the power generated by the turbines).

3. NEAR-SHORE AND OFFSHORE WIND

3.1 Introduction

Next to onshore wind, offshore wind got much attention recently. A distinction is made between near-shore and offshore wind (Section 3.3). The attractiveness of offshore wind depends on several factors, among which the remaining onshore potential. The onshore wind potential is not so much limited by availability of wind, but by economical and other criteria (preservation of landscape). Another important factor is cost. Going offshore, the generation cost tends to go up.

Section 3.2 gives an introduction to the onshore and offshore wind potential. Section 3.3 gives a very brief overview of recent developments in offshore wind in Denmark, as well as a definition of near-shore and offshore wind. Section 3.4 presents near-shore wind, and Section 3.5 gives a view on offshore wind. At last, results are compared and summarised in Section 3.6.

3.2 Onshore and offshore wind potential

'Wind force 10', published by Greenpeace, European Wind Energy Association (EWEA) and Forum for Energy and Development (FED), presents an ambitious target of 10% of the world's electricity originating from wind in 2020. This may be achieved by a staggering average growth of wind power of 23%/a to 1,200 GW – equivalent to 3,000 TWh/a – in 2020. The onshore potential in Europe is based on data from Utrecht University (1993). A penetration level of 20% is based on extrapolation of the electricity consumption in 1989, assuming a growth of 3%/a. Some 366 TWh could be generated onshore without exceeding 20% penetration (Table 3.1).

Table 3.1 *Technical potential of onshore wind power in Western Europe*

	Technical wind potential		< 20% penetration	> 20% penetration
	[GW]	[TWh]	[TWh]	[TWh]
Austria	1.5	3	3	-
Belgium	2.5	5	5	-
Denmark	4.5	10	6.2	3.8
Finland	3.5	7	7	-
France	42.5	85	85	-
Germany	12	24	24	-
Greece	22	44	8.2	?
Ireland	22	44	3.4	40.6
Italy	34.5	69	41.4	27.6
Luxembourg	0	0	-	-
Netherlands	3.5	7	7	-
Norway	38	76	23.2	52.8
Portugal	43	15	6.4	8.6
Spain	20.5	86	35.6	50.4
Sweden	20.5	41	35.2	5.8
UK	57	114	75.8	38.2
Total	315	630	366.4	227.8

Source: Greenpeace, European Wind Energy Association, Forum on Energy and Development: Wind force 10, 2000.

'Wind force 10' also gives an estimate of the 'realistic mid-term potential' of offshore wind on the North Sea, based on the technical potential in Table 3.2. It should be noted that this technical potential is rather hypothetical, particularly for water depths beyond 30 m (Table 3.2).

Table 3.2 *Offshore wind resources in Europe (exclusive of Finland, Norway and Sweden)*

Water depth	Up to 10 km offshore [TWh]	Up to 20 km offshore [TWh]	Up to 30 km offshore [TWh]
10 m	551	587	596
20 m	1,121	1,402	1,523
30 m	1,597	2,191	2,463
40 m	*1,852*	*2,615*	*3,028*

Note: The technical potential for a water depth beyond 30 m is more or less hypothetical (denoted by italics).
Source: Wind force 10 ('Study of offshore wind energy in the EC', Garrad Hassan & Germanischer Lloyd, 1995).

Greenpeace reduced this potential to a more realistic level, based on the following assumptions:
- All water depths over 20 m are excluded (reduction to 1,523 TWh).
- Sites up to 10 km from the shore are reduced by 90%, mainly for reasons of visual obtrusion (reduction from 1,523 to 514 TWh).
- Sites from 10 to 20 km from the shore are reduced by 50%, mainly for the same reasons (reduction from 514 to 374 TWh).
- Sites from 20 to 30 km from the shore are reduced by 50%, taking into account claims from fishery, shipping lines, etc. (reduction from 374 to 313 TWh).

Greenpeace compares the on- and offshore potential with the electricity demand in 2020, based on extrapolation of data for world regions from IEA's World Energy Outlook 1998 (Table 3.3).

Table 3.3 *Wind energy potential and electricity demand in world regions*

	Electricity demand 2020 [TWh/a]	20% of electr. demand [TWh/a]	Wind potential [TWh/a]	Wind potential >20% penetration [X 20% penetration]
OECD Europe	4,492	1,273	Onshore: 630	
			Offshore: 313	1.05
OECD N-America	6,363	1,273	14,000	11
OECD Pacific	1,865	373	3,600	8
Latin America	2,073	415	5,400	13
East Asia	2,030	406		
South Asia	1,657	331	4,600	3
China	3,857	771		
Middle East	839	167	n.a.	
Transition economies	3,298	660	10,600	16
Africa	851	170	10,600	63
World total	27,326	5,465	49,740	9

Source: Greenpeace, European Wind Energy Association, Forum on Energy and Development: Wind force 10, 2000.

Based on these estimates, Greenpeace presents a figure for the mid-term potential of wind in Europe of 940 TWh (630 TWh onshore and 313 TWh offshore). 940 TWh is enough to meet 20% of the electricity demand of OECD Europe based on IEA's business-as-usual scenario.

3.3 Recent developments

Denmark has formulated a target of 5,500 MW wind power in 2030. Taking into account the recent trend in onshore capacity, it is reasonable to expect that approximately 3,000 MW offshore would be needed to fulfil that target. The Danish North Sea and Baltic Sea offer a theoretical potential of 28 GW and a realistic potential of 12 GW. Promising offshore areas are:
- West of Horns Rev in the North Sea.
- South of the island Laesoe in the Kattegat.
- South of Omoe in Smaalands Huvet.
- South of Lolland.

In 2000, the Middelgrunden windfarm (3 km offshore from Copenhagen) was commissioned:
- 20 Turbines of 2 MW each.
- Water depth 3-6 meter.
- Concrete gravity foundations with provision to withstand drifting ice.
- Annual mean wind speed at hub height (64 m) 7.1 m/s.
- Anticipated electricity production 89 GWh/year.

Table 3.4 shows cost data of the Middelgrunden windfarm[21][22].

Table 3.4 *Investment cost of Middelgrunden offshore windfarm*

Component	[million $€_{2000}$]	[$€_{2000}$/kW]	% of total windfarm cost
Turbines	26.1	653	53
Foundations	9.9	248	20
Internal grid	4.56	114	9
External grid	4.1	102	8
Others	4.34	108	9
Total	49.0	1,225	100

Sources: EWEC 2001 Copenhagen, and CADDET Renewable Energy Newsletter, March 2001.

The specific investment cost (€ 1,225/kW) is approximately 35% higher than for onshore wind (€ 900/kW). The investment cost of large windfarms in the German coastal waters and offshore – outside the 12 nautical miles zone – is put at DM 3,600/kW ≈ €1,840/kW[23], or twice the level of onshore wind. According to an ECN study on large offshore windfarms (outside the 12 miles zone, up to 5,000 MW), the share of turbines and foundations in the total investment cost would be 32% and 44% respectively[24]. Possible developments of the specific investment cost of near-shore and offshore wind are elaborated in the next sections.

In 1997, the Danish Ministry of Energy closed an agreement with the Danish utilities to develop five offshore wind farms totalling 750 MW from 2001 to 2008, that would generate enough electricity to cover 8% of the Danish electricity demand. The utility Elsam A/S is building the first 160 MW (80 * 2 MW) windfarm in the Danish North Sea at Horns Rev. The windfarm is erected 14-20 km from the coast, west of Blavands Huk (near Esbjerg). A 150 kV high voltage line connects the windfarm to the existing grid. As will be elucidated later on, the specific investment cost amounts to € 1,675/kW, or about 35% more than in case of ‘Middelgrunden’.

Building large-scale windfarms is a major intervention in the ‘landscape’. Environmental Impact Assessments (EIAs) and public inquiries are required, before the Danish Energy Agency can give permission to build an offshore windfarm[25]. An EIA takes account of physical and biological aspects of the sites as well as the impact of human activities. Visualisations show the appearance of the wind farm from various positions onshore. An investigation of the noise emitted indicates that the turbines will be audible at a distance of no more than 1 km. Changes in the physical conditions at the site are expected to be limited. No direct adverse impact on the fauna in the areas is predicted. Migratory birds are at risk of colliding with the turbine blades, and their feeding area may be reduced. Whether the mere presence of wind turbines may discourage bird species from resting in the area needs to be investigated.

The following more or less arbitrary distinction is made between near-shore and offshore wind:
- Near-shore windfarms are assumed to be in sheltered offshore areas with relatively shallow waters, and at moderate distance from the coast, particularly in the Baltic Sea;
- Offshore windfarms are assumed to be in ‘real’ offshore areas, with higher wind speeds, deeper waters, higher waves, etc. Those areas are to be found on the Continental Shelf of the North Sea and in parts of the Baltic Sea that are far (20 km or more) from the coast.

Evidently, this distinction is not quite clear-cut, but it may be useful for this type of study.

Table 3.5 *Characteristics of near-shore windfarms*

Project	Country	Location	Start of operation [year]	Average wind speed [m/s]	Distance to shore [km]	Water depth [m]	Capacity [MW]	Investment cost [million €]	[€/kW]	Capacity factor [%]
Lely	NL	IJsselmeer	1994	7.7	0.8	4-5	2	5.3	2600	21.7
Vindeby	DK	Baltic Sea	1991	7.5	1.5-3	2.5-5	4.95	13.2	2660	24.4
Tunø Knob	DK	Baltic Sea	1995	7.4	3-6	3-5	5	11.6	2326	28.5
Middelgrunden	DK	Baltic Sea	2000	7.2	2	3-6	40	48.96	1224	25.4
Rødsand	DK	Lolland	2003		9-10		150	210.8	1406	38.1
Omø Stalgrunde	DK	Baltic Sea	2005		10		150	210.8	1406	32.7
Gedser	DK	Baltic Sea	2008		6-20		150	210.8	1406	38.1
Bockstigen	S	Gotland	1998		4	6	2.5	4.2	1681	24.7
Utgrunden	S	Kalmar Sound	2000	8.5	12.5	7-10	10	18.3	1833	43.3
Yttre Stengrund	S	Blekinge	2001				7.5	13.0	1730	44.6
	S	Landskrona	2003?		5	10-15	70	105.1	1501	43.3

3.4 Near-shore wind

3.4.1 Characteristics of near-shore windfarms

The world's first 'offshore' windfarm was the 11 * 450 kW (4.95 MW) windfarm near *Vindeby* in Denmark (Table 3.5). The distance to the shore is 1.5-3 km, and the water depth is 2.5-5 m. *Vindeby* was commissioned in 1991. The average wind speed is 7.5 m/s. Its specific investment cost is relatively high: approximately € 2,600/kW[26].

The first near-shore windfarm in the Netherlands was the 4 * 500 kW (2 MW) windfarm *Lely* near Medemblik. This tiny windfarm, approximately 1 km from the shore in the shallow water (4-5 m deep) of the IJsselmeer, was commissioned in 1994. The average wind speed is approximately 7.7 m/s. Due to its small size and first-of-a-kind character, its specific investment cost is rather high, viz. approximately € 2,600/kW[27].

The second near-shore windfarm in Denmark was the 10 * 500 kW (5 MW) windfarm *Tunø Knob*, commissioned in 1995. The distance to the shore is 3-6 km, and the water depth is 3-5 m. The average wind speed is 7.4 m/s. Its specific investment cost is € 2,300/kW[28].

The third Danish project of this kind was the 20 * 2 MW (40 MW) windfarm *Middelgrunden*, commissioned in 2000-2001. This windfarm is situated 3 km off the coast of Copenhagen. The water depth is 3-6 m. The average wind speed is approximately 7.2 m/s. The specific investment cost is relatively low, viz. € 1,225/kW[29,30,31].

The first 'offshore' windfarm in Sweden was the 5 * 500 kW (2.5 MW) windfarm *Bockstigen*, 4 km from Gotland in 6 m deep water. *Bockstigen* was commissioned in 1998. The specific investment cost amounts to approximately € 1,700/kW[32,33].

The second near-shore windfarm in Sweden – commissioned in 2000 – is the 7 * 1.43 MW (~ 10 MW) windfarm *Utgrunden*, 12.5 km from Kalmar Sound in 7-10 m deep water. The wind speed is 8.5 m/s. The specific investment cost is € 1,700/kW[34,35].

In 2001, a third 5 * 1.5 MW (7.5 MW) near-shore windfarm called *Yttre Stengrund* was commissioned. *Yttre Stengrund* has roughly the same specific investment cost as *Utgrunden* (approximately €1,700/kW)[36].

Another nearshore windfarm in Sweden is in the planning stage. The location is a few km north of Malmö and 5 km off the cost of *Landskrona*. The 70 MW windfarm (probably 20 * 3.5 MW) would cost approximately € 105 million, or € 1,500/kW[37].

At last, three almost identical near-shore windfarms in the Danish Baltic Sea are in the planning stage (to be commissioned in the period 2003-2008), viz. *Rødsand*, *Omø Stalgrunde*, and *Gedser*. The distance to the shore is some 10 km, and the size of the wind farm is 72 * 2.1 MW (~ 150 MW). The specific investment cost is estimated at € 1,400/kW.

With respect to the capacity factor of near-shore windfarms the following is observed:

- Five existing windfarms – Lely, Vindeby, Tunø Knob, Middelgrunden, and Bockstigen – show relatively modest capacity factors of 22-28%.
- For Utgrunden and Yttre Stengrund as well as the planned nearshore windfarms in the Swedish and Danish Baltic Sea the capacity factors range from 33 to 45%.

Figure 3.1 shows the relationship between the specific investment cost and the size of a near-shore windfarm in MW.

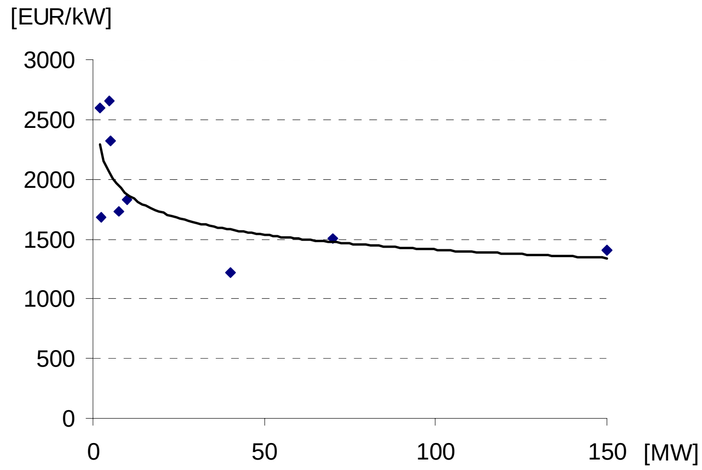


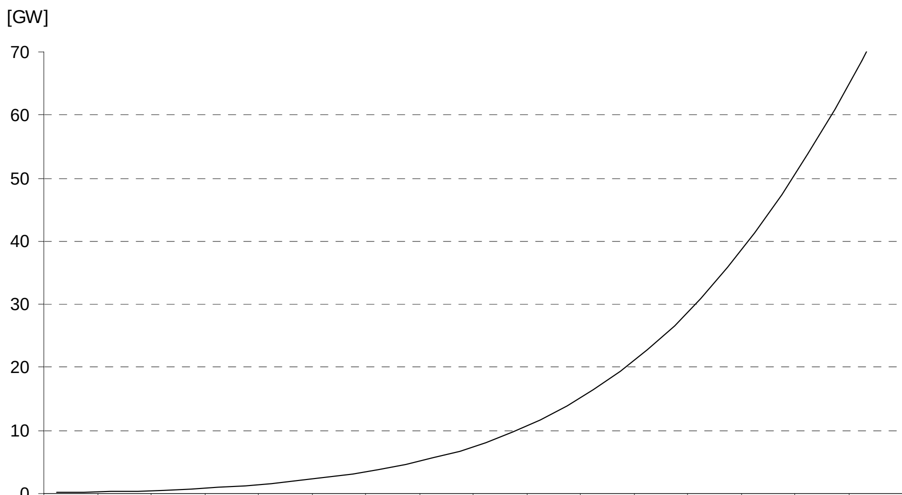
Figure 3.1 *Specific investment cost of nearshore wind as a function of installed capacity*

Apparently, the specific investment cost bottoms out at approximately € 1,375/kW for relatively large (> 100 MW) near-shore windfarms not too distant from the coast. Evidently, the 40 MW Middelgrunden windfarm in close proximity to Copenhagen is not so representative.

3.4.2 Perspectives for the next thirty years

The development of nearshore windfarms depends on a number of factors, among which the scarcity of favourable onshore sites, the availability of near-shore sites, and possible cost reductions for near-shore windfarms. Today, the specific investment cost of near-shore wind is at least 35% higher than for onshore wind (e.g. in case of *Middelgrunden*).

It is assumed that the capacity will grow by 25%/a on average from 2000 through 2030. The initial growth rate is really high (a trebling of capacity from 2000 to 2002). The growth rate comes down to 12.5%/a in 2030, and the installed capacity rises to 67.8 GW in 2030. Taking into account the decommissioning of windfarms after 25 years, the cumulative installed capacity in 2030 amounts to 68.55 GW. Figure 3.2 shows such a scenario for near-shore wind.



	2000	2002	2004	2006	2008	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
Capacity	0.09	0.27	0.56	0.99	1.62	2.50	3.77	5.58	8.14	11.66	16.43	22.75	30.94	41.31	53.87	68.55

Figure 3.2 *Projection of global cumulative capacity of near-shore wind*

3.4.3 Learning effects

Near-shore windfarms may show learning effects that are comparable to onshore wind. Cost reductions for the 'wind turbine' (rotor, nacelle, and tower) may be quite similar. The following 'components' of near-shore windfarms have been distinguished (Table 3.6).

Table 3.6 *Breakdown of investment cost of state-of-the-art 160 MW near-shore windfarm*

	[million $€_{2000}$]	[$€_{2000}$/kW]	% of total windfarm cost
Rotor & nacelle & tower	104.48	653	47
Offshore constructions	39.68	248	18
Cabling & grid connection	76.16	476	35
Total	220.00	1,375	100

The specific investment costs of 'turbines' and 'offshore constructions' are equal to those of the Middelgrunden windfarm (Table 3.4). However, it has been assumed that the distance to the shore is larger. Therefore, the cost of grid connection – a high voltage cable to the mainland's grid – is higher than in case of 'Middelgrunden', which is reflected by the component 'cabling & grid connection' (also including preparation costs).

The following progress ratios are assumed for the *default* and *low* cases with regard to 'turbines', 'offshore constructions', and 'cabling & grid connection' (Table 3.7).

Table 3.7 *'Learning profiles' for investment cost of a near-shore windfarm (2000-2030)*

	Period	Progress ratio rotor & nacelle & tower	Progress ratio offshore constructions	Progress ratio cabling & grid connection
Default	2000-2030	Parallel to 'onshore wind'	0.95	0.975
Low	2000-2030	Parallel to 'onshore wind'	0.925	0.95

The turbine cost (rotor, nacelle, and tower) may differ from the cost of an onshore turbine, as special precautions are required for the aggressive environment (marinisation) and the operational costs have to be scrutinised. This is because repairs and maintenance are more costly at near-shore windfarms. However, relatively high numbers of identical turbines might roughly outweigh the additional cost of marinisation, minimisation of maintenance, etc.

The *'default' learning profile* is based on the assumption that the specific investment cost of the 'turbine' will decline as a function of time parallel to an onshore turbine, more specifically to the cost of 'rotor & nacelle & tower' of an onshore turbine (Chapter 2). For offshore constructions, including installation, a progress ratio of 0.95 is assumed. For internal cables and grid connection (including 'other' cost) a more modest progress ratio of 0.975 is assumed.

The *learning profile 'low'* (low ultimate investment cost in 2030) also presumes that the specific investment cost of the turbine will decline parallel to the cost of an onshore turbine (viz. rotor & nacelle & tower). For offshore constructions on the one hand and cabling & grid connection on the other hand progress ratios of 0.925 and 0.95 respectively have been assumed.

Figure 3.3 shows the results of learning in case of a near-shore windfarm. The initial specific investment cost is assumed to be € 1,375/kW. This figure is higher than the corresponding cost figure for 'Middelgrunden', as the latter is in very close proximity to the mainland.

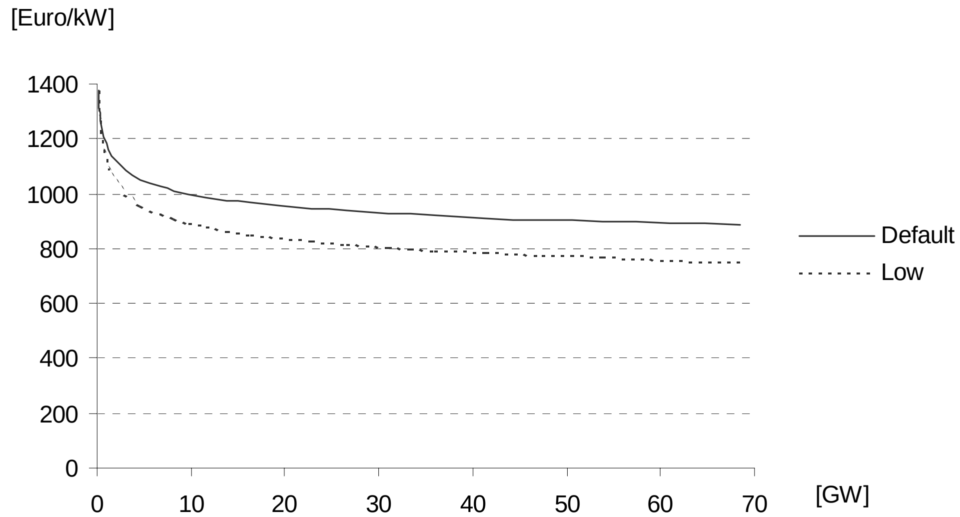


Figure 3.3 *Specific investment cost of near-shore wind vis-à-vis cumulative installed capacity*

The *default* learning profile shows a decline of the specific investment cost from € 1,375/kW in 2000 to € 885/kW in 2030. This is tantamount to a cost reduction of 35% in 30 years (comparable to onshore wind). The *default* case is a good yardstick for long-term modelling. The case *'low'*, with an ultimate level of € 755/kWin 2030, may be used for sensitivity analysis.

Figure 3.4 presents the *default* and *low* learning profiles as a function of time.

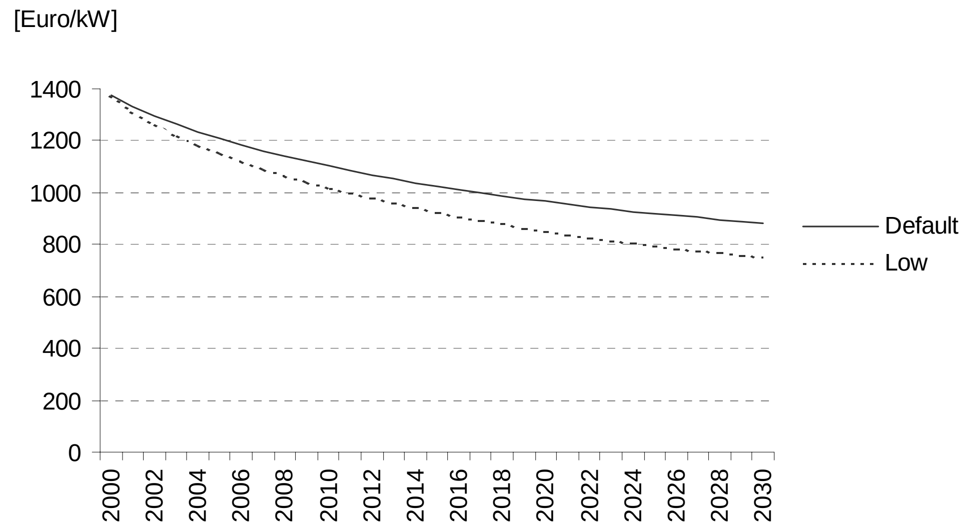


Figure 3.4 *Specific investment cost of a near-shore windfarm, 2000-2030*

Compared to onshore wind, the uncertainties with respect to the long-term potential, learning effects and the ultimate cost level in 2030 are even larger. The gap between *default* and *low* is larger in case of near-shore wind than for onshore wind. In the *default* case, the specific investment cost of nearshore wind is 50% higher than for onshore wind in 2030 (€ 885/kW and € 590/kW respectively). In the *low* case, however, the specific investment cost is only 35% higher (€ 755/kW and € 560/kW for nearshore and onshore wind respectively).

In 2030, near-shore wind could be nearly as competitive as onshore wind. The higher capacity factor of near-shore wind (approximately 36% vis-à-vis ~ 24%) might nearly outweigh the higher specific investment cost compared to onshore wind.

Table 3.8 *Characteristics of offshore windfarms*

Project	Country	Location	Start of operation [year]	Average wind speed [m/s]	Distance to shore [km]	Water depth [m]	Capacity [MW]	Investment cost [million €]	[€/kW]	Capacity factor [%]
Blyth Offshore Windfarm	UK	North Sea	2000	7.2	1	6	4	6.44	1,610	35.0
Pilot Phase "Borkum West" (Borkum III)	D	North Sea	2003		40-45	30	60	132.5	2,208	45.7
Scroby Sands Offshore Windfarm	UK	North Sea	2003		>2.3		76	112.7	1,483	31.9
Near-Shore Windfarm (NSW)	NL	North Sea	2003	8.5	23	15-20	100	185.7	1,857	34.2
Offshore Windfarm Wenduinebank	B	North Sea	2003	8.3	8.4	5-10	115	214.2	1,862	36.2
Offshore Windfarm Horns Rev	DK	North Sea	2002	9.7	14-20	6-14	160	268	1,675	41.0
Bürger-Windpark Butendiek	D	North Sea	2006		30		240	400	1,667	38.1
Phase One "Sandbank 24"	D	North Sea	2004			30	360	511	1,419	45.7
Arkona Bay South-East	D	Baltic Sea	2007?				860	1,278	1,486	41.1
Nördliche Pommersche Bucht	D	Baltic Sea	2007?		42	12-20	1,000	1,530	1,530	41.1
Borkum West (Borkum III)	D	North Sea	2007?		45	30	1,040	1,500	1,442	45.7

Table 3.9 summarises the projections for the global cumulative installed capacity (Figure 3.2), as well as for the specific investment cost and the maintenance cost of near-shore wind.

Table 3.9 *Specific investment cost and maintenance cost for a near-shore windfarm*

	Unit	2000	2005	2010	2015	2020	2025	2030
Assumed installed cap.	[GW]	0.09	0.75	2.50	6.76	16.42	35.77	67.80
Investment cost								
Default	[$€_{2000}$/kW]	1375	1209	1101	1024	965	919	885
Low	[$€_{2000}$/kW]	1375	1153	1020	925	852	796	754
Maintenance & insurance	[$€_{2000}$/kW/a]	45	40	37	34	32	31	30

3.5 Offshore wind

3.5.1 Characteristics of offshore windfarms

The firsts offshore windfarm in the North Sea was the 2 * 2 MW (4 MW) windfarm off the coast of *Blyth* (east coast UK, Table 3.8). The water depth is 6 m. The wind speed is 7.2 m/s. The specific investment cost is put at €1,600/kW[38,39]. A second offshore windfarm, the 38 * 2 MW (76 MW) *Scroby Sands* windfarm 3 km off the east coast of the UK, is due for 2003. The specific investment cost is € 2,200/kW[40,41].

Elsam A/S is building the first Danish offshore windfarm at *Horns Rev*, 14-20 km from the coast near Esbjerg in 6-14 m deep water. The capacity of the windfarm is 160 MW (80* 2 MW). The wind speed is 9.7 m/s. The specific investment cost is € 1,675/kW, including a high voltage cable to the shore of € 250/kW[42,43,44].

In the Netherlands, the 100 MW offshore windfarm (‘*Near-Shore Windfarm*’, *NSW*), 11-23 km off the coast of Egmond aan Zee, is due for 2003. The water depth is 15-20 m. The wind speed is 8.5 m/s. The specific investment cost is € 1,860/kW[45].

In Belgium, a 50 * 2.3 MW (115 MW) windfarm is planned 8.4 km off the coast of *Wenduine*, in 5-10 m deep water. The average wind speed is 8.3 m/s. The *Wenduinebank* windfarm is due for 2003. The specific investment is € 1,860/kW[46,47,48].

The first offshore windfarm in Germany (2003) could be the *Pilot Phase* of “*Borkum West*” in the North Sea, consisting of 12 turbines of 5 MW (60 MW). The distance to the shore of Borkum is 40-45 km, and the water depth is 30 m. The specific investment cost is € 2,200/kW.

Phase One of “*Sandbank 24*”, 120 km west of Sylt in the North Sea, will probably be commissioned in 2004. Its capacity is 120 * 3 MW (360 MW). The water depth is about 30 m. The specific investment cost is approximately € 1,420/kW[49].

Another offshore project in the planning stage is the 80 * 3 MW (240 MW) windfarm *Bürger-Windpark Butendiek*, due for 2006. ‘*Butendiek*’ will be built 30 km west of Sylt and 50 km south of Horns Rev. The specific investment cost is about € 1,670/kW[50].

Several other offshore windfarms in Germany are due for 2007, among which the 172 * 5 MW (860 MW) windfarm *Arkona Bay East*, 25 km northeast of Cape Arkona in the Baltic Sea. The specific investment cost is estimated at € 1,280/kW[51,52].

Also due for 2007 is the 200 * 5 MW (1,000 MW) offshore windfarm 42 km east of Rügen , in the Baltic Sea, called ‘*Nördliche Pommersche Bucht*’. The distance to the shore is 42 km, and the water depth is 12-20 m. The specific investment cost is € 1,530/kW[53].

Borkum West – 208 * 5 MW (1,040 MW) – is to be completed in 2007. The specific investment cost is € 1,440/kW, 30% of which for cabling and connection to the grid[54].

With respect to the capacity factor of offshore windfarms the following is observed:

- Two windfarms in the UK – Blyth and Scroby Sands – show modest capacity factors of 32-35%, which may be due to their location at the east coast of Great Britain.
- The other nine offshore windfarms have projected capacity factors from 34-36% (NSW Egmond and Wenduinebank) to as high as 45%.

Figure 3.5 shows the specific investment cost vis-à-vis the size of an offshore windfarm in MW.

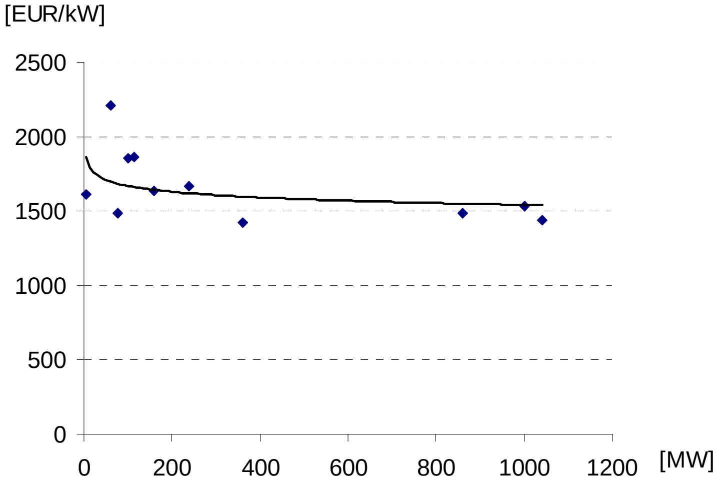
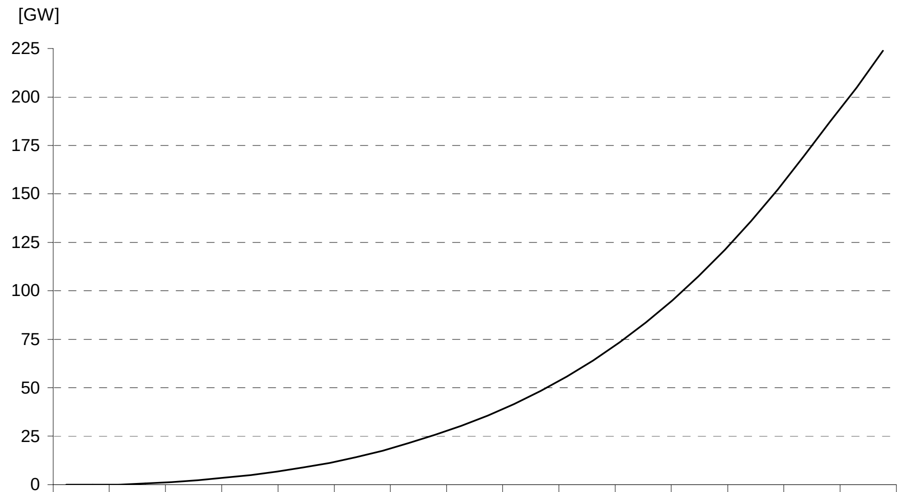


Figure 3.5 *Specific investment cost of offshore wind as a function of installed capacity*

The specific investment cost of offhore windfarms ranges from € 1,400/kW to € 2,200/kW. A representative figure for a 100-200 MW offshore windfarm in the year 2002 is € 1,700/kW.

3.5.2 Perspectives for the next thirty years

The development of offshore wind depends on the remaining onshore potential, the near-shore potential, and the cost reduction potential. The specific investment cost of offshore wind (*Horns Rev*) is about 85% higher than for onshore wind. Figure 3.6 shows a scenario for offshore wind.



	2000	2002	2004	2006	2009	2011	2013	2015	2017	2019	2021	2023	2026	2028	2030
Capacity	0.00	0.16	1.41	3.61	8.87	14.26	21.39	30.42	41.64	55.79	73.46	95.05	136.05	169.54	204.82

Figure 3.6 *Projection of global cumulative capacity of offshore wind*

Offshore wind energy is assumed to take off at an accelerated speed (e.g. nearly 40%/a in 2007). The growth rate is assumed to decline gradually to 11%/a in 2030. The installed capacity in 2030 is estimated at 200 GW. Taking into account the decommissioning of offshore windfarms after 25 years, the cumulative installed capacity in 2030 amounts to approximately 205 GW.

The combined installed capacity of near-shore and offshore wind in 2030 is estimated at some 268 GW, more than ten times the total global wind capacity at the end of 2001.

3.5.3 Learning effects

Offshore wind farms could show learning effects comparable to those of near-shore wind, particularly with regard to the 'wind turbine' (rotor, nacelle, and tower). The following costs have been attributed to the components 'turbines', 'offshore constructions', and 'cabling & grid connection' (including 'other' costs) of a state-of-the-art offshore windfarm (Table 3.10).

Table 3.10 *Breakdown of investment cost of state-of-the-art 160 MW offshore windfarm*

	[million $€_{2000}$]	[$€_{2000}$/kW]	% of total wind farm cost
Rotor & nacelle & tower	116	725	43
Offshore constructions	72	450	26
Cabling & grid connection	84	525	31
Total	272	1,700	100

For the two cases similar learning effects are assumed as for near-shore wind (Table 3.11).

Table 3.11 *'Learning profiles' for investment cost of an offshore windfarm (2000-2030)*

	Period	Progress ratio Rotor & nacelle & tower	Progress ratio offshore constructions	Progress ratio cabling & grid connection
Default	2000-2030	Parallel to 'onshore wind'	0.95	0.975
Low	2000-2030	Parallel to 'onshore wind'	0.925	0.95

Wind turbines for offshore application may be larger than those already applied onshore (today, the maximum rated power of onshore turbines is 2.5 MW). However, the manufacturing industry for offshore turbines may profit to a large extent from the onshore market, both in terms of technical learning and marketing. Profits generated from turbine sales at the onshore market may be diverted to RD&D of dedicated offshore turbines, with special attention for:

- Marinisation, in order to prevent undue non-availability.
- Minimisation of repairs and maintenance.
- Accessibility of turbines for boats and/or helicopters.
- Design optimised for offshore operation, e.g. higher rotational and tip speeds presumed that noise is not an issue.

It is assumed that offshore turbines are generally more costly in terms of €/kW than 'comparable' onshore turbines. This is because the optimum size is determined to a large extent by the economies of scale of the other components, viz. the offshore construction.

The *'default' learning profile* is based on a progress ratio of 0.95 for offshore constructions and a PR of 0.975 for cabling and grid connection (including 'other' cost). For the case *'low'* (low ultimate investment cost in 2030) the corresponding progress ratios are 0.925 and 0.95 respectively, reflecting a relatively high level of optimism with regard to learning effects.

Figure 3.7 shows the results of learning in case of offshore wind. The initial specific investment cost is put at € 1,700/kW, only slightly higher than the corresponding cost of 'Horns Rev'.

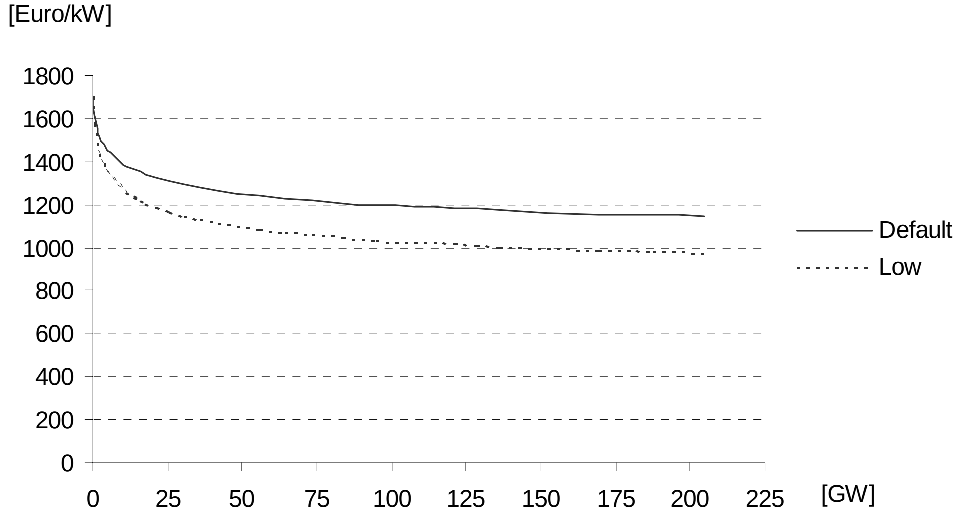


Figure 3.7 *Specific investment cost of offshore wind vis-à-vis cumulative installed capacity*

The *default* learning profile shows a decline of the specific investment cost from € 1,700/kW in 2002 to € 1,140/kW in 2030. This is tantamount to a cost reduction by one-third in 28 years (comparable to nearshore wind). The *default* value of € 1,140/kW is a good yardstick for long-term modelling. A considerably lower price of € 860/kW for 2050 has been calculated by D. van de Reepe, based on a 'gross' progress ratio of 0.9. However, a PR of 0.9 for the total system cost seems to be too optimistic for offshore wind. The case *'low'*, bottoming out at € 970/kWin 2030, seems to be appropriate for sensitivity analysis.

Figure 3.8 presents the *default* and *low* learning profiles as a function of time.

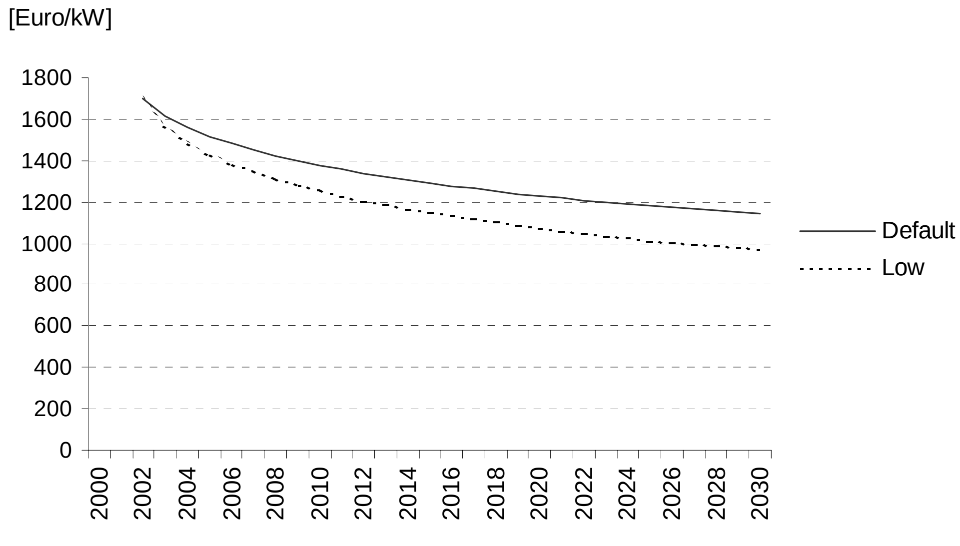


Figure 3.8 *Specific investment cost of offshore windfarms, 2000-2030*

Compared to onshore wind, the uncertainties with respect to the deployment potential, the learning effects, and the ultimate cost level in 2030 are significantly larger. Offshore wind shows a more widening gap between the *default* and *low* cases than onshore wind. In the *default* case, the specific investment cost of offshore wind in 2030 (€ 1,140/kW) is 95% higher than that of onshore wind (€ 590/kW). In the *low* case, the specific investment cost of offshore wind is 75% higher (€ 970/kW compared to € 560/kW).

Taking into account the higher capacity factor for offshore wind (approximately 40% vis-à-vis 24%), offshore wind would remain somewhat more costly than onshore wind in the long run.

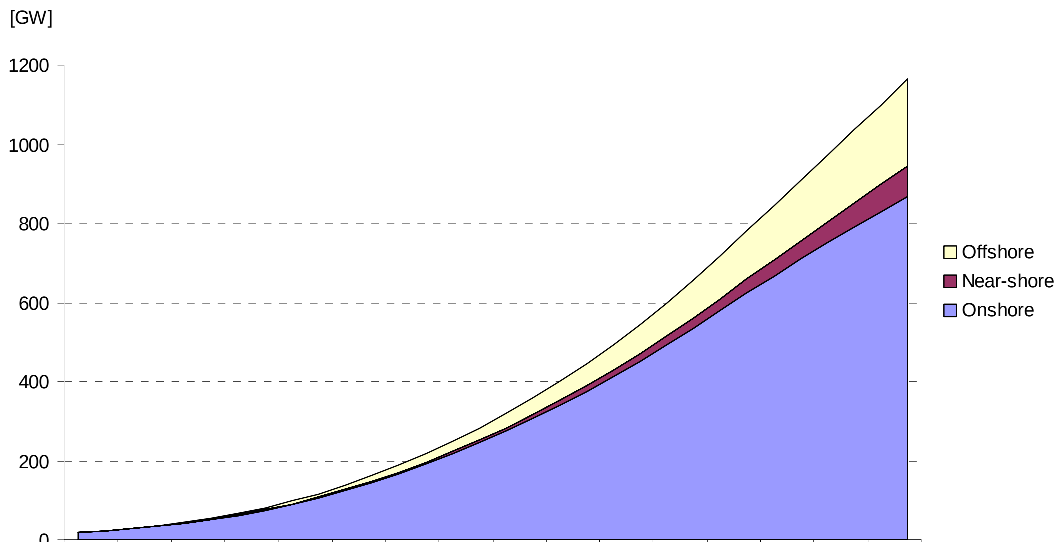
Table 3.12 summarises the projections for the global cumulative installed capacity of offshore wind (Figure 3.6), as well as for the specific investment cost and the maintenance cost.

Table 3.12 *Specific investment cost and maintenance cost for an offshore windfarm*

	Unit	2002	2005	2010	2015	2020	2025	2030
Assumed inst. cap.	[GW]	0.16	2.41	11.36	30.42	64.15	136.05	200.00
Investment cost								
Default	[$€_{2000}$/kW]	1,700	1,515	1,379	1,291	1,229	1,180	1,143
Low	[$€_{2000}$/kW]	1,700	1,300	1,256	1,149	1,074	1,016	972
Maintenance & ins.	[$€_{2000}$/kW/a]	52	50	47	45	43	41	40

3.6 Comparison between near-shore & offshore wind and onshore wind

The anticipated capacity of onshore wind, near-shore wind and offshore wind is shown in Figure 3.9. The total installed capacity of the three categories could be 1,100 GW in 2030. Onshore wind could account for about 75% of the total installed wind capacity, near-shore wind for 6%, and offshore wind for 18%.



	2000	2002	2004	2006	2008	2010	2012	2014	2016	2018	2020	2022	2024	2026	2028	2030
Offshore	0.0	0.2	1.4	3.6	6.8	11.4	17.6	25.7	35.7	48.3	64.2	83.7	107.5	136.0	168.3	200.0
Near-shore	0.1	0.3	0.6	1.0	1.6	2.5	3.8	5.6	8.1	11.7	16.4	22.7	30.9	41.1	53.5	67.8
Onshore	18.4	27.9	41.6	62.0	89.2	124.3	166.7	216.9	274.7	340.1	412.6	492.2	578.2	666.5	751.2	830.3

Figure 3.9 *Projection of global capacity of onshore, near-shore, and offshore wind*

The number of doublings of the installed capacity from 2000 to 2030 is:

- About 6 for onshore wind.
- Less than 10 for near-shore wind.
- More than 10 for offshore wind (from 2002 through 2030).

Figure 3.10 shows the cost curves of onshore, near-shore, and offshore wind as a function of time. The cost curves shown correspond to the *default* cases.

It turns out that the cost of offshore wind declines relatively fast in the first few years. This is because the installed capacity is assumed to show a rather spectacular growth in the stage of 'take-off'. After that, the growth rate is assumed to come down steadily. Therefore, the specific investment cost of offshore wind decreases correspondingly slower in the long run.

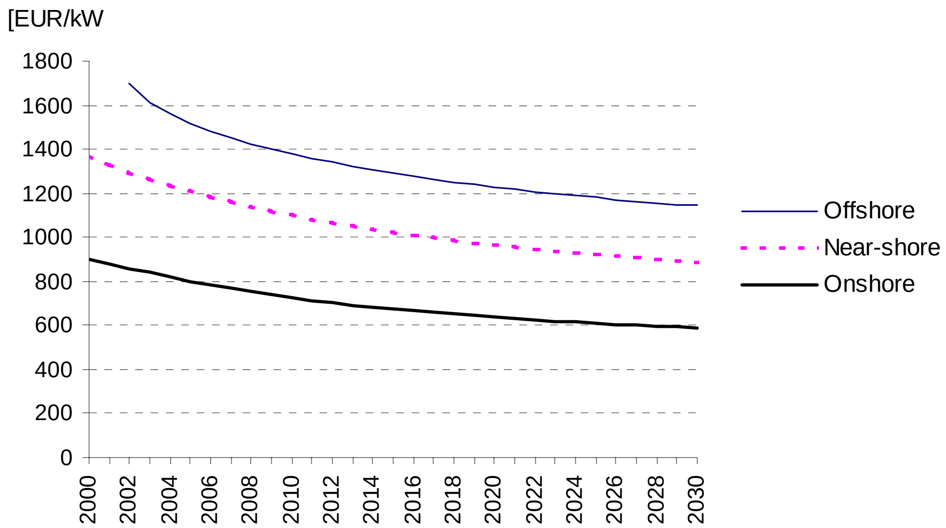


Figure 3.10 *Specific investment cost of onshore, near-shore, and offshore wind turbines*

Near-shore wind and onshore wind exhibit a more or less perpendicular decline of the cost as a function of time, despite different assumptions with regard to progress ratios of components (except the 'turbines') and numbers of doublings over the period considered.

4. PHOTOVOLTAIC POWER

4.1 Introduction

Photovoltaic (PV) power is a renewable option based on direct conversion of solar energy into electricity. Compared to 'solar thermal power' – based on steam generation by concentrating solar energy with mirrors or 'solar troughs' – PV power is rather straightforward. It offers a tremendous potential for small- and large-scale application because of to its modular character.

The challenge is to make PV an economically viable option. The efficiency of solar cells – typically 7-15 percent for commercially available solar cells – may be increased. Also, their lifetime may be prolonged by prevention of significant degradation. Furthermore, consumption of materials – high-grade silicon, precious metals – may be reduced to low and 'sustainable' levels. Last but not least, the cost of PV has to be reduced substantially: roughly by a factor five to ten depending on the application or the region (latitude) considered. This may be achieved by continued research and development as well as large-scale production. In the long term, PV may become competitive compared to other power generation options. Whether current power generation options – coal- and gas-fired power, nuclear power – will remain 'cheap', remains to be seen, as they have persistent problems: greenhouse gas (GHG) emissions in case of coal- or gas-fired power, and long-living nuclear waste in case of nuclear power.

Photovoltaic power – global installed capacity 1.43 GW in 2000 – is in an early commercial stage compared to wind power – 18.45 GW in 2000. Electricity from a 3 kW grid-connected system (single-family house) is priced at about 40-70 €ct/kWh (Western Europe), which is ten times more than wind power today. Therefore, a more or less dramatic cost reduction is needed.

Section 4.2 gives an overview of PV in OECD countries. The status of PV is briefly described in Section 4.3. Section 4.4 provides a short introduction into learning for PV. Finally, Section 4.5 addresses the possible cost reduction because of learning in the next 35 years.

4.2 Photovoltaic power in the OECD

In 1999, OECD countries accounted for 45% of the global installed PV capacity (Figure 4.1).

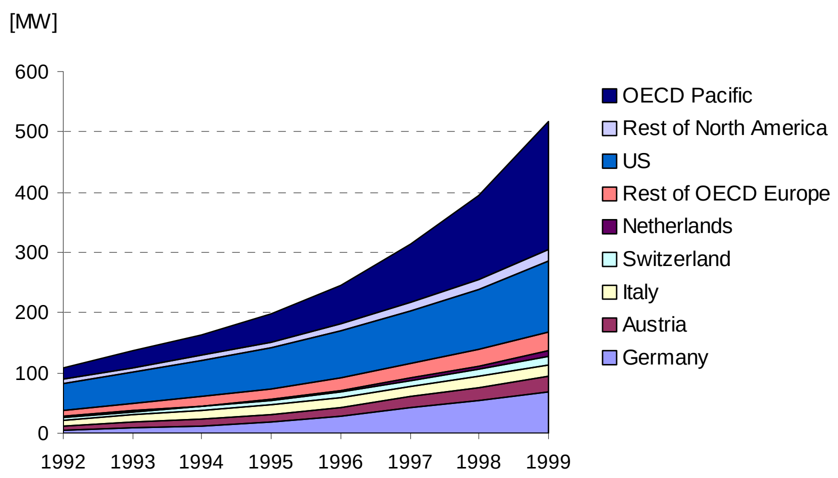


Figure 4.1 *Installed photovoltaic power (grid-connected and off-grid) in OECD countries*
Source: Dresdner Kleinwort Wasserstein, January 2001 (based on IEA data).

It should be noted that PV is characterised by relatively low numbers of full-load hours, viz. 800-2000 hours per year. At lower latitudes and under favourable solar conditions, solar thermal power plants – based on concentrating mirrors or 'solar troughs' – give higher yields in terms of energy efficiency than PV power plants. Also, solar thermal power plants may be operated at relatively high capacity factors by means of thermal energy storage, albeit at some cost. Thermal energy storage may be provided by e.g. fluids (specific oils) with a relatively high heat capacity. Therefore, thermal solar power is a competitor to PV at lower latitudes.

Figure 4.1 showed that PV has developed relatively fast and steadily during the last decade. The growth rates of PV in selected OECD countries and the OECD at large are shown in Figure 4.2.

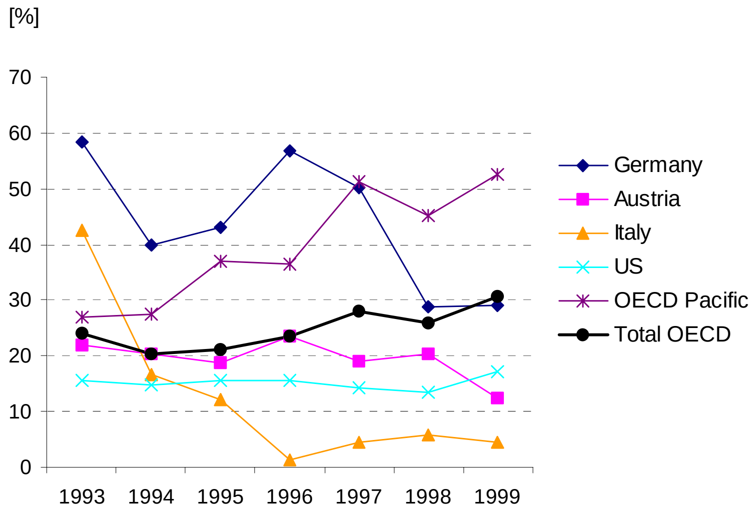


Figure 4.2 *Growth of photovoltaic power (grid-connected and off-grid) in OECD countries*
Source: Dresdner Kleinwort Wasserstein, January 2001 (based on IEA data).

The installed capacity of OECD countries, shown in the Figures 4.1 and 4.2 and Table 4.1, includes off-grid PV systems. The differences between countries may be explained by more or less favourable geographical conditions and foremost by differences in government policies. Besides, the applications of PV may be somewhat different – in some countries (e.g. the United States) photovoltaic power may be used for large-scale solar power generation (desert areas).

Regions/countries with above-average growth rates, viz. higher than 30%/a, are OECD Pacific and Germany. The US shows relatively low growth rates. The average OECD growth rate is 30%/a. Table 4.1 shows the distribution of several categories of PV among OECD countries.

More than half of the installed PV capacity in OECD countries is in grid-connected systems, most of which is distributed PV. In the US and Italy, large-scale PV power plants are in operation. Most of the power generators and distribution companies in OECD countries, however, are interested in distributed generation and few centralised plants have been built since 1996. An exception is the 13 MW solar power plant firmly planned in Murcia (Spain) at a total cost of approximately $65 million. The Spanish joint venture AstraSolar of the US manufacturer Astropower will supply solar cells for this plant[55].

In the OECD, the focus is mainly on grid-connected PV, because most of its residents are connected to the grid. Also, grid-connected systems are approximately two times less costly than off-grid systems. For instance, in the US the specific investment cost of grid connected systems in a specific area was $5,700/kW in 2000, whereas the corresponding figure for off-grid systems was $13,900/kW[56]. Off-grid (autonomous) systems need a battery and a power regulator and are commonly smaller in capacity than grid-connected systems.

Table 4.1 *Cumulative installed PV power in OECD countries (end of 1999)*

Country	Off-grid [kWp]	On-grid distributed [kWp]	On-grid centralised [kWp]	Cumulative installed [kWp]	Cumulative installed per capita [Wp/capita]	Installed in year 1999 [kWp]
Australia	1,413	2,119	140	3,672	0.45	811
Austria	23,180	1,490	650	25,320	1.34	2,800
Canada	5,529	287	10	5,826	0.19	1,356
Denmark	190	880	0	1,070	0.2	565
Finland	2,255	17	30	2,302	0.45	132
France	8,772	349	0	9,121	0.16	1,490
Germany	11,500	49,100	8,900	69,500	0.85	15,600
Israel	381	6	14	401	0.07	93
Italy	10,860	905	6,710	18,475	0.32	795
Japan	56,900	145,500	2,900	205,300	1.63	71,900
Korea	3,171	288	0	3,459	0.07	477
Mexico	12,920	2	0	12,922	0.13	900
Netherlands	3.886	5,309	0	9,195	0.59	2,715
Norway	5.670	0	0	5.670	1.28	320
Portugal	2,460	124	0	2,584	0.29	0
Spain	7,000	600	1,480	9,080	0.23	1,080
Sweden	2,460	124	0	2,548	0.29	214
Switzerland	2,500	9,420	1,480	13,400	1.89	1,900
UK	395	736	0	1.131	0.02	441
US	84,200	21,100	12,000	117,300	0.43	17,200
Total OECD	243,670	238,250	34,310	516,230	0.54	120,790

Source: Dresdner Kleinwort Wasserstein, January 2001 (based on IEA data).

In developing countries there is a huge potential for both off-grid and grid-connected PV:
- In rural areas that are not connected to the electrical grid.
- In areas with lack of sufficient or reliable generation and/or transmission capacity.

In developing countries PV is indeed a very important option to make electricity affordable for the rural population. Some areas are scarcely populated and far from industrial centres. A diesel power plant requires the scale of a small town and has high operational costs (diesel fuel). Also, many developing countries have favourable solar characteristics.

4.3 Status of PV

PV systems consist of modules (panels) that are assemblies of solar cells, and an inverter to convert DC power to AC power (in case of grid-connected systems). Modules are mounted on roofs of single- or multi-family dwellings, garages, office buildings, or own support structures.

Currently, the majority of PV modules is based on wafered cells sawn from crystalline ingots of high-grade silicon or specially grown silicon ribbons, applied in three forms:
- Monocrystalline silicon (black). This is the purest and most expensive of the three.
- Multi-crystalline silicon (blue).
- Amorphous silicon (black/reddish). Amorphous silicon is the cheapest (per square meter).

Crystalline cells are brittle wafers usually cut from a large silicon block, whereas amorphous silicon cells consist of a layer of uncrystallised silicon deposited on a substrate (mostly glass). ‘Cells’ are formed by scribing through the layers with a laser. The films are produced as large complete modules, not as individual cells that have to be mounted in frames and wired together. Today, crystalline cells have a longer lifetime than amorphous silicon cells. Other ways of growing the silicon are gaining importance, such as silicon sheets and ribbons, produced directly from the melt, without slicing. This reduces material consumption, which is crucial in silicon technology. Currently around 60% of the module cost is silicon related[57].

About 65% of the solar researchers worldwide are working on thin film technology. Amorphous silicon is the most common thin film material at present, but other technologies are approaching commercialisation, notably Cadmium Telluride (CdTe), and Copper Indium Diselenide (CIS, originally developed for space applications). These promise similar cost reduction potential to amorphous silicon but with higher stable conversion efficiencies. Several manufacturers have production plants for cadmium telluride cells of 10 MW in the stage of start-up or under construction. Some companies (Siemens Solar) started commercialisation of CIS technology.

Table 4.2 shows the state-of-the-art with respect to module and cell efficiencies. Although laboratory efficiencies of around 20% have been reported for multicrystalline silicon cells, the efficiencies of modules based on multicrystalline silicon are more somewhat lower (11-14%).

Table 4.2 *Module and cell efficiencies [%]*

	Typical module efficiency	Maximum recorded module efficiency	Maximum recorded laboratory efficiency
Single crystalline cell	12-15	22.7	24.7
Multicrystalline silicon	11-14	15.3	19.8
Amorphous silicon	5-7	-	12.7
Cadmium telluride	-	10.5	16
CIS	-	12.1	18.2

Source: Dresdner Kleinwort Wasserstein, January 2001.

PV cells/modules mainly originate from OECD countries like Japan, the US, EU countries. However, PV production plants are also found in India and China[58] (Table 4.3).

Table 4.3 *PV cell/module manufacturing – leading producers by region (2000)*

Country/region	Leading producers	Shipments in 2000 [MWp]	Total shipments in 2000 [MWp]	Growth compared to 1999 [%]
Europe	Photowatt (F)	14.0		
	ASE (D)	10.0		
	Isofoton (S)	9.5		
	BP Solar (S)	7.0	58.5	46
	Shell (D/NL)	6.5		
	Solar-Fabrik (D)	4.6		
US	Siemens Solar	28.0		
	Solarex	20.0		
	Astropower	18.0	78.5	29
	ASE Americas	6.0		
Japan	Sharp	50.4		
	Kyocera	42.0	116.6	46
	Sanyo	17.0		
Rest of world	BP Solar (AUS)	6.0		
	BP Solar (India)	5.0		
	Sinonar (Taiwan)	3.0	24.2	18
	China	2.5		

Source: Greenpeace/EPIA: Solar Generation, 2001 (based on PV News, 2001).

The leading manufacturers are Japan, the US, and Europe. The distribution among the several types of solar cells and modules in 1999 is shown in Table 4.4.

Table 4.4 *PV cell and module production in 1999 by region [MWp]*

Region/ Country	Cell production	Module production				Module production capacity
		Crystalline	Amorphous	Other	Total	(1999)
Europe	29.32	34.40	5.00	4.20	43.60	94.10
US	60.80	69.97	15.01	0.00	84.98	145.20
Japan	79.60	29.32	2.40	0.00	31.72	73.33
Other	7.50	7.50	0.00	0.00	7.50	12.50
Total	177.20	141.20	22.40	4.20	167.80	325.10

Source: Dresdner Kleinwort Wasserstein, January 2001.

As PV generating systems do not have moving parts, their maintenance costs are low. The modules are expected to operate for 20 years. The majority of the other components – inverters, controllers – are usually serviceable for ten years or more. Batteries for off-grid applications are currently the weak link in those systems, needing replacement at least every five years.

The competitiveness of PV systems is highly dependent on factors like the solar characteristics of the region (latitude), the availability of an electricity grid, electricity tariffs, etc.

4.4 Learning in the past decades

Photovoltaic cells, modules, other components, and systems are generally produced on a relatively small scale. This is because R&D are still going on strongly. Also, the PV market is not sufficiently large at this time to make large-scale production (say 500 MW/a) economically viable. Therefore, the market has to be developed and in the meantime the costs have to be reduced by further R&D. Today, plants for solar cells and modules have capacities of 10 to 25 MW/a. Production capacities of 100 to 250 MW appear to be achievable within this decade.

C. Harmon made an in-depth analysis of the price of PV modules. The price has come down steadily over the past two decades[59] (Figure 4.3).

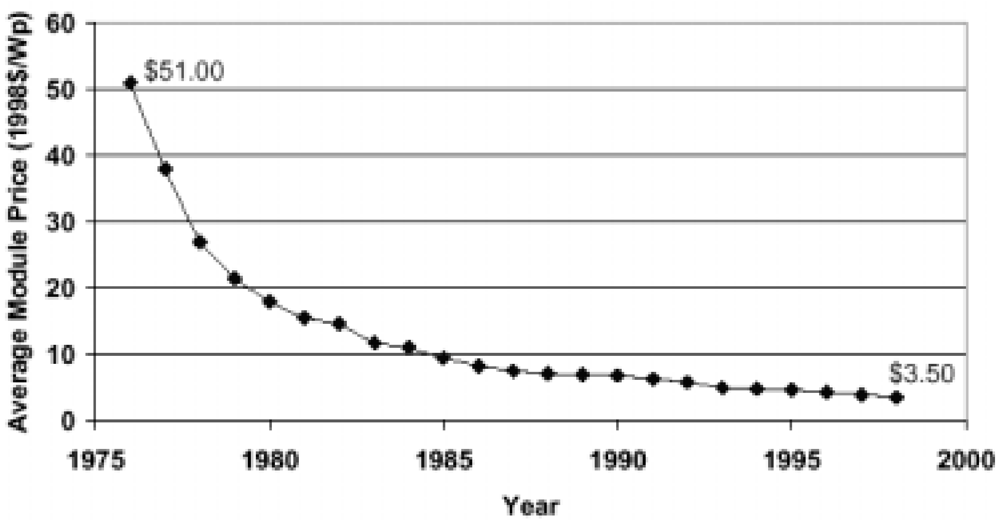


Figure 4.3 *Average selling price of PV modules 1976-1998*
Source: Experience curves of photovoltaic technologies (IIASA, 2000).

Figure 4.4 shows the resulting progress ratio (PR) for the period 1968-1998.

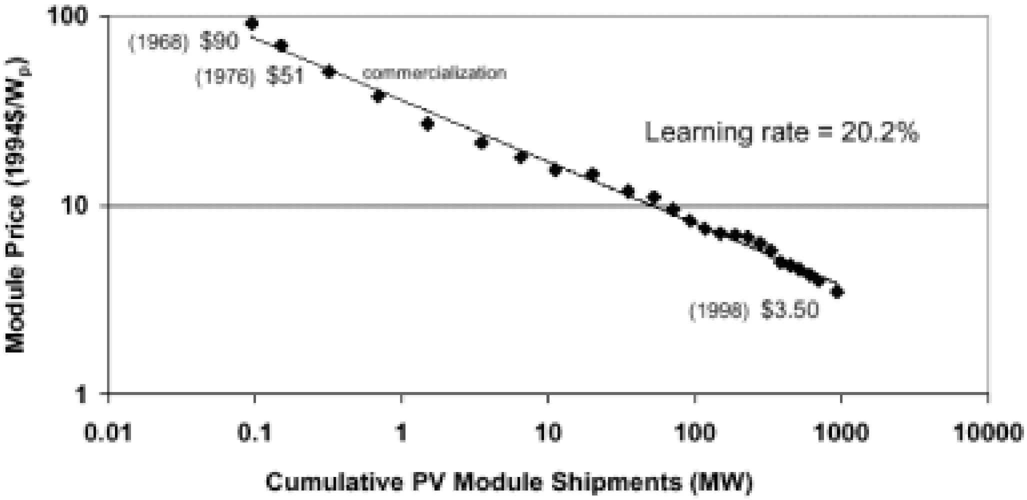


Figure 4.4 *Experience curve of PV modules 1968-1998*
Source: Experience curves of photovoltaic technologies (IIASA, 2000).

The PR of approximately 0.8 for PV modules is based on a cumulative installed capacity of 1000 MW. With increasing experience in the next few years, the slope of the curve may change. The PR may prove to be (slightly) higher or lower than 0.8 – the figure that gives the best fit up to 1998. Therefore, one has to be careful in using the PR for long-term cost projections.

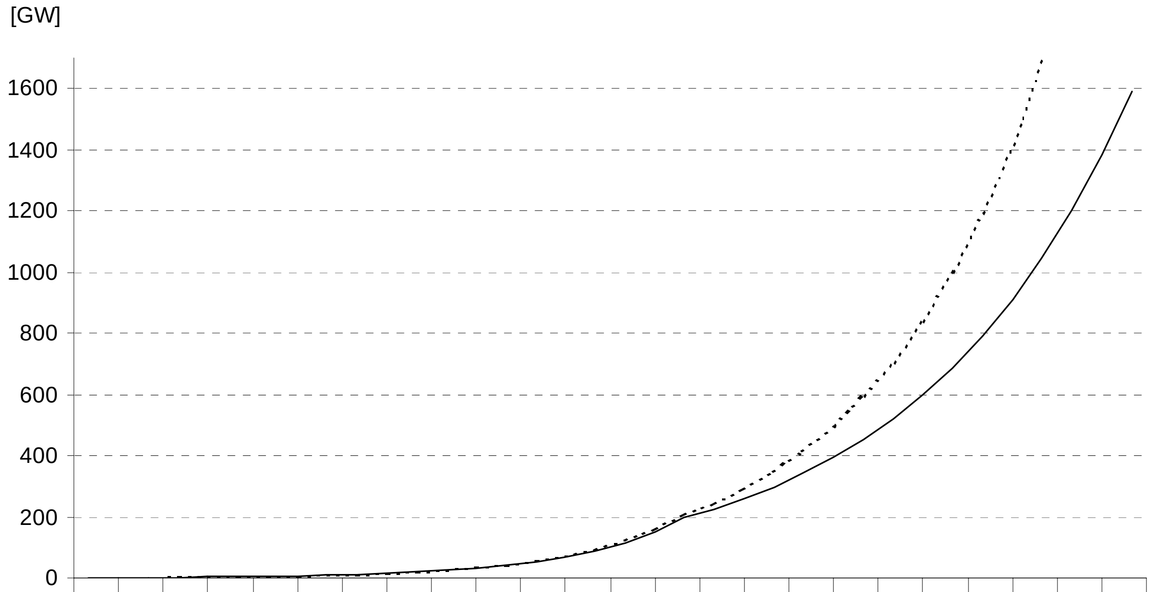
A similar progress ratio for the 'Balance of system' (BOS) – inverter, cabling, installation – has not been found. This is because there is so much divergence in solar systems:
- Grid-connected and off-grid applications.
- From tens of Watts up to 13 MW (e.g. in case of the 'Murcia' PV plant, Section 4.2).
- Integrated in roofs (dwellings, offices) or installed in frames (e.g. in the case of 'Murcia').

Because of the enormous differences in PV systems, it is not possible to make a systemic analysis of the cost of the so-called 'Balance of system' in the way the cost of modules has been analysed. It is not only possible but even probable that the 'BOS cost' has decreased as rapidly as the cost of modules for some time, due to increasing efficiency of solar panels and foremost due to economies of scale by increasing dimensions of modules and PV systems. However, impressive cost reductions of the 'BOS cost' cannot be expected for the next few decades. Solar cells and modules are the real 'high tech' part of the PV system, which will show ongoing technical breakthroughs, economies of scale, and related progressive cost reduction. The inverter, cabling, and installation are governed by somewhat different 'learning' processes. So, it is likely that the 'BOS cost' will show a more moderate progress ratio than the PV module.

4.5 The next thirty-five years

Recently, Greenpeace and the European Photovoltaic Industry Association (EPIA) published a study on the potential of PV power from a global point of view. Their projection towards 2040 has been used for an analysis of the possible cost reduction of PV in the next few decades.

The global scenario for PV in Figure 4.5 is based on data published by EPIA on an Internet site[60]. These data show some differences with the Greenpeace/EPIA study. Both the EPIA and Greenpeace/EPIA projections are pretty ambitious. It is obvious from Figure 4.5 that the Greenpeace/EPIA curve is even more ambitious than the EPIA curve (particularly from 2020).



	2000	2002	2003	2005	2006	2008	2009	2011	2012	2014	2015	2017	2018	2020	2021	2023	2024	2026	2027	2029	2030	2032	2033	2035
EPIA	1	2	3	4	5	8	11	18	24	40	53	89	116	195	225	297	342	452	520	687	791	1046	1202	1590
Greenpeace	1	2	3	5	6	10	12	20	26	44	57	95	124	207	247	350	417	591	704	999	1189	1687		

Figure 4.5 *Global cumulative PV capacity based on EPIA and Greenpeace/EPIA data*
Sources: Greenpeace/EPIA: Solar Generation, 2001; EPIA (Internet site).

The Greenpeace/EPIA projection is the most ambitious of the two:
- In 2020 the difference is small: 195 GW and 207 GW for the EPIA and the Greenpeace/EPIA projections respectively.
- After 2020, the difference becomes increasingly larger: in 2032 the forecasts show a range from 1046 GW to 1687 GW for the EPIA and Greenpeace/EPIA projections respectively.
- The EPIA forecast ends up at a generation of 7,368 TWh in 2040 (23% of global electricity demand). The Greenpeace/EPIA forecast for 2040 is 9,113 TWh (26% of global demand).

Part of the difference seems to be related to different estimates of the future electricity demand. Scenarios for 2040 are scarce. Even figures for electricity demand in 2020 from IEA's World Energy Outlook may be questioned on good grounds. Their 'business-as-usual' scenario does not consider the issue of GHG emissions as a constraint to economic and energy developments.

The projection for global PV in this study is defined as the EPIA projection from the Internet site (Figure 4.5). Besides, two 'learning profiles' for PV are introduced (Table 4.5).

Table 4.5 *'Learning profiles' for investment cost of grid-connected PV (starting in 2000)*

		Module	Inverter, cabling	Installation
Specific investment cost	[$€_{2000}$/kW]	4,000	750	650
Progress Ratio	Period	PR	PR	PR
Default	2000-2035	0.80	0.87	0.94
Low	2000-2035	0.80	0.85	0.90

The two cases reflect the experience from the past with regard to PV modules. However, the patterns of cost reduction in the past may not be representative for the future. Also, the database of PV modules is limited in terms of cumulative installed capacity. The uncertainty with respect to learning for inverters and the balance of plant is even larger than for modules.

The *'default' learning profile* is based on a Progress Ratio (PR) for the module of 0.8. Learning for solar modules – approximately € 4,000/kW in 2000 – is assumed to remain substantial. For the inverter, cabling, etc. (other equipment) a more modest learning effect is assumed, viz. a PR of 0.87 starting from € 750/kW in 2000. This is because these components do not provide so much learning effects, as they are already manufactured on a relatively large scale. At last, for the installation cost – € 650/kW in 2000 – a still lower learning effect is assumed (PR = 0.94).

The *learning profile 'low'* (low ultimate investment cost in 2035) is based on a PR of 0.8 for PV modules, just like in the case *default*. The learning potential for materials (inverter, cabling, etc.) is assumed to be higher than in case of *default*, viz. PR is 0.85. Finally, the learning process for installation is also assumed to be more pronounced than for the 'default' case, viz. PR is 0.90.

Figure 4.6 shows the results in terms of specific investment cost of grid-connected PV systems (typically 3 kW for single-family houses) as a function of the cumulative installed capacity.

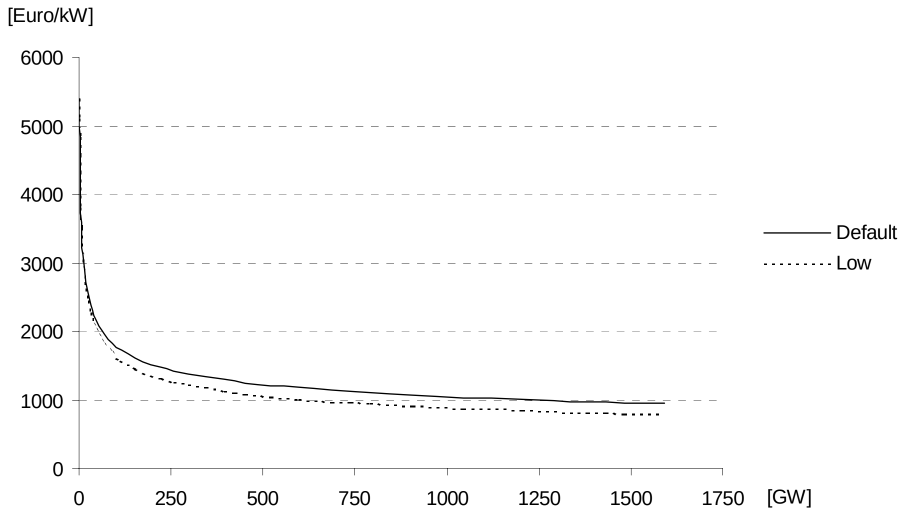


Figure 4.6 *Specific investment cost of PV as a function of cumulative installed capacity*

Figure 4.7 presents the results of the same two 'learning profiles' as a function of time.

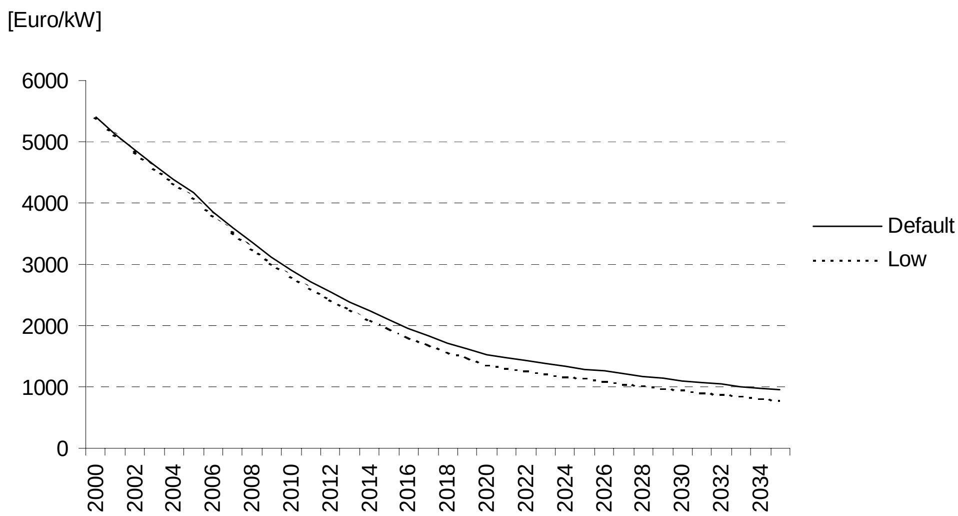


Figure 4.7 *Specific investment cost of PV (grid-connected)*

The assumptions made and the results of the analysis may be described as follows:
1. Data from EPIA suggest a cumulative capacity of 1,590 GW in 2035, and growth rates of:
   - 21%/a from 2000 to 2005;
   - 31%/a from 2005 to 2009;
   - 30%/a from 2009 to 2020;
   - 15%/a after 2020.

2. The implication of the 'EPIA scenario' could be more than 10 doublings of the cumulative installed capacity compared to the level of 2000.
3. The investment cost of € 5,400/kW for grid-connected 'single-family' systems in 2000 is based on the aforementioned US experience, viz. US$ 5,600/kW for grid-connected systems in 2000, and the projected cost of the 13 MW 'Murcia' solar plant, viz. $ 5,000/kW.
4. The distribution of the cost in 2000 between modules, inverter & cabling, and installation (74%, 14%, and 12% respectively) is based on an estimate of a Dutch consultant, viz. 75% for modules, 10% for the inverter (multicrystalline modules)[61]. This consultant also gives a projection of the system cost of € 4,95/Wp. This is the average of the '*default*' projections for the years 2001 and 2002 in Figure 4.7.
5. This analysis suggests an ultimate specific investment cost of grid-connected PV in 2035 of:
   - € 950/kW in case of the '*default*' learning profile.
   - € 790/kW in case of the learning profile '*low*'.

In case of long-term models, the '*default*' figure of € 950/kW may be useful as a cost level for the timeframe 2030-2035 (dependent on the scenario used, see Figure 4.5). D. van de Reepe suggests a price of € 720/kW for the year 2050. Taking into account the enormous cost reduction compared to the current cost level, this is 'all in the game'. The level of €790/kW, based on more ambitious PRs for the Balance of System, may be useful for sensitivity analysis.

Finally, Figure 4.8 shows how the projections of EPIA (Internet site) and Greenpeace/EPIA compare to potentials of PV calculated by IIASA for world regions in the year 2100[62].

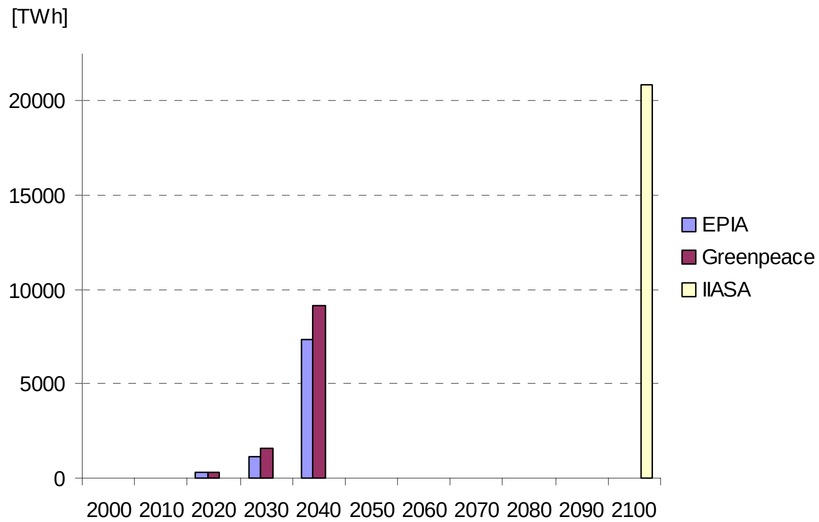


Figure 4.8 *Potential of PV according to EPIA (Internet site), Greenpeace/EPIA, and IIASA*

It turns out that both the estimates of EPIA and Greenpeace/EPIA are pretty ambitious for the years 2030 and 2040, if one assumes an S-curve from 2000 towards 2100. IIASA's figure of 20,880 TWh is based on estimates by world region (Table 4.6).

Table 4.6 *Potential of PV in world regions in 2040 and 2100*

Region	2000		2020		2040		2100
Source	EPIA		EPIA		EPIA		IIASA
	[GW]	[TWh]	[GW]	[TWh]	[GW]	[TWh]	[TWh]
North America							1,800
Latin America							1,564
Western Europe							1,293
Eastern Europe							880
FSU							2,104
Middle East							1,484
Africa							1,548
China							3,775
Southern Asia							1,420
Pacific Asia							4,675
Pacific OECD							337
Total world	1.428	2	195	274	3,190	7,368	20,880

IIASA's figure of 1,548 TWh for Africa in 2100 is about 20 percent of the projected global generation according to EPIA in 2040 (7,368 TWh). The 'technical' potential of regions like Africa and the Middle East is much larger than the estimates of IIASA suggest, taking account of the shear surface of the Sahara. The same holds for other world regions near the equator.

Much caution is needed with regard to the prospects of PV, not only because its future costs are uncertain, but also because PV is an intermittent renewable energy source. An advantage of PV is the predictability of day/night variations. Also advantageous is the similarity between the daily supply curve of PV and the corresponding electricity demand pattern, particularly in case of a climate that requires air conditioning.

However, in Europe and other regions at higher latitudes the strongly seasonal pattern of supply from PV does not fit with the electricity demand pattern. Therefore, with increasing capacities of PV provisions have to be made such as load management. Alternatively, inequalities between supply and demand for electricity may be matched by short- and long-term electricity storage systems that are available today (pumped hydro storage) or the stage of RD&D.

5. CONCLUSIONS

This study gives an analysis of the potential of cost reduction for onshore wind, offshore wind, and photovoltaic power. The process of cost reduction is driven by the amalgam of technological development and increasing sales. Wind energy has developed fast in Western Europe (the EU-15, Switzerland, and Norway). Reasons for sluggish growth are planning issues, lengthy approval procedures, and sometimes lack of financial incentives. Still, there is scope for improvement. Also, the upcoming offshore wind market offers new perspectives. Although Europe has the lead, non-European countries – the USA, China and India – are crucial as well, because of their sheer dimensions, population, wind climate, and electricity demand.

Cost reduction for onshore wind is based on a number of factors. Firstly, cost reduction may be linked to learning effects experienced in the past. Progress ratios are determined for key components of a wind turbine, viz. rotor & nacelle, tower, and other costs (civil work, infrastructure, and grid connection). Secondly, the specific investment cost of a state-of-the-art wind farm may be estimated, viz. € 900/kW in 2000. Thirdly, a company's view on market potential until 2020 and a corresponding cost reduction is used as a yardstick. The result is a scenario for onshore wind until 2030. Application of progress ratios for turbine components gives an specific investment cost of € 590/kW (*default*) or possibly € 560/kW ('*low'*) in 2030.

Fairly modest progress ratios applied to wind turbine components may be attributed to:

- Rather modern wind turbines with capacities from 500 kW to 2.5 MW.
- Limited potential for further upscaling, the main driver for cost reduction so far.
- Small learning effects for towers that are more and more sourced from local manufacturers.
- Minor learning effects for civil work, infrastructure, and grid connection.
- Cost reductions of 10-34% for production volumes ranging from 1,000 to 30,000 turbines.

The cumulative capacity of onshore wind may increase from 18,36 GW in 2000 to 400 GW in 2020 (according to Enron Wind Corp) and 860 GW in 2030, with an annual addition of 48 GW in 2025. The investment cost of € 590/kW (*default*) in 2030 is in accordance with an estimate from Enron, as well as from another study on learning effects of various energy technologies. The utilisation of the economic potential of onshore wind from a study by Garrad Hassan for a cut-off level of 6 ¢/kWh is fairly modest, e.g. around 30% for Europe. Further growth towards 2100 is generally not limited by wind potential but by economic and other considerations.

Data have been assembled of offshore wind farms that have been realised, or are in various stages of preparation. A distinction is made between near-shore and offshore windfarms.

The cumulative capacity of near-shore wind could increase from 0.09 GW in 2000 to 69 GW in 2030 (nearly 10 doublings). Based on progress ratios for turbine components, and an initial cost of € 1,375/kW in 2000, the specific investment cost could come down to € 885/kW (*default*) or possibly € 755/kW ('*low'*) in 2030. Near-shore wind could become nearly as competitive as onshore wind. The higher capacity factor of near-shore wind (approximately 36% vis-à-vis ~ 24%) might nearly outweigh the higher specific investment cost compared to onshore wind.

The cumulative capacity of offshore wind is assumed to increase from 0.16 GW in 2002 to approximately 205 GW in 2030 (more than 10 doublings). Taking account progress ratios for turbine components, and an initial cost of € 1,700/kW in 2002, the specific investment cost could come down to € 1,140/kW (*default*) or possibly € 970/kW ('*low'*) in 2030. Offshore wind will remain more costly than onshore wind. The higher capacity factor of offshore wind (about 40% vis-à-vis ~ 24%) is not sufficient to outweigh the higher specific investment cost.

The principle of photovoltaic power (PV) is rather straightforward, and it offers a tremendous potential for small- and large-scale application due to its modular character. The challenge is to make PV an economically viable option. The efficiency of solar cells may be increased, and the lifetime may be prolonged by prevention of significant degradation. Also, consumption of materials – high-grade silicon, precious metals – may be reduced to low and 'sustainable' levels. Last but not least, continued research and development as well as advanced large-scale production processes may well make PV more and more competitive in the long term.

The initial investment cost of € 5,400/kW for grid-connected 'single-family' PV systems in 2000 is based on US experience, viz. $ 5,600/kW for grid-connected systems, and the projected cost of a 13 MW solar plant in Murcia, Spain ($ 5,000/kW). The distribution of the cost in 2000 between modules, inverter & cabling, and installation (74%, 14%, and 12% respectively) is based on an estimate of a Dutch consultant. A progress ratio (PR) of 0.8 for modules (based on past experience) and more modest PRs for inverter & cabling and installation are applied to a scenario of the European Photovoltaic Industry Association (EPIA). The specific investment cost may come down by a factor 5 to 7 to € 950/kW (*default*) or € 790/kW ('*low'*) in 2035.

Such a cost reduction is confirmed by another study on learning effects for various energy technologies. This scenario presumes a co-ordinated policy from governments and industry. The scenario implies more than 10 doublings of the cumulative installed capacity compared to 2000. The growth of PV capacity after 2035 is limited by economic factors and by the intermittent nature of a renewable option like PV, rather than by its technical potential.

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