UK Biomass Strategy 2007

Working Paper 1 – Economic analysis of biomass energy

Energy Technologies Unit
Department of Trade and Industry
May 2007

URN 07/950

Executive Summary

Introduction

The UK Government, in its response to the Biomass Task Force, committed to publishing a strategy for UK biomass. The purpose of this strategy is to define Government policy with the aim of achieving optimal carbon savings from biomass, while complying with EU policies and the Biomass Action Plan. It is also intended that the strategy should support existing renewable energy and climate change targets, and should facilitate the development of a competitive and sustainable market and supply chain for biomass. Development of the strategy is being led jointly by DTI and DEFRA.

The work reported herein was undertaken to advise the strategy on the relative cost effectiveness of utilising biomass as a nominally carbon neutral energy source. It has aimed to provide an overview of biomass options and to give a clear and transparent appraisal, drawing on existing information on current and prospective costs and technical performance parameters. Broad estimates are given for the level of financial support needed to make these options commercially attractive, what this support equates to as a CO2 abatement cost (£/tCO2), and the level of carbon abatement that can be achieved.

Biomass is a developing supply chain with greater uncertainty and variations in costs and performance than some other energy sources, reflecting the influence of such factors as location and size, as well as financial and contractual arrangements. The assessment has aimed to cover these aspects by examining realistic ranges of prices for biomass and competing fossil fuels, nonetheless it should be stressed that the results are mainly for indicative and comparative purposes, and are not accurate assessments of particular applications or projects.

Scope

The term biomass is used to cover a broad range of biologically derived resources including various biodegradable fractions of municipal and commercial and industrial wastes, sewage sludge, food waste, forest woodfuel, agricultural residues, wood waste and specifically grown energy crops. Furthermore, there is a range of technical options for converting biomass into useable energy (e.g. combustion, gasification, pyrolysis, anaerobic digestion). The study has focused on a limited range of representative options, covering the production of heat, power, combined heat and power and liquid biofuels.

The study examines the main elements of biomass fuel chains covering collection or production and harvesting, preparation, storage, transport and final conversion to useful energy supplies for the resources listed in Table E1. The conversion options examined in this study are listed in Table E2.

Table E1 Biomass sources considered by the study

Biomass Sources
Forest woodfuel
Energy Crops
Arboriculture arisings
Sawmill co-product
Straw
Waste Wood
Municipal/Industrial waste
Agricultural waste

Table E2 Conversion processes to be assessed in the study

Conversion Processes
Power generation - co-firing
Dedicated power generation
Heat production
Combined heat and power production
Production of liquid biofuels
Anaerobic digestion

Resources and prices

Estimating for the amount of biomass likely to be available for energy purposes is fraught with uncertainty because it is affected by a range of drivers that could change in direction and importance over time. These include:

- Supply cost, market price and demand.
- Competing, non-energy markets for biomass.
- Preferences of farmers and woodland owners.
- Access to market
- Success of alternative waste recovery and recycling

An estimate for each of the sources in Table E1, based on technical potentials (ie neglecting such factors as market and physical constraints), has given a total resource of about 96TWh, which is about 4% of current UK primary energy consumption.

Because biomass is an emerging industry it does not yet have the established supply chains or quality standards of fossil fuels. Also there is no integrated market to support competition, balance supply and demand, and stabilise prices. Consequently some biomass suppliers, without alternative non-energy markets are price takers so long as their costs are covered, while others may benefit from a degree of competition for their supplies. For example farmers producing energy crops can weigh-up the profitability of producing crops for combustion compared to crops for processing into liquid biofuels, and similarly arboricultural arisings may be used for composting as well as for energy purposes. Another factor affecting prices is the seasonality of some supplies, which can lead to lower prices during the collection season but higher prices for material that has been stored for several months. As a result of these factors biomass prices may be quite variable year on year reflecting production/availability, and between localities reflecting differing supply/demand balances. Moreover, as biomass energy grows prices may either increase due to increased demand or fall through expanded production, economies of scale and strong supply side competition.

Against this uncertain background it is not realistic to consider single prices for each of the biomass sources to be covered by this assessment. Instead this study has considered realistic central prices and price ranges, drawing on published information on supply costs and market conditions together with input from suppliers and customers. These are listed in Table E3.

Table E3 Summary of biomass fuel price assumptions used in this study

Biomass Type	Central Price (£/GJ)	Price Range (£/GJ)
Forestry woodfuel - chips	2.5 (60)	2.0 - 3.0
Forest woodfuel – logs	2.0 (40)	1.5-2.5
Energy Crops		
SRC	3.5 (70)	3.0 - 4.0
Miscanthus	3.0 (53)	2.5 - 3.5
Arboricultural arisings	2.5 (49)	2.0 - 3.0
Straw	2.0 (35)	1.5-2.5
Waste wood (clean)	2.5 (49	2.0 - 3.0
Waste wood (contaminated)	1.0 (20)	0.5 - 1.5
Pellets to power/industry/commercial from woodfuel	4.5 (90)	4.0 – 5.0
Pellets to power/industry/commercial from SRC	5.5 (110)	5.0 – 6.0
Pellets to power/industry/commercial from miscanthus	5.0 (100)	4.5 – 5.5
Pellets to domestic (including delivery)	7.0 (140)	6.0 – 8.0
Imported biomass (including delivery)	4.5 (90)	3.5 - 5.5

<u>Note</u>
Figures in brackets are prices in £/odt.
Values exclude transport and delivery unless otherwise stated
Woodfuel is taken to consist of forest woodfuel, sawmill co-product, arboricultural arisings and clean waste wood.

Transportation

Because of their low densities the transportation of biomass fuels can be a significant element of their overall supply cost. For example freshly harvested and chipped SRC willow may have a density of about 0.14t(dry matter)/m3, compared to dry wood densities of around 0.4 to 0.5t/m3. This is due in part to the high moisture content of freshly harvested wood (35-50%) and also to the relatively low packing density attained with wood chips. Most woodland and arable land is not located close to railway lines, and the additional work in transferring loads between road and rail would add cost. Therefore it is likely that most biomass will be transported by road

Transport cost will vary depending on the number of round trips that can be made in a day, which in turn depends on the haulage distance and the time required for loading and unloading. Also the haulage distance depends on the spacial density of the energy source. Estimated average transport costs are listed in Table E4.

Table E4 Estimated average transport costs for a range of biomass sources (£/GJ)

Application	Energy Crops	Woodfuel	Straw
Power generation			
1% co-firing, 2000MW	NA	0.30 (17)	0.30 (23)
5% co-firing, 2000MW	0.50 (35)	NA	0.80 (52)
10% co-firing, 2000MW	0.66 (49)	NA	NA
30MW dedicated	0.36 (24)	0.37 (25)	0.38 (28)
Heat			
0.1 - 10 MW(th)	0.30 (17)	0.30 (17)	NA
CHP			
0.1 - 10 MWe	0.30 (17)	0.30 (17)	NA
>10MWe	0.36 (24)	0.37 (25)	0.38 (28)

Notes
1. Figures in brackets are estimated average transport distances in km.
2. NA=not assessed

Transport costs for the dedicated generation, heat and CHP plant are less than for co-firing because these smaller facilities need to draw fuel from a smaller transport radius.

The cost of biomass transport to domestic users has not been estimated as this may occur through a retail distribution system. Instead the cost of transport has been included in the delivered price assumed for domestic fuel.

Cost effectiveness of alternative biomass options

The principal motivation for switching to biomass fuel is to reduce carbon dioxide emissions, although biomass also contributes to diversity and security of supply. Therefore a key measure of the cost effectiveness of the various options for using biomass to abate carbon dioxide emissions is the abatement cost in £/tCO2. The method used for calculating this parameter in this study is based on the relationship below.

$$\text{Abatement Cost (£/tCO2)} = \frac{\text{NPV of the cost difference between biomass and fossil energy (£/MWh)}^{1}}{\text{Total CO2 emission avoided (tCO2/MWh)}^{2}}$$

Abatement costs calculated by this method, not including existing support measures (eg. Renewables Obligation, Climate Change Levy exemption), show that in broad terms the order of cost effectiveness is:

- Energy from waste[3], that would command a gate fee for alternative disposal, to produce:
  - Heat or CHP
  - Electricity
- Energy from non-waste biomass to :
  - Replacement of oil for commercial/industrial heat and CHP in high load applications.
  - Replacement of oil for commercial/industrial heat in seasonal load applications.
  - Medium scale anaerobic digestion of agricultural arisings for power generation or CHP replacing oil heating.
  - Replacement of gas for commercial/industrial heat in high load applications.
  - Co-firing on new coal fired power generation with CCS.
  - Replacement of gas for commercial/industrial heat in seasonal load applications.
  - Small scale anaerobic digestion of agricultural arisings for power or CHP replacing oil heat.
  - High load district heating replacing oil.
  - Co-firing on existing and new coal fired power stations.
  - Replacement of individual domestic oil boilers with biomass.
  - Electricity generation from power stations fired exclusively on biomass.
  - Replacement of individual domestic gas boilers with biomass.
  - First generation transport biofuels

It must be stressed that this is a broad classification based on indicative data. Undoubtedly there will be specific cases that go against this overall pattern, for example district heating is highly site specific and costs can vary considerably. Also the results are sensitive to both future biomass and fossil fuel prices. Another factor is the nature and level of processing applied to the biomass. Thus pellet fuels, that are probably the only option for replacing gas in many circumstances where boiler house space is limited, are significantly more

[1] NPV is the Net Present Value, calculated using a discount rate of 3.5%, of the difference in cost of producing 1 MWh/yr of final energy (e.g. heat, electricity) from biomass and fossil fuel over the lifetime of the project.
[2] Total CO2 avoided refers to the emissions avoided by producing 1 MWh/yr of final energy from biomass instead of fossil fuel. Note the CO2 emissions avoided are not discounted (i.e. CO2 avoided in year 15 has the same benefit as CO2 avoided in year 1)
[3] Includes both standard combustion and advanced conversion technologies.

expensive than wood chip, but the capital cost of pellet boilers (including storage and handling facilities) is less. Consequently pellet systems can be more cost effective than chip in some applications (e.g. small commercial boilers at low utilisation).

Biomass fuelled medium to large CHP appears less cost effective in terms of CO2 abatement cost when compared to the corresponding heat only biomass applications. But the difference is less than when the comparison is made in terms of heat costs. This is because the higher overall energy efficiency of CHP delivers more CO2 abatement. [NB CHP was credited with avoiding the CO2 emissions from gas fired power generation in addition to the avoided emissions from fossil heat supply.]

With regard to power generation, all options appear less competitive than the majority of heat options. Dedicated generation is less cost effective than co-firing for CO2 abatement. The difference in abatement costs between co-firing on existing and new coal power stations is small. Abatement costs for biomass power generation options have been calculated assuming they displace gas fired generation. Abatement costs are significantly lower if it is assumed that coal is the displaced fossil fuel (eg. to £50-70/tCO2 compared to £98-128/tCO2 for central fuel price assumptions), but even at these costs biomass co-firing is less cost effective than many of the heat options.

Energy from waste stands out as the most cost effective biomass option provided it is credited with a gate fee that reflects savings in landfill charges, the landfill tax avoided and, where applicable the LATS[4] charges avoided. Gate fee revenue dominates over the revenue derived from the energy supply which suggests that these options are more a matter for waste policy. However, there is a case to incentivise the particular options that utilize the waste most effectively to maximise both the energy extracted and carbon abated.

With regard to non-waste biomass, the most cost effective options for utilization arise from small to medium commercial/industrial boilers operating throughout the year (80% load). Biomass in the form of wood chips is more cost effective than pellet fuel at all boiler sizes operating at high load, but for seasonal applications the difference is smaller. This is because the higher cost of pellet fuels is partially offset by the lower cost of fuel storage and handling facilities needed with pellets. Pellet heating is a particularly expensive option for domestic applications, while large industrial boilers have intermediate abatement costs.

The cost of abatement from substituting diesel and petrol with liquid biofuels produced using current technology is also an expensive option. However, abatement costs for second generation bio-fuels could be substantially lower, of the order of £30-50/tCO2.

[4] Landfill Allowance Trading Scheme (LATS)

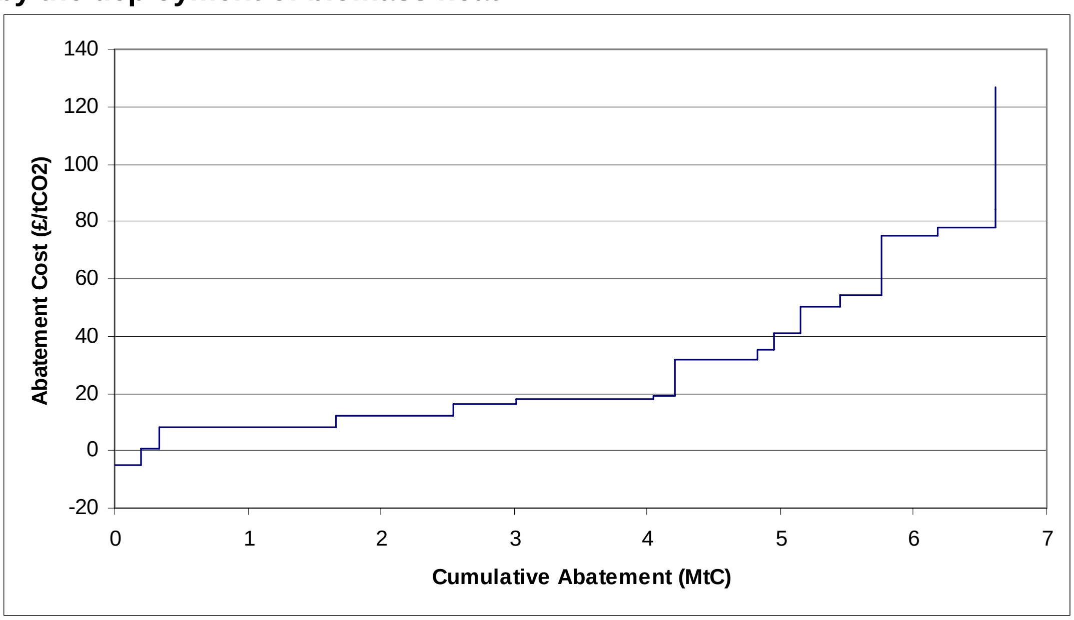
Marginal Cost of biomass deployment for heat production

The total level of deployment, and hence CO2 abatement, that can be gained from deploying biomass for heat production depends on the size of the fossil fuel heat market that can be replaced. Data to make such an assessment are sparse at present, but a crude indicative estimate has been developed utilising the sectoral heat demands discussed in Section 2 (Table 4) of the main report.

Scope for heat applications of energy from waste is limited by the public's reluctance to accept the siting of such facilities near centres of population owing to unfounded health concerns. Moreover, transportation of waste to established centres of energy demand is likely to be restricted unless these are located away from population centres or the waste has been processes into a more refined fuel. Consequently the use of waste for heat and CHP applications is likely to be restricted. An exception could be smaller scale AD applications utilising farm or food processing wastes which could be located on farms or processing plant. Because of these uncertainties energy from waste has not been included in this assessment of abatement potential. However, there is no doubt that energy from waste that attracts gate fees for alternative disposal options, is probably the most cost effective biomass energy option.

A cost versus abatement curve has been constructed for non-waste biomass to heat options, as shown in Figure E1. This figure omits CHP applications, once again due to lack of data on market potential, and also domestic heat because the costs are so much higher than for commercial boilers. The results, which use the central abatement costs from the study, show that about 6Mt carbon may be abated through the deployment of biomass heat at a marginal cost of around £80/tCO2.

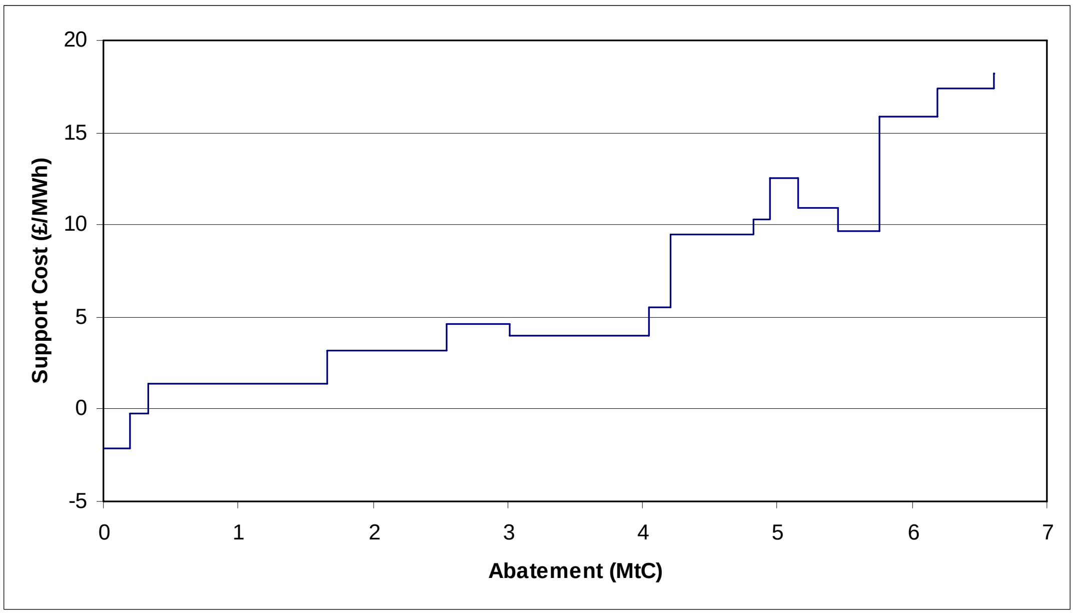
Figure E1 Illustrative CO2 cost versus abatement curve for CO2 avoided by the deployment of biomass heat.



The level of incentive needed to encourage the deployment of biomass heat to these levels is addressed through Figure E2, which shows the marginal level of support needed per unit of heat supplied. Support of the order of £15-20/MWh will be needed to deliver about 6MtC abatement. This is equivalent to supplying around 80TWh of heat to the commercial and industrial markets, which equates to about 20% of demand for space and low temperature process heating in these sectors.

It should be stressed that these estimates are only illustrative and do not consider the rate at which deployment could be increased to such levels, which clearly will be influences by the rate of turnover of boiler equipment as well as the build up of biomass supplies.

Figure E2 Illustrative support cost versus abatement curve for CO2 avoided by the deployment of biomass heat.



Contents

1. Introduction

The UK Government, in its response to the Biomass Task Force, committed to publishing a strategy for UK biomass. The purpose of this strategy is to define Government policy with the aim of achieving optimal carbon savings from biomass, while complying with EU policies and the Biomass Action Plan. It is also intended that the strategy should support existing renewable energy and climate change targets, and should facilitate the development of a competitive and sustainable market and supply chain for biomass. Development of the strategy is being led jointly by DTI and DEFRA.

The work reported herein was undertaken to advise the strategy on the relative cost effectiveness of utilising biomass as a nominally carbon neutral energy source. Results provide estimates of the level of economic support needed to enable a range of biomass to energy options to be competitive with fossil fuel alternatives, and what this support equates to in terms of a carbon abatement cost (£/tCO2). These results are compared to corresponding values for other low carbon energy supply technologies.

Various economic analyses have been made of biomass energy[5,6,7], but many of these have focussed on particular supply chains or end uses, and have used differing assumptions. This analysis has aimed to provide a broader overview of biomass options and to give a clear and transparent appraisal, drawing on existing information on current and prospective costs and technical performance parameters.

The term biomass is used to cover a broad range of biologically derived resources including various biodegradable fractions of municipal and industrial and commercial wastes, sewage sludge, food waste, forest woodfuel, agricultural residues, wood waste and specifically grown energy crops. Furthermore, there is a range of technical options for converting biomass into useable energy (e.g. combustion, gasification, pyrolysis, anaerobic digestion). Consequently it has been necessary to limit the study to a representative set of supply/conversion options, covering the production of heat, power, combined heat and power and liquid biofuels.

It has also been recognised that biomass is a developing supply chain with greater uncertainty and variations in costs and performance than some other energy sources, reflecting the influence of such factors as location and size, as well as financial and contractual arrangements. The assessment has aimed to cover these aspects by examining realistic ranges of prices for biomass and competing fossil fuels, nonetheless it should be stressed that the results should be regarded as indicative, and are not a precise assessment of particular applications or projects.

[5] Biomass as a renewable energy source, Royal Commission on Environmental Pollution, 2004.
[6] Biomass sector review for the Carbon Trust, Carbon Trust, 2005.
[7] Renewable heat and heat from combined heat and power plants – study and analysis, Report to DTI from AEA Technology, 2005.

The study examines the main elements of biomass fuel chains covering collection or production and harvesting, preparation, storage, transport and final conversion to useful energy supplies for the resources listed in Table 1. An assessment of the potential size of the UK biomass resource, and a comparison with the potential demand from alternative end use sectors, is followed by an assessment of the cost effectiveness of utilising biomass for various heat, electricity and combined heat and power supply options on the basis of both present and possible future biomass and fossil fuel prices and technology performance standards. Broad estimates are also given for the level of support needed to make these options commercially attractive, and the level of carbon abatement that can be achieved.

Table 1 Biomass sources considered by the study

Biomass Sources
Forest woodfuel
Energy Crops
Arboriculture arisings
Sawmill co-product
Straw
Waste Wood
Municipal/Industrial & Commercial waste
Agricultural residues

In general terms the options for converting biomass to usable energy are the same for each of the sources listed above, although they vary in size, and in the particular technologies to be used, to match the volume and physical characteristics of the feedstock. The conversion options examined in this study are listed in Table 2.

Table 2 Conversion processes to be assessed in the study

Conversion Processes
Power generation co-firing
Dedicated power generation
Heat production
Combined heat and power production
Anaerobic digestion

The study does not examine in detail the options for the production of liquid biofuels for transport, but draws on analysis undertaken by the Department for Transport (DfT) and DEFRA to compare the cost effectiveness, with regard to carbon abatement, of this application with the heat and power options listed in Table 2.

2. Comparison of potential UK biomass resources and demands

The main objective of this report is to compare the cost effectiveness of alternative options for the utilisation of biomass energy resources, but this information is of limited value without some indication of their potential deployment. Consequently, this section gives a rough assessment of the potential size of the UK resource and how it compares with potential demands from various energy applications.

Estimating the actual availability of biomass resource is both complex and uncertain because this will be subject to a range of interacting drivers. e.g.

- Supply cost, market price and demand.
- Competing, non-energy markets, for biomass.
- Preferences of farmers and woodland owners.
- Access to market.
- Success of alternative waste recovery and recycling.

For the indicative purpose of this section it is sufficient to consider the resource that could be technically available (i.e. neglecting financial and market constraints). Table 3 draws on a range of information sources to give such estimates for the UK.

Most wood biomass sources are expected to remain fairly constant up to 2020, but sawmill co-product could increase substantially (by up to a factor of five) as the volume of mature wood for harvesting is set to increase over this period. Alternatively if there is no market for this wood, whole log timber could be available for energy use, which would further increase the size of the resource. Energy crop production clearly will depend on the amount of land used for this purpose, which will in turn depend on the profitability of other options for the land including crops for liquid biofuels. This assessment has given an indication of energy crop potential based on the assumption that 350,000ha of arable and set aside land is turned over to such crops. This estimate neglects liquid biofuel production for which it is estimated an additional 740,000ha would be needed to produce half the Road Transport Fuel Obligation (RTFO) target of 5% biofuels by volume of road transport fuels by 2010. Clearly this potential could increase substantially if more land is used and if yields increase from the current day level assumed in the estimates. For example an European Environment Agency report has recently estimated that the UK could have 1.1 million hectares available for environmentally compatible bioenergy production by 2020[8]. It may also be possible to extend production to grassland, which would substantially increase the potential supply. However, there is concern that this could result in the release of substantial quantities of soil carbon as CO2, which would negate the benefit of biomass production. Also additional resources could be obtained as co-product from liquid biofuels production, although this has not been included in the estimate.

[8] How much bioenergy can Europe produce without harming the environment, European Environment Agency Report, No7, 2006 (http://reports.eea.europa/eea_report_2006_7/en)

Straw availability is determined by the amount of conventional crop production and the demand for this material for other uses, and will vary depending on farmers planting decisions, the quality of the harvest and competition from other users. For the purpose of this assessment it has been assumed that the quantity available (i.e. neglecting supply and economic constraints) for energy purposes will stay roughly constant at about 3 Mt/yr from a total resource of about 9-10Mt/yr[9].

Results given in Table 3 show that at the UK level about 28TWh of biomass are potentially available from existing forestry and agricultural sources, amounting to about 1% of total UK primary energy consumption. With the inclusion of energy crops[10] and waste wood, the resource could be increased to about 3% of UK primary energy, and if it were used to replace coal or oil from the current energy mix it would reduce UK carbon emissions respectively by about 22 MtCO2 and 18 MtCO2 (6MtC and 5MtC), or about 4% and 3% of the UK's CO_2 emissions[11].

Other sources of biomass are contained in Municipal Solid Waste (MSW), Commercial and Industrial Waste (C&I) streams and agricultural wastes, including slurries and manures much of which is currently spread to land. For the background purpose of this section the total biodegradable component, less that considered suitable for other recovery or recycling processes, has been included in the table. This shows that waste biomass has a technical energy potential of the order of 24TWh which is equivalent to about 1% of UK primary energy consumption.

In addition to indigenous resources the UK can import biomass material, including wood, olive and palm residues. It has been estimated that there are about 54TWh[12] of these resources available at present, with the potential to increase supplies, but of course the UK would have to compete with other markets for this material.

Several options are available for the utilisation of biomass to replace fossil fuels (Table 2), and the extent to which they are taken up will depend on a range of factors including cost, the reliability of the supply chain, competitiveness with other replacement options and, in the longer term, competition amongst applications for the biomass available (eg. heat versus power generation versus

[9] D Turley, Central Science Laboratory estimates for UK Biomass Strategy, 2007.
[10] Assuming energy crop production on 350,000ha (~6.5%) of arable and set aside land. At present production is much lower with about 7000ha expected to produce 0.5TWh in 2006.
[11] The carbon abatement percentages are higher because not all of the UK's primary energy comes from fossil fuel, and a significant proportion comes from natural gas which has a lower carbon content than coal or oil.
[12] The Economics of Co-firing, report to DTI from IPA Consulting and Mitsui Babcock, July 2006. (http://www.dti.gov.uk/files/file34449.pdf)

Table 3 Estimated technical potential of biomass energy sources (TWh of primary energy)

Region	Woodfuel	Straw	Waste Wood	Energy Crops	Waste	Agricultural Waste	Total
Total for UK	**13.0**	**14.5**	**26.0**	**17.2**	**15.5**	**10.0**	**96.2**

Notes
1. Estimates for woodfuel include forest woodfuel, arboriculture arisings and sawmill co-product, and are taken from recently up date estimates produced by the Forestry Commission. This includes an addition 2Mt/yr (green - equivalent to ~1Modt/yr) that FC estimates can be obtained from under-managed forestry in England.
2. The values for Energy Crops are only intended to be indicative for a range of options (e.g. SRC, miscanthus, canary grass, eucalyptus) but have been estimated using data for SRC and assume planting on 350,000ha (~6.5%) of arable and set aside land with an average annual yield of 9odt/ha.
3. Values for straw include arisings from both cereals and oil seed crops and equate to 3Mt/yr. (D Turley, Central Science Laboratory)
4. Values for waste wood are based on a total UK availability of 5.6Mt/yr, and included both clean and contaminated material. (DEFRA Waste Strategy, 2007)
5. The value for waste includes sewage sludge and the proportions of biodegradable UK MSW and Commercial and Industrial (C&I) Wastes that is considered more suited for energy production rather than for other recovery or recycling options. (DEFRA Waste Strategy 2007)
6. Agricultural waste includes poultry manure, cattle slurry and pig manures, and represents total annual production including material currently recycled to land. (D Turley, Central Science Laboratory estimates for the Biomass Strategy)

Table 4 Comparison of the estimated technical potential of UK biomass energy sources with the potential fuel requirement to replace oil and solid fuel heating (TWh)

Region	Supply					Demand			
	Total woodfuel	Straw	Energy Crops	Wastes	Total Supply	Industry	Domestic	Services	Total Demand
Total for UK	**39.0**	**14.5**	**17.2**	**23.6**	**94.3**	**75**	**76**	**25**	**176**

Notes

1. Industry and services demand potentials are taken from the report "Renewable heat and heat from combined heat and power plants – study and analysis", FES Report to DTI, 2005.
2. Domestic demand potential is based on total oil and solid fuel consumption used for space and water heating taken from DTI Report "UK Energy Consumption" (http://www.dti.gov.uk/energy/statistics/publications/ecuk/domestic/page18071.htmland)
3. The demand estimates are effectively technical potentials and take no account of market and supply considerations or physical constraints such as the availability of space to accommodate biomass equipment.

co-firing). To give a rough comparison of the size of the UK's biomass resource with the potential demand one particular application has been considered, namely the replacement of oil and solid fuel in heating applications. Estimates of the deployment potential for biomass in these applications are given in Table 4. These values are technical potentials that neglect market and physical factors that can limited deployment, and therefore probably represent the maximum possible demand from these applications. Also the table does not consider the rate of build up of capacity which is likely to be spread over 15-20 years.

The total potential biomass supplies, neglecting imports, are roughly 50% of the total potential for substituting oil and solid fuel heating. However, the commercial potential for deploying biomass in heating is likely to be less because of market, supply chain and physical constraints. Therefore biomass could also be available for other energy applications such as power generation, production of liquid biofuels, or some substitution of natural gas heating. For example 10% co-firing with biomass on all coal fired power power stations that have opted into the Large Combustion Plant directive, and therefore could be expected to operate beyond 2015, would add an additional 40TWh of demand.

Important observations from this part of the analysis are:

- Potential UK biomass resources are equivalent to about 3-4% of primary energy consumption.
- The greatest potential demands for biomass heat come from the industry and domestic sectors with smaller demands from commercial and public services.
- Total UK biomass amounts to about 50% of the total potential for substituting oil and solid fuel heating.
- Market, supply chain and physical constraints on deployment in the heat market mean that the UK biomass resource potential could also be available to supply a range of energy applications.

3. Biomass supply costs and prices

Biomass energy is an emerging industry and does not yet have the established supply chains or quality standards of fossil fuels. Also there is no integrated market to support competition, balance supply and demand, and stabilise prices. Consequently some biomass suppliers, without alternative non-energy markets are price takers so long as their costs are covered, while others may benefit from a degree of competition for their supplies. For example farmers producing energy crops can weigh-up the profitability of producing crops for combustion compared to crops for processing into liquid biofuels, and similarly arboricultural arisings may be used for composting as well as for energy purposes. Another factor affecting prices is the seasonality of some supplies, which can lead to lower prices during the collection season but higher prices for material that has been stored for several months. As a result of these factors biomass prices may be quite variable year on year reflecting production/availability, and between localities reflecting differing supply/demand balances. Moreover, as biomass energy expands prices may either increase due to increased demand or fall through increased production, economies of scale and strong supply side competition.

Against this uncertain background it is not realistic to consider single prices for each of the biomass sources to be covered by this assessment (Table 1). Instead this section considers realistic central prices and price ranges, drawing on published information on supply, costs and market conditions together with input from suppliers and customers. Transport costs are examined separately in Section 4.

Forest woodfuel

Forest woodfuel consist of small diameter stem wood, poor quality stem wood, stems tips and branches arising from coniferous and broad leaf forest. Three types of supply have been identified, namely:

- Large-scale production from forest harvesting, thinning and residue harvesting from cleared fell. This product is chipped at the forest for increased density and compaction for transport.
- Medium scale production from thinning operations. The wood is collected as round wood and chipped off site.
- Small scale production from thinning of under managed woodland producing logs mainly for personal use.

Small scale production is mainly relevant to local utilisation, for example for heat supply to buildings and dwellings within an estate.

There are only limited markets for forest woodfuel at present and consequently the price for medium to large volumes of wood chip will tend to be set by the cost of collection, processing and transport plus a small margin. A survey of published reports found supply price (or cost) estimates ranging from £0.77/GJ to £3.2/GJ for wood chip (Table 5). This range reflects a number of variables that affect prices including the moisture content of the wood (dry wood commands a higher price than green/wet wood), whether transport costs were included, access to market , volume of production and whether estimates were based on the cost of production or the price the resource could command for alternative uses. Thus the highest value, from IPA/Mitsui Babcock[13], was based on their estimate of the price paid by the wood board industry for the same forest material. However, these non-energy markets are saturated and it does not follow that the same price can be passed on to energy customers.

Looking to the future it could be argued that prices will increase as producers seek to gain a larger profit margin with growing demand, but on the other hand greater volumes of production could give economies of scale. Taking account of these opposing factors a central wood chip price of £2.5/GJ, and range of £2.0 to £3.0/GJ has been used in this study for supplies (excluding transport/delivery costs) to large and medium sized energy installations (i.e. neglecting any additional processing required at the energy installation). These prices are for none dried wood with a moisture content of 30-45%.

The price of log wood for domestic applications is even more variable because this depends on local supply chains. However, prices are likely to be lower than for wood chip because less processing is involved. Therefore a central price of £2.0/GJ has been used and a range of £1.5 to £2.5/GJ.

Energy Crops

Currently energy crops are being considered both for combustion applications and for the production of liquid biofuels. The supply prices considered here are for combustion for heat or power production, liquid biofuels are discussed separately in Section 9.

A range of combustible energy crops are considered suitable for the UK climate, including short rotation coppice (SRC) with willow, grasses including miscanthus, canary and switch, and eucalyptus. There are significant differences with these crops in terms of their cultivation and harvesting costs, and in their production patterns and requirement for further processing before they can be sold for energy use. In particular SRC is only harvested every three years while the grasses give an annual yield.

Conventional cereal crops such as wheat or barley could also be grown for energy purposes, with the full crop including grain going for combustion or processing to liquid biofuels. However, the prices of these crops are generally expected to be higher than for specifically planted energy crops, and have not been consider in this analysis. Yet another option is to utilise the co-product arising from liquid biofuel production for combustion. Prices for this material are also uncertain at this early stage of UK biofuel production, and therefore this option has not been considered.

A survey of recently published reports found supply prices (or costs) ranging from £2.0/GJ to £4.9/GJ for wood chip produced from SRC and £2.6/GJ to £3.4/GJ for miscanthus (Table 6). Again this range reflects a number of variables affecting

[13] The Economics of Co-firing, report to DTI from IPA Consulting and Mitsui Babcock, July 2006. (http://www.dti.gov.uk/files/file34449.pdf)

costs including the moisture content of the material, whether storage, drying and transport costs were included, and whether estimates were based on the cost of production or the price the resource could command for alternative uses. Thus for SRC, the higher costs (that exclude transport) from IPA/Mitsui Babcock and Cambridge/SAC[14] are based on the farm price, excluding support measures, needed to give a positive return to the farmer. Recent indications are that competition for land to produce non-food crops is increasing with growing interest in liquid biofuels. This could drive energy crop prices higher. Furthermore, as with forest woodfuel, it could be argued that prices will increase as producers seek to gain a larger profit margin with growing demand, but on the other hand greater volumes of production could give economies of scale

Although other potential energy crops have been suggested their production costs are less certain. Therefore SRC and miscanthus were selected as representative of energy crops and subject to detailed assessment in this study. Taking account of the price drivers outlined above the central farm price for wood chips produced from SRC to be investigated was set at £3.5/GJ within a range of £3.0-4.0/GJ (equivalent to about £60-80/odt). The corresponding prices for miscanthus were a central value of £3.0/GJ within a range of £2.5-3.5/GJ (equivalent to about £44-65/odt). These prices exclude transport delivery costs.

The above prices neglect the effect of any existing support mechanisms for energy crops. SRC and miscanthus have received planting grants of £1000/ha and £920/ha through DEFRA's Energy Crops Scheme[15], and also can qualify for an annual grant of Euro45/ha through EU Common Agricultural Policy funds. The combination of these two mechanisms reduced production costs for SRC and miscanthus by £0.6/GJ and £0.5/GJ (£12/odt and £8/odt) respectively. Accordingly the study has also investigated SRC and miscanthus prices of £2.9/GJ and £2.5/GJ (excluding transport/delivery costs).

Arboricultural arisings

Arboricultural arisings refer to the woody material produced from the maintenance and pruning of trees and woodland in urban locations. This material could be burned on site or collected and committed to landfill, but there is increasing interest in its use for composting or as an energy source. Like forest woodfuel this resource is essentially free at source, but other factors will affect its price to energy applications. There are significant costs associated with its collection, preparation and transportation to energy users, but these will be at least partially offset by the gate fees avoided by not sending this material to landfill. Consequently, in the near term prices could be comparatively low. However, in the longer term, if demand for biomass for energy increases, suppliers will look to gain higher prices in line with other sources of biomass such as energy crops.

[14] Farm Level Economic Impacts of Energy Crop Production, Report to DEFRA from Cambridge University and Scottish Agricultural College, June 2005.
[15] The DEFRA Energy Crops Scheme ended in July 2006

Table 5 Fuel supply prices or costs for forestry woodfuel

Source/Description	Condition	Fuel Cost/Price (£/t)	Fuel Cost/Price (£/GJ)	Comment
RCEP (min)[16]	Dry	15	0.8	Cost, at forest
RCEP (max)	Dry	35	1.8	Cost, at forest
Carbon Trust (2005)[17]	Dry	53	2.7	Delivered price
IPA/Mitsui Babcock (2006)[18]	Wet	45	3.2	Set by market price for other use, no transport costs
Forestry Commission (2006) (large scale felling)	Wet	11	1.3	Cost, Assume 50% moisture - chips, at forest
Forestry Commission (2006) (large scale thinning)	Wet	18	2.2	Cost, Assume 50% moisture - chips, at forest
Forestry Commission (2006) (large scale residue)	Wet	14	1.6	Cost, Assume 50% moisture - chips, at forest
Forestry Commission (2006) (medium scale)	Wet	26	1.6	Cost, Assume 50% moisture - chips, at forest
Forestry Commission (2006) (small scale)	Wet	25	1.6	Cost, Assume 50% moisture - logs, at forest
FES/Environment Agency (2002) (min – chip)	Dry	25	1.3	Delivered price
FES/Environment Agency (2002) (max – chip)	Dry	45	2.3	Delivered price
FES (2005) (min – chip)[19]	-	-	1.5	Delivered price, wood chip
FES (2005) (max – chip)	-	-	2.4	Delivered price, wood chip
FES (2005) (min – pellets)	-	80.0	4.2	Delivered price, wood pellet
FES (2005) (max – pellets)	-	159.0	8.3	Delivered price, wood pellet
Renewables East (2005) (min – chip)[20]	Dry	22	1.1	Delivered price
Renewables East (2005) (max – chip)	Dry	60	3.0	Delivered price

[16] Biomass as a renewable energy source, Royal Commission on Environmental Pollution, 2004
[17] Biomass sector review for the Carbon Trust, Carbon tTrust, 2005
[18] The Economics of Co-firing, report to DTI from IPA Consulting and Mitsui Babcock, July 2006
[19] Renewable heat and heat from combined heat and power plants – study and analysis, Report to DTI from AEA Technology, 2005
[20] East of England biomass foundation study, Renewables East, 2005

Table 6 Supply prices or costs for energy crops

Fuel Type	Calorific Value (GJ/odt)	Fuel Cost/Price (£/odt)	Fuel Cost/Price (£/GJ)	Comment
Willow SRC (min)[21]	20	40	2.0	Delivered price
Willow SRC (max)[19]	20	60	3.0	Delivered price
Willow SRC[22]	19.5	96	4.9	Cost of drying and storage included
Willow/Misc[23]	19.5	80	4.1	Farm gate price to displace arable crops/green wood
Willow SRC[24]	19.5	66	3.4	Production cost at farm
Willow SRC[25]	19.5	56	2.9	Production cost at farm
Willow SRC[26]	-	60	3.0	Delivered price
Energy Crops[27]		52	3.0	Delivered price
Energy Crops (min)[28]	16.9	40	2.4	Delivered price
Energy Crops (max)[26]	16.9	80	4.7	Delivered price
Energy Crops (min)[29]	-	-	1.9	Delivered, chip
Energy Crops (max)[27]	-	-	3.5	Delivered, chip
Miscanthus (min)[19]	19	50	2.6	Delivered price
Miscanthus (max)[19]	19	60	3.2	Delivered price
Miscanthus[22]	17.3	47.7	2.8	Production cost at farm
Miscanthus[23]	17.3	59.5	3.4	Production cost at farm
Miscanthus[24]	-	50	2.9	Delivered price

Note Costs are given on a dry basis unless otherwise stated

[21] Review of power production from renewables and related sources, FES report to the Environment Agency, 2002.
[22] The Economics of Co-firing, report to DTI from IPA Consulting and Mitsui Babcock, July 2006
[23] Review of the economic case for energy crops, LEK report to DTI, 2004.
[24] Farm level economic impacts of energy crop production, Report to DEFRA, Cambridge University and Scottish Agricultural College, June 2005
[25] ABNA, private communication, 2005
[26] East of England biomass foundation study, Renewables East, 2005
[27] Biomass sector review for the Carbon Trust, Carbon Trust, 2005
[28] Biomass as a renewable energy source, Royal Commission on Environmental Pollution, 2004
[29] Renewable heat and heat from combined heat and power plants – study and analysis, Report to DTI from AEA Technology, 2005

For the purpose of this assessment it has been assumed that arboricultural arisings will be delivered for energy applications at a price aligned with forest woodfuel, namely a central price of £2.5 /GJ within a range of £2.0-£3.0/GJ (excluding transport/delivery costs).

Sawmill co-product

Approximately 50% of the wood sold to saw mills is converted into usable timber in the form of planks, batons, etc. The other 50% includes bark, chips and sawdust and is referred to as co-product. Some of this co-product can find markets for applications such as board manufacture, or may be used for heat production at the sawmill. The resource levels given in Table 3 represent the surplus material available for energy use. Like forest residues this material has no market value and therefore its price is fixed by the cost of collection, preparation and transport to energy users. For the purpose of this assessment it has been assumed that sawmill co-product will be delivered for energy applications at the same price as forest woodfuel and arboricultural arisings, namely a central price of £2.5/GJ within a range of £2.0-£3.0/GJ (excluding transport/delivery costs).

Straw

Straw is derived from a range of arable crops including wheat, oats and barley as well as oil seed crops. Substantial quantities of these materials are produced but a large part of this already has other uses and is not available for energy production. The price of material delivered to power stations is determined by the cost of collection, baling, storage and transportation, which can vary widely depending on the transport distance, the availability of competing uses and weather conditions before and during harvesting. Estimates of prices of straw delivered to power stations have been found that range from about £2/GJ[30] to nearly £5/GJ[31]. The assessment has assumed a central price for energy applications of £2/GJ within a range of £1.5-£2.5/GJ (excluding transport/delivery costs).

Waste wood

In the UK sawn wood is used for a wide range of applications including construction, furniture manufacture and industrial use such as for pallets. A substantial part of the annual wood supply ends up as off-cuts which are committed to landfill. Other waste wood arises from demolition, broken pallets and unwanted furniture much of which also has no practical use and is burned or sent to landfill.

It has been estimated that about 4.5Mt of this material could be used for energy purposes (Table 3). Like other wastes this material has no market value and therefore its price is fixed by the cost of separating it from other wastes, collection, preparation and transport to energy users. These costs may be offset by saving in avoided landfill charges. For the purpose of this assessment it has been assumed that clean waste wood will be delivered for energy applications at the same price

[30] Biomas sector review for the Carbon Trust, 2005.
[31] The economics of co-firing, report to DTI, IPA and Mitsui Babcock, July 2006. (http://www.dti.gov.uk/files/file34449.pdf)

as forest woodfuel, namely a central price of £2.5/GJ within a range of £2.0-£3.0/GJ (excluding transport/delivery costs).

The above prices assume that the wood is clean and therefore can be burned within standard biomass combustion plant. Wood contaminated with paint or other chemicals would need to be burned in a plant meeting Waste Incineration Directive emissions standards. It is likely therefore that contaminated wood would be supplied at a lower price than clean material, and a central price of £1.0/GJ within a range of £0.5 – 1.5/GJ (excluding transport/delivery costs) has been assumed for this assessment.

Pellets

The above discussion has considered the cost of biomass sources that would be delivered in the form of wood chip or chopped grasses. Another possible supply option is to process biomass into pellets. The advantage of this source of biomass fuel is that it is more consistent with a lower moisture content and higher calorific value. Furthermore, it is more convenient to handle in both large and small scale applications. For example pelletised material is needed to feed larger volumes (>1%) of material for co-firing in coal power stations. Also pellets can be fed into small boilers through an automated system, which makes it particularly attractive for smaller commercial and domestic use.

Preparation of pellets, and the additional handling, add to the costs so that pellets are more expensive than chipped materials. Information from suppliers and end-users indicates that pelletising may add about £2/GJ to the cost of chipped material when supplied in large volumes to power and heat plant. Therefore three ranges of pellet price have been examined for large applications:

1. Pellets derived from forest woodfuel, arboricultural arisings, sawmill co-product and clean waste wood - £4.5/GJ within a range of £4.0 to £5.0/GJ (excluding transport and delivery costs.
2. Pellets derived from SRC - £5.5/GJ within a range of £5.0 to £6.0/GJ (excluding transport and delivery costs.
3. Pellets derived from miscanthus - £5.0/GJ within a range of £4.5 to £5.5/GJ (excluding transport and delivery costs).

With regard to the cost of pellets for domestic applications, FES[32] in their review reported a possible range from roughly £4-8/GJ or £80 - 160/t (Table 5). More recently REA members[33] have suggested a price range of £5.7 – 9.3/GJ or £110 – 180/t. Therefore for this study a central value of £7.0/GJ was investigated within a range of £6.0-8.0/GJ (including delivery).

Imported biomass

Biomass may be derived from a range of waste sources including wood products, olive products and palm products as well as specifically grown material. There is

[32] Renewable heat and heat from combined heat and power plants – study and analysis, Report to DTI from AEA Technology, 2005.
[33] Information provided in response to a workshop that reviewed the assumptions used in this analysis arranged by DTI on 15th December 2006.

an international market for these resources and prices can vary depending on the balance of supply and demand. IPC/Mitsui Babcock[34] have reported prices ranging from £3.5 to £5.4/GJ including delivery, therefore a central price of £4.5/GJ has been used in this study and a range of £3.5 to £5.5/GJ (including delivery).

Summary of biomass prices

Table 7 summarises the full range of biomass fuel cost assumptions adopted for the study. These values are considered to reasonably representative of current supply prices. There is potential to reduce production costs in the future through improved production and economies of scale in collection and processing. However, the increasing demand that is needed to drive these cost reductions is also likely to expand production beyond the lowest cost options thereby increasing marginal costs. Overall the best judgement is that these two factors will balance out and therefore supply prices will stay steady into the future, although there is much uncertainty at this early stage in UK biomass energy.

Table 7 Summary of biomass fuel price assumptions used in this study

Biomass Type	Central Price (£/GJ)	Price Range (£/GJ)
Forestry woodfuel - chips	2.5 (60)	2.0 - 3.0
Forest woodfuel – logs	2.0 (40)	1.5-2.5
Energy Crops		
SRC	3.5 (70)	3.0 - 4.0
Miscanthus	3.0 (53)	2.5 - 3.5
Arboricultural arisings	2.5 (49)	2.0 - 3.0
Straw	2.0 (35)	1.5-2.5
Waste wood (clean)	2.5 (49	2.0 - 3.0
Waste wood (contaminated)	1.0 (20)	0.5 - 1.5
Pellets to power/industry/commercial from woodfuel	4.5 (90)	4.0 – 5.0
Pellets to power/industry/commercial from SRC	5.5 (110)	5.0 – 6.0
Pellets to power/industry/commercial from miscanthus	5.0 (100)	4.5 – 5.5
Pellets to domerstic (including delivery)	7.0 (140)	6.0 – 8.0
Imported biomass (including delivery)	4.5 (90)	3.5 - 5.5

<u>Note</u>
Figures in brackets are prices in £/odt.
Values exclude transport and delivery unless otherwise stated
Woodfuel included forest woodfuel, arboricultural arisings, sawmill co-product and clean waste wood.

[34] The economics of co-firing, report to DTI from IPA and Mitsui Babcock, July 2006 (http://www.dti.gov.uk/files/file34449.pdf).

Important observations coming from this part of the analysis are:

- There is significant uncertainty over near and longer term prices of biomass supplies due to variability in the material and costs for collection, harvesting and preparation.
- Biomass prices are also sensitive to the supply-demand balance that can be affected by none energy markets for the same material.
- Accordingly this economic assessment has defined a central price for each biomass source and also a price range to be used in sensitivity analyses.
- It is uncertain what will happen to biomass supply prices in the future. Increased supply/demand could deliver economies of scale, but the increased demand will also cause the use of more expensive sources, thus increasing marginal costs. On balance the best judgement is that prices should stay fairly constant into the future, but there is much uncertainty as UK biomass energy is at an early stage of development.

4. Transport Costs

Because of their low densities the transportation of biomass fuels can be a significant element of their overall supply cost. For example freshly harvested and chipped SRC willow may have a density of about 0.14t(dry matter)/m3, compared to dry wood densities of around 0.4 to 0.5t/m3. This is due in part to the high moisture content of freshly harvested wood (35-50%) and also to the relatively low packing density attained with wood chips.

Most woodland and arable land is not located close to railway lines, and the additional work in transferring loads between road and rail would add cost. Therefore it is likely that most biomass will be transported by road. Costs for road transport have been estimated based on goods vehicle operating costs produced by the Freight Transport Association[35], which are summarised in Table 8.

Table 8 Operating costs for 38t gross tri-axle combination

Fixed cost	£240/day
Variable Cost	32.5p/km
Operating time	55h per week

With these values the transport cost varies depending on the number of round trips that can be made in a day, which in turn depends on the haulage distance and the time required for loading and unloading. Also the haulage distance depends on the spacial density of the energy source. Table 9 lists estimated transport costs for the range of fuel types and energy process plants covered by the study.

Cost estimates for SRC and Miscanthus were very similar so have been reported together. At the equivalent of 1.6p/GJ/km their cost of transport is higher than the 0.2-0.6p/GJ/km for SRC and 0.4-0.8p/GJ/km for miscanthus given in the IPA/Mitsui Babcock report for the co-firing review.

However, the same report gave higher transport costs for forest woodfuel of 1.6-2.0p/GJ/km, possibly because this material was assumed to be less compacted than SRC chip and involved difficult removal from more remote locations. The RCEP report gives transport costs for SRC of about 0.4p/GJ/km. In this work woodfuel from forests, sawmill co-product, aboriculture and clean waste wood have been grouped as “woodfuel” and the average transport cost has been estimated to be £0.3/GJ for an average transport distance of 17km (i.e. equivalent to about 1.8p/GJ/km).

Transport costs for the dedicated generation, heat and CHP plant are less than for co-firing because these smaller facilities need to draw fuel from a smaller transport radius.

[35] Goods vehicle operating costs 2006, Produced for the Freight Transport Association by DFF International

The cost of biomass transport to domestic users has not been estimated as this may occur through a retail distribution system. Instead the cost of transport has been included in the delivered price assumed for domestic fuel (see Section 3 and Table7). The same applies to imported biomass for co-firing for which a delivered price was given in Table 7.

Table 9 Estimated average transport costs for a range of biomass sources (£/GJ)

Application	Energy Crops	Woodfuel	Straw
Power generation			
1% co-firing, 2000MW	NA	0.30 (17)	0.30 (23)
5% co-firing, 2000MW	0.50 (35)	NA	0.80 (52)
10% co-firing, 2000MW	0.66 (49)	NA	NA
30MW dedicated	0.36 (24)	0.37 (25)	0.38 (28)
Heat			
0.1 MW(th)	0.30 (17)	0.30 (17)	NA
1 MW(th)	0.30 (17)	0.30 (17)	NA
10 MW(th)	0.30 (17)	0.30 (17)	NA
CHP			
0.1 MWe	0.30 (17)	0.30 (17)	NA
1 MWe	0.30 (17)	0.30 (17)	NA
10MWe	0.36 (24)	0.37 (25)	0.38 (28)

Notes

1. Figures in brackets are estimated average transport distances in km.
2. NA=not assessed

5. Economic assessment of biomass co-firing power generation

Co-firing is generally considered in relation to existing coal-fired power stations where the substitution of carbon neutral biomass for coal can give significant reductions in CO2 emissions. However, if co-firing is to have long term potential it will also need to be applied to new/refurbished coal power stations, possibly in combination with carbon dioxide capture and storage (CCS). This section examines the cost and CO2 abatement that could be gained from each of these applications.

Another longer-term option could be to integrate biomass within natural gas fired power stations either for boiler water preheat or as a source of synthetic gas. These options have not been considered in this assessment since they are not being pursued commercially at present and there is a lack of reliable data.

Co-firing in existing power stations

This option considers co-firing with energy crops (SRC willow or miscanthus), imported biomass, woodfuel (forest woodfuel, sawmill co-product, arboricultural arisings and clean waste wood are considered together because they have the same assumed price range) and straw from 2007. The availability of woodfuel and straw is limited compared to the fuel volumes required for substantial co-firing, therefore only 1% and 5% co-firing has been examined for these sources. SRC willow and miscanthus plus imported biomass could potentially be produced in much large volumes and therefore 5% and 10% co-firing levels are examined. It should be noted that there may also be technical limitations to the use of straw due to boiler corrosion risks in existing coal power stations.

The approach taken is to estimate the generation costs and CO2 emissions from a typical 2000MW coal fire power station with co-firing. The calculation assumes:

- Coal prices are taken from DTI's central fuel price scenario, as reported in the Updated Energy Projections published with the Energy Review (see Annex A, Table A1).
- Investment for co-firing requires a 12% internal rate of return over a 15 year project duration.
- The co-fired power stations operate with a 60% load factor and have an efficiency of 35% (other assumptions for the fossil fuel aspects of the plant are listed in Annex B, Table B1). This load factor was chose as representative of coal fired power stations opted into the Large Combustion Plant Directive (LCPD).
- The capital cost of the coal power station is assumed sunk (i.e. neither biomass nor coal generation attract any capital charges for the power plant).
- Future investments in the coal power station, for example to meet the requirements of the Large Combustion Plant Directive, would be undertaken in the absence of co-firing and therefore are not attributed to co-firing.

- Assumptions on capital investment costs and additional operating costs arising from adapting the plant to burn biomass are listed in Annex B, Table B2.
- All costs, prices and results are in £(2005) real, and neglect taxes, existing support measures and any other transfer charges.
- SRC and miscanthus are assumed to be used after pelletisation.
- Biomass resources when used with significant moisture contents (i.e. 20-30%), and in large quantities (i.e. over 5% of fuel input) can reduce the overall generation efficiency of power generation, thus increasing overall fuel consumption. However, in this analysis the biomass resources that may have high moisture contents (i.e. non-pelleted woodfuel and straw) are only considered for 1% co-firing, while other resources are considered for use with preparation that reduces their water content (e.g. as pellets). Therefore generation efficiency is assumed to be unaffected by the co-firing options considered herein.

Results for the generation costs of these options are summarised in Table 10. 1% co-firing with woodfuel or straw is the cheapest option because the feedstock has a low price and only limited investment in equipment is needed to handle such low volumes. The higher 5% and 10% levels of co-firing are more expensive because this requires the feedstock to be pelletised, as well as greater investment in equipment to handle the material at the power station. Generation with imported biomass has a price slightly higher than 1% co-firing with woodfuel and straw, but significantly less than with large volumes of UK produced biomass. This is because the imported material is cheaper and requires less investment in handling equipment at the power station.

Generation costs for co-fired biomass need to be compared to the wholesale price of electricity in order to assess the level of support needed to encourage commercial deployment. In the long run the wholesale price should be set by the cost of generation from new plant coming on to the electricity supply system (the long run marginal cost - LRMC). It is generally assumed that gas turbine combined cycle plant (GTCC) is the most likely technology to be built in the UK, therefore the cost of generation from new GTCC has been used as a benchmark for comparing co-firing costs.

Table 10 shows that the increase in generation cost for biomass over and above gas firing ranges from £14/MWh for 1% straw to £44/MWh for SRC. The corresponding increase in generation cost for biomass compared to new coal fired generation is included for completeness, and ranges from £18/MWh for 1% straw to £48/MWh for SRC. Fossil fuel fired generation attracts additional costs through inclusion in the EU-ETS. At present CO2 emission permit prices are depressed but taking a longer term view, an EU-ETS permit price of Euro 20/tCO2 would add £4.4/MWh to the cost gas fired generation [NB although most permits are allocated free it is assumed that generators will seek to recover the opportunity cost of the permits in their supply prices]. This would reduce the cost difference between gas and biomass generation to £10/MWh to £40/MWh.

Section 3 reported that a combination of the UK Government's Energy Crops Scheme and the EU Common Agricultural Policy support reduced energy crop production costs by about 15%. If this fed through to lower supply costs to power stations the additional cost of biomass generation over gas firing would come down to £38/MWh (from £44/MWh) for SRC and £34/MWh (from £39/MWh) for Miscanthus.[36]

Table 10 Summary of generation costs for biomass co-firing on existing coal fired power stations

Biomass Type	Biomass cost including transport (£/GJ)	Co-firing (%)	Total generation cost (£/MWh)	Increase in generation cost relative to new coal (£/MWh)	Increase in generation cost relative to new gas (£/MWh)
Straw	2.3	1%	47	18	14
Woodfuel	2.8	1%	52	23	19
Woodfuel	5.0	5%	67	38	34
SRC	6.0	5%	77	48	44
SRC	6.2	10%	77	48	44
Miscanthus	5.4	5%	72	43	39
Miscanthus	5.5	10%	71	42	39
Imports	4.5	5%	57	28	25
Imports	4.5	10%	56	27	23

<u>Notes</u>

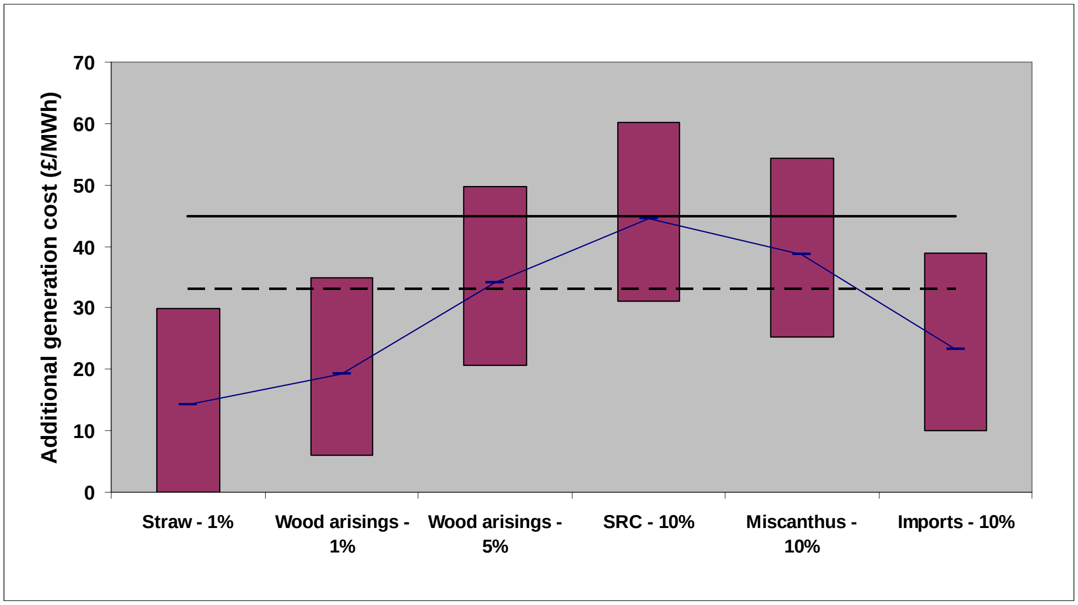
1. Woodfuel comprises forestry woodfuel, sawmill co-product, arboricultural arisings and clean waste wood.
2. All values rounded to two significant figures
3. Generation costs are NPV values based on a 15 year project duration.

The results in Table 10 are based on central assumptions for the cost of biomass, gas and coal. The sensitivity of the results to variations in biomass and fossil fuel prices has been investigated by assessing two other fuel price scenarios[37]:

a. High limit to biomass price range combined with DTI's low gas price scenario (HL Scenario).
b. Low limit to the biomass price range combined with DTI's high gas price scenario (LH Scenario).

The results in Figure 1 show the additional generation costs of co-firing (i.e. relative to gas) between the HL and LH scenarios. These differences equate to the support needed to encourage co-firing on coal fired power stations. The range of additional costs for the low volume and low cost co-firing options using straw and woodfuel lie mainly below the ROC[38] buyout price (£33/MWh). Also the additional cost range for co-firing with imported biomass lies mainly below the ROC buyout price. In contrast co-fired generation with significant volumes of SRC or miscanthus has additional costs exceeding the recent ROC trading price (£45/MWh) at the HL end of the fuel price ranges investigated.

[36] For 10% co-firing and including EU-ETS.
[37] Coal fuel price assumptions are listed in Annex A, Table A1.
[38] Renewables Obligation Certificates (ROC).



Notes

1. The high extreme of each bar indicates the additional cost of biomass co-fired generation with the HL scenario fuel prices and at the low extreme the additional cost with LH scenario fuel prices.
2. The linking line indicates the additional cost of biomass co-fired generation with the central fuel price assumptions.
3. Solid horizontal line indicates ROC trading price (£45/MWh)
4. Broken horizontal line indicates ROC buyout price (£33/MWh).

Figure 1 Variation in the additional generation costs associated with biomass co-firing compared to gas fired generation for differing scenario assumptions on biomass and natural gas prices

Co-firing in new power stations

Much of the UK's current coal fired power generation capacity is over 35 years old and of low conversion efficiency compared to modern standards. Therefore if coal is to have a long-term future for power generation in the UK plant will need to be replaced. For biomass co-firing to have a long-term future it is important that it should have comparable costs and performance on new/refurbished coal plant as it does with the existing stock.

Costs for power generation with various types of biomass on new coal power stations are listed in Table 11. These estimates use the same assumptions as given for existing plant, with two exceptions:

- the capital cost of the new build was included in the calculations in this case (Annex B, Table B1), and co-firing carried its share of this capital cost. This approach was taken because it could be argued that co-firing could influence the decision on whether to build new coal-fired power stations in preference to other options.
- The new plant was assumed to operate at a load factor of 80% compared to the 60% value used for existing plant

Comparison between the results in Tables 10 and 11 shows that the cost of biomass generation is only slightly higher for new coal power stations. This is because the higher efficiency of the new plant reduces the amount of expensive biomass needing to be burned, and because the plant is operated at a higher load factor. These savings offsets the capital cost of the new plant.

Table 11 Summary of generation costs for biomass co-firing on new coal fired power stations

Biomass Type	Biomass cost including transport (£/GJ)	Co-firing (%)	Total generation cost (£/MWh)	Increase in generation cost relative to new coal (£/MWh)	Increase in generation cost relative to new gas (£/MWh)
Straw	2.3	1%	54	25	22
Woodfuel	2.8	1%	58	29	26
Woodfuel	5.0	5%	70	41	37
SRC	6.0	5%	78	49	45
SRC	6.2	10%	78	49	45
Miscanthus	5.4	5%	74	45	41
Miscanthus	5.5	10%	74	44	41
Imports	4.5	5%	62	33	30
Imports	4.5	10%	61	32	29

Notes
1. Woodfuel comprises forestry woodfuel, sawmill co-product, arboricultural arisings and clean waste wood.
2. All values rounded to two significant figures
3. Generation costs are NPV values based on a 15 year project duration

Another potential future development is that the yield of energy crops could be increased by improved varieties of willow or grasses combined with better agricultural practices. It has been estimated that such advances over the next 5-10 years could increase the yield of SRC from 9 to 12t/ha and for miscanthus from 14 to 18t/ha without any increase in production costs. Comparison of the results in Tables 11 and 12 shows that such a reduction in biomass supply cost would reduce generation costs by about 9%, and the additional generation cost of biomass compared to gas by about 16%.

Table 12 Generation costs for biomass co-firing on new coal fired power stations with improved energy crop yields

Biomass Type	Biomass cost including transport (£/GJ)	Co-firing (%)	Total generation cost (£/MWh)	Increase in generation cost relative to new coal (£/MWh)	Increase in generation cost relative to new gas (£/MWh)*
SRC – 10%	5.3	10%	71	42	38
Miscanthus – 10%	4.8	10%	68	39	35

Notes
1. All values rounded to two significant figures
2. Generation costs are NPV values based on a 15 year project duration

Co-firing on new power stations with carbon dioxide capture and storage

The attainment of substantial reductions in CO2 emissions, of the order of 80-90%, on fossil fuel power plant will require the application of carbon dioxide capture and storage (CCS)[39]. This could be combined with co-firing to effectively achieve zero, or even negative, net emissions.

The cost of implementing 10% co-firing with SRC willow and miscanthus is given in Table 13. These estimates have been made using the assumptions listed in Section 5.1 except that the capital costs for the new coal plant, including CO2 capture equipment, have been attributed to the co-fired capacity as well as the coal fired element of the plant. Also the plant was assumed to operate at base load (90% load factor) since it seems reasonable to assume that near zero CO2 emission plant would be used in preference to non-capture fossil fuel plant.

Table 13 Summary of generation costs for biomass co-firing on new coal fired power station with carbon dioxide capture and storage

Biomass Type	Cost including transport (£/GJ)	Co-firing (%)	Total generation cost (£/MWh)	Increase in generation cost relative to new coal with CCS (£/MWh)	Increase in generation cost relative to new gas without CCS (£/MWh)
SRC – 10%	6.4	10%	97	55	65
Miscanthus – 10%	5.7	10%	91	49	59

Notes
1. All values rounded to two significant figures
2. Generation costs are NPV values based on a 15 year project duration

The table shows that the cost of biomass generation is substantial (£91-97/MWh). The additional cost of co-fired CCS generation compared to gas fired plant without CCS is about 45% greater than for co-firing without CCS (Table 11). These bigger cost differentials compared to gas fired generation and standard coal fired CCS arise mainly because of the lower fuel efficiency of CCS plant, which increases the consumption of expensive biomass.

[39] A strategy for the developing carbon abatement technologies for fossil fuel use, DTI, June 2005 (DTI/Pub URN 05/844)

Important observations coming from this part of the analysis are:

- It is likely that the additional cost of power generation from co-firing low volumes (~1%) of woodfuel and straw, and also significant volumes (5-10%) of imported biomass in existing coal fired power station will lie at or below the ROC buyout price of £33/MWh).
- Co-firing large volumes (5-10%) of woodfuel and energy crops requires more fuel preparation, and additional handling costs at the power station. Consequently the additional cost of co-firing in these circumstances may approach or exceed the current ROC trading price of about £45/MWh.
- An EU-ETS permit price of Euro 20/tCO_2 would reduce the cost differential between co-firing and gas fired generation by about £4.4/MWh.
- The additional cost of co-firing is about the same on new coal power stations compared to existing plant (£22-45/MWh vs £14-44/MWh) because the improved generation efficiency reduces the quantity of expensive biomass needing to be burnt, which offsets the share of the new plant's capital cost attributed to biomass.
- The cost of co-firing with energy crops could be reduced by about 9% by the improved yields and agricultural practices currently thought to be attainable over the next 5-10 years.
- Co-firing on new coal fired power stations fitted with carbon dioxide capture and storage has generation costs which are about 25% higher than that of standard CCS.
- The additional costs of co-firing arise mainly from the cost differential between the biomass and coal fuel supplies. Therefore an incentive based on capital allowances would not be effective for promoting co-firing.

6. Economic assessment of dedicated biomass power generation

Power stations dedicated to using only biomass tend to be much smaller than fossil fuel plant, typically of the order of 20-50MWe compared to 1000-2000MWe. Such plant have the advantage that they can be located more close to their fuel supplies thus minimising transport costs, and are designed to handle various forms of material including contaminated waste wood.

The costs and CO2 abatement performance of dedicated power stations have been evaluated on the basis of the same general assumptions as applied to co-firing and listed in Section 5. Additional assumptions specific to dedicated plant were:

- That the plant operates with an 80% load factor (compared to 60% for co-firing).
- Capital investment requires an internal rate of return of 15% and is amortised over 15 years.
- Capital and operating costs for the plant were assumed to be:
  - Capex - £2200/kWe
  - Fixed Opex – 3% of Capex
  - Variable Opex - £1.1/MWhe
- The plant was assumed to have a capacity of 30MWe and a generation efficiency of 30% (net).
- The plant is designed to comply with EU Waste Incineration Directive emission requirements while burning waste materials such as contaminated waste wood.

Estimates for the cost of electricity generation with different biomass sources are listed in Table 14. The table also lists the difference between these costs and the cost of conventional generation from new gas and coal fired power stations. The values in Table 14 are based on the central price assumptions for coal and natural gas (favourable to coal case) used in the DTI energy projections published with the Energy Review, and are listed in Appendix A Table A1.

Coal and natural gas fired generation attracts additional costs through their inclusion in the EU-ETS. At present CO2 emission permit prices are depressed but taking a longer term view, an EU-ETS permit price of Euro 20/tCO2 would add £4.4/MWh and £9.5/MWh respectively to the cost of gas and coal fired generation [NB although most permits are allocated free it is assumed that generators will seek to recover the opportunity cost through their supply prices]. This would reduce the cost difference between fossil and biomass generation by the same amounts, which although significant, would still leave biomass substantially more expensive than fossil.

Generation costs are higher for dedicated biomass power stations compared to co-firing (e.g. compare generation costs in Table 14 to Table 10). Also the support needed to bridge the cost gap between dedicated generation and the wholesale price of electricity[40] is higher than for co-firing, and generally exceeds the current ROC trading price of about £45/MWh.

Table 14 Summary of the generation costs for a dedicated biomass fired power stations

Biomass Type	Biomass cost including transport (£/GJ)	Total generation cost (£/MWh)	Increase in generation cost relative to new coal (£/MWh)	Increase in generation cost relative to new gas (£/MWh)
Woodfuel	2.9	99	70	66
Wood waste - contaminated	1.4	81	52	48
SRC	3.9	111	81	78
Miscanthus	3.3	104	75	71
Straw	2.4	93	64	60

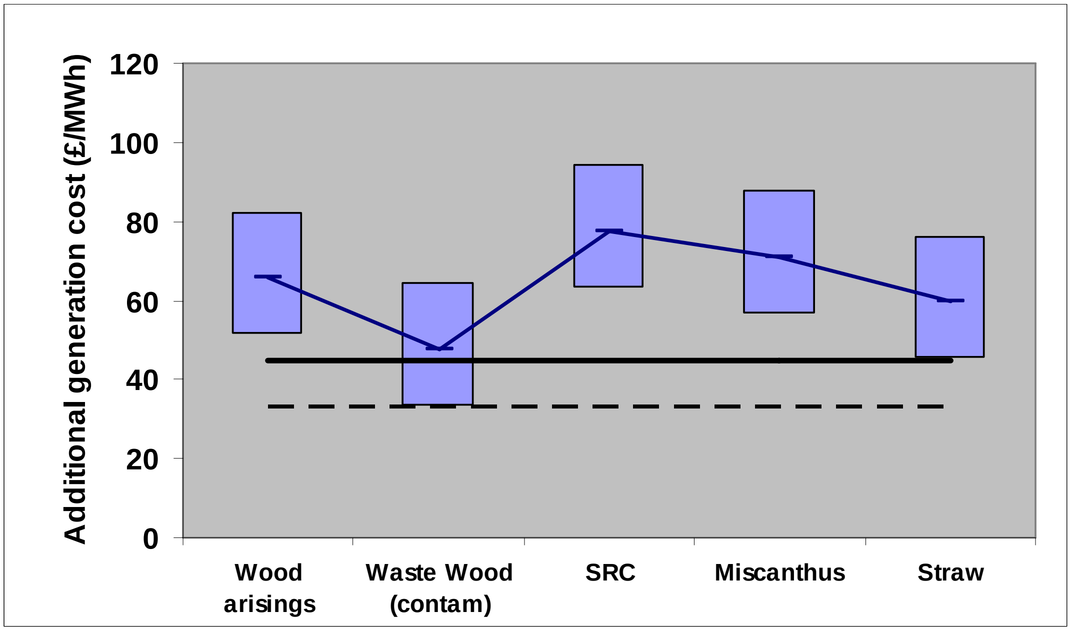
Notes
1. Woodfuel comprise forestry woodfuel, sawmill co-product, arboricultural arisings and clean waste wood.
2. All values rounded to two significant figures
3. Generation costs are levelised values based on a 15 year project duration

The results in Table 14 are based on central assumptions for the cost of biomass and natural gas. The sensitivity of the results to variations in biomass and natural gas prices has been investigated by assessing two other fuel price scenarios[41]:

a. High limit to biomass price range combined with DTI's low gas price scenario (HL Scenario).
b. Low limit to the biomass price range combined with DTI's high gas price scenario (LH Scenario).

The results in Figure 2 show the additional generation costs of dedicated generation relative to natural gas, which equates to the support needed to encourage dedicated biomass generation. It is significant that the central values all exceed the current ROC trading price, with the exception of contaminated waste wood, which is expected to have a particularly low supply price.

[40] In line with Section 5 the wholesale price of electricity is assumed to be set by the Long Run Marginal Cost of supply, which in turn is assumed to be the cost of generation from gas turbine combined cycle plant.
[41] Natural gas price assumptions are listed in Appendix A, Table A1.



Notes
1. The high extreme of each bar indicates the additional cost of biomass co-fired generation with the HL scenario fuel prices and the low extreme the additional cost with LH scenario fuel prices.
2. The variable linking line indicates the additional cost of biomass co-fired generation with the central fuel price assumptions.
3. Solid horizontal line indicates ROC trading price (£45/MWh)
4. Broken horizontal line indicates ROC buyout price (£33/MWh).

Figure 2 Variation in the additional generation costs associated with dedicated biomass generation with differing scenario assumptions on biomass and gas prices

It has been suggested that there is potential for reductions in the generation costs of biomass plant through improved conversion efficiency, particularly by moving from combustion/steam technology to gasification combined cycles. Current opinion is that, while this could lead to some improvement, small biomass generation will not attain the efficiency of large power stations without incurring unrealistic capital costs. For example some of the integration and pre-heating measures applied to large plant would be uneconomic on smaller units. Nonetheless there is potential for some improvement, which, when combined with improved energy crop production, could enhance the economics of dedicated generation. To assess the potential impact of such developments generation costs have been estimated for a plant with a 10% reduction in capital cost (i.e. £2000/kW from £2200) and an increased generation efficiency from 30% to 32%. This reduced generation cost by between £7-9/MWh, which again is significant, but leaves a substantial cost differential with fossil generation.

Important observations coming from this part of the analysis are:

- Generation costs with dedicated biomass power stations are higher than for fossil power generation, with a differential for central fossil fuel price assumptions of of between £48/MWh and £78/MWh depending on the costs of the biomass source.
- These cost differences should be compared to the Renewables Obligation buy-out price of £33/MWh, current RO Certificate trading price of about £45/MWh and the cost difference for co-firing of £14-44/MWh.
- The cost differential with fossil fuels would be reduced by about £4.4/MWh by an EU-ETS permit price of Euro20/tCO2.
- The lower limit of the above cost range is for generation using contaminated waste wood which has a limited supply.
- The higher generation costs of dedicated biomass power stations compared to fossil generation are due to the higher unit capital costs and lower efficiency of the small (20-50MWe) plant needed for dedicated generation, and, in the case of coal, the higher cost of most biomass sources.
- Improvements leading to increased generation efficiency and reduced capital cost will improve the cost of dedicated generation, but this is only expected to yield savings of £7-9/MWh in the foreseeable future.
- It is unlikely that the reductions will be sufficient to enable dedicated generation to match co-firing.

7. Economic assessment of biomass heat production

Heat energy is used in the domestic, services and industry sectors, mainly for space, water and process heating and cooking. Where sites are connected to the natural gas grid gas fired heating tends to be the preferred option because of its convenience, and until recently price competitiveness. For locations off the gas grid oil, liquid petroleum gas or solid fuel are the main options. The replacement of fossil fuels for heating applications offers an alternative to power generation for utilising biomass resources.

Biomass heating is most often considered for replacing oil in heating applications. The main reasons for this are:

- Heating oil prices are relatively high and therefore biomass is more likely to be cost competitive with oil rather than gas.
- Oil heating requires a storage tank and therefore it is more likely that the space need to store biomass will be available on sites with oil heating.
- Oil is a more carbon intensive fuel than natural gas and therefore its replacement with biomass will yield more CO2 abatement than if it was used to replace gas.

However, substitution for natural gas should not be discounted since gas accounts for a much larger share of the UK heating market. Moreover, it is possible that gas could compete with biomass to replace oil on sites connected to the gas grid, therefore the cost competitiveness of biomass relative to gas heating needs to be examined.

The potential for substituting biomass for oil in heating applications has been estimated in Table 4. This showed that the greatest potential, excluding cost considerations, lay in the domestic and industry sectors. Applications differ considerably between sectors both in terms of the size and type of boilers to be used and in the nature of the biomass fuel that can be handled. Consequently separate assessments have been made for the cost of substituting biomass for oil and natural gas fired heating in four broad types of application defined by boiler size:

1. Small domestic boilers within the central heating system of an individual house and fuelled with wood logs or pellets.
2. Commercial boilers used in small service and industrial applications with capacities of around 0.25MWth fuelled with woodchips or pellets.
3. Commercial boilers used in services and medium industrial applications with capacities of around 1.0MWth and fuelled with wood chips or pellets.
4. Large industrial boilers of around 20MWth capacity and fuelled with woodchips.

The costs and operating performances of these boiler types were gathered from a range of sources and are listed in Appendix C.

Domestic heat supply

Supply costs have been evaluated for the replacement of domestic oil and gas central heating boilers with two biomass options:

- Wood pellets
- Log wood

The calculations have been based on the following assumptions:

- Oil and gas fired boilers are replaced when they require replacement (i.e. no early scraping and residual cost write-off of boilers was considered).
- Oil boilers in this size range are assumed to use burning oil.
- Burning oil and natural gas prices are taken from DTI's central fuel price scenario, as reported in the Updated Energy Projections published with the Energy Review (see Annex A, Tables A2 and A3).
- Capital investment costs for installing biomass, oil and gas boilers are listed in Annex C, Table C1.
- The sector was assumed to require a payback period of 4 years with an interest rate of 10% on capital expenditure.
- All boilers were assumed to supply a total of 18,000kWh of heat annually (equivalent to a 20% load factor for a 10kW biomass boiler).

Results in Table 16 show that wood pellets are the more expensive biomass heating option, but neither pellets nor logs offer a cost effective substitute for oil or gas with the central fuel price assumptions.

Because of the low utilisation of domestic boilers due to seasonal variations in demand for space heat (i.e. their load factor is about 20%), the capital cost of the boiler accounts for a significant share of the heat supply cost. Consequently the cost of capital has a significant impact on the cost effectiveness of biomass heating because biomass boilers (and supporting equipment) are more expensive than oil or gas boilers. This is illustrated by Table 17 which shows the same heat supply costs estimated with a 6% interest rate and payback period of 15 years for both biomass and fossil heating. This reduces the difference in supply costs between biomass and oil/gas, although the costs are still appreciable particularly for wood pellets.

An interest rate of 6% is roughly what a local authority may use in considering investments. Therefore Table 17 shows that even public sector housing would require additional support to invest in biomass heating for individual houses.

Table 16 Cost of heat production from biomass and the level of support needed to make this economically attractive for replacing oil and gas domestic boilers

Biomass	Scenario	Cost of biomass heat (£/MWh)	Addition cost of heat relative to oil (£/MWh)	Additional cost of heat relative to gas (£/MWh)
Pellets	Central	116	47	51
	HL	120	60	N/A
	LH	112	33	N/A
Logs	Central	79	10	13
	HL	81	21	N/A
	LH	77	CE	N/A

N/A = not assessed CE = Cost effective

Table 17 Cost of heat production from biomass pellets and the level of support needed to make this economically attractive for replacing oil and gas domestic boilers (6% interest rate)

Biomass	Scenario	Cost of biomass heat (£/MWh)	Addition cost of heat relative to oil (£/MWh)	Additional cost of heat relative to gas (£/MWh)
Pellets	Central	65	20	21
	HL	69	36	N/A
	LH	60	3.2	N/A

N/A = not assessed CE = Cost effective

The sensitivity of the results to variations in biomass and oil prices has been investigated by assessing two other fuel price scenarios[42]:

a. High limit to biomass price range combined with DTI's low oil price scenario (HL Scenario).
b. Low limit to the biomass price range combined with DTI's high oil price scenario (LH Scenario).

These results are included in Tables 16 and 17 and show that with the exception of low cost logs, biomass is not cost competitive with oil under any of the scenarios investigated.

[42] Heating oil price assumptions are listed in Annex A, Table A2.

Small sized boilers for industrial and service sector heat supply (~0.25 MWth)

Supply costs have been estimated for replacing oil and gas fired heating with biomass in small industrial and commercial boilers. The calculations assumed that:

- Oil and gas fired boilers are replaced with ones fired on biomass chips or pellets when they require replacement (i.e. no early scraping and residual cost write-off of boilers was considered).
- Oil boilers in this size range are assumed to use burning oil.
- Burning oil and natural gas prices are taken from DTI's central fuel price scenario for the commercial/medium industry sector, as reported in the Updated Energy Projections published with the Energy Review[43] (see Annex A, Tables A2 and A3).
- Capital investment costs for installing replacement biomass, oil and gas boilers are listed in Annex C, Table C1.
- The sector was assumed to require an internal rate of return (IRR) of 25% or a 4-year simple payback on the additional capital expenditure involved with a biomass boiler system. Costs for both options have been examined and were found to be very similar.
- The costs of firing biomass boilers on chip and pellet fuels obtained from woodfuel and SRC willow have been assessed.

The results in Table 18, for central assumptions on biomass and oil fuel prices, show that when boilers are operated at high loads (80%) the substitution of oil with both chips and pellets from woodfuel is cost effective, as are chips from SRC. However, at the lower load (30%) none of the biomass fuels offer a cost effective substitute for oil.

The explanation for this trend is that biomass boilers have higher capital costs, particularly when balance of plant items such as storage and handling facilities are included. These higher capital costs are offset by lower fuel costs, and therefore the more the boiler is used the greater the fuel cost savings. Consequently the most cost effective applications for biomass heat are in establishments will high all year heat demands. However, the capital grants needed to make biomass heat commercially attractive in lower load applications are moderate (26-42%).

[43] The Energy Challenge, Energy Review Report, DTI, July 2006 (http://www.dti.gov.uk/energy/review/page31995.html)

Table 18 Cost of heat production from biomass and the level of support needed to make this commercially attractive for replacing oil boilers of about 0.25MWth capacity

Biomass Type	Total biomass cost (£/GJ)	Load (%)	Total cost of biomass heat £/MWh)	Increase in heat cost relative to oil (£/MWh)	Capital grant support needed (%)*
Woodfuel					
Chips	2.8	80%	26	CE	CE
Chips	2.8	30%	50	7	26%
Pellets	4.8	80%	31	CE	CE
Pellets	4.8	30%	49	6	28%
SRC					
Chips	3.8	80%	31	CE	CE
Chips	3.8	30%	54	10	35%
Pellets	5.8	80%	35	3	21%
Pellets	5.8	30%	53	9	32%

Notes
* for a 4 year payback; CE=Cost Effective

Corresponding results for the replacement of natural gas fired heating with biomass are given in Table 19. In this case chip from woodfuel would need a capital grant of 48% to be cost competitive for high load boilers, which increases to a grant of 66% for lower load operation. Pellets from woodfuel require a somewhat higher grant of about 80-100%, and pellets from SRC require grants exceeding 100% of capital. Wood pellets are more expensive than gas under these central assumptions, and therefore the required grant increases with boiler load.

The results in Tables 18 and 19 are based on central assumptions for the cost of biomass, oil and natural gas. The sensitivity of the results to variations in biomass and oil prices has been investigated by assessing two other fuel price scenarios[44]:

a. High limit to biomass price range combined with DTI's low oil price scenario (HL Scenario).
b. Low limit to the biomass price range combined with DTI's high oil price scenario (LH Scenario).

[44] Heating oil price assumptions are listed in Appendix A, Table A2.

Table 19 Cost of heat production from biomass and the level of support needed to make this commercially attractive for replacing gas fired boilers of about 0.25MWth capacity

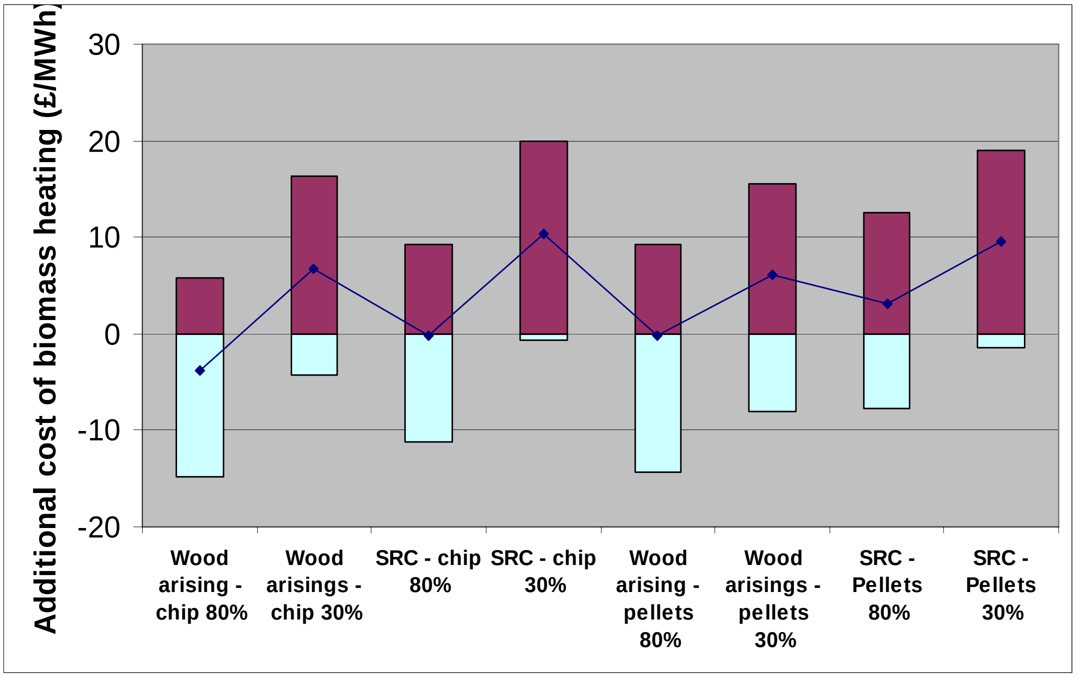
Biomass Type	Total biomass cost (£/GJ)	Load (%)	Total cost of biomass heat £/MWh)	Increase in heat cost relative to gas (£/MWh)	Capital grant support needed (%)*
Woodfuel					
Chips	2.8	80%	26	4	48%
Chips	2.8	30%	50	15	66%
Pellets	4.8	80%	31	8	103%
Pellets	4.8	30%	49	14	81%
SRC					
Chips	3.8	80%	11	8	82%
Chips	3.8	30%	54	18	79%
Pellets	5.8	80%	35	11	141%
Pellets	5.8	30%	53	17	95%

Notes
* for 4 year payback

The results in Figure 3 shown that high load biomass boilers fuelled with chip or pellets from woodfuel, and chip from SRC, may be cost effective without any support measures with the central and low biomass (LH) price scenarios. However, none of the biomass fuels are cost effective at the lower load factor, except with the high oil price (LH) scenario.

These results illustrate that the cost effectiveness of biomass heat is sensitive to the price relativity of biomass to competing fossil fuels, and to the operating pattern of the boiler.

Public sector offices and other facilities may often utilise heat boilers of the size considered in this section. Because the public sector may apply a lower discount rate compared to commercial organisations the cost of heat supply has also been estimated for a 6% IRR with 15 year payback. Comparison of the results given in Table 20 with those in Tables 18 and 19 shows that the lower discount rate reduces the additional cost of heat compared to oil and gas fired boilers, but does not make any additional options cost effective.



Notes
1. The high extreme of each bar indicates the additional cost of biomass heat with the HL scenario fuel prices and the low extreme the additional cost with LH scenario fuel prices.
2. Variable line links heat production costs with central fuel price assumptions.
3. Negative values indicate that biomass heating is cost effective

Figure 3 Variation in the additional heat production costs associated with biomass boilers compared to oil boilers with differing scenario assumptions on biomass and oil prices

Table 20 Cost of heat production from biomass and the level of support needed to make this commercially attractive for replacing oil and gas fired boilers of about 0.25MWth capacity (6% discount rate, central fuel price assumptions)

Biomass Type	Total biomass cost (£/GJ)	Load (%)	Total cost of biomass heat £/MWh)	Increase in heat cost relative to oil (£/MWh)	Increase in heat cost relative to gas (£/MWh
Woodfuel					
Pellets	4.8	80%	25	CE	5
Pellets	4.8	30%	33	3	8
SRC					
Pellets	5.8	80%	29	4	9
Pellets	5.8	30%	37	11	12

Medium sized boilers for industrial and service sector heat supply (~1MWth)

A similar analysis to the above has been undertaken for medium sized industrial and commercial boilers. The key assumptions made in this analysis were:

- Oil and gas fired boilers are replaced with ones fired on biomass chips or pellets when they require replacement (i.e. no early scraping and residual cost write-off of boilers was considered).
- Oil boilers in this size range are assumed to use gas oil.
- Gas oil and natural gas prices are taken from DTI's central fuel price scenario for commercial/medium industry, as reported in the Updated Energy Projections published with the Energy Review (see Annex A, Tables A2 and A3).
- Capital investment costs for installing replacement biomass, oil and gas boilers are listed in Annex C, Table C1.
- The sector was assumed to require an internal rate of return (IRR) of 25% or a 4-year simple payback on the additional capital expenditure involved with a biomass boiler system. Costs for both options have been examined and were found to be very similar.
- The costs of firing biomass boilers on woodfuel, SRC willow and wood pellets have been assessed.

The results in Table 21, for central assumptions for biomass and oil fuel prices, show that when boilers are operated at high loads (80%) the substitution of wood chips, derived from both woodfuel and SRC willow, for oil is cost effective. However, at lower loads (30%) neither source of wood chips is cost effective. Heating using wood pellets is estimated to be more expensive than oil at both loads, but the increased cost is relatively modest.

The explanation for these trends is that biomass boilers have higher capital costs, particularly when balance of plant items such as storage and handling facilities are included. These higher capital costs are offset by lower fuel costs, and therefore the more the boiler is used the greater the fuel cost savings. Consequently the most cost effective applications for biomass heat are in establishments will high all year heat demands. However, the capital grants needed to make biomass heat commercially attractive in lower load applications are quite modest.

Corresponding results for the replacement of natural gas fired heating with biomass are given in Table 22. In this case chip from woodfuel would need a capital grant of 35% to be cost competitive for high load boilers, which increases to a grant of 59% for lower load operation. Chip from SRC requires grants approaching 100%. Wood pellets are more expensive than gas under these central assumptions, and therefore the required grant increases with boiler load.

Table 21 Cost of heat production from biomass and the level of support needed to make this commercially attractive for replacing oil boilers of about 1MWth capacity

Biomass Type	Total biomass cost (£/GJ)	Load (%)	Total cost of biomass heat £/MWh)	Increase in heat cost relative to oil (£/MWh)	Capital grant support needed (%)*
Woodfuel					
Chips	2.8	80%	22	CE	CE
Chips	2.8	30%	38	2	35%
Pellets	4.8	80%	26	CE	CE
Pellets	4.8	30%	36	1	59%
SRC					
Chips	3.8	80%	26	CE	CE
Chips	3.8	30%	42	6	29%
Pellets	5.8	80%	30	1	80%
Pellets	5.8	30%	40	4	76%

<u>Notes</u>
* for 4 year payback
CE=Cost Effective

Table 22 Cost of heat production from biomass and the level of support needed to make this commercially attractive for replacing gas fired boilers of about 1MWth capacity

Biomass Type	Total biomass cost (£/GJ)	Load (%)	Total cost of biomass heat £/MWh)	Increase in heat cost relative to gas (£/MWh)	Capital grant support needed (%)*
Woodfuel					
Chips	2.8	80%	22	3	35%
Chips	2.8	30%	38	12	59%
Pellets	4.8	80%	26	6	136%
Pellets	4.8	30%	36	10	84%
SRC					
Chips	3.8	80%	26	6	80%
Chips	3.8	30%	42	15	29%
Pellets	5.8	80%	30	10	210%
Pellets	5.8	30%	40	14	112%

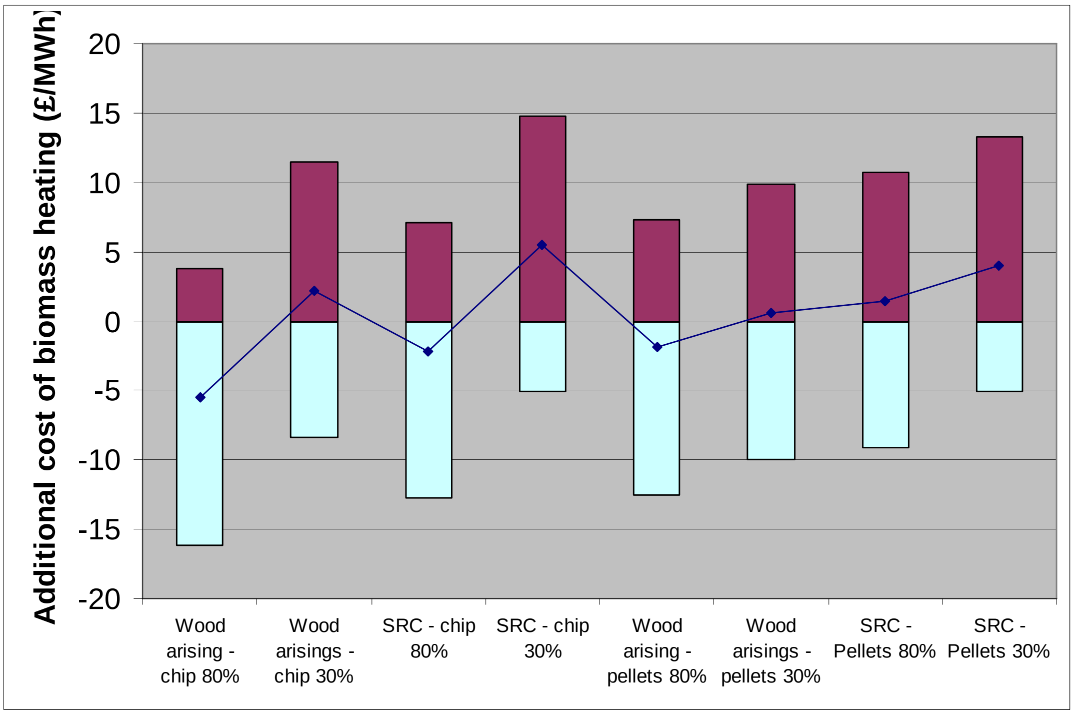
<u>Notes</u>
* for 4 year payback

The results in Tables 21 and 22 are based on central assumptions for the cost of biomass, oil and natural gas. The sensitivity of the results to variations in biomass and oil prices has been investigated by assessing two other fuel price scenarios[45]:

[45] Heating oil price assumptions are listed in Annex A, Table A2.

a. High limit to biomass price range combined with DTI's low oil price scenario (HL Scenario).
b. Low limit to the biomass price range combined with DTI's high oil price scenario (LH Scenario).

The results in Figure 4 shown that high load biomass boilers fuelled with wood chip may be cost effective without any support measures at the central and high (HL) oil prices used in the DTI's energy projections. Wood pellets are cost effective at low pellet prices combined with high oil prices (LH).



Notes
1. The high extreme of each bar indicates the additional cost of biomass heat with the HL scenario fuel prices and the low extreme the additional cost with LH scenario fuel prices.
2. Variable line links heat production costs with central fuel price assumptions.

Figure 4 Variation in the additional heat production costs associated with biomass boilers compared to oil boilers with differing scenario assumptions on biomass and oil prices

Large industrial boilers (20 MWth)

A similar analysis has been undertaken for large industrial boilers, except in this case only wood chip biomass has been examined. The focus on chip material is based on the assumption that large industrial facilities would have the space to store and handle this lower cost resource. Other key assumptions made in this analysis were:

- Oil and gas fired boilers are replaced with ones fired on biomass chips when they require replacement (i.e. no early scraping and residual cost write-off of boilers was considered).

- Fossil fuel boilers in this size range are assumed to use heavy fuel oil or natural gas.
- Heavy fuel oil and natural gas prices are taken from DTI's central fuel price scenario for large industry, as reported in the Updated Energy Projections published with the Energy Review (see Annex A, Tables A2 and A3).
- Capital investment costs for installing biomass, oil and gas boilers are listed in Annex C, Table C1.
- The sector was assumed to require an internal rate of return (IRR) of 25% or a 4-year simple payback on the additional capital expenditure involved with a biomass boiler system.
- The costs of firing biomass boilers on both woodfuel and SRC willow have been assessed.

The results in Table 23 show that when boilers are operated at high loads (80%) the cost differential between biomass and oil heating is quite small (£1-6/MWh), but this increases at lower loads (£9-12/MWh). The cost differential is greater between biomass and gas fired heating, £3-6/MWh at high load increasing to £11-14MWh at lower loads. While capital grants of 20-77% could bridge the economic gap between biomass chip from woodfuel and oil heating, grants of 49-100% of capital costs would be needed to bridge the economic gap between biomass and gas fired heating.

The sensitivity of the results to variations in biomass and heavy oil prices has been investigated by assessing two other fuel price scenarios[46]:

a. High limit to biomass price range combined with DTI's low oil price scenario (HL Scenario).
b. Low limit to the biomass price range combined with DTI's high oil price scenario (LH Scenario).

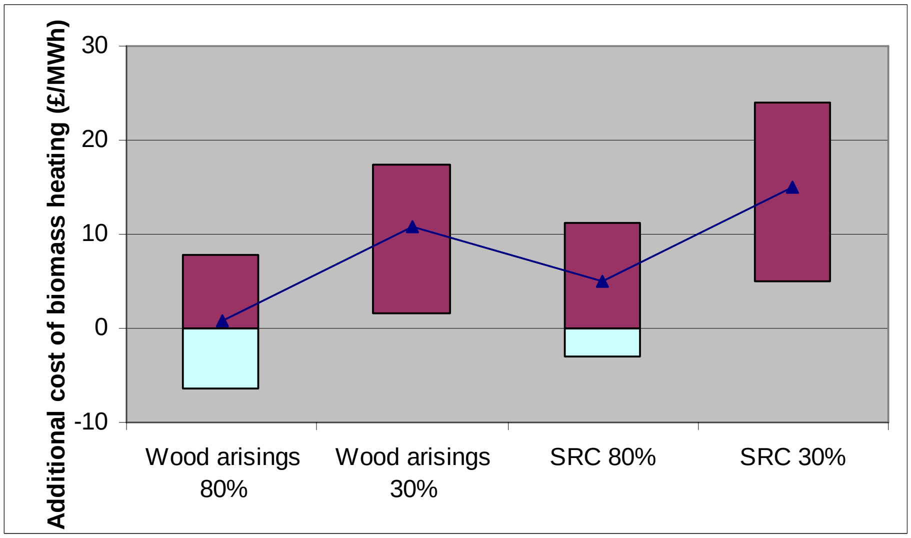
Table 23 Cost of heat production from biomass and the level of support needed to make this commercially attractive for replacing oil boilers of about 20MWth capacity

Biomass Type	Total biomass cost (£/GJ)	Load (%)	Total cost of heat biomass £/MWh)	Increase in heat cost relative to oil (£/MWh)	Capital grant support needed to replace oil(%)*	Increase in heat cost relative to gas (£/MWh)
Woodfuel	2.8	80%	20	1	20%	3
	2.8	30%	33	9	58%	11
SRC	3.8	80%	24	5	71%	6
	3.8	30%	37	12	77%	14

<u>Notes</u>
* for 4 year payback CE=Cost Effective

[46] Heating oil price assumptions are listed in Annex A, Table A2.

The results in Figure 5 shown that high load biomass boilers fuelled with woodfuel may be cost effective without any support measures with low biomass prices combined with high oil prices (LH), but will need some support at central and high biomass prices. The use of SRC is cost effective in high load boilers with the low biomass price assumption (LH), but both woodfuel and SRC are not fully cost effective in lower load boilers under any of the price assumptions.



Notes
1. The high extreme of each bar indicates the additional cost of biomass heat with the HL scenario fuel prices and the low extreme the additional cost with LH scenario fuel prices.
2. Variable line links heat production costs with central fuel price assumptions.

Figure 5 Variations in the additional heat production costs associated with biomass boilers compared to oil boilers with differing scenario assumptions on biomass and oil prices

Important observations coming from this part of the analysis are:

- Heat production offers some opportunities for utilising biomass as a cost effective substitute for fossil fuels. There are other situations where quite modest support could make utilisation commercially attractive.
- Generally the use of biomass in high utilisation boilers is significantly more cost effective than with boilers that are used seasonally.
- The use of biomass wood chip in small to medium sized commercial boilers, operating at high load, has the potential to be a cost effective replacement for oil fired heating with low to central biomass prices combined with high to central oil prices.
- The use of wood chip in large heat applications (20MWth) is less economically attractive because the biomass is replacing lower cost heavy fuel oil, and requires support of £1-5/MWh to break even.
- The use of biomass for heating in domestic dwellings is less cost effective than other heat applications, particularly if pelletised fuel is use.
- Pellet fuels are only cost competitive with oil in high load, small to medium boilers with the low pellet prices (~£90/t).
- Biomass heating did not offer a cost effective alternative to gas with any of the fuel price assumptions examined, but the level of support needed to bridge the price gap was relatively low for chip fuel at £3-8/MWh rising to £6-11/MWh for pellets (with high load small to medium sized boilers). Corresponding values for low load boilers were £10-17/MWh.
- Public sector interest rates on capital investments reduce the cost differential between commercial/services biomass and fossil heating, but even so support ranging from £5/MWh to £12/MWh would be required to close the cost gap between pellet fuels and gas.

8. Economic assessment of biomass combined heat and power (CHP) and district heating

The combined production of heat and electricity has the potential to utilise primary energy resources with greater overall efficiency. The most optimal situation for CHP deployment is where there is a significant heat demand that remains fairly steady over the year. As for heat only applications the preferred fuel for CHP, when available, tends to be natural gas. For locations off the gas grid oil, liquid petroleum gas or solid fuel are the main options.

This section examines the additional costs of substituting biomass fuelled CHP for oil and gas heat only boilers in two CHP applications defined by their heat load:

- Large scale industrial with a heat demand of 30MWth and an electricity output of 8MWe.
- Medium industrial/commercial with a heat demand of 1MWth and an electricity output of 0.3MWe.

This was considered to be the most meaningful comparison since it excludes the cost of establishing a heat distribution network which is generic to all CHP systems.

Another possible approach for utilising biomass is through district heating schemes. The advantage of such projects is that they utilise a central boiler, avoiding some of the high capital costs of small individual biomass boilers, for example in domestic dwellings. Also a central, purpose built, boiler house overcomes possible problems linked to the inconvenience of operating separate household biomass boilers, for example biomass storage, ash handling and disposal, which may deter some potential users. The disadvantage of district heating is that it involves additional capital investment in a system to distribute the heat to individual consumers. This option has been examined for the case of a system supplying to 50-150 dwellings each demanding about 18,000kWth of heat per year.

Large Scale CHP (30MWth and 8MWe)

This option has examined the additional cost of replacing/selecting a CHP system fuelled with biomass in preference to oil or gas fired heat only boilers. The assessment has assumed:

- Oil or gas fired heat only boilers are replaced with a biomass fuelled CHP unit when they require replacement (i.e. no early scraping and residual cost write-off was considered).
- Oil boilers in this size range are assumed to use heavy fuel oil.
- Biomass systems in this size range are assumed to meet Waste Incineration Directive (WID) emission standards.
- Heavy fuel oil and natural gas prices are taken from DTI's price scenarios, as reported in the Updated Energy Projections published with the Energy Review (see Annex A, Tables A2 and A3).

- Capital investment costs and other performance values for biomass CHP facilities are listed in Annex D, Table D1.
- The sector was assumed to require an internal rate of return (IRR) of 25% or a 4-year simple payback on the additional capital expenditure involved with a biomass boiler system.
- To assess the economics of biomass CHP its costs were compared to the costs of supplying the same quantities of heat from an oil or gas boiler and electricity from a centralised supply at current prices to large industrial customers (taken to be £45/MWh).

Results for central price assumptions for both biomass and fossil fuels are listed in Table 24, which lists the additional cost of CHP over and above oil and gas CHP. The results indicate the increase in heat or electricity costs should all the additional cost be applied to one or the other.

Table 24 Additional cost of substituting biomass CHP for oil and gas fired CHP of about 30MWth capacity

Biomass Type	Fossil fuel displaced	Total biomass cost (£/GJ)	Load (%)	Additional cost when placed on electricity (£/MWhe)	Additional cost when placed on heat (£/MWhth)
Waste wood - contaminated	Oil	1.3	80%	11	3
	Gas	1.3	80%	19	5
Woodfuel	Oil	2.8	80%	44	11
	Gas	2.8	80%	53	13
SRC	Oil	3.8	80%	67	17
	Gas	3.8	80%	75	19

Comparison of the results in Table 24 with the results in Section 7 (Table 23) shows that the substitution of large scale biomass CHP for heat only oil and gas boilers is a more expensive option than simply switching from fossil to biomass heat only boilers. The cost difference would be even greater at lower loads (30%). This is because the CHP installation has substantially higher capital costs that need to be spread over the maximum amount of production. Additionally the biomass is replacing relatively low cost fossil fuel options, because large industrial organisations buy fossil fuels and electricity at low costs compared to smaller consumers.

Because the CHP boilers are assumed to be WID compliant they are able to burn low cost contaminated wood. However, even with this low cost (£1/GJ) resource, CHP is not as cost competitive as the heat only biomass options. However, the additional cost of electricity generated with contaminated wood is significantly less than the Renewables Obligation Certificate (ROC) buyout price.

Medium scale CHP (1MWth and 0.3MWe)

This option has examined the cost of replacing oil and gas fired heat only boilers with a CHP system fuelled with biomass. The assessment used the same assumptions as for large CHP. Additionally:

- Oil boilers in this size range are assumed to use gas oil.
- Gas oil and natural gas prices are taken from DTI's price scenarios, as reported in the Updated Energy Projections published with the Energy Review (see Annex A, Tables A2 and A3).
- Capital investment costs and other performance values for biomass CHP facilities are listed in Annex D, Table D1.
- To assess the economics of biomass CHP its costs were compared to the costs of supplying the same quantities of heat from an oil or gas boiler and electricity from centralised supplies at current prices to medium commercial and industrial customers (taken to be £55/MWh).

Results for central price assumptions for both biomass and fossil fuels are listed in Table 25 in terms of the additional cost of CHP over and above oil and gas heating. The results indicate the increase in heat or electricity costs assuming all the additional cost is applied to one or the other.

Table 25 Additional cost of substituting biomass CHP for oil and gas fired boilers of about 10-30MWth capacity

Biomass Type	Fossil fuel displaced	Total biomass cost (£/GJ)	Load (%)	Additional cost when placed on electricity (£/MWhe)	Additional cost when placed on heat (£/MWhth)
Woodfuel	Oil	2.8	80%	38	9
SRC	Oil	3.8	80%	91	23
Woodfuel	Gas	2.8	80%	140	35
SRC	Gas	3.8	80%	193	48

Comparison of the results in Table 25 with the results in Section 7 (Table 20) shows that the substitution of medium scale biomass CHP for heat only oil and gas boilers is more expensive than simply switching from fossil to biomass heat only boilers at high heat loads.

District heating

This option has examined the cost of replacing domestic oil fired heat only boilers with new boilers using the same fuel or with (a) a heat only district heating system fuelled with bio-mass or (b) a CHP district heating system fuelled with biomass. The assessment has assumed:

- A grouping of 100-150 domestic dwellings replace their oil fired heat only boilers and are coupled to a district heating network (note the oil boilers were assumed to require replacement and had no residual value).
- Oil boilers in this size range are assumed to use burning oil.

- Burning oil prices are taken from DTI's price scenarios, as reported in the Updated Energy Projections published with the Energy Review (see Annex A, Table A2).
- Capital investment costs and other performance values for biomass district heating/CHP facilities are listed in Annex D, Table D1. These costs included installation of the heat network as well as the central facility.
- The sector was assumed to require an IRR of 6% on capital expenditure of this nature, on the premise that such projects were most likely to be implementation by local authority or other public sector organisations.
- The costs of firing biomass boilers/CHP on both woodfuel and SRC willow have been assessed.
- To assess the economics of biomass district heating its costs were compared to the costs of replacing the old oil boilers with new versions.
- To assess the economics of CHP its costs were compared to the costs of replacing the old boilers with new oil fired versions, and crediting the electricity at £80/MWh.

Results for biomass heat compared to oil are listed in Table 26 and the corresponding results for biomass CHP compared to oil heating in Table 27. The results indicate the additional cost of heat from a district heating system compared to modern oil fired domestic boilers.

Table 26 Additional cost of substituting biomass district heating for individual oil fired domestic boilers

Biomass Type	Fossil fuel displaced	Total biomass cost (£/GJ)	Additional cost of heat (£/MWhth)
Woodfuel	Oil	2.3	20
		2.8	34
		3.3	46
SRC	Oil	3.3	24
		3.8	38
		4.3	50

Table 27 Additional cost of substituting biomass CHP for individual domestic oil fired boilers

Biomass Type	Fossil fuel displaced	Total biomass cost (£/GJ)	Additional cost when placed on electricity (£/MWhe)	Additional cost when placed on heat (£/MWhth)
Woodfuel	Oil	2.3	24	6
		2.8	84	21
		3.3	135	34
SRC	Oil	3.3	47	12
		3.8	106	27
		4.3	158	40

The results show district heat and CHP to be an expensive option for utilising biomass, even when a low capital charge of a 6% interst rate is applied.

Important observations coming from this part of the analysis are:

- The replacement of fossil fuel CHP with biomass CHP is not cost effective, even with low cost contaminated waste wood.
- The higher capital cost of CHP equipment makes this option less economically attractive than heat only biomass options when considered in terms of heat supply costs, and crediting the electricity with market prices.
- District heating with or without co-generation also appears to be an expensive option for using biomass fuel.

9. Liquid biofuels for transport

So far this report has focused on the use of biomass in thermal energy processes to produce heat or power or a combination of both. However, some biomass materials may be processed into liquid fuels for road vehicles. The leading options are:

- Bio-diesel that can be blended with diesel derived from mineral oil.
- Bio-ethanol that can be blended with petrol.

This section considers the cost effectiveness of using UK biomass resources to produce bio-diesel or bio-ethanol to displace fossil fuels from road transport for comparison to heat and/or power applications.

Other possibilities are bio-methanol, hydrogen and bio-oils, but the processes to produce these are further from commercialisation and therefore are not considered herein. Bio-gas arising from anaerobic digestion of biomass materials and certain organic wastes could be used for transport, but for this assessment has been considered as a source of fuel for stationary applications (see Section 11, Anaerobic Digestion).

In the UK the established commercial processes for bio-diesel production utilise waste cooking oil, imported oils (e.g. palm oil) or oilseed rape as feedstock. Waste cooking oil, although economically competitive with rape seed, has limited supplies making rape seed the main option, at least in the short to medium term, for expanding indigenous production. In the longer term bio-diesel could also be produced by gasification of solid materials such as wood or straw, with subsequent conversion of the syngas through the Fischer-Tropsch process. However, this approach is further from market with uncertain costs at this stage.

Bio-ethanol can be produced through the fermentation of crops such as sugar cane, sugar beet or wheat. Sugar cane fermentation is well established in Brazil where bio-ethanol can be produced at prices approaching the cost of petrol, however, for the UK sugar beet or wheat are the main potential feedstocks. It is also technically feasible to produce bio-ethanol through the fermentation of waste organic materials including straw, wood and municipal solid waste. However, as for longer term options for bio-diesel production, these second generation processes are less well established and their costs more uncertain.

Table 28 lists estimated UK production costs for bio-diesel and bio-ethanol in 2010 and 2020[47]. The costs cover fairly broad ranges that reflect the influence of key variables, including:

- Production cost/market price for feedstock (i.e. waste cooking oil, oil seed rape, wheat and sugar beet).

[47] Partial Regulatory Impact Assessment (RIA) on biofuels, Department for Transport, December 2005
(http://www.dft.gov.uk/pgr/roads/environment/rtfo/secrtfoprogdocs/partialregulatoryimpactasses3848?page=5#1016)

- Balance between supply and demand.
- Transport and collection costs.
- Revenues from co-product (e.g. rape meal, glycerine, animal feed).
- Cost of the processing plant and input energy.
- Blending and distribution costs.

Of these variables production costs, the supply/demand balance and the value of co-products are the most uncertain. Production costs are dependent on yield as well as the fixed and variable costs of production that can vary significantly between farms. Furthermore, the market price may be driven up or down depending on the value of alternative markets either for the same crop or other crops that could be grown on the same land.

In general terms the low values reflect low production costs, high yields and high values for co-product, whereas the high costs reflect high production costs, low yields and low values for co-product. Furthermore the costs may under-estimate fully commercial costs because relatively low rates of return were used in the analyses (i.e. 3.5%).

Table 28 Fuel cost assumptions in 2010 and 2020 (excluding duty, 2005 prices)

Scenario	Cost of diesel (p/l)	Cost of biodiesel (p/l)	Additional Cost of biodiesel relative to diesel (£/MWh)	Cost of petrol (p/l)	Cost of Bioethanol (p/l	Additional cost of bioethanol relative to petrol (£/MWh)
'Low' cost Scenario						
2010	31	37	9.3	27	26	14.7
2020	31	18	-11.5	27	22	7.9
'Central' cost scenario						
2010	22	43	25	19	31	31.8
2020	22	29	9.6	19	25	21.7
'High' cost scenario						
2010	11	53	47.1	9	47	70
2020	13	43	34.1	11	32	42.3

Source: Partial Regulatory Impact Assessment (RIA) on biofuels, Department for Transport, December 2005. The 'low' cost scenario is based on 2005 petrol and diesel prices and low biofuels prices. The 'central' cost scenario assumes oil prices of around $40/barrel and higher biofuel prices. The 'high' cost scenario assumes oil prices of around $20/barrel and high prices for biofuels.

The additional costs in Table 28 are presented in units of £/MWh. This increases the costs of the biofuels relative to fossil fuels because these, and particularly ethanol, have lower energy contents per litre than their fossil fuel equivalents. The table shows that, for the central values, the difference between the 2010 costs for biomass and fossil fuel costs per MWh (i.e. the economic gap) are generally higher than for the options for heat supply in commercial applications examined previously (Section 7). In contrast the economic gap for second generation (2020) biofuels is significantly lower, and bio-diesel in particular could be competitive with biomass heat applications by 2020.

It is also noteworthy that there is the potential for lower cost imported sources for both bio-ethanol and bio-diesel.

Important observations coming from this part of the analysis are:

- Liquid biofuels produced from UK energy crops using current technology have higher additional cost compared to their fossil fuel equivalents than heat or electricity generation from biomass.
- Second generation liquid biofuel technologies have the potential to deliver substantial cost reductions that could make liquid biofuels competitive with biomass heat applications.
- There are lower cost imported sources for both bio-ethanol and bio-diesel.

10. Waste to energy

At present the UK produces about 35 million tonnes of municipal solid waste (MSW) and 80 million tonnes of commercial and industrial (C&I) waste per year[48]. Each of these waste streams contains a significant proportion of biodegradable material, 65% of MSW and 47% of C&I, which represents an additional biomass resource that could be used for a range of purposes including energy production. The biodegradable components of MSW and C&I amounts to about 29TWh/yr and 37TWh/yr respectively, and with about two thirds of this currently going to landfill, it represents a potential energy source comparable in magnitude to the other biomass resources (Table 3). Agricultural wastes such as animal manures and slurries as well as sewage sludge offer additional energy resources.

A range of policies and measures have been established to manage waste issues and the UK Government will shortly be issuing a revised waste strategy for England. Generally these policies are directed at reducing waste production and increasing recovery and recycling. Measures to improve the sustainable management of waste include the Landfill Tax, aimed at encouraging reductions in the amount of waste going to landfill, and Packaging Regulations that set targets on obligated businesses for recovery and recycling of packaging materials. Also the Waste and Emissions Trading Act 2003 places an obligation on local authorities (LAs) to reduce the amount of biodegradable municipal waste going to landfill to 75% of that produced in 1995 by 2010, 50% by 2013 and 35% by 2020. LAs exceeding their targets face a penalty of £150/t of additional biodegradable waste committed to landfill, although this could be reduced by allowance trading between LAs in the Landfill Allowance Trading Scheme (LATS).

Energy can be generated from waste by a range of options based on combustion, pyrolysis, gasification and anaerobic digestion, to deliver heat, electricity, combined heat and power or possibly gas or liquid fuels (Anaerobic digestion is considered in Section 11). Energy from waste plant need to meet the emission standards set by the Waste Incineration Directive, and need to be built of materials that can tolerate corrosive combustion gases, and consequently have relatively high capital costs. However, waste attracts a gate fee to take waste, which as a minimum will be the gate fee charged by landfill sites plus the landfill tax, and could well rise above this minimum as LA's seek to avoid paying penalties under the Waste and Emissions Trading Act. As a consequence the revenue stream to an energy from waste plant differs fundamentally from that of other non-waste biomass energy facilities. This is illustrated by data from a study of waste to electricity undertaken for DTI[49]. Revenue streams in 2010 were estimated to consist of:

Avoided landfill cost	£15/t
Avoided Landfill Tax	£35/t
Avoided LATS	£150/t (max.)
Revenue from electricity	£8/t (equivalent to £35/MWh)

[48] Impact of energy from waste and recycling policy on UK greenhouse gas emissions, ERM report to DEFRA, January 2006.
[49] Eligibility of energy from waste – study and analysis, ILEX report to DTI, March 2005.

The revenue from energy sales is a small fraction of total revenue. Indeed the study found that extending eligibility for Renewable Obligation Certificates (R)OCs) to standard electricity from waste technologies (at present only advanced conversion technologies are eligible) would only increase deployment by about 12% in 2015 from about 24 to 27Mt/yr.

These results show that energy from waste is driven primarily by waste policy rather than energy policy, and that from an energy perspective much of this waste resource could be exploited cost effectively without incentives for the power and/or heat produced. However, a purely waste driven market may not encourage the most effective use of waste for energy production and carbon abatement. For example, from a waste perspective it may be most cost effective to use low efficiency energy conversion processes, while from an energy perspective more efficient advanced conversion processes can deliver more energy and carbon abatement. It is important to note that recycling waste materials can also deliver significant carbon and energy savings.

A full analysis of the relative cost effectiveness of alternative waste to energy schemes goes beyond the scope of this broad assessment of biomass options. However, it is clear that the utilisation of biodegradable wastes as an energy resource represents one of the most cost effective biomass energy options that could deliver electricity or heat at costs that are competitive with fossil fuels.

Important observations coming from this part of the analysis are:

- Biodegradable wastes represent a significant, and nominally carbon neutral, energy resource.
- Policy measures to encourage waste recovery and reduce landfill should make it cost effective to utilise waste for energy without direct support for the energy supplied.
- However, some support may be justified to encourage the most efficient use of the waste for energy production and carbon abatement.

11. Anaerobic Digestion

Anaerobic digestion (AD) involves the conversion of organic matter to energy through the action of micro-organisms. The process can be applied, with suitable preparation, to most biodegradable materials including certain organic elements of municipal and C&I waste, agricultural manures and slurries and crops grown for energy purposes such as grain or grasses. The primary products from AD are biogas consisting of methane (~65%) and carbon dioxide (~35%) and solid or liquid residues that have value as fertiliser, or in the case of the solids, as an additional energy resource. The biogas can be used to produce useful energy in the form of heat or electricity, or it could be blended with propane to substitute for natural gas. For example in Sweden, biogas blended with propane is compressed and used to fuel a regional bus fleet. AD is considered particularly suited for the conversion of wet materials such as farm, food industry and catering wastes.

AD can be deployed at size ranges from a few hundred kWs to several MWs, depending upon the availability of biomass material and, in the case of heat, a suitable year round demand. For example individual farms could have small facilities, utilising their manures and slurries, while larger projects could draw material on a regional basis both from farms and other waste sources such as food processing. This analysis has considered four illustrative potential applications:

- Small scale (200-300kWe) AD/CHP based on a farm and utilising farm waste that otherwise would be spread to land (ie. the feed has some value and therefore the project would not collect a waste gate fee).
- Small scale AD/Power generation only utilising farm waste that otherwise would be spread to land (ie. the feed has some value and therefore the project would not collect a waste gate fee).
- Medium scale (1.0-1.5MWe) AD/CHP utilising food waste that otherwise would go to landfill (ie. will be credited with a gate fee)
- Medium scale AD/CHP utilising mixed waste that otherwise would be spread to land (ie. the feed has some value and therefore the project would not collect a waste gate fee).

The assessment used the following assumptions:

- Only oil boiler replacement was considered for farm based schemes but both oil and gas boiler replacement was assessed for the medium scale option.
- Oil and gas heat only boilers are replaced with an AD/CHP system when they require replacement (ie. no early scraping and residual cost write-off was considered).
- Oil boilers in this size range were assumed to use gas oil.

- Capital investment costs and other performance values for biomass AD facilities are listed in Annex D, Table 1.
- Capital investment requires an internal rate of return of 15% and is amortised over 15 years.
- Gas oil and natural gas prices are taken from DTI's price scenarios, as reported in the Updated Energy Projections published with the Energy Review (see Annex A, Tables A2 and A3).
- Waste is assumed to be delivered to the plant free of transport costs.
- In those cases involving a gate fee for the waste this was assumed to be £30/t of solid (NB Some materials have some value being spread to land and therefore do not command a gate fee.).
- To assess the economics of AD CHP its costs were compared to the costs of supplying the same quantities of heat from an oil or gas boiler. It was assumed that part of the electricity would be used on site and the remainder exported to the grid. The average electricity value for this arrangement was taken to be £45/MWh.
- It was assumed that 100% of the heat would be utilised to make the analysis consistent with the other CHP assessments in Section 8, although this may not always be possible, particularly for farm based schemes.

In addition to heat and power production AD produces other benefits including co-product that has value as a fertiliser. Also AD reduces the methane emissions produced by storing and spreading farm slurries and manures to land, which is a significant source of greenhouse gas emissions since methane has about 21 times the greenhouse forcing factor of CO2. These benefits have not been included in this assessment.

Results for these AD options are presented in Table 29 and show medium AD CHP (no gate fee) to be cheaper than CHP fuelled with woodfuel (compare to results in Table 25). AD CHP is a cost effective heat and power supply option with a gate fee of £30/t of dry matter, which is consistent with the general conclusion on waste to energy discussed in Section 10.

Table 29 Additional cost of substituting biomass AD CHP for oil and gas fired boilers of about 1 MWth capacity

Technology	Gate Fee (£/t)	Fossil fuel displaced	Load (%)	Additional cost when placed on electricity (£/MWhe)	Additional cost when placed on heat (£/MWhth)
Small AD CHP	None	Oil	85%	71	53
Small AD power	None	Oil	85%	47	-
Medium AD CHP	None	Oil	85%	25	22
Medium AD CHP	30	Oil	85%	CE	CE
Medium AD CHP	None	Gas	85%	31	35
Medium AD CHP	30	Gas	85%	CE	CE

Small scale AD appears less cost effective although this assessment does not include the additional benefits linked to abatement of methane and the fertiliser value of co-product.

Important observations coming from this part of the analysis are:

- Anaerobic digestion offers a flexible method for converting a broad range of biomass resources into biogas that can be used to produce heat, electricity or transport fuels.
- AD has particular advantages for processing wet biomass materials such as biodegradable municipal and commercial wastes and agricultural manures and slurries, for which its conversion efficiency is significantly better than for combustion processes.
- The economics of AD, like other waste to energy processes, depend on the gate fee received for taking the waste. With a realistic gate fee AD can be close to cost effective.
- Medium sized AD CHP (~ 1MWe) using material that would not command a waste gate fee is potentially cost competitive with CHP fired on woodfuel.

12. Conclusion

Sections 5 to 11 have examined on the additional cost of producing electricity, heat, combined heat and power or liquid transport fuels from biomass rather than fossil fuels. These results give an indication of the level of support needed to encourage the commercial use of biomass in each of these supply operations.

However, the motivation for switching to biomass fuel is primarily to reduce carbon dioxide emissions. Therefore a key measure of the cost effectiveness of the various options for using biomass to abate carbon dioxide emissions is the abatement cost in £/tCO2. The method used for calculating this parameter in this study is based on the relationship

$$\text{Abatement Cost (£/tCO2)} = \frac{\text{NPV of the cost difference between biomass and fossil energy (£/MWh)}^{50}}{\text{Total CO2 emission avoided (tCO2/MWh)}^{51}}$$

The CO2 emissions considered in the above calculation are those emitted at the point of combustion. Emissions associated with up stream aspects of the fuel supply chains, for example energy use in coal extraction, preparation and transportation or energy used for planting, harvesting, preparation and transportation of energy crops, have not been considered in this analysis. In most cases this will be only a small fraction[52] of the CO2 produced in fossil fuel combustion, and omitting these emissions for both the biomass and fossil fuels supply goes some way to cancelling out these omissions.

Another important assumption in making these estimates is the nature of the fossil fuel being replaced. For example the level of CO2 abatement would be almost double, and thus the abatement cost roughly halved, if coal was assumed to be replaced rather than natural gas. For the power generation applications examined in this study it has been assumed that the biomass would displace gas fired generation. This is based on the DTI's energy projections that show gas fired generation being the main source of new generation up to 2020[53]. It is also consistent with the approach used in the Energy review, which also used gas fired generation as the comparator for power generation options. For heat and CHP applications the displacement of both oil and gas fired alternatives have

[50] NPV is the Net Present Value, calculated using a discount rate of 3.5%, of the difference in cost of producing 1 MWh/yr of final energy (e.g. heat, electricity) from biomass and fossil fuel over the lifetime of the project.
[51] Total CO2 avoided refers to the emissions avoided by producing 1 MWh/yr of final energy from biomass instead of fossil fuel. Note the CO2 emissions avoided are not discounted (i.e. CO2 avoided in year 15 has the same benefit as CO2 avoided in year 1)
[52] Carbon – energy balances for a range of biofuels, Sheffield Hallam University report to DTI, URN 08/836, 2003 (http://www.dti.gov.uk/files/file14925.pdf)
[53] UK energy and CO2 projections, DTI Report URN 06/1611, 2006 (http://www.dti.gov.uk/files/file31861.pdf)

been considered, because there may be sufficient biomass resource to extend to both markets.

Abatement costs calculated by this method, not including existing support measures (eg. Renewables Obligation, Climate Change Levy exemption), are listed in increasing order in Table 30 for all the biomass applications considered in this assessment. In broad terms the results show that the order of cost effectiveness is:

- Energy from waste[54], that would command a gate fee for alternative disposal, to produce:
    - Heat or CHP
    - Electricity
- Energy from non-waste biomass to :
    - Replacement of oil for commercial/industrial heat and CHP in high load applications.
    - Replacement of oil for commercial/industrial heat in seasonal load applications.
    - Medium scale anaerobic digestion of agricultural arisings for power generation or CHP replacing oil heating.
    - Replacement of gas for commercial/industrial heat in high load applications.
    - Co-firing on new coal fired power generation with CCS.
    - Replacement of gas for commercial/industrial heat in seasonal load applications.
    - Small scale anaerobic digestion of agricultural arisings for power or CHP replacing oil heat.
    - High load district heating replacing oil.
    - Co-firing on existing and new coal fired power generation plant.
    - Replacement of individual domestic oil boilers with biomass.
    - Electricity generation from power stations fired exclusively on biomass.
    - Replacement of individual domestic gas boilers with biomass.
    - First generation transport biofuels

It must be stressed that this is a broad classification based on indicative data. Undoubtedly there will be specific cases that go against this overall pattern, for example district heating is highly site specific and costs can vary considerably. Also Table 30 shows the results are sensitive to both future biomass and fossil fuel prices. Another factor is the nature and level of processing applied to the biomass. Thus pellet fuels, that are probably the only option for replacing gas in many circumstances where boiler house space is limited, are significantly more expensive than wood chip, but the capital cost of pellet boilers (including storage and handling facilities) is less. Consequently pellet systems can be more cost

[54] Includes both standard combustion and advanced conversion technologies.

effective than chip in some applications (e.g. small commercial boilers at low utilisation).

Biomass fuelled medium to large CHP appears less cost effective in terms of abatement cost when compared to the corresponding heat only biomass applications. But the difference is less than when the comparison is made in terms of heat costs. This is because the higher overall energy efficiency of CHP delivers more CO2 abatement. [NB CHP was credited with avoiding the CO2 emissions from gas fired power generation in addition to the avoided emissions from fossil heat supply.]

With regard to power generation, all options appear less competitive than the majority of heat options. Dedicated generation is less cost effective than co-firing for CO2 abatement. The difference in abatement costs between co-firing on existing and new coal power stations is small. As discussed previously abatement costs for biomass power generation options have been calculated assuming they displace gas fired generation. Abatement costs are significantly lower if it is assumed that coal is the displaced fossil fuel (eg. to £50-70/tCO2 compared to £98-128/tCO2 for central fuel price assumptions), but even at these costs biomass co-firing is less cost effective than many of the heat options.

Energy from waste stands out as the most cost effective biomass option provided it is credited with a gate fee that reflects savings in landfill charges, the landfill tax avoided and, where applicable the LATS[55] avoided. Gate fee revenue dominates over the revenue derived from the energy supply which suggests that these options are more a matter for waste policy. However, there is a case to incentivise the particular options that utilize the waste most effectively to maximise both the energy extracted and carbon abated.

With regard to non-waste biomass, the most cost effective options for utilization arise from small to medium commercial/industrial boilers operating throughout the year (80% load). Biomass in the form of wood chips is more cost effective than pellet fuel at all boiler sizes operating at high load, but for season applications the difference is smaller. This is because the higher cost of pellet fuels is partially offset by the lower cost of fuel storage and handling facilities needed with pellets. Pellet heating is a particularly expensive option for domestic applications, while large industrial boilers have intermediate abatement costs.

For comparison purposes Table 30 includes the cost of abatement from renewable electricity supplies priced at both the buyout price (£33/MWh) and current trading price (£45/MWh) of Renewables Order Certificates (ROCs). In line with the other abatement costs these have been estimated assuming the electricity displaces gas fired generation, and the results show that this abatement is less cost effective than the majority of the heat options. A further comparison is given in Table 30 with the cost of abatement from substituting

[55] Landfill Allowance Trading Scheme (LATS)

Table 30 Illustrative comparison of the CO2 abatement costs for various biomass energy applications

Application	Biomass type	Load (%)	Fossil fuel displaced	CO2 abatement cost (£/tCO2)			Carbon Abatement Potential (tCO2)
				Low/High	Central	High/Low	Heat Applications
CHP or heat from waste	Biodegradable wastes	85%	Oil or gas	CE	CE	CE	-
Power generation from waste	Biodegradable wastes	85%	Oil or gas	CE	CE	CE	-
Medium industrial/commercial boilers	Chip	80%	Oil	-54	-5	28	0.20
Small commercial boilers	Chip	80%	Oil	-50	1	36	0.13
Medium industrial/commercial boilers	Pellet	80%	Oil	-53	8	51	1.33
Small commercial boilers	Pellet	80%	Oil	-38	12	46	0.88
Large industrial boilers	Chip	80%	Oil	-22	16	40	0.47
Medium industrial/commercial boilers	Pellet	30%	Oil	-43	18	61	1.03
Medium industrial/commercial boilers	Chip	30%	Oil	-30	19	53	0.15
Medium CHP	Chip	80%	Oil	-23	19	46	?
Medium AD CHP	Farm/food wastes	85%	Oil	N/A	22	N/A	?
Medium industrial/commercial boilers	Chip	80%	Gas	6	27	45	0
Small commercial boilers	Pellet	30%	Oil	-18	32	67	0.62
Small commercial boilers	Chip	80%	Gas	12	36	53	0
Small commercial boilers	Chip	30%	Oil	-16	35	70	0.13
Medium CHP	Chip	80%	Gas	31	38	67	?
Medium AD CHP	Farm/food wastes	85%	Gas	N/A	38	N/A	?
Large CHP	Chip	80%	Oil	3	39	58	?
Large industrial boiler	Chip	80%	Gas	6	39	47	0
Large industrial boilers	Chip	30%	Oil	3	41	65	0.2
10% co-firing with SRC on new coal plant with CCS	-	90%	Gas		41		
Large CHP	Chip	80%	Gas	22	44	51	?
Small commercial boilers	Pellet	80%	Gas	27	50	65	0.3
District heat/CHP	Chip	80%	Oil	12	52	78	?

Table 30 Illustrative comparison of the CO2 abatement costs for various biomass energy applications (cont.)

Application	Biomass type	Load (%)	Fossil fuel displaced	CO2 abatement cost (£/tCO2)			Carbon Abatement Potential (tCO2)
				Low/High	Central	High/Low	Heat Applications
Medium industrial/commercial boilers	Pellet	80%	Gas	27	54	74	0.3
Medium industrial/commercial boilers	Chip	30%	Gas	47	69	86	0
Small AD CHP	Farm waste	85%	Oil	N/A	71	N/A	?
District heat	Chip	80%	Oil	20	73	99	?
Medium industrial/commercial boilers	Pellet	30%	Gas	48	75	95	0.23
Large industrial boiler	Chip	30%	Gas	43	76	84	0
Small commercial boilers	Pellet	30%	Gas	56	78	94	0.42
Small commercial boilers	Chip	30%	Gas	60	84	93	0
Small AD power	Farm waste	85%	Gas	N/A	88	N/A	?
5% co-firing with woodfuel on existing coal power plant	-	60%	Gas	59	98	142	-
ROC Buyout price (£33/MWh)					103		-
10% co-firing with miscanthus on existing coal power plant	-	60%	Gas	72	111	155	-
10% co-firing with miscanthus on new coal power plant	-	60%	Gas	78	112	152	-
10% co-firing with SRC on new coal plant	-	60%	Gas	89	124	163	-
10% co-firing with SRC on existing coal plant	-	60%	Gas	88	128	172	-
Domestic heat	Pellets	-	Oil	86	127	165	2.1
Biodiesel			Diesel	58	137	310	-
ROC Trading price (£45/MWh)					141		-
Bioethanol from wheat			Petrol	70	152	333	-
Dedicated power generation using woodfuel		80%		155	200	249	-
Domestic heat	Pellets	-	Gas	180	205	225	3.3

Notes: Central abatement cost are based on central SRC fuel prices as given in Table 9, N/A = not assessed, ? = resource not quantified diesel and petrol with liquid biofuels using current technology. These estimates are based on the 2010 data presented in Section 9 and show biofuels produced from UK feedstocks to be an expensive abatement option in the near term[56]. Abatement costs for second generation bio-fuels could be substantially lower, of the order of £30-50/tCO2, but have not been included in the table which is aimed at comparing current options[57].

While the results in Table 30 illustrate the potential cost effectiveness of biomass heat as an option for reducing CO2 emissions from fossil fuels they give no indication of the total level of abatement that could be attained. This depends on the size of the fossil fuel heat market that could be replaced by each of the options listed in Table 30. Data to make such an assessment are sparse at present, but a crude indicative estimate has been developed utilising the sectoral heat demands discussed in Section 2, combined with the assumptions listed below. It must be stressed that these assumptions are purely arbitrary, and are used for illustrative purposes and are not based on any data on boiler stocks.

- All heat demands from commercial, public services and industrial sectors, currently met by oil or solid fuel, can potentially be met with biomass.
- Only 15% of the commercial, public services and industrial heat markets have the space to accommodate wood chip boilers, the remainder would need to use pellet fuel systems.
- In the commercial and public services sectors 50% of applications use small (~ 0.25MWth) boilers and 50% use medium (1.0MWth) boilers.
- In the industry sector 10% of boilers are small (0.25MWth), 20% medium (1.0MWth) and 70% large (20MWth).
- In the commercial and public services sectors 40% of boilers operate at high load (80%) and 60% at lower seasonal load (30%).
- In the industry sector 60% of boilers operate at high load (80%) and 40% at lower seasonal load (30%).
- Wood chip boilers will not be used to replace gas fired systems
- Substitution of biomass pellets for gas heating has been arbitrarily limited to 5TWh for each boiler size range.
- Potential limitations to biomass supply are not considered.

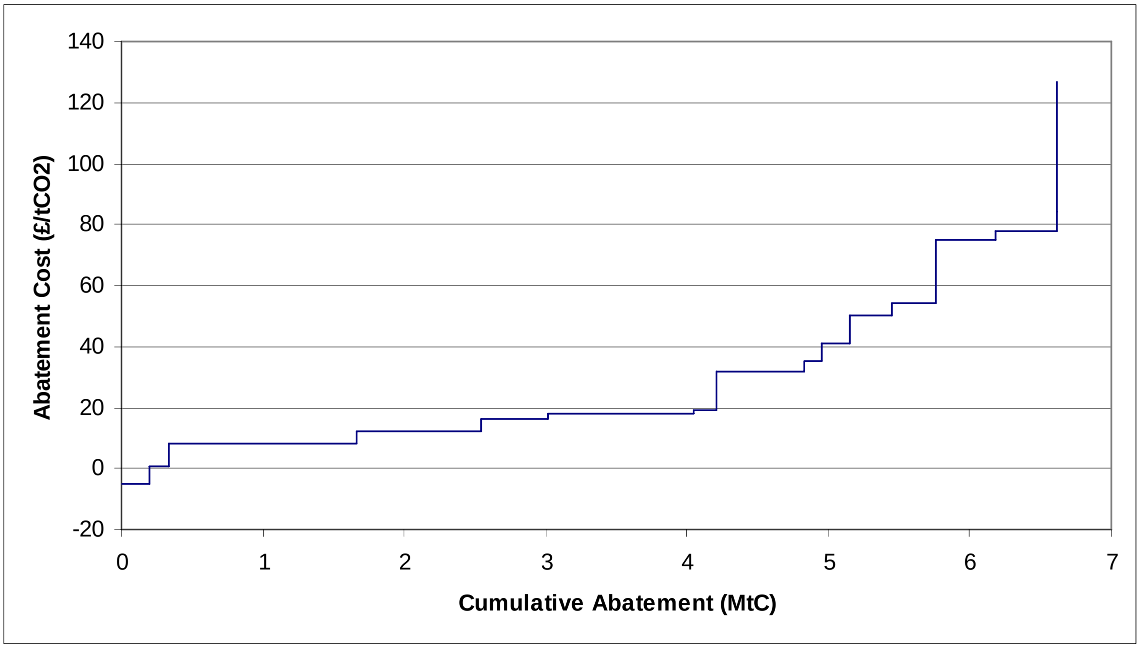
Energy from waste requires separate consideration because experience suggests that the location of such facilities will be limited by planning requirements as well as public acceptance. Generally such plant will be located close to the waste source or waste collection centre. Transportation of waste to established centres of energy demand is likely to be restricted unless these are located away from population centres or the waste has been processed into a more refined fuel. Consequently the use of waste for heat and CHP applications

[56] The full fuel cycle carbon balance was considered in estimating abatement costs for liquid biofuels because this is more significant than for the heat and power options.
[57] Analysis carried out by DfT assumes that biofuel prices will fall to 2020 and hence abatement costs would fall over time.

is likely to be restricted whereas electricity generation will not be subject to such limitations. An exception could be smaller scale AD applications utilising farm or food processing wastes which could be located on farms or food processing plant. Because of these uncertainties energy from waste has not been included in this assessment of abatement potential. However, there is no doubt that energy from waste is probably the most cost effective biomass energy option.

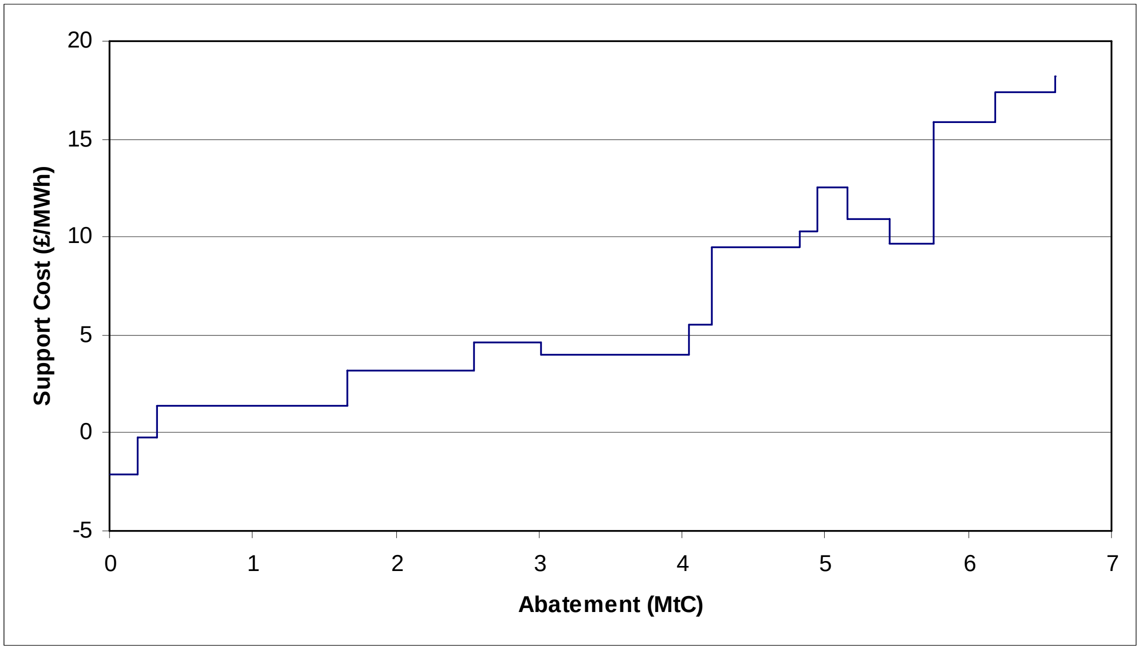
Using the above assumptions a cost versus abatement curve has been constructed for non-waste biomass to heat options, as shown in Figure 6. This figure omits CHP applications, once again due to lack of data on market potential, and also domestic because the costs are so much higher than for commercial boilers. The results, which use the central abatement costs from Table 30, show that about 6Mt of carbon may be abated through the deployment of biomass heat at a marginal cost of around £80/tCO2.

Figure 6 Illustrative CO2 cost vs abatement curve for CO2 avoided by the deployment of biomass heat.



The other issue to be considered is the level of incentive needed to encourage the deployment of biomass heat to the levels required to deliver the CO2 abatement shown in Figure 6. This is addressed through Figure 7 which shows the marginal level of support needed per unit of heat supplied to deliver abatement. Support of the order of £15-20/MWh will be needed to deliver about 6MtC abatement. This is equivalent to supplying around 80TWh of heat to the commercial and industrial markets, which equates to about 20% of demand for space and low temperature process heating. It should be stressed that these estimates are only illustrative and do not consider the rate at which deployment could be increased to such levels, which clearly will be influences by the rate of turnover of boiler equipment as well as the build up of biomass supplies.

Figure 7 Illustrative support cost vs abatement curve for CO2 avoided by the deployment of biomass heat.



Acknowledgement

The study benefited from a workshop involving interested parties in biomass energy, which reviewed the cost and performance assumptions to be used in the analysis. This was hosted by DTI on 15th December 2006.

Annex A – Fossil Fuel Price Assumptions used in the analysis

Table A1 – Fossil fuel prices for power generation in £(2005) (p/kWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Coal Price - High	0.49	0.50	0.51	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Coal Price - Central	0.43	0.41	0.39	0.37	0.37	0.37	0.36	0.36	0.36	0.36	0.35
Coal Price - Low	0.38	0.35	0.34	0.33	0.32	0.32	0.31	0.30	0.30	0.29	0.29
Gas Price - High	1.67	1.68	1.69	1.70	1.71	1.72	1.73	1.74	1.76	1.77	1.78
Gas Price - Central (fav to coal)	1.45	1.35	1.25	1.14	1.15	1.16	1.17	1.18	1.20	1.21	1.22
Gas Price - Central (fav to gas)	1.27	1.14	1.01	0.88	0.89	0.90	0.91	0.92	0.93	0.94	0.95
Gas Price - Low	0.75	0.67	0.58	0.58	0.59	0.60	0.61	0.62	0.63	0.63	0.64

Table A1 - Fossil fuel prices for power generation (cont.)

	2018	2019	2020	2021	2022
Coal Price - High	0.50	0.50	0.50	0.50	0.50
Coal Price - Central	0.35	0.35	0.34	0.34	0.34
Coal Price - Low	0.28	0.27	0.27	0.27	0.27
Gas Price - High	1.79	1.80	1.81	1.81	1.81
Gas Price - Central (fav to coal)	1.23	1.24	1.25	1.25	1.25
Gas Price - Central (fav to gas)	0.96	0.97	0.98	0.98	0.98
Gas Price - Low	0.65	0.66	0.67	0.67	0.67

Table A2 – Oil fuel prices for heat generation £(2005) (p/thm)

Fuel Type	Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015
Burning oil	Central	71.9	66.8	61.6	56.5	57.0	57.5	58.0	58.5	59.1
	Low	58.9	46.8	34.2	28.2	28.2	28.1	28.0	27.9	27.8
	High	85.7	88.2	91.1	94.6	95.0	95.4	95.8	96.2	96.6
Heavy fuel oil	Central	46.4	42.9	39.5	36.0	36.4	36.7	37.0	37.4	37.7
	Low	38.0	30.1	21.9	18.0	18.0	17.9	17.9	17.8	17.8
	High	55.3	56.7	58.3	60.3	60.6	60.9	61.2	61.4	61.7
Gas oil	Central	69.9	64.9	59.9	54.9	55.4	55.9	56.4	56.9	57.4
	Low	57.2	45.4	33.3	27.4	27.4	27.3	27.2	27.1	27.0
	High	83.2	85.7	88.5	91.9	92.3	92.7	93.1	93.5	93.8

Table A2 – Oil fuel prices for heat generation (p/thm) (cont)

Fuel Type	Scenario	2016	2017	2018	2019	2020
Burning oil	Central	59.6	60.1	60.6	61.1	61.6
	Low	27.7	27.6	27.5	27.5	27.4
	High	97.0	97.4	97.8	98.2	98.6
Heavy fuel oil	Central	38.1	38.4	38.8	39.1	39.5
	Low	17.7	17.7	17.6	17.6	17.5
	High	62.0	62.3	62.6	62.9	63.2
Gas oil	Central	57.9	58.4	58.9	59.4	59.9
	Low	26.9	26.8	26.8	26.7	26.6
	High	94.2	94.6	95.0	95.4	95.8

Table A3 – Natural gas prices for heat generation £(2005) (p/thm)

Market	Scenario	2007	2008	2009	2010	2011	2012	2013	2014	2015
Large Industry	Favourable to coal	38.0	36.3	34.7	33.1	33.3	33.5	33.8	34.0	34.3
	Favourable to gas	35.1	32.1	29.0	26.0	26.2	26.5	26.7	26.9	27.2
Commercial/ Medium Industry	Favourable to coal	41.5	39.3	37.1	34.9	35.2	35.4	35.7	35.9	36.1
	Favourable to gas	37.0	34.2	31.2	28.2	28.5	28.7	29.0	29.2	29.5
Domestic	Favourable to coal	54.6	56.4	58.1	59.9	60.1	60.3	60.5	60.8	61.0
	Favourable to gas	51.2	51.2	51.2	51.2	51.4	51.6	51.9	52.1	52.4

Table A3 – Natural gas prices for heat generation (p/thm) (cont)

Market	Scenario	2016	2017	2018	2019	2020
Large Industry	Favourable to coal	34.5	34.7	34.9	35.2	35.4
	Favourable to gas	27.4	27.6	27.9	28.1	28.4
Commercial/ Medium Industry	Favourable to coal	36.4	36.7	36.9	37.2	37.4
	Favourable to gas	29.8	30.0	30.3	30.5	30.8
Domestic	Favourable to coal	61.2	61.5	61.7	62.0	62.2
	Favourable to gas	52.6	52.8	53.1	53.3	53.5

Annex B – Assumptions on the cost and operational parameters of power plant

Table B1 – Cost and performance of conventional fossil fuelled power plant

Plant Type	Capital Cost (£/kWe)	Fixed Operating Cost (£/kWe)	Variable Operating Cost (£/kWhe)	Generation Efficiency (% HHV)
Existing pulverised coal	Assumed sunk	17.0	0.11	35
New coal	918	17.0	0.11	46
New coal with CCS	1162	26.0	0.27	37
New GTCC	440	7.0	0.20	58

Table B2 – Costs of operating co-firing on existing and new coal fired power plant

Biomass Type	Level of co-firing (% input, HHV)	Capital Cost (£/kWe)[1]	Operating Cost (£/odt)[2]
SRC	1%	5	10
	5%	10	10
	10%	15	10
Miscanthus	1%	1	10
	5%	10	10
	10%	15	10
Woodfuel	1%	5	10
Straw	1%	5	10
	5%	10	10
Imports	5%	5	7
	10%	7	7

<u>Notes</u>

1. Capital cost in £/kWe of total station capacity
2. Per Oven Dried Tonne (ODT) of biomass input

Annex C – Assumptions on the cost and operational parameters of heat plant

Table C1 – Cost and performance of fossil fuel and biomass heat plant

Application	Fuel Type	Capital cost (£/kWth)	Operating Cost (£/kWth)	Efficiency (%)
Large Industrial				
(20MWth)	Heavy Fuel Oil	50	1.0	85
	Natural Gas	50	1.0	85
	Wood Chip	200	4.0	80
Medium Industry and Commercial				
(1MWth)	Gas Oil	100	2.0	85
	Natural Gas	75	1.5	85
	Wood Chip	250	4.0	80
	Pellets	150	2.5	85
Small Commercial				
(0.25MWth)	Gas Oil	150	3.0	85
	Natural Gas	100	2.0	85
	Wood Chip	350	7.0	80
	Pellets	270	5.4	85
Domestic				
(30kW)	Burning Oil	75	120	85
(30kW)	Natural Gas	75	120	85
(10kW)	Pellets	500	120	85
(10kW)	Logs	450	120	85

Annex D – Assumptions on the cost and operational parameters of CHP and district heating plant

Table D1 – Cost and performance of fossil fuel and biomass plant

Application	Size Range	Capital cost (£/kW)	Operating Cost (£/kW)	Efficiency - Electrical(%)	Efficiency – Heat (%)
Large Industrial CHP	30MWth/8MWe	2500 (kWe)	50 (kWe)	16	64
Medium Industry and Commercial CHP	1.0MWth/0.3MWe	3000 (kWe)	60 (kWe)	16	64
Small AD CHP	0.2MWth/0.2MWe	3312 (kWe)	201 (kWe)	38%	48%
Small AD power only	0.49MWe	2240 (kWe)	161 (kWe)	38%	-
Medium AD CHP	1.2MWth/1.4MWe	2862 (kWe)	239 (kWe)	38%	47%
District heating	-	800 (kWth)	16 (kWth)	-	85