THE POTENTIAL OF WIND ENERGY TO REDUCE CO2 EMISSIONS

- APPENDICES

Report PH3/24
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APPENDIX A

ANALYTICAL METHOD – POTENTIAL FOR WIND ENERGY

CONTENTS

1 INTRODUCTION

1.1 Description of Appendix

The purpose of this appendix is to describe in detail the method used by Garrad Hassan and Partners Ltd. (GH) to generate the cost-supply curves presented in the Main Report. The degree of detail presented reflects an attempted balance between transparency and turgidity. Inevitably, there is some overlap with the more succinct descriptions of the method presented in the Main Report.

For this appendix, the analysis is divided into its constituent parts, each part being assigned its own section in the text. Each section reports on the methods employed in developing that part of the analysis, highlighting any differences in application between:

- the three scenarios (onshore small, onshore large and offshore wind farms)
- the study regions (China, the EU-15, India and the USA) which were modelled in detail, and the rest of the world regions (Africa, Australia, the FSU and Eastern Europe, Latin America, the Middle East and the Rest of Asia) which were modelled in less detail

1.2 Overview of Method

Four "maps" (i.e. files containing spatial data) were used as inputs to both onshore wind farm scenarios:

- available AEY (annual energy yield) at 50 m a.g.l. (above ground level)
- state identifier[1]
- proximity to existing transmission lines
- rural population

Four maps were also used as inputs to the offshore scenario:

- available AEY at 60 m a.g.l.
- offshore state identifier[1]
- distance from shore
- water depth

These input data, supplemented by state-specific[2] data in the study regions, were processed by software developed by GH. Summary files of filtered (and therefore discrete) 1 km data were created and post-processed using a database. The data produced from this were then pasted into a spreadsheet for final processing and presentation. These final data were passed to Econ to enable them to complete their part of the analysis.

Schematic overviews of the above process are shown in Figure 1.1 and Figure 1.2.

[1] For study regions only. Rest of the world regions were not divided into states – instead a single identifier was used to differentiate between land or sea assigned to the region and other land or sea.

[2] Each study region was an aggregation of smaller political entities. In the case of the EU-15, these smaller areas were the 15 European countries. For China, they were the 30 provinces, for India they were the 25 states, and for the USA they were the 48 contiguous states i.e. excluding Hawaii and Alaska.

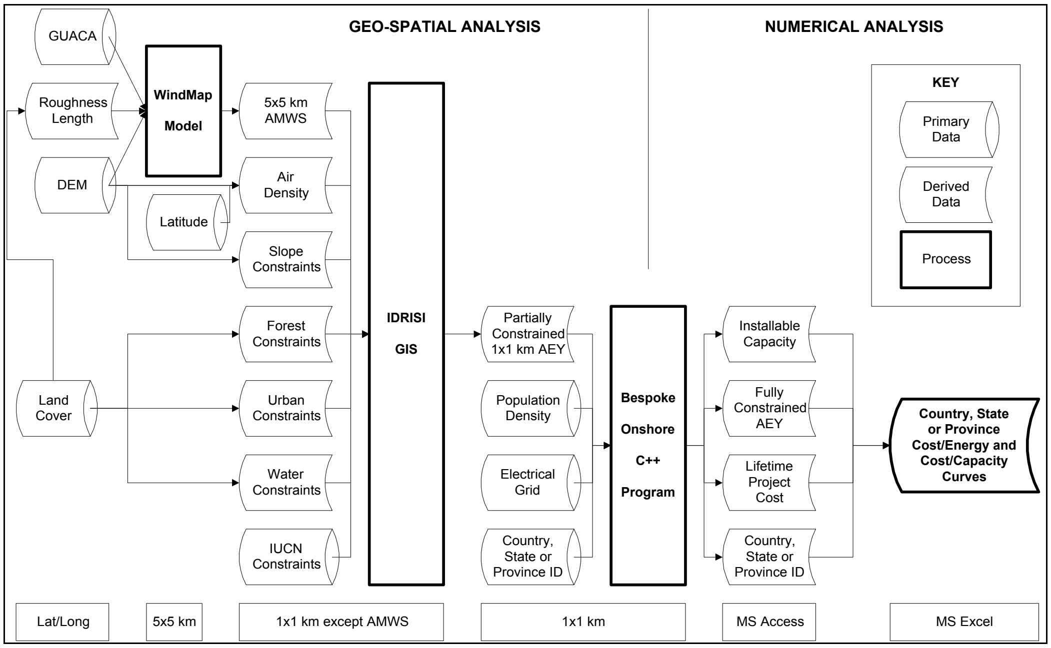


Figure 1.1: Overview of method for generating onshore wind cost-supply curves

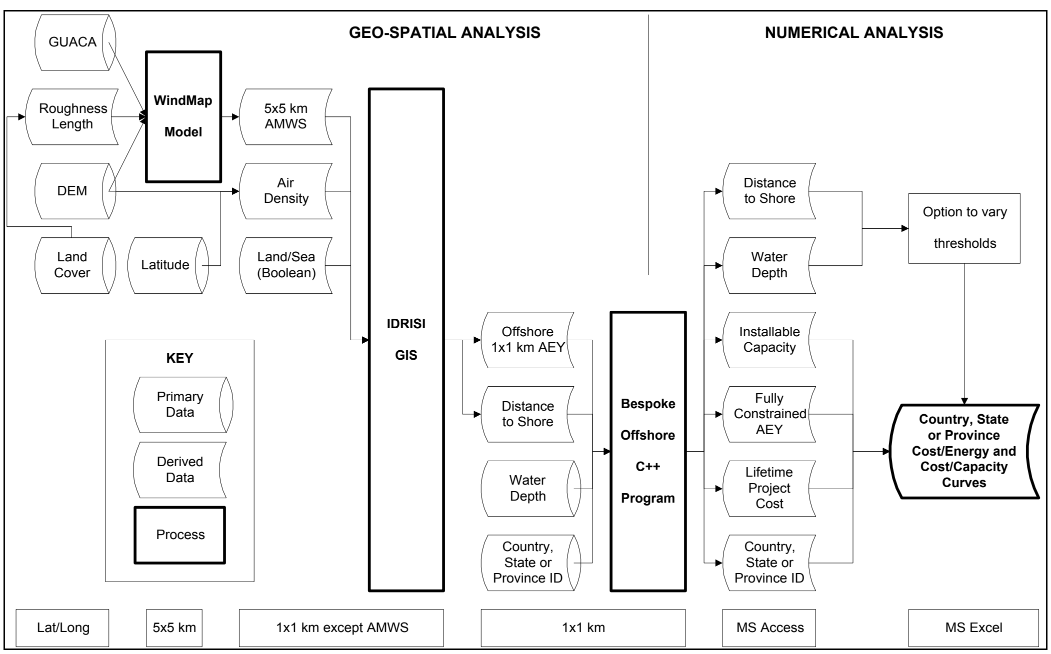


Figure 1.2: Overview of method for generating offshore wind cost-supply curves

2 WIND ENERGY MODELLING: STUDY REGIONS

2.1 Introduction

This section describes the models and data used to estimate the large scale wind resource for each of the four study regions. This part of the analysis, which is represented in Figure 1.1 and Figure 1.2 by the "WindMap Model" box and its input and output datasets, was the largest single task in the study.

This section should be read in conjunction with Section 4 which comments on the limitations of the models and data and describes how a method for compensating for errors in the initialising wind data was developed and applied.

2.2 Wind Flow Model

There are two types of wind flow model generally used in wind speed assessment. The first are based on the Jackson-Hunt theory, which aims to satisfy the Navier-Stokes equations conserving both mass and momentum. These are typically called dynamic models. The second type aim to satisfy only the conservation of mass, and are typically called mass-consistent models.

It is the second of these model types that has been used in this study. WindMap [1], a modified version of the NOABL mass-consistent model, is a commercially available software package which provides a potential flow solution. Potential flow provides a reasonable representation of the wind over flat terrain and also over hilltops at heights above the inner layer (typically 20 m above ground level).

Each region being modelled was divided into many overlapping "domains" which were rectangular arrays of "cells". Each cell represented an element of area to which was assigned a mean elevation, mean surface roughness value and, on completion of the computation, an annual mean wind speed (AMWS). The size of cell was determined by the resolution required, the resources available and the geographical scope of the study which, in this case, was world-wide. Each domain was modelled individually before being joined and smoothed across the overlapping areas to provide the wind map for the region as a whole.

The parameters used for the four study regions were as follows:

- cell size = 5×5 km
- domain size = 220×220 cells / 1,100×1,100 km
- domain overlaps > 40 cells / 200 km

Calculation of the annual mean wind speeds (AMWSs) over an area requires three main types of input data:

- an initialising wind field
- regional terrain data
- stability parameters defining the general character of the atmosphere

The first two of the above were obtained from global datasets, geo-referenced by latitude and longitude, and subsequently converted into the same planar co-ordinate system as that used in other stages of the analysis (see Section 5.1).

2.2.1 Wind data

Ideally, the initialising wind data would have comprised validated long term recorded wind measurements from suitably located surface meteorological stations, supplemented with suitable upper air data to enable a more accurate vertical profile to be established.

For this study, obtaining and verifying data from a sufficient number of meteorological stations was simply not practicable. An alternative approach was to obtain a suitably re-analysed[3] dataset providing uniform geographical coverage at a suitable resolution. A survey was made of the content and cost of commercially available datasets which resulted in the GUACA (Global Upper Air Climatic Atlas) dataset being purchased from NCDC (National Climatic Data Centre).

GUACA holds wind speed and direction data for the period 1980 to 1991 and is based on re-analysed ECMWF (European Centre for Medium-range Weather Forecasts) archives. Long term averaged wind roses can be extracted for 14 upper air levels (1000 to 10 mb) and for the near-surface at 10 m above ground level. The data are globally gridded with a horizontal resolution of 2.5º latitude and longitude (approximately 300 km at the equator).

For each domain modelled, two upper air datasets from the GUACA data closest to the domain centre, and the near-surface datasets from all GUACA data within the domain, were extracted. The upper air datasets used were the two lowest available above the surface closest the domain centre. In practice, these ranged from 850 mb (typically about 1,500 m elevation) for sea and low-lying land up to 400 mb (about 7,000 m elevation) for very high mountain areas such as the Himalayas.

GH was unable to establish quantitative indications of accuracy from either the suppliers or originators of the GUACA data or from a literature search to determine the confidence with which it could be used in the context of this study. However, correspondence with NREL suggested, from their experience, that systematic errors in GUACA wind speed statistics were likely to result in significant under-estimation of the wind resource in some, if not all, parts of the world. An empirically derived statistical approach to compensate for these errors was developed by GH and applied to onshore estimates in all regions as described in Section 4.

2.2.2 Terrain data

The calculation of the regional wind speeds requires a DEM (digital elevation model) of the terrain and, preferably, a map detailing surface roughness. The global DEM GTOPO-30 was purchased from the USGS (United States Geological Survey). This contains global coverage of land elevation at a horizontal resolution of 30 arc seconds latitude and longitude (approximately 1 km at the equator). A mean elevation was assigned to each 5×5 km cell in the GIS (Geographical Information System) using a simple averaging resampling method.

Surface roughness classes were derived from the USGS Global Land Cover Characterisation (GLCC) database and roughness lengths assigned as follows:

[3] Centres which deal in weather recording and forecasting, such as ECMWF, obtain real recorded data from their global network of meteorological stations, and analyse these data to obtain snapshots of the global weather system. These snapshots are then archived. The term re-analysis applies to the subsequent analysis of these archived snapshots, in order to investigate long term statistics.

Class	Roughness length (m)
Forest/urban	0.5
Low bush	0.1
Open plain	0.03
Ice/snow caps	0.001
Water	0.0003

Table 2.1: Surface roughness classes

Classes were assigned to each 5×5 km cell in the GIS using a simple thinning resampling method.

2.2.3 Meteorological parameters

WindMap uses three main parameters in determining atmospheric stability:

- surface layer height
- stability ratio
- Monin-Obhukov stability length

For studies of much more limited geographical scope, considerable effort has been made by the authors, e.g. [2], to establish appropriate settings for these parameters as they can be highly dependent on localised effects and circumstances. For a broad brush study such as this, however, it was only practicable to generalise the settings. The surface layer height was set to 100 m for all domains, while the stability ratio and stability length parameters were set for a neutral atmosphere.

2.3 AMWS Resolution Enhancement

As previously described, even though the input DEM and landcover data were available at 1 km^2 resolution, the wind flow modelling undertaken for the four study regions used a resolution of 5×5 km. This was a pragmatic and practical decision as modelling at 1 km resolution would simply not have been achievable in the project budget[4].

However, a resolution of 5×5 km is relatively coarse for estimating wind speeds for a region. This is particularly significant for hilly areas where the AMWS (annual mean wind speed) can vary significantly within each such cell. Indeed, AMWS may vary significantly even within an area as small as 1×1 km.

AMWSs at 1 km resolution were required for this study as it was at this resolution that the numerical analysis (see Section 8) identified the most favourable locations for wind energy development. Furthermore, AMWS generally has the greatest effect of any variable on the lifetime project cost (LPC = supply cost c/kWh) of a wind energy development. It was therefore important to establish a method that could be used to enhance the AMWS spatial resolution from 5 km to 1 km.

[4] To have modelled wind flow at 1 km resolution would have required approximately 25 times more effort and was not practicable within the study budget.

An equation for AMWS resolution enhancement was established empirically from wind speed and elevation data held by GH for the United Kingdom (UK) and for Eastern Cape Province (ECP) in South Africa. Within each 5×5 array of 1×1 km cells this equation related the deviation of each 1×1 km mean elevation from the 5×5 km mean elevation to the difference between the corresponding 1×1 and 5×5 km AMWSs as follows:

$$V_1 = V_5(1 + x * (H_1 - H_5))$$

Where:

V_1	= 1×1 km AMWS (m/s)
V_5	= 5×5 km AMWS (m/s)
H_1	= 1×1 km mean elevation (m)
H_5	= 5×5 km mean elevation (m)
x	= 0.0004

The method used to establish this relationship is described below.

2.3.1 Initial investigation

GH had access to 1 km elevation and wind speed data for both the UK [3] and ECP [2]. Both wind speed datasets were the result of large scale mass-consistent wind flow models initialised from long term surface data.

While it would have been preferable to have re-modelled both the UK and ECP wind speeds at 5×5 km resolution, this was not a practical option as GH did not have access to the initialising data for the UK. It was therefore decided to use on the ECP data to establish the relationship and to use the UK data to provide a test case.

The ECP was divided into “hilly” and “flat” regions to determine whether the relationship between the 1 km and 5 km mean wind speeds changed with terrain type. The 1 km and 5 km resolution datasets of elevation (*H*) and AMWS (*V*) were analysed to establish a relationship between them. Initially, four regressions were investigated:

1. Absolute change in V $(V_1 - V_5)$ against absolute change in H $(H_1 - H_5)$
2. Percentage change in V $((V_1 - V_5)/V_5)$ against absolute change in H $(H_1 - H_5)$
3. Absolute change in V $(V_1 - V_5)$ against percentage change in H $((H_1 - H_5)/H_5)$
4. Percentage change in V $((V_1 - V_5)/V_5)$ against percentage change in H $((H_1 - H_5)/H_5)$.

All relationships, when forced through the origin, were shown to give similar R-squared values. Percentage change in *V* against absolute change in *H* (relationship 2 from the above list) was selected for the following reasons:

- Using percentage change in *H* leads to numerical instability as *H* tends to 0. This excluded 3 and 4 from the list.
- Using absolute change in *V* could lead to unrealistically large changes in wind speed in situations where there is a big change in H_1 from H_5 yet only a small V_5 value.
- It is consistent with building design standards which assume a percentage change in *V* with absolute change in *H* [4].

Regression of data from both the hilly and flat regions gave similar results. The hilly region results, shown in Figure 2.1, had a slope of 0.0004 and an R-squared value of 0.755. The flat region results also had a slope of 0.0004 and a slightly better R-squared value of 0.784.

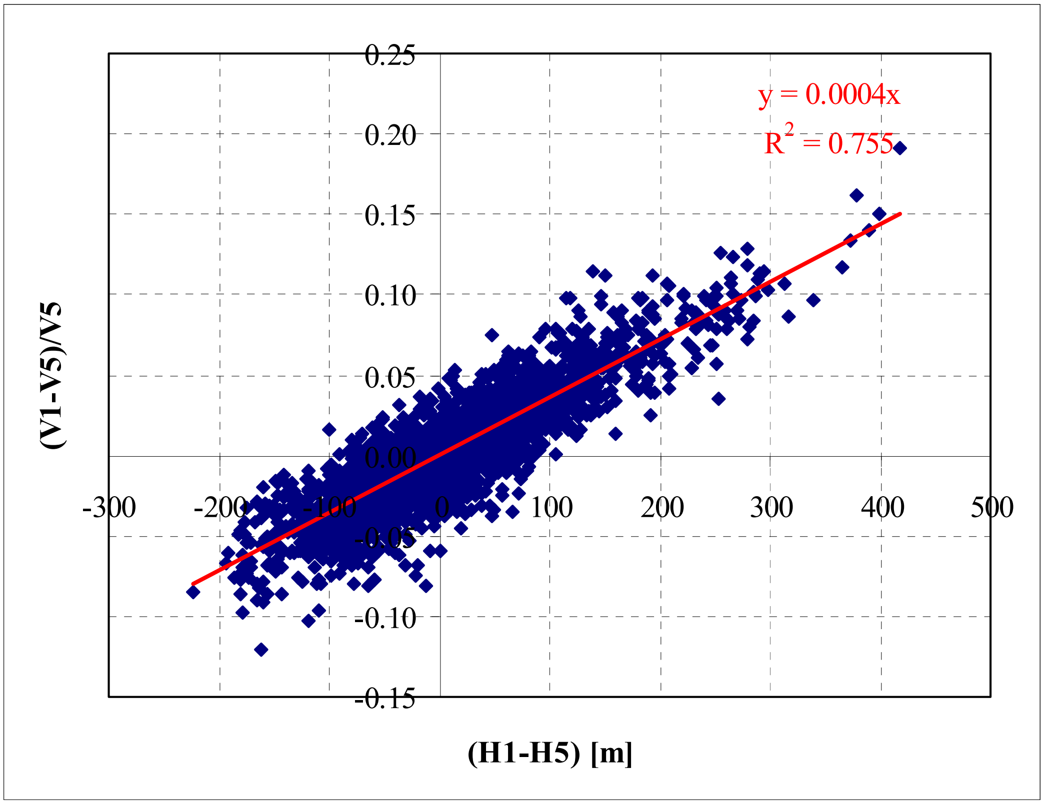


Figure 2.1: Linear regression (forced through origin) of AMWS and elevation differences at 1 and 5 km resolution

2.3.2 Validation

The above relationship was used to:

1. Estimate 1 km AMWSs from a 5 km model of a proportion of ECP (initialised by archive long term surface data);
2. Estimate 1 km AMWSs from a 5 km model of a proportion of ECP (initialised by surface and upper-air data from the GUACA dataset);
3. Estimate 1 km AMWSs from a 5 km model of a proportion of the UK (initialised by surface and upper-air data from the GUACA dataset).

The results from each of the above processes were compared with the modelled 1 km AMWSs to assess the effectiveness of the resolution enhancement technique. The comparisons are shown graphically in Figure 2.2 to Figure 2.5. There are two figures for the first process – one showing a simple regression analysis of 1 km results enhanced from 5 km results against modelled 1 km results, and a second showing the effects that modelling at 1 km and 5 km, and enhancing from 5 km to 1 km, have on the wind speed distributions.

It can be seen from Figure 2.2 that the enhancement technique worked well when applied to a region of ECP modelled from long term surface data. A simple linear regression provided an R-squared value of 0.786, with a slope of near unity. This degree of agreement is similar to that found when establishing the relationship originally, and was to be expected in this instance.

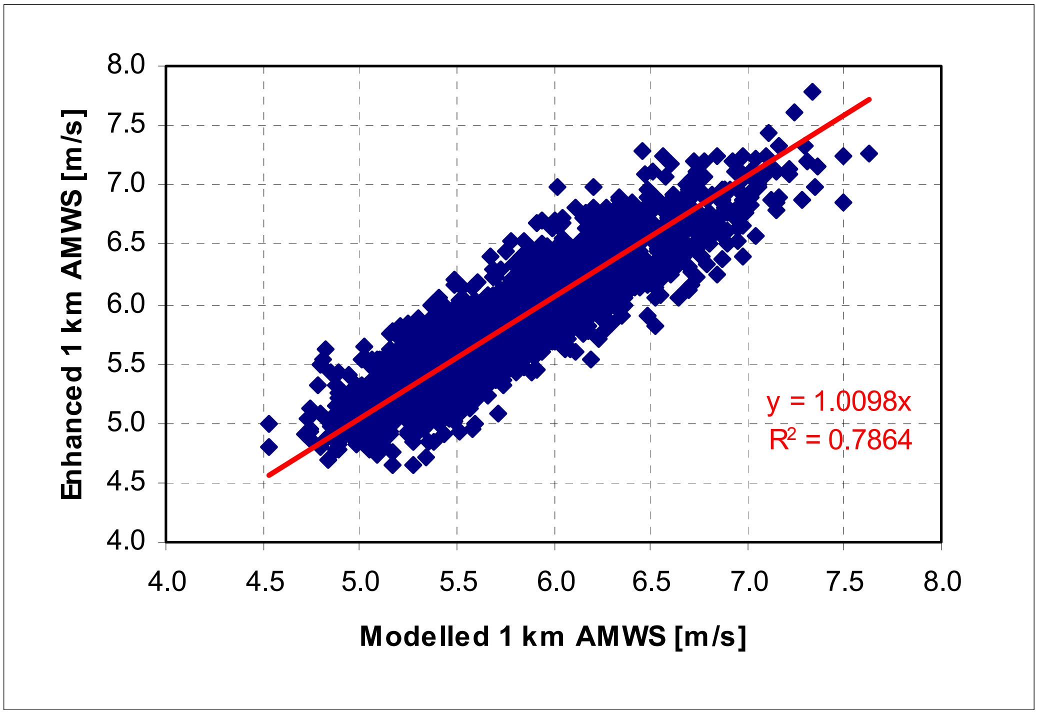


Figure 2.2: Estimated vs. modelled 1 km AMWS, ECP (surface)

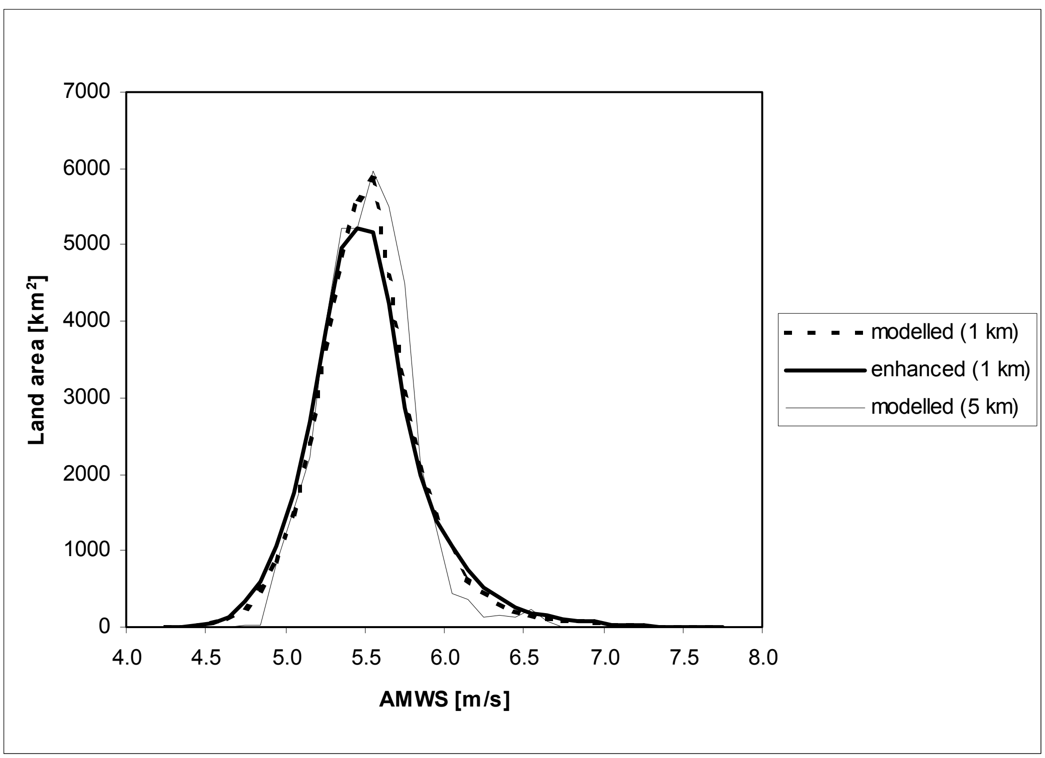


Figure 2.3: Distribution of 1 km AMWS, ECP (surface)

The true effect of the enhancement technique is perhaps better shown in Figure 2.3. It can be seen that enhancing the wind speed resolution from 5 to 1 km had the effect of stretching the distribution of the 5 km wind speeds to fit more closely with the distribution of the modelled 1 km wind speeds. It was exactly this effect that was sought when the enhancement technique was first conceived as the upper 10% of the wind speed distribution is critically important due to the preferential selection of high wind speed 1 km cells when applying the social constraints.

Figure 2.4 shows the correlation between enhanced and modelled 1 km wind speeds from another region of ECP, this time using GUACA data to initialise the model. Again, regression analysis showed that there was good agreement between modelled 1 km wind speeds and 1 km wind speeds enhanced from a 5 km resolution model.

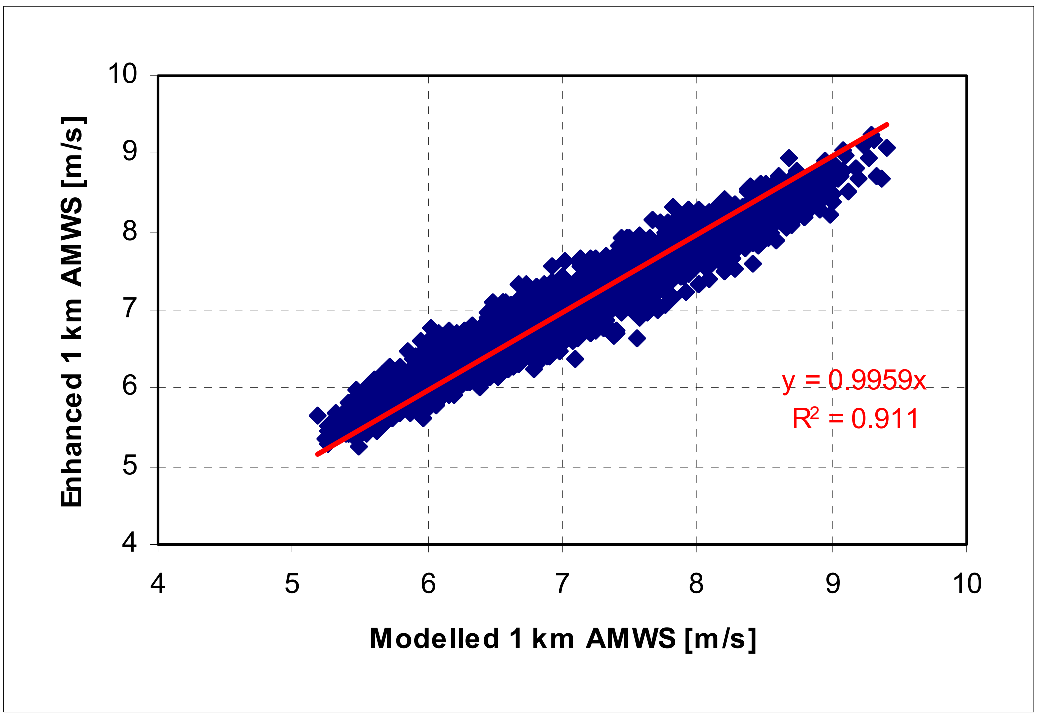


Figure 2.4: Estimated vs. modelled 1 km AMWS, ECP (GUACA)

Figure 2.5 shows the correlation between enhanced and modelled 1 km wind speeds from a region of the UK, again using GUACA data to initialise the model. Regression analysis showed that there was good agreement between modelled 1 km wind speeds and 1 km wind speeds enhanced from a 5 km resolution model.

It is considered that these results confirm that the empirical enhancement of AMWS from 5 km to 1 km resolution is statistically reasonable and its use justifiable. GH would not claim that the wind maps created using this method accurately represent the spatial distribution of AMWSs within each region. Implementation of the method was justified in this project as it reliably distinguished between high and low AMWS areas on a local scale (geographical areas of up to 20×20 km) and provided a better distribution of the AMWSs at the regional level than the 5 km mean AMWSs obtained from the modelling process alone.

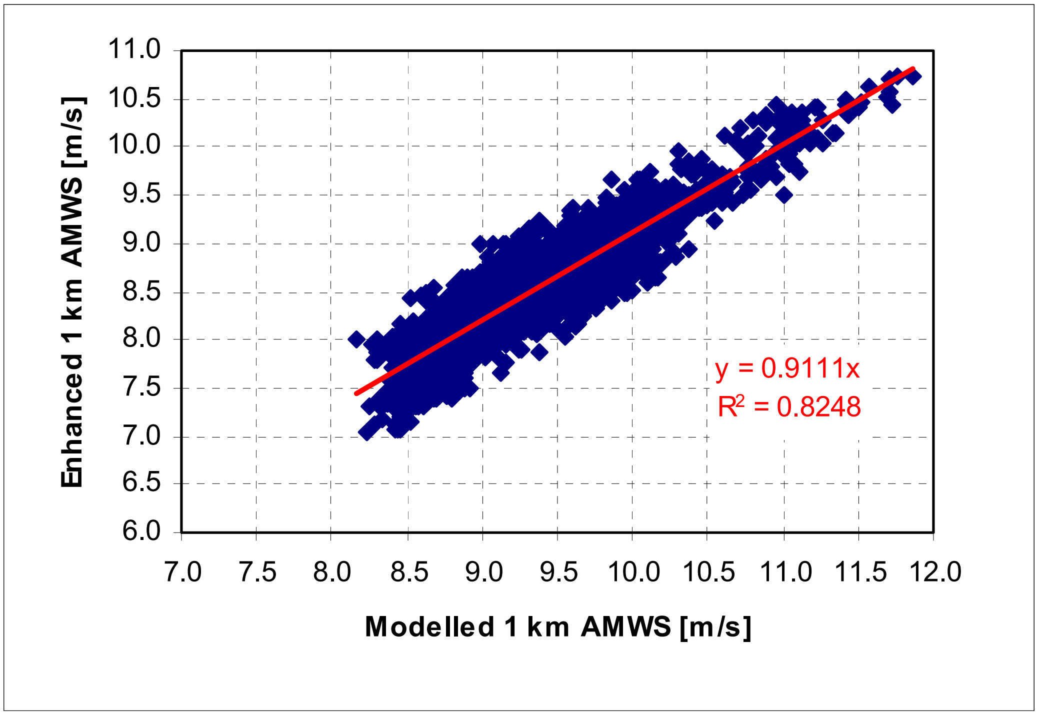


Figure 2.5: Estimated vs. modelled 1 km AMWS, UK (GUACA)

It is perhaps also worth noting that the enhancement technique established and applied a 4% change in wind speed per 100 m change in elevation. This is slightly conservative compared with the 7 % change suggested in [4].

2.4 Conversion from AMWS to AEY

2.4.1 Reference turbine

The maps of annual 1 km AMWSs were converted to maps of 1 km annual energy yields (AEYs) using a polynomial based on the power curve of a typical Danish 600 kW stall regulated wind turbine shown in Figure 2.6. Such turbines make up the large majority of present day onshore wind farms and are what might be termed "industry standard". A Rayleigh distribution of wind speeds was assumed throughout.

The resulting AEYs were scaled up to represent the 8 × 750 kW installed capacity per square kilometre in the onshore models and the 4 × 2 MW installed capacity per square kilometre in the offshore model.

Other wind turbine designs may be more cost effective at either very low or very high wind speed sites. However, modelling of such potential gains was beyond the remit of this study.

2.4.2 Onshore

The onshore analysis was based on local geographical areas of up to 20×20 km (small wind farms scenario) or 10×10 km (large wind farms scenario). It modelled the development of wind energy within these squares in increments of 6 MW (eight 750 kW turbines), up to a maximum of 60 MW – the "base case" wind farm comprising eighty 750 kW turbines (see

Appendix C). The AEY for each such increment was simply $10 \times A_{600}$, where A_{600} is the AEY for the reference turbine (MWh/yr) based on the 50 m AMWS for that cell.

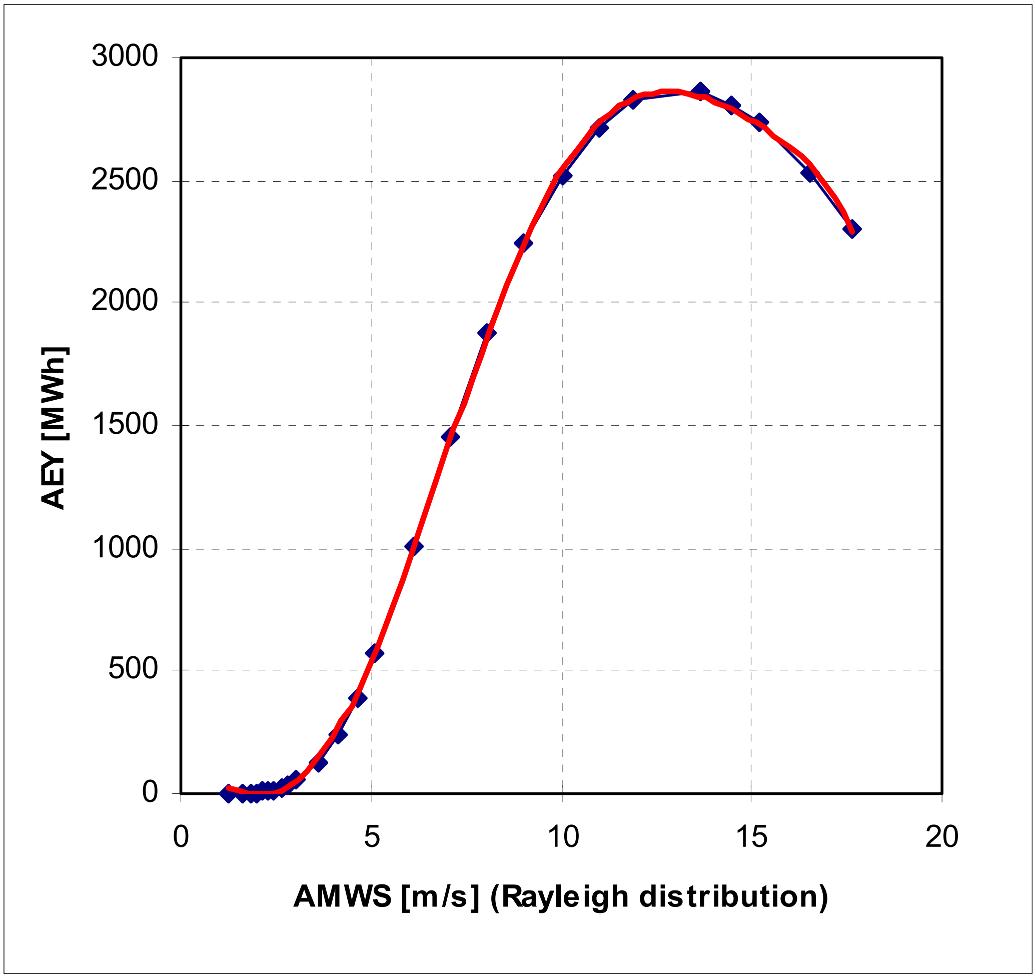


Figure 2.6: Relationship between AEY and AMWS for the 600 kW reference turbine

2.4.3 Offshore

The offshore analysis was simpler than the onshore analysis. Every offshore 1 km^2 cell was assigned 8 MW[5] (four 2 MW turbines). The AEY for each cell was simply $13.3 \times A_{600}$, where A_{600} was based on the 60 m AMWS for that cell.

2.4.4 Effect of air density

The power curve used for wind speed to AEY conversion given in Section 2.4.1 assumes an air density of 1.225 kg/m^3. However, mean air density changes with both latitude and elevation and, particularly for a global study, it was necessary to take these into account as AEY is linearly dependent on air density.

Mean sea level values of air density, averaged over the 12 year period covered by the dataset, were extracted from GUACA. The variation with latitude was found to be as follows:

[5] This "blanket coverage" is modified later in the post-processing of the results.

50 deg. N	1.25	kg/m^3
0 degrees	1.17	kg/m^3
50 deg. S	1.25	kg/m^3

The following equation was used:

$$SLD = 1.17 + 0.0016 * AL$$

where :

SLD = Sea Level Density (in kg/m^3)
AL = Absolute Latitude (in degrees)

The lapse rate of air density with elevation is defined by IEC/TC 88 as:

-0.116 kg/m^3 per 1000 m

These two relationships were applied to all AEY estimates.

3 WIND ENERGY MODELLING: REST OF THE WORLD

3.1 Introduction

The method used to model wind flow for each of the four study regions required a level of effort which could not be repeated for all the rest of the world regions within the project budget. However, the requirement for AEY, and therefore AMWS, estimates in establishing CO_2 abatement costs for the rest of the world was unavoidable.

A multivariate linear regression was established from the results of wind flow modelling in the EU-15. This was used instead of wind flow modelling to estimate the spatial distribution of AMWS for the rest of the world regions. Section 3.2 describes how 50 m AMWS was estimated both onshore and offshore in the rest of the world regions at 5 km resolution. The resolution of the resulting 50 m AMWS estimates was enhanced to 1 km using the technique described in Section 2.3. These 50 m AMWS estimates were subsequently converted to 50 m AEY estimates at 1 km resolution using the method described in Section 2.4. Conversion of 50 m AEY estimates to 60 m AEY estimates to reflect the greater hub height of offshore wind turbines is described in Section 3.3.

This section should be read in conjunction with Section 4 which comments on the limitations of the models and data and describes how a method for compensating for errors in the initialising wind data was developed and applied.

3.2 Estimation of 50 m AMWS

A section of Europe was "windowed" in the GIS for five spatial parameters:

- Elevation
- Roughness
- 700 mb mean wind speeds (derived from the GUACA dataset)
- Near surface mean wind speeds (derived from the GUACA dataset)
- Modelled 50 m AMWSs (i.e. results of the detailed wind flow modelling process)

All data had a resolution of 5 km - the resolution of the original detailed wind mapping. 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 AMWSs as the independent variable. The four input maps are shown in Figure 3.1.

The regression was shown to be very reasonable, both spatially and, with an R-squared value of 0.924, statistically, as shown on the following pages in Figure 3.2 to Figure 3.5. The statistical performance was important as the analytical method culminates in the production of cumulative cost of energy curves. The high R-squared value, and the even and relatively narrow band of over- and under-estimation of wind speeds, indicated that the use of the regression method would introduce relatively minor errors in this context, especially as greater order would be introduced into the results by the ranking process. A reasonable degree of confidence could thus be ascribed to this aspect of the subsequent production of regional cumulative CO_2 abatement cost curves for the rest of the world.

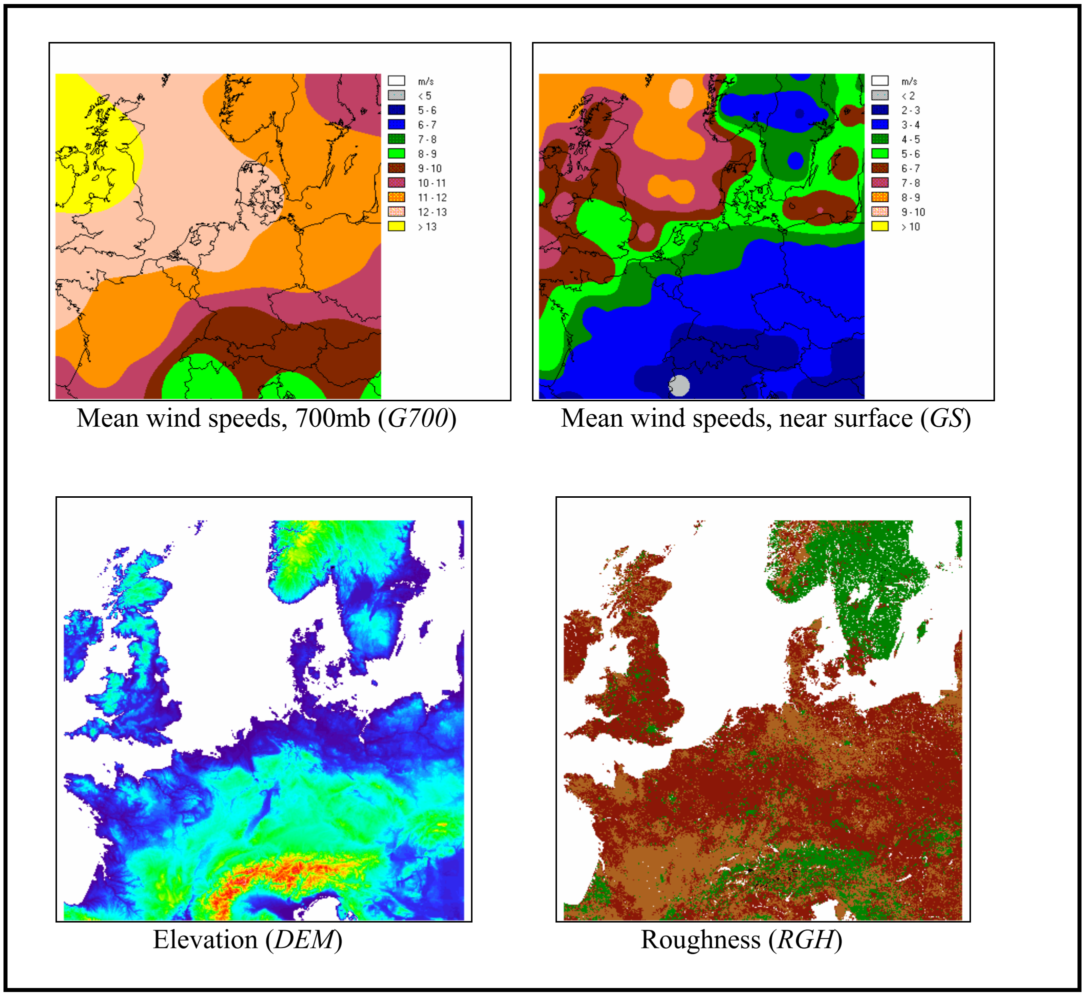


Figure 3.1: Input data for AMWS regression

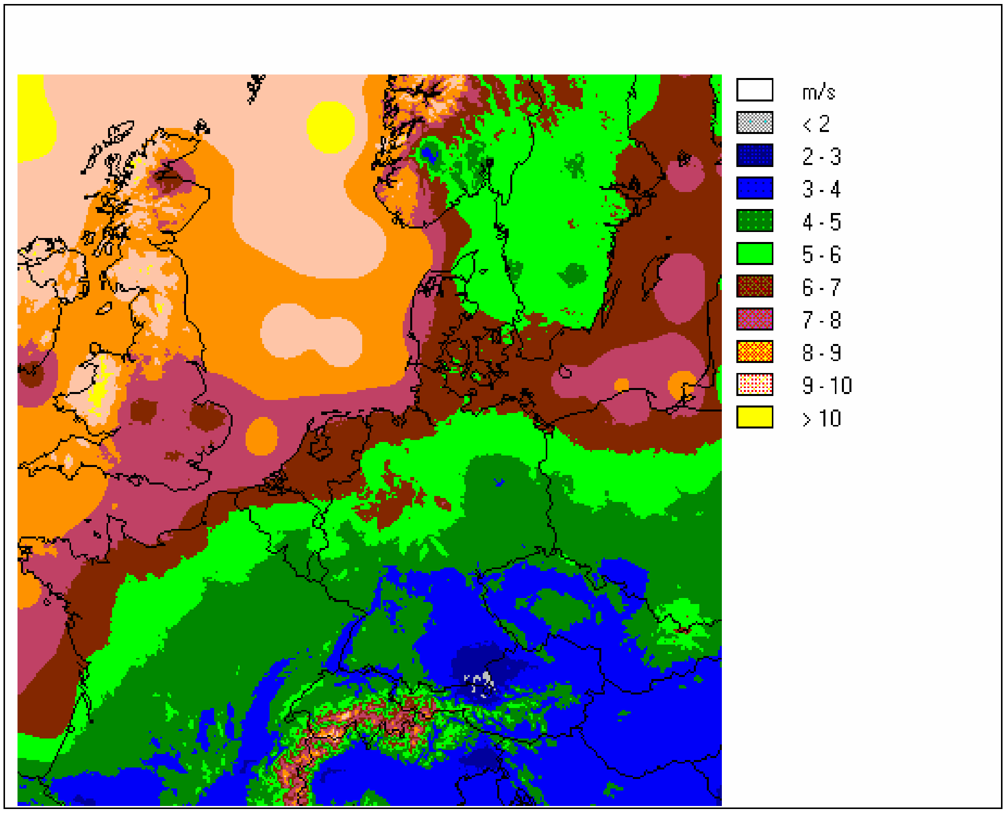


Figure 3.2: Modelled 50 m AMWS estimates

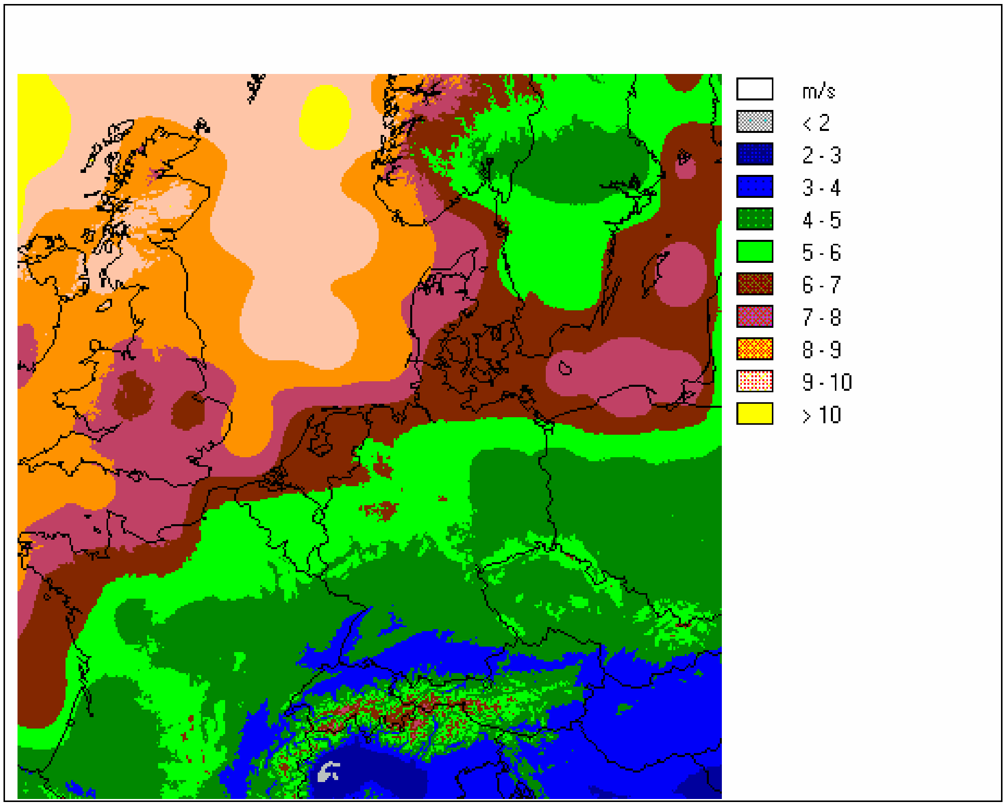


Figure 3.3: Regressed 50 m AMWS estimates

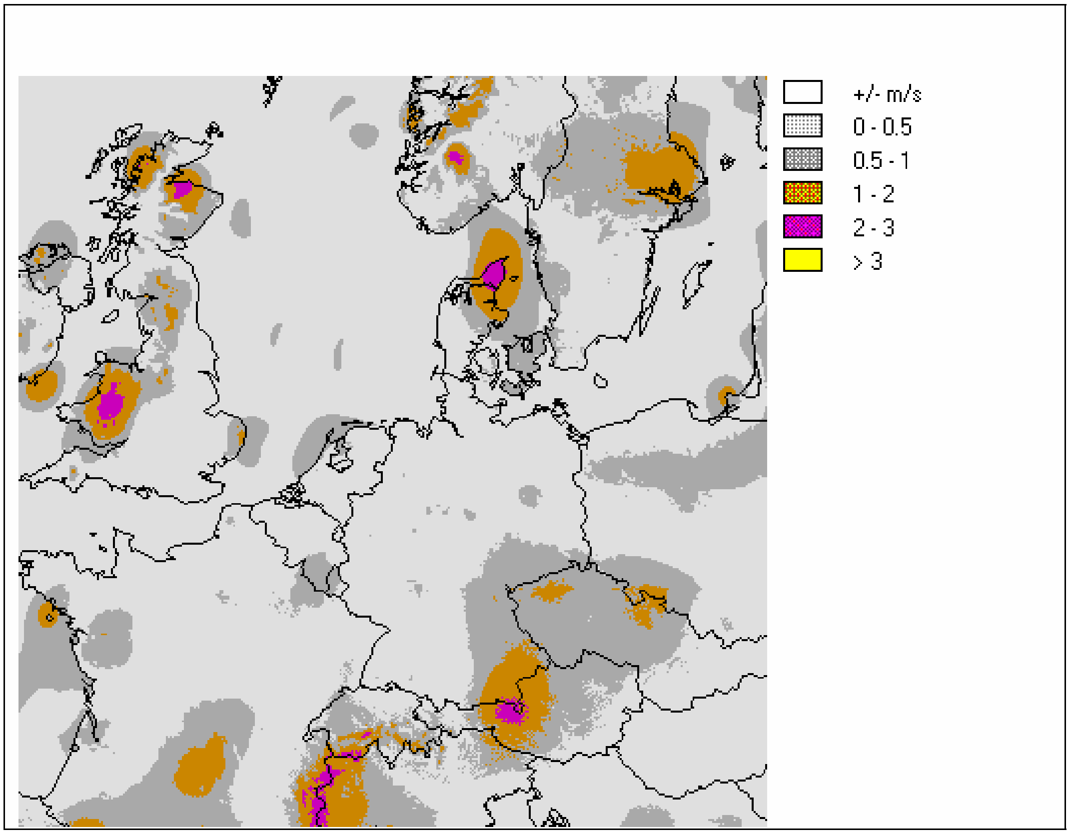


Figure 3.4: Modulus of mean AMWS error

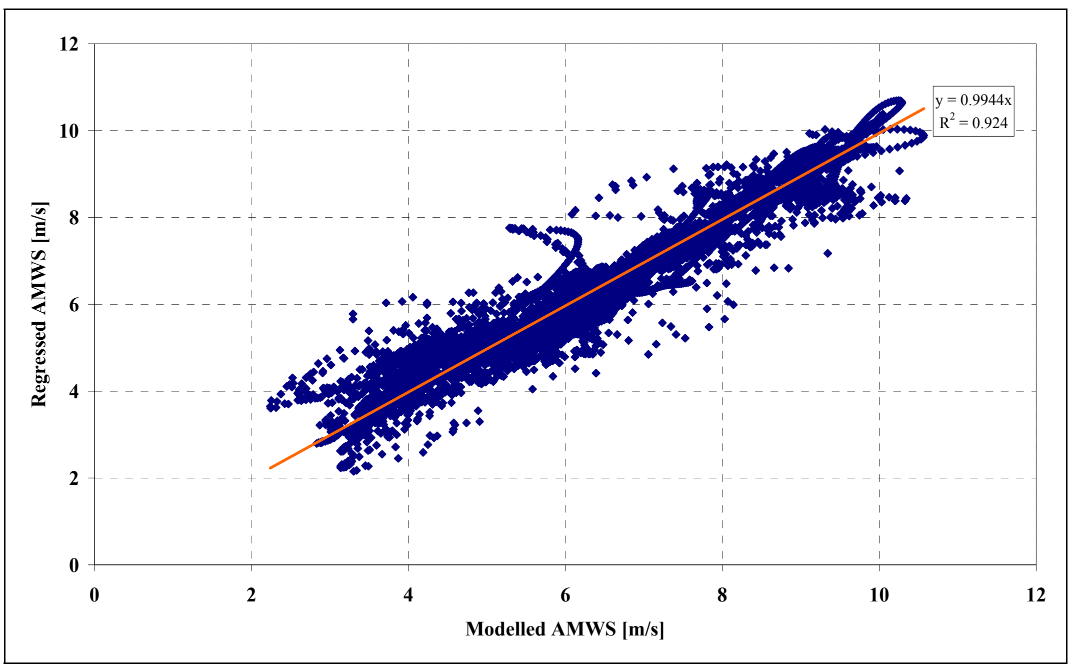


Figure 3.5: Result of AMWS regression

From the above, it was concluded that this relatively simple linear regression provided a satisfactory means of estimating wind speeds in the "rest of the world" regions without repeating the effort involved in a full wind mapping exercise.

3.3 Estimation of 60 m AEY

The above regression was a convenient way of establishing 50 m AMWSs at 5 km resolution. 50 m AEYs at 1 km resolution were subsequently estimated using the methods described in Sections 2.3 and 2.4. However, there was also a requirement for 60 m AEYs for use in the offshore analysis. A statistical relationship between 50 m and 60 m offshore AEYs was established from a linear regression on the study region results. As can be seen in Figure 3.6, this approach established a very robust method for estimating 60 m AEYs.

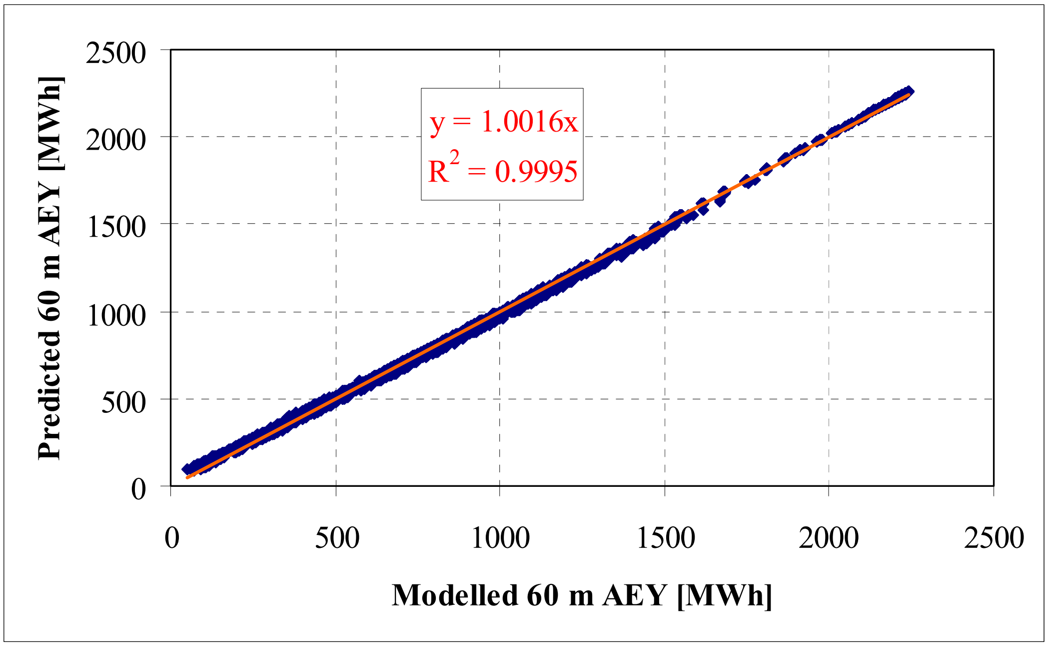


Figure 3.6: Validation of 60 m AEY predictions

4 WIND ENERGY MODELLING: GLOBAL COMPENSATION

4.1 Introduction

All AEY estimates generated either by the mass-consistent model described in Section 2 or by application of the statistical procedures described in Section 3 were dependent on the GUACA initialising wind speed data. Marc Schwartz and Dennis Elliott of the US National Renewable Energy Laboratory (NREL) provided some extremely useful insights into possible systematic errors in the GUACA data likely to result in widespread under-estimation of the wind resource in many, if not all, parts of the world. This section describes the development, validation and application of a statistical compensation for GUACA errors in onshore AEY estimates. The compensation was applied globally i.e. to study region onshore AEY estimates (Section 2) and to rest of the world onshore AEY estimates (Section 3). It was not applicable to offshore AEY estimates.

Before describing the global compensation approach, other significant limitations of the techniques reported in the preceding sections will be briefly discussed.

4.2 Other Analytical Limitations

A significant analytical limitation is the absence of localised, terrain-generated (thermal) winds in the model. Winds of this type, such as sea breezes, anabatic and katabatic winds etc., may not have been reflected in the initialising data, nor can a mass-consistent model such as WindMap cope with thermal effects. As noted earlier, the geographical scope of this work precluded the use of surface station data or a thorough study of the wind climatology of all the areas modelled.

The effect of omitting localised winds is generally to under-estimate the AMWS in areas where they are significant. This was immediately apparent when the results for the EU-15 (the first study region to be modelled) were compared with those presented in the European Wind Atlas [5] which were based on surface station data. Agreement between the two was generally reasonable but terrain-generated winds such as the Mistral in the south of France, which are clearly indicated in the European Wind Atlas, were noticeably absent from the results generated in this study.

It is difficult to envisage a basis on which any global assumptions about atmospheric stability might be justified and it is well known that conditions vary significantly with location and time. The global circulation and relatively predictable variations of other meteorological parameters with location, such as temperature and humidity ranges, suggest that some systematic large scale dependence of atmospheric stability upon factors such as latitude, distance from land or sea, and elevation might be identified. This was not possible in the context of the study, but could be an area that merits further research.

4.3 Development of Compensation Method

The only way to assess the accuracy of AEY estimates produced by the methods described in the preceding sections was to compare them with a large body of alternative estimates produced by a more detailed study to which a higher level of confidence could be ascribed. The most suitable such reference data were contained in the map of United States Annual Average Wind Power [6] which NREL kindly made available to GH in digital form enabling geo-referenced statistical comparisons to be undertaken in the GIS.

4.3.1 Regression analysis

A multi-variate linear regression analysis was used to determine a statistical relationship between the US Wind Atlas wind power estimates (Wm^{-2}) and corresponding original AEY estimates (MWh/yr).

Definitions used and assigned to each 10×10 km array of onshore 1×1 km cells were:

Data	Definition
U	Mean of US Wind Atlas average 5×5 km AEYs for reference turbine (no losses) [6]
G_{tt}	Mean of top ten 1×1 km AEYs for reference turbine (no losses)
G	Mean of all (100) 1×1 km AEYs for reference turbine (no losses)
H	Mean of all (100) 1×1 km elevations
S	Mean of all (100) 1×1 km slopes
R	Mean of all (100) 1×1 km surface roughnesses
D	Mean of all (100) 1×1 km distances from coast

Table 4.1: Parameters used in the regression analysis

A multi-variate linear regression using the above datasets was established and used to calculate G'_{tt}, a revised estimate of G_{tt}. The relationship was investigated with no technical and/or environmental constraints (apart from the necessity to be on land in the contiguous US) and zero population to regress the maximum possible number of 10×10 km arrays.

The R^2 value for the regression was 0.522. A significant limit on the fit was the coarseness of the US Wind Atlas AEY equivalents both spatially (initially 5 arc min lat/long) and in terms of class intervals (6 classes only in the contiguous US).

4.3.2 Results

Unconstrained AEY maps and fully constrained cost-energy curves were subsequently generated from ***U*** and G'_{tt} and, to complete the comparisons, from G_{tt}. The maps provided a check that the spatial distribution of the revised estimates of AEY compared well with those derived from the US Wind Atlas. The curves provided a check that the synthesised results approximated well with those from the US Wind Atlas in terms of characteristics for input to computation of the CO_2 cost-abatement curves. Both checks were needed to ascertain the applicability of the method, subject to other uncertainties, in other regions.

4.3.2.1 Spatial distributions of AEY

Maps of G_{tt} , ***U*** and G'_{tt} were created using the same classes and palettes to permit visual comparisons of the spatial distributions of the wind energy resource. These are shown overleaf:

[6] The data as supplied by NREL were in 7 classes for which maximum and minimum annual mean wind power density (W/m^2) and equivalent AMWS (assuming Rayleigh distribution) at 50 m were specified. These were converted into equivalent AEYs for 6 MW/km^2 installed capacity (no losses) by calculating the AMWS corresponding to the median wind power density for each class and applying the power curve polynomial described in Section 2.4.1 (which also assumes a Rayleigh distribution). It should also be noted that the NREL data were generated from surface station measurements and accounted for localised variation of mean air density and Weibull shape parameter (which was sometimes significantly non-Rayleigh), and that the classes "apply to terrain features that are well exposed to the wind, such as plains, tablelands, hilltops, ridge crests and mountain summits" [6]. These characteristics were considered to make the classes comparable with the top ten 1 km AEYs in each 10×10 km array.

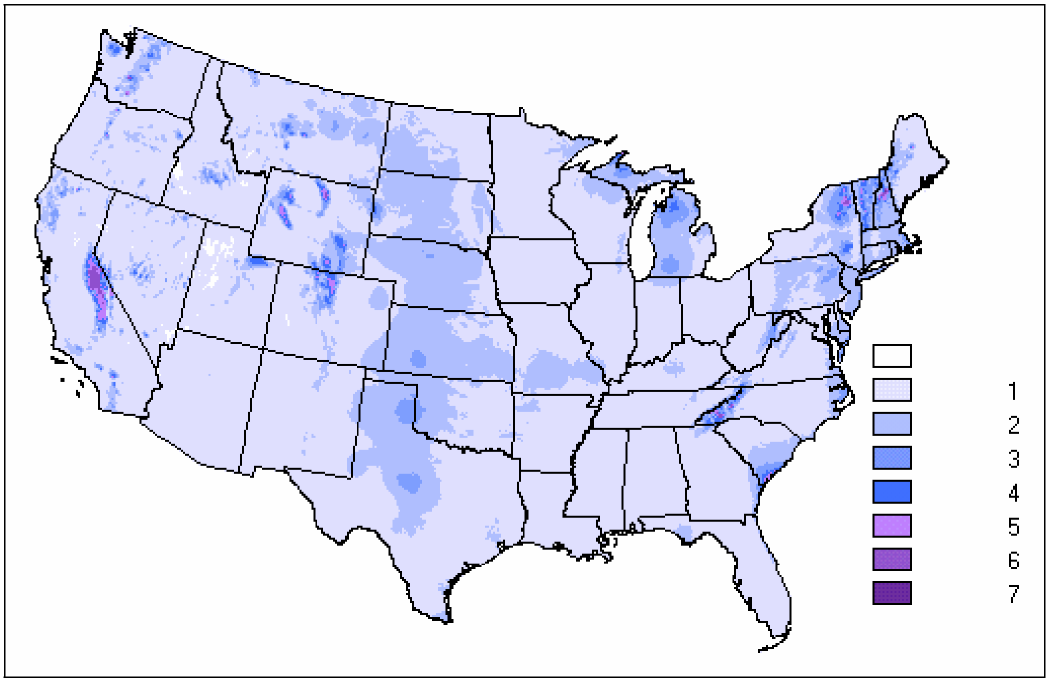


Figure 4.1: Original AEY estimates (G_{tt}) (equivalent US Wind Atlas Classes)

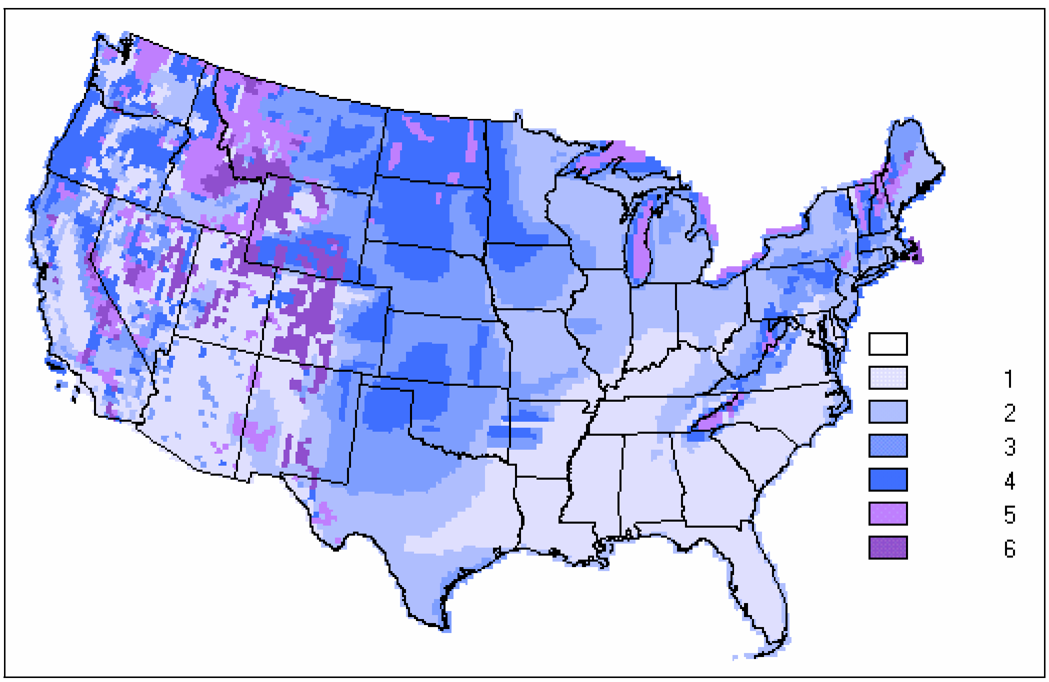


Figure 4.2: US Wind Atlas AEY estimates (*U*) (equivalent US Wind Atlas Classes)

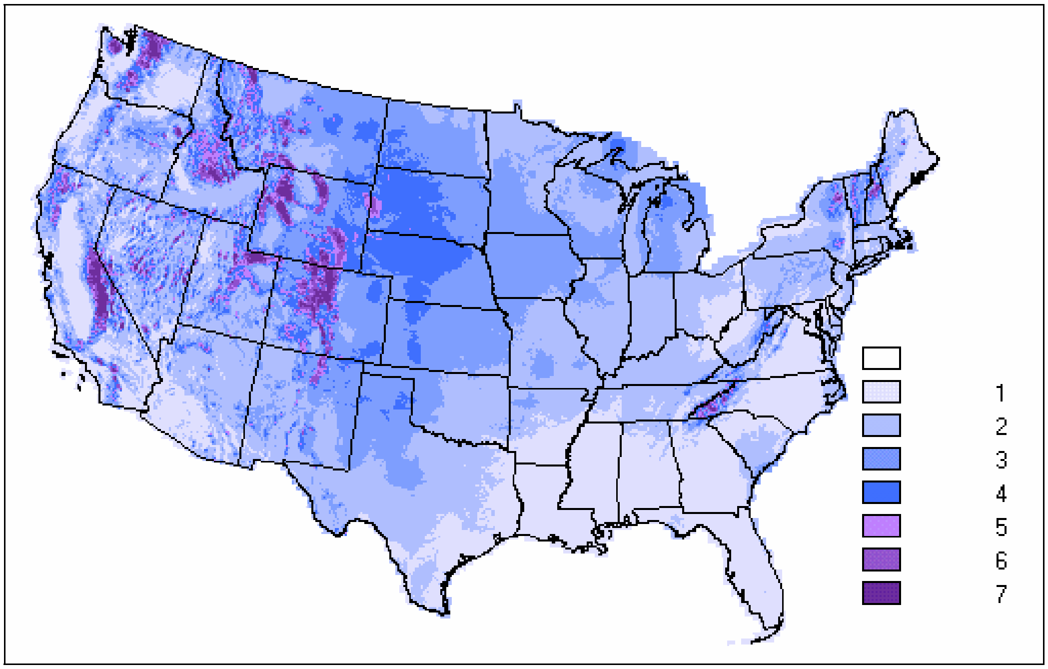


Figure 4.3: Revised AEY estimates (G'_{tt}) (equivalent US Wind Atlas Classes)

It is immediately apparent that revision of the AEY estimates resulted in a spatial distribution which resembles that derived from the US Wind Atlas much more closely. In broad terms, the effects of the adjustment were to increase the sensitivity of AEY to relief and to increase AEY over the Great Plains. The former suggests that boundary layer conditions are generally more stable (in the USA) than was assumed in the generic initialisation of WindMap. The latter suggests that GUACA under-estimations do, in accordance with anecdotal evidence, worsen further from the coast. These were among the assumptions under-pinning the selection of independent variables for the regression.

4.3.2.2 Cost-energy curves

Curves of cumulative AEY versus LPC were generated for both the small and large wind farms scenarios in year 2000 from $\boldsymbol{U}$ and $\boldsymbol{G'_{tt}}$ and, to complete the comparisons, from $\boldsymbol{G_{tt}}$. These are shown in Figure 4.4 and Figure 4.5. While the revised AEY estimates ($\boldsymbol{G'_{tt}}$) were clearly a major improvement, having produced results resembling those derived from the US Wind Atlas much more closely, they still under-estimated the critically important lower LPC results significantly.

It was subsequently established empirically that the lower LPC results derived from the US Wind Atlas could be synthesised more accurately for both scenarios by factoring $\boldsymbol{G'_{tt}}$ by 1.1 throughout. These curves are also shown in Figure 4.4 and Figure 4.5[7]. It can be seen that both fit the target curve almost perfectly up to 10 c/kWh and very well up to at least 15 c/kWh. It should be stressed that this is an empirical. It compensates for the difference in the distributions of AEYs in the US Wind Atlas and in $\boldsymbol{G'_{tt}}$ (which are largely attributable to areas such as the extreme north-west and the northern great plains where $\boldsymbol{G'_{tt}}$ is still significantly lower) by a small generalised AEY increase. It is more justifiable than manipulation of the curve itself and reflects the fact that the regression was established across the full range of AEY values i.e. not weighted towards higher AEYs which are generally associated with lower LPCs[8].

[7] Both the adjusted GH and 1.1x adjusted GH AEYs were capped at the maximum AEY defined in the generic power curve

[8] Weighted regressions were investigated by removing Classes 1 and 2 from $\boldsymbol{U}$, but neither the resulting maps or cost-resource curves were as close to those derived from the US Wind Atlas.

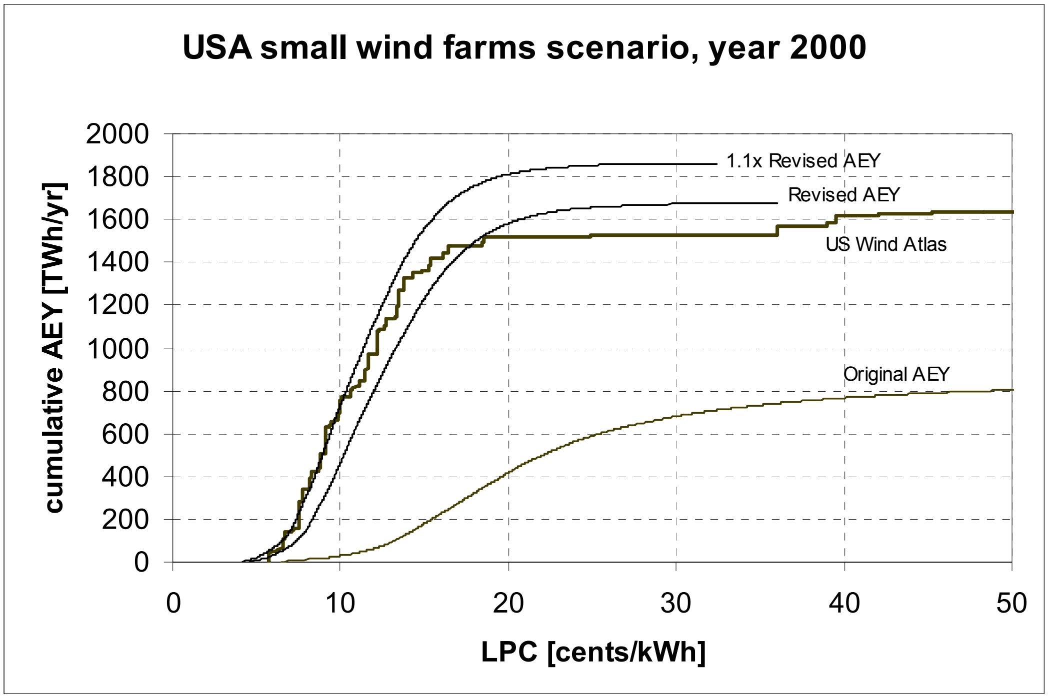


Figure 4.4: Small wind farms cost-energy curves

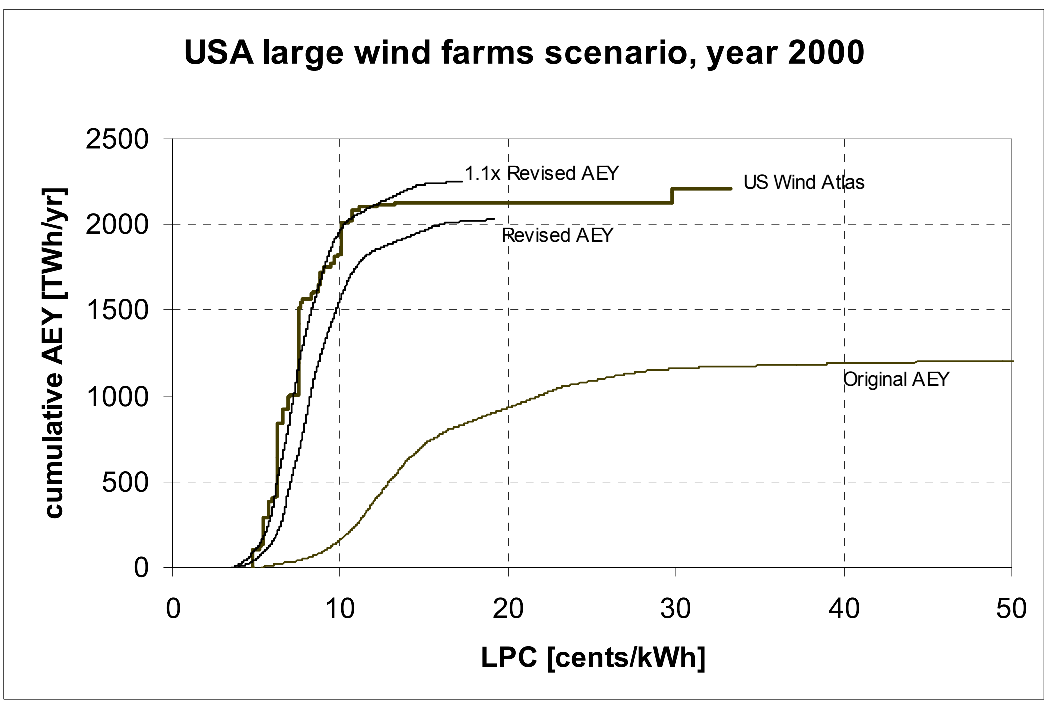


Figure 4.5: Large wind farms cost-energy curves

The US Wind Atlas curves are visibly quantised because they are generated from the median values of only 6 equivalent AEY classes. The fact that there are more than 6 steps illustrates the effect of location-specific electrical costs in the numerical analysis.

A map of $\boldsymbol{G'_{tt}}$ factored by 1.1 throughout is shown in Figure 4.6. Whether this looks more similar than $\boldsymbol{G'_{tt}}$ to the US Wind Atlas is debatable, but it does not look unreasonable.

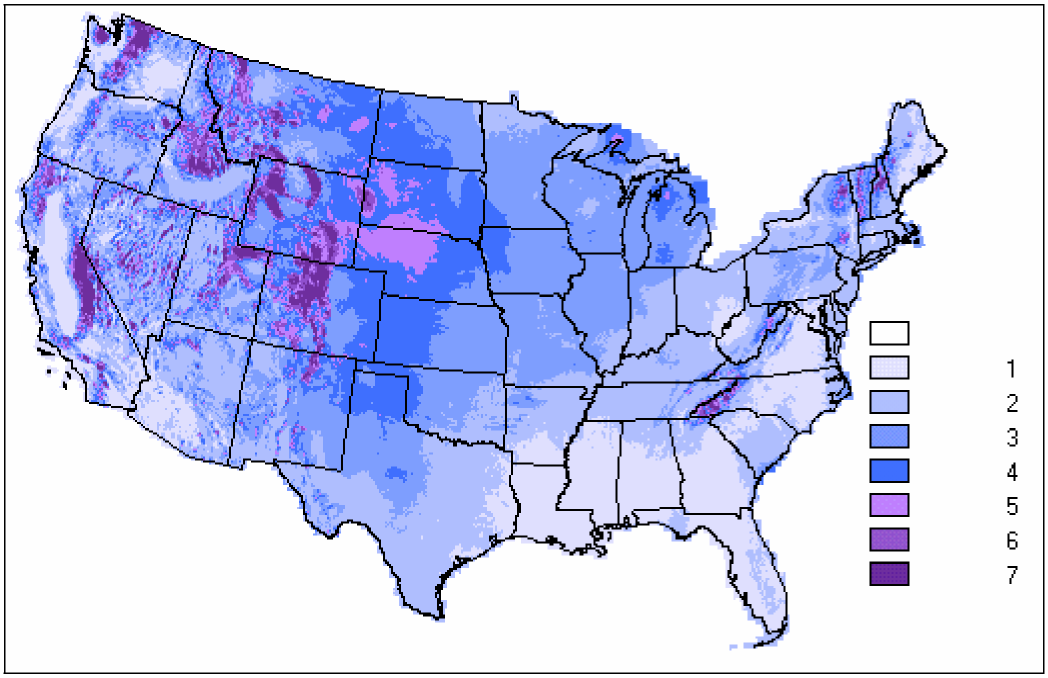


Figure 4.6: Factored revised AEY estimates (1.1 × G'_{tt}) (equivalent US Wind Atlas Classes)

4.4 Application and Validation

The above method was applied to the small and large onshore wind farm scenarios in years 2000 and 2020 for all regions including the USA where it was used in preference to the AEYs derived directly from US Wind Atlas as the latter resulted in severely quantised cost-resource curves. It was not applied to the offshore wind farms scenario for the following reasons:

- The regression was established for onshore AEYs only as this is the extent of the US Wind Atlas. There is no comparable body of high quality offshore wind energy resource estimates on which to base a regression.
- Only in the EU-15 is the market potential for offshore wind over the study timescale considered to be of comparable magnitude to that of onshore wind. Comparisons with the best available study of offshore potential in the EU [12] indicated adequate agreement with the original AEY estimates.
- Anecdotal evidence suggests that GUACA errors are generally less over large bodies of water. Although it is not unlikely that the original analyses are under-estimates in some parts of the world, they are likely to have been more accurate than their onshore regional counterparts.
- The study terms of reference acknowledged that the potential and costs for offshore wind are currently less well understood as the technology is less mature, and that it should therefore be analysed separately.

The resulting EU-15 AEY map was visually compared, albeit with difficulty, with Risø's European Wind Atlas [5] as the latter indicates wind resources which depend on the underlying topographic conditions. Agreement nonetheless appeared to be good, and significantly better in all areas after the compensation for GUACA errors had been applied. Interestingly, it was found that the compensation tended to reduce AEY estimates in areas exposed to the Atlantic ocean where they had previously been over-estimated, as well as increasing AEY estimates in areas far from the Atlantic such as Greece where they had previously been under-estimated.

The India AEY map was compared with very coarse data produced by Anna Mani [7] and the Africa map with surface station data compiled in a GH commercially confidential report. Neither comparison was conclusive. Finally, the China AEY map was compared over a very limited geographical area with (confidential) data recently produced by NREL, and found to indicate generally lower wind resources.

In all other regions, the resulting AEY maps were visually compared with the corresponding region in a paper copy of the "World-wide wind energy resource distribution estimates" map produced by Pacific Northwest Laboratory in 1981 [8] (hereafter referred to as the "PNL map"), although the limitations imposed by the PNL map format and projection rendered this almost impossible in many areas. Agreement was generally close, though the AEY maps used in this study (which were re-classed in the GIS into the same classes as shown in the PNL map) contain much more fine detail in terms of both spatial resolution and class interval.

Finally, the proportions of land area in the various PNL map classes in the AEY maps used in this study were calculated in the GIS and compared with corresponding estimates made by eye from the printed PNL map by Grubb and Meyer [9] and Turkenburg in the 1993 World Energy Council Report "Renewable Energy Resources: Opportunities and Constraints 1990-2020" [10]. Comparability was limited by the fact that regions were defined differently by different authors, and the results presented in Figure 4.7 and Figure 4.8 therefore focus on regions considered to be broadly similar in terms of land area and boundaries. The principal conclusions which may be drawn from these comparisons are:

- For most of the comparable regions, the distributions of the resource in the AEY maps and in [8] are broadly similar.
- For most of the comparable regions, the magnitudes of the resource in the AEY maps and in [9] or [10] are broadly similar.
- The magnitudes of the wind resource in the AEY map of the FSU and Eastern Europe are significantly higher than those in [8], [9] or [10].
- Overall, estimates of the wind resource in the AEY maps over broadly comparable regions are slightly higher than those in [9] or [10]. This is due mainly to the FSU and Eastern Europe results.

It should be borne in mind that NREL's subsequent experience has indicated that "*the estimates from the 1981 global wind map* (the PNL map) *are conservative for many regions of the world (particularly many of the developing countries where existing data were sparse or not reliable)*" [11], and that none of the above references should be considered to be an absolute benchmark. Nonetheless, widespread systematic discrepancies between estimates might have required some explanatory comments. However, the extent of agreement is considered to provide a degree of validation for all of the aforementioned attempts, including that presented in this study, to quantify the wind energy resource world-wide.

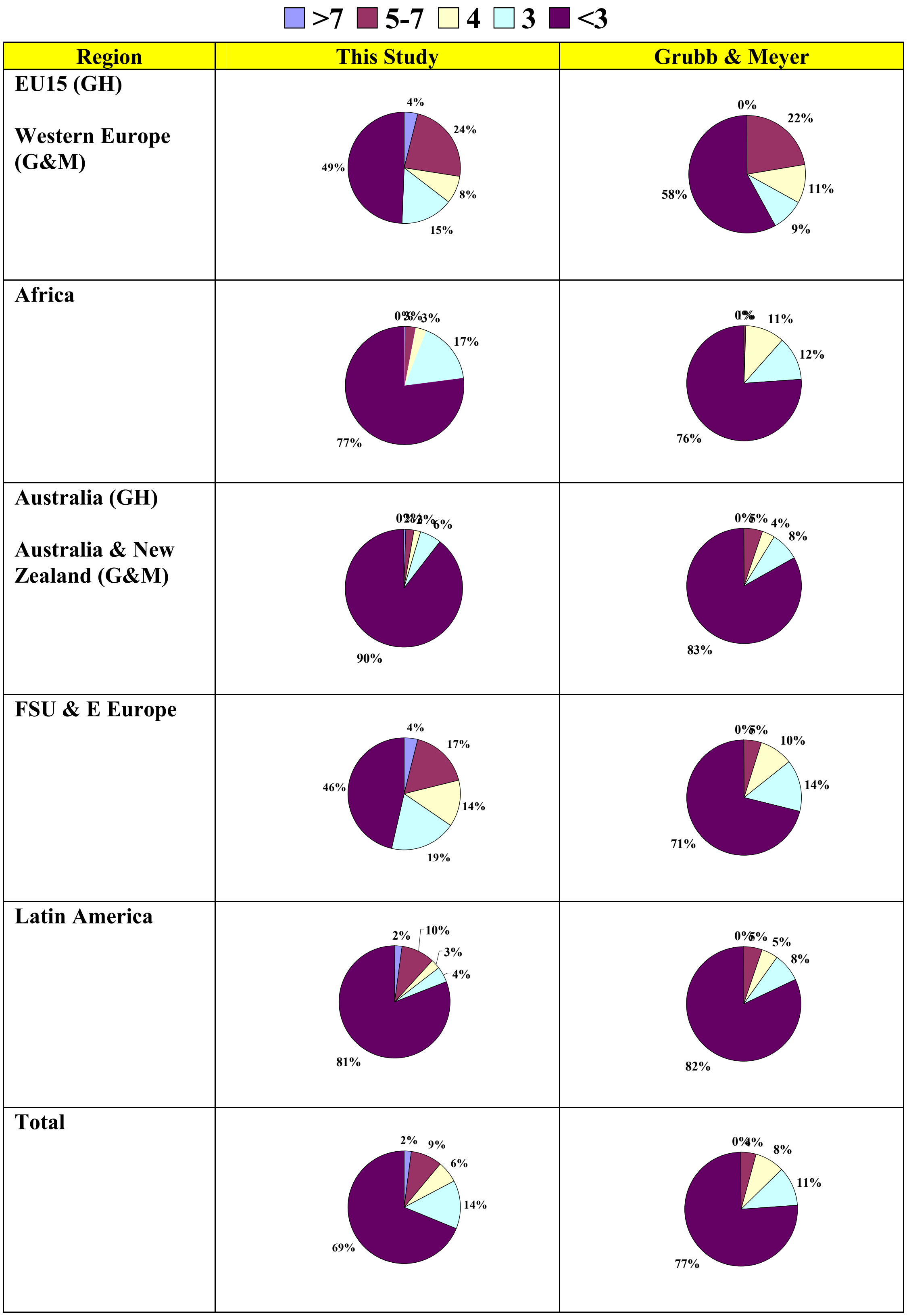


Figure 4.7: Comparison of proportions of land area by PNL map class [8] in final AEY maps with those estimated by Grubb & Meyer [9]

3-7 **1-2**

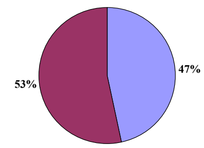
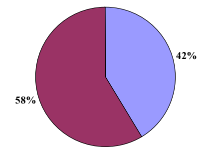
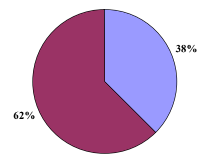
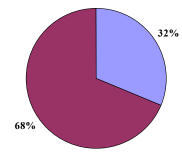
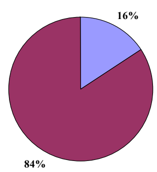
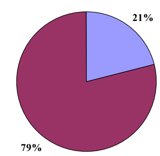
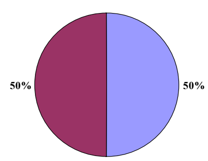
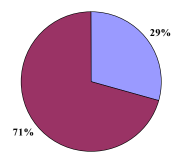
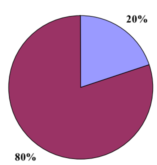
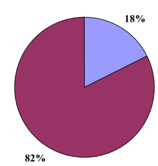
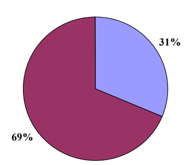
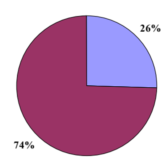
Region	This Study	Turkenburg
EU15 (GH) **Western Europe (Turkenburg)**		
Middle East (& N Africa)		
Asia & Pacific		
FSU & E Europe		
Latin America		
Total		

Figure 4.8: Comparison of proportions of land area by PNL map class [8] in final AEY maps with those estimated by Turkenburg in [10]

5 SPATIAL ANALYSIS

A geographical information system (GIS) is a computer-based tool for the acquisition, storage, manipulation, analysis and display of spatial data. The commercially available software package, IDRISI, was used in this study. This section describes the analyses for which the GIS was utilised.

5.1 Projections

Spherical-to-plane projections enable features of a three dimensional spherical surface, such as the Earth, to be represented on a two dimensional planar surface, such as a map. Most global datasets are provided geo-referenced to latitude and longitude (geodetic co-ordinates). There are several such systems as all geodetic co-ordinates are referenced to a geodetic datum. A datum is the exact definition of an ellipsoid which is a best fit to the Earth's true surface. Datums are most usually location specific to provide a "best fit" for chosen regions such as mainland USA, Europe, Sri Lanka, etc.. World geodetic datums provide best fits on a global scale.

While the majority of GIS analyses in this study could have been achieved using a simple geodetic co-ordinate system, the computational wind flow modelling described in Section 2 necessitated the use of a planar orthographic grid. For this study, therefore, all datasets were geo-referenced to orthogonal co-ordinate systems based on Lambert's Oblique Azimuthal Equal Area projection optimised for each of the four study regions (and subsequent Rest of the World regions). This projection was chosen in order to conserve the geometry of areas, and because it is suitable for large (continental) regions.

5.2 Spatial Data

The characteristics of the spatial datasets used are summarised in Table 5.1.

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

Table 5.1: Spatial datasets used in GIS analyses

5.3 Technical Constraints

5.3.1 Onshore

The GIS was used to "remove" areas that would technically constrain the implementation of wind energy projects. These constraints on wind energy developments were defined as follows:

- Forest areas
- Urban areas
- Water bodies
- Areas where 1 km slope > 10%
- Areas labelled "Unknown" on the PNL map [8] i.e. the Himalayas and the Andes

For these areas, available AEY was set to zero. For urban and water areas, rural population was also set to zero (as there can be no rural population in either).

Forest, urban and water areas were established from the USGS global landcover dataset.

Areas with 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[9] to unacceptable levels. There is no hard and fast relationship between local gradients and the relative elevations of adjoining 1×1 km cells. A gradient map was generated from these cells using a GIS context operator, and an area of northern Europe, well known to the authors, was viewed in Boolean form using a range of threshold gradients. This process suggested that a gradient threshold of 10% was a reasonable approximation to the rule of thumb local gradient threshold of about 25%. There are many types of complex terrain, from smoothly rounded hills to major vertical features, and the validity this approach will be variable around the world – it may be conservative in some areas and optimistic in others. Nonetheless, this was considered to be the best possible compromise with the available data.

5.3.2 Offshore

No spatial data defining offshore constraints were used in this study. However, GH had previously completed an extensive study of the European offshore wind resource [12] where datasets defining areas that could be regarded as constraints to wind energy development were obtained. The datasets were as follows:

- Pipes/cables
- Military use
- Shipping lanes
- Oil platforms [10]
- Conservation areas
- Sea bed slope restrictions [11]

[9] Short term variability of wind speed (and sometimes direction) which is the principal cause of fatigue loading on wind turbines
[10] A circle of radius 10 km was constrained around oil platforms.
[11] A constraint of 5^0, based on a DEM of approximately 2x2 km resolution, was implemented in [12].

For the present study, GH examined these existing datasets for the EU-15 and found that between 19 to 25 % of the near-shore (i.e. within 40 km of the coast) area was constrained from wind energy development due to the above datasets.

The offshore market for wind energy is just beginning to develop and, with so little experience world-wide, it was difficult to set an acceptable density at which to model offshore wind energy developments (i.e. similar to the 150 kW/km^2 limit set for the onshore analysis). Apart from the technical constraints discussed in [12], it was hard to envisage any reason why offshore wind farms should be constrained at all. The only obvious influence would be social acceptability, and greater allowance was made for visual impact in this study by using a minimum distance from shore of 5 km for offshore development[12].

It was decided to constrain 75 % of the sea bed between 5 to 40 km offshore and <40 m depth (the area that was analysed for the offshore scenario) by homogeneous "thinning" to allow for the following unquantified constraints:

- Unknown technical constraints (i.e. in addition to those discussed in [12])
- Unsuitable sea bed conditions
- Delineation between wind farms

This constraint was applied uniformly across the whole study area as no information about the actual locations of technical constraints was sought.

5.4 Onshore Environmental Constraints

The GIS was used to remove areas that would constrain onshore wind energy development on the basis of environmental protection.

It has to be recognised that there is a multitude of international, country and region specific environmental designations, all of which may or may not restrict wind energy development. Previous GH experience has shown that obtaining GIS data for all land designations, even for a small region within one country, can prove highly time consuming due to the large number of organisations involved and of formats in which they can provide the information. While investigating environmental constraints on wind energy on a country by country basis would have been attractive, the time and effort involved in obtaining such datasets was impractical within the bounds of this study. Therefore, a single dataset of internationally acknowledged environmental designations was used. The dataset was obtained from the IUCN (International Union for the Conservation of Nature) in digital form, and shows the location and size, if not the exact boundary[13], of all IUCN classifications I to VI. All of these land classifications were assumed to act as constraints on wind energy developments, with AEY within those areas being set to zero.

The classifications are discussed in detail in Annex I to this Appendix. It should be noted that in practice it is unlikely that all classifications would act as constraints to wind energy development. However, for the purposes of this study, this approach was adopted to compensate for all the local and national designations that were not considered in the analysis.

[12] This minimum distance was 1 km in [12]

[13] Designated areas for which no exact border was given were shown as a circle, centred on the site, with area equal to that of the designated area.

6 CAPITAL COST ASSUMPTIONS

The study required estimates of present and future cost trends of wind turbines and wind farm installations in order to evaluate the cost of energy production from wind generated electricity. This section presents the current best estimates of these cost breakdowns. Cost estimates are provided for the three analytical scenarios:

- Onshore small;
- Onshore large;
- Offshore.

6.1 Turbine Costs

The cost breakdown presented in Table 6.1 is typical of a medium sized (600 kW) land-based HAWT (horizontal axis wind turbine) [13].

Component	% of total cost
Tower	20
Electrics and control	19
Yaw system	3
Drive train	20
Rotor	30
Nacelle	8
Total	**100**

Table 6.1: **Approximate breakdown of costs for a 600 kW turbine**

The current cost of 600 kW wind turbines, including installation and commissioning, is given in [14] as $851/kW.

6.2 Wind Farm Costs – Small Onshore

Table 6.2 shows the cost breakdown of typical onshore wind farms, using 600 kW scale turbines, within the UK [14]. These costs are taken to be representative of typical north European sites – i.e. relatively small wind farms scattered over large areas – and are the costs applied to the “small onshore” scenario.

Item	Relative cost [%]	Specific cost [$/kW]	Unit cost (600 kW) [$k]
Turbine including commissioning and installation	**70**	**851**	**510**
Civils	**10**	**123**	**72**
Turbine bases		62	
Variable costs		61	
Electricals	**15**	**182**	**108**
Grid connection		92	
Transformers		30	
Variable costs		60	
Miscellaneous	**5**	**61**	**37**
Total	**100**	**1217**	**726**

Table 6.2: **Estimated costs of wind farms using 600 kW turbines, small onshore scenario**

6.3 Wind Farm Costs – Large Onshore

Recently, GH has gained extensive experience[14] in the USA where there has been a resurgence in wind energy developments. Here there has been a tendency for much larger single developments (hundreds of MW rather than the tens of MW typical of European sites) clustered in relatively windy areas. The larger size of developments has also resulted in cheaper installation costs. While detailed cost information for particular sites is subject to commercial confidence, it is GH's experience that typical installation costs for the more economic of these American sites are now around $1000/kW. It is not known in what areas of installation these cost reductions have been made. Therefore, in estimating the cost breakdown for the large onshore scenario, it was only possible to factor the total costs of a wind farm down (from $1217/kW to $1000/kW), keeping the same balance of costs. These costs are presented in Table 6.3.

Item	Relative cost [%]	Specific cost [$/kW]	Unit cost (600 kW) [$k]
Turbine including commissioning and installation	**70**	**700**	**419**
Civils	**10**	**100**	**59**
Turbine bases		50	
Variable costs		50	
Electricals	**15**	**150**	**89**
Grid connection		75	
Transformers		25	
Variable costs		50	
Miscellaneous	**5**	**50**	**30**
Total	**100**	**1000**	**597**

Table 6.3: **Estimated costs of wind farms using 600 kW turbines, large onshore scenario**

[14] In the last year or so, GH has worked on over 1000 MW of large onshore projects world-wide. Most of this has been in the USA.

The costs given in Table 6.2 and Table 6.3 for "Grid connection" are only an average for "typical" wind farms. The true cost of grid connection is dependent on the length of transmission line and the capacity of the wind farm. These factors are accounted for in the numerical analysis developed for this study.

6.4 Wind Farm Costs - Offshore

Most present day offshore developments are on a larger scale than their onshore equivalents (particularly in Europe, though less so in other developing wind markets) and use larger, MW scale turbines. Table 6.4 presents a typical cost breakdown for a 200 MW offshore development in a water depth of 15 m and with a distance of 20 km to the grid connection point onshore.

It should be noted with respect to Table 6.4 that the costs for foundations and installation in offshore wind farms are very dependent on site-specific conditions, particularly:

- Turbine rating;
- Depth;
- Ice/wave loading;
- Seabed conditions.

Offshore costs for this study assumed turbines of 2 MW rating and 60 m hub height. Depth was incorporated in the foundation/installation cost calculations, but ice/wave loading and seabed considerations were ignored.

Item	Relative cost [%]	Specific cost [$/kW]	Unit cost (2 MW) [$k]
Turbine including commissioning and installation	**62.2**	**1,043**	**2,086**
Civils	**14.0**	**234**	**468**
Turbine bases		281	
Variable costs		0	
Electricals	**20.2**	**338**	**676**
Grid connection		275	
Transformers		16	
Variable costs		47	
Miscellaneous	**3.6**	**61**	**122**
Total	**100**	**1,676**	**3,352**

Table 6.4: **Typical estimated costs of offshore wind farms using 2 MW turbines**

The full range of specific costs modelled was from $1,433/kW (5 km from shore, 1 m water depth) to $2,324/kW (40 km from shore, 40 m water depth), and the cost sensitivity to depth was greater than to distance from shore.

6.5 Future Wind Farm Costs

A 1% annual rate of wind farm capital cost reduction, excluding grid connection costs which remained constant, was assumed for the main analysis. This figure was taken from "Wind power development – Status and perspectives" published by Risø National Laboratory in August 1998 [15]. 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 by the results presented in the Main Report.

A comprehensive analysis of the former route is provided in a December 1997 draft "Advanced horizontal axis wind turbines in wind farms" in "Renewable energy technology characterizations", 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 [16]. 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 [17]. 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 [18] and "The effects of increased production on wind turbine costs" prepared for NREL by Princeton Economic Research Inc. in December 1995 [19]. 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.

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 appendix. Instead, the interested reader is invited to consult these four references directly.

7 GRID CONNECTION COSTS

This section describes the method used to determine the electrical grid connection costs associated with wind farms in the four study regions.

Two procedures were adopted:

- Procedure with no knowledge of the position and capacities of the existing electricity system
- An alternative procedure, making use of known proximity to existing electricity transmission systems

Both procedures are described below.

7.1 Procedure Without Knowledge of the Existing Electricity System

The basic principle was that the electrical costs were determined within the numerical analysis based on information available *for that square*[15]. For example, it was not feasible within the scope of this study to take into account issues such as:

- Distance to networks outside any particular square;
- Cumulative loading of an existing electricity system as more wind capacity is installed in an area consisting of several squares.

Such issues could be tackled by IDRISI or other GIS packages for smaller study areas, such as a particular state or province, given knowledge of the transmission and distribution systems in the area. For this study, the data required, and the time available, made this level of detail impossible.

The electrical cost inputs to the complete cost calculation were a set of parameters, entitled C_1, D_1, C_2 and D_2.

7.1.1 Existing electricity system

Electricity systems are conventionally split by function into two parts. Distribution systems are designed to transfer relatively small amounts of power over relatively short distances to individual customers. Transmission systems are designed to transfer large amounts of power over long distances at higher voltages from major power stations to the distribution systems. Distribution systems are more extensive, and are cheaper to connect to, and so are the first choice for connection of small generators such as wind farms. It must be understood that distribution systems were not designed to receive so-called 'embedded' generation and that there are technical difficulties which limit the amount and location of the generation that can be connected to them.

The lowest voltage within an electricity distribution system is usually in the range 10 to 15 kV. The maximum capacity of overhead lines and cables at this voltage level is of the order of 2 MW. At this voltage level there is frequently no automatic voltage control and the voltage range experienced by consumers often limits the generation capacity that can be connected to such systems. This voltage level has been ignored in this study.

[15] Where "square" means 20×20 km area for small onshore, and 10×10 km area for large onshore.

The next level within a distribution system is typically 20 to 35 kV, usually at the higher end of this range. These networks are extensive and can generally accept generation of 10 MW or more, and so are often the first choice for connection of smaller wind farms. For simplicity, this level will be referred to subsequently as the 35 kV level.

The next voltage level in an electricity distribution system is typically 60 to 150 kV. This level will be referred to subsequently as the 150 kV level.

Transmission system voltages are typically above 150 kV.

To determine the costs of connection of wind energy developments to distribution systems, GH considered many approaches. The basic difficulty was that whereas parameters such as capacity limits, physical extent etc. can be determined on a *per network* basis, and such information is available for networks in several countries, there was no route to determine related parameters on a *per area* basis (e.g. a 10×10 km square), except by including network maps as an integral part of the GIS/numerical analysis. This approach was used in [20, 21 and 22], for example. Because connection of generation to one point on a network will affect the capacity of the network to accept generation at other points, the analysis becomes iterative and therefore very complex. The requirement for network maps for all areas ruled it out for this study. Instead an alternative approach was adopted, which produced parameters on a *per area* basis. The reasoning was as follows.

For any distribution system, or for any reasonably homogeneous geographical area, the maximum total capacity of generation that can be connected to it *without significant reinforcement* is approximately the same as the maximum consumer demand on that system (or in that area). An alternative is to use the rated capacity of the substations feeding that distribution system from a higher-voltage system, which will be a higher figure, but in fact the maximum demand is a more useful figure as will be shown below.

Because wind generation infrequently reaches its rated output[16], the periods when the generated electricity exceeds the consumer demand on the distribution system (i.e. a net export from the system) will be infrequent. To cope with such periods it may well be necessary to make some modifications, in particular to automatic voltage control on the transformers feeding the network. When spread over all connected wind energy capacity, the costs of such modifications are small compared with other electrical system costs, and are ignored in this analysis. Alternatively, if these costs become high, generation can be curtailed at critical periods. Experience with similar situations shows that planning for infrequent curtailment allows significant increases in generation capacity with minor annual loss of production. Therefore this “cost” can also be ignored in the context of this study without significantly compromising accuracy.

To determine the maximum customer demand for a given area (e.g. any 10×10 km square) within a region, it was simple to divide the maximum demand for that region by the surface area, to get a figure in MW/km^2. This figure was an average for that region. However, it was possible to improve on this by noting that population density information was readily available for all of the study areas. The maximum demand for a region was then divided by the population of the region to give a figure in MW/person. As there is a strong relationship between population and energy consumption, this figure was significant. The maximum demand in any area could then be derived by multiplying by the population in that area.

The above argument was developed for the lower-voltage parts of distribution systems. It was then realised that it applies equally to all electricity systems. Put another way, the argument became:

[16] Typically between 10 to 20 % of the year, depending on mean wind speed, wind speed distribution and turbine design.

Major network reinforcement at any level is only needed once the installed wind generation in any area approaches or exceeds the maximum customer demand in that area.

Clearly, this would not be true if the calculation was performed for a large area, such as a country, because large generation capacities in rural areas of the country will require network reinforcement to export the power to the urban areas. However, the errors when this approach is applied to such areas will be small if the population density data has similar resolution.

It should also be noted that the above statement refers to "major network reinforcement". There is no doubt that some network investment will be needed before this point. The assumption, which appears to be justified, is that the costs of this are an insignificant proportion of the wind farm installed cost.

Following the above argument, the parameters for each square were defined. The first C_1 MW of wind turbine capacity was assumed to cost D_1 \$/MW to connect to the electrical system. This represents the capacity which can be connected to the existing electrical system without major network reinforcement. Values for these parameters are derived in Section 7.3.1.

7.1.2 Electrical system reinforcement

Following from the parameters developed above, the next C_2 MW of wind turbine capacity in any square was assumed to cost D_2 \$/MW. This cost was for connection to, and reinforcement of, the transmission system, because it was reasonable to assume that by this stage all capacity on the distribution systems has been allocated. Values for this parameter are derived in Section 7.3.2.

Clearly it is possible to define further sets of parameters for further increases in capacity. However, for the purposes of this study, C_2 was in effect set to infinity.

7.2 Procedure With Knowledge of the Existing Electricity System

As noted in Section 7.1, it was not possible in the scope of this study to determine parameters such as distance to the existing system, or capacity of sections of the existing system. However, there is a layer in the "Digital Chart of the World" (Table 5.1) which shows electricity "transmission" lines. No information is provided on the capacity or the voltage of each line. It is also suspected that underground cables are not shown. Comparison with system maps of certain areas from other sources show some disagreement. In some cases the layer appears to include the distribution system.

This information is therefore not perfect, but it seemed sensible to make use of it as far as could be justified. The procedure discussed in Section 7.1 was therefore followed except for squares through which at least one "transmission" line passes[17]. In those squares the alternative procedure was followed.

It was assumed that up to 60 MW of wind capacity in any N×N square (where N = 10 or 20 km) could be connected directly to the transmission line. The capacity of transmission lines is generally sufficient to accommodate 60 MW, but clearly there was a danger of not representing the capacity limitations of a long transmission line through a high-wind area. Determination of the cost of connection, called D_0, is described in Section 7.3.3.

[17] In practice this meant "if the area being analysed contained at least one cell which was within 5 km of an existing transmission line."

7.3 Grid Connection Costs: EU-15 Onshore

7.3.1 Local distribution system parameters, C_1 & D_1

Parameter C_1 is the maximum generation that can be connected in a square without requiring significant network reinforcement, at any level of the electricity system. The assumption was that this value was the same as the maximum electricity demand in the area.

Table 7.1 presents relevant statistics for the study regions. C_1 was determined for any area from C'_1 by multiplying by the population of the area. The population was determined from CIESIN population density data.

State	Popul'n [millions]	Surface area [km^2]	Population density [pop/km^2]	Annual electricity cons'n [1,2,4] [TWh/yr]	Max demand [1,3] [MW]	Max demand per capita (C'_1) [kW/person]
Europe:						
Austria	7.97	83,850	95.0	45.5	7,518	0.94
Belgium	10.11	33,100	305.5	77.1	12,424	1.23
Denmark	5.18	43,090	120.2	34.4	6,514	1.26
Finland	5.11	338,130	15.1	73.5	12,000 [4]	2.35
France	57.98	551,500	105.1	400.8	64,007	1.10
Germany	81.59	356,910	228.6	467.0	71,800	0.88
Greece	10.45	131,900	79.2	38.2	6,263	0.60
Ireland	3.55	70,280	50.6	20.2	3,552	1.00
Italy	57.19	301,270	189.8	272.6	45,267	0.79
Luxembourg	0.41	2586	157.0	5.2	764	1.88
Netherlands	15.50	37,330	415.3	71.2	11,711	0.76
Portugal	9.82	92,390	106.3	31.9	5,182	0.53
Spain	39.62	504,780	78.5	162	26,466	0.67
Sweden	8.78	449,960	19.5	146.2	26,300	3.00
UK	58.26	244,880	237.9	356.1	56,815	0.98
EU15 Total	**371.52**	**3241,956**		**2201.9**	**356,583**	
EU15 Ave			**114.6**			**0.96**
USA	**268.10**	**9,363,130**	**28.6**	**3216.0**	**629,100**	**2.35**
India [4]	**916.51**	**3,287,600**	**278.8**	[5] **359.6**	**65,800**	**0.07**
China [4, 6]	**1,221.46**	**9,596,960**	**127.3**	**788.4**	**See Table 7.5**	

1 UCPTE, 1997 [23] and personal communications
2 IEA, 1997 [24]
3 For UCPTE members, figures are for the time of the UCPTE combined system peak, not necessarily the time of the national peak.
4 Asian Development Bank (1995 data) [25].
5 Extrapolated from 1994 data at average growth rate 1984 - 1994.

Table 7.1: Data used to determine parameter C_1

D_1 was the cost (in \$/MW) for connection to the existing network, including an allowance for minor modifications and reinforcement, and excluding all electrical equipment within the wind farm.

There were several components to this cost, as detailed overleaf.

Overhead line
It was safe to assume for this study that underground cables were not an option for the vast majority of new generation. Any new overhead line required to connect the wind farm to the existing network can be a major cost, dependent on distance. As explained in Section 7.1, it was not possible within the constraints of this study to determine distance to network for any specified point.

Available network maps at the 35 kV level were studied, using the GIS, to determine the average distance to the existing network for all points in the area. The results are shown in Table 7.2.

Region	Type	Average distance to grid
Grampian region, UK	Rural and upland	6.3 km
Borders region, UK	Rural and upland	5.9 km
Eastern Turkey	Sparsely populated, rural	19.8 km
Central Turkey	Relatively dense network	7.3 km
Jiangsu province (part), China	Densely-populated, rural	4.4 km

Table 7.2: Average distance to grid for available network data at 35 kV level

These figures are for 35 kV systems only. However, they can be used with little error for all distribution system voltage levels, because the higher-voltage networks are much smaller in geographical extent, and will therefore not greatly affect the "average distance to grid" estimate.

These figures show the average length of the shortest direct route to the existing network. It is rarely possible to follow the most direct route. A factor of 1.5 was therefore applied. Based on the above, the following figures were derived:

- Rural areas (>100 people/km^2): 10 km (assumed range 5 to 15 km)
- Sparsely populated areas (<100 people/km^2): 30 km (assumed range 20 to 40 km)

The breakpoint at 100 people/km^2 was arbitrary but appeared reasonable from population density maps.

From cost data established by GH, a figure of $4,000/km/MW was determined for extensions to 35 kV networks. Because this stage of the procedure was for generation capacities low enough to avoid significant network reinforcement, it could be assumed that the majority of wind generation capacity at this stage would be connected to the 35 kV level. Costs for connection using higher voltages are lower (per MW of capacity), but of course there are additional fixed costs for transformation. Therefore it was reasonable to use the cost data for 35 kV connections to apply for all wind generation in this stage of the procedure.

Utility costs
This item was very difficult to estimate. Utility costs for wind farm connections are rarely made public. It should include some allowance for minor reinforcement of the network, such as improvement or modifications to protection and control equipment. An approximate figure only was possible, and it was decided that 100 % of the estimated cost of the equipment on the wind farm side of a 35 kV connection point were used as a conservative estimate, which corresponded to $23,000/MW.

Total
Using this, the following values of D_1 were determined for Europe:

- Rural areas: $63,000/MW
- Sparsely populated areas: $143,000/MW

These cost figures compared reasonably well with published cost data for network connections for wind farms [26]. Data for Germany, reviewed in [26], show that network connection costs 7.5 to 15 % of the turbine price, which is stated to be approximately $800,000/MW. This results in a range of $60,000/MW to $120,000/MW. Similar data for the UK results in a figure of 9 % of turbine price, i.e. $72,000/MW.

7.3.2 Electrical system reinforcement parameters, C_2 & D_2

This stage of the procedure occurs when the wind generation proposed for any area exceeds the maximum demand in the area, thus requiring network reinforcement. Any network reinforcement is likely to be at the highest levels of the distribution system (e.g. 150 kV) or at transmission voltages, not at 35 kV.

All new large generation projects will require some degree of network reinforcement. It is assumed that, when comparing competing options, the costs of reinforcement are included in the costs of each option. As large wind plants are often sited far from demand centres, the costs of transmission system reinforcement may be higher than for other generation options.

From information available to GH, it was found that the costs per MW of the wind farm electrical system are not affected by the higher connection voltage. This is because the higher fixed costs are spread over a larger wind farm capacity.

Overhead line
Based on information from wind farm connections, the following costs were obtained for overhead lines:

- 150 kV: $1000/km/MW
- above 150 kV: $800/km/MW

Within the level of accuracy of other estimates, it was justifiable to use a single figure of $1000/km/MW. These figures include design, construction and permitting.

Underground cable
The use of overhead lines has been assumed in this study. If the use of underground cable was thought necessary – perhaps due to public antipathy towards new overhead transmission lines – then a cost ratio of 10:1 has been stated for the voltage levels in question [27], which results in a cost of $10,000/km/MW.

Utility Costs
The costs for connection of overhead lines to the existing electricity networks are not well known, for the reasons stated in Section 7.3.1. GH information indicated a figure of $15,000/MW for major transformers, and a total cost of approximately $25,000/MW for substations. The net effect, assuming overhead lines, was:

$$D_2 = 25{,}000 + 1{,}000 * L \qquad (\$/MW)$$

where L is the length of the required reinforcement.

As noted earlier, C_2 was effectively infinite, as no further cost breakpoints were necessary. Because this study considered a maximum of 60 MW in each N×N square, C_2 was set to (60 - C_1) MW.

It was therefore necessary to determine values of L for the study areas. Each of the countries in the European study area was examined to determine the average distance from the preferred wind areas to the major load centres. The results are shown in Table 7.3. Note that these results assume no additional cross-border electricity trading as a result of the introduction of large-scale wind generation. This assumption is conservative.

Country	**Average distance of transmission reinforcement required (onshore case), L [km]**	**Average distance of onshore transmission reinforcement required (offshore case), M [km]**
Austria	300	N/A
Belgium[1]	150	200
Denmark	100	50
Finland	100	100
France	200	250
Germany	300	350
Greece	300	300
Ireland	200	50
Italy	600	200
Luxembourg[1]	150	200
Netherlands[1]	150	200
Portugal	200	200
Spain	250	250
Sweden	200	100
UK	200	100

1 Benelux countries treated as one unit.

Table 7.3: Average distance of transmission reinforcement required, EU-15

7.3.3 Alternative procedure, D_0

The cost of connection for wind farms connected directly to a nearby transmission line, called D_0, was based on the figures in Section 7.3.2 and was estimated to be:

- 4 km (average) at $1,000/km/MW;
- fixed cost of $25,000/MW.

Therefore D_0 = $29,000/MW.

Note that this option was not used for the rest of the world regions.

7.4 Grid Connection Costs: EU-15 Offshore

For the offshore analysis, the method was as follows.

As already described in Section 6.4, offshore costs were based on wind farms of 100×2 MW turbines. This was felt to be a reasonable assumption because all indications are that the costs of offshore wind favour large installations[18].

Internal information available to GH indicated a cost of transmission to shore of \$4,500/km/MW. The distance to landfall was determined by the GIS. However, other sources of cost data show:

- \$17,000/km/MW for a proposed 300 MW wind farm 15 km offshore in Dutch waters (assumed to include the electrical system within the wind farm) [28]
- \$19,000/km/MW for new submarine connections between the Channels Islands and France, which includes new substations, protection and control equipment, and an onshore component equivalent in distance to the submarine component [29]
- \$12,500/km/MW for a new submarine connection between the UK mainland and the Isle of Man, which includes substations at either end (105 km, 40 MW) [30]

Therefore, a revised figure of \$9,000/km/MW was used.

The offshore wind farms required transmission system reinforcement to transfer their output to the load centres. Therefore D_0, C_1 and D_1 for offshore wind farms were zero. Based on maps of the European transmission system, the average length of transmission system reinforcement *M* was determined and is shown in Table 7.3. The method used was similar to that used to determine *L* for the onshore case, and the parameter D_2 was calculated as stated in Section 7.3.2.

7.5 Determination of Parameter Values: India, Onshore

7.5.1 Existing electricity system

Parameter C_1 could be determined for any region of the study area from knowledge of the population density and parameter C_1' as derived in Table 7.1.

Parameter D_1 was likely to be different from the EU15 costs, as costs of electrical equipment and labour will be less in India. From [31], it was found that installed costs of 33 kV electrical equipment and overhead lines were approximately half the cost of the equivalent items in the EU. This was an approximate value only, but was considered to be sufficiently accurate for the purposes of this study. The resulting values of D_1 were:

- Rural areas: \$31,500/MW
- Sparsely populated areas: \$71,500/MW

7.5.2 Electrical system reinforcement

Parameter C_2 was infinite, as noted earlier.

For parameter D_2, the wind map for India produced as part of this study was compared with population density data and the known electricity network information. It was concluded that:

[18] e.g. Danish plans are based on arrays of 150 MW.

- Wind conditions were fairly uniform across much of India, with the best conditions along the west coast and the Himalayan foothills in the north east
- The windy areas in Jammu and Kashmir will be severely reduced by other restrictions, so network reinforcement costs for that area can be ignored

Therefore, most wind generation will be located relatively close to dense population. A nominal figure of 200 km for network reinforcement was assumed. This was an approximate figure only, but greater accuracy would have required significantly greater effort.

Therefore D_2 was set to \$112,500/MW.

7.5.3 Alternative procedure

As electrical equipment costs are approximately half of those in Europe, a figure of \$14,500/MW was used.

7.6 Determination of Parameter Values: India, Offshore

Offshore wind farms will be major projects involving international contractors and international financing. Therefore the costs of the offshore electrical equipment for Europe will also apply for India.

As there is high population density along the major part of India’s coast, the parameter M for the required onshore network reinforcement was chosen to be 100 km.

7.7 Determination of Parameter Values: USA, Onshore

7.7.1 Existing electricity system

Parameter C_1 could be derived from knowledge of the population density and parameter C_1’, as derived in Table 7.1. No information was readily available to allow C_1’ to be determined for each state.

Available electrical cost data [32] indicated that costs were similar to the cost data derived for Europe, and that distances to the existing grid were also similar. Therefore the European values of D_1 were used.

7.7.2 Electrical system reinforcement

Parameter C_2 was infinite, as before.

For parameter D_2 , comparison of the US wind map produced as part of this study with population density resulted in estimated distances for transmission reinforcement as shown in Table 7.4.

This analysis included export from each state where necessary (for example, from Montana and Wyoming).

State	Average distance of transmission reinforcement required (onshore case), L [km]	Average distance of transmission reinforcement required (offshore case), M [km]
Washington	200	50
Idaho	200	-
Montana	800	-
Maine	200	50
Minnesota	600	-
North Dakota	900	-
Oregon	200	50
New Hampshire	200	50
Vermont	200	-
Wisconsin	200	-
New York	300	50
Michigan	250	-
South Dakota	900	-
Wyoming	1200	-
Massachusetts	100	50
California	100	50
Rhode Island	50	50
Connecticut	50	50
Nevada	200	-
Pennsylvania	100	-
Iowa	100	-
Utah	1000	-
Nebraska	900	-
New Jersey	100	50
Ohio	100	-
Illinois	150	-
Indiana	100	-
Colorado	1200	-
W Virginia	100	-
Delaware	100	50
Maryland	100	50
Washington DC	50	-
Virginia	100	150
Missouri	300	-
Kansas	600	-
Kentucky	200	-
Arizona	200	-
North Carolina	400	150
New Mexico	600	-
Tennessee	300	-
Oklahoma	300	-
Texas	400	50
Arkansas	300	-
South Carolina	100	150
Georgia	100	150
Alabama	100	50
Mississippi	100	50
Louisiana	200	50
Florida	100	150

Table 7.4: Average distance of transmission reinforcement required: USA[19]

[19] Note that high values of L have been assumed in some areas, especially to the north and west of the Great Plains. As noted in the Main Report, these may partially offset the economic advantages conferred by the excellent wind resource in these areas

7.7.3 Alternative procedure

As costs and distances were expected to be similar to those assumed for Europe [32] the value of D_0 derived in Section 7.3.3 was used.

7.8 Determination of Parameter Values: US, Offshore

Note that, as elsewhere in this study, inland water bodies such as the Great Lakes were ignored.

The assumptions made for Europe in Section 7.4 apply in this case. Parameter D_2 was determined using the lengths of onshore network connection M listed in Table 7.4.

7.9 Determination of Parameter Values: China, Onshore

7.9.1 Existing Electricity System

Parameter C_1 was derived from knowledge of the population density and parameter C_1’ as shown in Table 7.5. Unlike the US and India, information was available which allowed C_1’ to be calculated for each province [25, 33].

For Europe, the US and India, maximum demand data was used to determine C_1’ (Table 7.1). However, no maximum demand data was available for China. Instead, an estimate of the maximum demand for each of the thirteen major power networks in China was calculated from the annual consumption data, using a figure of 0.18 GW/TWh. This ratio was determined by calculating the ratio of maximum demand to annual consumption for each of the EU 15 countries, India and the US. The results ranged from 0.147 (Luxembourg) to 0.196 (US), which was remarkably narrow given the differences in climate, economy and size. The ratio for India was 0.183.

The thirteen major power networks cover all provinces and autonomous regions except Tibet/Xizang. The figure given in the table for Tibet is therefore an estimate, chosen to be at the lower end of the range. However, Tibet was almost entirely excluded from the analysis due to the removal of the areas labelled “Unknown” in the PNL map as described in Section 5.3.1.

No cost data were readily available, and so the costs used for India (i.e. half European costs) were also used for China. The resulting values of D_1 were:

- Rural areas; $31,500/MW
- Sparsely populated areas: $71,500/MW

Note that values of C_1’ in Table 7.5 were based on recent data. It is likely in China and India that the distribution system will grow more rapidly than the population, i.e. parameter C_1’ should increase in future. However, as it is not known how much this parameter will increase, the conservative assumption was made that C_1’ remains constant.

Province or Region	Maximum Demand per capita (C_1') [kW/person]	Average distance of transmission reinforcement required (onshore case), L [km]	Average distance of transmission reinforcement required (offshore case), M [km]
Anhui	0.131	200	-
Fujian	0.110	200	100
Gansu	0.124	500	-
Guangdong	0.172	200	100
Guangxi Zhuang AR	0.061	200	100
Guizhou	0.070	200	-
Hainan	0.063	400	100
Hebei	0.160	150	100
Heilongjiang	0.176	200	-
Henan	0.082	200	-
Hubei	0.082	250	-
Hunan	0.082	200	-
Inner Mongolia AR	[1] 0.165	400	-
Jiangsu	0.131	300	100
Jiangxi	0.082	300	-
Jilin	0.176	200	-
Liaoning	0.176	200	100
Ningxia Hui AR	0.124	300	-
Beijing	0.160	30	-
Qinghai	0.124	700	-
Shaanxi	0.124	300	-
Shandong	0.120	300	100
Shanghai	0.131	20	100
Shanxi	0.160	300	-
Sichuan	0.065	300	-
Tianjin	0.160	20	100
Tibet/Xizang AR	[2] 0.070	900	-
Xinjiang Uighur AR	0.124	900	-
Yunnan	0.069	300	-
Zhejiang	0.131	300	100

1. Estimate: Inner Mongolia is covered by both the North China Power Network and the North East China Power network.
2. No data: estimate. Development of wind farms is totally excluded from this region in the analysis.

Table 7.5: Electrical cost parameters for China.

7.9.2 Electrical system reinforcement

Parameter C_2 was infinite, as before. For parameter D_2, the wind map for China produced as part of this study was compared with available network data and with physical maps. It was concluded that:

- It was safe to assume that there will be negligible export to other countries
- There will be no export from any of the coastal or central provinces
- Any surplus in Qinghai will be exported to Sichuan and the Lanzhou area
- Any surplus in the windy areas near Beijing will go to Beijing
- Any surplus in Xinjiang will go to Lanzhou and Xian

From this, the parameter L was estimated for each province as shown in Table 7.5. Using this parameter, D_2 was calculated, as in Section 7.3.2, using electrical costs which were half European costs.

7.9.3 Alternative procedure

As for India, a figure of $14,500/MW was used.

7.10 Determination of Parameter Values: China, Offshore

The offshore electrical costs were assumed to be as for Europe.

The onshore electrical costs were assumed to be half European costs. The distances of onshore transmission reinforcement required were estimated in a similar manner to Section 7.9.2, and are listed in Table 7.5.

7.11 Rest of the World

This section summarises the electrical cost data used for modelling the cost-resource curves for the rest of world.

The cost parameters were the same as used for the four study regions. Parameter C_2 was infinite, as before. D_o was set to zero because the transmission network data from the Digital Chart of the World were not used for the rest of the world analysis.

7.11.1 Assumptions

The costs of the electrical system within the wind farm were the same as for the four study regions.

For onshore wind farms, the average distance of transmission system reinforcement required (L) was estimated for each subdivision of the Rest of the World without looking at the relative locations of windy areas and populated areas in detail. A figure of 200 km was adopted throughout. The average values of L for the EU15, India and China are of this order.

For offshore wind farms, the distance of onshore transmission system reinforcement required (M) was estimated for each subdivision of the rest of the world. In all cases except the former Soviet Union and Eastern Europe, it was concluded that in general the population centres were located close to coasts, so a relatively low value of M was appropriate. For the former Soviet Union and Eastern Europe, a low figure was also chosen (100 km). This was applicable for the offshore areas in the Baltic and in the region of Vladivostok, which have relatively high wind speeds, but was inappropriate for the relatively low-wind speed areas of the northern coast which are far from population centres and are also subject to severe ice movements[20]. Using one value of M for this entire region will introduce errors, but the resulting overall error is expected to be relatively small, and will affect only the highest-cost end of the cost-resource curves.

[20] As noted previously, land and sea north of 70°N was excluded from the analysis

7.11.2 Results

The results are tabulated below.

	ONSHORE			OFFSHORE
	C'_1 [kW/person]	D_1	L [km]	M [km]
Africa	0.05	As India	200	100
Australia	1.9	As EU15	200	50
Latin America(S)	0.2	As India	200	100
Latin America(N)	0.2	As India	200	100
Middle East	0.2	As India	200	100
Thailand etc	0.2	As India	200	100
Indonesia etc	0.05	As India	200	50
New Zealand	1.8	As EU15	200	50
Japan	1.5	As EU15	200	50
FSU & E Europe	0.8	As EU15	200	100

Table 7.6: Electrical parameters used for Rest of the World analysis

8 NUMERICAL ANALYSIS

8.1 Onshore

8.1.1 Social constraints

A vital issue in a study such as this is the density at which to allow wind energy to be developed. There are areas of Denmark where it is recognised that onshore wind energy is already close to its acceptable limit. In April 1999 GH met with representatives of one such area, Ringkøbing Municipality, and ascertained the following:

- Wind energy developments must be >2 km apart and are defined in 3 categories:
  - Single turbine
  - 2 –3 turbines "group"
  - > 3 turbines - "wind farm"
- The total area of the Municipality is about 400 km^2 and wind energy development is excluded from about two thirds of this due to environmental designations
- The total population of the Municipality is about 17,500, of which approximately half is in Ringkøbing town, some 4,000 in 3 other towns and 5,000 scattered in rural areas
- Installed capacity in 1996 was 28 MW from 150 turbines (average turbine size 187 kW)
- Planned capacity is 40 MW by 2000, and could only by exceeded by increasing average turbine size
- Height limits (to the top of the rotor swept area) are 70 m in the coastal zone, and 75 m elsewhere
- The noise limit at inhabited dwellings is 45 dBA, although effectively 40-42 dBA is limit
- Turbines must be sited >300 m from isolated residences and >500 m from town areas
- Grid reinforcement is still not an issue
- Existing turbines are being replaced with larger, quieter machines. This involves digging up and removing the old foundations and constructing new from scratch.

The above limit of 40 MW represents an average density of 100 kW/km^2 across the Municipality. It seems not unreasonable to expect that this limit could, with the advent of larger turbines, be increased by 50% to 150 kW/km^2. The onshore wind turbines modelled in this study are 750 kW machines with 50 m hub heights. Only 80 such machines would represent 60 MW capacity instead of the 150 turbines in place in 1996. Moreover, the height limit suggests that significantly larger turbines than these would fall foul of planning regulations.

It is debatable whether the situation in a small part of one (highly developed) country should represent the global situation. Public attitudes to wind energy will depend on many factors, not least whether wind farms are simply replacing conventional generation where adequate capacity already exists (as in Denmark) or reducing a shortfall in capacity resulting in additional direct social and economic benefits from new or improved electrification. Thus, while the 150 kW/km^2 limit was applied globally in the analysis, it was found necessary to relax other social constraints to reflect actual development patterns in countries in the latter category.

The default density limit of 150 kW/km^2 was a useful figure, but it was decided that this should be reduced further at a local level if the population density was high enough. This was achieved by estimating the area of land restricted from development due to proximity to dwellings. This estimation was based on the following assumptions:

- *X* % of the rural population is clustered into a negligible area (villages, hamlets etc.)
- The remaining (100 - *X*) % is uniformly distributed spatially
- On average there are *Y* persons per dwelling
- No part of any wind farm can be within *Z* m of an inhabited dwelling

Unacceptable area per cell was thus: $\dfrac{p_r * \left(\dfrac{Z}{1000}\right)^2 * \pi}{Y * (100 - X)}$ km^2

For the analysis, the values for *X*, *Y* and *Z* were set in the header files when running the "Onshore" C++ code (see Table 8.2 in Section 8.2). The following values were initially applied in all regions:

- *X* = 90 % clustered into negligible area
- *Y* = 4 people per dwelling
- *Z* = 300 m

However, it was found that these population constraints, though reasonable for the EU-15 and other industrialised regions, resulted in over-severe constraints in India and China which do not reflect actual patterns of wind farm development there to date[21]. While the study approach is generally based on even-handed treatment of all regions, it was deemed necessary in this case make an exception to reflect very different actual wind farm development patterns in industrialising regions which will be a consequence of:

- increased local benefits from wind farms in regions with power shortages due to new electrification of homes and industries with resulting economic benefits
- commensurately more relaxed development control criteria
- commensurately more positive public attitudes to wind energy

A sensitivity analysis in India established that it was necessary to increase the rural population density threshold above which development is completely prohibited by a factor of 4 from the above level (of approximately 140 people/km^2) to include actual wind farm development in the modelled distribution. This factor could be interpreted as reducing the exclusion radius *Z* from 300 to 150 m, or adjusting other factors e.g. increasing the proportion of rural population in villages from 90 to 97.5% or the average number of people per household from 4 to 16 or some combination of these. In practice it was applied to all regions with the above characteristics by reducing *Z* to 150 m (see Table 8.1).

This was no more than a pragmatic arithmetical adjustment to accommodate different actual wind farm development patterns in regions such as the EU-15 and India more accurately. It should not be interpreted literally in terms of exclusion radius alone, nor does it purport to be based on any rigorous supporting demographic theory.

[21] For example, these constraints completely precluded development in almost all of those areas in India where over 900 MW of capacity has been installed to date.

Capacity > Demand (Z = 300 m)	Demand > Capacity (Z = 150 m)

• Australia
• EU-15
• FSU and Eastern Europe
• Middle East
• Rest of Asia:
  • Japan
  • New Zealand
• USA
	• Africa
	• China
	• India
	• Latin America
	• Rest of Asia:
	  • Indonesia
	  • Mainland Asian countries (Thailand, Korea, Vietnam etc.)

Table 8.1: Allocation of population constraints to regions

Unacceptable area was deducted by successively "removing" 1 km cells from the N×N array, starting with the cells of lowest AEY. Removal of a 1 km cell resulted in its AEY being set to zero.

The following notes apply:

- Population was assumed to favour less windy areas, hence the lowest AEY cells were removed first. However, since the resolution of AEY estimates was reduced to 10×10 km by final stage of their estimation (the compensation for GUACA errors described in Section 4) this only made a difference in the small wind farms scenario[22].
- Sea, lakes and urban areas were assumed to be uninhabited by rural populations and such cells were excluded from the above removal process.
- All other constrained areas (e.g. forests) were assumed to be inhabited with the same rural population density as unconstrained areas.
- An averaged rural population density d_r was calculated and applied to all N_r such cells as follows:

$$d_r = \frac{\sum_{1}^{N_r} p_r}{N_r}$$

This facilitated analysis even if the N×N array contained 1 km squares with different non-zero rural populations. However, for each N×N array it was assumed that the default maximum capacity C_{lmax} was 60 MW, requiring 10×1 km cells. The effect of the above was therefore only significant when it resulted in <10×1 km cells with non-zero AEYs remaining available.

8.1.2 Large and small onshore scenarios

It was considered that wind energy could develop along two rather different patterns: Those typical of Northern Europe – small wind farms widely scattered, termed the "Small Onshore Scenario" – and those typical of the USA – large wind farms concentrated in windy areas, termed the "Large Onshore Scenario". It is not at all clear which pattern of development will predominate in the future, or where, so it was decided to model both scenarios world-wide. For the purposes of this study, and particularly for the interpretation of its results, it should be assumed that the most likely pattern of onshore wind farm development will be in between these two scenarios..

[22] However, this assumption fundamentally underpins the compensation method described in Section 4.

Both scenarios implemented the above capacity density limit of 150 kW/km^2, though through different interpretations. Both divided the region being analysed into many smaller areas. For the small onshore scenario, this “local” area was 20×20 km. For the large onshore scenario, it was 10×10 km. Within these areas both scenarios aimed to utilise up to 10×1 km^2 cells for wind energy development. At a density 6 MW per km^2, this allowed up to 60 MW of wind energy to be developed within each area.

For the small onshore scenario, the 60 MW in 20×20 km limit was already equivalent to the accepted capacity density limit of 150 kW/km^2. The 60 MW maximum was potentially reduced through social constraints (see Section 8.1.1), therefore the overall capacity density for a region would be 150 kW/km^2 or less.

For the large onshore scenario, the initial 60 MW in 10×10 km limit was four times the capacity density limit of 150 kW/km^2. However, the latter limit was subsequently imposed in the study regions at state level in the post-processing of capacity ranked by cost. This approach meant that the overall density for a region was likely to be exactly 150 kW/km^2. Social constraints determined by rural population density were still significant on a local basis, but it would require a region to be densely populated everywhere for social constraints to reduce the regional density to much below 150 kW/km^2.

8.2 Analytical Stages: Study Regions

A detailed method for establishing the amount and cost of onshore wind energy installations was developed by GH. This is shown graphically in Figure 8.1 and described in detail below.

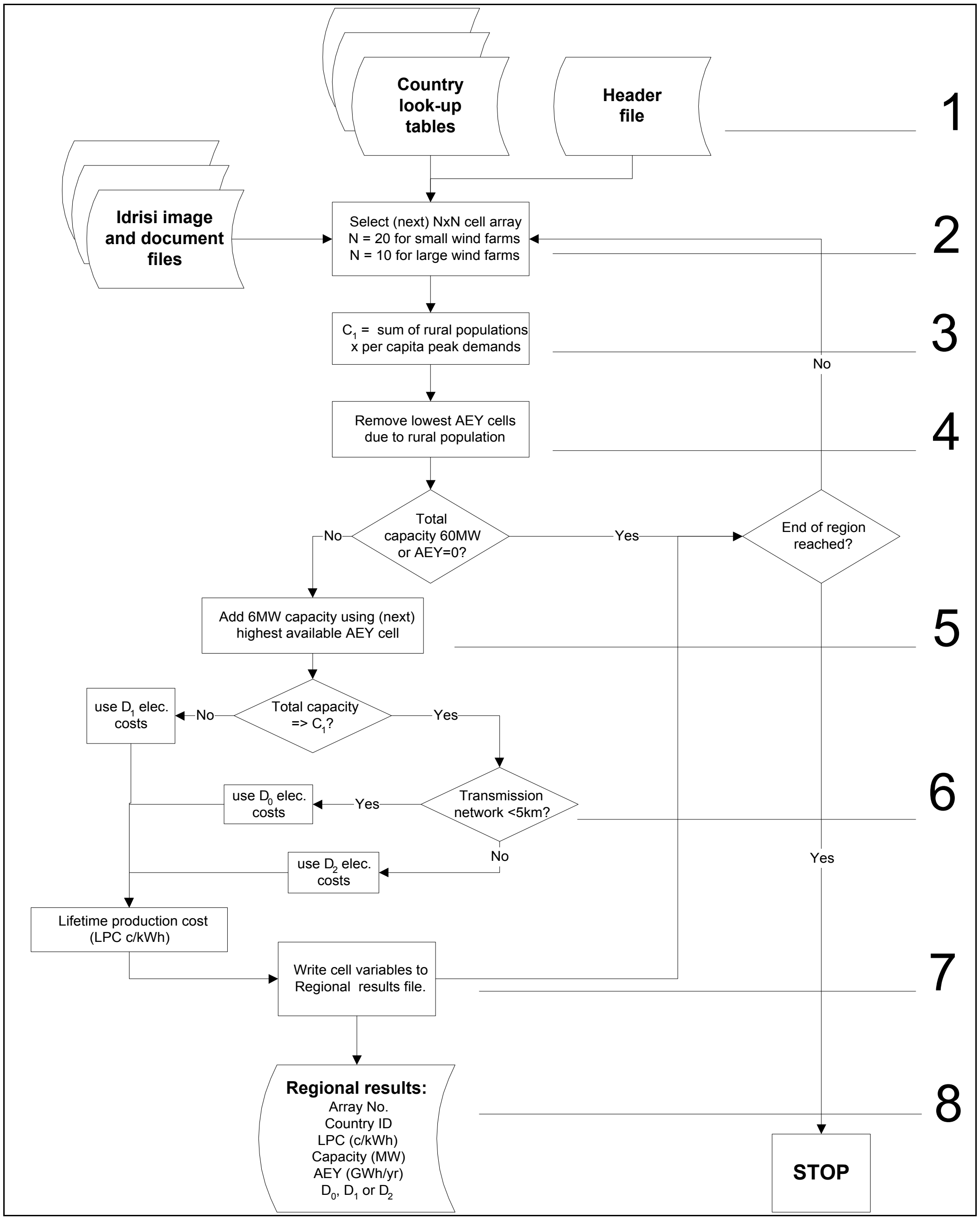


Figure 8.1: Method used to establish onshore wind energy capacity and costs

Stage 1 - Header information
This stage involved preparation of text files holding parameter settings for the analysis at region and state level. These are detailed in Table 8.2.

Parameter	Example
Region	CHINA
AEY file	mwh50net
Transmission file	et_5km
Country file	china_st
Population file	rpopdens
Year	2020
Occupancy factor	4
Acceptable distance (m)	150
Isolation factor (%)	10
No. of states	30
Cell Capacity (MW)	6
Available cells	10
Size of Big Square	10
Transmission line (1=OVD/0=UGD)	1
Use D0 costs(1=yes/0=no)	1
Onshore (1=yes/0=no)	1
Cost Reduction (%p.a.)	1
Net Efficiency (%)	90
Interest Rate (fraction)	0.1
Base wind farm costs ($/kW)	1000
Design Life (years)	20

Table 8.2: Regional header files

Look-up tables for each of N study region states was provided in N files (*state1.txt* - *stateN.txt*). The information contained in these files is detailed in Table 8.3.

Parameter	Example
Name	Hubei Sheng
Area (km sq.)	185779
Peak demand per capita (kW)	0.082
Transmission distance (Km)	250
Population (GIS)	59430550
Population (2000)	62727955
Population (2020)	73747561
Rural population factor (2000)	100
Rural population factor (2020)	65.45

Table 8.3: State specific header files

Stage 2 - Datasets for local analysis
N×N cell arrays were extracted from region maps, themselves derived from GIS analysis. There were four maps used in the analysis -

- Available AEY at 50 m a.g.l.(adjusted for air density);
- Population;
- Country ID;
- A boolean map, showing areas within 5 km of existing transmission lines.

Stage 3 - Determination of local network capacity
The costs for electrical connection to the existing grid were dependent on the capacity of the local grid which was approximated through a relationship with local population. This is explained further in Section 7.1.1.

Stage 4 - Constraints on wind energy due to local population
In this study, it was important to avoid putting wind farms everywhere that is not technically or environmentally constrained as such a scenario is simply unrealistic. One way around such blanket coverage was the imposition of acceptable density levels. In addition to this, the analysis used local population information to restrict development further. The method employed is described in detail in Section 8.1.1.

Stage 5 - Incremental addition of local wind energy capacity
Each N×N array was analysed independently. Once any further constraints due to local population were taken into account, the analysis found the next available cell with the highest AEY and established the costs for that cell. This process continued until either the next highest AEY was zero, or 10 cells (i.e. 60 MW) had been developed.

Stage 6 - Determination of grid connection costs
Standard wind farm costs were used except for the electrical connection. These costs were dependent on various local and state-specific parameters. The methods used to determine these costs are detailed in Section 7.

Stage 7 - Determination of lifetime production costs (LPC)
Once capital costs had been established (Stage 6), they were then combined with AEY to arrive at a lifetime production cost (LPC, c/kWh), discounted over the lifetime of the wind farm. This is detailed in Section 8.3.

Stage 8 - Output results
The output of the analysis was a text file holding, for each 1 km cell to which was assigned a (6 MW) wind farm:

- LPC [c/kWh]
- Capacity (in 6 MW increments)
- AEY [MWh]
- Country ID
- Electrical costs used

The file was then imported to an Access database for further aggregation and sorting of the data. This is discussed further in Section 9.

8.3 Offshore

Analysis of the offshore resource was simpler than that for onshore.

There were four input maps:

- Offshore state ID;
- Distance from shore;
- Depth;
- AEY at 60 m.

There was one input header file, containing the information detailed in Table 8.4.

Parameter	Example
Region	CHINA
AEY file	off_mwh
Height (m)	60
Depth file	depth
Distance file	off_dist
State file	off_st
No. of states	30
Cell capacity (MW)	8
Max distance (km)	50
Year	2020
Cost reduction (% p.a.)	1
Net efficiency (%)	90
Turbine rating (MW)	2
No. of turbines	100
State 3 name	Fujian
State 3 L-dist (km)	100
State 5 name	Guangdong
State 5 L-dist (km)	100
State 6 name	Guangxi
State 6 L-dist (km)	100

Table 8.4: Header information for offshore analysis

Each 1 km cell was assigned 8 MW capacity, with initial costs based on those given in Section 6.4[23]. The installation, electrical connection and foundation costs were calculated based on the depth and distance from shore for that 1 km cell, and the electrical cost parameters specific to that state ID. The revised wind farm costs for that 8 MW unit, together with the net AEY available, were then used to establish the LPC for that cell. The LPC, AEY, capacity (8 MW) and State ID were then output to file for post-processing.

The analysis is shown schematically in Figure 8.2 overleaf.

[23]Assuming a wind farm of 100×2 MW turbines, 15 m depth and 20 km to shore, 8 MW = 8000x1676 = $13.4M.

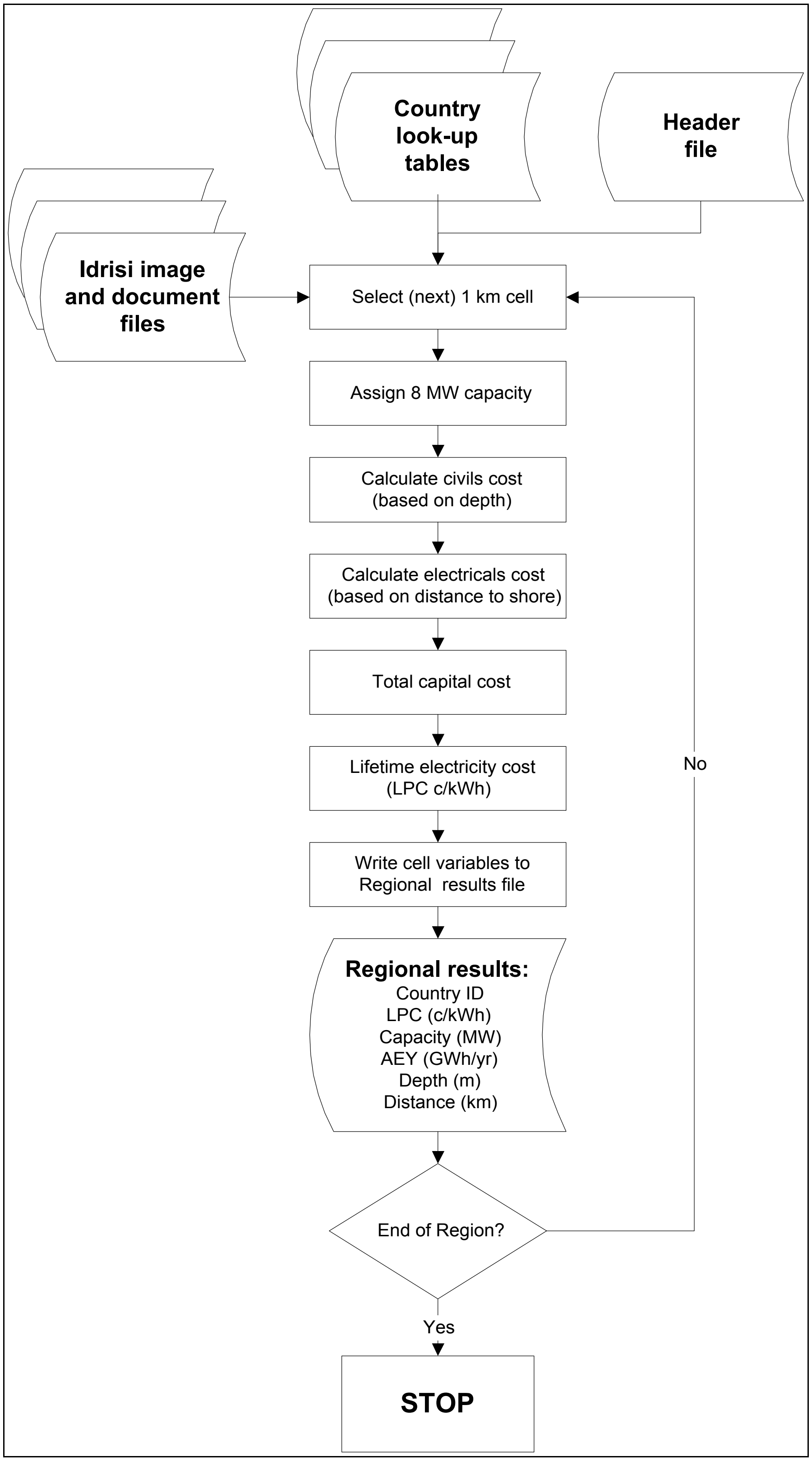


Figure 8.2: Method used to establish offshore capacity and costs

8.4 Lifetime Production Costs

8.4.1 S-curve costs

The standard assessment criteria (Appendix C) specified the need to include in the analysis the cost of borrowing during construction. A typical S-curve expenditure profile was implemented for both onshore and offshore projects. A construction time of 3 months was assumed for onshore developments and 9 months for offshore developments. The details are provided in Table 8.5 and Table 8.6 below.

In summary, onshore wind farm costs were increased by 0.68 % while offshore costs were increased by 2.06 %.

Month	Spend (incremental) [%]	"Cost" of spend [%][1]
12	35	0
11	45	0.359
10	20	0.320
9	0	0
8	0	0
7	0	0
6	0	0
5	0	0
4	0	0
3	0	0
2	0	0
1	0	0

1 as % of total capital cost

Table 8.5: Spend in year 0, onshore scenarios

Month	Spend (incremental) [%]	"Cost" of spend [%][1]
12	35	0
11	0	0
10	0	0
9	45	1.085
8	0	0
7	0	0
6	20	0.976
5	0	0
4	0	0
3	0	0
2	0	0
1	0	0

1 as % of total capital cost

Table 8.6: Spend in year 0, offshore scenario

8.4.2 Formulae and assumptions

The ultimate requirement of the numerical analysis was to turn AEY figures (supplied in the form of a map at 1 km resolution) into Lifetime Production Cost figures (in US cents/kWh).

This was achieved as follows :

Annuity factor, a

$$a = \left(\frac{1}{R}\right) * \left(1 - \left(\frac{1}{(1+R)^{DL}}\right)\right)$$

where
R = Interest Rate, given as a fraction (i.e. 10 % = 0.1)
DL = Design Life, given in years.

Discounted O & M costs, D_R

$$D_R = cap\_costs * OM_p * a$$

where
cap_costs = total capital outlay for 1 km cell (i.e. 6 MW)
OM_p = annual O & M costs, given as a percentage of capital costs per annum
a = annuity factor

Discounted "other" costs, D_x

$$D_x = cap\_costs * O_p * a$$

where
cap_costs = total capital outlay for 1 km cell (i.e. 6 MW)
O_p = other costs, given as a percentage of capital costs per annum
a = annuity factor

Lifetime Production Cost, LPC

$$LPC = \left(\frac{1}{a}\right) * \left(\frac{cap\_costs + D_R + D_x}{AEY}\right)$$

where
a = annuity factor
cap_costs = total capital outlay, in US cents
D_R = discounted lifetime O & M costs, in US cents
D_x = discounted lifetime other costs, in US cents
AEY = Annual Energy Yield, in kWh

The following assumptions applied.

Interest Rate, R = 10%

Design Life, DL = 20 years

Percentage O & M, OM_p = 2% (of capital outlay, per annum)

Percentage of other costs, O_p = 1.25% (of capital outlay, per annum)

All wind energy developments had an overall efficiency of 90 %.

8.5 Rest of the World

The rest of the world regions were analysed in almost exactly the same way as the four study regions. The approach differed only in the following aspects:

- There was no state level of information;
- There was no transmission system map (hence D_0 was never utilised for electrical costs).

9 POST-PROCESSING

9.1 Onshore: Study Regions

The output file from the onshore numerical analysis was in ASCII form and contained the following parameters for each 1 km cell (6 MW) that was utilised for wind energy.

- LPC
- AEY
- Capacity (6 MW)
- State ID
- Electrical costs

These data were post-processed in Access to provide capacity and AEY increments ordered by LPC and in a user-defined step size. This was applied first to individual states, in capacity increments of 60 MW. The LPC assigned to each 60 MW increment was the greatest of the ten 6 MW increment LPCs. These ordered state data were then combined (at 60 MW resolution) to establish the same information for the study region as a whole. The regional data were output in increments of 600 MW. This process was exactly the same for both small and large onshore scenarios except that the large onshore scenario had the state results capped at a capacity for that state equivalent to 150 kW/km^2.

The incremental data output from Access were then passed to Excel to create the cumulative cost/resource curves which Econ required for their analysis.

9.2 Offshore: Study Regions

The output file from the offshore numerical analysis was in ASCII form and contained the following parameters for each 1 km cell (or 8 MW).

- LPC;
- AEY;
- Capacity (8 MW);
- State ID;
- Distance from shore;
- Water depth.

These data were passed to Access for post-processing. The post-processing allowed various parameters to be set when sorting the data, namely:

- Minimum distance from shore (5 km);
- Percentage of sea bed available for development (25 %, as discussed in Section 5.3.2);
- Maximum depth to be considered (40 m);
- Regional and state output increment (200 MW).

The incremental data output from Access were then passed to Excel to create the cumulative cost/resource curves which Econ required for their analysis.

9.3 Rest of the World

For the offshore and small onshore scenarios, the rest of the world regions were post-processed in exactly the same manner as the four study regions, except that only region-wide results were established. However, the method employed for the large onshore scenario in the study regions had utilised knowledge of the geographical scope of the interior states of each region to "cap" capacity at the 150 kW/km^2 limit for each state in turn. This information was not available for the rest of the world regions, so a method was developed which synthesised the effect of the capacity capping implemented for the four study regions, as follows.

The results from the four study regions were combined to provide four curves:

- Cumulative capacity, capped and uncapped
- Cumulative AEY, capped and uncapped

These curves are shown in Figure 9.1 and Figure 9.2 below. Each curve-pair (i.e. capped and uncapped) was then summarised into 500 LPC bins from minimum LPC to 20 cents/kWh. The ratio of capped to uncapped values was then calculated for each bin. These ratios are shown in Figure 9.3.

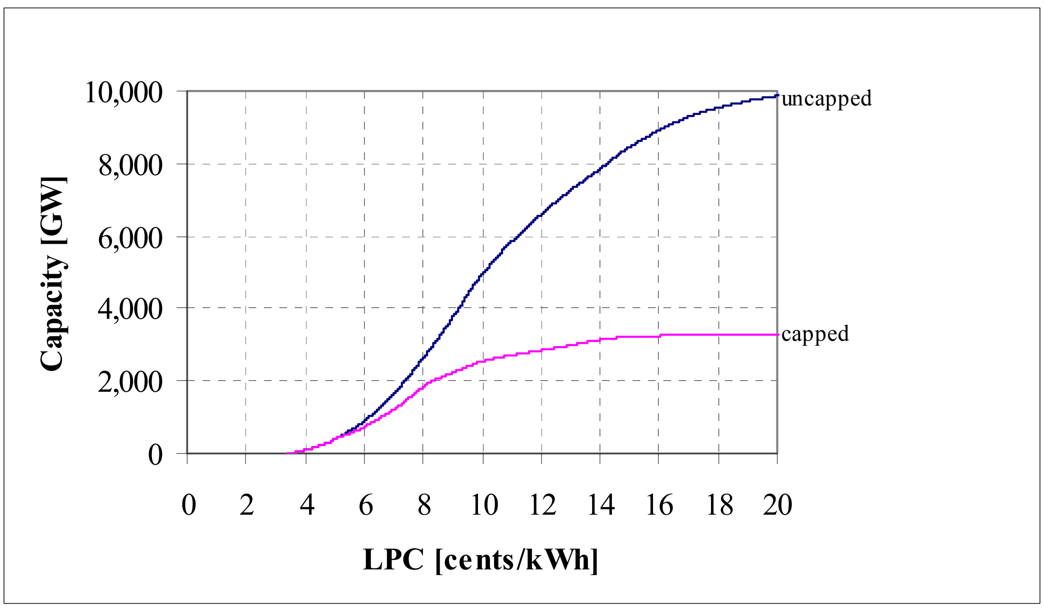


Figure 9.1: Large onshore capacity, capped and uncapped

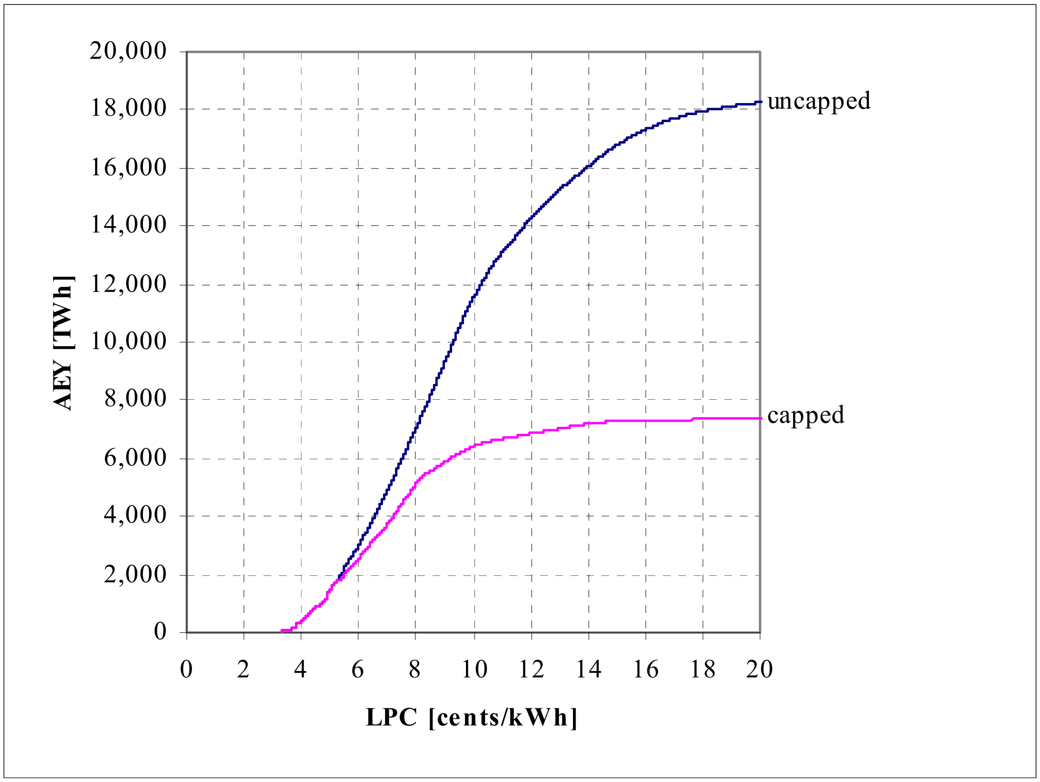


Figure 9.2: Large onshore AEY, capped and uncapped

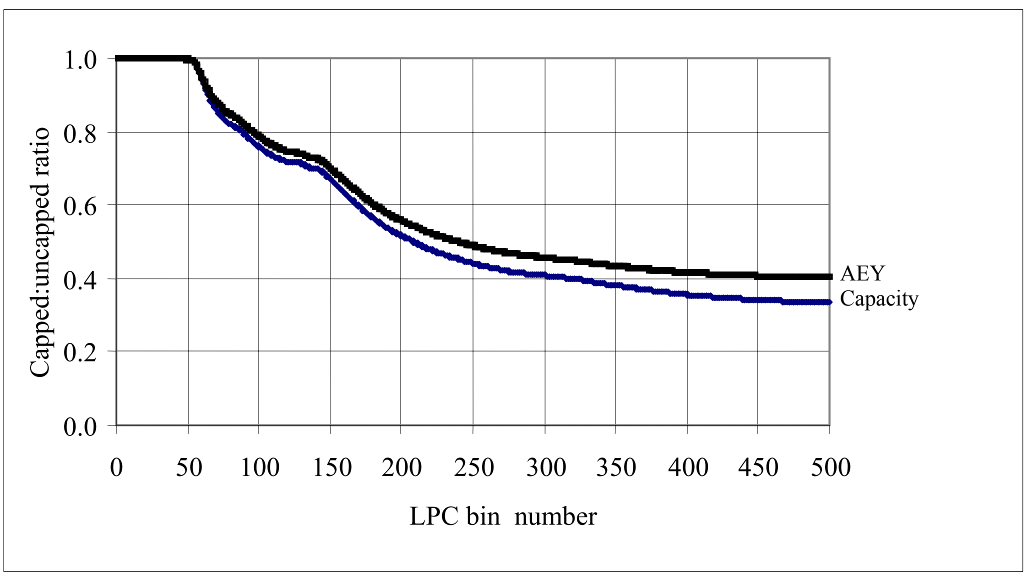


Figure 9.3: Ratios established for capacity and AEY

The large onshore results for the rest of the world regions were then synthesised by first establishing the uncapped cumulative curves, binning these from minimum LPC (the same in each case) to 20 c/kWh, then finally applying the ratios presented in Figure 9.3 to those bins.

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ANNEX I IUCN designations

The definition of a protected area adopted by International Union for the Conservation of Nature (IUCN) is: "an area of land and/or sea especially dedicated to the protection and maintenance of biological diversity, and of natural and associated cultural resources, and managed through legal or other effective means."

The IUCN recognises that "although all protected areas meet the general purposes contained in this definition, in practice the precise purposes for which protected areas are managed differ greatly."

The main purposes for which protected areas are managed (or indeed actively not managed as the case may be) are considered to be the following -

- Scientific Research
- Wilderness protection
- Preservation of species and genetic diversity
- Maintenance of environmental services
- Protection of specific natural and cultural features
- Tourism and recreation
- Education
- Sustainable use of resources from natural ecosystems
- Maintenance of cultural and traditional attributes

Thus the IUCN has adopted a system for categorising protected areas according to the management objective and/or the reason for designation. The first 6 categories are reproduced below. The level of active human intervention generally increases from I-VI.

CATEGORY Ia: Strict Nature Reserve: protected area managed mainly for science

Definition: Area of land and/or sea possessing some outstanding or representative ecosystems, geological or physiological features and/or species, available primarily for scientific research and/or environmental monitoring.

CATEGORY Ib : Wilderness Area: protected area managed mainly for wilderness protection

Definition: Large area of unmodified or slightly modified land, and/or sea, retaining its natural character and influence, without permanent or significant habitation, which is protected and managed so as to preserve its natural condition.

CATEGORY II : National Park: protected area managed mainly for ecosystem protection and recreation

Definition: Natural area of land and/or sea, designated to (a) protect the ecological integrity of one or more ecosystems for present and future generations, (b) exclude exploitation or occupation inimical to the purposes of designation of the area and (c) provide a foundation for spiritual, scientific, educational, recreational and visitor opportunities, all of which must be environmentally and culturally compatible.

CATEGORY III : Natural Monument: protected area managed mainly for conservation of specific natural features

Definition: Area containing one, or more, specific natural or natural/cultural feature which is of outstanding or unique value because of its inherent rarity, representative or aesthetic qualities or cultural significance.

CATEGORY IV : Habitat/Species Management Area: protected area managed mainly for conservation through management intervention

Definition: Area of land and/or sea subject to active intervention for management purposes so as to ensure the maintenance of habitats and/or to meet the requirements of specific species.

CATEGORY V : Protected Landscape/Seascape: protected area managed mainly for landscape/seascape conservation and recreation

Definition: Area of land, with coast and sea as appropriate, where the interaction of people and nature over time has produced an area of distinct character with significant aesthetic, ecological and/or cultural value, and often with high biological diversity. Safeguarding the integrity of this traditional interaction is vital to the protection, maintenance and evolution of such an area.

CATEGORY VI : Managed Resource Protected Area: protected area managed mainly for the sustainable use of natural ecosystems

Definition: Area containing predominantly unmodified natural systems, managed to ensure long term protection and maintenance of biological diversity, while providing at the same time a sustainable flow of natural products and services to meet community needs.

****

The categories are not intended as a league table, rather they are designed to facilitate comparisons at an international level. Thus IUCN say that "regions like Europe with long-settled, long-managed landscapes in multiple ownership are not, on the whole, as suited to the establishment of Category II areas - but on the other hand, their circumstances are more conducive to the establishment of Category IV and V areas. IUCN does not favour different standards being used in the application of these categories in different parts of the world, as this would counter the value of having a defined standard."

In the United Kingdom for instance, Sites of Special Scientific Interest (SSSIs) form the mainstay of areas designated on all but landscape criteria. European and international designations generally follow the SSSI series. Only those SSSIs which were previously designated as an National Nature Reserve (NNR) are considered appropriate for IUCN category IV. National Scenic Areas (NSAs) are the UK's main landscape designation, and fall into IUCN category V.

Thus the UK does not contain any areas which qualify for categories I-III. For instance, the IUCN state that "the habitats and landscapes of Scotland are man-modified and so categories IV and V are generally the most appropriate."

The IUCN recommends that at the very least 10% of the Earth's land surface should be maintained as natural forest. In an attempt to quantify sustainable land use in 'Environmental Space' calculations, Friends of the Earth translate IUCNs recommendation into a requirement to protect (from development and excessive intrusion) at least 10% of the total land area, which must include 10% of the forest area of each country.

The reasoning behind the Friends of the Earth protected area requirements rest on biodiversity considerations and the flexibility of species to adapt to change. Ideally, protected areas should comprise a system of 'corridors' through which species can migrate if and when environmental changes occur.

Friends of the Earth Europe define a protected area as IUCN category I-III.

A designation is a consideration for a wind farm development when the wind farm could conceivably impact upon the qualities for which an area was designated.

Experience and studies to date suggest that the foremost environmental constraints on wind farm developments are the perception of landscape quality and any adverse effects on bird populations.

Biodiversity impacts in theory should relate to any disturbance caused by construction and access roads, and in the context of conventional power stations are minimal. Characteristics of a particular site may rule out a wind farm on biodiversity grounds, but on a global scale this is very difficult to determine.

Data on protected areas is available in GIS format as IUCN categories, and thus any approach to taking out inappropriate areas for development must necessarily use the IUCN categories. Categories 1b 'Wilderness Area', III 'Natural Monument', V 'Protected Landscape' and 1a 'Strict Nature Reserve', would appear to require consideration as to the merits of disregarding all or part of these areas for development, on grounds of visual and cultural intrusion.

IUCN categories do not specifically identify areas important for birds, and any bird designations should in any case be treated with caution as any effect of wind farms on bird populations is highly dependent on the particular site-specific circumstances. In addition, potential effects on bird populations may be mitigated through micrositing considerations. Thus an initial recommendation is to include IUCN category IV 'Habitat/Species Management Area' in areas considered for wind farms, pending identification of spatial datasets on bird populations and migration routes and any other relevant datasets.

Category II 'National Park' again appears to allow for environmentally and culturally compatible exploitation which does not impact upon the reason for designation. Further investigation as to the nature and extent of Category II is required in order to recommend its treatment in this study.

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APPENDIX B

ANALYTICAL METHOD – ENERGY MODELLING, ELECTRICITY DEMAND OUTLOOK AND COST ASSUMPTIONS

CONTENTS

1 ENERGY MODELLING

1.1 Overview of Power Model Structure

Figure 1.1 provides a simplified view of the power sector model structure. 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 impact 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.

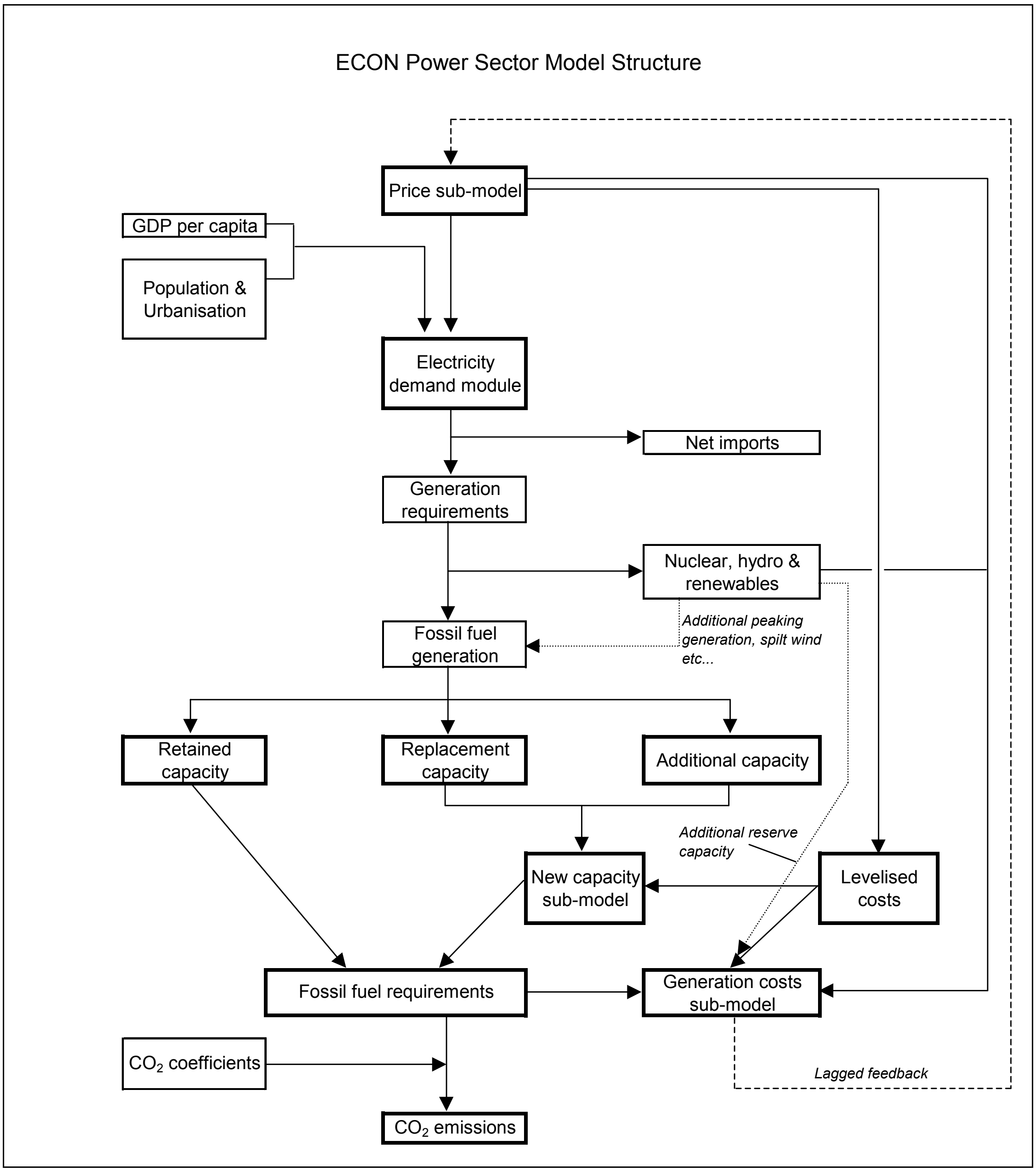


Figure 1.1: Simplified flow diagram of power sector model structure

The model first determines the level of electricity demand based on the rate of growth in GDP per capita, the rate of population growth and urbanisation, as well as the price of electricity. There is a lag on the price of electricity such that changes in each period's cost of generation feed through into the next period's level of demand. Net imports are then subtracted from the electricity demand to determine the call on indigenous generation. Net imports are an exogenous factor.

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 justified because of the lower operating costs of nuclear, hydro and renewable generation vis-à-vis existing fossil-fuelled generation which mean that they will always be dispatched, when available, ahead of fossil-fuelled plants. Even though the full cost of generation from these sources may be higher than the full cost of fossil-fuelled generation, the marginal costs tend to be a lot lower. It is the marginal cost that determines the dispatching of existing capacity.

The future development of these generation types is treated exogenously for a number of reasons:

- nuclear because of its political nature;
- hydro because of the limited resource potential and environmental constraints;
- renewables because of similar resource constraints as well as special measures designed to encourage their uptake.

Fossil-fuelled generation covers the residual output, including the need for additional peaking output or to cover spilt wind that results from technical constraints on dispatching wind power. The choice of fossil 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 model is not a stock model and does not have the age profile of all the existing capacity. As a result, it is assumed that a certain percentage of installed capacity is retired each year. The rate of retirement is set assuming an economic life of 25 years, which implies a rate of turnover of 4% per annum.

The choice of additional and replacement capacity is based on the least cost technology and fuel combination using full levelised 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 from 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, establish the end-use electricity prices which feed back into electricity demand.

1.2 Wind Energy Modelling

1.2.1 General approach

Wind generation is treated exogenously, along with the other renewable technologies. The introduction of wind generation, however, 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 are expected to decline. The generation cost from other technologies also varies and we are able to compare the relative cost of wind energy over time. The 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.

1.2.2 Specific wind generation issues

The introduction of large-scale wind generation, however, raises a number of issues including:

- the need for additional grid strengthening;
- the impact on spinning reserve;
- additional back-up capacity;
- additional peaking capacity;
- the extent of wind spillage or curtailment at high penetrations.

All of these issues have been discussed at length Section 8 of the Main Report The need for any additional grid strengthening and any additional operating costs are included in the wind energy cost curves shown Sections 4 to 7 of the Main Report. 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 remaining three issues in this stage of the analysis.

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 increase it resembles more closely a fixed block of generation; 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.

Putting a figure on the additional peaking requirement and back-up capacity needed in a high penetration scenario is difficult given the limited practical experience. It is also difficult to determine what is meant by low and high penetration. The studies reviewed in Section 8 of the Main Report suggest that wind penetrations of up to 10% can be accommodated within the existing generation system and structure, while a ceiling of 50% may represent the maximum wind share. The maximum occurs when the back-up and spilt wind start to match the level of dispatched wind capacity.

In the model, the amount of system peaking generation is increased once wind exceeds 10% of the total electricity output. The total reserve/back-up capacity rises exponentially with wind's market share to accommodate failures/outages of wind capacity. The amount of spilt wind increases from 0% at 25% wind penetration to 40% at 100% wind penetration. This is explained further in the following sections.

1.3 Adaptations to the Power Model

1.3.1 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 no capacity credit has been assumed for wind generation. It also means that sufficient reactive 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.

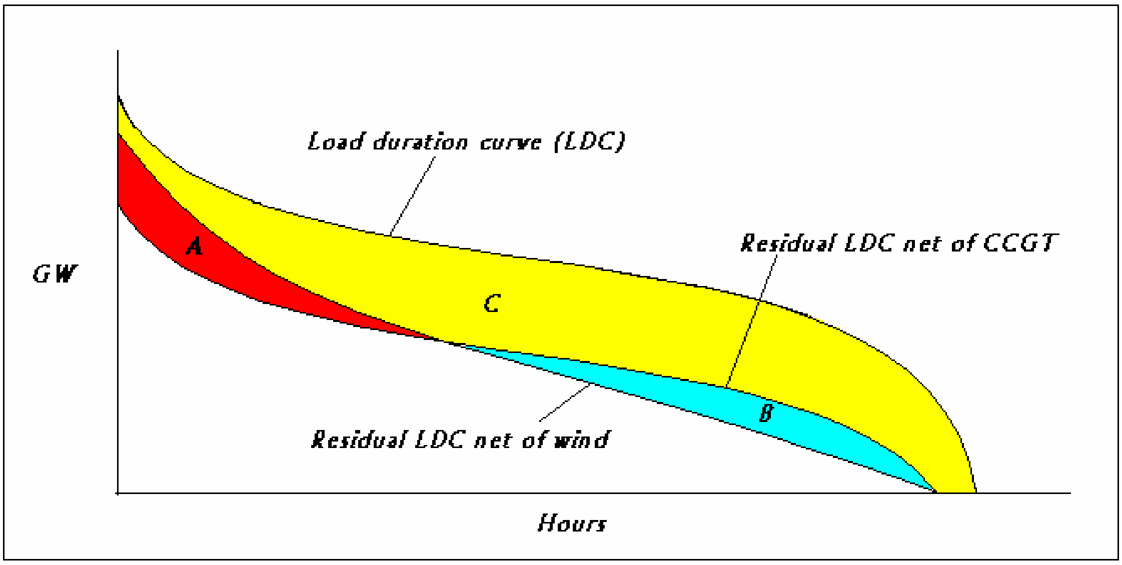


Figure 1.2: Impact of wind energy on the load duration curve

This can be seen in Figure 1.2, which shows a stylised load duration curve (LDC), the same curve once a given amount of wind generation has been deducted and when the same amount of conventional CCGT generation is netted out. 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 1.2**.

Figure 1.3 shows the assumptions made about 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 increases by assuming the peaking requirement remains the same for a wind system regardless of the amount of wind generation. This is not the case with conventional CCGT capacity, where adding more generation lowers the peaking requirement. By comparing the two peaking requirements for the same additional generation the size of 'A' can be estimated.

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 wind 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% there is no significant difference. This is also because as the amount of generation increases it resembles more closely conventional capacity and there is less additional peaking requirement.

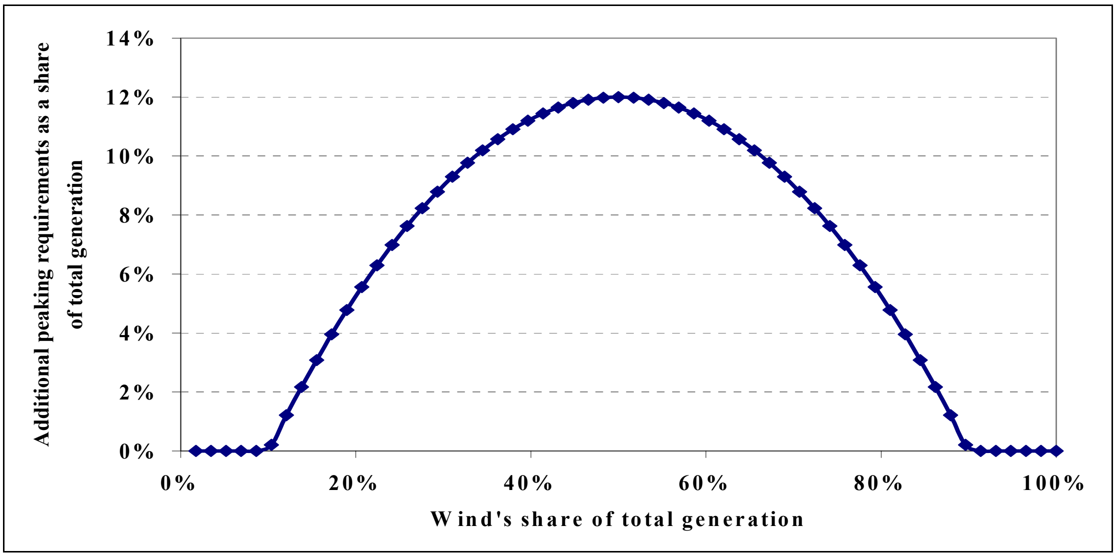


Figure 1.3: Proportion of additional peaking generation as wind's share of total generation increases

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 this is deducted from the additional peaking requirement before any thermal plant is introduced.

Accurate figures for this amount of spare hydro capacity are not available. It is therefore assumed that if the level of hydro output is less than 10% of the total output it is likely that it is already being used to meet peaking needs, or what can be used for peaking purposes is being used. In this situation it is assumed that there is no further hydro capacity available to meet additional peaking requirements. Any hydro output over the 10% threshold is assumed to be currently dispatched at base-load and could, therefore, be used to meet additional peaking needs. The advantage of this approach is that the spare hydro is a function of total demand. As electricity costs increase due to increased wind output, total electricity demand declines and the amount of spare hydro capacity increases.

Table 1.1 shows the outlook for hydro output in 2020 and how much is available to meet any additional peaking demand. This "spare" hydro output is shown for the base case and when there is the maximum amount of wind dispatched on the system. The final column shows the maximum dispatched wind output. The USA has no spare hydro output, while China has between 45% and 50% of its hydro output available. India has between 25% and 30% available and the EU-15 10% to 15%.

TWh	Hydro output	Spare hydro (Base case)	Spare Hydro (max dispatched wind)	Max dispatched wind
China	650	294	311	2400
EU-15	343	40	50	1200
India	188	47	52	600
USA	369	0	0	2000

Table 1.1: "Spare" hydro available to meet additional peaking requirements (2020)

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.

1.3.2 Wind spillage and curtailment

Section 8 (Table 8.1) of the Main Report showed the proportion of wind dispatched as a share of total wind available as the share of wind energy in total generation increased. An equation based on the proposed wind utilisation share has been estimated. Figure 1.4 shows the percentage of available wind energy spilt as wind's share of total generation increases based on our equation. No wind energy is split until wind's share of total generation exceeds 25%.

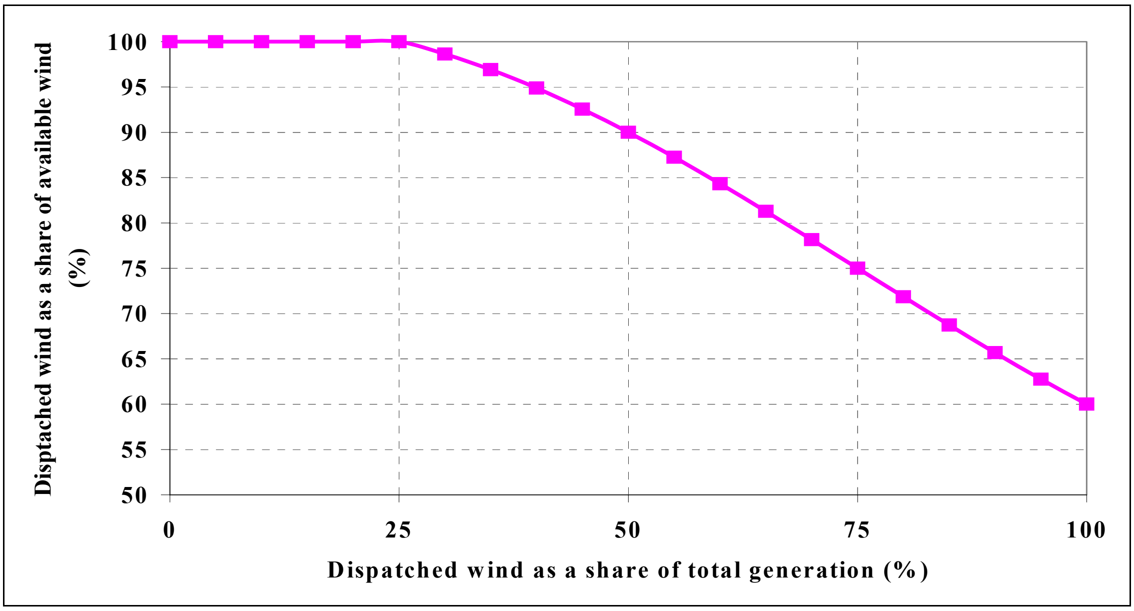


Figure 1.4: Relationship between dispatched wind's share of total generation and share of available wind energy

1.3.3 Capacity fee

Capacity fee is calculated as the average non-fuel costs of thermal plants (primarily coal and gas) for a 15% reserve margin[1]. However, as wind penetration increases, so does the reserve margin. The dependence is exponential, such that at low wind penetrations the impact is virtually non-existent, whilst at higher penetrations it is significant. The additional capacity fee is fed through into the overall generating costs as shown in Figure 1.1.

The model formulation is as follows:

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

where capacity fee and average capacity costs are measured in \$/kWh. The above equation can be derived from the following expression:

$$\textit{Reserve margin cost (\$)} = \textit{reserve margin}(15\%+85\%\times e^{1.5})\times \textit{peak capacity(kW)}\times \textit{capacity cost (\$/kW)}$$

where e = (wind generated energy (TWH/year)/total generated energy (TWh/year))

Multiplying the right hand side by hours per hour gives:

$$\textit{Cost (\$)} = (15\%+85\%\times e^{1.5})\times kWh\times \$/kWh$$

Dividing both sides by kWh gives:

$$\textit{Cost (\$/kWh)} = (15\%+85\%\times e^{1.5})\times \$/kWh$$

The capacity fee is then added to the unit generating costs to represent the system cost of maintaining back-up capacity.

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

For example, if wind generated energy is 10% of the total, the reserve margin increases from 15% to 18%, but if wind accounts for 50% of the total, the reserve margin increases to 45%. At a 100% wind penetration, the reserve margin is also 100%.

1.3.4 Uplift charge

This reflects the grid operator's costs, including provision of ancillary services such as reactive power and frequency control. It is calculated as approximately 1% of the total generating cost in the base case, and is included in the "Capacity Fee" components in Figures 9.4, 9.7, 9.10 and 9.13 in the Main Report. The uplift charges are fed into the price sub-model shown in Figure 1.1.

As noted previously, the additional costs imposed by wind generation for reinforcing the existing grid and constructing new transmission lines are already included in the wind energy cost curves.

1.4 Electricity Demand Module

The outlook for electricity demand is linked to the growth in GDP per capita, and therefore to the growth in population, as well as the urbanisation and the price of electricity. GDP per capita is by far the most important of these factors, whilst price elasticities tend to be relatively low reflecting the unsubstitutability of electricity in an increasing number of applications and appliances.

The equation used to calculate electricity demand is of the generalised form:

$$\textit{Elc. Demand per capita} = \alpha \times (\textit{Price Elc.})^{\varepsilon 1} \times (\textit{GDP per capita})^{\varepsilon 2} \times (\textit{Urbanisation})^{\varepsilon 3}$$

Where α is a function of electricity efficiency improvements (i.e. α declines as the efficiency increases, reducing the level of electricity demand). The elasticities for each parameter for each country are shown in Table 1.2.

	Electricity Price Elasticity (ε1)	GDP per capita Elasticity (ε2)	Urbanisation Elasticity (ε3)
China	-0.10	0.85	0.20
India	-0.10	1.00	0.30
EU-15	-0.20	0.80	0.20
US	-0.10	0.70	0.20

Source : Econ

Table 1.2: Electricity demand elasticities

Figure 1.5 and Figure 1.6 show the relationship between electricity demand and GDP for the four regions/countries covered in the study. For the EU-15, India and China the historical data is from 1980 to 1997, while for the US historical data has been obtained from 1949 to 1997. The figures also show the forecast electricity demand for the period up to 2030. They clearly show that the US has a more electricity intensive economy than the EU-15, but that the Indian and Chinese economies are even more electricity intensive. Figure 1.6 also points to similar gradients in the slope of the curves, implying that the elasticities attached to GDP are not too dissimilar between the countries/regions.

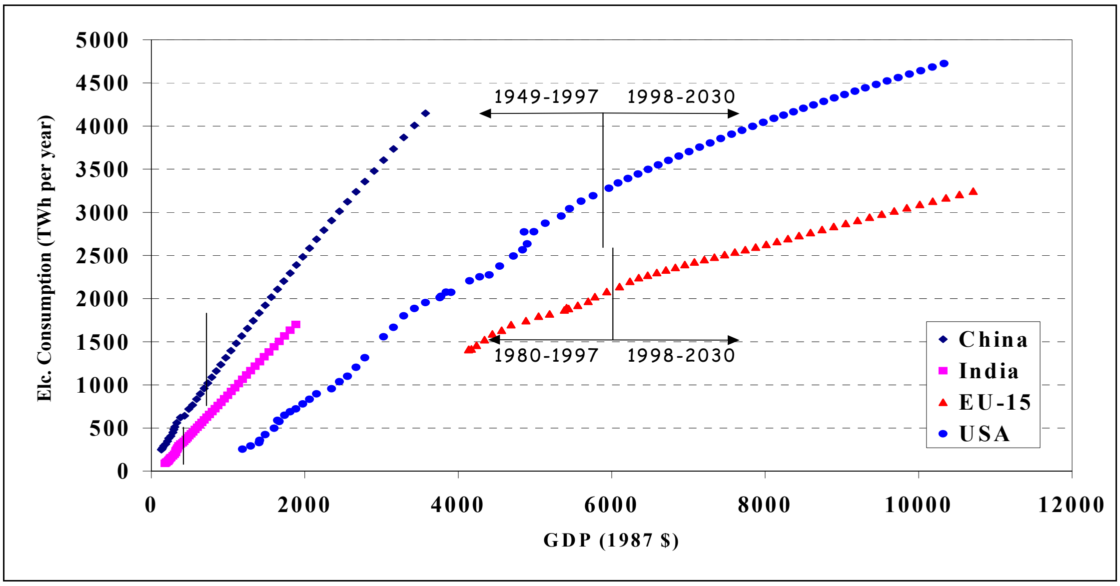


Figure 1.5: Relationship between electricity demand and GDP

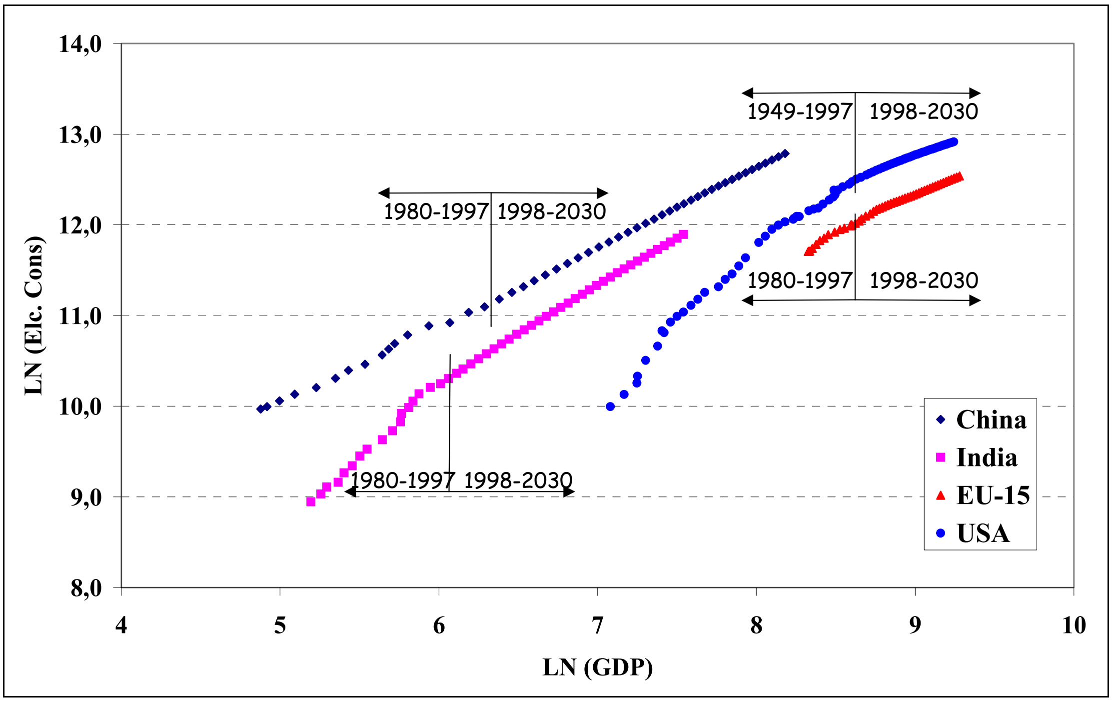


Figure 1.6: Relationship between the log of electricity demand and the log of GDP

2 GDP, POPULATION AND URBANISATION ASSUMPTIONS

2.1 Real GDP Per Capita

Econ used the trend growth rates for real GDP per capita for the USA, EU-15 and India. The Chinese growth rates are complicated by the lack of accurate historical data, but are expected to be at the top end of historical trends seen elsewhere: the World Development Report indicates that South Korea has been the fastest growing economy since the 1960s, with real GDP per capita growing by an average of 7.5% p.a. between 1960 and 1995. In the 35 years between 1980 and 2015, Econ anticipates that China's real GDP per capita will have grown by an annual average of 6.9%, and by 4.0% p.a. between 2015 and 2020.

	1980-85	1985-90	1990-95	1995-00	2000-05	2005-10	2010-15	2015-20
China	8.36	5.88	10.74	7.08	6.20	5.40	4.40	4.00
EU-15	1.27	2.78	1.46	1.95	1.60	1.60	1.60	1.60
India	3.14	4.02	1.92	3.44	3.30	3.30	3.30	3.30
USA	1.59	1.77	1.12	1.87	1.40	1.40	1.40	1.40

Source : US EIA - 1980-96 ; Econ 1997-2020

Table 2.1: Real GDP per capita growth rates (% p.a.)

2.2 Population

Growth in the population of the EU-15 is expected to fall from around 0.30% p.a. to 0.15% between 1995 and 2020. The EU-15's population is expected to exceed 390 million by 2020, compared with 375 million today. In the USA, the rate of growth in the population is currently running at around 1.0% p.a., but US DOE figures indicate that they expect the rate of growth to slow to around 0.15% p.a. by 2015, remaining at this level until 2020. The USA population should reach almost 300 million by 2020, up from just under 270 million today.

In China the rate of growth in the population has been running at just over 1.0% p.a., but is widely anticipated to fall to around 0.8% p.a. by the turn of the century. The growth rate is expected to fall steadily to around 0.4% p.a. by 2020, with the population reaching 1.43 billion in 2020, compared with 1.25 billion today. India has the fastest growing population, averaging 1.9% p.a. between 1990 and 1995. The rate of growth is expected to fall, but only drops below 1.0% p.a. after 2020. India's total population is expected to reach 1.31 billion in 2020, up from 950 million today.

	1985	1990	1995	2000	2005	2010	2015	2020
China	1059	1155	1222	1273	1320	1362	1398	1428
EU-15	359	366	373	378	382	386	389	392
India	751	835	916	999	1081	1161	1239	1312
USA	238	250	263	273	282	290	294	297

Source : US EIA - 1980-96 ; Econ 1997-2020

Table 2.2: Population (millions)

2.3 Real GDP

Table 2.3 indicates the corresponding growth rates in real GDP when the real GDP per capita figures are combined with the population figures. These figures are broadly consistent with the outlook from other sources, such as the US DOE and the IEA/OECD.

Econ's forecast for real GDP growth in China is slightly more conservative than the US DOE's outlook, but their major report was produced prior to the Asian economic fall out that has led to most economic forecasts for China being revised down. The IEA/OECD, in their latest World Energy Outlook, expects real Chinese GDP to grow by 5.5% between 1995 and 2020, while Econ has a figure of 6.1% for the same period. Econ's figures for the Indian economy are consistent with the IEA's outlook for Southern Asia, and take account of the lower growth expectations in the light of the sanctions imposed on the country following its nuclear tests.

	1980-85	1985-90	1990-95	1995-00	2000-05	2005-10	2010-15	2015-20
China	9.88	7.75	11.98	7.96	6.97	6.06	4.95	4.44
EU-15	1.46	3.15	1.87	2.21	1.82	1.81	1.75	1.75
India	5.36	6.25	3.83	5.24	4.95	4.79	4.64	4.49
USA	2.53	2.73	2.16	2.66	2.04	1.93	1.73	1.55

Source : US EIA - 1980-96 ; Econ 1997-2020

Table 2.3: Real GDP growth rates (% p.a.)

2.4 Urbanisation

The level of urbanisation is an important factor in assessing future energy requirements and infrastructure needs. In developing countries it is estimated that more than half of GDP originates in cities[2], and is therefore a major source of energy demand. In addition, the urban population tend to have a higher energy requirement that further compounds the importance of urban conglomerates in national energy requirements.

As Figure 2.1 overleaf indicates, urbanisation is already high in the US and the EU-15, where the urban population represents almost 80% of the total, and is expected to increase marginally over the period up to 2020 - the urban population reaches 86% in the US, 88% in the EU-15.

[2] "1997 World Development Indicators" The World Bank (April 1997)

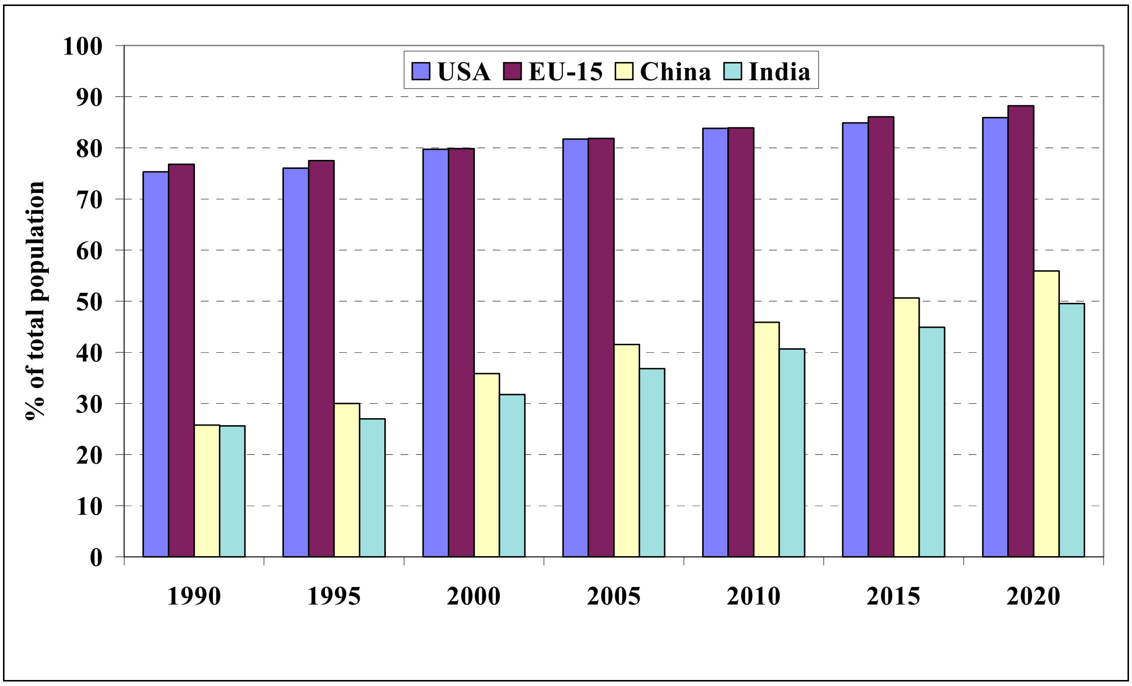


Figure 2.1 : Urbanisation Outlook

In China and India, the levels of urbanisation are much lower at 33% and 30% respectively, but are expected to increase significantly over the next twenty years. By 2020, the urban population is expected to account for 56% of the total Chinese population and 50% of the Indian population. The World Bank notes[3] that 22% of the world population was urban in 1960, rising to 34% in 1990 and is expected to reach 50% by 2015. Both China and India are, below the global average, but their rate of urbanisation is consistent with the World Bank's outlook.

	1990-95	1995-00	2000-05	2005-10	2010-15	2015-20	1995-2020
China	3.09	3.62	3.00	2.00	2.00	2.00	3.16
EU-15	0.18	0.60	0.50	0.50	0.50	0.50	0.72
India	1.08	3.30	3.00	2.00	2.00	2.00	3.94
US	0.18	0.96	0.50	0.50	0.25	0.25	0.97

Source : The World Bank - 1990-95 ; Econ 1996-2030

Table 2.4: Growth Rate in Urban Population

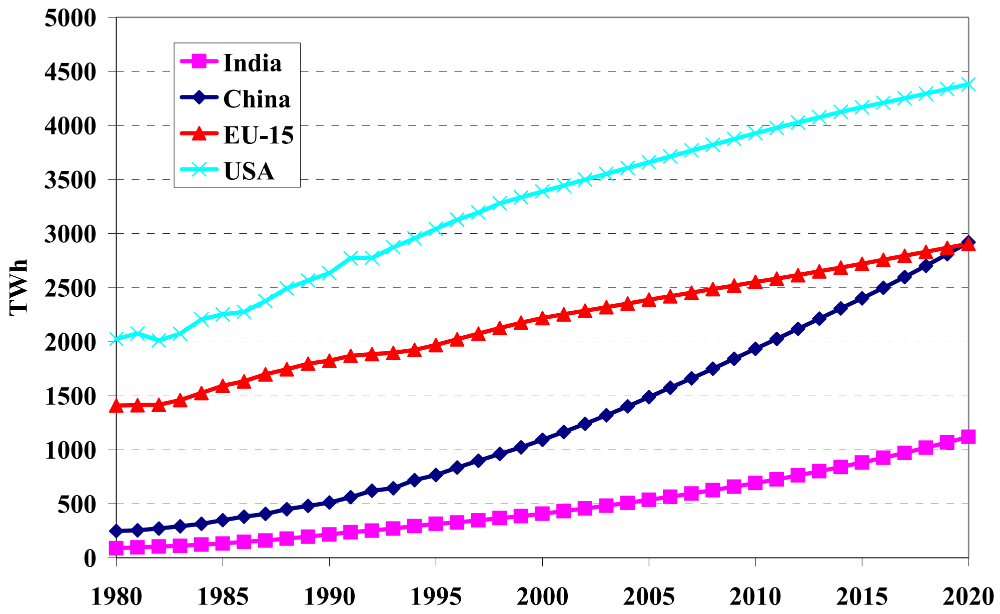
[3] "1997 World Development Indicators" The World Bank (April 1997)

3 ELECTRICITY DEMAND OUTLOOK

3.1 Forecast Electricity Demand

3.1.1 Overview and key indicators

Table 3.1 to Table 3.3 show the growth rates in electricity consumption and the level of consumption per unit GDP and per capita for the four study regions. Consumption per unit real GDP declines in all instances with the exception of India, while consumption per capita increases without exception. The growth in China's electricity consumption per capita is consistent with a rapidly developing economy, even if its consumption per unit GDP does not perform to the norm (see Figure 3.2). The consumption per capita figures help to support Econ's view of the growth in electricity consumption.



Source : IEA - 1985-96 ; Econ 1997-2030

Figure 3.1: Total final electricity consumption (TWh)

	1980-85	1985-90	1990-95	1995-00	2000-05	2005-10	2010-15	2015-20
China	7.00	7.98	8.45	7.28	6.35	5.36	4.42	3.99
EU-15	2.46	2.76	1.55	2.68	1.32	1.16	1.20	1.26
India	8.27	10.19	7.88	5.35	5.60	5.14	4.99	4.85
USA	2.15	3.17	2.93	2.22	1.47	1.34	1.11	0.94

Source : IEA - 1980-96 ; Econ 1997-2030

Table 3.1: Growth in electricity consumption (% p.a.)

	1985	1990	1995	2000	2005	2010	2015	2020
China	1655	1673	1425	1380	1340	1297	1265	1237
EU-15	358	351	346	354	345	334	325	318
India	567	680	824	828	854	868	883	898
USA	527	538	558	546	531	516	501	486

Source : IEA & US DOE - 1985-96 ; Econ 1997-2030

Table 3.2: Electricity consumption per unit real GDP (Wh/$1987)

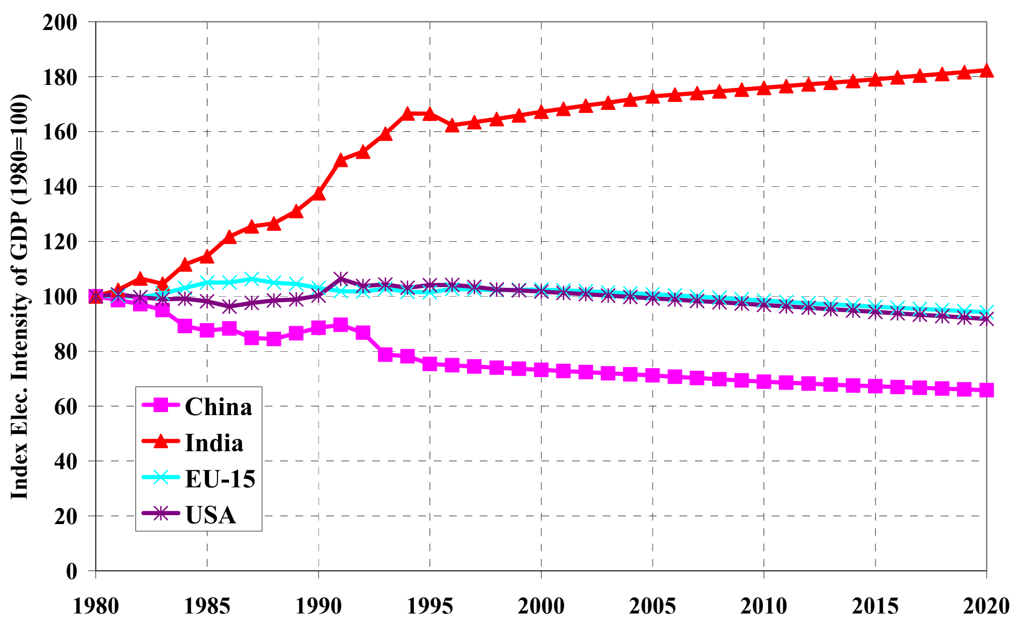
	1985	1990	1995	2000	2005	2010	2015	2020
China	329	442	628	856	1123	1413	1709	2035
EU-15	4432	4988	5280	5948	6281	6586	6939	7333
India	177	258	344	409	497	594	710	850
USA	9468	10540	11567	12420	12949	13486	14021	14583

Source : IEA & US DOE - 1985-96 ; Econ 1997-2030

Table 3.3: Electricity consumption per capita (kWh per person.)

	Cons./GDP	Cons./Capita
China	-0.56	4.82
EU-15	-0.34	1.32
India	+0.34	3.68
USA	-0.55	0.93

Table 3.4: Rate of change in electricity intensities 1995 to 2020 (% p.a.)



Source : IEA & US DOE - 1985-96 ; Econ 1997-2030

Figure 3.2: Index of Electricity Intensity of Real GDP (1980 = 100)

3.1.2 China

In China, growth in electricity consumption has not matched the growth in real GDP. Real GDP has grown by an annual average of 9.9% between 1980 and 1995, while electricity consumption has risen by 7.8% p.a. over the same period. In fact the differential has widened since 1990 from 1.4 percentage points prior to this date to 3.6 percentage points since. This could be due to Chinese GDP having been over-estimated in recent years. In general, countries undergoing a rapid development phase tend to experience a faster increase in electricity consumption than GDP. On the other hand, it could be that under-reporting of electricity consumption is the reason for this apparent discrepancy.

It is forecast by Econ that electricity demand will rise by 5.5% p.a. between 1995 and 2020, 0.6 percentage points lower than the growth in real GDP over the same period. The growth in electricity consumption is more or less the same as that presented by the IEA (a forecast of 5.4% p.a. between 1995 and 2020), while the US DOE expects China's electricity consumption to triple between 1995 and 2015, which matches Econ's outlook.

3.1.3 EU-15

In the EU, growth in GDP has been marginally stronger than that of electricity since 1990, with real GDP increasing by 14.4% between 1990 and 1997 and electricity consumption rising 14.2% over the same period. However, over the 1980s, real GDP grew by less than electricity demand (22.1% compared with 27.5% for electricity demand).

Over the forecast period, real GDP is expected to grow faster than electricity demand. Real GDP is expected to increase by 52% between 1997 and 2020 (1.8% p.a.), while electricity demand rises by 38% (1.4% p.a.) over the same period. Consequently, the electricity intensity for the EU-15 will decline from around 350 Wh/1987$ in 1997 to 320 Wh/1987$ by 2020.

Electricity intensities vary widely across the EU. Sweden has the highest electricity intensity (725 Wh/1987$), while Denmark has the least electric intensive economy (267 Wh/1987$). The availability of low cost hydro power has supported electric-intensive industries in Sweden, whilst the lack of low cost indigenous supply options in Denmark has limited the development of these industries.

3.1.4 India

India's average annual electricity consumption growth rate has exceeded the growth in real GDP by 3.7 percentage points between 1980 and 1995, with electricity demand increasing by 8.8% p.a., while real GDP grew by 5.1% p.a.. However, over the forecast period there is a much closer relationship with the rate of expansion of real GDP, which is also consistent with the outlooks presented by the IEA and US DOE. In the period from 1995 to 2020, Econ forecasts that electricity consumption will grow by 5.2% p.a. (marginally faster than the 5.0% p.a. presented by the IEA for the South Asia region), compared with real GDP growth of 4.8% p.a. - i.e. the percentage point difference narrows to 0.4.

One reason for believing that India's growth rate in electricity consumption may move closer to that of its real GDP is the need to reform the electricity sector. Subsidisation of residential tariffs has led to demand outstripping capacity additions and to the problem of "brown outs". The removal of the subsidies should reduce the rate of growth in demand, while capacity growth will increasingly be tied to the ability of the generation sector to raise the capital necessary to undertake the investments, which is likely to be tied to the growth in the wider economy. It may well be that growth in electricity demand is limited by the growth in capacity for some considerable time to come.

3.1.5 USA

In the US, the growth in electricity demand has accelerated since 1990, compared with the decade of the 1980s. Between 1980 and 1989 real GDP rose by 28.1% (2.8% p.a.), while electricity demand rose by 26.6% (2.7% p.a.). However, in the period from 1990 to 1997, real GDP has increased at a slower pace (2.3% p.a.), but electricity demand has accelerated to a growth rate of 2.8% p.a.

As a result, the decline in the electricity intensity of real GDP experienced over the 1980s has been reversed in the 1990s. However, the picture is more complicated than the headline figures suggest. The electricity intensity declined between 1980 and 1986, but then rose sharply up to 1991 with the electricity intensity in 1991 6% higher than in 1980. Since 1991 the intensity has remained more-or-less constant. Whether the falling energy prices triggered by the collapse in oil prices in 1986 has contributed to the growth in electricity demand, or whether there has been a structural shift in the economy towards a more electricity intensive structure, are points that are open to debate. It could simply be normal variations around a trend that points to lower electricity intensity.

The US EIA in their 1998 Annual Energy Outlook note that, "During the 1960s, electricity demand grew by more than 7 percent a year, nearly twice the rate of economic growth. In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Several factors have contributed to this trend, including increased market saturation of electric appliances; improvements in equipment efficiency and utility investments in demand-side management programs; and legislation establishing more stringent equipment efficiency standards. For similar reasons, a continued decline is expected throughout the forecast."[4]

Econ's outlook for electricity demand reflects the longer-term trend in the US's electricity intensity. While real GDP is expected to increase by 55% between 1997 and 2020 (1.9% p.a.), electricity demand rises by 37% (1.4% p.a.) over the same period. Consequently, the electricity intensity for the US will decline from around 555 Wh/1987$ in 1997 to 490 Wh/1987$ by 2020.

[4] "Annual Energy Outlook 1998" US Energy Information Administration (December 1997)

4 GENERATING COSTS

4.1 Levelised Costs

The levelised cost assumptions used in this report were gathered from a number of sources, including the IEA World Energy Outlook, the IEA's Projected Costs of Generating Electricity, the Danish Wind Turbine Manufactures Association, as well as national source information. The fuel price data are from the IEA and national sources.

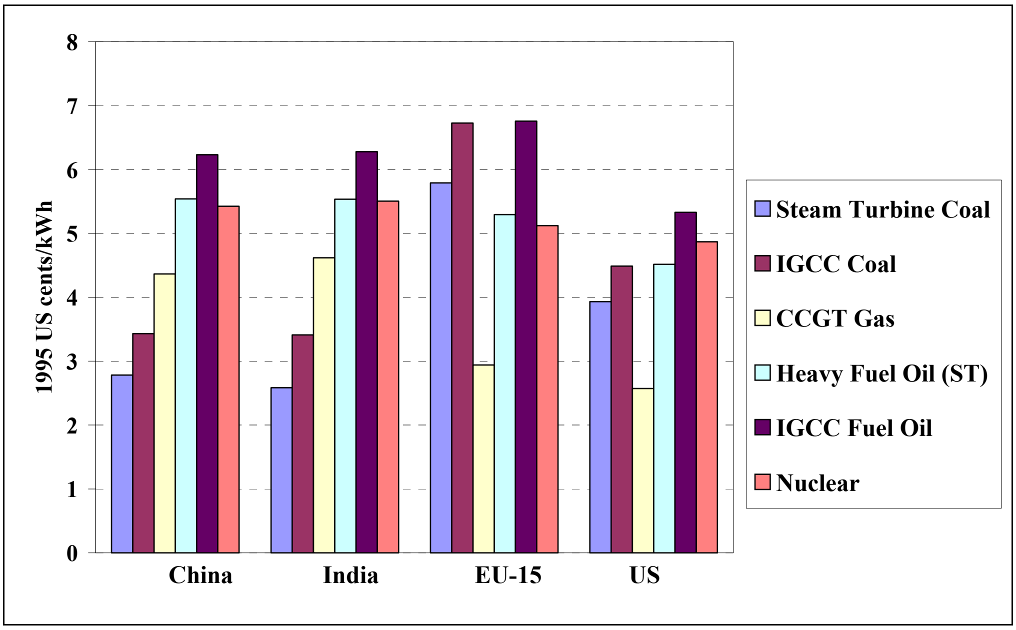


Figure 4.1: Levelised generating costs – 1995

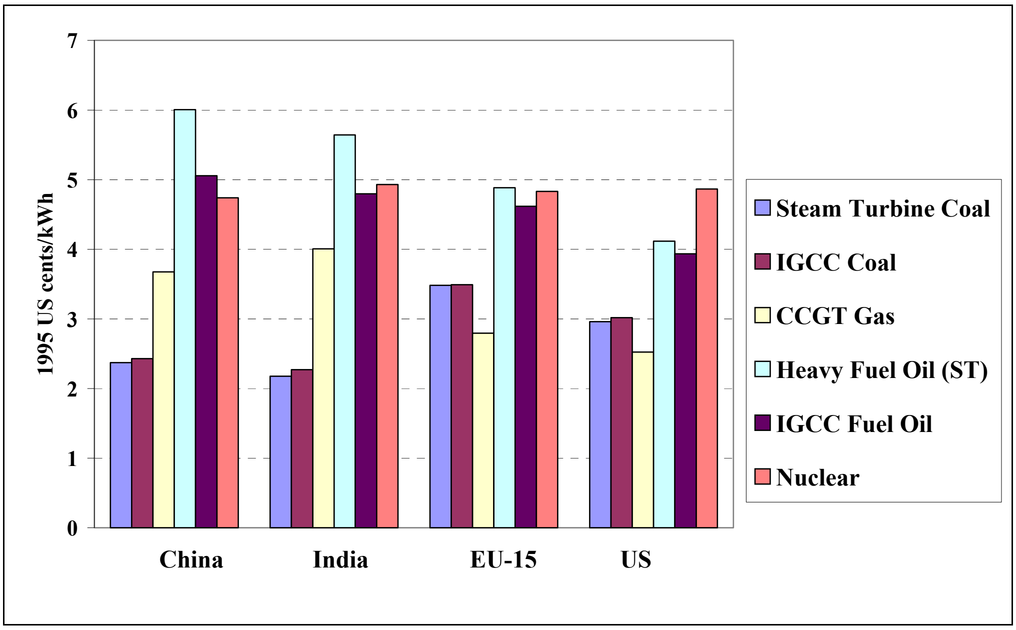


Figure 4.2: Levelised generating costs – 2020

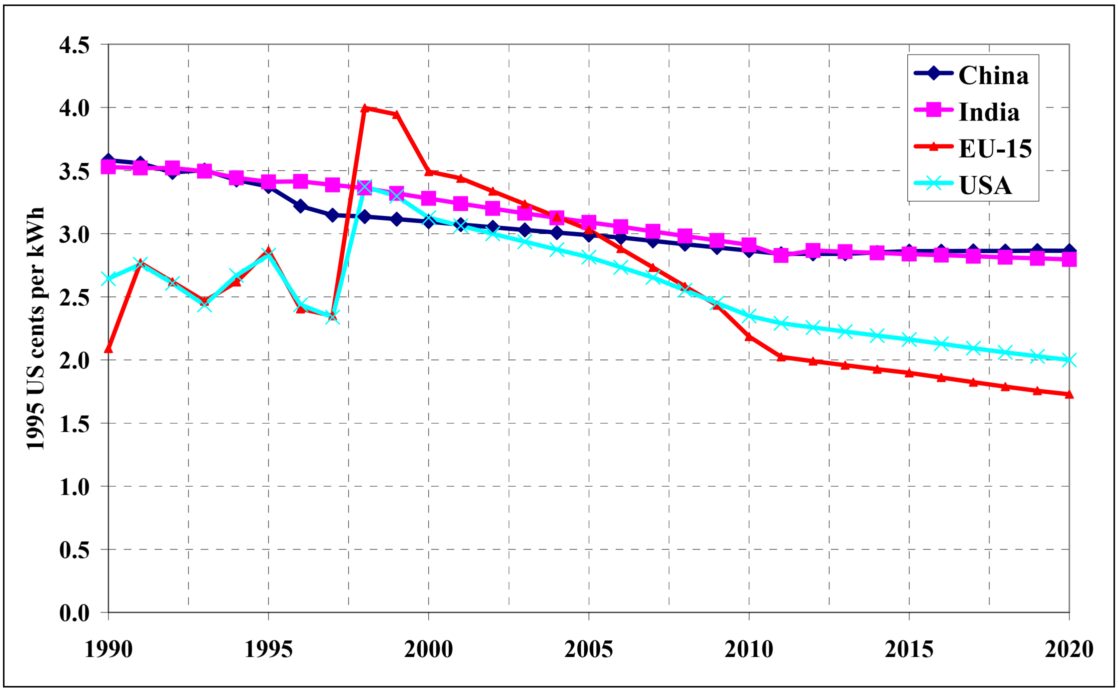


Figure 4.3: Cost of wind generation relative to the least cost option

Note: Wind costs in the above comparison assume an average load factor of 25% for wind generation and 75% load factor for the alternative, least cost, technology.

	China		India		EU-15		USA	
	1995	2020	1995	2020	1995	2020	1995	2020
Capital cost ($/kW)	1115	750	1050	750	1550	1025	1350	940
FGD (% of cap.)	12	12	0	12	12	12	12	12
de NOX (% of cap.)	0	0	0	0	9	9	9	9
O&M ($/kW)	33	33	33	33	33	33	33	33
Efficiency (%)	38	43	38	43	40	45	40	45
Life (years)	25	25	25	25	25	25	25	25
Load factor (%)	75	75	75	75	75	75	75	75
Discount Rate (%)	10	10	10	10	10	10	10	10
Levelised cost (c/kWh)	2.37	1.76	2.26	1.76	3.10	2.22	2.77	2.08
Fuel cost (c/kWh)	0.41	0.61	0.32	0.42	2.69	1.26	1.17	0.88
TOTAL (c/kWh)	2.78	2.37	2.58	2.18	5.79	3.48	3.93	2.96

Table 4.1: Steam turbine coal generation costs (1995 $)

	China		India		EU-15		USA	
	1995	2020	1995	2020	1995	2020	1995	2020
Capital cost ($/kW)	1330	790	1365	790	2020	1080	1530	990
FGD (% of cap.)	0	0	0	0	0	0	0	0
de NOX (% of cap.)	0	0	0	0	0	0	0	0
O&M ($/kW)	55	40	55	40	55	40	55	40
Efficiency (%)	43	53	43	53	43	53	43	53
Life (years)	25	25	25	25	25	25	25	25
Load factor (%)	75	75	75	75	75	75	75	75
Discount Rate (%)	10	10	10	10	10	10	10	10
Levelised cost (c/kWh)	3.07	1.93	3.13	1.93	4.22	2.42	3.40	2.27
Fuel cost (c/kWh)	0.36	0.50	0.28	0.34	2.50	1.07	1.08	0.75
TOTAL (c/kWh)	3.43	2.43	3.41	2.27	6.73	3.49	4.49	3.02

Table 4.2: IGCC coal generation costs (1995 $)

	China		India		EU-15		USA	
	1995	2020	1995	2020	1995	2020	1995	2020
Capital cost ($/kW)	750	600	750	600	950	658	950	658
FGD (% of cap.)	0	12	0	12	12	12	12	12
de NOX (% of cap.)	0	0	0	0	9	9	0	0
O&M ($/kW)	30	30	30	30	30	30	30	30
Efficiency (%)	38	38	38	38	38	38	38	38
Life (years)	25	25	25	25	25	25	25	25
Load factor (%)	75	75	75	75	75	75	75	75
Discount Rate (%)	10	10	10	10	10	10	10	10
Levelised cost (c/kWh)	1.71	1.46	1.71	1.46	2.05	1.56	2.05	1.56
Fuel cost (c/kWh)	3.83	4.54	3.82	4.18	3.24	3.32	2.46	2.56
TOTAL (c/kWh)	5.54	6.01	5.54	5.64	5.29	4.88	4.51	4.12

Table 4.3: Steam turbine heavy fuel oil generation costs (1995 $)

	China		India		EU-15		USA	
	1995	2020	1995	2020	1995	2020	1995	2020
Capital cost ($/kW)	1200	710	1230	710	1820	970	1380	890
FGD (% of cap.)	0	0	0	0	0	0	0	0
de NOX (% of cap.)	0	0	0	0	0	0	0	0
O&M ($/kW)	55	40	55	40	55	40	55	40
Efficiency (%)	43	53	43	53	43	53	43	53
Life (years)	25	25	25	25	25	25	25	25
Load factor (%)	75	75	75	75	75	75	75	75
Discount Rate (%)	10	10	10	10	10	10	10	10
Levelised cost (c/kWh)	2.85	1.80	2.90	1.80	3.89	2.24	3.15	2.10
Fuel cost (c/kWh)	3.38	3.26	3.38	3.00	2.87	2.38	2.18	1.83
TOTAL (c/kWh)	6.23	5.06	6.28	4.80	6.76	4.62	5.33	3.93

Table 4.4: IGCC fuel oil generation costs (1995 $)

	China		India		EU-15		USA	
	1995	2020	1995	2020	1995	2020	1995	2020
Capital cost ($/kW)	550	400	570	400	730	400	510	400
O&M ($/kW)	20	20	20	20	20	20	20	20
Efficiency (%)	50	60	50	60	52	62	52	62
Life (years)	25	25	25	25	25	25	25	25
Load factor (%)	75	75	75	75	75	75	75	75
Discount Rate (%)	10	10	10	10	10	10	10	10
Levelised cost (c/kWh)	1.23	0.98	1.26	0.98	1.53	0.98	1.16	0.98
Fuel cost (c/kWh)	3.14	2.70	3.36	3.03	1.41	1.82	1.41	1.55
TOTAL (c/kWh)	4.36	3.68	4.62	4.01	2.94	2.80	2.57	2.52

Table 4.5: CCGT gas generation costs (1995 $)

	China		India		EU-15		USA	
	1995	2020	1995	2020	1995	2020	1995	2020
Capital cost ($/kW)	2430	2100	2460	2200	2280	2100	2065	2065
O&M ($/kW)	38	38	40	40	44	44	58	58
Efficiency (%)	100	100	100	100	100	100	100	100
Life (years)	25	30	25	30	30	30	40	40
Load factor (%)	75	75	75	75	75	75	75	75
Discount Rate (%)	10	10	10	10	10	10	10	10
Levelised cost (c/kWh)	4.65	3.97	4.73	4.16	4.35	4.06	4.10	4.10
Fuel cost (c/kWh)	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
TOTAL (c/kWh)	5.42	4.74	5.50	4.93	5.12	4.83	4.87	4.87

Table 4.6: Nuclear generation costs (1995 $)

	China		India		EU-15		US	
	1995	2020	1995	2020	1995	2020	1995	2020
Capital cost ($/kW)	330	260	330	260	330	260	330	260
O&M ($/kW)	7	5	7	5	7	5	7	5
Efficiency (%)	28	37	28	37	28	37	28	37
Life (years)	25	25	25	25	25	25	25	25
Load factor (%)	15	15	15	15	15	15	15	15
Discount Rate (%)	10	10	10	10	10	10	10	10
Levelised cost (c/kWh)	3.27	2.58	3.27	2.58	3.27	2.58	3.27	2.58
Fuel cost (c/kWh)	5.60	4.38	6.00	4.92	2.62	3.05	2.62	2.59
TOTAL (c/kWh)	8.87	6.95	9.26	7.49	5.89	5.63	5.89	5.17

Table 4.7: Peaking gas combustion turbine generation costs (1995 $)

	China		India		EU-15		US	
	1995	2020	1995	2020	1995	2020	1995	2020
Capital cost ($/kW)	330	260	330	260	330	260	330	260
O&M ($/kW)	7	5	7	5	7	5	6.6	5
Efficiency (%)	28	37	28	37	28	37	28	37
Life (years)	25	25	25	25	25	25	25	25
Load factor (%)	15	15	15	15	15	15	15	15
Discount Rate (%)	10	10	10	10	10	10	10	10
Levelised cost (c/kWh)	3.27	2.58	3.27	2.58	3.27	2.58	3.27	2.58
Fuel cost (c/kWh)	5.19	4.67	5.19	4.29	4.40	3.41	3.34	2.63
TOTAL (c/kWh)	8.46	7.24	8.46	6.87	7.67	5.99	6.61	5.20

Table 4.8: peaking oil combustion turbine generation costs (1995 $)

4.2 International Oil and Coal Price Assumptions

4.2.1 Oil price outlook

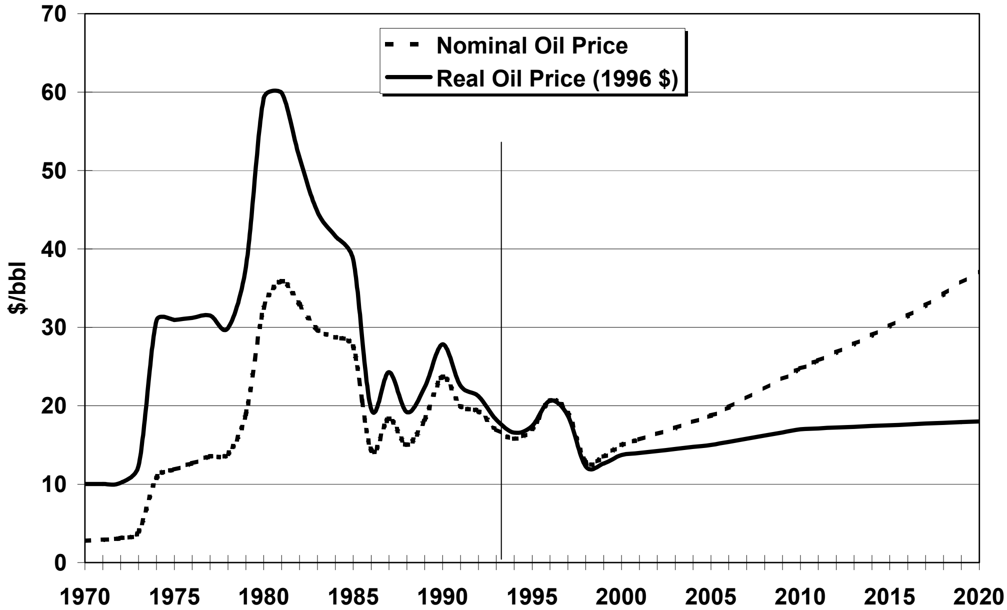
	Oil Price	Change over previous 5 years
	(1996 $/Barrel)	(% per annum)
1975	30.94	25.3
1980	59.22	13.9
1985	38.67	-8.2
1990	27.84	-6.4
1995	17.43	-8.9
2000	13.70	-4.7
2005	15.00	1.8
2010	17.00	2.5
2015	17.50	0.6
2020	18.00	0.6

* Arab light to 1985, Brent blend thereafter.

Table 4.9: Real oil price*

The real oil price outlook is assumed to follow the reference path outlined in the US Energy Information Administration's Annual Energy Outlook for 1998, which covers the period until 2020. Total world-wide oil demand is expected to exceed 116 million barrels in 2020 (an annual average growth rate of around 2%).

The real (1996) spot price of dated Brent is expected to remain below $15 per barrel until 2005, and then to rise to a plateau of around $18.00 per barrel by 2020.



Source : History - Platt's ; Outlook - based on US DOE AEO 98

Figure 4.4: Oil price (history and outlook)

4.2.2 Coal price outlook

	Coal Price	Change over previous 5 years
	(1996 $/tonne)	(% per annum)
1980	93.61	
1985	67.48	-6.3
1990	60.25	-2.2
1995	46.40	-5.1
2000	33.84	-6.1
2005	31.62	-1.4
2010	30.50	-0.7
2015	30.00	-0.4
2020	29.30	-0.4

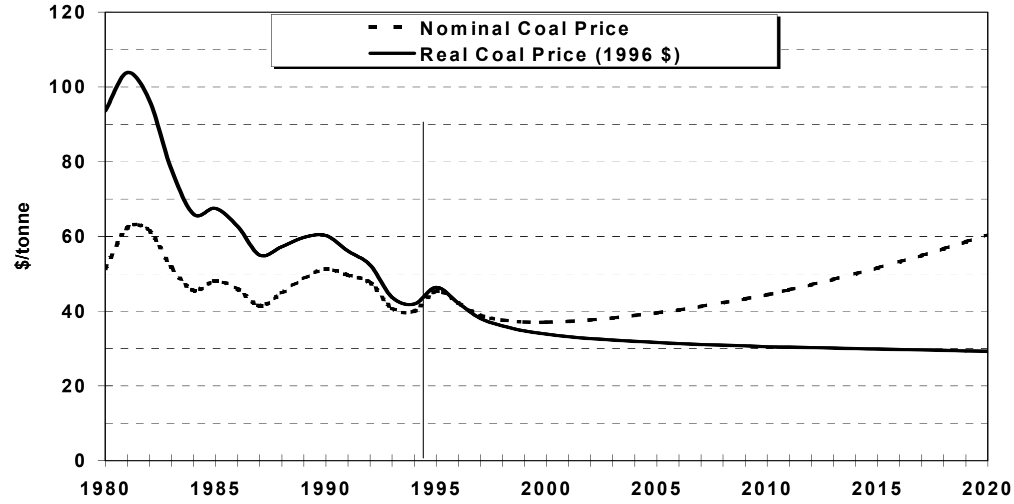
Table 4.10: Real coal price

Econ's outlook for Amsterdam-Rotterdam-Antwerp (ARA) coal prices is based on recent developments in ARA stream coal prices and the long-term outlook for US mined coal, as presented in the US Energy Information Administration's Annual Energy Outlook for 1998.

The US is the marginal source of supply to Europe and hence its production costs will be key in setting European ARA prices. The Annual Energy Outlook for 1998 anticipates that real coal minemouth prices will fall by $5.23 per tonne between 1996 and 2020 (a decline of 1.4% per annum).

In addition, coal consumption in Europe is increasingly centred on the power sector, where natural gas is rapidly eating into coal's market share and compelling coal to cut prices to compete. In this situation a continued slide in real ARA coal prices to around $30 per tonne ($6 per tonne lower than at present) is not unreasonable and would allow coal to compete at the margin against new gas-fired power stations over the latter part of the outlook.

The ARA steam coal prices are transferred to the Asian markets via South Africa. South African producers are able to arbitrage between Europe and Asia and to a certain extent provide a conduit by which the differential between ARA prices and those in Asia are held relatively constant, subject to variations in freight rates. Changes in Asian steam coal prices are assumed to follow the development in ARA prices. However, in both China and India, domestic steam coal prices are below the US minemouth price, despite the fact that costs are not significantly lower. A combination of the need to raise the profitability of the coal sector and to raise export revenues is expected to lead to a gradual alignment of Chinese and Indian coal prices with those in the international markets.



Source: History - Coal Week International; Outlook – ECON

Figure 4.5: ARA coal price (history and outlook)

4.3 Regional Outlook for Coal and Gas Prices to the Power Sector

4.3.1 Coal prices

Figure 4.6 shows Econ's outlook for steam coal prices to the power sector in the four study regions. The gradual alignment of international wholesale prices is also seen in the overall narrowing in the real price differentials between regions.

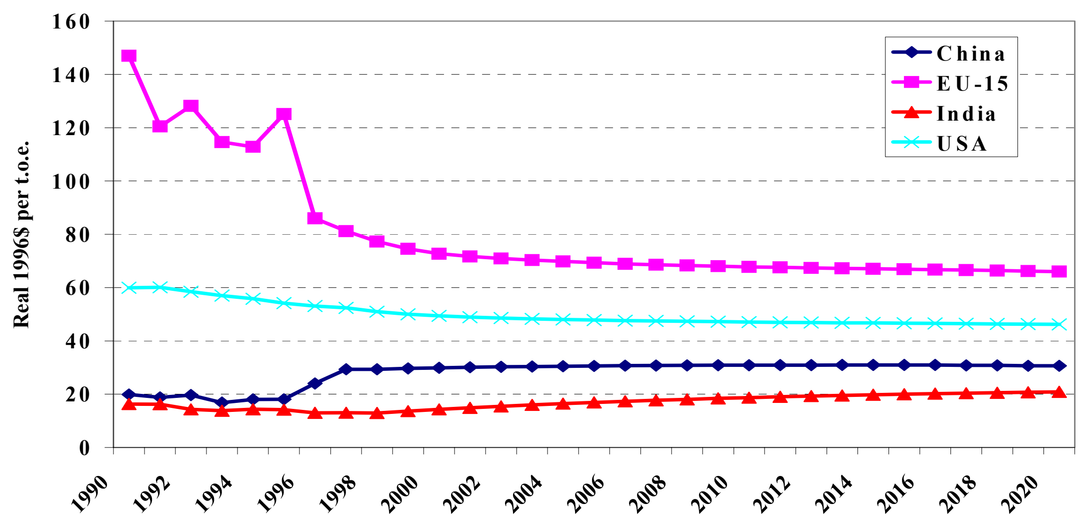


Figure 4.6: Coal prices to the power sector (history and outlook)

4.3.2 Gas prices

Gas prices are linked to changes in the price of oil. This is both directly through price escalation clauses in certain gas contracts and indirectly through inter-fuel competition. Currently almost all European long-term gas contracts have a price formula linked to competing oil prices. This is also true for both China and India. While in the USA there is no formal price indexation to oil, the price of oil sets the ceiling for natural gas because power producers will switch to oil if oil is cheaper.

The sharp fall in oil prices between 1997 and 1998 produced a sharp reduction in natural gas prices. The fall will be eradicated over the course of the forecast period. Figure 4.7 shows the natural gas price developments to the power sector in the four study regions.

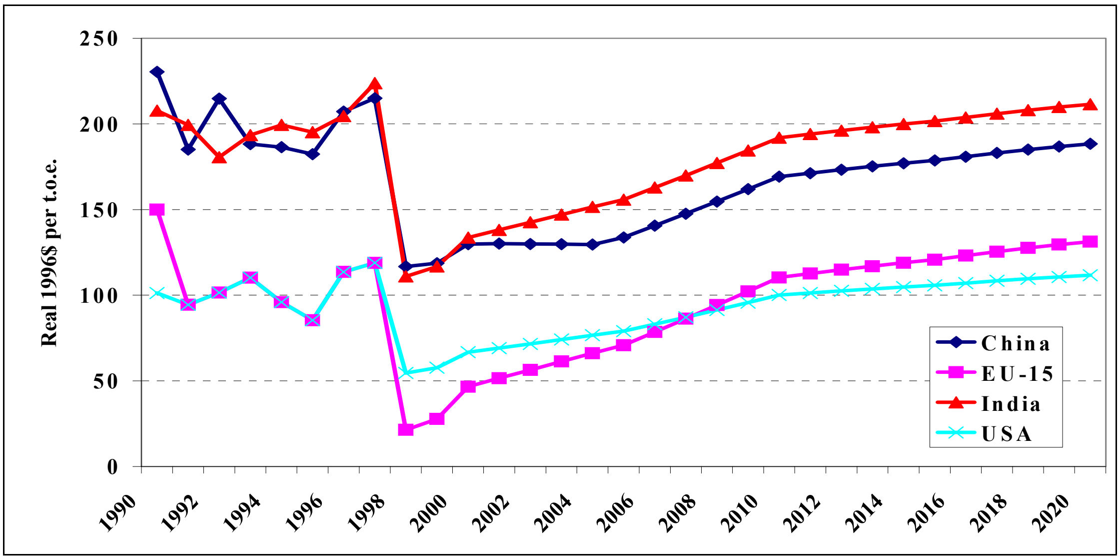


Figure 4.7: Natural gas prices to the power sector (history and outlook)

4.3.3 Heavy fuel oil prices

Figure 4.8 shows Econ's outlook for heavy fuel oil prices to the power sector in the four study regions. The price movements reflect the underlying changes in the price of crude oil.

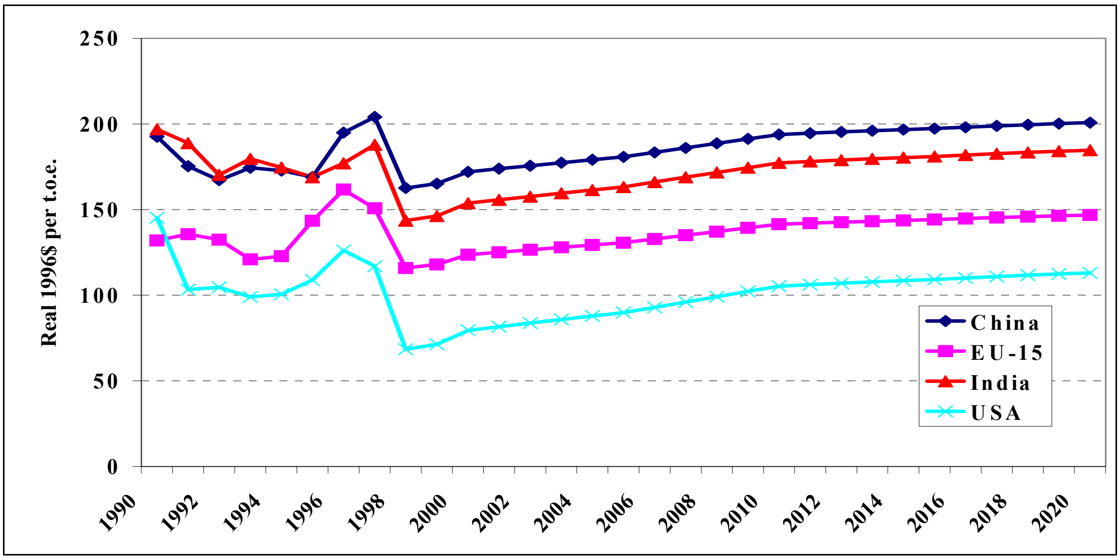


Figure 4.8: Heavy fuel oil prices to the power sector (history and outlook)

APPENDIX C

STANDARD ASSESSMENT CRITERIA

Technical and Financial Assessment Criteria: Wind Energy

This Appendix contains a general list of technical and financial factors likely to be required for wind energy appraisal studies. It is intended to ensure that studies for the IEA Greenhouse Gas R&D programme are conducted using a consistent set of technical and financial conventions. In the event of conflicting requirements the main specification takes precedence.

Costs of raw materials and labour and the value of by-products have not been suggested as they are likely to differ significantly from case to case.

CRITERIA FOR WIND ENERGY APPRAISAL STUDIES

Technical/Financial Factor (notes)	**Assessment Convention**
1. <u>Development Status</u> ***(It is well documented that the cost of technology decreases and its performance improves as experience is gained.)***	***For commercially available wind energy technology current 'state-of-the-art' cost and performance figures will be assumed. On-shore and off-shore wind farms differ in several respects and will be therefore be considered separately. In particular, off-shore development is relatively new and untried whereas a substantial body of experience has been built up from several GW of on-shore development over more than two decades.***
2. <u>Plant Size</u> ***(Significant economics of scale can apply up to the size at which increases can only be obtained by using plant modules and/or the cost of working capital due to extended construction periods outweighs benefits of scale.)*** *With wind farms this is not really a limit because a properly planned large wind farm can start commercial production in phases.*	***Wind energy is a modular technology with individual turbine rated electrical outputs from 50 W to multi-MW. The present study will be limited to grid-connected wind farms which account for almost 100% of capacity installed to date. Individual wind farms have rated outputs from <1 MW to >100 MW.*** ***The base case on-shore wind farm will consist of eighty 750 kW turbines with a total net rated power output of 60 MW(e).*** ***The base case off-shore wind farm will consist of one hundred 2 MW turbines with a total net rated power output of 200 MW(e).***
3. <u>Design and Construction Period</u> ***(Project finances can be sensitive to the time required to erect the plant.)***	***For the base case wind turbines a 3 month manufacturing period and unlimited parallel production will be assumed.*** ***Construction periods of 3 months and 9 months will be assumed for the base case on-shore and off-shore wind farms respectively. Typical `S' curves of expenditure during construction will be used, viz:*** ***On-shore Off-shore*** ***Month % Quarter %*** ***1 20 1 20*** ***2 45 2 45*** ***3 35 3 35***
4. <u>Plant Life</u>	***Twenty years. Where for technical reasons this is regarded as excessive, provision will be made for***

Technical/Financial Factor (notes)	**Assessment Convention**
(Design life to be used as a basis for economic appraisal. A financial assessment convention; actual life is frequently extended.)	*the cost of any major maintenance/refurbishment.*
5. Load Factor *(Achieved output as a percentage of rated/nameplate capacity. Appropriate to the ranking of technical options; in practice, because of system limitations, many power plants achieve considerably less output.)*	*The power available from the wind is proportional to the cube of the wind speed. Wind turbine outputs are both intermittent and variable and "must take" power purchase agreements are assumed. Load factors range from <20% to >50% depending on site wind climate.* *Load factors will therefore be determined on a site by site basis using generic power curves for the base case turbines together with uniform assumptions for array losses, on-site electrical losses, and availability.*
6. Cost of Debt *(Note that money is required during design, construction and commissioning i.e. before any returns on sales are achieved.)*	*For simplicity, all capital requirements will be treated as debt at the same discount rate used to derive capital charges. No allowance for grants, cheap loans etc. (More complex financial modelling might be considered for certain studies.)* *Specific cost figures should be presented without including an allowance for funds used during construction (i.e. independent of discount rate).*
7. Capital charges; inflation *(In the event of the reduction in carbon emissions being achieved at a significantly later date than the expenditure, the investment costs should be projected forwards.)*	*Discounted cash flow calculations will be expressed at a discount rate of 10% and, to illustrate sensitivity, at 5%; the resulting capital charge rate will be quoted. All annual expenditures will be assumed to be incurred at the end of the year.* *Inflation assumptions will not be made. No allowance will be made for escalation of fuel, labour, or other costs relative to each other.*
8. Currency *(Converting US$ costs to a local currency equivalent involves more than using the current exchange rate; members of the IEA GHG programme will need to take their own views on appropriate rates.)*	*The results of the studies will be expressed in US $ applicable to a specific year. Data obtained in other currencies will be converted at rates specified in the Main Report.*
9. Commissioning and Working Capital *(Commissioning is defined as the period between the construction period [item 3] and the start of the 1st year of operation [item 4]. Working capital includes raw materials in store, catalysts, chemicals etc.)*	*Wind farm commissioning times for the base case wind farms are assumed to be as follows:* *days per turbine + fixed days = total days* *On-shore 1/3 (x 80 turbines) 2 - 3 30 days* *Off-shore 1 (x 100 turbines) 4 - 5 105 days*

Technical/Financial Factor (notes)	**Assessment Convention**
	Wind cannot be stored as working capital. Provision of other materials in store as required for O&M will be reflected in assumed availablity of 99%.
10. Decommissioning *(Costs associated with final shut down of the plant, long term provisions and 'making good' the Site).*	*Although experience of decommissioning wind farms is very limited, studies indicate that the recoverable scrap value may cover all costs and net costs will therefore be set to zero. These will be included nonetheless to facilitate comparison with technologies where decommissioning can be a significant proportion of project cost.*
11. Location *(The standard site for IEAGHG studies is on the NE coast of The Netherlands; this appears to give costs which are in the middle of the range for OECD member countries.)*	*For on-shore wind farms, green field sites with no special civil works implications will be assumed. High wind speed sites are often far (10 km or more) from the electrical grid and proportionate allowance will be made for increased cost of access tracks.* *For off-shore wind farms both proximity to shore (and electrical grid) and water depth affect infrastructure costs.* *The above dependencies, together with suitable allowances for site rental, will be established and applied.*
12. Taxation and Insurance *(The treatment of these items will differ markedly from country to country. Therefore, a simple treatment is used which can be readily adapted to suit the circumstances of individual members.)*	*Allow 1% of the installed plant cost (overnight construction) to cover specific services e.g. local rates. Taxation on profits will not be included in the assessments. Insurance will be taken as 0.25% p.a. of capital*
13. Fees *(The contractor's fees for design and build will form part of the estimate; additional fees covered here include:- process/patent fees, fees for agents or consultants, legal and planning costs etc.)* *14. Contingencies* *(There are numerous methods of treating access to capital required to cover; unforeseen set-backs, cost under-estimates, programme overruns etc. Hence, a simple method with a clear basis that can be readily adapted to the norm of IEA GHG member countries is required.)*	*Normally a total of 5% of installed plant cost.* *Normal procedure will be fixed in the EPC (engineer, procure, construct) turnkey contract.* *Allow for project contingency costs as a prortion of total project capital cost by adding a factor of the balance of plant (i.e. ex-turbines) cost as follows:* *Balance of plant cost / Factor / Contingency* *On-shore: 30% / 10% / 3.0%* *Off-shore: 50% / 15% / 7.5%*

Technical/Financial Factor (notes)	Assessment Convention
	Allowances for estimating error and process unknowns/development will be treated by quoting confidence limits ie: ± x %. ***All plant should be assumed to be built on a turnkey basis, ie; the cost of risk should be built into the contractor's fees.***
15. Maintenance ***(To include routine, breakdown and any major refurbishment activities.)***	***Routine operation and breakdown maintenance (O&M) will be allowed for at 2% p.a. of installed plant cost (overnight build).***
16. Labour ***(Agreed conventions are required for the treatment of operating, supervising, maintenance and other labour elements; including administrative, other general overheads and items such as social security payments.)***	***The cost of operation and maintenance (O&M) labour is assumed to be covered by item 15.*** ***There is no other significant labour cost.***
17. Fuels and Raw Materials ***(Where a range of fossil fuels could be used, coal and natural gas will normally be specified as they span the range of H:C ratios for fossil fuels.)***	***The sole fuel is wind, for which the cost is zero. The cost of materials and sundries for O&M is covered by item 15.***
18. Water.	***Nil.***
19. Effluent/Emissions and Solids Disposal	
(a) Sulphur, ash, oils and tars, NO_x, SO_x etc (other than CO_2)	***Nil***
(b) CO_2 processing.	***Nil***
20. Site Conditions	***Ambient air temperature 9°C*** ***Ambient air relative humidity 60%*** ***Ambient air pressure 1.013 bar***
21. Heat Content	***Nil***

APPENDIX D

INFLUENCE OF MARKETS AND REGULATION

CONTENTS

1 EXECUTIVE SUMMARY

Regulatory regimes, including government support programmes and emerging "green power" markets, have influenced the cost of wind power in countries that have been particularly active in promoting wind power development. The rapid growth rate of wind energy development world-wide is attributable to various support measures that have allowed economies of scale to be realised and costs to fall. A limited number of qualitative conclusions can be drawn from experience to date with respect to the relative effectiveness of different types of national programmes. However, it is not possible to quantify the proportion of the cost reduction achieved over time either to regulation in general or to specific government policies or, for that matter, to market programmes. This is because of the many variables that make up the installation and production costs of a wind energy project, including wind conditions, the particular equipment selected, land costs, financing costs, a variety of taxes and local fees, operations and maintenance costs etc. For every project, at least some cost information is proprietary.

It is, however, possible to draw some conclusions regarding the relative effectiveness of different government programmes in reducing wind power costs over time. This is because some national programmes, such as the US, German, and UK programmes, have been in operation for a number of years and have had remarkable and remarkably different effects on the costs of wind power.

Until very recently the market for wind power as a segment of general electricity supply (as distinct from small, off-grid or remote applications) has been a creature of government regulatory policies and support programmes. It has only been in the last few years that wind power has become part of the mix of sources serving new "green power" markets, all of which are subsidised, thus remaining, at least in part, creatures of government. It is possible to identify some representative costs of green power in a few countries and to draw some conclusions regarding the relative costs of particular renewable sources.

Comparison of the government regulatory and support programmes of five of the most pro-active countries in wind energy development allows the following limited but straightforward conclusions:

- Germany's programme has been both the most productive in terms of fostering penetration of wind energy into domestic electricity supply and the most expensive (not to mention the most controversial). German utilities have been required to pay independent wind generators the equivalent of US $0.105/kWh, approximately double the average price new US projects are getting, and more than triple the lowest rate ($0.0315) that will be paid to a UK project approved under SRO-3. Among the national programmes examined in this report, Germany's fixed-price approach has done the least to reduce wind power costs. It is also being challenged in the courts by those utilities required to take the most wind power simply because developable sites happen to have been located in their service areas. These utilities have contended that either the programme should be abandoned or that the costs should be paid by all German taxpayers rather than by electricity consumers living in areas where wind power development is concentrated. The European Commission has indicated that it finds these arguments compelling and that the German approach is distortionary and inconsistent with the principles of the fledgling European liberalised electricity market. Germany has now adopted a new law which retains the fixed price principle, but which equalises costs across utilities.

- The UK and Irish governments have sought to develop wind power at minimum cost to consumers. They have done this by sponsoring rounds of competitive bidding in which renewables projects bid against each other within technology bands. The UK's NFFO programme further subdivides wind projects into two competing bands, one for larger, the other for smaller, projects, while the Irish AER programme divides wind projects into four size bands. Accepted projects receive either their bid price or a marginal price under long-term contracts. The difference between the contract price and the market price of conventional power is paid out of funds from a levy. The Fossil Fuel Levy in England and Wales added 10% to the average household's electricity bill (mainly to support nuclear) between 1990 and 1996. Today it adds less than 1%. Within the next few years, as NFFO-5 (fifth round) projects begin operating, the price paid for a marginal kilowatt-hour of wind energy will have been reduced from over \$0.07 in 1994, under NFFO-4 (the fourth round), to less than \$US0.05 under NFFO-5, a fall of almost a third.
- US support programmes highlight the pitfalls of applying policy with an unsteady hand. In the 1980s, the PURPA Act launched the world's first major surge of wind power development. PURPA, like the German EFL today, required utilities to buy wind power at premium rates ultimately passed onto electricity consumers. It was abandoned in the late 1980s, along with federal and state investment tax credits which had the effect of spurring hasty, sometimes low-quality, projects. Today, wind energy in the US is reviving, after a hiatus of several years, due to the sprouting of green power markets made possible by deregulation combined with modest federal and state incentives. In terms of marginal costs, the US and UK are on a par. New projects are being built based on prices in the range of \$0.05 to \$0.06/kWh. Existing US projects, totalling around 1,700 MW in installed capacity, continue to earn higher rates under long-standing contracts.
- The Danish support programme differs from the UK, German, and US programmes in having been more oriented to stimulate dispersed development of small, locally-owned projects. As in the case of the German programme, the government has required its monopoly utilities to pay premium rates that are passed onto electricity customers. The government has also required utilities to develop specific amounts of wind power themselves as a spur to turbine exports. Tax breaks, which, until recently, favoured small co-operatives and municipalities, provide additional stimulus, needed because of the government's goal to have wind power supply 35% of the country's electricity by 2030. But to reach this potential, additional government incentives will be needed to support development of Denmark's offshore wind resource.
- The Netherlands abandoned its generous direct capital subsidy in 1996, replacing it with a complex set of fiscal incentives for renewables development. These include investment tax credits and rebates to renewables generators of a consumer tax on energy ("ecotax"), from which purchases of "green power" are exempt. In addition to these (and other) incentives, the government, through the utilities' trade association, has organised a market in tradable green energy credits. In addition to earning a fixed price for their energy, plus receiving ecotax rebates, wind energy producers are issued "green labels". Wind energy suppliers may sell these to distribution utilities, which are assigned renewable energy quotas by the government. A utility can meet its quota either by generating renewable energy itself or through the purchase of green labels. Among the options being considered by the EC for meeting a renewables target, if one is adopted, is one based on this Dutch model.

Green power markets are springing up as these, and other, countries liberalise their electricity sectors, introducing consumer choice of supplier. Several programmes are being set up, notably in the US, and numerous others are in the planning stage or have been proposed. No programme is at this point so well established that it can be called a success or judged to have influenced wind power costs. It can be surmised that such programmes will eventually put downward pressure on wind power costs by engendering economies of scale. However, as long as a wide gap remains between the cost of wind power and that of gas-fired CCGT power, green power markets for wind energy will depend on (gradually diminishing) subsidies, thus remaining artificial markets until the time when global supply constraints and/or laws aimed at internalising the external costs of gas-fired power, close the gap once and for all.

2 INTRODUCTION

This analysis concentrates on regulatory regimes and markets in the US and four EU countries with the longest history of supportive regulatory policies and government incentives. The report also provides, a brief description of government support and new market programmes in four other EU countries active in wind energy development. There is also a brief overview of the market and regulatory situation in China and India as these are two of the study regions covered in detail in the Main Report and are both among the top ten wind generators in the world.

Markets and regulation have evolved rapidly in many countries and may reasonably be expected to continue to do so. This appendix should be regarded at best as a "snapshot" of the situation in the above countries, and as such will inevitably soon be out of date.

Regulatory regimes in the US and several EU-15 countries have been created or modified for the express purpose of supporting the development of significant grid-connected wind power for electricity supply. The US was the first country to require electric utilities to purchase wind power from independent producers (as one among several forms of "alternative" energy). The German government is generally credited with having in place today the most favourable regulatory environment. As a result, Germany surpassed the US in 1997 as the country with the largest installed capacity of wind energy.

The objectives of supportive government policies have varied. In the US the Public Utility Regulatory Policy Act (PURPA), passed in 1979, was primarily aimed at reducing dependence on imported fossil fuels. A secondary objective was to diversify sources of supply because the US electricity supply system had become excessively dependent on large, regional power plants requiring equally large backup units in the event of a forced outage. In the UK the Non Fossil Fuel Obligation (NFFO) was originally a vehicle for channelling government support to nuclear power stations that could not be privatised because they were not competitive with gas-fired CCGT plants and not of interest to investors. At the outset of the NFFO, only 1% of the fossil fuel levy was earmarked for renewables, while the remaining 99% supported nuclear. Support for renewables was included mainly to make the scheme more politically acceptable, in view of nuclear's unpopularity. Government support programmes initiated more recently by OECD countries have been aimed at reducing local and/or regional air pollution or have been established as part of their governments' national climate change programmes. All OECD countries have created such programmes in connection with their efforts to fulfil voluntary commitments under the UN Framework Convention on Climate Change, under which developed countries (members of Annex I of the Convention) agreed to stabilise their CO_2 emissions at 1990 levels by 2000.

The kinds of support offered by OECD country governments to wind power development include:

1. Favourable regulation, such as:
   - Requiring electric utilities to purchase wind power from independent generators at fixed, premium prices. The German and Danish programmes use this approach.
   - Requiring utilities to grant grid access to independent generators to enable them to wheel energy to their customers.
   - Requiring utilities to bear the costs of interconnecting independent wind power facilities to their transmission systems.

- Requiring local authorities to include wind energy in their land-use plans, or to meet specific targets for wind energy development within their jurisdictions, or to streamline the approval process for permitting wind energy projects.

 In some cases the national government administers the regulation itself; in others it delegates authority and responsibility to local governments or subordinate regulatory bodies.

2. Subsidies from the government, which can be paid:

    - To wind plant developers or operators
    - To electricity consumers; or
    - To utilities that purchase wind power from independent operators.

   Subsidies can be in the form of capital credits or investment tax credits which reduce the front-end costs of a wind energy project, or they can be in the form of production credits which reduce operating costs. Such credits can be in the form of direct grants or tax rebates. In some cases, governments do not pay subsidies directly but instead require electric utilities to pay them as cross-subsidies. In this case the costs are passed onto electricity consumers or utility investors (or both) rather than to the taxpayers. In some cases national governments require, encourage, or permit local governments to support wind energy projects.

The following sections examine the regulatory and support programmes of countries that have been particularly active in promoting wind power development. It is not a comprehensive survey, however, since many countries today are supporting wind energy development, usually as part of their national climate change programmes.

3 THE UNITED STATES

As of the end of 1999, the US ranked second in the world in terms of wind energy installed capacity, with 2,684MW (20% of the world total). In recent years there has been a dramatic turnaround in the fortunes of wind power in the US. Between 1992 and 1997 there was a decline in installed capacity of 222 MW (12% of the 1992 installed capacity), but since then annual capacity additions have risen sharply. Last year, 732 MW of wind capacity was installed, and total installed capacity reached a new all time high.

3.1 PURPA

In 1978 the US Congress passed PURPA, which required electric utilities to purchase power at premium rates from independent suppliers of "alternative" energy, defined as co-generation (including gas-fired) and "new renewables", including wind energy. PURPA retained the utilities' monopoly over transmission and distribution. (Note: PURPA is still officially in force, though it is largely ineffective today having been eclipsed by competitive bidding processes).

Under PURPA, the premium price that utilities were required to pay so-called Qualifying Facilities (QFs) was equal to the price they would have had to pay to either generate or buy an additional kWh of energy or an additional unit of capacity – the so-called "avoided cost". The Federal Energy Regulatory Commission (FERC) left it up to each public utility commission (PUC) to calculate avoided cost, stipulating only that a QF be paid a price equal to that of the most expensive plant in the utility's system when the QF generates electricity. PUCs in the various states used different methods to calculate avoided cost. Some differentiated the rate, requiring utilities to pay more for power delivered during peak load hours (as distinguished from low load hours). Some required "partial capacity" credits to be paid in addition to energy rates and differentiated between "firm" energy and "as-available" energy, requiring higher rates to be paid for the former.

In addition, PURPA established a 15% federal investment tax credit for energy projects. This was made available on top of a 10% general investment tax credit established in 1979 to spur economic recovery from the recession caused by the second "oil shock". Until the end of 1985, when they expired, federal investment tax credits available to wind energy projects totalled 25%. In addition, some states adopted their own tax credits; California's was 25%. The addition of this to the federal tax credits reduced the tax liabilities of a wind project's investors by over 50%, raising return on investment levels to unheard of levels and sparking an investment boom. California's state tax credit was reduced to 15% in 1986 and allowed to expire a year later.

3.2 The California "Wind Rush"

In California the utilities' estimated long run avoided cost in 1983 was $0.06/kWh. Anticipating increases in the world market price of oil, an annual inflation factor was included in "standard" contracts between utilities and independent suppliers, increasing the average price over the life of contracts signed before 1985 to $0.14/kWh. Later, as the utilities switched from oil to natural gas following the removal of the federal restriction on burning gas for electricity generation, the utilities' avoided energy cost plummeted. As of 1993 it was only $0.035/kWh based on the reference case of a natural gas-fired CCGT plant.

By the end of the 1980s, it had become clear to electricity rate-payers in California that renewable energy was poised to become even more expensive than the State's nuclear power, which at the time cost around $0.11/kWh. They lobbied for reform, which led to deregulation.

California's standard contracts have two components: a 10-year fixed price period and a 20-year period of floating prices. The partial capacity value allowed by the PUC set the floor price for wind energy at $0.02. Today, this price plus the calculated avoided energy cost has resulted in a total wind energy cost of about $0.055 per kWh, which is substantially higher than the cost of power from a natural gas-fired CCGT plant.

The California wind energy boom of the 1980s, driven by PURPA, favourable power contracts, and generous federal and state tax credits, led to the installation between 1981 and 1989, of over 2,000 MW of new turbines, representing a total investment exceeding $2 billion. It also led to hastily designed projects and the installation of a great deal of low-quality equipment, leading to numerous replacements, a few abandoned projects, and several well-publicised bankruptcies. To make matters worse, many individual investors lost their investments, either because the project in which they invested failed or because the US Internal Revenue Service subsequently disallowed the tax credits they had claimed.

The cumulative result of the California wind rush is that today about a dozen companies are operating approximately 1,500 MW of wind generating capacity, virtually all of it set in place during the 1980s since very little new capacity has been added since 1990.

California may be on the verge of a second wind rush, or at least a "second wind". Two circumstances are responsible for this: (1) Deregulation of energy supply and the emergence of green power markets; and (2) New forms of government support, both federal and state, aimed on the one hand at cushioning the impact of deregulation on the state's electric utilities and, on the other, fostering further wind energy development.

3.3 California Today

Twenty one US states[1] have approved deregulation (as of end-1999), and others are studying the issue or operating pilot programmes. The US Congress is meanwhile considering whether the federal government should set a deadline for all states to open their electricity markets.

Just as it led the way in wind energy development in the 1980s, in 1996 California was the first US state to adopt a comprehensive electricity deregulation plan. In addition to enabling the utilities to amortise their debts without incurring heavy losses, the plan includes support for renewables, setting aside $540 million for renewables support programmes for the 1998 through 2001 period of "transition to an open market". (The $540 million is in addition to R&D funds of $250 million for the same period). To put these figures in perspective, the utilities are allowed to recover from customers a total of $27 billion in costs associated with unproductive and stranded power plant assets, $21 billion of which is associated with shut-down or uncompleted nuclear facilities. $70 million of the $540 million set aside is going to support existing wind projects. Those projects operating under standard contracts are eligible to receive state production credits after the expiration of the ten-year fixed price period. Up to $0.010/kWh is added to the contract price. The State credit is paid in addition to any federal

[1] Arizona, Arkansas, California, Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia.

production credits for which a project is eligible (discussed below). As of May 1998, 79 projects had applied for credits.

Also out of the $540 million, $162 million is to be used by the California Energy Commission for production credits for new projects. The maximum to be awarded to an individual project is $0.015/kWh for five years. Applicants bid the amount of subsidy they think they will need up to $0.015, and they also bid the length of time. The lower bids/shorter lengths-of-time receive priority.

The goal of the California renewables support programmes with respect to wind energy is to get the wind power capacity up to 2,000 MW. After 1991, the State's aggregate installed wind capacity declined for six straight years. At the time of writing, California State subsidies for renewables represent 70% of the total being made available by US states. About $281 million is being made available yearly in six states – California, Connecticut, Illinois, Massachusetts, Montana, and Rhode Island. Also, new projects installed before 1 January 2002 in any US state are eligible to receive a per kWh federal production tax credit (PTC) for a ten year period from the installation date. The PTC started out at $0.015/kWh and of late has been at $0.017. (See further discussion below).

As a result of deregulation, all California households today may choose their electricity supplier. The State's deregulation legislation also calls for customers of renewable energy to receive a rebate of $0.015/kWh. This is capped for large users at $1,000 per year. The California Energy Commission certifies "Renewable Suppliers". Deregulation has led to an upsurge in green power marketing schemes in which customers are invited to pay a premium for clean power. The mix of energy sources included in such schemes varies and few offer 100% of their electricity from "new" (i.e. excluding large-scale hydro) renewables.

California is not the only state where such schemes have been initiated. However, it offers some interesting examples that are more or less representative of initiatives in other states:

- Green Mountain Energy Resources is offering to install a new wind turbine for every 4,000 customers that sign up to buy electricity from its particular mix of energy sources.
- Enron Energy is building a 16 MW wind farm near Palm Springs, CA to provide power to Patagonia, a manufacturer and supplier of outdoor sports clothing that has committed to using wind energy to power all of its facilities in California.
- The Sacramento Municipal Utility District (SMUD) is offering its customers the opportunity to purchase either 50% or 100% of their electricity from renewables, including wind energy, at a premium per kWh of $0.015/kWh.
- Recently Santa Monica City voted to purchase 5 MW of green power to power all municipal facilities, and Toyota Motor Company announced it will purchase 12 MW.
- Automated Power Exchange (APX) provides a market for buying and selling green power. It requires energy companies wishing to sell into this market to be registered with the California Energy Commission "Renewable Suppliers". In August 1999, APX reported that the "green ticket premium" generators were receiving (above commodity energy price) ranged from $3.72 - $4.34/MWh from May to July 1999. By selling to aggregators or exchanges, such as APX, generators do not have to market to individual households.

3.4 Green Power Markets in Other US States

Oregon is the scene of a pioneering green market scheme based exclusively on wind energy. Eugene Water & Electricity Board (EWEB) is part owner of a 42 MW wind farm in Wyoming. EWEB is planning to offer its 75,000 customers an option to buy green power generated by the Wyoming wind plant. It plans to sell the wind power in 100 kWh blocks at a premium of $0.03/kWh (the average price of electricity now is $0.04/kWh). Based on current wholesale rates, EWEB projects that it will lose $4.6million on its investment if no customers sign up. However, if customers subscribe for all the wind power produced, the loss will be eliminated.

In Colorado, as of January 1998, several thousand residences and 56 businesses, including IBM and Coors brewing company, had signed up for wind power in the service areas of four utilities. This was regarded at the time as sufficient to justify the first 10 MW of planned installed capacity. The Governor announced a set aside of $500,000 to $1 million to support 250 MW of wind development over the coming decade, one-fifth of the estimated new generating capacity that Colorado will need in that period. The Governor is recommending to the legislature: (1) A surcharge on all electricity, once the market is deregulated, to fund renewables development; (2) A requirement that utilities disclose their resource mix; (3) Reduced property taxes for renewables plants; and (4) Income tax credits for renewables. One possibility is that wind plants located to the north in Carbon County, Wyoming, may end up serving Colorado green power markets because the area has a better wind resource and development of wind farms is underway.

3.5 Setting Standards for Green Power

A potentially serious problem facing green power schemes is setting standards for and ensuring disclosure of sources. Some green power marketers have offered nuclear power as green, while others are selling fossil fuel power as green on the basis of carbon offsets or contributions to environmental groups. To reduce the potential for misleading claims, certification schemes are springing up. A programme administered by the Center for Resource Solutions, identifies certified products with its “Green-e” label. The programme’s web site lists the energy sources in the mix and, in some cases, estimates the monthly difference between particular green power offerings and utility prices for conventional power. Green-e certification is meant to complement EC certification.

3.6 The Federal Production Tax Credit

The US Congress approved the federal Production Tax Credit (PTC) for new wind energy projects as part of the 1992 Energy Policy Act. The PTC has done little to spur development of projects, because enforcement of PURPA by state PUCs effectively ceased in the late 1980s, leaving wind energy to fend for itself in an increasingly competitive market against utilities turned hostile by the mounting pressures of impending deregulation. To meet new capacity requirements, state PUCs turned increasingly to all-source bidding procedures, which usually resulted in contracts being awarded to gas-fired plants. FERC allowed this to happen since PURPA includes gas-fired cogeneration among its “alternative sources” and the federal government under Presidents Reagan and Bush was more interested in supporting competitive energy markets than renewable energy development.

Attempts during 1998 to extend the PTC failed, the result being that throughout 1999 it was thought that the wind energy subsidy would only be applicable to new projects completed by 30 June 1999. A "second wind" of projects in the US, totalling around 800 MW, was propelled by the deadline. The PTC has subsequently been extended for 2.5 years, effective retrospectively to the 30 June deadline.

3.7 State Renewables Portfolio Standards

The Federal Government's 1998 Comprehensive Electricity Competition Plan proposes Renewables Portfolio Standards (RPS) for all electricity suppliers from 2000. Five US states have adopted RPS, specifying a minimum standard for renewables content in the energy supply mix. For example, Connecticut has ruled that within nine years of liberalising its electricity market in 2000, 6% of the state's electricity must come from wind, solar, biomass, landfill gas, or fuel cells. Progress towards this target must be shown each year. The other states using the RPS approach are Massachusetts, Maine, Nevada, and Arizona.

3.8 Conclusions from the US Experience

3.8.1 Subsidies and support schemes

- By requiring electric utilities to purchase power from alternative sources at premium rates, PURPA fostered rapid wind energy development but led to a consumers' revolt when fossil fuel prices declined. PURPA proved unsustainable as political pressure mounted for a competitive, deregulated market.
- Investment tax incentives adopted in the early 1980s and cancelled in the mid- to late-1980s contributed to an upsurge in development but led to the hasty construction of projects, many of which were poorly planned or installed low-quality equipment.
- The PTC announced in 1992, now being allowed to expire, will do little to revive the wind power industry because of its modesty and the fact that in the absence of PURPA enforcement, wind projects are not competitive with gas-fired projects. As happened in the 1980s, the short life of the programme combined with uncertainty regarding its continuation, has led to industry insecurity and instability, reducing the viability and competitiveness of most US manufacturers and developers.

3.8.2 Deregulation

It is too early to draw any conclusions regarding the impact of deregulation on the wind energy industry. However, at the moment it seems to be having one negative and one positive effect. The negative effect is that utilities are so concerned about surviving deregulation without going bankrupt or being acquired as the industry consolidates that increasing their renewables portfolios is low on their list of priorities. The positive effect is that a few power brokers and pioneering green power marketing firms are finding small but growing niche markets for renewable energy, including wind.

3.8.3 Effect on the costs of wind power

PURPA sparked a surge in development, especially in California, which led to economies of scale and technological improvements that gradually lowered the production costs of wind turbines deployed in large wind farms from over \$0.08/kWh in the early 1980s to around

$0.06/kWh by the end of the decade. The removal of subsidies and increased use by utilities and PUCs of competitive bidding procedures to award contracts for capacity additions has had little impact on costs because virtually no new wind energy capacity was added in the US between 1990 and 1997. Today's lower cost, in the range of $0.05/kWh for large projects at windy sites, is attributable to a combination of refinements in equipment, including more efficient blades, improvements in knowledge of how to array turbines on a given site, and larger, more productive turbines (average 600kW).

The vulnerability of the US wind power industry to volatile and unpredictable federal and state policies and politics has led to considerable instability, as evidenced by numerous bankruptcies and consolidations. The largest US wind power manufacturer and developer, Kenetech, declared bankruptcy in 1996. Only two major companies from the 1980s "wind rush" remain viable today – SeaWest, which recently split into two companies, and Zond, which was acquired last year by Enron Corporation.

4 EUROPEAN UNION

Five of the seven most prolific countries in the world in wind energy development- Germany, Denmark, Spain, the Netherlands, and the UK-are member states of the European Union (the other two are the US and India). European Commission (EC) policies, pronouncements, and actions have begun to affect both government support policies and market developments in these countries.

In 1997 the EC published a White Paper (policy document) on renewable energy, committing the EU to double renewables' current share of EU gross inland energy consumption to 12% by 2010. The White Paper did not call for a specific approach to renewables support. The EC has been working on a directive which was originally intended to lay down a common approach to renewables support that is compatible with the competitive EU "Internal Electricity Market". The EC has been concerned that without a set of common rules the various support schemes in individual countries will lead to market distortions, including favouring renewable energy suppliers from one country at the expense of those in another.

One mechanism considered is a system of fixed quotas of renewable energy in the power supply mix, backed by trade in "green certificates", a system recently started up in the Netherlands (see below). The EC seems to regard the green certificate approach as one compatible with a competitive market. Under such a system, electricity distributors and large consumers are required to produce or buy a fixed percentage of their electricity from renewable sources. They earn certificates for what they produce and are allowed to make up any shortfalls in their own production by purchasing certificates from sellers that generate more electricity from renewables than is required under their quota. A secondary market in certificates will develop, and its existence will put downward pressure on prices as developers undertake projects that they estimate will generate electricity at a cost lower than the market price of certificates.

Other approaches considered by the European Parliament are a system of national renewables quotas, a system of fixed, premium payments, modelled after the current REFIT system in Germany or its Danish counterpart, and a system of tradable CO_2 emission permits or credits. Under the latter, wind energy would be favoured relative to conventional sources of electricity that burn fossil fuels.

EU Competition Commissioner, Karel van Miert, has warned the German government that the preferential, fixed tariff it requires utilities to pay for wind energy, the so-called REFIT tariff (discussed below), is inconsistent with the EU's Internal Electricity Market, which does not allow for market distorting subsidies. One result of this intervention has been to provide encouragement to German utilities, such as Preussenelektra, which have challenged the tariff programme in a series of lawsuits before the German Constitutional Court. Reinforcing van Miert's statements, the European Parliament in June 1998 rejected a German proposal to extend its system of mandated premium prices for renewables to the whole of the EU.

The plethora of support schemes operated in member countries have proved difficult to rationalise. Fixed tariff schemes in particular have proved most effective at fostering large amounts of development and thus there is a reluctance by many to abandon them. The Commission's original draft directive calling for harmonisation of schemes has been replaced by a proposed Directive on "The Promotion of Electricity from Renewable Energy Sources in the Internal Electricity Market." The proposal calls for member countries to set renewable energy targets commensurate with the Community Renewables White Paper and national greenhouse gas targets. The Commission remains of the belief that a harmonised support mechanism is a desirable ultimate objective, and is proposing to review the situation 5 years after the currently proposed directive comes into force.

4.1 Germany

As of the end of 1999, Germany ranked first in the world in terms of wind energy installed capacity, with 4,444 MW (33% of the world total). The German market overtook the USA in terms of installed capacity in 1997 and continues to have the largest annual additions of any market in the world. Last year, Germany installed almost 1.6 GW of wind capacity, which represented 45% of the world total installation and is also double the German capacity additions of 1998.

4.1.1 Electricity Feed-in-Law

In 1990 the Bundestag enacted the Stromeinspeisungsgesetz or “Electricity Feed-in Law” (EFL). Its intent was similar to that of PURPA - to foster development of renewables in order to reduce Germany’s dependence on imported fossil fuels, decentralise generation somewhat, and reduce air pollution. Through the work of the Enquete Kommission, German parliamentarians were already concerned about greenhouse gas emissions at the time. As of 1990 only 0.2% of electricity was sourced from solar and wind, and only 4.2% came from renewable sources, mostly large-scale hydro. The EFL obligates the utilities to buy power generated from hydro, wind, solar, sewage, and landfill gas and from biomass or biogas derived from municipal, agricultural, or forest waste. For power from solar and wind the utility is required to pay a price per kWh equal to at least 90% of the average price paid by all end-users during the year. In 1998 this amounted to 17 pfennigs/kWh ($0.1063). The fixed price is called the “renewable energy feed-in tariff” or REFIT.

The utilities have filed several lawsuits against the EFL, none of which has to date been upheld by the Constitutional Court. Some utilities have refused to pay the required rates, and the resulting court battles continue. Utilities argue that renewables are more expensive than conventional power and that the federal authorities should take responsibility for absorbing the extra costs. They also argue that decentralised technologies, such as wind power, pose problems for transmission grids.

The large utility, Preussenelektra, claims that Germany is the only European country in which individual utilities are forced to pay charges for wind energy laid down by law. Under the EFL, the greatest burden was on the utilities that have the greatest wind power capacity in their service area. Preussenelektra claims that whereas it must pay 17 pfennigs (pf) equivalent to $0.106, the average rate for wind generated power in Europe is between 9.8 pf ($0.061) and 10.8 pf ($0.068), per kWh. It asserts, moreover, that in most other countries the financial burden is borne either by the state, i.e. all taxpayers, or by all electricity customers.

The utilities proposed legislation that would, among other things, impose a cap on their obligation to purchase renewable energy. No utility would be required to buy wind energy exceeding 5% of its total generation. Needless to say, Germany’s wind and renewables trade associations oppose this legislation, arguing it would make it impossible for the country to achieve its Kyoto obligation. The BWE (Bundesverband Windenergie) supports other features of the proposed legislation, including a provision allowing utilities to pass on the additional costs of renewable energy to the consumer by including the costs in the transmission charge.

Minor changes were made to the EFL during its merger with the recent energy market liberalisation legislation. The obligation to take up renewables power was transferred from utilities to grid operators, and the so-called "hardship clause" in the EFL was made more specific. This clause has allowed specific utilities to cap the amount of wind energy they must purchase at 5% of the amount of electricity they supply. They could do this by transferring any amounts above 5% to the next higher utility in the chain of supply. The clause has been tightened to limit the amount of renewable energy a grid operator must take to 10% of the energy it transmits. At the same time, the government has promised to review the policy before any grid operator hits the 10% ceiling or by the end of 1999. To date, only one regional utility, Schleswag, has invoked the hardship clause, passing responsibility for some of its REFIT payments in its distribution area to its affiliate, Preussenelektra, which, as indicated, is disputing its obligation in court.

4.1.2 Renewable Energy Sources Act

A new Act – The Renewable Energy Sources Act or Erneuerbare-Energien-Gesetz (EEG) – has now been passed. It retains the basic principle of a feed-in tariff but promotes smearing of extra costs between utilities on an equal basis. A fixed rate per kWh is paid which varies by technology. For wind there is a premium rate of at least 17.8 pf/kWh for the first 5 years (for onshore) or 9 years (for offshore). Thereafter the premium rate may be extended at the same or a reduced fixed tariff – if production reaches 150% of a specified reference yield, the kWh tariff steps down to at least 12.1 pf/kWh. If not, the high rate is extended for a period calculated according to the difference between actual and reference production.

The EEG also stipulates that for projects commissioned in 2002 onwards, tariffs will be reduced annually by 1.5%.

Under the EFL, falling consumer tariff prices (to which the EFL price was linked) and legal challenges had raised uncertainty and depressed profitability. The new law is considered to be more secure, especially in view of the fact that the feed-in tariffs are a fixed rate rather than a % of market price. Early indications are that wind energy activity has increased as a result.

4.1.3 Federal subsidies

In 1989, BMFT (Ministry for Technology Development) initiated the 100-MW-Wind programme, which offered a subsidy of 8 pf/kWh ($0.05) for wind generation. Participation was limited, and the programme was quickly over-subscribed. In 1990, BMFT expanded the programme by initiating the 250-MW-Wind programme. It offered a subsidy of 6 pf/kWh ($0.0375), which was paid in addition to the favourable rate – 16.52 pf/kWh ($0.1033) required by the EFL. This programme has been widely criticised for being overly generous. BMFT received applications for the installation of over 9,000 turbines. By 1993 only one-third of the turbines installed in Germany represented participants in the BMFT subsidy programme, indicating that EFL rates alone were sufficient to foster substantial development without additional subsidies.

A question raised by the 100 and 250 MW programmes is why did BMFT undertake "test" programmes of fixed size rather than offer incentives for commercial deployment, letting the market determine the scale of actual development. The ostensible objective of the programme was to evaluate, over a ten-year period, the potential of wind energy and its level of public acceptance. Such a "test" seems to be a highly conservative approach in view of the information available from development efforts in California, Denmark, and the Netherlands. Some critics allege that the utilities preferred a small scale pilot phase with large subsidies in order to demonstrate not the technical feasibility of wind power but rather its high costs and low potential.

4.1.4 State support programmes

Schleswig-Holstein has a goal of obtaining 20% of its electricity supply from renewable sources by 2010. It offers investment and tax credits to wind energy projects equivalent to between 14 and 17% of installed costs. Mecklenburg-Vorpommern offers a subsidy of up to 10% of invested capital for wind turbines planned for sites where wind speeds do not exceed 5.5 m/sec. at a height of 30 metres and/or where grid connections require high investments. Niedersachsen has established a target of 1,000 MW installed capacity by 2000. It provides support for new turbines over 250 kW, subject to their being located on approved sites and to operating for 1600-2000 full load hours per year. The subsidy is up to DM 150/kW ($93.8) or around 9% of the cost of a 600 kW machine.

4.1.5 Electricity market liberalisation

Germany's liberalisation law, *Gesetz zur Neuregelung des Energie-wirtschaftsrechts* came into force in May 1998. Its two pillars are negotiated third party access and use of the so-called "single buyer" system. Theoretically, the law removes the utilities' demarcated monopoly supply areas and gives consumers free choice of supplier. In actuality, there is no administrative infrastructure for making this happen, the result being that so far only a few large industrial consumers, such as Daimler Benz, have availed themselves of the opportunity to shop around.

To gain third party access, an independent supplier is authorised to draw up contracts with both its customer and the owner of one of the grids through which the power will pass. To date such agreements have only been entered into between utilities and big industry. The new law requires utilities that own grids to operate them autonomously. From 2000, grid operators must publish a tariff guide based on average values for the previous 12 months. Utilities are required to unbundle generation, transmission, and distribution in their accounting.

Under the single buyer system, a utility effectively adopts the supply contract signed between the independent supplier and its customer, integrating the power purchased into its load management. The supplier must pay for the use of the grid, the tariff being authorised and published by the regional supervisory authority.

4.1.6 Green power markets

Several German utilities are offering green electricity to their customers, who pay a premium on their normal electricity bill. The utility invests the money, often along with some of its own, in new renewable energy projects. These initiatives are barely underway, and it is too early to measure any results. In addition, several independent green power traders are preparing to enter the market. One group, Energie-Stiftung Schleswig-Holstein, is working with Danish and Dutch counterparts to develop a quota and green credit trading system. It wants to see fixed quotas for renewables in the supply system, regarding them as more open and fairer to both buyers and sellers than competitive tender systems such as NFFO. (The German wind energy trade association opposes quotas, arguing they will favour large companies and lead to a situation where small- and medium-sized suppliers will be bought out or pushed out by large companies, including utilities.) A second group, Naturstrom AG (NatAG), was founded for the sole purpose of facilitating trades of renewable energy. NatAG plans to enter into purchase contracts with operators of renewables plants and sell the "natural power" they generate to customers at a premium price. NatAG plans to operate its own dispatcher station to provide green power around the clock. It plans to provide proof that all electricity it sells is from renewable sources and to provide on demand a direct price comparison with conventional power.

4.1.7 Conclusions from the German experience

One result of Germany's generous support programmes is that Germany now leads the world in terms of wind energy capacity installed. Another outcome is that the price of German wind power is about 80% higher than the price of British wind power. Part of the reason for this is that Britain is windier: average sites in Britain are equal to the best sites in Germany. Overall productivity of British wind farms is about 40% greater than for German wind farms. The rest of the price difference is explained by the fact that German wind turbines, 70% of which are manufactured domestically, are on average 25% more expensive than the Danish turbines that have dominated sales in Britain. Furthermore, installation costs are about 25% higher in Germany, a function of higher wage levels and living costs.

Because prices paid for wind energy are fixed by the government and also because installation and production costs (and profitability figures) are private information, it is not certain if wind energy costs are declining in Germany. However, it can be concluded that Germany's fixed price approach to subsidies is clearly inferior to the UK's NFFO approach as a method of gradually and continuously bringing about "cost convergence" with gas-fired generation. However, this is not to conclude that the German programme is not being successful in terms of achieving the German government's particular mix of objectives, including fostering development of environmentally and technically sound projects using high-quality (but relatively expensive) German equipment, as well as encouraging development of Germany's modest wind resources.

How Germany's planned electricity liberalisation will affect its wind support programmes and wind power development in general is an open question. Also, it is unclear what new policies the recently elected Social Democratic/Green coalition government will adopt. It is too early to tell what effect liberalisation and green power markets will have on German wind energy costs.

4.2 The United Kingdom

As of the end of 1999, the UK ranked seventh in the world in terms of wind energy installed capacity, with 345 MW (3% of the world total). In recent years there has been a marked decline in annual wind capacity additions, with just 26 MW added last year. The decline has been due mainly to difficulties in getting planning permission.

4.2.1 Non Fossil Fuel Obligation (NFFO)

The NFFO was announced in 1989 and implemented in the context of privatisation of the electricity supply industry (ESI). Implemented in England and Wales (E&W) in the first instance, the NFFO's later counterparts in Scotland and Northern Ireland were the Scottish Renewables Obligation (SRO) and the Northern Ireland NFFO (NI-NFFO) respectively. Although the scheme was primarily intended to support nuclear power about 1% of revenue from the proposed fossil fuel levy (in E&W) was earmarked for renewables. The original plan was to contract for new renewables capacity of 600 MW in stages until the year 2000. Prior to the Rio Conference in 1992, the government announced a more ambitious goal for the NFFOs[2] – to bring on line 1,500 MW Declared Net Capacity[3] (DNC) of new commercial

[2] The NFFO, SRO and NI-NFFO are in this report collectively referred to as the NFFOs.

renewable energy by 2000. The higher target was part of a new government commitment to reduce the UK's carbon emissions to 10 million tonnes below their 1990 level by 2000 (a target which was subsequently replaced by a commitment to "return" carbon emissions to their 1990 level by 2000).

The NFFOs have achieved two noteworthy objectives. First, they have succeeded in fostering the development of nearly 750 MW DNC of new renewables capacity (as of 31 December 1999) and of contracting for an additional 2,890 MW DNC. With respect to wind energy, to date nearly 150 MW DNC has been commissioned and an additional 1000 MW DNC has been contracted. Second, the NFFOs have progressively reduced the costs of wind power through their rounds ("tranches") of competitive bidding. For the NFFO orders in E&W:

- NFFO-1, announced in 1989, contracted for 9 wind energy projects (out of 75 total renewable energy projects). Projects were paid their bid price, ranging from 5.75 to 10 p/kWh ($0.09-0.16) for contracted wind projects.
- NFFO-2, announced in 1991, contracted for 49 wind energy projects (out of 122 total). This tranche approved projects coming in below a strike price of 11 p/kWh ($0.18). Projects were paid the marginal "band Price". For NFFO-1 and 2, contracts were terminated in 1998.
- NFFO-3 was announced in 1994. Contracts for NFFO-3 onwards were awarded on the basis of individual bid prices. Wind projects were divided into "small" and "large" categories with installed capacities below and above 1.6 MW respectively. The average price paid to larger projects was 4.32 p/kWh ($0.0734), while the average price paid to smaller projects was 5.29 p/kWh ($0.0899). The price drop relative to NFFO-2 was due mainly to the length of the contracts awarded: 15 years versus 6-8 years.
- NFFO-4 was announced in 1997. Wind projects were again divided into "small" and "large" categories, this time with installed capacities below and above 0.768 MW respectively. Small projects were paid an average of 4.57 p/kWh ($0.078), and large projects were paid an average of 3.53 p/kWh ($0.060). 48 large projects, totalling 330 MW, and 17 small projects, totalling 10 MW, were approved. Among the 65 new wind projects were the first two offshore projects. NFFO-4 contracts run for 15 years from commissioning and projects must be commissioned before 1 May 2002.
- NFFO-5 was announced in September 1998. 117 bids were received. Wind projects were again divided by size, into projects smaller than 0.995MW and ones larger than 0.995MW. 33 larger projects, totalling 340 MW, were approved, while 28 projects, totalling 28MW, were approved. The average contract price for larger projects is 2.88p/kWh ($4.9), while the average price for smaller projects is 4.18p/kWh ($7.11). NFFO-5 contracts run for 15 years from commissioning and projects must be commissioned before 1 December 2003.
- The NFFO's Scottish counterpart the SRO demonstrates similar price reductions. In the third and last round, the cheapest awarded contract was for $0.0315/kWh, which it has been claimed is probably the cheapest wind power in the world.

The NFFO model has been highly successful at fostering both development and "cost convergence" (i.e. bringing the cost of renewables down closer to the cost of gas-fired

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[3] Government figures are often presented as Declared Net Capacity. This is to facilitate comparison of intermittent and variable output such as wind power with more conventional power. DNC is calculated by subtracting on-site electrical power consumption and losses from installed capacity and multiplying the remainder by 0.43.

generation) though there is still a substantial gap. Wind project developers have been critical of elements of the NFFO, because of the uncertainty of project approval, the costs and time involved to prepare bids (in the face of uncertainty), and the gaps in time between tranches, during which periods overhead costs accumulate. There is also concern over the limited amount of capacity that has actually been installed compared to the NFFO orders, although this is primarily due to planning consent difficulties.

The Fossil Fuel Levy (FFL) recovers the difference between the "reference price" paid by the supply companies and the contract price received by generators. In England and Wales the FFL amounted to about 10% of the average retail electricity price between 1990 and 1996, at which time it fell to 3.7% following the flotation of British Energy (the nuclear plant operator). In 1997 it fell to 2.2% and in 1998 to 0.9%. As of April 1996, renewables had received approximately £309 million from the levy, which added approximately £3.50 ($5.95) to the average annual domestic electricity bill. In 1997/98 the levy raised £279 million (US $474) for renewables. The renewables portion of the levy, which started at 1% in 1990, reached 49% in 1997/98. Since March 1998, when support for nuclear ceased, all funds go to renewables. The amount of support, however, is expected to decline as the most expensive NFFO-1 and –2 contracts end. From January 1999, renewable energy will add 0.7% to the average customer's electricity bill, up from 0.9% now. The levy is now at its lowest level since it was introduced.

4.2.2 Green tariffs

Electricity liberalisation has been extended to households so that all UK customers are now able to shop around for their electricity supplies. Some are interested in purchasing green power, and the government has introduced an accreditation scheme – "Future Energy" – aimed at reassuring potential green electricity consumers that the product is genuine. As of November 1999 there were 12 green electricity tariffs on offer in various parts of the UK.

4.2.3 New Electricity Trading Arrangements

At the heart of the UK's liberalised electricity market will be the New Electricity Trading Arrangements (NETA) in England and Wales. Reform of the trading system was called for in the government's Energy White Paper, which was published in October 1998. The existing pool is perceived to have exacerbated market distortions, including abuses of market power by large coal-fired generators.

NETA will do away with the Pool, replacing it with a structure consisting of three elements: (1) A forward market in bilateral contracts supported by a derivatives market in futures and options; (2) A short-term (up to 3.5 hours ahead of delivery) market that generators, suppliers, and large customers will be able to use to adjust their contract positions; and (3) A balancing market (from 3.5 hours ahead of the start of each half hour trading period to real time) in which National Grid Company can buy offers of flexible capacity and load reductions to balance supply and demand. Post-event settlement will reconcile differences between contracted and metered positions – it is expected that the terms under which differences are "cashed out" will be onerous for intermittent plant such as wind.

NETA is currently expected to go live towards the end of this year.

Trading arrangements are also under review in Scotland, which is expected to result in arrangements compatible with, but not necessarily identical to, those in England and Wales.

4.2.4 A new Supplier's Percentage Obligation

The Utilities Bill was introduced to the Houses of Parliament in January 2000 and received Royal Assent in July 2000. The Bill provides for placing an obligation on suppliers to source a minimum percentage of their purchases from renewable sources. The obligation will be imposed via a Statutory Instrument which will be subject to approval by the Houses of Parliament (in England and Wales) and the Scottish Parliament (in Scotland). The order will specify the level of the obligation, eligible sources and compliance requirements.

It is anticipated that "green certificates" will be used as evidence of compliance with the obligation. Certificates will be tradable, thus removing the need for a physical connection between suppliers and generators. It is therefore conceivable that, for example, a supplier in London could obtain its quota of Green Certificates from wind farms in Scotland. Suppliers will also have the option to "buy out" of the obligation at a pre-specified buy-out price for any shortfalls in meeting their quota. Government has suggested that this might be some 2p/kWh above the price paid for 'brown' electricity.

If, as is expected, there are no technology bands under this mechanism, only the cheapest technologies are likely to supported in this way. Furthermore, generators will have to trade in the open market under significantly revised arrangements also to be provided for in the Bill.

It is worth noting that another consequence of the Utilities Bill is expected to be a relaxation of the recently imposed moratorium on the construction of new CCGT plant in the UK.

4.2.5 Climate Change Levy

The Government will also introduce the Climate Change Levy, which will come into effect in April 2001. It is a tax on the business use of energy (electricity, coal, natural gas and Liquefied Petroleum Gas) and is calculated on the basis of fuel energy content. Energy supplied from renewables sources is exempt from the tax. For electricity users, this represents a price advantage of approximately $0.01/kWh over conventional generation. Levy receipts will be recycled back to businesses through a 0.3% cut in employer's National Insurance Contributions, a £50 million energy efficiency and renewable energy fund, and tax deductible energy efficiency investments.

4.2.6 Prognosis

The prognosis for wind is mixed. On the one hand it is, along with energy from waste, among the cheapest qualifying technologies for the supplier's percentage obligation. Furthermore, it will be exempt from the Climate Change Levy.

On the other hand, intermittent generators may be heavily penalised under the revised trading arrangements. It remains to be seen to what extent these penalties will limit the exploitation of the UK's excellent wind resource.

4.2.7 Conclusions from the UK experience

The UK's NFFO is the only national wind energy support programme that has achieved cost reductions through the conscious design of the scheme rather than as a fortuitous consequence of technological improvements, market penetration and economies of scale. In spite of the many variables that go into cost calculations, and the impossibility of isolating them, the effect of successive rounds of competitive bidding has been both unmistakable and dramatic.

Between 1993 and 1998, the price per installed kW of wind power fell about 22% and the price per kWh delivered fell about 46%. Downward price pressure has been even stronger than these figures suggest, because finance and operations and maintenance costs have fallen even faster as confidence in the technology on the part of investors has led to lower financing costs.

At the time of writing, prospects for wind energy in the new regime remain a matter for speculation. The biggest challenge for projects developed over the next few years is likely to be securing finance in the unfamiliar and relatively uncertain new era.

4.3 Denmark

As of the end of 1999, Denmark ranked third in the world in terms of wind energy installed capacity, with 1,700 MW (13% of the world total). Danish firms account for approximately 60% of the world market for wind turbines.

4.3.1 Subsidies and price supports

During the 1980s, 30-50 MW of wind energy capacity was installed in Denmark each year. Private wind turbine owners were exempted from electricity taxes, which reached DK 0.31/kWh ($0.052) by the end of the decade. In addition, since the 1980s utilities, by agreement with the government, have paid wind energy producers 85% of the prevailing retail electricity price. For a time in the early 1990s, the policy was changed in such a way that co-operatives and owners of single turbines under 150kW in capacity continued to receive this rate, while owners of larger turbines were paid 70% of the retail rate. In the mid-1990s the size limitation was eliminated.

In 1986 the Danish government reached an accord with the country's utilities for installation of 100 MW of utility owned wind plants by 1990. ELSAM, the utility serving Jutland and Funen, was assigned responsibility for installing 55 MW, while ELKRAFT, which serves Copenhagen, was made responsible for 45 MW. The goal was actually achieved in 1992. The utilities agreed in 1990 to install an additional 100 MW, subject to approvals from local planning agencies, which were becoming difficult to secure. Since 1992 utilities have also been given an offset of DK 0.10/kWh ($0.0167) against their carbon taxes for the wind energy they generate.

Prior to the entry of utilities into the market, nearly all wind turbines were installed either individually, by co-operatives or municipalities. Approximately 100,000 Danish households, representing 5% of the population, own shares in a wind energy co-operative. Individuals or co-operatives own 75% of Danish turbines. Current tax rules favour members of co-operatives. Each household can own a share of a turbine corresponding to 150% of its electricity consumption. Profits are only taxed if they exceed the household's electricity bill by more than 10%. Investors receive DK 0.27/kWh ($US0.045) as a refund on the electricity taxes. (Tariffs are set at 85% of the average local before-tax retail price of electricity). On average, a turbine owner receives DK 0.30 ($0.050) plus DK 0.27 ($0.045) for a total of DK 0.57 ($0.095). Power companies receive less: DK 0.10($0.0167). It is estimated that with production costs now down to DK 0.25-0.30 ($0.042 –0.050), the net cost is DK 0.15-0.20 ($0.025-0.33) per kWh i.e. lower than the cost of new coal-fired generation.

4.3.2 Other benefits to wind energy developers

Farmers who own wind turbines are exempted from paying value added tax on the electricity they buy. Small co-operatives and single turbines are also advantaged by the lending policies of Danish banks and savings and loan institutions, which offer, at attractive rates, 10-12 year loans covering 60-80% of the installed cost.

4.3.3 Deregulation of electricity supply

Denmark's new electricity supply law went into effect in January 1998. It allows most of the country's electricity distributors and a few large industrial consumers to buy electricity from their supplier of choice. The long-standing "Windmill Law" requiring all output from wind turbines to be bought at 85% of the consumer price of electricity will remain in place unless disallowed in the future by the European Commission (which is speaking out against Germany's EFL).

The new electricity supply law requires generation and transmission to be unbundled. This means that the two vertically-integrated utilities, ELSAM and ELKRAFT, which have enjoyed territorial monopolies and controlled both generation and transmission within their respective territories, will each be split in two.

4.3.4 Proposed quotas combined with trade in certificates

The government is proposing a combined system of quotas for consumer and utility purchases of renewable energy and trade in green electricity certificates. The plan includes phasing out the existing system of fixed tariffs for electricity from wind energy and replacing it with a trading market for green credits. Distribution utilities would be required to supply fixed amounts of electricity from renewables. They can meet their quotas either by buying electricity from independent suppliers or through their own generation. Overall, quotas will be designed to meet the government's goal of having renewables provide 36% of Denmark's electricity by 2010.

Denmark is also examining the potential for trading in greenhouse gas emission reduction credits (or permits). Denmark hopes to be able to earn credits by selling wind power, thereby offsetting the credits it would need to possess in order to be able to continue exporting power sourced from fossil fuel combustion. Denmark's domestic CO_2 emissions have been declining, but its overall emissions have been increasing sharply because of exports of coal-fired power.

4.3.5 Conclusions from the Danish experience

Denmark can claim the world's most successful programme in terms of realising development in small increments throughout the country and in terms of fostering widespread ownership by Danish citizens, especially farmers, small co-operatives, and communities. In turn, the success of Denmark's domestic programme has contributed to Denmark's status as the world's number one exporter of turbines and related equipment. In 1997, even though Danish firms supplied 75% of the turbines sold world-wide, Denmark was still the largest single national market for Danish turbines.

Denmark has relied heavily on coal and imported electricity, mostly hydropower from Norway. In a given year up to 40% of Danish electricity is imported, and imported coal has been the source of as much of 80% of Denmark's annual electricity generation in recent years.

The government is now committed to phasing out the use of coal and obtaining 35% of the country's electricity from wind by 2030. This is by far the most ambitious target of any country and much of it will have to be met from offshore installations which are considerably more expensive to build and operate than onshore facilities.

Only limited conclusions can be drawn regarding the effect of the government's support programmes on the costs of wind energy in Denmark. The programmes have combined several elements: (1) The government has required the two major utilities to build fixed amounts of wind energy capacity as well as to pay a fixed premium tariff to independent wind energy suppliers; (2) A number of tax incentives favouring farmers, small co-operatives, and communities have been used to foster development in small increments; and (3) The government has applied its programmes in such a way that downward cost pressure has been exerted, the result being that today wind energy production costs for projects on windy sites in Denmark are comparable (between $0.05 and $0.06) with costs for projects developed in the competitive environments of the US and UK.

The principal benefit of the Danish experience has been the economies of scale and improved technology grounded in a robust, long term domestic market which has driven down the cost of wind energy in terms of both per kW installed and per kWh generated. This in turn has enabled wind turbine manufacture to become Denmark's third largest foreign currency earner. Other markets, such as NFFO which have resulted in much more modest capacities being installed, have also benefited from these cost reductions.

4.4 The Netherlands

As of the end of 1999, the Netherlands ranked sixth in the world in terms of wind energy installed capacity, with 409MW (3% of the world total). Annual capacity installations have not exceeded 100 MW and the Netherlands will not now reach its 1 GW target set back in 1991 for the end of 2000.

4.4.1 Subsidies and price supports

In the mid-1980s, the government began offering an investment subsidy of NLG 700/kWh ($400), corresponding to about 30% of installed cost. This subsidy prompted Dutch manufacturers to exaggerate the nameplate capacity ratings of their turbines in order to maximise the subsidy payment. Having realised its mistake, the government in 1991 changed the nature of the subsidy by linking it to the swept area of the turbine rotor which is a more direct measure than generator size of the actual productive capacity of the turbine. As in the case of the investment tax credit in the US, the investment subsidy encouraged the installation of capacity rather than the efficient continuous production of electricity. Investment subsidies may not deliver optimum operating performance if poorly designed or constructed turbines are handicapped by excessive maintenance problems.

Commercial development of wind turbines surged in 1991 after the government, the utilities, and the seven windiest provinces agreed on a goal of 1,000 MW by the year 2000 and 2,000 MW by 2010. Each province agreed to accept a portion of the total capacity, and the utilities agreed to install 250 MW by 1995 as part of the Environment Action Plan (MAP) for reducing CO_2 emissions. The current expectation is that the 1,000 MW target will not be achieved by 2000.

In the early 1990s, the utilities required wind turbine manufacturers to meet certain technical requirements. These proved to be out of step with technical developments in other countries, leaving Dutch manufacturers with designs inappropriate for foreign markets. To make matters worse, the utilities subsequently reneged on their orders for Dutch turbines, nearly killing the industry.

Individuals (mostly farmers) and co-operatives put up the first projects. As of 1995, 32% of all installed turbines were single units: 68% were owned by farms or agricultural co-operatives. More recently the trend has been to larger schemes sponsored by wind turbine manufacturers.

As of 1994, Dutch utilities were paying a tariff based on a marginal cost of NLG 0.07/kWh ($0.04). They were also paying an incentive for renewables and CHP of NLG 0.03 to 0.08/kWh ($0.017 to $0.046), depending on the utility. As a result, some Dutch utilities were paying a total of NLG 0.15/kWh ($0.086). The Private Wind Energy Developers Association (PAWEX) sought to standardise the incentive payment at the high end of the range. In combination with a capital subsidy of up to 30%, ample financial incentive was offered to encourage rapid development. Since then the main constraint has been siting conflicts. These have been ameliorated somewhat by the availability of bank financing to local entities, mainly farms, on reasonable terms. This has increased local acceptance of wind energy installations.

In 1995 the government eliminated the 30% investment subsidy, replacing it with a series of fiscal measures, including an ecotax on fossil fuels, an allowance for early depreciation of the capital costs of turbines, and a system of green investment funds (see below).

4.4.2 1997 White Paper on Renewable Energy

The White Paper outlines the steps that will be taken to meet the targets set for renewables: 3% share of electricity supply by 2000, 10% share by 2020. Measures include: (1) Broadening the range of fiscal instruments; (2) Amending the Electricity Act to set a minimum requirement for renewables in electricity supply starting in 2000; (3) Including large wind farms in the Electricity Supply Master Plan; and (4) Expanding the agreement between the national and regional authorities for resolving wind turbine siting problems.

The White Paper confirmed the government's plan to go ahead, subject to European Commission approval, with a reduced VAT rate (6% versus the standard 17.5%) for green (renewables-based) electricity. However, the EC subsequently denied approval on grounds it would violate EU fair competition legislation. The White Paper also confirmed that the Regulatory Energy Tax exemption (described below) will apply to renewable energy generated outside the Netherlands, except for large-scale hydro, including Norwegian hydro. The EC approved the so-called "zero rating" proposal as being consistent with EU guidelines on state aid for environmental protection. Finally, the White Paper described the renewables targets to which the electric utilities must commit themselves, which are based on each company's market share.

4.4.3 1998 Electricity Act

The 1998 electricity act seeks to promote the production of renewable energies through a system of "green certificates". Renewable energy producers are provided with a transferable document showing how much electricity they produced or will produce in a given year. Electricity consumers are then required to acquire a given number of these certificates to cover a given share of their total consumption, the share to be set by the government. The electricity act allows supply companies to act on behalf of their individual consumers in buying green certificates.

This system creates a single market for renewable electricity, the size of which is largely determined by the government and its requirement for a given share of electricity supply to be covered by renewables. The Memorandum on Renewable Energy, due to be published this autumn, will propose a timetable of target shares. Under this system there is no differentiation between renewable energies that qualify for certificates. In other words, the relative importance of each is determined by the relative costs of each technology and the willingness of consumers to pay.

The green certificates system for promoting renewable electricity generation will only come into force at the start of 2001. Until then a voluntary agreement has been put in place with EnergieNed, the Dutch utilities' umbrella organisation. This voluntary scheme is called the Green Label System and is outlined below. Details of the share of electricity to be covered by the green certificates have yet to be outlined, and indeed the government now appears to favour maintaining the voluntary system. The 1999 Energy Report merely mentions that the government would like renewable energy to account for 5% of total primary energy demand by 2010 and 10% by 2020.

4.4.4 Fiscal measures

- ***VAMIL.*** In 1997 the government declared wind plant investors eligible for tax breaks under VAMIL, the "accelerated depreciation on environmental investments" scheme. Investors may decide when and by how much they depreciate their turbines. The effect of early write-offs for eligible equipment is to reduce taxable income and increase after-tax profits. NLG 7.5 million ($4.3 million) a year is to be made available.
- ***Ecotax.*** In 1996 the government introduced the Regulatory Energy Tax (REB), known as the "ecotax". The tax, which raised the price of electricity 15% for the average household, is collected from customers by utilities and forwarded by them to the tax authorities. In the case of renewable energy, the utilities repay this tax to the generator. Green electricity purchasers are exempted from paying the tax.
- ***Green funds.*** The Minister of Finance allows banks to create so-called 'green funds', investors in which are exempted from income tax. 70% of the fund must be invested in government approved green projects. The fund makes loans to projects at below commercial interest rates (about 2 percentage rates lower).
- ***New investment tax credit.*** This is offered to "qualifying investments" in energy conservation and renewable energy technologies. The credit varies from 40 to 52% of eligible investment up to a limit of NLG 50 million ($28.6 million). The credit allows investments in wind energy to be offset against taxable profit, improving the rate of return.
- ***Electricity pricing.*** Owners of projects under 2 MW in capacity receive a higher energy price from the utility. Owners of projects larger than 2 MW have to negotiate the price.

4.4.5 ESI liberalisation and emerging green power markets

The government's plan is to meet the EU timetable for energy sector liberalisation by extending the right of free choice to users of more than 10 GW per year. European legislation stipulates that 'major users', defined as those consuming 40 GW or more annually, should be free to shop for power beginning in 2000, while users of 20 GW or more should have this right from 2003. The goal for penetration of renewables is 10% of generation by 2010.

As of May 1998, the utility PNEM had signed up 12,000 subscribers to its green electricity scheme. PNEM charges NLG 0.276 ($0.158) for green power. A zero rated REB will reduce this to NLG 0.25 ($0.143), just NLG 0.02 ($0.011) more than the current price of non-green power when it includes the REB. Although green electricity is still more expensive, the reduction in the price differential from over NLG 0.04 ($0.029) to NLG 0.02 ($0.011) is psychologically important, because at this level, the cost for an average household consuming 3,000 kWh yearly is under10 guilders.

The Dutch utilities' umbrella organisation, EnergieNed, is organising a market in green energy credits, called the Green Label System, which went into operation in January 1998. Under the system, local power distribution companies pay renewable energy producers a set price made up of the current price paid for power from the central reserve, plus the ecotax (REB). In addition to this price, the producer is issued "green labels" at the rate of one for every 10,000 kWh supplied over the previous month. The producer makes his profit by selling the labels back to the Dutch distribution companies on an open market driven by the utilities' obligation to have secured 1.7 billion kWh of renewables generation by 2000. This they can do either through purchase of green labels or their own production of green power. In February 1998, with the central reserve rate at NLG 0.08/kWh ($0.046), and the ecotax rate at NLG 0.03/kWh ($0.017), and with the generation cost of wind energy calculated at NLG 0.16 ($0.091), producers would have to sell their labels NLG 0.05 ($0.028) to reach break even.

Some developers prefer this system to the former subsidy programme because it is open ended. There are no limitations placed on rebates of the ecotax nor on the number of green labels that can be sold. In contrast, the previous subsidies were limited to the government budget.

4.4.6 Conclusions from the Dutch experience

Although the Netherlands ranks among the leading countries in wind energy development, the amount of new capacity coming on line has decreased since 1995 when the investment subsidy was eliminated. While 102 MW were installed in 1996, only 48 MW were added in 1997 and around 50 MW in each of 1997 and 1998. As a result, the Netherlands failed to reach the target set by the government in 1991 of 1000 MW in place by 2000.

The main reason for the slow growth, in spite of the incentives made available, is local resistance to new developments and resulting difficulties in obtaining local permits from planning authorities. There are also complaints from the industry that the fiscal instruments introduced in 1995 are a poor substitute for the previous subsidy.

Given the number of variables involved, including wind patterns at specific sites and variable land costs, only a tentative conclusion can be drawn regarding the effect of government support policies and new markets on the costs of wind energy in the Netherlands. The combination of energy price, ecotax rebate, and green labels results in an effective price paid to wind plant operators a few US cents higher than in the UK but a few US cents lower than the effective price paid in Germany. Wind energy production costs are higher than in the US, UK, and Denmark, owing to a number of factors (land costs, the small unit size of projects, wind conditions, etc.) but lower than in Germany.

4.5 Other EU Countries

4.5.1 Spain

As of the end of 1999, Spain ranked fourth in the world in terms of wind energy installed capacity, with 1,180 MW (9% of the world total). Spain has had the fastest growing market in the world for wind power. Installed capacity has risen from 72 MW at the end of 1994, an average annual growth rate of 75%. Annual capacity additions have accelerated from 50 MW in the mid-1990s to almost 350 MW last year.

Strong incentives for wind developers, coupled with regional incentives to spur local investment and willingness from banks to finance projects, have created a vibrant new industry that barely existed in 1994. Many of the incentives are coupled to the local manufacturing of equipment, which has created a rush from international wind turbine manufacturers to set up joint ventures with local industrial consortiums.

A temporary slowdown in the spectacular rate of growth is expected to occur this year because the regional governments in Castilla and Leon, where a very high number of projects are proposed, have introduced additional requirements regarding siting. Nevertheless, strong political support on both a regional and central government level will continue to promote wind energy developments. Presently the governments of the Canary Islands, Catalonia, Andalucia, Navarra, and Galicia support wind power. Ultimately, Galicia wants to have 5,000 MW of wind plant capacity, while Navarra, which has already achieved more than 20% wind energy penetration, wants 100% of its generation from renewables.

At the national level, a system similar to the German REFIT, introduced in 1994 and reformulated in 1998, ensures a payment equivalent to 80-90% of the retail price to wind energy producers (around Pta 12/kWh or $0.08). In addition, the national government has earmarked Pta 10.1 billion ($70.6 million) for renewables subsidies. Subsidies of up to 40% of the entire investment are offered up to a limit of Pta 400 million ($2,760,000).

4.5.2 Ireland

As of the end of 1999, Ireland ranked thirteenth in the world in terms of wind energy installed capacity, with 68 MW (less than 1% of the world total). Its importance, however, is greater than this ranking indicates because under its renewables support programme, the Alternative Energy Requirement (AER) the lowest standard prices in the world have been established for future capacity. These are under $0.05/kWh.

The AER, established in 1994, is similar to Britain's NFFO, in that new capacity is acquired through successive rounds of competitive bidding in which applicants compete for 10 and 15 year power purchase contracts. Standard prices are made available to successful applicants. In the first AER round, the wind energy price was IEP 0.04/kWh. Proposers first had to qualify technically, after which they submitted bids indicating the amount of grants they were requesting. 100 proposed renewables projects passed the technical evaluation. These offered five times the 75 MW being sought. In the end 34 projects totalling 111 MW were accepted, 73 MW of which were wind. Many wind project bidders did not ask for grants. Because AER-1 did not include any biomass or waste-to-energy projects, AER-2 was limited to these technologies.

AER-3 was announced in March 1997. It included a 90 MW target for new wind energy projects out of a total of 100 MW. Bids were made on the basis of price per kWh, not for a grant. As in AER-1, purchase contracts will have a maximum term of 15 years.
The Irish Wind Energy Association (IWEA) is proposing further AER rounds. Specifically it would like to see each round have four bands, each with a different tariff. The largest band, to include projects larger than 10 MW, would have a base price of at least IEP 0.03/kWh, while the second band, consisting of projects 2-10 MW in capacity, would have a base price of at least IEP 0.033/kWh. The IWEA argues that its proposal could achieve the installation by 2010 of 1,150 MW of wind energy capacity, providing 12% of projected electricity demand and contributing significantly to Ireland's objective of reducing its dependence on imported fossil fuels. The government's target for wind penetration has been more modest: to add 30 MW per year in order to achieve a total installed capacity of 469 MW by 2010.

To support wind energy development, the government makes available an investment tax credit covering up to 50% of the capital cost of a project, subject to a cap of IEP 7.5 million. Projects approved before the end of 1999 are eligible.

4.5.3 Sweden

As of the end of 1999, Sweden ranked tenth in the world in terms of wind energy installed capacity, with 195 MW (1% of the world total).

The government offered an investment subsidy of 35% of capital costs through mid-1996, at which point in time 100 MW had been built. It then discontinued the subsidy with the result that only 17 MW of new capacity were installed between mid-1996 and the end of 1997.

In May 1997, the government announced a new support programme that would make available a 15% investment subsidy as part of its new energy law. Within days of the law coming into effect in February 1998, following approval by the European Commission, 50 new applications for wind energy projects were submitted. In addition to supporting the development of new renewables, the new law establishes the Swedish National Energy Administration (SNEA), which is responsible for phasing out nuclear energy.

Deregulation of the Swedish electricity market in 1996 paved the way for green power sales. The Swedish nature conservation association, SNC, certifies green power projects meeting its criteria.

The biggest problem facing Sweden's wind energy developers is difficulty securing local siting approvals and building permits. Many of the best sites have been placed off limits by comprehensive land use studies. However, the government recently declared wind power development in the "national interest", requiring the setting of regional quotas. New regional wind maps identify specific areas to be zoned for wind energy development. Once the comprehensive zoning plan is complete, planning permission is expected to become easier to obtain.

4.5.4 Italy

As of the end of 1999, Italy ranked ninth in the world in terms of wind energy installed capacity, with 281 MW (2 % of the world total). The government offers a premium tariff to renewable energy and cogeneration plants. In addition, some regional governments, including those of Apulia, Campania, and Umbria, are making available capital subsidies.

Wind energy development in Italy faces two problems. First, developers complain that the process of securing building permits from local authorities is frustratingly slow. Second, most projects are sited in the mountainous rural areas where the distribution network is inadequate to support large-scale wind generation.

5 CHINA

As of the end of 1999, China ranked eighth in the world in terms of wind energy installed capacity, with 300 MW (2 % of the world total). The government has a target of 400 MW of installed wind capacity by the end of 2000, and 1 GW by 2010. There is around 200 MW currently in the pipeline, which should ensure that China achieves its 2000 target.

China is seen as a wind energy sleeping giant, as it has been slow to develop its vast wind energy potential. The country's immense energy requirements and air pollution problems create a favourable environment for wind energy developments. But the reliance on bilateral donor support means that projects have tended to remain small. This is beginning to change, as both large and small-scale turbine manufacturers have set up joint ventures under the "double increase" initiative. The expectation is that rapid growth in wind energy will take place early in the next decade.

5.1 "Double Increase" Initiative

This scheme was initiated in 1996. Under this initiative, an international tender for a wind farm will be awarded on the basis that half the wind turbines are produced locally. The winning tender is required to set up a joint venture with a Chinese company to manufacture turbines in China. In this way, the Chinese hope to develop an indigenous wind manufacturing industry based on the best international practise. The first three wind farms built under this initiative were commissioned in 1997 and 1998.

6 INDIA

As of the end of 1999, India ranked fifth in the world in terms of wind energy installed capacity, with 1,077 MW (8 % of the world total). The growth in the Indian market has been extremely fast, from just 200 MW of installed capacity at the end of 1992 to over 1 GW today. Nevertheless, the annual capacity additions have been declining since they reached a peak of 400 MW in 1996. In 1999, India added just 62 MW to its installed wind capacity.

6.1 Indian Wind Rush

India was one of the fastest growing wind energy markets in the mid 90's, based on extensive use of investment tax credits and premium prices paid for wind output. As a result, 100 MW of new wind was installed in 1995 and 400 MW in 1996, with total installed capacity reaching 783 MW. Since then, the wind rush has declined to a trickle. Under-performance of some of these projects (often due to poor siting), transmission problems, and political and economic instability have all affected investments, but the main reason for the slow-down has been modification of the tax credit scheme. The previous scheme resulted in unsustainable revenue losses for the government. The impact on wind capacity additions was immediate, with only 150 MW installed in 1997 and less than 150 MW installed in the next two years.

Nevertheless, the Indian electricity market has retained its fast rate of growth, and the country continues to be considered a key market for wind developers. In order to re-ignite the installation of significant amounts of wind energy, several factors are required. The introduction of a production tax credit is seen as the most important and preferable to an investment tax credit.

APPENDIX E

COST OF AVOIDED CO_2 EMISSIONS

CONTENTS

1 COST OF AVOIDED CO_2 EMISSIONS: FOUR STUDY REGIONS

1.1 China

1.1.1 Small onshore wind farms

Figure 1.1 and Table 1.1 show the abatement cost curves for small onshore wind farms in China. Although the abatement costs are relatively low for annual CO_2 savings up to 200 million tonnes, they rise quite steeply reflecting the large disparity between the generating cost of coal-fired power and that of small wind farms.

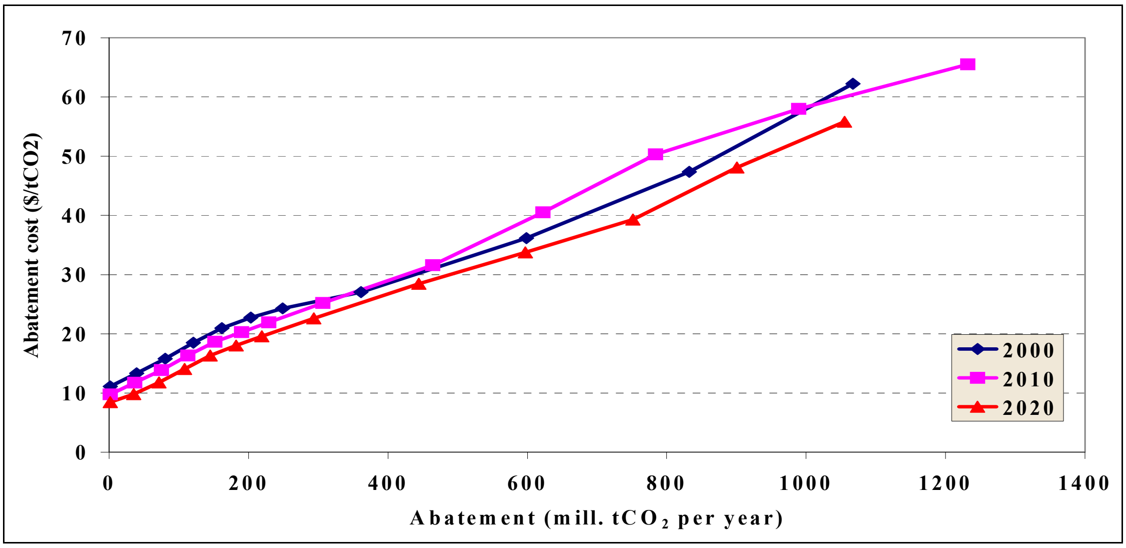

Figure 1.1: Annual abatement cost curves for small onshore wind in China

Wind	2000		2010		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
2	1.55	11.10	1.47	9.76	1.38	8.46
50	39.59	13.32	36.93	11.73	35.33	9.78
100	80.14	15.77	74.88	13.86	71.65	11.78
200	161.95	20.93	151.60	18.65	145.06	16.34
400	361.17	27.02	306.85	25.21	293.60	22.57
600	598.85	36.18	464.46	31.57	444.39	28.42
800	832.43	47.37	622.48	40.50	596.95	33.76
1000	1067.09	62.25	784.10	50.32	751.47	39.29
1200			989.54	58	900.85	48.09
1400			1232.18	65.5	1055.07	55.81
1600			1482.31	79.98	1214.62	63.35
1800					1383.33	73.19

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

Table 1.1: CO_2 abatement and abatement costs for small onshore wind in China

1.1.2 Large onshore wind farms

Figure 1.2 and Table 1.2 show the abatement cost curves for large onshore wind farms in China. The costs are lower for any given level of abatement than for the small wind farms, and considerable annual CO2 savings can be achieved - between 500-800 million tonnes at abatement costs of $20 per tonne of CO_2.

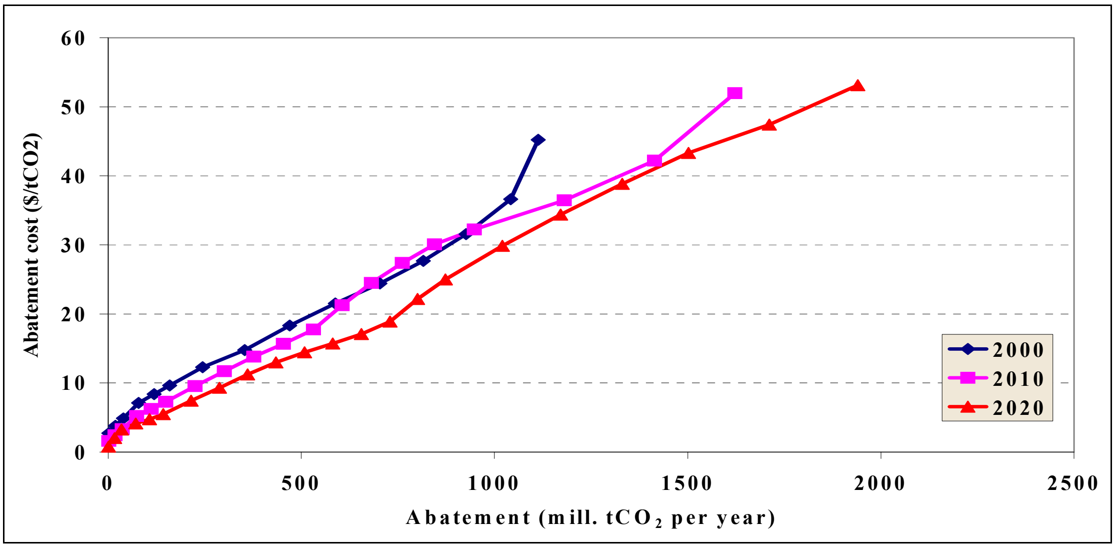

Figure 1.2: Annual abatement cost curves for large onshore wind in China

Wind	2000		2010		2020	
TWh	M tCO_2	$/tCO_2$	M tCO_2	$/tCO_2$	M tCO_2	$/tCO_2$
2	1.50	2.71	1.42	1.60	1.34	0.81
50	39.08	4.89	36.42	3.32	34.96	3.25
100	79.22	7.11	73.87	5.23	70.81	4.15
200	159.73	9.66	148.99	7.30	142.70	5.51
400	353.94	14.78	300.69	11.72	287.78	9.33
600	587.53	21.51	453.99	15.70	434.36	13.01
800	815.82	27.70	606.15	21.28	581.74	15.73
1000	1042.06	36.61	761.08	27.39	729.88	18.91
1200			948.02	32.25	872.8	25
1400			1180.96	36.47	1019.89	29.89
1600			1413.65	42.19	1171.62	34.37
1800			1621.82	51.98	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 wind output from the installed wind generation capacity, assuming no curtailment (wind spilt) due to system operational restrictions.

Table 1.2: CO_2 abatement and abatement costs for large onshore wind in China

1.1.3 Offshore wind farms

Figure 1.3 and Table 1.3 show the abatement cost curves for offshore wind in China. The high cost of offshore wind compared with coal-fired generation means that its development is a relatively expensive option for reducing the country's carbon dioxide emissions.

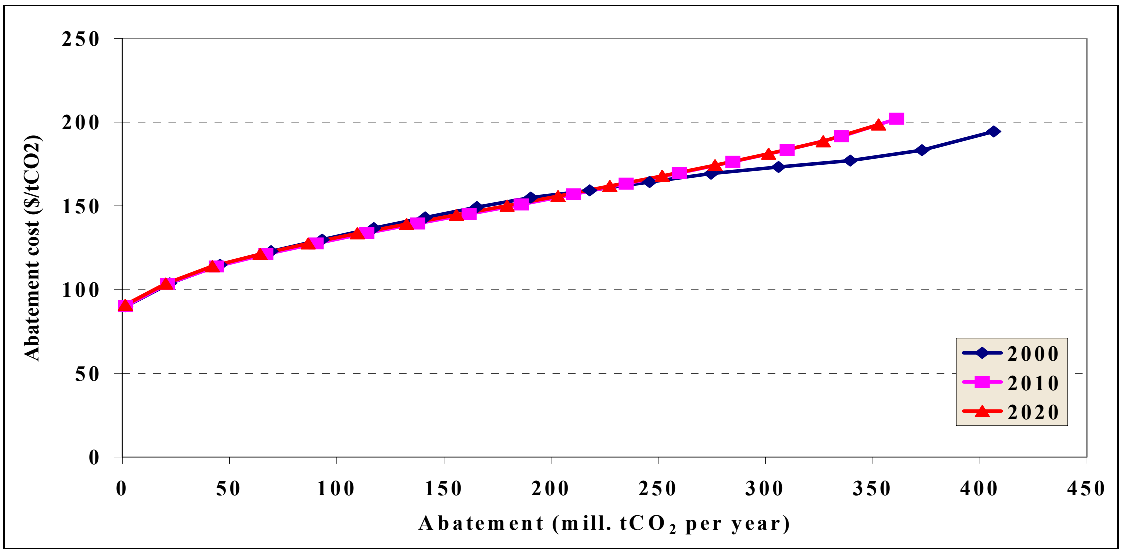

Figure 1.3: Annual abatement cost curves for offshore wind in China

Wind	2000		2010		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
2	1.53	89.95	1.45	90.21	1.37	90.94
25	22.02	103.82	21.10	103.42	20.18	103.59
50	45.53	114.88	43.83	113.72	41.99	113.88
75	69.31	122.97	66.96	121.22	64.21	121.29
100	93.21	129.88	90.34	127.67	86.72	127.59
125	117.19	136.65	113.96	133.76	109.53	133.56
150	141.26	143.06	137.81	139.56	132.59	139.18
175	165.40	149.30	161.84	145.16	155.90	144.58
200	190.50	154.93	186.03	150.91	179.44	150.12
225	218.10	159.39	210.42	156.97	203.28	155.90
250	245.84	164.39	235.07	163.23	227.43	161.88
275	274.63	169.27	259.89	169.67	251.85	167.98
300	306.11	173.23	284.90	176.36	276.54	174.31
325	339.54	177.06	310.10	183.53	301.52	181.16
350	372.98	183.32	335.51	191.54	326.93	188.67
375	406.45	194.55	361.26	202.11	352.84	198.61

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

Table 1.3: CO_2 abatement and abatement costs for offshore wind in China

1.2 EU-15

1.2.1 Small onshore wind farms

Figure 1.4 and Table 1.4 show the abatement cost curves for small onshore wind farms in the EU-15. Up to 400 TWh of wind per year the abatement cost curves simply reflect the difference in costs between wind generation and the capacity displaced (gas-fired CCGTs). Beyond this threshold, wind generation starts to incur additional system costs that accelerate the rise in the abatement cost curves beyond the natural rise in wind generation costs.

The 2000 figures are complicated by the fact that at the higher wind generation levels, existing coal capacity is displaced. This leads to a sharp increase in the level of abatement, but no account has been taken of the stranded investment costs.

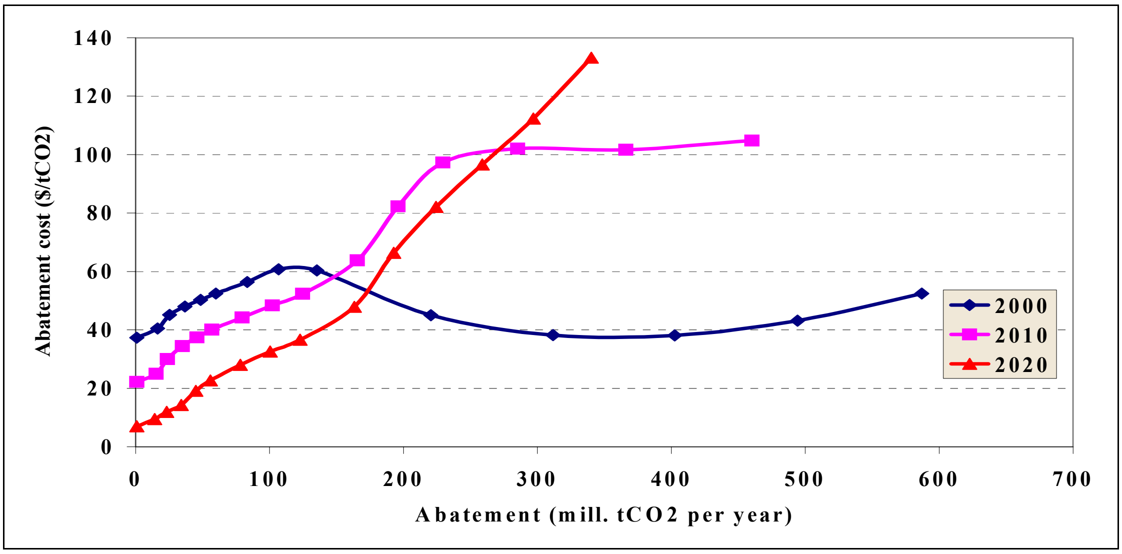

Figure 1.4: Annual abatement cost curves for small onshore wind in the EU-15

Wind	2000		2010		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
3	0.93	37.39	0.87	22.22	0.81	7.05
50	16.29	40.49	15.24	24.99	14.19	9.50
100	36.76	48.01	34.73	34.46	33.98	14.34
200	83.34	56.45	79.37	44.23	78.02	28.01
300	135.27	60.38	124.76	52.37	122.77	36.69
400	220.58	45.02	165.51	63.79	163.19	47.92
500	311.71	38.20	195.86	82.27	192.57	66.43
600	402.62	38.11	229.48	97.34	224.34	82.09
700	494.21	43.22	285.14	102.05	258.91	96.66
800	587.01	52.47	366.17	101.64	297.03	112.32
900			460.15	104.87	340.14	133.2

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

Table 1.4: CO_2 abatement and abatement costs for small onshore wind in the EU-15

1.2.2 Large onshore wind farms

Figure 1.5 and Table 1.5 show the abatement cost curves for large onshore wind farms in the EU-15. The curves indicate that large onshore wind is a relatively inexpensive option as a carbon dioxide abatement technology, at least up until wind generations of 400 TWh (i.e. up to 10% of total generation).

The assumptions concerning the need for additional peaking generation for wind penetrations above 10% leads to a rapid increase in the abatement cost curve once wind generation exceeds 400 TWh. The impact of these assumptions is reviewed as part of the sensitivity analyses in Section 14 of the Main Report.

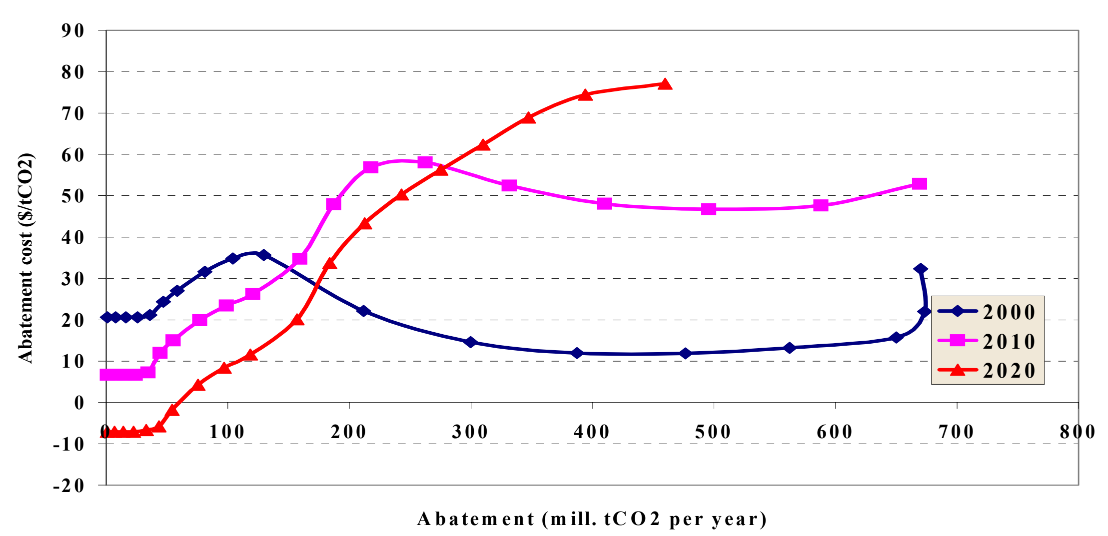

Figure 1.5: Annual abatement cost curves for large onshore wind in the EU-15

Wind	2000		2010		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
3	0.93	20.57	0.87	6.73	0.81	-7.10
100	35.91	21.14	34.39	7.25	32.88	-6.64
200	81.26	31.59	76.90	19.92	75.53	4.25
300	129.83	35.69	120.69	26.26	118.69	11.62
400	211.80	22.14	159.40	34.76	157.05	20.14
500	299.91	14.61	187.32	47.91	183.97	33.69
600	387.25	11.97	217.61	56.89	212.62	43.35
800	562.11	13.20	331.47	52.48	275.28	56.33
1000	673.37	21.97	495.63	46.77	347.35	68.92
1200			669.08	52.92	459.84	77.08

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

Table 1.5: CO_2 abatement and abatement costs for large onshore wind in the EU-15

1.2.3 Offshore wind farms

Figure 1.6 and Table 1.6 show the abatement cost curves for offshore wind in the EU-15. The abatement costs are relatively high reflecting the higher cost of offshore wind energy.

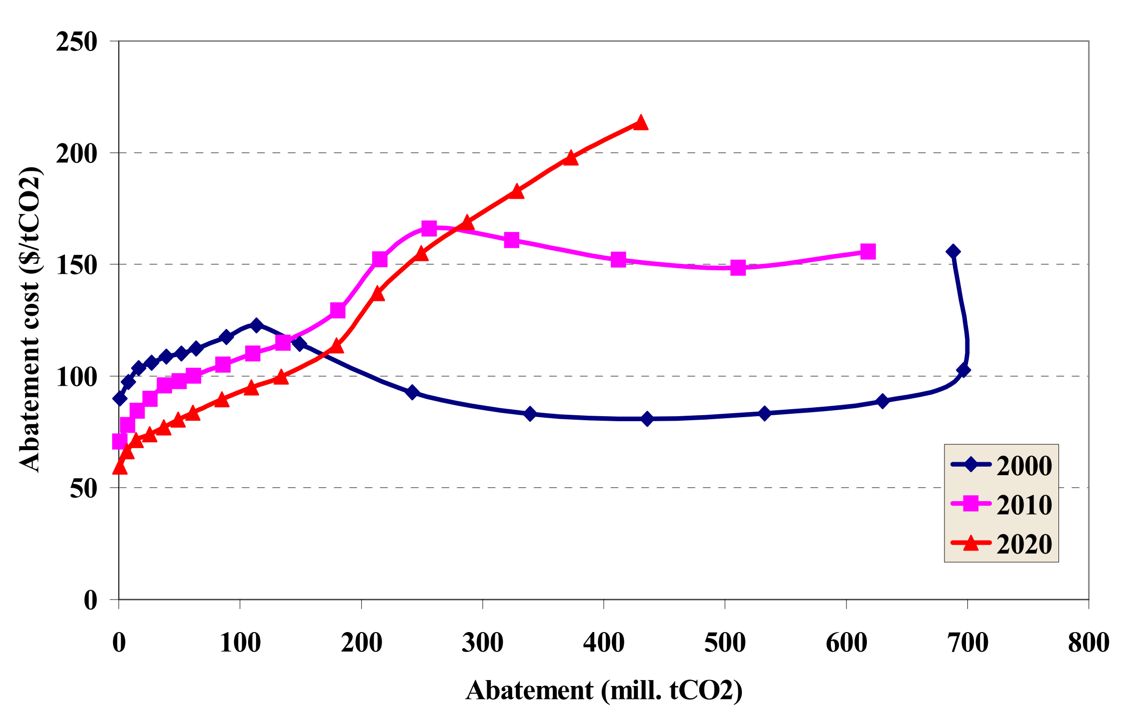

Figure 1.6: Annual abatement cost curves for offshore wind in the EU-15

Wind	2000		2010		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
3	0.93	90.00	0.87	70.79	0.81	59.45
100	39.25	108.71	37.77	95.88	37.14	77.15
200	88.64	117.48	86.06	105.07	85.03	89.57
300	149.16	114.49	135.40	114.90	134.03	99.84
400	241.97	92.78	180.60	129.33	179.43	113.66
500	339.11	83.15	215.35	152.26	213.29	137.13
600	435.78	80.84	256.04	166.06	249.22	154.98
800	629.95	88.72	412.13	152.17	328.26	182.91
1000	688.13	155.74	618.16	155.71	430.56	213.63

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

Table 1.6: CO_2 abatement and abatement costs for offshore wind in the EU-15

1.3 India

1.3.1 Small onshore wind farms

Figure 1.7 and Table 1.7 show the abatement cost curves for small onshore wind farms in India. Since wind output does not exceed more than 30% of the total generation requirement, the abatement cost supply curves largely reflect the cost difference between wind and coal-fired generation (i.e. the least cost alternative). The 2000 figures are complicated by the fact that at the higher wind generation levels, existing coal capacity is displaced. This leads to a sharp increase in the level of abatement since the existing plant tends to have lower thermal efficiencies than new plant. However, as indicated before, no account has been taken of the stranded investment costs, which means the cost curve is artificially low at this point.

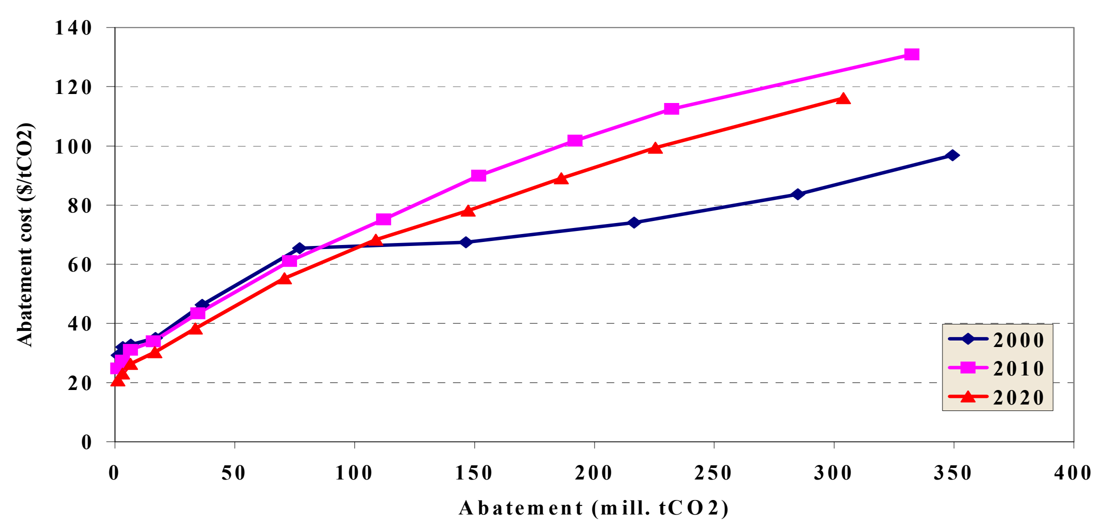

Figure 1.7: Annual abatement cost curves for small onshore wind in India

Wind	2000		2010		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
2	1.29	29.27	1.28	24.82	1.26	20.71
10	6.59	32.79	6.52	31.06	6.44	26.30
25	16.91	35.09	15.99	33.98	16.60	30.26
50	36.47	46.34	34.59	43.42	33.54	38.35
100	77.14	65.39	72.90	61.05	70.70	55.33
150	146.46	67.48	112.09	75.18	108.79	68.33
200	216.59	74.13	151.79	89.88	147.33	78.18
250	284.85	83.69	191.86	101.75	186.16	89.01
300	349.43	96.88	232.30	112.52	225.41	99.41
400			332.42	130.89	303.86	116.13

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

Table 1.7: CO_2 abatement and abatement costs for small onshore wind in India

1.3.2 Large onshore wind farms

Figure 1.8 and Table 1.8 show the abatement cost curves for large onshore wind farms in India. Although the abatement cost curves are lower than the small wind farm curves, the abatement costs rise quite steeply and exceed $40 per tonne CO_2 abated at annual CO_2 savings of 100-150 million tonnes.

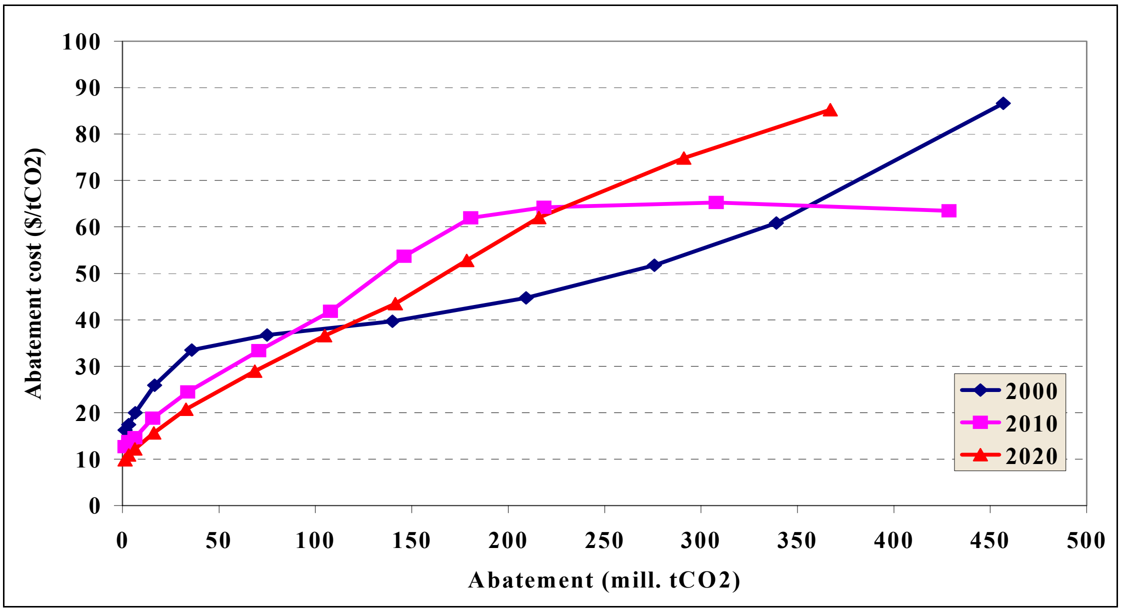

Figure 1.8: Annual abatement cost curves for large onshore wind in India

Wind	2000		2010		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
2	1.29	16.26	1.28	12.65	1.26	9.87
10	6.59	19.97	6.52	14.61	6.44	12.18
25	16.65	25.92	15.70	18.79	16.26	15.62
50	35.84	33.47	33.81	24.44	32.84	20.73
100	74.93	36.70	70.56	33.38	68.50	28.95
150	139.90	39.68	107.93	41.83	104.76	36.59
200	209.35	44.72	145.93	53.67	141.49	43.48
250	275.82	51.79	180.58	61.94	178.54	52.79
300	339.04	60.88	218.53	64.20	215.96	62.00
400	456.71	86.65	307.97	65.26	291.16	74.83
500			428.59	63.49	367.11	85.27
600			548.11	65.63	445.13	95.2

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

Table 1.8: CO_2 abatement and abatement costs for large onshore wind in India

1.3.3 Offshore wind farms

Figure 1.9 and Table 1.9 show the abatement cost curves for offshore wind in India. The offshore wind potential is less than the onshore potential, and is a lot more expensive. The abatement cost curves are, therefore, considerably higher, starting above \$100 per tonne CO2.

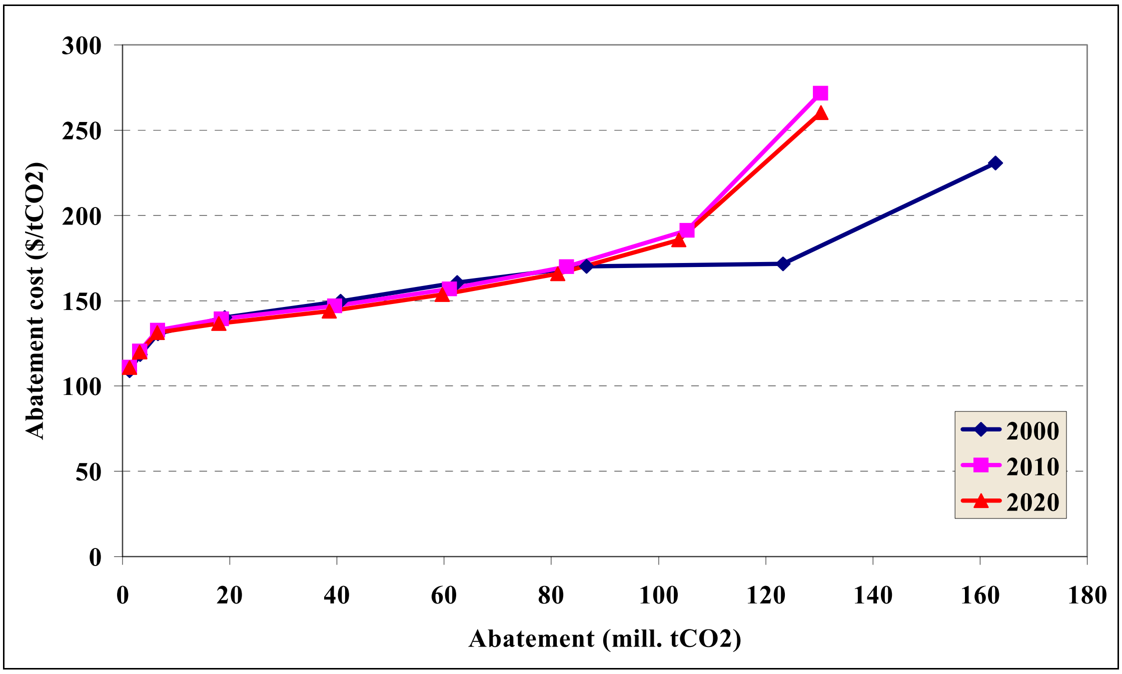

Figure 1.9: Annual abatement cost curves for offshore wind in India

Wind	2000		2010		2020	
TWh	M tCO_2	\$/tCO_2	M tCO_2	\$/tCO_2	M tCO_2	\$/tCO_2
2	1.29	109.02	1.28	111.12	1.26	110.84
5	3.26	118.51	3.23	120.61	3.19	119.94
10	6.59	130.72	6.52	132.66	6.44	131.36
25	19.02	140.15	18.43	139.36	17.92	136.75
50	40.68	149.75	39.60	147.04	38.59	143.94
75	62.44	160.58	61.03	156.84	59.63	153.54
100	86.57	170.20	82.82	169.95	81.20	165.84
125	123.21	171.53	105.35	191.15	103.79	185.72
150	162.88	230.72	130.19	271.68	130.32	260.27

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

Table 1.9: CO_2 abatement and abatement costs for offshore wind in India

1.4 USA

1.4.1 Small onshore wind farms

Figure 1.10 and Table 1.10 show the abatement cost curves for small onshore wind farms in the USA. Up to 350 TWh in 2000, 400 TWh in 2010 and 450 TWh in 2020, the abatement costs curves reflect the difference between wind generation costs and the least costs alternative (i.e. predominately gas-fired CCGTs, but with some coal-fired capacity). After these points the cost curves also include additional system costs that accelerate the rate of increase in the cost of abatement. Even low levels of abatement incur costs of $40 per tonne of carbon dioxide abated or more.

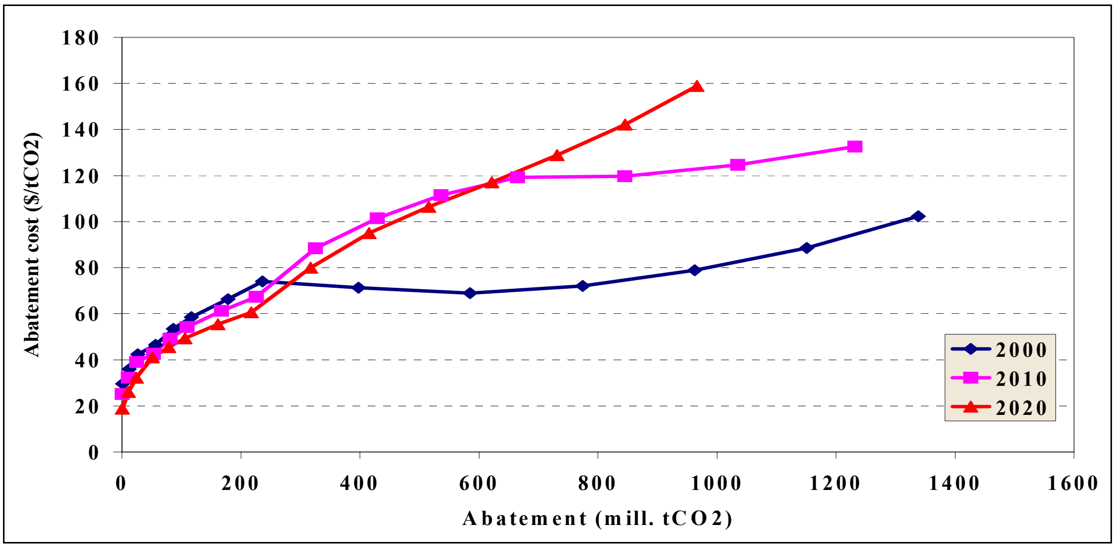

Figure 1.10: Annual abatement cost curves for small onshore wind in the USA

Wind	2000		2010		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
2	0.94	29.60	0.90	25.13	0.86	18.87
50	26.70	42.45	24.85	39.06	24.19	32.31
100	56.54	46.51	52.87	42.73	51.17	41.01
200	117.04	58.56	109.86	54.15	106.04	49.36
400	236.52	74.03	225.63	67.34	217.65	60.68
600	397.60	71.34	325.32	88.43	317.34	80.00
800	585.26	69.02	429.03	101.43	415.25	95.05
1000	774.40	72.13	536.28	111.56	515.49	106.38
1200	962.61	78.95	664.75	119.18	621.51	117.10
1400	1150.83	88.56	844.75	119.73	731.20	128.87
1600	1338.28	102.31	1035.07	124.66	845.51	142.15
1800			1231.83	132.67	966.36	158.92

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

Table 1.10: CO_2 abatement and abatement costs for small onshore wind in the USA

1.4.2 Large onshore wind farms

Figure 1.11 and Table 1.11 show the abatement cost curves for large onshore wind farms in the USA. The cost of abatement is less than for small onshore wind farm developments, but still has a limited abatement potential below $40 per tonne of CO_2.

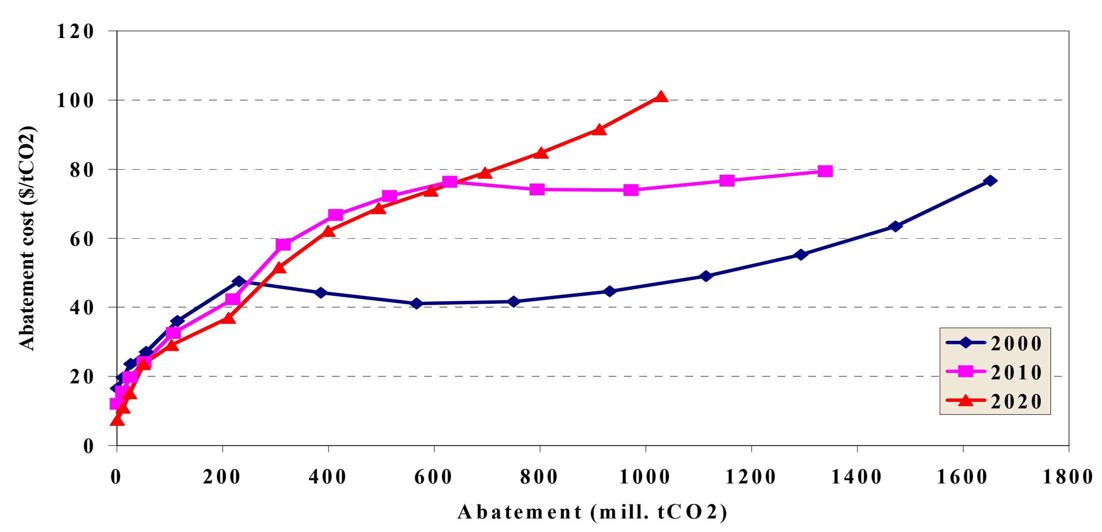

Figure 1.11: Annual abatement cost curves for large onshore wind in the USA

Wind	2000		2010		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
2	0.93	16.52	0.93	12.07	0.93	7.41
25	11.74	19.68	10.81	15.63	11.73	10.98
50	26.28	23.64	24.35	19.77	23.69	15.11
100	55.56	27.16	51.66	24.13	49.96	23.61
200	114.65	36.07	106.96	32.59	103.15	29.08
400	231.06	47.54	218.99	42.32	210.96	36.95
600	385.64	44.21	314.49	58.15	306.34	51.60
800	566.77	41.07	413.51	66.73	399.41	62.12
1000	749.98	41.68	515.65	72.17	495.19	68.70
1200	931.84	44.63	629.38	76.31	593.83	73.76
1400	1113.98	49.07	794.51	74.09	696.10	79.02
1600	1292.85	55.21	972.18	73.96	802.03	84.75
1800	1471.64	63.46	1153.21	76.69	912.08	91.51
2000	1651.36	76.63	1338.94	79.38	1028.92	101.14

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

Table 1.11: CO_2 abatement and abatement costs for large onshore wind in the USA

1.4.3 Offshore wind farms

Figure 1.12 and Table 1.12 show the abatement cost curves for offshore wind in the USA. The limited offshore wind potential means that no additional system costs are incurred much before the maximum is reached. The costs curves therefore reflect the difference between the wind generation costs curves and the least cost alternative. The offshore cost curves are a lot more expensive than the onshore curves, starting at an annual abatement cost of around \$100 per tonne CO_2.

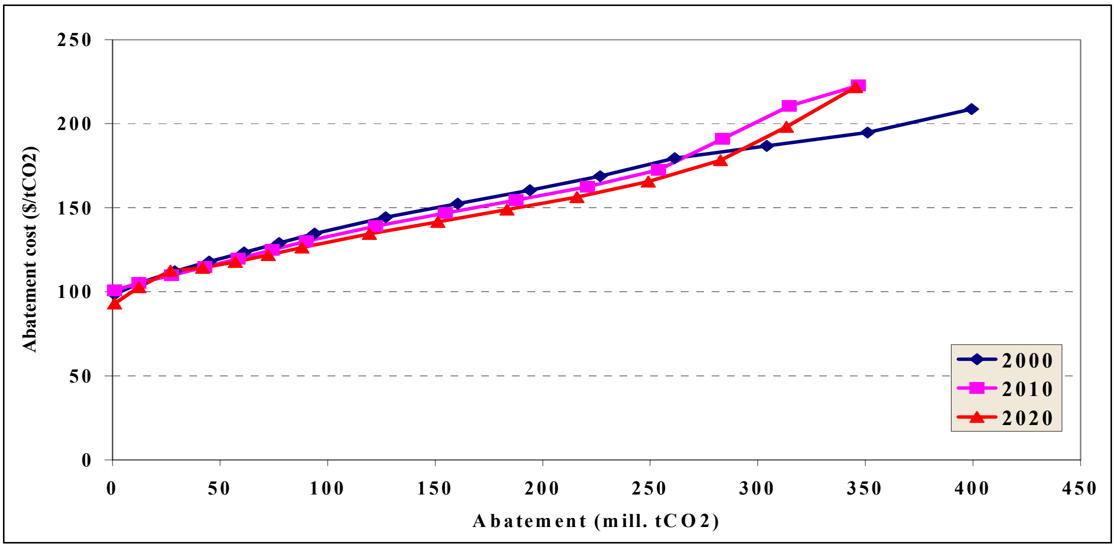

Figure 1.12: Annual abatement cost curves for offshore wind in the USA

Wind	2000		2010		2020	
TWh	M tCO_2	$/tCO_2$	M tCO_2	$/tCO_2$	M tCO_2	$/tCO_2$
2	1.03	98.44	1.00	100.81	0.97	93.03
50	28.93	112.34	27.52	109.86	27.00	112.58
100	61.19	123.45	58.52	119.80	57.15	117.80
150	93.90	134.67	90.17	130.17	88.04	126.44
200	127.05	144.31	122.35	139.13	119.46	134.51
250	160.49	152.47	154.82	146.89	151.21	141.68
300	194.07	160.52	187.59	154.53	183.34	148.91
350	226.60	168.87	220.71	162.45	215.86	156.36
400	261.32	179.51	253.82	172.47	249.00	165.65
450	304.09	186.86	283.65	191.13	282.65	178.38
500	350.92	194.88	314.54	210.62	313.18	198.13
550	399.24	208.69	346.68	222.83	345.35	221.88

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

Table 1.12: CO_2 abatement and abatement costs for offshore wind in the USA

2 COST OF AVOIDED CO_2 EMISSIONS: REST OF THE WORLD

2.1 Africa

2.1.1 Small onshore wind farms

The 2000 cost curve is truncated due to wind reaching 100% of the region's total generation requirements. The same applies to the 2020 data, but the growth in generation requirements enables more wind energy to be dispatched.

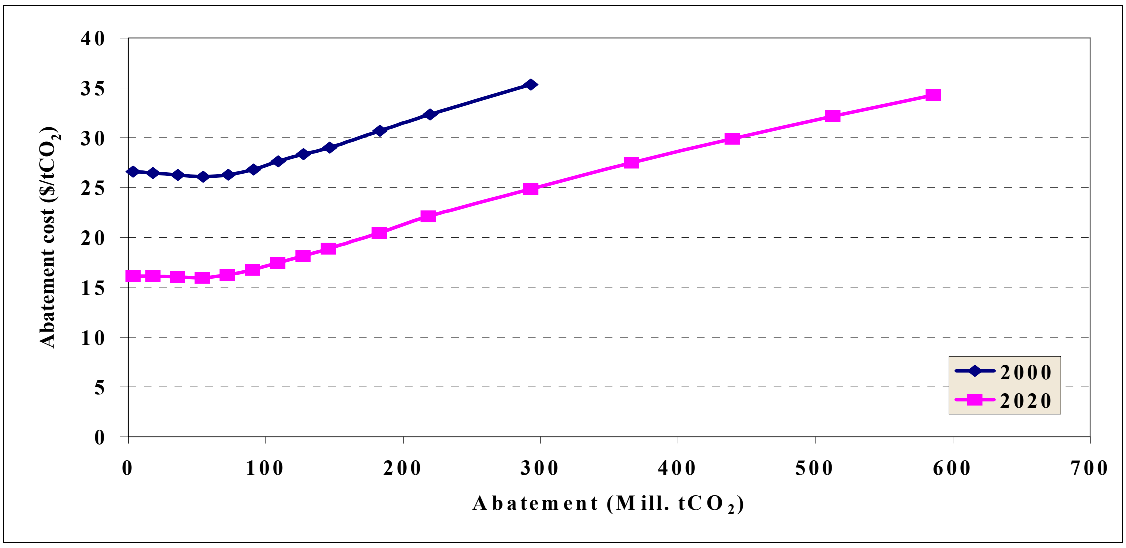

Figure 2.1: Annual abatement cost curves for small onshore wind in Africa

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	4	27	4	16
25	18	26	18	16
50	36	26	36	16
100	73	26	72	16
150	109	28	109	17
200	146	29	145	19
250	183	31	182	20
300	220	32	218	22
400	293	35	293	25
500	#N/A	#N/A	366	27
600	#N/A	#N/A	439	30
700	#N/A	#N/A	513	32
800	#N/A	#N/A	586	34

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

Table 2.1: CO_2 abatement and abatement costs for small onshore wind in Africa

2.1.2 Large onshore wind farms

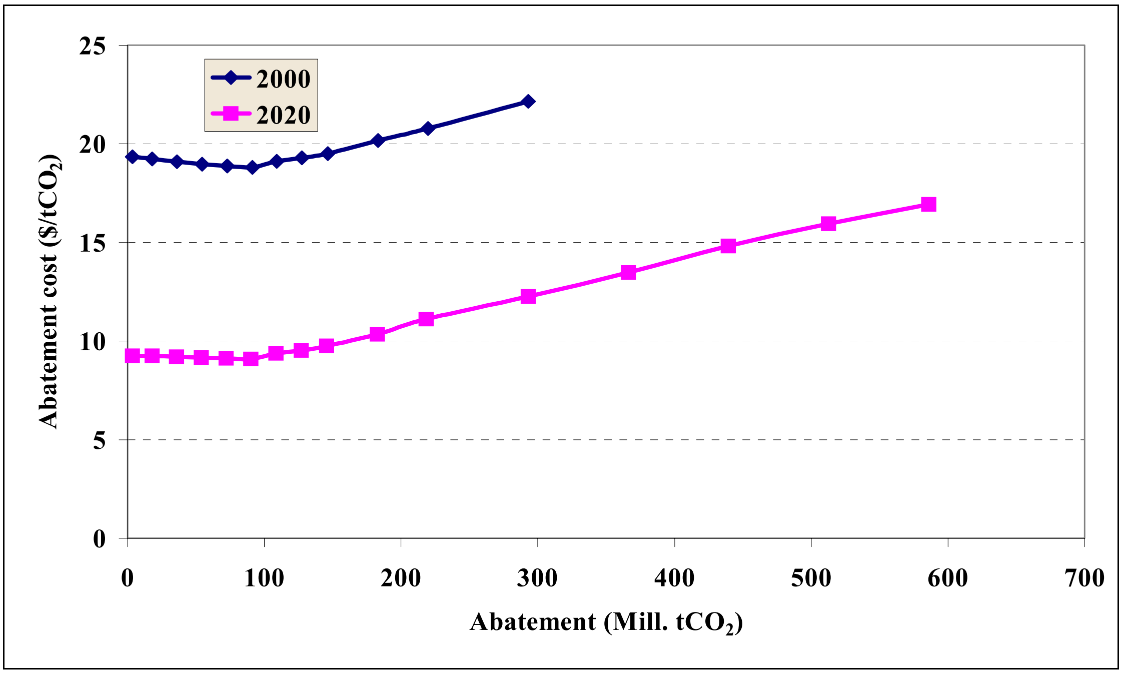

Figure 2.2: Annual abatement cost curves for large onshore wind in Africa

Wind	2000		2020	
TWh	M tCO_2	\$/tCO_2	M tCO_2	\$/tCO_2
5	4	19	4	9
25	18	19	18	9
50	36	19	36	9
100	73	19	72	9
150	109	19	109	9
200	146	20	145	10
250	183	20	182	10
300	220	21	218	11
400	293	22	293	12
500	#N/A	#N/A	366	13
600	#N/A	#N/A	439	15
700	#N/A	#N/A	513	16
800	#N/A	#N/A	586	17

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

Table 2.2: CO_2 abatement and abatement costs for large onshore wind in Africa

2.1.3 Offshore wind farms

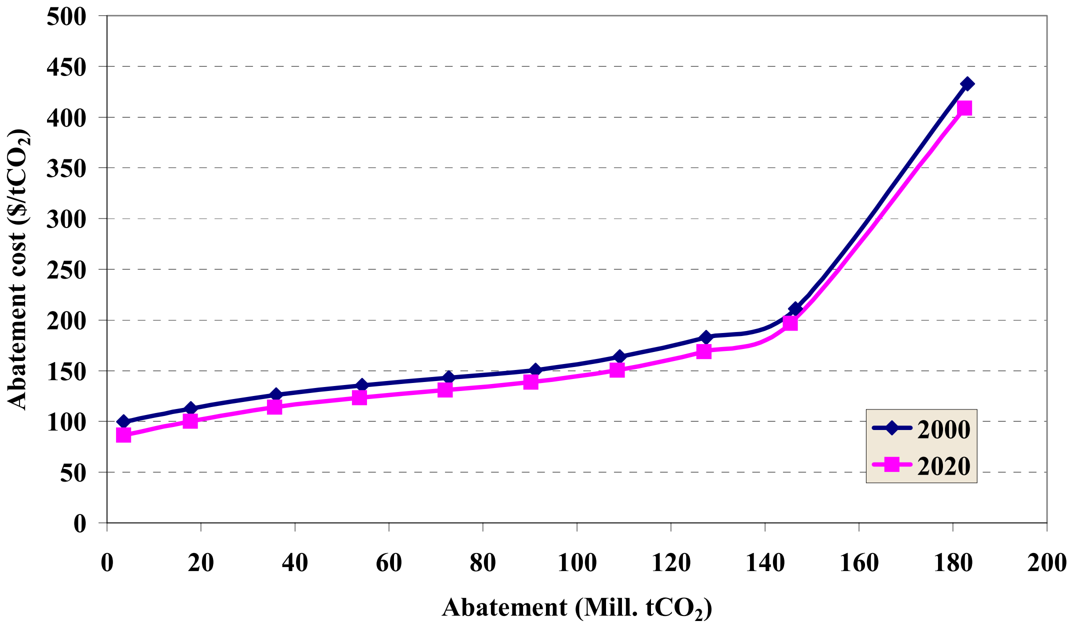

Figure 2.3: Annual abatement cost curves for offshore wind in Africa

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	4	100	4	86
10	4	100	4	86
20	4	100	4	86
30	18	113	18	100
50	36	126	36	114
75	54	136	54	123
100	73	143	72	131
150	109	164	109	151
200	146	211	145	197
250	183	433	182	409

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

Table 2.3: CO_2 abatement and abatement costs for offshore wind in Africa

2.2 Australia

2.2.1 Small onshore wind farms

As with Africa, Australia's 2000 cost curve is truncated due to wind reaching 100% of the region's total generation requirements. The same applies to the 2020 data, but the growth in generation requirements enables more wind energy to be dispatched. This is also true for the large onshore and offshore cost curves.

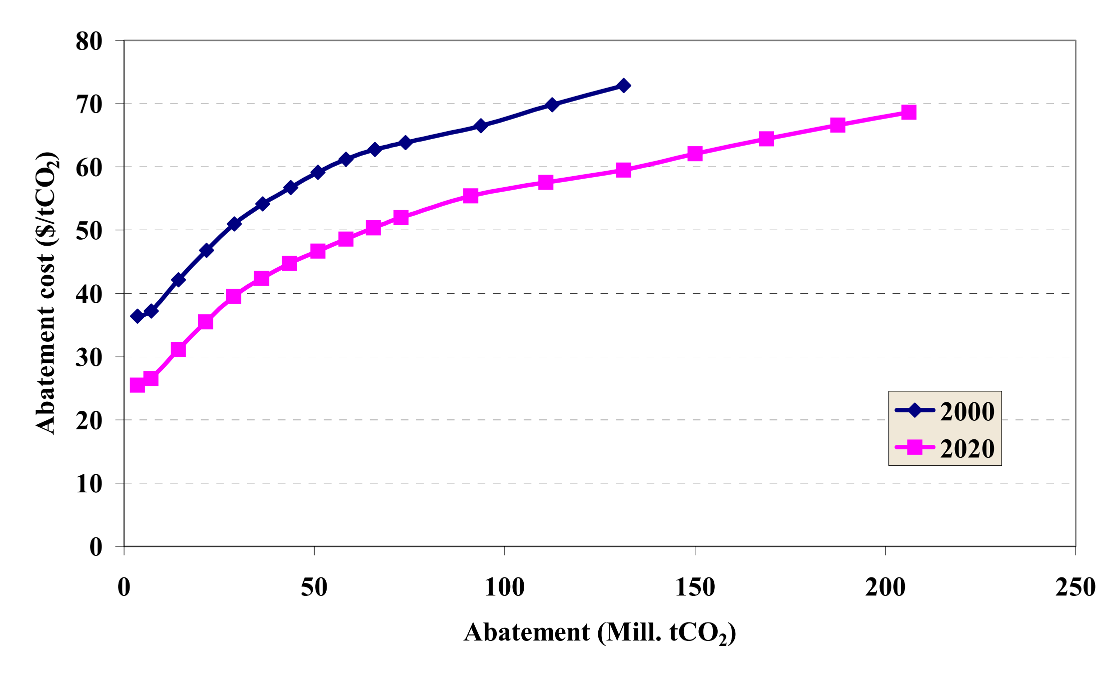

Figure 2.4: Annual abatement cost curves for small onshore wind in Australia

Wind	2000		2020	
TWh	M tCO_2	\$/tCO_2	M tCO_2	\$/tCO_2
5	3	36	3	25
10	7	37	7	27
25	14	42	14	31
50	36	54	36	42
75	51	59	51	47
100	74	64	73	52
125	94	67	91	55
150	113	70	111	58
175	131	73	131	60
200	#N/A	#N/A	150	62
225	#N/A	#N/A	169	64
250	#N/A	#N/A	188	67
275	#N/A	#N/A	206	69

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

Table 2.4: CO_2 abatement and abatement costs for small onshore wind in Australia

2.2.2 Large onshore wind farms

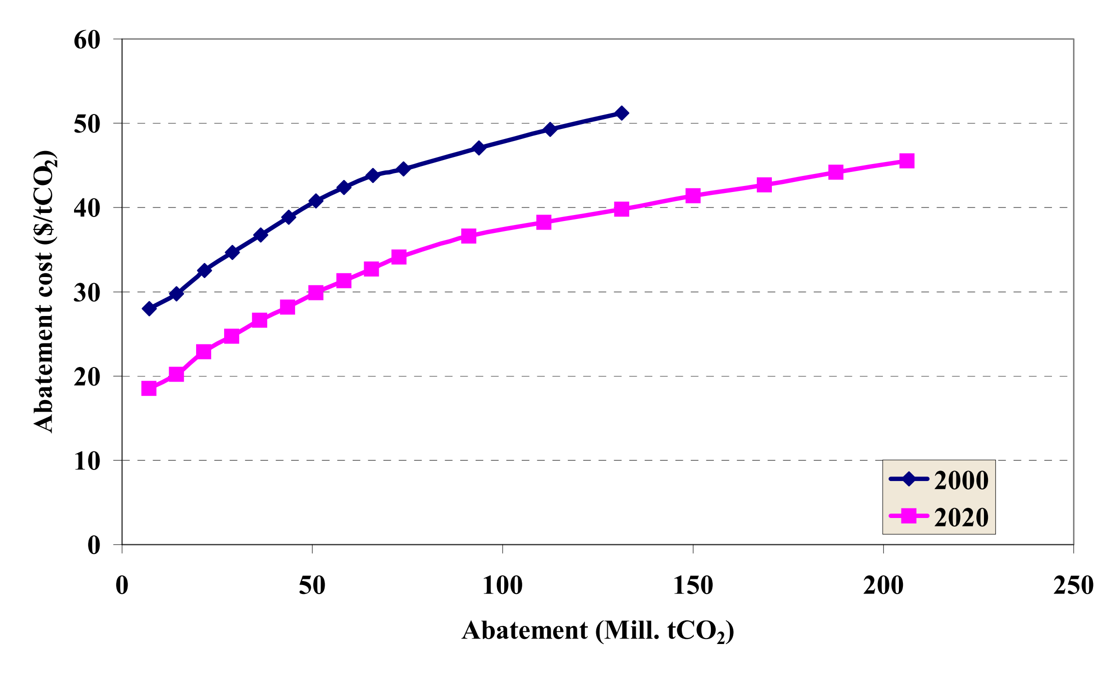

Figure 2.5: Annual abatement cost curves for large onshore wind in Australia

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	3	28	3	18
10	7	28	7	19
25	14	30	14	20
50	36	37	36	27
75	51	41	51	30
100	74	45	73	34
125	94	47	91	37
150	113	49	111	38
175	131	51	131	40
200	#N/A	#N/A	150	41
225	#N/A	#N/A	169	43
250	#N/A	#N/A	188	44
275	#N/A	#N/A	206	46

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

Table 2.5: CO_2 abatement and abatement costs for large onshore wind in Australia

2.2.3 Offshore wind farms

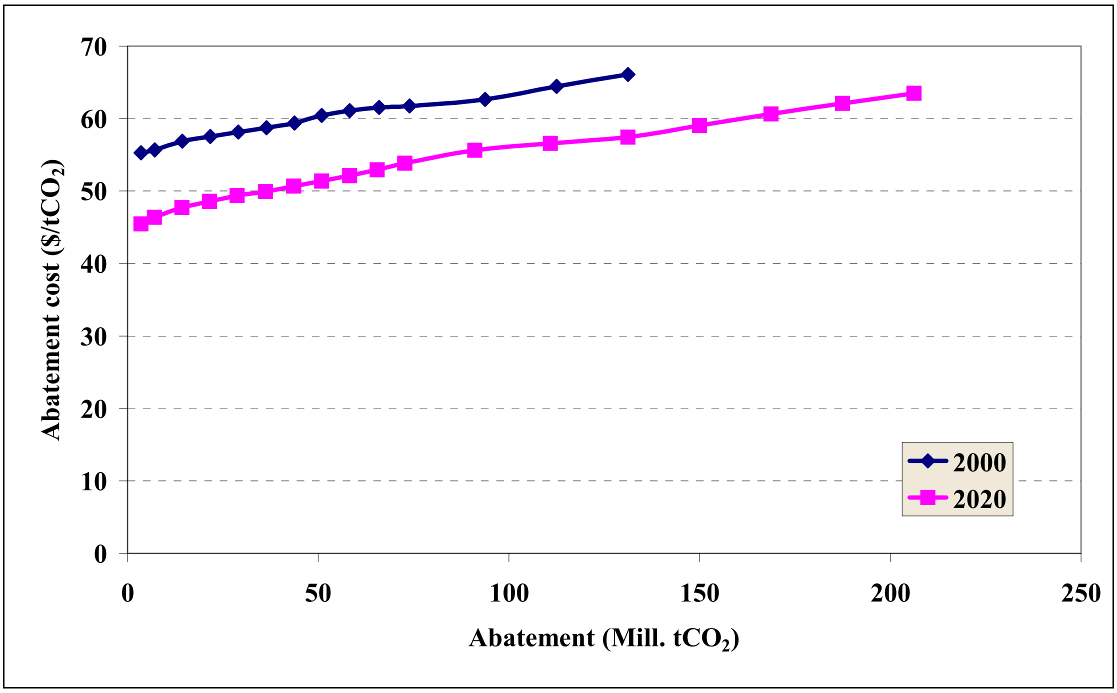

Figure 2.6: Annual abatement cost curves for offshore wind in Australia

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	3	55	3	45
10	7	56	7	46
20	14	57	14	48
30	22	58	22	49
50	36	59	36	50
75	51	60	51	51
100	74	62	73	54
150	113	64	111	57
200	#N/A	#N/A	150	59
250	#N/A	#N/A	188	62

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

Table 2.6: CO_2 abatement and abatement costs for offshore wind in Australia

2.3 Former Soviet Union and Eastern Europe

The 2000 cost curve is truncated due to wind reaching 100% of total generation requirements. The same applies to the 2020 data, but the growth in generation requirements enables more wind energy to be dispatched. This is also true for the large onshore and offshore cost curves.

2.3.1 Small onshore wind farms

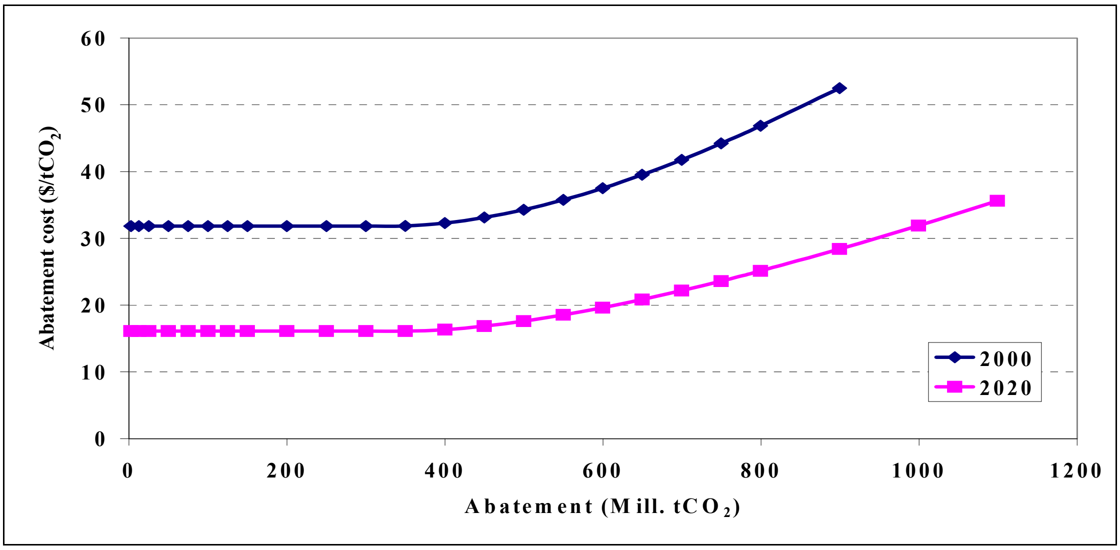

Figure 2.7: Annual abatement cost curves for small onshore wind in the FSU and Eastern Europe

Wind	2000		2020	
TWh	M tCO_2	$/tCO_2$	M tCO_2	$/tCO_2$
5	2	32	2	16
25	12	32	12	16
50	25	32	25	16
100	50	32	50	16
150	75	32	75	16
200	100	32	100	16
300	150	32	150	16
400	200	32	200	16
500	250	32	250	16
600	300	32	300	16
800	400	32	400	16
1000	500	34	500	18
1500	749	44	749	24
2000	#N/A	#N/A	999	32
2500	#N/A	#N/A	1199	40
3000	#N/A	#N/A	1499	54

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

Table 2.7: CO_2 abatement and abatement costs for small onshore wind in the FSU and Eastern Europe

2.3.2 Large onshore wind farms

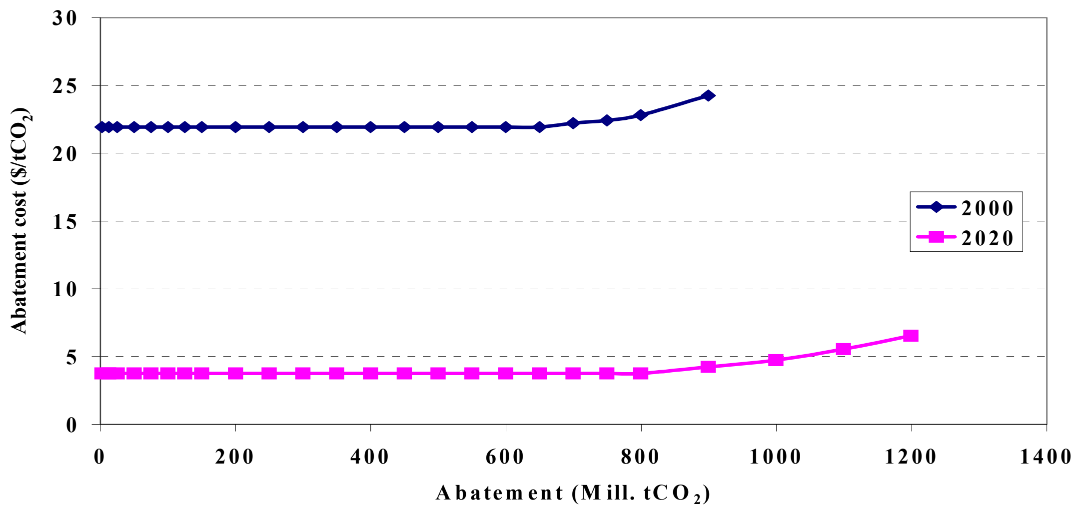

Figure 2.8: Annual abatement cost curves for large onshore wind in the FSU and Eastern Europe

Wind	2000		2020	
TWh	M tCO2	$/tCO2	M tCO2	$/tCO2
5	2	22	2	4
25	12	22	12	4
50	25	22	25	4
100	50	22	50	4
150	75	22	75	4
200	100	22	100	4
250	125	22	125	4
300	150	22	150	4
400	200	22	200	4
500	250	22	250	4
600	300	22	300	4
800	400	22	400	4
1000	500	22	500	4
1500	749	22	749	4
2000	#N/A	#N/A	999	5
2500	#N/A	#N/A	1199	7
3000	#N/A	#N/A	1499	11

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

Table 2.8: CO_2 abatement and abatement costs for large onshore wind in the FSU and Eastern Europe

2.3.3 Offshore wind farms

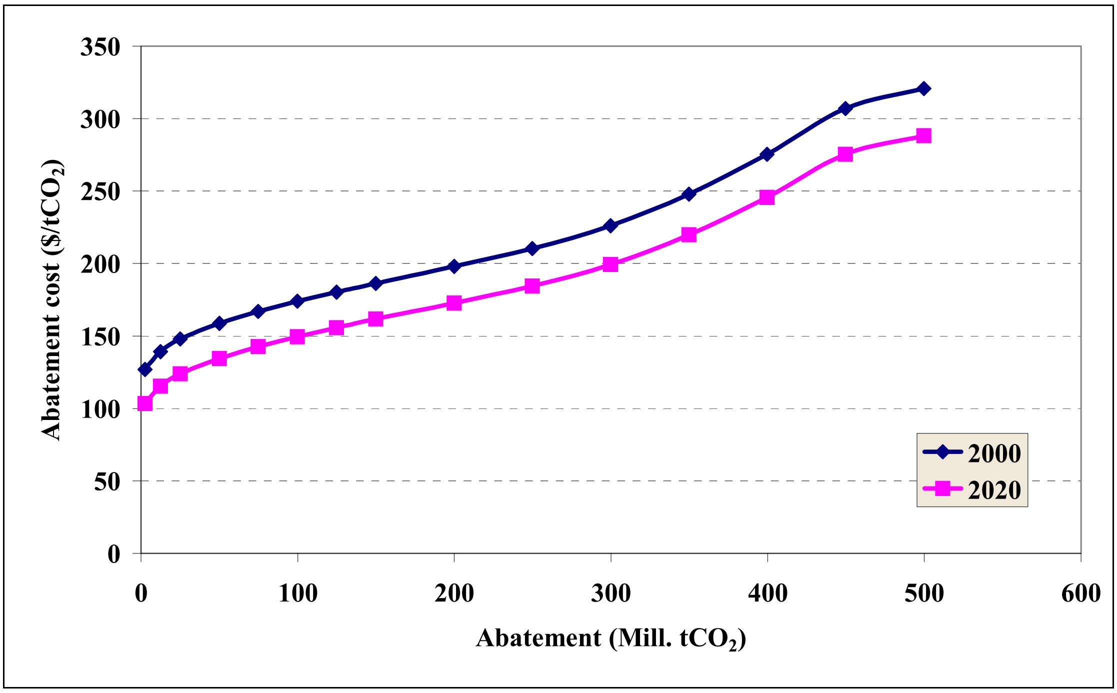

Figure 2.9: Annual abatement cost curves for offshore wind in the FSU and Eastern Europe

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	127	2	103
25	12	139	12	115
50	25	148	25	124
100	50	159	50	134
150	75	167	75	143
200	100	174	100	150
250	125	180	125	156
300	150	186	150	162
400	200	198	200	173
500	250	210	250	184
600	300	226	300	199
800	400	275	400	246
1000	500	321	500	288

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

Table 2.9: CO_2 abatement and abatement costs for offshore wind in the FSU and Eastern Europe

2.4 Latin America

The 2000 cost curve is truncated due to wind reaching 100% of total generation requirements. The same applies to the 2020 data, but the growth in generation requirements enables more wind energy to be dispatched. This is also true for the large onshore and offshore cost curves.

2.4.1 Small onshore wind farms

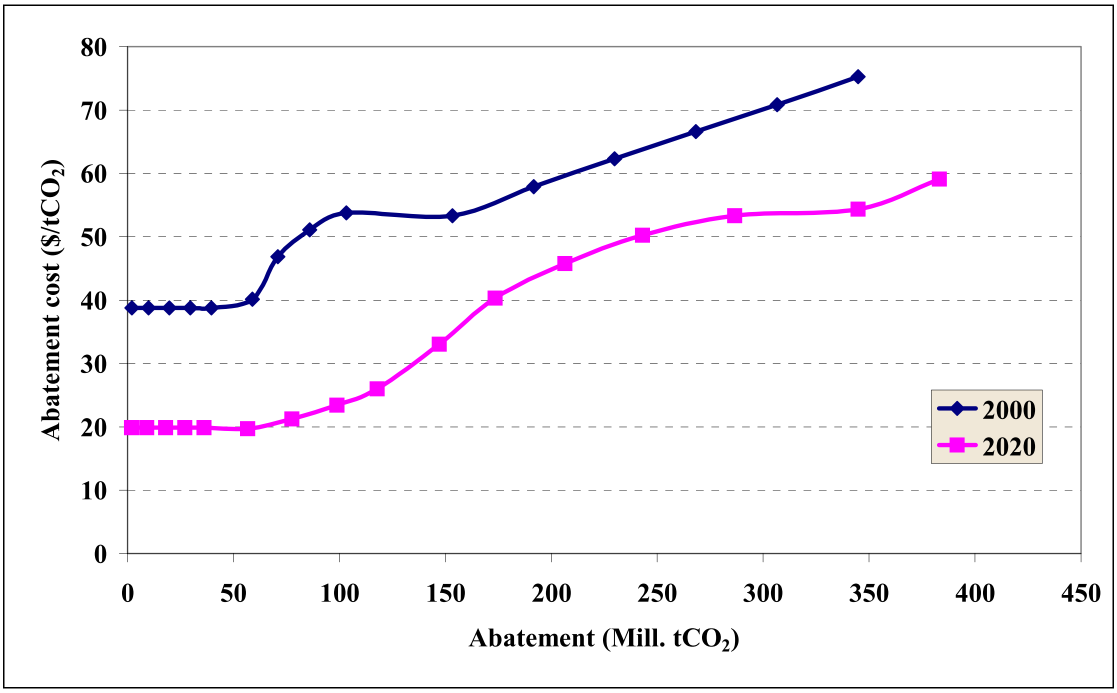

Figure 2.10: Annual abatement cost curves for small onshore wind in Latin America

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	39	2	20
25	10	39	9	20
50	20	39	18	20
100	40	39	36	20
150	59	40	57	20
200	71	47	78	21
300	103	54	118	26
400	153	53	147	33
500	192	58	174	40
1000	#N/A	#N/A	383	59
1500	#N/A	#N/A	536	82
2000	#N/A	#N/A	766	119

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

Table 2.10: CO_2 abatement and abatement costs for small onshore wind in Latin America

2.4.2 Large onshore wind farms

The 2000 abatement cost curve is curtailed by wind exceeding 100% of total generation requirements.

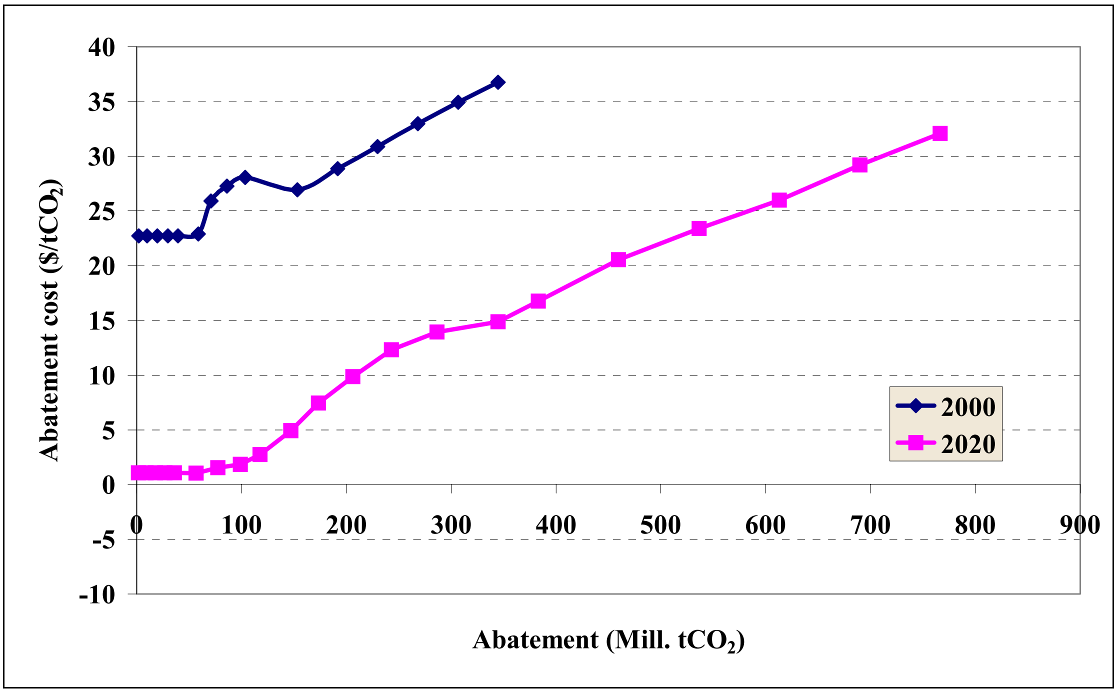

Figure 2.11: Annual abatement cost curves for large onshore wind in Latin America

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	23	2	1
25	10	23	9	1
50	20	23	18	1
100	40	23	36	1
150	59	23	57	1
200	71	26	78	2
300	103	28	118	3
400	153	27	147	5
500	192	29	174	7
1000	#N/A	#N/A	383	17
1500	#N/A	#N/A	536	23
2000	#N/A	#N/A	766	32

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

Table 2.11: CO_2 abatement and abatement costs for large onshore wind in Latin America

2.4.3 Offshore wind farms

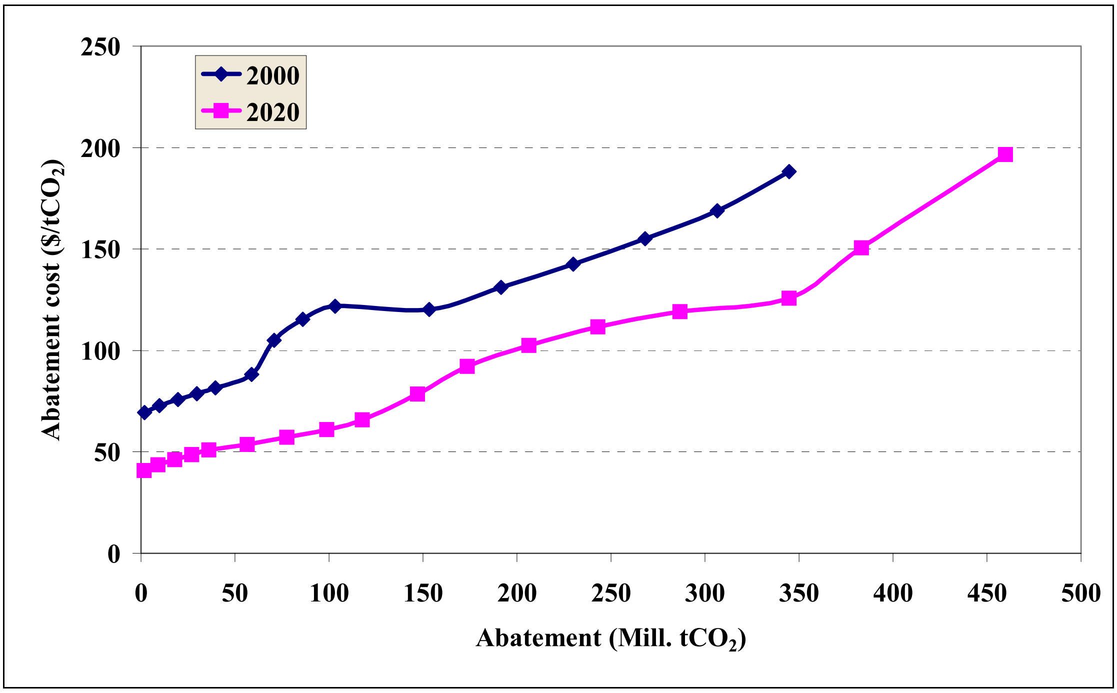

Figure 2.12: Annual abatement cost curves for offshore wind in Latin America

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	69	2	41
25	10	73	9	44
50	20	76	18	46
100	40	82	36	51
150	59	88	57	54
200	71	105	78	57
300	103	122	118	66
400	153	120	147	79
500	192	131	174	92
1000	#N/A	#N/A	383	151

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

Table 2.12: CO_2 abatement and abatement costs for offshore wind in Latin America

2.5 Middle East

2.5.1 Small onshore wind farms

As with Africa and Australia, the Middle East's 2000 cost curve is truncated due to wind reaching 100% of the region's total generation requirements. The same applies to the 2020 data, but the growth in generation requirements enables more wind energy to be dispatched. The large onshore abatement cost curve is flat because the wind generation costs are flat over the output covered by the entire generation.

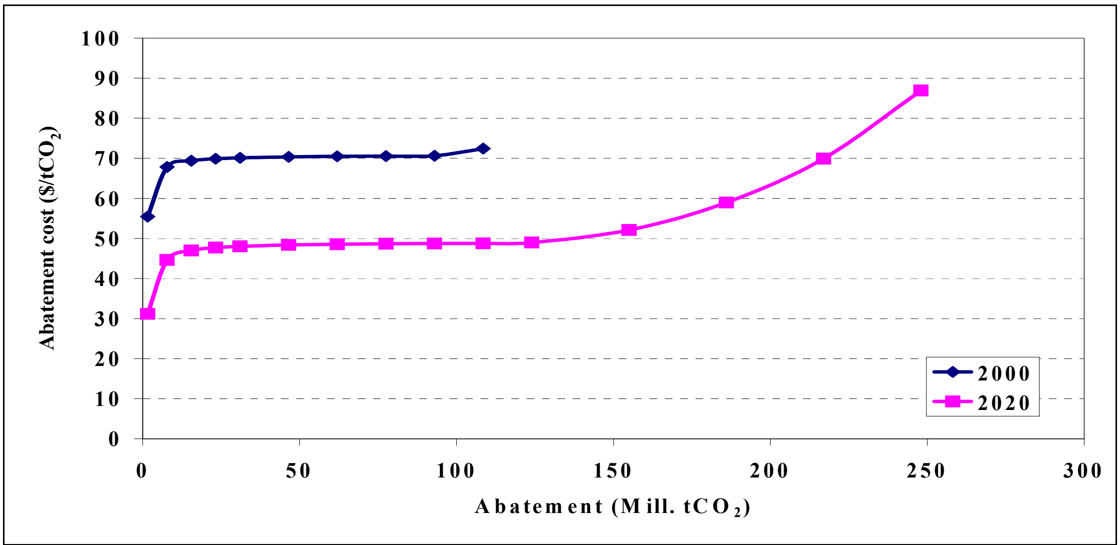

Figure 2.13: Annual abatement cost curves for small onshore wind in the Middle East

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	55	2	31
25	8	68	8	45
50	16	69	16	47
100	31	70	31	48
200	62	70	62	49
300	93	71	93	49
400	#N/A	#N/A	124	49
500	#N/A	#N/A	155	52
600	#N/A	#N/A	186	59
700	#N/A	#N/A	217	70
800	#N/A	#N/A	248	87

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

Table 2.13: CO_2 abatement and abatement costs for small onshore wind in the Middle East

2.5.2 Large onshore wind farms

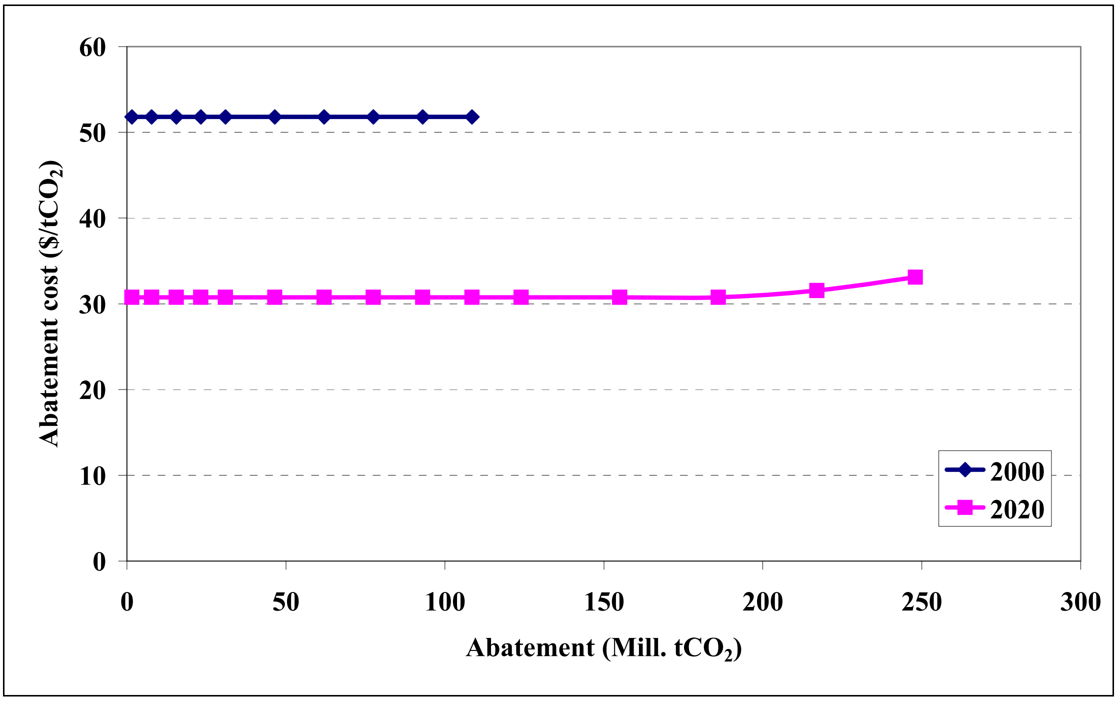

Figure 2.14: Annual abatement cost curves for large onshore wind in the Middle East

Wind	2000		2020	
TWh	M tCO_2	$\$/tCO_2$	M tCO_2	$\$/tCO_2$
5	2	52	2	31
25	8	52	8	31
50	16	52	16	31
100	31	52	31	31
200	62	52	62	31
300	93	52	93	31
400	#N/A	#N/A	124	31
500	#N/A	#N/A	155	31
600	#N/A	#N/A	186	31
700	#N/A	#N/A	217	32
800	#N/A	#N/A	248	33

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

Table 2.14: CO_2 abatement and abatement costs for large onshore wind in the Middle East

2.5.3 Offshore wind farms

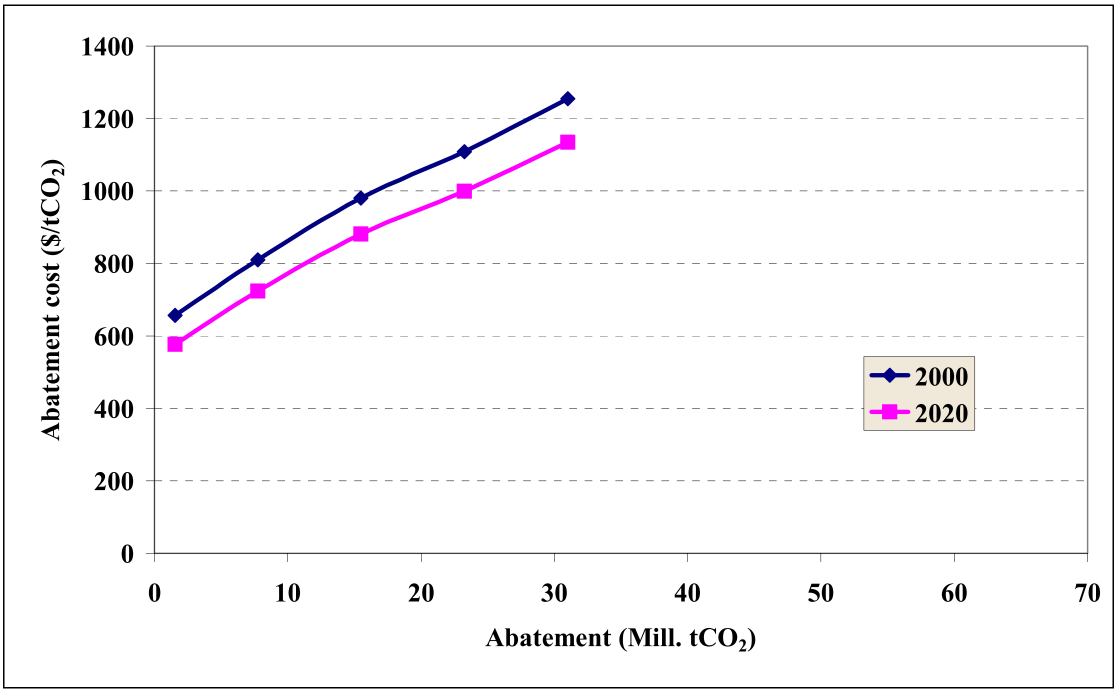

Figure 2.15: Annual abatement cost curves for offshore wind in the Middle East

Wind	2000		2020	
TWh	M tCO_2	$/tCO$_2$	M tCO_2	$/tCO$_2$
5	2	657	2	576
10	2	657	2	576
20	2	657	2	576
30	8	810	8	724
40	8	810	8	724
50	16	980	16	881
75	23	1109	23	1000
100	31	1255	31	1134
125	31	1255	31	1134

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

Table 2.15: CO_2 abatement and abatement costs for offshore wind in the Middle East

2.6 Rest of Asia

2.6.1 Small onshore wind farms

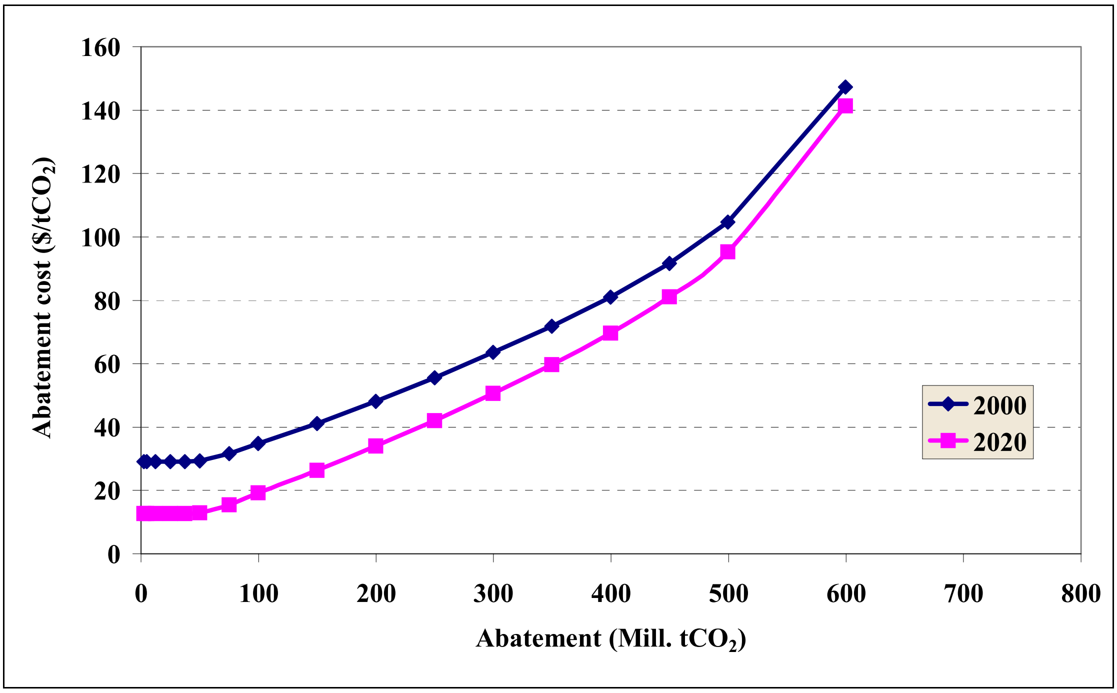

Figure 2.16: Annual abatement cost curves for small onshore wind in the rest of Asia

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	29	2	13
10	5	29	5	13
25	12	29	12	13
50	25	29	25	13
100	50	29	50	13
150	75	32	75	15
200	100	35	100	19
300	150	41	150	26
400	200	48	200	34
500	250	56	250	42
600	300	64	300	51
800	400	81	400	70
1000	500	105	500	95
1200	600	147	600	141

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

Table 2.16: CO_2 abatement and abatement costs for small onshore wind in the rest of Asia

2.6.2 Large onshore wind farms

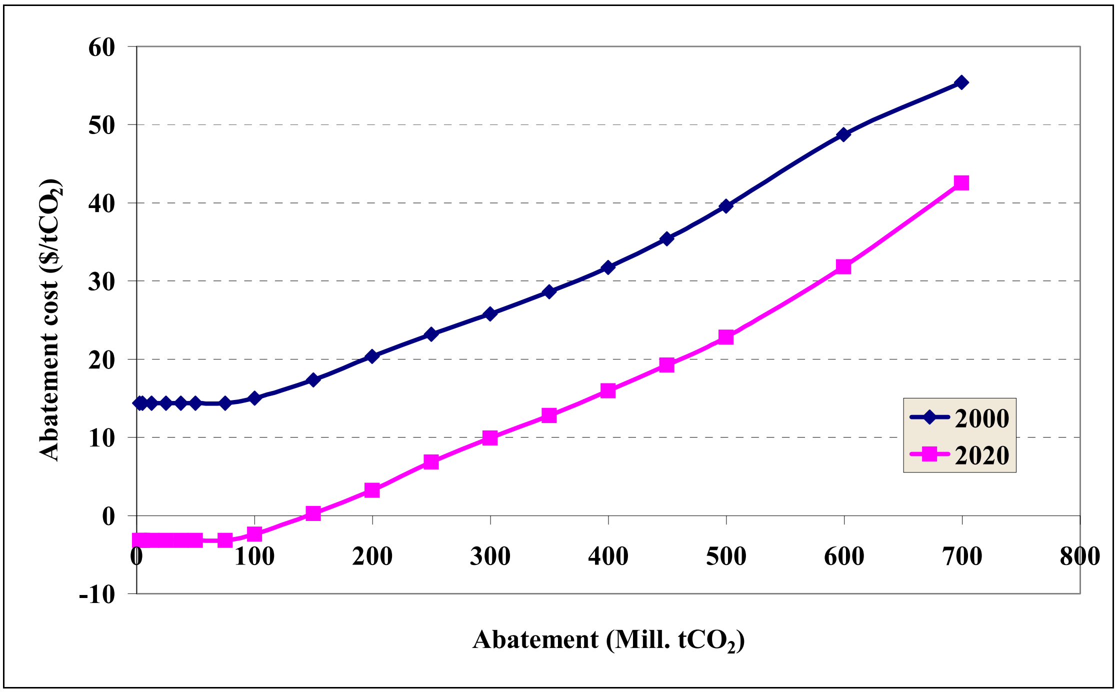

Figure 2.17: Annual abatement cost curves for large onshore wind in the rest of Asia

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	14	2	-3
10	5	14	5	-3
25	12	14	12	-3
50	25	14	25	-3
100	50	14	50	-3
150	75	14	75	-3
200	100	15	100	-2
300	150	17	150	0
400	200	20	200	3
500	250	23	250	7
600	300	26	300	10
800	400	32	400	16
1000	500	40	500	23
1200	600	49	600	32
1400	699	55	699	43

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

Table 2.17: CO_2 abatement and abatement costs for large onshore wind in the rest of Asia

2.6.3 Offshore wind farms

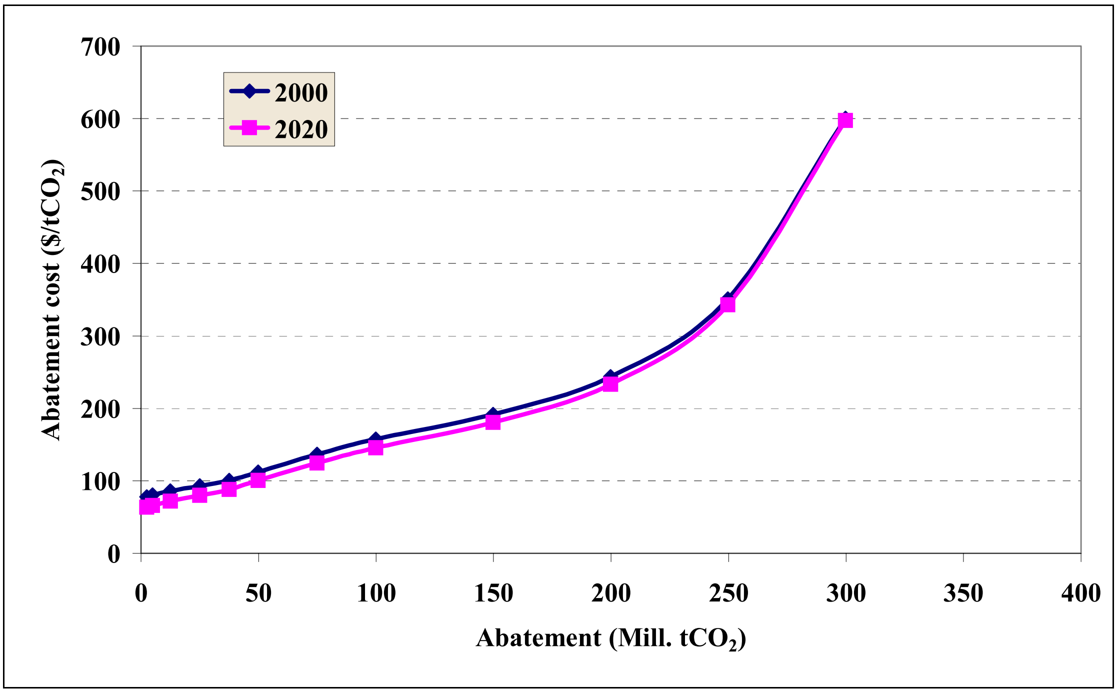

Figure 2.18: Annual abatement cost curves for offshore wind in the rest of Asia

Wind	2000		2020	
TWh	M tCO_2	$/$tCO_2$	M tCO_2	$/$tCO_2$
5	2	78	2	64
10	5	81	5	66
25	12	86	12	72
50	25	93	25	80
100	50	112	50	100
150	75	137	75	124
200	100	158	100	146
300	150	192	150	181
400	200	244	200	233
500	250	351	250	343
600	300	600	300	597

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

Table 2.18: CO_2 abatement and abatement costs for offshore wind in the rest of Asia