THE POTENTIAL OF WIND ENERGY TO REDUCE CO2 EMISSIONS

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Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) evaluates technologies that can be used to mitigate greenhouse gas emissions and identifies targets for useful R&D. IEA GHG has so far concentrated mainly on assessment of separation and storage of CO_2 from power stations, although studies on various other methods of greenhouse gas abatement have also been carried out. To put these assessments into context, alternative greenhouse gas mitigation options need to be assessed using the same technical and economic assumptions. Published studies often use widely different assumptions, which are not always apparent from the reports.

This study is the first in a series of studies by IEA GHG to assess the costs and potentials of alternative greenhouse gas abatement options for electricity generation. Wind energy was selected for the first of these studies because it is a relatively proven technology, with low costs and a large potential capacity for CO_2 abatement. About 4 GW of wind energy generating capacity was installed during 1999, bringing the global total to nearly 14 GW.

The study was carried out by Garrad Hassan, an international wind energy consultancy based in the UK, and ECON, an international economic consultancy based in Norway.

Approach Adopted

The study concentrated on four regions: the EU, the USA, India and China. These regions were chosen because they account for a large proportion (over 60%) of global CO_2 emissions and they include a broad range of wind resources and electricity generation systems. Less detailed analyses were produced for the rest of the world, broken down into six regions: Africa, Australia, the Former Soviet Union and Eastern Europe, Latin America, the Middle East and the Rest of Asia. Supply curves for wind energy in each of these regions were estimated. Costs of avoiding CO_2 emissions were then determined by comparing electricity generation system costs with and without wind energy.

The analysis consisted of the following stages:

- Computer modelling techniques were used to assess the wind energy resource in each of the main study regions, broken down into 1km squares.

- Environmental and technical constraints on wind farm siting were applied to eliminate, for example, sites with steep local gradients, nature conservation areas and forests. Social constraints were then applied to limit the number of wind turbines that could be installed in a given area and to prevent wind turbines being sited close to houses. Further information on this is given below.

- Electricity generation costs were calculated based on the wind resource estimates and wind turbine performance and cost data. Electrical grid connection and transmission costs were included. Transmission costs in the main study regions were based on typical transmission distances for each state, province or country.

- The types of electricity generating plant that would be displaced by wind energy in each study region were determined and their costs and CO_2 emissions were estimated.

- The net costs of abating CO_2 emissions were calculated by comparing the costs of electricity systems with and without wind energy. Electrical system effects were included, for example the increased need for back-up fossil fuel fired generation.

It was considered that onshore wind energy could develop along two rather different patterns: those currently typical of Northern Europe – small wind farms widely scattered, termed the "Small Onshore Scenario" – and those currently typical of the USA – large wind farms concentrated in favourable areas, termed the "Large Onshore Scenario". It is not clear which pattern of development will predominate in the future, as this will depend on public acceptability, so it was decided to model both scenarios in all regions. The two scenarios were modelled by applying a criterion of maximum wind farm density over different areas. In the small wind farms scenario the land was divided into 20x20km blocks and the criterion was applied to each of these blocks. In the large wind farms scenario it was applied over a broader area: individual states in the USA and India, provinces in China and countries in the EU. The maximum density criterion (150 kW/km^2) was based on experience in Denmark, where the concentration of wind turbines in some localities is considered to be close to acceptable limits. However, it is recognised that this criterion may not apply in all regions. The other difference between the two scenarios is that the wind farm capital cost is lower in the large wind farms scenario ($1000/kW compared to $1217/kW in the small wind farms scenario). These are "typical" year 2000 costs. The costs varied by location according to estimated electrical connection costs.

Offshore wind farms were considered as a third scenario. It was assumed that offshore wind farms could not be built closer than 5km to the shore, because of public acceptability, further than 40km, because of electrical and access costs, or in water deeper than 40m, because of high foundation costs. 75% of the area within these constraints was assumed to be excluded due to unsuitable seabed conditions, shipping lanes, marine conservation areas etc. The cost of offshore wind farms varied in this study according to estimated electrical connection costs, the distance to shore and the depth of water - the typical year 2000 cost was $1676/kW.

Results

Wind energy availability
Environmental, technical and social constraints on the siting of wind farms are all significant factors that greatly affect the potential for electricity generation from wind. The effects of these constraints for large and small onshore windfarms in each of the main study regions are shown in figure 1 (note the log scale).

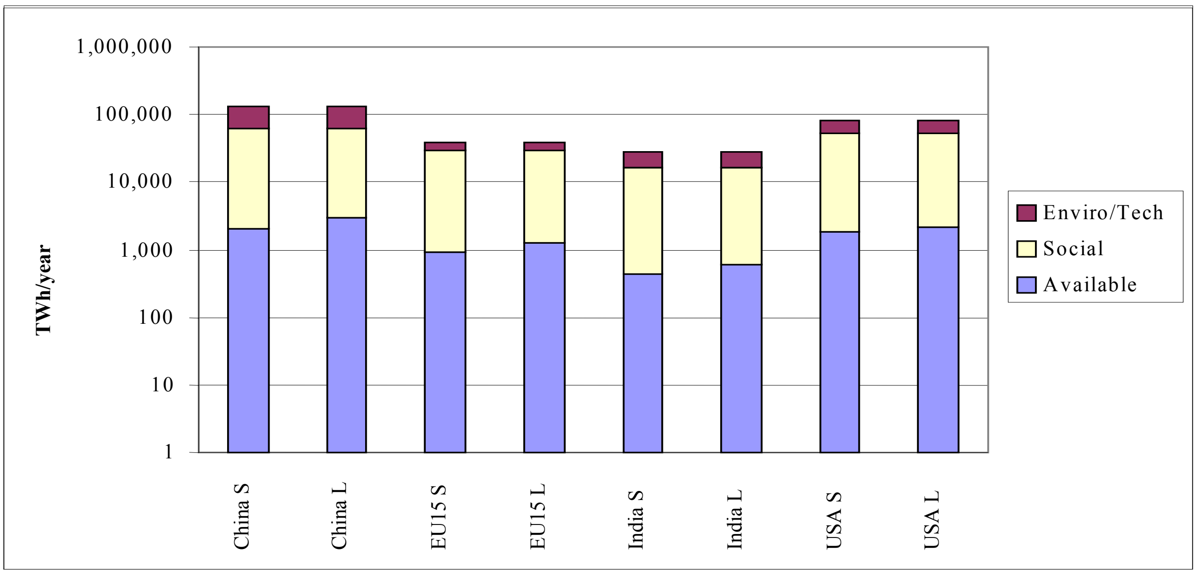

Figure 1 Effects of onshore wind farm development constraints (S = small L = large)

The environmental and technical constraints, described earlier, reduce the potential electricity generation by about 25-50%. The social constraints result in an even greater proportional reduction in the wind energy potential. For example, the total wind resource in the EU is estimated to be nearly 40,000 TWh/y. Environmental and technical constraints reduce this to about 30,000 TWh/y and the social constraints in the large wind farms scenario reduce the potential electricity generation to about 1,300 TWh/y.

A maximum of 2.5% of the total land area would be used for wind farms in any of the main study regions and scenarios. The area of land occupied by the turbines and infrastructure would be typically no more than 2% of this, i.e. about 0.05% of the total land area. It is a matter of judgement whether this would be acceptable.

Cost of electricity

Marginal cost of supply curves for wind energy for each of the study regions and scenarios are included in the main report. Cost curves are provided for the year 2000, based on current costs, and for 2020, based on predicted 1% per annum cost savings over the next 20 years. The predicted capital costs of wind farms in 2020 are 82% of current costs. A sensitivity study, described later, was carried out to assess the effects of greater cost reductions. The costs include electrical transmission and distribution costs but exclude costs of electrical system effects, which become significant when wind energy supplies more than 10% of the total electricity demand, as discussed later.

The wind energy supply curve for the EU in 2020 is shown as an example in figure 2. To put this in context, the electricity demand in the EU in 2020 is projected to be about 3000 TWh. These results assume no additional cross-border electricity trading between the countries within the EU as a result of the introduction of large-scale wind generation.

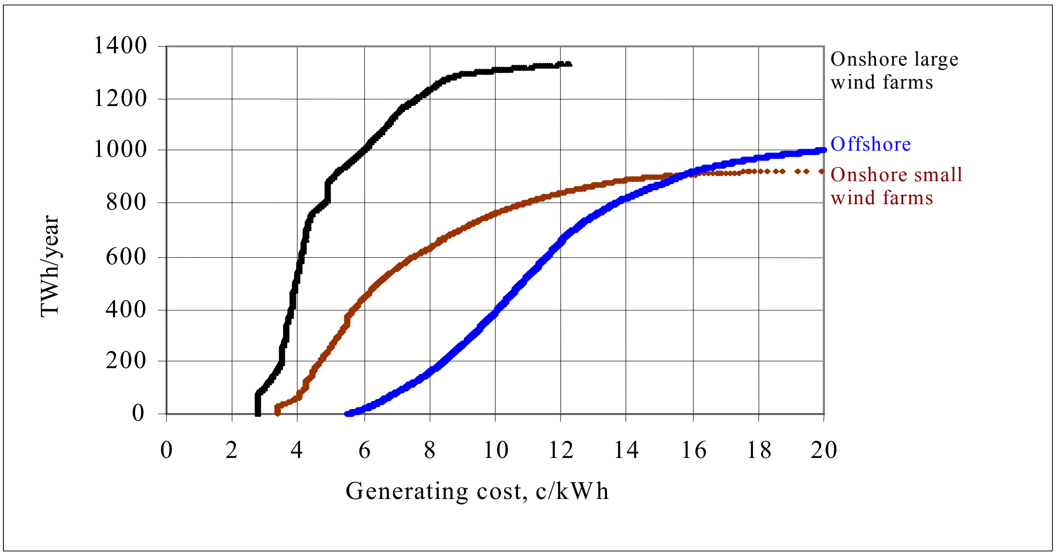

Figure 2 Cost of wind energy in the EU in 2020

Figure 2 shows that the cost of wind power increases as the amount of electricity generated increases because less favourable sites for wind turbines have to be used. Costs are lower in the large onshore wind farms scenario than in the small wind farms scenario because the capital costs are lower and because the wind farms are concentrated in the windiest areas, resulting in higher capacity (load) factors. Costs are highest in the offshore wind farms scenario. This is true to varying degrees in all of the regions.

System effects

Wind is an intermittent energy source. Typical electricity grids can accommodate small amounts of wind energy without significant effects but as the proportion of energy supplied by wind increases, the overall system effects increase. Additional peaking generation is required, which is not only more expensive than base load generation, but peaking plants (eg open cycle gas turbines) tend to operate at lower efficiencies than base load plants, resulting in higher CO_2 emissions. Extra fossil fuel fired back-up generating capacity has to be installed to cope with times when wind energy availability is low. In addition, as wind energy moves beyond about 25% of total generation, an increasing proportion of the wind energy will have to be curtailed to ensure system reliability. All these system effects add significantly to the overall cost and are largely a function of wind's share of total generation. These costs are therefore added to the base wind supply curve in order to calculate the generation system cost and the cost of the avoided greenhouse gas emissions.

The system costs depend on the other types of generating plant on the grid. Existing hydro power plants may be able to provide some of the additional peaking generation required when wind energy is introduced to the grid. However, if the grid includes a large amount of relatively inflexible generating capacity, such as nuclear power, the hydro plants may already be fulfilling this role and there may not be any spare peaking capacity. The system penalties of wind energy are expected to be lowest in regions, for example China, which have relatively large hydro and low nuclear generating capacities.

Displaced electricity generation
Wind turbines installed between now and 2020 would mainly displace new fossil fuel fired electricity generating plant. The types of plant that would be displaced by wind energy would be different in different regions. In China and India most of the new generating capacity installed between now and 2020 is expected to be coal fired. In the EU most of the new plant is expected to be natural gas fired, while in the USA there is expected to be more of a mixture of coal and gas. The emissions of CO_2 per kWh of electricity are much greater for coal fired plant, and thus the quantity of CO_2 emissions avoided per kWh of wind energy in China and India in 2020 is predicted to be about twice as much as in the EU. From this point of view, the EU is not the best region for CO_2 abatement by wind energy. However, the relatively low initial cost of wind energy and the relatively high cost of fossil fuel power generation means that the initial cost of emissions avoidance in the EU is lower than in the other main study regions.

Technical potential to avoid greenhouse gas emissions
The technical potentials for avoiding greenhouse gas emissions in the main study regions (China, the EU, India and the USA) in 2020 and the resulting costs are shown in figures 3a-3d. To put the emissions in figure 3 in context, the projected CO_2 emissions from power generation in 2020 in China, the EU, India and the USA are 2190, 950, 920 and 2170 Mt/y respectively. Corresponding emissions in 2000 are 1120, 820, 470 and 1870 Mt. Such estimates assume that wind turbine manufacture can be scaled up fast enough to cope with such massively increased demand and that planning permission can be obtained for all wind farms and grid reinforcements modelled. Any shortfall in either respect will reduce the capacity installed and thus the level of emissions avoided.

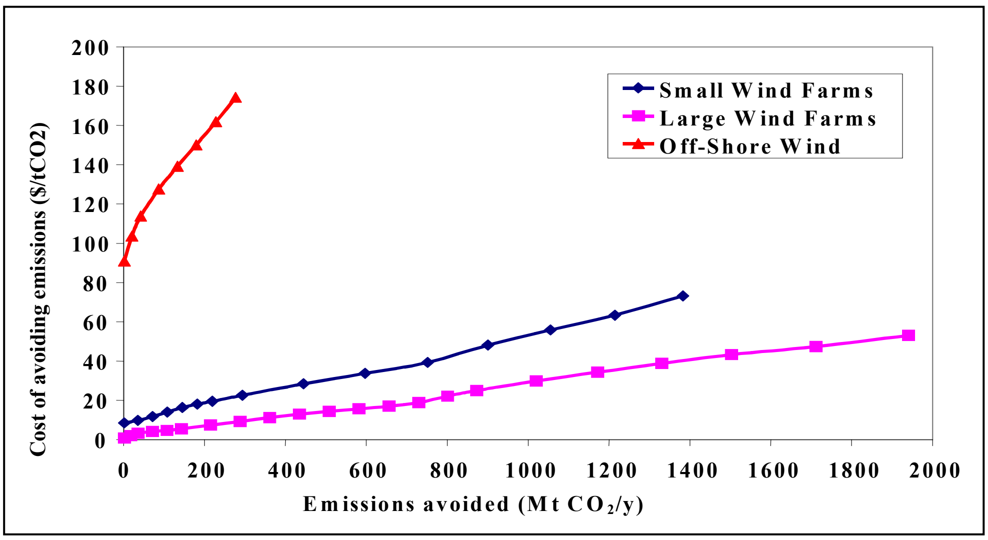

Figure 3a   Costs of avoiding emissions in China in 2020

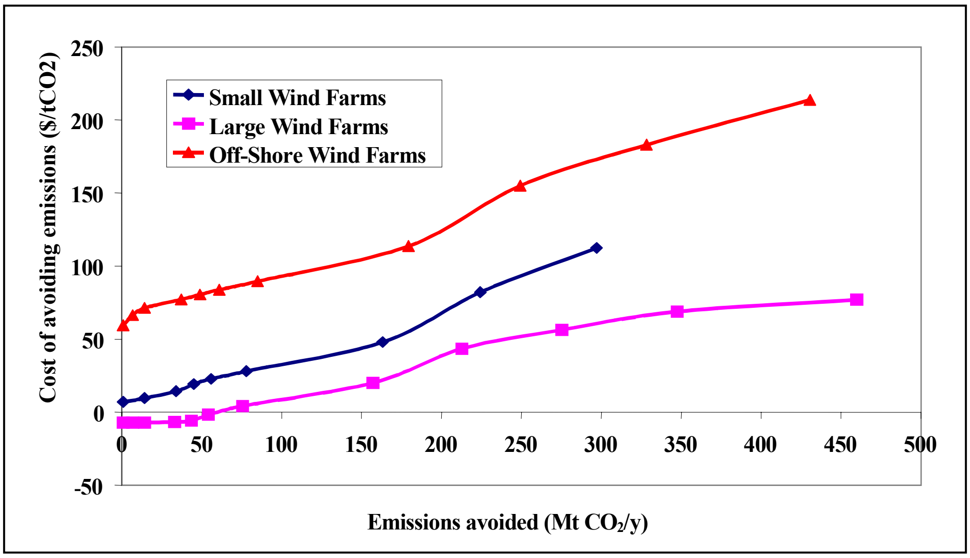

Figure 3b   Costs of avoiding emissions in the EU in 2020

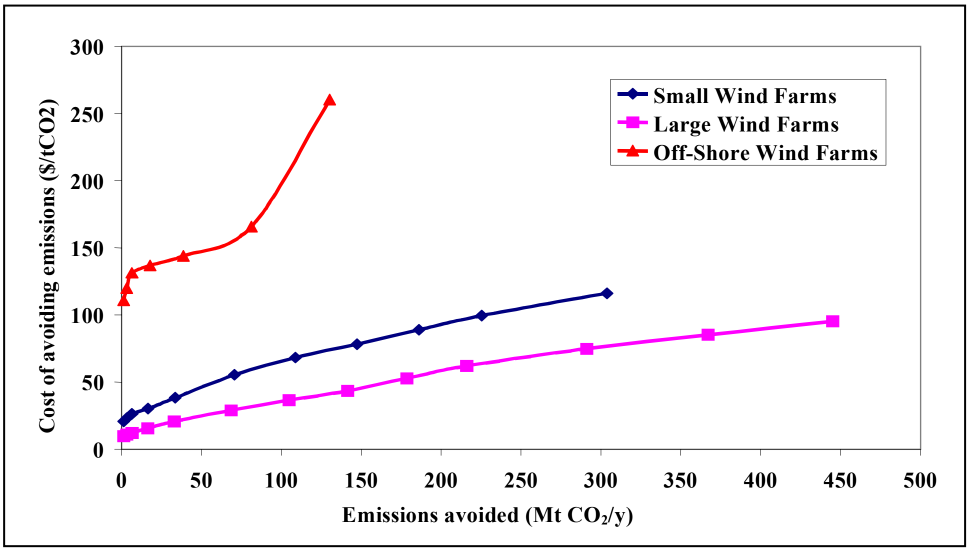

Figure 3c   Costs of avoiding emissions in India in 2020

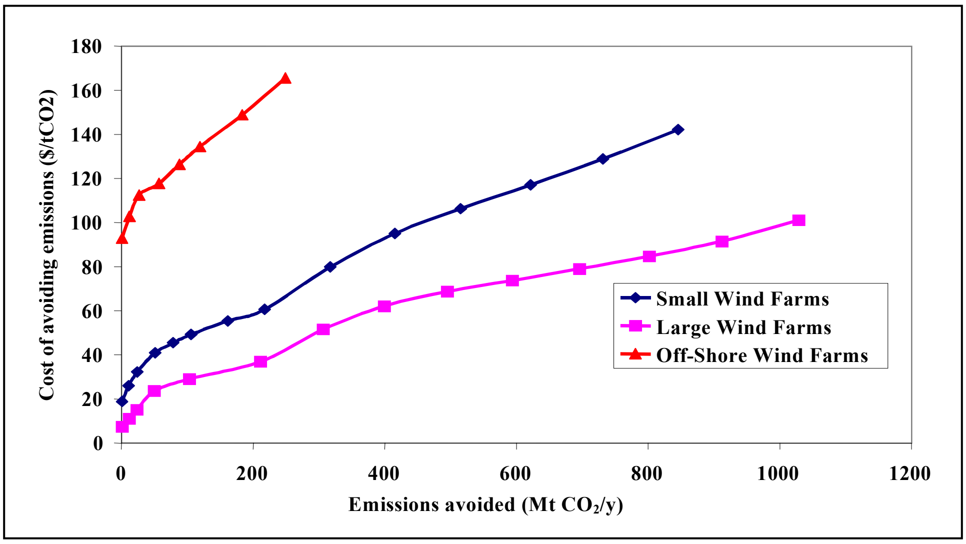

Figure 3d   Costs of avoiding emissions in the USA in 2020

The lowest initial cost of avoiding CO_2 emissions is in the large wind farms scenario in the EU, where about 60 million tonnes/year of CO_2 can be avoided at negative costs, because the cost of generating electricity from wind energy at the best sites is lower than the cost of generating from fossil fuels. The greatest potential for low cost emissions avoidance by wind energy in the four main study regions is in China. In the main study regions overall, about 1300 million tonnes/year of CO_2 emissions could be avoided in 2020 in the small wind farms scenario at a cost of $50/t CO_2 emissions avoided. About 2500 million tonnes/year of CO_2 emissions could be avoided at a cost of $50/t in the large wind farms scenario. To put this in context, the total emissions of CO_2 from power generation in the main study regions in 2020 is projected to be about 6200 Mt/y. The cost of avoiding CO_2 emissions by offshore wind energy is greater than $50/t in all of the study regions. However, the potential for future cost reductions for offshore wind farms may be greater than for onshore wind farms.

The potential for avoiding CO_2 emissions in the rest of the world was assessed in less detail than for the four main study regions. Overall, the proportion of total CO_2 emissions from power generation that could be avoided by wind energy in the rest of the world at a given cost is greater than in the main study regions. The rest of the world regions, on average, are not significantly windier than the main study regions but they tend to have lower population densities and/or per capita electricity consumptions. The rest of the world regions account for 83% of the global land area but only 39% of current power sector CO_2 emissions. A large proportion of the power sector CO_2 emissions in the rest of the world could be avoided by using only the most favourable wind sites. The potential for low cost emissions avoidance is largest in the Former Soviet Union and Eastern Europe but there is also considerable potential in Africa, Latin America and the Rest of Asia.

Sensitivity Studies

The sensitivities to wind farm capital cost, discount rate and electrical system costs were examined. To limit the amount of work required, the sensitivity studies were only carried out for the EU.

Wind farm capital cost

In the base case it was assumed that the average capital cost of wind farms built in 2020 would be 82% of current costs (based on a 1% per year reduction). Expected improvements in the costs and efficiencies of the fossil fuel power plants that would be displaced by wind energy were also taken into account. There is uncertainty about how much wind farm costs will decrease in future. This will depend on technical developments and manufacturing economies of scale, which will depend on how many wind turbines are built. A sensitivity study was carried out to assess the effects of reducing the average cost of wind farms built in 2020 to 64% of current costs (based on a 2.2% per year reduction). The net effect was to reduce the average cost of avoiding CO_2 emissions by about $15/t CO_2.

Discount rate

To conform with IEA GHG's standard assessment criteria, an annual discount rate of 10% was used as the base case and the effect of reducing the discount rate to 5% was examined in a sensitivity study. The same discount rates were applied to fossil fuel fired plants and wind farms.

Wind farms are more capital intensive than fossil fuel fired power plants, so low discount rates improve the competitiveness of wind energy and hence reduce the cost of avoiding CO_2 emissions. The effect of reducing the discount rate from 10% to 5% in the large wind farms scenario is to reduce the average cost by about $15/t$CO_2$. The effects are somewhat greater in the other scenarios and tend to increase as the amount of emissions avoided increases.

Electrical system costs

As discussed earlier, the intermittent nature of wind energy results in significant electrical system costs. There is uncertainty about the magnitude of these system costs because no large grids have been operated with high levels of wind energy. The costs also depend on local conditions, such as the timing of peak electricity demand and wind availability. A sensitivity study was carried out to quantify the electrical system effects included in this study. At 200 Mt/y of CO_2 emissions avoided in the EU large wind farms scenario, the system effects account for about $20/t of CO_2 avoided and at 400 Mt/y of emissions avoided they are equivalent to nearly \$40/t CO_2. The total CO_2 emissions from power generation in the EU in 2020 are projected to be 950 Mt/y. As the electrical system costs are predicted to have a large effect on the overall costs of avoiding emissions, and are subject to significant uncertainty, more research should be carried out on this subject.

Discussion

Implications of wind energy for other low-CO_2 power generation technologies

This study indicates that wind energy could make a significant contribution to reducing CO_2 emissions from power generation. This has implications for other low-CO_2 power generation technologies. Studies carried out to date by IEA GHG and others have usually assumed that other low-CO_2 power generation technologies will operate at base load to make maximum use of the expensive CO_2 abatement equipment. However, if large amounts of intermittent renewable energy such as wind energy are used in future, the opportunities to operate other power plants at base load will be reduced. It will be important to ensure that other low-CO_2 power generation technologies are able to operate flexibly and with rapid response rates to enable them to be used in combination with wind energy and other intermittent energy sources.

This study assessed the large scale addition of wind energy to electricity systems that consist mainly of fossil fuel fired power plants, together with some nuclear and hydro plants. To determine the optimum combination of technologies for abatement of CO_2 emissions, system studies including wind energy and a variety of other low-CO_2 power generation technologies would be required.

Type of cost curves

The cost curves for electricity generation from wind energy in this study are *marginal* cost curves built up from costs of individual wind farms. For example in figure 2, if 1000 TWh/y of electricity is already being provided by wind energy in the EU, the cost of providing a further 1 kWh/y would be about 6c/kWh in the large wind farms scenario. In contrast, the costs of abating CO_2 are derived by modelling the overall electricity supply system. This analysis produces an overall cost of operating the system with a given amount of wind energy, and the quantity of emissions avoided. The analysis is repeated by modelling different amounts of wind energy in the system. The results from these model runs are plotted to give a cost curve showing the overall *average* system costs of avoiding CO_2 emissions.

Average cost curves are the best way of showing the overall cost of avoiding a given quantity of emissions (the cost, as shown in figure 3, can be multiplied by the quantity of emissions, to give the overall cost, in \$). *Marginal* cost curves are useful for showing the breakeven between different options, as discussed below.

Approximate *marginal* costs of avoiding CO_2 emissions in the small wind farms scenario in the EU in 2020 were derived from the *average* cost curves, for the purposes of this summary, and are shown in figure 4. This shows the significant difference between *marginal* and *average* cost curves for wind energy.

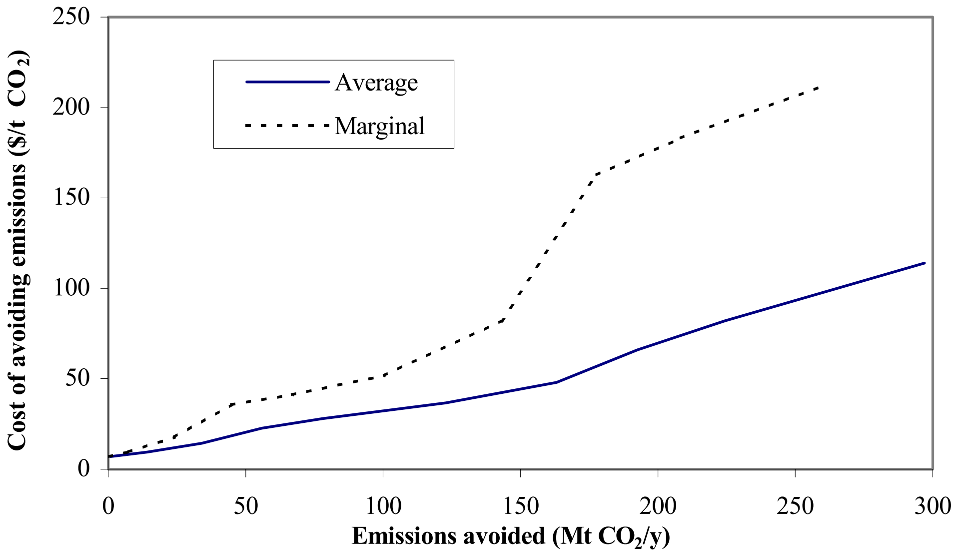

Figure 4 Marginal and average system costs – EU small wind farms scenario

Figure 4 shows that, for example, the first 100 Mt/y of CO_2 would be abated at *marginal* costs of less than $50/t. A further 70 Mt/y of emissions would be abated at *marginal* costs of between 50 and 140 $/t CO_2. The overall *average* cost of abating the first 170 Mt/y of CO_2 would be $50/t.

Other studies carried out by IEA GHG have shown that CO_2 capture and storage, an alternative CO_2 abatement technology, has costs of about $50/t CO_2 emissions avoided, compared to base load fossil fuel power generation without CO_2 capture. The least cost strategy for avoiding CO_2 emissions in the EU small wind farms scenario would be to use wind energy to avoid the first 100 Mt/y of emissions at *marginal* costs less than $50/t CO_2 and then to capture and store CO_2 at a *marginal* cost of $50/t CO_2. The electrical system costs in this study are based on costs for existing power generation technologies. If fossil fuel power plants had to include CO_2 capture and storage, the system costs may be higher and the breakeven between wind energy and CO_2 capture and storage may be different.

Expert Reviewers' Comments

A draft version of this report was sent for review to 10 experts on wind energy and power systems worldwide. Most of the reviewers commented that it was a good, comprehensive study.

Experts at the National Renewable Energy Laboratory (NREL) in the USA provided detailed comments on the wind resource assessment. They also provided additional wind resource data for the USA. The wind resource estimates in this study were revised in view of these comments and data.

A wind turbine manufacturer thought that the wind farm capital costs were too high, by about 10% onshore and 15-20% offshore. They also expected costs to decrease more rapidly than in the study base case and they expected greater cost reductions for offshore wind farms. One of the sensitivity cases in the study considered the effects of a more rapid cost reduction. In contrast, a power utility commented that the cost-capacity curves seemed optimistic.

Major Conclusions

The cost of avoiding greenhouse gas emissions by wind energy can be very low, or even negative, for the most favourable sites but costs increase as less favourable sites are used and electrical system costs increase. This leads to a rising cost of supply as the amount of wind generation increases.

Public acceptability will determine how many wind turbines can be installed, and where. Costs are significantly lower in a large wind farm scenario where wind turbines are concentrated on the windiest sites rather than being more evenly distributed throughout a country. In essence there is a trade-off between the cost of wind energy and local planning considerations driven by public perceptions of wind energy. Experience to date suggests that perceptions vary considerably between countries and even within local communities.

In the main study regions (China, the EU, India and the USA) overall, the technical potential for avoiding CO_2 emissions from electricity generation in 2020 in a small wind farms scenario at an average system cost of \$50/t CO_2-avoided is about 1300 Mt/y. The corresponding technical potential in a large wind farms scenario is about 2500 Mt/y of CO_2-avoided. Such estimates assume that wind turbine manufacture can be scaled up fast enough to cope with such massively increased demand and that planning permission can be obtained for all wind farms and grid reinforcements modelled. Any shortfall in either respect will reduce the capacity installed and thus the level of emissions avoided.

There is also a large potential for low cost emissions avoidance in the rest of the world, in particular the Former Soviet Union and Eastern Europe, Africa, Latin America and the Rest of Asia.

In some regions, notably the EU, large amounts of wind energy are available offshore. Costs for offshore wind farms are in general significantly higher than for on-shore wind farms at the best sites. However, offshore wind farms are at an early stage of technological development, so there may be scope for greater cost reductions.

When wind energy provides a large part of the total electricity demand there are significant electrical system costs, such as the need for increased fossil fuel fired peaking generation. There is a high degree of uncertainty about these costs in future electrical systems. The introduction of a large amount of intermittent energy, such as wind energy, has implications for the design and operation of other generating plants on the grid.

Recommendations

This study has identified further work, which should be carried out by IEA GHG or others.

- There is scope for reducing the uncertainties in this study through more detailed studies of individual regions, countries, states or provinces. The present work has prepared the way for such studies, and the method may be adapted for replication over a smaller geographical range.

- Further sensitivity studies should be carried out, for example to assess the effects of different social constraints on wind farm development.

- Similar studies should be carried out to assess the costs and potentials of other renewable energy technologies for abatement of greenhouse gas emissions.

- The implications of large scale use of wind energy on the design, operation and costs of other low-CO_2 power generation options should be assessed.

- To determine the optimum combination of technologies for abatement of CO_2 emissions, system studies including all of the main options should be carried out.

THE POTENTIAL OF WIND ENERGY TO REDUCE CARBON DIOXIDE EMISSIONS

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1 INTRODUCTION

1.1 Study Background

Acknowledgement of the potential of anthropogenic greenhouse gas emissions to cause climate change has resulted in national and international commitments to reduce emissions of the principal greenhouse gas, carbon dioxide (CO_2). The IEA Greenhouse Gas R&D Programme has commissioned a series of studies investigating the technical and economic feasibility of CO_2 mitigation options within the energy sector, beginning with sequestration measures.

This report describes a study of the potential of large scale wind energy to reduce CO_2 emissions by displacing fossil fuel use in the electricity generation sector world-wide. Wind energy is one of several renewable energy technologies which have extremely low life-cycle CO_2 emissions, and is currently the fastest growing electricity generating technology in the world[1]. This study and report are intended to be the first in a series of assessments of the world-wide potential of different renewable energy technologies to reduce CO_2 emissions.

The study objectives and scope of work were initially defined by the IEA Greenhouse Gas R&D Programme in their Technical Specification IEA/CON/98/39, and supplemented by another Technical Specification IEA/CON/99/60. The end results of the study are global abatement cost curves indicating how much CO_2 emission could be avoided, and at what cost, by large-scale deployment of wind energy in year 2020 in a competitive electricity market.

The work was undertaken from September 1998 to June 2000 by Garrad Hassan and Econ. Garrad Hassan, an independent international wind energy consultancy registered in the UK, was responsible for all wind energy aspects of the work and for project management and reporting. Econ, an international economics consultancy registered in Norway, was responsible for modelling the impact of wind energy on existing generating plant mix under realistic market conditions.

1.2 Study Approach

1.2.1 Analytical method

The world was divided for the purpose of this study into ten regions encompassing all countries with significant anthropogenic CO_2 emissions. Four of these regions were analysed in detail, and the remainder analysed using a simplified method.

Three large scale grid-connected wind energy "scenarios" were modelled for each region:

- Small onshore wind farms
- Large onshore wind farms
- Large offshore wind farms

The analysis for each region was in two stages – generation of cost-resource curves for each scenario in 2000 and 2020 by Garrad Hassan, and generation of cost-abatement curves from these by Econ. The steps within each stage are summarised overleaf and described more fully later in this report and in the Appendices.

[1] Percentage, rather than absolute, growth of installed capacity per year.

1.2.2 Wind energy cost-resource curves

1. Wind resource: Long term mean wind speeds at turbine hub height (50 m onshore, 60 m offshore) were estimated for each 1 km square.
2. Constraints: Areas where development was judged to be prohibited by technical and/or environmental constraints (urban areas, forests, lakes, protected areas and rugged terrain onshore, water depth >40 m and sea areas <5 km or >40 km from land offshore) were removed from the analysis.
3. Annual energy yield (AEY): The amounts (MWh/year) of energy from hypothetical wind farms sited on each remaining square were calculated from estimated mean wind speed and air density. Capacity increments modelled were 6 MW/km^2 (8 × 750 kW turbines) onshore and 8 MW/km^2 (4 × 2,000 kW turbines) offshore.
4. Lifetime project cost (LPC): The costs (c/kWh) of energy from hypothetical wind farms sited on each remaining square were calculated from AEY and generic cost assumptions. Onshore electrical costs were determined by proximity to the transmission grid and local demand estimated from population density. Offshore civil and electrical costs were determined by water depth and distance to shore respectively.
5. Social acceptability: Onshore capacity was further constrained by local population density to limits comparable with current planning in Denmark. The overall capacity density limit of 0.15 MW/km^2 was applied differently in the small and large onshore scenarios.
6. Offshore constraints: Offshore capacity density was uniformly “thinned” by 75% to allow for possible constraints such as unsuitable sea-bed conditions, shipping lanes and marine conservation areas.
7. Cost-resource curves: For each scenario and region in turn, marginal cost curves of cumulative capacity and cumulative AEY for LPCs up to 20 c/kWh were generated assuming installation in years 2000 and 2020.

1.2.3 Carbon dioxide cost-abatement curves

Figure 1.1 overleaf provides a brief outline of the method used in the study to generate the wind energy carbon dioxide abatement curves. It should be noted that these curves show average cumulative, rather than marginal, costs.

The wind supply marginal cost curves were fed into Econ’s power sector model for each study region. The impacts of additional wind on the carbon dioxide emissions from the power sector and the overall system generating costs were determined by comparing the results with and without wind energy generation. The additional generating cost divided by the reduction in carbon dioxide emissions produced the wind energy carbon dioxide abatement cost, a measure of how much it costs to reduce carbon dioxide emissions by one tonne per year by introducing wind power into the generation mix.

If the contribution from wind is varied, the level of emissions and costs also varies. This enables a wind energy carbon dioxide abatement supply curve to be produced showing how the average abatement costs increase with the amount of wind energy. Alternatively, the dependence of average abatement costs on the level of annual carbon dioxide emissions abated by the introduction of wind can be shown. This latter approach enables the average cost difference between, say, reducing annual carbon dioxide emissions by 10 tonnes and 100 tonnes to be seen. In this manner it may be possible to determine up to what level of annual abatement it is cost effective to use wind energy to displace fossil fuels and, therefore, the cost effective level of wind energy generation required to reduce carbon dioxide emissions.

The key parameters in determining these costs are the additional system generating costs from incorporating wind energy into the generation mix, and the type of capacity wind displaces. The additional cost is a function of the wind supply costs and the generation cost of the displaced technology, as well as the share of wind in the total generation mix. The type of capacity displaced will determine the type of fuel displaced and ultimately the amount of carbon dioxide abated.

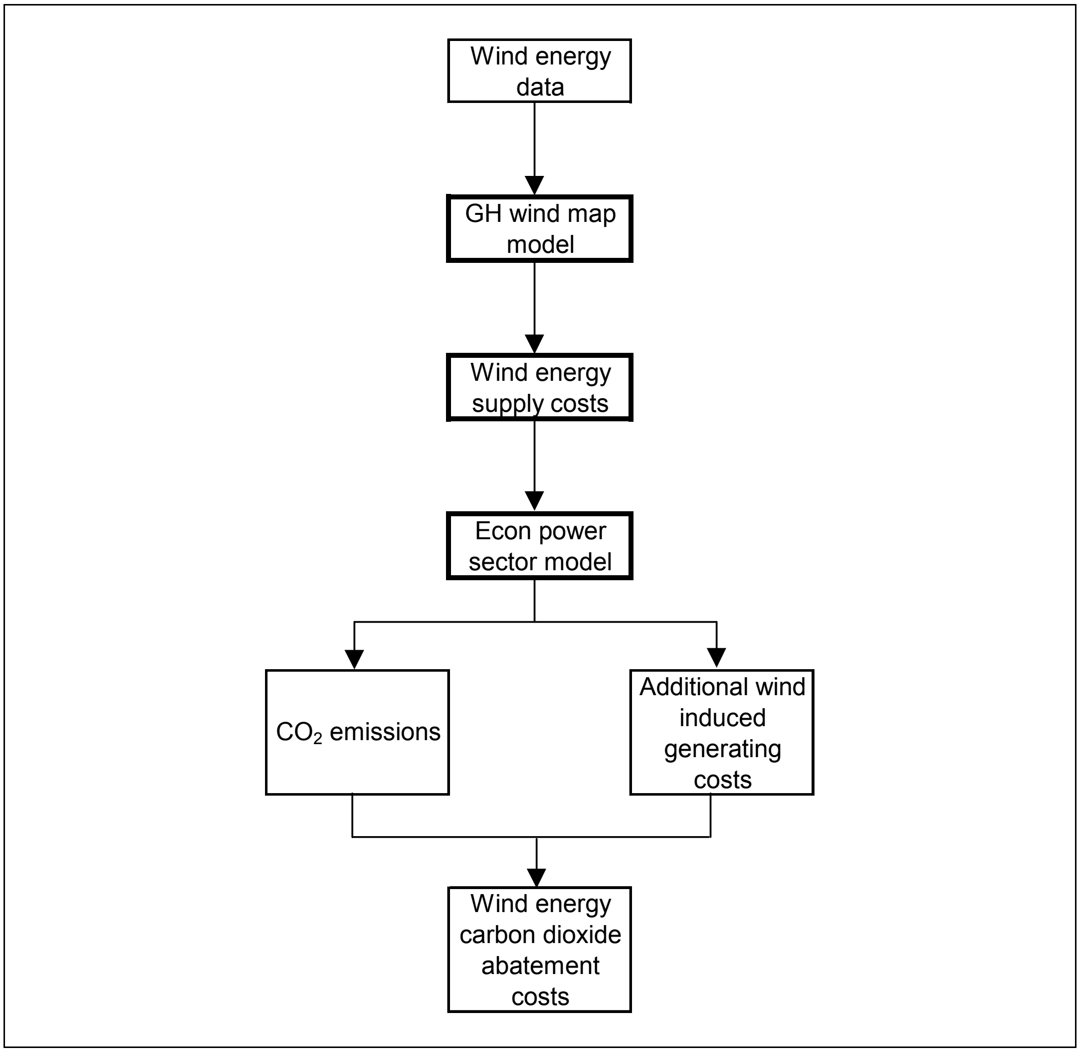

Figure 1.1: Overview of model methodology

The method adopted for this study was designed to capture the main elements in determining wind abatement costs with a reasonable level of confidence without creating too great a demand on data inputs. The high degree of uncertainty in some aspects of the work – for example the system costs associated with a very high share of wind energy in the total generation mix – implied that a practical and robust approach was required to produce a set of results with sufficient confidence.

Extrapolation to the rest of the world and global results

Extrapolation to the rest of the world was based on first order approximations. However, given the uncertainties elsewhere they represented a reasonable estimate of the wind energy carbon dioxide abatement costs in these regions. This can be seen as a screening process to indicate the least and most attractive potential regions for carbon dioxide abatement from wind energy.

The extrapolation did not require Econ's power sector model. Estimates from the study regions enabled a relationship between wind supply costs and the abatement costs per GWh of wind energy (adjusted for differences in existing generating costs) to be established. An assessment of the likely displaced generating capacity then enabled the amount of carbon dioxide abated as wind's share of total generation increases to be determined. With these estimates, and using total generation forecasts for the rest of the world regions, it was possible to estimate the wind energy carbon dioxide abatement costs. Factors which determine whether a region has a low abatement cost include the size of the wind resource and its associated supply cost, the type of existing capacity and therefore fuel displaced, and the existing generating costs.

The global results are the ranked outputs from all the regions.

1.2.4 Study regions

Four "study regions" were selected for detailed analysis as follows:

- Republic of China (excluding Hong Kong)
- EU-15 (Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, The Netherlands, Portugal, Spain, Sweden, United Kingdom)
- India
- USA (excluding Alaska and Hawaii)

Table 1.1 below shows the land area, population and annual electrical power generation sector CO_2 emissions in 2000 for each selected region and their combined share of world totals.

Region	Area ($km^2 \times 10^6$)	Population ($\times 10^6$)	Power sector CO_2 (t.p.a. $\times 10^6$)
World	148.8	5,700	7,000
China	9.6	1,221	1,121
EU-15	3.2	373	817
India	3.3	936	471
USA	9.8	263	1,869
Total	25.9	2,793	4,278
Proportion of World	**17%**	**49%**	**61%**

Table 1.1: Characteristics of the four study regions

The selected regions represent approximately one sixth of the world's land surface area, about half of the world's population and three fifths of the world's power sector CO_2 emissions. The results obtained for the study regions were extrapolated to the rest of the world which was divided, on the basis of existing fuel mix, into the groups listed (in alphabetical order):

- Africa (including Egypt)
- Australia (and Tasmania)
- The Former Soviet Union, Mongolia and Central and Eastern Europe (henceforth referred to as "FSU and Eastern Europe")
- Latin America (South and Central America and the Caribbean islands)

- Middle East (including Turkey, Afghanistan and Pakistan)
- Rest of Asia (SE mainland Asia, Indonesia, Japan, Taiwan and New Zealand)

Canada, Norway, Iceland, Switzerland, Alaska and Antarctica were omitted from the analysis due to their negligible potential for CO_2 emissions mitigation. This is not to say that these areas do not have a potentially economically exploitable wind resource, but that the carbon abatement potential is very low and/or the wind costs are so uncertain as to make any estimation of the carbon dioxide abatement cost virtually meaningless. In Canada, for example, the use of wind would need to displace other non carbon intensive technologies and the effective domestic abatement costs would be very high. Wind could be utilised for export to the USA if this results in costs lower than the USA's indigenous wind energy carbon dioxide abatement costs, but this is highly dependent on long range transmission costs. It was felt that the data availability and understanding of the USA resources and markets was such that the level of certainty of the results would be compromised by incorporating Canada in a North American region.

The exclusion of the non-EU countries of western Europe (Norway, Iceland and Switzerland) was done because aggregate data was more readily to hand for the EU-15 than for the western European region as a whole. The Icelandic system is isolated from other grids and is based on non-carbon technology, while Norway and Switzerland are both dependent on hydro power. Both Norway and Switzerland could export wind power, but this again runs into uncertainties over establishing transmission capacity to handle the exports. It was judged by Garrad Hassan and Econ that the wind potential, its location and its likely cost would not make such trade economically viable. For simplicity, and because it would not significantly compromise the results, Norway, Iceland and Switzerland were excluded from the analysis.

More generally, offshore wind energy potential was not modelled north of 70°N (i.e. along the north coast of the former Soviet Union) due to the anticipated technical difficulties resulting from sea ice and other severe environmental conditions.

1.2.5 Analytical parameters

The parameters of the analyses reflect the need to reconcile demands on staff and computing resources generated by a study of such scope and complexity with practical cost and timescale constraints. The principal comments on these parameters may be summarised as follows:

- Only large scale grid-connected wind energy projects were considered. The "base case" onshore wind farm was rated at 60 MW and capacity was incremented in 6 MW tranches in the analysis. Offshore equivalents were 200 MW and 8 MW respectively.
- Capital costs of wind energy projects, apart from electrical costs, were assumed to decrease at a rate of 1% per year. A sensitivity study was performed to assess the effects of increasing this rate to 2.2% per year.
- The computational wind flow modelling approach did not include localised winds and therefore under-estimated near-surface wind speeds in some areas.
- The three scenarios (small onshore, large onshore and large offshore wind farms) were treated separately and no attempt was made to model the potential of a least-cost combination of them.
- Assumptions about public acceptability, based on current information from the most mature wind energy market in the world (Denmark), were imposed:
    - Onshore installed capacity density was limited to a maximum of 0.15 MW/km^2. For the small wind farms scenario, this limit was applied to each 20×20 km area

modelled. For the large wind farms scenario, this was applied as a provincial (China), national (EU-15), or state (India, USA) limit.

- Offshore developments less than 5 km from the coast were excluded.
- Hub heights were limited to 50 m onshore and 60 m offshore. These are typical for current machines of the capacities assumed on medium to high wind speed sites. Taller towers are in use, notably in Germany where the wind resource is modest (wind speeds generally increase with height above ground level), but there is a trade-off between increased energy capture and capital cost.

- Onshore capacity was assumed to be embedded within local distribution networks unless output exceeded local demand, in which case the cost of grid reinforcement at higher voltages was estimated.
- Offshore capacity was always assumed to require transmission reinforcement which was costed in 200 MW increments.
- Reinforcement costs were estimated from studies of average distances from preferred wind areas to major load centres. No reinforcement across national boundaries was assumed.
- System effects, notably reserve margin and requirements for wind curtailment, were modelled in the analysis to allow for the intermittent and unpredictable nature of wind energy.
- Over the study period (2000 – 2020) the rollover of conventional generating plant and limitations on fossil fuel availability was assumed to be of secondary significance.
- Although interventionist market measures already exist in many countries and are discussed in Appendix D, no allowance was made for their potential to stimulate the growth of wind energy.
- No allowance was made for the external costs of any electricity generation process or technology.
- No allowance was made for large scale energy conservation measures in the electricity sector.
- No allowance was made for stranded costs of existing power plant.

All costs and prices presented in this report are in US Dollars (US$). The effects of inflation have been assumed to be constant across the board, and have been excluded from the analyses. All results are therefore at current prices.

1.3 Report Structure

Reporting of this study is in two parts – the Main Report (this document) and a second document containing the Appendices. The contents of these are as follows:

Main Report: Presentation of results with brief descriptions of method as required

Appendices: A: Detailed description of wind energy analyses by Garrad Hassan
B: Detailed description of emission reduction analyses by Econ
C: Standard assessment criteria used in the analyses
D: Detailed description of the influences of markets and regulation
E: Detailed results showing the cost of avoided CO_2 emissions

It is anticipated that most readers will be interested primarily in the results of the study. However, more detailed descriptions of the analytical methods and background assumptions used are offered for the benefit of those readers who may already be familiar with wind energy and wish to know how the results were generated.

A large number of acronyms are used in this report. Explanations of each are normally given when they first appear and they are also listed in the Glossary at the end of this document

The sections in this document fall into the following three groups:

1. Introductory remarks and generic observations in Sections 1 and 2.
2. Method and results of the wind energy analyses by Garrad Hassan in Sections 3 to 7 with system effects discussed in Section 8.
3. Method and results of the emissions reduction analyses by Econ in Sections 9 to 15.

The content of individual sections is previewed in more detail below.

Section 2 introduces readers unfamiliar with wind energy to key aspects of the technology and provides references for further reading.

Section 3 describes the analytical data, methods and assumptions used by Garrad Hassan to generate the results presented in Sections 4 to 7. Fuller details are provided in Appendix A.

Section 4 shows the potential for wind energy in the four study regions in the form of cost-energy and cost-capacity curves for the three wind energy scenarios in 2000 and 2020, and investigates further the differences between the small and large onshore wind scenarios.

Section 5 presents cost-energy curves in the same format for the six rest of the world regions in 2000 and 2020.

Section 6 presents cost-energy and cost-capacity curves in the same format for the EU-15 in 2020 using alternative discount rate and capital cost assumptions, and comments on their impacts.

Section 7 combines the results from all regions to present global cost-energy and cost-capacity curves in the same format for 2000 and 2020 and investigates further the differences between regions and scenarios.

Section 8 discusses system integration aspects of wind energy, providing the interface between Garrad Hassan and Econ's analyses.

Section 9 describes the analytical model and system integration assumptions used by Econ to generate the results presented in Sections 11 and 12.

Section 10 predicts the generation fuel mixes in the four study regions in 2000 and 2020 used by Econ to generate the results presented in Sections 11 and 12.

Section 11 explores the potential for CO_2 abatement in the four study regions.

Section 12 presents the potential for emissions reduction in the four study regions in the form of abatement cost curves for the three wind energy scenarios in 2000 and 2020 generated from the corresponding cost-energy and cost-capacity curves presented in Section 4.

Section 13 describes the analytical data, method and assumptions used by Econ to generate emissions reduction results for the rest of the world in the form of abatement cost curves for the three wind energy scenarios in 2000 and 2020, and presents these results. These were generated from the corresponding cost-energy and cost-capacity curves presented in Section 5

Section 14 presents results in the same format for the EU-15 in 2020 using alternative discount rate and capital cost assumptions, and comments on their impacts. The sensitivity of these results to additional peaking generation assumptions is also investigated.

Section 15 combines the results from all regions to present global results in the same format.

Finally, Section 16 draws succinct conclusions from the foregoing analyses and results.

1.4 Acknowledgements

This study was commissioned by the IEA Greenhouse Gas R&D Programme. Their financial support and thorough scrutiny are both gratefully acknowledged. This report draws together contributions from the following researchers (in alphabetical order):

- Dean Anderson (Econ): influences of markets and regulation
- Andrew Ellis (Econ): fuel mix and demand projections, generation of cost-abatement results
- Andrew Fellows (Garrad Hassan): project management and reporting
- Paul Gardner (Garrad Hassan): electrical costs and system integration
- Graham Gow (Garrad Hassan): GIS analyses, wind flow modelling, generation of cost-supply results
- David Robb (Garrad Hassan): C++ coding
- Helen Snodin (Garrad Hassan): data sourcing, GIS analyses

Thanks are also due to the numerous expert individuals and organisations with whom we have consulted in the course of this study, in particular Dennis Elliott and Marc Schwartz at the US National Renewable Energy Laboratory (NREL). While we have endeavoured to acknowledge such assistance explicitly at the appropriate junctures in this report and/or the appendices, we apologise now for any inadvertent oversights!

2 WIND ENERGY TECHNOLOGY

2.1 Introduction

It is beyond the remit of this study to provide a full description of wind energy technology. For a comprehensive and up-to-date review, the recent report for the European Wind Energy Association (EWEA) produced under the European Commission's "Altener" programme "Wind Energy – The Facts" [1] is recommended. A detailed set of predictions about wind energy technology developments, insofar as these are possible, is made in "Renewable energy technology characterisations", a joint project of the Office of Power Technologies, Energy Efficiency and Renewable Energy, the US Department of Energy and the Electric Power Research Institute [2].

2.2 Key Features

For readers who are totally unfamiliar with wind energy technology, the following key features may be useful:

- Wind turbines convert mechanical power from the wind into electrical power via a rotor connected to a generator. The power in the wind is proportional to the cube of the wind speed and to the air density.
- Wind energy is a capital-intensive technology with short construction times (typically a few months), low operating costs and zero fuel costs. The economics of wind energy are therefore more sensitive to discount rate and plant capital cost than, for example, are those of fossil or nuclear fuelled generation.
- Wind energy is a modular technology. Wind farms comprise arrays of wind turbines laid out to optimise energy yield subject to planning constraints.
- Wind energy is a de-centralised technology. Onshore wind farms are predominantly sited in rural areas and connected to the distribution network. Wind farms are typically remote from large centres of demand and also from conventional plant, with mixed implications for grid integration:
  - Wind farms may be very remote from the existing electrical infrastructure, or their output may exceed local demand, and therefore grid reinforcement and/or additional local power quality control measures may be required.
  - Wind farms may, through being embedded in the distribution network, help to offset transmission losses.
- Rated capacities of typical large grid-connected turbines currently range from about 600-1500 kW onshore and 750-3000 kW offshore.
- Individual wind farms in excess of 100 MW capacity have been built, and more than 14 GW of capacity has been installed world-wide. As of February 2000 the yearly growth rate was around 36%.
- Wind turbine design has converged to the extent that virtually all machines are 3-bladed horizontal axis designs with the rotor upwind of the tower. Competing design options within this specification include:
  - Stall regulation versus pitch regulation.
  - Fixed speed versus variable speed operation.
- For each of the above pairs of options, the former has lower capital cost but the latter may achieve higher energy yield in a given location.

- The principal site-specific determinant of wind energy lifetime project cost (LPC), expressed as cost/kWh, is annual mean wind speed (AMWS). High wind speed sites are associated with:
  - Terrain modification of wind flow through topographical forcing (hilltops and upland sites)
  - Supplementary terrain generation of wind flow through localised effects such as anabatic and katabatic winds and sea breezes (mountain passes and coastal sites)
  - Low surface roughness (all sites, especially offshore)
- AMWS is highly location-specific and may, especially in hilly terrain, vary by several tens of percent between sites only a kilometre or so apart.
- AMWS typically increases with height above ground at a rate largely determined by the surface roughness.
- Because the output from wind turbines is determined by wind speed it is both variable and intermittent. Although relatively predictable in the long term, e.g. over a year, prediction of output a few hours ahead is limited by the accuracy of short-term wind forecasting. Output may, however, exhibit strong and relatively predictable seasonal and/or diurnal variation.
- The options for central despatch of wind energy are limited, and constraining-off increases LPC. Wind output should be regarded as negative demand in despatch analyses at low penetration levels. However, system effects reduce the economic competitiveness of wind energy at higher penetration levels, as discussed in Sections 8 and 9.

3 POTENTIAL FOR WIND ENERGY: ANALYTICAL APPROACH

3.1 Introduction

As noted in Section 1.3, the primary purpose of this report is to present the findings of the study. An overview of the analytical method was presented in Section 1.2 and a detailed description of this stage of the analysis is given in Appendix A. This section provides intermediate coverage and should be read after Section 1.2. The standard assessment criteria agreed with the Client are presented in Appendix C. Explanations of the acronyms used are provided in the Glossary at the end of this document.

This section describes the method and assumptions used in modelling the three wind energy scenarios listed in Section 1:

1. Small onshore wind farms
2. Large onshore wind farms
3. Large offshore wind farms

Two levels of approach were used for each scenario – the four "study regions" were modelled in detail, and the results of these extrapolated to the rest of the world in the form of simplified analyses. The modelling of the three scenarios in the four study regions is described first.

3.2 Study Regions

For all three scenarios, the analyses for the four study regions were in three stages:

- Computational wind flow modelling to determine the hub height annual mean wind speed (AMWS) for each 5×5 km unit of land or sea area. This was achieved using WindMap™, a commercially available[2] model, and a geographical information system (GIS). WindMap has been used previously for wind resource modelling in the USA [3, 4, 5] and by Garrad Hassan in South Africa [6]. This was the most intensive stage of the analysis in terms of both staff and computing resources.
- Further GIS analysis to enhance the AMWS resolution to 1×1 km, calculate the annual energy yield (AEY) theoretically available from each such unit of land or sea area, and to remove unavailable areas. This stage of the analysis was also computationally intensive.
- Numerical analysis to apply further constraints on wind farm siting. This stage of the analysis was totally original and took a long time to develop. Once developed, however, results could be generated relatively quickly.

3.2.1 Geo-spatial data

The origins and characteristics of the geo-spatial datasets used are summarised in Table 3.1 overleaf. All were obtained on CD-ROM or downloaded from the internet either free of charge or for a modest fee as the supplying organisations are all in the public domain.

[2] Brower & Company <http://www.browerco.com/windmap.html>

Type	Name	Supplier	Characteristics
Wind	GUACA	NCDC	Raster, lat/long 2.5º resolution
Elevation (DEM)	GTOPO30	USGS	Raster, at/long 30" resolution
Land cover	GLCC	USGS	Raster, 1 global or 5 continental projections 1 km resolution
Environmental constraints	A Global Overview of Forest Conservation	IUCN	IUCN Protected Areas ESRI "SHAPE" format
Population	Gridded Population of the World (GPW)	CIESIN	Raster, lat/long 5' resolution
Electrical transmission network, general	Vector Map Level 0 (VMap0) "Digital Chart of the World"	USGS	Vector, 1:1,000,000 c1.5 km accuracy
Offshore bathymetry	ETOPO5	NGDC	Raster, lat/long 5' resolution

Table 3.1: Geo-spatial datasets used in GIS and/or WindMap analyses

Lambert's Oblique Azimuthal Equal Area projection was used to conserve the geometry of areas, and because it is suitable for large (continental) regions.

3.2.2 Other data

In addition to the geo-spatial data described above, the following information was used in the analyses:

- Electrical system parameters for each country, state or province in the study regions (see Section 8) to enable estimation of grid connection and integration costs.
- Power curve data for a typical Danish 600 kW turbine which was used in conjunction with AMWS and air density in the calculation of AEY. Air density was estimated in the GIS from the latitude and elevation of each 1×1 km cell.
- Current commercial wind farm performance parameters – availability (the proportion of time turbines are available to generate), array losses (due to wake interactions) and on-site electrical losses etc.
- Current commercial wind farm cost parameters – turbine and balance of plant capital costs, total installed cost per MW nameplate capacity and ongoing cost per MW per year.

The above information was compiled from external sources and Garrad Hassan's commercial experience. Further details are given in Appendix A.

3.2.3 Onshore analyses

Figure 3.1 overleaf provides an overview of the analytical method for generating cost-supply curves for scenarios 1 and 2 – small and large onshore wind farms.

From left to right, the boxes at the bottom of Figure 3.1 show:

- geo-referencing system
- horizontal resolution of projected geo-spatial data
- supplementary software used to post-process results

The three "processes" represented by bold boxes correspond with the three analytical stages summarised above. In fact, the GIS was used to prepare or manipulate data within each analytical stage, and Figure 3.1 is a considerably simplified representation of the entire analysis. An outline explanation for each process and its inputs and outputs will now be given – again, the reader is referred to Appendix A for a more technical and quantitative description.

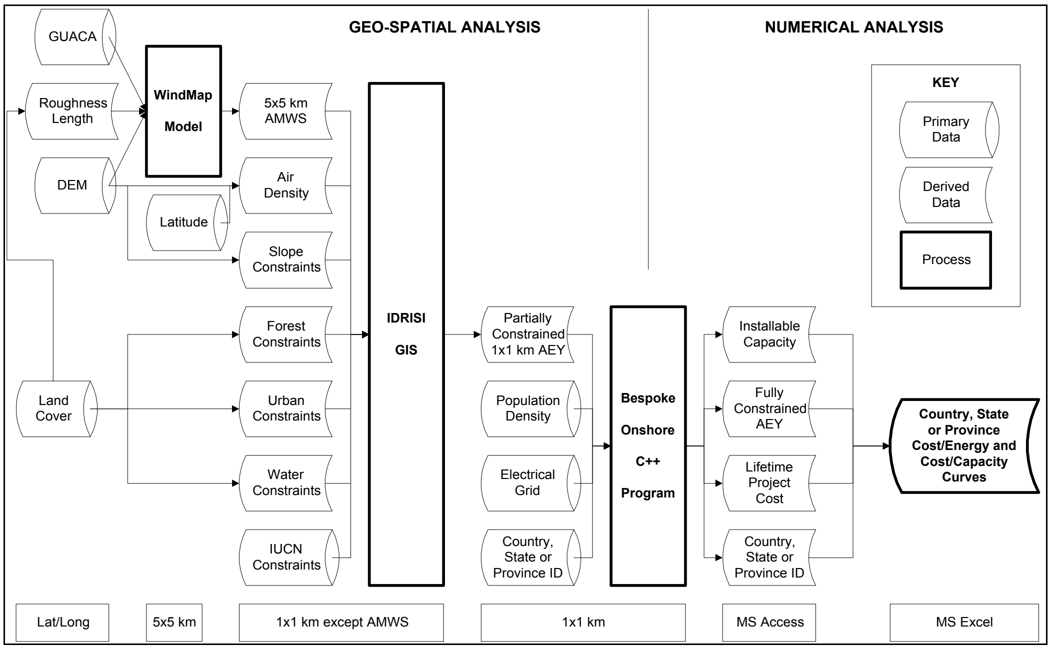

Figure 3.1: Overview of method for generating onshore wind cost-supply curves

3.2.3.1 Wind flow modelling

The three input datasets were prepared in the GIS at 5×5 km resolution as follows:

- Annual upper air and "10 m" wind speed and direction statistics were taken from the GUACA data.
- Roughness length (an indicator of surface friction which determines the variation of wind speed with height within the atmospheric boundary layer) was derived from the global land cover data in the following classes:
    - Water
    - Forest
    - Urban areas
    - Other land
- Elevation was derived from the 1×1 km digital elevation model (DEM) by block averaging.

These datasets were input to WindMap to generate AMWS estimates for each 5×5 km unit at 50 m and 60 m above ground level. The 50 m and 60 m estimates were used to calculate onshore and offshore AEY respectively.

Suspicions that the GUACA wind data contained extensive systematic errors were borne out by comparisons with other large scale wind modelling results which suggested that wind speeds were significantly under-estimated in many parts of the world. Neither the originators (ECMWF – the European Centre for Medium-range Weather Forecasting) nor suppliers of the GUACA data provided the information needed to understand or correct these errors. However, Marc Schwartz and Dennis Elliott of NREL provided a very useful commentary on GUACA errors based on their own experience which enabled a statistical correction method to be formulated by Garrad Hassan and applied to the subsequent AEY estimates. This is outlined in the following section and described in greater detail in Appendix A.

It must be borne in mind that no sufficiently accurate global gridded wind data are currently available and that all the alternative datasets have different shortcomings in this context. GUACA was chosen largely on the grounds of affordability, homogeneity, ease of access and relatively modest computing requirements.

It is acknowledged that the use of upper air data to initialise WindMap will tend to result in localised near-surface thermally generated winds[3] being overlooked, and that this will lead to under-estimates of the wind resource in certain areas. To overcome this shortcoming would have required a combination of surface station meteorological data and a much more computationally intensive modelling approach. The quality and availability of surface station data around the world are extremely erratic, and sourcing, checking and correcting such data could not have been undertaken within the cost and timescale constraints of this study. Computational software capable of accurately modelling such effects is only now being developed and is currently at the validation stage.

3.2.3.2 Further geo-spatial analysis

The GIS was used to perform a series of analyses sequentially – for simplicity these have been shown in parallel in Figure 3.1. The analyses were as follows:

AMWS resolution enhancement

This process was particularly important in complex terrain where many wind turbines are likely to be located due to the generally high wind speeds in upland areas. The horizontal resolution of the AMWS estimates was enhanced from 5×5 km to 1×1 km using an algorithm based on an empirically determined relationship between the variation of 1×1 km AMWS from the 5×5 km mean and the variation of 1×1 km elevation from the 5×5 km mean.

Annual energy yield

For each 1×1 km cell, the AMWS and air density were used to calculate the net AEY from 600 kW of installed capacity assuming 100% efficiency. Scaling up to 6 MW/km^2 capacity density and deducting 10% efficiency to allow for availability, array losses and on-site electrical losses were performed in the subsequent numerical analysis.

As noted above, AEY estimates were adjusted at this stage to compensate for systematic errors due to the GUACA initialising data. The correction algorithm used was a multi-variate linear regression derived empirically from a statistical comparison between 10×10 km wind power estimates in the US Wind Atlas [7] and their counterpart AEYs as originally calculated from GUACA-derived AMWS estimates. The revised AEY estimates were seen to resemble more closely wind power estimates in the global wind power map produced in 1981 by Pacific Northwest Laboratories (the "PNL map"[8]) in those regions of the world where visual comparison was possible. This correction method was derived from, and only applied to, onshore AEYs.

[3] e.g. sea breezes, anabatic and katabatic winds

Technical constraints

1×1 km cells where wind energy development was judged to be technically impossible were removed from the analysis. These were in the following categories:

- Areas where steep local gradients are likely to make site access prohibitively difficult and expensive and/or to result in wind flow separation which reduces AEY and, more importantly, increases turbulence intensity[4] to unacceptable levels.
- Areas labelled "Unknown" on the PNL map. The Himalayan massif, including the whole of Tibet, was entirely removed from the analyses of China and India. The Andes were likewise removed from the analysis of Latin America.
- Afforested areas identified from the global land cover data were removed. This is arguably a conservative approach as several large wind farms have been, or are being, developed either on exposed high ground within forests or in large clearings.
- Urban areas were likewise removed. Although several wind farms have been built in urban areas, such developments generally are unlikely to receive planning consent and have unfavourable wind regimes.
- Areas of inland water were removed. It would be pointlessly expensive to site "onshore" wind farms in lakes. Furthermore, such areas usually have high amenity and/or ecological value, so planning permission would almost certainly not be granted anyway.

Environmental constraints

All areas designated by the International Union for the Conservation of Nature (IUCN) into categories I to VI were removed. The geo-spatial data provided by IUCN sometimes represented these as circles scaled in proportion to the enclosed areas, rather than as polygons defining the true perimeters. This was considered to be a reasonable approximation given the large number of areas. Wind energy development is also constrained by national, regional and local environmental designations, but no global database of these is available. Arguably, the use of IUCN designations alone represents an under-estimation of environmental constraints, although it is worth pointing out that not all IUCN designations were considered automatically to preclude wind farm development. This approach, combined with the removal of all forests (with the caveats noted above) is considered to result in a reasonably realistic level of constraint, even if the precise locations are not invariably incontestable.

Partially constrained AEY

The AEY results generated as described were modified in accordance with the above constraints and saved for input to the "Onshore" C++ program.

3.2.3.3 Numerical analysis

An overview of the operations performed in the "Onshore" program is provided in Figure 3.2 overleaf. The basis on which electrical costs D_0, D_1 and D_2 were estimated, is given in Appendix A. Essentially, they were determined by the localised grid connection options which, in turn, reflected a combination of local demand (based on population and national demand) and the presence or otherwise of a nearby transmission line.

The term "Country" used in Figure 3.2 denotes provinces in China, states in India and the USA, and countries in the EU-15. Information provided in the input files included, in addition to those shown in Figure 3.1, wind farm and electrical capital cost parameters.

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[4] Short term variability of wind speed (and sometimes direction) which is the principal cause of fatigue loading on wind turbines

Removal of the lowest AEY cells due to rural (i.e. local) population attempted to model localised public acceptability limits. It was assumed that inhabited dwellings tended to be in the least windy local areas, that 90% were clustered in settlements, and that no wind farm could be within a specified minimum distance from any inhabited dwelling due to noise constraints. No attempt was made to model public attitudes to visual impact, cumulative or otherwise, beyond imposition of the capacity density limits described in Table 3.2.

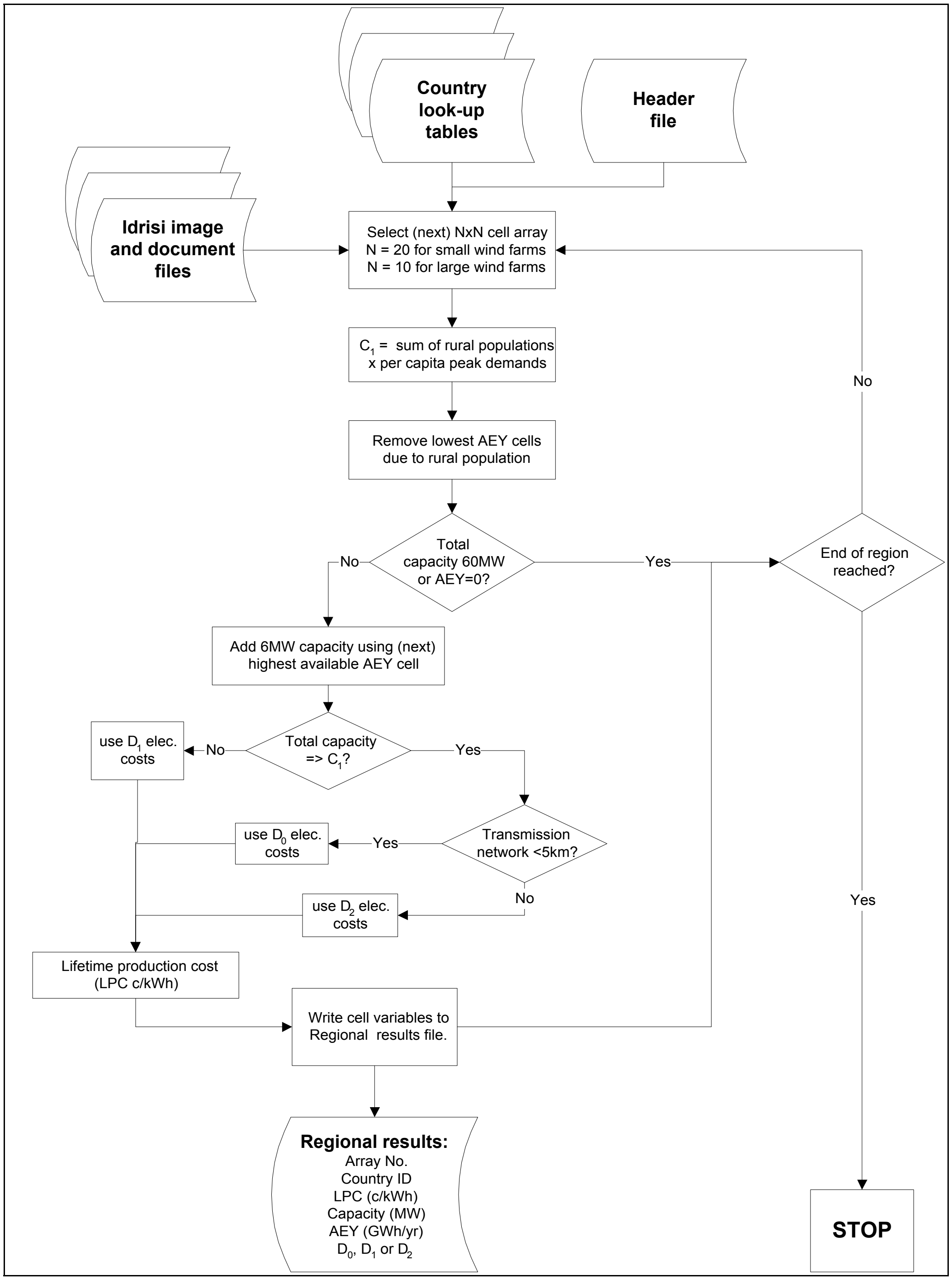


Figure 3.2: Overview of bespoke Onshore C++ program

All assumptions about public acceptability, apart from minimum distance to dwellings[5] (see Appendix A for a full discussion), were applied uniformly to all four study regions and, subsequently, to the rest of the world. Summary details of the principal analytical parameters used in both the small and large onshore wind analyses are shown below in Table 3.2.

Parameter	Value	Comments
Wind turbine rated capacity	750 kW	Typical onshore wind turbine
Wind turbine power curve		Scaled from typical Danish 600 kW stall-regulated machine
Wind speed distribution	Rayleigh	Global assumption, but may vary significantly in different locations
Wind turbine hub height	50 m	Hub heights >100 m have been mooted in Germany where AMWS is low but are unlikely to be widely acceptable
Wind farm density	8 turbines = 6 MW per 1×1 km cell	Turbines uniformly spaced approximately 7 rotor diameters apart
Incremental capacity / area	6 MW / 1×1 km	Added on "highest available AMWS first" basis
Maximum capacity density	0.15 MW/km^2	Ringkøbing Municipality (Denmark) target is equivalent to c.0.1 MW/km^2 (40 MW by year 2000 in approximately 400 km^2, of which about two thirds is excluded) and "could be increased for larger turbines"
Annual rate of wind farm capital cost reduction	1%	Risø estimates [9] compiled from several sources range from 1 – 2.5%
Wind farm efficiency	90%	Allows for availability, array losses and electrical losses

Table 3.2: Summary of principal analytical parameters for onshore analysis

Further parameters common to both the small and large onshore analyses are listed in Appendix C.

3.2.3.4 Small and large wind farms

Where the modelling of small and large onshore wind farms did diverge was in the wind farm capital cost assumptions and the geographical scale on which capacity density was limited to 0.15 MW/km^2. These are summarised in Table 3.3.

Assumption	Small Wind Farms	Large Wind Farms
Capital cost (year 2000)	$1217/kW	$1000/kW
Unit area for 60 MW local capacity limit	20×20 km	10×10 km
Scale for 0.15 MW/km^2 limit	20×20 km	"National"[6]

Table 3.3: Differences between small and large onshore analyses

[5] Originally set to 300 m everywhere reflecting common European planning practice, this excluded wind farms from parts of India (e.g. Tamil Nadu) where significant real development has occurred. It was therefore reduced to 150 m in those regions where, as in India, shortage of capacity was considered to be a significant market driver in addition to environmental considerations: Africa, China, India, Latin America and parts of the Rest of Asia.

[6] Country in EU-15, State in US and India, Province in China

The 0.15 MW/km^2 limit for the large wind farms scenario was applied during post-processing of results which allowed data to be sorted by country, state or province and ranked by LPC to generate the cost-resource curves presented in the following sections. As these curves demonstrate, the impact of the above differences is profound. Not only is the minimum LPC from large wind farms invariably lower, as would be expected from the lower capital cost, but the cumulative AEY and capacity up to a given LPC are significantly higher. The latter effect is due to both lower capital cost and a radically different geographical distribution of developments modelled. Small wind farms will, subject to the constraints described previously, tend to be distributed relatively uniformly throughout each study region. Large wind farms will, however, tend to be clustered more densely in high wind speed areas.

Which pattern of development would prove to be more acceptable on the scales modelled, which far exceed any actual development to date, can only be a matter for speculation. Broadly speaking, small wind farms would impact upon a greater proportion of rural residents, whereas large wind farms would encroach more heavily upon undesignated wilderness areas which, though sparsely populated, might have high amenity value to non-residents as well as inhabitants.

3.2.4 Offshore analyses

Figure 3.3 provides an overview of the analytical method for generating cost-supply curves for offshore wind energy.

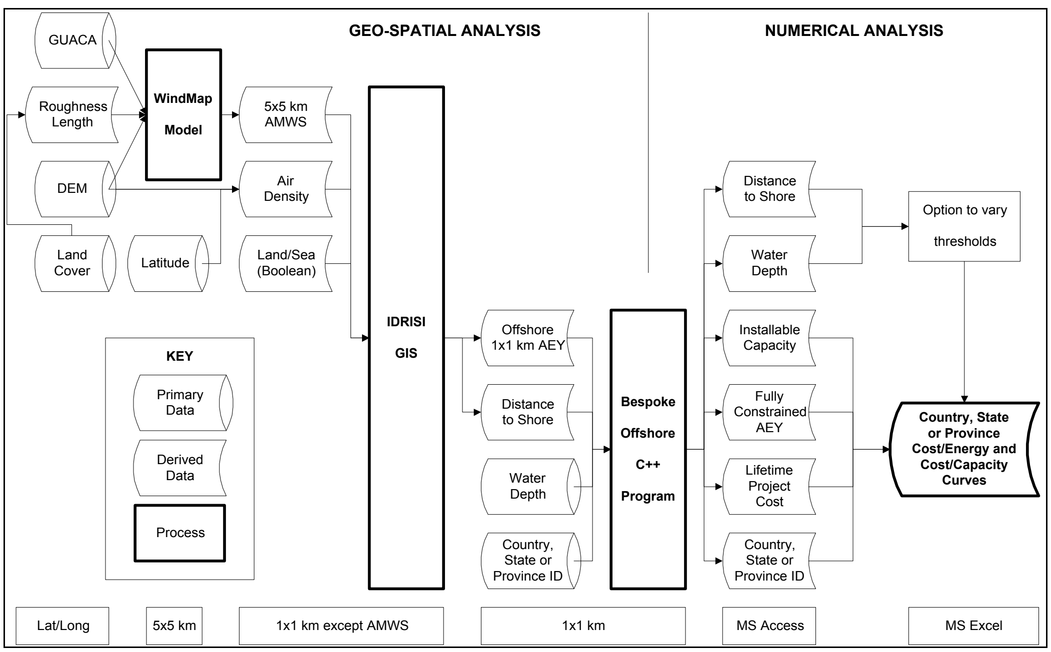


Figure 3.3: Overview of method for generating offshore wind cost-supply curves

3.2.4.1 Wind flow modelling and geo-spatial analysis

Wind flow modelling and AEY calculations were performed using the methods described for onshore wind apart from application of the AEY correction algorithm which was only valid onshore. Although the resulting offshore AMWS estimates in Europe were very similar to those obtained from Voluntary Observer Fleet (VOF) data in a more detailed study [10], it is possible that they have been systematically under-estimated in some other regions of the world due to the aforementioned GUACA data errors.

AMWS estimates for 60 m above (sea) surface level were used to reflect the greater hub height of the larger offshore turbines modelled. Resolution enhancement was achieved by resampling in the GIS. Distance from shore and water depth were used to set limits on areas for development. Electrical costs were determined in part by distance from shore, and wind farm capital costs in part by water depth. Allowance was made for shipping lanes, marine conservation areas and other potential exclusion zones such as areas with inappropriate seabed conditions by uniformly "thinning" capacity as described in the following section.

3.2.4.2 Numerical analysis

The numerical analysis was somewhat simpler than that for onshore wind because rural population density was not judged to be a constraint on development, and all grid connection was assumed to be directly to the transmission network due to the larger capacities of offshore wind farms. An overview of the bespoke C++ Offshore program is provided in Figure 3.4 overleaf. Again, the term "Country" denotes provinces in China, states in India and the USA, and countries in the EU-15. "Country" IDs were assigned to sea areas using a nearest neighbour algorithm in the GIS. Information provided in the input files included, in addition to those shown in Figure 3.3, wind farm and electrical capital cost parameters. Summary details of the principal analytical parameters used in the offshore wind analysis are shown below in Table 3.4. Further parameters for the offshore analyses are listed in Appendix C.

Parameter	Value	Comments
Wind turbine rated capacity	2 MW	Typical large offshore wind turbine under development
Wind turbine power curve		Scaled from typical Danish 600 kW stall-regulated machine
Wind speed distribution	Rayleigh	Global assumption, but may vary significantly in different locations
Wind turbine hub height	60 m	Offshore hub heights may be lower than onshore counterparts of same rated capacity due to lower wind shear
Wind farm density	4 turbines = 8 MW per 1×1 km cell	Turbines uniformly spaced approx. 7 rotor diameters apart
Incremental capacity / area	8 MW / 1×1 km	Added on "highest available AMWS first" basis
Distance from shore	5 – 40 km	Lower limit set by visual impact, upper limit by electricals and access costs
Maximum water depth	40 m	Turbine foundation costs tend to increase steeply beyond this limit
Maximum local capacity	25% of available area	Global assumption of 75% exclusion due to technically unsuitable sea bed conditions and/or shipping lanes, marine conservation areas etc.
Annual rate of wind farm capital cost reduction	1%	Risø estimates [9] compiled from several sources range from 1 – 2.5%
Wind farm efficiency	90%	Allows for availability, array losses and electrical losses

Table 3.4: Summary of principal analytical parameters for offshore analysis

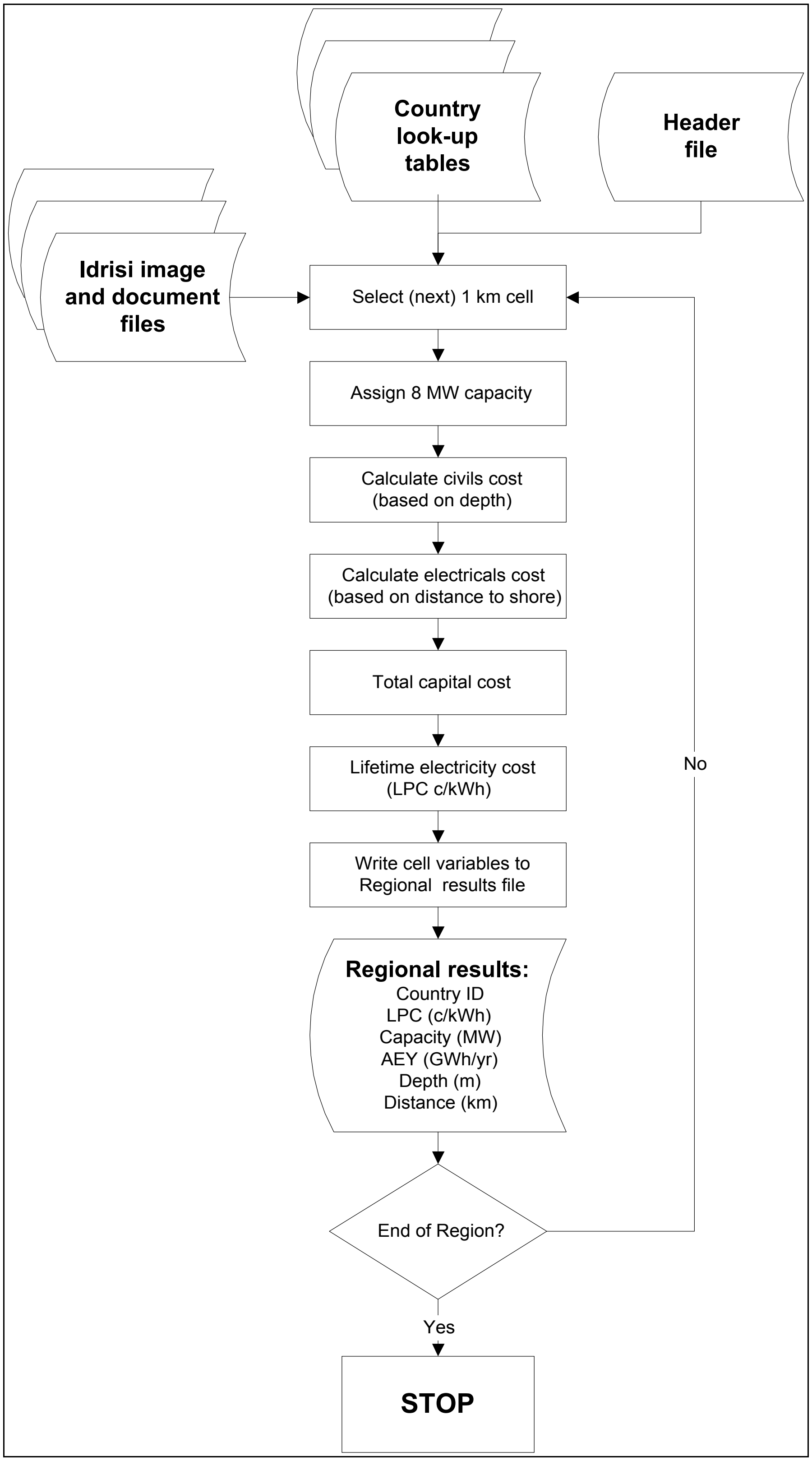


Figure 3.4: Overview of bespoke Offshore C++ program

The blanket coverage of offshore wind farms was uniformly "thinned" by 75%[7] during post-processing to allow for areas excluded from development. This also allowed, as for onshore wind, data to be sorted by country, state or province and ranked by LPC to generate the cumulative cost-energy and cost-capacity curves presented in the following sections.

3.2.4.3 Offshore capital costs

As indicated previously, the capital costs estimated for offshore wind farms contained variable elements to accommodate a range of water depths and distances from shore, and it is therefore not possible to assign a single value as was done for the small and large onshore wind farm scenarios. However, a typical figure to facilitate comparison with onshore capital costs is $1,676/kW installed (c.f. $1,217/kW small onshore, $1,000/kW large onshore). This figure was calculated for a 200 MW offshore wind farm sited in 15 m of water some 20 km from the coast. Further details about the range of costs modelled are given in Appendix A.

3.3 Rest of the World

3.3.1 Regions

It was agreed with Econ that the rest of the world would be disaggregated into regions based on fuel mix as follows:

- Africa (south of the Mediterranean Sea and west of the Red Sea)
- Australia (Australia and Tasmania)
- Latin America (south of USA including Mexico and the Caribbean islands)
- Middle East (including Turkey, Afghanistan and Pakistan)
- Rest of Asia (east of India including Bangladesh, Indonesia, Philippines, Japan and New Zealand)
- Former Soviet Union (FSU), Mongolia and Eastern Europe

Remote islands were only modelled when they lay within the bounding rectangles of the above regions. While they may offer good potential as niche markets for small-scale wind energy due to the high cost of importing fuel for conventional generation, the impact of their omission from this study is negligible.

Canada, Iceland, Greenland, Norway and Switzerland were omitted as they all are primarily non-fossil fuel generators – almost 100% non-fossil in the cases of Iceland, Greenland, Norway and Switzerland, and >80% in the case of Canada. It is therefore reasonable to exclude these countries from the analysis as there are no meaningful avoided costs from wind generation.

These omissions are discussed in greater detail in Section 1.2.4.

3.3.2 Analyses

The majority of data, assumptions and analytical processes were as described above for the corresponding scenarios in the four study regions. However, it was necessary to adopt simplified approaches to wind flow modelling and to applying social constraints on the

[7] It was estimated in [10] that only 25-30% of offshore area was unavailable. Removal of 75% is conservative to allow for additional constraints, in particular minimum distance between offshore wind farms

development of large onshore wind farms. These differences are summarised in the following sections.

3.3.2.1 Wind flow modelling

A section of Europe was "windowed" in the GIS, and five geo-spatial parameters selected:

- Elevation
- Roughness
- 700 mb mean wind speeds (derived from the GUACA dataset)
- Near surface mean wind speeds (derived from the GUACA dataset)
- 50 m mean wind speeds modelled as described in Section 3.2.3.1

All data had a resolution of 5 km as for the original wind flow modelling.

The GIS was used to perform a multivariate linear regression on the four input parameters (elevation, roughness, upper air and near surface wind speeds), using the map of modelled 50 m wind speeds as the independent variable. The result was shown to be very reasonable, both statistically, with an R^2 value of 0.924, and geo-spatially. The latter is demonstrated by the geo-spatial distribution of the modulus of mean error for the EU-15 shown below in Figure 3.5.

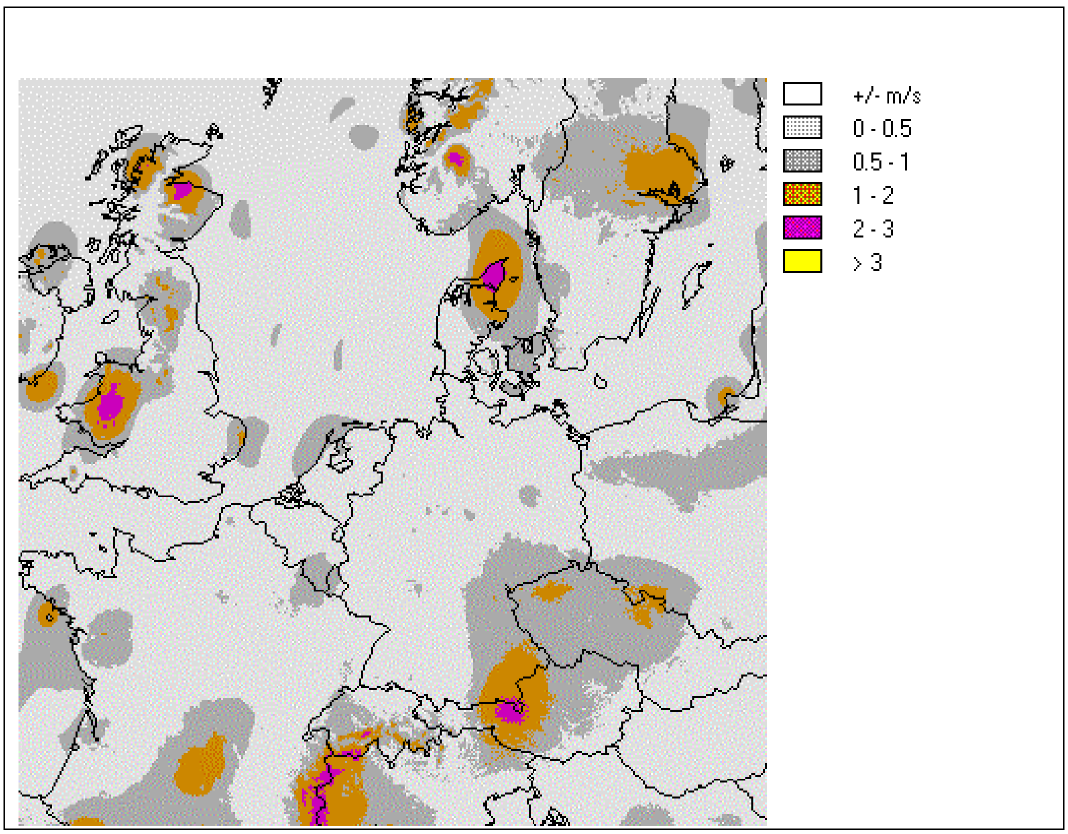


Figure 3.5: Modulus of mean error between modelled and regressed mean wind speeds

Figure 3.5 shows that, for most of the area compared, regressed 50 m mean wind speed estimates are within 0.5 m/s of modelled estimates, and within 1 m/s for almost all of the area.

The method is, as might be expected, particularly effective for estimating offshore 50 m mean wind speeds.

The regression equation was applied to the above data for the rest of the world to generate 50 m mean wind speed estimates at 5 km resolution for the onshore scenarios, with subsequent resolution enhancement to 1×1 km and AEY calculation and adjustment for GUACA errors performed as for the study regions.

A second regression was performed as described above on modelled AEY at 50 m and 60 m and surface roughness over the same area to enable modelling of the offshore resource. Again, a very high R^2 value (0.9995) was achieved, allowing this approach to be applied to the rest of the world with a high level of confidence.

A fuller description of these procedures is provided in Appendix A.

3.3.2.2 Large onshore wind farms

As described in Section 3.2.3.4, the extent of large onshore wind farm development for the four study regions was constrained by post-processing to an average density of 0.15 MW/km^2 per country in the EU-15, per state in India and the USA, and per province in China. The results before and after this stage will be referred to as "uncapped" and "capped" respectively. However, the rest of the world regions were not disaggregated into such units, so an alternative approach was adopted.

Firstly, the year 2000 uncapped and capped cost-energy and cost-capacity curves for the four study regions up to 20c/kWh LPC were combined. Each pair of curves was then resampled into 500 evenly spaced LPC bins, the lowest bin being centred on the minimum LPC and the highest on 20c/kWh. The ratios between the capped and uncapped values in each bin were then determined for both AEY and capacity. The results are shown graphically in Figure 3.6 below.

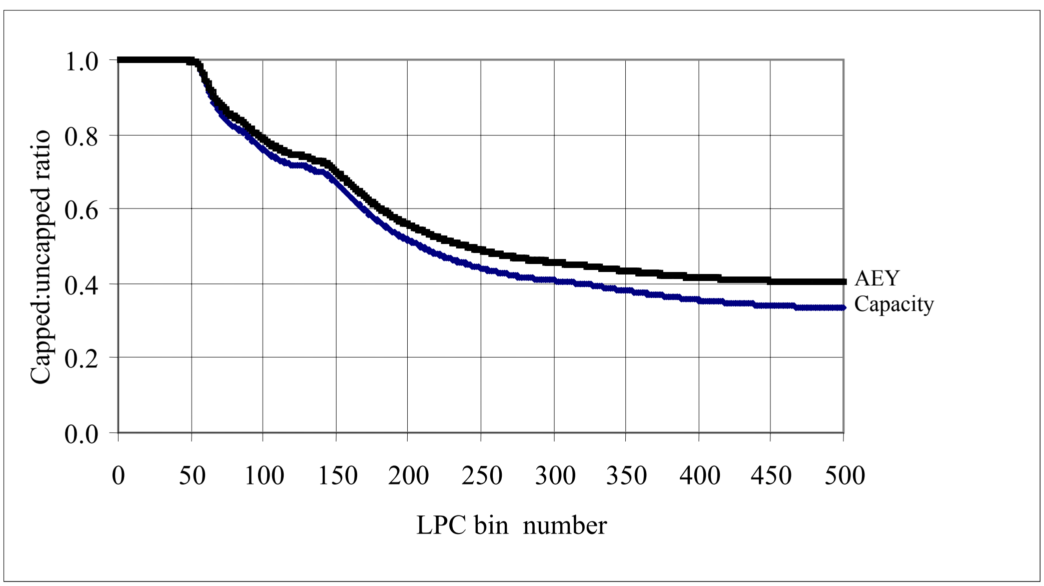


Figure 3.6: Effect of capping on large onshore wind in the four study regions

For each rest of the world region in turn, uncapped cost-energy and cost-capacity curves were generated as for the four study regions (apart from the alternative wind modelling procedure described in Section 3.3.2.1). Again, each pair of curves was then binned by LPC into 500 evenly spaced bins, the lowest bin being centred on the minimum LPC and the highest on 20c/kWh. The ratios shown above were then applied to the corresponding bins to synthesise capped cost curves representing the large onshore wind potential up to 20c/kWh.

One consequence of this approach is that the resulting cost-energy and cost-capacity curves comprise 500 points apiece, evenly spaced by cost but with capacity being added in variable increments. The corresponding small onshore and offshore curves, and all study region curves, were generated from fixed capacity increments (normally 200 or 600 MW) and typically contain many thousands of points.

In a few instances, uncapped cumulative energy or capacity increased more slowly at high LPCs than the ratios declined. As this would have resulted in sections of the capped cumulative curves having a negative gradient, the approach was modified slightly to level off these sections instead. The errors introduced by this work-around are not considered to be significant.

Again, a fuller description of this approach is given in Appendix A.

3.4 Analytical Limitations

As has been made clear at several points in this report, AEY is the most important single factor in determining how much wind energy resource is available at a given unit cost. While it has been possible to validate carefully the AEY estimates used in this study in regions such as the USA and the EU-15 where adequate reference data are available, elsewhere little may be known about the wind energy resource apart from in the few small areas studied in detail to date. The nature and origins of wind flow are known not to be uniform across the globe, and are especially different between, for example, tropical and mid-latitude regions and between large and small areas of land or water (see, for example, [11]). It is therefore unlikely that a correction to onshore AEY estimates developed using reference data for the USA will, however robust it may be in that context, be applicable anywhere else onshore with the same degree of confidence. Furthermore, it is not considered appropriate to apply this correction to offshore AEY estimates. These issues are covered more fully in Appendix A.

Other analytical assumptions made are open to challenge and will also affect significantly the results of this study. However, they are all transparent and it is up to the reader to decide whether they are reasonable.

It must be borne in mind throughout this report that the most important global parameter – the wind resource itself – is unfortunately the least well understood. None of the global datasets currently available have been prepared with computational modelling of boundary layer wind flow in mind. When, as is anticipated within the next decade, significantly improved global wind resource distribution estimates become available, it would be worth re-visiting the analyses presented in this report.

4 POTENTIAL FOR WIND ENERGY: STUDY REGIONS

4.1 Introduction

The analyses described in Section 3.2 were used to generate the graphs of cumulative annual energy yield (AEY) and cumulative installed capacity versus lifetime production cost (LPC) presented in Sections 4.2 to 4.5 below. The following should be noted:

- These wind resource curves indicate marginal costs, whereas the CO_2 abatement curves in Sections 12 to 15 indicate average cumulative costs.
- Points for the onshore and offshore wind energy scenarios were generated at intervals of 600 MW and 200 MW capacity respectively to limit datasets to manageable sizes.
- The LPC assigned to each point is that of the most expensive increment of capacity (see Table 3.2 and Table 3.4) in that capacity interval. LPC for individual projects from which each point is generated may be anywhere between that LPC and the LPC of the next lowest point. In particular, capacity may be added initially with lower LPC than that assigned to the first point in each data series.
- Although many of the graphs appear to be line plots, they are all scatter plots with no curve-fitting to the points. This allows discontinuities between points, indicating more limited resources, to be seen.
- LPC has been limited to US$20c/kWh and does not include system integration cost penalties which start to become significant at penetrations above 10% of regional demand. Such costs are, however, modelled in the CO_2 abatement cost curves.
- Different Y-axis scales have been used for different study regions as the range of results is large. However, for any region, the same scales have been used for year 2000 and year 2020 curves of the same type to facilitate comparisons.
- The curves largely speak for themselves, and commentary on them at this stage has been kept to a minimum. They are discussed further in Section 4.6 and compared with existing and forecast total generation region by region in Section 7.1.

4.2 China

4.2.1 China in 2000

Figure 4.1 and Figure 4.2 show, respectively, the relationship between estimated cumulative annual energy yield and installed capacity with lifetime production cost up to US$20c/kWh for the three wind energy scenarios in China in year 2000.

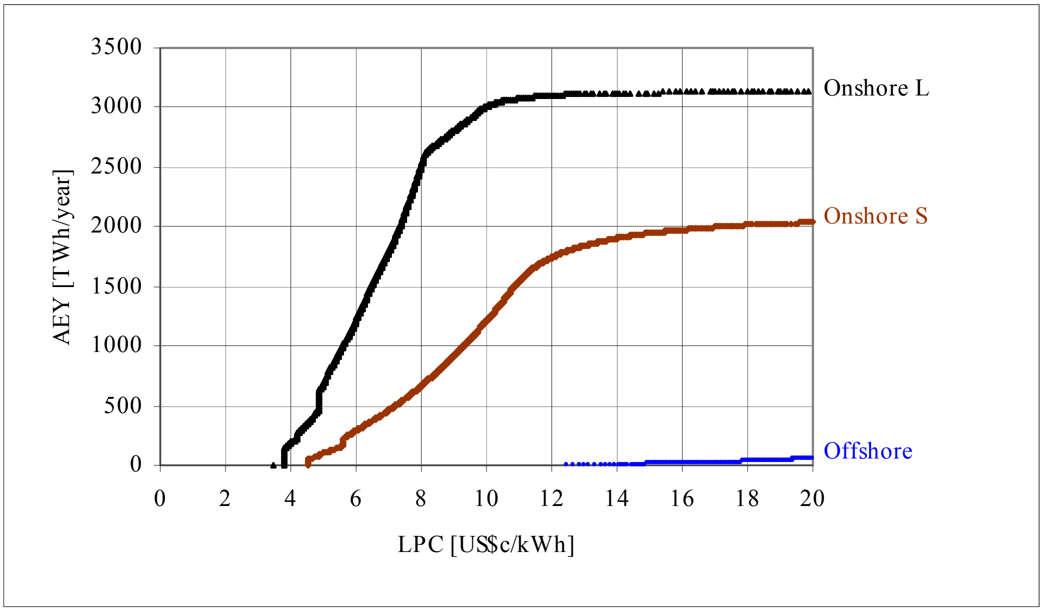


Figure 4.1: Cost-energy curves for China in 2000

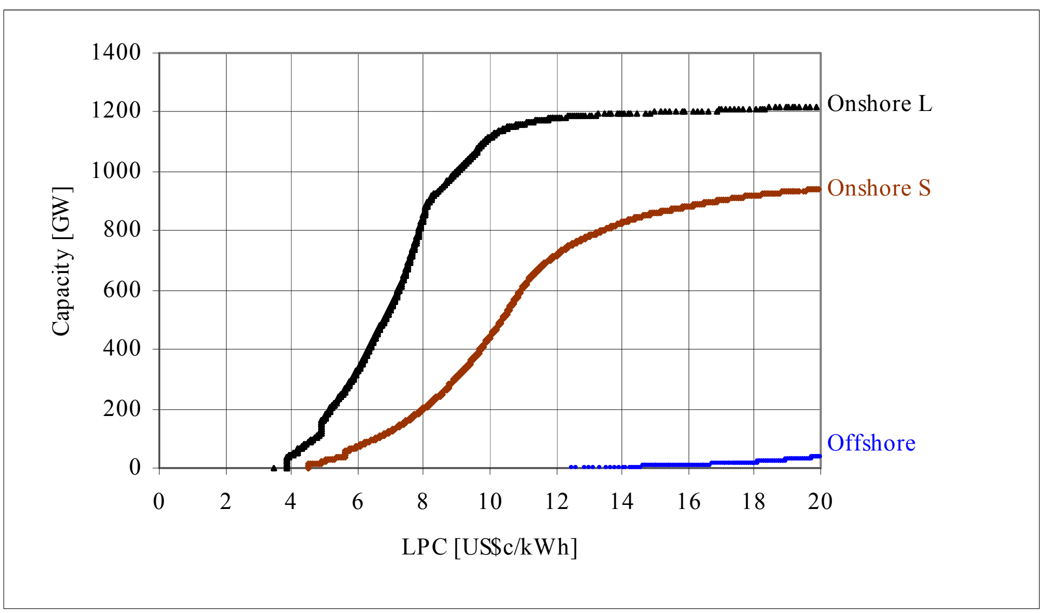


Figure 4.2: Cost-capacity curves for China in 2000

4.2.2 China in 2020

Figure 4.3 and Figure 4.4 show, respectively, the relationship between estimated cumulative annual energy yield and installed capacity with lifetime production cost up to US$20c/kWh for the three wind energy scenarios in China in year 2020.

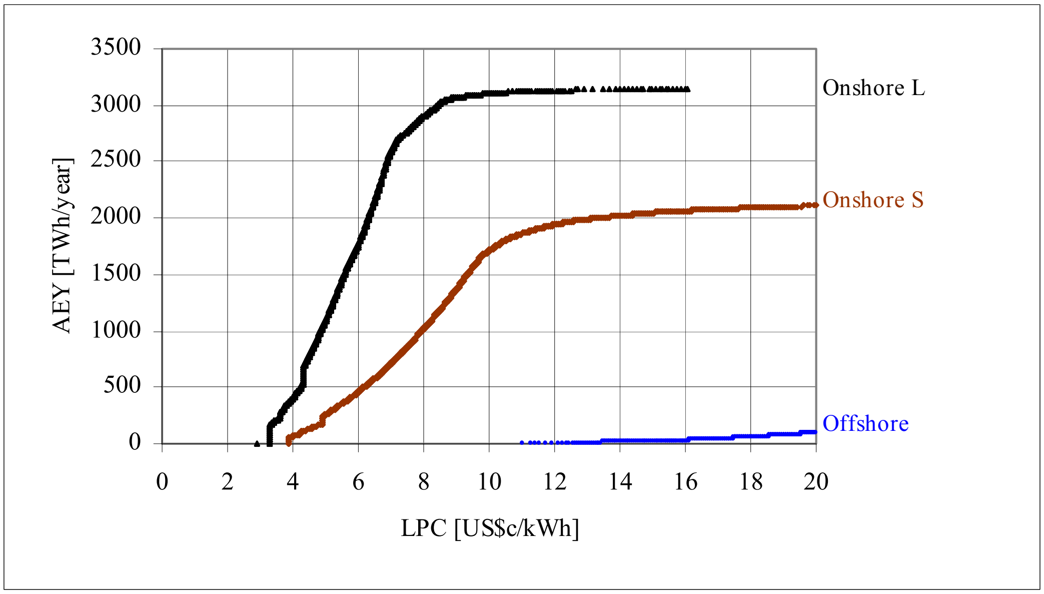


Figure 4.3: Cost-energy curves for China in 2020

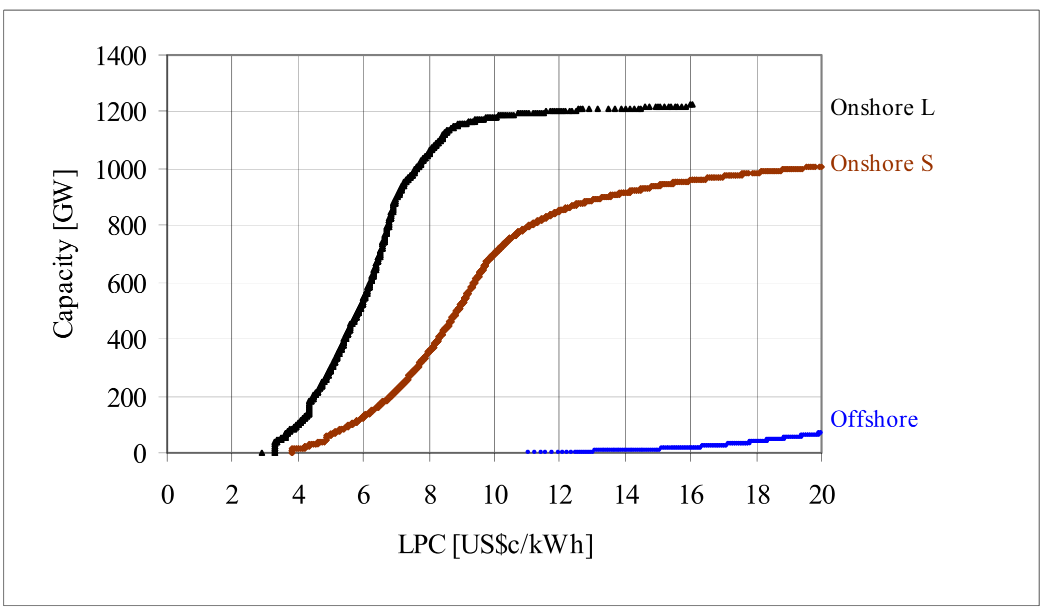


Figure 4.4: Cost-capacity curves for China in 2020

The Chinese Ministry of Electric Power estimates the national exploitable wind resource to be around 250 GW [12]. Figure 4.4 indicates that in 2020 this could be achieved from small onshore wind farms at LPCs up to 7.25 c/kWh producing 783 TWh/year or from large onshore wind farms at LPCs up to 4.78 c/kWh producing 952 TWh/year.

4.3 EU-15

4.3.1 EU-15 in 2000

Figure 4.5 and Figure 4.6 show, respectively, the relationship between estimated cumulative annual energy yield and installed capacity with lifetime production cost up to US$20c/kWh for the three wind energy scenarios in the EU-15 in year 2000.

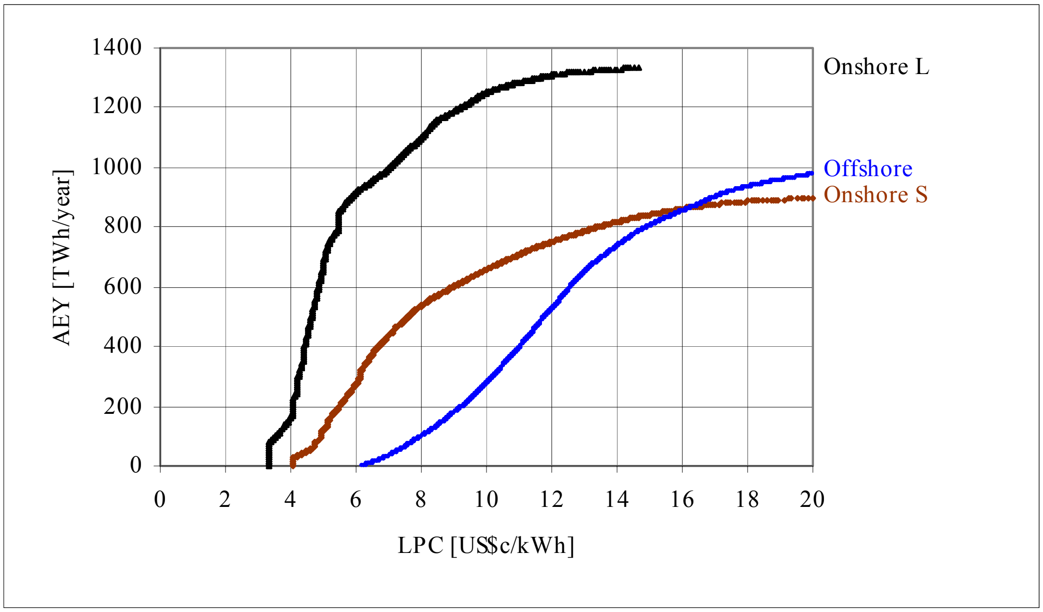


Figure 4.5: Cost-energy curves for the EU-15 in 2000

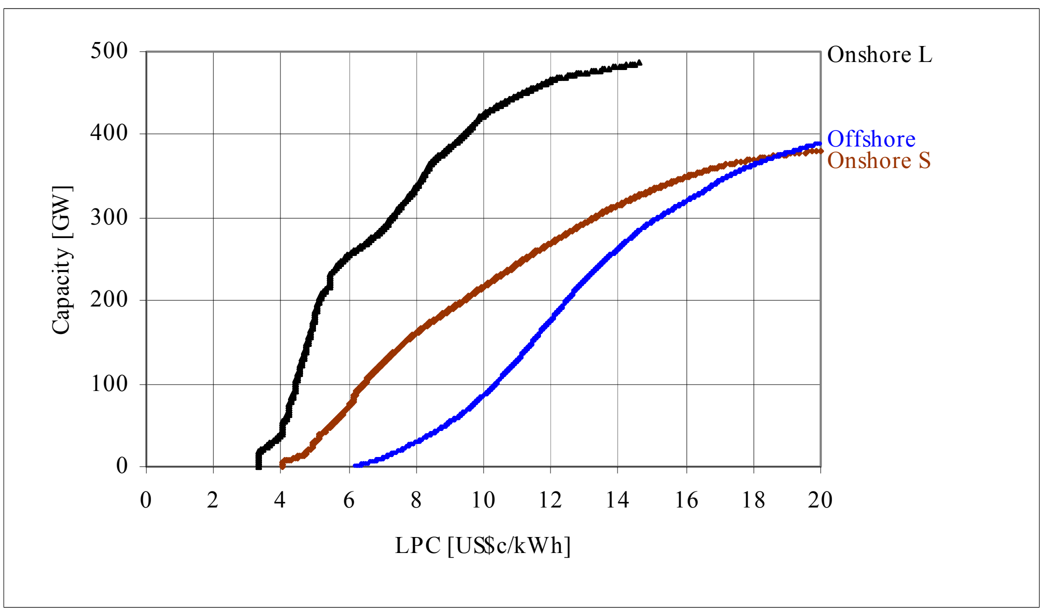


Figure 4.6: Cost-capacity curves for the EU-15 in 2000

4.3.2 EU-15 in 2020

Figure 4.7 and Figure 4.8 show, respectively, the relationship between estimated cumulative annual energy yield and installed capacity with lifetime production cost up to US$20c/kWh for the three wind energy scenarios in the EU15 in year 2020.

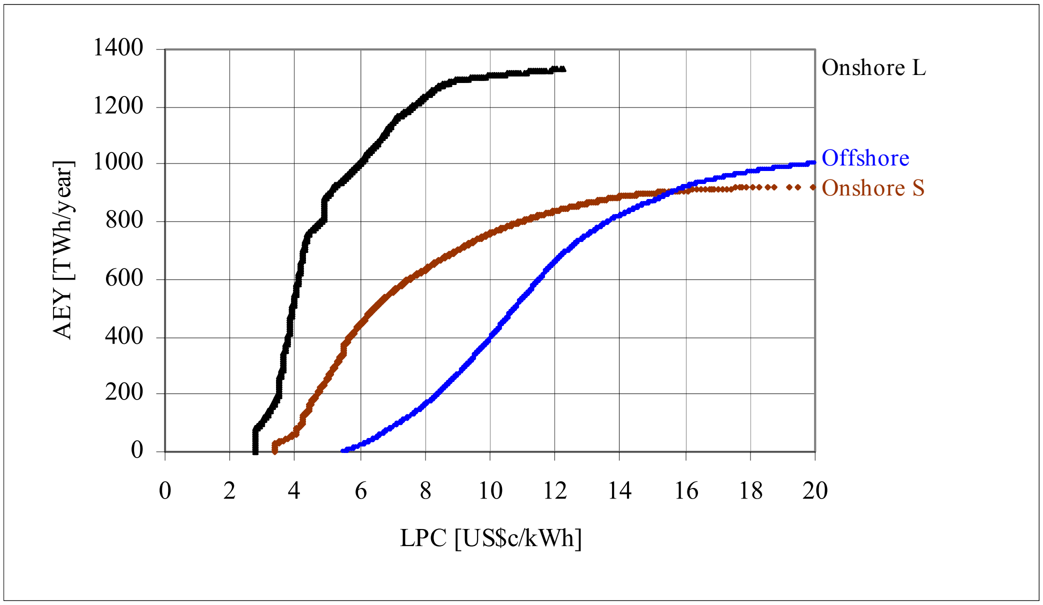


Figure 4.7: Cost-energy curves for the EU-15 in 2020

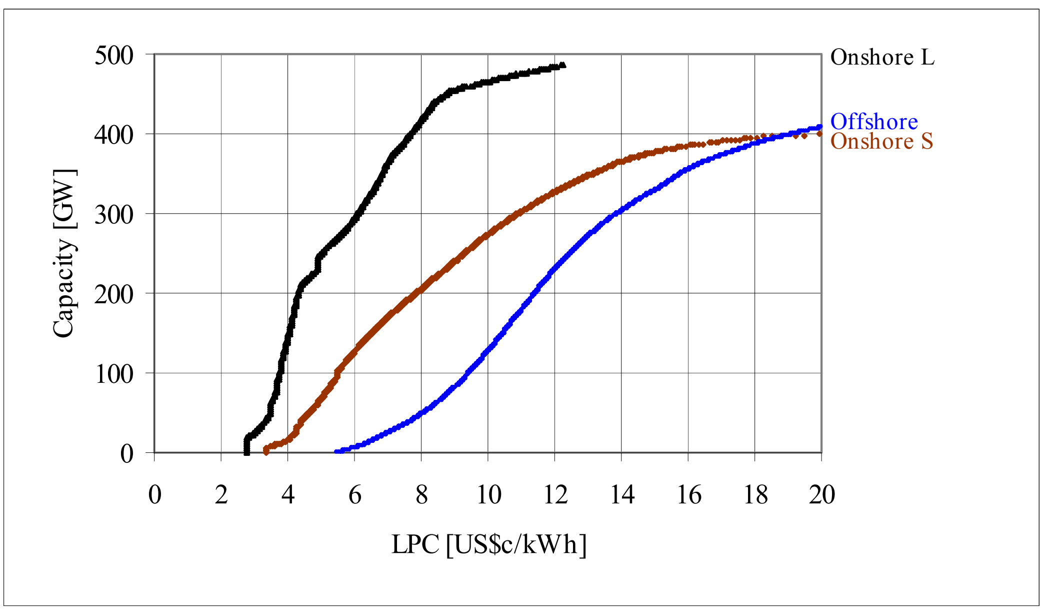


Figure 4.8: Cost-capacity curves for the EU-15 in 2020

The European Wind Energy Association and others [15] estimate European onshore and offshore wind energy potential to be 630 and 314 TWh/year respectively. Figure 4.7 indicates that in 2020 the former could be delivered by small wind farms at LPCs of up to 7.94 c/kWh or by large wind farms at up to 4.15 c/kWh, and that the offshore potential could be delivered at LPCs up to 9.42 c/kWh.

4.4 India

4.4.1 India in 2000

Figure 4.9 and Figure 4.10 show, respectively, the relationship between estimated cumulative annual energy yield and installed capacity with lifetime production cost up to US$20c/kWh for the three wind energy scenarios in India in year 2000.

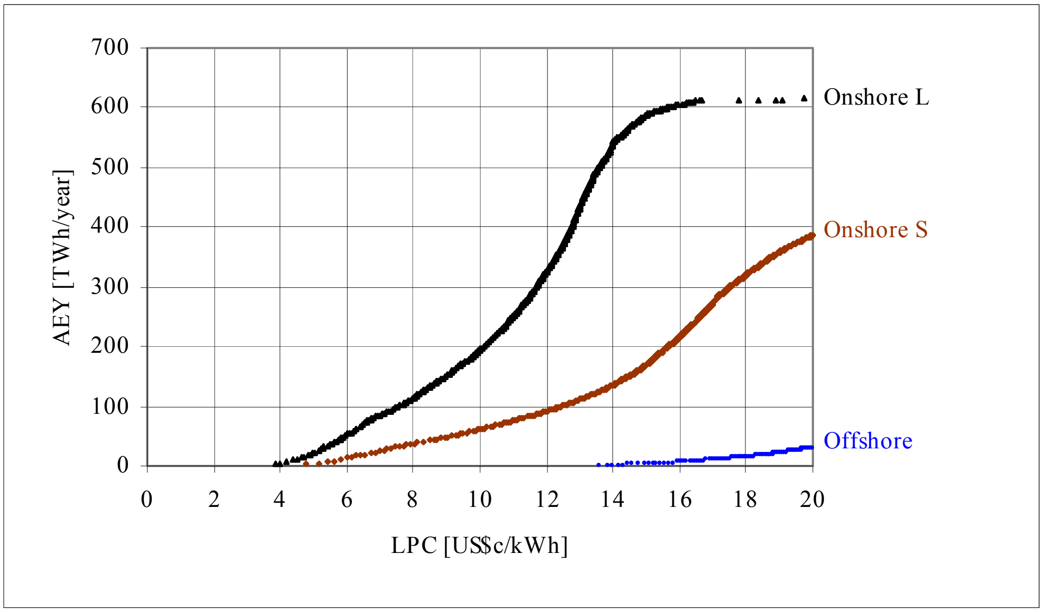


Figure 4.9: Cost-energy curves for India in 2000

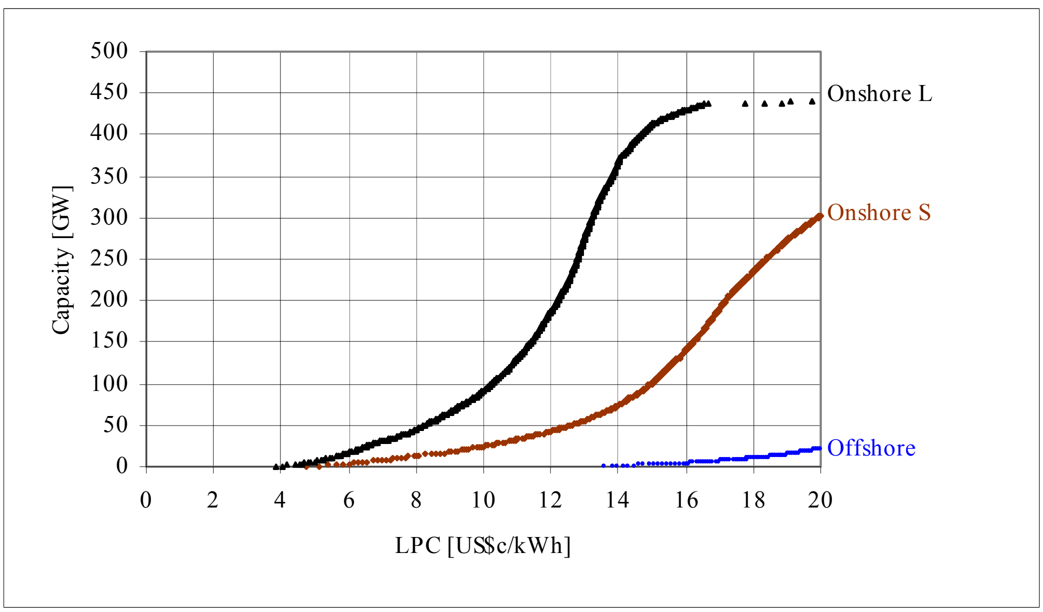


Figure 4.10: Cost-capacity curves for India in 2000

4.4.2 India in 2020

Figure 4.11 and Figure 4.12 show, respectively, the relationship between estimated cumulative annual energy yield and installed capacity with lifetime production cost up to US$20c/kWh for the three wind energy scenarios in India in year 2020.

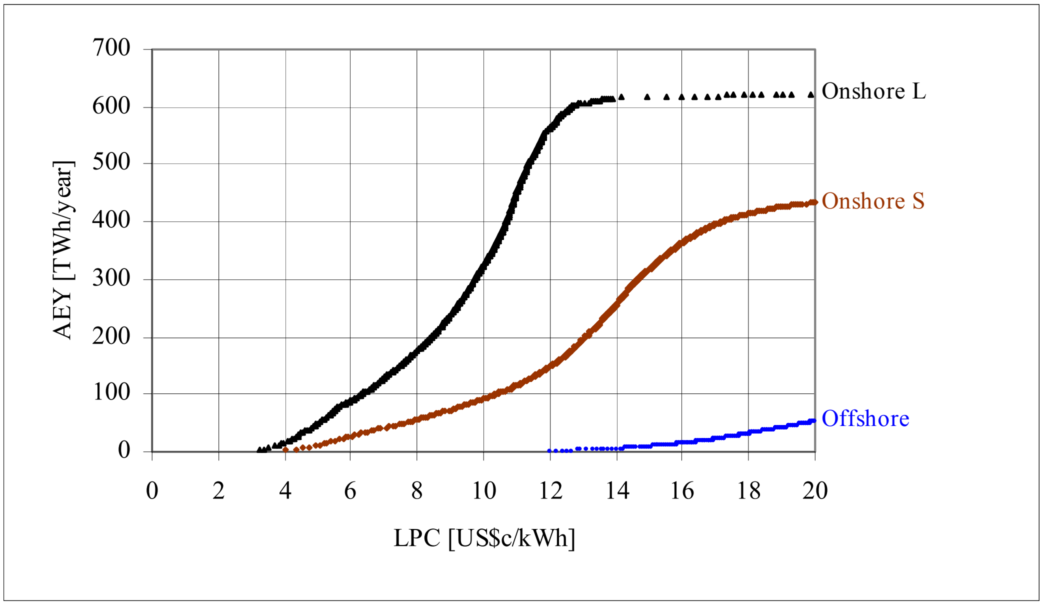


Figure 4.11: Cost-energy curves for India in 2020

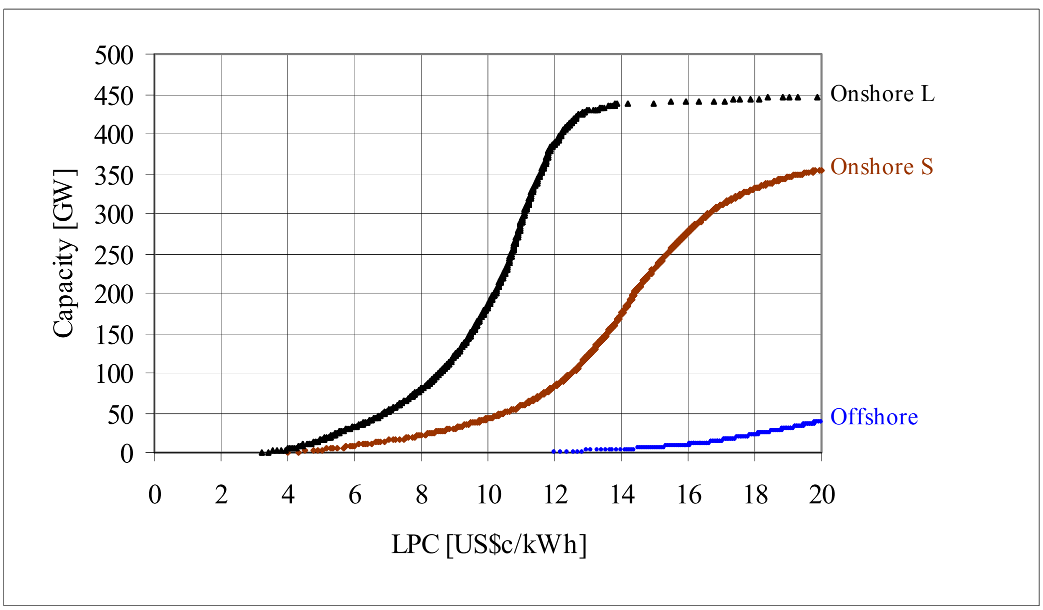


Figure 4.12: Cost-capacity curves for India in 2020

The Indian Ministry of Non-Conventional Energy Sources (MNES) estimate of 20 GW wind potential has been scaled up recently to 45 GW at 50 m [13]. Figure 4.12 indicates that in 2020 this could be achieved from small or large onshore wind farms at LPCs up to 10.19 or 6.71 c/kWh respectively.

4.5 USA

4.5.1 USA in 2000

Figure 4.13 and Figure 4.14 show, respectively, the relationship between estimated cumulative annual energy yield and installed capacity with lifetime production cost up to US$20c/kWh for the three wind energy scenarios in the USA in year 2000.

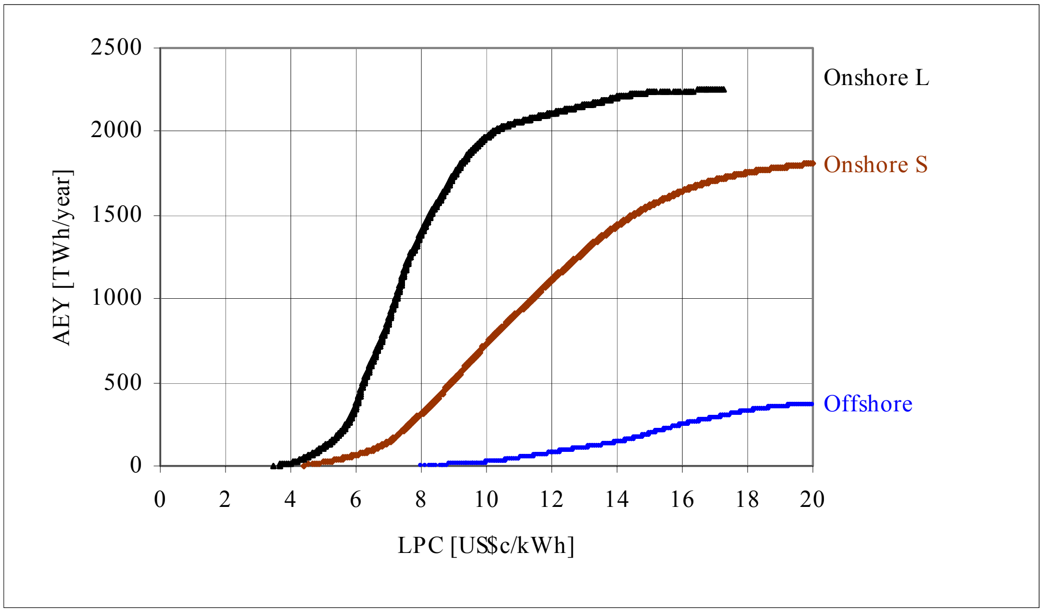


Figure 4.13: Cost-energy curves for the USA in 2000

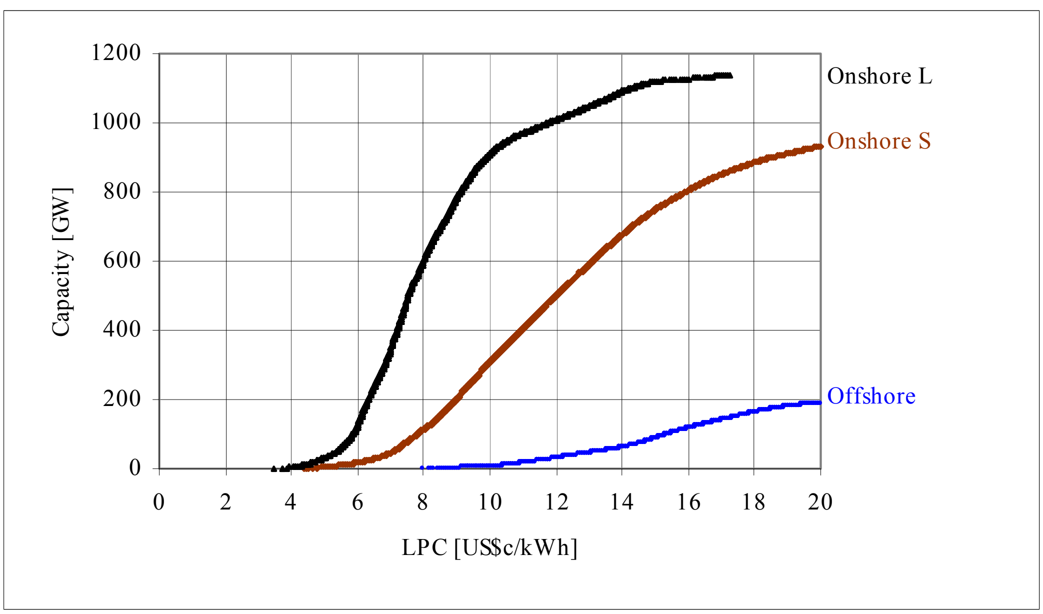


Figure 4.14: Cost-capacity curves for the USA in 2000

4.5.2 USA in 2020

Figure 4.15 and Figure 4.16 show, respectively, the relationship between estimated cumulative annual energy yield and installed capacity with lifetime production cost up to US$20c/kWh for the three wind energy scenarios in the USA in year 2020.

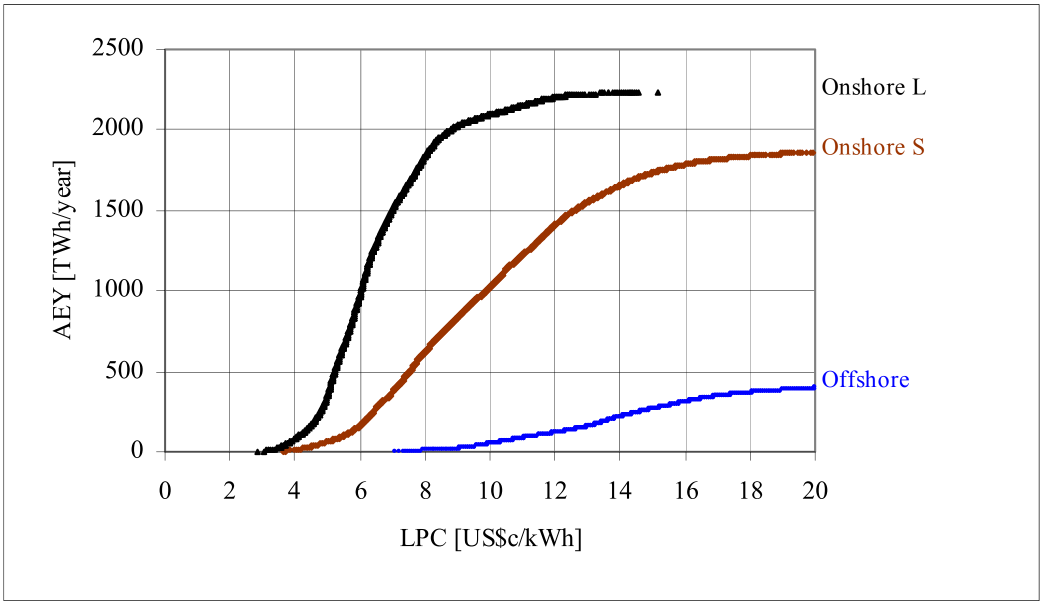


Figure 4.15: Cost-energy curves for the USA in 2020

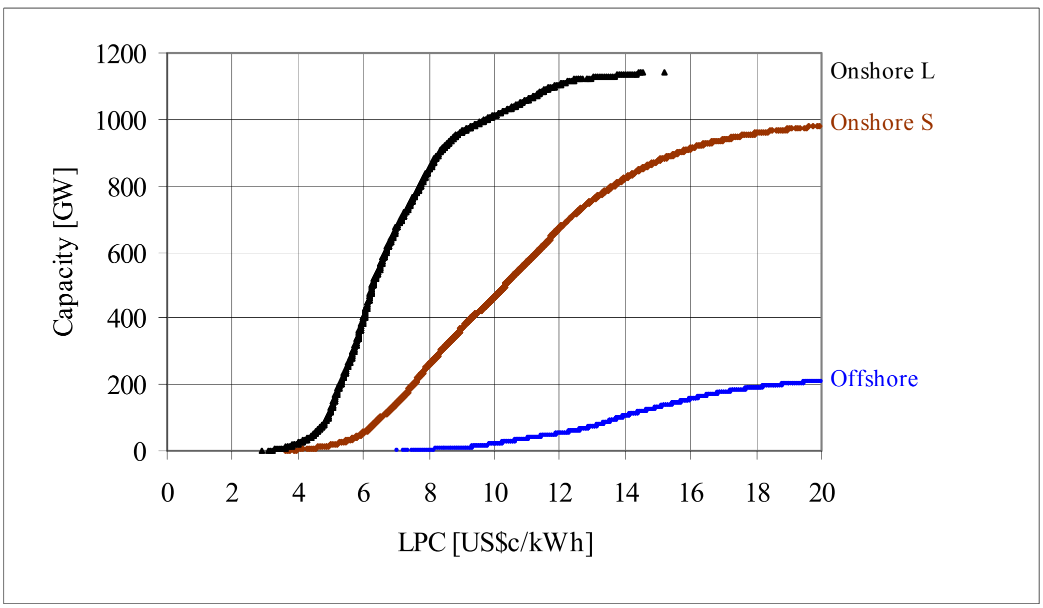


Figure 4.16: Cost-capacity curves for the USA in 2020

The "Wind Powering America" programme [14] aims to supply 5% of the nation's electricity from wind by 2020. From Table 7.2 it can be seen that this is some 227.5 TWh/year which Figure 4.15 indicates could be delivered from small or large onshore wind farms at LPCs up to 6.31 or 4.73 c/kWh respectively.

4.6 Discussion

The cost curves presented in Figure 4.1 to Figure 4.16 inclusive show, up to a maximum LPC of US$20c/kWh, the potential for wind energy as input to the emissions reduction analysis reported in Section 12. The dependence of the curves on scenario year is of secondary importance, apart from the general trend towards lower costs, due to the assumed 1% per annum reduction in wind farm capital costs (excluding grid connection). The other reason for differences between year 2000 and 2020 results is forecast changes in rural population densities and distributions. However, these do not appear to have altered the shapes of the curves significantly. It should be borne in mind throughout this discussion that LPCs are net of the system integration cost penalties which become increasingly significant for wind energy penetrations greater than 10% of regional demand.

4.6.1 Study regions and scenarios

Figure 4.17, Figure 4.18 and Figure 4.19 overleaf summarise the results for small onshore, large onshore, and offshore wind energy respectively in the four study regions in year 2020. Although the data ranges in the three graphs are different, the axes have been forced to the same scales to facilitate comparison between the three scenarios. Both axes are cumulative. Each line is a smoothed fit to points corresponding with LPCs from 4 to 20 c/kWh at 2 c/kWh intervals, with costs increasing with distance from the origin. Only small onshore curves extend over this LPC range for all four study regions. All large onshore curves start at 4 c/kWh and, where they end below 20 c/kWh, the highest LPCs are shown as labels in c/kWh on Figure 4.18. All offshore curves end at 20 c/kWh, but start at the following values: China and India 12 c/kWh, the EU-15 6 c/kWh, USA 8 c/kWh. Curves which start well away from the origin include a significant resource with LPC <4 c/kWh.

Cumulative capacity in each case is limited by the amount of available land or sea and by LPC which is primarily determined by wind speed. The gradients and positions of the lines reflect available wind speeds i.e. the closer a line is to the Y-axis, the higher the cumulative capacity factor. Furthermore, distances from the origin of given LPC points give an indication of available high wind speed land and sea areas.

It can be seen from Figure 4.1 to Figure 4.19 inclusive that:

- The first (i.e. lowest LPC) tranches of capacity are always most cheaply provided by large onshore wind farms, with small onshore wind farms being the next most expensive and offshore wind farms being the most expensive option. This is the same merit order as specific capital costs.
- Large onshore wind farms invariably offer greater potential at lower cost than do small onshore wind farms due to lower specific capital cost and greater concentration in high wind speed areas.
- Where the large onshore wind curves have pronounced “kinks”, these are due to capacity density limits being reached in individual countries, states or provinces.
- The potentials for onshore wind energy in China and the USA are on a similar scale, whereas those for the EU-15 and India are significantly smaller. The cumulative capacity factors for the EU-15 are intermediate between those for China and the USA, whereas those for India are significantly lower.
- In all four study regions, large onshore wind farms offer the greatest potential, though the three scenarios, especially onshore versus offshore, need not be mutually exclusive.
- The EU-15 offshore potential is comparable with its onshore potential. The USA also has a significant offshore potential, though much smaller than its onshore potential.

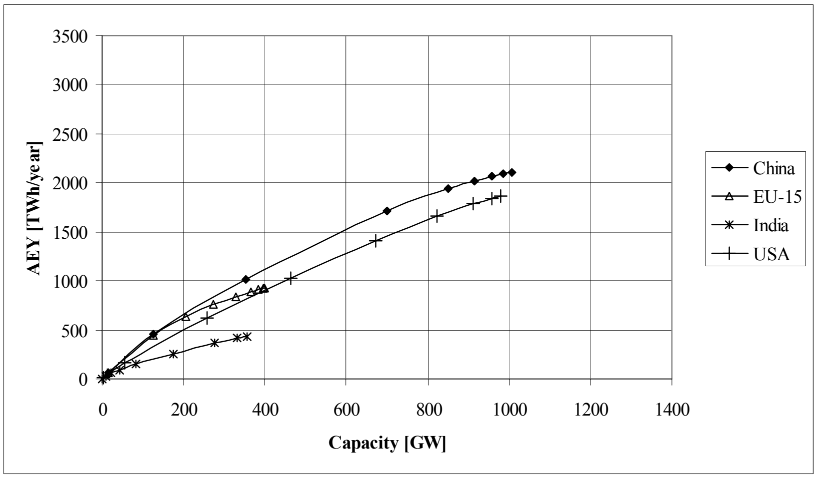


Figure 4.17: AEY vs capacity for small onshore wind farms in the study regions (2020)[8]

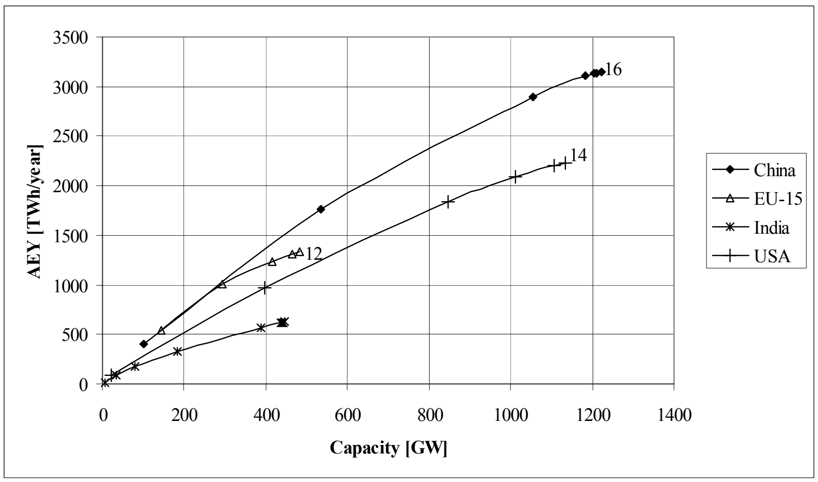


Figure 4.18: AEY vs capacity for large onshore wind farms in the study regions (2020)[8]

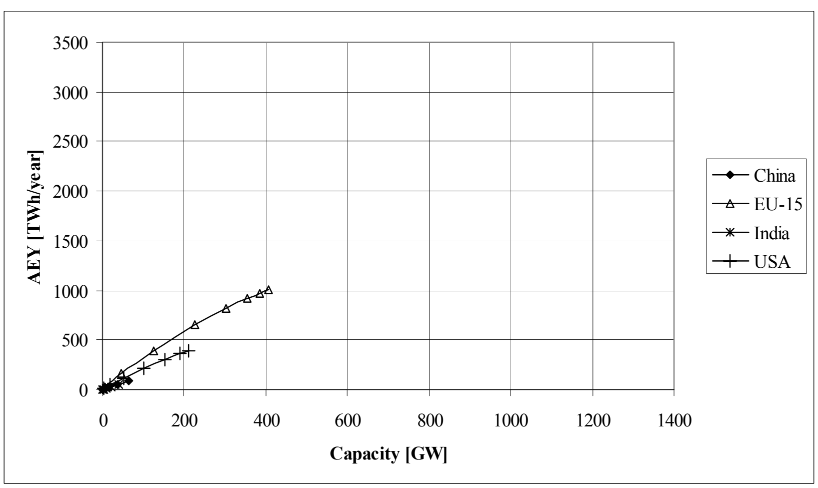


Figure 4.19: AEY vs capacity for offshore wind farms in the study regions (2020)[8]

[8] All unlabelled curves are generated from LPC points in 2c/kWh intervals up to 20c/kWh (furthest from origin). Maximum LPCs <20c/kWh are shown as labels in c/kWh on Figure 4.18.

4.6.2 Constraints on onshore wind farms

As described in Section 3.2.3, the analyses successively imposed constraints on the land available for onshore wind farm development:

- Environmental and technical constraints:
    - All IUCN Protected Areas in Categories I-VI.
    - Areas which are technically unsuitable e.g. forestry, inland water, urban and mountainous areas, and the entire Himalayan massif equivalent to the area labelled "Unknown" in the PNL map [8].
- Social constraints:
    - Local siting constraints, due to noise, determined by rural population density
    - A more general public acceptability limit of 0.15 MW/km^2 applied at different scales in the small and large wind farm scenarios (see Section 3.2.3.4)
- Cost constraints reflecting LPC for successive tranches of installed capacity, and limited to US$20c/kWh.

The cumulative impacts of these constraints were investigated for both small and large onshore wind farms as modelled in the four study regions for year 2020 to gain further insight into the reasons why the results for these two scenarios were more different than could be explained by capital cost assumptions alone. The results of these investigations are presented on the following pages in Figure 4.20 and Figure 4.21. The legends used in these figures should be interpreted as follows:

Legend	Definition
Enviro/Tech	Reduction due to environmental and technical constraints
Social	Reduction due to social constraints
Available	Remaining after environmental, technical and social constraints

Table 4.1: Legends used in Figure 4.20 and Figure 4.21

Each of these figures presents the same information using three different Y-axes (linear, logarithmic and percentage) to highlight different aspects of the results.

The logarithmic plots indicate that social constraints reduce wind energy potential by a broadly similar factor in all four study regions, that this reduction is well over an order of magnitude in all cases and that it is therefore the most important factor limiting the development of wind energy. AEY is consistently reduced less than capacity due to the preferential exclusion of low wind speed areas as explained in Section 3.

The greater proportions of AEY reduction in China and India due to technical and environmental constraints indicated in the percentage plot of Figure 4.20 may be attributed to removal of the entire Himalayan massif (for which high wind speeds were estimated) from the analysis as noted above. In terms of the proportion of land area, and hence capacity, removed, these are most significant in China and the USA.

Both AEY and capacity are invariably greater for large wind farms than for small wind farms in any study region. The difference is, however, consistently greater for AEY, confirming as expected that the capacity distribution of large wind farms is more concentrated into high wind speed locations.

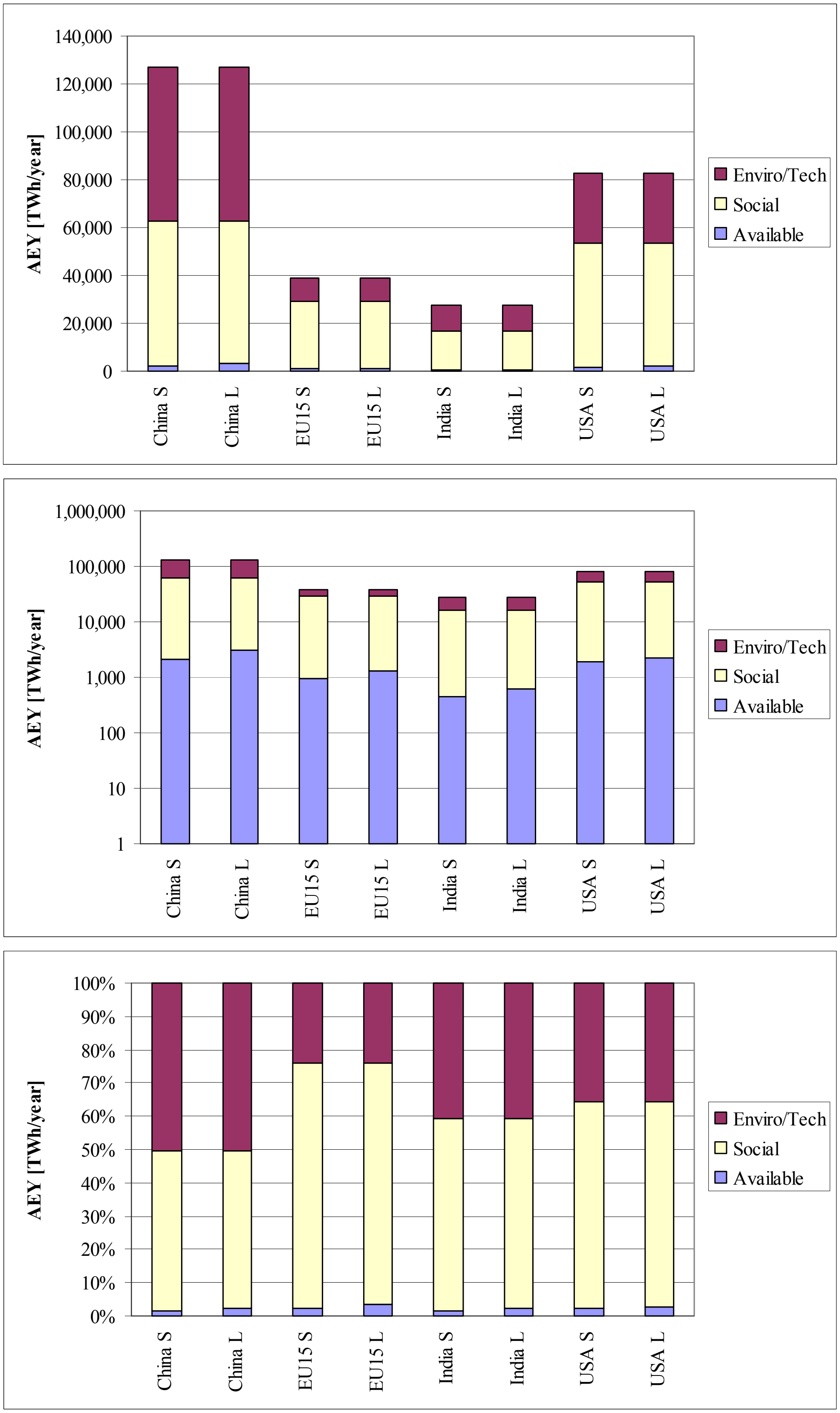


Figure 4.20: Effect of onshore wind farm development constraints on AEY (2020)

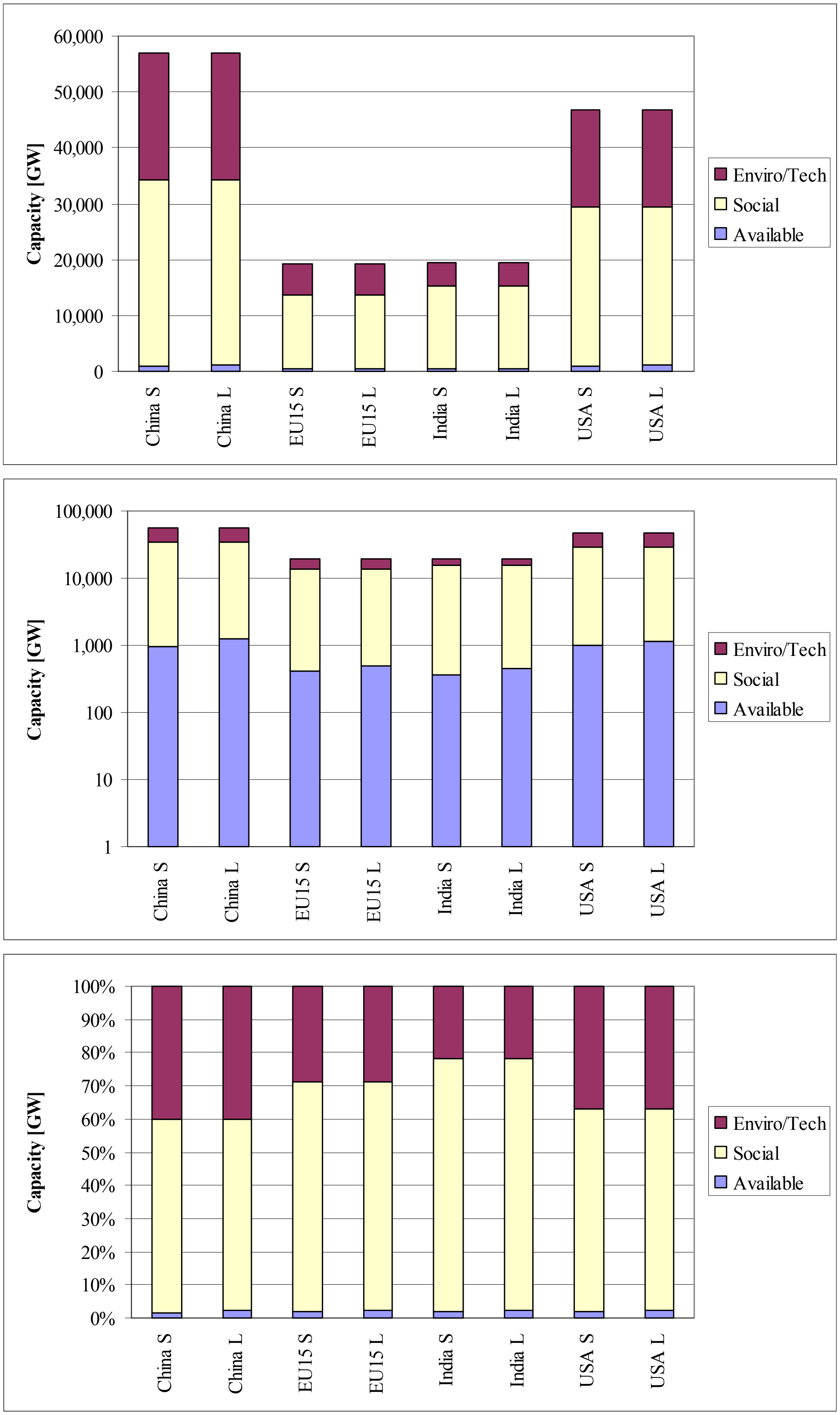


Figure 4.21: Effect of onshore wind farm development constraints on capacity (2020)

Even with zero rural population densities, the maximum capacity density allowed for onshore wind is 60 MW per 20×20 km area for small wind farms and 0.15 MW/km^2 per country, state or province for large wind farms. This limits the sites available for development to just 2.5% of total land area, although the maximum actual land take by turbines and infrastructure would typically be no more than 2% of this i.e. 0.05% of total land area.

Table 4.2 shows how land availability for wind farm development is reduced by the successive imposition of constraints, and shows more clearly the relative importance of these in the four study regions.

Study Region	Environmental and Technical	Social (Small)	Social (Large)
China	60.0%	1.7%	2.1%
EU-15	71.2%	2.1%	2.5%
India	78.3%	1.9%	2.3%
USA	63.0%	2.1%	2.4%

Table 4.2: Percent of total land area remaining after cumulative constraints

Finally, Figure 4.22 below shows the effect of cumulative constraints on mean capacity factor which is an indicator of the quality, as opposed to quantity, of the wind energy resource. It should be noted that these mean capacity factors have been calculated from cumulative AEY and capacity up to the limits imposed by the constraints, and that the Y-axis scale is linear.

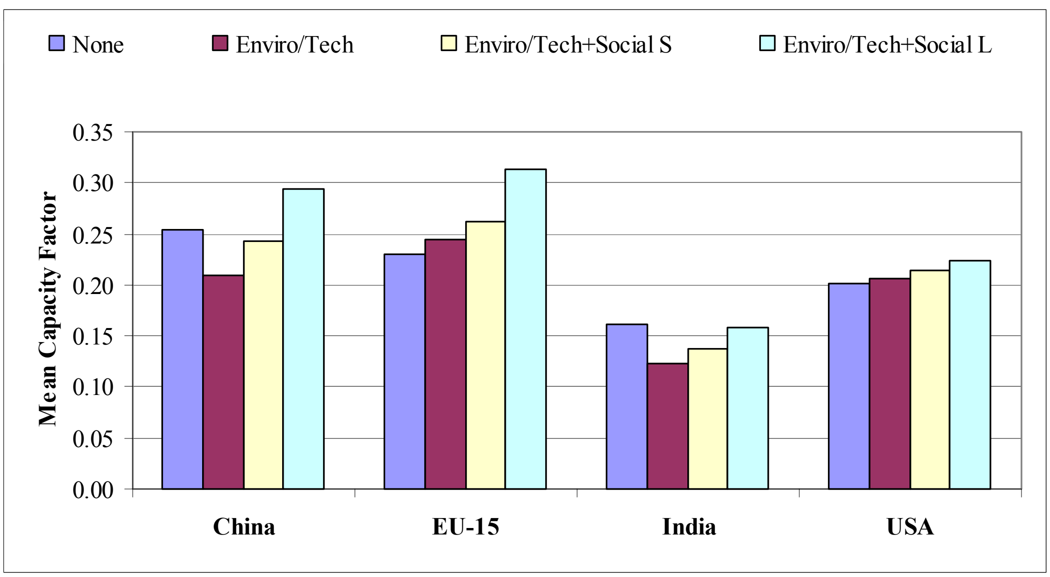


Figure 4.22: Effect of constraints on mean onshore wind farm capacity factors (2020)

This shows some rather more subtle effects of the constraints which may be summarised as follows:

- Technical and environmental constraints preferentially exclude onshore wind farm development from high wind speed areas in China and India, again due largely to the blanket exclusion of the Himalayan massif which has a particularly significant effect in India where wind speeds are otherwise generally low.

- Contrary to perceptions in some EU-15 countries, technical and environmental constraints do not preferentially exclude onshore wind farm development from high wind speed areas in the EU-15 or the USA. While some such constraints, such as mountainous areas, may be associated with above average wind resource, others such as urban areas may not. Furthermore, such constraints on development in the Great Plains of America's mid-west, where the largest wind resource in the USA is concentrated, are minimal.
- Social constraints preferentially exclude low wind speed areas from the remaining land in all four study regions. This reflects the analytical method, part of which removes available land on a "lowest wind speed first" basis, to an extent determined by rural population density, because most human settlement tends to be in sheltered locations.
- The large wind farms siting strategy, which permits increased clustering of developments in high wind speed areas subject to country, state or province-wide capacity density limits, invariably achieves higher mean capacity factors. This advantage is particularly significant in China and the EU-15, suggesting greater variability of the wind resource within, rather than between, states than in India and the USA. Only in India is the mean capacity factor of the socially constrained large wind farms scenario less than that of the whole country with no constraints at all.

5 POTENTIAL FOR WIND ENERGY: REST OF THE WORLD

5.1 Introduction

The analyses described in Section 3.3 were used to generate the graphs of cumulative annual energy yield (AEY) and cumulative capacity versus lifetime production cost (LPC). Only the former are presented in Sections 5.2 to 5.7 below as the cost-capacity curves were not used by Econ in their analysis described in Section 13. The following should be noted:

- These wind resource curves indicate marginal costs, whereas the CO_2 abatement curves in Sections 12 to 15 indicate average cumulative costs.
- Points for the small onshore and the offshore scenarios were generated at intervals of 600 MW and 200 MW capacity respectively to limit datasets to manageable sizes. The LPC assigned to each point is that of the most expensive increment of capacity (see Table 3.2 and Table 3.4) in that capacity interval. LPC for individual projects from which each point is generated may be anywhere between that LPC and the LPC of the next lowest point. In particular, capacity may be added initially with lower LPC than that assigned to the first point in each data series.
- Points for the large onshore scenarios were generated at 500 uniform LPC intervals between the minimum LPC and US$20c/kWh (see Section 3.3.2.2). The LPC assigned to each point is the mean of the range of maximum LPCs represented by that point. LPC for individual projects from which each point is generated may be anywhere between the maximum LPC for that point and the maximum LPC of the next lowest point.
- Although many of the graphs appear to be line plots, they are all scatter plots with no curve-fitting to the points. The discontinuities between the large onshore points should not be interpreted as indicating more limited resources, although this is still the case for the small onshore and offshore points. Indeed, the discontinuities at the start of several of the large onshore curves are due to very large tranches of energy (relative to the Y-axis scale) being introduced within each LPC interval.
- Several of the large onshore curves level off at higher LPCs and, in the case of the Middle East, intermittently at lower LPCs. This is because the capping factors applied (see Section 3.3.2.2) are decreasing more rapidly than the uncapped cumulative AEY is increasing over these ranges, and the algorithm used does not permit capped cumulative AEY to decrease with increasing LPC. The errors introduced by this limitation are negligible.
- LPC has been limited to US$20c/kWh and does not include system integration cost penalties which start to become significant at penetrations above 10% of regional demand. Such costs are, however, again modelled in the CO_2 abatement cost curves.
- Different Y-axis scales have been used for different study regions as the range of results is large. However, for any region, the same scales have been used for year 2000 and year 2020 curves of the same type to facilitate comparisons.
- The curves largely speak for themselves, and commentary on them at this stage has been kept to a minimum. They are discussed further in Section 5.8 and compared with existing and forecast total generation region by region in Section 7.1.

5.2 Africa

Figure 5.1 and Figure 5.2 show, respectively, the relationship between estimated cumulative annual energy yield and lifetime production cost up to US$20c/kWh for the three wind energy scenarios in Africa in years 2000 and 2020.

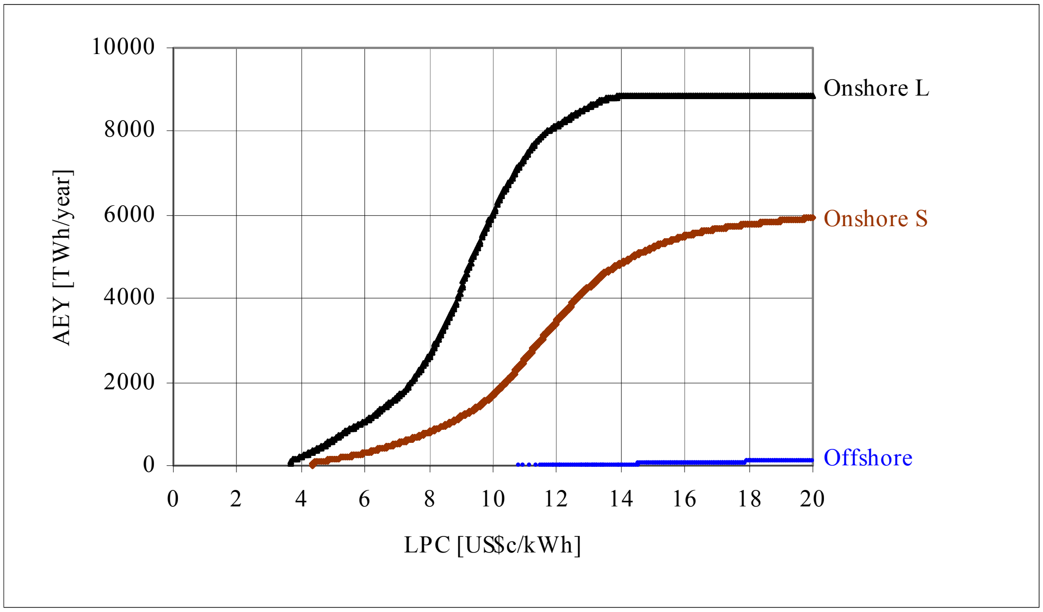


Figure 5.1: Cost-energy curves for Africa in 2000

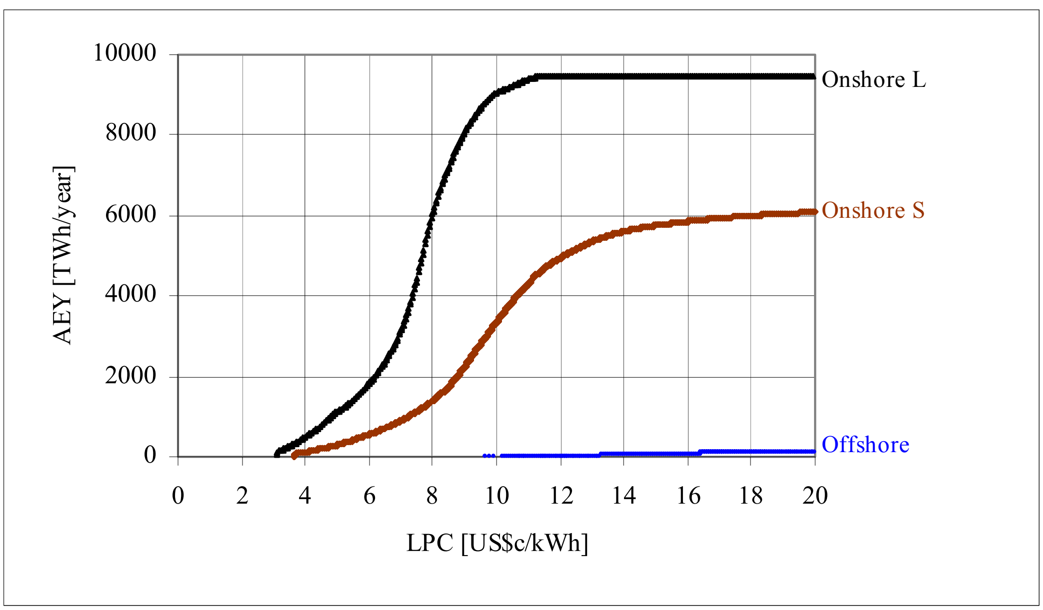


Figure 5.2: Cost-energy curves for Africa in 2020

5.3 Australia

Figure 5.3 and Figure 5.4 show, respectively, the relationship between estimated cumulative annual energy yield and lifetime production cost up to US$20c/kWh for the three wind energy scenarios in Australia in years 2000 and 2020.

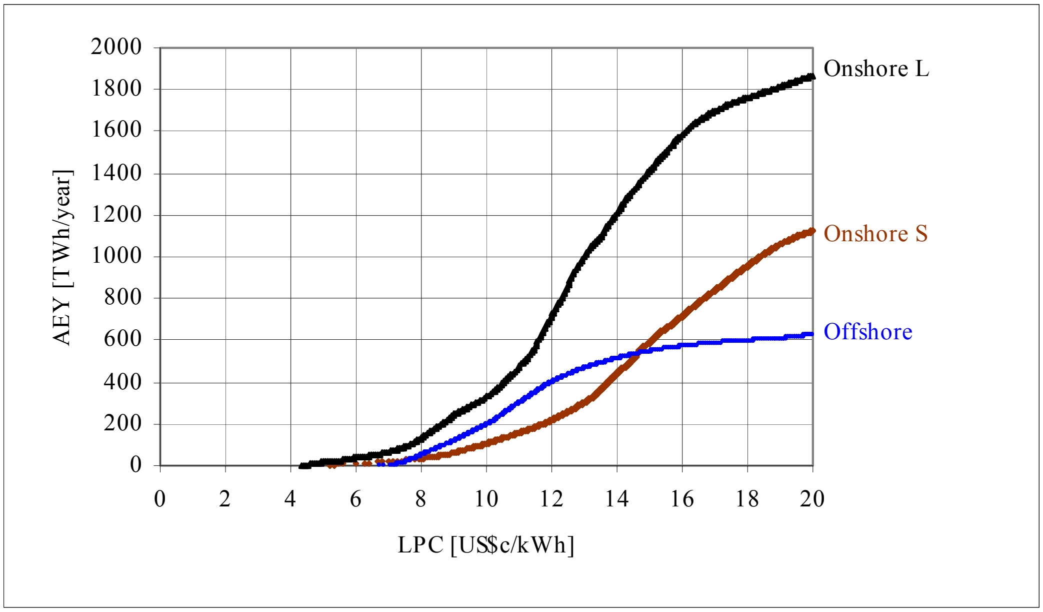


Figure 5.3: Cost-energy curves for Australia in 2000

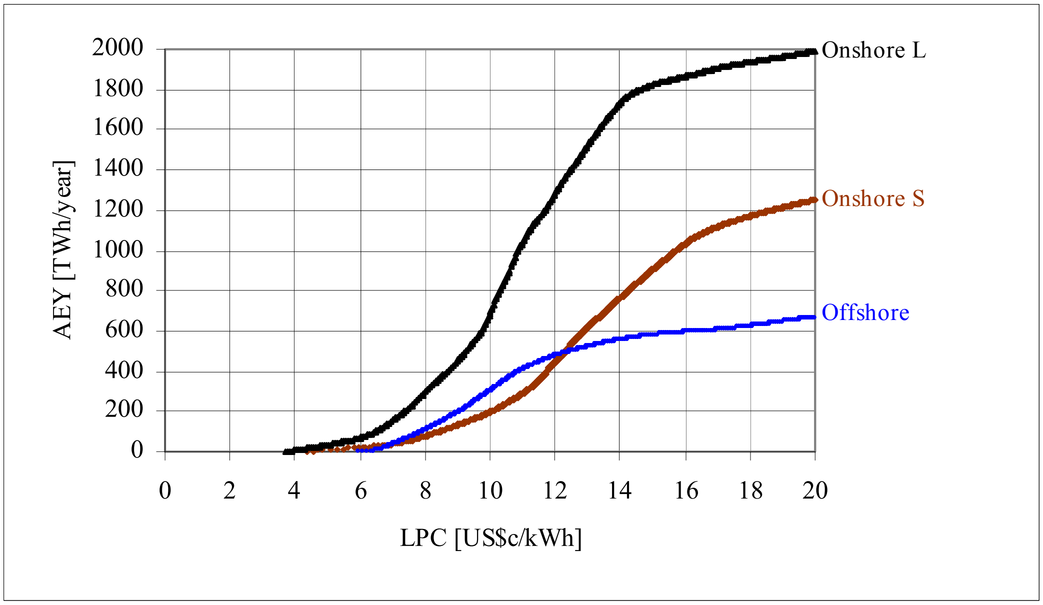


Figure 5.4: Cost-energy curves for Australia in 2020

5.4 Former Soviet Union and Eastern Europe

Figure 5.5 and Figure 5.6 show, respectively, the relationship between estimated cumulative annual energy yield and lifetime production cost up to US$20c/kWh for the three wind energy scenarios in the former Soviet Union (FSU) and Eastern Europe in years 2000 and 2020.

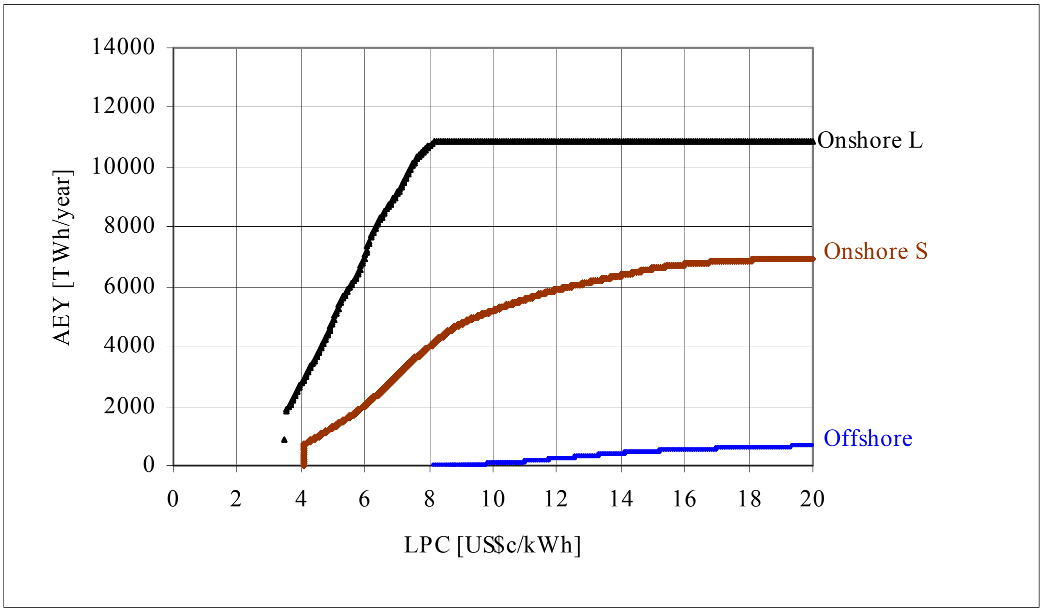


Figure 5.5: Cost-energy curves for the FSU and Eastern Europe in 2000

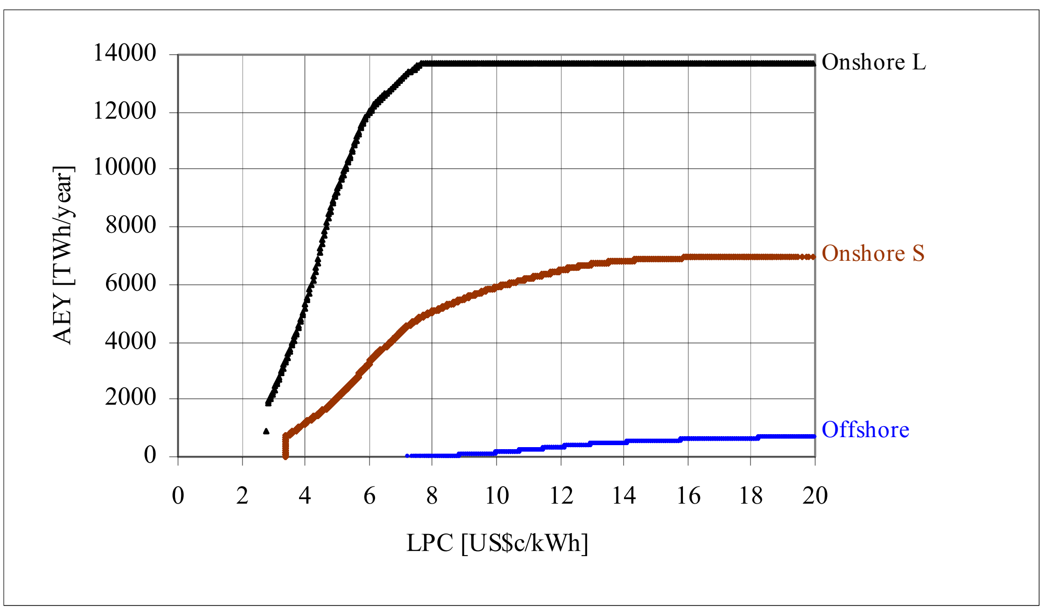


Figure 5.6: Cost-energy curves for the FSU and Eastern Europe in 2020

5.5 Latin America

Figure 5.7 and Figure 5.8 show, respectively, the relationship between estimated cumulative annual energy yield and lifetime production cost up to US$20c/kWh for the three wind energy scenarios in Latin America in years 2000 and 2020.

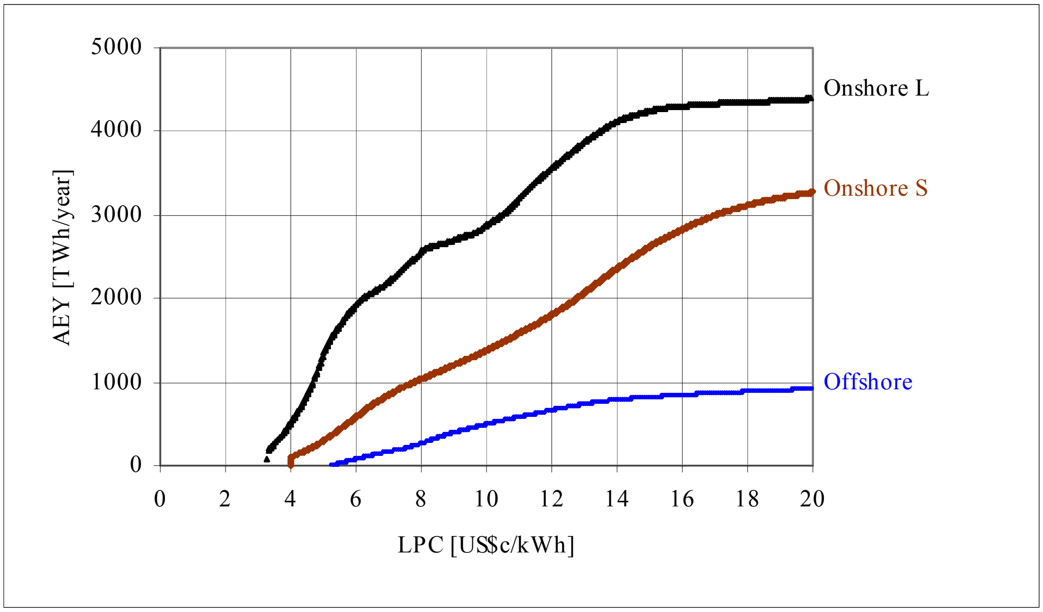


Figure 5.7: Cost-energy curves for Latin America in 2000

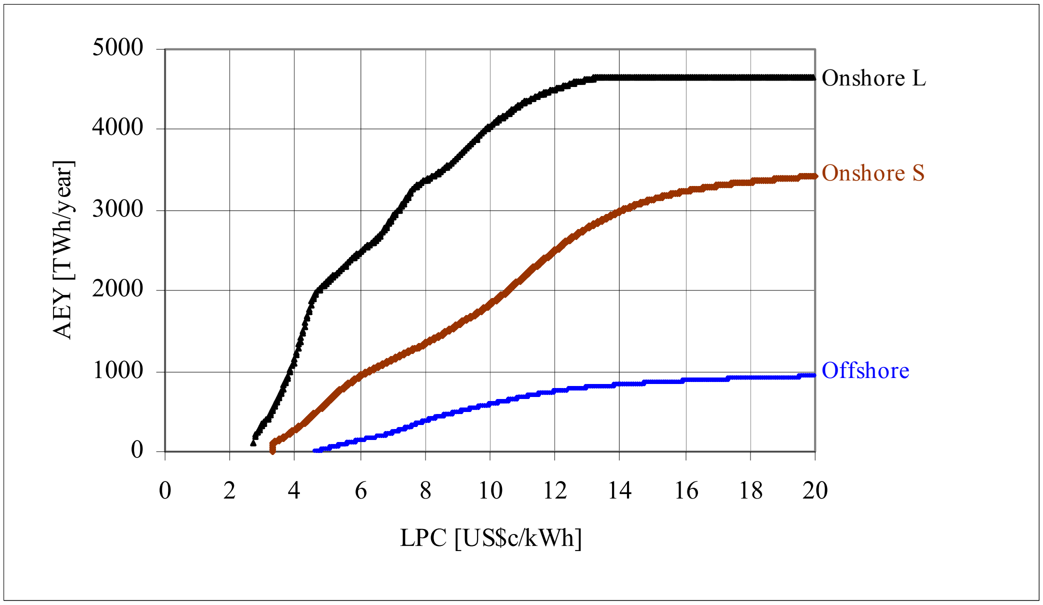


Figure 5.8: Cost-energy curves for Latin America in 2020

5.6 Middle East

Figure 5.9 and Figure 5.10 show, respectively, the relationship between estimated cumulative annual energy yield and lifetime production cost up to US$20c/kWh for the two onshore wind energy scenarios in the Middle East in years 2000 and 2020[9].

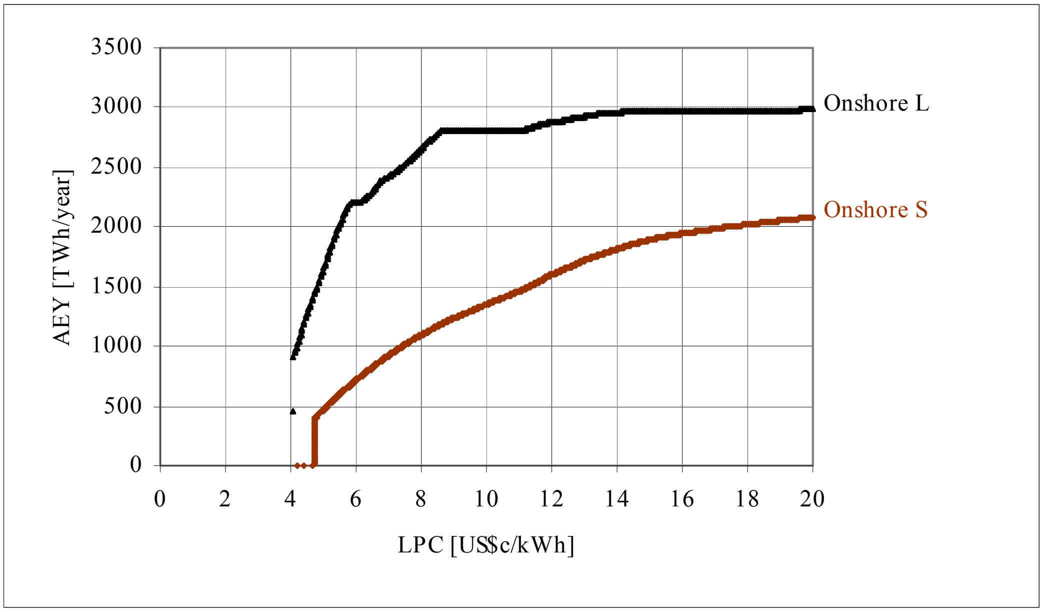


Figure 5.9: Cost-energy curves for the Middle East in 2000

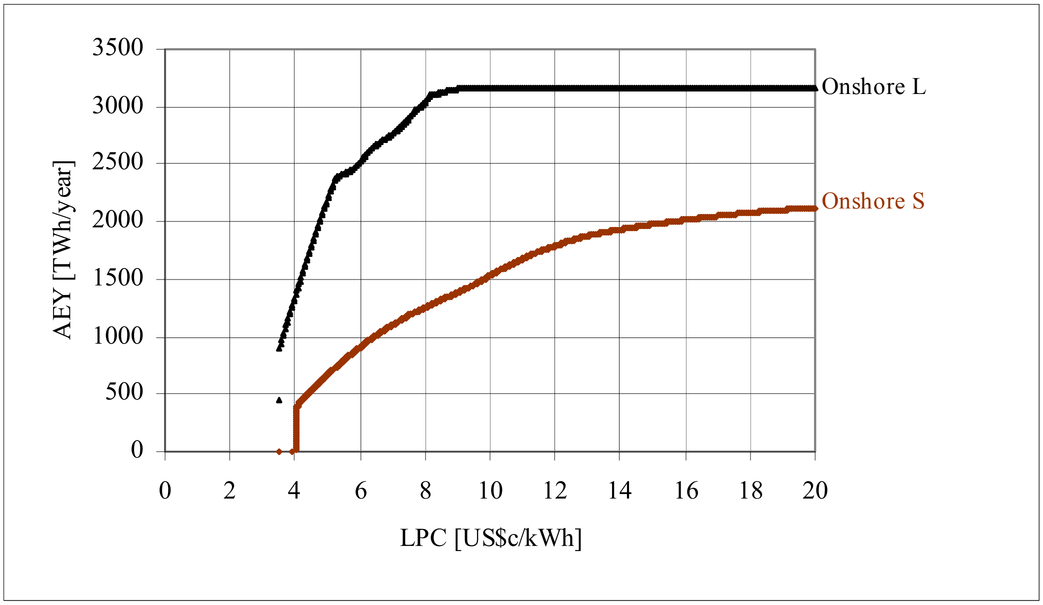


Figure 5.10: Cost-energy curves for the Middle East in 2020

[9] There is no offshore wind energy potential with LPC <20 c/kWh

5.7 Rest of Asia

Figure 5.11 and Figure 5.12 show, respectively, the relationship between estimated cumulative annual energy yield and lifetime production cost up to US$20c/kWh for the three wind energy scenarios in the rest of Asia in years 2000 and 2020.

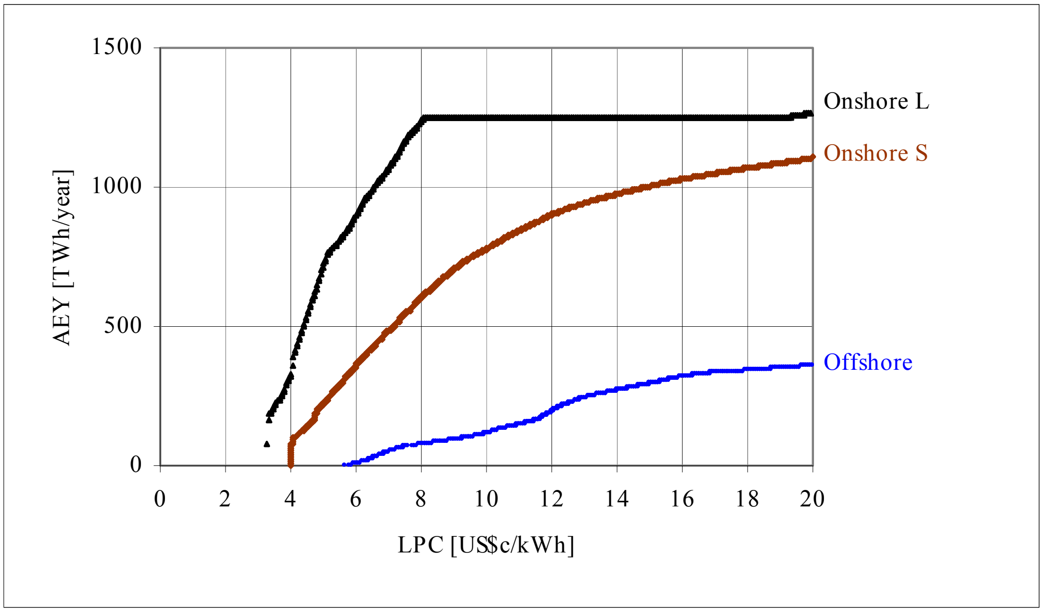


Figure 5.11: Cost-energy curves for the rest of Asia in 2000

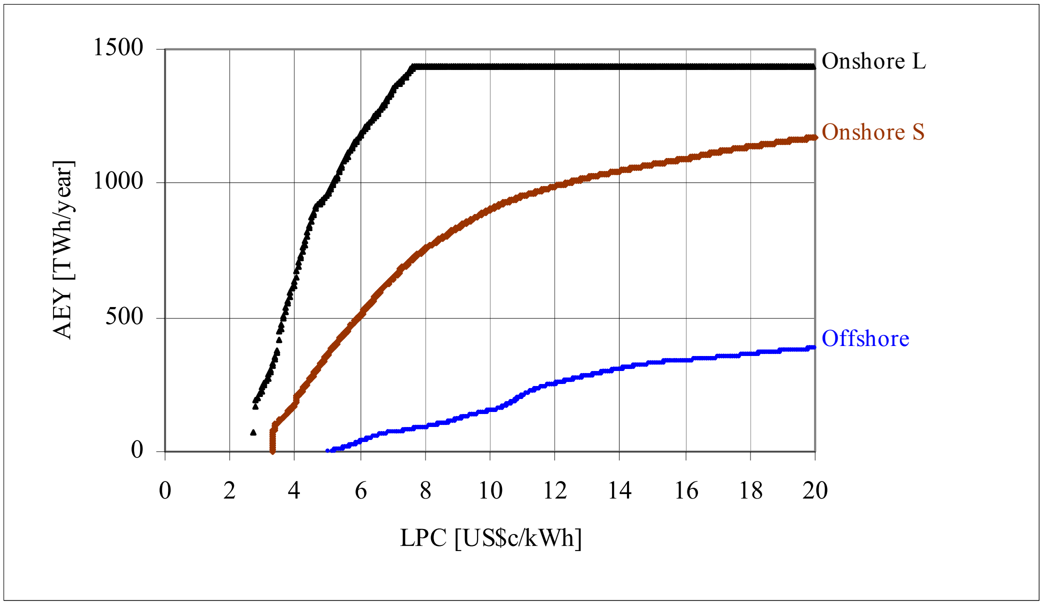


Figure 5.12: Cost-energy curves for the rest of Asia in 2020

5.8 Discussion

The cost curves presented in Figure 5.1 to Figure 5.12 inclusive show, up to a maximum LPC of US$20c/kWh, the potential for wind energy as input to the emissions reduction analysis reported in Section 13. Again, the dependence of the curves on scenario year is of secondary importance, apart from the slight lowering of costs across the board.

It can be seen from Figure 5.1 to Figure 5.12 inclusive that, over the range of lifetime production costs modelled, the general characteristics observed in the results for the four study regions are again apparent:

- The first (i.e. lowest LPC) tranches of capacity are always most cheaply provided by large onshore wind farms, with small onshore wind farms being the next cheapest and offshore wind farms being the most expensive option. This is the same merit order as specific capital costs.
- Large onshore wind farms invariably offer greater potential at lower cost than do small onshore wind farms due to lower specific capital cost and greater concentration in high wind speed areas.
- The large onshore wind curves have pronounced "kinks". However, the origin of these is somewhat different than for the study regions, and may be attributed to the combined effect of the uncapped curves, the ratios applied and other aspects of the method described in Section 3.3.2.2.

Additionally:

- In all regions, large onshore wind farms again offer the greatest potential. As noted previously, the three scenarios, especially onshore versus offshore, need not be mutually exclusive.
- Only in Australia do offshore wind farms offer greater potential than small onshore wind farms at any point along the cost curves.
- Africa, the FSU and Eastern Europe, and the Middle East have very little offshore potential compared with that onshore[10]. All three regions have a high ratio of land area to available offshore waters (as noted previously, the entire FSU coastline north of 70° N was removed from the analysis due to the severity of environmental conditions such as sea ice).

[10] The Middle East has no offshore potential below 20 c/kWh

6 POTENTIAL FOR WIND ENERGY: SENSITIVITY STUDIES

6.1 Introduction

The analytical assumptions summarised in Section 3, while either specified in the standard assessment criteria (Appendix C) or informed "best guesses" made by Garrad Hassan, are all open to challenge. The impact of two plausible alternative key assumptions was tested for the EU-15 by re-running the analyses for each scenario in year 2020.

6.1.1 Discount rate

The standard assessment criteria specify that a 10% discount rate be used for the main analyses, but that the effect of a 5% discount rate be investigated. These discount rates are used in all of the IEA Greenhouse Gas R&D Programme's studies of greenhouse gas abatement options to ensure a consistent approach and to facilitate comparisons. Some energy sector industries routinely use discount rates higher than 10%. On the other hand, it is known to Garrad Hassan that some wind farm developers have used discount rates even lower than 5%, and that Utilities developing wind farms routinely use discount rates of 6 - 8%.

6.1.2 Future wind farm capital costs

As indicated in Table 3.2 and Table 3.4, a 1% annual rate of wind farm capital cost reduction, excluding grid connection costs which remained constant, was assumed for the main analyses. This figure was taken from "Wind power development – Status and perspectives" published by Risø National Laboratory in August 1998 [9]. This reviewed several independent analyses and concluded that the rate of future wind farm annual capital cost reduction range was likely to be between 1% and 2.5%.

A subsequent literature review by Garrad Hassan revealed a good deal of speculation about future unit electricity costs from wind farms, but few authoritative indications of future capital costs. To complicate matters further, future capital cost projections tend to be associated with increased wind turbine sizes, whereas the terms of reference of this study specified that constant sizes be assumed between 2000 and 2020.

Essentially, there are two inter-dependent routes to future wind farm capital cost reductions:

- Improved wind turbine design (which need not result in larger machines, though this has been the trend for more than a decade)
- Increased manufacturing volumes, which would undoubtedly be required to provide the capacities indicated in Sections 4 and 5.

A comprehensive analysis of the former route is provided in a December 1997 document "Advanced horizontal axis wind turbines in wind farms" in "Renewable energy technology characterisations", a joint project of the Office of Power Technologies, Energy Efficiency and Renewable Energy, U S Department of Energy and the Electric Power Research Institute [2]. This forecasts capital cost reductions due to technology improvement without assuming massive increase of production volume. The cost trends for wind turbine component groups are provided with explanations. The predicted reduction of all-in capital cost from $1000/kW "now" (1996) to $655/kW in 2020 is equivalent to an annual reduction rate of approximately 1.75%.

The emphasis is on the latter route in "Wind Force 10 – a blueprint to achieve 10% of the world's electricity from wind power by 2020" published jointly by the European Wind Energy Association, the Forum for Energy and Development, and Greenpeace International in

October 1999 [15]. The analysis therein, by BTM Consult, is based on industrial learning curve theories, developed by the Boston Consulting Group, which can be expressed as "progress ratios" i.e. generalised indications of the sensitivity of cost upon production volume for manufactured goods. Wind farm capital costs are forecast to fall from $1000/kW "now" (1998) to $522/kW in 2020, equivalent to an annual reduction rate of approximately 2.9%.

Two other noteworthy references addressing the impacts of increased manufacturing volumes are “Grid-connected wind energy technology: progress and prospects” published by the US National Renewable Energy Laboratory (NREL) in November 1998 [16] and “The effects of increased production on wind turbine costs” prepared for NREL by Princeton Economic Research Inc. in December 1995 [17]. The former predicts that wind turbine costs will fall by about 5% every time industry production doubles, with 4 – 5 doublings expected by 2030. The latter, which includes a comprehensive review of relevant learning curve papers, anticipates volume discounts of 10 – 34% for production volumes ranging from 1,000 to 30,000 turbines. This is equivalent to an annual cost reduction of about 0.7%.

Taken together, these four key references suggested that a reasonable alternative annual rate of wind farm capital cost reduction, excluding grid connection costs, was 2.2%. The detailed arguments are not reproduced in this report. Instead, the interested reader is invited to consult these four references directly.

6.2 Results

The results of the sensitivity analyses, using the alternative assumptions described above for all three scenarios in the EU-15 in 2020, are presented in Figure 6.1 to Figure 6.6 on the following three pages. Again, these graphs are scatter plots with no lines fitted between the points.

In each graph, the line labelled “Base case” has been taken from the main analyses i.e. using 10% discount rate and 1% annual capital cost reduction. The lines labelled “5% discount” and “-2.2% pa capex” show the effects of reduced discount rate and capital cost respectively. The combined effect of these alternative assumptions was not modelled.

For all three scenarios, LPCs falls further as a result of reducing the discount rate than of reducing capital costs. The effects of both are greatest at the low cost end of the curves, and tend to become insignificant, especially on cumulative AEY, at higher costs.

6.2.1 Small onshore wind farms

Figure 6.1 and Figure 6.2 show, respectively, the impacts of reduced discount rates and wind farm capital costs, as described above, on the cost-energy and cost-capacity curves for small offshore wind farms in the EU-15 in year 2020.

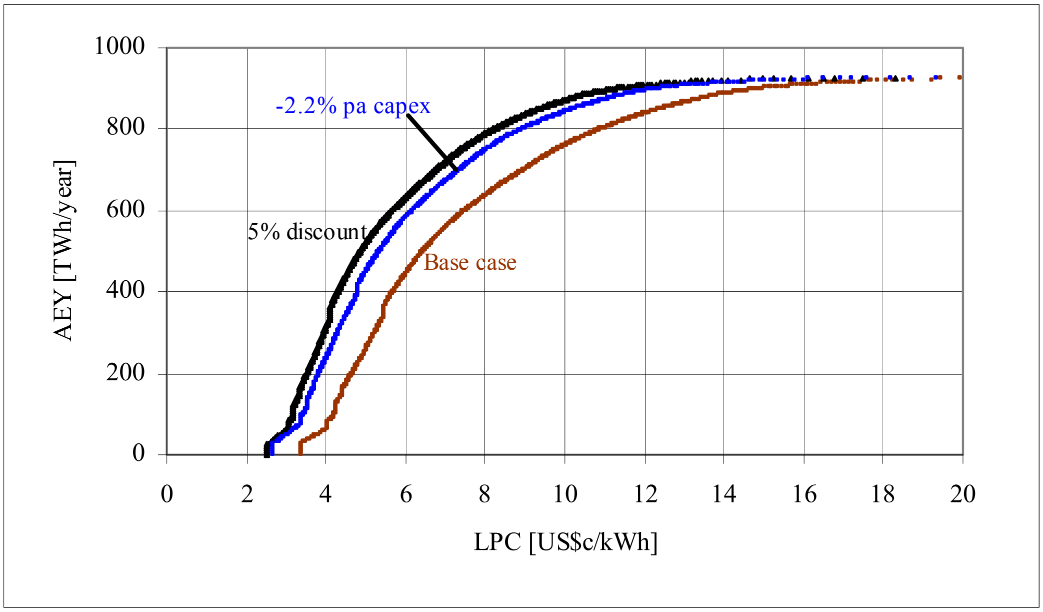


Figure 6.1: Sensitivities of small onshore wind farm cost-energy curves

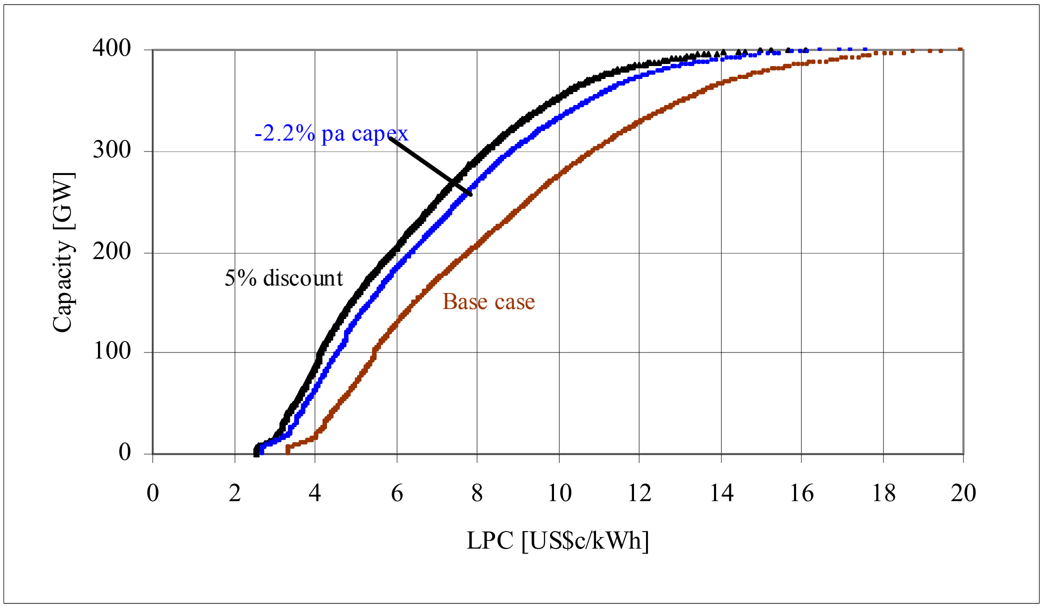


Figure 6.2: Sensitivities of small onshore wind farm cost-capacity curves

6.2.2 Large onshore wind farms

Figure 6.3 and Figure 6.4 show, respectively, the impacts of reduced discount rates and wind farm capital costs, as described above, on the cost-energy and cost-capacity curves for large onshore wind farms in the EU-15 in year 2020.

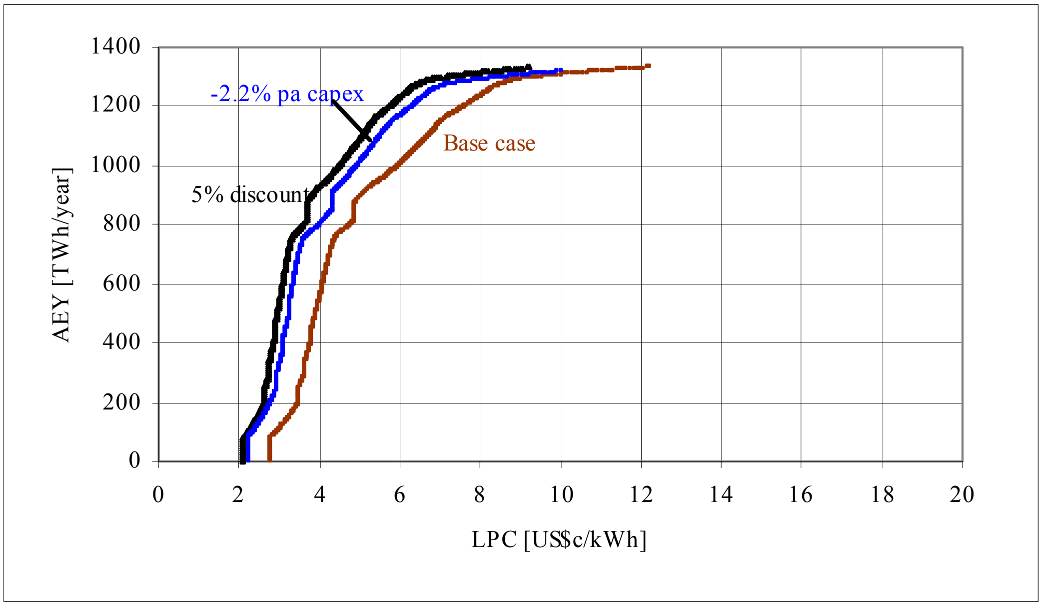


Figure 6.3: Sensitivities of large onshore wind farm cost-energy curves

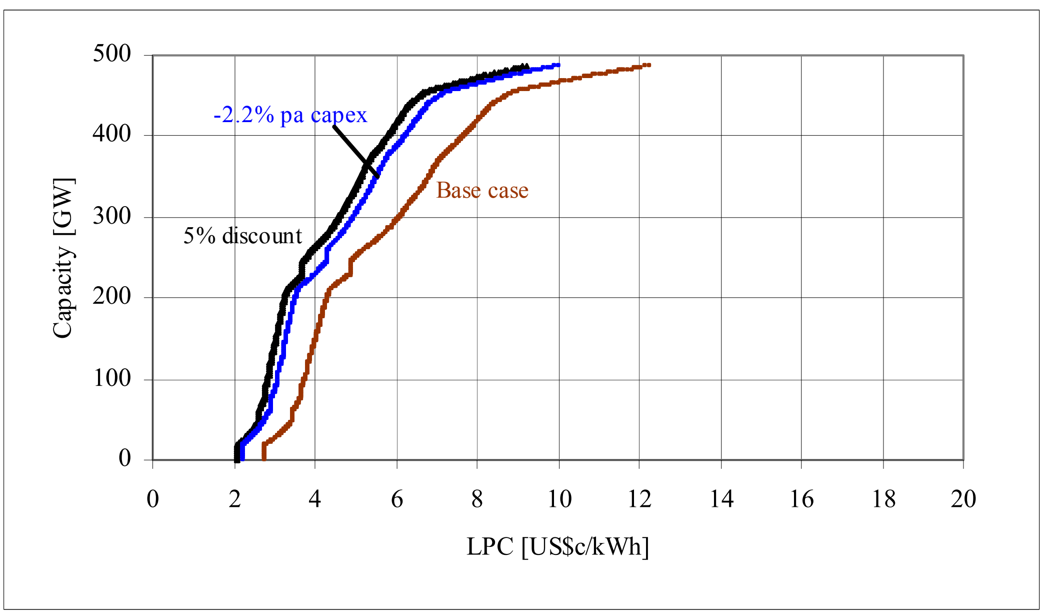


Figure 6.4: Sensitivities of large onshore wind farm cost-capacity curves

6.2.3 Offshore wind farms

Figure 6.5 and Figure 6.6 show, respectively, the impacts of reduced discount rates and wind farm capital costs, as described above, on the cost-energy and cost-capacity curves for offshore wind farms in the EU-15 in year 2020.

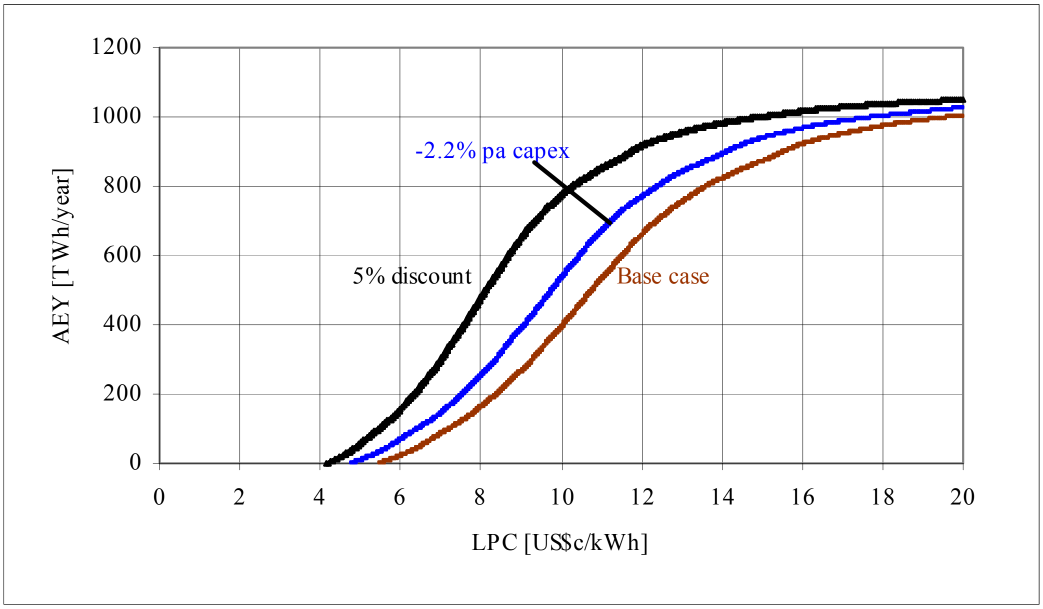


Figure 6.5: Sensitivities of offshore wind farm cost-energy curves

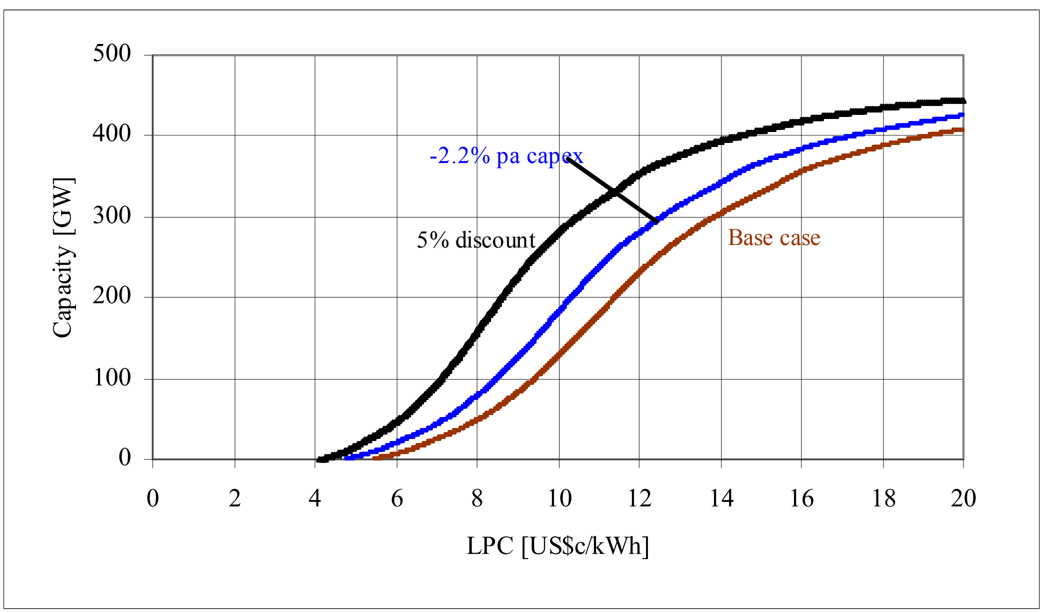


Figure 6.6: Sensitivities of offshore wind farm cost-capacity curves

7 GLOBAL POTENTIAL FOR WIND ENERGY

7.1 Largest and Cheapest Scenarios

Table 7.1 and Table 7.2 below summarise the key interim results for large onshore wind energy potential in each of the regions in 2000 and 2020 respectively. In all cases this was both the largest and the cheapest of the three scenarios modelled. Both tables show, for each region in turn, and from left to right: forecast total annual electricity demand in TWh, estimated AEY from large onshore wind farms at <20c/kWh in TWh and as a proportion of forecast total annual demand, similar estimates for <5c/kWh, and the lowest LPC in c/kWh.

It is important to note that the wind AEY figures in Table 7.1 and Table 7.2, like the cost-resource curves from which they are derived, make no allowance for curtailment and other system integration cost penalties[11] discussed in Section 8, nor can they be interpreted as indications of firm capacity. They are, nonetheless, of interest for comparison between regions on the same interim basis.

Region	Total demand TWh/yr	Wind AEY <20c/kWh TWh/yr	Proportion of total demand	Wind AEY <5c/kWh TWh/yr	Proportion of total demand	Min LPC c/kWh
Africa	437	8,864	2,028%	627	143%	3.65
Australia	195	1,864	956%	16	8%	4.32
China	1,392	3,144	226%	673	48%	3.49
EU-15	2,334	1,334	57%	667	29%	3.36
FSU+E Europe	1,882	10,882	578%	4,742	252%	3.48
India	536	614	115%	22	4%	3.84
Latin America	944	4,391	465%	1,309	139%	3.30
Middle East	379	2,987	788%	1,629	430%	4.05
Rest of Asia	1,996	1,267	63%	727	36%	3.30
USA	3,519	2,254	64%	107	3%	3.45
Global	**13,614**	**37,601**	**276%**	**10,519**	**77%**	**3.30**

Table 7.1: Summary results for large onshore wind energy potential in 2000

Region	Total demand TWh/yr	Wind AEY <20c/kWh TWh/yr	Proportion of total demand	Wind AEY <5c/kWh TWh/yr	Proportion of total demand	Min LPC c/kWh
Africa	851	9,464	1,112%	1,116	131%	3.09
Australia	290	1,991	687%	32	11%	3.71
China	3,565	3,149	88%	1,088	31%	2.89
EU-15	3,030	1,332	44%	891	29%	2.79
FSU+E Europe	3,298	13,715	416%	9,245	280%	2.78
India	1,408	624	44%	50	4%	3.25
Latin America	2,073	4,661	225%	2,107	102%	2.73
Middle East	839	3,167	377%	2,180	260%	3.48
Rest of Asia	3,853	1,439	37%	956	25%	2.73
USA	4,550	2,238	49%	345	8%	2.87
Global	**23,757**	**41,780**	**176%**	**18,010**	**76%**	**2.73**

Table 7.2: Summary results for large onshore wind energy potential in 2020

[11] Subsequent sections indicate that wind penetrations of up to 10% do not incur system integration cost penalties beyond those modelled in the analyses thus far.

Table 7.1 and Table 7.2 provide useful insights into the potential of wind energy as a generation option in its own right, aside from the issue of CO_2 mitigation. The range of proportions of total electricity demand represented by wind energy potentials varies widely from region to region. This is illustrated graphically in Figure 7.1 and Figure 7.2 below. The bold line on each plot shows parity of total electricity demand and wind energy potential.

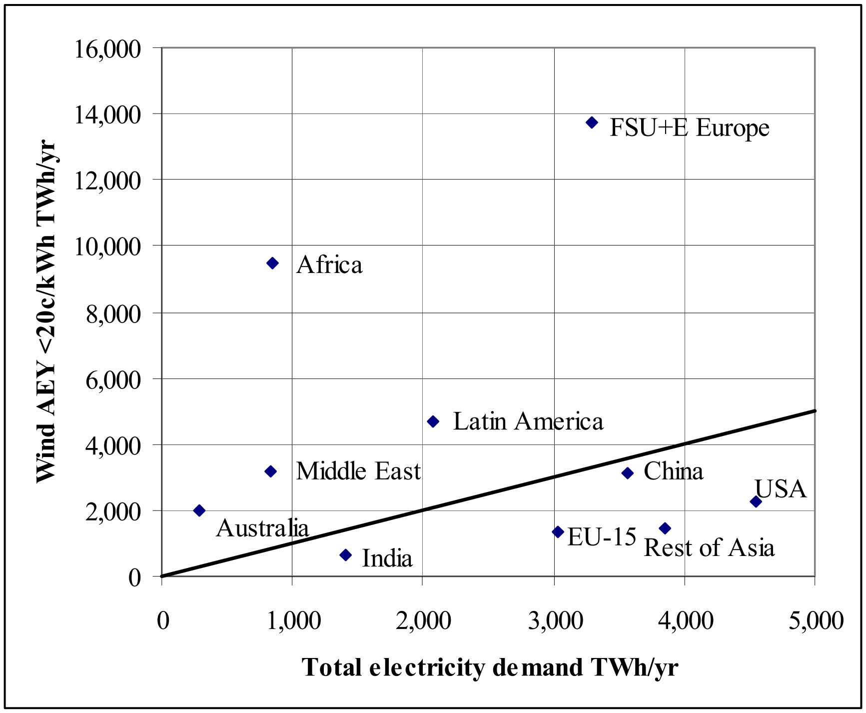


Figure 7.1: Large onshore wind potential <20c/kWh v total electricity demand (2020)

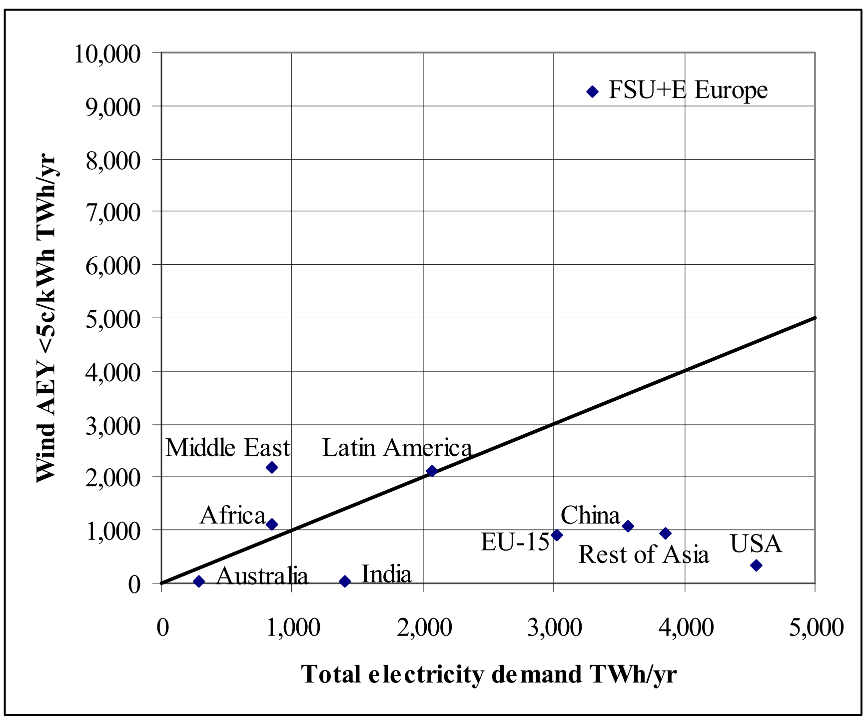


Figure 7.2: Large onshore wind potential <5c/kWh v total electricity demand (2020)

To investigate this range of results further, all annual energy figures in Table 7.2 were divided by the total surface areas of the regions modelled to estimate their mean spatial densities. These results are shown graphically below in Figure 7.3 and Figure 7.4 and summarised in Figure 7.5 overleaf. The bold line on each plot shows parity of total electricity demand density and wind energy potential density.

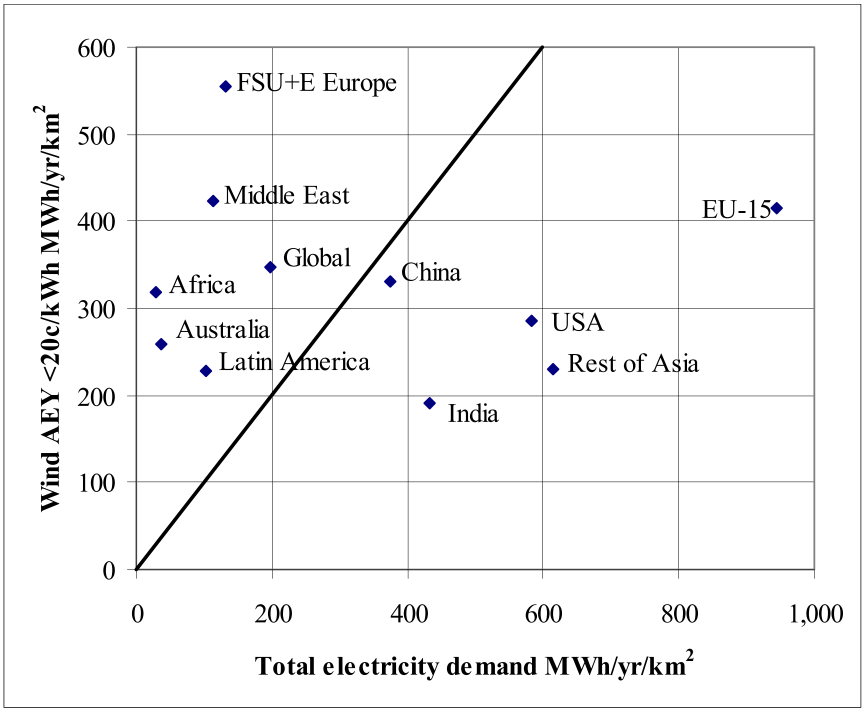


Figure 7.3: Potential AEY density <20c/kWh v total electricity demand density (2020)

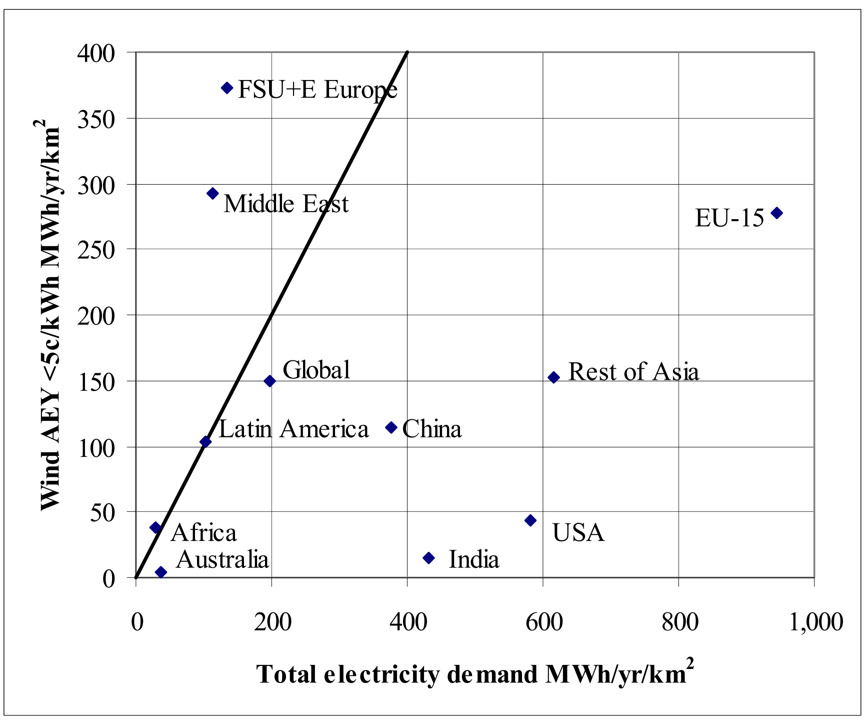


Figure 7.4: Potential AEY density <5c/kWh v total electricity demand density (2020)

Figure 7.5 shows the information presented in Figure 7.3 and Figure 7.4 in a different format.

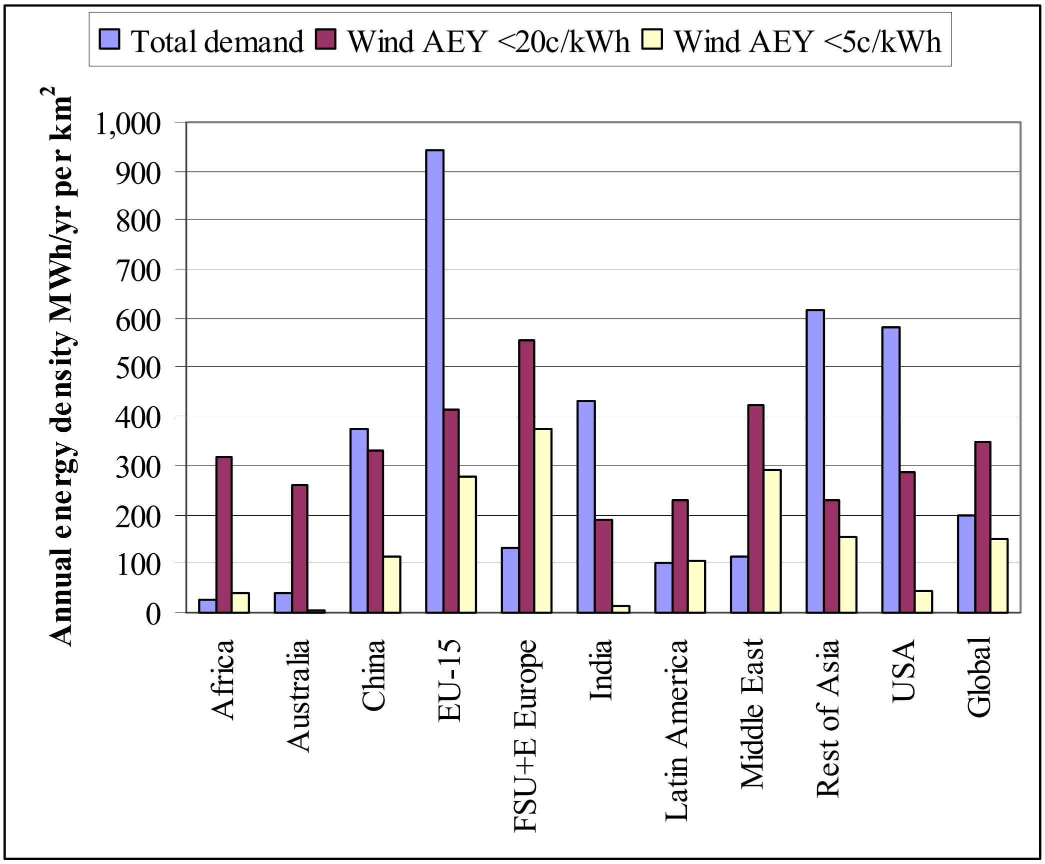


Figure 7.5: Total demand and wind AEYs normalised to surface area by region (2020)

The following interim conclusions may be drawn from Table 7.1, Table 7.2 and Figure 7.1 to Figure 7.5:

- Relating the large onshore wind energy potential to forecasts of total annual electricity demand highlights the differences between 2000 and 2020, especially in high growth regions. Over this period estimated global demand will increase by 75% and global wind potential at <5c/kWh by 71%.
- There is no significant correlation between total electricity demand and wind energy potential, either in absolute amounts or as spatial densities.
- There is a much wider range between regions of density of total electricity demand than of wind AEY <20 c/kWh. Demand density in the EU-15, for example, is some 33 times greater than that in Africa. This factor is the principal determinant of the wide range of relationships between wind energy potential and total electricity demand. The greatest density of wind AEY <20 c/kWh is less than three times the size of the smallest.
- To a first approximation, installable wind energy capacity will be roughly proportional to surface area, and the density of wind AEY therefore provides a broad indication of the average windiness of each region. It can be seen that the EU-15, the FSU and Eastern Europe and the Middle East are all above the global average in this respect for LPCs <20 c/kWh. These same regions, plus the Rest of Asia, are above the global average for LPCs <5 c/kWh.

- The FSU and Eastern Europe is the clear winner in terms of wind energy potential which greatly exceeds its total electricity demand. Resource also exceeds demand in Africa, the Middle East, Latin America and, at <20 c/kWh only, Australia, though it must be remembered that all LPC thresholds are net of system integration cost penalties as noted earlier.
- The minimum LPC net of system costs in any region is invariably lower in 2020 than in 2000, as is the LPC for a given amount of capacity or energy. This is due to reductions in capital costs. As total electricity demand invariably increases from 2000 to 2020, system integration cost penalties for a given level of wind energy output may also be expected to decrease over this period.
- The maximum LPC for a given level of wind penetration, however, is not necessarily lower in 2020 than in 2000. This is illustrated for 10% penetration (the maximum before system cost penalties are assumed to arise) in Table 7.3 below which indicates that the maximum LPC increases over this period in China, India and the Rest of Asia. These increases arise because growth in demand (and hence the wind capacity required for 10% penetration) has forced the development of less cost-effective sites which more than offsets the effects of capital cost reductions. Maximum LPC does not increase in other high growth regions such as Africa, Latin America and the Middle East because the wind energy potential still exceeds 10% of demand by such a large margin.

Region	10% of 2000 demand TWh/yr	Max LPC c/kWh	10% of 2020 demand TWh/yr	Max LPC c/kWh	Demand increase 2000 to 2020 percent	Change in max LPC 2000 to 2020 c/kWh
Africa	43.7	3.6	85.1	3.1	94.7%	-0.50
Australia	19.5	5.2	29.0	4.9	48.7%	-0.30
China	139.2	3.8	356.5	3.9	156.1%	+0.10
EU-15	233.4	4.1	303.0	3.7	29.8%	-0.40
FSU+E Europe	188.2	3.5	329.8	2.8	75.2%	-0.70
India	53.6	6.0	140.8	7.3	162.7%	+1.30
Latin America	94.4	3.3	207.3	2.8	119.6%	-0.50
Middle East	37.9	4.0	83.9	3.5	121.4%	-0.50
Rest of Asia	199.6	3.4	385.3	3.5	93.0%	+0.10
USA	351.9	6.0	455.0	5.2	29.3%	-0.80

Table 7.3: Change of maximum large onshore LPC for 10% penetration 2000 - 2020

7.2 Global Cost Curves

The potential for wind energy in each of the ten regions modelled has been presented in the form of individual cost-energy and cost-capacity curves for each scenario in Sections 4 and 5. These results have been aggregated to generate the global curves shown on the following two pages in Figure 7.6 to Figure 7.9.

7.2.1 2000

Figure 7.6 and Figure 7.7 show, respectively, aggregated global cost-energy and cost-capacity curves for the three scenarios in 2000. For comparison, the total generated output in the ten regions modelled is estimated to be 13,614 TWh/year.

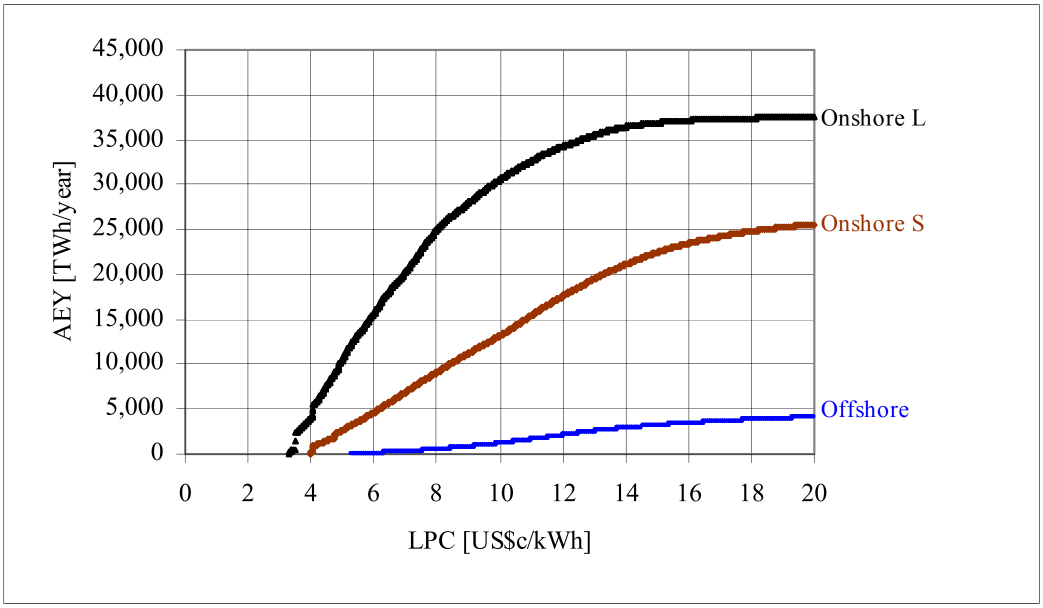


Figure 7.6: Global cost-energy curves in 2000

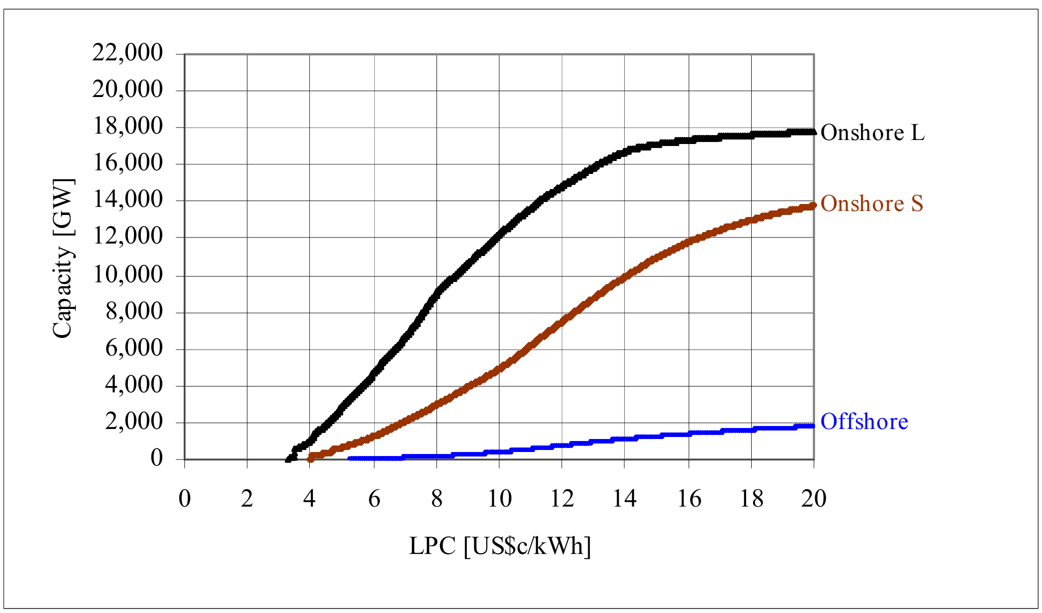


Figure 7.7: Global cost-capacity curves in 2000

7.2.2 2020

Figure 7.8 and Figure 7.9 show, respectively, aggregated global cost-energy and cost-capacity curves for the three scenarios in 2020. For comparison, the total generated output in the ten regions modelled is estimated to be 23,757 TWh/year.

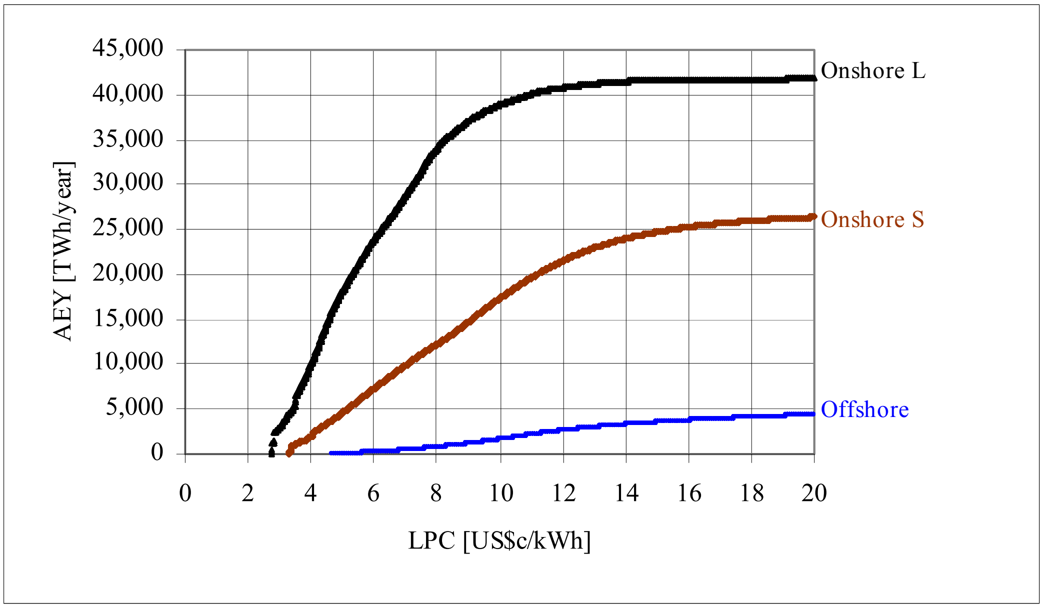


Figure 7.8: Global cost-energy curves in 2020

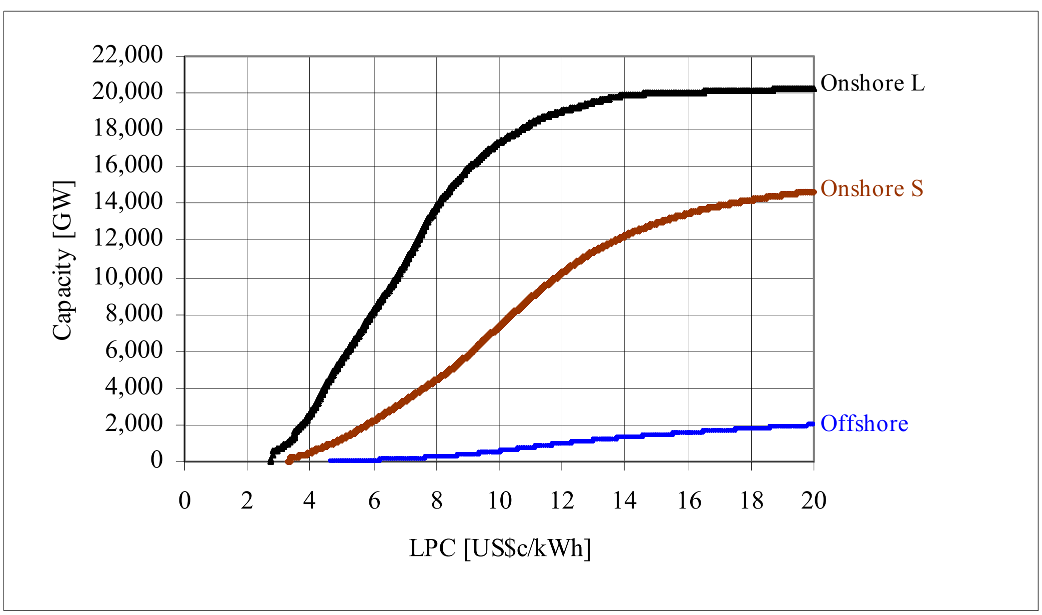


Figure 7.9: Global cost-capacity curves in 2020

7.3 Distribution of Potential Within Regions

The preceding tables and figures in this section compare and sum regional potentials. The purpose of the following brief discussion is to indicate in broad terms where the most promising (i.e. lowest LPC for large onshore wind farms) areas for wind energy development within each region are located. This is particularly important in non-contiguous regions such as the Rest of Asia. It should be borne in mind that, although there is generally a high degree of correlation between high wind speed and low LPC, these areas have been identified after all constraints and location-specific electrical costs have been applied in the analysis, and therefore do not necessarily have the highest wind speeds.

7.3.1 Africa

The best potential is in Morocco, Algeria, South Africa, Ethiopa and along the Red Sea coast. More generally, there are areas of good potential in the Sahara, the east African highlands and at the northern and southern ends of Madagascar. Potential in west and equatorial Africa is generally poor.

7.3.2 Australia

The best potential is in Tasmania and the hilly regions of southeast Australia. There is also good potential along the majority of the south coast of Australia and in the far southwest. Potential along, and far inland from, the north coast is generally poor.

7.3.3 China

Exclusion of the Himalayan area labelled "Unknown" on the PNL map [8] removed the whole of Tibet, most of Qinghai Province and the most mountainous areas of Sichuan Province, Gansu Province and the Xinjiang Uygur Autonomous Region from the analysis. The best potential is in the remaining areas of these provinces and in Yunnan Province, Hainan Province, Shanxi Province, Hebei Province and Inner Mongolia. There is scattered good potential in most coastal provinces and in Jilin Province, Shaanxi Province and Hubei Province. Potential is generally poor in the inland eastern provinces.

7.3.4 EU-15

The best potential is throughout the British Isles, apart from central and southeast England, in Spain and Portugal, in Italy, Greece and the Mediterranean islands, and in the far north of Sweden. There is also good potential along the North Sea coast from Brittany to Sweden and in the southeast of France. It is interesting to note that Germany, where the world's largest wind energy market in terms of capacity installed to date[12] has been established, has relatively poor potential.

7.3.5 FSU and Eastern Europe

The best potential is in the central Asian republics, notably Kazakhstan and Mongolia, in the area between the Black Sea and the Caspian Sea (Georgia, Armenia and Azerbaijan), in the far east of Siberia and along the Baltic Sea coast. Potential is generally lower elsewhere in central and eastern Europe, in eastern Russia, throughout the western Siberian lowland and in central and northern Siberia where much is constrained out by the "Taiga" forest and/or by the 70°N latitude limit.

[12] 4,442 MW by the end of 1999

7.3.6 India

Exclusion of the Himalayan area labelled "Unknown" on the PNL map [8] removed Jammu and Kashmir from the analysis, but left much of Assam where good potential is indicated in some mountainous areas. There is also good potential in the Western and Eastern Ghats, in parts of Kerala and Tamil Nadu, and in other hilly regions of the country. Potential is poor in the lowlands of the eastern states, northern Gujarat, West Bengal, Uttar Pradesh and the rest of the Ganges basin.

7.3.7 Latin America

Exclusion of the Andean area labelled "Unknown" on the PNL map [8] removed significant parts of Peru, Bolivia, Argentina, Ecuador, Colombia and Chile from the analysis. The best potential in South America is in Patagonia and outlying foothills along the length of the Andes. More scattered areas of good potential are in Colombia, Venezuela, Uruguay, Argentina and southern Brazil. Potential is poor and heavily constrained throughout the Amazon basin, and is more generally poor in much of Brazil and northern Argentina.

The best potential in Central America is scattered throughout the highlands of each country, notably Mexico, Guatemala and Costa Rica. The potential is poor on the Yucatan peninsula, in the eastern parts of Honduras and Nicaragua, and along the east coast of the Gulf of California.

The best potential in the Caribbean islands is in Haiti, the Dominican Republic, Puerto Rico, Jamaica and the southern coast of Cuba. There appears to be good potential scattered throughout the Leeward Islands and Windward Islands, but potential in the Bahamas and the remainder of Cuba is poor.

7.3.8 Middle East

The best potential is in Turkey, Iran and Afghanistan. There are more scattered areas of good potential along the Red Sea coast of Saudi Arabia, the south coast of Yemen, the Gulf coast of Oman and in Cyprus and Pakistan. Potential is poor in much of the rest of Oman, Saudi Arabia and Pakistan, and in Iraq, Syria and Kuwait. Development has been largely excluded from Israel and Lebanon and from much of the Mediterranean coast and Pakistan.

7.3.9 Rest of Asia

The best potential in mainland southeast Asia is in Vietnam and Korea, with more scattered areas of good potential in Myanmar (Burma), Thailand and peninsular Malaysia. Potential is very poor in Bangladesh and poor in much of Laos, Cambodia, Singapore and Myanmar.

Of the islands, Japan, the Philippines, Taiwan, Sri Lanka and New Zealand have the best potential. Areas of good potential are also scattered throughout Indonesia, although Borneo, Sarawak and Sumatra have relatively poor potential overall, and development is severely constrained in Papua New Guinea.

7.3.10 USA

The best potential is in California, the mid-west and scattered throughout the western seaboard and the Rockies. However, the potential of the good wind resource in the north and west of the Great Plains is somewhat offset by the large transmission distances assumed in the analysis[13]. Potential is generally poor in Florida and the southern states toward the Gulf of Mexico, and development is heavily constrained throughout most of the Appalachians, New England and the eastern seaboard.

[13] Where grid reinforcement was required, location-specific transmission distances were only assigned in the four study regions. In the rest of the world regions, uniform transmission distances were assumed and may be optimistic for some remote areas with significant potential e.g. Mongolia. Full details are given in Appendix A.

8 SYSTEM EFFECTS

8.1 Introduction

Transmission and distribution systems are discussed in Appendix A, and the costs of network reinforcement for a range of installed wind generation capacity have been estimated. Therefore this section will concentrate on other network effects for which increasing wind generation capacity may have cost implications. Previously published work tends to give conflicting results, depending on the assumptions made [18].

8.2 Reserve Margin

'Reserve margin' is the additional generation capacity which must be constructed as an allowance to meet demand uncertainty, and to cope with unforeseen failures, in order to provide a known level of system reliability. The system reliability is usually measured by the 'loss of load probability' or similar. The presence of wind on the system does not increase the total conventional generation required - the question is how much it can contribute towards meeting the requirement for reserve.

A related term is 'capacity credit', which is the contribution that wind generation can make to the required reserve margin. Capacity credit is stated in terms of the capacity of conventional generation that need not be constructed, while maintaining the same level of system reliability. For example, if a 10 MW wind farm can provide the same contribution to system reliability as a 3.5 MW conventional generator, the wind farm provides a capacity credit of 3.5 MW.

A review of the subject of capacity credit concludes that the capacity credit of wind generation approximates to its capacity factor [19], provided that the capacity factor is determined over the same period(s) as the peak demand on the system and the level of penetration is low. This illustrates the difficulty of reaching a single figure. For example, on the ELSAM system (Denmark) [20], the output of the wind generation is generally uncorrelated with demand and has a capacity factor of 25 to 30%. But at the time of system peak demand, the wind generation capacity factor may be only 1 to 3%. This may be because peak demand in northern Europe can occur during clear, cold and calm spells in winter.

An Italian study [21] on the ENEL system showed, with some pessimistic assumptions, that at low penetrations the capacity credit of wind was equivalent to conventional generation with 20% of the wind generation capacity, which is approximately the annual capacity factor of the wind generation. This study was carried out for very low penetrations (2% maximum).

A Finnish study [22] showed that at low penetrations (2% of annual energy), wind capacity reduced the need for conventional generation capacity approximately proportionally, i.e. a megawatt of wind plant could replace a megawatt of coal plant, for the same level of system reliability. This is surprisingly high. At higher penetrations (8%), the ratio decreased to approximately 0.6.

The ELSAM result is significant, as it is from an operating system with high wind penetration (wind generation capacity equivalent to 17% of maximum demand), not a simulation. However it will not apply to all systems, where demand may be more constant throughout the year, or where there may be a good correlation between peak demand and wind.

In the context of this study, it is not practicable to determine realistic values for reserve margin or for capacity credit for each utility or even for each region. Therefore it is assumed that:

- wind has no capacity credit (i.e. that conventional capacity must match the peak capacity requirement in case of a complete wind outage during the time of peak demand)
- wind has no effect on the reserve margin (since conventional capacity must match peak capacity there is no need for additional reserve)

The effect of this is that the total capacity (in MW terms) of conventional generation which is required is unaffected by the installed wind capacity, though of course the optimum mix of plant types will change. These assumptions are considered to be conservative, i.e. to overestimate the system costs of wind generation.

8.3 Spinning Reserve

Much of the published work on the effect of wind generation on system stability is concerned with isolated systems. For relatively large isolated systems such as Crete (350 MW peak demand, up to 200 MW wind capacity planned) [23] [24], it appears that the threat to system stability comes not from the short-term power fluctuations from the wind generation, but from the possible sudden loss of a large part of the wind generation due to system disturbances and faults. Therefore in this respect, wind generation can be treated like conventional centralised generation, except that it is usually remote from local centres and the stronger parts of the electricity system.

The ELSAM experience supports this conclusion. The worst-case change in total wind output over 15 minutes is of the order of 10 to 15% of wind output. This includes shut downs of entire wind farms due to high wind. Variations over 1 minute are “only a little” higher.

The conclusion is that for large systems with high wind power penetration, the short-term fluctuations in output power do not cause difficulties with voltage and frequency control. The difficulties come from:

- Sudden loss of a significant proportion of the wind generation due to faults or system disturbances. This is in principle no different from conventional forms of generation
- Relatively sudden loss (over a few minutes) of a significant proportion of the wind generation due to passage of storms with winds above the turbines’ shutdown limit.

To cope with these events, generating plant, termed spinning reserve, is required which can start up or increase its output very rapidly. Normally this is obtained by conventional thermal generation operated at less than its full rating.

The study of the Finnish system [22] showed that when wind penetration reached 15% of annual electricity consumption, i.e. 5,000 MW of wind capacity, an additional 1,500 MW of “fast regulating” generation capacity was required in order to maintain system stability. In this case the additional plant would be gas turbines. This suggests that the spinning reserve needs to be increased by 30% of the wind capacity. However other detailed simulations of the larger UK system [18] have shown that a figure of 15% of the *forecast* wind output is satisfactory.

Recent discussions on methods for operating the Danish system with the large wind penetration currently proposed (50% of energy) have raised the prospect of curtailing wind output in critical circumstances. This limitation can take two forms:

- rate limitation, i.e. controlling the rate of change (increase or decrease) of total wind output to a rate that conventional generation can match
- output limitation, i.e. limiting the total wind output to a level that, if suddenly lost, can be rapidly met by the conventional generation operating at the time

The latter point meets the situation where very high winds are forecast, such that there is a risk that the wind farms may shut down from full power in a short period.

The forecasting and communications systems necessary to implement these limits are expected to have negligible cost in relation to the wind farm capital costs.

Curtailment of output in these circumstances is expected to occur infrequently. Taking into account increased use of wind forecasting, it is concluded that major operational benefits can be provided by curtailment, at the cost of very little loss of production. The curtailment implemented in this study is discussed in Section 8.7.3 below, and a conservative procedure is adopted.

In this study it is assumed that forecasting and curtailment are sufficient to avoid any appreciable increase in spinning reserve requirements. Therefore no additional spinning reserve costs are included.

8.4 System Losses

Electrical losses within wind farms are already included in the energy capture calculations.

Electrical losses in the transmission and distribution systems are typically 8% (EU and US), 15% in China, and 21% in India [25], [26]. These are 'technical losses', i.e. excluding theft and fraud. Most of the energy is lost in the distribution system, and so wind generation 'embedded' in the distribution system can reduce losses. A UK study [27] showed that distribution losses could be reduced by embedded generation, at a level which equates to approximately 3 to 4% of the output of the embedded generator. This is the central case, as clearly there can be major differences between particular locations and installations. Based on this, it can be estimated that wind generation embedded in the distribution system can be credited with saving losses, equivalent to additional output, as follows:

- EU and USA: 3% of wind production
- China: 6% of wind production
- India: 10% of wind production.

However, this applies only to generation connected to the distribution system. At higher wind penetrations, the generation will be connected directly to the transmission system, which has much lower losses. Therefore on average, the savings in losses will be less than indicated above, and may become negative at high penetrations, when large amounts of power may be transferred long distances. Therefore in this study no benefit is assumed.

8.5 Other Issues

The UK study referred to above [27] considered other possible costs and benefits of embedded generation, over and above the value of the energy produced. It concluded that their value lay in the range 0 to 30% of the energy value. This figure included an allowance for distribution losses, discussed above.

The range is wide, reflecting the site-specific nature of many of the items that could be important. Most of the benefits occur on the distribution system, and will not apply at high wind penetrations, where most capacity will be connected at higher voltages.

A study of the effects of high wind penetration in Donegal [28] found that increased operation of transformer tap-changers could be expected, which will incur some increased maintenance costs. This was not taken into account in the UK study, but is expected to be very small.

Reactive power costs can be significant in some circumstances, though in other circumstances reactive power production or consumption may actually be seen as a benefit by the distribution system operator.

It is concluded that these potential costs and benefits cannot be quantified for all areas within all study regions within the scope of this study, and they are therefore ignored. The effect of this approximation is considered to be small.

8.6 Energy Storage

This section provides a brief review of the prospects for energy storage within the study timescale, for two areas:

- local installation, to improve power quality and voltage control on distribution networks
- larger installations on the transmission system, to assist generation scheduling and to reduce the need for “spinning reserve”

In [29], where a weak rural distribution system in Ireland was studied, it was found that, if a suitable site had been available, a pumped storage facility would have reduced or removed the need for network reinforcement, or curtailment of wind generation at critical periods. This illustrates that storage and curtailment are competing options. Curtailment is discussed in Sections 8.7.2 and 8.7.3.

8.6.1 Power quality and voltage control

Energy storage devices can improve the quality of the supply received by customers. A large paper mill has benefited from such an installation [30], and there are of course many millions of Uninterruptible Power Supply (UPS) units installed world wide which incorporate some form of energy storage. However their relevance to this study is extremely limited. This is because it is expected, based on experience to date, that utilities will require any adverse effect of wind generation on power quality to be dealt with at source, i.e. within or close to the wind farm installation.

The effects of wind turbines on the power quality experienced by consumers are now well understood, and can be ameliorated by the choice of wind turbine technology and improvements in control. In particular, control of reactive power can achieve many objectives. At present this is cheaper and simpler than control of active power, i.e. energy storage, and is not a major cost component. Even if costs of energy storage reduce significantly in the timescale of the study, it is unlikely that there will be a significant effect on total costs of wind generation, and very unlikely that there will be any significant effect on the locations available to wind generation.

In short, it is expected that even a major improvement in the costs of localised energy storage would not have a significant effect on the extent or cost of wind generation, although there could be a significant niche market for such devices [31].

8.6.2 Large installations

In [32], a study of the CEGB system (England and Wales) showed that no storage was justified, i.e. there were no insurmountable operational difficulties, until wind capacity reached at least 20% of maximum demand. Thereafter, large energy storage installations could be used as pumped storage is used today, to:

- provide spinning reserve
- provide frequency control (in some cases)
- increase use of the most efficient base-load plant by shifting net demand over a few hours
- reduce the need for other peak-load plant.

All of these issues will be more important as the wind penetration in a system increases.

In order to offer these benefits, energy storage devices with discharge times of several minutes to several hours are required. A recent review [33] concludes that only electrochemical systems (batteries and fuel cells) will fit this requirement in the foreseeable future.

However, it is not simple at present to determine the effect of developments in energy storage on the costs of wind generation. This is partly because the costs of energy storage are not clear, but mainly because the benefits will be very system-specific (i.e. depending on daily and annual demand patterns, generation mix, and similar factors).

The best estimate that can be made within the context of this study is as follows:

- At relatively low wind penetrations (perhaps 20%), the benefits of energy storage are very small (tending to zero) because the variability of the wind generation output on all timescales is very small compared with the variability of customer demand
- At high wind penetrations the value of energy storage is approximately the value of the wind curtailment it prevents

The above statements put some bounds on the value of energy storage attributable to wind generation. In particular it makes clear that for situations occurring a few times per year, curtailment of wind output is a cheaper option, particularly if forecasting of demand and wind is used. There will be other benefits of storage in addition to the reduction of curtailment, depending on the characteristics of the electricity system, but these are expected to have much lower economic values.

In the rest of this study, it is assumed as a conservative estimate that there is no storage. If major improvements in the costs of energy storage do emerge in future, the prospects for wind will improve. At the present time, dedicated storage does not make economic or technical sense and the cheapest way of coping with unpredictable generation is simply to increase the system reserve and run more thermal plants at part load [34]. In the UK, for example, the reserve kept on the NGC system to cover loss of a circuit with France (or Sizewell B) could already cope with very large fluctuations of wind energy output.

8.7 Wind Generation Potential Lost

For each study region, network constraints on wind generation have been estimated (Appendix A). These are represented as requirements for transmission system reinforcement, resulting in increases in capital cost as wind capacity in an area increases.

This section considers the following additional representations of network constraints:

- load management
- curtailment of output to save on transmission system reinforcement
- curtailment of output for other 'system' reasons

'Curtailment' in this case is used to mean automatic or manual reduction of the output of wind generation. This is done by shutting down some of the wind turbines, or by reducing the power demand set point of pitch-regulated wind turbines.

8.7.1 Load management

Load management has been proposed, and in some cases implemented, for small isolated electricity systems with high wind penetration. In most cases the principal reason has been for reasons of system stability, to allow adequate control of voltage and frequency in the presence of large power fluctuations from small numbers of wind turbines which are not geographically widespread. This is not important for this study.

Load management has also been proposed for economic reasons, to increase the wind generation capacity which is permissible on a rural network. A study based on a real section of distribution network in the UK [35] showed that this was feasible, and possibly economic under the conditions assumed. However a high take-up rate amongst customers was found to be necessary in order to have a significant effect on the permissible wind capacity. It was found that in order to avoid any curtailment of wind generation, it was necessary for the controllable load to be approximately twice the wind generation capacity. It is also highly likely that utilities or financing institutions would not be attracted to such schemes unless they covered a relatively large customer base, because of the risk of customers withdrawing from the arrangement (either because they moved location, or because they were attracted by tariffs offered by competing electricity suppliers). Therefore the rôle of load management is likely to be for matching supply and demand over a large geographical area to give benefits in system operation, rather than at local level for voltage control. It is therefore very similar in effect to energy storage, discussed above. Load management of electric storage heaters for this purpose is already used by many utilities, using several different techniques and signalling methods.

The equipment installed to provide control of customers' loads allows the utility to provide many other benefits, such as remote meter reading, response to fault conditions, meeting sudden sharp demands due to so-called 'TV peaks', and shifting demand from the day to night periods. Much of the 'system' benefit is to do with short-term events (several minutes or less), which is not relevant for geographically-distributed wind generation.

Load management will therefore be implemented by utilities (as electricity suppliers or as network operators) when it is economically advantageous, and wind generation is only one of many factors which will affect that decision. In the context of this study, it is considered that load management may reduce the system costs of wind generation when high penetrations are reached, but that there is no evidence from which the scale of this effect can be quantified. Therefore, as a conservative estimate, no benefit is assumed.

The situation may be different if there is widespread popular support for renewable energies in general, to the extent that a significant amount of electricity is traded with a 'green label'. Such customers may be persuaded to make more effort to adjust their consumption patterns appropriately. However, at present the evidence on the take-up rate of 'green label' schemes is insufficient to allow this assumption to be made.

8.7.2 Curtailment to avoid transmission system reinforcement

Transmission and distribution systems are designed to meet a combination of environmental (wind, temperature, ice) and demand conditions. In most locations this combination of conditions occurs rarely. Unlike consumers, wind farm operators can often accept an increased risk of curtailment if it results in a significant reduction in the capital costs of the electrical connection. The same argument applies for network reinforcement for wind generation. Because the limiting combination of conditions occurs rarely, the effect on annual energy production can be very small.

No published studies have been found which address this issue in general terms. Detailed simulation of national electricity systems is specifically excluded from the scope of this study, and so it has not been possible to estimate for any of the study regions the points at which it is advantageous to accept curtailment of wind generation rather than build new transmission capacity.

The study of a weak electricity distribution network in Ireland [32] showed that curtailing output (in this case for reasons of voltage control) was preferable to reinforcement of the system.

Costs of transmission system reinforcement were determined in other parts of this project to be on average approximately $1,000 per km per MW of capacity. This compares to approximately $1,000,000 per MW for wind turbine capacity (installed). Therefore, as a first approximation, 10 km of new transmission line is justified if it avoids curtailment of 1% or more of the potential output of a wind farm.

For the purposes of this study, it is concluded that curtailment to avoid system reinforcement will be economically justified in some circumstances. This will result in a reduction in the cost of energy predicted in this study, but the net effect on the cost-supply curves will be very small, compared with the approximations made in estimating the transmission system reinforcement required. This effect is therefore not taken into account in this study.

8.7.3 Other curtailment

Typical reasons for curtailment are the minimum load limits or rate-of-change limits on conventional generation units which are required to run to cope with unforeseen shortages, or to provide voltage and frequency control. Very few simulation results, and no practical results, have been found for high-penetration systems.

Results from a simulation of the Egyptian system [36] show that no wind energy is curtailed until wind penetration (as a percentage of total annual electricity consumption) reaches 50%. The energy curtailed then rises approximately linearly until, when total potential wind generation equals annual electricity consumption, 30% is lost due to curtailment. These figures do not necessarily translate directly to other systems, because the Egyptian system has a daily load curve which varies little throughout the year.

Detailed simulation results for the UK system [18] showed similar results. The two sets of results are tabulated below, together with a conservative set of curtailment assumptions.

Available wind production as percentage of annual electricity demand	Egypt [36]	UK [18]	Proposed
25%	100%	100%	100%
50%	99%	92%	90%
75%	82%	77%	75%
100%	66%	61%	60%

Table 8.1: Wind energy utilised as a percentage of wind energy available

8.8 Developments in Electricity Trading

This section describes the implications of the development of electricity markets and trading that have been incorporated in the modelling of cost-supply curves reported in Sections 4 and 5. The broader commercial implications of such developments for the growth of wind energy are dealt with in Section 3, but have not been incorporated in the modelling assumptions.

Liberalisation of electricity markets across the world is expected to produce major changes in the way in which electricity is traded, both at the wholesale and retail levels. These changes may provide new sources of investment for wind generation, such as 'green consumers'. They are also likely to allow governments or commercial organisations to meet their emissions commitments by investing in the cheapest available technology, irrespective of location. This currently appears to be a favoured option within the EU.

However, the effects of these changes on the cost-supply curves will be very limited. Capital costs including electrical equipment costs will not be affected. The network reinforcement costs assumed in this study for high wind penetrations may be reduced as a result of more flexible use of the electricity system, for example wider acceptable voltage ranges. Reserve margin costs attributable to increased wind capacity may also be decreased because system operators may be able to find lower-cost ways of providing this service, such as interruptible loads. This argument applies in general to all the 'system effects' described above.

However, it is also possible that liberalised electricity markets will become more differentiated and reflect true costs more accurately. Therefore system costs for network users in non-urban areas (such as wind farms) may rise compared with those in urban areas. This clearly has political implications. These political considerations may prevent rural consumers being affected, but there is less of an argument to protect generators in rural areas.

The conclusion is that developments in electricity trading, and market liberalisation in general, are expected to have only a small effect on the cost-resource curves. This effect is unlikely to be positive (i.e. reduce costs), but cannot be quantified at present. Therefore this effect has been ignored.

8.9 Cross-border Network Interconnection

8.9.1 Export from study regions

For each of the study regions the working assumption was made, when determining the electrical system costs, that there would be no export of wind generated electricity beyond the region boundaries. This assumption is valid because for all study regions, the lengths of transmission system reinforcement required to export the power to suitable areas are great. 'Suitable area' is defined as one with:

- substantial electricity demand
- substantially lower wind resource than the study region (otherwise that area too would be seeking to export electricity)

To illustrate the latter point, consider the case of India. Export to Bangladesh and Pakistan would be feasible, but the wind resource is similar in those countries.

8.9.2 Transfers within the EU-15

It is clear that the electricity systems of the EU-15 will continue to become more interconnected, both internally and with neighbouring systems. Neighbouring systems in this context are principally those of eastern European countries such as Poland, Hungary, and the Czech and Slovak Republics, but also include Norway and the Balkans.

The methodology of this study does not make use of national boundaries within Europe, except to use national figures of population and electricity demand to calculate electricity network reinforcement costs (see Appendix A). With this approach, the effect of developments in network interconnection to serve general increases in population and electricity demand is automatically taken into account.

In 1997 [37], the total annual energy exchanged between UCPTE members (the Benelux countries, Germany, Austria, Switzerland, Italy, France, Spain, Portugal, Greece and members of the former Yugoslavia) was only 8.6% of total consumption. The international transfer at the time of system peak demand was only 5%. The conclusion is that an assumption of no cross-border trading of wind-generated electricity within Europe will not introduce a significant error at the present time.

However, developments are expected. Deregulation of the electricity market in Europe is only just beginning. If the intention of a 'level playing field', including equal treatment of renewables, is achieved, there may be an increase in cross-border transfers as a fraction of total consumption. As the means by which deregulation will be achieved are not decided at present, it is not at all clear how the electricity supply industry in Europe will have developed by 2020.

The cost-supply curves produced in this study for Europe contain electrical cost estimates which include an estimate of transmission reinforcement costs within each country. They assume no extra costs for transmission between countries.

For the other three study regions, less information was available on population and electricity consumption at the state or province level. Transmission reinforcement costs were therefore estimated by considering the distances between areas with good wind conditions and areas of high electricity consumption, including transfers across state or province boundaries. This is explained in Appendix A.

It was therefore considered important to review in detail the cost-resource curves produced for the EU-15 countries, to determine if, for any country, it would be necessary or desirable to export power across its boundaries, and what the effect of the resulting additional transmission reinforcement costs on the cost-resource curves for that country could be. This was done by comparing the highest-cost point on the cost-resource curves for year 2000 (both for energy and for wind capacity) against the annual electricity consumption and maximum demand. This is shown in Table 8.2.

Country	Annual energy demand [TWh/yr]	Maximum power demand [GW]	Maximum wind energy[1] [TWh/yr]	Maximum wind capacity[1] [GW]	Maximum cost[1] [c/kWh]
Austria	45.5	7.518	51.3	12.6	4.8
Belgium	77.1	12.424	7.6	5.0	11.8
Denmark	34.4	6.514	13.3	6.5	7.6
Finland	73.5	12.0[2]	72.1	50.8	14.7
France	400.8	64.0	224.2	82.9	8.5
Germany	467.0	71.8	87.2	53.6	12.1
Greece	38.2	6.263	66.5	19.8	6.7
Ireland	20.2	3.552	35.1	10.6	5.1
Italy	272.6	45.267	171.5	45.2	6.0
Luxembourg	5.2	0.764	0.4	0.24	10.6
Netherlands	71.2	11.711	10.1	5.6	8.5
Portugal	31.9	5.182	44.6	13.9	5.4
Spain	162.0	26.466	272.3	75.7	5.2
Sweden	146.2	26.300	152.1	67.5	9.9
UK	356.1	56.815	126.4	36.8	5.1

(1) From 'large onshore wind farm' cost-resource curves. Figures are for the highest LPC points on the curves.
(2) Estimated

Table 8.2: Investigation of the need for export from each EU-15 country

For countries where the maximum wind production is well below the annual electricity consumption, and the maximum wind capacity is well below the maximum demand, it is concluded that export of wind-generated electricity from that country is highly unlikely. Only Belgium, Germany, Luxembourg, the Netherlands and the UK pass this test. For all other countries, full exploitation of their resource will require export to other EU-15 countries. The transmission system reinforcement required for this has not been included in the costs. However, it is unlikely that much of the wind energy available for export will be exported. This is because, as is shown above, all EU-15 countries have a considerable wind resource within their own borders.

The conclusion is that the transmission system reinforcement costs assumed for the EU-15 introduce some error (i.e. are too low) at the high end of the cost-resource curves, i.e. for the resource least likely to be exploited. The benefit of the transmission system reinforcement costs adopted for the EU-15 is that greater accuracy has been obtained at the lower end of the cost-resource curves, where it is more important.

Note that all transmission system costs assumed in this study are determined on the basis of overhead lines. If public pressure prevents new overhead transmission capacity being constructed, this will represent a constraint on the exploitation of wind energy beyond what can be accommodated within the existing system. Costs for underground cables are much greater than for overhead lines. Such a constraint has not been evaluated in this study, as it is assumed that if the public is prepared to countenance sufficient numbers of wind turbines such that large-scale network reinforcement is required, they will also be prepared to accept any necessary reinforcement of the overhead transmission system.

9 ENERGY MODELLING: STUDY REGIONS

9.1 Model Methodology

9.1.1 Overview of power model structure

Figure 9.1 provides a simplified view of the power sector model structure (see also Appendix B). The model is an econometric time series model that can forecast electricity demand, supply, prices, costs, fuel inputs to power generation and carbon dioxide emissions. The model allows the impacts of introducing large scale wind generation into the power sector, in terms of the impact on generation costs and electricity prices, the feedback on electricity demand and the reduced call on fossil fuels and carbon dioxide emissions, to be examined. The cost of carbon abatement from increasing wind generation can be calculated by comparing the generating costs and the carbon dioxide emissions with a base case outlook.

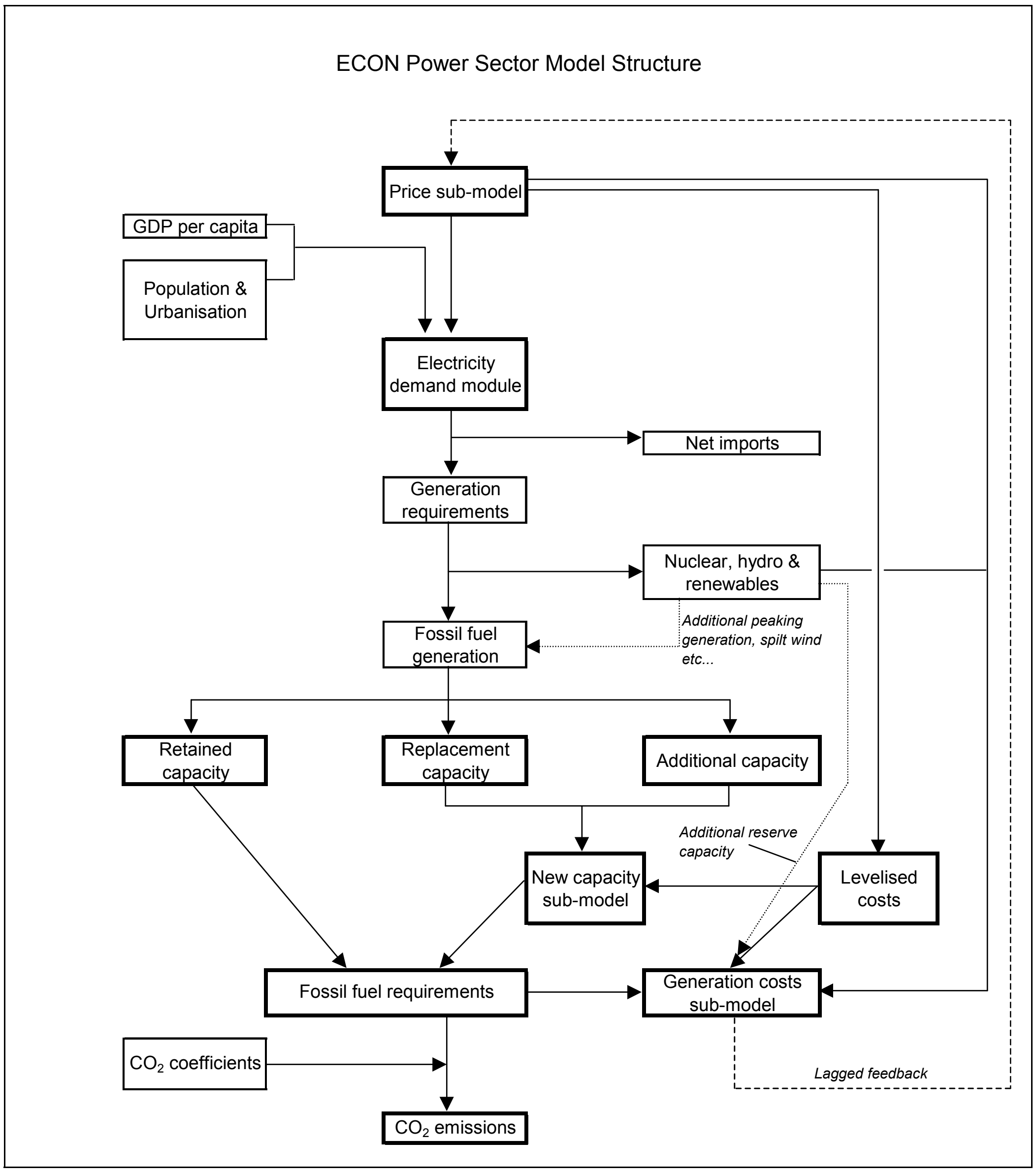


Figure 9.1: Simplified flow diagram of power sector model structure

The model first determines the level of electricity demand. Net imports are then subtracted from the electricity demand to determine the call on indigenous generation. Net imports are an exogenous factor based on the historical trends for each region. China, the EU-15 and India are more or less self-contained areas meeting electricity demand from their own generation sources. The USA is a net importer from Canada. The outlook for USA net electricity imports is based on the EIA's 1998 Annual Energy Outlook [39].

Power generation is divided into a set of preferences. Nuclear, hydro and renewable sources of generation are dealt with exogenously and have priority in meeting generation requirements. This is because their marginal costs tend to be a lot lower than other technologies, and it is the marginal cost that determines the dispatching of existing capacity. The future development of these generation technologies is also treated exogenously because capacity additions/retirements are not based exclusively on their relative full levelised cost of electricity production, but are subject to political and environmental constraints. The outlook for each of these non-fossil fuel generation technologies in the base case is based on forecasts from other organisations such as the US EIA, the IEA and the World Bank referenced in Section 10.

Fossil-fuel generation covers the residual output. The choice of fuel reflects the existing mix, the additional call on fossil-fuelled plants, and the changeover in the capacity. The additional call on fossil-fuel generation reflects the growth in electricity consumption net of imports and the output from nuclear, hydro and renewables. The changeover in capacity reflects the retirement of existing capacity. The choice of additional and replacement capacity is based on the least cost technology and fuel combination using full levelised costs (see Appendix B for details of generating costs). However, because the levelised costs are calculated as a country average they do not reflect the full variation within a region. As a result, not all the new capacity is allocated to the technology with the lowest levelised cost, but is distributed based on the relative cost differences. This means that the share of the least cost new generation technology increases as the cost difference to other technologies increases.

The new fossil fuel generation requirements combined with the retained fossil fuel generation enables the fossil fuel inputs and the carbon dioxide emissions to be calculated. The former is a function of the thermal efficiency of the generation units, while the latter is a function of the fuel type and its carbon content. The generation costs reflect the fuel inputs, the cost of the installed capacity and fuel costs. These costs plus transmission costs, distribution costs and margins, as well as any taxes, then establish the end-use electricity prices, which feed back into electricity demand.

9.1.2 Wind energy modelling

Wind generation is treated exogenously, along with the other renewable technologies. To increase wind generation it is introduced linearly over time to reach a desired level in a designated year i.e. from 2000 to 2020. The desired wind generation level is varied and the impacts on generation costs and the level of carbon dioxide emissions are analysed.

The introduction of wind generation will tend to displace the current favoured fuel for additional generation. This is because existing non-retired capacity must only cover its marginal (variable) cost to remain in operation, while new capacity must cover the full cost (variable plus capital) before it is built. This means that existing capacity is the least cost and will be retained ahead of new capacity, even if the full cost of new capacity is lower than the full cost of existing units. From a system perspective, the introduction of wind displaces the most expensive alternative for base-load generation, which is the full cost new capacity and not the variable cost existing capacity. The new capacity is met from the least cost option for new plants. As a result, the forced introduction of wind displaces the least cost new capacity.

The cost of the wind energy is derived from Garrad Hassan's wind energy supply curves. The supply curves vary over time as the capital and operating costs of the wind turbines is expected to decline. The generation cost from other technologies also varies and it is possible to compare the relative cost of wind energy over time. The higher wind generation costs are reflected in the overall system generating costs and these are fed back into the demand calculations. The low price elasticities of electricity demand means that even quite large prices changes have only a modest impact on demand and the subsequent call on generation. In addition, taxes on consumer prices can also reduce the impact of lower generating costs. For example, in the EU-15 a 50% increase in the generating cost leads to a 30% increase in industrial prices and 5.1% drop in electricity demand. The EU-15 countries are the most price-responsive due to the relatively high cost of electricity – almost 70% higher than in the USA – and the maturity of the economies. Elsewhere, the relative impact of cost increases on demand is smaller. In the USA, a 100% increase in generating costs feeds through into a 5.7% fall in demand, while in India a 100% increase in generating costs results in a 3.2% decline in demand. Higher generating cost has a marginal impact in lowering the requirement for new generation.

One important point to note is that unlike the other technologies, wind generation costs reflect the supply cost for the given year. In general, for any given year average costs for non-wind technologies reflect the cost of new capacity additions in that year plus the cost of existing retained capacity. The average cost is determined from the weighted average of new and retained capacity. This means that costs in any given year reflect the costs of capacity that is installed in that year as well as capacity installed in previous years. In the case of wind energy it is important not to over-emphasise the timing of capacity additions as this is not the object of this study. For example, if the impact of wind generation on abatement costs in 2020 is being modelled, then the linear introduction of wind up to 2020 implies that half the installed capacity would reflect the supply costs prior to 2010 and that these would be the best wind sites. This means that the average wind costs would be higher than those obtained by simply using the 2020 supply cost curve as the supply costs fall over time. In this situation the timing of wind capacity installations becomes very important. While this may be an accurate assessment of reality, it is not what the study is trying to examine.

One way round this problem would be to introduce all the wind in one year. This is problematic for the model when it comes to very large capacity additions and fails to capture the feedback effects on prices and demand. The simplest solution to this problem is to allow average wind generation costs to reflect the current year's supply costs. In other words, the average wind generation costs in a given year are set to reflect the marginal cost curve for that year. This means that the cost of the best wind sites is not fixed at its current cost, but changes over time to reflect the decline in generation costs from each site using improved technology and lower unit cost turbines. The timing of the capacity additions is then no longer so important, but some of the feedback effects from the previous year can still be captured. Varying the wind contribution in a particular year will reflect changes in costs along the marginal supply curve for that year. In one sense this makes the findings less realistic, but in another it enables the abatement supply curve for each year to be isolated. Since this study is primarily interested in the latter, this approach is considered to be the most appropriate.

As previously noted, the introduction of large-scale wind generation raises a number of issues regarding grid strengthening, back-up capacity, spinning reserve, peaking capacity and the extent of wind spillage or curtailment at high penetrations. All of these issues have been discussed at length in Section 8. The need for any additional grid strengthening and any additional operating costs are included in the wind energy cost curves shown in Sections 4 to 7 inclusive. The use of wind forecasting, wind curtailment and additional peaking capacity removes the need for any additional spinning reserve. However, the requirement remains to model the costs of the back-up capacity, additional peaking requirements and spilt wind.

Generation from a single wind farm tends to show a high degree of variability, reflecting changes in the wind speed. As the number of wind farms increases and wind generation is dispersed throughout a region, the variability in aggregated output narrows (i.e. there is limited correlation in the wind speed variation between sites). While this is not a significant effect for areas the size of some of the smaller European countries, it is a good approximation for areas the size of the four study regions. This means that as installed wind capacity increases it more closely resembles a fixed block of generation, i.e. the variability declines as a share of maximum output, although the absolute size of the variability still increases. This variability has to be covered by part-loading other plants and holding additional peaking capacity. At low penetrations the variability can be accommodated by adjusting the load on existing shoulder generating plants with only marginal impact on the system reliability, fuel consumption and costs. At high penetration levels, restrictions on part-loading certain capacities comes into play and back-up capacity and peaking capacity need to be available to meet the wind variations.

After a review of available research, three equations have been formulated to try and capture the need for additional peaking generation, to cope with wind spillage and curtailment at high wind penetrations, and to ensure sufficient back-up capacity (see Appendix B for a detailed explanation).

Additional peaking generation

Wind generation is subject to different degrees of variability, but output is generally not synchronised with variations in demand. In the extreme case there may be virtually no wind output at the time of maximum demand, and for that reason it is assumed that wind generation has no capacity credit. This assumption is conservative. It also means that sufficient rapid response capacity is needed to meet the variations in wind output, which implies an increased demand for peaking generation at the expense of shoulder and base-load generation.

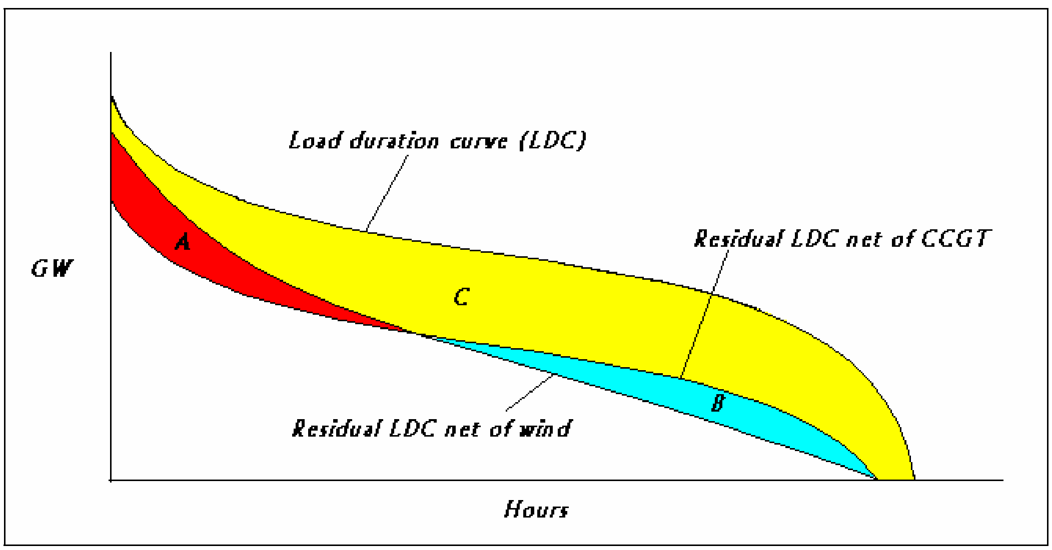


Figure 9.2: Impact of wind energy on the load duration curve

This can be seen in Figure 9.2, which shows a stylised load duration curve and the same curve once a given amount of wind generation has been deducted and when the same amount of conventional CCGT generated energy[14] is deducted. The figure as drawn makes the conservative assumption that, on average, the wind generation has a lower capacity factor at

[14] Throughout this discussion, “generation” refers to energy, not power, unless otherwise specified

times of peak demand than during the rest of the year. These "residual" load duration curves have the same amount of electricity generation removed, but the distribution of that generation is different, reflecting the higher variability in wind output. The difference between the LDC and the "residual" LDC net of wind (C+B) must be equal to the difference between the LDC and the "residual" LDC net of CCGT (A+C). This means that the additional peaking requirement of the wind system (A) must be equal to the lower shoulder generation (B).

Whilst the net difference in generation (A-B) is zero, the energy inputs are not the same as the thermal efficiency of peaking units tends to be lower than that of shoulder units. In other words, more energy is required to produce a unit of peaking generation than a unit of shoulder generation. The significance of this additional energy input to generation is dependent on the size of area 'A' in Figure 9.2.

Figure 9.3 shows assumptions regarding the size of 'A' - the additional peaking generation requirement. Because it is assumed that wind generation has no capacity credit, the size of area 'A' can be estimated as the amount of wind generation is increased by assuming the peaking requirement remains the same regardless of the amount of wind generation. This is not the case with conventional CCGT capacity, where adding more generation lowers the peaking requirement. The size of 'A' can be estimated by comparing the two peaking requirements for the same additional generation.

At low wind penetration 'A' is very small and assumed to be zero. However, once wind exceeds 10% of the total generation then area 'A' becomes more significant, and increases until wind generation reaches 50% of total generation. After this point the size of 'A' declines as the area under the residual LDC falls to zero. As wind approaches 100% of total generation the wind residual LDC approaches that of the conventional residual curve. It is assumed that from a wind share of total generation of 90% upwards there is no significant difference. This is also because as the amount of generation increases it more closely resembles conventional capacity and there is less additional peaking requirement. Behaviour at these very high penetration depends, of course, on the curtailment strategy.

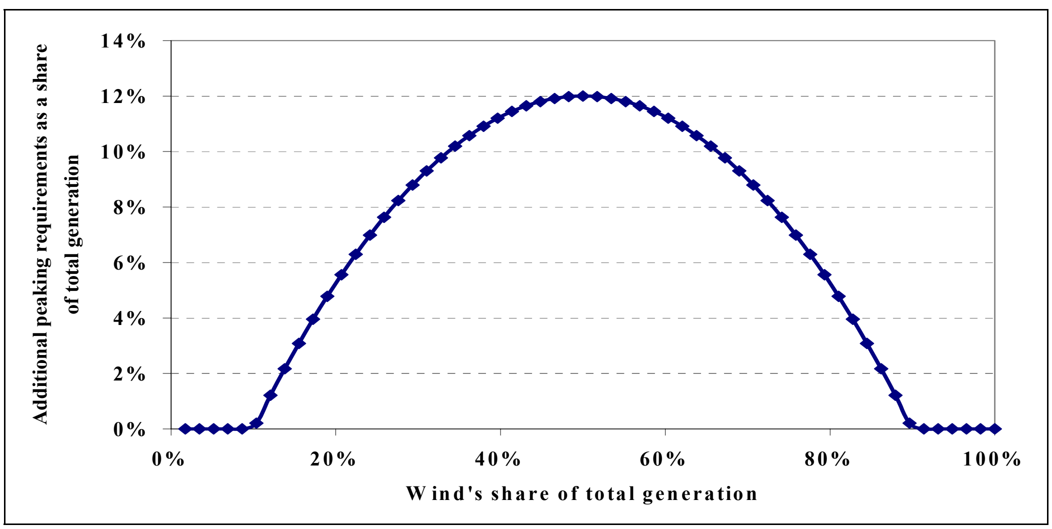


Figure 9.3: Proportion of additional peaking generation as wind's share of total generation increases

The additional peaking requirement of the wind generation system could be met from hydropower dams as well as from thermal plants. In many instances, the hydropower is already fulfilling this role and there may not be any spare hydro capacity to meet further peaking requirements. In this instance all the additional peaking demand is met from thermal plants. However, where there is spare hydro capacity[15] this is deducted from the additional peaking requirement before any thermal plant is introduced.

The additional thermal peaking generation not only has a lower thermal efficiency, but a higher generation cost than shoulder-load generation. This is taken into account in determining total generation costs, as is the lower shoulder generation requirement with its concomitant lower shoulder-load fuel inputs and lower shoulder-load generation costs.

Wind spillage and curtailment

Table 8.1 showed the amount of wind dispatched as a proportion of total wind available as the share of wind energy in total generation increased. From this an equation based on proposed wind utilisation share has been estimated. Figure 9.4 shows the percentage of available wind energy dispatched as wind's share of total generation increases, based on this equation. No wind energy is split until wind's share of total generation exceeds 25%.

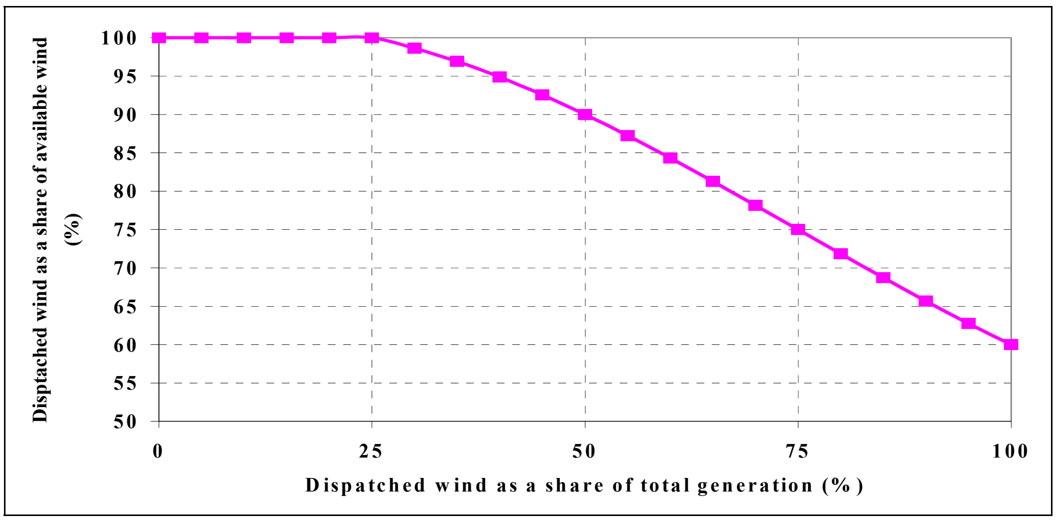


Figure 9.4: Relationship between dispatched wind's share of total generation and share of available wind energy

Capacity fee

Capacity fee is calculated as the average non-fuel costs of thermal plants for a 15% reserve margin[16]. The capacity fee is used to meet the costs of maintaining reserve capacity to accommodate unexpected plant outages that go beyond simple output fluctuations. As indicated in Section 8, wind energy is assumed to have no capacity credit. This means that back-up/reserve capacity must be in place to meet total peak capacity requirements such that the system is able to cope with no wind generation at peak demand.

[15] It is assumed that, if hydro generation accounts for <10% of the total requirement, it is already fully utilised for peaking purposes, and that any hydro in excess of this proportion could be made available for additional peaking generation.

[16] Reserve margin is the additional generation capacity needed, over and above maximum demand, to achieve a stated level of system reliability.

At relatively low wind penetrations the additional back-up capacity can be met from the existing reserve capacity, but at higher penetrations the additional back-up capacity cannot be accommodated so easily and adds to the requirement for reserve. The total capacity held in reserve is a function of the total amount of peak capacity.

The introduction of wind energy on the generation system is modelled as an exponential share of total electricity generation. At low wind penetrations the impact is virtually non-existent, whilst at higher penetrations it is significant. When wind generation reaches 10% of total generation the reserve margin is 18%, while at 100% wind generation the reserve margin is 100% of peak demand.

$$\textit{Capacity Fee} = \{15\%+85\%\times(\textit{Wind Gen/Total Gen})^{1.5}\}\times \textit{average capacity cost}$$ [17]

The capacity fee and average capacity costs are measured in \$/kWh. The additional capacity fee is fed through into the overall generating costs.

9.1.3 Other wind modelling issues

The introduction of wind incurs a number of other system costs that have not been considered:

- Stranded investments;
- The cost of using existing base-load capacity to meet shoulder-load.

It has already been explained that wind displaces new capacity. This is true so long as the level of wind generation is at or below the new generation requirements. However, as soon as the wind generation increases above this threshold, wind displaces existing capacity i.e. capacity that was not due to be retired and is not at the end of its economic life. There is a cost in retiring this capacity early which is equal to the return on the capital foregone by early retirement. These stranded costs should be added to the cost of introducing wind energy beyond the new capacity requirements.

Calculating the stranded investment and determining over what period it should be recuperated is not a simple matter and complicates the issue. For this reason the client specified that stranded investments be excluded from the analysis. In addition, the problem only affects the estimates for the period 2000 in the EU-15 and the USA. Even in these countries, by 2020 new capacity (i.e. installed since 1997) will be more than the available wind generation.

The issue of whether existing base-load capacity is prematurely moved from base to shoulder-load by the introduction of wind is not addressed. The variability of wind and the increased peak and shoulder load requirements set by the residual load-duration curve (i.e. after netting out the wind contribution) are covered, but the economic cost of base-load capacity shifting to operate at shoulder-load is not considered. It is assumed that this cost is minimal compared with some of the other considerations, and is unlikely to challenge the main findings.

[17] Econ formulation

10 GENERATION FUEL MIX: STUDY REGIONS

10.1 Base Case

The generation fuel mixes tend to reflect the least cost options in each region and are largely in line with the forecasts from the US Department of Energy (DOE) and the International Energy Agency (IEA). Nuclear and hydro forecasts were taken directly from these sources. In China and India, coal dominates the generation mix - this is unlikely to change over the forecast period. In the USA and EU-15, gas is the least cost option and displaces coal and nuclear. Policy measures designed to meet country's commitments under the Kyoto agreement are not included in the base case as it remains uncertain at this stage what policies will be implemented.

Table 10.1 compares Econ's forecasts with those from the IEA [38], US Energy Information Administration (EIA) [39] and DRI [40] for the four study regions. The generation mix is very similar for China and India, while in the USA and EU-15 there is a slightly higher gas share and slightly lower coal share than in the other forecasts. However, the US and DRI forecasts were done prior to the low oil price and its knock-on impact on gas prices. In Econ's forecast, very low real gas prices are maintained, and this should explain why there is more gas-fired generation. The 1999 US EIA Annual Energy Outlook does include lower oil and gas prices, and as a result gas accounts for 33% of the generation share in 2020.

	China		India (2010)		USA		EU-15	
	Econ	IEA	Econ	US DOE	Econ	US DOE	Econ	DRI
Coal	67	68	68	70	43	50	12	24
Oil	7	7	1	4	0	1	6	4
Gas	4	3	15	10	37	31	42	32
Nuclear	4	3	2	2	9	9	24	22
Renewables	18	19	14	14	8	9	12	10
Other[18]	0	0	0	0	2	0	3	8

Table 10.1: Comparison of generation mix in 2020 (% of total)

The European Commission has published a report looking at the European Union's energy markets up to 2020 under three scenarios [41] which shows the fuel inputs into power generation. Table 10.2 overleaf compares the share of fuel inputs from the scenarios in the Commission's report with those from Econ. The Commission's scenarios represent an extension of historical trends (Conventional Wisdom), a scenario where the world degenerates into a number of protectionist trade blocs (Battlefield), and one where there is greater institutional integration and collaboration to tackle global issues (Forum). There is also a "Hypermarket" scenario where there is a radical acceleration of market liberalisation and greater development of energy markets. The radical changes in the "Hypermarket" scenario make it less suitable as a comparison with the base case scenario, which is closer to the Commission's "Conventional Wisdom" scenario. Econ's fuel share outlook reflects elements from the Commission's "Conventional Wisdom" and "Battlefield" scenarios.

[18] Other – biomass, industrial and municipal waste and hydrogen

	Conventional Wisdom	Battlefield	Forum	Econ
Solid Fuels	28	23	10	23
Oil	5	7	5	10
Gas	44	40	38	44
Nuclear	9	15	24	15
Renewables	8	8	10	7
Other[18]	7	7	13	1

Table 10.2: Comparison of fuel inputs to generation in the EU-15 in 2020 (% of total)

10.2 Impact of Increased Wind Generation

In the base case, wind generation is maintained over the forecast period at the current committed level (i.e. current generation plus existing construction). In all instances this represents less than 1% of total generation, and is easily accommodated within the generation system without incurring any additional costs. In the alternative scenarios, wind energy is varied to see what generation technology and fuel input is displaced and the concomitant impact on generation costs and the level of carbon dioxide emissions.

The overall picture is of wind displacing natural gas in the EU-15 and the USA, and displacing coal in China and India. Since coal-fired generation produces more carbon dioxide per kWh than gas-fired CCGTs, a unit increase of wind generation in China or India displaces more carbon dioxide than a unit increase in the EU-15 or the USA.

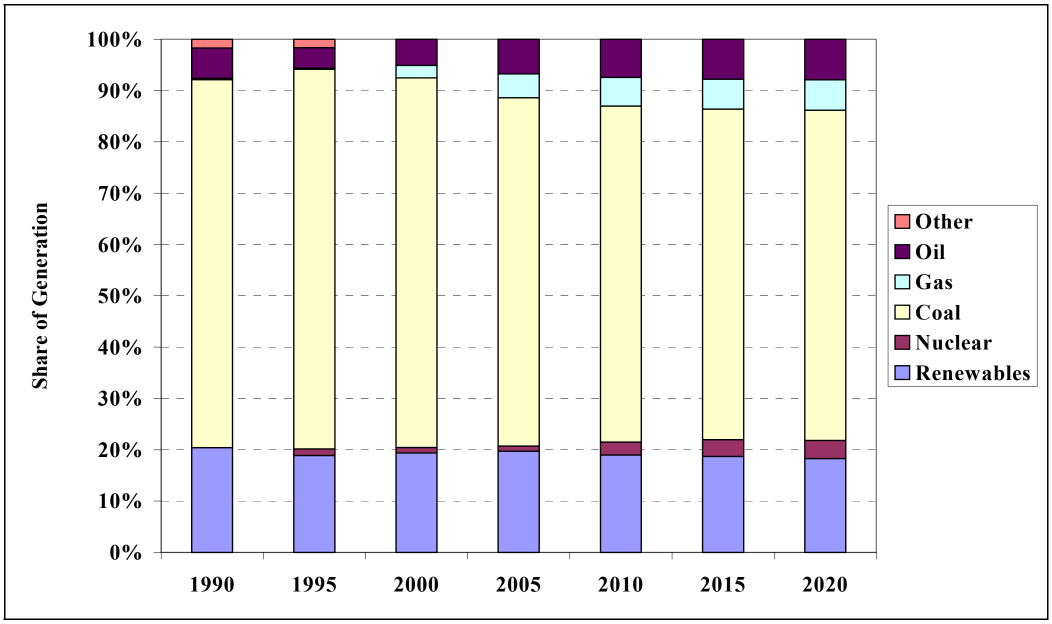
10.3 China

10.3.1 Base case

China's electricity generation is on track to grow by an annual average of 8.4% this decade, slowing to a growth rate of 4.8% per annum between 2000 and 2020. This means that electricity generation in 2020 will be more than 3 times today's level, and China will have to add an additional 2,400-2,500 TWh of annual output (approximately 500 GW or 22 GW per year). Thus almost 98% of the new generation will stem from the growth in electricity demand and less than 2% from the replacement of existing capacity.

In China the low cost of domestic coal means that coal dominates the fuel mix and continues to do so over the forecast period (see Figure 10.1). Coal prices are expected to come into line within international prices, but this does not undermine coal as the least cost option for future power generation.

Natural gas begins to enter the generation picture, as does nuclear. Nuclear is driven by political factors, while gas is driven by low real fuel costs and further technological improvements raising the thermal efficiency and cutting capital costs. In 1995 gas prices were 10 times higher than coal prices, but the fall in crude and gas prices coupled with an increase in coal prices has halved the difference. This has improved the position of gas within China's generation market.



Source : IEA 1990-1996 ; Econ 1997-2030

Figure 10.1: Generation fuel mix – China

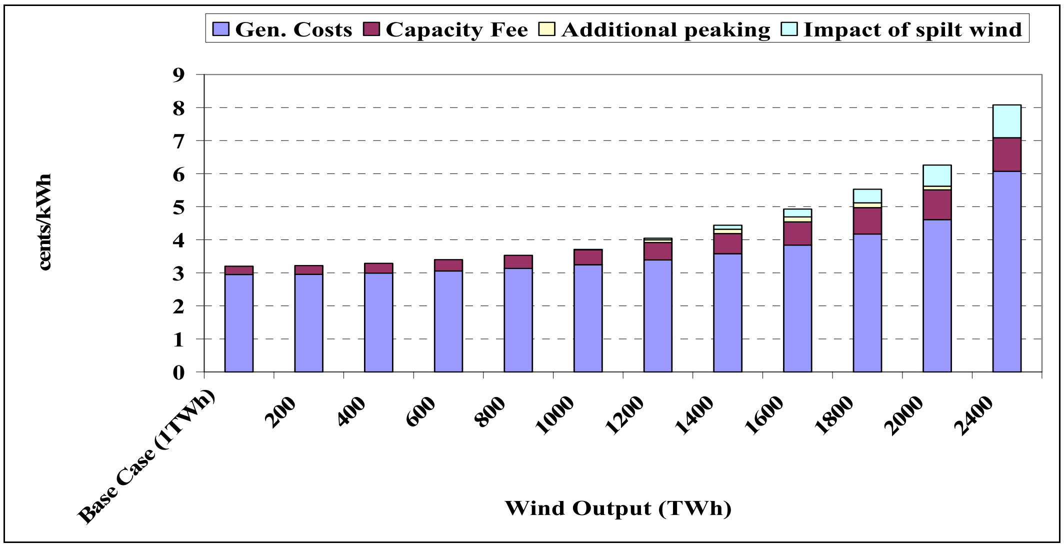
10.3.2 Impact of increased wind generation

Onshore wind power potential is estimated to be about 3,150 TWh per year for large wind farms and 2,100 TWh per year for small wind farms, while the offshore potential is put at less than 400 TWh per year. These figures represent 230%, 150% and 30% of China's current total electricity generation, but only 90%, 60% and 10% respectively of the expected total generation in 2020. However, the impact of spilt wind means that a maximum of 2,400 TWh of wind generation could be dispatched in 2020 which would account for up to 70% of total electricity generation. Small onshore plants are similarly affected, which means that the potential wind share in 2020 is reduced from 60% to just over 50%. Offshore wind is not affected because of the assumption that no wind is spilt at 10% penetration.

The dispatched large onshore wind farm potential represents 100% of the total additional generation requirement between 1997 and 2020, small onshore represents just under 80% and offshore wind potential represents around 15%. Wind generation could therefore have a significant impact on reducing the need for fossil fuel-fired generation.

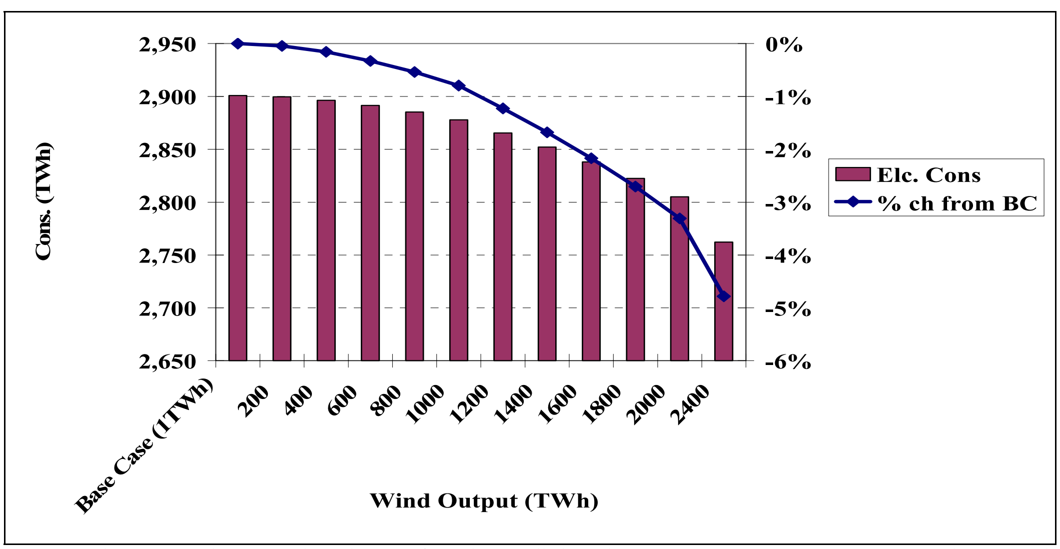
Wind power displaces coal-fired generation in China. At wind's maximum potential onshore generation, coal's share of total generation in 2020 is cut from 64% in the base case to virtually 0%. Oil and gas show large declines in their market share as a result of the increase in wind generation. Overall, at maximum onshore wind generation in 2020, total fossil fuel consumption is cut by 514 Mtoe compared with the base case (a saving of 90%), with 80% of the reduction associated with coal.

Figure 10.2 shows the impact of increased large onshore wind farm generation on total system generation costs, and Figure 10.3 shows how the resulting higher price impacts on electricity demand. In Figure 10.2 the costs are broken down into their different components - generating costs, the cost of maintaining sufficient reserve capacity, the cost of operating additional peaking generation and the cost of spilt wind (i.e. the cost of dispatching less wind generation than is available to the system). Prices to consumers include a gross margin on transmitting and distributing the electricity (T&D) which is not shown as it does not change with the introduction of more wind generation on the system, although it may change over time. For any given time period, changes in consumer prices reflect the changes in the underlying system generation costs. The major cause of the rise in system generation costs is the higher plant generation costs associated with exploiting increasingly marginal and more expensive wind resources. Generating costs double as dispatched wind output rises from 1 TWh to 2,400 TWh per year. The higher costs feed through into a 5.0% cut in electricity consumption compared with the base case. The decline in electricity demand reduces the call on electricity generation and is another, albeit small, mechanism by which fossil fuel-fired generation is cut. Of the 514 Mtoe of fossil fuel consumption cut by the introduction of large onshore wind energy to its maximum potential, 35-40 Mtoe (7-8%) is due to the higher electricity prices reducing demand.



Note 1: "Additional peaking" represents the impact of additional peaking generation and lower shoulder/base generation resulting from high wind penetration.
Note 2: 'Wind Output' is the potential wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Figure 10.2: Impact on system generation costs of large onshore wind in China (2020)



Note: 'Wind Output' is the potential wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Figure 10.3: Impact of large onshore wind on electricity consumption in China (2020)

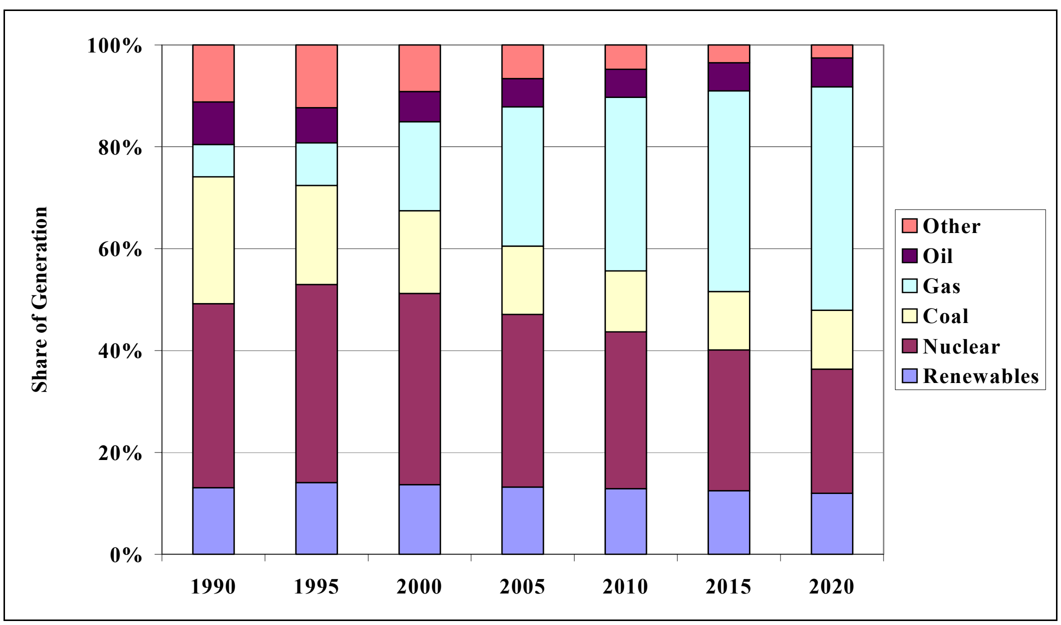
Figure 10.2 and Figure 10.3 highlight the impact of increased wind generation on costs and levels of consumption. Just two figures are shown for illustrative purposes as figures for other time periods as well as for small wind farms and offshore wind generation follow the same pattern. Wind output in the base case represents the onshore installed capacity of 180 MW at the beginning of 1998 [42] and the current committed capacity additions (there is 252.1 MW of total committed capacity plus another 150 MW or so that is likely to be given consents), implying a total installed capacity of 400 MW and annual energy output of 876 GWh by 2000) [43].

10.4 EU-15

10.4.1 Base case

The EU-15's electricity output is expected to show an annual increase of 1.6% between 1990 and 2000, and is forecast to grow by 2.6% per annum from 2000 to 2020. Total generation in 2020 is expected to be just under 40% higher than today, requiring an additional 840 TWh in annual output from 175 GW of capacity. In addition to meeting this growth in electricity demand, new capacity will need to be built to replace retired capacity. In the EU-15, replacement capacity represents over 60% of the total requirement for the period 1997-2020.

The generation mix within the EU-15 is experiencing radical change (see Figure 10.4). Natural gas is becoming increasingly important as it becomes the fuel of choice for new capacity. The main impact of the higher gas share is initially a cut in coal's share of the generation mix, and subsequently nuclear's. Oil has already been confined to niche markets and peak-load requirements. By the turn of the century gas-fired generation has overtaken coal, and by 2010 gas overtakes nuclear. This rapid expansion of gas is being driven by the fact that gas is the least cost option, and is expected to remain so over the forecast period. Environmental concerns have added to the capital cost of coal-fired generating plants as flue-gas desulphurisation and NO_x reduction facilities are incorporated.



Source : IEA 1990-1996 ; Econ 1997-2030

Figure 10.4: Generation fuel mix in the EU-15

Meanwhile, security of energy supply concerns have receded, and with them nuclear's fortunes. Nuclear power is now judged on its economics and acceptability, neither of which offer much solace. Nuclear capacity has reached its peak in the EU-15 at 126 GW (22% of the total installed capacity). Only France has plans to build any more nuclear plants, whilst elsewhere the debate is over how quickly and safely the existing plants can be decommissioned. By 2020, it is anticipated that 20 GW of nuclear capacity will be decommissioned, leaving just over 105 GW in place (about 15% of the total installed capacity).

Liberalisation of the electricity sector and the emphasis on greater competition has further boosted the prospects for gas. Gas-fired CCGT's are quicker to build and less capital intensive than coal or nuclear plant, with a shorter pay-back. These are valuable characteristics in a changing market where risks are greater due to competition and where market entry requires large up-front capital investments.

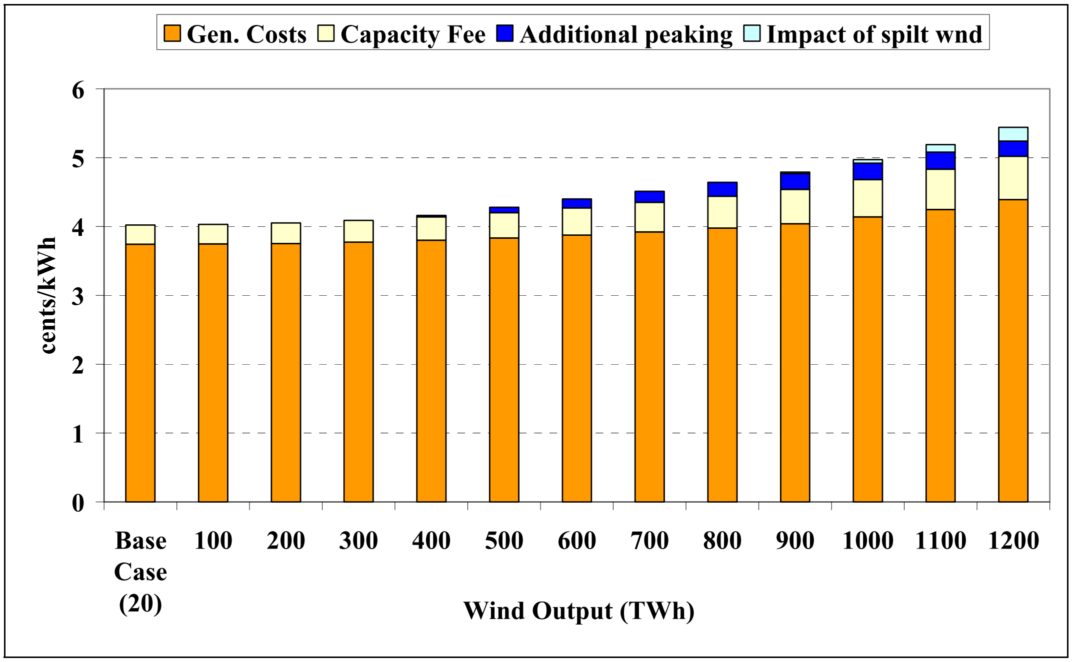
10.4.2 Impact of increased wind generation

The total large onshore wind farm potential in the EU-15 is estimated at about 1,300 TWh per year, which is 60% of the current total generation. The small wind farm potential is 900 TWh per year, or 40% of current total generation. The offshore wind potential is just under 1,100 TWh per year (50% of current generation) and approximately matches the increase in total generation requirements between 1997 and 2010.

Wind displaces the least cost option for new generation. In the EU-15's case this is gas-fired CCGTs. In 2020, with large onshore wind farm generation at its maximum potential, generation from nuclear, hydro and renewables accounts for 78% of the total, with coal accounting for 5% and gas for 9%. The development of wind power delays the "dash for gas" within the EU-15. The combined effect of higher prices/lower demand and the increased use of wind mean that, when onshore wind is at its maximum output, fossil fuel consumption is cut by 42% in 2020 compared with the base case. The higher offshore wind potential leads to a cut of 53% in fossil fuel consumption in 2020 compared with the base case.

Figure 10.5 shows the impact of increased amounts of large onshore wind farm generation on system generation costs split into the different components[19]. For up to 400 TWh of wind there is little impact on generating costs, but beyond this level costs rise quite steeply. It is only at about 400 TWh that additional peaking generation is required, which adds to the costs. The reserve margin also increases beyond 400 TWh, which adds to the cost increases.

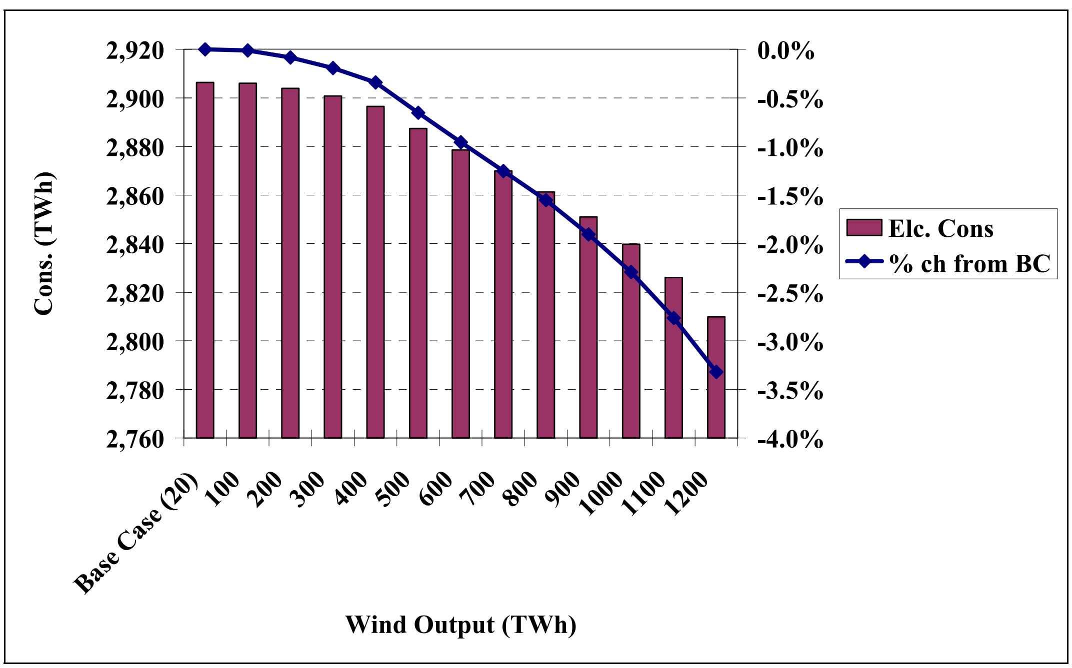
[19] Base case wind generation consists of 4,764 MW of installed on-shore capacity at the end of 1998 (national data sources, EWEA and Danish Wind Turbine Manufactures Association) and a further 4.2 GW in the pipeline (EWEA). Total installed capacity is around 9 GW in 2000 (19.6 TWh).



Note: 'Wind Output' is the potential wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Figure 10.5: Impact on system generation costs of large onshore wind in the EU-15 (2020)

The impact of the higher prices is shown in Figure 10.6. It demonstrates the impact of the steeply rising prices when onshore wind exceeds 400 TWh. Nevertheless, the overall impact on demand is only about 3.5%.



Note: 'Wind Output' is the potential wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Figure 10.6: Impact of large onshore wind on electricity consumption in the EU-15 (2020)

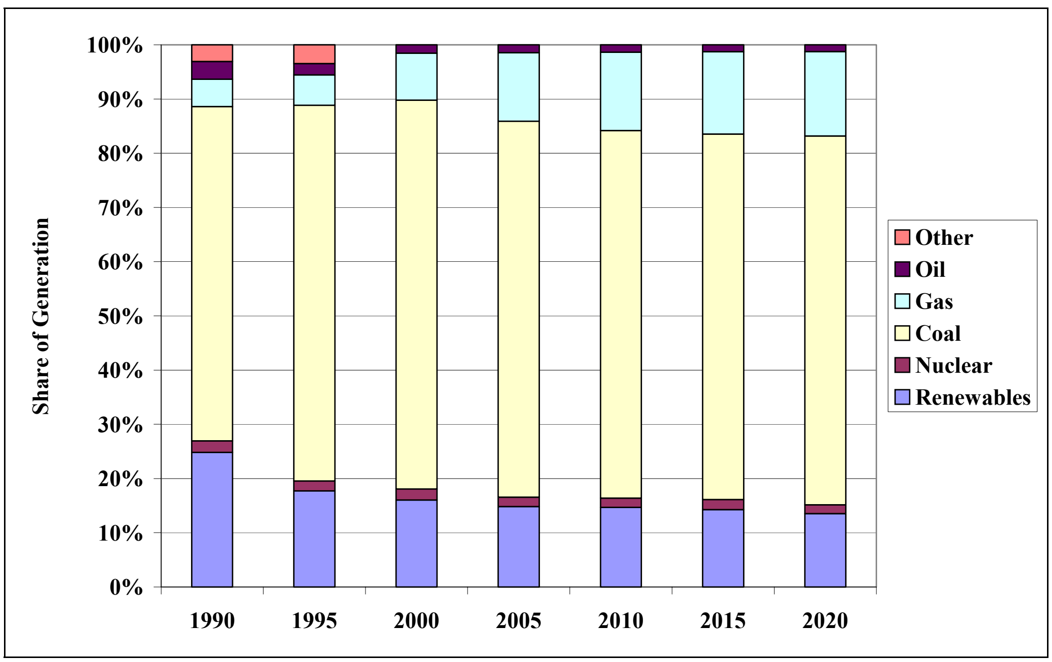
Offshore wind produces similar results, with prices rising steeply towards the total wind potential. Again the higher prices have only a modest impact on demand. Electricity consumption is 7.6% lower in 2020 than in the base case when the maximum offshore wind potential is installed, with generating costs over 90% higher and prices to industrial consumers almost 50% higher.

10.5 India

10.5.1 Base case

India's electricity generation grew by an annual average of 6.4% in the 1990s. Between 2000 and 2020 it is expected to increase by almost 5.0% per annum. This means that electricity generation in 2020 will be about three times today's level, and India will have to add 900-1,000 TWh of annual output (approximately 184 GW, or 8 GW per year, of capacity). As with China, there is little retirement of existing capacity in India, and 98% of the new generation capacity is to meet the growth in generation requirements. India is easing the rules governing foreign investment in power generation to help meet this requirement.

The Indian generation mix, like that of China, is dominated by coal which currently represents some 70% of output (see Figure 10.7). Coal is expected to remain the single largest source of generation, but its share of the total is expected to edge back to just under 70% by 2020. Natural gas is expected gain market share, partly from coal, but predominantly from hydro. Its market share increases from some 8% in 2000 to 15% in 2020. Hydro output is expected to expand, but is not able to keep up with the overall growth in power generation.



Source : IEA 1990-1996 ; Econ 1997-2030

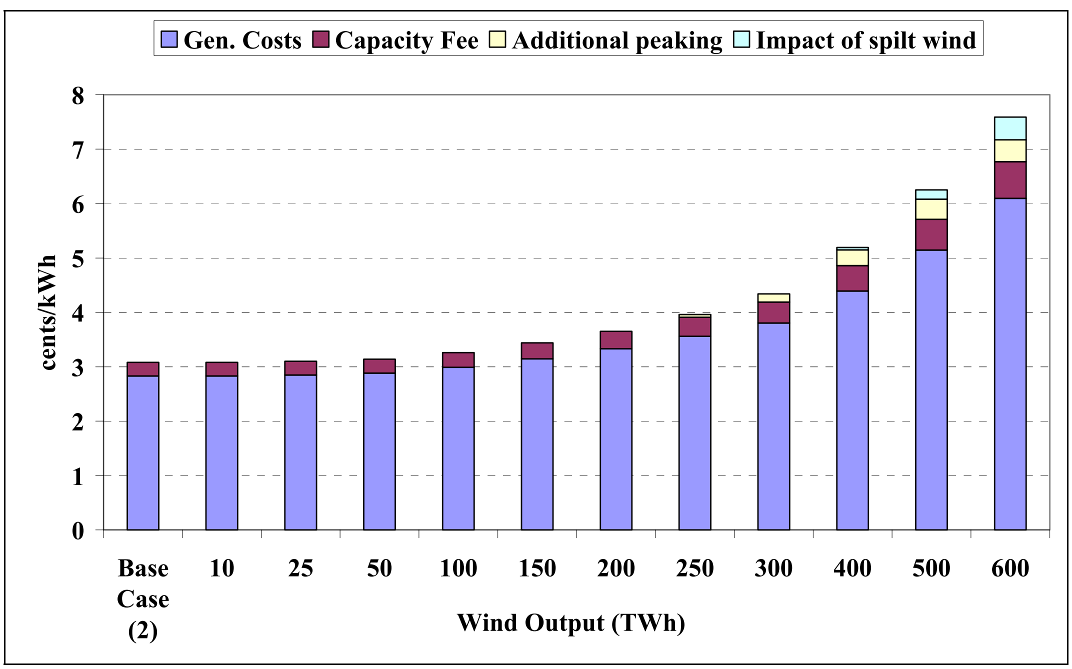
Figure 10.7: Generation fuel mix in India

10.5.2 Impact of increased wind generation

As wind displaces the least cost new capacity option, coal-fired capacity is reduced as a result. There is over 600 TWh per year of large onshore wind farm potential, 400 TWh per year for small onshore wind farm potential and 150 TWh per year of offshore potential. The large and small onshore wind farm potentials amount to 130% and 90% respectively of current total generation; the figures are 44% and 31% in 2020. The offshore wind potential represents 30% of current total generation, or 10% of expected generation requirements in 2020. At maximum onshore large wind farm potential, the generation share of fossil fuels is cut from 85% in the base case in 2020 to 42%. Most of the reduction is in coal-fired generation (90% of the reduction in fossil-fuel-fired generation).

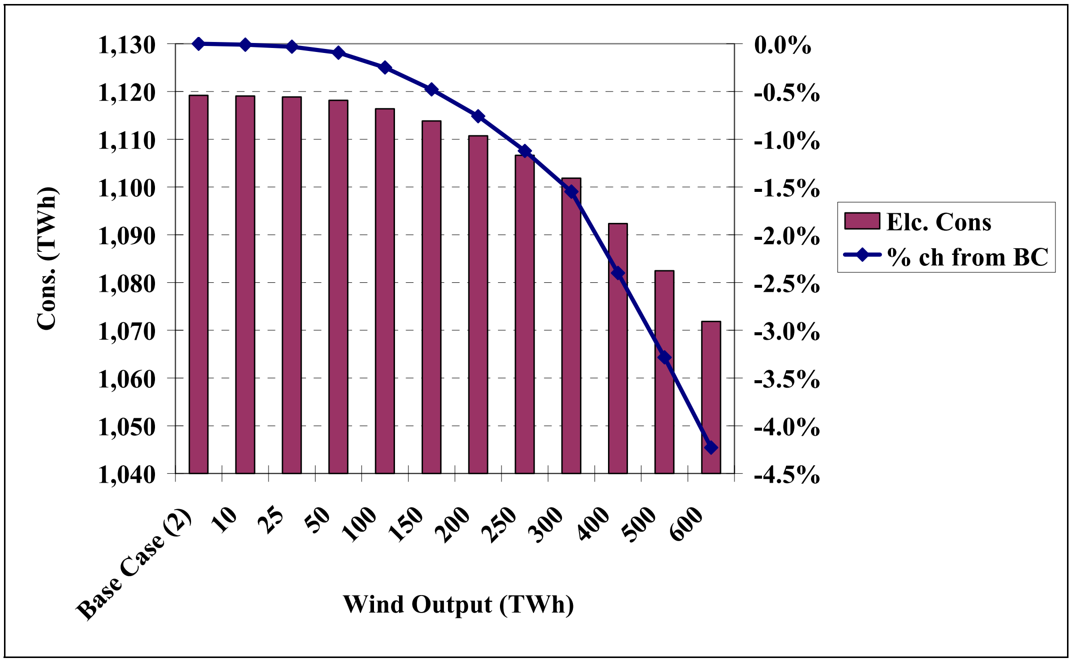
Figure 10.8 shows the impact of increased large onshore wind generation on system generation costs, and Figure 10.9 shows the limited impact on overall levels of electricity consumption. There is currently no installed offshore wind capacity, although India has 930 MW of installed onshore capacity according to the Ministry of Non-Conventional Energy Sources (MNES) and a further 450 MW in the pipeline.

At maximum potential large onshore wind penetration, electricity consumption is cut by 4.2% in 2020 compared with the base case, with generating costs 100% higher and prices to industrial consumers almost 40% higher. A similar exercise for small onshore wind farms results in consumption 3.7% lower than for the base case in 2020, with generating costs 110% higher and prices to industrial consumers over 45% higher. The offshore wind farms produce results slightly below those for the small onshore wind farms.



Note: 'Wind Output' is the potential wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Figure 10.8: Impact on system generation costs of large onshore wind in India (2020)



Note: 'Wind Output' is the potential wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Figure 10.9: Impact of large onshore wind on electricity consumption in India (2020)

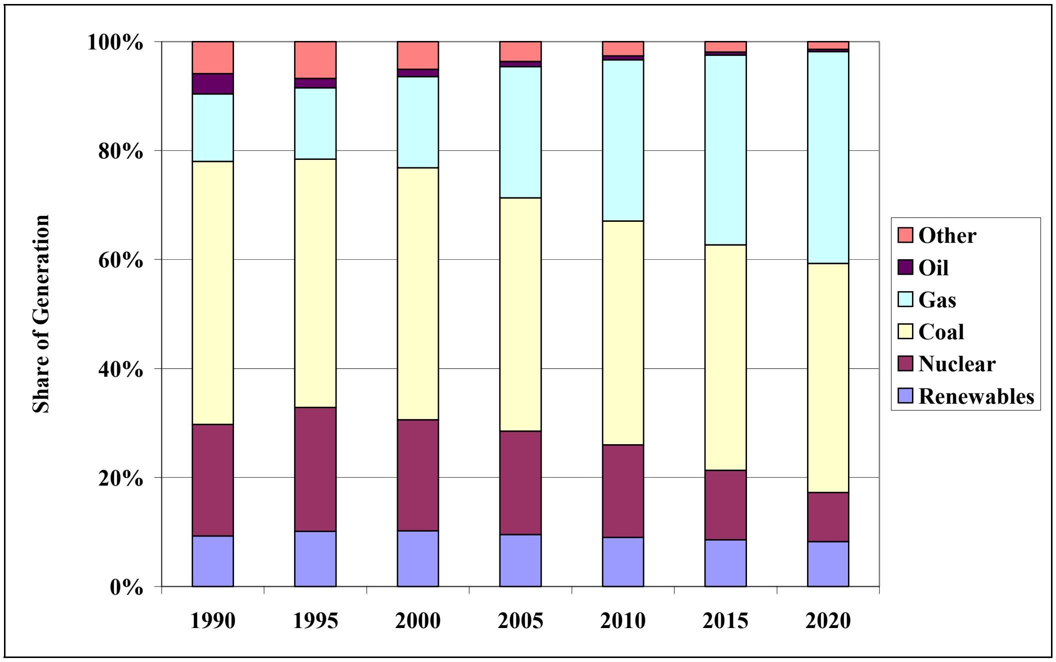
The overall impact of higher prices/lower demand and the substitution of wind for fossil fuel-fired generation means that the total amount of fossil fuel consumed declines. At maximum potential offshore wind farm generation total fossil fuel consumption is some 15% lower than in the base case in 2020. At maximum small onshore wind generation total fossil fuel consumption in 2020 is 30% lower, while the large wind farm generation produces a decline of more than 40%.

10.6 USA

10.6.1 Base case

USA electricity generation grew by 1.7% per annum last decade, but the growth rate is forecast to slow to 1.3% per annum from 2000 to 2020. Total generation in 2020 is expected to be 36% higher than today, with an additional 1,200 TWh of annual demand. Installed capacity will need to be increased by about 260 GW. However, the bulk of the new capacity will come from the replacement of retired capacity. Just over 70% of all new additions will be replacement of retired capacity between 1997 and 2020.

The USA generation mix is currently dominated by coal, which accounts for 45-50% of the total (see Figure 10.10). None of the other sources of generation accounts for more than 20%. Coal is expected to remain the dominant generation source, although gas is expected to challenge that dominance by the end of the forecast period. Gas is expected to gain at the expense of nuclear and, to a certain extent, hydro. Gas is the least cost option in the USA and is expected to remain so. Nevertheless, coal narrows the gap over the forecast period ensuring that not all the new generating capacity is gas-fired. Nuclear capacity, at 108 GW, has reached its peak, and only a small improvement in the load factor enables nuclear output to increase. However, from 2010 an increasing rate of nuclear decommissioning is expected, with 45% of the installed capacity removed by 2020 (48 GW).



Source : IEA 1990-1996 ; Econ 1997-2030

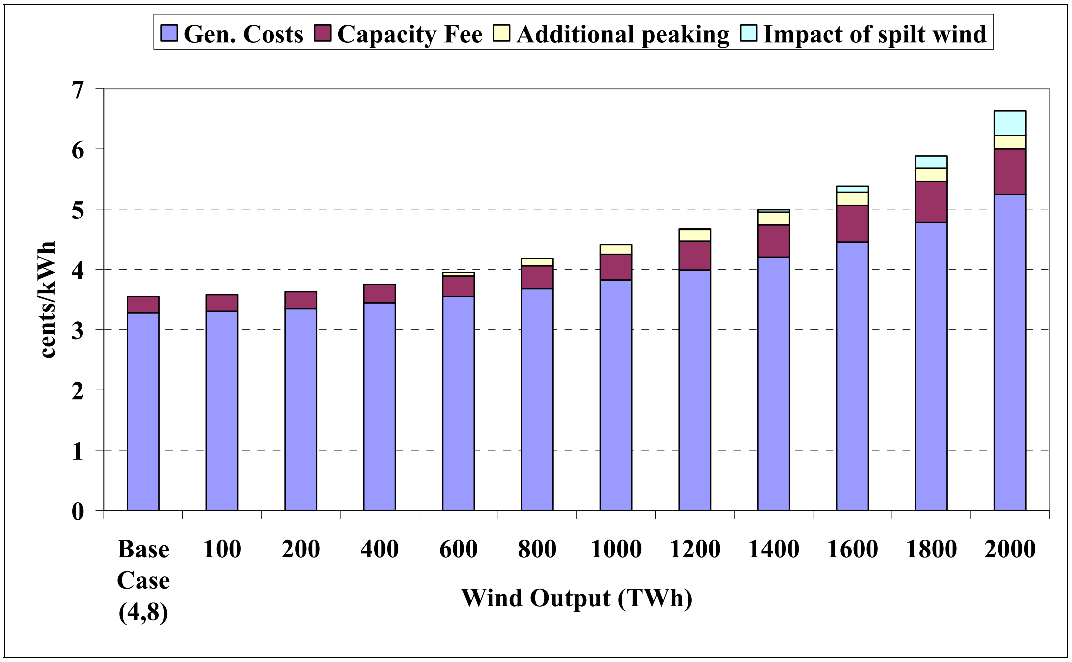
Figure 10.10: Generation fuel mix in the USA

10.6.2 Impact of increased wind generation

The total large onshore wind farm generation potential is estimated to be about 2,200 TWh per year. This represents 65% of the USA's current total generation, and less than 50% of the expected total generation in 2020. The small wind farm generation potential is estimated to be some 1,900 TWh per year, while the total offshore wind potential is not as great and is estimated at 580 TWh per year. The offshore wind potential is equivalent to 17% of total generation in 2000, and just over 10% of the anticipated total in 2020.

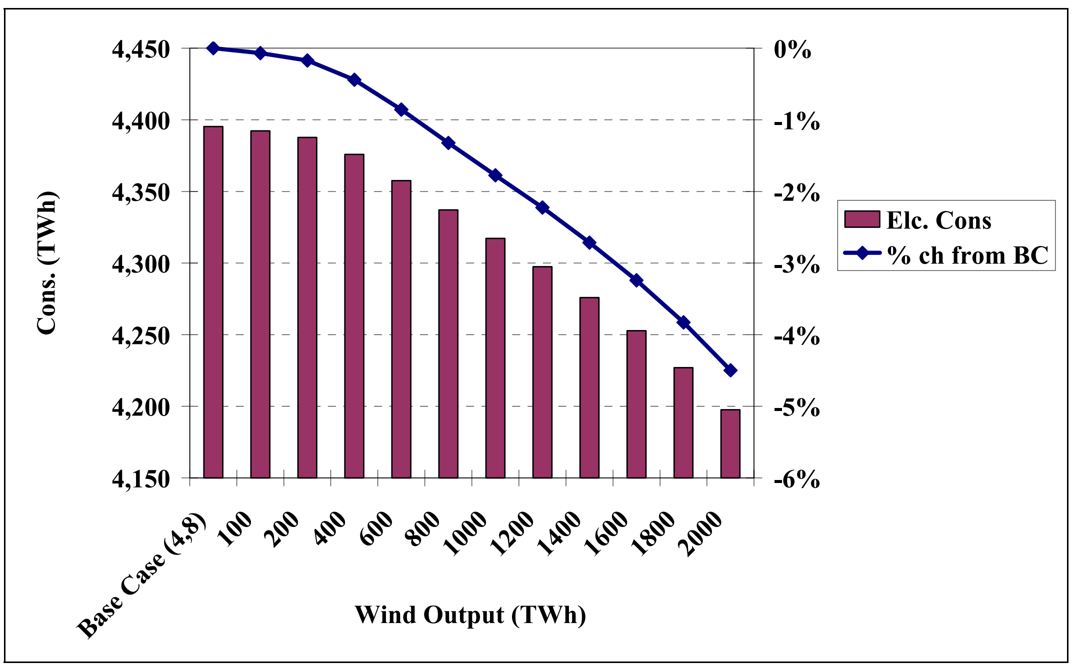
Figure 10.11 shows the impact of increased large onshore wind farm generation on system generation costs[20]. Figure 10.12 shows the limited impact on overall levels of electricity consumption. At maximum potential large onshore wind farm penetration, electricity consumption is cut by 4.5% in 2020 compared with the base case, with generating costs approximately 75% higher and prices to industrial consumers 60% higher. A similar exercise for offshore wind results in consumption 3.8% lower than the base case in 2020, with generating costs 60% higher and prices to industrial consumers 50% higher.

[20] Wind generation in the base case comes from 1600 MW of installed on-shore capacity and a further 525 MW of capacity additions (Source: American Wind Energy Association). Total committed capacity is 2100 MW (4.8 TWh).



Note: 'Wind Output' is the potential wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Figure 10.11: Impact on system generation costs of large onshore wind in the USA (2020)



Note: 'Wind Output' is the potential wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Figure 10.12: Impact of large onshore wind on electricity consumption in the USA (2020)

The price and substitution effects of higher wind generation result in less fossil fuel consumption in the power sector. At maximum potential large onshore wind farm generation, total fossil fuel consumption is 44% lower than in the base case in 2020. At maximum offshore wind generation total fossil fuel consumption in 2020 is 17% lower.

The fossil fuels most affected by the introduction of large scale wind generation are natural gas and coal. Gas and coal-fired generation are the main source of new generation in the USA in the base case, with gas showing particularly strong gains. Wind cuts into the development of gas-fired generation as well as limiting the need for additional coal-fired plants.

At large onshore wind's maximum potential generation, natural gas consumption in the power sector falls by 26% compared with the base case in 2020, while coal consumption falls by 56%. In the base case, coal accounts for just over 43% of total generation in 2020, but with large onshore wind farms at their maximum potential coal's market share is limited to just 17%. Natural gas's market share falls from 37% to 17%. Natural gas consumption does not fall proportionately to coal, as gas is used for additional peaking generation purposes.

11 CO_2 EMISSIONS: STUDY REGIONS

11.1 Base case

Figure 11.1 and Table 11.2 show the CO_2 emissions from the power sector in each study region under the base case. The growth in emissions from the USA and EU-15 is primarily driven by growth in electricity demand, as the carbon intensity of the sector shows only a modest decline (see Figure 11.2). The switch out of nuclear and into gas as well as the modest growth in coal consumption help to limit the reduction in emissions per unit of generation that might otherwise have been expected given the improvement in thermal efficiencies. In China and India, emissions tend to move in line with the growth in electricity generation. However, the penetration of nuclear and gas-fired generation means that emissions do not increase quite as fast as there is a sharper reduction in the power sector's carbon intensity.

Compared with 1990 levels, carbon dioxide emissions from the power sector are higher by the following percentages in the base case[21] by 2020:

Region	CO_2 increase
China	320%
EU-15	10%
India	300%
USA	30%

Table 11.1: Power sector CO_2 emission increases from 2000 to 2020

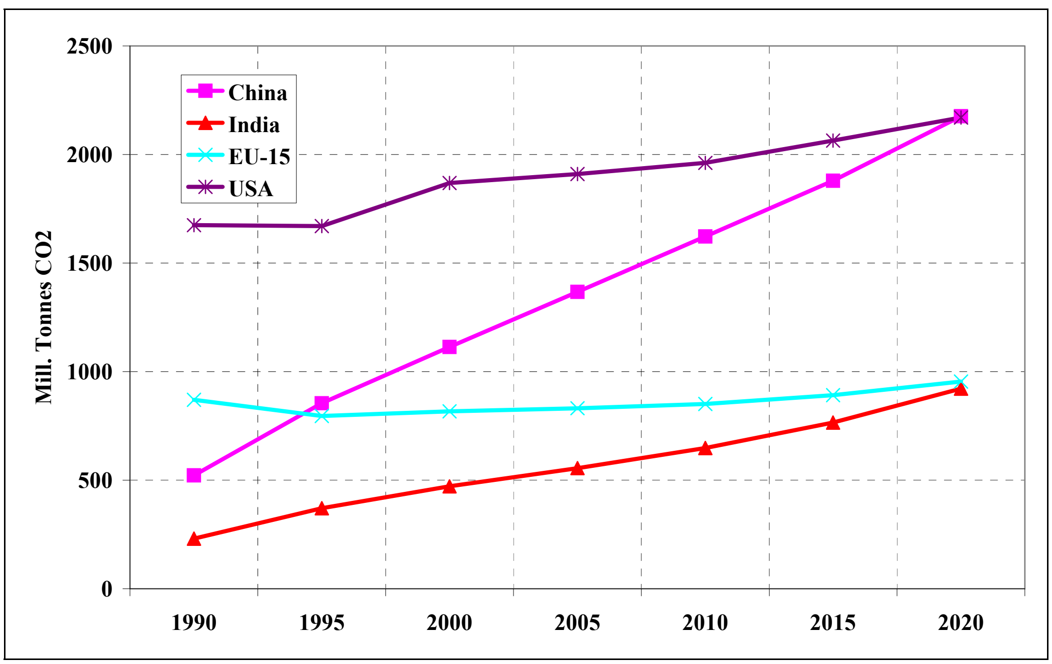


Figure 11.1: CO_2 emissions from the power sector (base case)

[21] As noted previously, the base case does not include the Kyoto Commitments.

Base Case	1990	1995	2000	2005	2010	2015	2020
China	522.3	853.9	1120.6	1376.2	1633.9	1893.0	2193.2
EU-15*	869.9	795.4	816.6	830.9	851.4	891.6	953.7
India	230.3	370.5	471.4	555.2	648.0	765.5	921.4
USA	1674.0	1670.4	1868.6	1909.8	1960.8	2064.5	2170.5

** Excluding CHP*

Table 11.2: Carbon dioxide emissions in the power sector (million tonnes of CO_2)

Table 11.3 shows emission coefficients used to calculate the carbon dioxide emitted from the power sector. The analysis only takes account of the emissions from operating the power stations. No account is taken of the emissions produced in fuel extraction and construction of the power plant. Estimates from the World Energy Council [44] indicate that these non-operating emissions account for less than 1% of the total for power plants. There are greater variations in the carbon content of coal, oil and gas, although for simplicity a single set of emission coefficients that are constant across time and study region has been adopted.

Fuel	kg CO_2 per GJ	tCO_2 per GWh$_t$
Hard Coal	94.6	340.7
Sub-bituminous	101.2	364.4
Natural Gas	56.1	202.0
Gasoil	74.0	266.5
Fuel Oil	77.58	279.4
Other Oil Products	73.33	264.1
Nuclear	0	0
Hydro	0	0
Wind	0	0

Source: IPCC Greenhouse Gas Inventory Reporting Instructions

Table 11.3: Carbon dioxide emission coefficients

Table 11.4 shows the emissions by power generation technology type. The emission factors are calculated using the emission coefficients in Table 11.3 and the efficiency factors for each technology presented in Appendix B. Table 11.4 highlights the low carbon intensity of CCGT gas generation. The range reflects the range of efficiencies, with lower carbon output per GWh$_e$ reflecting higher thermal efficiency. This tends to mean that lower carbon emissions are achieved in later years as thermal efficiencies increase.

Technology	tCO_2 per GWh$_e$
Steam turbine coal	757 – 897
IGCC coal	643 – 792
Steam turbine heavy fuel oil	735
IGCC heavy fuel oil	527 – 650
CCGT gas	326 – 404
Nuclear	0

Table 11.4: Carbon dioxide emissions by technology

Figure 11.2 and Table 11.5 show the carbon intensity of the power sector in each study region. The carbon intensity is a measure of the annual carbon dioxide from the sector emitted per unit of electricity generated.

There is a modest improvement in the USA, where the carbon intensity falls by almost 15% between 1990 and 2010. This reflects the switch to more efficient generating technologies. After 2010 the decommissioning of the nuclear parc arrests the decline in the carbon intensity as fossil fuelled generation replaces the nuclear output. A similar picture occurs in the EU-15, with initial modest declines in carbon intensity followed by stable or slightly increasing intensity later. The initial improvement is technology driven, while the subsequent slight increase reflects the decommissioning of nuclear and its replacement by gas and coal-fired units. The EU-15 has the least carbon intensive power sector of all the regions studied due to the large nuclear and hydro shares in generation which together currently account for over half the total electricity generated.

In China and India there is a dramatic reduction in the carbon intensity after 2000 as technological developments produce a huge improvement in the thermal efficiencies of power plants. This improvement is particularly strong for coal generation, where existing plants in both India and China have very low thermal efficiencies (less than 30%), while new plants being installed have efficiencies of 40% or more. The inclusion of gas-fired CCGT's further adds to the thermal efficiency, while the expansion of nuclear generation also helps to reduce the amount of carbon emitted per unit of generation. China and India's power sector carbon intensities fall by 27% and 18% respectively between 1990 and 2020.

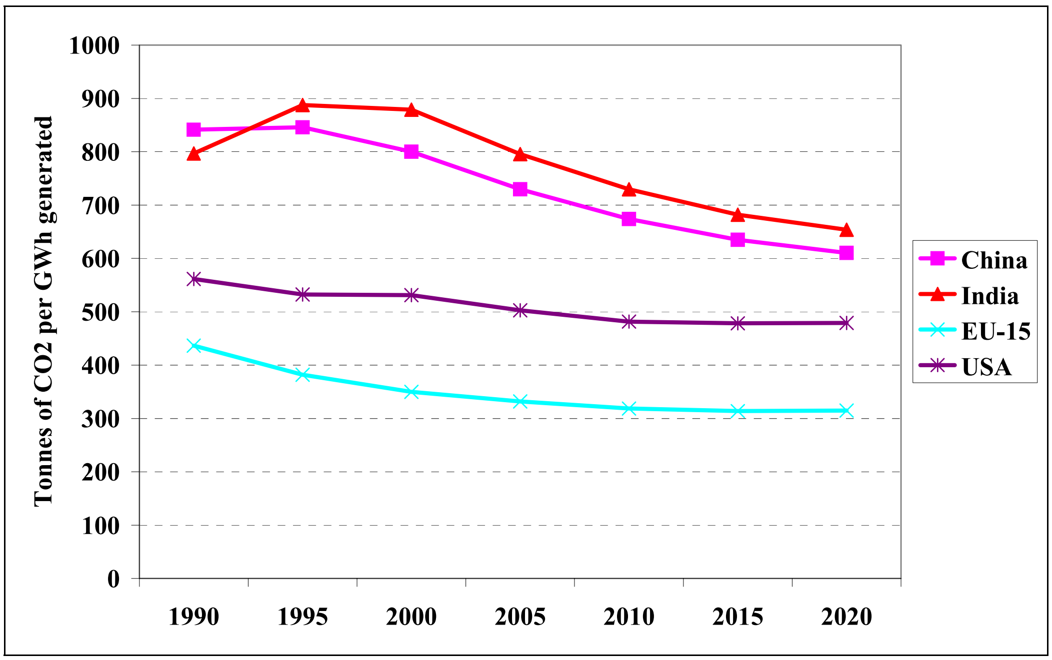


Figure 11.2: Carbon intensity (tonnes of CO_2 per GWh of generated electricity)

Base Case	1990	1995	2000	2005	2010	2015	2020
China	841	846	800	730	674	635	611
EU-15	436	382	350	332	319	314	315
India	797	888	879	795	729	682	654
USA	561	532	531	503	481	478	479

Table 11.5: Carbon intensity (tonnes of CO_2 per GWh of generated electricity)

11.2 Emissions Reduction

11.2.1 Overview

The greatest reductions in carbon dioxide emissions from the power sector are achieved onshore in China and the USA. These results tend to reflect the much greater wind potentials in these regions than in the other study regions. They also reflect the carbon intensity of the capacity displaced by wind, which explains why the EU-15 has about two-thirds of the USA's large onshore wind farm resource but achieves less than half the carbon dioxide reduction at full utilisation.

Table 11.6 shows the reduction in annual carbon dioxide emissions achieved as a result of developing wind to its maximum potential. The reduction is compared with the base case in 2020. The table not only highlights the absolute level of the reduction, but also the reduction achieved per unit of wind generation (measured in tonnes of carbon dioxide per GWh of wind generated). The latter indicates that the EU-15 has the lowest level of reduction per GWh of wind, while India has the highest. This reflects the fact that wind is primarily displacing natural gas in the EU-15 and coal in India. In the USA it displaces both gas and coal, although slightly more gas. The carbon content of coal is greater than that of natural gas, and the thermal efficiency of gas-fired CCGT is greater than that of coal-fired units. Both factors result in less carbon dioxide being displaced in Europe than in China, India or the USA.

	Small Onshore Wind Farms			**Large Onshore Wind Farms**			**Offshore Wind Farms**		
	Mt CO_2	tCO_2/GWh Wind[1]	tCO_2/GWh Wind[2]	Mt CO_2	tCO_2/GWh Wind[1]	tCO_2/GWh Wind[2]	Mt CO_2	tCO_2/GWh Wind[1]	tCO_2/GWh Wind[2]
China	1383.3	759.1	689.64	1940.6	808.6	645.56	352.8	940.9	940.9
EU-15	340.1	377.7	377.7	459.8	383.2	373.3	430.6	430.6	427.2
India	303.9	759.7	759.7	445.1	741.9	741.9	130.3	868.8	868.8
USA	966.4	536.9	481.8	1028.9	514.5	445.6	345.4	627.9	627.9

[1] Dispatched wind generation (i.e. available wind generation minus spilt wind)
[2] Available wind generation

Table 11.6: Annual CO_2 reduction from base case at maximum wind potential (2020)

Figure 11.3 shows the percentage reduction in carbon dioxide emissions from the power sector achieved at maximum wind potential compared with the base case in 2020. For the EU-15, India and the USA the reductions are almost 50% for large onshore wind farms, while for China the reduction is almost 90%. These figures further highlight the large onshore wind resource in all the study regions relative to their generation requirements. The potential reduction from small onshore wind farms is generally slightly less than for large wind farms (70-75% of the large onshore potential). In the USA, however, this is not the case, and the small onshore wind potential is about 90% of the large onshore wind farm potential. The reasons for this are that the small wind farm potential is only 15% lower than the large wind farm potential in the USA, compared to 30% lower elsewhere, and system constraints lead to increasing amounts of spilt wind. The net result is that there is only a small additional amount of wind generation dispatched under the large onshore wind farm scenario than the small wind farm scenario.

The potential carbon dioxide reduction from installing offshore wind is considerably less than from onshore wind in most cases, although the potential reduction from offshore wind in the EU-15 is about 45%. For the other study regions the reduction is in the range of 10-20%.

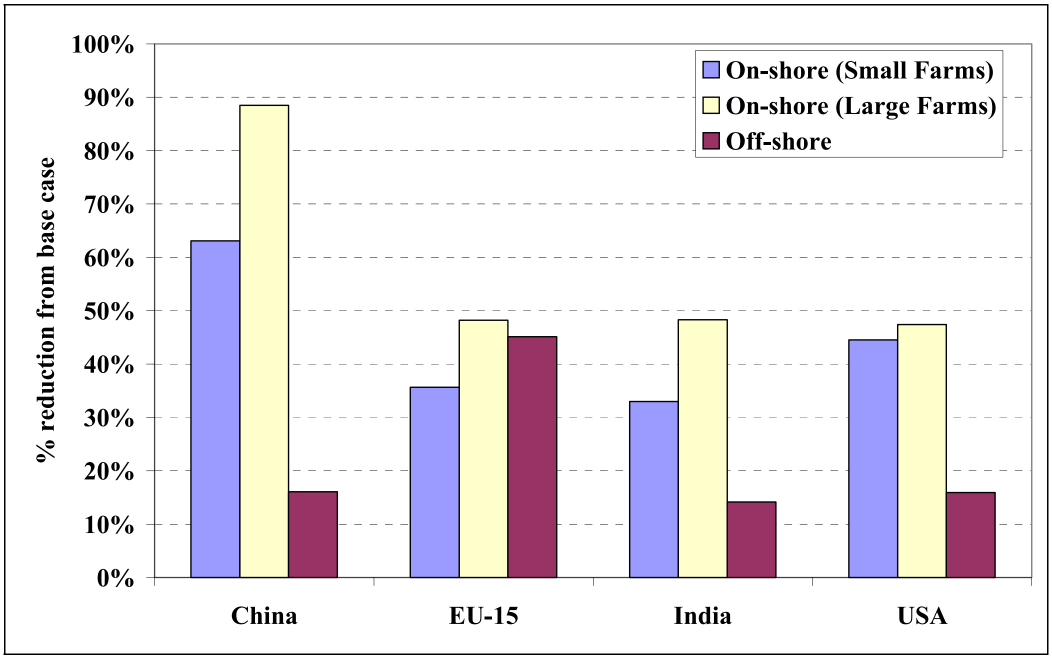


Figure 11.3: Maximum potential reduction in CO_2 emissions from wind energy compared with base case (2020)

Table 11.7 provides a comparison of the carbon intensities for the different scenarios in 2020 based on the maximum wind potential. These figures take into account any spilt wind associated with high wind penetrations. The largest reduction in the carbon intensity of power production is achieved in China where the intensity is almost 90% lower than the base case when the large wind farm potential is utilised. Elsewhere the decline is close to 50% for large onshore wind farms.

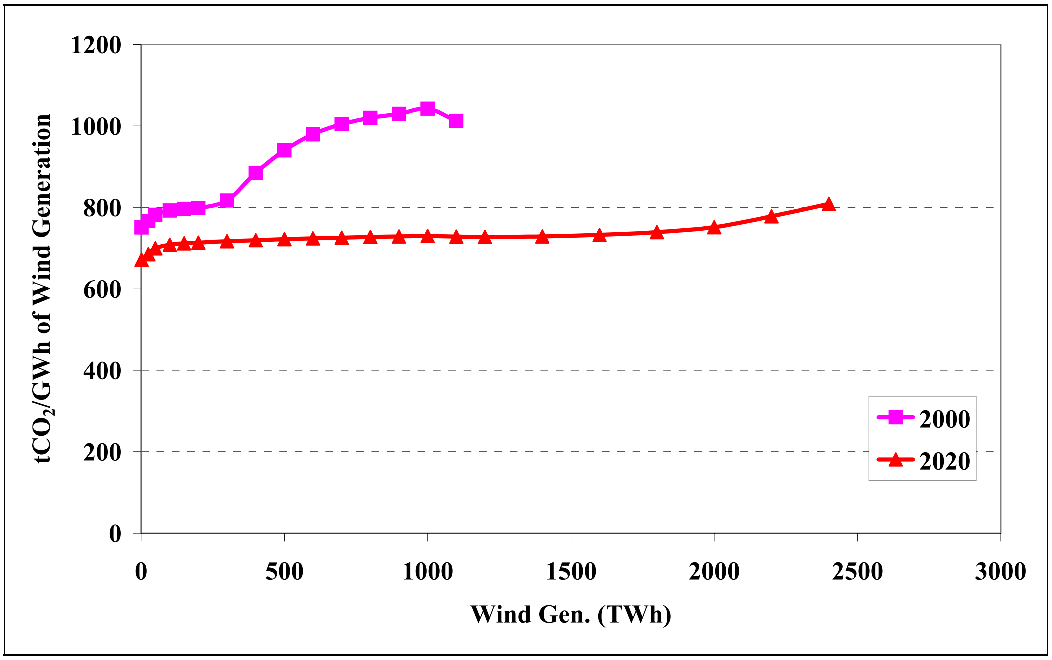
	Base case	Small Onshore	Large Onshore	Offshore
China	611	226	70	513
EU-15	315	203	163	173
India	654	438	338	562
USA	479	266	252	403

Table 11.7: Carbon intensity by scenario in 2020 (tonnes of CO_2 per GWh_e)

11.2.2 China

In China the reduction in carbon dioxide emissions from the power sector, when wind is utilised to its maximum potential, amounts to 88% and 63% for large onshore wind farms and small wind farms respectively, and 16% for offshore generation compared with total base case emissions in 2020. The carbon intensity of the power sector declines by as much as 90% at maximum large onshore wind output in 2020, and as little as 15% at maximum offshore wind output, compared to the base case.

The displacement of coal by wind produces a relatively large carbon saving per unit of wind generation installed. This is because coal produces more carbon dioxide than most other power generation fuels, and coal-fired generation has a relatively low thermal efficiency. The carbon dioxide abated per unit of wind generation is shown in Figure 11.4. China is shown to have one of the largest carbon dioxide savings per unit of installed wind generation. The data points for the year 2000 mirror those for 2020 until wind exceeds the replacement capacity requirements. At this point, additional wind generation displaces existing plants that would not be retired under normal circumstances. The thermal efficiency of the existing power plants tends to be lower than that of new plants; hence the increase in the carbon savings. However, as we have mentioned before, there is an economic cost in retiring units early as these stranded investment costs would add to the overall generation system costs.



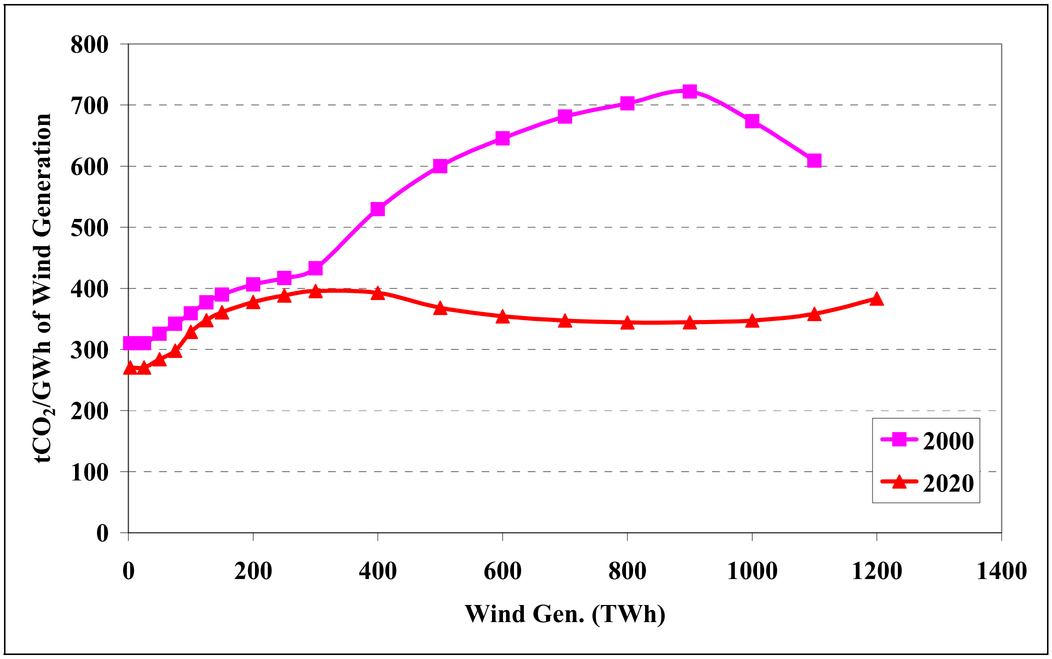
Note: 'Wind Gen' is the dispatched wind output from the installed wind generation capacity, taking into account curtailment (wind spilt) due to system operational restrictions.

Figure 11.4: CO_2 abatement per GWh of wind generation in China

11.2.3 EU-15

In the EU-15 the reduction in carbon dioxide emissions from small onshore and large wind generation amounts to 36% and 48% respectively of total base case emissions in 2020 when wind is utilised to its potential maximum. The offshore figure is 45%. The carbon intensity of the power sector declines from 315 tCO_2 per GWh_e to a low of 163 tCO_2 per GWh_e at maximum wind output from large onshore wind farms in 2020. The EU already has the lowest carbon intensive power sector of the four regions covered in the in-depth analysis, but it also has a large wind resource relative to its generation requirements. Consequently, the deployment of that wind resource leads to a large reduction in the generating sector's carbon intensity.

The fact that wind largely displaces gas-fired generation reduces the amount of carbon dioxide abated per kWh of wind introduced compared with some other regions. Gas-fired generation using CCGTs is more efficient than coal-fired technology, with thermal efficiencies close to 60% compared with coal-fired units where efficiencies are about 40%. Displacing one unit of gas-fired generation therefore has a smaller impact on fuel inputs than displacing one unit of coal-fired generation. In addition, the carbon dioxide emitted by natural gas is 40% less than that of coal on an energy basis. The combined effect of these two factors means that the amount of carbon dioxide displaced by replacing gas-fired CCGTs is 60% less than that from displacing the same amount of coal-fired generation.



Note: 'Wind Gen' is the dispatched wind output from the installed wind generation capacity, taking into account curtailment (wind spilt) due to system operational restrictions.

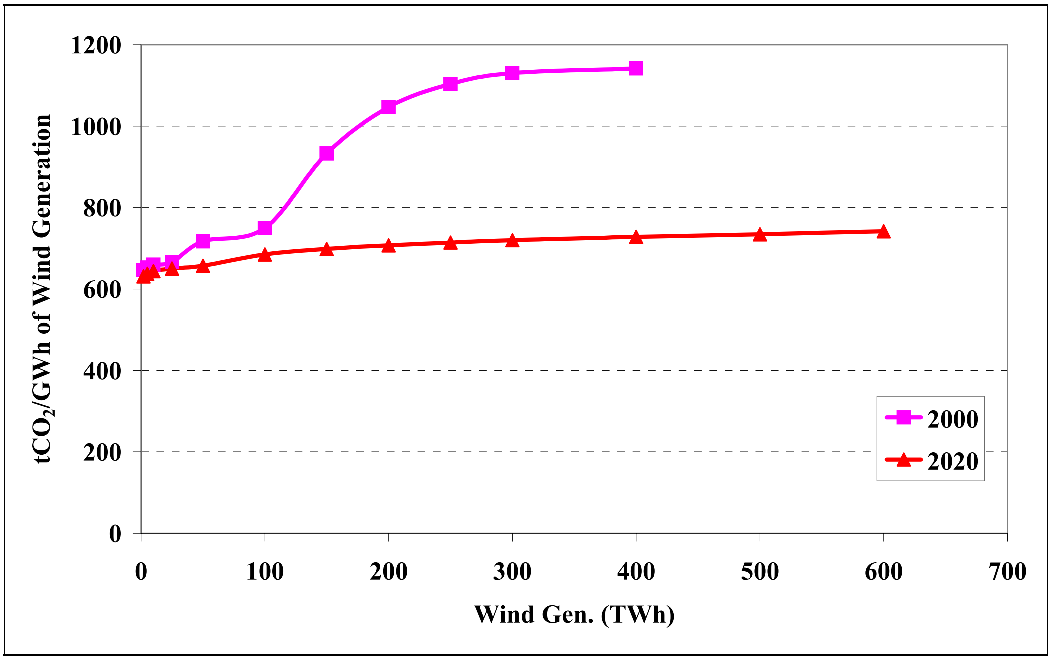
Figure 11.5: CO_2 abatement per GWh of wind generation in the EU-15

Figure 11.5 shows the amount of carbon abated per unit of wind output as wind generation is increased. Initially, wind displaces new gas-fired capacity. However, as the amount of wind generation increases, and as the build-up to that capacity stretches further back towards the start of the forecast period, so less gas-fired capacity is built in earlier periods. This earlier gas capacity is assumed to have a lower thermal efficiency than later designs, such that its displacement by wind power results in a slightly higher carbon abatement per unit of wind generation. This continues until wind generation exceeds 10% of total generation at which point additional peaking generation is required which adds to the carbon dioxide emissions and reduces the level of abatement per unit of wind output.

11.2.4 India

In India, the reduction in carbon dioxide emissions from wind generation, when utilised to its maximum potential, amounts to 48% and 33% for large onshore wind farms and small wind farms respectively, and 14% for offshore generation, compared with total base case emissions in 2020. The carbon intensity of the power sector declines from 654 tCO_2 per GWh_e to 338 tCO_2 per GWh_e at maximum large onshore wind output in 2020. India already has the most carbon intensive power sector of the four study regions. It also does not have as large a wind resource as some of the other study regions and at maximum wind output in 2020 its carbon intensity of electricity generation remains the highest.

Because coal produces more carbon dioxide than most other power generation fuels and because coal-fired generation has a relatively low thermal efficiency, the displacement of coal by wind has the greatest carbon saving per unit of wind generation installed. In India wind displaces coal-fired generation and consequently the carbon saving per unit of dispatched wind generation is the highest of all the study regions. The level of carbon savings per unit of dispatched wind generation is shown in Figure 11.6.



Note: 'Wind Gen' is the dispatched wind output from the installed wind generation capacity, taking into account curtailment (wind spilt) due to system operational restrictions.

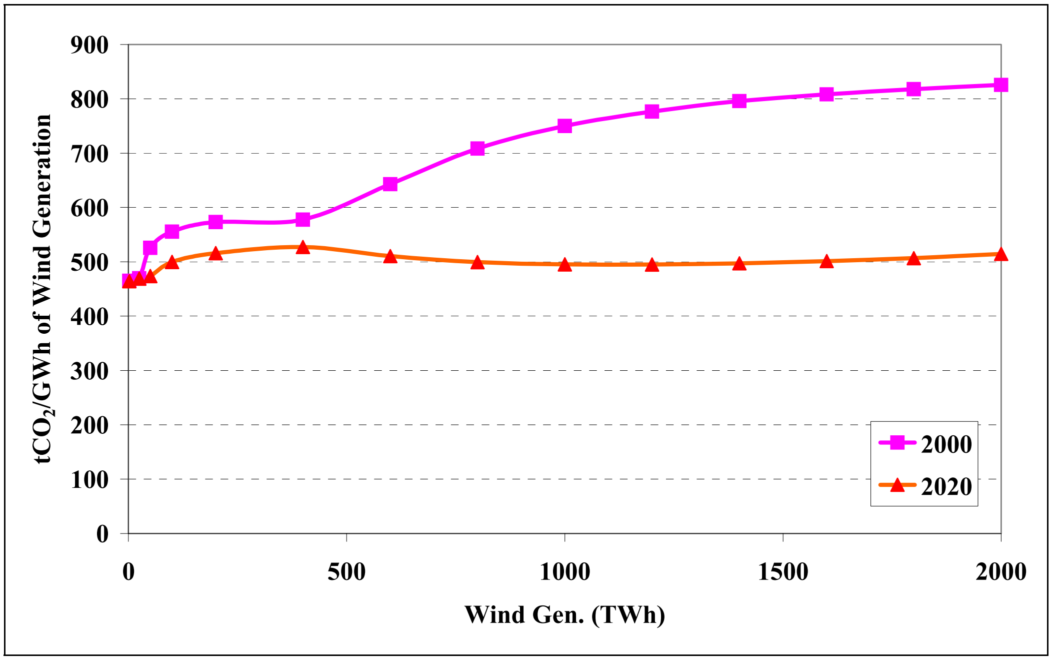
Figure 11.6: CO_2 abatement per GWh of wind generation in India

11.2.5 USA

In the USA the reduction in carbon dioxide emissions from onshore wind generation amounts to 45% (small wind farms) and 47% (large wind farms) of total base case emissions in 2020 when wind is utilised to its potential maximum. The comparable offshore figure is 16%. The carbon intensity of the power sector declines by similar percentages, from 479 tCO_2 per GWh_e in 2020 in the base case to a low of 252 tCO_2 per GWh_e at maximum large wind farm output.

The USA's power generation carbon intensity is just over 50% higher than that in the EU-15 in the 2020 base case. When the large onshore wind resource is fully utilised in both the EU-15 and the USA, the USA's carbon intensity is 55% higher than the EU-15's. Although the USA has a much larger onshore wind resource than the EU-15 (70% higher), it only represents a slightly higher share of total generation (49% versus 44%). This is one factor behind the larger call on fossil fuel generation in the USA system than in the EU-15. Another factor is the lower nuclear and hydro share of total generation in the USA compared with the EU-15, which further adds to the need for fossil fuel generation.

The USA lies between India and the EU-15 in terms of the amount of carbon dioxide avoided per unit of wind generated. This reflects the mix of natural gas and coal-fired generation that is displaced by wind output. Although disproportionately more gas generation is displaced than coal generation, the lower thermal efficiencies of coal results in more coal being displaced than gas (on an energy basis). For example, at the large onshore wind farm generation maximum potential, some 1,200 TWh of coal generation is displaced, while 990 TWh of gas-fired generation is removed in 2020 compared to the base case. The reduction in fuel inputs associated with these declines in generation are 220 Mtoe of coal and 70 Mtoe of gas (gas consumed for base-load generation is partly offset by additional gas consumed for peaking purposes where the thermal efficiency is lower - generation per unit of gas consumed falls). When the carbon produced from coal and gas is factored in, it is easy to see why the USA is closer to India in terms of carbon reduction per unit of wind generation than it is to the EU-15.



Note: 'Wind Gen' is the dispatched wind output from the installed wind generation capacity, taking into account curtailment (wind spilt) due to system operational restrictions.

Figure 11.7: CO_2 abatement per GWh of wind generation in the USA

12 COSTS OF AVOIDED CO_2 EMISSIONS: STUDY REGIONS

12.1 Overview

The cost of avoided emissions reflects the difference in the system costs with and without wind generation i.e. the additional generating costs incurred by incorporating wind power into the overall generation mix. As has already been noted, this is not just the cost of the energy from wind farms, but also the need for additional peaking generation, back-up capacity and grid strengthening. The avoided cost was calculated at various levels of wind generation in 2000 and 2020 to produce average cumulative cost curves.

It has already been noted that the introduction of wind produces different levels of carbon dioxide emission reductions depending on the type of generation displaced. If the carbon dioxide reductions are integrated with the system cost of introducing wind generation into the power mix, cost curves for wind abatement of carbon dioxide can be generated. These curves, and the data used to create them, are presented in the following sections.

Figure 12.1 to Figure 12.3 provide regional comparisons of the abatement cost curves produced for 2020. The curves show a wide spread of costs in achieving similar carbon dioxide reductions. The three figures reflect the cost curves for small onshore wind farms, large onshore wind farms and offshore wind farms. The onshore curves indicate that the EU-15 starts off with the lowest abatement costs, but that the costs rise steeply exceeding those in China and the USA. China emerges with not only the largest potential for carbon dioxide abatement, but also at the least cost. China's enormous onshore wind resource means that large amounts of coal-fired generation can be displaced at little additional cost. The USA also has a large wind resource, although not as large as China's, but the wind generation costs are higher (least cost wind generation costs in 2020 for large wind farms are 6% higher in the USA than in China). The USA abatement costs start off higher and rise more steeply than China's. India's wind resource is smaller than those of the other study regions (20% of China's and half the EU-15's) and tends to be more expensive due to lower wind speeds. Least cost wind generation costs in India in 2020 are 12% higher than China's for large wind farms and 6% higher than the USA. India has high and sharply rising abatement cost curves.

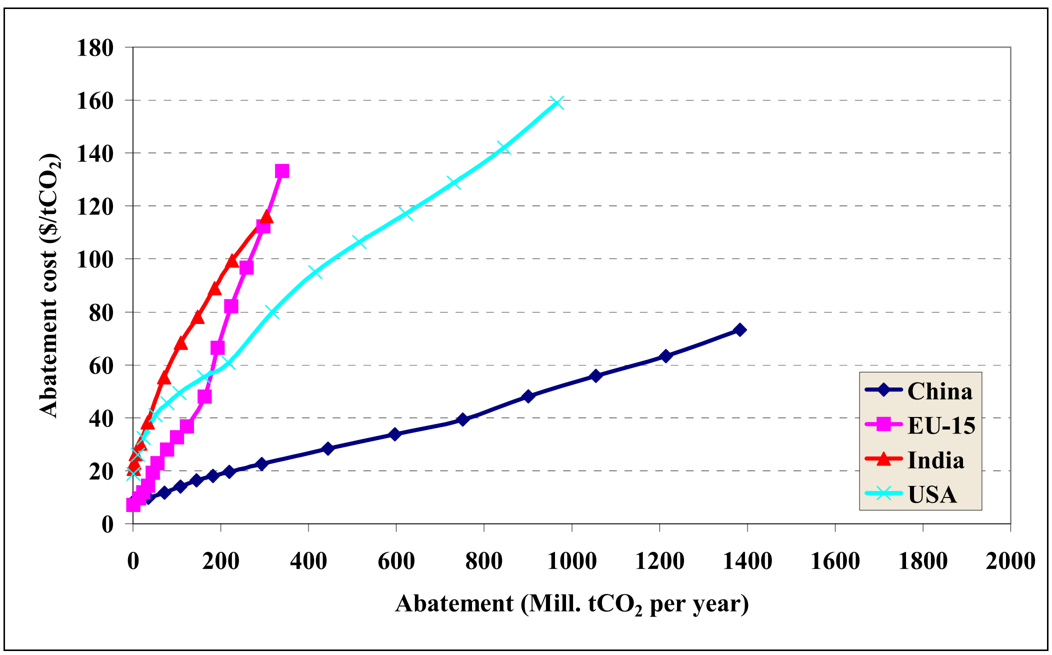


Figure 12.1: Comparison of annual abatement cost curves for small onshore wind (2020)

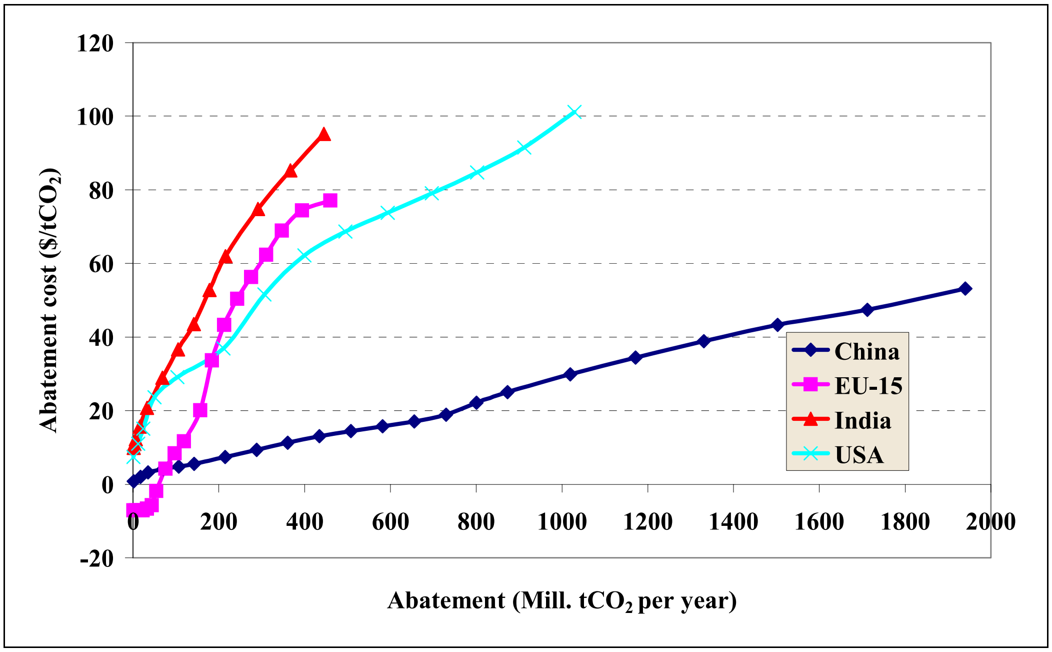


Figure 12.2: Comparison of annual abatement cost curves for large onshore wind (2020)

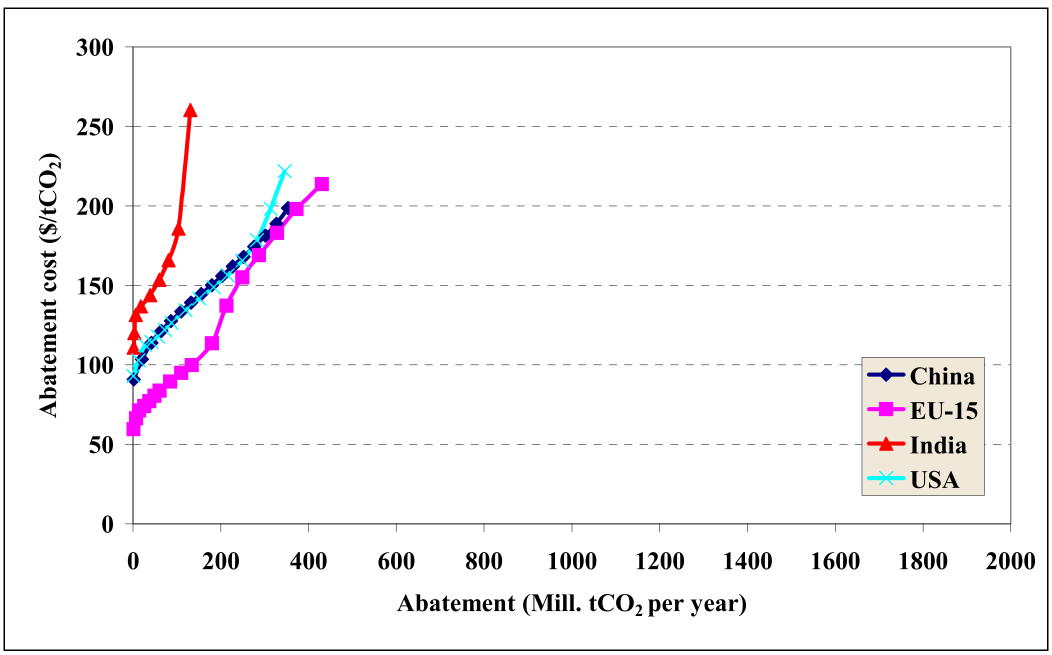


Figure 12.3: Comparison of annual abatement cost curves for offshore wind (2020)

The least cost options are, not surprisingly, for large onshore wind farms, where abatement costs tend to start at less than $10 per tonne of CO_2 abated. However, costs rise sharply and in the case of the EU-15, India and USA exceed $40 per tonne of CO_2 abated at an annual carbon dioxide saving of less than 200-250 million tonnes (India exceeds $40 per tonne of CO_2 at a carbon dioxide saving of around 100 million tonnes). The exception is China, where abatement costs remain below $20 per tonne of CO_2 abated up to an abatement level of 750 million tonnes of CO_2 for large wind farms; the level of annual abatement falls to 230 million tonnes of CO_2 for small wind farms.

Figure 12.4 compares the cost of abatement in the different regions for the same level of emission reduction. The comparison is restricted by the limited offshore wind potential, particularly in India and is based on a limited carbon reduction of 100 million tonnes of carbon dioxide. It shows that China has the lowest abatement costs at this level of abatement. India has the highest costs. It also shows that the abatement costs from offshore wind generation are typically an order of magnitude greater than the onshore wind abatement costs.

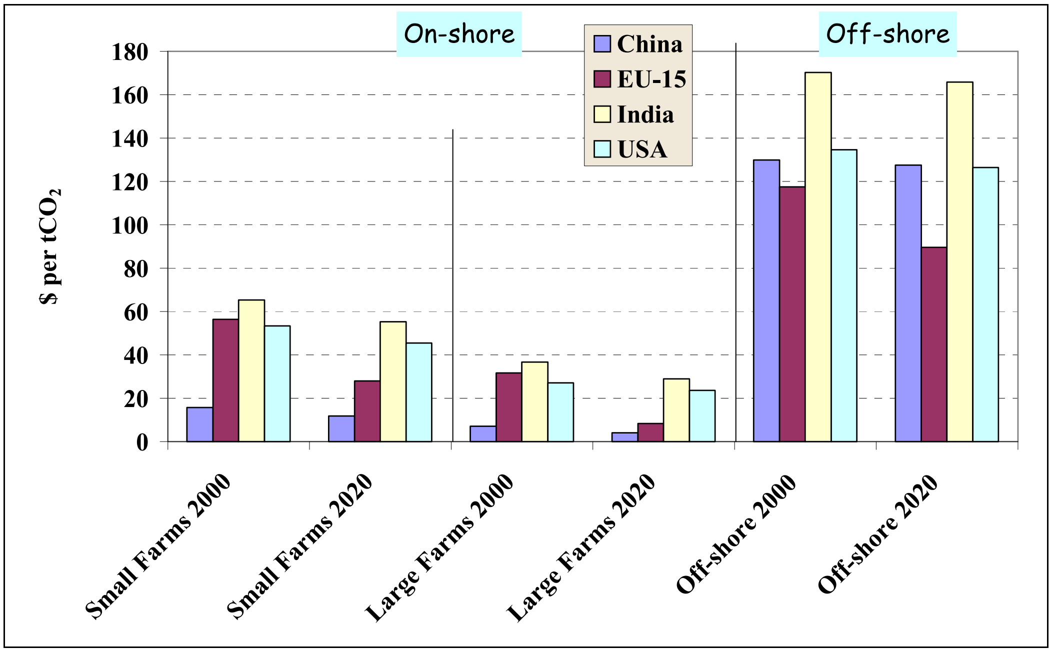


Figure 12.4: Abatement costs comparison at 100 million tonnes of CO_2 abated per year

Figure 12.4 shows that in 2020 the EU-15 has lower abatement costs from wind generation than India and the USA despite also having a lower level of abatement per unit of wind generation. This serves to highlight the fact that it is not the amount of carbon that is abated that is most important, but the cost of achieving that abatement. The EU-15 has a relatively large wind resource that can be exploited at relatively low cost. Because of this, the EU-15 offers the potential for wind to achieve a reduction in carbon dioxide emissions at relatively low cost.

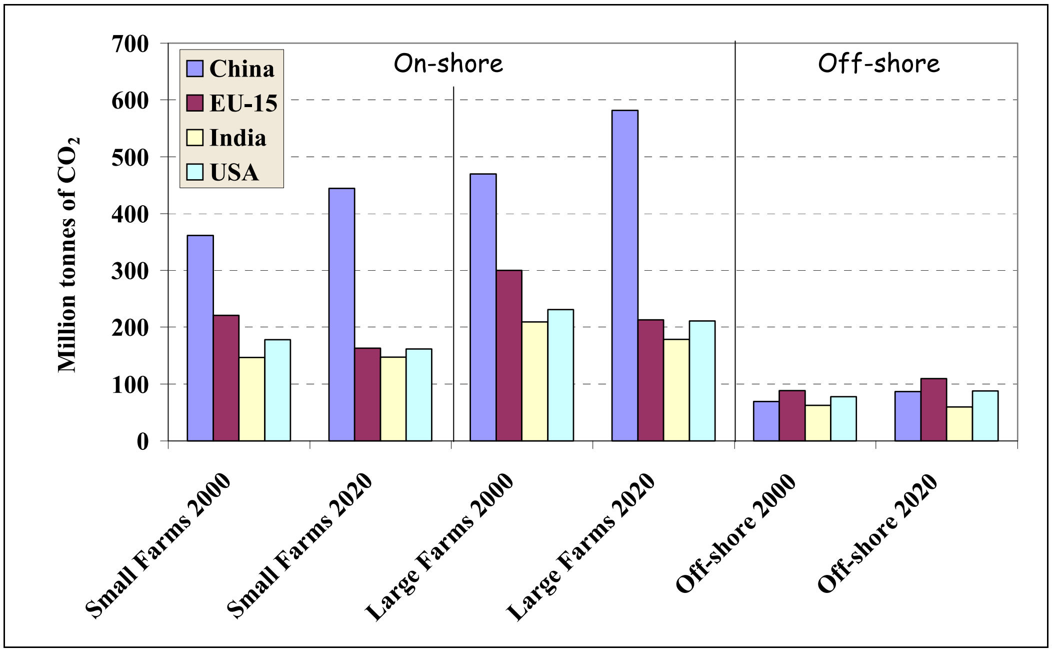


Figure 12.5: Amount of annual CO_2 abated at a cost of \$10 billion

Figure 12.5 provides another way of looking at the same results. The graph indicates the amount of annual carbon dioxide abated for the same cost in all four study regions for both onshore and offshore wind generation. The figure confirms that China offers a large level of emissions reduction for a given level of additional generating costs. It also indicates that all the other regions offer similar levels of benefits, and that the onshore potential is 50-100% greater than the offshore potential.

This analysis highlights the fact that wind generation costs are the key element in determining the ultimate cost of avoided emissions. The sensitivity of wind generation costs to social constraints (i.e. the density and location of wind sites) is one of the most important factors in limiting the exploitation of wind and pushing up its costs. This can be seen by comparing the small wind farm results with the large wind farm results, which indicate that the additional CO_2 abated, at a cost of \$10 billion dollars, is anywhere from 20% to 40% higher in the large wind farms scenario – more than can be accounted for by the different capital cost assumptions alone. This indicates that there may be a trade off between achieving lower cost carbon dioxide reductions and public resistance to wind farms – reduce the resistance and the costs come down. Whether this can be characterised as a clash between the local and the global requirements is a moot point since there may be other lower cost alternatives for carbon dioxide abatement. However, within the context of this study it does represent a clear dichotomy.

12.2 China

Figure 12.6 shows the abatement cost curves for China in 2020 for small wind farms, large wind farms and offshore wind farms. The kinked abatement cost curves reflect the fact that, up to a certain level, wind generation remains below 10% of total generation and the curves reflect the difference in the cost of wind generation compared with the displaced capacity. When wind penetration exceeds 10%, additional operational costs (additional peaking capacity) add to the abatement costs. In all cases available wind generation runs out before the maximum generation requirement is reached, although in the large onshore wind scenario wind accounts for 70% of the total in 2020.

Figure 12.6 indicates that the least cost option in China is from the development of large onshore wind farms, whilst offshore costs are the most expensive. At a level of abatement of 1,400 million tonnes of CO_2 per year, large onshore wind farm abatement costs are 45% lower than small onshore costs. The introduction of wind generation could make a considerable carbon dioxide saving in China at relatively low costs. However, restricting the size of the onshore wind farms will have a significant impact on the level of abatement. At an abatement cost of $20 per tonne CO_2, annual CO_2 savings of around 800 million tonnes are possible using large wind farms, but this is reduced to just 200 million tonnes using small wind farms.

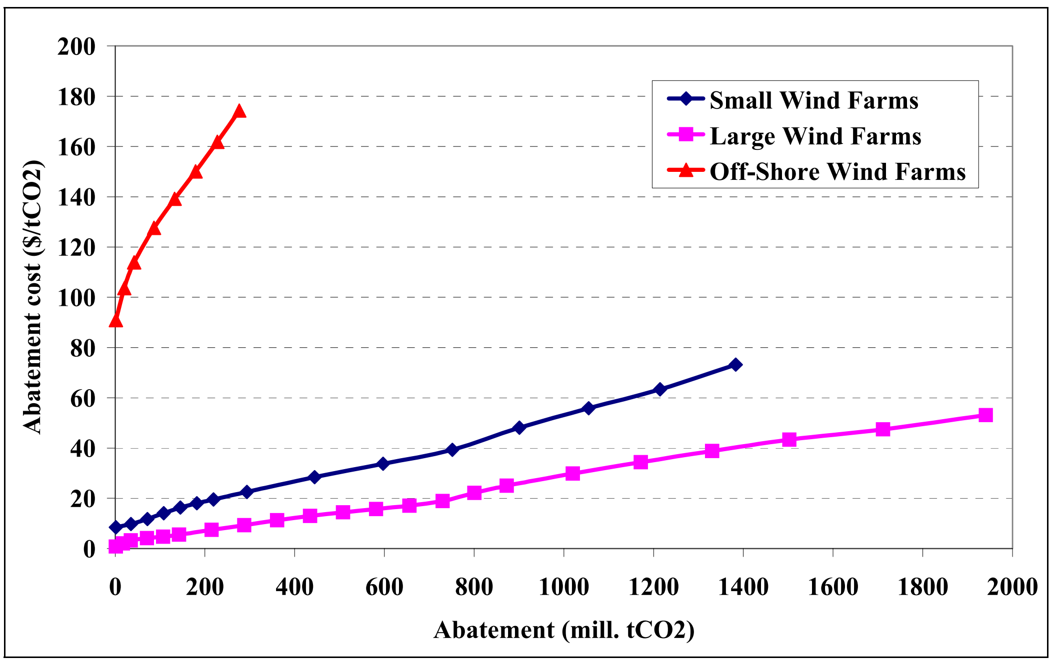


Figure 12.6: Comparison of annual abatement cost curves for China (2020)

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	$/tCO_2$	M tCO_2	$/tCO_2$	M tCO_2	$/tCO_2$
2	1.38	8.46	1.34	0.81	1.37	90.94
50	35.33	9.78	34.96	3.25	41.99	113.88
100	71.65	11.78	70.81	4.15	86.72	127.59
150	108.23	14.07	106.72	4.75	132.59	139.18
200	145.06	16.34	142.70	5.51	179.44	150.12
300	219.03	19.54	215.05	7.43	276.54	174.31
400	293.60	22.57	287.78	9.33		
600	444.39	28.42	434.36	13.01		
800	596.95	33.76	581.74	15.73		
1000	751.47	39.29	729.88	18.91		
1200	900.85	48.09	872.80	25.00		
1400	1055.07	55.81	1019.89	29.89		
1600	1214.62	63.35	1171.62	34.37		
1800	1383.33	73.19	1330.54	38.84		
2000			1502.65	43.33		
2200			1711.62	47.44		
2400			1940.61	53.13		

Note: The first column is the potential annual output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Table 12.1: Annual CO_2 abatement and abatement costs for China (2020)

It should be noted that the same amount of wind generation does not lead to the same level of CO_2 abatement for each scenario due to the feedback effect of electricity prices on demand. Essentially, the higher wind costs earlier in the forecast period lead to higher generation costs, higher electricity prices, lower electricity demand and a slightly larger decline in CO_2 emissions.

12.3 EU-15

Figure 12.7 shows the abatement cost curves for the EU-15 in 2020 for small wind farms, large wind farms and offshore wind farms. Figure 12.7 indicates that the least cost option in the EU-15 is from the development of large onshore wind farms, whilst offshore costs are the most expensive. Abatement costs are negative for large wind farms up to an annual abatement of 50 million tonnes CO_2, as wind generation costs up to 150 TWh are expected to be lower than the conventional generation technology wind displaces Restricting the size of wind farms leads to an increase in wind generation costs and the abatement costs are positive over the same abatement range.

At a level of abatement of 160 million tonnes of CO_2 (17% of the base case 2020 power sector emissions) large onshore wind farm abatement costs are $20 per tonne CO_2, 60% lower than small onshore costs and over 80% lower than offshore costs. However, at an abatement level of 200 million tonnes of CO_2 large onshore wind farm abatement costs are around $40 per tonne CO_2, 45% lower than small onshore wind farms and 70% lower than offshore wind farms. There is a rapid increase in abatement costs between 160 million tonnes and 200 million tonnes CO_2 per year as wind generation exceeds 10% of total generation and system costs start to increase beyond those expected with conventional technologies.

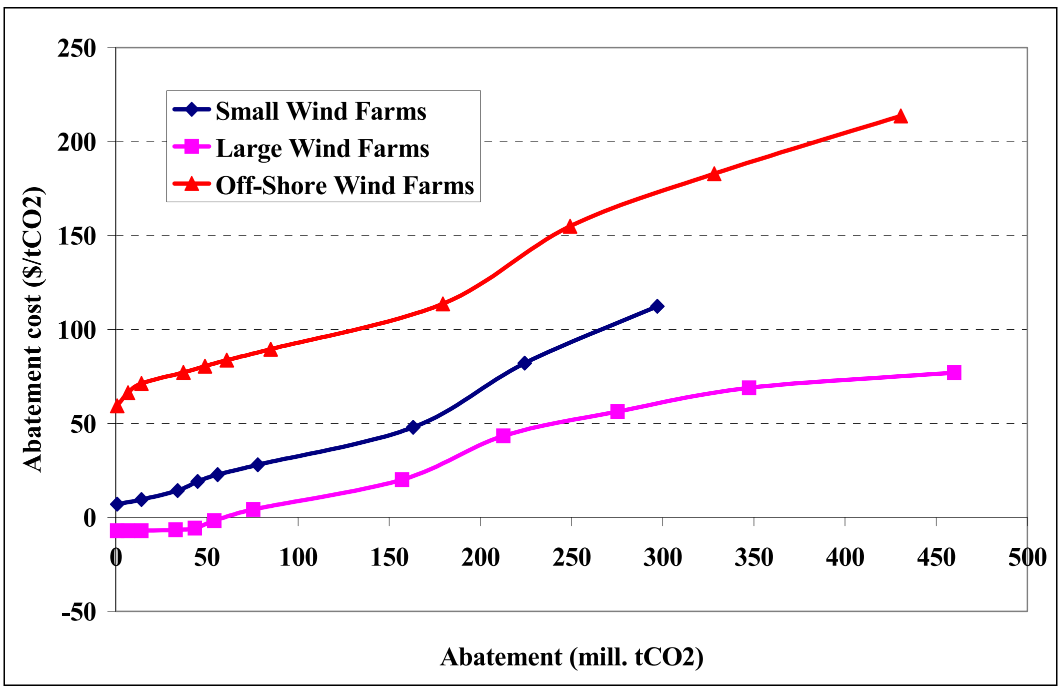


Figure 12.7: Comparison of annual abatement cost curves for the EU-15 (2020)

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
3	0.81	7.05	0.81	-7.10	0.81	59.45
50	14.19	9.50	14.19	-7.10	14.19	71.34
100	33.98	14.34	32.88	-6.64	37.14	77.15
150	55.91	22.76	54.11	-1.77	60.92	83.69
200	78.02	28.01	75.53	4.25	85.03	89.57
300	122.77	36.69	118.69	11.62	134.03	99.84
400	163.19	47.92	157.05	20.14	179.43	113.66
500	192.57	66.43	183.97	33.69	213.29	137.13
600	224.34	82.09	212.62	43.35	249.22	154.98
800	297.03	112.32	275.28	56.33	328.26	182.91
1000			347.35	68.92	430.56	213.63
1200			459.84	77.08		

Note: The first column is the potential annual output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Table 12.2: Annual CO_2 abatement and abatement costs for the EU-15 (2020)

12.4 India

Figure 12.8 shows the abatement cost curves for India in 2020 for small wind farms, large wind farms and offshore wind farms. Figure 12.8 indicates that the least cost option in India is the development of large onshore wind farms. Wind supply costs rise quite steeply as more wind is added to the generation parc, and this leads to a relatively steep rise in the abatement costs curves from an initially relatively low level (around $10 per tonne CO_2 for large wind farms and $20 per tonne CO_2 for small wind farms). The offshore wind resource is much more expensive and abatement costs start at over $100 per tonne CO_2.

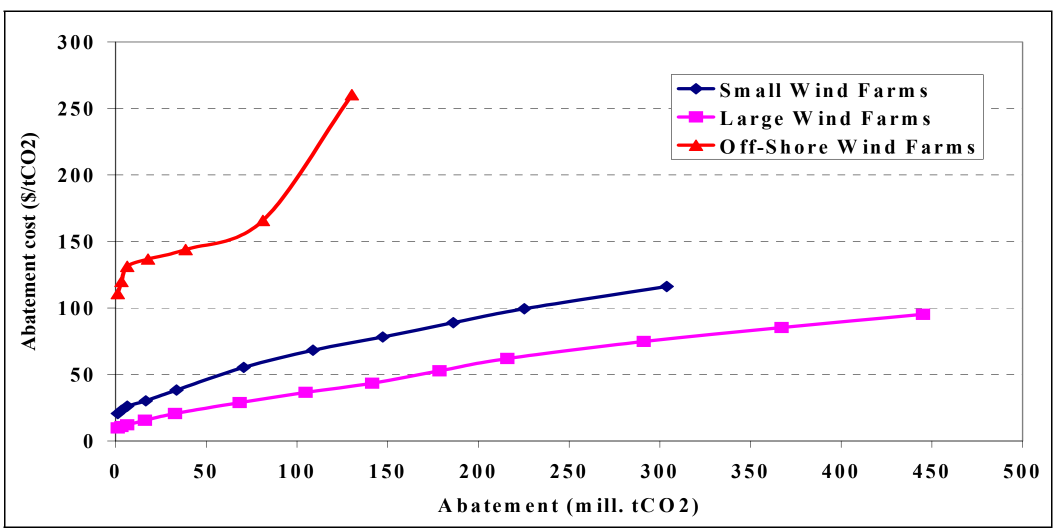


Figure 12.8: Comparison of annual abatement cost curves for India in 2020

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
2	1.26	20.71	1.26	9.87	1.26	110.84
5	3.19	23.05	3.19	10.89	3.19	119.94
10	6.44	26.30	6.44	12.18	6.44	131.36
25	16.60	30.26	16.26	15.62	17.92	136.75
50	33.54	38.35	32.84	20.73	38.59	143.94
100	70.70	55.33	68.50	28.95	81.20	165.84
150	108.79	68.33	104.76	36.59	130.32	260.27
200	147.33	78.18	141.49	43.48		
250	186.16	89.01	178.54	52.79		
300	225.41	99.41	215.96	62.00		
400	303.86	116.13	291.16	74.83		
500			367.11	85.27		
600			445.13	95.20		

Note: The first column is the potential annual output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Table 12.3: Annual CO_2 abatement and abatement costs for India (2020)

12.5 USA

Figure 12.9 shows the abatement cost curves for the USA in 2020 for small wind farms, large wind farms and offshore wind farms. Figure 12.9 indicates that the least cost option in the USA is from the development of large onshore wind farms, while offshore costs are the most expensive.

The abatement costs start relatively low - especially for large onshore wind farms where abatement costs are less than $10 per tonne CO_2 - but they rise rapidly. This reflects the fact that there are a few sites with very low generation costs. However, the marginal costs of wind energy from large wind farms rises relatively steeply up to about 100 TWh (0.5-2% per 600 MW of additional installed capacity). Thereafter, the rise in the marginal costs is much more modest (0.0-0.1% per 600 MW of installed wind capacity) up to 2000 TWh of cumulative wind generation. This explains why there is a steep rise in the abatement costs up to 50 million tonnes of carbon dioxide abated annually.

At a level of abatement of 200 million tonnes of CO_2, large onshore wind farm abatement costs are $35 per tonne CO_2, 40% lower than small onshore costs and 80% lower than offshore costs. However, at an abatement level of 400 million tonnes of CO_2 large onshore wind farm abatement costs are almost double at $62 per tonne CO_2, 30% lower than those of small onshore wind farms. Offshore wind farms only have a CO_2 abatement potential of 250 million tonnes per year.

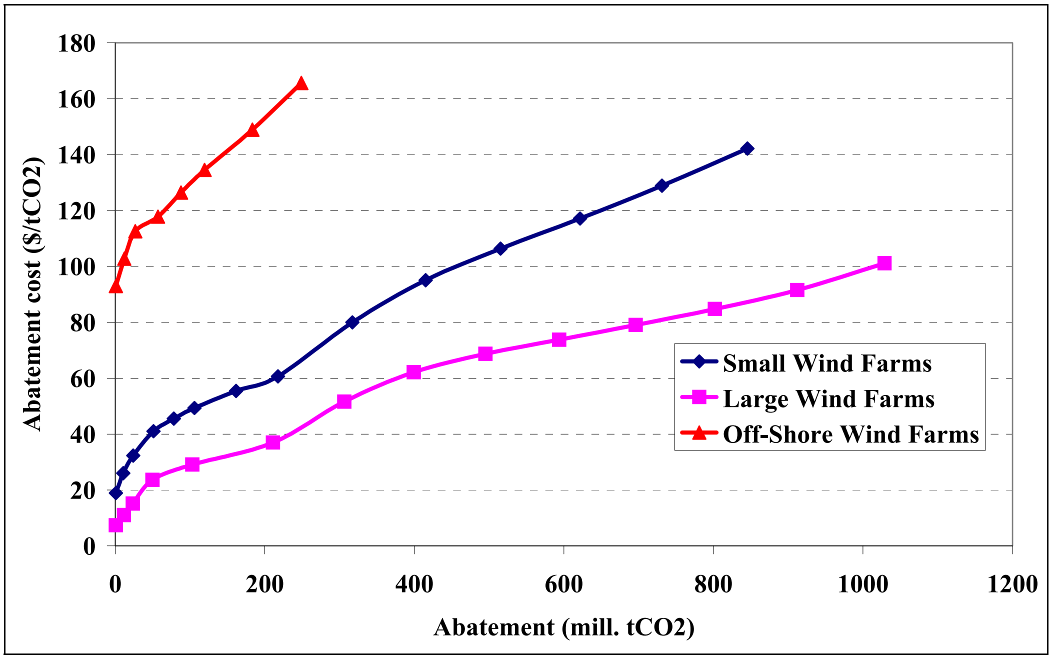


Figure 12.9: Comparison of annual abatement cost curves for the USA (2020)

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	\$/tCO_2	M tCO_2	\$/tCO_2	M tCO_2	\$/tCO_2
2	0.86	18.87	0.93	7.41	0.97	93.03
25	10.90	26.02	11.73	10.98	12.22	102.81
50	24.19	32.31	23.69	15.11	27.00	112.58
100	51.17	41.01	49.96	23.61	57.15	117.80
200	106.04	49.36	103.15	29.08	119.46	134.51
400	217.65	60.68	210.96	36.95	249.00	165.65
600	317.34	80.00	306.34	51.60		
800	415.25	95.05	399.41	62.12		
1000	515.49	106.38	495.19	68.70		
1200	621.51	117.10	593.83	73.76		
1400	731.20	128.87	696.10	79.02		
1600	845.51	142.15	802.03	84.75		
1800	966.36	158.92	912.08	91.51		
2000			1028.92	101.14		

Note: The first column is the potential annual output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Table 12.4: Annual CO_2 abatement and abatement costs for the USA (2020)

13 COSTS OF AVOIDED CO_2 EMISSIONS: REST OF THE WORLD

13.1 Overview

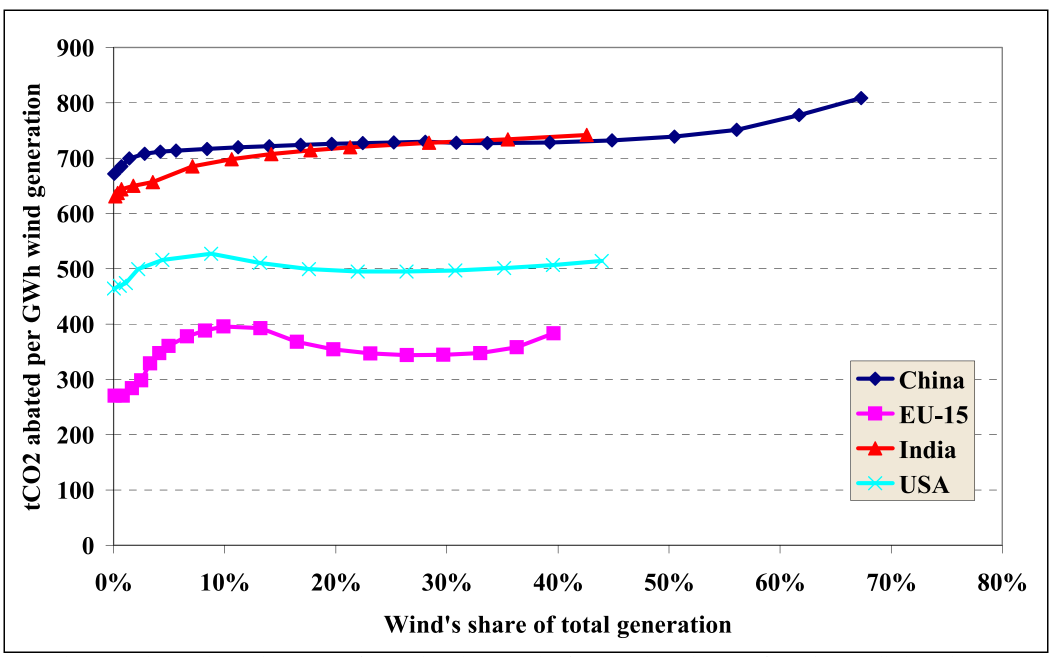
The abatement costs for the rest of the world were based on extrapolations from the four study regions. There are two components to the abatement cost calculations - the amount of carbon dioxide abated by the introduction of wind, and the system cost of including wind energy in the generation mix. Again, the resulting cost curves were average cumulative in nature.

13.1.1 Levels of carbon abatement

The amount of carbon dioxide abated is a function of the fuels displaced. The results from the study regions have to be extrapolated to the rest of the world on the basis of the likely fuel displaced and a comparison with one of the study regions with a similar fuel displacement.

In Section 11 a series of figures showing the amount of carbon dioxide abated per GWh of wind generation relative to the absolute level of wind generation was presented. It was noted in that section that, once wind generation exceeds 10% of total generation, additional peaking generation is required, some of which may be fossil fuel-fired and which reduces the level of carbon dioxide abatement per GWh of wind generation. These curves can be adapted to determine the level of carbon dioxide abatement from the other regions in the world.

Figure 13.1 shows the level of abatement per GWh of wind generation for the four study regions. The figure shows how the level of abatement varies as wind's share of total electricity generation increases. The curves follow a similar pattern, with the level of abatement per GWh of wind generation rising marginally up to 10% of the total electricity output and then declining to a lower plateau thereafter. The difference in the level of abatement between the study regions reflects the differences in technologies displaced by wind. In China and India, wind displaces coal-fired generation, while in the EU-15 it displaces CCGTs.



Note: the vertical axis shows the tonnes of CO_2 abated per GWh of potential wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Figure 13.1: Comparison of CO2 abatement per GWh of wind generation (2020)

The results from Figure 13.1 can be used to determine the level of abatement in the rest of the world. To do this it is necessary to know the share of wind in total generation and the likely technology to be displaced. For example, if it is assumed that wind is likely to displace coal-fired generation, the curves for China or India can be used. By determining wind's share of total generation it is possible to read off the level of carbon dioxide abatement per GWh of wind. If this is then multiplied by the actual level of wind generation, the total amount of carbon dioxide abated can be estimated.

The rest of the world has, therefore, been divided into groups based on the technology that wind is most likely to displace. This division of the rest of the world is shown in Table 13.1.

Coal displaced	Gas displaced
Africa	Former Soviet Union and Eastern Europe
Australia	Latin America
	Middle East
	Rest of Asia

Table 13.1: Technology displaced by wind generation

The coal displaced regions (Africa and Australia) are compared with the Chinese abatement curve, while the other regions are compared with either the USA or EU-15 depending on the extent of gas and coal displaced (i.e. if it is mostly gas that is displaced the EU-15 is used, while if there is a more even mix of gas and coal the USA is used). This means that Latin America and the Middle East are compared with the EU-15, while the rest of Asia and the FSU and Eastern Europe are compared with the USA.

The other factor that is required for each region is the current and forecast level of total electricity generation. This is required so that wind's share of the total generation can be estimated in order to determine positions along the abatement curves. Data and forecasts were taken from the IEA's 1998 edition of the World Energy Outlook. This publication provides similar regional aggregates. The exception is that Australia is grouped with the other OECD Pacific countries. It has been assumed that the rate of growth in Australia's total electricity generation is the same as the region total (i.e. 2% p.a. between 1995 and 2020). The generation assumptions are shown in Table 13.2

	2000 (TWh)	2020 (TWh)	Growth Rate (%p.a.)
Africa	437	851	3.4
Australia	195	290	2.0
FSU+E Europe	1,882	3,298	2.8
Latin America	944	2,073	4.0
Middle East	379	839	4.1
Other Asia	1,996	3,853	3.3

Table 13.2: Total electricity generation assumptions

13.1.2 Abatement costs

The abatement costs are a function of the wind generation costs and the generation costs from the technology displaced by wind. It can be seen that there is, therefore, a relationship between the wind supply costs and the abatement cost per GWh of wind generation. This relationship can be used to estimate the costs for the rest of the world. However, differences in the replacement generating costs will raise or lower the cost curve relative to the other countries in the study region. An adjustment based on the ratio of the replacement generating costs needs to be made so that costs across the four regions can be compared.

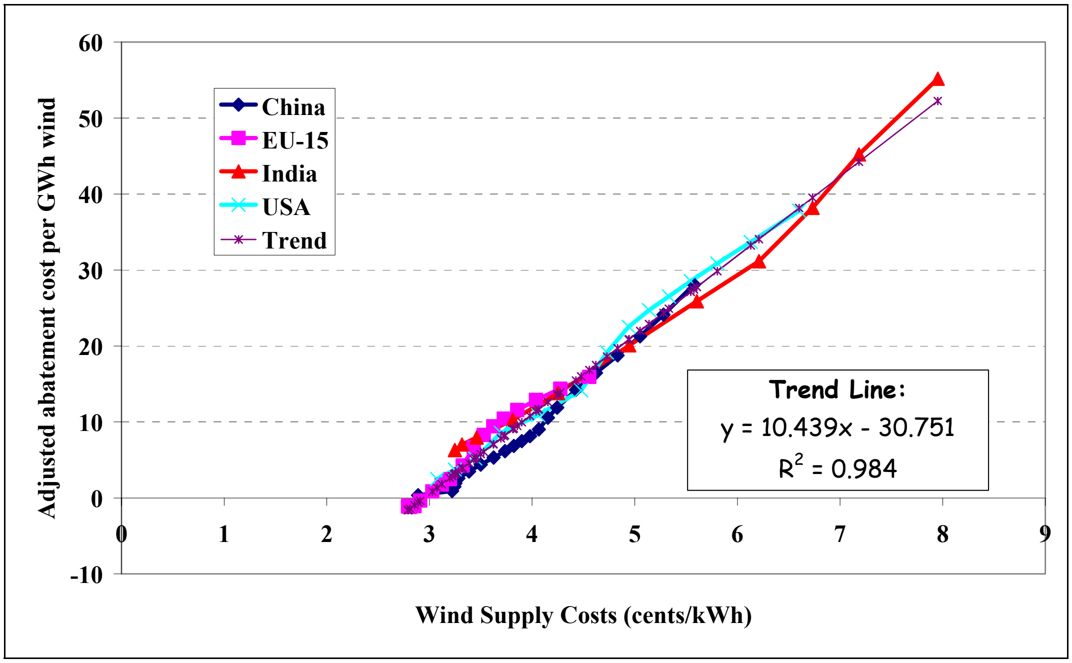


Figure 13.2: Relationship between wind supply costs and abatement costs per GWh of wind generation for large onshore wind farms (2020)

Figure 13.2 shows the adjusted abatement costs relative to wind generation costs. A trend line has been fitted to these data to produce an estimate of the abatement cost for a given wind generation cost. Similar analysis was carried out for the small onshore wind farms and offshore wind farms and for 2000 and 2020.

The coefficients from the fitted trend lines are presented in Table 13.3, along with the associated R^2 values.

The equation is of the form:

Adjusted abatement cost per GWh wind generation = alpha x wind supply costs + beta

	Alpha	Beta	R^2
Large Wind Farms (2000)	12.115	-34.743	0.936
Small Wind Farms (2000)	11.787	-36.636	0.940
Offshore Wind Farms (2000)	12.169	-53.726	0.988
All Wind (2000)	**11.241**	**-35.024**	**0.986**
Large Wind Farms (2020)	10.439	-30.751	0.984
Small Wind Farms (2020)	9.742	-31.753	0.981
Offshore Wind Farms (2020)	10.118	-30.008	0.976
All Wind (2020)	**9.893**	**-29.720**	**0.989**

Table 13.3: Estimated coefficients of wind abatement costs

There is no reason why moving from large to small wind farms, or from onshore to offshore, should change the relationship between wind costs and abatement costs. That is not to say that the wind costs will not change between these scenarios, but the abatement costs should be the same for the same wind costs. The coefficients presented in Table 13.3 would be expected to be the same, or very close, for each time period. The data for 2020 do show a consistent picture, with very little variation between the coefficients. The 2000 data, however, do not show the same degree of consistency, particularly with regard to the beta coefficient.

The "All Wind" values are calculated when all the data for small and large onshore and offshore wind are combined. The average coefficients for the 2020 equation are very close to the All Wind (2020) coefficients and the alpha and beta coefficients can be set to approximate the All Wind coefficients at 9.9 and –29.7 respectively with reasonable confidence. The same cannot be said of the 2000 coefficients. The alphas for 2000 are fairly consistent, but there is a wide variation in the betas. It is difficult to be certain about the correct choice of alpha and beta coefficients in this instance, so again values of 11.2 and –35.0, approximating to the All Wind coefficients, were used.

The abatement costs are calculated by reference to the wind supply cost. For a given level of wind generation the abatement equations produce an adjusted abatement cost per GWh of wind generation. The adjusted figure needs to be inflated or deflated by a replacement cost index and multiplied by the wind generation to produce the total level of abatement costs. These are then divided by the level of carbon dioxide abatement to produce the abatement cost curve for each region. The replacement cost index reflects the relative difference in replacement costs between regions and is set in relation to the EU-15 costs. The replacement cost indices used in the adjustment process are Econ estimates and are presented in Table 13.4.

	2000	**2020**
EU-15	1.000	1.000
Africa	0.803	0.744
Australia	0.803	0.712
FSU+E Europe	1.120	0.874
Latin America	1.044	0.874
Middle East	0.964	0.809
Rest of Asia	1.185	0.922

Table 13.4: Generation cost indices

An overview of the results of this analysis is presented in the following sections. A comparison of abatement costs between scenarios is presented for 2020, while the detailed results for 2000 and 2020 are presented in Appendix E.

13.2 Africa

The IEA's World Energy Outlook (1998) [38] indicates that over 50% of Africa's electricity generation is from solid fuels. Whilst solid fuels' share is expected to decline, the IEA forecasts that they will still account for 43% of total generation in 2020 and that generation from solid fuels will increase by 2.7% per annum between 1995 and 2020. The dominance of solid fuels, and coal in particular, closely resembles the situation in China and India and for that reason the China CO_2 abatement curves have been used when calculating Africa's CO_2 emissions abatement level.

The abatement cost curves for small and large onshore wind farms and offshore wind farms are shown in the tables and figures below. Figure 13.3 provides a comparison on the results for small and large onshore and offshore wind farms in 2020. Africa has a large onshore wind resource that is estimated to be over twenty times current generation requirements and more than ten times the generation requirement anticipated in 2020. The limiting factor on the use of wind is the total generation requirement, which indirectly determines the limit on the level of carbon dioxide abatement.

Wind generation costs are also relatively low, which means that onshore abatement costs are low despite the availability of low cost coal in the south of Africa, low cost gas in the north and low cost oil in the west. Carbon dioxide savings of almost 600 million tonnes per year can be achieved at costs below \$20 per tCO_2 for large wind farms and for about \$34 per tCO_2 for small wind farms.

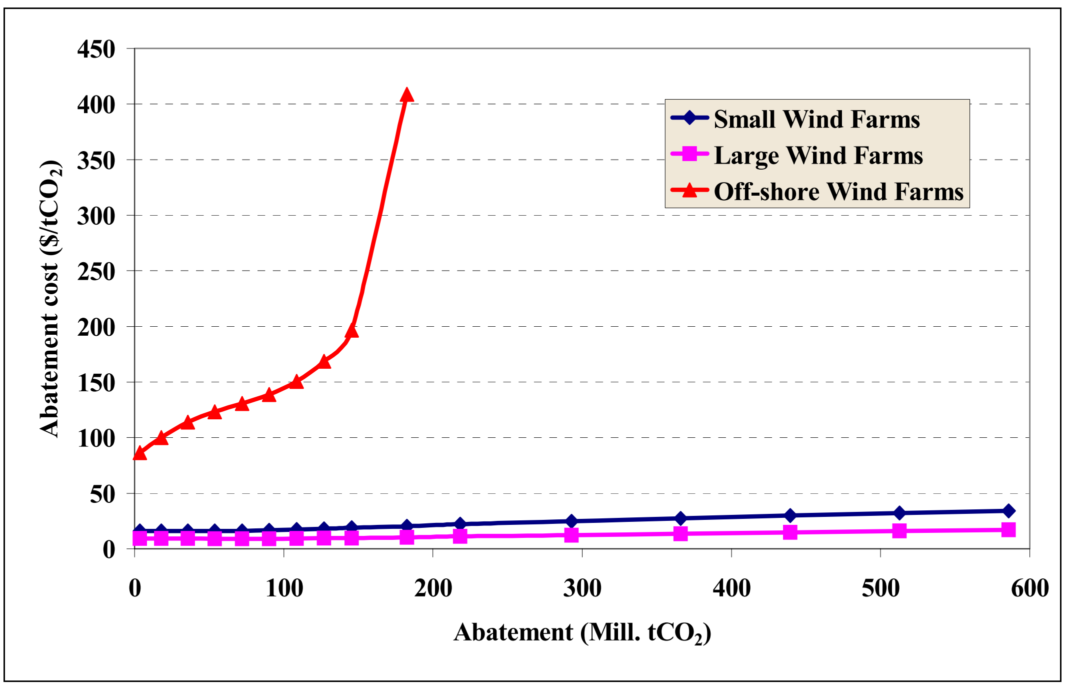


Figure 13.3: Comparison of annual abatement cost curves for Africa (2020)

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	4	16	4	9	4	86
25	18	16	18	9	18	100
50	36	16	36	9	36	114
100	72	16	72	9	72	131
150	109	17	109	9	109	151
200	145	19	145	10	145	197
250	182	20	182	10	182	409
300	218	22	218	11	218	N/A
400	293	25	293	12	293	N/A
500	366	27	366	13	366	N/A
600	439	30	439	15	439	N/A
700	513	32	513	16	513	N/A
800	586	34	586	17	586	N/A

Table 13.5: Annual CO_2 abatement and abatement costs for Africa (2020)

13.3 Australia

IEA energy balances indicate that between 80-90% of Australia's electricity generation is coal-based. Given the abundance of coal reserves in Australia and the limited alternative energy reserves, it is expected that Australia will remain highly dependent on coal to meet the bulk of its future generation requirements. The dominance of coal is on a similar scale to that in China and India, and for that reason the China CO_2 abatement curves have been used when calculating Australia's CO_2 emissions abatement level.

Figure 13.4 provides a comparison of the results for small and large onshore and offshore wind farms in 2020. The abatement costs are relatively low at low levels of abatement, but rise fairly rapidly. The availability of low cost coal-fired generation and the relatively high and fast rising cost of wind means that abatement costs tend to be relatively high. The limited total generation need means that the 10% threshold is achieved at a relatively low level of wind exploitation, especially in comparison with the available resource. It also means that the abatement cost curves are truncated by wind energy reaching Australia's total generation requirement long before the limits of the country's wind energy potential are approached.

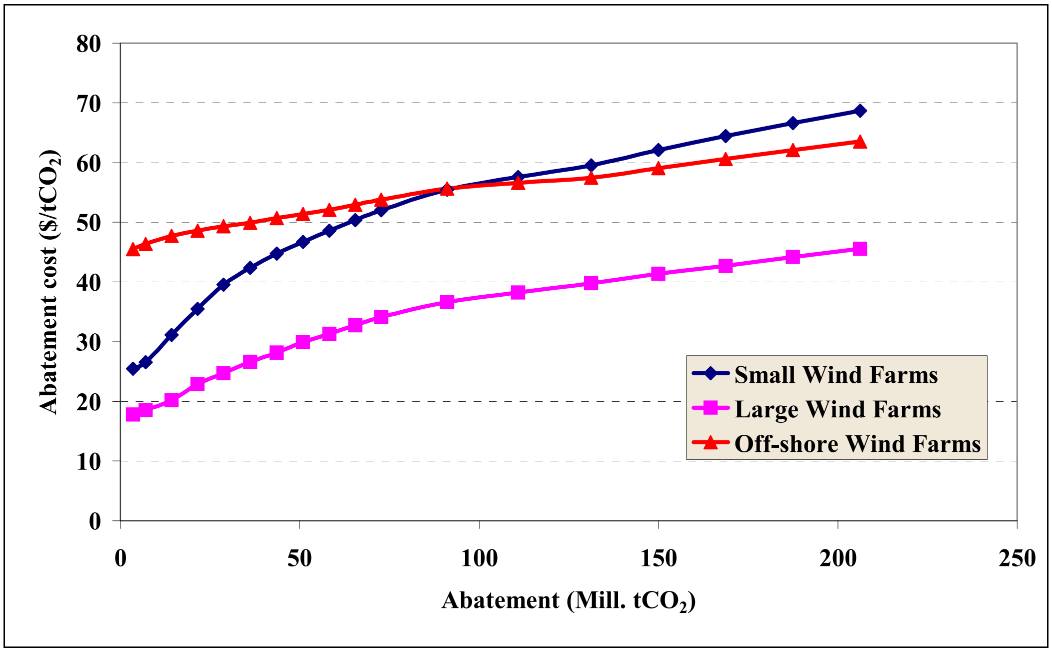


Figure 13.4: Comparison of annual abatement cost curves for Australia (2020)

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	3	25	3	18	3	45
10	7	27	7	19	7	46
25	14	31	14	20	14	48
50	36	42	36	27	36	50
75	51	47	51	30	51	51
100	73	52	73	34	73	54
125	91	55	91	37	91	56
150	111	58	111	38	111	57
175	131	60	131	40	131	57
200	150	62	150	41	150	59
225	169	64	169	43	169	61
250	188	67	188	44	188	62
275	206	69	206	46	206	64

Table 13.6: Annual CO_2 abatement and abatement costs for Australia (2020)

13.4 Former Soviet Union and Eastern Europe

This heterogeneous group of countries has a varied generation fuel mix. Poland and Kazakhstan are almost entirely dependent on coal, Russia and Belarus are largely dependent on gas, Lithuania and Bulgaria are reliant on nuclear, and Tajikistan and Kyrgystan are almost completely dependent on hydropower. The IEA's figures indicate that in aggregate the region relies most heavily on coal and gas, and to this extent is not too dissimilar from the USA. As with the USA, gas is expected to account for the lion's share of new generation, while coal accounts for a smaller but still significant share. For these reasons the USA CO_2 abatement curves have been used when calculating the region's CO_2 emissions abatement level.

Figure 13.5 provides a comparison of the results for small and large onshore and offshore wind farms in 2020. The figure indicates that there is a massive onshore wind potential that has very low abatement costs. The onshore wind potential from large wind farms is about seven times as large as the current total generation requirement, and four times greater than estimated total generation in 2020. Wind generation, therefore, exceeds the region's generation requirements long before the resource runs out. The wind resource is not only large but, with significant high wind speed areas, holds out the prospect for relatively low wind generation costs.

The abatement cost curves are very low, especially for large wind farms, where abatement cost do not exceed $10 per tonne CO_2 even at the maximum abatement of 1,500 million tonnes of carbon dioxide per year in 2020. The costs for small wind farms are slightly higher, but only exceed $20 per tonne CO_2 when the level of abatement exceeds 1,300 million tonnes per year. The offshore wind potential is not as good, with high costs resulting in abatement costs starting at around $100 per tonne CO_2.

These results are sensitive to the assumptions made concerning the generation cost of the technology that wind replaces. In this region it is assumed that wind replaces a mixture of coal and gas and a weighted average replacement cost of 2.60 US cents per kWh in 2020 has been used. This reflects the availability of low cost coal and gas, but it could be argued that lower demand for coal and gas will result in lower coal and gas prices. Exactly how low is far from sure, but even if the replacement generation cost were lowered to 2.00 US cents per kWh in 2020, this would still leave the large wind abatement costs below $20 per tonne CO_2.

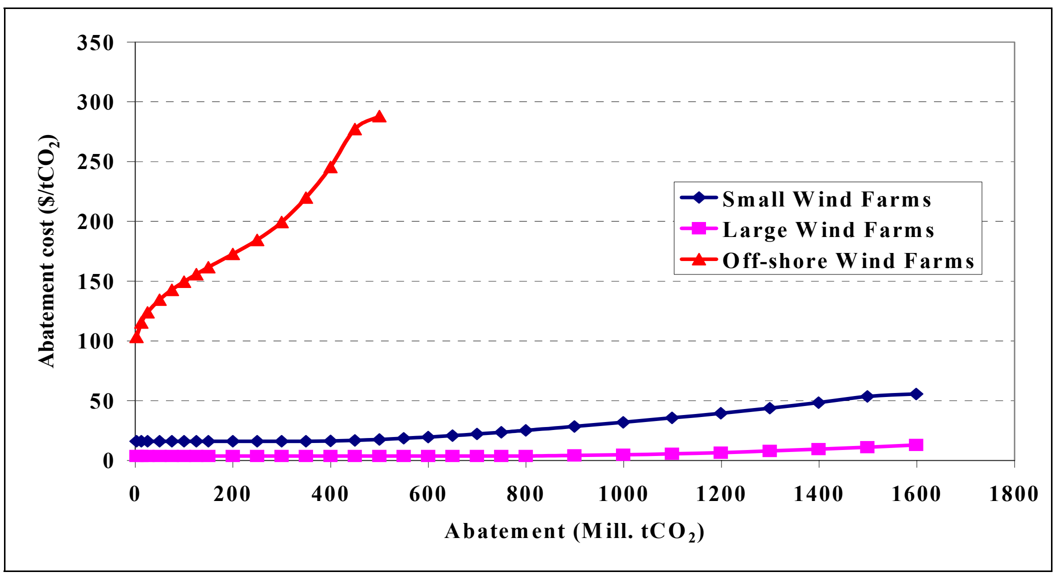


Figure 13.5: Comparison of annual abatement cost curves for the FSU and Eastern Europe (2020)

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	16	2	4	2	103
25	12	16	12	4	12	115
50	25	16	25	4	25	124
100	50	16	50	4	50	134
150	75	16	75	4	75	143
200	100	16	100	4	100	150
250	125	16	125	4	125	156
300	150	16	150	4	150	162
400	200	16	200	4	200	173
500	250	16	250	4	250	184
750	350	16	350	4	350	220
1000	500	18	500	4	500	288
1250	600	20	600	4	600	N/A
1500	749	24	749	4	749	N/A
2000	999	32	999	5	999	N/A
2500	1199	40	1199	7	1199	N/A
3000	1499	54	1499	11	1499	N/A

Table 13.7: Annual CO_2 abatement and abatement costs for the FSU & Eastern Europe (2020)

13.5 Latin America

Latin America's generation requirements are largely met from the region's massive hydropower resources. In 1995, hydropower accounted for almost two-thirds of total generation. In the future gas-fired capacity is expected to dominate the new generation requirements and, in the words of the IEA World Energy Report, "make spectacular gains, as gas supplies become increasingly available." The high share of non-fossil fuels in the existing generation mix and the dependence on gas-fired generation to meet future generation requirements looks similar to the situation in the European Union. For this reason the EU-15 CO_2 abatement curves have been used when calculating the region's CO_2 emissions abatement level.

Figure 13.6 provides a comparison of the results for small and large onshore and offshore wind farms in 2020. The abatement cost curves are very encouraging and show some of the lowest abatement costs anywhere for large wind farms. For large onshore wind farms the results indicate zero, or near zero, abatement cost for CO_2 abatement of up to 100 million tonnes. Latin America has a large, low cost wind resource, a relatively large electricity requirement and low generating costs. The introduction of gas-fired generation into the fuel mix is tending to raise costs, which means that the replacement of gas with wind has a much more limited impact on the overall system cost than in Europe where the introduction of gas-fired generation is tending to reduce generating costs.

Latin America's onshore wind resource is almost five times larger than the current generation requirement, and more than twice the expected total generation requirement in 2020. Once again all generation demand can be met within the relatively low cost wind supply range. At a cost of $20 per tonne CO_2 Latin America can achieve annual carbon dioxide savings of about 450 million tonnes in 2020 by exploiting large wind farms. The level of abatement drops substantially to around 75 million tonnes for small wind farms. The abatement costs from offshore wind farms are a lot higher, due to the high cost of offshore wind generation.

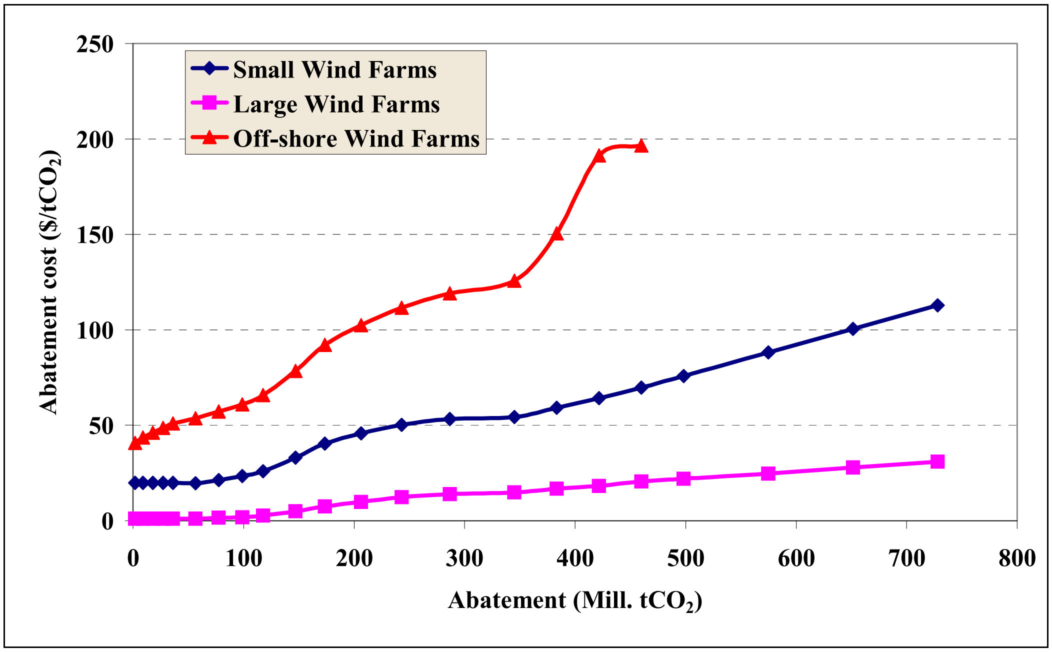


Figure 13.6: Annual Comparison of annual abatement cost curves for Latin America (2020)

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	20	2	1	2	41
25	9	20	9	1	9	44
50	18	20	18	1	18	46
100	36	20	36	1	36	51
150	57	20	57	1	57	54
200	78	21	78	2	78	57
300	118	26	118	3	118	66
400	147	33	147	5	147	79
500	174	40	174	7	174	92
750	243	50	243	12	243	112
1000	383	59	383	17	383	151
1250	460	70	460	21	460	197
1500	536	82	536	23	536	N/A
1750	613	94	613	26	613	N/A
2000	766	119	766	32	766	N/A

Table 13.8: Annual CO_2 abatement and abatement costs for Latin America (2020)

13.6 Middle East

The Middle East's power generation is dominated by oil and gas, which in 1995 accounted for 90% of total generation. The IEA's World Energy Report states that the "majority of the Middle East's new capacity is likely to be gas-fired." As with Latin America, the profile of new capacity additions is in keeping with the outlook for Europe and for that reason the EU-15 CO_2 abatement curves have been used when calculating the region's CO_2 emissions abatement levels.

Figure 13.7 provides a comparison of the results for small and large onshore and offshore wind farms in 2020. The onshore costs are shown on the left axis and the offshore on the right axis. The Middle East has a relatively large wind resource - eight times current generation requirements and three to four times the expected generation needs in 2020. However, the wind generation costs are relatively high compared with gas-fired generation. As a result, the abatement costs tend to be on the high side (above \$30 per tonne CO_2) and flat for onshore wind farms due to the limited wind utilisation possible. Total generation requirements are expected to be around 839 TWh in 2020. However, the average wind supply cost curve is flat at 3.50 US cents per kWh up to 1,000 TWh and only rises to an average of 3.60 US cents per kWh at 1,400 TWh (the amount that needs to be installed when wind generation equals 100% of the generation requirements). As a result, the CO_2 abatement cost curve is virtually flat even when wind accounts for total generation requirements.

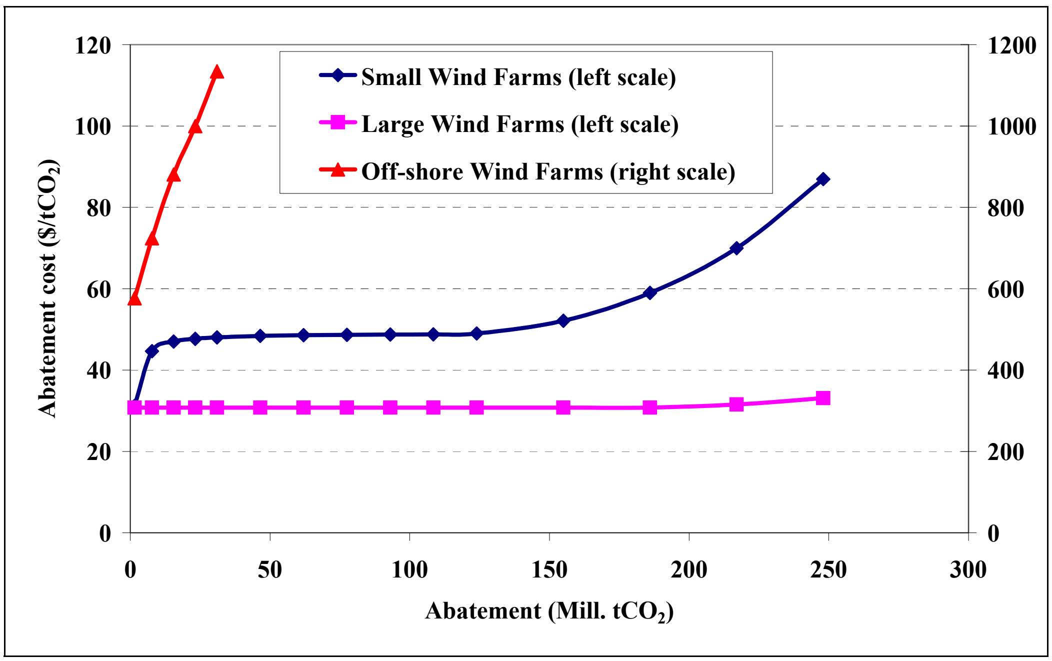


Figure 13.7: Comparison of annual abatement cost curves for the Middle East (2020)

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	31	2	31	2	576
25	8	45	8	31	8	724
50	16	47	16	31	16	881
100	31	48	31	31	31	1134
200	62	49	62	31	62	N/A
300	93	49	93	31	93	N/A
400	124	49	124	31	124	N/A
500	155	52	155	31	155	N/A
600	186	59	186	31	186	N/A
700	217	70	217	32	217	N/A
800	248	87	248	33	248	N/A

Table 13.9: Annual CO_2 abatement and abatement costs for the Middle East (2020)

13.7 Rest of Asia

The "Rest of Asia" is another heterogeneous group with a varied choice of generation fuel mixes. Japan and South Korea have a high share of nuclear in the generation mix, while Vietnam is almost all hydro and Taiwan (Chinese Taipei) is a mix of coal, oil, gas and hydro. As an aggregate group, the Rest of Asia is largely dependent on fossil fuels, but with a significant nuclear and hydro component. The outlook for generation is focused on the increasing use of gas and coal-fired generation, with nuclear, hydro and oil tending to lag behind. Compared with the four study regions, the Rest of Asia taken in aggregate looks closest to the USA in terms of current fuel mix and future developments, and the USA CO_2 abatement curves have been used when calculating the region's CO_2 emissions abatement level.

Figure 13.8 provides a comparison of the results for small and large onshore and offshore wind farms in 2020. The results are somewhat mixed, with relatively low abatement costs at low levels of abatement, but costs rising steeply as the level of abatement increases, particularly for offshore and small onshore wind. The limited wind potential in the region is the primary cause of the rapid increase in costs. The onshore wind potential is about 70% of current generation requirements and about 40% of the expected generation requirement in 2020. The abatement costs are kept down by the relatively low wind generation costs, even compared to other region's wind supply curves.

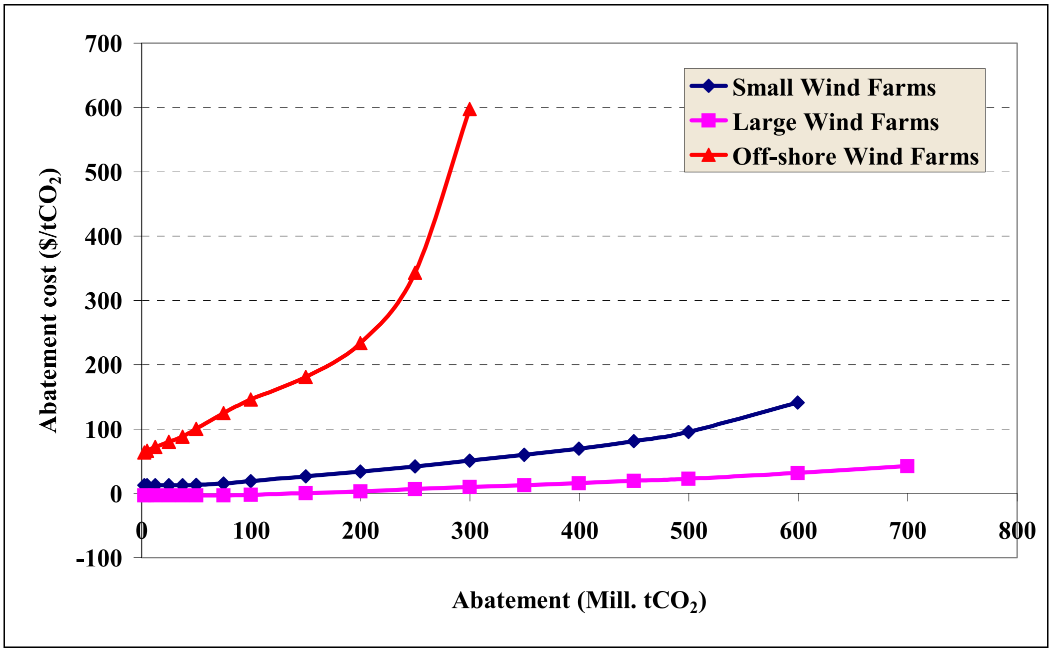


Figure 13.8: Comparison of annual abatement cost curves for the rest of Asia (2020)

Wind	Small Onshore		Large Onshore		Offshore	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	13	2	-3	2	64
25	12	13	12	-3	12	72
50	25	13	25	-3	25	80
75	37	13	37	-3	37	88
100	50	13	50	-3	50	100
150	75	15	75	-3	75	124
200	100	19	100	-2	100	146
300	150	26	150	0	150	181
400	200	34	200	3	200	233
500	250	42	250	7	250	343
600	300	51	300	10	300	597
800	400	70	400	16	N/A	N/A
1000	500	95	500	23	N/A	N/A
1200	600	141	600	32	N/A	N/A
1400	N/A	N/A	699	43	N/A	N/A

Table 13.10: Annual CO_2 abatement and abatement costs for the Rest of Asia (2020)

14 SENSITIVITY ANALYSES

14.1 Overview

The sensitivity analyses are confined to the EU-15 in 2020. The sensitivities explore the impact of the following alternative assumptions:

- the rate of decline in the capital cost of wind turbines (i.e. the impact of accelerating the annual rate of decline in capital costs from 1.0% to 2.2%)
- the discount rate used to calculate the full cost of generating technologies and, as a result, the system generating costs (i.e. using a 5% discount rate instead of 10%)
- the impact on the cost curve of assumptions concerning the effect of large scale wind generation on the system costs (i.e. the need for additional peaking generation and less shoulder/base generation) – these system costs are referred to as the impact of "additional peaking generation requirement" in the text.

The first two sensitivities are explored in detail for small and large onshore wind farms and for offshore farms. The impact of the assumptions on the system costs from additional peaking generation is only shown for large onshore wind farms as this is a function of wind's share of total generation and does not have a direct impact on the cost of wind power. Each sensitivity is explored in more detail in Sections 14.2 to 14.4.

The overall effects of the sensitivities are explored in Figure 14.1, which compares the different abatement costs in the EU-15 in 2020 at levels of abatement of 100 million tonnes of CO_2 and 200 million tonnes of CO_2. The comparison is across the scenarios and sensitivities, and provides an indication of some of the most important factors in determining the abatement costs. The figure highlights the fact that changes to the discount rate, the rate of decline in wind's capital costs and the need for additional peaking generation have only a marginal impact on the abatement costs, especially at an annual abatement of 100 million tonnes of CO_2. The largest impacts are the wind farm distribution (i.e. whether small or large farms are developed) and whether the offshore option is preferred to onshore wind farms.

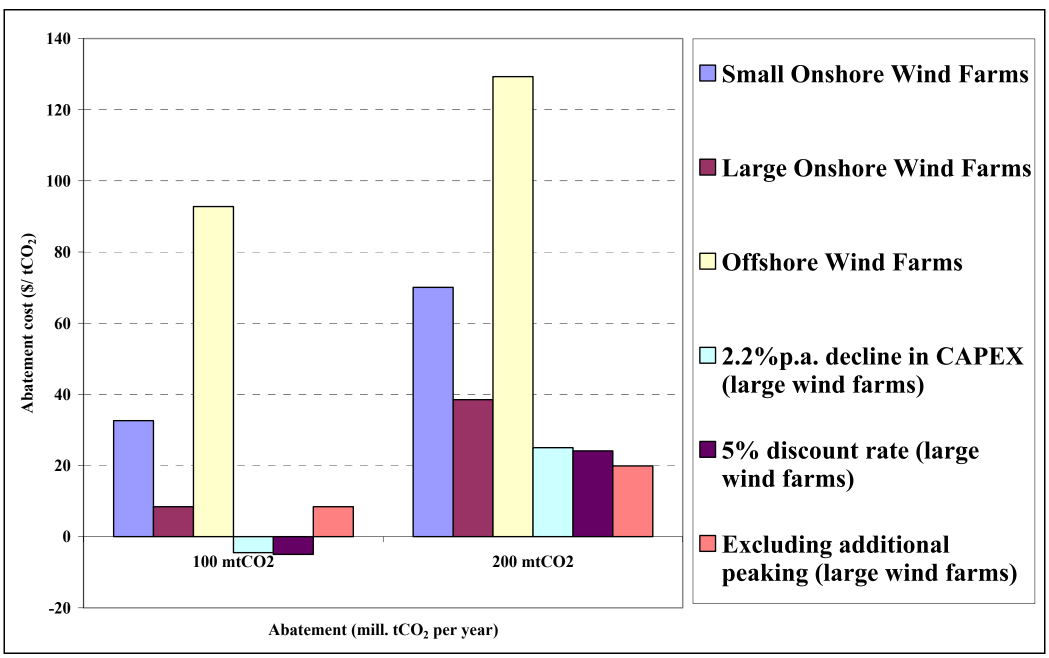


Figure 14.1: Comparison of abatement costs by scenario for the EU-15 (2020)

Compared with the abatement cost of large wind farms with a 1.0% annual decline in wind farm capital costs, the abatement cost reductions achieved by a 2.2% decline in wind farm capital costs amount to \$15 per tonne CO_2 (both at an abatement level of 100 and 200 million tonnes of CO_2). The difference in the large wind farm abatement costs curves between a 10% and 5% discount rate vary from \$14 per tonne of CO_2 at 100 million tonnes of CO_2 abated to \$16 per tonne of CO_2 at 200 million tonnes abated. However, developing small wind farms as opposed to large farms results in abatement cost increases of \$24 per tonne of CO_2 at 100 million tonnes of CO_2 abated, and \$32 per tonne of CO_2 at 200 million tonne of CO_2 abated. Switching from large onshore to offshore wind farms would have an even bigger cost penalty at the lower abatement level and only slightly less at the higher level.

The impact of the additional peaking generation is only felt once wind output exceeds 10% of total generation. At 100 million tonnes of CO_2 abated wind's share remains below this threshold and the abatement costs are the same. At 200 million tonnes of CO_2, however, wind exceeds 10% and the additional peaking generation adds \$19 per tonne of CO_2 to the abatement cost. This could be very important if costs of up to \$20 per tonne are considered attractive abatement technologies, but not above this level. Without the impact of the additional peaking generation large-scale wind generation would be an attractive abatement technology up to 200 million tonne of CO_2 saved per year. However, if the need for additional peaking generation is included, large onshore wind potential would be limited to around 160 million tonnes CO_2 saved per year (20% lower).

14.2 Future Wind Farm Capital Costs

Figure 14.2 to Figure 14.4 show the impact on the abatement cost curves of increasing the rate of decline in wind's capital costs from 1.0% per annum to 2.2% per annum. The result is a shift down in the cost curve by about \$15 per tonne of CO_2 for all three scenarios in 2020. The lower capital costs mean that the best wind sites have lower LPCs than the least cost fossil fuel technology. As a result, the abatement costs for small and large onshore wind farms are negative at relatively low levels of carbon dioxide abatement. In fact, the abatement cost curve for large onshore wind farms only becomes positive after a carbon abatement level of 125 million tonnes (300 TWh of wind generation). Offshore cost abatement curves remain above \$50 per tonne of CO_2.

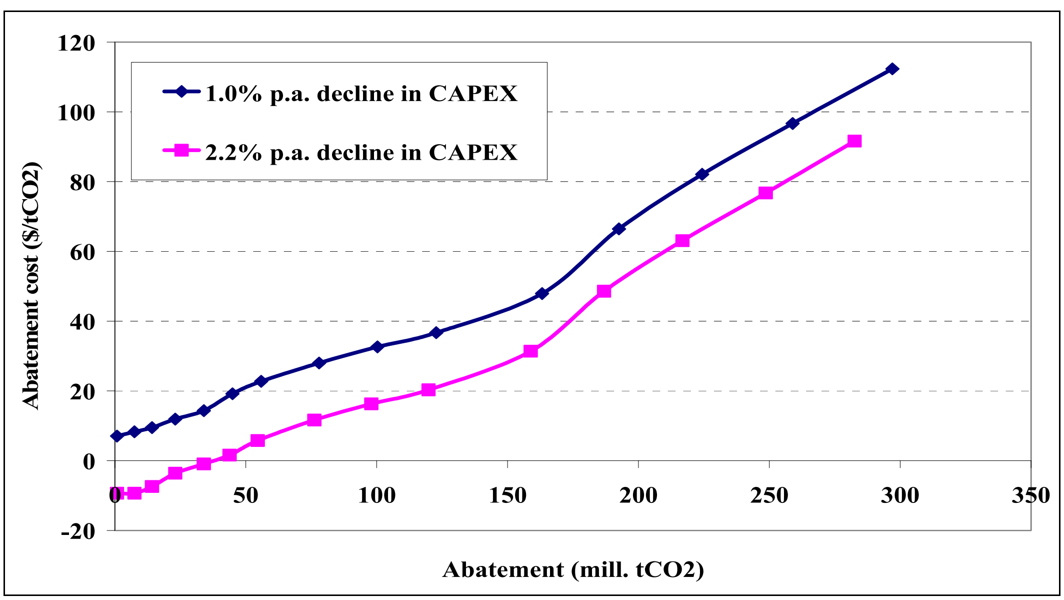


Figure 14.2: Sensitivity to wind farm capital costs for small onshore wind farms (2020)

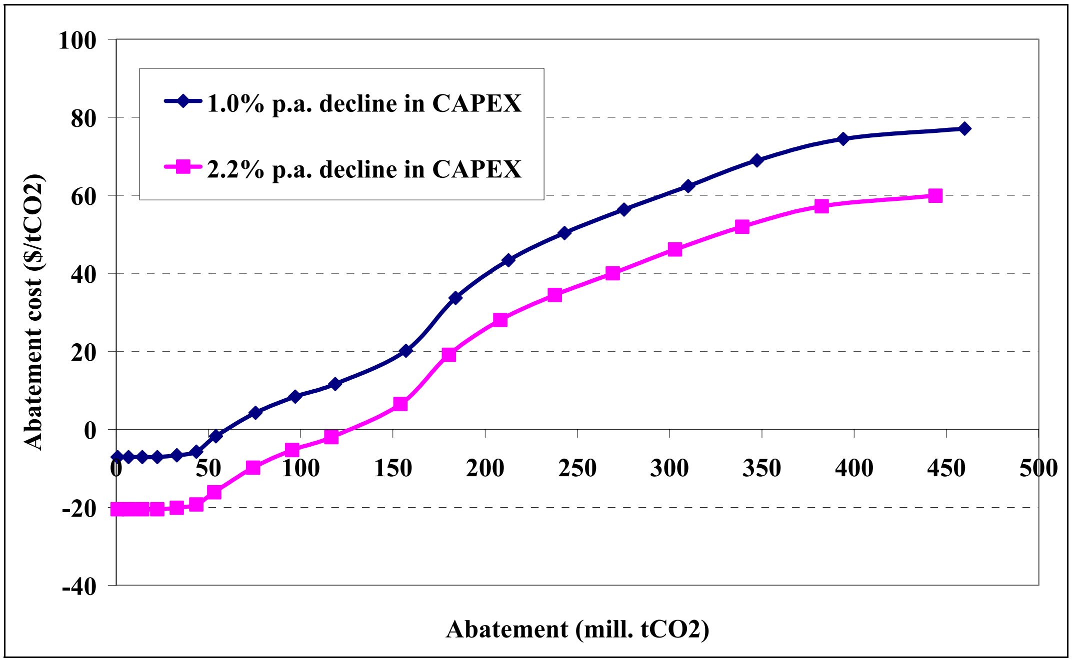


Figure 14.3: Sensitivity to wind farm capital costs for large onshore wind farms (2020)

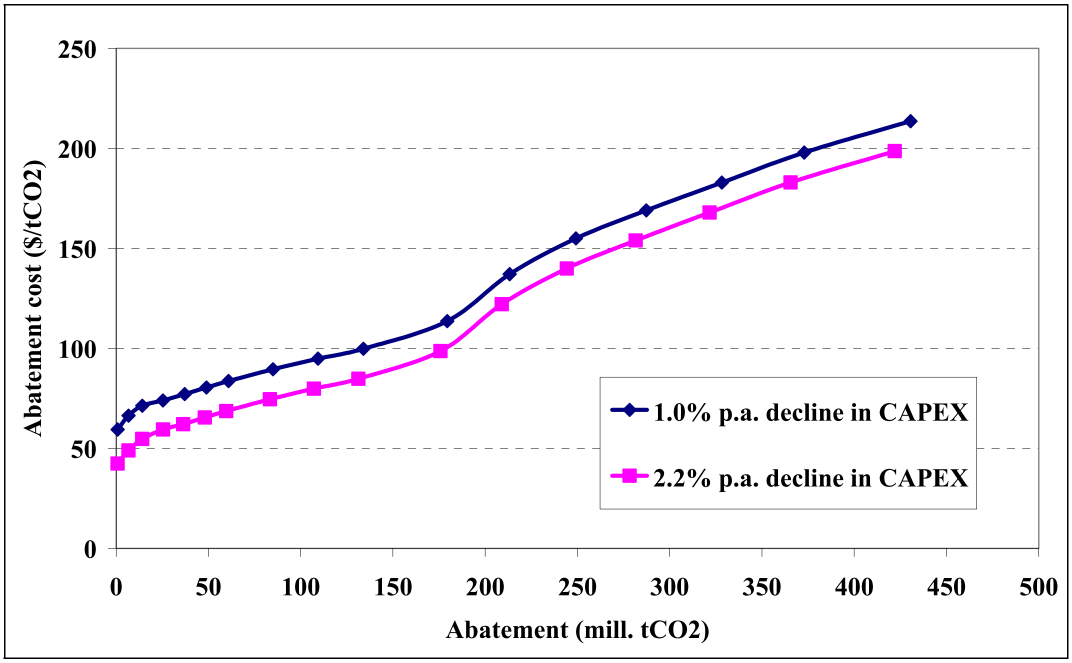


Figure 14.4: Sensitivity to wind farm capital costs for offshore wind farms (2020)

14.3 Discount Rate

Figure 14.5 to Figure 14.7 show the impact on the abatement cost curves of reducing the discount rate from 10% to 5%. Reducing the discount rate lowers the capital cost of power plants per unit of generated electricity. As a result, it tends to favour those technologies, like wind, that are capital intensive. The 5% discount rate was applied across all generation technologies and a new base case was established from which the impact of variations in wind generation were measured.

The result is not the parallel shift in the curves seen for reduced wind farm capital costs, but a gradual widening of the difference as the level of abatement increases. In other words, the significance of the lower discount rate is increasingly felt as the amount of wind generation and level of carbon dioxide abatement rise. This is because all generation technologies are affected by the lower discount rate and not just wind. As a result, the best wind sites still have generation costs that remain above the least cost fossil fuel option, although the difference narrows somewhat.

At an abatement level of 100 million tonnes of CO_2, the difference between the 5% and 10% discount rate abatement costs is just \$14 per tonne of CO_2 for large onshore wind farms, \$20 per tonne of CO_2 for small onshore wind farms, and about \$28 per tonne of CO_2 for offshore farms. Comparable figures for an abatement level of 200 million tonnes of CO_2 are \$16, \$25 and \$30 per tonne of CO_2. The overall effect is to improve the viability of large onshore wind as an abatement technology, and to bring small wind farms into contention. Offshore wind remains a more expensive option.

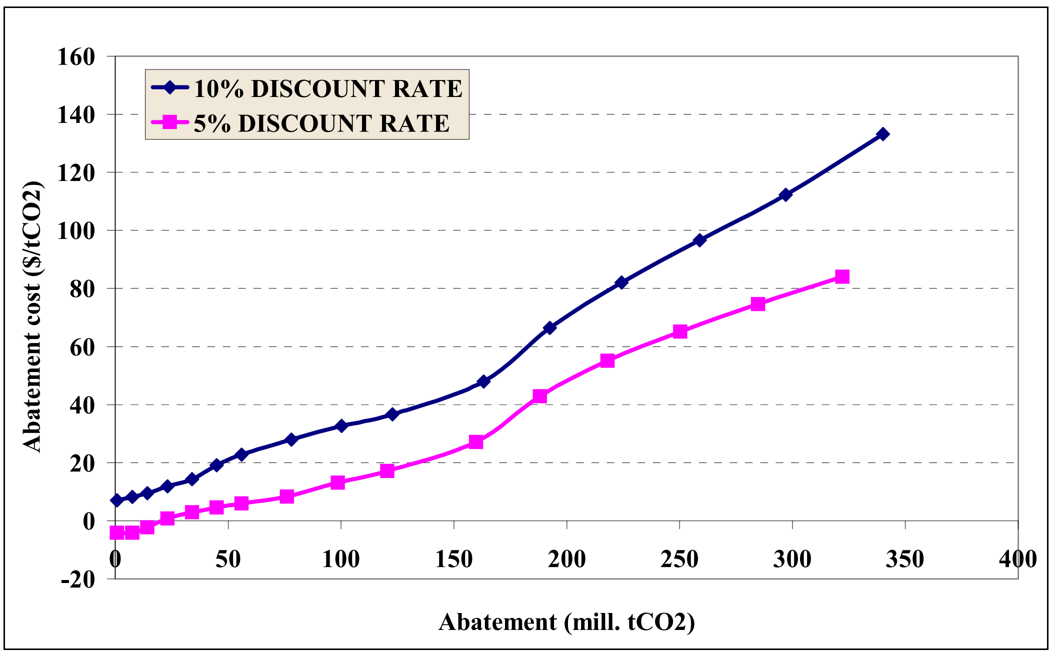


Figure 14.5: Sensitivity to discount rate for small onshore wind farms (2020)

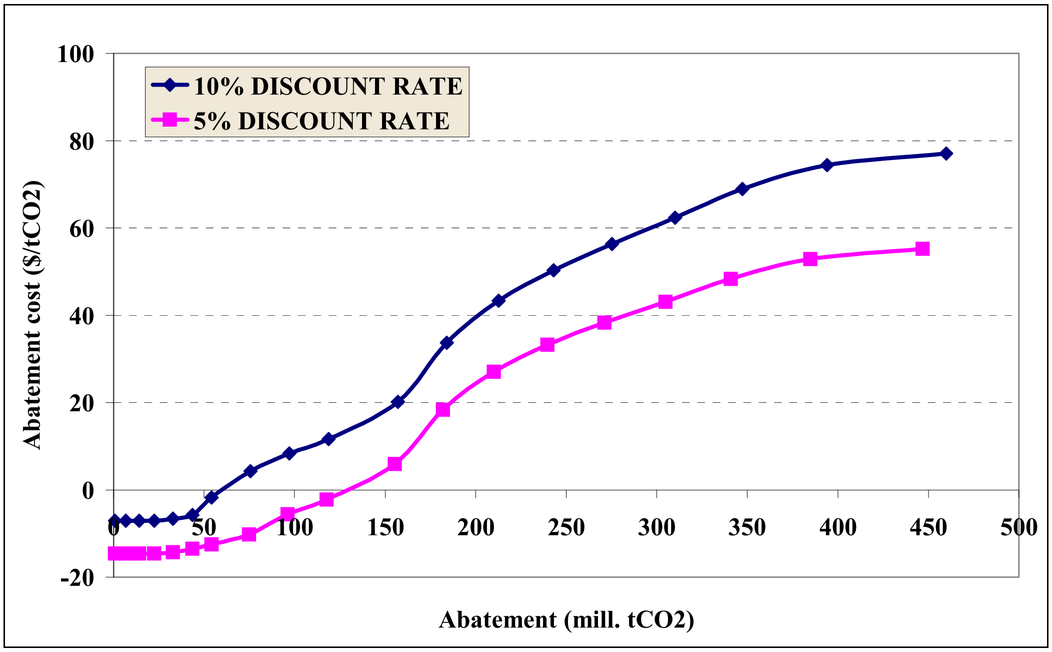


Figure 14.6: Sensitivity to discount rate for large onshore wind farms (2020)

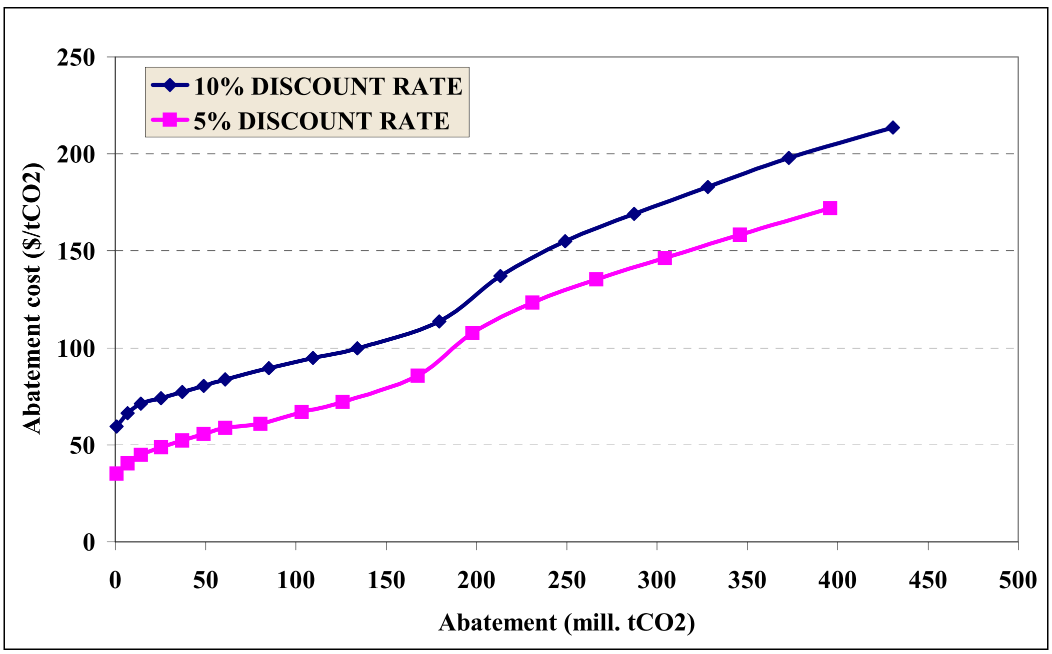


Figure 14.7: Sensitivity to discount rate for offshore wind farms (2020)

14.4 Impact of Additional Peaking Generation Assumptions

Figure 14.8 shows the impact of removing the additional peaking generation requirement on the large onshore wind farm abatement cost curve. In other words, it shows the cost curve if wind capacity is treated as any conventional capacity – for a given level of wind generation the "residual" load curve is identical to that from a conventional power plant with the same level of generated electricity. The elimination of the additional need for peaking capacity is accompanied by an increased call on shoulder/base load. However, the higher thermal efficiencies of the shoulder and base-load generation relative to peaking capacity results in a net fall in energy consumed for the same level of generation. The lower energy consumption explains part of the reduction in the abatement costs curve, the rest is explained by the lower levelised capital cost - to get the same return from capital used intermittently a higher cost is incurred than capital used more frequently. The levelised cost of peaking capacity can be two or three times the cost of base-load technologies.

As previously indicated, the impact of the additional peaking capacity is only felt once wind output exceeds 10% of total generation, which is achieved in 2020 at 400 TWh. The abatement cost curves are, therefore, identical up to this point. From 400 TWh, wind output exceeds 10% of total electricity generation on an annual basis and the model imposes additional peaking requirements on the generating system (see Section 9.1.2 for details). This additional peaking requirement is used to meet non-predicted fluctuations in wind generation as well as to maintain overall system reliability.

The additional peaking generation not only adds to the system generating costs but also tends to increase the carbon dioxide emissions above those that would otherwise be expected, because of the lower thermal efficiency of the peaking plants compared to the base/shoulder-load plant it displaces. Consequently, the overall system cost increases as wind generation increases, while the carbon dioxide savings per unit of wind generation capacity declines. These effects are captured in the modelling approach, although the additional peaking need is not known and the assumptions outlined in Section 9.1.2 are based on other estimates in the current literature. Nevertheless, this literature indicates that the effect is real and significant at wind penetrations above 10% and the net effect is the sharp rise in the abatement cost curve. The extent of this rise is shown as the difference between the two lines in Figure 14.8. The figure shows the impact due to the decline in the carbon dioxide savings per unit of installed wind capacity (the reduction in carbon dioxide abated) and that due to increased system costs (cost of additional fuel and capacity). The reduction in abatement has the largest effect.

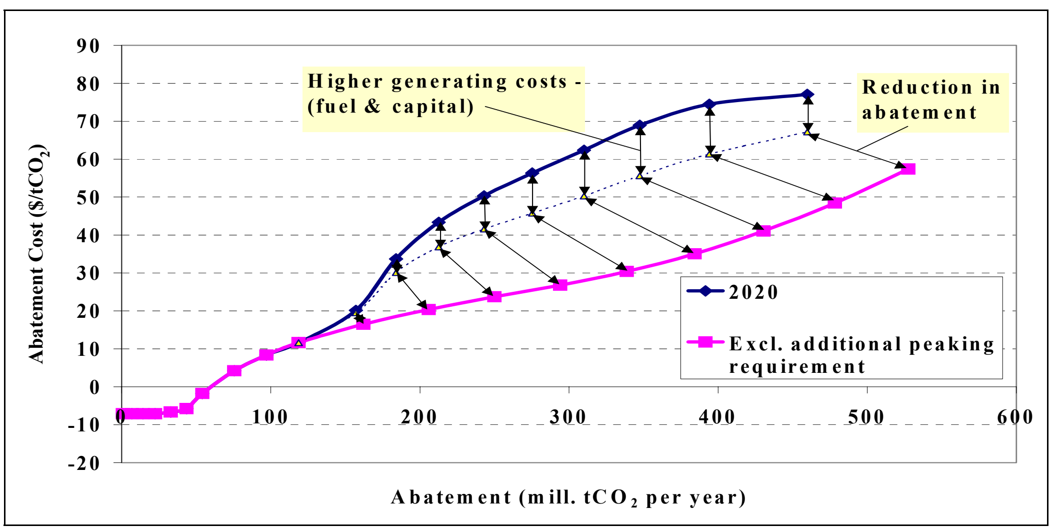


Figure 14.8: Sensitivity to additional peaking generation for large onshore wind farms (2020)

The difference in the amount of annual CO_2 abated at \$20 per tonne CO_2 is relatively small between the two curves (160 million tonnes and 200 million tonnes). However, at \$40 per tonne of CO_2 abated the amount of annual CO_2 saved is more than double if the assumptions concerning the need for additional peaking generation are excluded (200 million tonnes versus 420 million tonnes). By any standards this represents a large variation, and it increases as the abatement costs rise. Given the uncertainties attached to the methodology and modelling of the additional peaking generation, extreme caution is required in drawing any concrete conclusions regarding the viability of wind generation as a CO_2 abatement technology at high penetrations.

15 GLOBAL COSTS OF AVOIDED CO_2 EMISSIONS

15.1 Overview

Figure 15.1 shows the average cumulative abatement cost curves for all the regions for large onshore wind farms in 2020. It can be seen that almost all the abatement cost curves start at less than \$20 per tonne of CO_2 abated and a few have negative costs. However, the abatement cost curve that stands out is that of the Former Soviet Union and Eastern Europe where there is a vast abatement potential (just over 1500 million tonnes CO_2 per year) at extremely low costs (less than \$10 per tonne CO_2).

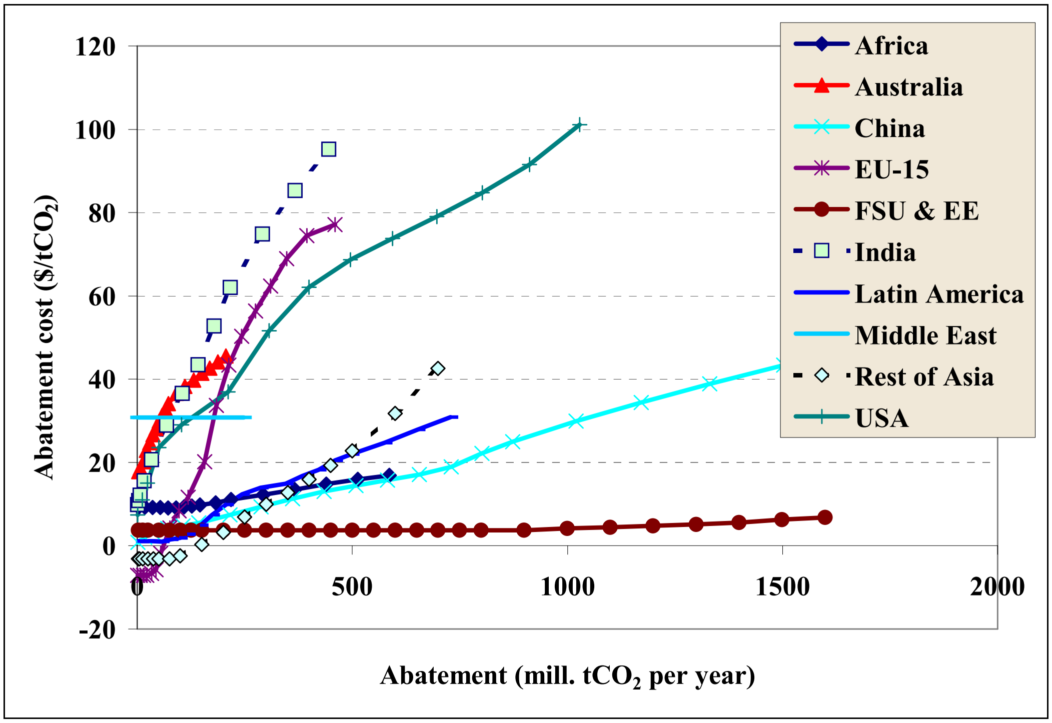


Figure 15.1: Comparison of large onshore abatement cost curves by region (2020)

Of the other regions of the world, Africa, China, Latin America and Rest of Asia all have annual CO_2 savings of 400 million tonnes or more in 2020 at less than \$20 per tonne CO_2. The other regions have savings of less than 50 million tonnes CO_2 at \$20, with the exception of the EU-15 where annual savings of over 150 million tonnes CO_2 are possible in 2020. These results can also be seen in Figure 15.2, which shows the regional annual CO_2 savings in 2020 at abatement costs of \$20 and \$40 per tonne CO_2. The figure just shows the level of abatement for small and large onshore wind farms, since the abatement costs for offshore farms in all cases exceed \$40 per tonne CO_2.

Figure 15.2 provides further graphic illustration of the massive potential for CO_2 savings in the Former Soviet Union and Eastern European region. At an abatement cost of \$20 per tonne CO_2, the level of annual CO_2 abatement is three times that of the next best option (China) for small wind farms and twice that of the next best large wind farm option (again China).

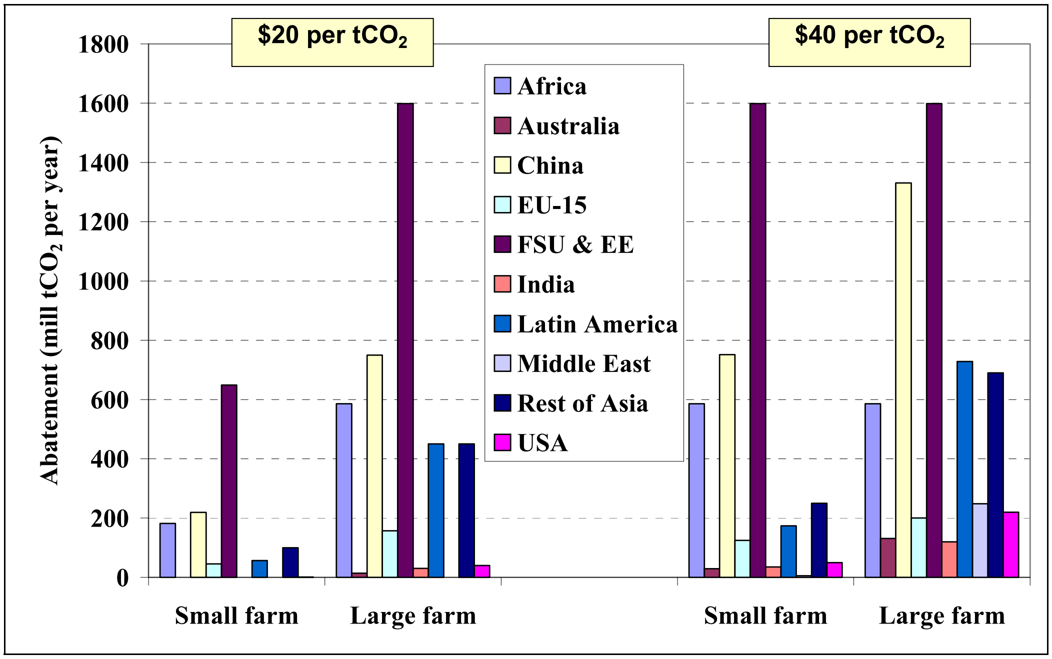


Figure 15.2: CO_2 abatement at \$20 and \$40 per tCO_2 abatement costs in 2020

Figure 15.1 and Figure 15.2 confirm that large onshore wind farms are at their most attractive as a CO_2 abatement option in the Former Soviet Union and Eastern Europe, which consists mainly of UNFCCC Annex I countries (see Glossary), and in the UNFCCC non-Annex I countries in Africa, China, Latin America and the Rest of Asia.

The results from the regional analyses have been brought together and ranked to provide a set of global abatement cost curves. Figure 15.3 shows the global abatement cost curves in 2020. The figure compares the small and large onshore results, as well as the offshore results.

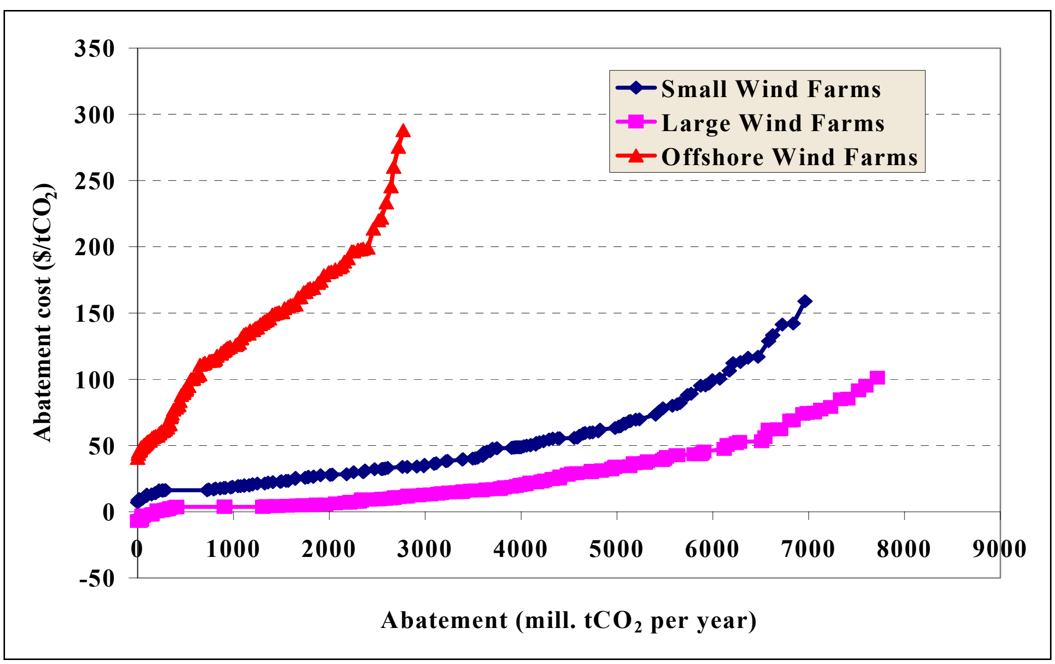


Figure 15.3: Comparison of global abatement cost curves (2020)

Figure 15.3 indicates that large onshore wind farms are an economically attractive CO_2 abatement technology up to abatement levels of 4 billion tonnes CO_2 per year, assuming that alternative abatement options may be in the range of \$10-20 per tonne CO_2[22]. To put this figure into context, 4 billion tonnes CO_2 is 17-18% of current global energy related CO_2 emissions[23] and represents 60% of the current global emissions from the power sector.

The global abatement potential is significantly smaller for both small onshore wind farms and offshore wind farms. This is shown in Figure 15.4 where the annual carbon dioxide saving is shown at abatement costs of \$20 per tonne CO_2 and \$40 per tonne CO_2 for small, large and offshore wind farms for the years 2000 and 2020. The first point to note is that there is no, or virtually no, abatement from offshore wind farms at these costs - offshore wind abatement costs only begin at \$40 per tonne CO_2. The second point to note is that the difference between \$20 and \$40 per tonne CO_2 abatement costs is far more significant for small wind farms than for large. In 2020, the difference between the level of CO_2 abatement at \$20 per tonne CO_2 and \$40 is 1.5 billion tonnes per year for large wind farms (or 38% above the \$20 figure). The same comparison for small wind farms reveals a difference of over 2.3 billion tonnes per year (194% above the \$20 figure). The CO_2 abatement potential is considerably lower for small wind farms at costs of \$20 per tonne CO_2 (70% less than large wind farms in 2020) than at abatement costs of \$40 (35% less than large wind farms).

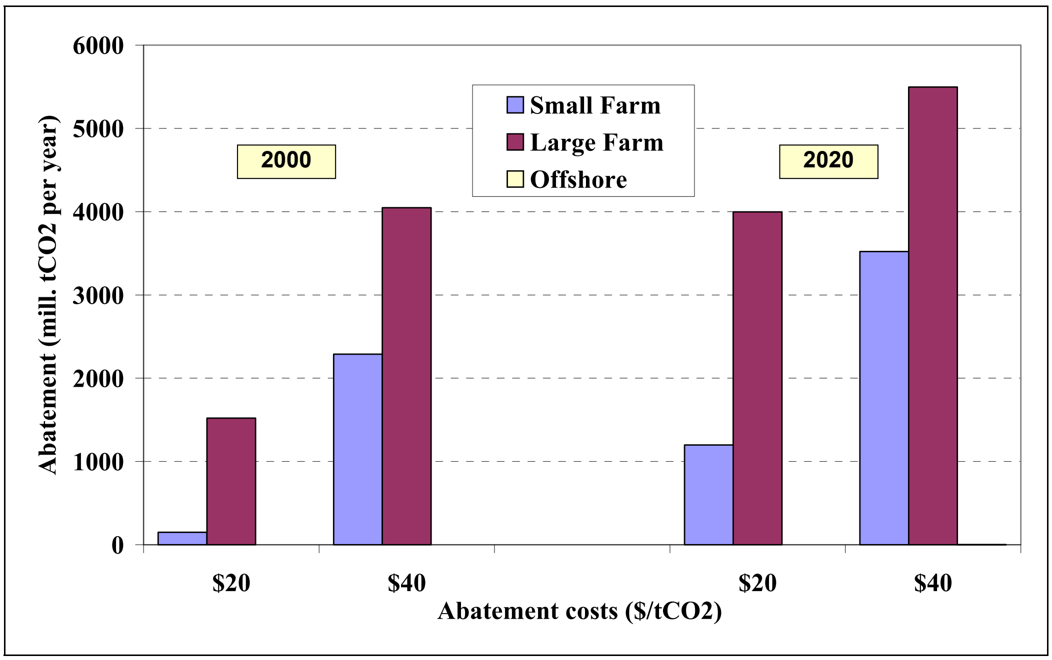


Figure 15.4: Global CO_2 abatement at \$20 and \$40 per tCO_2 abatement costs

The wind generation is also considerably different depending on whether abatement costs of \$20 or \$40 per tCO_2 are considered and whether small or large wind farms are developed. In 2020, at an abatement cost of \$20 per tCO_2, wind generation is 2,300 TWh for small wind farms, but 7,500 TWh for large farms. At \$40 per tCO_2 wind generation is just over 6,300 TWh for small wind farms and 10,900 TWh for large farms. Their respective shares of global generation in 2020 are 10%, 32%, 27% and 46%.

[22] Studies by the US EPA and other organisations have suggested abatement costs in this range.
[23] Assuming world energy-related CO_2 emissions of 23 billion tonnes per year and power sector emissions of 7 billion tonnes per year (Source: IEA "CO_2 Emissions from Fuel Combustion" and UNFCCC extrapolations).

Wind	Small onshore		Large onshore		Offshore	
TWh	M tCO2	$/tCO2	M tCO2	$/tCO2	M tCO2	$/tCO2
5	0	7	0	-7	0	41
50	7	8	7	-7	7	45
100	41	10	41	-7	41	49
200	85	13	85	-3	87	53
300	128	13	127	-3	130	57
400	201	15	200	-2	204	59
500	251	16	250	1	255	61
1000	502	16	499	4	509	91
2000	1081	19	1076	4	1097	124
3000	1573	23	1565	4	1596	155
4000	2111	28	2101	6	2143	189
5000	2639	34	2626	9	2678	260
6000	3167	38	3151	13	N/A	N/A
8000	2855	53	2841	24	N/A	N/A
10000	3558	73	3540	31	N/A	N/A
12000	4192	116	4172	50	N/A	N/A
14000	N/A	N/A	4897	85	N/A	N/A

Table 15.1: Global CO_2 abatement and abatement costs (2020)

The global abatement cost results for small and large onshore wind farms and offshore wind farms are shown on the following pages in Figure 15.5 to Figure 15.7 and Table 15.2 to Table 15.4.

15.2 Small Onshore Wind Farms

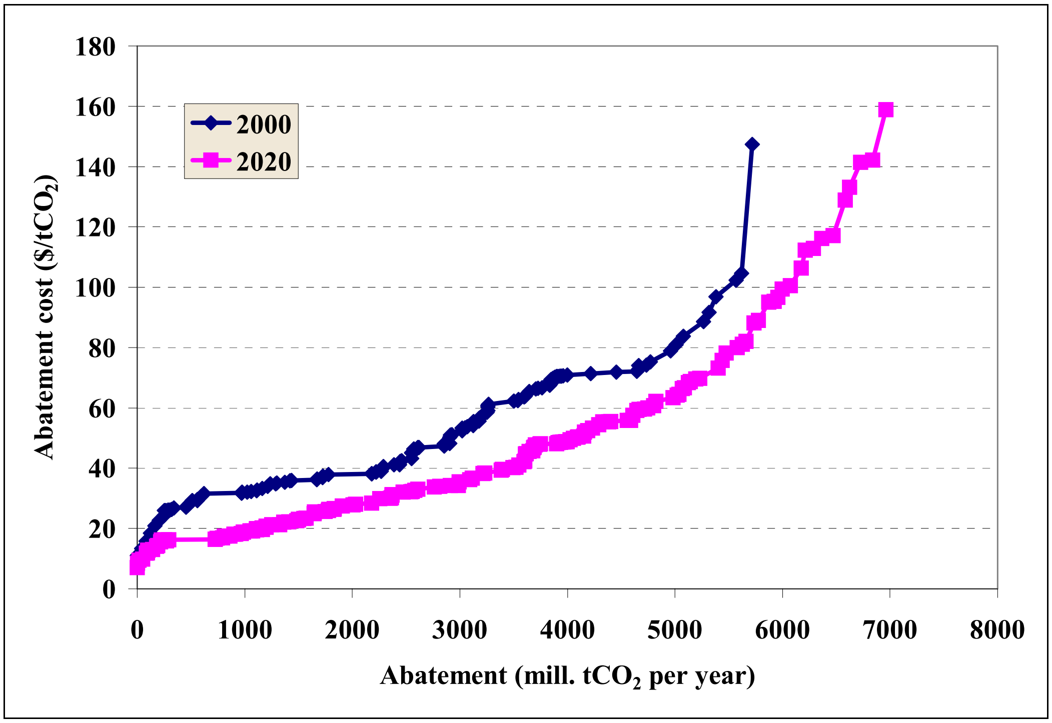


Figure 15.5: Global abatement cost curves for small onshore wind farms

Wind	2000		2020	
TWh	M tCO2	$/tCO2	M tCO2	$/tCO2
5	2	11	1	7
50	40	13	2	8
100	80	16	50	10
200	162	21	97	13
300	249	24	145	13
400	321	26	217	15
500	340	27	255	16
1000	971	32	255	16
2000	1213	34	1073	19
3000	2219	39	1570	23
4000	2621	47	2180	28
5000	3222	58	2763	34
6000	3840	68	3232	38
8000	5316	92	4233	53
10000	N/A	N/A	5401	73
12000	N/A	N/A	6366	116

Note: The first column is the potential annual output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Table 15.2: Global CO_2 abatement and abatement costs for small onshore wind farms

15.3 Large Onshore Wind Farms

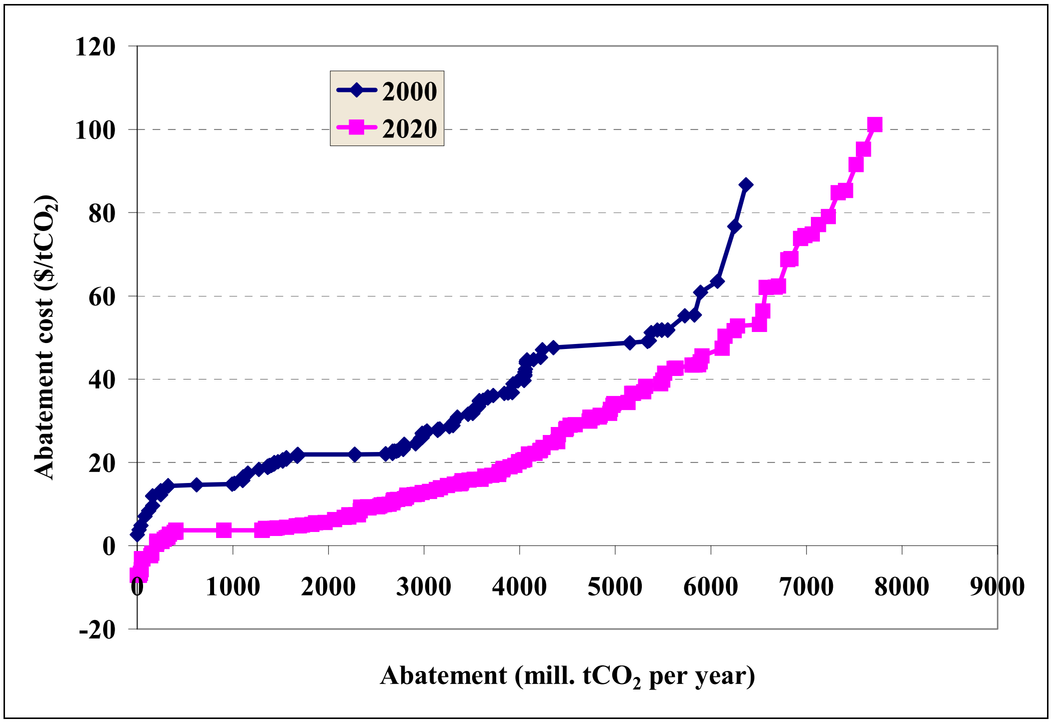


Figure 15.6: Global abatement cost curves for large onshore wind farms

Wind	2000		2020	
TWh	M tCO2	$/tCO2	M tCO2	$/tCO2
5	2	3	1	-7
50	39	5	7	-7
100	79	7	33	-7
200	160	10	56	-3
300	160	12	46	-3
400	160	12	154	-2
500	245	12	205	1
1000	1016	15	407	4
2000	1678	22	906	4
3000	2275	22	1463	4
4000	2598	22	1964	6
5000	3164	28	2411	9
6000	3615	35	3056	13
8000	4354	48	4244	24
10000	N/A	N/A	4842	31
12000	N/A	N/A	6149	50
14000	N/A	N/A	7335	85

Note: The first column is the potential annual output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Table 15.3: Global CO_2 abatement and abatement costs for large onshore wind farms

15.4 Offshore Wind

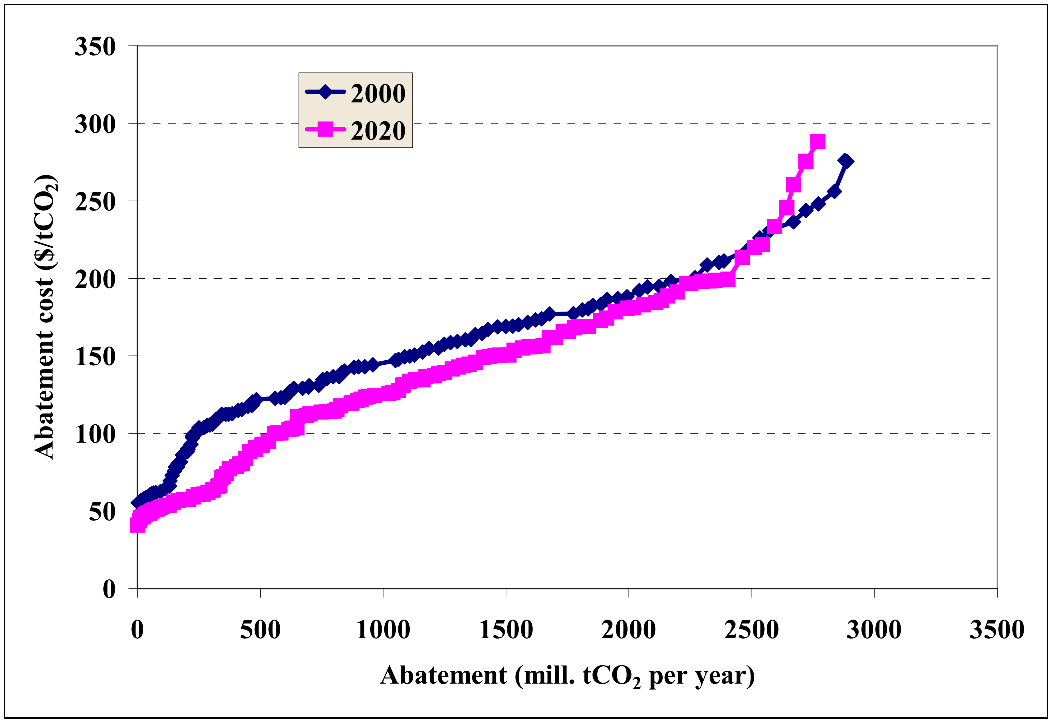


Figure 15.7: Global abatement cost curves for offshore wind farms

Wind	2000		2020	
TWh	M tCO2	$/tCO2	M tCO2	$/tCO2
5	3	55	2	41
50	36	59	13	45
100	74	62	40	49
200	141	73	102	53
300	183	86	168	57
400	218	93	228	59
500	270	104	268	61
1000	467	120	481	91
1500	821	137	702	113
2000	1186	155	966	124
3000	1887	183	1570	155
4000	2573	231	2158	189
5000	3115	600	2670	260

Note: The first column is the potential annual output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Table 15.4: Global CO_2 abatement and abatement costs for offshore wind farms

16 CONCLUSIONS

The analyses in this study indicate that wind energy can be an attractive CO_2 abatement technology, although there are wide variations between regions, between onshore and offshore wind farms, and between small and large onshore wind farms. The potential for low cost abatement is greatest for large onshore wind farms in the Former Soviet Union and Eastern Europe and there is also considerable potential in Africa, China, Latin America and the Rest of Asia. Other regions of the world also have potential for CO_2 abatement from wind energy but generally at significantly higher costs. The EU-15 falls between these two groups with the lowest abatement costs for very low reductions in annual CO_2 emissions but some of the highest costs as the abatement potential increases.

The global potential for CO_2 abatement from large onshore wind farms in 2020 is estimated to be some 4 billion tonnes per year at abatement costs of up to \$20 per tonne. This is equivalent to over 17% and 57% of current global energy-related and power sector CO_2 emissions respectively.

The principal determinants of abatement costs for wind energy are:

- Wind speeds (subject to significant uncertainty in many regions of the world as noted)
- Wind farm distribution (i.e. whether small or large onshore wind farms are developed)
- Whether the offshore option is preferred to onshore wind farms
- Carbon intensity of displaced generation
- The impact of additional system costs and spilt wind as wind penetrations increase

The results of the sensitivity analyses suggest that changes to the discount rate and rate of decline in wind farm capital costs have a relatively small impact on the abatement costs. The need for additional peaking generation, however, can have a very large impact on the abatement costs, but is highly speculative given that currently there is only very localised real life experience of high wind penetrations. This means that the additional peaking generation requirement is only a theoretical consideration. Given the uncertainties attached to the methodology and modelling of the additional system costs, it must be reiterated that caution is required in drawing any concrete conclusions regarding the costs of wind generation as a CO_2 abatement technology at wind penetration levels above 10%. Additional uncertainty at all levels of generation results from the limitations of the global data available to intialise wind flow modelling and the ability of models to capture accurately all local effects.

There is ample scope for reducing the above uncertainties through more detailed studies of individual regions, countries, states or provinces using improved data and more sophisticated models. The present work has prepared the way for such studies, and the method may be adapted for replication over a smaller geographical range.

What is clear from this study, however, is that restricting the size and location of onshore wind farms has a dramatic impact on the CO_2 abatement potential from wind energy. In essence this comes down to a trade-off between the cost of wind energy and local planning considerations driven by public perceptions of wind energy. The more restrictive the local planning conditions, the less wind energy can be developed on prime sites and the higher the average generation costs[24].

[24] Wind generation costs are now only marginally higher than those of some fossil fuelled plants at high mean wind speed sites, but are sensitive to site mean wind speeds. This characteristic means the single most important prerequisite is the ability to exploit more fully prime wind sites. Restricting wind farm development to lower wind speed sites leads to higher unit costs.

In the context of this study, higher wind energy unit costs lead to higher CO_2 abatement costs. This could be interpreted as a trade-off between global environmental goals and local objections to wind farms. If wind resources are more efficiently exploited via the large wind farm scenario, wind energy can achieve CO_2 abatement costs comparable with, or even below, those of other abatement/sequestration options. However, if local opposition limits the ability to exploit wind resources in this way, abatement costs may be significantly higher and the abatement potential a lot lower. Experience to date suggests that local objections vary quite considerably between countries and even within local communities.

Policy makers, and ultimately the general public, must judge whether the global benefits of wind energy outweigh the local costs.

GLOSSARY

Acronym	Definition	Units
AEY	Annual energy yield	N Wh/yr[25]
AMWS	Annual mean wind speed (at wind turbine hub height)	m/s
CCGT	Combined cycle gas turbine	
CIESIN	Consortium for International Earth Science Information Network	
CO_2	Carbon dioxide	
DEM	Digital elevation model	
ECMWF	European Centre for Medium-range Weather Forecasting	
EIA	Energy Information Administration (USA)	
FSU	Former Soviet Union	
GIS	Geographical information system (geo-spatial analysis software)	
GLCC	Global Land Cover Characterisation	
GUACA	Gridded Upper Air Climate Atlas (source of wind speed data)	
ID	Identifier	
IEA	International Energy Agency	
IUCN	International Union for the Conservation of Nature	
LDC	Load duration curve	
LPC	Lifetime production cost	\$/kWh
NCDC	National Climatic Data Center (USA)	
NFFO	Non Fossil Fuel Obligation (UK market support mechanism)	
NGDC	National Geophysical Data Center (USA)	
NOABL	Numerically Optimised Atmospheric Boundary Layer model	
NREL	National Renewable Energy Laboratory (USA)	
OECD	Organisation for Economic Cooperation and Development	
PNL	Pacific Northwest Laboratory (USA)	
PV	Photovoltaics (solar)	
UNFCCC	United Nations Framework Convention on Climate Change[26]	
USGS	United States Geological Survey	
WEC	World Energy Council	

[25] Where N = k (kilo, 10^3), M (mega, 10^6), G (giga, 10^9) or T (terra, 10^{12})
[26] Annex I - Parties to the UNFCCC that have emissions commitments under Article 4 of the UNFCCC and Article 3 of the Kyoto Protocol, Annex II - OECD-24 (i.e. members of OECD in 1992)

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