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EXECUTIVE SUMMARY

This report describes the results of Enviros Consulting's research underpinning a joint study by Enviros Consulting and Oxera Consulting for the DTI to examine the economic and technical potential of low cost renewable energy technologies in the context of the EU Emissions Trading Scheme.

This report, dated 5 July 2005, follows on from the original report delivered to the DTI on 17th March 2005. This revised report has been updated to take account of the most recent information on resource assessments for onshore wind. The approach taken is explained in more detail in Section 3.

The purpose of the overall study is to advise the DTI on the implications of possible changes to the Renewables Obligation (RO) taking into account the operating experience of the RO and the additional support provided to renewables by other policies, such as the EU Emissions Trading Scheme (EU ETS).

The purpose of this report is to provide a detailed analysis of the supply curves for each low cost renewable energy technology based on the economic and technical characteristics of each technology as well as resource availability. The report also provides cost and capacity information for higher cost renewable energy technologies although in less detail.

The technologies covered in the analysis are shown in Table E.1. As requested by the DTI, the majority of the analysis has concentrated on the low cost technologies, in particular LFG and onshore wind, but with the exclusion of biomass co-firing. A less detailed analysis was required for the high cost technologies. Biomass/coal co-firing is excluded from the analysis because it has already been reviewed extensively in 2003. [1]

Table E.1 Categorisation of technologies

Low Cost Technologies	High Cost Technologies
Landfill Gas (LFG)	Biomass (Stand alone)
Onshore Wind	Offshore Wind
Sewage Gas	PV
Small Scale Hydro	Advanced Conversion Technologies
Biomass/Coal Co-Firing	Tidal / Wave

The approach to this report is to provide as much detail as possible on the modelling used to generate the supply curves, since decisions on any potential changes to the RO will be strongly influenced by the shape of these curves, and it is important for policy makers to understand the calculation methodology, the assumptions used and the sensitivity of the curves to changes in these assumptions. Industry consultees will also wish to see the workings we have used.

The supply curves described in this report show for each renewable technology how the marginal costs of generation for new plant (£/MWh) are expected to change as annual output increases. The curves themselves do not show how much renewable capacity will be built in each year, although we do provide estimates of future maximum build rates for each technology. Nor does the report try to predict future

1 DTI 2003, Assessment of Changes to RO Rules relating to Co-Firing

ROC prices, although the link between supply curves, build rates and future ROC prices can be made fairly easily.

General Conclusions

The simple conclusion from the analysis is that, with the exception of biomass co-firing, and assuming a brown power price of the order of £30/MWh no technology is able to generate power commercially without some form of financial support. Conclusions specific to each low cost technology are provided below.

Landfill Gas

The analysis indicates that the LFG industry is gradually approaching saturation in the development of new low cost sites. The model shows a sharp increase in costs at around 5.0TWh. This is due to the exhaustion of large sites capable of utilising large engines and where LFG collection systems are required under the Landfill Directive. Sites that make up the part of the curve between £45 and £100/MWh are all Type 3a, 3b and 4 sites (i.e. have comprehensive gas collection systems), but have low gas production volumes and consequently small and less efficient generating engines. In developing the older sites the full set of gas collection equipment is attributable to the power generation system, since gas collection and flaring is not required under the directive for these sites. At these sites, generation costs are in excess of £100/MWh.

The modelling shows that under the mid growth-mid diversion scenario *in the short term* an additional 1.8TWh (approximately 300MW) of LFG output is achievable at a cost below £45/MWh from 2003 levels. The additional available capacity below £45/MWh from expected 2004 output levels is around 1.5TWh (250MW). These calculations assume that new capacity will be developed with a load factor of 70%.

The model also indicates that the rate of increase in LFG production from new waste disposed to landfill will, over the duration of the analysis, outweigh the decline in yields from historic wastes, resulting in an extension of lower cost generation opportunities over time. By 2015 we would expect to see the available capacity at below £45/MWh increase to 5.8TWh, representing an increase on 2003 levels of 2.6TWh (420MW), or 2.3TWh (370MWh) from expected output in 2004. Learning effects are slight in the context of LFG reducing the cost of generation by £2/MWh between 2005 and 2015.

At build rates experienced in the last seven years of 60 to 70MW per year these low cost project opportunities would exhausted within four to five years.

Although we have not presented these figures as ranges, they are subject to high levels of uncertainty, in particular the resource potential in 2015 which is sensitive to future biodegradable waste deposits and the modelling of future LFG gas yields.

Onshore Wind

The analysis of onshore wind indicates that costs vary widely between sites. The average wind speed is the factor that has the largest impact on the economics of individual projects but the planning system and public acceptability will ultimately determine how much of the UK wind resource is developed onshore.

The supply curves in Section 3 show a relatively gradual increase from current costs of around £40/MWh up to £100/MWh. The curves suggest that between 60 and 100TWh could be generated at a cost of less than £100/MWh. The analysis also shows that the UK's wind resource could generate between 20 and 45TWh at a cost of less than £60/MWh. The upper end of this range is of a similar magnitude as those from other studies (see Table 3.1). Due to the maturity of onshore wind technology learning effects for onshore wind are expected to be small. By 2015 we would expect the marginal cost of wind power to reduce by approximately £5 to 7/MWh.

It is possible to divide onshore wind sites into three bands of economic viability, less than £50/MWh (low cost), £50-60/MWh (medium cost) and £60-80/MWh (high cost). The modelling indicates that, relative to 2003/4 output, the following additional capacity is available in the cost bands (Table E.2).

Table E.2 Additional resource potential for onshore wind

Cost band	Low resource scenario		High resource scenario	
	(TWh)	(GW)	(TWh)	(GW)
Low cost (<£50/MWh)	8	2.8	22	7.8
Medium cost (£50-60/MWh)	11	3.9	22	7.8
High cost (£60-80/MWh)	30	10.7	43	15.3

Over time, the slight fall in capital costs for onshore wind developments could lead to an increase in the available capacity at lower costs. However this would have to weighed against the fact that these lower cost sites are the ones most likely to be developed first.

A relevant consideration in the wind sector is the rate of development of new sites. BWEA, for example, estimates that 600MW of capacity will be built in 2005. At this rate of development low cost sites (<£50/MWh) will be exhausted in two to ten years.

Sewage Gas

Scope for further development of sewage is limited given regulations on the disposal of digested sludge. Digesters with engines attached also produce a relatively regular supply of gas and use standard gas processing and engine technology. For these reasons the sewage gas supply curve is expressed as a single point. This shows total electrical output of 251GWh/yr at a cost of £63/MWh in 2005. By 2015 we expect total electrical output to increase marginally to 278GWh/yr and the cost to decrease to £62/MWh.

Hydro

Hydro generation costs depend on the size of the unit and load factor, as well as a number of site specific factors. Generation costs for <1.25MW units are estimated at an around £84/MWh. For 1.25-20MW and >20MW units costs are £67/MWh and £77/MWh respectively. By 2020 the costs of the micro and small hydro installations are expected to fall by over 20% and the cost of large hydro is expected to fall by over 10%. Although the generation costs for hydro are high, the total potential capacity available from hydro schemes is large, in the region of 12TWh for all sizes of scheme.

1. INTRODUCTION

1.1 Background

The Renewables Obligation (RO) is the main government policy for encouraging investment in electricity generation from renewable sources. The RO requires licensed electricity suppliers to demonstrate that an increasing proportion of the electricity generated in the UK is produced from renewable sources. The RO sets targets annually for electricity suppliers, with 10.4% achievable by 2010/11. The RO is currently being increased to 15.4% by 2015. (The government also has an aspiration of achieving 20% of power generation from renewables by 2020). If electricity suppliers are unable to meet their targets under the RO they may either purchase Renewable Obligation Certificates (ROCs) from the market to make up the difference or make a payment to a buy-out fund, the proceeds of which are recycled back to electricity suppliers in proportion to each supplier's share of the total ROCs held by suppliers.

Following a commitment made in the Energy White Paper[2], the Government is undertaking a review of the RO to take account of the operating experience of the RO and to consider the additional support provided to renewables by other policies, such as the EU Emissions Trading Scheme (EU ETS).

This report by Enviros Consulting is part of a joint study by Enviros Consulting and Oxera Consulting for the DTI to examine the economic and technical potential of low cost renewable energy technologies in the context of the EU Emissions Trading Scheme.

This report describes the fundamental research underpinning the study. In undertaking this work Enviros has created a highly detailed analysis of the supply curves for each low cost renewable energy technology taking into account economic and technical factors as well as resource availability. We have also provided cost and capacity information for higher cost renewable energy technologies although in less detail. As far as we are aware this is the most complete and up to date economic analysis of the potential for renewable energy exploitation in the UK.

The aim of this report is to provide as much detail as possible on the modelling used to generate the supply curves, since decisions on any potential changes to the RO will be strongly influenced by the shape of these curves, particularly at the low cost end. It is therefore important for policy makers to understand the calculation methodology, the assumptions used and the sensitivity of the curves to changes in these assumptions. Industry consultees will also wish to see the workings we have used.

The supply curves described in this report show for each renewable technology how the marginal costs of generation for new plant (£/MWh) are expected to change as annual output increases. The curves themselves do not show how much renewable capacity will be built in each year, although we do provide estimates of future maximum build rates for each technology. Nor does the report try to predict future ROC prices, although the link between supply curves, build rates and future ROC prices can be made fairly easily.

The supply curves sit alongside and feed into the Oxera analysis. The main purpose of the Oxera work is to examine the impact of these renewable energy

2 Energy White Paper (2003) Our Energy Future – Creating a Low Carbon Economy

supply curves on the UK electricity market and to comment on the implications for the viability of renewable energy in the context of the EU ETS.

The Enviros team responsible for this report has been drawn from a wide range of disciplines including energy economics, renewable power engineering, planning and environmental impacts assessment, project finance, waste management and landfill engineering. We are also grateful to the many contacts that have provided information for this work. Acknowledgements are provided in the Appendix.

1.2 Renewable energy technologies

The renewable energy technologies covered by this review are grouped into low and high cost categories, as shown in Table 1.1. As requested by the DTI, the majority of the analysis has concentrated on the low cost technologies, in particular LFG and onshore wind, but with the exclusion of biomass co-firing. A less detailed analysis was required for the high cost technologies. Biomass/coal co-firing is excluded from the analysis because it has already been reviewed extensively in 2003. [3]

Table 1.1 Categorisation of technologies

Low Cost Technologies	High Cost Technologies
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Biomass/Coal Co-Firing	Tidal / Wave

1.3 Method of approach

In order to generate supply curves for the low cost technologies separate models have been created for each technology. These models apply a consistent methodology based around four components: calculation of the maximum resource potential, a detailed “bottom-up” analysis of the costs of generating power at different levels of output, changes in these costs over time and build rates. The approach to these four components is described below.

Maximum resource potential

The maximum resource potential represents the maximum theoretical electrical power that can be generated from each technology. These potentials are determined for all technologies (low and high cost). For wind (onshore and offshore) the resource potential is a function of wind speed, land or sea area, density of installation, and public acceptance. Resource potentials for small scale hydro, all biomass related technologies, PV, advanced conversion technologies and tidal/wave are all calculated on the basis of published sources and leading industry opinions. The maximum resource potentials for these technologies are all assumed to stay constant over time.

For LFG and sewage gas the maximum resource potential changes over time. For LFG the main determinants of the available resource are the quantity of

3 DTI 2003, Assessment of Changes to RO Rules relating to Co-Firing

biodegradable material flowing into the landfill, the rate of degradation of the material in the landfill, and the rate of change in calorific value of the LFG. The degree of capture from site does not alter the potential available. In the case of sewage gas, the resource potential depends on the quantity of sewage sludge created and the sludge disposal strategies of the water companies.

Power generation costs

Power generation costs are built up from a detailed analysis of capital, operating and financing elements at different scales of plant. Throughout the analysis, considerable efforts have been made to validate cost assumptions through discussions with industry groups and technology suppliers. Several cost factors are common to all renewable energy technologies. These are: grid connection and grid upgrade, transmission charges, business rates, discount rates and planning permission. The approach taken in the modelling to these factors is described below.

Grid connection, grid upgrade and use of system

Grid connection and grid upgrade charges are one-off costs to allow generators to access the network of wires that transmits power from the generation facility to the point of use. Depending on the size of the generating facility, the facility will connect either to the national transmission network (the National Grid) or the local distribution network. Typically, a generator of more than 30MW will connect to the transmission network, with smaller facilities connected to the local distribution network. The costs of grid connection and grid upgrade are additional to use of system charges that are levied annually to cover the operating cost of the network.

Grid connection costs referred to in this report reflect the electrical engineering work required to make the physical connection from the generator to the network. Grid upgrade costs cover the costs of improving the transmission or distribution network to accept the new generation capacity. These costs are levied through a charge by the network operator on the generator.

Connection costs are largely a function of the distance between the facility and the point of connection. In the model these costs are split into three categories: onshore wind, off-shore technologies and all other onshore technologies. For all onshore technologies, other than wind, we have assumed a constant grid connection cost of £45,000/MW installed capacity. For onshore wind facilities, which are likely to be located further from the point of connection, we assume a connection cost of £55,000/MW. For offshore technologies, offshore wind, wave and tidal, we assume a cost of £77,000/MW. The off-shore cost allows for the greater distances involved bringing power from the sea to land, and the increased complexity of burying cables into the seabed.

Grid upgrades are levied on all new generating facilities to cover the costs of maintaining network stability with increased generating capacity. Upgrade charges differ depending on whether the connection is made to the national grid or the local distribution network. Where upgrades are required to the transmission network costs are assumed to average £95,000/MW installed. [4] The costs of connecting to the local network are more complex and are in the process of revision. The new charging structure will take affect from 1 April 2005 and this is the structure used in the model.

4 Mott McDonald, 2003, Renewables Network Impacts Study, Annex 3

Under the new structure the costs of upgrading the distribution network will be spread amongst the new generating facilities to be connected to the network. This is more equitable than the current approach where the cost of upgrading the grid to cater for new generation capacity falls heavily on the incremental facility that triggers the upgrade. The new charging structure will also split the one off cost of up-grading the network from the annual costs of operating and maintaining the network (Generator Distribution Use of System (GDUoS) charges). Under this new charging structure we use an average one-off cost of upgrading a local distribution network of £82,000/MW. [5] [6]

In the context of renewable power generation, annual use of system charges for the National Grid (Transmission Network Use of System, TNUoS) are of most relevance to onshore wind facilities since they are large enough to be able to connect to the National Grid. Most other renewable technologies will connect to the local distribution network.

In the model we calculate an average TNUoS charge for each region according to the percentage of the region covered by each grid tariff zone. The TNUoS charge varies from £18,000/MW/yr for Scotland to £800/MW/yr for the South West. [7] Note these charges are still awaiting regulatory approval. For the local distribution network we use an annual GDUoS charge of £2,500/MW/yr - as referred to in the Ofgem Electricity Distribution Price Control Review, November 2004, footnoted earlier.

Business Rates

All businesses are required to pay business rates. In the model we distinguish between renewable generating facilities according to whether they are part of a larger industrial site (e.g. sewage gas) or stand-alone units (e.g. onshore wind). [8] Where the generation unit is part of a larger industrial site the business rates levied as a result of installing the generator are currently determined by the capital value of the generator (i.e. the rateable value) multiplied by a de-capitalisation rate of 0.05 and the tax multiplier, currently 0.422. These costs therefore change according to the capital cost of the generating unit.

For stand alone generating facilities, business rates are currently calculated using a single taxable value multiplied by the tax multiplier. For a typical wind farm this results in an annual cost of around £5,000/MW installed.

A new business rate structure will be introduced in April 2005. The new method will introduce a ‘receipts and expenditure’ methodology where business rates will be determined by the projected income of the generator rather than its rateable value. This is consistent with the methodology applied to other non-renewable generators. This change will affect all stand-alone renewable generation facilities by altering the basis upon which rates are calculated. For example, a higher tax rate will be levied on wind farms located in areas of high wind speed relative to those located in low wind speed areas. Whether or not this change leads to higher total business rate burden on the renewable sector depends on the factors applied in the new calculation methodology.

5 OFGEM (Nov 2004), Electricity Distribution Price Control Review
6 Based on the operating allowance and incentive rate allowed for in the OFGEM price control review (2004)
7 The TNUoS charges are currently based on the National Grid’s Revised Use of System Charging Methodology Proposals published in Dec 2004.
8 This methodology was developed following discussions with the relevant departments in the Valuation Office Agency (VOA).

Under the guidance of the DTI we have not modelled the effect of the proposed changes in business rates for renewable energy. This partly reflects the uncertainty in these policies at the time of the study.

Discount Rate

To model the costs of financing we assume that all low cost technologies and biomass co-firing are sufficiently mature to attract significant debt financing. For these technologies we assume a weighted average cost of capital (WACC) of 7.9%, comprising a debt to value ratio of 75%, cost of debt of 6.5%, and cost of equity of 18%. As the remaining high cost technologies are subject to greater perceptions of project-specific risk, they are typically financed using investment vehicles with less debt leveraging. For these technologies, we assume a debt to value ratio of 45%, leading to a WACC of 11.9%.

These assumptions are based on the principle that for the purposes of modelling national level supply curves we are only interested in technologies that are likely to be built on a commercial scale. We therefore ignore potentially higher values for the cost of equity and debt that would arise for technologies at their pre-commercial stages. [9]

Planning

The cost of applying for planning permission includes the capitalised costs of management and professional advice associated with consultation with the local community, environmental impact assessments and seeing the planning application through the planning process. For onshore technologies that are built on a stand alone basis, LFG, onshore wind, small and large hydro but with the exception of advanced conversion technologies, we assume a standard planning cost of £187,500 per site. [10] For advanced conversion technologies, such as gasification, which are able to use wastes as their fuel source, planning permission will be more difficult to obtain. In the model planning costs for these technologies are assumed to be £250,000.[11]

Where a site is developed as a part of a larger site development, such as PV, small scale hydro, sewage gas, and co-firing of biomass we assume that there are no additional planning costs associated with the project's development.

Changes in costs over time

The supply curves produced by the model show the costs of developing new renewable energy facilities at increasing levels of output for each year from 2005 to 2020. Over this time the cost of equipment and general renewable energy project development will change as a result of improvements in equipment design, equipment manufacturing processes, evolution of support services and scale economies. In some cases unit costs might increase as functionality is improved, but on the whole the trend is towards reducing costs over time.

A common approach to taking account of these changes in costs is through a concept known as the "learning rate". This is the rate at which unit costs change with each doubling of "output". Output here may be defined in a number of ways, such as the number of units manufactured, MWh of electricity generated or cumulative installed capacity. The same concept is often presented as a progress

9 The cost of debt and equity and their relative split have been determined following communication with various financial institutions
10 Project development experience and planning permission experience within Enviros.
11 Confidential client report.

ratio (PR), which is equal to 1 minus the learning rate. The PR describes the new unit cost that would be expected following a doubling in output. In most analyses of learning effects output is measured in terms of cumulative installed capacity. A PR of 100% for example, indicates that there is no change in cost installed capacity increases. A PR of 92% indicates that unit costs fall by 8% for each doubling of installed capacity.

A pertinent point on modelling learning effects is that PRs can reduce as a technology matures since there is less scope for further cost reductions. For example, it has been suggested that the PR of gas turbines was 80% in the R&D phase, and 90% in the commercialisation phase. [12] The rate at which PRs change over time is different for different technologies. In some cases the PR value may not decline at all.

In the model, progress ratios have been estimated from historic data in a number of academic and policy studies. Sources include the International Institute for Applied Systems Analysis (IIASA), the International Energy Agency (IEA), academic econometric research and Enviros and Oxera estimates. The PR values used in the model are shown in Table 1.2.

Table 1.2 Progress Ratios used in the model

Technology	Progress Ratio
Onshore wind	
Technology	92
Project development	90
Planning permission	110
O&M	90
LFG	
Capital cost of 1 MW engine	92
Capital cost of 0.22 MW engine	85
Capital cost of retrofitting a cap	85
Capital cost of installing pipes wells & extraction equipment	85
Project development	90
Planning permission	100
O&M	90
Offshore wind	85
Solar photovoltaics	85
Tidal	85
Wave	85
Gasification of wastes	85
Biomass	85
Micro hydro (<1.25MW)	90
Small hydro (1.25-20 MW)	90
Hydro >20 MW	95
Sewage gas	92

Build Rates

The rate of new build does not have a direct impact on the cost curves presented within this report. However they are important when projecting future ROC prices and assessing the impact of changes to the RO on wholesale electricity prices and

12 Source: Junginger et al, 2003.

incentives for the renewables sector. We therefore provide estimates of expected future build rates to be used in the Oxera analysis (see Table 1.3). These are *expected* maximum build rates in the UK and not *theoretical* maximum build rates. The difference is that expected build rates are based on historical trends updated for the most recent installation evidence. Observed build rates will be limited by planning as much the capacity of the supply industry. The theoretical maximum build rate could be much larger than this. For example, in Germany an annual build rate for onshore wind of 3000MW/yr has been achieved.

The build rates are shown as MW electrical (MWe/yr) installed capacity for all technologies with the exception of biomass co-firing which is expressed as the annual increase in the proportion of coal burned for power generation. These build rates are generally in line with accepted industry figures. For example, with regard to onshore wind, the recent report by the Sustainable Development Commission on suggests a build rate of 600MW/yr. [13]

Table 1.3 Maximum build rates by technology

Technology	Maximum build rate	Units
LFG	100	MWe/yr
Onshore wind	600	MWe/yr
Hydro <1.25MW	4	MWe/yr
Hydro 1.25-20 MW	50	MWe/yr
Hydro >20 MW	70	MWe/yr
Sewage gas	10	MWe/yr
Offshore wind	500	MWe/yr
Solar PV	10	MWe/yr
Tidal	10	MWe/yr
Wave	10	MWe/yr
Gasification of MSW	10	MWe/yr
Biomass - stand alone	70	MWe/yr
Biomass – co-firing	0.7%	percentage of coal burn

13 Sustainable Development Commission, 2005, Wind Power in the UK - A Guide to the Key Issues Surrounding Wind Power Development in the UK

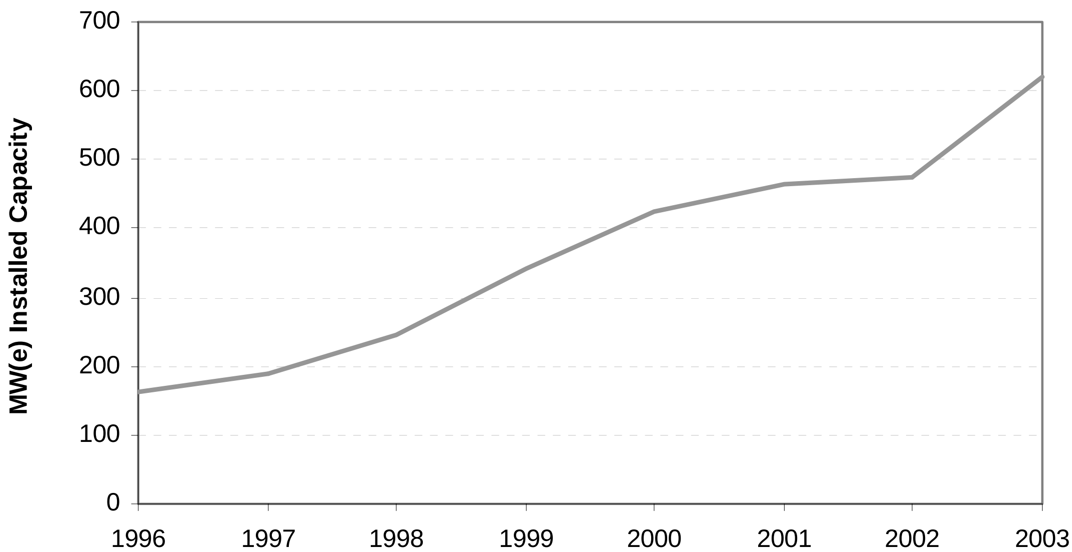
2. LANDFILL GAS

2.1 Overview of the Sector

LFG is generated by the decomposition of biodegradable waste in an anaerobic atmosphere leading to the production of LFG. The major components of LFG are methane, carbon dioxide and nitrogen with the relative composition between each gas primarily being determined by the type of waste that has been deposited in the landfill and the age of the material. The modelling conducted for this study considers LFG emissions from four waste streams: municipal solid waste (MSW), commercial and industrial (C&I) wastes, construction and demolition (C&D) waste and sewage sludge. It does not cover other hazardous wastes, emissions from which are trivial compared to those from the other waste streams.

Generating power from LFG in the UK has developed substantially since its commercial inception in the late 1980s. Figure 2.1 shows annual LFG capacity increasing from 160MW in 1996 to around 620MW in 2003. The chart includes installations commissioned under the Non-Fossil Fuel Obligation (NFFO) regime and the RO.

Figure 2.1 Installed Capacity of LFG Engines



source: Digest of UK Energy Statistics

To identify the remaining potential for LFG and to assess the current cost of generation, we categorise landfills according to the age of the landfill and the quality of site design. The most important site design characteristics are the quality of the cover placed on top of the landfill (i.e. the cap), the quality of the lining around the base and sides of the landfill, and whether or not LFG emissions are flared or combusted. These design characteristics are broadly correlated with the age of the site.

2.2 Legislative background

The main legislative drivers governing the management of landfill sites are local air quality controls and UK implementation of the EU Landfill Directive. The timing and implications of the legislative drivers are summarised in Table 2.1.

Table 2.1 Regulations governing the utilisation of gas in landfill sites [14]

Sites applied to	Regulations	LFG Requirements
All sites open after 16th July 2001	Landfill Regulations (2002)	LFG as must be collected from all landfills receiving biodegradable waste LFG which can not be used to produce energy must be flared
	Pollution Prevention and Control Regulations (2000)	Ensure that Best Available Technology is applied to receive an operating permit - Schedule 2 of the regulations Best Available Technology is superseded by Landfill Regulations 2002 - but may be applied to combustion installation
Licensed Sites closed before 16th July 2001 or sites not granted a PPC permit	Amended Waste Management Licensing Regulations (1994)	May require gas management depending on a risk assessment
Unlicensed sites – i.e. those that do not have a waste licence under Part II of the Environmental Protection Act 1990	Possibly regulated by the definition of contaminated land in Part II Section 57 of the Environment Act 1995	No LFG requirements

An important implication of the Landfill Regulations (2002)[15] is that LFG should be combusted in an engine wherever feasible, or else it must be flared. Although the Environment Agency has released some indicative criteria, there is no clear guidance on when flaring will be accepted as an alternative to generation[16]. In the model we assume that LFG engines will be required on all sites where it is cost effective to install them. Assuming that LFG remains eligible for generating ROCs then the value of these ROCs will be taken into account in this economic assessment.

The second important implication of the landfill regulations concerns the volume of waste deposited into landfills. The landfill regulations place strict targets on the quantity of biodegradable MSW that can be sent to landfill.

2.3 Model methodology

The modelling approach for LFG is based on a detailed assessment of the maximum resource available, generation costs and developments over time.

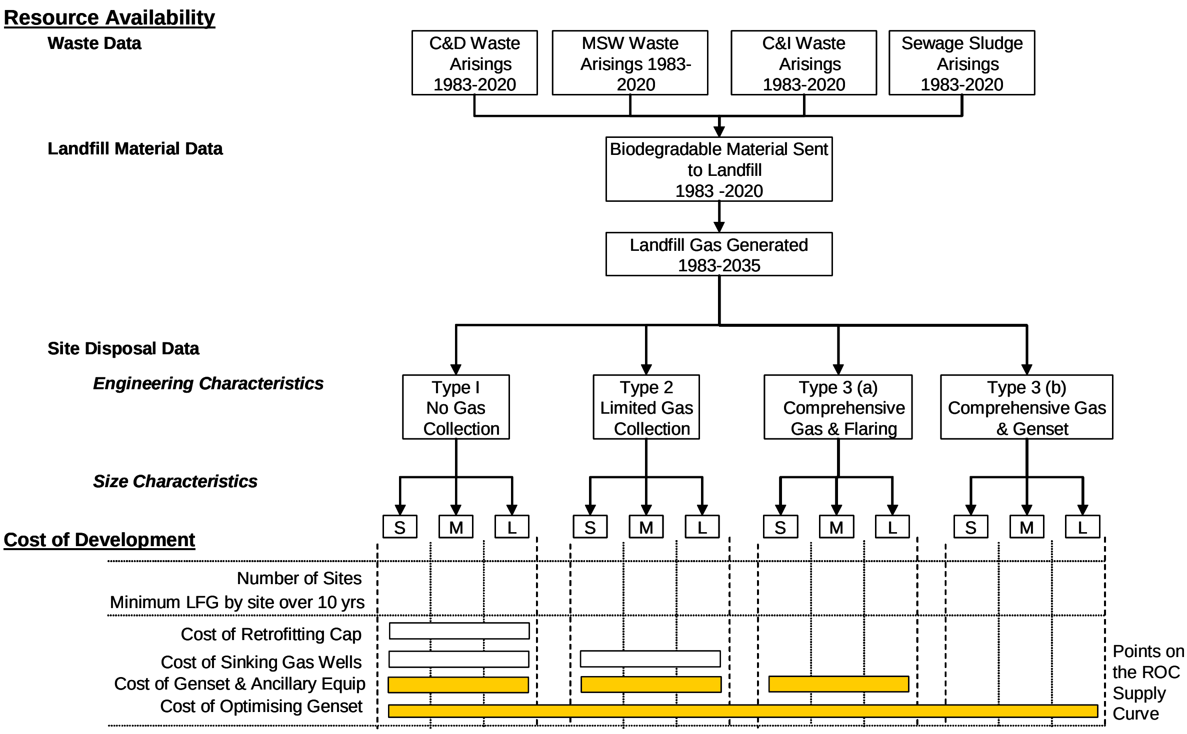
14 Based on Environment Agency (2004) Guidance on the Management of LFG
15 The Landfill regulations (2002) include the transposition of the technical requirements of the European Landfill Directive into national legislation.
16 Environment Agency (2004) and personal communications with the Environment Agency

Assessing resource availability is particularly challenging as data on LFG emissions at the UK level are poor and the interaction between changes in waste deposited and decay rates in methane production are complex. In the description below we refer to LFG but in practice it is the methane content of the gas that is important for power generation. The model explicitly takes account of changing LFG composition over time, but for ease of description we refer to LFG below.

In modelling LFG emissions we have developed a detailed "bottom up" analysis that takes into account emissions from historical and future waste deposits. LFG emissions from historical and future wastes are calculated using the generally accepted LFG assessment tool GasSim [17].

The cost of developing the LFG resource depends on the technical and engineering characteristics of the landfill site. Where sites do not have a gas collection system the cost of generation will include the cost of retrofitting the cap, sinking wells and extracting the gas as well as the cost of installing generation equipment. At a site with existing flares, the cost of generation will be limited to the cost of adding a generator and grid connection hardware. An overview of the modelling methodology is shown in Figure 2.2.

Figure 2.2 Overview of LFG model



2.4 Available resource

To project the total LFG resource in the UK between 2004 and 2020, we take into account historical and future waste deposits. Based on Enviros in-house models developed for the waste management sector we have constructed scenarios to explore the relationship between waste arisings, their disposal route and their

17 GasSim is a LFG simulation model provided by the Environment Agency (2002). See the inset box at the end of this section for further details.

impact on the volume of LFG produced. Separate LFG emission factors are used for each type of waste landfilled and its residence time in the landfill.

Historical waste deposits

The model quantifies the four waste streams identified above and the proportion of those wastes sent to landfill. Because there is insufficient historical data available on waste arisings and disposal methods to generate a good basis for estimating LFG emissions, several sources of information have been used across different years. Assumptions used in the model for historical waste deposits are summarised in Table 2.2.

Table 2.2 Waste Deposit Assumptions

Waste Stream	Percentage of Total Waste Arising[18]	Percentage of Waste Stream sent to Landfill [19] Pre 2000	Percentage of Waste Stream sent to Landfill [20] 2000 – 2004	Biodegradable Fraction of Waste Stream [21]
Municipal Solid Waste (MSW)	8%	90%	90%	71%
Construction and Demolition Waste (C&D)	24%	33%	15%	38%
Commercial and Industrial Waste (C&I)	19%	50%	50%	58%
Sewage Sludge	1%	10%	5%	100%

We do not include arisings of either agricultural waste or other inert material in the LFG model. Other inert material – such as dredging or mining and quarrying material – does not generate material quantities of methane. Whilst agricultural waste contains significant quantities of biodegradable material and is a large proportion of total waste arisings in the UK these wastes have historically been disposed of on the agricultural site. [22] Currently legislation is being introduced to improve the management of agricultural wastes, however this is focused on non-biodegradable wastes. In the model, we therefore assume that all agricultural biodegradable wastes will continue to be disposed of at the agricultural site and not enter landfills.

To calculate LFG and methane emissions, the biodegradable proportion of each waste stream is separated into seven sub-streams. Each sub-stream has a different rate of decay and hence a different methane generation profile. The assumptions used in the part of the model are shown in Table 2.3.

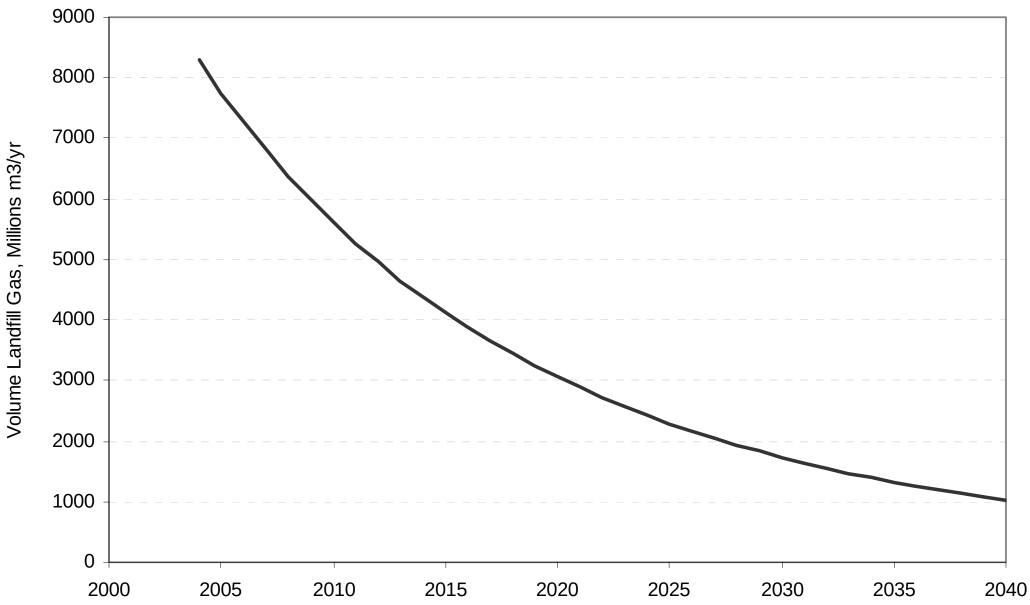
18 DEFRA Environment Statistics http://www.defra.gov.uk/environment/statistics/waste/kf/wrkf02.htm
19 Various sources including the Environment Agency and DEFRA
20 Various sources including the Environment Agency and DEFRA
21 Suggested default values in GasSim for MSW, C&I and C&D waste streams
22 Environment Agency (2003) Agricultural Waste Survey

Table 2.3 Waste component sub-streams [23]

Waste Sub-Stream	Typical Composition	Biodegradable profile		
		Readily Degradable	Moderately Degradable	Slowly Degradable
Paper	News, Magazines, Card, and cartons	0%	25%	75%
Textiles	All	0%	0%	100%
Misc. Combustibles	Nappies etc.	0%	100%	0%
Putrescibles	Garden Waste	100%	0%	0%
Non Inert Fines	Less than 10 mm	100%	0%	0%
Sludge	Sewage Sludge	100%	0%	0%
Non Biological	Inert	0%	0%	0%

Using this data, we then use the GasSim model (see Box 2.1) to calculate the total LFG resource generated between 2004 and 2035 from all wastes deposited in landfill between 1983 and 2004. This projection is shown in Figure 2.3. The model starts at 1983 because waste deposited prior to this date has substantially degraded and produces a quantity of methane that makes power generation infeasible.

Figure 2.3 LFG emissions from waste deposited from 1983 to 2004



23 Suggested values from GasSim and LQM (2003) Methane Emissions from UK Landfill Sites

Box 2.1 GasSim

GasSim was developed by the Environment Agency as a result of increasing concern over the potential health effects of landfills as well as the need for a management tool to help the UK meet international agreements to reduce the emissions of greenhouse gases. GasSim is a probabilistic model that considers the landfill as a single unit – rather than isolated cells – and is divided into four parts:

- source term;
- emissions model;
- environmental transport; and
- exposure/impact.

In the LFG model for the DTI we have used the first two parts of the model, the source term and the emissions model, to predict the LFG generated from historical waste deposits. The source term calculates the generation of LFG for an individual site based on the mass of waste deposited and the composition of the waste streams. The waste is assumed to degrade following a first-order decay model that calculates the LFG generation for up to 200 years.

The emissions model takes this output of the source model and uses it to calculate LFG emissions of bulk and trace gases after allowing for LFG collection, flaring, utilisation (energy recovery) and biological methane oxidation. When calculating the total LFG resource from waste deposited in the UK we have assumed a single representative landfill with an engineered barrier (a cap and liner) and that there is no site gas collection system, flare, or engine on site.

Future waste deposits

Future LFG emissions will depend on future waste arisings and ways in which that waste is treated and disposed. Currently there are no legislative drivers for reducing the total amount of waste generated. However, there are legislative drivers for determining how that waste is managed. The main drivers are:

- Local Authority Best Value Targets - statutory targets imposed on each local authority to increase the amount of the material recycled from the MSW waste stream.

- Landfill Directive Targets - an absolute constraint placed on the volume of the biodegradable material that can be sent to landfill from the MSW waste stream relative to its 1995 volume. These constraints require a reduction of 25% from the volume of biodegradable MSW landfilled in 1995 by 2010, 50% by 2013 and 65% by 2020.

- Landfill Tax - the landfill tax escalator will increase the amount of tax paid per tonne of waste sent to landfill by £3 per year from the current £15/t until a tax rate of £35/t is achieved. This will apply to all waste streams that have a biodegradable component (known as active wastes).

Other drivers exist that target specific elements of the waste stream, such as packaging waste recovery notes, the disposal of refrigeration equipment and the disposal of waste electronic and electrical goods. However, these are not expected to have a significant impact on the amount of biodegradable material sent to landfill and hence methane generation. In the model three scenarios were created to describe the potential increase in the amount of waste sent to landfill:

- *Low growth* in waste arisings and a *high rate* of diversion from landfill (resulting in low LFG and methane emissions)
- *Mid growth* in waste arisings and a *mid rate* of diversion from landfill (resulting in medium LFG and methane emissions)
- *High growth* in waste arisings and a *low rate* of diversion from landfill (resulting in high LFG and methane emissions)

The values used in each scenario are presented in Table 2.4. Projections for annual waste arisings are based on historical waste arisings data, published reports (for MSW), population growth (for sewage sludge) and annual GDP growth (Other Waste Streams & C&I Waste). [24] Landfill diversion estimates determine the rate at which waste will be diverted away from landfill as a result of the landfill directive, landfill tax and scarcity of remaining void space. In the model we assume that MSW diversion achieves the targets in the Landfill Directive. [25] For C&I waste we assume that diversion follows the government's aspirational target of a 15% reduction in C&I waste landfilled. [26] In the sensitivity analysis however we change our assumptions about the year in which this target is achieved.

Table 2.4 Future landfill scenarios

Waste Stream	Low Growth, High Diversion scenario	Mid Growth, Mid Diversion scenario	High Growth, Low Diversion scenario
Arisings growth rate (%/yr)			
MSW	1.9%	2.8%	3.8%
C&I	2.2%	2.7%	3.3%
C&D	0.6%	1.3%	1.9%
Sewage Sludge	0.2%	0.3%	0.5%
Other Waste Streams (Inert)	2.2%	2.7%	3.3%
Increase in waste diverted from landfill (%/yr)			
MSW	Landfill directive targets are met		
C&I	6.9%	5.3%	5.1%
C&D	1.5%	1%	0.5%
Sewage Sludge	1.5%	1%	0.5%
Other Waste Streams (Inert)	1.5%	1%	0.5%

24 Compiled from historical waste arisings data, published reports (ERM (2003) and Enviros studies for local and regional waste strategies, population growth (sewage sludge) and annual GDP growth (Other Waste Streams & C&I Waste). Annual GDP growth projections are provided by the Bank of England's Monetary Policy Committee's 3 year GDP Forecasts.

25 Landfill Directive Targets for a reduction in the biodegradable waste (BMW) sent to landfill in relation to the 1995 BMW landfill are a 25% reduction by 2010, a 50% reduction in 2013, and a 65% reduction in 2020.

26 The aspirational target of an 85% reduction in the C&I waste to being sent to landfill by 2005 was published in the Waste Strategy 2000. In the high diversion scenario we assume that this is achieved in 2010, in the mid diversion scenario by 2015 and in the low diversion scenario by 2020.

LFG Quality

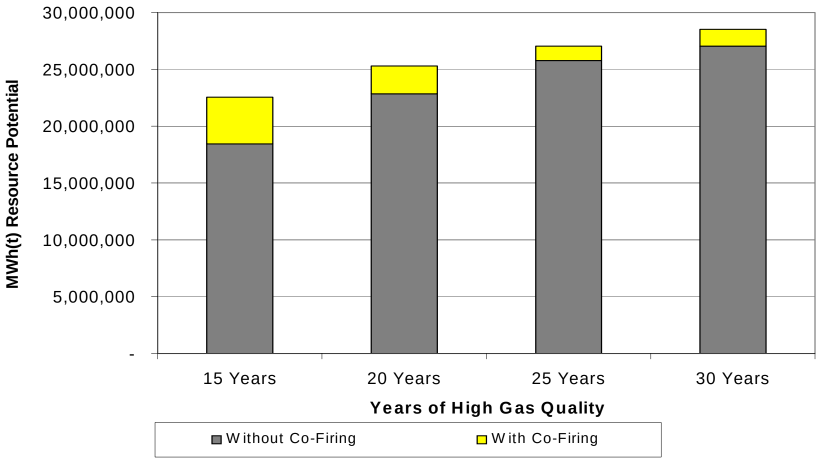
A key factor in modelling the potential LFG resource is the quality of LFG, i.e. its specific calorific value. This depends upon the methane content of the gas which in turn depends on the mix of anaerobic and aerobic decomposition of the waste. As the LFG is generated, its composition is expected to average 50% CO2 and 50% methane. However, with active extraction of LFG there is an increase in the rate of oxygen ingress into the landfill with a subsequent increase in the quantity of methane oxidised prior to extraction and reduction in the methane content of LFG.

Once the methane content of LFG falls below 40% it is unlikely that the calorific value of the gas will be sufficient to maintain stable combustion within a generator. [27] In the model we assume that this reduction occurs over a 20 year time period. [28] However, this can be extended if LFG operators mix LFG with a fossil fuel. Under the terms of the RO a maximum of 10% of the thermal input into a generator can come from a non-renewable source. We estimate that using the maximum input of 10% of non-renewable energy could extend generating lifetime of the LFG generator by approximately 4 years.

The impact of co-firing fossil fuels with LFG depends upon the rate of degradation in LFG quality. Figure 2.4 shows the additional impact of co-firing LFG with natural gas according to the years of high gas quality (when the calorific value of the LFG generated is high enough to sustain a generator). This demonstrates that co-firing becomes more beneficial the higher the rate of degradation in landfill quality. If we assume high quality LFG is available for 15 years, then blending natural gas with LFG increases the quantity of LFG that can be combusted across the UK by 4,000,000MWh(thermal) (assuming a 10% natural gas blend). If high quality LFG is available for 20 years, then the additional resource available from co-firing is reduced to 2,000,000 MWh(thermal).

In the model we assume 20 years of high quality LFG production and that sites are able to co-fire to maximise their output of ROC eligible power.

Figure 2.4 Impact of co-firing on LFG resource in 2015



27 This is an Enviros estimate based on our operating experience. The precise level will vary according to the humidity of the gas and the characteristics of the generating engine.
28 There is very little research about the rate of degradation in LFG quality, GE Jenbacher estimates an economic lifetime of 15 to 25 years, Caterpillar expects economic viability of greater than 20 year and the RPA estimates economic viability of less than 30 years from the year of waste emplacement. Based on Enviros experience we have estimated a 20 year period.

Site Characteristics

In order to create a supply curve for LFG power generation the model distinguishes between landfill sites with different generation cost profiles. Four categories of site are used: [29]

- *Type 1 – Closed sites without an effective cap or any flaring on site (closed after 1980).* In these sites all LFG generated is vented directly to atmosphere. However, the quantity of methane produced for each tonne of deposited waste is relatively low due to less densely packed waste and a high rate of oxidisation whilst passing through the upper layers of the landfill.

- *Type 2 – Closed sites with a limited cap and limited flaring (closed after 1980)*. These sites may have some flaring to reduce the potential risk of lateral migration of LFG, but the majority of LFG is vented directly to atmosphere. Placing flares along the edge of a landfill near residential or other sensitive areas became industrial practice following an accident in 1986.

- *Type 3 – Open (or recently closed) sites that have a completely engineered cap and comprehensive flaring.* Typically these sites accepted waste from 1986 onwards. These sites are likely to have effective gas collection and flaring systems. In the model, we divide this group into two subgroups, those with LFG flares (3a) and those with LFG power generation (3b).

- Type *4 – Sites that closed prior to 1980*. Whilst these may still generate methane, their age has significantly reduced the volumes emitted. These sites are not generally considered to be viable opportunities for LFG power generation because of the low quantity of methane produced.

Because landfill site engineering has historically developed in the absence of formal regulations, there is considerable uncertainty regarding the quality of landfill site engineering and the split of waste between these sites. In the model, we estimate the quantity of waste deposited in each category according to the most recent national emissions data, the amount of electricity generated through ROC and NFFO contracts and historical trends in landfill site engineering.

- *National emissions data.* The most recent estimates of national methane emissions from landfill sites is used to determine the LFG vented directly and hence the volume of waste deposited in Type 1 and Type 2 landfill sites.

- *ROC and NFFO Contracts.* These data are used to determine the amount of gas produced to generate electricity - Type 3b landfills. This suggests that approximately 1.26 million tonnes of methane are currently combusted to generate electricity. Type 3a landfill sites – where LFG is flared – is then the difference between the total emissions projected using GasSim and the emissions accounted for through national emissions and electricity generation.

- *Historical trends in landfill site engineering.* Although there are authoritative data on standards of landfill engineering, there has been a trend since the early 1980s towards more engineered caps with caps being retrofitted to existing sites according to the perceived risk to the surrounding area.

This information is then used to calculate the split of waste deposited in each type of landfill (Table 2.5). As a simplification we assume that all future waste deposits

29 These site categories match those used by AEA Technology (1999) and LQM (2003) analysis of methane emissions from landfill.

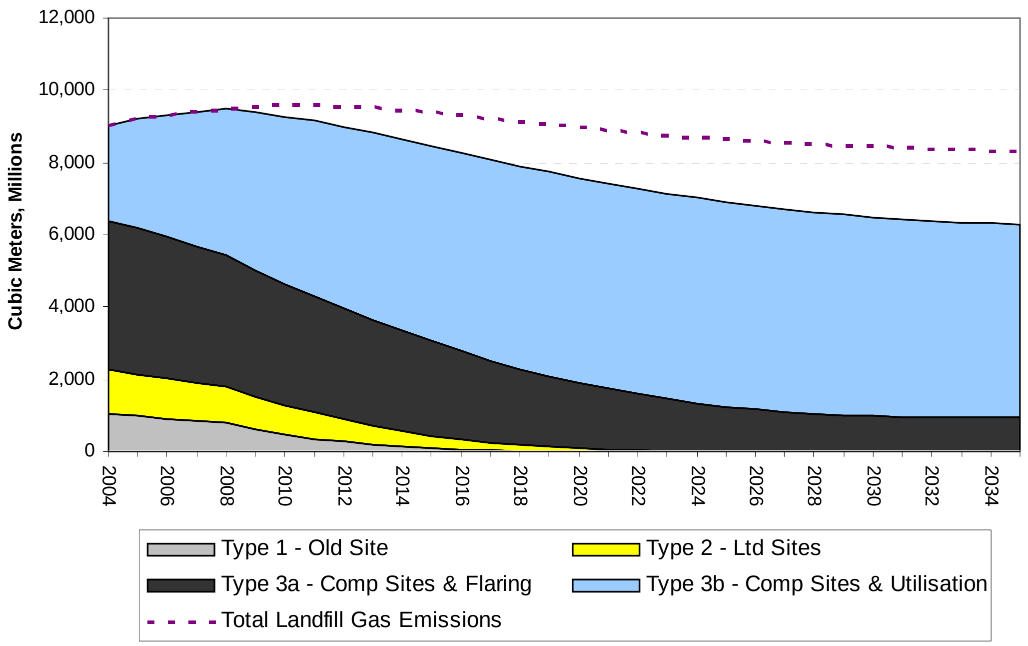
go into a Type 3 landfill with an effective cap and either generation or flaring. These assumptions are used to forecast LFG production from 2004 to 2020 (Figure 2.5).

Table 2.5 Assumptions on waste deposited by landfill type in 2004

Year Deposited	Type 1 No Cap & No Flaring	Type 2 Limited Cap – No Flaring	Type 3 (a & b) Comprehensive Cap & Flaring / generation
1983	95%	5%	0%
1986	40%	40%	20%
1994	0%	20%	80%
2000	0%	0%	100%
2006	0%	0%	100%

To obtain further resolution on the modelling LFG generation costs, LFG emissions are further divided according to the size of the site within each landfill type. LFG emissions are categorised into small, medium and large sites on the basis of the total number of sites, the annual tonnage of waste each site is allowed to accept within the terms of their licence, and the sites closing date. [30] Assumptions on the split of waste deposited by size category for 2004 are shown in Table 2.6.

Figure 2.5 Production of LFG by type of site (base case scenario)



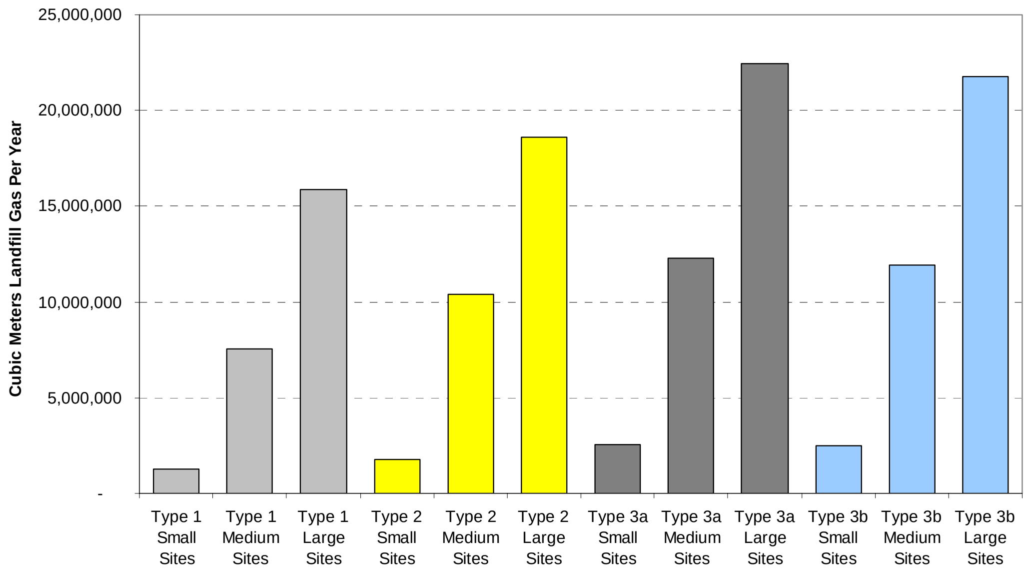
30 Site File 1998

Table 2.6 Waste deposited by size of landfill site in 2004

	Annual Deposit (tonnes)	Share of Waste			Number of Sites		
		Type 1	Type 2	Type 3 (a & b)	Type 1	Type 2	Type 3 (a & b)
		No Cap & No Flaring	Ltd Cap - No Flaring	Comprehen-sive Cap & Flaring / Gen	No Cap & No Flaring	Ltd Cap - No Flaring	Comprehen-sive Cap & Flaring/Gen
Small	< 75,000	10%	10%	9%	56	25	271
Medium	75,000 - 250,000	51%	52%	43%	55	19	276
Large	>250,000	39%	38%	48%	20	8	168

Figure 2.6 shows the resultant LFG emissions between each type and size of landfill site in 2004. This emissions profile will change each year as the resource available in the older Type 1 and Type 2 sites – those no longer accepting new emplacements – diminishes and Type 3 increases.

Figure 2.6 LFG emissions from representative landfill sites in the UK (2004)



2.5 Generation costs

Having defined the total resource of LFG available at representative landfill sites the model then establishes the cost of developing these resources to generate electricity. Costs are divided into capital costs, operating costs and financing costs.

Capital Costs

Capital costs largely depend on the size of the site and its engineering characteristics. We consider four categories of capital costs for each site. These are the cost of site preparation, the generating equipment, grid connection / upgrade and project development costs.

Site Preparation

The level of preparation required on each site before an engine can be installed depends on the existing level of engineering and the size of the site. Site preparation costs depend on the sites roof area, engineering status of the cap and the presence of wells and piping. These factors only apply to Type 1 and Type 2 landfill sites, since Type 3 sites already have flares and caps in place.

Roof Area. Roof area is a function of the average depth of the landfill, its age and the expected volume of waste input into the site [31]. The following average roof areas are used in the model (Table 2.7).

Table 2.7 Roof area of landfill sites

Size of Landfill	Size of Roof (Hectares)
Large Sites	16.8
Medium Sites	10.9
Small Sites	3.4

Cap status. Introducing a fully engineered cap to a landfill site allows LFG that would otherwise be vented to atmosphere to be collected and reduces the influx of oxygen to the landfill site thereby enhancing the production of methane. [32] Table 2.8 shows the current coverage of an engineered cap that we expect to be present on each type of landfill site and the amount of LFG that can be collected assuming a cap is placed across the whole site. The cost of a cap is assumed to be £220,000 per hectare. [33]

Table 2.8 Coverage of an engineered cap

Type of Site	Current Coverage of Engineered Cap	LFG Collection Efficiency with a Complete Cap Installed
Type 1 - No Cap and No Flaring	0%	70%
Type 2 - Limited Cap and No Flaring	50%	75%
Type 3a - Comp Sites & Flaring	100%	85%
Type 3b - Comp Sites & Utilisation	100%	85%

Wells and Piping. The costs of installing gas collection wells, pipe work and extraction equipment are given in Table 2.9

31 The average depth of the landfill is reference from the Environment Agency's Technical Report (1999). All other details are provided by SiteFile (1998)
32 Conversations with industry however also provided examples of dramatic reductions in LFG production due to a change in the environmental balance of the landfill, in particular a reduction of water influx as a result of installing a cap.
33 Environment Agency Technical Report (1999)

Table 2.9 Costs of wells and piping [34]

Assumption		Value
Wells	Cost per well	£2,508
	Number of Wells per Hectare	4
	Cost of Wells Per Hectare	£10,032
Pipe Work	Average Distance of Pipework per Hectare	250
	Cost of Pipework per Hectare	£7,125
Extraction Equipment	Cost of Extraction Equipment Per Hectare	£9,861

Generating Engine

The cost model is based on two engine sizes, 1MW and a 0.25MW. [35] The performance and cost assumptions for each engine are shown in Table 2.10. We assume that generators are installed on a site if there is sufficient gas to generate power for the following ten years. This allows for a degree of non-utilisation, where insufficient LFG inhibits the installation of an additional engine on the site, or where LFG is expected to decline significantly over time. In practice there will also be fluctuations in LFG production.

Table 2.10 Generating engine assumptions

	MW(e) Output	Generating Efficiency	Availability	MWh(t) Input	MWh(e) Output	Cost Per MW(e)[36]
Small Engine	0.25	33%	70%	5,840	1,734	£980,000
Large Engine	1	36%	70%	24,333	7,884	£700,000

Grid Connection and Grid Upgrade

Section 1.3 describes the general assumptions applied for grid connection and grid upgrade. These are applied to LFG generation sites in the following manner. The onsite engineering required to connect the generating unit to the grid is assumed to be £45,000/MW. For grid upgrade costs we assume that all LFG engines connect to the distribution network and hence the average charge for upgrading the grid is £82,000/MW.

Project Development

Project development costs are assumed to be 15% of the total capital costs. The cost of planning permission is treated separately and estimated to be £187,500 per site. These figures were established from communications with site developers and in-house experience.

34 Environment Agency Technical Report (1999)
35 The minimum size of engine currently considered viable by industry for landfill site use is 0.3 to 0.4 MW. With developments in micro-generation, we expect this size threshold to be reduced and have assumed 0.25 MW.
36 Cost were established following discussion with industry

Operating Costs

Operating costs comprise three main elements: maintenance, business rates and use of system charges. No land costs are assumed for LFG.

Maintenance Costs

Maintenance covers the annual cost of maintaining the wells, pipe work and the engine. As these depend on the age of the site, different maintenance costs are used for landfill sites Types 1 and 2 (15% of site preparation and engine costs) and landfill site types 3a and 3b (13% of site preparation and engine costs).

Business Rates

For LFG, the addition of a generator is treated as a new capital asset. Business rates are therefore assumed to be £15,000/MW/yr based on the current market value for generating turbines. [37]

Generation Charges

As discussed in Section 1 GDUoS charges are assumed to be £2,500/MW/yr.

Financial Assumptions

The main financial assumptions used in the model are the discount rate and the project lifetime. Because LFG engines are mature technologies we use a discount rate of 7.9%. For project lifetime we assume that LFG engines operate for 10yrs.

Changes over time

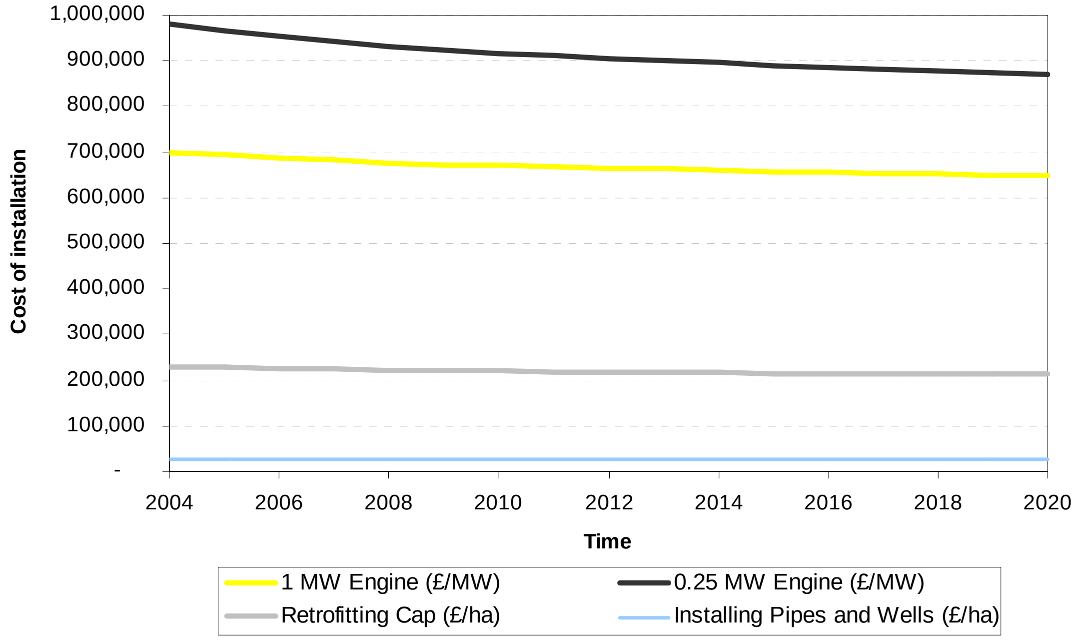
There are two changes that we would expect in the shape of the supply curve for LFG over time. Firstly LFG resource available will change – as discussed in the previous section – and secondly the unit cost of generation will alter due to learning effects. To capture these learning we use the PR values as shown in Table 2.11. [38] The impact of these PR values on the cost of generation engines and site development costs are shown in Figure 2.7.

Table 2.11 PR values assumed for LFG

Cost Component	PR value	Measure used in the PR calculation
1 MW engine	92%	Global Capacity
0.25 MW engine	88%	Global Capacity
Retrofitting a Cap	92%	Global Capacity
Installing Pipes, Wells & Extraction equipment	92%	Global Capacity
Project Development	92%	UK Capacity
Planning Permission	100%	UK Capacity
Operating and Maintenance	92%	UK Capacity

37 Following communication with the Valuation Office Agency, as discussed in section 1
38 There are no studies on the PR ratio for LFG. We have therefore used numerous studies that look at the PR ratio of gas turbines and other renewables to develop internal estimates.

Figure 2.7 Change in LFG engine and installation costs over time.



2.6 The LFG supply curve

Figure 2.8 shows the resultant supply curve for LFG in 2005 and 2015 assuming the *mid growth - mid diversion* waste to landfill scenario alongside the power output from LFG in 2003 as recorded in DUKES (3.2TWh). We would expect LFG output in 2004 to be around 3.5TWh based on an installed capacity at the end of 2004 of 630MW and a ROC output for the first seven months of 2004 of 2.0TWh. [39]

The analysis indicates that the LFG industry is gradually approaching saturation in the development of new low cost sites. Model shows a sharp increase in costs at around 5.0TWh. This is due to the exhaustion of large sites capable of utilising large engines and where LFG collection systems are required under the Landfill Directive. Sites that make up the part of the curve between £45 and £100/MWh are all Type 3a, 3b and 4 sites (i.e. have comprehensive gas collection systems), but have low gas production volumes and consequently small and less efficient generating engines. In developing the older sites the full set of gas collection equipment is attributable to the power generation system, since gas collection and flaring is not required under the directive for these sites. At these sites, generation costs are in excess of £100/MWh.

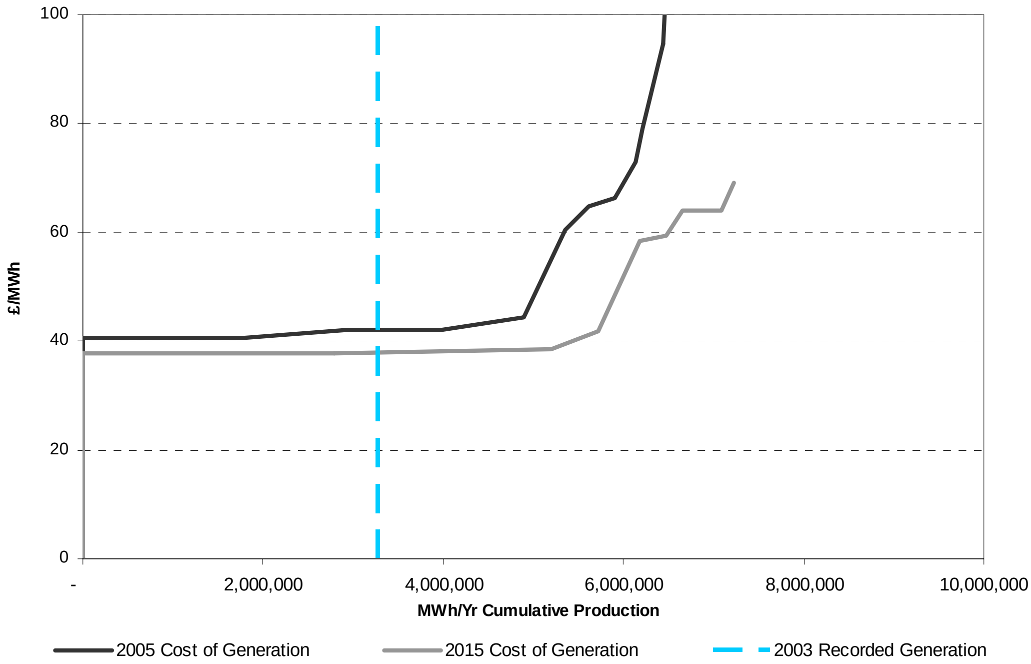
Figure 2.8 shows that under the mid growth-mid diversion scenario *in the short term* an additional 1.8TWh (approximately 300MW) of LFG output is achievable at a cost below £45/MWh from 2003 levels. The additional available capacity below £45/MWh from expected 2004 output levels is around 1.5TWh (250MW). These calculations assume that new capacity will be developed with a load factor of 70% as shown in Table 2.10.

The model also indicates that the rate of increase in LFG production from new waste disposed to landfill will outweigh the decline in yields from historic wastes, resulting in an extension of lower cost generation opportunities over time. By 2015

39 source Ofgem, Jan 2005

we would expect to see the available capacity at below £45/MWh increase to 5.8TWh, representing an increase on 2003 levels of 2.6TWh (420MW), or 2.3TWh (370MWh) from expected output in 2004. Learning effects are slight in the context of LFG reducing the cost of generation by £2/MWh between 2005 and 2015.

Figure 2.8 Cost of supply curve in 2005 and 2015 (mid growth-mid diversion scenario)



2.7 Sensitivity analysis

Three sets of scenarios have been run of the LFG supply curves. The first two look at changes in engineering costs and methane resources available in 2005. The third assess changes in waste deposits to landfill over time. Tables 2.12 and 2.13 show the assumptions used in the 2005 scenarios. The assumptions in the waste deposits scenario are contained in Table 2.4. Figures 2.9, 2.10 and 2.11 show the effect of these scenarios on the supply curves.

These scenarios indicate that – on the basis of the scenarios modelled - the 2005 supply curve is most sensitive to assumptions about the quantity of LFG available rather than the costs of generation. Figure 2.10 illustrates that between the Low and High Resource scenarios additional LFG generation capacity beyond present day levels and exploitable over £50/MWh varies by a factor of nearly three.

Figure 2.11 shows that the 2015 curve is sensitive to assumptions about waste deposit rates. The difference between the Low and High Deposit scenarios alters the additional LFG generation beyond present day levels by a factor of two. The extent to which these scenarios are realised will depend upon the impact of the landfill tax and if and when the aspirational target for the diversion of C&I waste is achieved.

Table 2.12 LFG engineering cost scenarios

	Low Cost	Mid Cost	High Cost
Cost of Retrofitting Cap Per Hectare	£210,000	£220,000	£230,000
Expected Cost per well	£2,400	£2,500	£2,600
Expected Cost of Extraction Equipment/ha	£9,300	£9,900	£10,300
Cost of Grid Connection	£43,000	£45,000	£47,000
Grid Upgrade Cost	£78,000	£82,000	£86,000
GDUoS Charges - Across All Regions	£2,350	£2,500	£2,650
Type 1 & Type 2 Sites (Old Site & Ltd Caps)	13%	15%	18%
Type 3 & Type 4 Sites (Comp caps & Comp with Flaring)	11%	13%	15%
Discount Rate	7%	8%	9%

Table 2.13 LFG resource scenarios

	Low Resource	Mid Resource	High Resource
No of Years gas quality with no co-firing	15	20	25
Collection Efficiency - Type 1	65%	70%	75%
Collection Efficiency - Type 2	70%	75%	80%
Collection Efficiency - Type 3a	80%	85%	90%
Collection Efficiency - Type 3b	80%	85%	90%

Figure 2.9 LFG supply curve – engineering cost scenarios (2005)

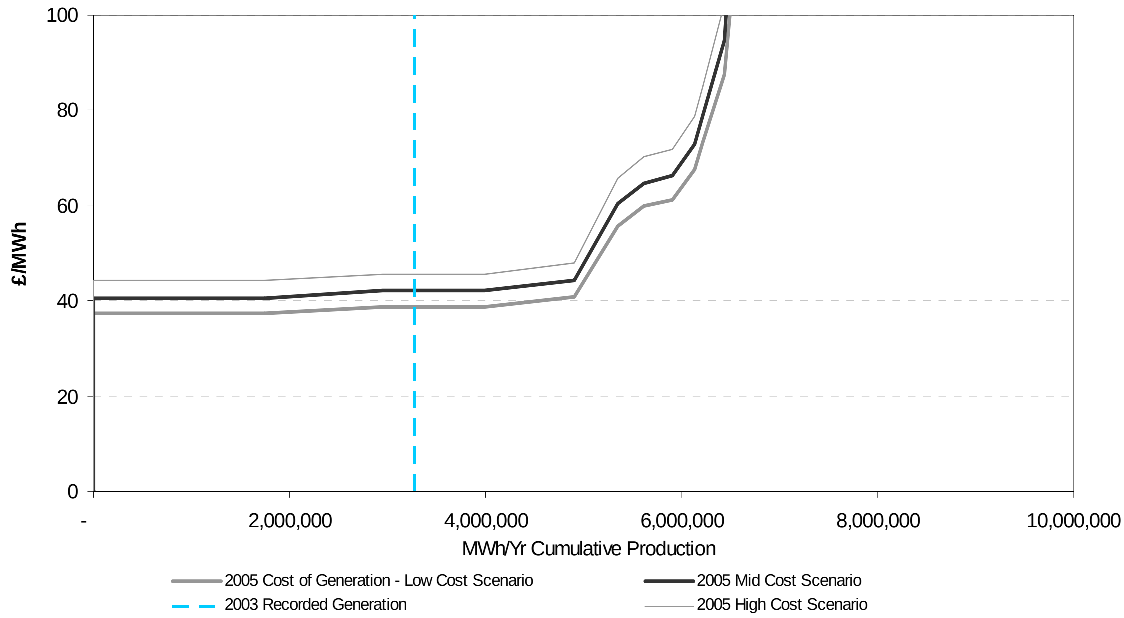


Figure 2.10 LFG supply curve – methane resource availability scenarios (2005)

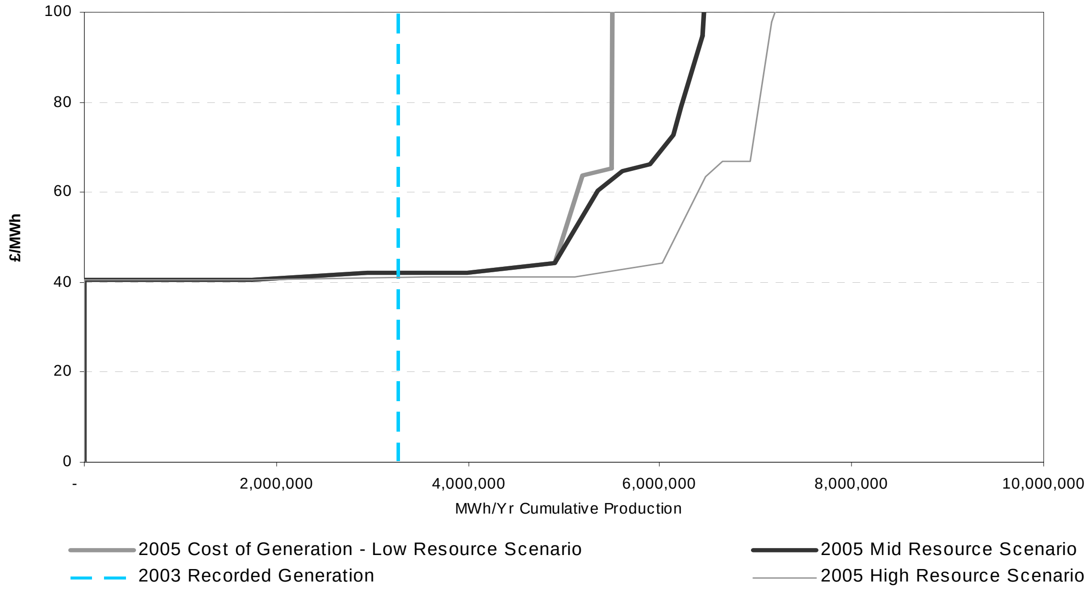
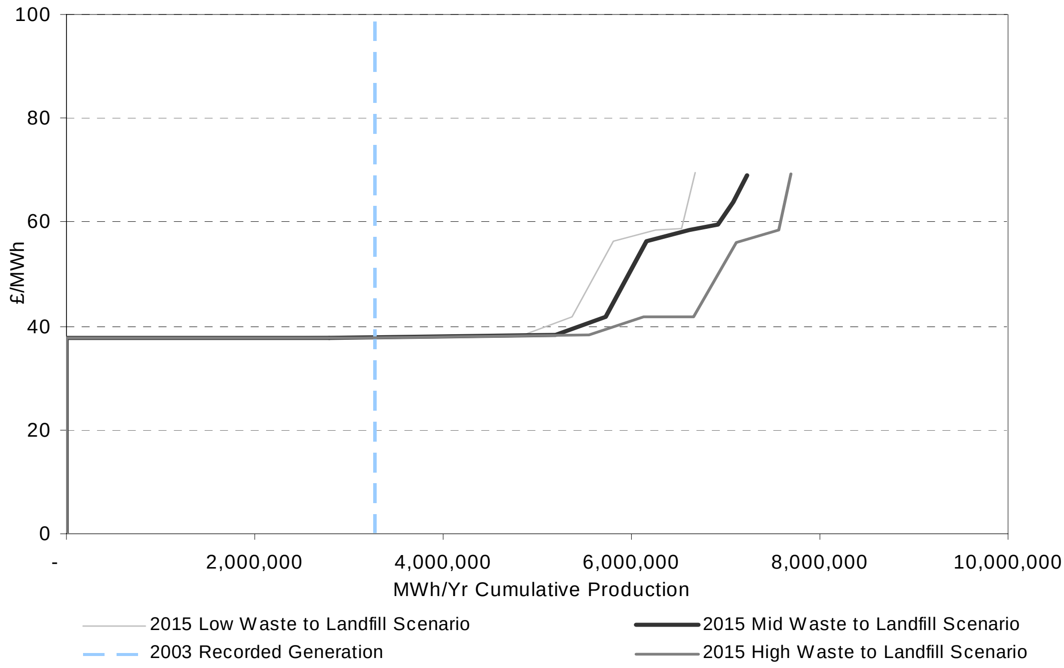


Figure 2.11 LFG supply curve – waste deposit scenarios (2015)

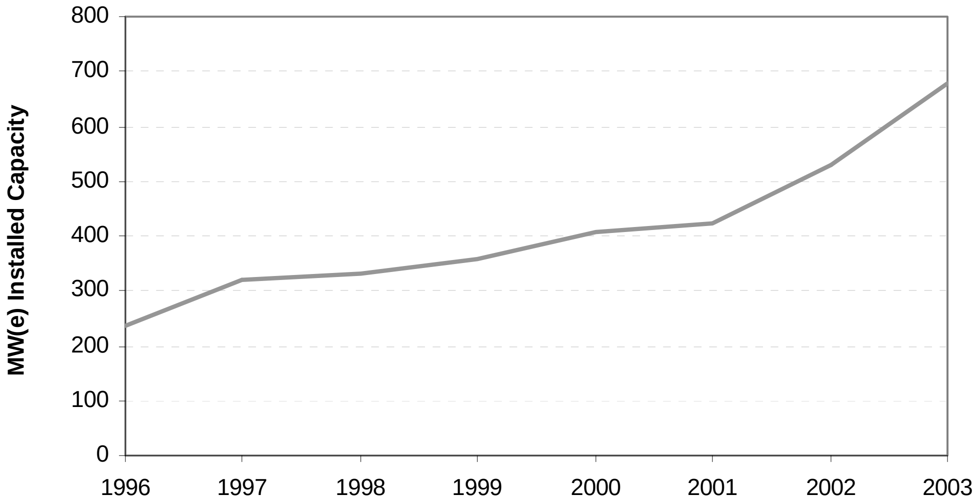


3. ONSHORE WIND

3.1 Overview of the sector

The onshore wind sector is currently the fastest growing source of renewable energy generation in the UK with over 200MW generating capacity installed in the 2004. There is currently around 1000MW of onshore generation capacity in the UK. Figure 3.1 shows the rapid increase in capacity additions in recent years. The British Wind Energy Association (BWEA) estimates that this rate of capacity growth will accelerate over the next few years with an additional 600MW expected to be installed in 2005. [40]

Figure 3.1 Installed onshore wind capacity



source: Digest of UK Energy Statistics

3.2 Legislative background

There is no legislation that mandates or prohibits the uptake of wind generation, although some legislation – such as planning guidance – impacts both the speed and the cost of additional wind generation capacity.

3.3 Model methodology

The principal challenge in generating the onshore wind supply curve for the UK is in estimating the practical resource potential. Costs, by contrast, are generally more widely known. Our cost assumptions are shown in detail in Section 3.5. With regard to resource estimates, whilst it is possible to calculate the theoretical wind resource in the UK, estimating the practical resource potential is made difficult by the uncertainties in public acceptance of wind farms and the associated constraints imposed by the planning system.

Information on the practical resource potential can be obtained through two approaches. The first, the top down method, uses estimates of the total wind

40 BWEA Growth estimates for onshore wind generation

resource potential for the UK, using wind speed maps, and then scales these back according to assumptions on restrictions on what land can be developed for wind power. The key source of this type of analysis is the study conducted by ETSU in 1997, from which most other policy estimates are derived.[41] Other studies of the UK wind resource potential are summarised in Table 3.1

Table 3.1 Previous UK Wind Resource Estimates

Source	**Onshore Potential (England and Wales)**	
	GW	**TWh**
Sustainable Development Commission, 2005, Wind Power in the UK - A Guide to the Key Issues Surrounding Wind Power Development in the UK	-	50
DTI / Oxera, 2004, Results of Renewable Energy Modelling	15	39
DTI, 2003, Renewable Energy Innovation Review Consultation Document	15 – 20	39 - 52
DTI, June 2001, Wind Energy Fact Sheet	-	"something over 50TWh"

The second method uses the latest regional planning policy guidance for onshore wind to build up a "bottom-up" picture of the practical onshore wind resource for the UK.

The top down analysis conducted by ETSU assessed the wind resource potential for wind speed sites in excess of 7m/s. It did this in several stages. It first determined the maximum theoretical power output from onshore wind by applying density and turbine size assumptions to the wind speed map of the UK. This figure was then reduced to take account of land use categories where wind farms would *a priori* not be built, including for example beaches, slopes over 10^{O} gradient, and buffers around roads, woodland, settlements and airports. This is referred to as the "feasible" resource. This figure was then refined to produce an estimate of the "accessible" resource, to allow for areas of ecological sensitivity, such as Areas of Outstanding Natural Beauty (AONB) and Sites of Special Scientific Interest (SSSI). Finally, the analysis assumed a separation between sites in order to take into account public opposition to densely sited wind farms. This generated a "practical" resource. Sensitivities were then run on different settlement buffers, network limits and transmission constraints. The results are summarised in Table 3.2. The central figure of 57TWh for the practical resource has been widely used in policy documents, although the range 17 to 82TWh is less widely reported.

41 ETSU, F. Brocklehurst, 1997, A Review of the Onshore Wind Energy Resource.

Table 3.2 Summary of ETSU R-99 Study Results

	MW Capacity	GWh/yr	Comments
Headline resource assessments			
Feasible	223,373	660,787	
Accessible	109,679	317,854	Excludes: national Parks, AONBs, National nature reserves, SSSIs, Greenbelt
Practical	**19,496**	**57,627**	**Based on clustering and proximity constraints**
Minimum case	5,633	17,154	Restricted turbine density (7/kms)
Maximum case	27,928	82,752	Increased wind farm size (100 turbines)
Sensitivities			
800 m Settlement Buffer	11,210	35,959	Total Resource - No wind restriction
1500 m Settlement Buffer	5,771	20,112	Total Resource - No wind restriction
Electricity Network limit	8,998	31,360	Includes: limits of flow of electricity from North to South, network constraints in the UK and that the Scottish network is reinforced.
Transmission constraint	4,651	16,210	
Transmission + network constraint	2,750	8,180	

This top down analysis, whilst robust methodologically, is now dated and arguably does not fully reflect the latest the public opposition to onshore wind developments. In particular it does not take into account the implications of cumulative visual and noise intrusion, nor the sterilisation of land between designated development sites. We therefore regard the 50 to 57TWh range as an upper estimate of the practical resource potential for onshore wind development.

The bottom up approach attempts to capture the realities of the current planning situation in examining the onshore wind resource estimates published by each region in the UK. Some regions provide figures for pre- and post- planning stages, whereas others give revised figures following a public consultation process. For some regions, the assumptions behind the reported figures are not clear. Nonetheless, on the basis of these published reports our research has sought to identify on a consistent basis, the maximum resource potential for each region, along with high and low scenarios for the development of on shore wind power. All these resource assessments relate to sites with annual mean wind speeds above 6 to 7m/s. The thresholds above which the resources are estimated differ by region.

The figures presented below ignore any constraints imposed by grid networks. Although grid constraints do impose real restrictions on the development of wind farms in the short term, in the fullness of time it is reasonable to assume that grid issues will be resolved to accommodate the required number and location of power generation facilities.

3.4 Available resource

Table 3.3 summarises the results of Enviros' research into the on-shore wind resource for the UK regions. The high scenario reflects the potential under a supportive planning framework where there are few planning constraints, whereas the low scenario assumes a more restrictive planning environment. In some regions (e.g. Yorkshire and the Humber, and the South West), the difference between the two scenarios is a result of a consultation process, and may therefore be regarded as an accurate prediction of future planning decisions for those regions.

In most regions, the resource estimates are set out in terms of what could be achievable within a specified timeframe. Where years are provided in the original reports these are shown in brackets in the table. "u/c" means time "unconstrained", ie no date limit is provided. Generally, we have taken estimates for 2020 to be the high scenario, with the low scenario representing estimates for 2010.

The aim of this research is to determine the resource potential for renewable energy technologies at any point in the future, not just by a particular year. However, the 2010 and 2020 estimates are reasonable approximations for the low and high scenarios. The 2010 figures in the regional resource assessments are often derived from an assumption about a restrictive planning environment, rather than how much capacity could be built by that date. Similarly, the 2020 figures are generally associated with the maximum onshore wind resource that would be publicly acceptable in that region. The analysis and references supporting this table are contained in Appendix 3. Note that the range determined for Scotland is inferred from the observed trends in planning applications in Scotland and the low and high scenarios from other UK regions.

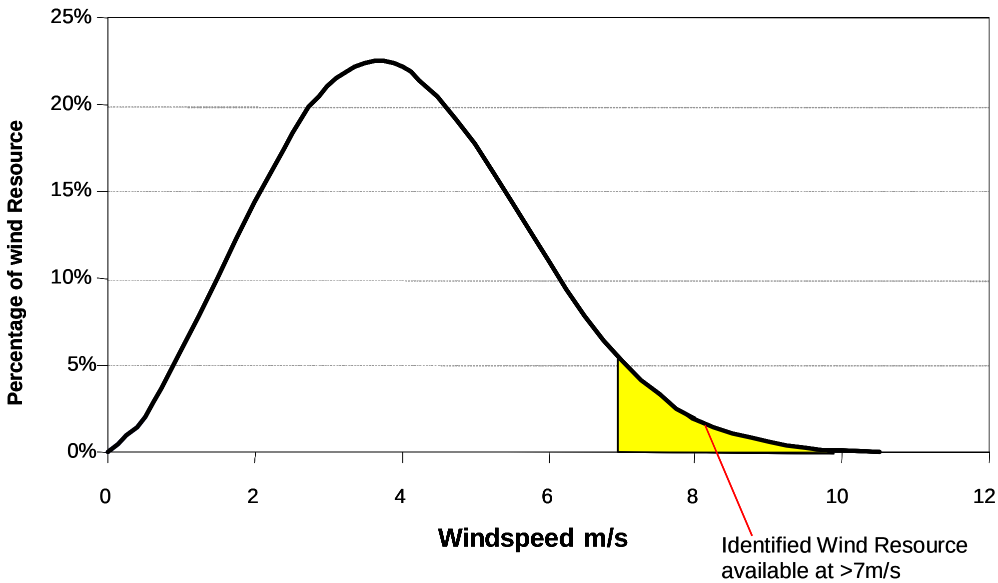
This bottom up analysis suggests that the UK has a practical and cost effective onshore wind potential of between 20 and 48TWh. These figures relate to annual average wind speeds of between 6 and 7 m/s. For the rest of this report we assume they apply to an average wind speed of 6.5m/s. These figures are broadly consistent with the upper estimate provided by the range in the top down analysis of 50 to 57TWh. On the basis of this analysis we therefore use the 20 to 48TWh as a guide for the range for the practical UK onshore wind potential at an annual average wind speed of greater than 6.5m/s.

This analysis provides an estimate of the UK onshore wind resource above 6.5m/s. Very little analysis has been undertaken to examine the resource below 6.5m/s. To do this, we use the estimate of the resource identified above as a single point on a probability distribution of wind speeds across a region. It is generally accepted that a "Weibull" distribution most closely represents the distribution of wind speed at a particular site. In the absence of any relevant data at the regional level, we adopt the same probability distribution to provide an estimate of the regional wind speed profile. An example for the East Midlands wind resource is shown in Figure 3.3.

Table 3.3 Summary of regional wind resource assessments (MWe)

Region	High scenario	Low scenario
East of England	1,218 (2020)	685 (2020)
East Midlands	388 (u/c)	122 (2010)
London	18 (u/c)	18 (u/c)
North East	866 (2020)	341 (2010)
North West	606 (2020)	334 (2020)
South East	229 (2016)	172 (2010)
South West	788 (2010)	367 (2010)
West Midlands	300 (2020)	100 (2010)
Yorkshire and the Humber	1,953 (2020)	725 (2010)
Wales	1,493 (2020)	1,093 (2010)
Northern Ireland	1,559 (u/c)	577 (u/c)
Scotland	8,660 (u/c)	2,887 (u/c)
Total MWe	**18,077**	**7,420**

Figure 3.3 Sample wind resource profile for the East Midlands.



By converting this into a cumulative probability distribution, we are then able to determine the share of the total wind resource that occurs between different wind speeds. This wind resource is then divided between large and small wind farms, 80MW and 30MW respectively. If there is insufficient wind resource for an 80MW wind farm at a given wind speed then a 30MW wind farm is selected. These sizes are selected to represent the different cost of connecting to either the national grid or the local distribution network.

The model assumes that a 30MW wind farm is the smallest increment that can be installed, and does not allow wind farms to span several wind speed categories. This places a constraint on the resource that can be developed in each region.

Combining the resource identified in each region and at each wind speed with the expected capacity factor of a wind turbine operating at those wind speeds we generated a maximum potential energy output. The capacity factor assumptions are based on a 2MW wind turbine. [42] For the low wind speed resource – below 6.5m/s – we adjust the capacity factor to account for turbine design optimisation such as increased rotor diameter. We model this to increase the capacity factor by 20% at low wind speeds. The capacity factors used are given in Table 3.4.

Table 3.4 Wind capacity factor assumptions

Wind speed (m/s)	Capacity Factor
9	47%
8.5	43%
8	39%
7.5	35%
7	31%
6.5	27%
6	26%
5.5	22%
5	17%

3.5 Generation costs

Having defined the total resource available at each wind speed, we then establish the cost of developing that resource for both large and small wind farms. These are split into capital costs, operating costs and financial assumptions. The key cost assumptions have been validated with wind energy suppliers.

Capital costs

Capital costs for onshore wind are split into 5 elements, site preparation, turbines and foundations, grid connection and grid upgrade, project development and planning.

Site preparation

The model assumes that each site costs £91,000 to develop. [43] This covers the cost of access roads and landscaping and is expected to be independent of the size of the wind farm.

42 Capacity factors are calculated on the Danish Wind Industry Association website
43 Based on BWEA estimates

Turbines and foundations

Following discussion with various suppliers, we expect each turbine to cost £548,000/MW. [44] This cost includes the cost of the support tower, assuming that each tower is a standard height. The foundations for each tower are expected to cost an additional £43,000/MW.

Grid connection and grid upgrade

The cost of grid connection for wind sites is assumed to be £55,000/MW installed generating capacity independent of the wind farm size. For grid upgrade costs we assume that large wind farms will be connected to the transmission network with an upgrade cost of £95,000/MW and that small wind farms will be connected to the distribution network with an upgrade cost of £82,000/MW.

Project Development and Planning Permission

Project development costs are assumed to be 10% of the total project capital costs. This covers the cost of project design, environmental impact assessments, legal and search costs. The cost of planning permission is assumed to be independent of the size of site and is expected to be £187,500 per site, assuming there is no planning enquiry. [45]

Operating Costs

The operating costs were separated into four elements: maintenance, business rates, use of system charges and land costs.

Maintenance costs

The maintenance costs cover the cost of salaries, management and maintenance but exclude the cost or rent and use of system charges. We therefore use a figure for annual maintenance of 5% of total capital expenditure, including grid connection.

Business rates

As described in section 1 we have assumed that all wind turbines have a rateable value of £5,000/MW creating an annual business rate of £2,110/MW installed capacity.

Use of system charges

Because we expect large wind farms to be connected to the transmission network, they are liable to pay TNUoS charges according to their grid tariff zone. Small wind farms tend to be connected to the local grid, giving rise to an annual charge of £2,500/MW.

Cost of Land

We assume that all wind farms have to pay rent for the land-take of each turbine, and that this is charged at the cost of agricultural land. To calculate the cost of land rental, we assume that a wind turbine with a 25 m blade diameter has a land take of

44 Confirmed through conversation with industry
45 Enviros project development experience

0.15ha. In the model agricultural land is valued at around £6,600/ha in England and Wales, £4,000/ha in Scotland and £9,000/ha in Northern Ireland. [46]

Financial Assumptions

As with the LFG model the two sets of financial assumptions used in the model are the discount rate and the project lifetime. Because wind turbines are a mature technology we use a discount rate of 7.9%. Wind turbines are assumed to have a 15 year project lifetime.

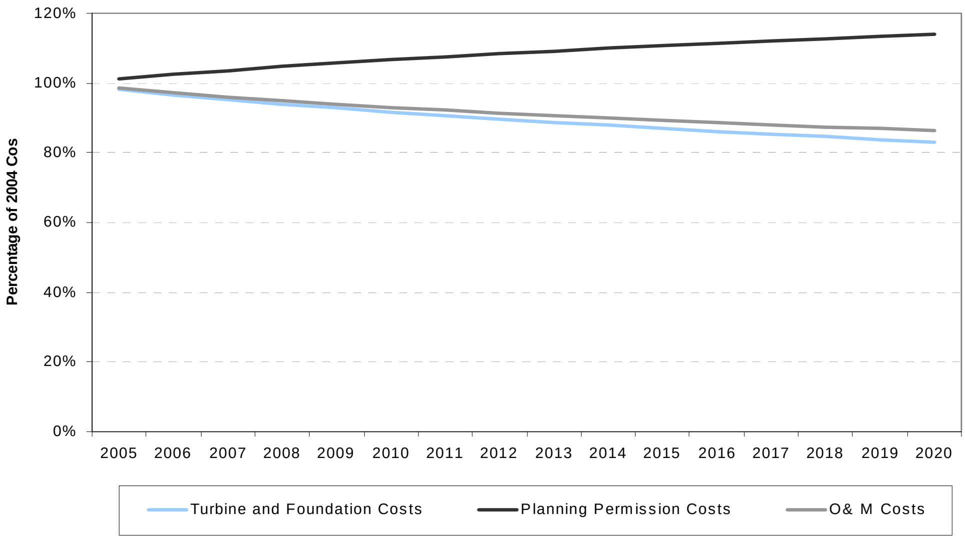
3.6 Changes over time

Although we do not expect any change to the total resource available over time, we would expect the cost of utilising that resource to change through learning effects. The PR values used in the model are shown in Table 3.5. [47] For the cost of planning, we use a PR of 110% to reflect the increasing costs of obtaining planning permission. This relatively simple might underestimate the true impact of planning constraints on wind farm development as capacity increases further and public opposition reaches new levels. From a modelling perspective, there are few reliable methodologies that can quantify these costs. Arguably planning constraints are better incorporated into the overall analysis through future build rates rather than on the cost side. The impact of these PR values on unit costs is shown in Figure 3.5.

Table 3.5 PR values for wind generation

Cost Component	PR Value	Installed Capacity
Technology	92%	Global Capacity
Project Development	90%	Global Capacity
Planning Permission	110%	UK Capacity
Operating and Maintenance	90%	UK Capacity

Figure 3.5 Changes in wind turbine costs and installation costs over time



46 Agricultural Land Rental Values by region, published by DEFRA.
47 Source: Neiji et al (2003)

3.7 The wind supply curve

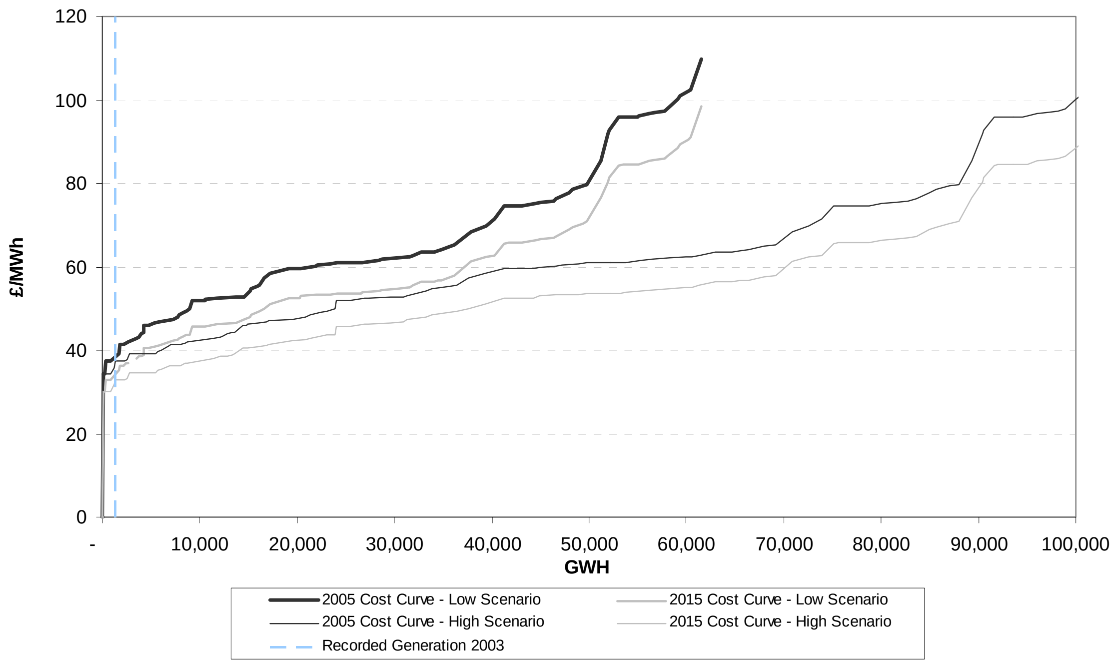
Figure 3.6 shows the resultant supply curves for wind generation in the UK for 2005 and 2015 for all wind speeds above 5m/s and up to £100/MWh. Two curves are shown for the low and high practical resource scenarios described in section 3.4, along with the actual wind generation output at 1,270GWh/yr in 2003/4.

Both curves show a relatively gradual increase from current costs of around £40/MWh up to £100/MWh. The curves suggest that between 60 and 100TWh could be generated at a cost of less than £100/MWh.

Figure 3.7 truncates the y-axis to a cost of less than £60/MWh to provide greater resolution on the low cost part of the curve. This shows that the UK's wind resources could generate between 20 and 45TWh at a cost of less than £60/MWh. The upper end of this range is of a similar magnitude to those from other studies (see Table 3.1). For reference 45TWh is approximately 14% of UK electricity demand in 2004 and 10% of projected electricity demand in 2010. [48] 45TWh corresponds to 8,000 2MW turbines. If arranged in clusters of 25 turbines this output would represent 320 separate wind farms. 20TWh is somewhat lower than other estimates. This reflects assumptions of a tighter planning environment based on recent analysis of regional planning guidance.

By 2015 we expect the marginal cost of wind power to reduce by approximately £5 - 7/MWh through learning effects.

Figure 3.6 Supply curve for wind in 2005 and 2015



48 source: DUKES and National Grid Transco, 2003, Seven year statement

Figure 3.7 Supply curve for wind in 2005 and 2015 below £60/MWh

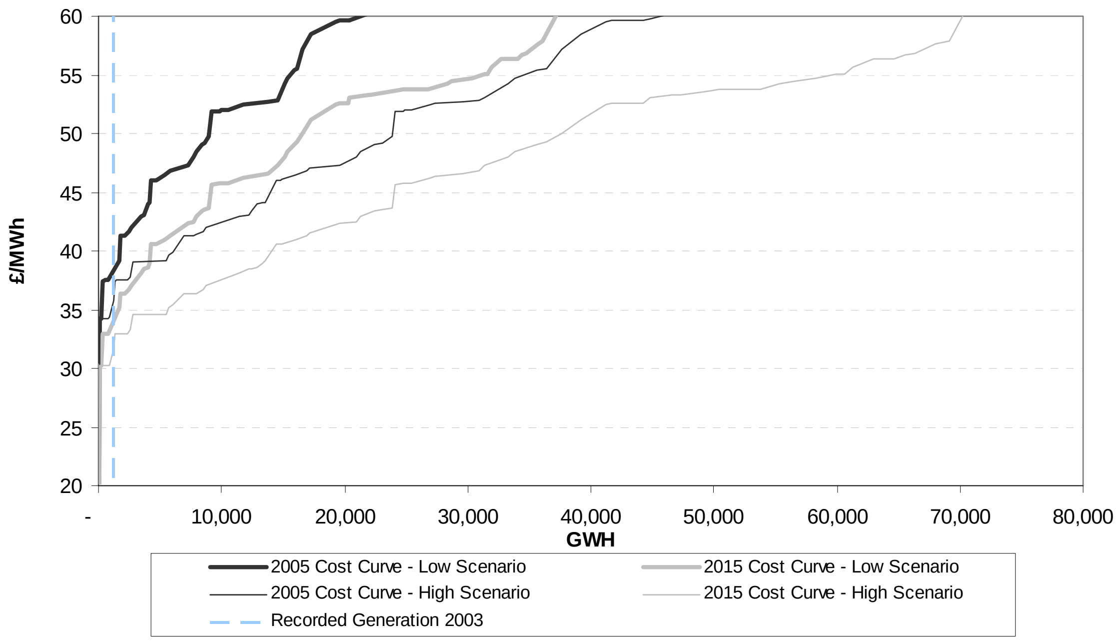


Table 3.6 shows the approximate relationship between wind speed, genertation potential and generation costs. The range in generation costs at a particular wind speed band reflects variable site characteristics associated with a given wind speed. For example sites with the same wind speed may be different sizes and have different grid connection costs.

Table 3.6 Generation potential by wind speed (2005)

Windspeed (m/s)	Generation Potential (MWH)		Cost of Generation 2005 (£/MWh)		
	Low Wind Resource Scenario	High Wind Resource Scenario	Maximum (£/MWH)	Average (£/MWH)	Minimum (£/MWH)
5	10,358,000	13,098,000	£109.8	£97.5	£91.9
5.5	11,699,000	17,715,000	£85.4	£76.3	£71.5
6	12,259,000	20,525,000	£69.8	£62.1	£58.5
6.5	9,175,000	14,927,000	£68.3	£61.2	£57.2
7	7,454,000	17,262,000	£59.5	£53.0	£49.8
7.5	5,132,000	10,779,000	£52.7	£47.3	£44.1
8	2,921,000	3,962,000	£47.3	£42.6	£41.3
8.5	1,424,000	3,955,248	£42.9	£38.4	£37.4
9	1,112,000	1,114,952	£39.2	£35.9	£34.3
Total Resource	**61,534,000**	**103,340,000**	-	-	-
Resource > = 6.5m/s	**27,218,000**	**52,000,200**	-	-	-

3.8 Sensitivity analysis

Of all the inputs into the UK wind supply curve the most important relate to the calculation of resource potential. Resource potential in turn is linked to planning and wind speed. Planning scenarios have been illustrated above and with a relatively mature technology such as wind power, unit costs are quite tightly defined as are financing costs. Table 3.7 shows three resource scenarios indicating low, medium and high assumptions on capacity factors at different wind speeds, as well as three assumptions on the low wind speed optimisation factor. The effect on the supply curve is shown in Figures 3.8 and 3.9.

Increasing the assumed capacity factor even by two basis points has a significant impact on the shape of the supply curve. Under the low resource scenario, moving from the medium to the high capacity factor scenario increases the output from 15 to 18TWh at £55/MWh. Under the high resource scenario moving from the medium to high capacity factor scenario increases the output from 35 to 40TWh.

Table 3.7 Wind supply curve – scenario assumptions

	Low	Medium	High
Capacity Factor 9 m/s	45%	47%	49%
Capacity Factor 8.5 m/s	41%	43%	45%
Capacity Factor 8 m/s	37%	39%	41%
Capacity Factor 7.5 m/s	33%	35%	37%
Capacity Factor 7 m/s	29%	31%	33%
Capacity Factor 6.5 m/s	26%	27%	28%
Low Wind Speed Optimisation	18%	20%	23%

Figure 3.8 Wind supply curve capacity factor sensitivity (low resource scenario)

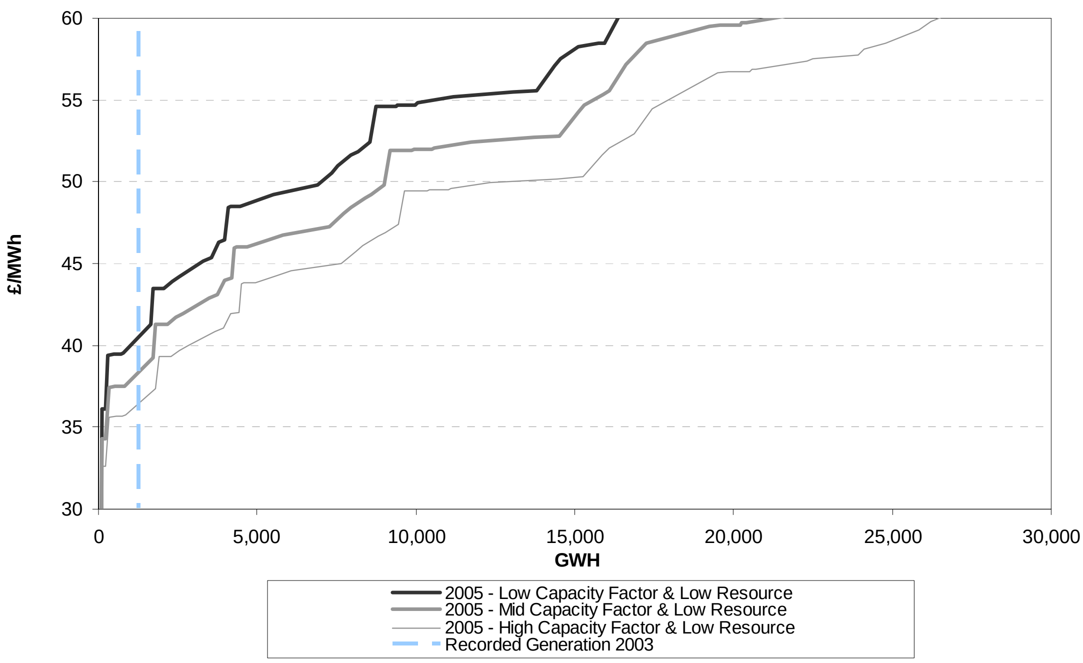
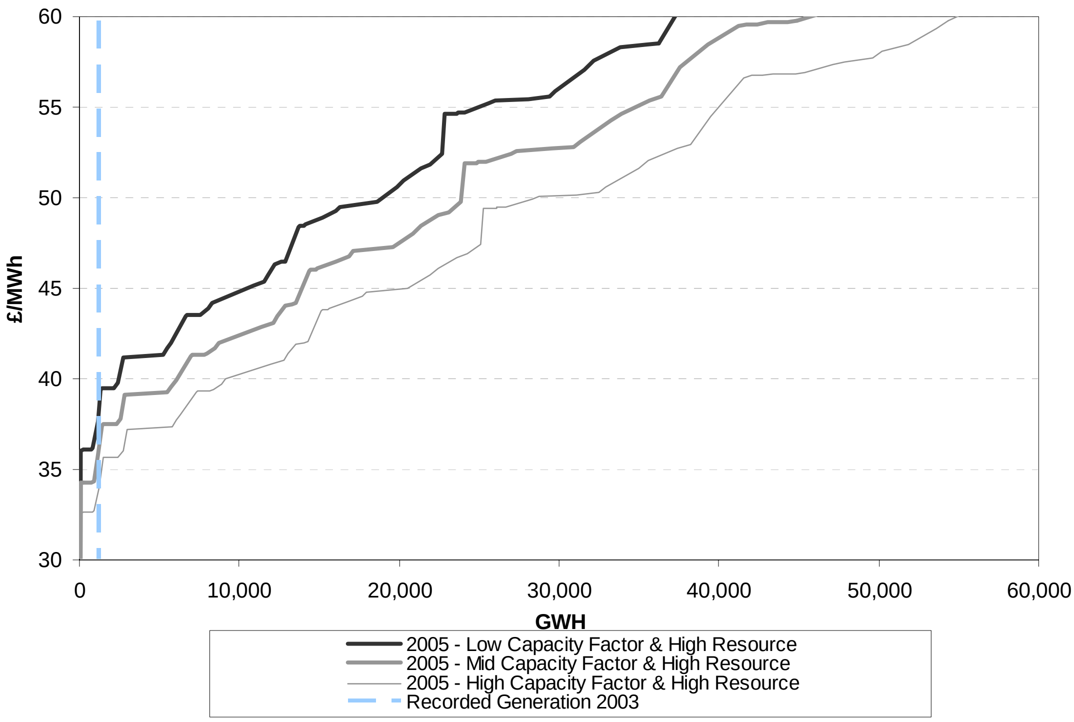


Figure 3.9 Wind supply curve capacity factor sensitivity (high resource scenario)



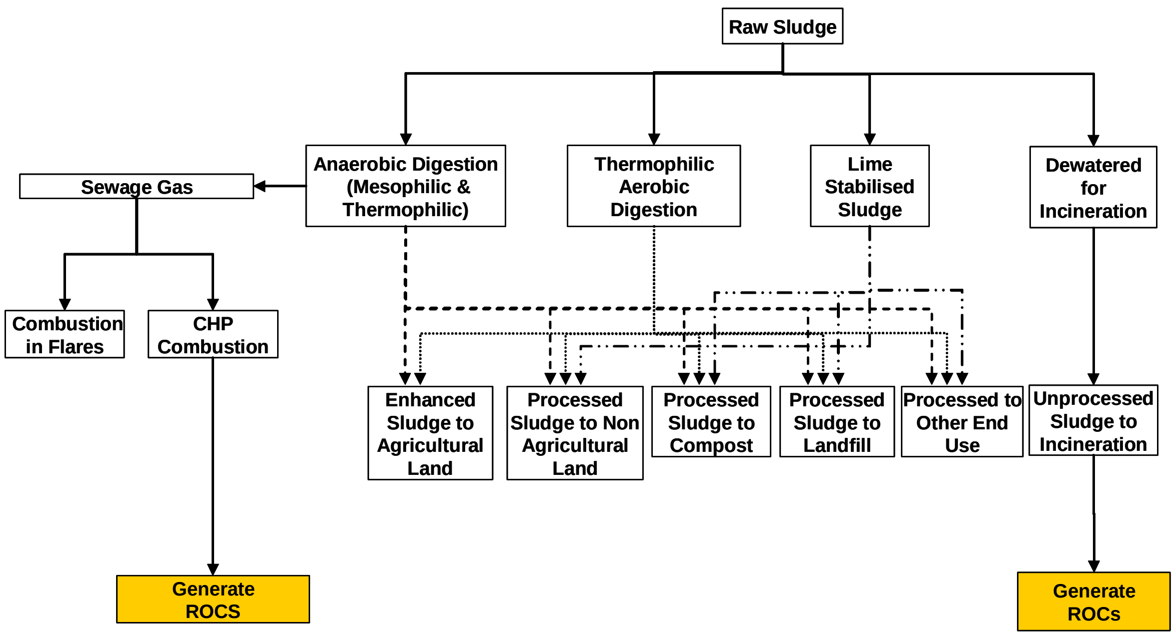
4. SEWAGE GAS

4.1 Overview of the Sector

Sewage gas is generated by the decomposition of sewage sludge within an anaerobic digester to produce methane. In most instances the methane produced will be captured and used as a fuel to maintain the digesters internal temperature. Larger digesters generate sufficient quantities of methane to operate a combined heat and power (CHP) unit, generating electricity whilst producing sufficient heat for the digester.

The use of anaerobic digesters reduces the volume of sludge as well as the number of pathogens, although some residual waste disposal is still required. It is one of several of sludge treatment and disposal methods used by the waste water industry. The choice of sludge treatment methods depends on the quantity of sludge, the cost of treatment and the disposal options available for the final residue. Sludge disposal routes are summarised in Figure 4.1.

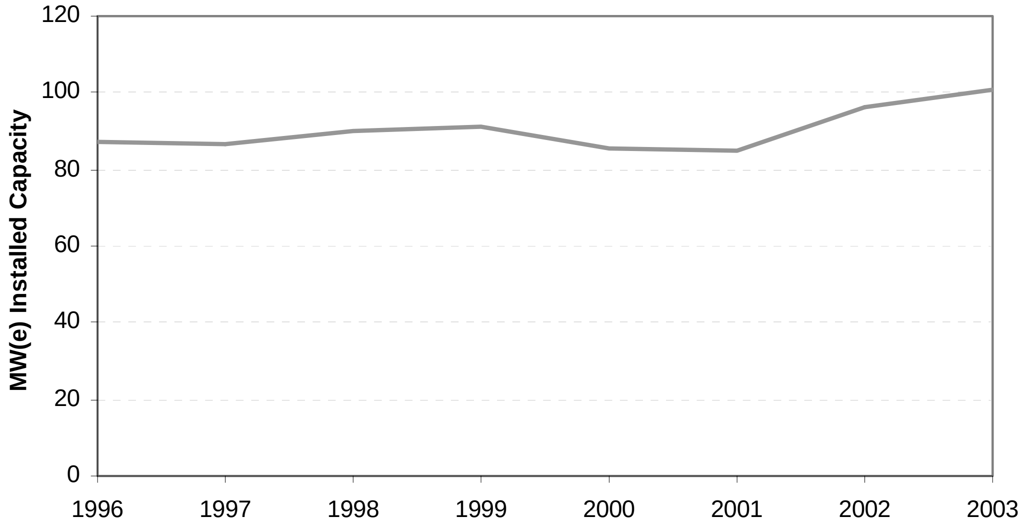
Figure 4.1 Sewage sludge disposal routes



This figure shows that there are two ways in which power can be generated from sewage sludge: from *combustion of sewage gas from anaerobic digestion* and direct *combustion of dewatered sludge.* Industry practice tends to use Combined Heat and Power units for sewage gas using the waste heat for the digestion process. Generators can be configured to optimise electrical output but this is less common. The combustion of sewage sludge normally requires the co-firing of sewage sludge with fossil fuel, so its eligibility for ROCs is governed by the rules on co-firing. It is possible to burn sewage sludge without co-firing if energy is used to reduce the moisture content of the sludge.

Over the last five years, the rate of additional CHP capacity installed has been relatively low although it accelerated in 2002 to around 9MW. An average of 4MW of additional capacity has been installed each year (Figure 4.2). Any additional growth in new capacity is dependent on the costs of sludge disposal. Currently most digested sludge is disposed to the relatively cheap route of land disposal. The direction of government policy however is to phase out land disposal meaning that digested sludge will need to be landfilled, a far more costly route. In the sewage gas model we assume that no new digesters are built and any change in the amount of electricity generated by the waste water industry is due adding generation units to existing anaerobic digesters and through improved generator and digester performance.

Figure 4.2 Installed sewage gas power generation capacity



4.2 Legislative Background

The waste water industry is subject to high levels of regulation. Industry financial performance is determined by the 5 year AMP (Asset Management Programme) cycle. This provides a broad strategy agreed with the regulator OFWAT on the prices the industry can set and the investment that is undertaken. The industry's environmental activities are governed by framework legislation such as the Urban Waste Water Directive and the Water Framework Directive. Together these impose strict controls on standards of effluent quality and sludge disposal methods.

One of the most important issues is the control of sludge disposal. Currently, disposal methods are guided by the Environment Agency's "safe sludge matrix". This matrix requires that only enhanced treated sludge is applied to agricultural land whilst conventionally treated sludge can be applied to non-agricultural land. Enhanced sludge needs to eliminate 99.9% of pathogens whilst conventionally treated sludge has to eliminate 99% of pathogens. Currently however, there is uncertainty about how the safe sludge matrix will be implemented and the treatment processes that will enable the enhanced treatment criteria to be met.

4.3 Overview of Model Methodology

Because the waste water industry has a number of environmental and financial regulations that govern how they operate, the generation of electricity is a low priority within the industry. As a result a full model of the impact of renewable obligation on the water industry should consider the interactions between different legislative scenarios, different disposal opportunities and relative costs of each disposal option. This is beyond the scope of the current project.

In the model, we assess the maximum potential for ROCs to be generated from sewage gas assuming no change in sludge disposal routes. This also assumes that no additional material – such as biodegradable municipal waste – is treated in an anaerobic digester, which is one option for increasing sewage gas output.

4.4 Available resource

On the basis of the above assumptions about sludge disposal additional power generation opportunities from sewage gas are limited to sites with existing anaerobic digesters. It should be noted that the opportunities to introduce new CHP units to digesters is limited by the size of the anaerobic digester on site; many water companies have a dispersed waste water treatment network that is unsuitable for CHP.

Data on the volume of sludge arisings and the final disposal route is relatively good. [49] However, there is relatively little information on the types of treatment processes used. Following conversations with various industrial organisations we have assumed that the current treatment processes follow the split given in Table 4.1.

Table 4.1 Assumed treatment process applied to sludge arisings

Treatment Process	Share of Sludge Arisings[50]	Volume of Sludge (tonnes of dried sludge)
Anaerobic Digestion	45%	638,000
Aerobic Digestion	< 1%	2,000
Lime Stabilised Sludge	10%	141,000
Incineration	45%	638,000

These figures suggest that the total potential resource of sewage gas under ideal conditions is 986,000 MWh thermal. This assumes the CV of dry sewage sludge to be 13.7 GJ/tds [51] and that an anaerobic digester converts 45%[52] of the total volatile organic solids to methane and has 90% methane collection efficiency. We assume that the CHP unit can operate at a maximum electrical conversion efficiency of 30% and that due to the corrosive nature of hydrogen sulphide – a component of sewage gas - the expected availability is 85%.

4.5 Generation costs

The cost of generating additional power from this resource is assumed to be the cost of installing a new CHP unit onto an existing anaerobic digester. Cost assumptions are outlined below.

49 Data provided by OFWAT
50 Suggested values from presentations given to the RPA Biogas Conference
51 ECN Phyllis Database
52 WRC (1996)

Capital Costs

We assume no site preparation costs, as the digester is currently installed, and that the cost of CHP turbine is £552,000/MW. Grid connection and grid upgrades are assumed to be £45,000/MW and £82,000/MW respectively. Planning permission costs are trivial and capitalised project development costs expected to be 5% of capital expenditure at £30,000/MW.

Operating Costs

Because of the corrosive nature of sewage gas, maintenance costs are high as lubricating oils and the turbine blades need to be changed more frequently. Industry studies have suggested that maintenance costs can average around 0.025 £/KWh generated, which is equivalent to £55,000 per year per MW installed capacity. [53]

We assumed that there is no impact on business rates paid for by the waste water industry because there is a replacement of equipment - either a boiler or an existing CHP plant. We therefore assume that any change in business rates will be negligible.

As any CHP unit attached to an anaerobic digester is likely to be small we assume annual GDUoS charges are levied at a cost of £2,500/MW. The cost of land associated with the addition of a CHP unit to a waste water treatment plant is negligible.

Financial Assumptions

The sewage gas model uses two financial assumptions, the discount rate and the project lifetime. Because CHP units attached to anaerobic digesters are well established technologies the sewage gas model uses a discount rate of 7.9%. All CHP units are expected to have a 15 year project lifetime.

4.6 Changes over time

Since the sewage gas generating unit is based on the CHP plant and not the digester any learning effects will apply to the CHP units. In the model we assume that capital equipment costs and the maintenance costs have a PR ratio of 92%.

In terms of in resources over time we assume that an additional 2MW CHP capacity is installed each year and that total sludge arisings grow at an annual rate of 0.9%/yr. This is the average change that has been reported between 1996 and 2000. [54]

4.7 Supply curve

Given the limited scope for development of sewage gas and the uniformity of technology used, the supply curve is expressed as a single point showing total electrical output of 251,500MWh/yr at a cost of £63.07/MWh in 2005.

By 2015 the total electrical output has increased marginally to 277,500MWh/yr and the cost has decreased to £62.09/MWh. We currently estimate that 200,500MWh

53 Industry studies completed by Enviros
54 These years were selected to avoid the impact of the water framework directive on sludge arisings.

should be able to be generated from ROCs accredited sewage gas CHP units and NFFO contracts for sewage gas CHP units.

4.8 Sensitivity analysis

Given the small contribution from sewage to the total UK potential for renewable energy any sensitivity analysis on sewage gas would be trivial compared to the uncertainties for the other supply curves.

5. HYDRO

5.1 Overview of the Sector

Hydro power is currently the UK's largest source of renewable electricity generation accounting for approximately 1% of total UK generation. The majority of this comes from large reservoir based on hydroelectric schemes built in Scotland during the 1950s and 1960s. For this analysis we have been asked to consider three sizes of hydro installation, the size categories as defined by the current RO regulations:

- Micro Hydro – with an installed capacity of less than 1.25MW. These are eligible for ROCs under the current regulations.
- Small Hydro – with an installed capacity between 1.25 - 20MW. These are eligible if the installation has been commissioned or refurbished after the 1st January 1990.
- Large Hydro - with an installed capacity greater than 20 MW. These are ineligible unless the scheme is commissioned after 2002 or additional capacity is added through the refurbishment of an existing plant.

The current installed capacities of each category of Hydro generation are shown in Table 5.1.

Table 5.1 Installed Hydro Capacity by Region and Size[55]

Country	Micro Hydro (MW)	Small Hydro (MW)	Large Hydro (MW)	Total Installed Capacity MW (excl. Pumped Storage)
England	9	10	0	20
Scotland	27	434	824	1,286
Wales	7	58	83	148
Northern Ireland	3	0	0	3
Total	46	503	907	1,468

ROC eligible hydro capacity has increased slowly in recent years with on average one small hydro scheme over 20MW, two small scale hydro and one micro hydro schemes being completed each year. See Figures 5.1 and 5.2. Because of the small size of a typical micro hydro installation, some micro hydro installations may have chosen not to register for ROCs.

55 Harrison (2004) Prospects for Hydro in the UK: Between a ROC and a Hard Place, http://www.see.ed.ac.uk/~gph/publications/Hydro05_ROC.pdf

Figure 5.1 Small hydro capacity

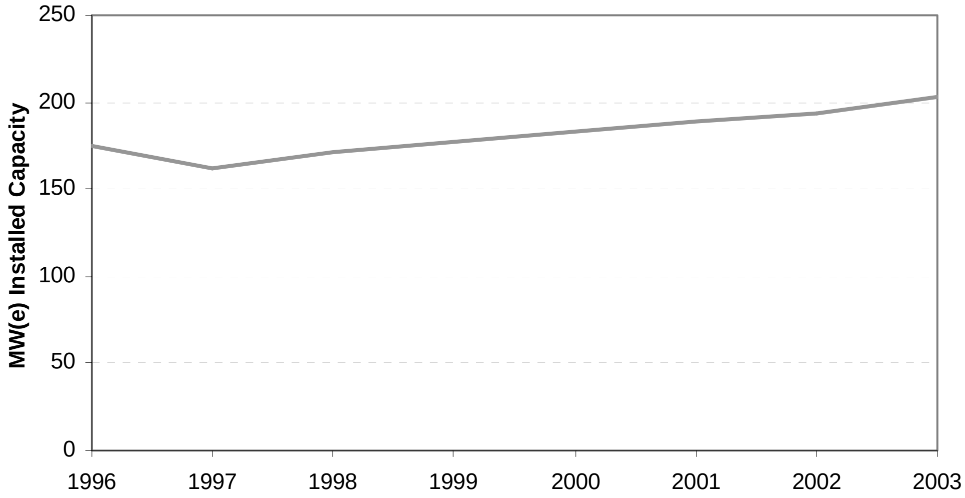
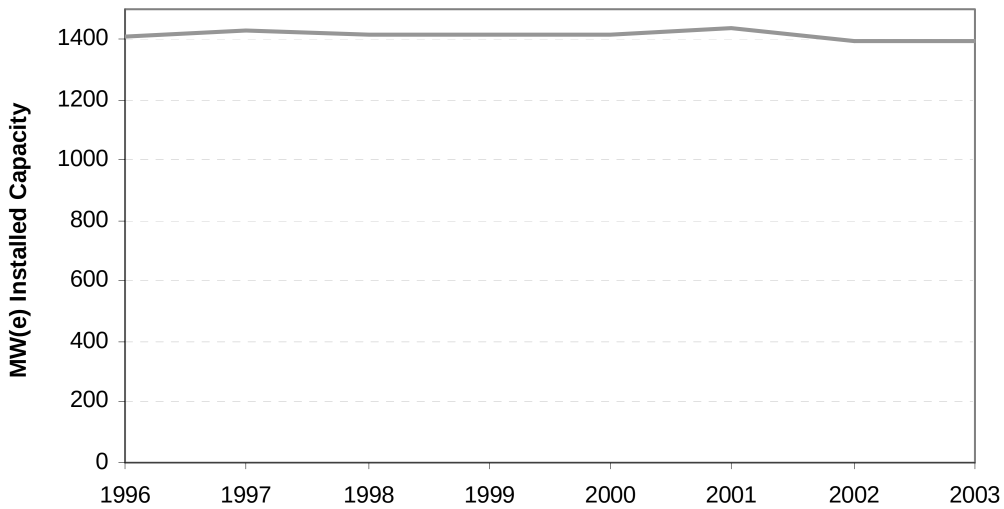


Figure 5.2 Large hydro installed capacity



5.2 Legislative Background

There is no national level legislation that has a significant direct impact on the uptake of hydro resources.

5.3 Model methodology

In order to provide a cost of supply curve, we estimated the total resource available and the cost of accessing that resource for each scale of hydro generation. Due to the variations in site characteristics, this methodology requires a number of simplifying assumptions

5.4 Available resource

It is estimated that there is 1,000 – 2,000 MW of exploitable hydro capacity available in the UK. [56] There is however, considerable uncertainty regarding both the total resource available and potential barriers to developing that resource. The majority of the resource is believed to be under the control of either private individuals or commercial utilities. This makes it very difficult to complete full resource assessments and introduces non-market barriers to resource development (as electricity generation will typically be a lower order priority). In assessing the supply curve for further hydro power in the UK we assume the following remaining capacity and split by installation size (Table 5.2).

Table 5.2 Resource Available by Size of Hydro

	Micro Hydro (MW)	Small Hydro (MW)	Large Hydro (MW)	Total Installed Capacity MW (excl. Pumped Storage)
Installed Capacity	46	503	907	1,468
Remaining Capacity	750	900	350	2,000

Each size of hydro electric generator will have different generation efficiencies. Although a large turbine is expected to have a higher generating efficiency, we would also expect it to have a lower capacity factor due to greater variation in the flow of water and longer maintenance times. This reduces the actual output relative to micro hydro. Electrical output assumptions are shown in Table 5.3.

Table 5.3 Generating Efficiency by Size of Hydro

Country	Micro Hydro (MW)	Small Hydro (MW)	Large Hydro (MW)
Capacity factor	50%[57]	39%[58]	31%[59]
Generating Efficiency[60]	70%	80%	90%
Electrical Output of 1 MW (MWh/yr)	4380	3416	2716

5.5 Generating costs

The cost of power generation for hydro resources is highly site specific. Locations vary considerably according to whether existing civil works are in place – such as with old mill sites – or whether the water has to be transported or stored in a reservoir. Whilst some of these costs are scale dependent, most installations are bespoke and therefore the costs are highly site specific.

One of the most important factors is the head of water above the turbine. This changes the type of turbine installed and the hence the cost of development. There are generally four different categories:

56 Communication with the British Hydro Power Association There is currently expected to between 300 and 400MW of additional large scale hydro capacity being considered, and the remaining capacity is split between small and micro hydro.
57 Energy Saving Trust, Factsheet 7 Small Scale Hydro
58 Expected Load Factor reported in RPA Renewables Year Book 2004
59 Average Load factor reported in DUKES 2004 over last 8 years
60 TV Energy (2003) Low Head Hydro Power In SE England

- High Head (above 100m) utilising Pelton, Turgo, and High Head Francis turbine designs.
- Medium Head (20m to 100m) utilising Francis and Cross Flow turbine designs
- Low Head (5m to 20m) utilising Cross Flow, Propeller and Kaplan turbine designs.
- Ultra Low Head (below 5m) utilising Propeller and Kaplan turbine designs.

The size of the generating unit is then determined by the head above the turbine and the volume flow of water across the turbine. For example, a high head turbine with a low volume flow may have the same electrical output as a low head turbine with a high volume.

Capital Costs

As with the other low cost technologies, the capital costs of hydro development are divided into the cost of site preparation, the cost of turbines, the cost of grid connection and the cost of project development. We express all costs as cost per MW installed. These costs have either been provided by the industry trade association or other published sources of information. Costs assumptions are summarised in Table 5.4.

The cost of site *preparation* will depend on the size of the site. We would expect the cost of site preparation per MW installed to be highest for micro sites. The next lowest cost of site preparation per MW would be expected for large scale sites >20MW. And the lowest site preparation costs per MW have been assumed for small scale sites in the 1.25-20MW range which are often able to utilise existing weirs or mill sites.

In order to provide an assessment of the costs of *turbines* we have assume that the micro hydro turbine is most likely to be a low head turbine, the small hydro turbine is most likely to be a medium head turbine with an average cost, and the large hydro turbine is likely to be a high head turbine.

The cost of grid upgrades and the cost of grid connection used in the model are the same for all turbines. For project development and planning permission costs, we assume that micro-hydro is undertaken as a part of a larger project and does not have a direct cost of planning. Other assumptions are shown in Table 5.4.

Table 5.4 Capital cost assumptions for hydro plants

Capital item	<1.25 MW	1.25 – 20 MW	>20 MW
Site preparation (£/MW)	£400,000	£177,100	£278,500
Turbine (£/MW)	£900,000	£531,500	£417,800
Grid connection (£/MW)	£45,000	£45,000	£45,000
Grid Upgrade (£/MW)	£82,000	£82,000	£82,000
Project Development (£/MW)	150,000 £/MW	142,000	£104,000
Planning Permission (£/site)	-	187,500	£187,500

Operating Costs

For maintenance costs we assume that maintenance charges are 10% of total capital costs for all hydro generation installations. For business rates we assume that charges vary between £8,000 and £18,000 per year per MW depending on the expected capital cost of generator.

For use of system charges, although there is currently the potential for three or four large schemes greater than 75MW which would probably connect to the transmission network, we assume that all hydro generation installations connect to the local distribution network. Their annual GDUoS charge is therefore £2,500/MW/yr.

Hydro also incurs water abstraction costs in place of land costs. The water extraction charges are applied to all hydro electric installations greater than 5MW and are determined by the volume of water extracted from the river and any water losses incurred. In the model we calculate the volume of water required to generate 1MW according to the assumed head of each turbine size[61]. For small hydro plants we assume that 10% of the installations are greater than 5MW [62]. The charges assumed are as follows: 1.25 – 20MW £1,400 and > 20MW £8,700.

Financial Assumptions

We employed the same financial assumptions for each size of hydro electric turbine. Because the turbine technology is well established we have assumed a discount rate of 7.9%. We assume that all installations have a 25 year project lifetime.

5.6 Changes over time

The resource changes over time relate to both changes in the total resource across years and seasonal resource fluctuations. We have assumed that the total water resource remains constant over time over the long term, and that the capacity of the turbine is sized such that it is able to operate at full capacity during periods of low flow to avoid seasonal fluctuations.

We model the learning effects of hydro in relation to global installed capacity and use a PR of 90% for micro and small turbines and a PR of 95% for large turbines.

61 EST (2003)
62 DETR Economic Instruments in Relation to Water Abstraction

5.7 Supply curve

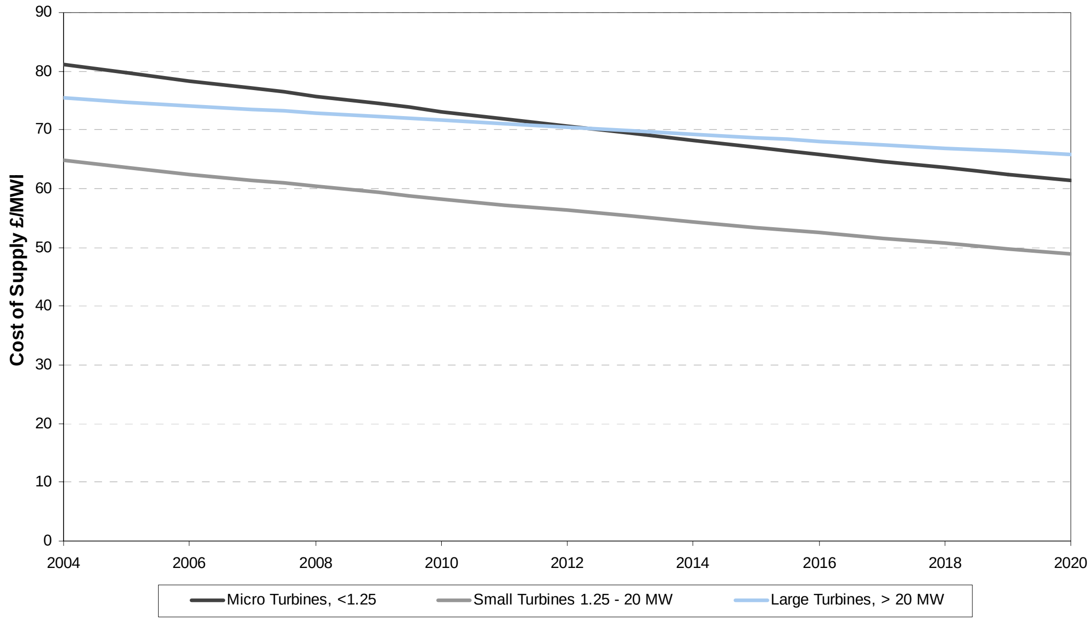
For each size of hydro plant we calculate the current cost of the technology along with the total generation potential to give a single point on supply curve. The values are shown in Table 5.5.

Table 5.5 Hydro cost of generation in 2004

	<1.25 MW	1.25 - 20 MW	>20 MW
Cost of generation (£/MWh)	£84	£67	£77
Potential Generation MWh	3,500,000	4,400,000	3,400,000

By 2020 the costs of the micro and small hydro installations are expected to fall by over 20% and the cost of large hydro is expected to fall by over 10%. The change in the cost of installation over time is shown in Figure 5.3.

Figure 5.3 Cost of hydro generation over time



5.8 Sensitivity analysis

From the research conducted for this study any uncertainty in the estimates of hydro generating costs are unlikely to be material to considering whether hydro schemes would be classed as low enough such that changes to the RO would be justified. Our calculations and industry information suggests that present day costs generally exceed £60/MWh. In terms of the model, the greatest uncertainty surrounds the estimates of resource potential. Given the lack of research in this field we would place error ranges of +/- 25% on the figures shown in Table 5.5.

6. HIGH COST TECHNOLOGIES

This section of the report provides an overview of the higher cost renewable energy technologies. The high cost technologies include: advanced conversion of mixed wastes, co-firing of coal with biomass, stand-alone biomass, tidal stream and onshore wave power, offshore wind energy and photovoltaics.

6.1 Overview of technologies

Offshore Wind

Offshore wind energy is a relatively new development in the UK, the technology for which has evolved rapidly in recent years. With over 62MW of capacity installed during 2003 and over 100MW of capacity installed during 2004, offshore wind energy is expected to provide a significant proportion of future renewable energy supply.

As with onshore wind, there is potentially an enormous offshore wind resource available within the UK's coastal waters. The Crown Estates has allocated sites for offshore wind development in designated strategic areas in two specific 'Rounds' so for subsequent analysis we have constrained the resource according to these Rounds.

'Round One' sites have a potential for 1,200MW, and are assumed to be developed between 2004 and 2008. In 'Round Two', 15 projects have been proposed with a combined capacity of 7,200MW, and it has been assumed that these will be developed between 2008 and 2014. By 2015, the full resource identified by for the UK – 327,000 MW – is considered to be available for development in territorial waters with a depth between 5 and 30 meters. [63]

For the purposes of this report we assume that all offshore wind sites have an annual average mean wind speed of 9m/s - a modern 2MW wind turbine would be expected to have a capacity factor of 39% at such a site. [64] The average annual availability is 5% lower than onshore wind at 90%, suggesting that 1MW installed could generate 3,075 MWh per year.

Although substantial cost gains are expected from increasing individual turbine capacity to 5MW, the costs used in this report are based on the cost of development in North Hoyle and Scroby Sands. The potential for additional cost savings through increased turbine sizes are represented through the learning effects for offshore wind turbines.

The costs estimates of offshore wind are based on published reports by Garrad Hassan (2003), Caddet (2000), and communication with industry.

Biomass co-firing

The slow development of dedicated biomass power generation plant has resulted in active support for biomass co-firing in existing coal-fired power stations. Biomass co-firing was designed to stimulate and demonstrate biomass fuel supply chains at commercial scale and to encourage in particular the development of energy crops.

63 http://www.dti.gov.uk/energy/leg_and_reg/consents/future_offshore/chp2.pdf
64 http://www.windpower.org/en/tour/wres/pow/index.htm

Following a review of co-firing in 2004 a timetable has been agreed for phasing out co-firing biomass and a phased increase in the amount of energy supply from energy crops. The phase-out of biomass co-firing from the RO will restrict the amount of co-firing to 25% of the ROCs generated until 2006; 10% until 2011; and, 5% until 2016. In 2016, biomass co-firing will no longer be eligible for ROCs. Meanwhile the proportion of energy that has to come from energy crops increases from 25% in 2009 to 2010, 50% in 2010 to 2011 and 75% from 2011 to 2016.

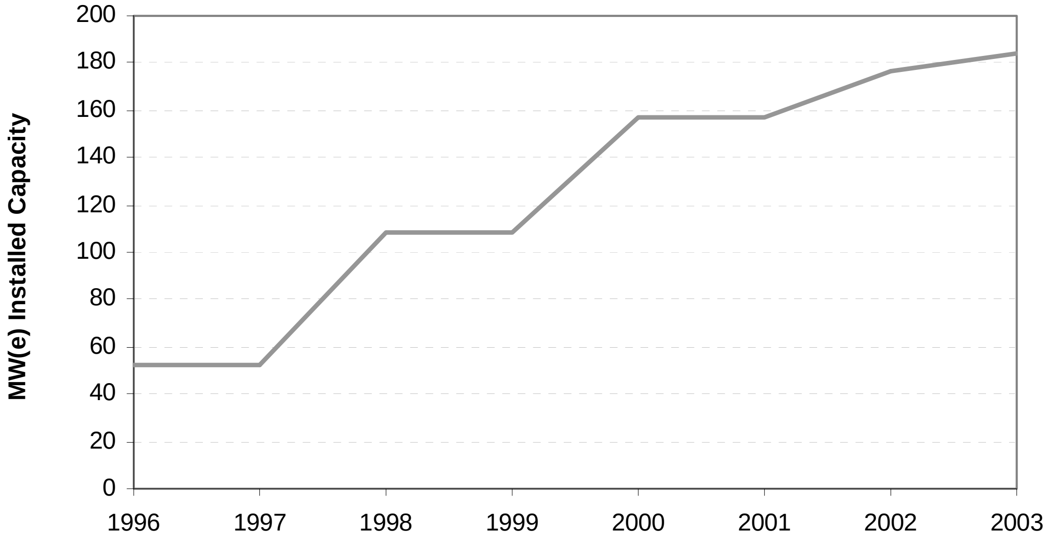
To determine the resource potential for biomass co-firing, we assume that biomass is co-fired with coal in existing coal-fired power stations and that the maximum proportion of biomass (by heat input) that can be co-fired without significantly impacting the generating efficiency of the power station is 5%. [65] This limits the potential installed co-firing capacity to 1,580MW, of which 255MW capacity is currently being used.

Power stations are currently not prepared to enter into long-term fuel supply contracts for biomass, largely because of uncertainty about performance and emissions impacts. [66] We assume that as uncertainties are resolved, then all coal-fired generators can achieve 1% minimum biomass co-firing by 2006, and that they can all achieve 5% by 2011. Constraints placed on co-firing as a proportion of the total renewable generation are made through the interaction of the supply curve with total electricity demand.

Biomass stand-alone

The majority of the stand-alone biomass plant currently operational in the UK was developed during the late 1990's and utilises poultry litter and straw - Figure 6.1. A further batch of projects has been proposed under the governments Bio-energy Capital Grants Scheme but there has been little sustained development activity over the last couple of years following the insolvency of two high profile biomass development companies.

Figure 6.1 Installed stand-alone biomass capacity



65 Technical assessment completed by Enviros and presentations given to the Biomass Co-firing Workshop (2004)
66 Discussion with Industry and internal Enviros experience

In this report we use values given for five sites currently operating in the UK and one planned site. Based on the regional resource assessments we estimate the total resource potential for the UK to be 1,400 MW. [67]

Photovoltaics (PV)

By converting solar energy directly to electricity, solar photovoltaics (PV) is a simple albeit costly, source of power. Despite the relatively low solar radiance resource in the UK, the use of solar PV has increased steadily to the point that there is around $6MW_e$ installed capacity in this country. Around 85% of this is on-grid distributed generation. Among the thousands of small PV installations in the UK, there are a significant number of commercial/ industrial sites currently using the technology.

To model the cost and potentials for PV within the UK, we assumed an annual average solar incidence of 1,058 kWh/m2/yr. This is based on average daily solar incidence for the South of England. We assume that all PV cells installed are Crystaline PV modules which have an average efficiency of 14% and generate 145 kWh per m2 per year.

To quantify the potential resource we assume that a 10m2 installation is added to 2 million rooftops. This generates a potential electrical output of 2,896,000 MWh/yr. The full potential resource is considerably greater than this; however we consider additional development unlikely.

We assumed that the PV installations are all stand-alone modules placed on top of existing surfaces, there is a potential to lower the marginal cost of PV installations by fully integrating them into the building envelope. This technology is currently less established and is not included in this model. All the costs used in this model are the costs from the manufacturer and exclude the value of grants or subsidies that may be available through government backed programmes. The cost assumptions for PV are from a variety of published reports for the DTI

Advanced conversion technologies for wastes

Advanced conversion technologies (ACTs) for waste convert source-separated waste feedstocks into either a gas or liquid ‘bio-oil’ which can then be combusted in either a boiler or an engine/generator. Although very few facilities have currently been built in UK there are two principal types of conversion technology that have been commonly researched, developed and demonstrated internationally.

- Pyrolysis is the thermal degradation of feedstock in the absence of air at temperatures of between 400 and 800^{o}C to create a gas that can be condensed into liquid ‘bio-oil’, solid carbon char and non-condensable gases. The liquid bio-oil - calorific value typically ~16.5MJ/kg - can be used as a substitute boiler fuel, for co-firing, supplementary firing, or combusted directly in a suitably modified engine/generator to generate electricity.

- Gasification is the partial combustion of material in a reduced oxygen environment. This process maximises the production of combustible gases and requires operating temperatures of between 900 and 1400^{o}C in a process similar to the pyrolysis process. Under gasification, however, the gases are not condensed and no liquids are produced. Instead the combustible gases are cooled and scrubbed and can be fed directly to a boiler or engine, or with intermediate gas compression to a gas turbine generator.

67 Oxera (2002) Regional Renewable Resource Assessment

ACTs are currently being evaluated by numerous potential developers in the UK as a result of local authority waste disposal targets and the economic incentive provided by ROCs.

The cost data for gasification is based on financial submissions of gasification plant suppliers to a hypothetical report produced for the Greater London Authority. [68] To calculate the resource potential of electricity generation from advance conversion technologies we assume that all biodegradable municipal waste can be treated using gasification. Assuming that 15,000 tonnes of municipal waste is required to fuel a 1MWe generator, there is sufficient waste to operate 1,065MW installed electrical capacity, which would generate an estimated 7,900,000MWh per annum. [69]

Tidal and wave power

Marine currents caused by the predictable tidal flows into estuaries and around islands and headlands; and waves resulting from wind blowing over surface waters together represent two highly significant renewable energy resources for the UK.

Although the accessible wave power resource in the waters around the UK is estimated to be 700TWh per year (twice our current electricity consumption) 50TWh is considered to be practicably accessible and exploiting this resource will require the successful development and demonstration of a range of technologies. [70] These include:

- Shoreline wave converters – these channel waves into constricted chambers inducing air flow through a 'Wells' turbine. These devices can be readily integrated with shoreline protection, and are considered proven and near commercial technology.

- Fixed or semi-fixed wave converters **-** exploit the pressure differential that occurs in the water at a submerged point as a wave passes over. Oscillating water columns or other induced fluid movements drive the turbines.

- Buoyancy wave converters - exploit differential mechanical movement as the device rides the waves. The movement is used either directly or indirectly to drive a generator.

High initial capital costs and unknown operational and maintenance costs make estimates of the generating costs unreliable. However if a conservative estimate of around 25% of the total practical resource was available for development prior to 2020 the contribution from wave power could be approximately 12.5 TWh/yr. The costs figures used are from published DTI reports. [71]

Tidal stream potential is more site-specific than wave power. Conventional tidal barrage technology utilising turbines in an estuarine barrage to generate on the rising and falling tide is highly costly and carries a significant environmental downside. Newer technology to extract energy from a tidal stream that is accelerated by a shelving sea-bed, funnelling into an estuary, or around islands and headlands is the focus of much research and development. Tidal stream turbines arranged singly or in arrays can produce significant predictable power outputs. The ten most promising tidal stream sites around the UK are estimated to have a

68 City Solutions, New and Emerging Technologies for Sustainable Waste Management, GLA 2003
69 City Solutions, New and Emerging Technologies for Sustainable Waste Management, GLA 2003
70 BWEA website http://www.bwea.org/marine/resource.html
71 Reports completed by Binnie Black and Veatch (2001) and Ocean Power Delivery (2002)

potential of 36 TWh[72] per year, as with wave we have assumed that 25% of this could be developed prior to 2020, providing a potential for the generation of 9TWh of electricity per year.

As both of these technologies are currently at a pre-market stage of development we have based the data on hypothetical assessments for tidal stream technologies and a pilot project for offshore wave. [73] [74].

6.2 Capital costs

As with the low cost technologies, the capital costs of development are divided into the cost of site preparation, the cost of turbines, the cost of grid connection and the cost of project development. The cost factors used in the analysis for the high cost technologies are shown in Tables 6.1 to 6.3.

Table 6.1 Site preparation costs

Technology	Cost per MW installed	Notes
Offshore Wind	£ 17,000 / MW	Reported Costs [75]
Solar PV	£ 86 / m2	Reported Costs [76]
Tidal	£ 667,000 / MW	Reported Costs [77]
Wave	£0 / MW	Assumed the same as Offshore wind
Gasification	£0 / MW	Assumed to be part of an existing development
Biomass Stand-alone	£ 82,000 / MW	Based on operating sites
Biomass Co-firing	£0 / MW	Assumed to be part of an existing development

Table 6.2 Equipment costs (mostly turbines)

Technology	Cost per MW installed	Notes
Offshore Wind	£ 1,029,000 / MW	Reported Costs [78]
Solar PV	£ 425 / m2	Reported Costs [79]
Tidal	£ 1,238,000 / MW	Reported Costs [80]
Wave	£1,930,000 / MW	Assumed the same as Offshore wind
Gasification	£10,625,000 / MW	Assumed the same as stand alone biomass
Biomass Stand-alone	£ 1,452,000 / MW	Based on operating sites
Biomass Co-firing	£4,800 / MW	Electrical connection charges already exist.

72 BWEA http://www.bwea.org/marine/resource.html
73 DTI - Commercial Prospects for Tidal Stream Power DTI/Pub URN 01/1016
74 DTI - Pelamis WEC ETSU V/06/00181/REP
75 Maintenance value suggested in Garrad Hassan 2003
76 Potential Cost Reduction in PV Systems DTI/ PUB URN 01/759
77 DTI - Pelamis WEC ETSU V/06/00181/REP
78 Maintenance value suggested in Garrad Hassan 2003
79 Potential Cost Reduction in PV Systems DTI/ PUB URN 01/759
80 DTI - Pelamis WEC ETSU V/06/00181/REP

It should be noted that the cost of gasification includes the cost of the gasifier as well as the cost of the turbine; this higher cost is partially offset by the inclusion of the gate fee as an additional source of revenue.

The cost of grid connection covers the cost of connecting the generator to the grid connection point. The cost per MW installed capacity is primarily determined by the distance involved. As a result we have assumed a flat rate of £45,000/MW for all shore based technologies with the exception of on shore wind. For offshore wind, wave and tidal we have assumed a grid connection cost of £77,000/MW to allow for the greater distances involved and the increased complexity of sinking cables in the seabed.

As reported in the first section the cost of planning permission is set at £187,600 per site. The exception to this is micro hydro, co-firing and PV, where we assume that the renewable generation project is a part of a wider development programme and therefore not subject to additional planning costs.

The cost of project development may vary considerably between installations, and be dependent on the scale at which the technology can currently be deployed. As experience is developed with each technology these costs may be reduced.

Table 6.3 Cost of Project Development

	Cost per MW installed	Notes
Offshore Wind	£ 64,000 / MW	Reported Costs [81]
Solar PV	£ 15 / m2	Reported Costs[82]
Tidal	£ 211,000 / MW	Reported Costs[83]
Wave	£ 60,000 / MW	Assumes 10% of capital costs.
Gasification	£31,000 / MW	Assumes 5 % of capital costs.
Biomass - Stand Alone	£ 120,000	Based on operating sites
Biomass Co-firing	£0 / MW	Planning costs are considered negligible

6.3 Operating costs

Because of the uncertainties and technological risks associated with each technology, many of the high cost technologies are expected to have high maintenance costs. With more established combustion technologies the annual maintenance costs are expected to be relatively low. Maintenance costs are summarised in Table 6.4.

81 Maintenance value suggested in Garrad Hassan 2003
82 Potential Cost Reduction in PV Systems DTI/ PUB URN 01/759
83 DTI - Pelamis WEC ETSU V/06/00181/REP

Table 6.4 Maintenance Costs

	Cost per MW installed	Notes
Offshore Wind	£ 70,000 / MW	Reported Costs [84]
Solar PV	£ 11 / m2	Reported Costs [85]
Tidal	£ 43,000 / MW	Reported Costs [86]
Wave	£ 207,605 / MW	Assumes 10% of capital costs.
Gasification	£541,000 / MW	Assumes 5 % of capital costs.
Biomass Stand-alone	£ 42,500	Confidential Industry Report
Biomass Co-firing	£500 / MW	Reported Coal fired Generator Operating Costs multiplied by 10%[87]

For business rates we assume that rate charges are £2,100 per year per MW installed capacity for all high cost technologies.

For use of system charges, with the exception of offshore wind and co-firing we assume that all high cost generation is connected to the local network and therefore subject to an annual GDUoS charge of £2,500/MW/yr. We assume that offshore wind is connected to the national grid and therefore subject to National Grid use of system charges. We have averaged the TNUoS charge across the North of England and expect an annual charge of £5,000/MW/yr. For biomass co-firing because the electrical infrastructure is already in place, it is not an element in the marginal cost calculation. Assumptions on land costs are given in Table 6.5.

Table 6.5 Land costs (£/yr)

	Cost per MW installed	Notes
Offshore Wind	£ 2,700	Seabed Rental Costs
Solar PV	£ 0	Assumed to be added onto an existing building
Tidal	£ 2000	Seabed Rental Costs
Wave	£ 0	Assumed to be free floating structures.
Gasification	£ 0	Assumed to occur at an existing waste disposal site.
Biomass Stand-alone	£ 0	Assumed to occur at an existing site.
Biomass – Co-firing	£ 0	Assumed to occur at an existing site.

Biomass co-firing and stand-alone biomass have an additional annual operating costs associated with the cost of fuel. [88] For stand-alone biomass combustion, we assume biomass fuel is available at a cost of £9/MW of fuel input.

84 Maintenance value suggested in Garrad Hassan 2003
85 Recorded experience of the ECO Millennium Building - DTI, Pub URN 04/557
86 DTI - Pelamis WEC ETSU V/06/00181/REP
87 Dresdner Kleinwort (2001)
88 The biomass fuel costs are derived from Enviros inhouse knowledge and presented to the RPA biomass conference 2004,

For biomass co-firing, we use the cost for a blend of fuels using both energy crops (£14/MW) and other biomass fuels (£9/MW). The percentage of each fuel type used in the blend is dependent upon the legislation governing co-firing for ROCs.

6.4 Financial Assumptions

The same financial assumptions are applied to each high cost technology, with the exception of biomass co-firing. As described in Section 1.3, for the high cost technologies we use a discount rate of 11.9%. Biomass co-firing is considered mature enough to have a discount rate of 7.9%. Expected project lifetimes are given in Table 6.6. For biomass co-firing the project lifetime is assumed to be the remaining time between the year of installation and 2016, when co-firing is no longer eligible to generate ROCs.

Table 6.6 Expected project lifetimes for high cost technologies

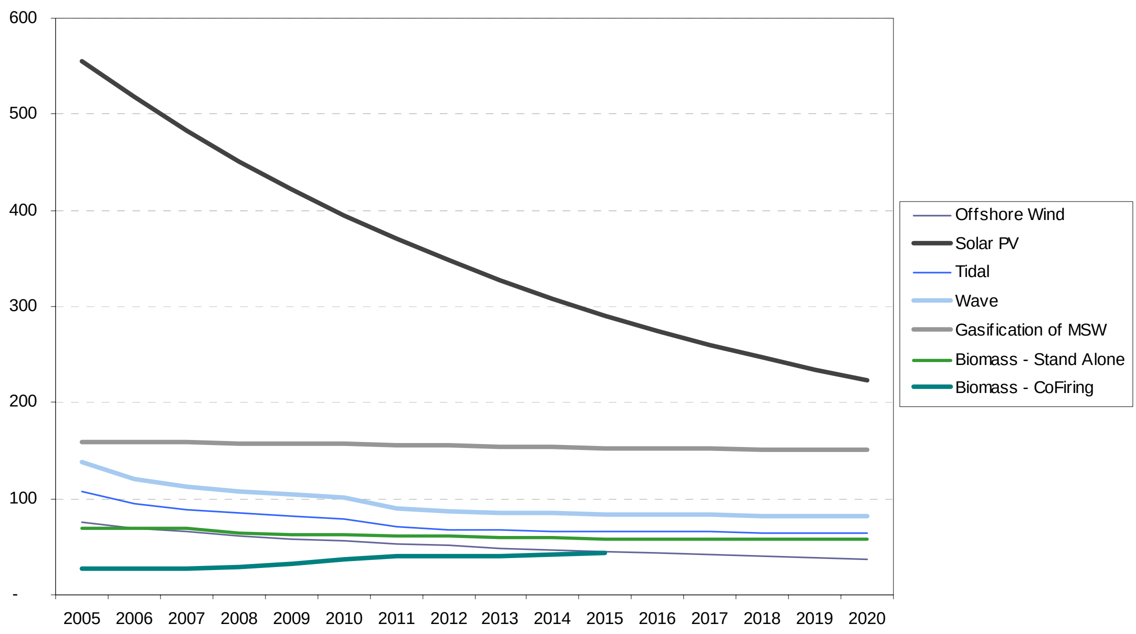
	Project life (yrs)
Offshore Wind	20
Solar PV	15
Tidal	15
Wave	15
Gasification	25
Biomass Stand-alone	25
Biomass – Co-firing	n/a

6.5 Changes over time

We expect that the costs of all high cost technologies will fall more rapidly than for low cost technologies. We therefore use a PR of 85% for all high cost technologies with the exception of biomass co-firing. Biomass Co-firing is considered an established technology and has a PR of 95%. The assumed cost of resource development over time is shown in Figure 6.2.

The increase in biomass co-firing is due to a reducing project life over which to amortise capital costs in view of the co-firing limits in 2016, and the legislated increasing proportion of energy crops in the fuel blend. Other sources of renewable energy generation are expected to have significant reductions in cost, in particular solar PV.

Figure 6.2 High cost technologies over time



6.6 Generation costs

Using the assumptions described above the unit costs for power generated from new plant built in 2004 are shown in Table 6.7.

Table 6.7 Cost of generation in 2004 for high cost technologies

	£/MWh	Potential Generation MWh/yr
Offshore Wind	75	3,700,000
Solar PV	555	2,900,000
Tidal	108	9,000,000
Wave	137	11,800,000
Gasification of MSW	159	8,000,000
Biomass – Stand Alone	66	12,600,000
Biomass – Co-firing	27	12,500,000

Biomass co-firing stands out as being a low cost renewable energy technology. This is because co-firing has few capital costs to recover. Of the remaining true high cost technologies the lowest cost options in 2004 are stand alone biomass and offshore wind. The cost of offshore wind is expected to decline rapidly if current build rates are sustained. By 2008, we expect the cost of offshore wind will fall to £61/MWh and the cost of stand-alone biomass to decline to £64/MWh. These figures assume no revenue streams from capital grants or other forms of public subsidies.

7. CONCLUSIONS

Sections 2 to 6 have described in detail the construction of the renewable energy supply curves for what are regarded as low cost technologies. Section 7 has presented a more simplified analysis of generating costs and capacities for high cost technologies. From this analysis we can draw the following conclusions.

General Conclusions

Biomass co-firing is the lowest cost source of renewable energy, followed by onshore wind (at 9m/s) and LFG. Over this time, resource availability and costs for renewable energy technologies will change. LFG is most affected by changes in resource availability due to declining methane production from existing sites one the one hand and future waste deposits on the other. The available resources for the other low cost technologies, onshore wind, sewage gas and hydro are not expected to change significantly.

Over time the costs of most technologies will also reduce due to learning effects. This effect is most pronounced for early stage (high cost) technologies such as PV, wave and tidal but has less effect on the more mature low cost technologies. Onshore wind will see increasing costs associated planning but these will be offset by continued reductions in capital and operating costs. Biomass co-firing, although able to generate power at very low cost today, will become more expensive due to the limitations imposed by the co-firing rules.

This report is restricted to assessing the supply curves for these technologies and it is not appropriate to discuss policy implications here. However, from the point of view of possible amendments to the RO for low cost technologies the simple conclusion from this analysis is that, with the exception of biomass co-firing, and assuming a brown power price of the order of £30/MWh, no technology is able to generate power commercially without some form of financial support.

Appendix 3 shows an aggregate renewable energy supply curve for the UK. Conclusions specific to each low cost technology are provided below.

Landfill Gas

The analysis indicates that the LFG industry is gradually approaching saturation in the development of new low cost sites. Model shows a sharp increase in costs at around 5.0TWh. This is due to the exhaustion of large sites capable of utilising large engines and where LFG collection systems are required under the Landfill Directive. Sites that make up the part of the curve between £45 and £100/MWh are all Type 3a, 3b and 4 sites (i.e. have comprehensive gas collection systems), but have low gas production volumes and consequently small and less efficient generating engines. In developing the older sites the full set of gas collection equipment is attributable to the power generation system, since gas collection and flaring is not required under the directive for these sites. At these sites, generation costs are in excess of £100/MWh.

The modelling shows that under the mid growth-mid diversion scenario *in the short term* an additional 1.8TWh (approximately 300MW) of LFG output is achievable at a cost below £45/MWh from 2003 levels. The additional available capacity below £45/MWh from expected 2004 output levels is around 1.5TWh (250MW). These calculations assume that new capacity will be developed with a load factor of 70%.

The model also indicates that the rate of increase in LFG production from new waste disposed to landfill will, over the duration of the analysis, outweigh the decline in yields from historic wastes, resulting in an extension of lower cost generation opportunities over time. By 2015 we would expect to see the available capacity at below £45/MWh increase to 5.8TWh, representing an increase on 2003 levels of 2.6TWh (420MW), or 2.3TWh (370MWh) from expected output in 2004. Learning effects are slight in the context of LFG reducing the cost of generation by £2/MWh between 2005 and 2015.

At build rates experienced in the last seven years of 60 to 70MW per year these low cost project opportunities would exhausted within four to five years.

Although we have not presented these figures as ranges, they are subject to high levels of uncertainty, in particular the resource potential in 2015 which is sensitive to future biodegradable waste deposits and the modelling of future LFG gas yields.

Onshore Wind

The analysis of onshore wind indicates that costs vary widely between sites. The average wind speed is the factor that has the largest impact on the economics of individual projects but the planning system and public acceptability will ultimately determine how much of the UK wind resource is developed onshore.

The supply curves in Section 3 show a relatively gradual increase from current costs of around £40/MWh up to £100/MWh. The curves suggest that between 60 and 100TWh could be generated at a cost of less than £100/MWh. The analysis also shows that the UK's wind resource could generate between 20 and 45TWh at a cost of less than £60/MWh. The upper end of this range is of a similar magnitude as those from other studies (see Table 3.1). Due to the maturity of onshore wind technology learning effects for onshore wind are expected to be small. By 2015 we would expect the marginal cost of wind power to reduce by approximately £5 to 7/MWh.

It is possible to divide onshore wind sites into three bands of economic viability, less than £50/MWh (low cost), £50-60/MWh (medium cost) and £60-80/MWh (high cost). The modelling indicates that, relative to 2003/4 output, the following additional capacity is available in the cost bands (Table 7.1).

Table 7.1 Additional resource potential for onshore wind

Cost band	Low resource scenario		High resource scenario	
	(TWh)	(GW)	(TWh)	(GW)
Low cost (<£50/MWh)	8	2.8	22	7.8
Medium cost (£50-60/MWh)	11	3.9	22	7.8
High cost (£60-80/MWh)	30	10.7	43	15.3

Over time, the slight fall in capital costs for onshore wind developments could lead to an increase in the available capacity at lower costs. However this would have to weighed against the fact that these lower cost sites are the ones most likely to be developed first.

A relevant consideration in the wind sector is the rate of development of new sites. BWEA, for example, estimates that 600MW of capacity will be built in 2005. At this rate of development low cost sites (<£50/MWh) will be exhausted in two to ten years.

Sewage Gas

Scope for further development of sewage is limited given regulations on the disposal of digested sludge. Digesters with engines attached also produce a relatively regular supply of gas and use standard gas processing and engine technology. For these reasons the sewage gas supply curve is expressed as a single point. This shows total electrical output of 251GWh/yr at a cost of £63/MWh in 2005. By 2015 we expect total electrical output to increase marginally to 278GWh/yr and the cost to decrease to £62/MWh.

Hydro

Hydro generation costs depend on the size of the unit and load factor, as well as a number of site specific factors. Generation costs for <1.25MW units are estimated at an around £84/MWh. For 1.25-20MW and >20MW costs are £67/MWh and £77/MWh respectively. By 2020 the costs of the micro and small hydro installations are expected to fall by over 20% and the cost of large hydro is expected to fall by over 10%. Although the generation costs for hydro are high, the total potential capacity available from hydro schemes is large, in the region of 12TWh for all sizes of scheme.

APPENDICES

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- Carnegie Mellon University – Experience Curves for Environmental Technology and their relationship to Government Action
- Margolis – Photovoltaic Technology Experience Curves and Markets
- ISET – Experience Curves for Wind and Observed Cost Reductions

3. REGIONAL WIND ASSESSMENTS

This appendix provides the explanatory text to the high and low scenarios for regional on-shore wind assessments developed in Section 3. These tables have been built up from a review of each region's most up to date planning guidance for wind farm development.

East of England

	MWe	Notes
Max	1,903	This data is for the "feasibly accessible potential, in other words that fraction of the theoretical maximum technical potential that could be accessed after taking account of physical constraints (such as built-up areas, areas of outstanding natural beauty, national parks etc), but not taking into account the very important political, social, environmental, institutional or social constraints that in practice are a key limiting factor" (Global to Local & ESD 2004 report p5).
High	1,218	The figure is for the 2020 elevated case scenario, and it estimated from a table. Under the Elevated Case Scenario, "Public acceptability of renewables rises strongly, perhaps in response to climate change events. Local resistance reduces as schemes come on-line and the impacts are limited. Planning is used as a positive incentive to the integration of renewables in new buildings, and planning becomes much less of an obstacle to most renewables schemes." (p9 of report).
Low	685	The figure is for the BAU 2020 scenario. It is estimated from a table and therefore approximate. Under the BAU scenario, "Public acceptability of the need for renewables grows slowly, but local resistance to planning applications for wind and biomass remains a block. Regional renewable energy targets and new planning guidance does not translate into faster or easier approvals." (p9 of report).

Sources: Terence O'Rourke plc, July 1997, "Eastern Region Renewable Energy Planning Study Final Report", ETSU, and *ESD, 2004, "Regional Renewable Energy Targets for the East of England 2010 and 2020".*

East Midlands

	MWe	Notes
Max	2,423	This is "the technically feasible resource, taking account of urban areas, villages, isolated buildings, reservoirs, roads, rivers, and woodland" (p50 of referenced report). It assumes a wind speed of 7 m/s or more is required for economic turbines.
High	388	This figure (termed the 'accessible on-shore resource") is based on the technically feasible resource but additionally takes into account planning and development constraints such as "National Parks, Green Belts, Areas of Outstanding Natural Beauty (AONBs), Sites of Special Scientific Interest (SSSI) and National Nature Reserves (NNR)" (p51).
Low	122	This figure is based on the accessible on-shore resource but has been further reduced to produce "recommended on-shore wind energy targets for 2003 and 2010" (here the 2010 target figure is given). The report states that these targets take "into account economic, planning and network constraints" (p52), though the impact of each of these constraints issues is not detailed. It can be noted that the figure, combined with targets for other technologies, would generate approx 10% of region's electricity consumption, so possibly the figure is target-constrained.

Source: LUC and IT Power (March 2001) "Viewpoints on Sustainable Energy in the East Midlands: A Study of Current Energy Projects and Future Prospects"

London

Only one scenario is identified for London.

MWe	Notes
18	Proposal 6 of the Major's Energy Strategy (2004) states that London should install at least six large wind turbines (here assumed to be 1.8MW) and 500 small wind generators associated with public or private sector buildings (here assumed to be 15kW). There is no discussion of a high scenario.

Source: Greater London Authority (Feb 2004) "Green light to clean power - The Mayor's Energy Strategy"

North East

The North East will "strive to achieve the Government's targets and aspirations for renewable electricity, namely 10% of regional consumption by 2010 and 20% by 2020" (p6 of report). In order to develop technology specific targets, "a sequential approach has been taken using future onshore wind as a "floating" final figure to achieve the relevant target. The approach taken tends to minimise the likely contribution of onshore wind developments, which means that the figures quoted should be regarded as the minimum required to meet the overall 10% and 20% target/aspiration." I.e. onshore wind is used to make up the shortfall between what other technologies can deliver, and the region's target.

No figures have been identified for the region's total potential resource, taking into account National Parks etc. However, it appears that the 20% 2020 target is stretching the region to its limit (see 'High scenario' table below). This can therefore be taken as the high scenario.

	MWe	Notes
High	866	The referenced report states that meeting the 2020 target will be considerably more challenging than the 2010 target and will require significant additional onshore wind capacity. Achievement of this target will require the identification of a Strategic Wind Resource Area (SWRA). Kielder may have the potential to become a SWRA, providing that the right locations for wind can be found in relation to MoD and other interests. "Kielder Forest has been the subject of a previous large scale wind project which failed largely because of MoD objections" (p5 of report). There are no other locations which would qualify as an SWRA without some sacrifice of one or more of the constraints accepted in this study (either NP, AONB, SPA or area with a relatively high landscape sensitivity).
Low	341	The referenced report states that if onshore wind is treated as the "final category" needed to make up the 10% target after other renewable technologies have made their contribution, then at least 240 MW installed capacity of new onshore wind will be needed in the Region up to 2010 (p37).

Source: Government Office for the North East (2003, July) "North East of England Regional Renewable Energy Strategy" pp. 23-24 and 37.

North West

	MWe	Notes
High	606	This is the high 2020 deployment scenario, in which "wind energy schemes come forward within a supportive and pro-active regional and sub-regional planning context" (p29).
Low	334	This is the indicative 2020 target which is based on the moderate deployment scenario for renewable technologies, in which on-shore wind is "granted only a low priority, with landscape protection and the minimisation of visual intrusion being accorded precedence in most places across the region." (p31)

Source: Report for North West Regional Assembly (November 2004) "Advancing Sustainable Energy in the North West", ERM and FES

South East

	MWe	Notes
High	229	The deployment of onshore wind is assumed to increase between 2010 and 2016, and then remain constant to 2026. As with the 2010 target, it is not clear what constraints are taken into account and what their impacts are (see notes for low scenario).
Low	172	This is the target for 2010. However, it is not clear how the figure was arrived at or what assumptions were made, but they are affected by a range of factors. The referenced report (May 2003) states that "The regional assessments made assumptions on the uptake of resources and technologies through time, in order to highlight the possible scale and numbers of schemes that might be built in the region. The technology breakdowns shown are only illustrative." Similarly, a 2000 report states that "The figures do not necessarily represent any one set of assumptions about the future but are rather an amalgamation of the numerous factors that could influence future deployment". (Government Office for the South East (2000) "Development of a Renewable Energy Assessment and Targets for the South East").

Source: South East England Regional Assembly (2003, May) "Harnessing the Elements - Supporting Statement to the Proposed Alterations to Regional Planning Guidance, South East – Energy Efficiency and Renewable Energy", p30

South West

	MWe	Notes
Max	1694	The figure is for the "accessible economic resource potential" that takes account of "landscape character" (and therefore no wind farms are developed within 7km of another wind farm), but does not take account of the "landscape sensitivity assessment" (ie "the degree to which a particular landscape character type or area can accommodate change without unacceptable detrimental effects on character") - based on Countryside Agency and Scottish Natural Heritage (1999) Interim Landscape Character Assessment Guidance). Whilst the data is from GOSW and SWRA (June 2004) "REvision 2010 - Target Scenarios Final Report Version", the description is from "REvision 2010 – Empowering the region. Renewable electricity targets for the South West" Annexes 4 and 7 (June 2004).
High	788	The figure adapts the "accessible economic resource potential" to take account of the 'landscape sensitivity assessment' as detailed above.
Low	367	The figure is the average of the low and high proposed targets for 2010. It is not clear why this figure is much lower than the high scenario figure, although a consultation process was involved so possibly reflects local opposition to wind farms.

Source: GOSW and SWRA (June 2004) "REvision 2010 - Target Scenarios Final Report Version" (labelled as "Summary of sub-regional targets" on website).

West Midlands

	MWe	Notes
High	300	This is the 'maximum strategy estimate' for onshore wind and also the onshore wind 2020 target. It assumes an "encouraging planning policy and other regulatory policies plus wider public acceptability" (p56).
Low	100	The West Midlands Wind Energy Resource Assessment (March 2004) and the West Midlands Regional Urban Wind Study suggest that a 100 MW target for wind could be achievable by 2010. The Energy Strategy proposes a more likely figure of 50-150 MW. The 2010 figure assumes no real change in planning policy but active encouragement.

Source: West Midlands Regional Assembly, Advantage West Midlands and Government Office for the West Midlands (Nov 2004) "West Midlands Regional Energy Strategy" p53-56.

Yorkshire and the Humber

	MWe	Notes
High	1,953	This is the maximum potential resource which takes account of high sensitivity landscapes, landscape sensitivity, and ecological impact assessments. By 2021, it is assumed that the grid will have been strengthened to accommodate new capacity increasing the maximum potential resource to 1953MW.
Low	725	The figure is the 'refined potential'. This is based on the maximum potential resource (high scenario) which was then refined following feedback on the proposed figures from local planning authorities and other stakeholders. This feedback showed that the onshore wind figures needed to be scaled back so they had more of an "acceptable impact" (p14). In addition, more recent MOD air defence radar consultative zones were taken into consideration.

Source: Report for Government Office for Yorkshire and Humber, and the Yorkshire and Humber Assembly (2004, December) "Planning for Renewable Energy Targets in Yorkshire and Humber" pp12-23

Wales

No report has been identified that examines the onshore wind resource for Wales pre- and post- planning. However, the 2020 20% target seems to stretch onshore wind resource to its maximum, and is therefore used as the high scenario.

	MWe	Notes
High	1,493	"When the information from the environmental and technical constraints mapping and the network capacity study are combined, it becomes clear that there are only a few unconstrained areas in Wales that are capable of accommodating large (25MW+) wind power developments... [There is] approximately 1200MW of renewable energy that could be developed within the strategic areas. This allows for any modification or fine-tuning that could occur through the consultation process and also offers some scope towards addressing the 2020 renewable energy target. Within the strategic areas, whilst cumulative impact can be a material consideration, it must be balanced against the need to meet the national target" (p6)

Low	1,093	Wales already has 173MW installed and 120 MW approved. In addition, the Assembly has decided that in order to meet its 4TWh target, 800MW of additional capacity will be required to be provided by large-scale on-shore wind by 2010. This assessment takes account of environmental, landscape, technical, national security and economic constraints.

Source: Welsh Assembly Government (July 2004) Consultation Draft, Planning Policy Wales, Draft Technical Advice Note 8 "Renewable Energy"

Northern Ireland

	MWe	Notes
Max	2,968	Takes account of designated and protected sites, radar and aviation, visual impact (though not clustering), noise impact, topography, closest grid connection, and issues relating to wind flow (e.g. interference from adjacent wind farms). The figure also takes account of existing onshore wind capacity (12.7MW).
High	1,559	The figure takes account of relevant constraints including clustering effects with regard to planning approval: "As more sites are developed, each new development will impact upon the environment and upon people's acceptance of that development to a greater extent. The development of sites will have a cumulative impact on the acceptability of further developments until a saturation level is reached.". Low (1209MW with 81 sites) and high (1546MW/ with 103 sites) figures are given. The figure also includes existing onshore wind capacity (12.7MW).
Low	577	This figure reflects "practical potential" by "assessing the remaining sites in greater detail, and weighting those sites which could be considered to be more benign from a planning or environmental impact viewpoint by assigning a probability factor to each site." The figure includes existing onshore wind capacity (12.7MW).

Source: PB Power, on behalf of Action Renewables (a joint initiative in Northern Ireland between the Department of Enterprise, Trade and Investment and the Viridian Group) (2004, July) "A Study into the Renewable Energy Resource in the Six Counties of Northern Ireland" Annex A.

Scotland

Two reports have been identified that examine the on-shore wind resource for Scotland: ETSU (1999) and Garrad Hassan (2001). Both of these take account of physical constraints and designated/protected areas, although do not appear to sufficiently take account of the clustering constraint. This maximum resource potential is shown below.

	MWe	Notes
Max	11,547	This is the average of the two base case resource assessments made by ETSU (1999) and Garrad Hassan (2001). Both of these reports take account of a range of constraints, including physical and some environmental and social constraints, but potentially do not sufficiently account for the impact of clustering.

Source: Scottish Executive (December 2001) "Scotland's Renewable Resource", Garrad Hassan. ETSU (1999) "A review of the UK onshore wind energy resource"

It is not clear how the 11.5 GWe maximum potential is likely to be affected by planning constraints. No report has been identified that satisfactorily addresses this issue. However, there are a number of sources that can inform the creation of a high and low scenario for Scotland.

One approach is to examine other UK regions which have a maximum resource potential and a high and low development scenarios and apply these ratios to Scotland. The table below summarises the information from the three regions discussed above that report on the region's maximum resource potential, as well as high and low scenarios.

Table A3.1 Summary of regions that specify a maximum resource and a high and low scenario

Region	Max resource MWe	High scenario MWe	Low scenario MWe	% change max to high scenario	% change max to low scenario
East of England	1,903	1,218	685	-36%	-64%
South West	1,694	788	367	-53%	-78%
Northern Ireland	2,968	1,559	577	-47%	-81%
Av of changes				**-46%**	**-74%**

For the three regions identified in the table above, the high and low scenarios are on average 46% and 76% respectively below the maximum resource potential. These figures could then be applied to Scotland's maximum resource figure of 11.5 GWe to generate high and low scenarios. However, on-shore wind projects historically have lower rejection figures in Scotland than in other parts of the UK. A November 2003 BWEA Briefing Sheet reports that local approval rates in terms of MW capacity between 1999 and 2003 were 94% in Scotland, compared to 75% in Northern Ireland, 50% in England and 40% in Wales. [89] The Scottish Executive's recent decisions on on-shore wind applications under Section 36 renewable energy consents granted permission to all 604 MW applied for.[90] The table below shows information from Scottish Renewables' database of renewable projects.

Table A3.2 Status of on-shore wind projects in Scotland [91]

Status	MWe	%
Existing	410	22%
Consented	1,046	56%
Withdrawn/ refused	414	22%
Total	**1,870**	100%

The actual refusal rate for onshore projects in Scotland is likely to be less than 22%, since the 414MW figure includes withdrawn projects. It may also include some off-shore wind projects. 22% can however be used as an initial upper estimate of the current on-shore wind refusal rate. Note that this is still markedly lower than the refusal rates observed in England (50%) and Wales (60%) for 2003.

However, it is likely that over time the refusal rate will increase in Scotland due to clustering. A Scottish Wind Assessment Project report notes that wind applications

89 BWEA (5th November 2003) "BWEA Briefing Sheet – PPS22: Renewable Energy"
90 http://www.scotland.gov.uk/Topics/Business-Industry/infrastructure/19185/19102
91 Scottish Renewables (June 2005) "Overview of renewable energy projects in Scotland"

are clustering along grid corridors, where connection costs are minimised. [92] A 2002 Scottish Executive Planning Advice Note states that “there have been few instances where cumulative effect has had to be addressed but with more proposals coming forward this could change” (p32). [93] It is possible therefore, that objections to the clustering of wind farms will reduce the total available wind resource.

On the basis of the above information we therefore make the following assumptions for Scotland for the purposes of this study:

- ***High scenario*** = 75% of maximum resource is exploited. This is based on the high estimate of a 22% refusal rate, which is then assumed to increase slightly over time to 25% due to objections to clustering. It is also informed by the experiences of the East of England, the South West, and Northern Ireland, which have a difference of 46% between maximum resource and their high scenario. The reasoning for Scotland’s difference is to its lower population density and a currently more favourable public attitude towards wind farms.

- ***Low scenario*** = 25% of maximum resource is exploited. In this scenario, planning decisions oppose the clustering of wind farms. The figure is informed by information from the East of England, the South West, and Northern Ireland.

Table A3.3 High and low scenario for Scotland

Region	Max resource MWe	High scenario MWe	Low scenario MWe	% change max to high scenario	% change max to low scenario
Scotland	11,547	8,660	2,887	-25%	-75%

92 The Scottish Wind Assessment Project, (Jan 2005) “Gazetteer of wind power in Scotland”
93 The Scottish Executive Development Department (Jan 2002) “Renewable Energy Technologies” Planning Advice Note, p32