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The UK Supply Curve for Renewable Heat

Study for the Department of Energy and Climate Change

NERA
Economic Consulting

AEA

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Executive Summary

DECC has commissioned NERA Economic Consulting and AEA Technology to investigate the UK supply curve for renewable heat—i.e., how much renewable heat may be achievable under different scenarios, and at what cost. The research aims to improve the evidence base for developing the renewable heat incentive (RHI), but has not extended to detailed consideration of design options for this policy.

The heat market is characterised by significant diversity of fuels, customer types, size and other heat load characteristics, etc. While the current work builds on previous analyses of renewable heat, all of the underlying assumptions have been revisited and the representation of the options for renewable heat improved through a more detailed characterisation of the various renewable heat technologies and variations in the features of heat demand. In the process, we have used information from existing studies, a range of published literature, in-house data previously held by AEA and NERA, as well as information from stakeholders contacted throughout the process.[1]

The supply curve is constructed using a financial model of heat technologies that draws on, but goes beyond, previous work for Government. In addition to a detailed review of cost and technical data and much more detailed characterisation of demand for heat, the approach to selecting where renewable heat is taken up to ensure that a specified share of heat is delivered at least cost has been significantly improved. This relies on various input assumptions, including detailed estimates of heat demand and the market for heating equipment, assumptions about the feasible expansion of supply capacity, and estimates of the cost of using renewable heat technologies across some 250 different market segments. The technologies covered include air-source and ground-source heat pumps, biomass individual boilers and district heating, biogas heat-only combustion and injection to the gas grid, and solar thermal. Consideration of the heat generated through CHP has been outside the scope of this research, but is the subject of a separate research project funded by DECC and currently underway.

In addition to data characterising technology options and heat demand, the supply curve uses data on fuel prices, emissions allowance prices, and other quantities relevant to the heat market. It also embodies assumptions about discount rates, and estimates of the cost of overcoming various barriers to renewable heat. Given the various input data, the modelling finds the composition of renewable heat that would result in the lowest cost to serve a given heat load (thus reflecting the choice of consumers), while also delivering a specified share of renewables in overall heat generation.

The findings of the research are similar in many respects to those of previous work, but there also are important differences. Headline findings include:

- The rate at which supply capacity for renewable heat technologies can grow is very uncertain, and this will have a significant impact on the costs of delivering a specific share of renewable heat.

[1] Previous studies include, most recently, NERA (2008), Enviros (2008a and 2008b), and Element Energy (2008). These in turn drew on a number of prior studies as detailed in the references in NERA (2008).

- A mix of technologies are likely to be required to meet the share of renewables in heat required for the UK's renewable energy commitments. Biomass boilers and heat pumps offer significant potential, in some cases at relatively low cost. The per-unit cost of solar thermal is higher than was found in previous work, significantly exceeding that of other renewable heat technologies. The findings differ from previous research, which ascribed a smaller role to heat pumps, and a larger role to solar thermal and heat-only biogas because of constraints on other technologies.

- The industrial and commercial / public sectors generally offer lower-cost opportunities for renewable heat than the domestic sector; depending on growth rates, the non-domestic sectors may be able to deliver most of the renewable heat required. This finding differs from previous work, which indicated a higher contribution from the domestic sector.

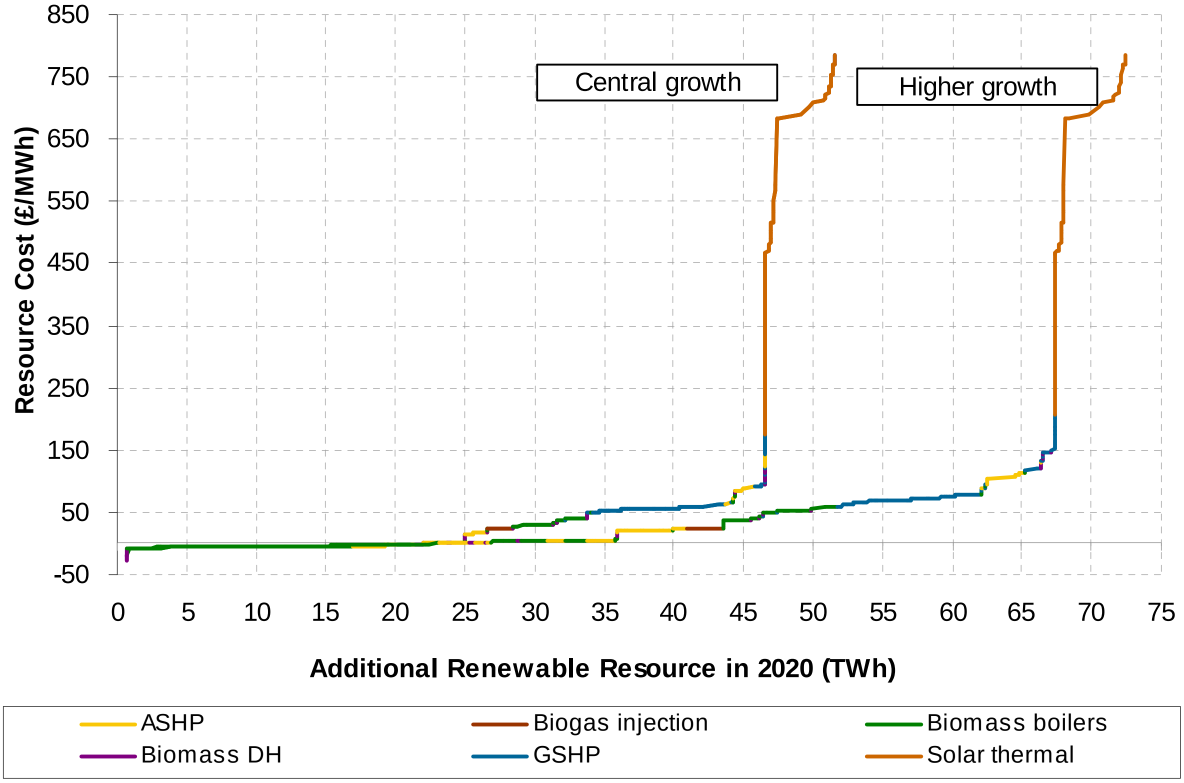
Summary Supply Curve

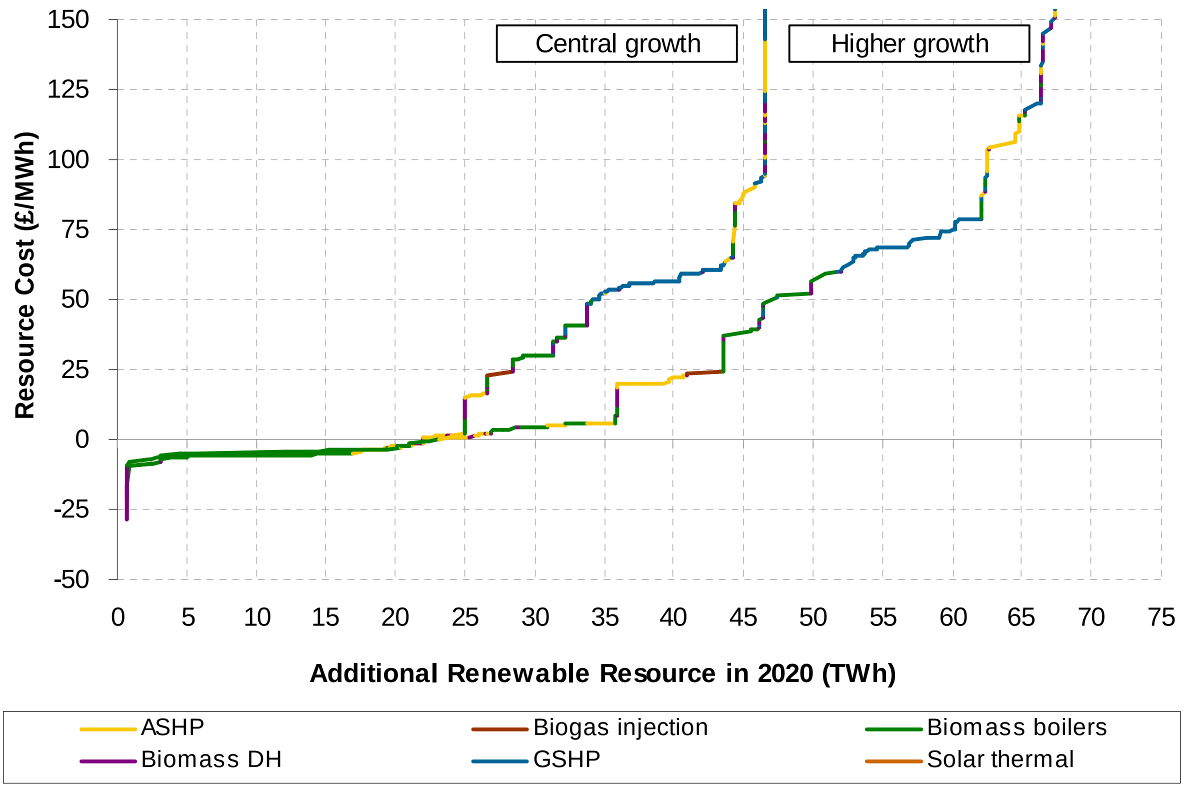
Figure ES-1 shows a summary representation of the "supply curve" estimated under two different assumptions about the growth of supply capacity (discussed in more detail below). The horizontal axis shows the *additional renewable resource* (ARR) from renewable heat in 2020. ARR is a measure of the contribution to the UK's renewable energy targets under EU legislation, and for various reasons it differs from useful heat *output*.[2] The vertical axis shows the *resource cost* per megawatt-hour of renewable heat, calculated as the cost over and above that of the relevant fossil fuel or electric heating alternative.[3] The curve is segmented so that different technologies are shown with a different colour. We include two charts, one showing the full range of costs up to around £800 / MWh, and one with a cut-off at £150 / MWh, which allows for more detail on technologies below this cost level.

[2] The difference between the ARR and the useful heat output varies by technology. In the aggregate, useful heat output is around 5-10 percent higher than the ARR for the composition of renewable heat technologies found in the modelling.

[3] DECC's preferred methodology for calculating resource cost means that in most cases this cost is higher than the incremental cost that is actually perceived by heat users. We provide further details in the main report.

Figure ES-1
2020 Supply Curves for Central and Higher Growth Scenarios





Note: The per-MWh cost of solar thermal is never below £150/MWh, and therefore it does not appear in the bottom panel of the Figure.

Potential for Renewable Heat

As the figures indicate, the amount of renewable heat achievable by 2020 depends heavily on the rate at which UK supply capacity can grow. Because supply starts from a very low base, projections of future developments are intrinsically very uncertain. The central growth rate scenario depicted in the supply curves above corresponds to AEA's central estimate of the growth rates achievable to 2020. The implied average annual growth rates are in between 20-35 percent for the main technologies in a maturing market in the period 2015-2020 (with higher average growth rates in the earlier period from 2010-2015), similar to the rates of sustained growth achieved in other countries where renewable heat technologies have become mass market options. In the higher growth scenario, the average growth rate in 2015-2020 increases to 30-50 percent for most technologies, which is similar to the maximum rates observed for individual technologies in other countries, but less than a theoretical maximum where all barriers to growth are overcome.

Under the central growth scenario, some 46 TWh of additional renewable heat could be achieved by 2020 at a resource cost less than £100 / MWh. Under the higher growth rate scenario, this increases to 66 TWh. When added to the 6 TWh of renewable heat that is expected under "Business As Usual", these levels correspond to 8.5 percent and 12 percent of projected 2020 heat demand, respectively. Above £100 / MWh there is relatively limited additional renewable heat potential available, including around 5-6 TWh of ARR from solar thermal and 1-2 TWh from district heating.[4]

The overall potential for renewable heat also depends on demand-side considerations. Our estimates account for the suitability of renewable heat technologies for particular applications, as well as the rate of replacement of heating equipment. Expanding renewable heat requires that certain technologies account for a substantial proportion of equipment purchases by 2020: achieving an 8.5 percent share of renewables in heat supply would require that renewable heat technologies reached a market share in new heating equipment of around 30 percent by 2020. Meeting a 12 percent heat share would require a market share of 50 percent.

As noted, the estimates of potential presented here do not reflect heat that could be provided by renewable CHP, which is being investigated separately. If renewable CHP were adopted on a significant scale, this could add significant additional volume of renewable heat. The size of the additional contribution depends on a number of factors, including the extent of overlap of renewable CHP with sites taking up biomass boilers.

Composition of Heat Output

The composition of output associated with the various growth rate assumptions and different shares of renewable heat in total heat supply is detailed in Table ES-1. The table shows that the respective additional renewable heat levels are met using a mix of heat pumps, biomass,

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[4] Comparisons of the potential to previous work are complicated by the change in the denomination of the output (ARR vs. useful heat output). The supply potential for biomass boilers is similar to that found in previous work, while that for both air-source and ground-source heat pumps is significantly larger. District heating is smaller, mostly because CHP has been outside the scope of this work. Solar thermal potential is reduced chiefly because the output per unit is much lower than was assumed in previous research. Biogas potential is similar in terms of gas generation, but lower in terms of the amount available for heat. The main report contains further detail.

and biogas. Heat pumps and individual biomass boilers are particularly large contributors, although the shares of different technologies and sectors vary significantly across scenarios. The modelling results show the composition of technologies that would achieve the specified renewable heat shares at lowest cost. As a consequence, the tables do not include any solar thermal output, because solar thermal's cost per unit output (£/MWh) is considerably higher than those of the other technologies.

Table ES-1
Composition of Heat Output by Technology and Sector

Technology	Sector	Central growth 8.5% share		Higher growth 8.5% share		Higher growth 12% share	
		TWh	1000 units	TWh	1000 units	TWh	1000 units
ASHP	Domestic	2.1	221	0.0	0	3.1	325
ASHP	Non-domestic	7.7	23	11.6	41	11.6	37
GSHP	Domestic	1.8	204	0.0	0	1.6	187
GSHP	Non-domestic	8.1	34	0.0	0	8.8	44
Biomass boilers	Domestic	5.5	299	2.0	100	8.2	448
Biomass boilers	Non-domestic	17.3	2	27.7	4	27.7	4
Biomass DH	Domestic	0.8	0	0.8	0	0.8	0
Biomass DH	Non-domestic	0.9	1	0.9	1	0.9	1
Biogas injection	All	2.3	0	3.5	0	3.5	0
Subtotal	Domestic	10.1	725	2.8	101	13.7	961
Subtotal	Non-domestic	34.0	60	40.2	46	49.0	86
Total		46.4	785	46.5	147	66.2	1047

Note: For district heating, the number of units refers to the number of heat consumers; for biogas injection, the number of AD plants. For other technologies, the column indicates the number of individual units installed.

One implication of these results is that growth rates are a key determinant of the technology mix required to achieve a given share of renewables in heat use. Notably, under the higher growth rate scenario the 8.5 percent share could be achieved almost entirely through large-scale biomass boilers and air-source heat pumps (with some contribution from biogas injection), requiring only a small contribution from the domestic sector or from other technologies. However, if these technologies are not able to expand as quickly (as in the central growth scenario), or if a higher share of renewable heat is to be reached, contributions from the domestic sector and from more expensive technologies would be required.

Cost and Detailed Modelling Results

A summary of headline results for the different renewable heat shares and growth rate assumptions is shown in Table ES-2. The values in the table are annual values in 2020. The cost of achieving the specified level of output is around £860 million per year under the central growth scenario and 8.5 percent renewable heat share. (Costs are substantially lower to reach 8.5 percent share under the higher growth scenario.) Under the higher growth scenario and with the 12 percent share, the annual cost rises to around £1600.

As noted, this work has not analysed design options for the RHI. Where the table shows subsidies these are a stylised subsidy paid per unit of heat output, on an ongoing basis, and with the same subsidy level paid to all eligible projects. Calculated on this basis, the subsidies required to achieve an 8.5 share of renewables in heat supply are between £1.7-3.7 billion per year, depending on growth scenario, or £6.2 billion for the 12 percent share. Previous research has indicated that the total subsidy could be reduced by differentiating the support paid to different types of renewable heat projects (that is, by "banding" the support levels).

Table ES.2
Summary Modelling Results for 2020

Variable	Units	Central growth, 8.5% share	Higher growth, 8.5% share	Higher growth, 12% share
Additional renewable resource[1]	TWh	46	46	66
CO_2 emissions abatement	MtCO2	14	13	18
Covered by EU ETS	MtCO2	7	7	8
Not covered by EU ETS	MtCO2	7	6	10
Number of installations	million	0.8	0.1	1.0
Total resource cost, variable price	£m	860	180	1,600
Technology costs	£m	600	100	1,200
Barrier costs	£m	260	78	410
Resource cost, retail prices	£m	550	-300	1,200
Value of CO2 emissions abated	£m	450	430	580
Total subsidies	£m	3,700	1,700	6,200
RHI level	£/MWh	75	38	89
Resource cost / MWh[2]	£/MWh	19	4	24
Average CO_2 abatement cost	£/tCO2	64	14	90
CO_2 abatement cost at margin[3]	£/tCO2	260	130	340

Notes:

1. Output eligible for the UK's obligations under the relevant EU legislation. Actual heat output is c. 5-10 percent higher, depending on the combination of technologies.
2. Calculated using the "variable component" of fuel prices, as explained in report.
3. Implied cost of CO_2 abatement assuming average abatement potential of all output, and the cost characteristics of the marginal renewable heat technology.
4. All data are in shown in real terms in 2008 prices and have not been discounted.

Sensitivity Analysis

The costs and other results are sensitive to the input assumptions used. One important input variable is the biomass price. The central biomass price assumptions are based on research for DECC by E4tech and are substantially lower than current prices. This is a key reason for the finding that, with optimistic growth, a significant increase in renewable heat from biomass boilers could be achieved at very low or even "negative" cost. If we assume biomass prices that are more similar to current price levels these “negative costs” are largely eliminated. Even with biomass prices as current levels, however, biomass remains an attractive renewable heat option and its overall contribution is not reduced much .

Fuel prices are another important influence on the results. With sufficiently high fossil fuel prices many renewable heat options may become attractive even without subsidy, whereas lower prices makes the switch to renewable heat costlier. Similarly, the discount rate – i.e., the rate determining how consumers weigh up-front costs against future savings or other benefits – used in making investment decisions can have a significant impact. Many renewable heat technologies entail high up-front costs compared to fossil fuel or electric heating. With lower discount rates (which imply less concern about up-front costs) the cost can drop by about 40 percent, whereas higher discount rates could increase costs by a similar amount or more. Finally, there are various barriers in the transition from the current low take-up to the mass-market adoption required for the contribution envisaged from heat to the UK renewable energy target. Different assumptions about the cost of overcoming these barriers could lead to different results.

Conclusions

Overall there appears to be significant potential for renewable heat to supply much of the market that currently is served by fossil fuels or electric heating. Nonetheless, the low current base of UK renewable heat means that significant expansion by 2020 will be challenging; even achieving a 12 percent share requires the gradual establishment of renewable heat technologies as the dominant choice in large parts of the UK heat market. This research indicates that, with sufficient subsidy, there is no intrinsic limitation to demand-side potential to prevent such a mass-market adoption of renewable heat. The most important constraint therefore may be on the supply-side, where different trajectories for growth can have widely different implications for the cost as well as composition of output.

1. Introduction

Under EU renewables policy the UK has taken on a target to increase the share of renewables in the energy mix from current levels of around 2 percent, to 15 percent of energy use by 2020. As indicated in the 2008 Renewable Energy Strategy Consultation last year, reaching this target is likely to require a very substantial increase in the use of renewables to generate heat, where renewables currently account for around 1 percent of energy consumption. Anticipating the need for a significant increase in the use of renewable energy for heating, the 2008 Energy Act laid the foundation for a renewable heat incentive (RHI) to support a large-scale increase in renewable heating technologies.

In this context, DECC has commissioned NERA Economic Consulting and AEA Technology to investigate the UK supply curve for renewable heat—i.e., how much renewable heat may be achievable under different scenarios, and at what cost. A major aim of the research has been to improve on previous research (Enviros 2008a and 2008b, NERA 2008), through a more detailed characterisation of heat demand, renewable heat technologies, and the various factors that influence the potential for and cost of renewable heat. The research also considers the level of subsidy that may be required to achieve different levels of renewable heat. It does not extend to investigating detailed design options for the RHI.

The report is structured as follows. The next section presents an overview of the modelling that has been undertaken to derive the supply curve. This includes the technologies and heat users covered, scenarios for the expansion of renewable heat supply, and the modelling framework and assumptions. Section 3 presents a summary of the resulting supply curves, under different input assumptions. Section 4 shows additional modelling results, with a focus on the cost and composition of renewable heat output. The final section offers some conclusions and recommendations for further research.

Annexes A, B, C provide additional information on the underlying technology assumptions and their associated growth rates as well as more detailed modelling outputs.

2. Overview of Supply Curve and Modelling

In this section we provide an overview of the assumptions and modelling framework used to characterise the UK supply curve for renewable heat. We start by describing the data categories, including the technologies covered and the characterisation of heat demand, and then describe the modelling framework and scenarios for the feasible expansion in renewable heat supply. Finally, we describe various additional assumptions – including technology cost characteristics – used for the modelling.

The modelling of a supply curve for renewable heat requires financial modelling, which incorporates characteristics of renewable heat supply, but also the properties and restrictions on demand for renewable heat. One significant complication is that, because most heating technologies are mutually exclusive, the aggregate supply for a particular technology depends not only on its own characteristics, but also on the extent to which other competing technologies are taken up by heat users. Further, both the cost and the feasibility of using renewable heat technologies depend heavily on the circumstances of their application.

2.1. Supply Curve and Modelling Categories

2.1.1. Renewable heat technologies

The technologies covered by this work include air-source heat pumps, ground-source heat pumps, biomass boilers, biomass district heating, heat-only biogas combustion and injection into the gas grid, and solar thermal heat. Consideration of other technologies, including geothermal heat, renewable fuel cells, and liquid biofuels for heating has not been within the scope of the work, because they were judged to be either too speculative or to offer too little potential.[5] Heat (and cooling) from combined heat and power is also outside the scope of this study, but is the subject of a separate project being undertaken for DECC that will be published at a later date.

2.1.1.1. Air-source heat pumps

Air-source heat pumps (ASHPs) use a vapour compression cycle to pump heat from ambient air into the target heating system.

For the purposes of the modelling, we assume that ASHPs will be used only for space heating in the domestic and commercial sectors. We have considered only those systems that supply whole-of-premises heating. For domestic properties this will be by water born system, while commercial properties may use refrigerant flow types. Water temperatures used in such systems are lower than the temperatures typically used in conventional (i.e. gas- or oil-fired) systems, so we assume that additional costs must be incurred or reductions in efficiency will apply when these heat pumps are applied to existing wet heating systems (see section 2.4.1). We exclude small reversible air conditioners (so called "splits"). This exclusion is discussed further below. Cooling using air-source heat pumps has not been considered in this work.

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5 An initial review of the potential for geothermal heat in the UK concluded that although some potential exists, it is quite limited and concentrated in only a few locations.

All in all, 5 different sizes of system are represented, ranging between 6-14 kW domestic units to large-scale heat pumps installations of up to 300 kW in the commercial / public sectors and for industrial space-heating.

2.1.1.2. Ground-source heat pumps

Ground-source heat pumps (GSHPs) use a vapour compression cycle to pump heat into the target heating system from underground heat exchange coils and boreholes.

We assume that these will be used only for space heating in the domestic and commercial / public sectors. As with ASHPs, the heating system water temperatures are lower than in conventional fossil-fired wet heating systems, and the additional cost associated with installing such systems is accounted for in cost estimates. Cooling using ground-source heat pumps has not been considered in this work.

A range of GSHP sizes spanning 6 to 300 kW are included in the modelling. Domestic systems include both bore-hole and ground loop systems, depending on house type and location. Larger systems in the commercial / public and industrial sectors are assumed to be bore-hole systems.

2.1.1.3. Biomass boilers

For the purposes of the exercise, we assume new installations in the domestic sector would be fuelled by wood pellets. This is based on experience in Ireland, Austria and elsewhere in Europe. Non-domestic sectors would be fuelled by a mix of pellet and wood chip, with the proportions depending on location and size. In addition to space and hot water heating applications, some industrial process heating by direct flame has been allowed for.

Biomass boilers also span a wide range of applications. The domestic sector is represented by pellet boilers between 12 and 20 kW; while smaller commercial systems range between 110 and 180 kW and larger systems from 350 to 1,600 kW.

2.1.1.4. Biomass district heating

This is heat derived from biomass combustion and delivered to heat clients through a hot water distribution system.

The modelling distinguishes a range of schemes, differentiating between heat users in the domestic and commercial / public sectors, as well as rural and urban settings (see section 2.2.2.2). Commercial / public sector schemes range from small schemes of a few hundred kW to large schemes of over 1,000 kW. The systems are modelled as heat-only rather than combined heat and power (see section 2.1.1.7).[6]

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[6] As noted, CHP is the subject of a separate forthcoming report. In theory, renewable CHP could provide significant additional potential.

2.1.1.5. Biogas injection

This is the injection of methane rich gas derived from biomass sources into the natural gas transmission and distribution network. Biogas is manufactured either by the biological process of anaerobic digestion or the thermal processes of gasification.

In AEA's opinion the most resource efficient thermal route would be to build large scale gasification plant (i.e., hundreds of MW) sized to make best use of the high grade heat from the methanation reaction. This implies a location on a petrochemical or similar site. Whilst this could be both efficient and financially advantageous, the time frame for development was considered too long for the time horizon envisaged under this project (2020). Large-scale gasification therefore has not been considered further after the original assessment.

Anaerobic digestion for methane is relatively well proven, although not yet deployed in large numbers, and injection into the gas grid could be an alternative to using the gas for on-site CHP, with many resource efficiency and operational advantages. The production of gas for injection is modelled through a representative plant capable of producing 14 GWh of biogas for export per year, including equipment required to upgrade gas for injection into the gas grid. The feedstock is assumed to be household food / garden waste, alongside suitable commercial and industrial waste streams (food waste, pharmaceutical broth, etc.). Cost and performance data are not readily available and have been built up from estimates based on other analogous systems.

The modelling also accounts for the possibility of biogas direct combustion for heat production. However, because of the seasonality of heat demand, the most likely use of directly burned biogas would be in CHP plants, which have not been considered within this exercise. Thus heat-only biogas combustion is not likely to make a contribution.

2.1.1.6. Solar thermal

Solar thermal refers to the absorption of solar energy as heat into water using a purpose-built collector.

Installations between domestic systems of 2.4 kW and commercial / public systems of 12.4 kW are included in the supply curve, corresponding to the supply of up to 50 percent of hot water demand for the relevant buildings.

2.1.1.7. Treatment of combined heat and power

Analysis of the potential for renewable combined heat and power (CHP) generation has not been within the scope of this project, but is being investigated in a separate project commissioned by DECC. The absence of CHP from the supply curve has implications for several of the technologies noted above, including:

- Biogas: District heating powered by biogas combustion is not represented in the supply curve. Although district heating using biogas is not infeasible, AEA considers that heat-only schemes are very unlikely, and that any biogas district heating schemes are likely to be CHP. As discussed in Appendix C, under current policies, the use of biogas for CHP (or more likely for power-only generation) could account for a significant proportion of the biogas produced, and this is accounted for when projecting the potential for heat from biogas injection.

- Biomass district heating: the potential represented in the supply curve is a subset of the full potential for district heating using biomass fuels. Like with biogas, such district heating schemes are more likely to be connected to CHP schemes than to heat-only. The potential for district heating reflects this, and thus is smaller than it would be if CHP schemes also were considered.
- Biomass boilers: much of the industrial heat load suitable for biomass boilers also could be served by CHP. Moreover, there may be industrial users for whom CHP (whether renewable or not) is the most likely choice. This project has not investigated the extent to which biomass CHP is likely to be complementary to, or a substitute for, stand-alone boilers.[7] The potential could be significant, as some large industrial CHP sites could in principle switch to biomass.
- Renewable cooling: DECC has advised that cooling will only contribute to the UK's renewables target if the cooling is generated from heat produced from renewable sources. Cooling from heat pumps, water-based technologies, and some other options therefore would not qualify. The main option for renewable cooling meeting this specification is "tri-generation" of cooling, heat, and power from biomass fuel. Without analysis of CHP this is outside the scope of this analysis.

2.1.1.8. Other technologies

Other technologies that may count as renewable heat but which are not included in the supply curve include heat pumps using deep geothermal heat and water-source heat pumps. The analysis also does not include liquid biofuels for heating, or more generally the co-firing of fossil fuels and biofuels for heat generation. Finally, we also do not consider more speculative technologies for heat generation, such as fuel cells using biofuels, or hydrogen fuel cells using renewable energy to produce the fuel.

2.1.2. Heat demand segments

The characteristics of the heat load can significantly affect the suitability, performance, and financial viability of renewable heat technologies. Relevant differences include the suitability of particular technologies, the size of the heat load, the incumbent heating fuel, load factor, amount of additional adaptation of heating systems required, and various other considerations. We represent these through a detailed mapping of UK heat demand to different heat demand segments.

2.1.2.1. End-use sector and consumer segment

The high-level end-use sectors represented in the modelling are the domestic (residential), commercial and public, and industrial sectors. These are further split into sub-segments to distinguish important differences:

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[7] As noted, an ongoing project for DECC seeks to clarify this and other questions concerning biomass CHP, but the outputs of this research have not been available in time for this project.

- The domestic sector is split between detached houses, flats, and other houses (semi-detached, terraced). The average heat load differs for each house, and the type of building also influences the suitability of technologies, notably where space constraints are important (biomass storage, solar panel roof space, land for ground-source heat pumps, etc.).
- The commercial / public sector is split into four groups by distinguishing public and private and small and large heat loads. Apart from the overall size, this influences load factors.
- Industrial heat use is split between space heating and process heat (further split into high-temperature and low-temperature heat), with very different implications for load factors. These categories are further split into large and small loads.

2.1.2.2. Counterfactual heating technology

Our general approach to assessing the resource cost associated with the use of renewable heat is to calculate the difference between the cost of the renewable heat technology and the cost of the relevant counterfactual conventional heating technology (fossil fuel or electric heating). This requires that the heat loads within each technology and sector combination are further subdivided into counterfactual fuel categories. We use three segments: natural gas, electricity, and non net-bound fuels (comprising heating oil, burning oil, coke, LPG, and coal). Apart from the widely different cost of serving a given heat load with different conventional technologies, the type of pre-existing heating technology influences the cost of adopting renewable heat technologies. In particular, many of the renewable heating systems considered require a wet heating system; if no wet heating system is currently in use, converting to one would entail additional costs.

2.1.2.3. Location and building age

The supply curve also accounts for two additional categorisations. First, the modelling distinguishes between urban, suburban, and rural heat loads. Important implications include limitations on the amount of biomass combustion that is feasible in urban areas without adverse impacts on air quality, the type of fuel used for biomass boilers, and the influence of density of occupation on the economic viability of district heating schemes.

Second, the cost curve also distinguishes between buildings constructed before and after 1990. Particularly in the domestic sector, this is an important influence on the size of the heat load. The post-1990 category also contains an allowance for the lower cost of fitting renewables in new build, compared to retrofitting in buildings with pre-existing conventional heating systems.[8]

All in all, this segmentation results in around 250 distinct demand segments, each of which can be combined with the five renewable heat technologies (excluding biogas injection). More detailed statistics on the technology costs and assumption are presented in Appendix B.

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[8] New build assumptions reflect the addition of between 150,000-200,000 homes per year over the period analysed. Expected heat loads in new build properties are much lower than in the existing housing stock, however, which reduces this impact of new build on the results.

2.2. Renewable Heat Potential

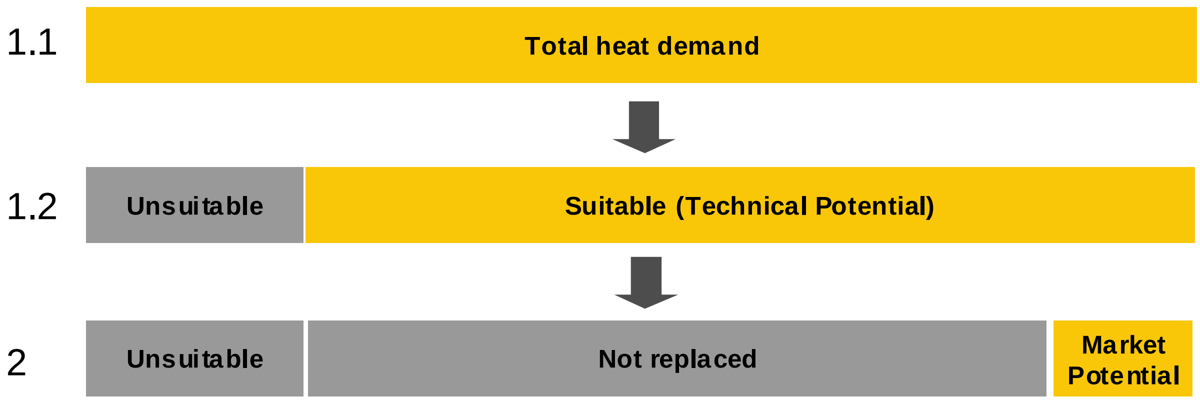
As mentioned above, the potential for renewable heat depends on the interaction of supply and demand factors, and cannot easily be considered without joint consideration of all relevant heating options available to consumers.

2.2.1. Overview of Approach to Modelling of Renewable Heat Potential

The figure below shows schematically the first steps in the modelling of renewable heat potential:

1. **Technical potential:** The first step is to estimate the maximum technical potential for each renewable heat technology. This accounts for two factors:
    1.1. the total level of heat demand, and
    1.2. the suitability of each technology to serve different types of heat load.
2. **Market potential:** Each year, only a small proportion of heating equipment is replaced. This subset of the technical potential gives what we refer to as the market potential for a given technology and year.

Figure 2.1
Overview of Technical Potential and Market Potential for a Single Technology (1 of 2)



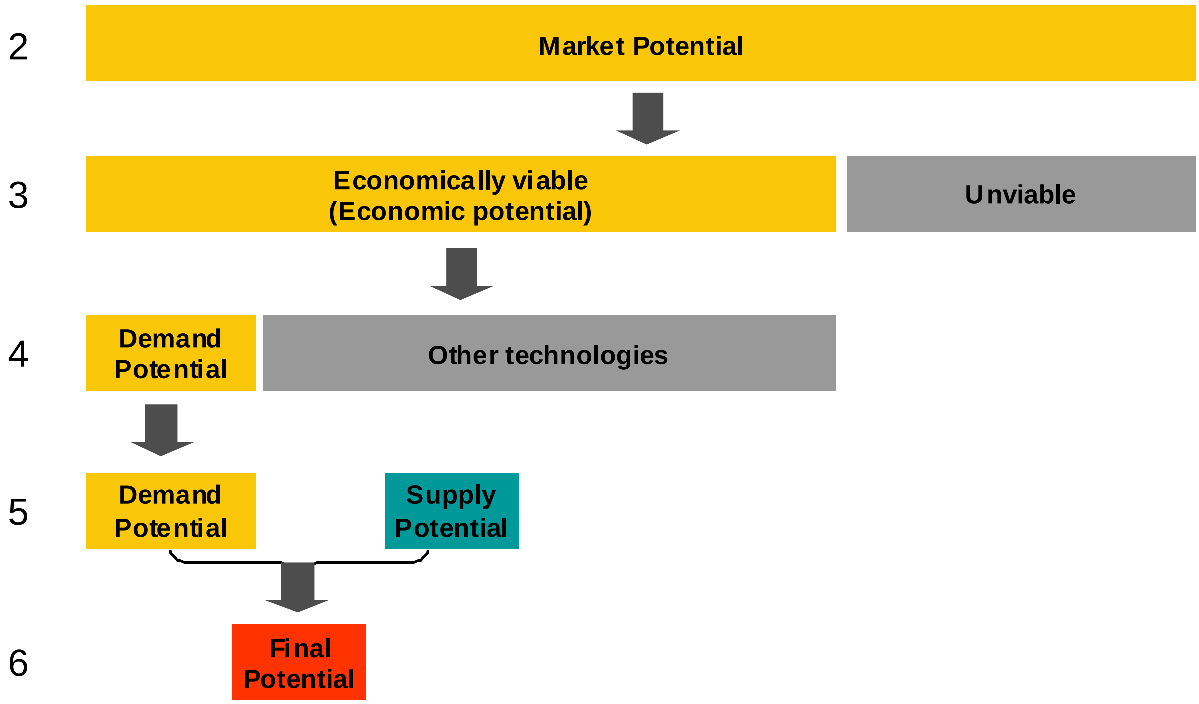
A number of demand-side and supply-side considerations further limit the potential ***for a given technology***. Figure 2.2 summarises the steps that we apply for each technology to arrive at its final potential:

3. **Economic potential:** This is the portion of the market potential that is economically viable for the given renewable heat technology, in the sense of having a lower cost than the incumbent (counterfactual) fossil fuel or electric heating technology. The size of the economic potential depends on a range of factors, including the subsidy available and the extent of demand-side barriers for the particular renewable heat technology.
4. **Demand potential:** This accounts for the interaction of the renewable heat technology in question with other renewable heat technologies. Even though the given technology may be viable *relative to the incumbent* heating technology, it may be possible to serve the same heat load at lower cost using *another* renewable heat technology. The potential for

one renewable technology therefore depends on the pattern of uptake of other technologies.

5. **Supply potential**: It also is necessary to account for constraints on overall resource and supplier capacity to serve potential demand. Depending on the size of the demand potential, it therefore may be limited further by the available supply potential.
6. **Final potential:** In the last step, the final potential is estimated accounting for the joint impact of all of the above factors.

Figure 2.2
Overview of Technical Potential and Market Potential for a Single Technology (2 of 2)



The above steps are applied to each of the technologies considered.

This representation is schematic and highly simplified. In the actual modelling, it is necessary to account jointly and simultaneously for all of the above factors, while also minimising the overall cost. For example, if one technology is limited by supply potential, this affects the demand for other technologies; the amount of subsidy available for one technology will affect the uptake of other technologies; etc.

We describe the steps in more detail below.

2.2.2. Technical Potential: heat demand and technical suitability

The starting point for an assessment of demand-side constraints is to identify the *technical potential*, defined as the heat demand that could feasibly be served by the respective renewable heat technologies. This has two components: establishing the heat demand of each segment, and assessing the suitability of renewable heat technologies to serve this demand.

2.2.2.1. Heat demand

Technical potential is estimated individually for each technology, and based on two components. First, we use recent Updated Energy Projections (UEP) estimates of total heat demand for the period until 2020, as given in DECC (2009). The overall demand has been apportioned by AEA to the various demand segments using a range of sources on industrial, domestic, commercial and public heat demand, with main sources including the English Housing Condition Survey, the BRE Domestic Energy Factfile, data from the ENUSIM and BRE models, assessments by the Carbon Trust of commercial and public sector heat demand, and proprietary AEA data.

2.2.2.2. Suitability of renewable heat technologies

AEA has assessed the suitability of each renewable heat technology for each demand segment. The supply curve is highly differentiated, so the factors that affect the suitability of renewable heat technologies can be specific to individual demand segments, but even so the assessment reflects a degree of approximation.

- Air source heat pumps: ASHPs are deemed suitable for urban, rural and suburban properties. ASHPs in flats are ruled out because limited space is available for indoor units and because outdoor units can be difficult to access for maintenance. For the purposes of the model it is assumed that ASHP are suitable for both pre- and post-1990s buildings, albeit with reduced performance in older buildings, reflected in a lower seasonal performance factor. The low grade of heat from ASHPs excludes them from much of industrial heat demand.
- Ground-source heat pumps: Individual flats ruled out as considered that there will be not opportunity to install a ground loop except in ground floor properties and this is unlikely given communal ownership of land. Although older properties (1960s and before) with poor levels of insulation (and resulting high heat demand) may not be as suitable as newer houses, all pre-1990 houses are deemed suitable, but with a lower coefficient of performance to reflect the impact of older housing stock. Due to space requirements GSHPs are not deemed suitable for urban areas.
- Biomass boilers: All smaller urban domestic properties are assumed to be excluded due to air quality concerns and difficulties with access. Detached urban properties are retained in the supply curve, as some will probably be suitable. Coverage in the domestic sector is further reduced by air quality concerns in high density areas. By contrast, the ability to limit emissions from larger installations makes it possible to use biomass boilers for commercial / public and industrial heat loads even in urban areas. Biomass burners are restricted to those that meet relatively high air quality standards.[9]
- Biomass district heating: Biomass district heating is assumed to be potentially suitable in all urban and rural areas. Urban areas are high density areas supplied by traditional networks fuelled by waste wood and other cheaper biomass in large installations. This also includes social housing renovation and re-powering of existing schemes. The rural areas are small mini networks covering pockets of high density buildings with the benefit

[9] We assume that the majority of boilers below 300kW would meet En303-5 class 3 performance for thermal efficiency and emissions. Larger boilers would be expected to be fitted with abatement equipment.

of local fuel which is often the driver for take up. Suburban areas are excluded given the low density of heat loads and resulting higher cost.

- Solar thermal: Solar thermal is assumed to be potentially suitable for all buildings, but not for process heat.

2.2.2.3. Treatment of electric heating

We have made a further adjustment to demand potential in the case of electric heating. With some exceptions (for example, very small heat loads), the use of electricity for heating is significantly more expensive than either natural gas, oil, or solid fuels. Despite this, a substantial proportion of total heat demand is served by electric heating. We have not been able to investigate the reasons for the prevalence of electric heating in any detail, but it seems likely that the same barriers that prevent the adoption of fossil fuel fired heating systems also would stand in the way of the use of some or all renewable heat technologies. These may include space constraints, safety considerations, or other factors.

To reflect these factors in the modelling, we assume that 25 percent of the heat load served by electric heating is suitable for the conversion to renewable heat. This assumption would benefit from being refined through further research; however, it seems a more realistic representation of the potential for renewable heat than one that implies wide-spread switching from electricity to renewables, given that widespread switching from electricity to fossil-fuel-fired heating has not taken place. In addition to the adjustment to potential, we also make adjustments to the counterfactual cost of switching to electric heat (see section 2.4.1 below).

2.2.3. Demand-side constraint 1: Market potential

The second step in the demand-side assessment is to calculate the *market potential* for each technology. This is defined as the size of the market for ***replacement*** heating equipment that each technology could feasibly serve in the relevant time period. We calculate market potential by assuming a stock replacement rate linked to the counterfactual technology lifetime.

It may be possible to accelerate uptake above this level, at the cost of accelerated depreciation of heating systems before they would normally be retired. We deem this an unlikely route to increasing potential, especially as the rate of replacement is not the binding constraint on overall potential in our central scenario; even without accelerated depreciation, the size of the replacement market exceeds supply potential for all technologies in the central case (see section 4.2.1).

There are two main exceptions to the stock replacement approach to defining demand-side potential. First, solar thermal is complementary to, rather than a substitute for, existing heating equipment. The market potential therefore is estimated as the total number of heat consumers that have not already taken up the technology, assuming a representative size for each solar thermal installation.

Second, the market potential for biogas injection also is not dependent on the replacement of existing heating equipment, as it relies on the use of existing gas-fired equipment. Instead, the main potential limitation is that the rate of supply of biogas to the grid should not exceed the total local off-peak gas demand[10], which again is unlikely to pose a binding constraint in the scenarios modelled.

2.2.4. Demand-side constraint 2: Economic potential

The third step in the assessment is to establish the economic potential. This is the portion of market potential that can be more profitably served by each relevant renewable technology than by another heating technology, whether "conventional" (fossil fuel or electric) or renewable. This in turn depends on a variety of modelling assumptions that feed into the financial modelling, including renewable heat and incumbent technology assumptions, energy prices, and consumer behavioural assumptions. (It also depends on the level of subsidy, if any, offered to renewable heat.)

The cost of each technology option is calculated on a levelised basis over the lifetime of the equipment. See section 2.4 for more detailed discussion of the assumptions and methodology used.

2.2.5. Demand-side constraint 3: Demand potential

The market potential defines an upper bound on the adoption of a *single* renewable heat technology. However, a general feature of marginal abatement cost curves is that the adoption of one measure affects the emissions abatement potential available from other measures included in the curve. In the case of renewable heat this is particularly relevant, as many of the measures are direct substitutes. The use of one technology therefore fully excludes the potential for the use of other technologies to serve the same heat demand.

We refer to the potential available once these interactions have been accounted for as the "demand potential". Estimating this potential requires simultaneous modelling of all technology options for all demand segments. The decision of which technology to adopt is determined by the financial viability of the various heating options available. The model also ensures that the same heat load is served by one technology only (with the exception of solar thermal). Because the total supply of a given technology is likely to be constrained (see below), the availability of low-cost options may be limited by other consumers' technology choices.

One effect of these interactions is that some technologies may be limited in the supply curve not because they are technically infeasible or expensive compared to their counterfactual heating technology when subsidies are applied, but because they are less attractive than other (similarly subsidised) renewable heat options. The demand potential for a technology therefore can be small (or even zero), even where its technical potential is large.

2.2.6. Supply potential

The demand potential is further restricted and reconfigured by limitations to supply potential. This is defined as the available supply of a technology, given a situation where demand is not the binding constraint. The model accounts for two main sources of such restrictions:

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[10] Local peak demand is relevant because the biogas units will inject into the low-pressure gas grid, not the high pressure system.

First, for the technologies involving biological feedstock (biomass boilers, biomass district heating, and biogas injection), there may be an overall resource constraint. The total amount of biomass, including material available for production of biogas, is restricted not to exceed estimates of the total available resource. These estimates, in turn, are derived from E4tech (2009) as well as additional estimates developed by AEA.

Second, we apply supply industry constraints. Many renewable heat technologies start from a very small UK base, and the adoption of high levels of renewable heat depends on the rapid development of a supply industry. There are several potentially relevant constraints on supply growth, including shortage of skilled workers, limited infrastructure, small number of companies, institutions, and other elements of the supply chain required to deploy renewable heat. AEA has developed scenarios for the feasible rate of expansion of the capacity to supply renewable heat technologies. Assumptions about the available supply of a particular technology are a very important aspect of the modelling, with direct implications for the results, and we present the scenarios for feasible supply growth in detail in section 2.3.

2.2.7. Final potential

Modelling is required to calculate how the above considerations translate into adoption of renewable heat. The model estimates the least-cost supply curve by ordering technology options by their levelised cost of heat output, ensuring that the cheapest available technology (net of subsidy) is used to fill a given heat demand segment. The technology adopted by consumers in a given segment therefore depends jointly on all of the various factors discussed above. For example, limited supply potential may prevent the uptake in a given segment of the renewable heat technology with the lowest cost per MWh; this in turn would lead to the uptake of another technology; which in turn would influence the available demand potential for other technologies. The final pattern of uptake thus depends on the joint consideration of all of the above factors.

The potential for renewable heat cannot be deduced simply from the aggregate constraints on demand or supply potential. For example, given an aggregate constraint on domestic ASHPs, the amount of renewable heat output and associated resource cost depends heavily on which domestic segments take up the technology, which in turn depends on the interaction with the potential for other technologies. The final potential therefore depends on the interaction of the supply potential as well as the various factors that influence demand.

2.3. Supply Scenarios

Because supply constraints are a potentially important influence on the potential for renewable heat, it is important to consider what rates of expansion of the different renewable heat technologies may be feasible. Currently, renewable heat technologies serve only a small proportion of the UK heat load. Achieving the significant uptake envisaged for 2020 therefore will require the significant expansion of supply capacity, including increased capacity for equipment supply, growth or creation of installer companies, training of skilled personnel, and the development of required infrastructure. In the case of biomass and to some extent biogas, analogous constraints may arise for fuel supply, including limitations on the overall resource, the development of handling and distribution capacity, and a strengthening of supply reliability.

These and other factors can limit the amount of renewable heat output that can be achieved even in a situation where demand in principle is stimulated through subsidies. To account for this in the modelling, we use scenarios for feasible expansion of the supply of each technology, developed by AEA. In developing these scenarios, AEA has conducted a review of the situation in other countries where renewable heat technologies are much more widespread than they are in the UK, and also drawn on discussions with industry stakeholders and on internal expertise. Nonetheless, projections of future supply constraints are inherently uncertain and involve judgement. Reflecting this uncertainty, we present results throughout the report for more than one growth scenario. A more detailed account of the approach and assumptions used to develop the scenarios is found in Appendix C.

2.3.1. Central growth scenario

The central growth scenario is AEA's projection of a plausible expansion in renewable heat supply, assuming a situation where subsidies make the respective renewable heat technologies financially no worse than relevant fossil fuel or electric heating options.

The following is a brief summary of the underlying assumptions and barriers that limit expansion for each of the technologies. Appendix C contains further information about how these growth rates were derived, the relevant barriers and their influence on the growth scenarios.

§ **Air-source heat pumps (ASHPs).** The baseline data for existing installations is taken from published reports and we estimate that the total number of air to water heat pumps sold in the UK by 2010 could be 1,750. Based on a review of experience in other countries we assumed high annual growth in installation capacity of 100 percent for the first two years as the industry goes through an introductory phase following the introduction of the RHI, and then annual growth in sales of 30 percent each following year. This corresponds to the levels of growth experienced in other EU member states under the influence of strong incentives.

§ **Ground-source heat pumps (GSHPs):** Our best estimate for 2009 GSP installations based on discussions with stakeholders was up to 10,000 systems with a central estimate of around 8,000 systems. The growth trajectory assumes that in the early stages of the market high growth in installation capacity averaging around 50 percent per year can be achieved. However as annual numbers increase the cumulative impact of potential market barriers means growth in installation capacity gradually slows (although the cumulative number of installations grows by an average of 20 percent per year in the last years before 2020).

§ **Biogas injection:** We have calculated the bio-methane potential for the base case by assuming that waste authorities will initiate separate food waste collection to meet Landfill Directive targets. To this will be added an equal quantity of food industry waste. We also assume that waste authorities will co-operate to achieve economy of scale. We assume an initial growth period where the capacity installed increases at 100 percent per year, followed by steady growth at around 30 percent per year to 2020. This results in capacity corresponding to around 400 2 MW units by 2020. In the central case we did not consider manures as they are likely to be rural in origin and more likely to be used in CHP, or more likely electricity only, installations. We did however allow a small number of small, "on farm" digesters supplying larger rural properties with heat.

- **Biomass boilers:** We considered what proportion of users would be likely to take up biomass boilers, accounting for the location of the heat load and other factors, bearing in mind the barriers identified in Appendix C (Section C.1.1). For the non-domestic sectors we assume that sales (annual increment in capacity) could grow steadily from the current base at a rate of just over 20 percent. The domestic sector starts from a much smaller base, and we assume a large boost initially in the domestic sector as pellet-firing equipment is introduced in response to financial incentives, in line with experience from Ireland and elsewhere. Following this, we assume a growth in sales of 35 percent per year.
- **Biomass district heating:** District heating was taken as 20 percent of the deployment for biomass individual boilers and restricted to space heating applications.
- **Solar thermal:** The scenario is based on data on initial deployment from published sources, the rates of growth achieved in other EU Member States, and an analysis of the number of installers required to reach the implied capacity. The pattern is one of an initial boost followed by a more sustainable rate of growth, with an implied growth rate in installed capacity is around 45 percent in the period 2010-15, and 20 percent in 2015-20.

The key features of the scenario are summarised in Table 2.1. The table shows a maximum increase in heat output to 61 TWh by 2020, representing a ten-fold increase from the current baseline of around 6 TWh. The largest contribution is from biomass, followed by ground-source and air-source heat pumps.

Solar thermal and biomass district heating show significantly less potential.[11] For solar thermal this is driven by a reduction in the technology's assumed load factor, which limits its renewable output contribution (and therefore raises its per unit costs). This reflects new data that have become available since the publication of earlier analysis on the potential for renewable heat in the UK (Enviros 2008a).

Note that the growth scenario presented in Table 2.1 reflects supply-side capacity only. As described above, whether there is demand for the technologies depends on a range of factors that determine the availability of suitable heat load for which the particular technology is advantageous.

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[11] As noted in section 2.1.1.7, the limitation in district heating is due in large part to the fact that district heating using biomass CHP is not considered here.

Table 2.1
Summary of Central Growth Scenario

Technology	Sector	Potential (TWh)			Growth rate (% per year)	
		2010	2015	2020	2010-2015	2015-2020
ASHP	Non-domestic	0.3	2.3	10.7	51%	36%
ASHP	Domestic	0.1	0.8	3.5	51%	36%
Biomass boilers	Non-domestic	2.8	6.5	16.9	18%	21%
Biomass boilers	Domestic	0.0	1.0	4.7	90%	37%
Biomass DH	Non-domestic	0.5	0.7	1.4	7%	13%
Biomass DH	Domestic	0.5	0.7	1.3	7%	12%
GSHP	Non-domestic	0.5	4.0	11.4	52%	23%
GSHP	Domestic	0.2	1.3	3.7	52%	23%
Solar Thermal	Non-domestic	0.1	0.3	0.8	25%	18%
Solar Thermal	Domestic	0.2	1.9	4.6	51%	20%
Biogas injection	All	0.2	0.6	2.3	29%	30%
Total		**6**	**20**	**61**	**30%**	**25%**

Source: AEA estimates as explained in text.

The growth rates shown in the tables are the implied average growth rates in output over 5-year periods, summarising what may be more complex trajectories for technology deployment in the underlying projections. In particular, growth rates in the early years can appear very high because the technology is starting from a low base. In most cases, the rate in the 2015-2020 period is more indicative of the increase assumed for the technology after an initial growth phase.

The potential is complicated in some cases by the scope of the analysis. The most notable example is biogas injection, where the potential depends on assumptions about the use of biogas for injection into the grid, electricity generation, and combined heat and power generation. As discussed in Appendix C, the potential of 2.3 TWh in 2020 corresponds to the generation of biogas for export with a calorific value of 7 TWh, produced from 400 AD units, each with a capacity of around 2 MW. Because a large share of the gas generated is assumed to be used for electricity generation and combined heat and power generation, the amount available for injection is smaller than the total gas produced.

2.3.2. Stretch and higher growth scenarios

2.3.2.1. Stretch growth scenario

In addition to the central growth scenario, AEA was asked to consider a “stretch” growth scenario with the maximum deployment achievable for each technology in a situation where all of the limiting barriers to growth were overcome. This gives a total supply potential for renewable heat in 2020 of over 200 TWh (not accounting for demand considerations), and is described in more detail in Appendix C. The significant increase on the central case represents the simultaneous achievement of the maximum potential for all technologies, overcoming all the relevant barriers and achieving growth rates in many cases exceeding those achieved in other countries where significant renewable heat deployment has been achieved. The stretch scenario therefore is closer to technical potential than to realistically feasible potential. It s not used for the modelling scenarios in this report.

2.3.2.2. Higher growth scenario

In order to reflect uncertainties around these growth rates, a third "higher growth" scenario was developed at DECC's request. This scenario assumes a more optimistic development than the central growth scenario, but lower growth than the "stretch" scenario. Specifically, the scenario assumes that the output levels implied by the central scenario in 2020 can be increased by 50 percent for selected technologies.[12] For most technologies, this results in potential that is near the mid-point of the output implied by the central growth scenario and the stretch growth scenario.

The potential and growth rates in the higher growth scenario are summarised in Table 2.2. The total available potential in 2020 is 88 TWh, with increases proportionately across all technologies (excluding solar thermal and biomass district heating).

Table 2.2
Summary of Higher Growth Scenario

Technology	Sector	Potential (TWh)			Growth rate (% per year)	
		2010	2015	2020	2010-2015	2015-2020
ASHP	Non-domestic	0.3	2.3	16.0	51%	47%
ASHP	Domestic	0.1	0.8	5.3	51%	47%
Biomass boilers	Non-domestic	2.8	6.5	25.3	18%	31%
Biomass boilers	Domestic	0.0	1.0	7.0	90%	48%
Biomass DH	Non-domestic	0.5	0.7	1.4	7%	13%
Biomass DH	Domestic	0.5	0.7	1.3	7%	12%
GSHP	Non-domestic	0.5	4.0	17.0	52%	33%
GSHP	Domestic	0.2	1.3	5.6	52%	33%
Solar Thermal	Non-domestic	0.1	0.3	0.8	25%	18%
Solar Thermal	Domestic	0.2	1.9	4.6	51%	20%
Biogas injection	All	0.2	0.6	3.5	29%	41%
Total		**6**	**20**	**88**	**30%**	**34%**

[12] The scenario scales the potential for air-source heat pumps, biogas injection, biomass boilers, biomass district heating, and ground source heat pumps. It does not consider additional potential output from solar thermal or biomass district heating, as these technologies face limitations which restrict their contribution to a least-cost technology mix for overall renewable heat output under the modelling assumptions of this project (in the case of solar thermal because of its high cost; in the case of district heating because CHP is not considered).

2.3.2.3. Cost implications of achieving higher growth rates

Although the higher growth scenario has not been directly developed by AEA it remains within the range proposed by AEA's analysis. AEA has considered the additional costs that could arise if growth were to take place at this elevated rate compared to the central scenario. The main types of cost considered are:

- additional cost for capital expenditure ("capex") to reflect higher installation costs in a market with faster growth;
- additional operating expenditure ("opex") costs for installations in less suitable locations; and
- changes to the fuel mix of biomass boilers to reflect an increased proportion of urban installations.

Section B.9 contains additional information about these cost assumptions.

2.4. Cost of Renewable Heat and Other Modelling Input Assumptions

As the above illustrates, the modelling approach depends on the simultaneous estimation of renewable heat potential and cost. We calculate per MWh costs on a levelised basis over the equipment lifetime, incorporating capex, opex, fuel costs, emissions allowance costs (where applicable), as well as the cost of overcoming barriers to renewable heat. Many "supply-side" barriers (such as the need for additional works to adapt buildings for the use of renewable heat) are included in the capex. "Demand-side" barriers, including time costs, are separately accounted for.

2.4.1. Technology Characteristics and Cost

For each demand segment, we use estimates of technical and cost characteristics to develop an estimate of the cost of using each of the renewable heat technologies to serve the heat load. Specifically, we use estimates of the following quantities for each renewable heat technology and each relevant incumbent (fossil fuel or electric heating) technology:

- Capex (including equipment costs, installation costs, auxiliary works, etc.);
- Fixed opex (chiefly maintenance)
- Lifetime
- Thermal efficiency
- Load factor
- Representative size

The technical data have been estimated by AEA, relying on a range of sources. Appendix B contains details of the specific values, underlying assumptions, and sources used.

For a given technology, the technology parameters can vary significantly between different demand segments. The demand segmentation therefore also results in significant cost heterogeneity that captures many factors that sometimes are characterised as "supply-side barriers" to renewable heat (e.g., district heating pipes, costs of fuel storage, adaptation of heating systems, boreholes, or other auxiliary works).

We estimate costs on a levelised basis over the equipment lifetime, using additional assumptions about fuel and other input prices and discount rates. The model then calculates the *net technology cost* of renewable heat as the difference between the levelised cost of each renewable heat technology and its relevant counterfactual fossil fuel or electric heating option. For most technologies, the relevant counterfactual is a conventional boiler, fired using the relevant incumbent fossil fuel (gas, oil, solid fuel), or electricity. The net technology cost therefore is the difference between renewable heat and fossil fuel / electric heating costs, calculated on a per-MWh basis.

There are three main exceptions to this general approach. First, in the case of biogas injection the counterfactual is the wholesale price of natural gas, rather than a specific heating technology (this is because we assume biogas is injected in the grid at the point of production and is not attributed to specific sectors). The technology cost includes the cost of generating the gas and upgrading it for injection.

Second, solar thermal installations typically are complementary to, rather than substitutes for, conventional boilers. The fixed costs associated with conventional technologies therefore are incurred even if solar thermal is installed, and when calculating the net technology cost we do not subtract the counterfactual capital cost and fixed opex. The counterfactual cost for solar thermal thus is limited to the cost of the fuel or electricity inputs that would have been required to generate the heat provided by the solar thermal installation.

Third, we estimate the counterfactual cost when replacing electric heating using a slightly different methodology. As noted in section 2.2.2.3, we limit the potential for replacement of electric heating by renewable heat technologies to 25 percent of electric heating demand. Where replacement of electric heating is feasible, we make an additional modification that affects the counterfactual costs. Instead of using electrical heating as the counterfactual in this case, we assume that the relevant counterfactual cost is that of off-grid fuels, where these are lower. The rationale for this approach is that if it is possible to switch to a renewable heating technology, it would also be possible to switch to a non-net-bound fossil fuel, which would be less expensive. This is an approximation, but is likely to be more accurate in most cases than simply modelling the (high) cost of electric heating as the relevant counterfactual.

2.4.2. Fuel and Allowance Prices

2.4.2.1. Fuel prices

Fossil fuel and electricity prices influence the difference in cost between renewable heat technologies and their relevant counterfactual conventional heating technology, and therefore the resource cost of renewables. In addition, heat pumps use electricity, and we incorporate electricity costs as a variable cost of using this technology.

Projections for end-user fuel and electricity prices for the period to 2025 have been provided by DECC based on recent Updated Energy Projections (UEP) model runs and other modelling (DECC, 2009). The projections include four scenarios—referred to here as "low", "central", "high", and "high-high" scenarios—for petroleum, natural gas, coal, and electricity.[13]

The prices used for individual fuels and electricity in the model differ for the domestic, commercial / public (large and small), and industrial sectors. For the non net-bound counterfactual segment we have calculated a weighted average price based on the end-user prices for coal and heating oil (burning oil in the domestic sector) in the relevant sector, using the current split between solid fuels and oil fuels in the most recent data from DUKES.

We assume that investors make forward-looking decisions on the basis of future input prices, which are discounted using sector-specific discount rates and the lifetime of the relevant equipment (typically around 15 years). This calculation requires price projections beyond the period for which DECC has provided them, so we have assumed that long-term fuel prices stay constant (in real terms) at 2025 levels.

2.4.2.2. EU ETS coverage and allowance prices

We also incorporate the price of CO_2 allowances for installations covered by the EU ETS. Projections for the price of allowances have been provided by DECC, with one set of prices to accompany each of the fuel price scenarios described above.

We assume that the EU ETS covers 2 $MtCO_2$ of emissions from large public and large commercial segments, similar to 2007 verified emissions for the *c.* 200 installations in the EU ETS "Services" sector. For the industrial sector, we approximate actual coverage by assuming that process heat at large industrial installations is in the EU ETS. This results in coverage broadly consistent with data on EU ETS coverage of emissions in the sectors of the ENUSIM model of industrial energy use. This approach represents an improvement on past mappings of renewable heat potential and EU ETS coverage, which did not include the commercial sector. Nonetheless, the estimate could benefit from further research.

2.4.2.3. Biomass prices

The starting point for biomass prices used in the modelling are price projections developed by E4Tech for DECC (E4Tech, 2009), accounting for the resource cost of biomass fuel production as well as transport costs. For consistency with other DECC analysis we have used the import prices in the E4Tech modelling as the central biomass price scenario, resulting in prices from around £25 / MWh in 2010, falling to £15-16 / MWh by 2020, and further to £13-14 / MWh by 2030. The prices for the domestic and non-domestic sectors are similar, differing by around £1-2 / MWh.

The future of biomass prices is very uncertain. Key uncertain factors include the availability of supply and development of the UK supply chain; the development of import capacity and of relevant international biomass markets; the level of demand for non-fuel uses for biomass

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[13] These scenarios names correspond to the following scenarios described in DECC (2009):
- "Low" = Low energy demand;
- "Central" = Timely investment, moderate demand;
- "High" = High demand, producers' market power;
- "High-high"= High demand, significant supply constraints

(e.g., in agriculture, or in the pulp and paper or wood board industries); and the extent to which demand increases as a result of EU and international policies to promote renewables or reduce emissions. It also is possible that, with higher levels of demand and the development of more standardised biomass fuel product markets, biomass becomes more substitutable with fossil fuels, and therefore becomes more linked to prices in fossil fuel markets.

To reflect this uncertainty, we model a scenario with higher biomass prices. There are three main differences between this and the central case. First, prices start at levels similar to current market prices. For the price of wood chips we use E4tech's projections of commercial / industry biomass import prices of £26 / MWh. For pellets prices we use a price of £40 / MWh over the modelling period, a level somewhat lower than current UK pellets prices but higher than ones found in some EU markets.

Second, prices are kept constant over the modelling period (rather than declining steeply, as in the central case based on E4Tech's projections). Third, we account for potential differences in fuel mix in different consumer segments.[14] AEA has provided indicative information about the use of the different fuels in different consumer segments, with variation both by the size of the heat load and its location (see section C.2.1). Based on this, we have calculated different average biomass prices for the different demand segments.

Although these prices are described as "higher", they arguably represent a relatively conservative case, not reflecting the possibility of prices increasing from their current levels. A significant increase in prices is also possible, given the increased demand for renewable energy to meet 2020 targets throughout Europe. NERA has not analysed these issues in the context of this project, and the assumption of constant prices should not be taken as a projection.

2.4.2.4. Variable component of fossil fuel prices

In addition to the retail cost of fuels, we have been provided by DECC with a set of fuel prices that include only the "variable component" of fuel and electricity prices (see DECC, 2009) . This excludes from the retail price various items, including taxes, network costs, and emissions allowance costs. For consistency with DECC guidelines we use these lower prices to calculate resource costs.[15] For all quantities other than fuel we use standard retail prices (including taxes and fixed cost elements) for the calculation of resource costs.

The impact of using these prices on the cost of renewable heat varies by technology. For biomass, biogas, and solar thermal, they increase the cost of renewable heat, as the cost of conventional fossil fuel or electric heating options is lower. In the case of heat pumps, however, the cost can be either higher or lower, depending on whether the lower cost of electricity to power the heat pump is higher or lower than the reduction in fuel costs for the relevant counterfactual technology.

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14 The two primary types of biomass fuel are pellets and wood-chips. Pelletised fuel has higher energy density and is significantly easier to handle than wood-chip, and therefore is the dominant form in domestic applications and also is more common in urban settings where access for fuel handling is limited or space at a premium. Pellets are significantly more expensive than chips per MWh, however. For commercial, public, and industrial applications, we assume a split between pellets and wood chips, with larger heat users using a higher proportion of wood chip than pellet.

15 http://www.defra.gov.uk/environment/climatechange/uk/ukccp/pdf/greengas-policyevaluation.pdf

For reference, in case the resource cost estimates are used in other contexts, where it may be more appropriate to use retail prices for cost-benefit analysis, we also report resource cost calculations using standard retail prices.

2.4.3. Discount Rates and Cost of Capital

Discount rates are used in the model to calculate levelised costs of the different technologies. Discount rate assumptions therefore affect the relative importance of up-front costs (capex) and future variable costs (opex) in decisions about heating technologies.

One aim of the analysis is make it possible to estimate what subsidy levels may be necessary to reach a specified level of renewable heat output. The discount rates used in the modelling therefore are chosen to represent actual decision rules by individuals and organisations that would be likely to take up a subsidy if offered.

2.4.3.1. Household discount rates

There is considerable uncertainty about the discount rate that would be used by households when considering purchases of renewable heat technologies. As a lower bound on plausible discount rates, some households have access to savings and borrowing (including mortgage) rates at relatively low levels, in the region of 5 percent. At the other extreme, empirical estimates of discount rates for energy-related purchases, as well as survey evidence, suggest significantly higher rates, with estimates in excess of 30 percent not unusual.[16] There also is a wider literature on time preference, documenting high rates of discount in a wide range of situations.[17] As a further complication, empirically estimated discount rates also vary significantly between different demographic groups. On top of this, adoption of renewable heat technologies can entail higher risk to households than tried and tested conventional heating technologies, leading to higher effective rates of discount. Finally, the average tenure of a house is less than half the lifetime of most of the heating equipment considered. The ability of households to continue to benefit from a previous investment in renewable heat equipment upon selling a house is far from certain, which could significantly reduce the realistic required payback period on an investment in renewable heat.

Given the considerable uncertainty about the appropriate domestic sector discount rate to use, we consider scenarios with a range of rates, from a “low” scenario of 8 percent to a “high” scenario of 32 percent. Although the balance of various influences on the discount rate is uncertain, our assessment is that the most appropriate discount rate is probably not at the higher end of this range. One reason for this is that the relevant households are likely to be home owners (or potentially social housing), with access to cheaper credit than many other consumers. Also, the fact that investment would entail entitlement to relatively certain future

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[16] A directly relevant example is the implied discount rate of 30-35 percent found in a survey of attitudes to microgeneration (BERR 2005). Econometric studies of energy efficient appliances have found still higher values (e.g., Jerry A. Hausman (1979), ‘Individual Discount Rates and the Purchase and Utilization of Energy-Using Durables’, *The Bell Journal of Economics*, Vol. 10, No. 1, pp. 33-54). A complication is that empirical estimates may be inflated by costs that are not easily observed (“hidden and missing costs”), limiting their applicability outside the situation where they were estimated.

[17] See Frederick et al., Frederick, S, George Loewenstein and Ted O'donoghue (2002), ‘Time Discounting and Time Preference: A Critical Review’, *Journal of Economic Literature*, Vol. XL (June 2002), pp. 351–401.

subsidy payments could aid the development of a loan market at relatively low interest rates, potentially using the subsidy entitlement as security. For most of the analysis we therefore use a "mid-low" rate of 16 percent, with sensitivity analysis using the "low" rate of 8 percent as well as a "mid-high" rate of 25 percent (see section 4.3.3).

2.4.3.2. Non-household discount rates

There also is uncertainty about the appropriate rate for the non-domestic sector. As in the case of households, the pure cost of capital can differ significantly between different sectors and industries, and the appropriate value depends on where renewable heat would be deployed. In addition, in organisations where energy use is not a major focus of business activity, it is common for organisations to account for the (opportunity) cost of using scarce capital and uncertainty of benefits of investment in energy equipment with very stringent payback criteria; for example, a payback requirement of 3 years implies an investment hurdle rate of 33 percent. There also may be some aspects of decisions (such as split incentives) that may be particular to energy decisions.

Just as in the household sector, we therefore use a range of discount rates, ranging between a "low" scenario of 8 percent and "high" scenario of 20 percent to reflect uncertainty about the cost of capital. The "mid-low" rate used as a starting point for much of the analysis is 12 percent, with a "mid-high" rate of 16 percent used for sensitivity analysis alongside the "low" rate.[18]

2.4.3.3. Discount rates used for social cost calculations

When calculating the net present value of costs and benefits, we use the 3.5 percent social discount rate recommended by the HM Treasury Green Book. The private costs implied by the discount rates discussed above are accounted for before such discounting, turning private costs into a stream of costs and benefits over time, which subsequently is discounted at the recommended social discount rate.

2.4.4. Demand-side Barrier and Administrative Costs

2.4.4.1. Demand-side barriers

Experience from energy efficiency policy and other energy policy involving households suggests that demand-side barriers can be significant in energy consumption decisions in both the domestic and commercial sectors. In the case of renewable heat, demand-side barriers include a wide range of phenomena including time input required for project identification, appraisal, and commissioning; perceived risks associated with unfamiliar technologies; the costs of disruption or "hassle"; and various other aspects of projects that are not captured in equipment, installation, and ongoing variable costs.

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[18] This is higher than the weighted average cost of capital for many industries, but in line with some published estimates (e.g., McLaney et al. (2004), McLaney, E, J. Pointon, M. Thomas, J. Tucker, 'Practitioners' perspectives on the UK cost of capital', *The European Journal of Finance*, Volume 10, Issue 2 April 2004, pages 123 - 138). It is lower than the hurdle rates used by many organisations in practice.

There are three main approaches that can be taken to modelling demand-side barriers: First, barriers can be modelled as "uptake rates" which constrain the rate at which technologies are deployed and used by consumers. This can have the advantage of avoiding unrealistic increases in activity, but has the disadvantage of exogenously constraining modelling results independently of other input assumptions. For example, increases in fuel prices would be expected to increase the propensity to use renewable technologies, which would not be captured by a generic uptake rate scenario. In addition, uptake rates often become the dominant determinant of modelling results, even though it often is difficult to establish an empirical basis for a particular uptake rate.

A second approach is to model barriers implicitly through high discount rates. The magnitude of barriers of hidden and missing costs can be estimated as the value implied by the difference between a high hurdle rates of return and the actual cost of capital when applied to the relevant initial outlay and subsequent revenue or costs streams. A drawback of this approach is that it postulates payback rules and behaviours that may not actually be in use. It also conflates genuine capital costs with entirely separate categories of costs in a single discount rate number, making it less transparent what is influencing particular outcomes. Moreover, the approach implies that barriers influence the distribution of costs and benefits over time, whereas it is likely that many barriers actually are better seen as up-front costs.

A third approach, which we adopt here, is to attempt explicitly to account for demand-side barriers through bottom-up estimates of time input or risk premiums. These in turn can be entered into the model as fixed or ongoing costs associated with particular technologies. Our primary source for estimates of demand-side barrier costs is Enviros (2008a, 2008b). The costs accounted for by Enviros include the "hassle" (time cost) of project appraisal, installation, and maintenance that arise from the use of renewables but not for the relevant counterfactual heating technology using fossil fuels. The estimates also include additional costs of obtaining planning permission that may be incurred when using renewables.

We also use estimates derived by Element Energy (2008) of household hassle costs, covering issues such as the inconvenience of fuel deliveries and space requirements for biomass boilers and fuel storage, and the need to dig up gardens for ground-source heat pumps.

One difficulty with accounting for barriers is that they are not only inherently uncertain, but also likely to change over time. Barriers in a situation where renewable heat technologies are a well-developed mass market are likely to be substantially smaller than in immature markets.

2.4.4.2. Administrative costs

We also account for the administrative costs incurred by the users of the scheme (as opposed to those incurred by the administrator of the scheme) that are likely to arise in a subsidy programme. As the exact format of the subsidy has not been determined we have not attempted to reflect any particular policy programme, but use estimates developed in previous research (see NERA 2008 for details).

2.4.4.3. Costs of time

Both demand-side barrier costs and administrative costs require an estimate of the cost of time spent by affected individuals and companies. We use as a starting point for estimates of time costs the information developed by the Transport Analysis Guidance (TAG) produced by the Department for Transport, and make some modifications to fit the context of this project. This results in a value of £15 per hour for the domestic sector and £70 per hour in the non-domestic sectors. The motivation for these numbers is described in NERA (2008)

2.4.5. Other Input Assumptions

2.4.5.1. Emissions factors

To calculate the emissions savings from the use of renewable heat we use the emissions factors in Defra's guidelines for company reporting of greenhouse gases (Defra, 2007). For the non net-bound sector we use a sector-specific average based on the weighted average emissions factor of coal and oil fuels (heating oil in the non-domestic sector and burning oil in the domestic sector), using the consumption of each fuel as weights. For electricity we use the "long-term marginal factor" of 0.43 tCO_2 / MWh for electricity.

There are two main considerations that we see arising from the use of these factors. First, in our view the electricity factor appears to be an overestimate of the actual long-term marginal factor. The guidance document states that the factor is intended to reflect the fact that avoided electricity use will "displace generation at a new Combined Cycle Gas Turbine (CCGT) plant". However, new CCGT plant can achieve emissions factors of around 0.35 tCO_2 / MWh, and even accounting for distribution losses of 6-7 percent a factor in excess of 0.375 therefore would seem to be an overestimate. There also is the more difficult question whether it is appropriate to treat CCGT plant as the marginal baseload entrant for all years until 2020. If, for example, new entrants equipped with carbon capture and storage, new nuclear capacity, or other low-emissions technologies come on-line within this period the expected emissions factor may be substantially smaller.

A second consideration is whether any emissions should be assigned to biomass fuels. We have followed Defra guidance to use an emissions factor of zero for biomass fuels. However, it is likely that the production of some biofuels will be associated with some emissions of CO_2 or other greenhouse gases. While this may be more of a consideration for the transport sector it could also be the case for some fuels in the heating sector.

2.4.5.2. Shadow Price of Carbon

For the valuation of the social benefit of emissions reductions we use the Shadow Price of Carbon numbers recommended by Defra (2008) for emissions reductions outside the EU ETS. For valuation of reductions of emissions within the EU ETS we follow the current practice for appraisal within the Government Economic Service, using the price of EU ETS allowances to estimate social benefits. The allowance price projections were provided to us by DECC and are detailed in DECC (2009).

2.4.6. Subsidy and Policy Assumptions

The focus of this report is on the development of a renewable heat supply curve, and to characterise the cost, emissions savings, and other relevant aspects of achieving different level of renewable heat deployment. We do not model a specific policy package, or investigate how different RHI designs may influence the results.

The model finds the composition of renewable heat projects that achieves a certain level of output at least cost with respect to *useful heat output*. This models the choices of heat consumers given the technology options available to them. As we describe below, because the various technologies' contribution to the UK's renewable energy target differ, this is *not* necessarily the same as achieving the specified contribution of heat *to the renewables target* at the lowest cost to the UK economy.

The model also calculates the per-unit, ongoing subsidy required to achieve a certain level of renewable output. In place of a precise format of the RHI, which is yet to be determined, we model a simple generic subsidy, paid per unit of eligible renewable heat output generated on an ongoing basis. In the modelling, the same level of subsidy is paid to all eligible heat projects.

The modelling period runs from 2011 to 2020, and covers only renewable heat projects undertaken in this period. It is assumed that subsidy support is continued for the lifetime of the projects undertaken. Subsidies thus are modelled also after the 2020 modelling cut-off, but only to projects undertaken no later than 2020.

2.4.6.1. Renewable heat scenarios

The modelling uses recent UEP projections of heat demand and associated levels of renewable heat provided by DECC. To reflect guidelines from the EU Commission on how renewable heat will apply to national renewable energy targets, the levels for certain technologies are denominated on an *input* basis, i.e., as a proportion of the energy content of the fuel used to generate heat. In contrast, previous analyses were undertaken based on the level of useful heat output. Because there are typically some losses in the conversion of fuel energy to useful heat output (boiler and overall system energy conversion efficiencies are less than 100 percent) the energy input level is higher than the level of heat output.

The scenario levels used in the modelling are shown in Table 2.3. The overall level of energy input required to satisfy heat demand in 2020, as well as baseline level of renewable heat output have been provided by DECC. All energy quantities are expressed on a net (lower heating value, or LHV) basis.

Table 2.3
Scenario Levels of Renewable Heat 2020 (TWh, input basis)

Quantity	Heat demand (input basis) TWh
Total heat demand	599
Baseline level of renewable heat	6
12 percent share	
Total renewable heat	72
Additional renewable heat	66
8.5 percent share	
Total renewable heat	51
Additional renewable heat	45

Source: Heat demand and baseline level of renewable heat have been provided by DECC and are based on recent UEP modelling.
Notes: All values are denominated on an "input" basis, and reflect a lower heating value.

2.4.6.2. Contribution of technologies to renewable heat levels and denomination of subsidy

Although all of the technologies that we model have the potential to contribute to meeting the UK's renewable energy target, they do not contribute on an equal basis. That is, one MWh of heat output provided by one technology may be worth less, in terms of meeting the target, than one MWh provided by another technology. Table 2.4 shows the high level principle governing how each technology is assumed to contribute to the UK target.

To avoid confusion with heat output, we refer to the contribution toward the renewable energy target as the *additional renewable resource* (ARR). In the case of biomass boilers the ARR is equal to the calorific value of the fuel input, a definition closely corresponding to the input energy definition of the overall target. In the case of district heating, the ARR contribution is equal to the heat provided to the end-user (closer to heat output), whereas the contribution of injected biogas is equal to the calorific value of the injected gas (heat input). For solar thermal, the ARR is the useful heat provided by the installation. Heat pumps are a special case, as the renewable contribution is equal to the difference between the net heat output and the net electricity input.[19]

[19] There also are additional restrictions on the eligibility of heat pumps. As the precise definitions are not clear, we have assumed, on DECC's advice, that for the purposes of this modelling all heat pumps will be eligible.

Table 2.4
Contribution of Technologies to the UK Renewable Energy Target

Technology	Contribution to ARR
Heat pumps	Heat output less electricity input
Biomass boilers	Calorific value of fuel input
Biomass district heating	Heat delivered to end-user
Solar thermal	Heat output from unit
Biogas injection	Calorific value of gas injected

Source: Definitions provided by DECC.

These definitions mean that there is a difference between technologies' contribution to ARR (the policy objective) and their heat output (the consumer's objective). DECC has requested that we model a subsidy provided per unit of useful heat output to the consumer. This means that even if the same level of subsidy (per unit output) is provided to all technologies, they will each receive different levels of subsidy with respect to their contribution to the overall policy objective.

Some illustrative examples of this effect are provided in Table 2.5. For solar thermal and district heating, the ARR and heat output are identical, so a subsidy per unit output translates to an identical subsidy per unit ARR. The same applies to biogas injection, where the subsidy is provided per unit of gas injected. For heat pumps, the subtraction of input electricity means that the net ARR provided depends on the coefficient of performance (COP) but is always lower than the heat output. The opposite applies to biomass, where the ARR is denominated in terms of fuel ***input***, which is always higher than the useful heat output because of losses in conversion. [20] Thus one implication is that uniform payment per unit heat output would result in the overpayment of heat pumps (relative to the most cost-effective way of attaining the target) and underpayment of biomass boilers. For example:

- The subsidy to heat pumps is higher than their contribution to ARR: For example a subsidy of £50 / MWh to the heat output from an ASHP with a coefficient of performance of 2.75 implies a unit cost to contribute to the target of £80 / MWh ARR.[21]

- The subsidy to biomass is lower than its contribution to ARR: Offering a heat output subsidy of £50 / MWh heat output from a biomass boiler with efficiency of 85 percent implies a unit cost per contribution to the target of just over £40 / MWh ARR.

[20] One implication of this is that for heat pumps the subsidy per ARR *increases* the less efficient is the system; whereas for biomass boilers the subsidy per ARR *decreases* with less efficient units.

[21] A coefficient of performance of 2.75 means 2.75 units of heat output are obtained for each unit of electricity input. A heat pump with these characteristics thus provides 0.6 MWh of ARR for each unit of useful heat output; correspondingly, the subsidy received per unit ARR is higher by the factor 1.6 than the subsidy per unit output.

Table 2.5
Illustrative Additional Renewable Resource and Heat Output from Selected Renewable Heat Technologies

Technology and sector	Illustrative efficiency / COP	MWh ARR per MWh heat output	Subsidy per unit ARR / subsidy per MWh output
ASHP, large-scale	350%	0.7	1.4
ASHP, domestic	275%	0.6	1.6
Biogas injection[1]	-	-	1.0
Biomass boiler	85%	1.2	0.9
Biomass district heating	100%	1.0	1.0
GSHP, large-scale	400%	0.8	1.3
Solar thermal	100%	1.0	1.0

Source: NERA calculations as explained in text.

Notes:

1. The subsidy of biogas injection is per unit of gas injected into the grid. The conversion efficiency and heat output therefore are not relevant to the calculation.

An implication of the above is that a uniform subsidy per unit heat output is *not* generally the least-cost method of achieving the overall target. The least-cost approach would be to provide the same subsidy per marginal contribution towards the overall policy objective, i.e., for each unit of ARR. A subsidy denominated per unit of heat output is likely to deliver the target at a higher overall cost. As the differences in subsidy per unit ARR can be relatively large, this effect may be significant.

3. Summary Supply Curves for Renewable Heat

3.1. Summary Supply Curves

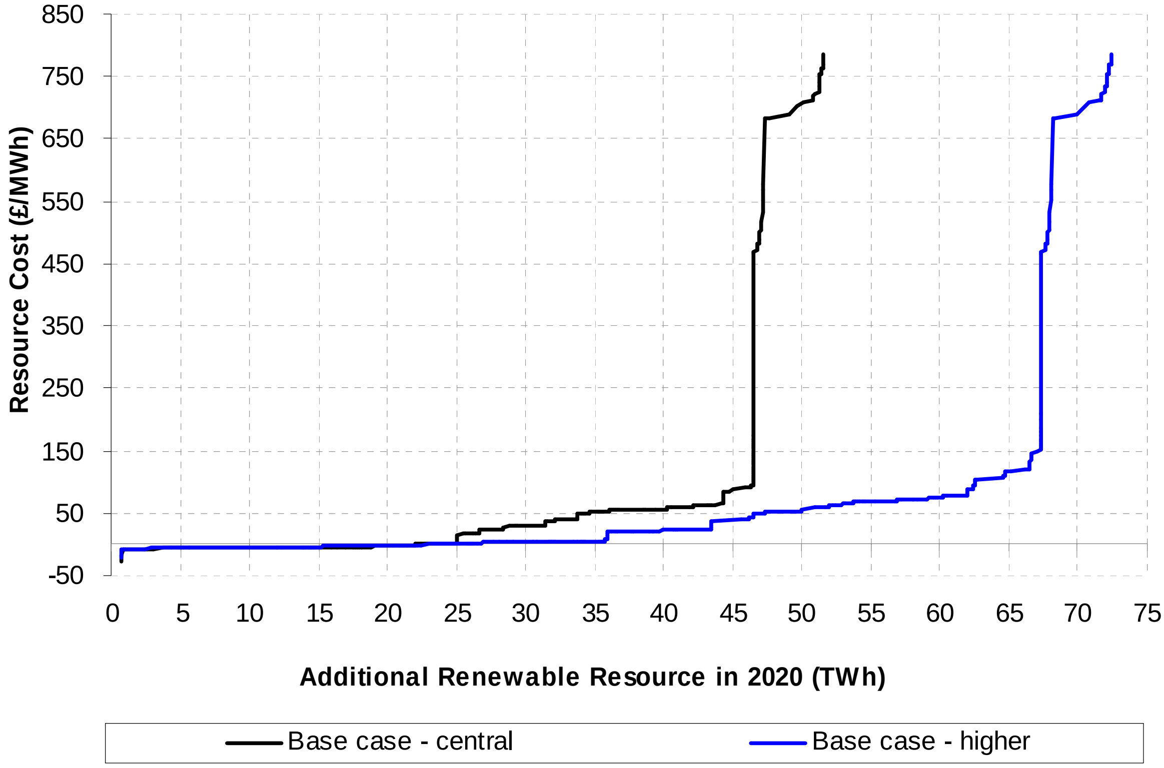
3.1.1. Supply Curves Overview

Figure 3.1. shows the supply curves calculated for the central growth and higher growth scenarios under base case assumptions for other input variables. The horizontal axis of the figure indicates total *additional renewable resource* from renewable heat technologies in 2020, relative to the business as usual level (which is expected to be around 6 TWh). The vertical axis indicates the net *resource cost* associated with each output level – i.e., the total cost of using renewable heat, *over and above* the relevant alternative conventional heating technology. This is calculated using the "variable component" of fuel prices, as discussed in section 2.4.2.4. The resource cost reflects the costs of both renewable and conventional heat technologies, and also the costs associated with administration, supply-side barriers, and demand-side barriers. Note that the definitions of additional renewable resource as well as the resource cost shown here differ from what would be perceived as relevant to a heat consumer: for the consumer, the relevant quantity would be denominated in heat output and the additional cost per MWh would be calculated by comparing retail prices / costs. We present a figure on this basis below.

The amount of renewable heat achievable by 2020 depends on the growth assumptions. In the base case, the maximum is just over 50 TWh, whereas the higher growth case shows a maximum of 72 TWh.[22]. In both cases, there is a sharp increase in resource above £150 / MWh, reflecting the very high costs associated with solar thermal heating.

[22] The potential shown in these curves differs from the supply potential shown in Table 2.1 and Table 2.2 above in a number of respects. First, the figure shows only *additional* potential, so does not include the baseline heat output. Second, the potential in the figure is denominated in additional renewable resource (see section 2.4.6.2), whereas the supply potential is denominated in heat output (and therefore 5-10 percent higher). Finally, the supply curve modelling accounts for demand-side restrictions which may limit potential in some cases.

Figure 3.1
2020 Supply Curve for Central and Higher Growth Scenarios by Technology – Overview



Source: NERA calculations as described in text.

Another notable feature of these cost curves is the suggestion that a significant proportion of the new renewable heat potential (around 20 TWh by 2020 in the higher growth scenario) could be available at no additional or resource cost. Various actors contribute to this. The most prominent may be that much of the low-cost potential is biomass, which in this particular scenario benefits from biomass prices that start lower than current market prices and that fall significantly until 2020 (see discussion below). Another factor is that technology costs for renewable heat are assumed to decline in the period to 2020, whereas costs for conventional technologies do not decline (section B.8 shows our assumptions about how capex changes over time).

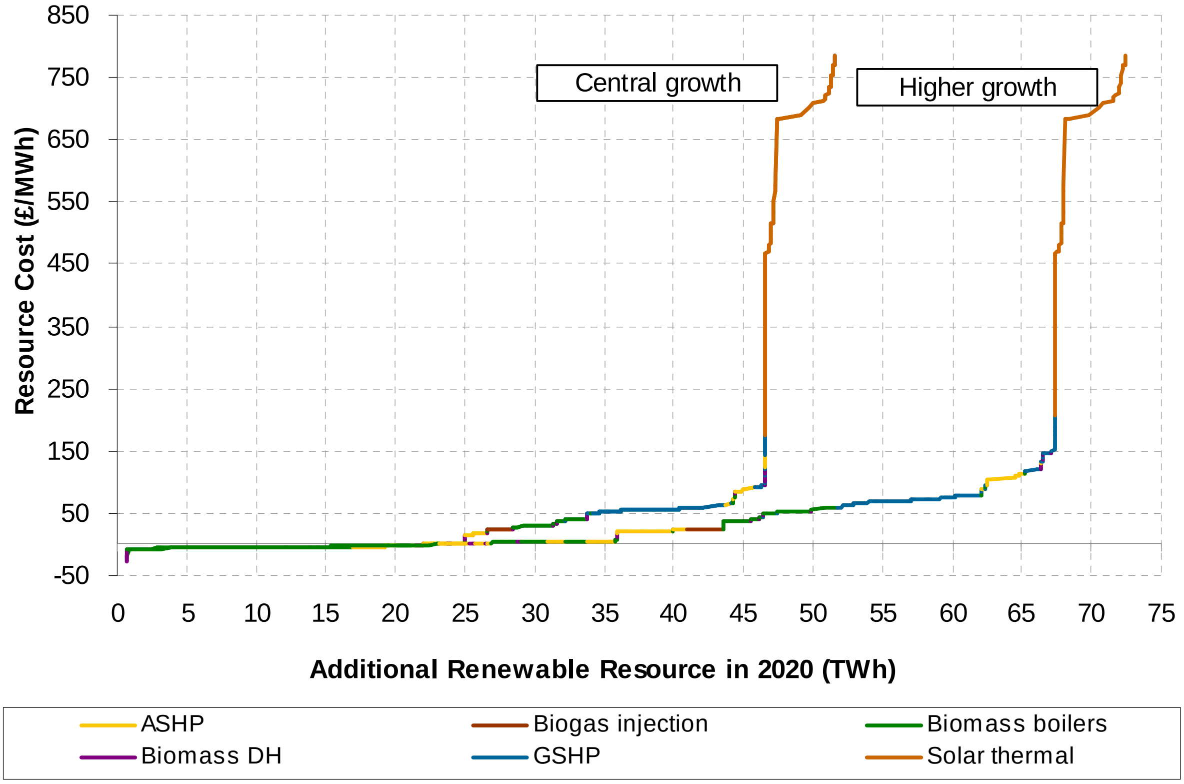
The finding of low costs also depends on overcoming barriers that in the past have been significant in limiting the adoption of renewable heat. The barrier costs and growth scenarios modelled implicitly assume widespread adoption of renewable heat technologies, including no or little performance or reliability penalty compared to conventional heating technologies. It may cost more to overcome various barriers (e.g., to achieve reliable fuel supply or equipment supply chains) without the large-scale use of renewable heat technologies implied by these scenarios.

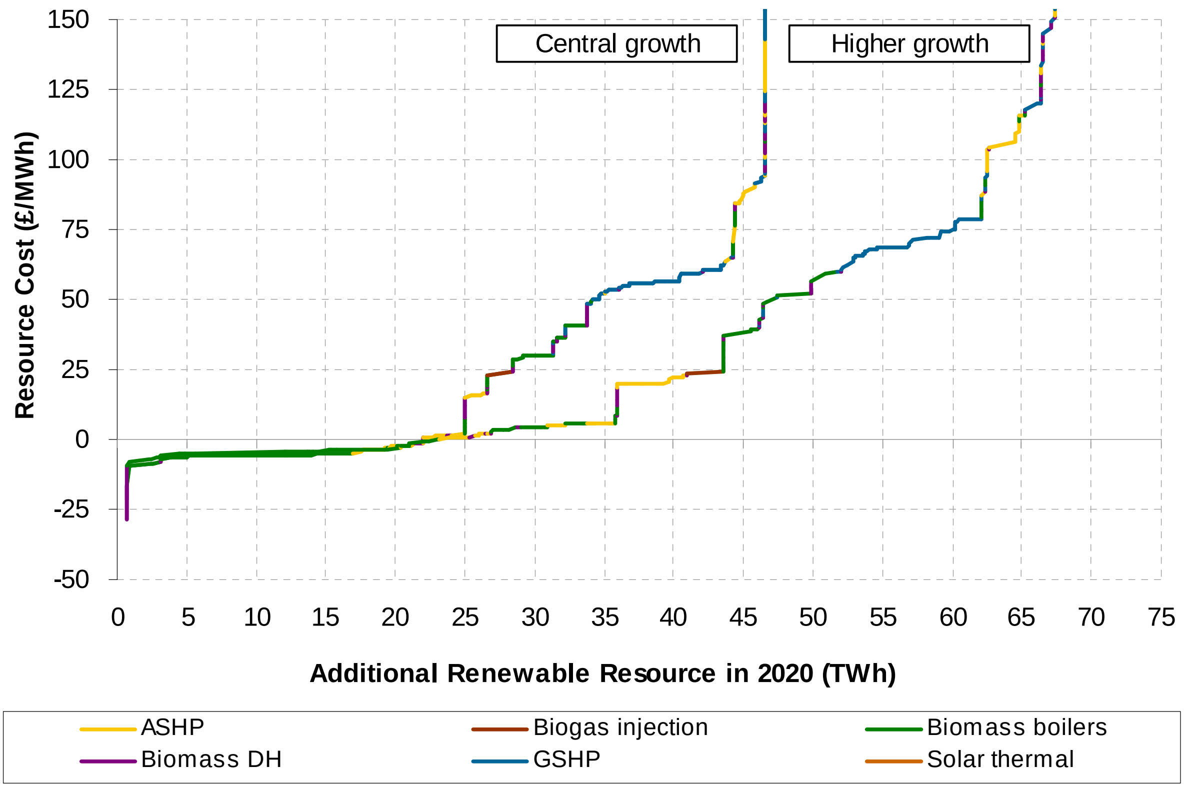
There are thus several reasons to treat the negative cost results with a degree of caution.

3.1.2. Supply curve by Technology

Figure 3.2 shows two graphs, the first the complete supply curve, and the second the potential available at a resource cost of £150 / MWh or less, capturing the large majority of the potential. The curves also are colour-coded to show the different renewable heat technologies. Overall, the greatest potential is found among biomass boilers, air-source heat pumps, and ground-source heat pumps. The low-cost segment below £15 / MWh, which also has significant “negative” cost potential, is dominated by biomass boilers, with some contribution also from air-source heat pumps. From around 15 / MWh there is a gradual increase up to £100-125 / MWh, with biogas injection and ground-source heat pumps added to the mix, and all technologies interspersed and appearing at a range of cost levels. There is a subsequent sharp increase in costs above £100 / MWh, with most of the potential for biomass district heating and all of solar thermal potential appearing above the £150 / MWh that is the maximum of the scale in the figure.

Figure 3.2
2020 Supply Curves for Central and Higher Growth Scenarios by Technology





Source: NERA calculations as described in text.

As the figure shows, there is a segment representing a significant amount of biomass with very low cost per MWh ARR, although biomass boilers appear throughout the range of costs. The figure also makes clear that the cost of solar thermal is substantially higher than that of other technologies.[23] , Beyond this, there is no neat segmentation of technologies, but each technology appears with a range of costs.

An important implication of the findings is that the growth rate assumptions have a profound effect on the cost and potential available. As costs rise quickly after a certain point, the amount of low-cost opportunities that realistically can be made available before 2020 are a very important factor in determining the overall cost of achieving a given level of renewable heat.

The growth rates assumed also have other effects. Costs are assumed to be somewhat higher under the higher growth scenario (see section 2.3.2.3 and Appendix C), but there also are other effects that complicate a direct comparison of costs across the supply curves. The resource cost depends not only on the cost characteristics of the renewable heat technology, but also on the cost of the counterfactual conventional heating technology; and both of these in turn depend on very specific features of the heat load being served (total size, load factor, etc.). With different growth rates, different technologies may serve the same heat load, meaning the same technology appears with different costs in the two curves.

3.1.3. Supply Curves By Consumer Sector and Fuel Counterfactual

One of the reasons that there is no neat separation by technology is that the total resource cost varies significantly with demand factors. We illustrate some examples at a high level in the discussion below.

Figure 3.3 shows the same supply curves as in the preceding figure, but colour-coded by consumer segment – domestic, commercial / public, and industrial heat demand – rather than by technology. This shows that the low-cost opportunities up to £10-15 / MWh are made up of two main types: low-cost biomass in industry, and air-source heat pumps in the commercial / public sector. Overall, these combinations of technology and consumer segment appear to be the opportunities for renewable heat that have the lowest cost and that are closest to commercial viability. The cost of achieving a given level of renewable heat therefore depends heavily on the feasibility of expanding the use of these technologies in these consumer segments.

From around £15 / MWh the picture is more complicated, with a mixture of contributions from all three consumer sectors. Although the domestic sector accounts for 45-50 percent of heat demand over the relevant period, it does not represent a commensurate share of the potential for renewable heat. This reflects a range of factors, including the suitability of renewable heat technologies, but is chiefly a result of the growth rate assumptions in the

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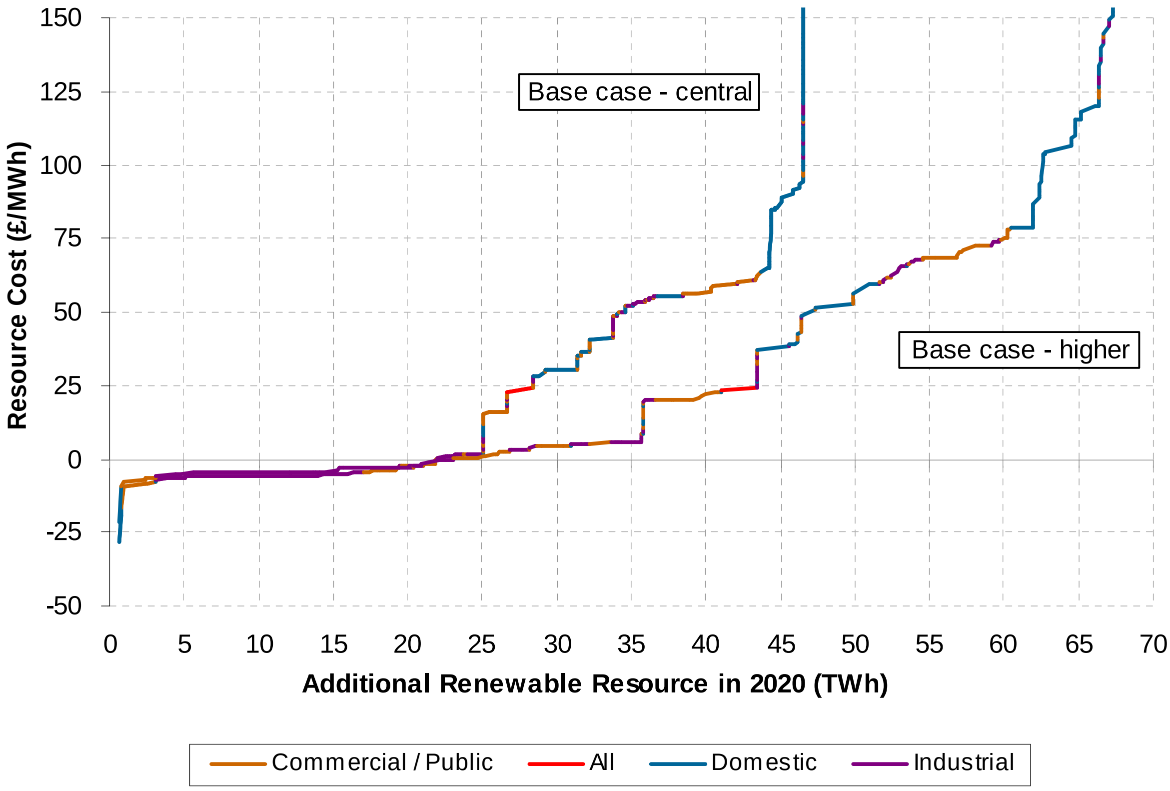
[23] The cost of solar thermal is significantly higher than in previous analyses, reflecting a number of factors. First, the capex is some 80 percent higher than in Enviros (2008a), while new data indicate significantly lower heat output from solar thermal units than we previously assumed (see section B.5 for details of the assumptions used). Second, the calculation assumes that solar thermal complements rather than replaces other technologies, and that the capital maintenance costs of the counterfactual technology are not avoided by installing solar thermal (see section 2.4.1). Finally, the cost is highly sensitive to the discount rate used.

scenarios shown. As the figure shows, it also is generally the case the opportunities for renewable heat in the domestic sector have a higher cost than those in the industrial and commercial / public sectors.

Figure 3.3
2020 Supply Curve for Central and Higher Growth Scenarios by Sector



Source: NERA calculations as described in text.

The corresponding information organised by fuel counterfactual – i.e., the fuel of the incumbent heating technology – is presented in Figure 3.4. Natural gas accounts for some three-quarters of heat demand, but a much smaller share of the potential for renewable heat. This reflects the generally higher cost of switching from gas compared to switching from non-net-bound or electric heating, which translates in the modelling to a lower degree of adoption by gas users.[24] The effect is particularly pronounced in the low-cost potential below £15 / MWh, which reflects exclusively opportunities to replace non-net-bound and electric heating with the non-domestic biomass boilers and air-source heat pumps discussed above. Nonetheless, there are limits on what can be achieved by replacing these fuels alone, and above £15 / MWh the picture is more mixed, with no clear aggregate correlation between cost and counterfactual fuel once demand-side constraints have been accounted for.

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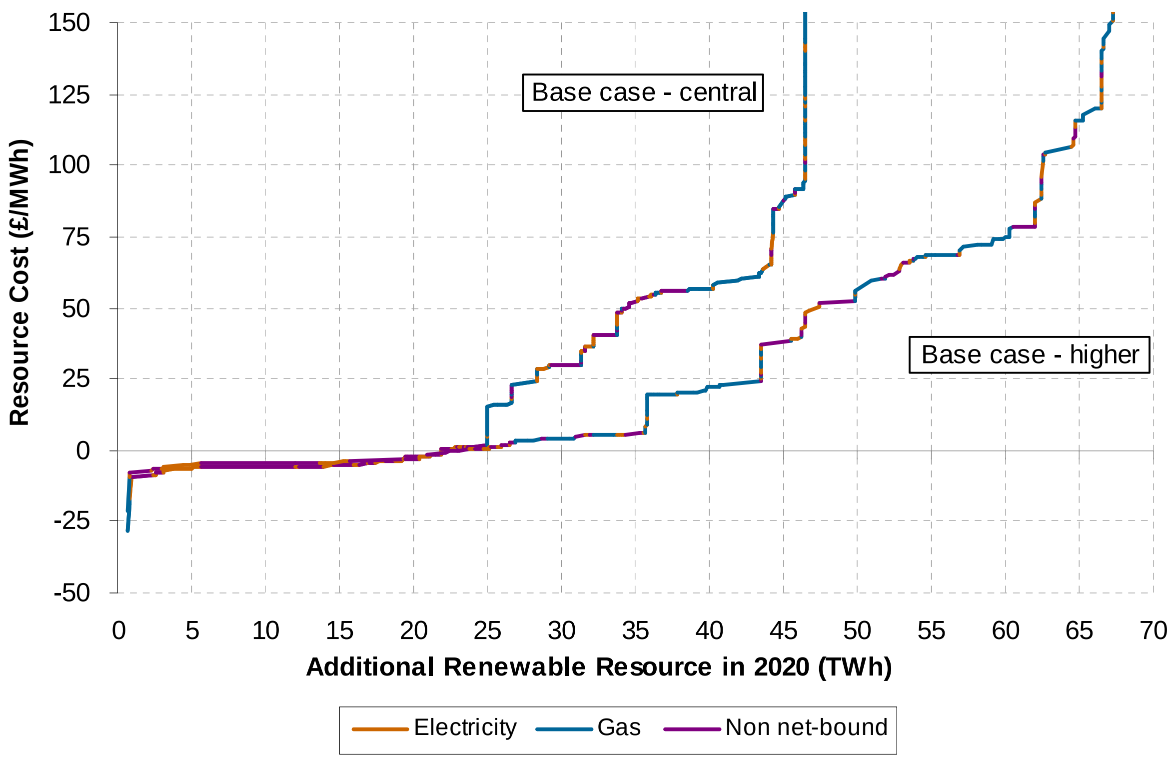
[24] As discussed in section 2.4.1, the methodology and assumptions underlying the calculations mean that the cost associated with replacing electric heating with renewable heat technologies in some cases is identical to that of replacing non-net-bound fuels.

Figure 3.4
2020 Supply Curve for Central and Higher Growth Scenarios by Fuel Counterfactual



Source: NERA calculations as described in text.

3.2. Impact of Input Assumptions on Supply Curves

The above supply curves are sensitive to a range of input assumptions used in the modelling. Among the more prominent are fuel costs (including biomass prices) and discount rates. In the next sections we present supply curves that result when we vary these assumptions.

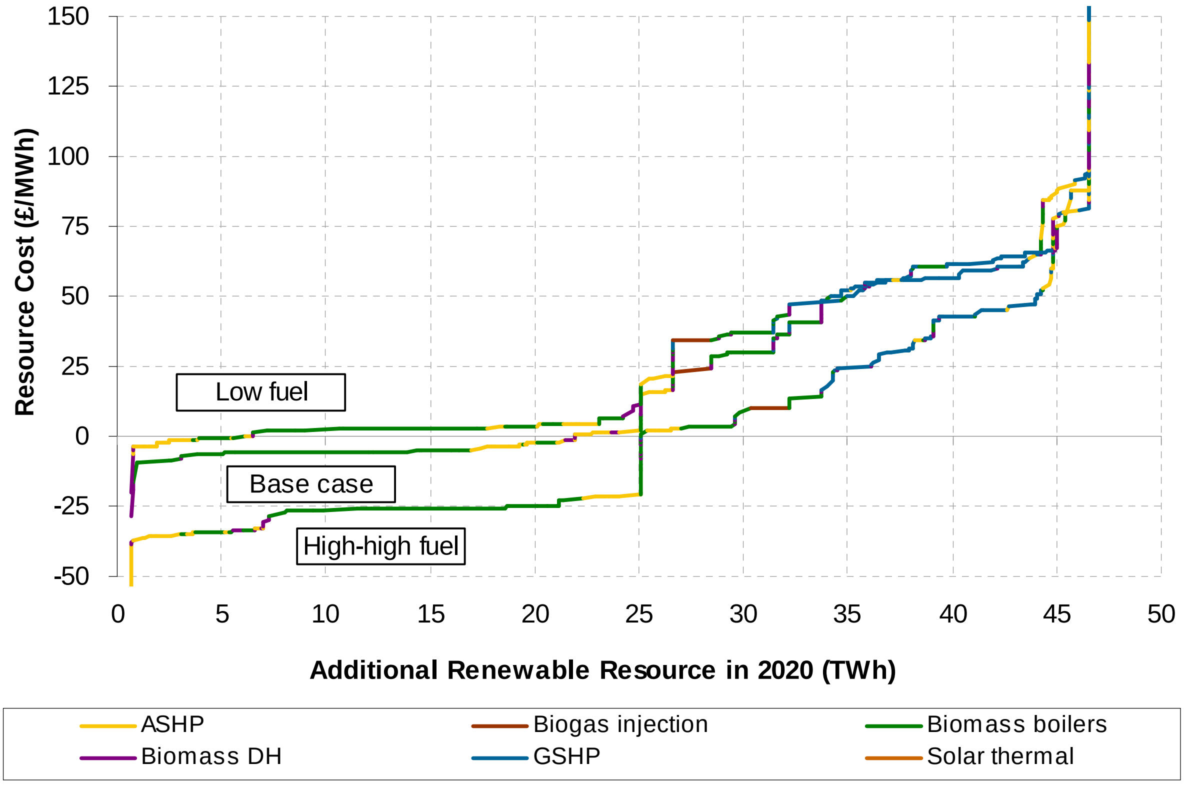
3.2.1. Impact of Fuel Costs

The cost of fossil fuels and electricity (and for some heat users the related cost of CO_2 emissions allowances) directly affects the attractiveness of renewable heat by raising the cost of conventional heating: under high fuel prices, renewable heat generally is more attractive, whereas low fuel prices typically raise the cost of renewable heat. For heat pumps, however, the effect is less clear-cut, as their running costs depend on electricity prices; the net effect of higher/lower fuel prices therefore depends on specific circumstances.

Figure 3.5 shows supply curves for the central case under three sets of fuel price assumptions. As this illustrates, different fuel prices can have a very significant influence on the attractiveness of renewable heat relative to conventional heating technologies. The "high-high" fuel price scenario dramatically reduces the cost of renewable heat by raising the cost of conventional heating by around £15-20 / MWh, depending on technology and other circumstances. The resource cost of the low-cost segment costing £15 / MWh in the central case therefore is shown as substantially negative. The main source of this is the very sharp difference between "high-high" scenario and the central scenario is the difference between oil

/ coal prices and biomass prices.[25] By contrast, the low case is not as dramatically different from the central fuel price assumptions. It nonetheless raises the cost of renewable heat sufficiently to eliminate nearly all "negative cost" potential. As in previous cost curves, comparison of the curves is complicated by the different pattern of uptake in different demand segments that occurs with different fuel prices.

Figure 3.5
2020 Supply Curves under Different Fuel Price Assumptions (Central Growth)



Source: NERA calculations as described in text.

3.2.2. Impact of Biomass Prices

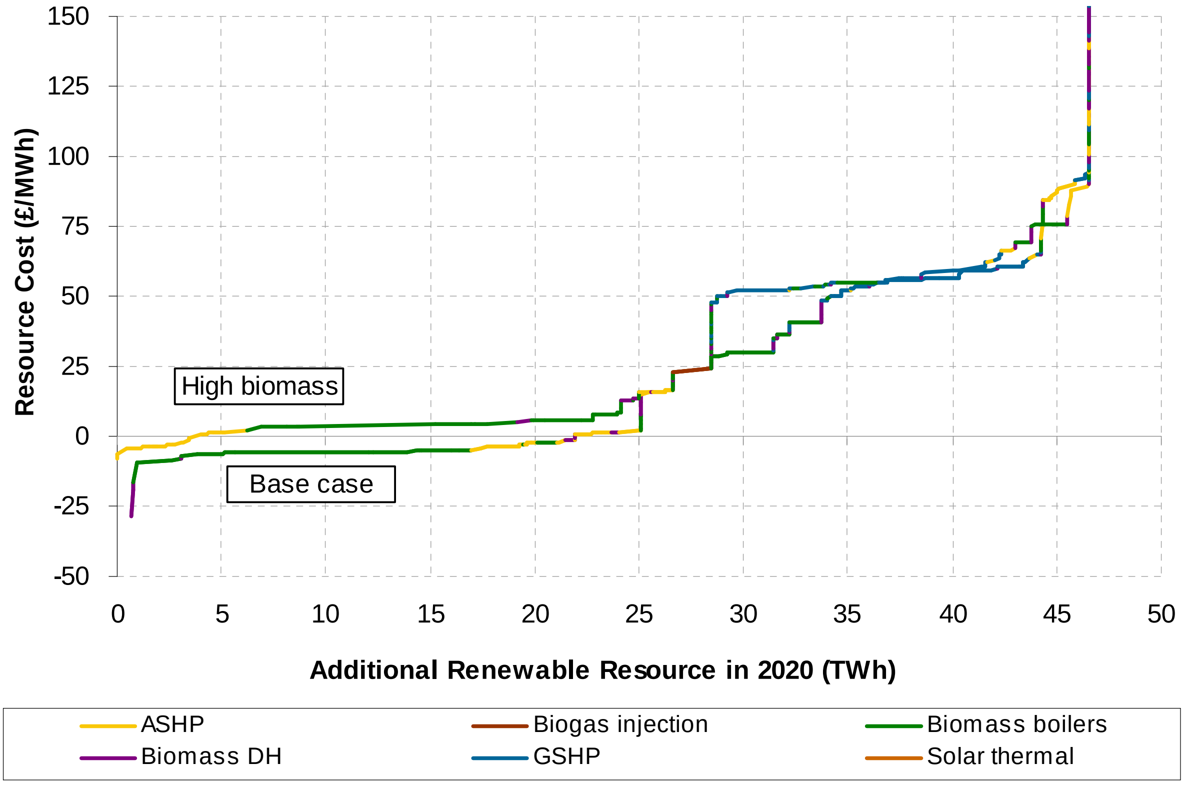
A substantial proportion of the low-cost potential shown in the above figures is represented by industrial and commercial / public biomass boilers. We believe that the primary reason for the apparent low cost is the E4Tech projection of low biomass prices, starting at around £25 / MWh in 2010 but falling to around £15 / MWh around 2020 and thereafter. Biomass prices therefore are significantly lower than fossil fuel prices for much of the period relevant to a potential investor in biomass boilers (retail oil prices in the central case are around three times higher in the period after 2020, and the "variable component" price is more than twice as high).

To investigate the sensitivity of our findings to these prices, we also investigate a scenario with higher biomass prices more similar to current prices (see section 2.4.2.3). Figure 3.6

[25] For example, in 2020 the biomass price is around £17 / MWh, whereas the oil price in the high-high scenario is over £60/MWh (DECC, 2009).

shows the supply curve for this scenario. As the figure shows, changes to the biomass price can have a significant impact both on the overall cost level of achieving a given amount of output, as well on the merit order of technologies. The amount of "negative cost" potential is significantly reduced with the alternative biomass prices.

Figure 3.6
2020 Supply Curves under Different Biomass Price Assumptions (Central Growth)



Source: NERA calculations as described in text.

4. Modelling Results

In this section we present more detailed modelling results on the composition of renewable heat output and cost.

4.1. Headline Modelling Results

4.1.1. Central growth case

Headline modelling results for the central growth case are shown in Table 4.1.[26] We show results both for 2020 (not discounted) and the cumulative results to 2030, for which future costs and benefits are presented as the net present value (NPV) using a discount rate of 3.5 percent. The 8.5 percent renewable heat scenario corresponds to additional renewable resource of 46 TWh in 2020, from 0.8 million heat users.[27] CO_2 emissions are reduced by 14 million tonnes of CO_2 ($MtCO_2$), split evenly between sources covered by the EU Emissions Trading Scheme (EU ETS) and sources outside the trading scheme.

The (levelised) resource cost of all renewable heat installations in 2020 is £860 million (£550 million using retail prices), of which some £600 million are technology costs and the remaining barrier costs.

The average cost is significantly lower than the cost of the marginal technology, reflecting the steeply rising supply curve discussed in preceding sections. Under the simple uniform subsidy described in section 2.4.6, a subsidy of £75 / MWh renewable heat is required to achieve an 8.5 percent share of renewables in heat supply, resulting in a total annual subsidy of £3.7 billion. For comparison, the value of CO_2 abatement is £450 million, with an average resource cost of CO_2 abatement of £64 / tCO_2. However, for marginal technologies with a cost near the subsidy level (£75 / MWh output) the abatement cost is substantially higher (in the region of £250 / tCO_2, assuming the abatement characteristics are similar to the average).

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[26] For these and all subsequent tables, we show results in real terms (2008 prices). Data in most cases have been rounded to two significant figures.

[27] The associated level of renewable heat output is just under 50 TWh, see section 2.4.6.2.

Table 4.1
Headline Modelling Results for Central Growth Scenario

Variable	Units	2020 Central growth, 8.5% share	NPV to 2030 Central growth, 8.5% share
Additional renewable resource[1]	TWh	46	620
CO_2 emissions abatement	MtCO2	14	180
Covered by EU ETS	MtCO2	6.8	91
Not covered by EU ETS	MtCO2	6.7	92
Number of installations	million	0.8	0.8
Total resource cost, variable prices[2]	£m	860	7,100
Technology costs	£m	600	5,100
Barrier costs	£m	260	2,000
Resource cost, retail prices	£m	550	4,600
Value of CO2 emissions abated	£m	450	3,800
Total subsidies	£m	3,700	30,000
RHI level	£/MWh	75	75
Resource cost / MWh [2]	£/MWh	19	--
Average CO_2 abatement cost	£/tCO2	64	--
CO_2 abatement cost at margin[3]	£/tCO2	260	--

Notes:

1. Output eligible for the UK's obligations under the relevant EU legislation. Actual heat output is c. 5-10 percent higher, depending on the combination of technologies.
2. Calculated using the "variable component" of fuel prices. See section 2.4.2.
3. Implied cost of CO2 abatement assuming average abatement potential of all output, and the cost characteristics of the marginal renewable heat technology.
4. Results are shown in real terms in 2008 prices. 2020 sterling values are not discounted; the NPVs of cumulative costs and benefits to 2030 are discounted at the social time preference rate of 3.5 percent.

As noted in section 2.4.6, the modelling represents renewable heat projects undertaken between 2011 and 2020. These projects continue to receive support until the end of their life, but no renewable heat investments undertaken after 2020 are included in the results. The NPV results to 2030 therefore show quantities associated with the installations that are in place by 2020, the large majority of which carry on being paid subsidies and generating heat until 2030. Calculated in this way, the NPV cost until 2030 is just over £7 billion while subsidies are some £30 billion. The associated monetised benefits of CO_2 abatement are some £3.8 billion.

4.1.2. Higher growth case

Results for the higher growth scenario are shown in Table 4.2, with results both for the 46 TWh of ARR (8.5 percent share renewable heat) achievable under the central growth scenario, and a higher level of output with 66 TWh of ARR (12 percent share renewable heat). The results for the 8.5 percent level show the importance of the growth rate assumptions for the modelling results. In the central growth scenario results shown above, the 46 TWh of ARR could be achieved only by recourse to relatively large number of high-cost technologies and consumer segments. If, however, low-cost options for renewable heat – notably, industrial biomass boilers – could grow more quickly, the resource cost would be much smaller (as would the subsidy required to reach this level of output). The more relaxed constraints on supply in the higher growth scenario therefore lead to a reduction in annual cost from some £860 million to just £180 million, and the subsidy required from £75 / MWh to £38 / MWh. There also is a sharp drop in the number of installations, from 0.8 million to 0.1 million – reflecting the higher potential among large heat users and a substantially reduced need to rely on the domestic sector.

Table 4.2
Headline Modelling Results for Higher Growth Scenario

		8.5% share		12% share	
Variable	**Units**	**2020**	**NPV to 2030**	**2020**	**NPV to 2030**
Additional renewable resource[1]	TWh	46	590	66	860
CO_2 emissions abatement	MtCO2	13	170	18	230
Covered by EU ETS	MtCO2	6.9	89	7.9	100
Not covered by EU ETS	MtCO2	6.1	79	9.7	130
Number of installations	million	0.1	0.1	1.0	1.0
Total resource cost, variable prices[2]	£m	180	1,300	1,600	13,000
Technology costs	£m	100	710	1,200	9,500
Barrier costs	£m	78	590	410	3,100
Resource cost, retail prices	£m	-300	-2,000	1,200	9,400
Value of CO2 emissions abated	£m	430	3,500	580	4,900
Total subsidies	£m	1,700	13,000	6,200	48,000
RHI level	£/MWh	38	38	89	89
Resource cost / MWh [2]	£/MWh	4	--	24	--
Average CO_2 abatement cost	£/tCO2	14	--	90	--
CO_2 abatement cost at margin[3]	£/tCO2	130	--	340	--

Notes:

1. Output eligible for the UK's obligations under the relevant EU legislation. Actual heat output is c. 5-10 percent higher, depending on the combination of technologies.
2. Calculated using the "variable component" of fuel prices. See section 2.4.2.
3. Implied cost of CO_2 abatement assuming average abatement potential of all output, and he cost characteristics of the marginal renewable heat technology.
4. Results are shown in real terms in 2008 prices. 2020 sterling values are not discounted; the NPVs of cumulative costs and benefits to 2030 are discounted at the social time preference rate of 3.5 percent.

The higher growth scenario also makes possible a higher share of 12 percent renewables in overall heat supply, with 66 TWh of ARR by 2020. This stretches the available supply in this scenario, just as the 8.5 percent share stretches the available supply in the central growth scenario. In the higher growth scenario, the 12 percent share is feasible only if a significant number of relatively small and high-cost renewable heat installations are delivered (1 million in total). The subsidy required is £89 / MWh, while costs are £1.6 billion per year (£1.2

billion at retail prices), and total subsidies £6.2 billion. Emissions reductions and associated benefits also increase, to 18 $MtCO_2$ and £580 million, respectively, but the average cost of emissions abatement is higher than in any of the other scenarios at £90 / tCO_2. At the margin, the abatement cost rises to £340 / tCO_2.

If still higher levels of supply from low-cost technologies and consumer segments were possible, it is possible that the 12 percent level could be achieved at lower cost and subsidy levels, similar to the effect that the step from the central growth to the higher growth scenario has on reaching the 8.5 percent level of renewables. Conversely, however, if growth for particular technologies or overall is more constrained than the higher growth scenario assumes, the subsidy required may be still higher, or a 12 percent share may not be achievable at all.

4.2. Detailed Modelling Results

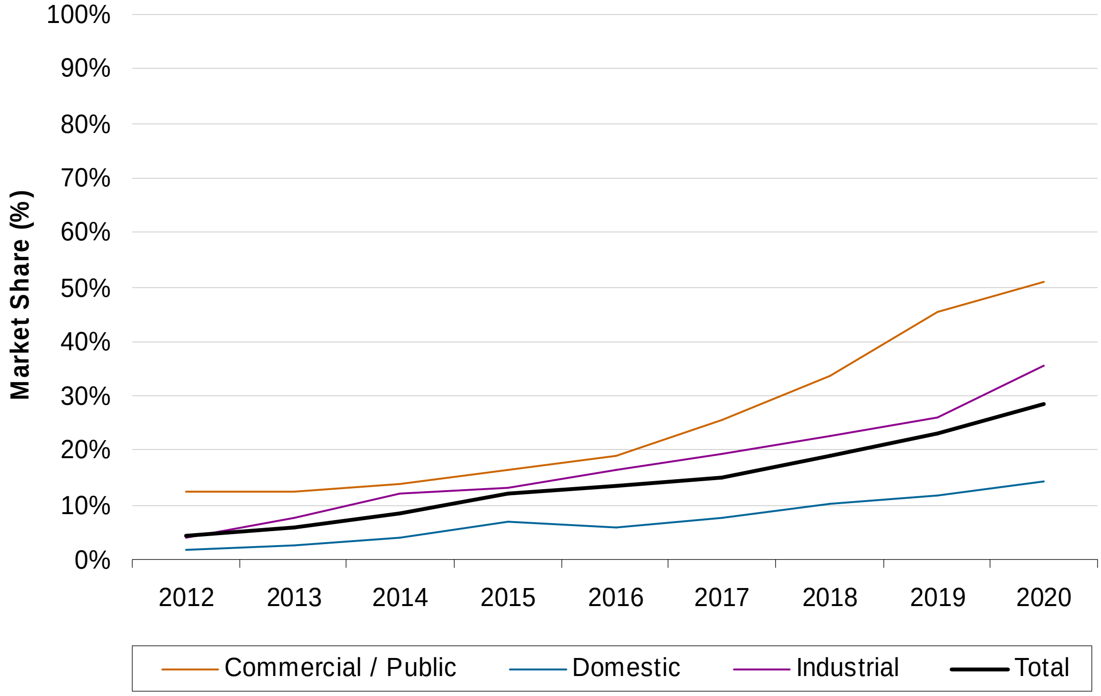
This sub-section presents more detailed modelling results. We first show the demand-side implications of the above modelling scenarios, followed by a more detailed breakdown of renewable heat output and cost, and then the sensitivity of the cost curve to various input assumptions.

4.2.1. Demand-side implications and renewable heat market share

4.2.1.1. Central growth scenario

The shares of renewable heat implied by the results presented above are small compared to the overall heat market. Nonetheless, the growth rates mean that by 2020 renewable heat reaches a significant market share of *new* heating equipment. Figure 4.1 shows the overall market share for renewable heat under the central growth scenario and an 8.5 percent share of renewables in total heat supply. By 2020, renewable heat technologies account for just under 30 percent of all heat load replacing its heating equipment in that year. This masks significant variation between the sectors, with a higher share of over 50 percent in the commercial / public sector, and a lower share of less than 15 percent in the domestic sector.

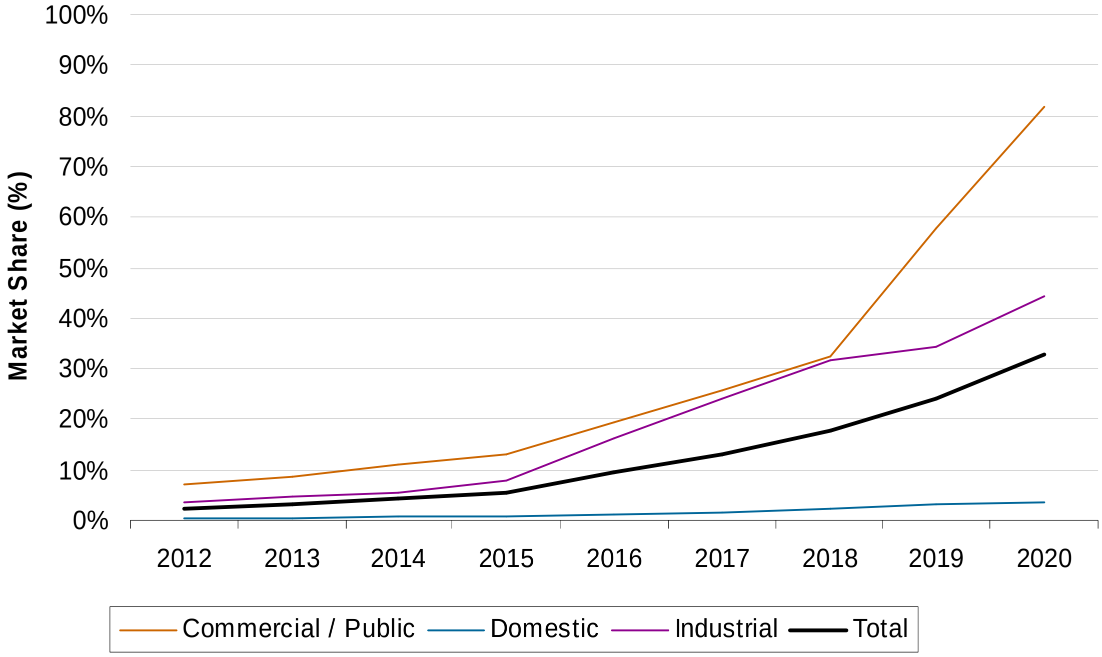
Figure 4.1
Implied Renewable Heat Market Share in 2020
(Central Growth Scenario, 8.5 Percent Share of Renewable Heat)



4.2.1.2. Higher growth scenario

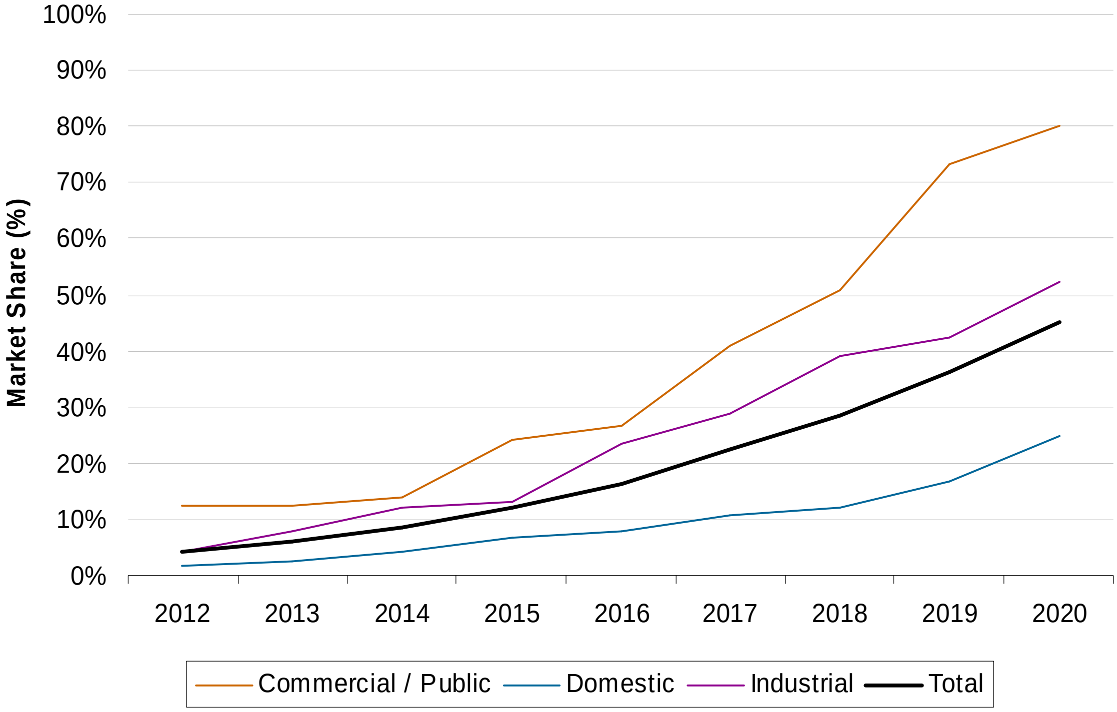
Figure 4.2 shows the corresponding information for the higher growth scenario when the 8.5 percent share of renewables in heat supply is reached. The overall market share remains around 30 percent, as the share of renewable heat in overall heat supply is the same. However, higher growth makes possible a switch from higher-cost potential in the domestic sector to lower-cost options in the commercial / public and industrial sectors. The market share in the domestic sector therefore is just 5 percent, whereas it is 45 percent in industry, and as much as 80 percent in the commercial / public sector. This also illustrates that the higher growth scenario requires that most of the barriers to renewable heat are overcome in the non-domestic sector, allowing renewable heat technologies to be the dominant replacement technologies by 2020.

Figure 4.2
Implied Renewable Heat Market Share in 2020
(Higher Growth Scenario, 8.5 Percent Share of Renewable Heat)



Finally, Figure 4.3 shows the market share for the higher growth scenario and renewable heat corresponding to 12 percent of total heat supply. The increase on the 8.5 percent share is achieved largely in the domestic sector, where renewables have a market share of 25 percent by 2020, along with some increase also in the industrial sectors. The total market share increases to 45 percent, and under the assumptions of the modelling the 12 percent share therefore requires that nearly half of the heating load that replaces equipment in 2020 does so with renewable heat technologies.

Figure 4.3
Implied Renewable Heat Market Share in 2020
(Higher Growth Scenario, 12 Percent Share of Renewable Heat)



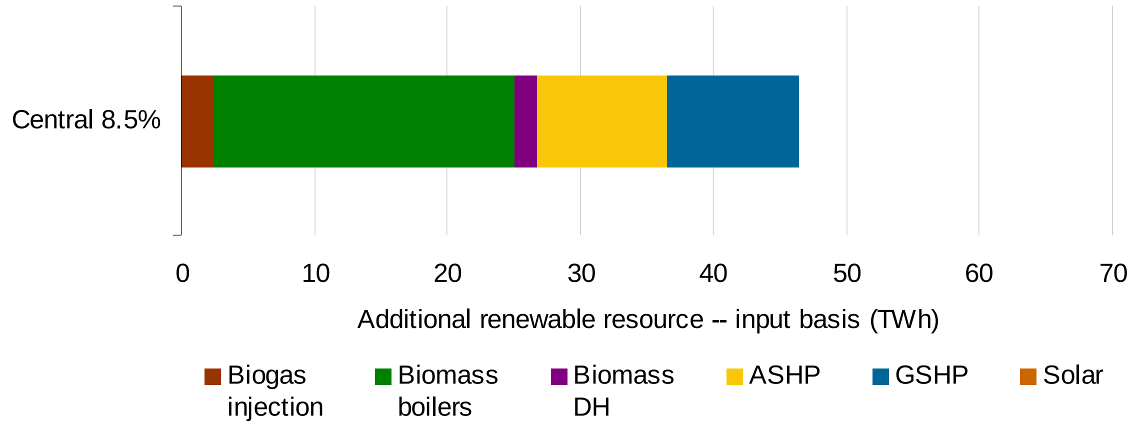
The above figures illustrate that the above levels of renewable heat are more ambitious than their overall share of heat demand first suggests. Under the assumptions of the modelling, achieving an 8.5 percent share of renewables in heat supply would require that around one-third of heating equipment sold in 2020 (weighted by heat load) was accounted for by renewable heat technologies, while the 12 percent share would require a market share of nearly half. This in turn is driven by the pattern of the supply growth trajectories, which start from a very small base and achieve large-scale growth only in the last years before 2020.

4.2.2. Composition of additional renewable resource

4.2.2.1. Central growth scenario

Figure 4.4 shows the composition of additional renewable resource by technology for the central growth scenario and an 8.5 percent share of renewables in heat supply (46 TWh ARR) based on the technology costs assumptions listed in Annex B. The dominant technology is biomass boilers, which contribute 23 TWh, followed by air-source and ground-source heat pump, which each contribute 10 TWh. Biogas injection accounts for just over 2 TWh ARR, while biomass district heating is just under 2 TWh ARR. The modelling indicates no solar thermal contribution because there is sufficient potential available from the lower cost technologies to deliver 46 TWh ARR without relying on solar thermal.

Figure 4.4
Composition of Renewable Heat by Technology (Central Growth, 2020)

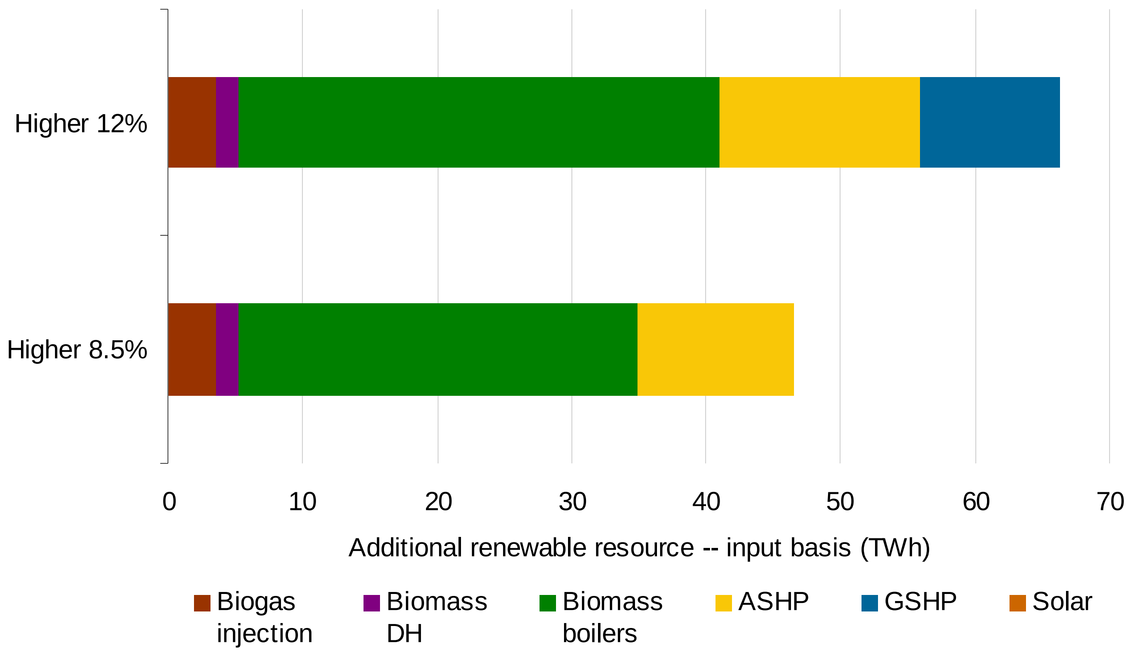


Source: NERA calculations as described in text.

4.2.2.2. Higher growth scenario

Figure 4.5 shows the corresponding information for the higher growth scenario, with the results for the 12 percent share in the upper bar of the chart and the results for the 8.5 percent renewable heat level in the lower bar. As this shows, biomass dominates heavily under the 12 percent renewable heat level, accounting for more than half of the total ARR at 36 TWh, while air-source heat pumps follow with 15 TWh of ARR and ground-source heat pumps with 10 TWh. Biogas injection and biomass district heating contribute 4 and 2 TWh, respectively. With the lower 8.5 percent level (46 TWh total ARR), there is a reduction in biomass boilers to 30 TWh and air-source heat pumps to 12 TWh, while biomass district heating and biogas injection are unchanged. The biggest difference is that ground-source heat pumps are not used in the higher growth, 8.5 percent share scenario, reflecting their higher cost among the demand segments that take up renewable heat.

Figure 4.5
Composition of Renewable Heat by Technology (Higher Growth, 2020)



Source: NERA calculations as described in text.

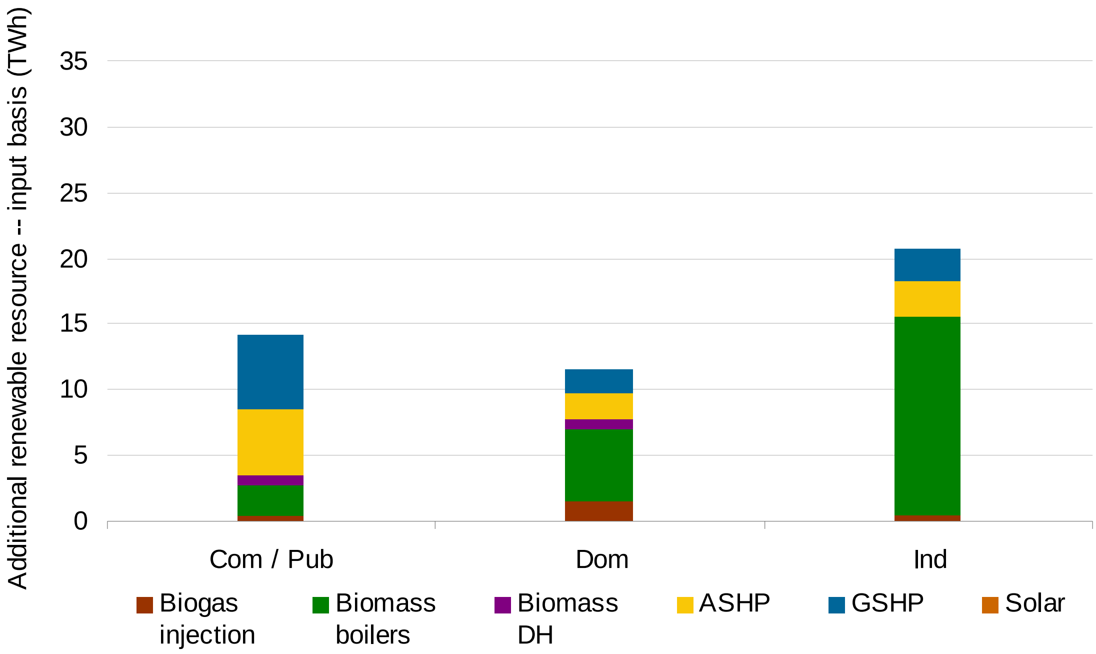
These results illustrate the point made above, that the composition of output (as well as cost) associated with a given share of renewables in heat supply depends heavily on the feasibility of expanding the supply of low-cost opportunities for renewable heat. In the central growth scenario a combination of all technologies (with the exception of solar thermal) is used to reach 46 TWh of ARR by 2020, including 10 TWh of ARR from ground-source heat pumps. With the higher growth rate, by contrast, the technology mix is much more weighted towards lower-cost biomass boilers and air-source heat pumps, and ground-source heat pumps do not appear in the least-cost technology mix for the given share of renewables in heat supply. With the more ambitious 12 percent share of renewables in heat supply (66 TWh ARR), the modelling assumptions mean that additional opportunities for air-source heat pumps and biomass boilers come at a higher cost, and ground-source heat pumps therefore once again become part of the competitive technology mix.

4.2.3. Additional renewable resource by technology and sector

4.2.3.1. Central growth scenario

A more detailed breakdown of additional renewable resource by technology and sector in the central growth scenario is shown in Figure 4.6. The largest contribution of 21 TWh is from the industrial sector, three-quarters of which is biomass boilers (primarily used for industrial process heat). There also is some use of air-source and ground-source heat pumps for space heating in industry. The commercial / public sectors jointly contribute some 14 TWh, with the least-cost opportunities for renewable heat through air-source and ground-source heat pumps, which together account for 75 percent of ARR from this segment. The domestic sector share is smaller, at 12 TWh in total. Biomass boilers account for just under half of this, with a relatively even split between the other technologies. (The ARR from biogas injection is apportioned between sectors proportionally to each sector's share of total natural gas consumption, with the greatest share in the domestic sector.)

Figure 4.6
Composition of Renewable Heat by Technology and Sector
(Central Growth, 2020)



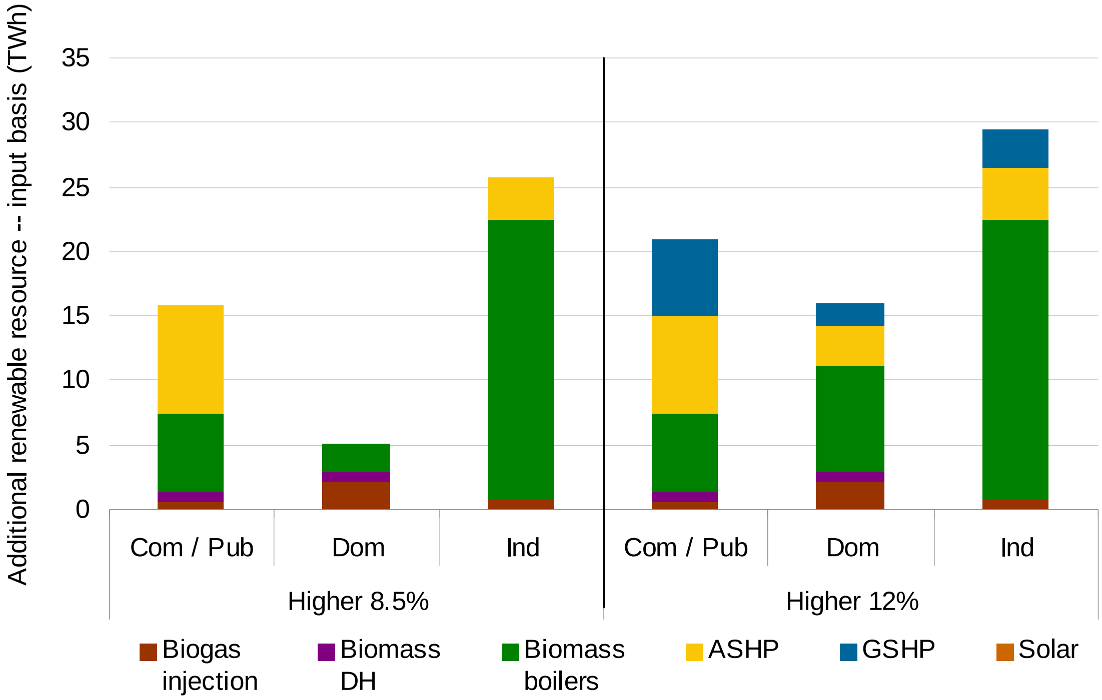
Source: NERA calculations as described in text.

4.2.3.2. Higher growth scenario

Results for the higher growth scenario are shown in Figure 4.7. The pattern for the 12 percent renewable heat level is similar to that described in the central growth scenario and 8.5% level above, with the largest contribution from industry, followed by the commercial / public and domestic sectors, and also with the same pattern of technologies (biomass boilers in industry and domestic sector; air- and ground-source heat pumps in the commercial / public sectors).

The increase in output between the 8.5 percent and 12 percent renewable heat levels comes chiefly from an expansion in output in the commercial / public and domestic sectors. With the lower 8.5 percent share, ARR in the domestic sector is small, at just 5 TWh, much of which from biogas injection. This reflects the generally higher cost of renewable heat for domestic users. In the commercial / public and industrial sectors much of the difference between the two target levels is attributable to output from ground-source heat pumps, which are absent under the lower 8.5 percent renewable heat level.

Figure 4.7
Composition of Renewable Heat by Technology and Sector
(Higher Growth, 2020)



Source: NERA calculations as described in text.

4.2.3.3. Summary results

Table 4.3 shows a summary of the above information, along with a breakdown of the number of installations / units implied by technology and sector.

Table 4.3
Summary Composition of Additional Renewable Resource by Technology and Sector

Technology	Sector	Central growth 8.5% share		Higher growth 8.5% share		Higher growth 12% share	
		TWh	1000 units	TWh	1000 units	TWh	1000 units
ASHP	Domestic	2.1	221	0.0	0	3.1	325
ASHP	Non-domestic	7.7	23	11.6	41	11.6	37
GSHP	Domestic	1.8	204	0.0	0	1.6	187
GSHP	Non-domestic	8.1	34	0.0	0	8.8	44
Biomass boilers	Domestic	5.5	299	2.0	100	8.2	448
Biomass boilers	Non-domestic	17.3	2	27.7	4	27.7	4
Biomass DH	Domestic	0.8	0	0.8	0	0.8	0
Biomass DH	Non-domestic	0.9	1	0.9	1	0.9	1
Biogas injection	All	2.3	0	3.5	0	3.5	0
Subtotal	Domestic	10.1	725	2.8	101	13.7	961
Subtotal	Non-domestic	34.0	60	40.2	46	49.0	86
Total		46.4	785	46.5	147	66.2	1047

Note: For district heating, the number of units refers to the number of heat consumers; for biogas injection, the number of AD plants. For other technologies, the units column shows the number of individual installations.

These results differ from the results in previous analyses in a number of respects:

§ The overall contribution from biomass boilers is similar, but in the new results much more heavily weighted towards the non-domestic applications.

§ Heat pumps contribute a substantially larger share of output, with more than twice the potential indicated in the previous analysis.

§ Biomass district heating has reduced role, with around one-fifth of the potential that it had in the previous results.

§ The expansion of non-domestic biomass and heat pumps means that solar thermal does not form part of the new technology mix, whereas it accounted for as much as 15 percent of the heat output in the previous results.

§ The results are much more weighted towards the non-domestic sector, which accounts for three-quarters of output in the above results, but only 40 percent in previous analyses.

As noted above, adding the contribution of renewable CHP to the analysis is likely to affect these results.

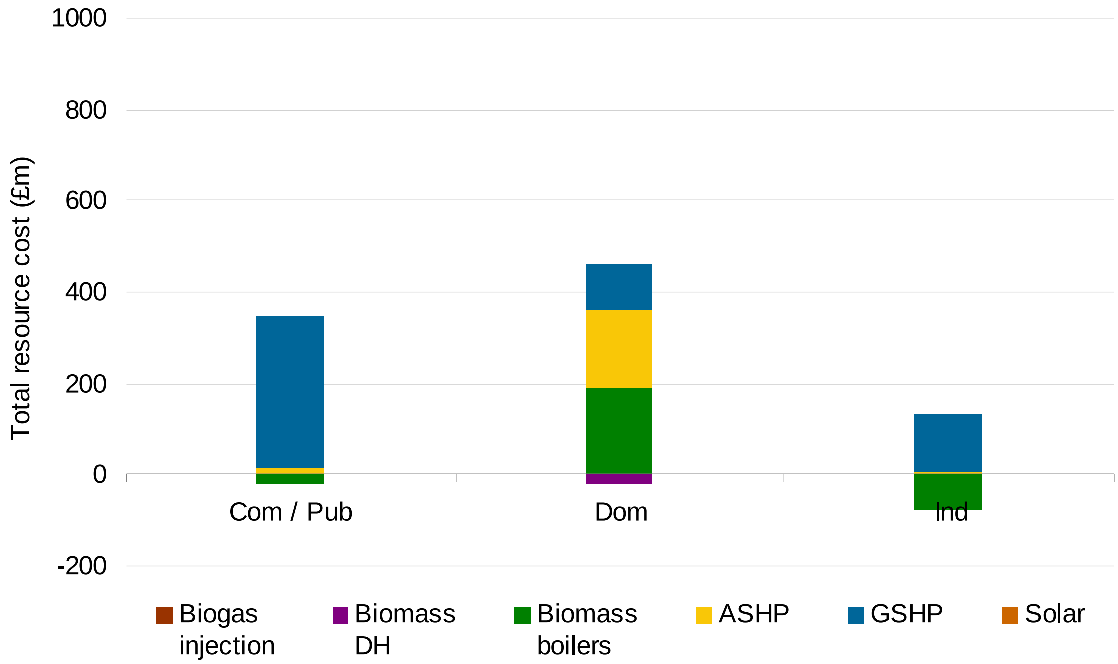
4.2.4. Distribution of resource cost

4.2.4.1. Central growth scenario

The distribution of cost by technology and sector, shown in Figure 4.8 for the central growth scenario and 8.5 percent renewable heat share, differs significantly from the distribution of ARR. Although the industrial sector accounts for the largest share of ARR, the total cost of these renewable heat installations is significantly smaller than that in other sectors. This is in large part because of the "negative cost" of biomass boilers discussed above, but also because air-source heat pumps have a very low average cost. The inverse relationship holds for the domestic sector, which has the smallest share of ARR, but the highest overall resource cost. The pattern of costs matches the pattern of output more closely in this sector.[28] In the commercial / public sectors, both biomass boilers and air-source heat pumps have very low costs. The large majority of costs therefore is attributable to ground-source heat pumps. These patterns again confirm the observation above, that overall costs could be significantly reduced if higher growth could be achieved within the low-cost biomass boiler and air-source heat pump segments of industrial and commercial / public users.

[28] The negative cost element in the domestic sector arises from a small quantity of biomass district heating in very specific circumstances, *viz.*, rural schemes serving new homes with low heat demand and where the counterfactual is relatively high-cost fuels (notably, heating oil). Actual schemes serving a mix of houses may have significantly higher resource cost.

Figure 4.8
Composition of Annual Resource Cost by Technology and Sector
(Central Growth, 2020)

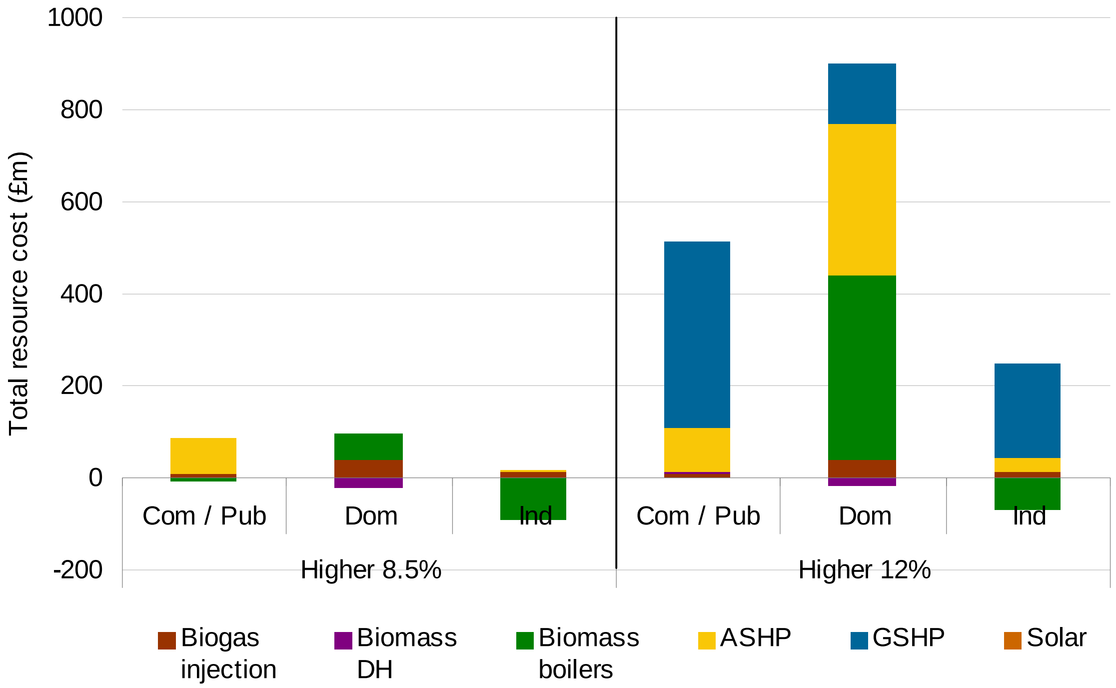


Source: NERA calculations as described in text.

4.2.4.2. Higher growth scenario

In the higher growth scenario the difference in cost is even starker. As shown in Table 4.2, the subsidy under the 8.5 percent renewable heat share case is just under £40 / MWh, while that under the 12 percent renewable heat share is just under £90 / MWh. The renewable heat projects accounting for the 46 TWh ARR under the 8.5 percent share of renewables in heat supply are low-cost, with costs below £100 million in all sectors. By contrast, the next 20 TWh required to achieve the 12 percent share (66 TWh) come at substantially higher costs, with the primary increases from domestic biomass boilers and air-source heat pumps, and ground-source heat pumps in all sectors. The pattern of the central growth scenario also applies, with large costs in the domestic sectors and much lower costs in industry.

Figure 4.9
Composition of Annual Resource Cost by Technology and Sector
(Higher Growth, 2020)



Source: NERA calculations as described in text.

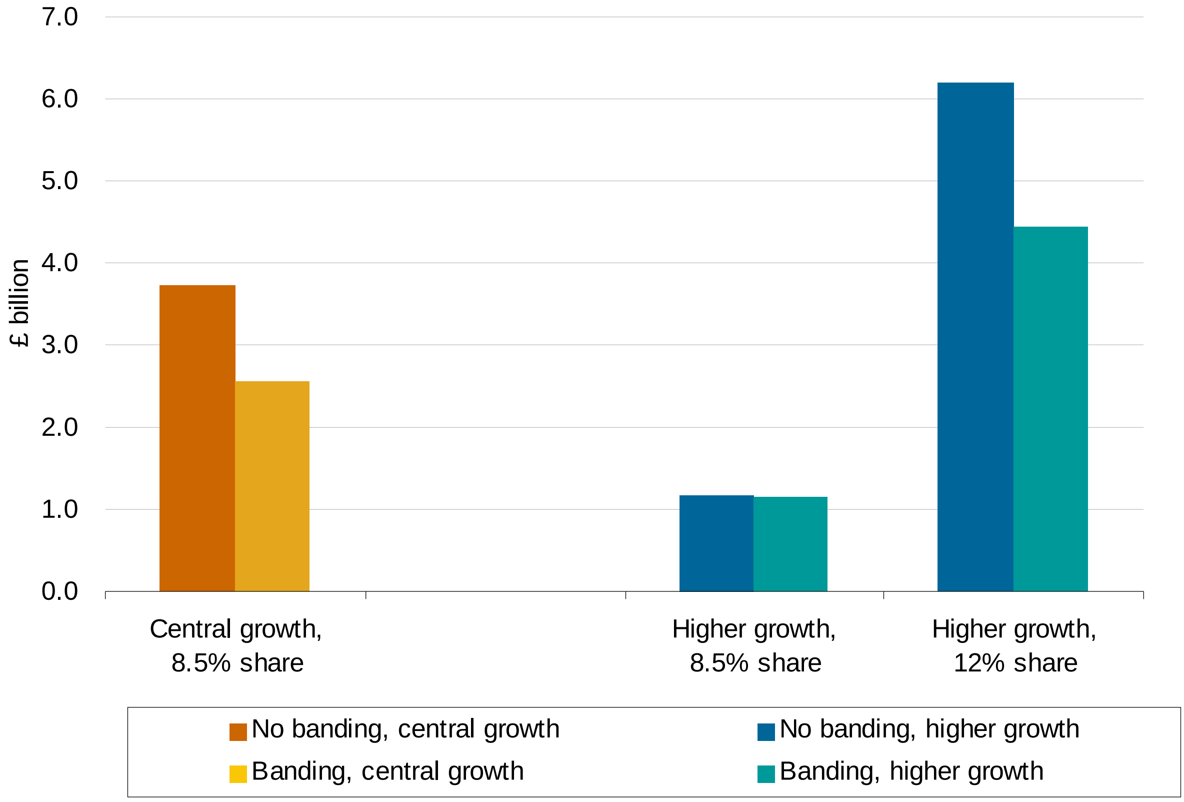
4.2.5. Subsidies

As noted in section 2.4.6, the scenarios presented above are calculated on the assumption that that all eligible renewable heat projects are paid the same ongoing subsidy per MWh of eligible heat output. The resulting annual subsidy levels under the central growth scenario are £3.7 billion to reach 46 TWh ARR by 2020; for the higher growth scenario, the subsidies paid to achieve the 46 TWh are £1.2 billion, and £6.2 billion to achieve 66 TWh ARR by 2020.

However previous analysis (NERA, 2008) has shown that applying a uniform level of subsidy across all technologies can result in significant economic "rents", or overpayment compared to what would be necessary to achieve the same result. These rents arise because of variations on the underlying costs of renewable projects. Providing different levels of support to different projects, often referred to as "banding", could help reduce the overall level of payments required under specified renewable heat scenarios. The possible impact of banding is illustrated in Figure 4.10 which models changes in subsidy levels as support payments are banded by technology and scale. The analysis suggests that the impact of banding could be significant in some scenarios; for example, the subsidy to reach the 12 percent level under the higher growth rate is reduced from around £6 billion to around £4 billion. By contrast, only a negligible reduction in subsidies is possible when meeting the 8.5 percent level under the higher growth rate scenario, because the banding is not as successful in distinguishing between high- and low-cost measures.

We emphasise that these results show only the impact on subsidies under an idealised form of banding. They do not account for potential disadvantages of banding—notably, the risk that providing different support levels may have an impact on the cost of achieving an overall level of renewables in heat supply (see NERA 2008 for a discussion).

Figure 4.10
Annual Subsidies with and without Banding (2020)



Source: NERA calculations as described in text.

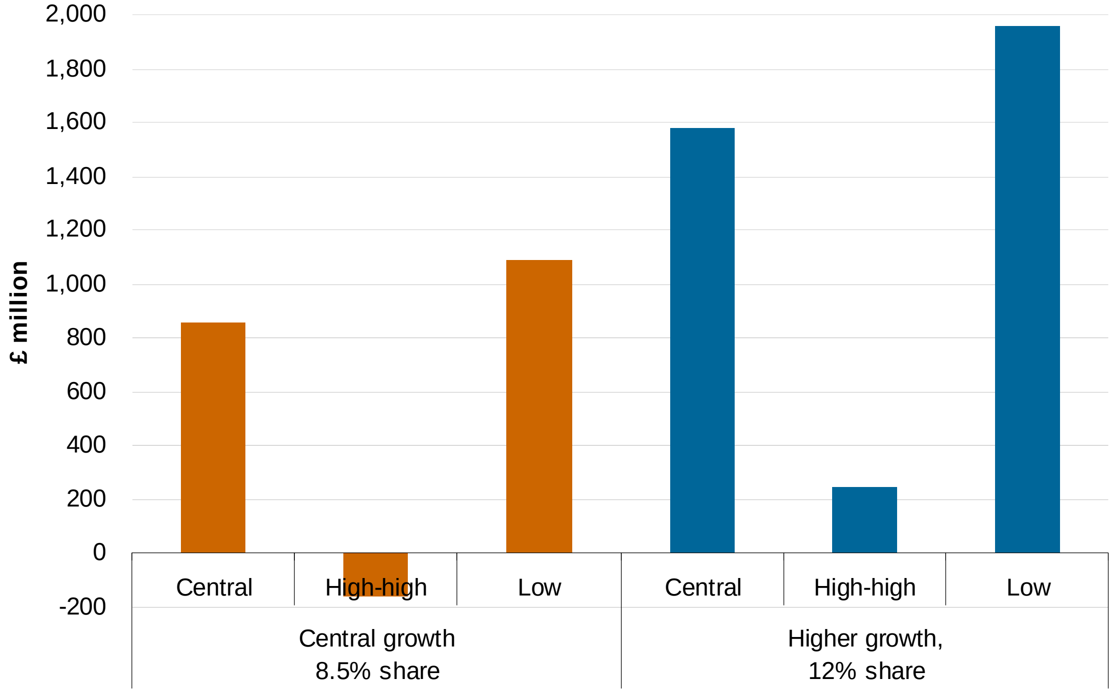
4.3. Sensitivity Analysis

In this section we show how the results are affected by different fuel prices, biomass prices, and discount rate assumptions. We focus on overall resource cost, as the most compact summary measure of how the supply curve for renewable heat, and attractiveness of renewable heat technologies, are affected by the input parameters. We present tables with more detailed results in Appendix A.

4.3.1. Impact of fuel price assumptions

As noted above, the price of fossil fuel is a key determinant of the attractiveness of renewable heat as well as its resource cost. The impact is shown in Figure 4.11. For each growth scenario, share of renewables in heat supply, and fuel price scenario the bars show the resource cost in 2020 associated with each growth scenario (on the left-hand scale). The fuel price scenarios shown are the base assumptions ("central" fuel prices) as well as the "high-high" and "low" fuel price scenarios provided by DECC. In the case with central growth and a 8.5 share of renewables in heat supply (46 TWh ARR), high-high fuel prices would result in a negative overall resource cost, whereas low fuel prices would increase the cost from the £0.9 billion in the base case to £1.1 billion. Under the higher growth rate and a 12 percent share, the resource cost in 2020 is reduced from £1.6 billion to just over £0.2 billion in the high-high case, whereas low prices result in resource costs of nearly £2 billion.

Figure 4.11
Resource Cost under Different Growth, Renewable Heat Share, and Fuel Price Scenarios (2020)



Source: NERA calculations as described in text.

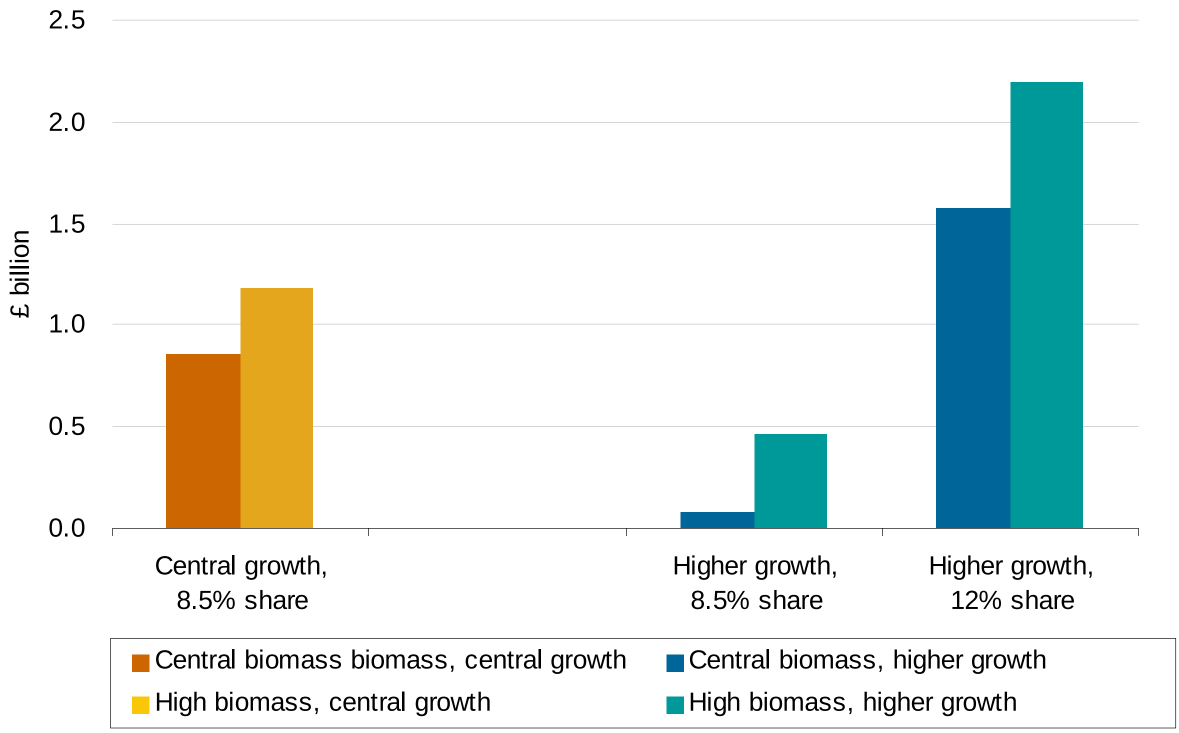
The changes to the attractiveness occur across all renewables, although as noted increased electricity prices mean there is a partially offsetting effect in the case of heat pumps. Different fuel prices therefore do not have much effect on the aggregate merit order of technologies, and therefore do not significantly change the aggregate technology mix. However, there are changes to the attractiveness of different technologies in different demand segments. Depending on the conventional heating technology used as well as other characteristics of the heat load, different fuel prices therefore can make a significant difference to the merit order of technologies for individual heat consumers.

Another modelling finding is that the marginal subsidy (RHI level) required to achieve a given ARR level varies much less than does the resource cost under different fuel prices. The explanation for this is that the most expensive technologies required to achieve a given share of renewables in heat supply are much less affected by the changes to fuel prices than are many of the cheaper technologies (technologies at the margin are less affected than are infra-marginal technologies). This in turn is in large part because the cost of heat pumps is much less affected by fuel prices than are other technologies. Because the modelling assumes a single subsidy for all renewable heat projects, this means that total subsidy paid shows the same pattern as the RHI level, with relatively small changes under different fuel price scenarios.

4.3.2. Impact of biomass price assumptions

Biomass prices are another important influence on the modelling results, and especially on the finding that some renewable heat may be available at "negative cost". Figure 4.12 shows how total resource cost is affected by substituting the central biomass prices for prices more similar to current price levels, as outlined in section 2.4.2.3. Under the central growth case and 8.5 percent renewable heat level, costs rise from £0.9 billion to £1.2 billion, and a similar proportionate change results in the higher growth case under the 12 percent renewable heat level (from £1.6 billion to £2.2 billion). The change is greater with the higher growth scenario and 8.5 share of renewables, where costs increase from £0.1 billion to £0.5 billion. The reason for this that, as discussed in section 4.2.2, biomass contributes a greater share of total output in this scenario.

Figure 4.12
Resource Cost under Different Growth, Renewable Heat Share, and Biomass Price Scenarios (2020)



Source: NERA calculations as described in text.

Increasing biomass prices also affects the relative cost of different technologies, making biomass boilers (and district heating) relatively less attractive than heat pumps (and solar thermal). However, the impact on which technologies are undertaken is relatively small, with only 1-2 TWh less biomass undertaken for the 8.5 share of renewables (although, as with changes to other fuel prices, the technologies undertaken by particular demand segments change more) . This suggests that many opportunities for the use of biomass remain cheap relative to other technologies even with higher prices. Conversely, as noted before, the findings under the higher growth scenario and 8.5 share of renewables illustrate once again that, if more biomass opportunities were available, a given level of ARR could be achieved at lower cost.

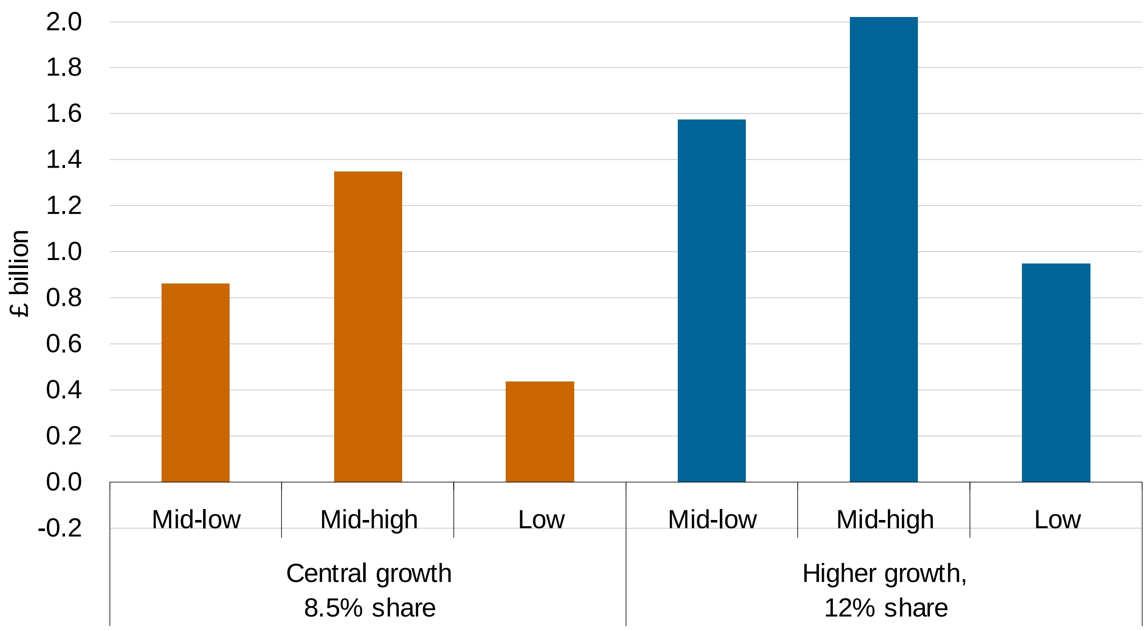
4.3.3. Impact of discount rate assumptions

The switch from fossil fuel or electric heating to renewable heat generally involves higher up-front costs. Total costs of renewable heat therefore are highly dependent on the discount rate used to evaluate the investment decision. As noted in section 2.4.3, there is little consensus on the discount rate that is likely to apply for the decision to invest in renewable heat. The rate may vary with a range of factors, including credit conditions; the precise implementation of the policy (e.g., through loans, ongoing subsidies, or upfront subsidies), and the perceived risk associated with renewable heat compared to conventional technologies. There also are different schools of thought on whether all of the factors contributing to the discount rate used by private sector agents to evaluate investment decisions should be reflected in social cost-benefit analysis.

Figure 4.13 shows the impact of discount rates on total resource cost. The “mid low” case is that used for the scenarios presented above, with a 12 percent discount rate for the commercial / public and industrial sectors, and a 16 percent discount rate for the domestic sector. The “low” scenario uses 8 percent for all sectors, whereas the “mid-high” uses rates of 25 and 16 percent, for domestic and non-domestic discounting, respectively.

The mid-high discount rate increases cost from £0.9 billion to £1.4 billion in the scenario with central growth and a share of renewables in heat supply of 8.5 percent, while the low discount rate reduces cost to £0.4 billion. The changes in the higher growth scenario and a share of 12 percent are similar in proportion, with costs ranging from £2 billion in the mid-high case to £0.9 billion in the low case.

Figure 4.13
Resource Cost under Different Growth, Share of Renewable Heat, and Discount Rate Scenarios (2020)



Source: NERA calculations as described in text.

Changing the discount rate also has a significant impact on the subsidy required to achieve a given level of ARR. Under the central growth scenario and 8.5 percent renewable heat level, the mid-low discount rate requires a subsidy of £75 / MWh heat output. This is reduced to £54 / MWh with the low discount rates, and increases to £103 / MWh in the mid-high discount rate case. Similarly, for the higher growth rate and 12 percent renewable heat share, the subsidy levels in the mid-low, low, and mid-high discount rate cases are £89 / MWh, £62 / MWh, and £117 / MWh, respectively.

One implication of these findings is that any aspects of policy that could reduce either the cost of capital or other aspects of effective discount rates (including perceived risk), or the upfront cost to participants, also has the potential to make renewable heat substantially more attractive to consumers.

5. Conclusions

The supply curves developed in the course of this research indicate that renewable heat could contribute between 45-65 TWh to the UK's renewables target (8.5-12 percent of total heat demand defined on a fuel input basis), at a resource cost less than £100 / MWh output. The wide range primarily reflects uncertainty about the rate at which supply capacity could feasibly expand. The lower end of the range is based on a "central" growth scenario where the main technologies grow at average annual rates of 20-35 percent in the period 2015-2020 (this is after growing at rates as high as 50 and 90 percent in earlier years). To achieve the "higher growth" scenario, growth rates of 30-50 percent are required from 2015-2020, similar to the maximum rates observed in other countries. Of course, with still more optimistic scenarios for growth, even higher output levels could be achievable. This would depend on simultaneously overcoming barriers to renewable heat across all technologies and consumer segments. Renewable CHP could make significant contributions to renewable heat output, although we have not analysed the extent to which this will be additional to the potential indicated here. The modelling of different growth scenarios in part reflects the uncertainty surrounding how much renewable heat could be delivered through CHP.

In the UK renewable heat starts from a very low supply base and market share. The ramp-up is likely to be gradual, requiring several years to achieve mass-market adoption. Achieving an 8.5-12 percent share of renewables in heat generation therefore would require a ***market share*** of renewable heat in new heating equipment of 30-50 percent by 2020. In some sectors, notably commercial heating, renewable heat technologies would need to become the dominant technology for replacement heating equipment. At output levels above 66 TWh (12 percent share of renewables) the availability of suitable heat loads starts becoming a limiting factor for some technologies. Even if there were no supply constraints, demand-side considerations therefore may start to limit the amount of renewable heat that could plausibly be achieved.

The detailed segmentation of the supply curve shows starkly that the cost of renewable heat varies very significantly with a range of factors, including

- the technology used,
- the type of incumbent fossil fuel / electric heating technology being replaced,
- the size and other characteristics of the heat load,
- the thermal efficiency of the building, and
- characteristics of the pre-existing heating system.

The lowest-cost opportunities for renewable heat are found through large-scale biomass boilers, primarily in industry but also in the public sector, along with air-source heat pumps to heat commercial / public buildings, and to some extent also domestic biomass boilers in locations off the gas grid. If some of the modelling assumptions were to hold – notably, the reliable availability of low-cost biomass and fuel / electricity prices as projected – some of these may be close to commercial viability even without dedicated subsidy. However, even with these assumptions, this would depend on the emergence of a mass market that helped overcome fuel supply and other barriers.

Unless these and other low-cost opportunities can grow significantly, other technologies with higher cost also will be required to meet the renewable heat levels considered here.[29] In most of the modelling scenarios, there is an important contribution from more expensive heating technologies, including a substantial number of units in the domestic sector. This is the case for the 8.5 share of renewable heat in the central growth case, and for the 12 percent share in the higher growth scenario, both of which require projects across a range of technologies and applications, with widely varying costs. For example, with the higher growth scenario and a 12 percent share of renewable heat in heat supply, there are around half a million heat pumps and more than 450,000 domestic biomass boilers. Costs are around £1.2 billion per year by 2020, despite the large volume of low-cost opportunities.

Under the higher growth rate and 8.5 percent share of renewables in heat supply, by contrast, there is a sufficient supply of low-cost opportunities that costs and subsidies are significantly lower. The number of units also is much lower, at around 100,000 units, as the focus is on large-scale projects. The implication is that, if low-cost and large-scale applications of renewable heat could grow sufficiently, a much smaller number of installations would be necessary, and costs potentially could be much reduced through a large-scale expansion of the technologies closest to commercial viability.

Apart from contributing to the UK's target for renewable energy, renewable heat may reduce UK CO_2 emissions by some 13-18 million tonnes, with 6-10 million tonnes CO_2 outside the EU ETS and therefore potentially additional to reductions that would otherwise take place. Renewable heat nonetheless remains a relatively expensive abatement option. The abatement cost at the margin could reach in excess of £300 / tCO_2 to achieve a 12 percent share of renewables in heat supply, and even with substantial abatement potential at very low or even "negative" cost, the average cost of abatement is £60-90 / tCO_2.

The cost of renewable heat is highly sensitive to a range of uncertain factors. As emphasised above, the feasible expansion of supply capacity has a very strong influence on the composition of heat output and cost of expanding renewable heat. Other prominent influences include the prices of fossil fuels, biomass, and electricity, which can significantly alter the attractiveness of renewable heating options to consumers. It also is uncertain at what (implied) discount rate consumers would evaluate decisions to adopt renewable heat technologies, and what the cost and feasibility is of overcoming the various barriers to their adoption. Overall, this uncertainty makes policy design (which has not been considered in this report) more difficult.

5.1. Areas for Further Work

The following are areas for further work that would improve the understanding of the opportunities for renewable heat:

§ The mapping of UK heat demand to opportunities for renewable heat is complex and data-intensive. Further improvements to this work could refine estimates, including a

[29] The importance of growth potential was also a feature of previous findings (NERA 2008, Enviros 2008a): this earlier work found more limited growth potential among some of the lower cost technologies, and therefore suggested the need to rely on the more expensive technologies such as solar thermal.

better understanding of the suitability and performance of technologies in different applications, and the coverage of EU ETS of UK heat demand.

- Given the potentially important contribution that heat pumps could make to the UK renewable energy target, a better understanding of their performance in different types of UK housing stock could be particularly useful.

§ The characteristics of the supply curve depend very significantly on the feasible growth of supply capacity. Starting from the current low base, future projections are inherently very uncertain. Further consultation with industry representatives could add to the existing information, and help to identify obstacles that may hold back a significant expansion in renewable heat.

- In particular, it would be useful to develop a more detailed understanding of the supply-side limitations, cost of adoption, and barriers that affect the technologies that are closest to commercial viability, notably large-scale biomass boilers and commercial / public heat pumps. A significant expansion in the use of these technologies could reduce the need to rely on costlier contributions from other technologies, notably in the domestic sector.

6. References

The study draws on research reflected in NERA (2008), and we refer to the references contained therein. The following are additional references to work used to inform this study and referred to in the text:

DECC (2009), *The UK Renewable Energy Strategy 2009: An Analytical Annex*

E4Tech (2009) *Biomass Supply Curve for the UK*

Element Energy (2008), *The growth potential for Microgeneration in England, Wales and Scotland*.

Enviros Consulting (2008a), *Barriers to renewable heat part 1: supply side*, report for BERR.

Enviros Consulting (2008b), *Barriers to renewable heat part 1: supply side*, report for BERR.

NERA (2008), *Evaluation of Financial Instruments for Renewable Heat*, Report for the Department for Business, Enterprise and Regulatory Reform.

Appendix A. Additional Modelling Results

A.1. Impact of Fuel Price Assumptions

Table A.1
Summary Modelling Results: Sensitivity to Fuel Prices
(2020, Central Growth Rate, 8.5 Percent Share)

Variable	Units	Central fuel prices	Low fuel prices	High fuel prices
Additional renewable resource[1]	TWh	46	46	46
CO_2 emissions abatement	MtCO2	14	14	14
Covered by EU ETS	MtCO2	6.8	7	6.9
Not covered by EU ETS	MtCO2	6.7	7	6.7
Number of installations	million	0.8	0.8	0.8
Total resource cost, variable prices	£m	860	-200	1,100
Technology costs	£m	600	-400	830
Barrier costs	£m	260	270	270
Resource cost, retail prices	£m	550	-700	860
Value of CO2 emissions abated	£m	450	700	330
Total subsidies	£m	3,700	3,400	3,600
RHI level	£/MWh	75	68	73
Resource cost / MWh[2]	£/MWh	19	-3	24
Average CO_2 abatement cost	£/tCO2	64	-12	80
CO_2 abatement cost at margin[3]	£/tCO2	260	240	260

Notes:

5. Output eligible for the UK's obligations under the relevant EU legislation. Actual heat output is c. 5-10 percent higher, depending on the combination of technologies.
6. Calculated using the "variable component" of fuel prices. See section 2.4.2.
7. Implied cost of CO2 abatement assuming average abatement potential of all output, and the cost characteristics of the marginal renewable heat technology.
8. Results are in shown in real terms in 2008 prices.

Table A.2
Summary Modelling Results: Sensitivity to Fuel Prices
(2020, Higher Growth Rate, 12 Percent Share)

Variable	Units	Central fuel prices	Low fuel prices	High fuel prices
Additional renewable resource[1]	TWh	66	66	66
CO_2 emissions abatement	MtCO2	18	18	18
Covered by EU ETS	MtCO2	7.9	8	7.9
Not covered by EU ETS	MtCO2	9.7	10	9.8
Number of installations	million	1.0	1.1	1.0
Total resource cost, variable prices	£m	1,600	250	2,000
Technology costs	£m	1,200	-200	1,500
Barrier costs	£m	410	420	410
Resource cost, retail prices	£m	1,200	-500	1,600
Value of CO2 emissions abated	£m	580	870	450
Total subsidies	£m	6,200	6,000	5,800
RHI level	£/MWh	89	86	84
Resource cost / MWh[2]	£/MWh	24	4	30
Average CO_2 abatement cost	£/tCO2	90	14	111
CO_2 abatement cost at margin[3]	£/tCO2	340	330	320

Notes:

1. Output eligible for the UK's obligations under the relevant EU legislation. Actual heat output is c. 5-10 percent higher, depending on the combination of technologies.
2. Calculated using the "variable component" of fuel prices. See section 2.4.2.
3. Implied cost of CO2 abatement assuming average abatement potential of all output, and the cost characteristics of the marginal renewable heat technology.
4. Results are in shown in real terms in 2008 prices.

A.2. Impact of Biomass Price Assumptions

Table A.3
Summary Modelling Results: Sensitivity to Biomass Prices
(2020, Central Growth Rate, 8.5 Percent Share)

Variable	Units	Central biomass price	High biomass price
Additional renewable resource[1]	TWh	46	46
CO_2 emissions abatement	MtCO2	14	13
Covered by EU ETS	MtCO2	6.8	7
Not covered by EU ETS	MtCO2	6.7	7
Number of installations	million	0.8	0.8
Total resource cost, variable prices[2]	£m	860	1,200
Technology costs	£m	600	940
Barrier costs	£m	260	240
Resource cost, retail prices	£m	550	890
Value of CO2 emissions abated	£m	450	450
Total subsidies	£m	3,700	3,700
RHI level	£/MWh	75	74
Resource cost / MWh[2]	£/MWh	19	26
Average CO_2 abatement cost	£/tCO2	64	88
CO_2 abatement cost at margin[3]	£/tCO2	260	280

Notes:

1. Output eligible for the UK's obligations under the relevant EU legislation. Actual heat output is c. 5-10 percent higher, depending on the combination of technologies.
2. Calculated using the "variable component" of fuel prices. See section 2.4.2.
3. Implied cost of CO2 abatement assuming average abatement potential of all output, and the cost characteristics of the marginal renewable heat technology.
4. Results are in shown in real terms in 2008 prices.

Table A.4
Summary Modelling Results: Alternative Biomass Prices
(2020, Higher Growth Rate, 12 Percent Share)

Variable	Units	Central biomass price	High biomass price
Additional renewable resource[1]	TWh	66	67
CO_2 emissions abatement	MtCO2	18	18
Covered by EU ETS	MtCO2	7.9	8
Not covered by EU ETS	MtCO2	9.7	10
Number of installations	million	1.0	1.1
Total resource cost, variable prices[2]	£m	1,600	2,200
Technology costs	£m	1,200	1,800
Barrier costs	£m	410	400
Resource cost, retail prices	£m	1,200	1,800
Value of CO2 emissions abated	£m	580	590
Total subsidies	£m	6,200	6,300
RHI level	£/MWh	89	88
Resource cost / MWh[2]	£/MWh	24	33
Average CO_2 abatement cost	£/tCO2	90	124
CO_2 abatement cost at margin[3]	£/tCO2	340	350

Notes:

1. Output eligible for the UK's obligations under the relevant EU legislation. Actual heat output is c. 5-10 percent higher, depending on the combination of technologies.
2. Calculated using the "variable component" of fuel prices. See section 2.4.2.
3. Implied cost of CO2 abatement assuming average abatement potential of all output, and the cost characteristics of the marginal renewable heat technology.
4. Results are in shown in real terms in 2008 prices.

A.3. Impact of Discount Rate Assumptions

Table A.5
Summary Modelling Results: Sensitivity to Discount Rate
(2020, Central Growth Rate, 8.5 Percent Share)

Variable	Units	Mid-low discount rate	Mid-high discount rate	Low discount rate
Additional renewable resource[1]	TWh	46	47	46
CO_2 emissions abatement	MtCO2	14	13	14
Covered by EU ETS	MtCO2	6.8	7	7.0
Not covered by EU ETS	MtCO2	6.7	7	6.7
Number of installations	million	0.8	0.8	0.8
Total resource cost, variable prices	£m	860	1,400	430
Technology costs	£m	600	1,000	220
Barrier costs	£m	260	330	220
Resource cost, retail prices	£m	550	1,000	120
Value of CO2 emissions abated	£m	450	450	450
Total subsidies	£m	3,700	5,200	2,700
RHI level	£/MWh	75	103	54
Resource cost / MWh[2]	£/MWh	19	29	9
Average CO_2 abatement cost	£/tCO2	64	100	32
CO_2 abatement cost at margin[3]	£/tCO2	260	400	190

Notes:

1. Output eligible for the UK's obligations under the relevant EU legislation. Actual heat output is c. 5-10 percent higher, depending on the combination of technologies.
2. Calculated using the "variable component" of fuel prices. See section 2.4.2.
3. Implied cost of CO2 abatement assuming average abatement potential of all output, and the cost characteristics of the marginal renewable heat technology.
4. Results are in shown in real terms in 2008 prices.

Table A.6
Summary Modelling Results: Sensitivity to Discount Rate
(2020, Higher Growth Rate, 12 Percent Share)

Variable	Units	Mid-low discount rate	Mid-high discount rate	Low discount rate
Additional renewable resource[1]	TWh	66	67	66
CO_2 emissions abatement	MtCO2	18	18	18
Covered by EU ETS	MtCO2	7.9	8	7.9
Not covered by EU ETS	MtCO2	9.7	10	9.8
Number of installations	million	1.0	1.0	1.1
Total resource cost, variable prices	£m	1,600	2,300	950
Technology costs	£m	1,200	1,800	600
Barrier costs	£m	410	520	350
Resource cost, retail prices	£m	1,200	1,900	540
Value of CO2 emissions abated	£m	580	580	590
Total subsidies	£m	6,200	8,200	4,300
RHI level	£/MWh	89	117	62
Resource cost / MWh[2]	£/MWh	24	35	14
Average CO_2 abatement cost	£/tCO2	90	132	54
CO_2 abatement cost at margin[3]	£/tCO2	340	460	240

Notes:

1. Output eligible for the UK's obligations under the relevant EU legislation. Actual heat output is c. 5-10 percent higher, depending on the combination of technologies.
2. Calculated using the "variable component" of fuel prices. See section 2.4.2.
3. Implied cost of CO2 abatement assuming average abatement potential of all output, and the cost characteristics of the marginal renewable heat technology.
4. Results are in shown in real terms in 2008 prices.

Appendix B. Detailed Technology Assumptions

This appendix gives detailed technology assumptions for each technology, including capital costs, operating costs, efficiency, load factor, lifetime, and the applicability of the technology. For each technology, we show first the main assumptions and sources, and then the detailed values used in the modelling. All costs are shown in 2008 values. In section B.8 we also give information about how the capex for different technologies and sectors is assumed to develop over time.

B.1. Air-Source Heat Pumps

Table B.1
Main Assumptions and Sources of Information for Air-Source Heat Pumps

Main assumptions	Source
Capital costs. Domestic is for true air to water heat pumps not reversible split air conditioners Domestic properties with electric heating are apportioned higher capital costs as the building will also require the installation of a wet distribution system. Not for commercial who are assumed to have warm air heating. Commercial based on more complex Variable Refrigerant Flow (VRF) or Caloris water circulation systems Economy of number is taken into account with approx 10% reduction.	Taken from published prices and AEA Estimates. Domestic prices based on 14kW and 6kW units as appropriate to house type. Includes upgrade to existing internal system. Based on www.lowcarbonbuildings.org.uk, E.ON response Heat call for Evidence, ICE Energy. Commercial systems are assumed to be made up of a higher number of units e.g. 6 x 50kW units for a 300kW demand.
Operating costs assumed fixed opex was maintenance cost.	Average values. Dimplex Design Guidance, RAB Report, based on 0.5 days service over 5 years
Efficiency – assumed as Coefficient of Performance	Domestic is an average estimate based on figures from IEA heat pump centre, Vailant response to heat call for evidence, Microgen C scheme, Heat call for evidence and manufacturers data. Commercial are average estimates of information from manufacturers (Colt, Dimplex, Mitsubishi, De Longhi) EU Heat Pump Association.
Load factor	Domestic figure quoted in RAB report based on 1762 hours. Commercial AEA estimate based on sector usage.
Lifetime The lifetime of an ASHP is estimated at around 15-20 years. This is less than a GSHP as they are more exposed to the elements which can cause them more wear and damage.	AEA estimates and manufacturers literature and discussions
Applicability. Flats ruled out as considered that there will be	AEA estimates

Main assumptions	Source
limited space for an indoor unit and outdoor units could not be accessed for maintenance apart from the ground floor unit (which may be susceptible to vandalism)	
For the purposes of the model assumed ASHP equally suitable for new and pre-1990 buildings, although older properties with poor levels of insulation (and high heat demand) may not be as suitable.	
Due to relatively small space requirements ASHPs are deemed suitable for urban, rural and suburban properties.	
Industrial applications not applicable due to small size of sector due to low grade of heat.	
Cooling is not included.	
Impact on counterfactual.	
Domestic electrically heated properties have new low temperature heating system.	AEA.

Table B.2
Summary Technology Assumptions for Air-Source Heat Pumps

Customer Segment	Variable	Unit	Values
Domestic	Capital Cost	£/kW	650-1,650
Domestic	Opex	£/kW/year	4-9
Domestic	Size of installation	kW	6-14
Domestic	Efficiency	%	250%-275%
Domestic	Lifetime	years	18
Domestic	Load factor	%	10%-24%
Domestic	Total install cost	£'000s	4-23
Commercial / Public -- Small	Capital Cost	£/kW	545
Commercial / Public -- Small	Opex	£/kW/year	6
Commercial / Public -- Small	Size of installation	kW	55
Commercial / Public -- Small	Efficiency	%	350%
Commercial / Public -- Small	Lifetime	years	20
Commercial / Public -- Small	Load factor	%	35%
Commercial / Public -- Small	Total install cost	£'000s	30
Commercial / Public -- Large	Capital Cost	£/kW	610
Commercial / Public -- Large	Opex	£/kW/year	1
Commercial / Public -- Large	Size of installation	kW	300
Commercial / Public -- Large	Efficiency	%	400%
Commercial / Public -- Large	Lifetime	years	20
Commercial / Public -- Large	Load factor	%	35%
Commercial / Public -- Large	Total install cost	£'000s	183
Industrial -- Small	Capital Cost	£/kW	610
Industrial -- Small	Opex	£/kW/year	1
Industrial -- Small	Size of installation	kW	300
Industrial -- Small	Efficiency	%	400%
Industrial -- Small	Lifetime	years	20
Industrial -- Small	Load factor	%	35%
Industrial -- Small	Total install cost	£'000s	183
Industrial -- Large	Capital Cost	£/kW	610
Industrial -- Large	Opex	£/kW/year	1
Industrial -- Large	Size of installation	kW	300
Industrial -- Large	Efficiency	%	400%
Industrial -- Large	Lifetime	years	20
Industrial -- Large	Load factor	%	35%
Industrial -- Large	Total install cost	£'000s	183

Table B.3
Detailed Assumptions for Domestic Air-Source Heat Pumps

Counterfactual fuel	House type	Building Age	Capex	Representative size	Total cost	COP
			£/kW	kW	£	
Gas / non net-bound	Detached	Pre-1990	650	14	9,100	2.50
Gas / non net-bound	Detached	Post-1990	650			2.75
Gas / non net-bound	Other	Pre-1990	1,400	6	8,400	2.50
Gas / non net-bound	Other	Post-1990	1,400			2.75
Electricity	Detached	Pre-1990	750	14	10,500	2.50
Electricity	Detached	Post-1990	750			2.75
Electricity	Other	Pre-1990	1,650	6	9,900	2.50
Electricity	Other	Post-1990	1,650	6	9,900	2.75

Note: The “Other” house type includes semi-detached and terraced houses, but excludes flats.

B.2. Ground Source Heat Pumps

Table B.4
Main Assumptions and Sources of Information for Ground-Source Heat Pumps

Main assumptions	Source
Capital costs. AEA have tried to reflect the cost variation which will occur with different sizes of system and levels of internal heat distribution system upgrade / replacement which may be typical for each group. The costs utilised by AEA are fully installed costs per kW including the HP unit itself alongside internal works and ground loop. Domestic: Suburban properties are assumed to need a borehole heat exchanger and high capital costs, while rural can use a horizontal slinky ground coil. Domestic properties with electric heating are apportioned higher capital costs as the building will also require the installation of a wet distribution system. Other properties upgraded. Not for commercial who are assumed to have warm air heating. Assumed commercial buildings will require a borehole in order to meet higher heat demand in suitable land area. Post 1990 properties have lower capital costs as it is assumed the proportion of these that are new have lower installed costs for heat distribution systems (internals) or, as there is lower heat loss, better suitability with standard radiators.	Average figures. Domestic sources are E.ON in heat call for Evidence, EST case study with 10kW system for £14,000 installed, Average of DTI/Halcrow range of £800-1200 for an 8kW system Commercial US case study on IGSHPA website. Based on a total capacity of 210kWth (6 x 35kW units) and project cost of £140k 300kW Cost would be in the region of £435,000 (area required for boreholes approximately 1100m2). Geothermal International. Other information from suppliers e.g. Viessmann, Stiebel and Kensa.
Operating costs assumed fixed opex was maintenance cost.	Average of opinions from installers and AEA estimates
Efficiency – assumed as Coefficient of Performance Post 1990 properties assumed to have a higher efficiency due to larger percentage of these (new build) able to use lower temp underfloor heating or having lower heat loss and hence capable of using lower temp wall hanging radiators. Larger domestic assumed to have underfloor heating with lower temperature hence higher COP.	Average values from Domestic EST case study with 10kW HP, In SAP, with auxiliary. 2.1 with radiators (x 0.7), In SAP, all heat. 2.24 with radiators (x 0.7) GSHPA in heat call for Evidence Average of 3.5-5.5 range from Veissmann, GSHPA, Greenfield, Eco Heat Pump Systems Ltd, Earth Energy Ltd. & E.ON in heat call for Evidence Commercial Published data from manufacturers, Steibel Eltron, Veissman and US case study on IGSHPA website
Load factor	Domestic figure quoted in RAB report based on 1762 hours. Commercial AEA estimate based on sector usage.

Main assumptions	Source
Lifetime	AEA estimates and manufacturers literature.
Typical sizes	AEA estimates from sector information. Assumed detached to be larger properties and other house to be smaller, hence an 11 and 6kW
Applicability. Individual flats ruled out as considered that there will be not opportunity to install a ground loop except in ground floor properties and in this case it is unlikely due to communal ownership of land. Assumed GSHP is suitable for new and pre-1990 buildings, although older properties (1960's and before) with poor levels of insulation (and high heat demand) may not be as suitable. Due to space requirements GSHPs are not deemed suitable for urban areas. Cooling is not included.	AEA estimates
Impact on counterfactual. Heating system upgrade for gas and oil heated domestic properties£90/kw, £166/kW with low temperature system. All electric figures are as figures for Gas but with full cost of internals added e.g. £181/kW for 11kW system and £333/kW for a 6kW system	AEA based on published prices for similar systems.

Table B.5
Summary Technology Assumptions for Ground-Source Heat Pumps

Customer Segment	Variable	Unit	Values
Domestic	Capital Cost	£/kW	771-1,899
Domestic	Opex	£/kW/year	5-9
Domestic	Size of installation	kW	6-11
Domestic	Efficiency	%	315%-385%
Domestic	Lifetime	years	23
Domestic	Load factor	%	13%-24%
Domestic	Total install cost	£'000s	5-21
Commercial / Public -- Small	Capital Cost	£/kW	1,420-1,560
Commercial / Public -- Small	Opex	£/kW/year	4
Commercial / Public -- Small	Size of installation	kW	55
Commercial / Public -- Small	Efficiency	%	360%-425%
Commercial / Public -- Small	Lifetime	years	20
Commercial / Public -- Small	Load factor	%	35%
Commercial / Public -- Small	Total install cost	£'000s	78-86
Commercial / Public -- Large	Capital Cost	£/kW	1,410-1,526
Commercial / Public -- Large	Opex	£/kW/year	1
Commercial / Public -- Large	Size of installation	kW	300
Commercial / Public -- Large	Efficiency	%	360%-425%
Commercial / Public -- Large	Lifetime	years	20
Commercial / Public -- Large	Load factor	%	35%
Commercial / Public -- Large	Total install cost	£'000s	423-458
Industrial -- Small	Capital Cost	£/kW	1,420-1,560
Industrial -- Small	Opex	£/kW/year	4
Industrial -- Small	Size of installation	kW	55
Industrial -- Small	Efficiency	%	400%-425%
Industrial -- Small	Lifetime	years	20
Industrial -- Small	Load factor	%	35%
Industrial -- Small	Total install cost	£'000s	78-86
Industrial -- Large	Capital Cost	£/kW	1,410-1,526
Industrial -- Large	Opex	£/kW/year	1
Industrial -- Large	Size of installation	kW	300
Industrial -- Large	Efficiency	%	400%-425%
Industrial -- Large	Lifetime	years	20
Industrial -- Large	Load factor	%	35%
Industrial -- Large	Total install cost	£'000s	423-458

Table B.6
Detailed Assumptions for Domestic Ground-Source Heat Pumps

Counterfactual fuel	House type	Location	Building Age	Capex	Representative size	COP	Total cost
				£/kW	kW		£
Gas / non net-bound	Detached	Suburban	Pre-1990	1,106	11	3.25	12,166
Gas / non net-bound	Detached	Suburban	Post-1990	1,016	11	3.75	11,176
Gas / non net-bound	Detached	Rural	Pre-1990	861	11	3.25	9,466
Gas / non net-bound	Detached	Rural	Post-1990	771	11	3.75	8,476
Gas / non net-bound	Other House	Suburban	Pre-1990	1,566	6	3.15	9,396
Gas / non net-bound	Other House	Suburban	Post-1990	1,400	6	3.75	8,400
Gas / non net-bound	Other House	Rural	Pre-1990	1,241	6	3.15	7,446
Gas / non net-bound	Other House	Rural	Post-1990	1,075	6	3.75	6,450
Electricity	Detached	Suburban	Pre-1990	1,287	11	3.35	14,157
Electricity	Detached	Suburban	Post-1990	1,197	11	3.85	13,167
Electricity	Detached	Rural	Pre-1990	1,042	11	3.35	11,457
Electricity	Detached	Rural	Post-1990	952	11	3.85	10,467
Electricity	Other House	Suburban	Pre-1990	1,899	6	3.25	11,394
Electricity	Other House	Suburban	Post-1990	1,733	6	3.85	10,398
Electricity	Other House	Rural	Pre-1990	1,574	6	3.25	9,444
Electricity	Other House	Rural	Post-1990	1,408	6	3.85	8,448

Note: The “Other” house type includes semi-detached and terraced houses, but excludes flats.

B.3. Biomass boilers

Table B.7
Main Assumptions and Sources of Information for Biomass Boilers

Main assumptions	Reference
Capital Costs. These are for the full installation costs including, plant and machinery, building works, flue and fuel handling. It does not include the internal heating system in premises heated by gas and off grid. Domestic includes VAT otherwise not. We assume that the majority of boilers below 300kW would meet En303-5 class 3 performance for thermal efficiency and emissions. Larger boilers would be expected to be fitted with abatement equipment.	Bioenergy Capital Grants Scheme (BECGS) figures from latest two rounds. There are very few industrial installations so the data is less accurate here.
Typical size. These are AEA estimates based on the numbers of installations, consumption and knowledge of the sectors.	BECGS average size for type of installation where possible. There are very few industrial installations so the data is less accurate here.
Efficiency. Annual efficiency on net basis. This differs from earlier work where peak efficiencies were used.	Taken as the annual efficiency from IEA Task 32. http://www.ieabcc.nl/ All domestic assumed to be pellet boilers and increased by 5% over Enviros figures in previous work (AEA estimate)
Load factor	Taken from Carbon Trust Users Guide to Biomass Heating and AEA estimates.
Applicability. All smaller urban properties are assumed to be excluded due to air quality concerns and difficulties with access. We have surveyed potential improvements to the technology and reached the conclusion that no technical fix will be available in volume before 2020 that will reduce the emissions adequately to make domestic sized installations acceptable in high density areas. Commercial and industrial will be OK however as filters are available at this size. Detached properties are retained as some will probably be suitable.	Ref IEA Task 32 seminars, and surveys. Workshop on Aerosols in Biomass Combustion, Jyväskylä, Finland, September 2007 Workshop on Next Generation Small Scale Biomass Combustion, Amsterdam, Oct 20, 2008 http://www.ieabcc.nl/
Lifetime	Enviros figures and AEA estimates used
Impact on counterfactual. For domestic no impact on gas and off grid but £300/kW added to electrically heated to allow for the installation of a	Web search on current market prices paid by consumers for central heating systems less

Main assumptions	Reference
wet system.	£1000 for cost of boiler.
Commercial and industrial are assumed to supply existing and suitable heating systems such as warm air and wet.	www.whatprice.co.uk
Fuel supply limitation on domestic is equal to E4Tech BAU pellets supply of 27.7 TWh in 2020 and say 14 TWh in 2015.	E4Tech report.

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Table B.8
Summary Technology Assumptions for Biomass Boilers

Customer Segment	Variable	Unit	Values
Domestic	Capital Cost	£/kW	330-550
Domestic	Opex	£/kW/year	11-18
Domestic	Size of installation	kW	12-20
Domestic	Efficiency	%	85%
Domestic	Lifetime	years	15
Domestic	Load factor	%	7%-12%
Domestic	Total install cost	£'000s	4-11
Commercial / Public -- Small	Capital Cost	£/kW	345-655
Commercial / Public -- Small	Opex	£/kW/year	5-8
Commercial / Public -- Small	Size of installation	kW	110-180
Commercial / Public -- Small	Efficiency	%	81%
Commercial / Public -- Small	Lifetime	years	15
Commercial / Public -- Small	Load factor	%	20%
Commercial / Public -- Small	Total install cost	£'000s	37-117
Commercial / Public -- Large	Capital Cost	£/kW	317-423
Commercial / Public -- Large	Opex	£/kW/year	16-21
Commercial / Public -- Large	Size of installation	kW	350-1,600
Commercial / Public -- Large	Efficiency	%	81%
Commercial / Public -- Large	Lifetime	years	15
Commercial / Public -- Large	Load factor	%	20%-45%
Commercial / Public -- Large	Total install cost	£'000s	111-678
Industrial -- Small	Capital Cost	£/kW	345-423
Industrial -- Small	Opex	£/kW/year	17-21
Industrial -- Small	Size of installation	kW	100-1,000
Industrial -- Small	Efficiency	%	81%
Industrial -- Small	Lifetime	years	15
Industrial -- Small	Load factor	%	20%-60%
Industrial -- Small	Total install cost	£'000s	35-423
Industrial -- Large	Capital Cost	£/kW	275-423
Industrial -- Large	Opex	£/kW/year	14-21
Industrial -- Large	Size of installation	kW	350-5,000
Industrial -- Large	Efficiency	%	81%
Industrial -- Large	Lifetime	years	15
Industrial -- Large	Load factor	%	20%-60%
Industrial -- Large	Total install cost	£'000s	96-2,120

B.4. Biomass District Heating

Table B.9
Main Assumptions and Sources of Information for Biomass District Heating

Main assumptions	Source
Capital costs. These are for all investment costs up to and including the heat exchanger in the heated property.	Reported costs from Bioenergy Capital Grants scheme for rural systems. AEA figure from Community Energy Scheme for urban. http://www.energysavingtrust.org.uk/uploads/documents/housingbuildings/UK%20CH%20potential%20report_CTFinal.pdf
Operating costs are 2% of capex	Bioheat Project figures as reported by Austrian Energy Agency course material. www.bioheat.info
Boiler efficiency is 80% on net basis. Note this is annual, not peak as reported by Enviros	AEA figure for annual efficiency.
Overall efficiency to consumer net basis is less due to loss of 10% in pipework and distribution	Bioheat Project figures as reported by Austrian Energy Agency course material. www.bioheat.info
Load factor	Taken from Carbon Trust Users Guide to Biomass Heating
Lifetime	Enviros figures and AEA estimates used
Applicability is all urban areas plus all rural areas. Urban areas are high density areas supplied by traditional networks fuelled by waste wood and other cheaper biomass in large installations. This also includes social housing renovation and repowering. The rural areas are small mini networks covering pockets of high density buildings with the benefit of local fuel which is often the driver for take up. Suburban areas are excluded as the loading per km is too low to be economic in comparison with other alternatives particularly stand alone biomass.	Bioheat Project figures as reported by Austrian Energy Agency course material. www.bioheat.info.
Impact on counterfactual. For domestic no impact on gas and off grid but £300/kW added to electrically heated domestic to allow for the installation of a wet system. Commercial and industrial are assumed to supply existing and suitable heating systems such as warm air and wet.	Web search on current market prices paid by consumers for central heating systems less £1000 for cost of boiler. www.whatprice.co.uk

Table B.10
Summary Technology Assumptions for Biomass District Heating

Customer Segment	Variable	Unit	Values
Domestic	Capital Cost	£/kW	635-1,550
Domestic	Opex	£/kW/year	16-39
Domestic	Size of installation	kW	1200
Domestic	Efficiency	%	73%
Domestic	Lifetime	years	35
Domestic	Load factor	%	20%
Domestic	Total install cost	£'000s	762-1,860
Commercial / Public -- Small	Capital Cost	£/kW	635-1,250
Commercial / Public -- Small	Opex	£/kW/year	16-31
Commercial / Public -- Small	Size of installation	kW	110-180
Commercial / Public -- Small	Efficiency	%	73%
Commercial / Public -- Small	Lifetime	years	15-35
Commercial / Public -- Small	Load factor	%	20%-45%
Commercial / Public -- Small	Total install cost	£'000s	68-224
Commercial / Public -- Large	Capital Cost	£/kW	635-1,250
Commercial / Public -- Large	Opex	£/kW/year	16-31
Commercial / Public -- Large	Size of installation	kW	350-1,600
Commercial / Public -- Large	Efficiency	%	73%
Commercial / Public -- Large	Lifetime	years	15-35
Commercial / Public -- Large	Load factor	%	20%-45%
Commercial / Public -- Large	Total install cost	£'000s	222-2,000
Industrial -- Small	Capital Cost	£/kW	635-1,250
Industrial -- Small	Opex	£/kW/year	16-31
Industrial -- Small	Size of installation	kW	100-350
Industrial -- Small	Efficiency	%	73%
Industrial -- Small	Lifetime	years	35
Industrial -- Small	Load factor	%	20%
Industrial -- Small	Total install cost	£'000s	64-438
Industrial -- Large	Capital Cost	£/kW	635-1,250
Industrial -- Large	Opex	£/kW/year	16-31
Industrial -- Large	Size of installation	kW	350
Industrial -- Large	Efficiency	%	73%
Industrial -- Large	Lifetime	years	35
Industrial -- Large	Load factor	%	20%
Industrial -- Large	Total install cost	£'000s	222-438

B.5. Biogas Injection

Table B.11
Main Assumptions and Sources of Information for Biogas Injection

Main assumptions	Comments / Source
Capital costs	AD unit: fixed cost of £2 million and additional cost of £730 / kW gas export capacity (£550 / gas generating capacity). Scrubber: £110 / kW Source: Information from AEA commercial work
Operating and maintenance costs	Assumed to be 5% of capex Source: AEA estimate
Efficiency	75 percent of gas produced available for export, the rest consumed to keep digester at correct temperature Source: AEA estimate
Load factor	Assumes constant operation. Source: AEA estimate
Lifetime	Source: AEA estimate

Notes: AEA has drawn on a range of sources and experience from commercial work to develop these estimates. Examples of relevant AEA commercial work informing the estimates in this table include:

- Project Case study - Feasibility study into centralised anaerobic digestion in the dairy supply chain, work concluded February 2009, for Dairy UK and Welsh Assembly Government.
- Assessment of Methane Management and Recovery Options for Livestock Manures and Slurries, December 2005, AEA study for Defra.

Table B.12
Summary Technology Assumptions for Biogas Injection

Variable	Unit	Values
Capital Cost		
AD unit	£/kW	1,900
Scrubber	£/kW	110
Total	£/kW	2,000
Opex	£/kW/year	98
Size of installation	kW	1,800
Efficiency	%	75%
Lifetime	years	20
Load factor	%	100%
Total install cost	£'000s	3,500

B.6. Solar Thermal

Table B.13
Main Assumptions and Sources of Information for Solar Thermal

Main assumptions	Source
Capital costs.	Element Energy Report but 2007 price used assuming no drop before then £2,000 + £1,000/kWt peak Cross checked with Spons[30]
Operating costs.	Element Energy Report based on £2,000 + £1,000/kWt peak
Efficiency 50% assumed	AEA estimate based on generally available information for all collectors
Load factor	Commercial Element Energy study 643kWh/kWp Domestic AEA Calculation based on 60% of HW load assumed to be 25% of annual thermal load or 643kWh/kW whichever is the lower Industrial Element Energy study 643kWh/kWp
Lifetime	AEA estimate
Applicability. All buildings assumed suitable but not process heat	AEA estimate based on sector knowledge
Impact on counterfactual. None	AEA estimate

30 Spon's M&E Services Price Book 40th Ed (2009)

Table B.14
Summary Technology Assumptions for Solar Thermal

Customer Segment	Variable	Unit	Values
Domestic	Capital Cost	£/kW	1,806
Domestic	Opex	£/kW/year	18
Domestic	Size of installation	kW	2.5
Domestic	Efficiency	%	50%
Domestic	Lifetime	years	20
Domestic	Load factor	%	5%
Domestic	Total install cost	£'000s	4
Commercial / Public -- Small	Capital Cost	£/kW	1,600
Commercial / Public -- Small	Opex	£/kW/year	18
Commercial / Public -- Small	Size of installation	kW	12
Commercial / Public -- Small	Efficiency	%	50%
Commercial / Public -- Small	Lifetime	years	20
Commercial / Public -- Small	Load factor	%	5%
Commercial / Public -- Small	Total install cost	£'000s	20
Commercial / Public -- Large	Capital Cost	£/kW	1,600
Commercial / Public -- Large	Opex	£/kW/year	18
Commercial / Public -- Large	Size of installation	kW	12
Commercial / Public -- Large	Efficiency	%	50%
Commercial / Public -- Large	Lifetime	years	20
Commercial / Public -- Large	Load factor	%	5%
Commercial / Public -- Large	Total install cost	£'000s	20
Industrial -- Small	Capital Cost	£/kW	1,600
Industrial -- Small	Opex	£/kW/year	18
Industrial -- Small	Size of installation	kW	12
Industrial -- Small	Efficiency	%	50%
Industrial -- Small	Lifetime	years	20
Industrial -- Small	Load factor	%	5%
Industrial -- Small	Total install cost	£'000s	20
Industrial -- Large	Capital Cost	£/kW	1,600
Industrial -- Large	Opex	£/kW/year	18
Industrial -- Large	Size of installation	kW	12
Industrial -- Large	Efficiency	%	50%
Industrial -- Large	Lifetime	years	20
Industrial -- Large	Load factor	%	5%
Industrial -- Large	Total install cost	£'000s	20

B.7. Fossil Fuel and Electric Heating

B.7.1. Main assumptions and sources of information

These are the costs and performance factors for the technologies that would be installed in place of the renewable heat alternative. We have set out below the sources of the data and important changes from previous work.

The counterfactuals are electricity, natural gas and "off grid" which covers both LPG and oil.

B.7.1.1. Capex

Electrical heating systems

The figures from the Enviros report were checked against Spons [31] and found to agree and so used for the modelling.

Where an electrical system is replaced by a wet radiator system the cost of the radiator system is included in the capex for the RH alternative. This was determined from a survey of quoted prices available on the web and Spons.

Natural gas and off grid

For domestic systems the figures from the Element Energy study were used.

For commercial systems AEA made estimates based on the base costs in Spons.

B.7.1.2. Opex

These were deduced from the Element Energy study and AEA estimates.

B.7.1.3. Efficiency

- All values were converted to Lower Heating Value base.
- Natural gas boiler figures were based on Carbon Trust boiler trials.
- Oil boiler efficiencies were based on AEA internal knowledge.
- Where electrical storage heaters are indicated the efficiency has been reduced by 10% to compensate for excess heat emitted when not wanted during changing.

B.7.1.4. Load Factors

These were based on AEA estimates for the character of the sector.

[31] Spon's M&E Services Price Book 40th Ed (2009)

B.7.1.5. Typical size

For commercial and domestic these were deduced from load factors and relative renewable capacity.

For industrial boilers these were taken from the Enviros work.

Detailed values used for the modelling are given in tables A6 – A8 below for completeness.

B.7.2. Counterfactual – Natural Gas

Table B.15
Summary Technology Assumptions for Natural Gas Heating

Customer Segment	Variable	Unit	Values
Domestic	Capital Cost	£/kW	125-150
Domestic	Opex	£/kW/year	9
Domestic	Size of installation	kW	20
Domestic	Efficiency	%	94%
Domestic	Lifetime	years	15
Domestic	Load factor	%	3%-10%
Domestic	Total install cost	£'000s	3-3
Commercial / Public -- Small	Capital Cost	£/kW	93
Commercial / Public -- Small	Opex	£/kW/year	3
Commercial / Public -- Small	Size of installation	kW	50-180
Commercial / Public -- Small	Efficiency	%	94%
Commercial / Public -- Small	Lifetime	years	15
Commercial / Public -- Small	Load factor	%	20%
Commercial / Public -- Small	Total install cost	£'000s	5-17
Commercial / Public -- Large	Capital Cost	£/kW	65
Commercial / Public -- Large	Opex	£/kW/year	1
Commercial / Public -- Large	Size of installation	kW	350-3,600
Commercial / Public -- Large	Efficiency	%	94%
Commercial / Public -- Large	Lifetime	years	15
Commercial / Public -- Large	Load factor	%	20%
Commercial / Public -- Large	Total install cost	£'000s	23-234
Industrial -- Small	Capital Cost	£/kW	30-65
Industrial -- Small	Opex	£/kW/year	0
Industrial -- Small	Size of installation	kW	96-1,000
Industrial -- Small	Efficiency	%	94%
Industrial -- Small	Lifetime	years	15
Industrial -- Small	Load factor	%	20%-82%
Industrial -- Small	Total install cost	£'000s	3-65
Industrial -- Large	Capital Cost	£/kW	30-65
Industrial -- Large	Opex	£/kW/year	0
Industrial -- Large	Size of installation	kW	350-3,600
Industrial -- Large	Efficiency	%	94%
Industrial -- Large	Lifetime	years	15
Industrial -- Large	Load factor	%	20%-82%
Industrial -- Large	Total install cost	£'000s	11-237

B.7.3. Counterfactual – Off-grid

Table B.16
Summary Technology Assumptions for Off-Grid Fossil Fuel Heating

Customer Segment	Variable	Unit	Values
Domestic	Capital Cost	£/kW	125-150
Domestic	Opex	£/kW/year	9
Domestic	Size of installation	kW	20
Domestic	Efficiency	%	80%
Domestic	Lifetime	years	15
Domestic	Load factor	%	5%-10%
Domestic	Total install cost	£'000s	3-3
Commercial / Public -- Small	Capital Cost	£/kW	93
Commercial / Public -- Small	Opex	£/kW/year	3
Commercial / Public -- Small	Size of installation	kW	50-180
Commercial / Public -- Small	Efficiency	%	80%
Commercial / Public -- Small	Lifetime	years	15
Commercial / Public -- Small	Load factor	%	20%
Commercial / Public -- Small	Total install cost	£'000s	5-17
Commercial / Public -- Large	Capital Cost	£/kW	65
Commercial / Public -- Large	Opex	£/kW/year	1
Commercial / Public -- Large	Size of installation	kW	350-3,000
Commercial / Public -- Large	Efficiency	%	80%
Commercial / Public -- Large	Lifetime	years	15
Commercial / Public -- Large	Load factor	%	20%
Commercial / Public -- Large	Total install cost	£'000s	23-195
Industrial -- Small	Capital Cost	£/kW	30-65
Industrial -- Small	Opex	£/kW/year	0
Industrial -- Small	Size of installation	kW	96-1,000
Industrial -- Small	Efficiency	%	80%
Industrial -- Small	Lifetime	years	15
Industrial -- Small	Load factor	%	20%-82%
Industrial -- Small	Total install cost	£'000s	3-65
Industrial -- Large	Capital Cost	£/kW	30-65
Industrial -- Large	Opex	£/kW/year	0
Industrial -- Large	Size of installation	kW	350-3,600
Industrial -- Large	Efficiency	%	80%
Industrial -- Large	Lifetime	years	15
Industrial -- Large	Load factor	%	20%-82%
Industrial -- Large	Total install cost	£'000s	11-237

B.7.4. Counterfactual – Electric heating

Table B.17
Summary Technology Assumptions for Electric Fuel Heating

Customer Segment	Variable	Unit	Values
Domestic	Capital Cost	£/kW	175
Domestic	Opex	£/kW/year	
Domestic	Size of installation	kW	10-23
Domestic	Efficiency	%	90%
Domestic	Lifetime	years	15
Domestic	Load factor	%	5%-9%
Domestic	Total install cost	£'000s	2-4
Commercial / Public -- Small	Capital Cost	£/kW	221
Commercial / Public -- Small	Opex	£/kW/year	1
Commercial / Public -- Small	Size of installation	kW	50-180
Commercial / Public -- Small	Efficiency	%	100%
Commercial / Public -- Small	Lifetime	years	15
Commercial / Public -- Small	Load factor	%	20%
Commercial / Public -- Small	Total install cost	£'000s	11-40
Commercial / Public -- Large	Capital Cost	£/kW	221
Commercial / Public -- Large	Opex	£/kW/year	0
Commercial / Public -- Large	Size of installation	kW	350-3,600
Commercial / Public -- Large	Efficiency	%	100%
Commercial / Public -- Large	Lifetime	years	15
Commercial / Public -- Large	Load factor	%	20%
Commercial / Public -- Large	Total install cost	£'000s	77-797
Industrial -- Small	Capital Cost	£/kW	147
Industrial -- Small	Opex	£/kW/year	0
Industrial -- Small	Size of installation	kW	96-1,000
Industrial -- Small	Efficiency	%	100%
Industrial -- Small	Lifetime	years	15
Industrial -- Small	Load factor	%	20%-82%
Industrial -- Small	Total install cost	£'000s	14-147
Industrial -- Large	Capital Cost	£/kW	147
Industrial -- Large	Opex	£/kW/year	0
Industrial -- Large	Size of installation	kW	350-3,600
Industrial -- Large	Efficiency	%	100%
Industrial -- Large	Lifetime	years	15
Industrial -- Large	Load factor	%	20%-82%
Industrial -- Large	Total install cost	£'000s	51-535

B.8. Capex Indices

Table B.18 shows an index of how capex is assumed to develop over time. The index is shown for each technology and for the domestic and non-domestic (commercial, public, and industrial) sectors, and for each of 2010, 2015, and 2020. The values are expressed in terms of the proportion of 2010 costs. For example, a value of 0.91 in 2015 indicates that the capex in that year is 91 percent of the capex estimated for 2010.

Table B.18
Index of Capex over Time (2010 cost = 1)

	Domestic			Non-domestic		
	2010	2015	2020	2010	2015	2020
Biomass boilers	1.00	0.91	0.83	1.00	1.00	1.00
ASHP	1.00	0.86	0.77	1.00	0.87	0.77
GSHP	1.00	0.86	0.77	1.00	0.87	0.77
Biomass DH	1.00	1.00	1.00	1.00	1.00	1.00
Solar Thermal	1.00	0.85	0.80	1.00	0.83	0.73
Biogas	1.00	0.95	0.90	1.00	0.95	0.90

Source: Element Energy (2008) and additional AEA analysis and assumptions.

B.9. Additional Cost in Higher Growth Rate Scenario

The below table shows estimates of additional costs associated with the “higher” growth rate scenario, based on an analysis the barriers presented in section C.1 below.

Table B.19
Summary of Additional Costs in Higher Growth Scenario

Technology	Impact on cost
Biomass boilers	§ 20 percent increase in local installation costs, resulting in an 8 percent increase in capex. § 20 percent increase in maintenance cost, reflecting increased demand for scarce skilled labour § Large, urban boilers only: 15 percent addition to capex to reflect additional cost of installation in areas sensitive to air pollution
Air-source heat pumps	§ 10 percent increase in capex to account for increased labour costs § 2 percent increase in capex to reflect noise abatement measures required for increased deployment in sensitive areas
Ground-source heat pumps	§ 10 percent increase in capex to account for increased labour costs § Add £225/kW to capex of one-third of installations, reflecting increased use of boreholes over ground loops

Appendix C. Details of Growth Rate Scenarios

C.1. Barriers to Deployment

The tables below set out factors that influence the adoption of renewable heat technologies. These were used as background when assessing the suitability of technologies for particular applications, and when developing estimates as to how the supply potential of each of the technologies might grow. They were identified from previous work, consultations, literature review, and AEA internal knowledge.

C.1.1. Individual Biomass Boilers

Barrier	Description	Mitigation
Unfamiliarity	Biomass and pellet boilers and room heaters are unfamiliar to most of the UK population.	Information and awareness raising. Experience from Ireland suggests there is relatively little consumer resistance to change in off grid areas where pellets are available and supported by fuel suppliers.
High capital cost	The installed cost of a biomass boiler system is typically three times the cost of an oil or gas equivalent. Running cost is usually lower than oil or LPG	Incentive acknowledges the high up front cost.
Poor choice of fuel suppliers and unfamiliar fuel	There are currently no major suppliers of wood fuel to the domestic market outside of Northern Ireland. This is a stark contrast to the situation with oil and gas where there is strong competition. This contrast means market is concentrated on first adopters. Much of the attraction of biomass heat is the perception of price stability that is in contrast with the recent record of heating oil	Facilitate the building of supply infrastructure. Underpin the initial market with strategic public sector purchases. Accelerate introduction of fuel standards. Experience from Ireland has shown that customer support at all stages is absolutely critical to a successful uptake. Customers need a relationship that is stronger and more responsive than their current oil supplier.
Space constraints	Biomass boilers need space for fuel storage. This is not always available.	Pellet boilers can normally be fitted in place of oil systems but smaller urban properties are unlikely to be suitable.
Air quality legislation prevents installation	Many dense urban areas exceed threshold values for particulate and nitrogen oxides emissions. All new sources receive increased scrutiny and may not be approved. The clean air act regulates deployment in other areas but needs updating to recognise characteristics of biomass. Potential for delay and a pause in deployment whilst this is achieved.	Better information on sensitive areas. Clarity in regulation of appliance and installation before mass deployment.
Consumer unwilling to load	Many smaller boilers and room heaters involve the handling of 15kg sacks or	Encourage hybrid systems with solar or ASHP to reduce load and effort in

Barrier	Description	Mitigation
fuel manually	baskets of logs.	shoulder seasons and summer. There is little other mitigation for this barrier other than the selection of a more expensive solution with bulk storage.
Disruption to existing system	Many biomass systems require non standard controls, large accumulators and larger installation space than the equivalent standard oil or gas boiler. This often necessitates relocation of several components of the existing system and results in additional cost and disruption.	There is no mitigation for this barrier other than technical development.
Poor fit to household usage pattern.	Biomass boilers work best when operating at high and constant load. This means that they have a lower output and operate for longer periods than an equivalent oil or gas unit. This may not suit modern lifestyles where the property is not occupied through the day but needs to warm quickly in the evening.	Encourage high levels of insulation as a complement to biomass and to retain and conserve heat. Disseminate information on suitability. There is no other mitigation for this barrier other than technical development.

C.1.2. Biomass District Heating

Barrier	Description	Mitigation
Unfamiliarity	Buying a metered supply of energy in the form of hot water is unfamiliar to most of the UK population.	Information and awareness raising. Stress similarity to gas and electricity.
High capital cost	The cost of connection and the pipework infrastructure is very high when compared to individual solutions, while the load factor in the UK is low compared to other countries where DH is commonplace.	Infrastructure that has a very long lifetime could be funded on a different basis to alternatives with a shorter lifetime.
Consumer resists loss of competition for energy supply.	Consumers, particularly in urban areas may resist the long term contracts necessary to finance DH infrastructure fearing price rises after a monopoly position is established.	A substantial advantage to the consumer through a lower price, would need to be demonstrated along with other guarantees (such as linking prices to gas or oil prices). Public sector can show leadership by underpinning the base heat load, particularly with large year round loads.
Social cost of disruption of roadways and public areas	Urban networks will require substantial excavation and pipelaying works which will require denial of use of some facilities and traffic diversions.	Co-ordinate with other activities to minimise the impact.

C.1.3. Biogas from Anaerobic Digestion

Barriers	Description	Mitigation
Lack of secure disposal route for digestate	Land suitable for disposal may be limited	The ability of the UK land bank to accept digestate as a soil conditioner and fertiliser needs to be fully understood. Areas and capacities need to be mapped.
Unfamiliar technology	UK is unfamiliar with anaerobic digestion technology outside of the water industry. As a result there are few skilled designers or operators	Promote and disseminate results of pioneer projects. Training schemes. Establish an accreditation system and engage suppliers and installers
Negative perception of performance	Holsworthy was technically and financially difficult	Disseminate results of pioneer projects and of experience in other countries
No feedstock supply chain	Routes for food waste and other feedstock are not established	Government support (e.g. Defra, Waste and Resources Action Programme) Use incentives to encourage disposal to CAD.
High capital cost		Grant support, favourable loan schemes, RHI
Lack of markets for digestate products	Digestate has low value due to its uncertain status.	Address regulatory uncertainty and define standards Education to encourage use
Grid connection issues	Location of AD plant is a function of grid connection, feedstock supply, and digestate disposal routes. Balancing these reduces availability of sites	Already being addressed for other forms of distributed generation Planning could be used to encourage developments including the infrastructure. The Community Energy Grant Scheme can also provide grants for heat infrastructure. Financial incentives to use renewable heat
Planning	AD Plants are unfamiliar to planners who are concerned by transport issues and perceived problems with odours and appearance.	Issue guidance to planners. Engage in dialogue with local communities
GHG performance degraded by poor practice	Overall GHG emissions abatement can be reduced by emissions of N2O, ammonia and methane from digestate storage and spreading	Ensure appropriate spreading practice through education of farmers Ensure incentives include requirement for correct digestate management.

C.1.4. Ground Source Heat Pumps and Air Source Heat Pumps

Barrier	Description	Mitigation
UK Electricity Distribution Network	Inductive load can cause disturbances to the electricity distribution network due to high starting currents. With the UK's single-phase domestic electricity supply only a maximum 12kW input can be supported without grid re-enforcement. Larger systems will require a 3-phase supply. This will not be a problem for commercial and public buildings, but larger domestic properties, may find this a limiting factor. The cumulative effect of multiple heat pump systems in one location, a trend which is currently being observed in the social housing market, may require an upgrade to the local distribution network and discussion with the Distribution Network Operator (DNO).	Expected to be a permanent limit on the application of heat pumps in larger domestic properties. Upgrading of the distribution network in specific areas will involve bespoke costs which would need to be discussed with the DNO. Ensuring a uniform domestic 3-phase, supply as is the case in several European nations, would necessitate a prohibitively high investment which would not be made to increase the number of heat pump installations. Soft start systems are usually fitted to remediate some of the effects of inductive start up currents.
Introduction of smart metering	Tariffs may reflect the market cost of seasonal and time of day generation. Heat pumps provide heat in response to a demand that mirrors the electricity demand profile. This means they are always using electricity at higher prices.	Introduce special tariffs for heat pumps Increase thermal storage of systems to allow off peak usage A hardware solution would be a large accumulator at a cost of £275/kW.
Prevalence of Gas Distribution Network	The UK domestic sector remains dominated by gas fired conventional wet central heating systems which serves approximately 75% of UK housing and most urban areas. The ratio of gas to electricity prices in the UK also lengthens the payback on investment. Currently the ratio of 1:3 (June 2008) is more significant than that found in for example, in Austria or Germany at a ratio of 1:2.2.	Permanent inhibitor on the number of systems installed in areas connected the gas network. The possibility of mitigation is modest as the gas network will not reduce in size.
Capital Investment & payback	Generally it can be stated that heat pumps, especially ground source using a borehole, have a higher capital cost than gas boilers at all scales. As such the marginal cost payback can be unacceptable to	Incentives taking into account high upfront cost This should be less of an issue for the public sector, which is generally able to accept longer paybacks than commercial organisations, and will therefore play a vital

Barrier	Description	Mitigation
	some individuals or organisations.	role in kick starting the market. Public procurement can drive product development and market initiation. Planning polices which make the use of a renewable system mandatory (such as the Merton Rule) can also override cost premiums.
Thermal Efficiency of UK Housing Stock	Buildings with poor thermal performance are less suitable for heat pump systems as it results in a higher and more variable heat demand, whereas heat pumps work best with a steady and generally low heat demand. Disappointed, cold consumers damage credibility.	Immediate limitation on access to the retrofit market however, this should reduce gradually with time. No affect on new build installations, which are built to tighter building regulations. Link incentives to minimum standards of energy efficiency ensure consumers receive optimum packages of measures for their properties. Accept that some properties are not suitable and restrict incentives accordingly (e.g., by setting a minimum expected coefficient of performance).
Awareness & Acceptance	The UK market for heat pumps suffers from a "lack of understanding and confidence around their use amongst both potential users and investors"	Public awareness programmes and promotion of existing installations etc.
Insufficient Installer Network to Cope with Increased Demand	With continued high annual growth rate in heat pump markets a lack of trained design and heating engineers could become a problem. This could be an issue as integration with the heat distribution system requires specialist knowledge of heat pump operation. Suppliers of underfloor heating could also be in short supply.	Expected to have a moderate affect. When the market is small this is not a problem and when market becomes established new installation capacity will enter. Can be mitigated through training programmes, of which several are already available from recognised providers, and also through offering incentives for gas engineers to enter the heap pump industry.

Barrier	Description	Mitigation
Accessing Retrofit Market	The primary focus currently is the installation of systems in new build properties. However to meet targets increasing numbers will need to be installed as retrofit in existing homes.	There is increasing retrofit activity in the social housing sector, with projects involving a mass installation of heat pump systems. Public procurement could be used to drive product development targeted at the retrofit market.
	Heat pumps supply heat at lower temperature than conventional boilers which requires underfloor heating or oversized radiators. This incurs a substantial additional cost to the user replacing a conventional boiler.	R&D investment in order that heat pump units have the ability to still achieve good efficiencies at higher distribution temperatures would reduce retrofit cost..
	Retrofitting underfloor heating may be impossible or prohibitively expensive in many cases.	
Limited Manufacturing Capacity	High annual increases in demand could see this exceed manufacturing capacity.	If consistent growth is observed market signals should encourage investment in manufacturing facilities, government intervention to encourage foreign manufacturers to set up in the UK could also be undertaken. More a problem for GSHP that have specialist components than ASHP which are linked to the global air conditioning market
Legionnaires Legislation:	In the UK Legionnaires' disease requires the temperature of HW storage to be constantly above 60ºC.	Ensure problem is recognised and heating cycles are implemented Investigate the potential of altering this legislation to facilitate greater use of heat pump systems while also continuing to protect the public.
Quality of Installation	The potential for 'cowboy' installers and poor quality installations to give the industry / technology a bad name and result in a loss in customer confidence is a potential risk. This was evident in the early boom and bust development of heat pump markets in Germany and Austria in the early 1980s.	Several factors can be used to ensure good quality, these are: • Schemes such as the MCS • A quality label for heat pump systems e.g. such as the D-A-CH label used in Austria, Germany and Switzerland • Investing in training • Regulation, especially in relation to open loop ground source systems • A British Standard for borehole and installation design

C.1.4.1. Barriers that apply to Ground Source Heat Pumps Only

Barrier	Description	Mitigation
Availability of Installation, Ground Engineering Skills and Drilling Capacity	A clear understanding of geological and ground engineering issues is required for sizing and installation of the ground collector (borehole, slinky, trench system etc). For open loop systems hydro-geological skills are required. There may also be a possible lack of Building Service Engineers with experience of dealing with ground source systems. In addition a lack of drilling capacity could become an issue when number of annual installations increases. This happened in European markets during the HP boom of the later 1970's / early 1980's, and was an issue in Germany when market went through significant expansion.	Can be mitigated through training and higher education programmes. Hydrogeology has become a mainstream branch of the geosciences. The demand for groundwater specialists therefore seems set to continue to rise. Encouragement for extra drilling capacity will need to come from giving out the correct market signals. When the market is small this is not a problem and when market established new drilling capacity will enter the market. At the recent 'Ground Source Live' conference there was a large presence of drilling contractors that had 'woken up' to the potential of the market. Further to this it was stated that "at the moment the market is in over supply and all of the skills necessary are transferable from other trades" (Earth Energy Ltd.) (e.g., drilling, pipe laying, pluming and electrical wiring).
Lack of space to install ground collectors	Many sites may have limited space to install the ground collector. In the case of domestic systems where a horizontal loop cannot be installed a borehole can usually be used. Although this has higher associated capital costs. For commercial scale systems many buildings will not have an associated land area suitable for a bore-field (multiple boreholes); in these cases if there is a suitable aquifer an open loop system can be used since these can extract more energy from a reduced footprint.	There is little that can be done to increase the space available on a site;

C.1.4.2. Barriers that Apply to Air Source Heat Pumps Only

Barrier	Description	Mitigation
Noise & Planning	While on a domestic scale GSHPs have been granted permitted development status, ASHPs are in a similar situation to micro wind in that until they are granted such status consultation with the local authority regarding planning permission is required. The reason why ASHPs have not been granted this status is due to potential for noise disturbance from the motor.	This could be a constraint on domestic installations until resolved. Could be mitigated either by changes in planning policy or technological improvement to reduce noise from systems in the near future.
Potential for Vandalism	As ASHP systems are located outside the building in some cases they could be at risk of vandalism.	Minimal effect. Units may be obscured behind barriers or even placed in enclosures such as sheds or garages. As long as the units are given adequate ventilation / airflow the efficiency of the unit should not be affected. In some cases units can be placed in cages.

C.1.5. Solar Thermal

Solar energy is largely a discretionary purchase as it provides only a proportion of hot water. The barriers have been largely overcome and a wide range of equipment is available to the installer and DIY market. Take up will be largely in proportion to the incentive offered.

Barrier	Description	Mitigation
Unfamiliarity	Solar collectors are becoming commonplace but are still regarded as a specialist installation.	Information and awareness raising.
High capital cost	The installed cost of a solar collector is much higher than the additional cost for hot water from oil or LPG	Incentive acknowledges the high up front cost. Encourage higher efficiency systems that can provide a boost for heating as well as hot water – pay per M2 rather than per installation.
Space constraints	Solar collectors need a south or south west facing roof. This is not always available.	Promote guidelines to ensure optimum placing. Take performance into account in designing incentives.

C.2. Development of Growth Scenarios

In this section we provide details of scenarios for growth in industry supply capacity. There are two main scenarios:

- A "stretch" growth scenario, corresponding to the outcome if all barriers were removed to the maximum extent thought possible by 2020; and
- A "central" growth scenario, corresponding to AEA's assessment of a plausible expansion in renewable heat supply, assuming a situation where subsidies make the respective renewable heat technologies financially no worse than relevant fossil fuel or electric heating options

As discussed in the main body of the report, a third "higher" growth scenario also was developed to investigate the uncertainty around feasible growth. This scenario assumes higher growth rates than the "central" scenario but remains within the bounds of the " stretch" scenario.

C.2.1. Biomass boilers

In developing growth scenarios for biomass boilers we considered the market in two broad categories, broadly corresponding to the sectors used in the modelling; commercial and industrial, and domestic. We discuss scenarios for each of these sectors in turn.

C.2.1.1. Commercial and industrial use of upgraded and traded fuel

This market was the target of the Bioenergy Capital Grants Scheme and can now be considered to be beyond the introduction phase and into a growth phase.

We spoke with all of the major suppliers in this sector. Some clear messages have come through:

The most established suppliers have financial backing either from utilities or large building contractors. This has greatly helped cash flow. This could be a pattern for the future with smaller companies initiating the business through the introductory phase of development and larger companies providing the stability and cash flow for major expansion.

Growth will come from regionalisation. There will be a central core of competence that will deal with larger more complex projects and support the regional offices with queries and problems. The establishment of these offices does drain resources from the core however. New start ups will also contribute to this growth but could be considered as a part of the regionalisation process.

The main growth areas are expected to be those driven by the need to reduce carbon emissions to meet mandated limits. Many of these are in the public sector, hospitals, larger schools, higher education and high use public buildings are increasingly converting and the scope is seen as enormous by the industry.

Re-powering existing campus and community heating schemes is regarded as particularly cost effective and profitable for all concerned.

The industrial market grows largely as a function of the oil price. High energy rural users such as greenhouses are converting, usually with a grant but sometimes without. The fuel is predominantly chip and always local.

C.2.1.1.1. Barriers to growth

The main barriers to rapid growth given in our discussions with industry were:

- The attitude and lack of knowledge of architects and building services engineers. This is a considerable drain on the resources of the installers as they need to inform and support the client who is usually completely unaware of the implications of using biomass.
- Gaps in the infrastructure for fuel supply. Fuel availability is not regarded as a serious problem yet; although some criticism was levelled at the uneven quality of fuel suppliers and lack of quality standards for the products. The situation compares unfavourably with Austria where fuel supply is an established business sector with many local companies that have a range of delivery vehicle sizes and types.

Additionally, rapid growth can bring difficulties for organisations. All suppliers experienced growth in turnover of over 100% in the first years of their operations, all found this rate to be uncomfortable; problems were experienced with poor quality of installation and unacceptable stress on staff. Rates of 20% to 30% were regarded as more sustainable for the current size of the company but may be too low for major investors.

Manpower resource is not perceived as a major long term problem by the industry. There is however a short term shortage of skilled building service designers and specifiers that understand biomass systems. This is a substantial bottleneck as they come first in the supply chain.

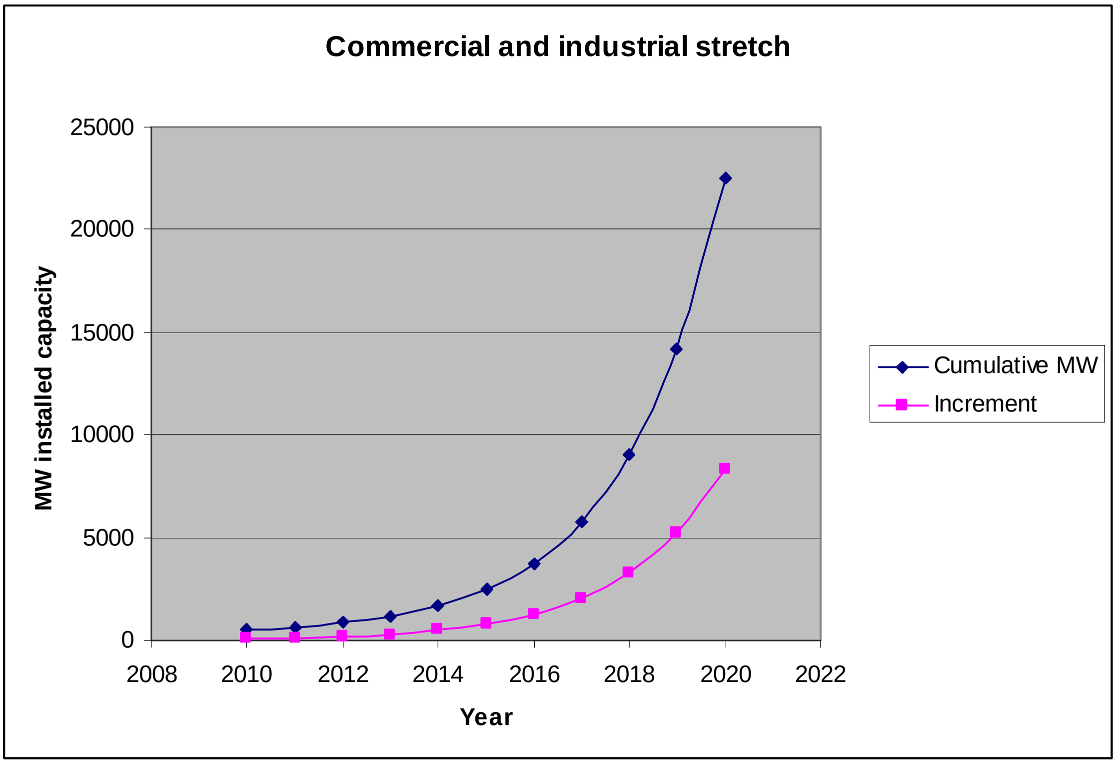
The availability of skilled plumbers and pipe fitters was not felt to be a serious constraint. Building heating services are complex whether they are oil or biomass so the conversion is not too much of an issue. There is more work with a biomass system but installation is not fundamentally different to oil and gas and the industry should be able to cope.

Commissioning and troubleshooting was a problem in the initial phases but is much better now and not expected to be a problem in future.

C.2.1.1.2. Stretch growth scenario for commercial and industrial sectors

In developing a stretch scenario, we start from the current market size, which is approximately 450MW of installed capacity with an annual increment of 80MW in the past year. Based on discussions with the suppliers outlined above, we assume a pattern of slow growth initially and prior to the introduction of the RHI in 2011. After that, we assume one year of 100 percent growth in the capacity *increment* , followed by year-on-year growth in the amount installed of 60 percent until 2020. This results in 22 GW of installed capacity by 2020, with annual average installation of 4 GW per year in 2015-2020 period. The pattern is shown in Figure C.1.

Figure C.1
Stretch Scenario for Commercial / Public and Industrial Biomass Boilers



If the main use of the boilers were industrial process heat and high-load commercial / public applications with load factors in the region of 50 percent or more, then the above capacity could corresponds to over 100 TWh of heat load by 2020.

C.2.1.1.3. Central growth scenario for commercial and industrial sectors

The growth of 60 percent per year in the stretch case is at the upper end of what was deemed feasible in our discussions with industry. As noted, many existing suppliers found year-on-year growth of 20-30 percent more sustainable. Additional barriers likely to limit growth include:

§ The long order and build times.

§ The high levels of skill needed to specify and install this class of equipment.

§ The unfamiliarity of users.

To reflect these, we assume the same introductory pattern of low growth until the introduction of the RHI in 2011. We then assume steady growth, with the installed capacity reaching 3,400 MW by 2020. This number was arrived at by considering the applications in each sector and allocating a suitability factor depending upon, heat grade, location, alternative fuel, and familiarity. Reaching this level of capacity corresponds to a steady growth rate of 22 percent after the introduction of the RHI. This is consistent with rates considered feasible by industry, and corresponds to the installation of an average of 400 MW per year in the 2015-2020 period, on the same order as total current installed capacity. This level of deployment results in around 17 TWh of heat output by 2020.

This assessment does not account for the potential to use biomass CHP rather than boilers, and there is a possibility accounting for this would reduce the potential. . This would depend to a large extent on the relative levels of support offered for heat and electricity.

C.2.1.1.4. Feedstock availability and composition

Most commercial and industrial installations are fuelled by wood chip but pellets are growing in popularity. The general practice is that larger > 200kw boilers and those with a high use factor tend to be chip. Smaller boilers and ones with low load factors use pellet. Pellets are also favoured by architects seeking to meet planning conditions at minimum cost and building footprint. The exceptions to this are urban installations that tend to be pellet at any size because of constraints on delivery access and storage.

Based on discussions with suppliers of equipment and fuel we derived the broad classifications below to inform the economic model on the price implications of fuel. The composition of fuel used varies with the growth scenario, with a higher proportion of pellets in the stretch and higher growth scenarios. This reflects the fact that higher growth is likely to be associated with the use of biomass boilers in locations that are more difficult to access and / or which have more limited options for storage.

Table C.1
Trends in Feedstock Supply for Biomass Boilers – Stretch and Higher Growth Scenario

	Typical size	Urban	Suburban	Rural
Small commercial	Up to 200kW boiler output	3/3 Pellets	2/3 pellets 1/3 chip	1/3 pellets 2/3 chip
Large commercial	Above 200kW	3/3 Pellets	1/3 Pellets 2/3 chip	3/3 chips
Small industrial	Below 200kW	2/3 pellets 1/3 chip	2/3 Pellets 1/3 chip	3/3 chips
Large industrial	Above 200kW	1/3 pellets 2/3 Chips	1/3 pellets 2/3 Chips	3/3 Chips

Table C.2
Trends in Feedstock Supply for Biomass Boilers – Central Growth Scenario

	Typical size	Urban	Suburban	Rural
Small commercial	Up to 200kW boiler output	3/3 Pellets	2/3 pellets 1/3 chip	1/3 pellets 2/3 chip
Large commercial	Above 200kW	3/3 Pellets	1/3 Pellets 2/3 chip	3/3 chips
Small industrial	Below 200kW	2/3 pellets 1/3 chip	1/3 Pellets 2/3 chip	3/3 chips
Large industrial	Above 200kW	3/3 Chips	3/3 Chips	3/3 Chips

C.2.1.2. Domestic use of upgraded and traded fuel

There is very little use of biomass for domestic heating in the UK. Experience in Austria, Sweden, Germany, Italy and Ireland suggests that the domestic market will be dominated by pellet fuel, and pellet boilers therefore is the technology we consider for household heating.

C.2.1.2.1. Barriers to growth

Pellet boiler technology is fully mature and productised. The opinion in the industry is that domestic scale installations could be undertaken by the current corps of plumbers and heating engineers, following suitable conversion training.

More than any other renewable energy technology pellets are seen by the consumer as a straight economic choice against heating oil. If the higher upfront cost of the boiler can be mitigated to some extent then using a completely different fuel seems not to be a problem. Word of mouth recommendation also seems to be positive.

The use of biomass boilers depends on a range of demand-side factors that are considered in the modelling. Potentials were determined firstly by excluding certain sectors in the grounds of unsuitability, most notably smaller urban properties where the combination of space accessibility and air quality concerns would make installations highly unlikely. The remaining sectors were graded in terms of suitability depending on their location and alternative fuel. The most suitable sectors were larger dwellings in rural areas off the gas grid. Although the scenarios described below primarily are concerned with the supply-side, we have been mindful of these factors when assessing the feasible growth of the industry and in order to make comparisons to growth experienced in other markets.

C.2.1.2.2. Stretch growth scenario for the domestic sector

There is very little deployment at present in England, Scotland and Wales. Assuming a percentage growth rate therefore will not give accurate results. Ireland on the other hand has experienced strong growth in the last two years as a result of the proximity of the Balcas pellets production plant, the pool of installers, and experience from the Republic of Ireland's successful subsidy programme and high oil prices.

We therefore suggest we use the experience in Ireland to calculate an initial starting level comparable with the Irish introductory phase. For the stretch scenario we then assume a growth rate in the annual capacity installed of 60 percent, similar to the assumption for the commercial and industrial sectors.

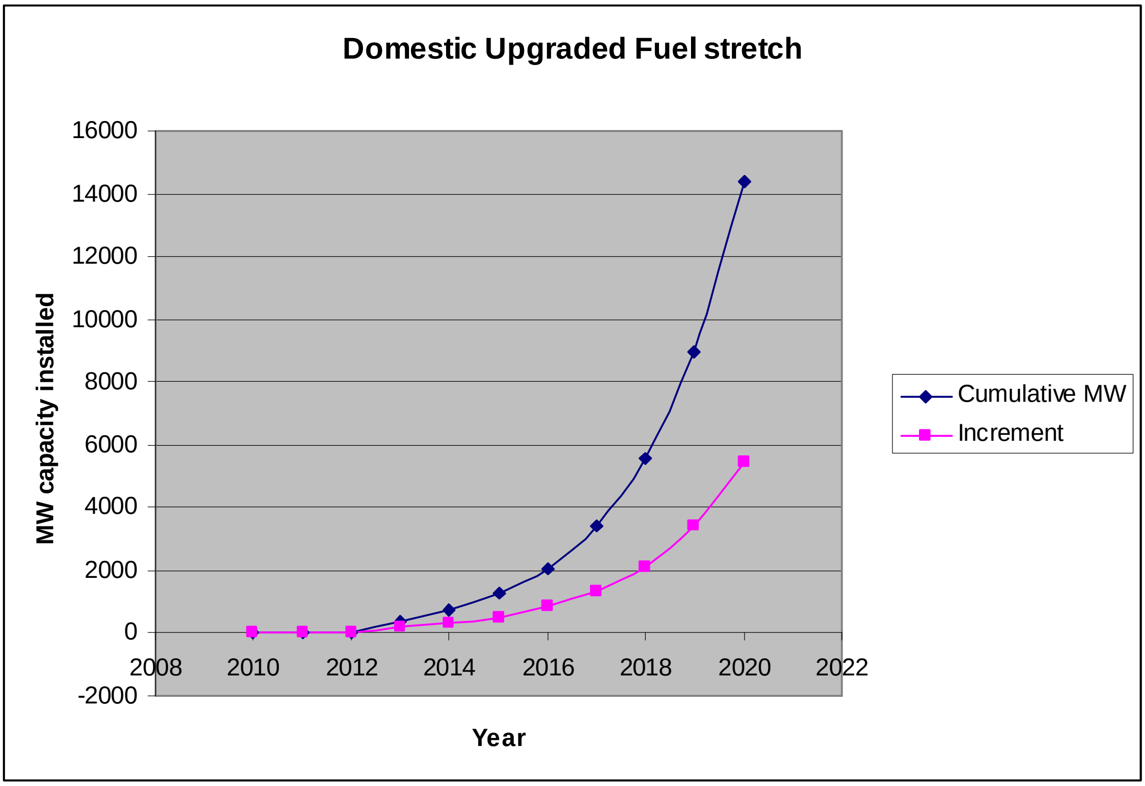
Balcas manufactures 55k tonnes of pellet fuel in Enniskillen, Northern Ireland. Initially all of the production went to co-firing applications but in the space of three years all of it has been absorbed by the residential and commercial market. This is a very rapid take up that was largely driven by the subsidies of up to €4200 per household boiler installation (approx 50%) .

Balcas estimate the total number of residential units to be approximately 4500 units of approximately 20kW each in the whole of Ireland. They tend to be the larger detached houses in rural areas. If we assume that off grid households in England, Wales and Scotland are broadly comparable with the situation in Ireland then we should be able to achieve proportionately the same result.

There are 1.5 million households in Eire and 6.8 million off grid in GB. If we assume that we have an introductory phase of three years between 2011 and 2013 then it should be possible to enter a growth phase of the market from 2013/14 with around 20,000 installations, with a combined capacity of 400 MW. Growth at a rate of 60 percent per year then results in some 14 GW of installed capacity, corresponding to over 700,000 boilers with an output of just over 11 TWh.

The pattern of capacity growth is shown in Figure C.2 below.

Figure C.2
Stretch Scenario for Domestic Biomass Boilers



C.2.1.2.3. Central growth scenario for the domestic sector

For each sector we estimated what proportion of users would be likely to take up the option based on the location character of the heat load and any regulatory pressure that might exist bearing in mind the barriers identified in section C.1.

To develop the central scenario, we assume the same high initial rate of growth as in the stretch case, reaching some 20,000 units by 2013. This corresponds to the period where the absolute increase in capacity each year is relatively small, and suppressed demand of highly suitable opportunities is released. After this initial high growth, we assume a more modest increase, to reach 300,000 units by 2020. This corresponds to growth of the capacity installed of 35 percent year-on-year, more characteristic of an industry undergoing strong organic growth. The lower rate compared to the stretch scenario is motivated by the fact that biomass heating is relatively complex and unfamiliar compared to conventional sources, and the lower rate corresponds to skills being transferred and acquired from the existing industry.

The rates indicated were felt to be achievable by the industry, and are comparable to rates experienced elsewhere where biomass boilers have enjoyed significant uptake.

C.2.1.2.4. Sense check with other more advanced markets

At 20kW per unit the deployment in the stretch scenario is equivalent to some 700k units by 2020. This is 10 times the current installed boilers in Austria, and five times that in Sweden. For comparison, the population of these countries is around one-sixth of the UK's. Figures for Germany are difficult to find but current pellet production is 1.3 million tonnes which suggests a level of deployment of around 200k units for a population 35 percent larger than the UK's.

The corresponding numbers for the central growth scenario is 300k boilers by 2020. This corresponds to 5 times the Austrian deployment and 2-3 times that in Sweden. Adjusted for total population, this is a lower level of penetration. However, a proper comparison requires that other factors are taken into account, notably the UK's widespread natural gas grid to domestic properties (which in the case of Sweden is entirely absent).

C.2.1.2.5. Feedstock availability and composition

Fuel supply is unlikely to be a constraint in the early years. Discussions with pellet fuel suppliers indicate that there are some 490k tonnes of capacity planned or under construction in the UK. By 2020 however the demand will be of the order of 3.5 million tonnes which exceeds UK forestry production capacity by a substantial margin. Many UK sawmillers have strong historic links with the Baltic region and imports from there and further afield in Russia should be available. Current EU pellet production capacity is 6 million tonnes.

C.2.1.3. Potential for overcompensation

We have considered whether there are types of biomass heating options that are already established and which therefore may be overcompensated by a subsidy. The main currently established, traditional markets in wood fuel are:

- domestic use of logs on open fires and in roomheaters, and
- use of own wastes by joinery shops and furniture manufacturers.

An estimate made by Forestry Commission in 2005 suggests that 600k tonnes are used by the "informal" domestic market. Also it seems that approximately 10 percent of households use wood during the year but few <1 percent regard it as their main, or a main source of heat. This suggests that there are some 50,000 - 100,000 users that would be regarded as wood heated properties. Anecdotally we understand that the sector is still expanding rapidly in response to the oil price rises of a year ago. Clearly as the oil price increases this sector is capable of responding and growing without additional support.

Similarly many furniture manufacturers and wood working shops are installing wood fired boilers and heaters to heat their premises using their own wastes as fuel at effectively zero or minus cost – the alternative is landfill which is becoming increasingly expensive.

C.2.1.4. Summary of growth scenarios

The below tables summarises the key features of the growth scenarios. As noted, the "higher" growth scenario represents potential between the central and stretch scenarios.

Table C.3
Summary of Growth Scenarios for Biomass Boilers

	Domestic sector			Non-domestic sector	
Year	Units	Installed capacity	Heat output	Installed capacity	Heat output
	thousand	GW	TWh	GW	TWh
Stretch growth scenario					
2015	63	0.5	1.0	2.5	12.0
2020	720	5.4	11.0	23.0	110.0
Central growth scenario					
2015	52	0.4	0.8	1.3	6.6
2020	300	1.7	4.7	3.4	17.0
Higher growth scenario					
2015	79	0.6	1.2	2.0	9.9
2020	450	2.5	7.0	5.0	25.0

C.2.2. Biomass district heating

Based on current installation practice we pro-rated the biomass district heating growth rates as a fixed percentage of 20% of biomass individual boilers. In addition we applied a restriction to limit the take up to space heat only and rural and urban areas only. This reflects our assessment that urban schemes may progress due to the subscriber density and rural schemes due to fuel access, whereas suburban schemes face much higher obstacles due to low subscriber density and poor availability of fuel.

The central growth scenario potential under these assumptions is around 3 TWh in 2020. This refers to heat-only biomass district heating. Adding CHP to the analysis could add additional potential. We have not developed a stretch case for biomass district heating.

C.2.3. Air source heat pumps

The section below refers to air-source heat pump (ASHP) installations designed to replace conventional heating systems typically radiators, convectors or underfloor heating. It is also possible to use air conditioning units in reverse configuration to supply heat but these are not covered for the domestic market as they are regarded primarily as cooling devices.

C.2.3.1. Current deployment

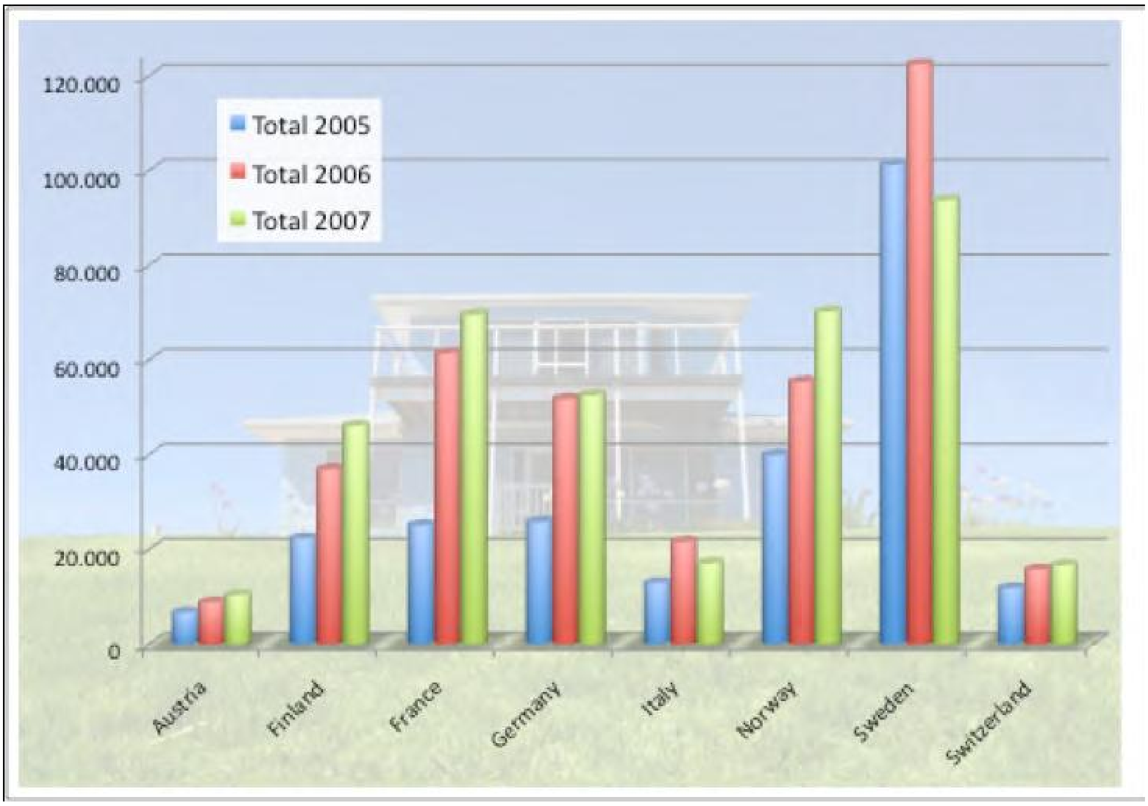
The Building Services Research and Information Association (BSRIA) reported in 2007 that 200 air-to-water heat pumps were sold in the UK in 2006, of which around twenty were sold to the commercial market (>20kW).[32] The same report estimates that the total number of air to water heat pumps sold in the UK by 2010 could be 1,750. We use as a starting point for the construction of growth scenarios a stock of 2,500 units in 2008.

C.2.3.2. International experience

UK deployment is at a relatively low level in comparison with many other European countries. The European Heat Pump Association shows the following statistics for annual sales in their annual survey of the industry 'Outlook 2008'

[32] BSRIA, 'World Renewables 2007 – Heat Pumps, Report 40264/5 July 2007'

Figure C.3
ASHP Market Size in Selected European Countries



Source: European Heat Pump Association

Experience in other EU states has shown that sales per year can grow at up to 100% during an initial phase but this settles at around 30% during the growth phase, i.e., once the technology is beyond the first few years of take-up and constitutes an established choice for consumers. The Outlook 2008 report gives the following rates for those countries in the growth phase.

Table C.4
Growth Rates of Air-Source Heat Pump Sales in Selected European Countries

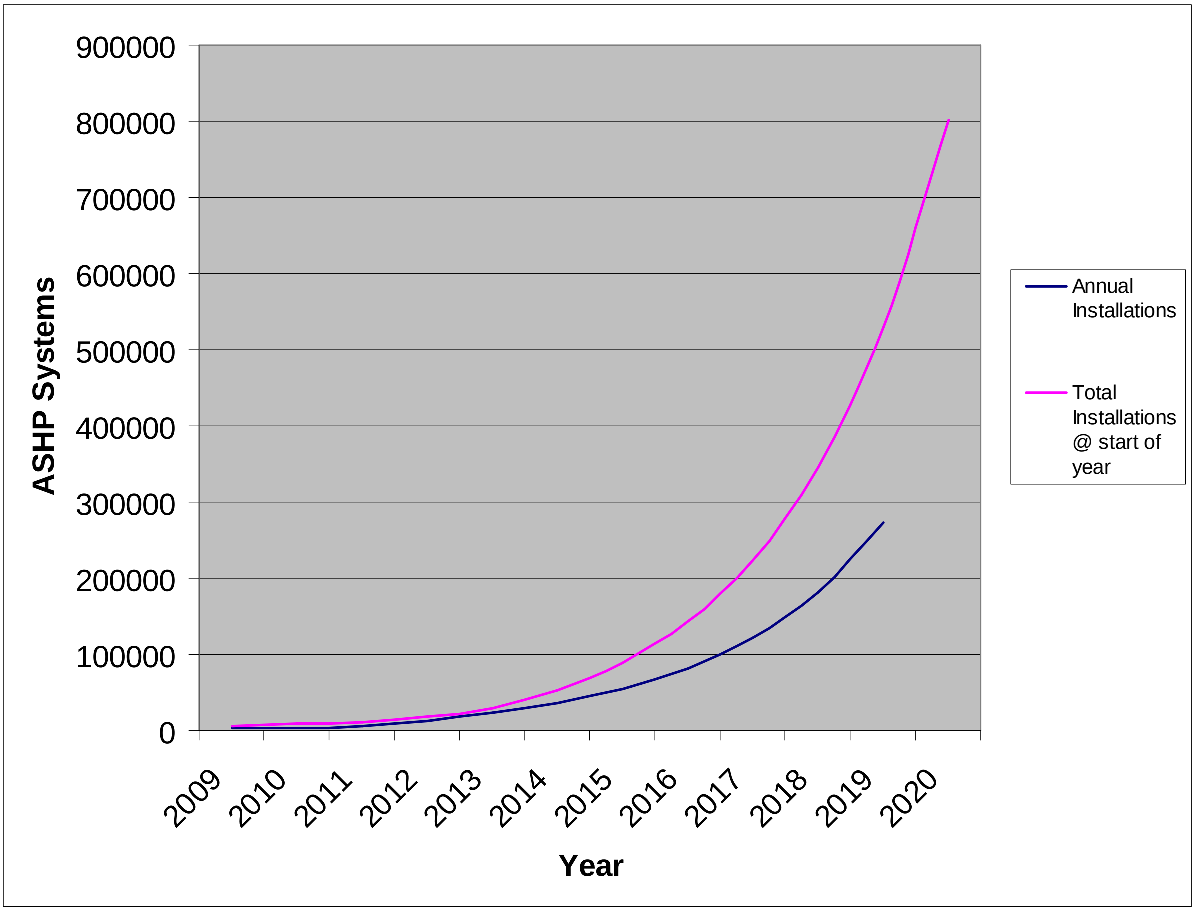
Country	Annual growth rate
Finland	25%
Austria	15%
France	30%
Italy	33%
Norway	27%
Finland	25%

Source: European Heat Pump Association

C.2.3.2.1. Stretch growth scenario

Based on the findings above we have assumed current sales of around 3,000 units annually. We assume sales stagnate at this level prior to the introduction of the renewable heat incentive in 2011, after which they grow at a rate of 100 percent for 3 years. This gives sales of around 25,000 units in 2013. We then assume growth in sales by 50 percent per year in each year until 2020. At this rate, the average number of units installed per year between 2015-2020 is just over 200,000, and the number of units installed by 2020 is 800,000. The below figure shows the resulting deployment of ASHPs.

Figure C.4
Stretch Growth Scenario for Air-Source Heat Pumps



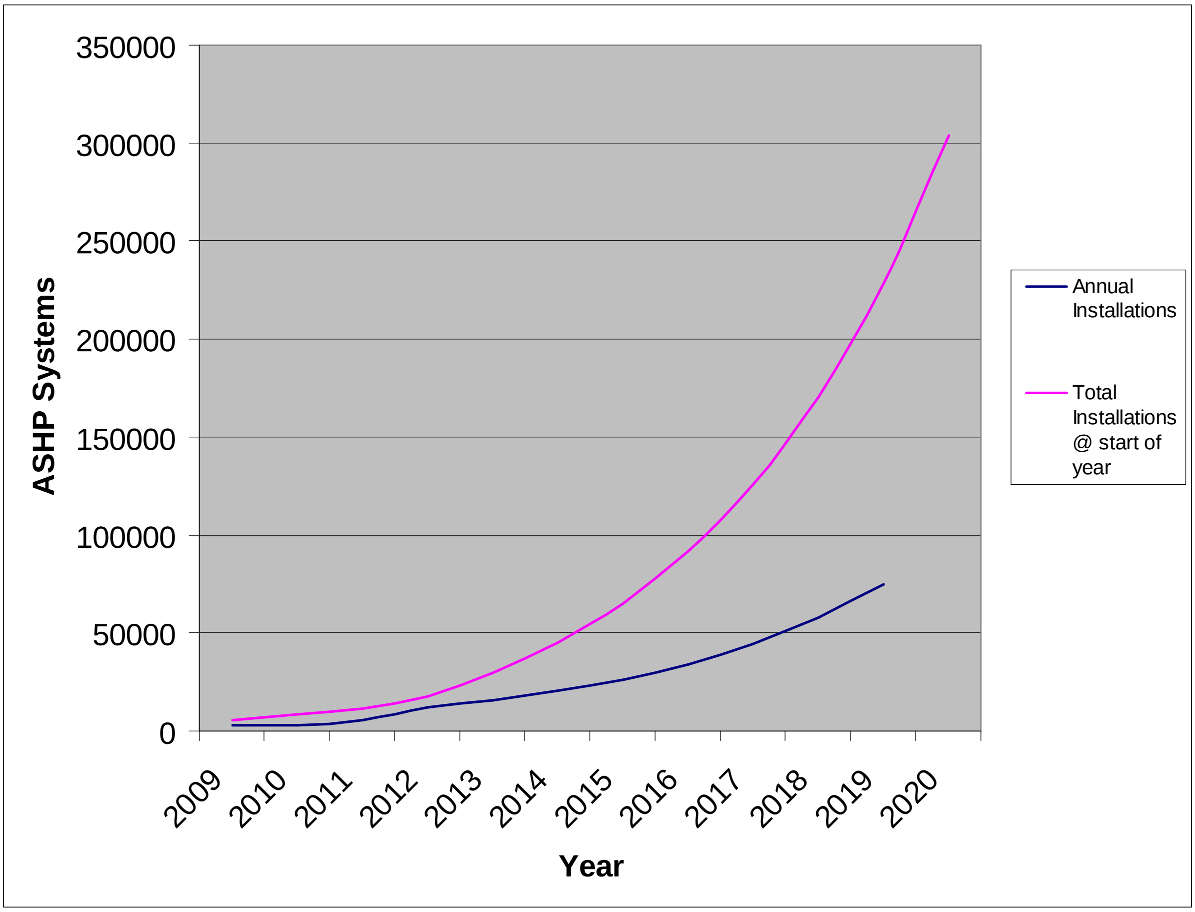
We use the same assumptions as for GSHP when partitioning this between domestic and non-domestic units, i.e., assuming that 90 percent of the units are installed in the domestic sectors. This results in some 720,000 systems in the domestic sector by 2020, and 80,000 in the non-domestic sector. The implied heat output is around 9 TWh in the domestic sector and 28 TWh in non-domestic applications, for a total of 37 TWh.

C.2.3.2.2. Central growth scenario

For the central growth scenario we use the same starting assumptions, but use a shorter period of growth at 100 percent (two years instead of three), and then apply a more modest growth rate of 30 percent after 2013. Unlike the GSHP central growth scenario, we have not projected a linear growth rate, but allow for year-on-year increases in sales throughout the period. This reflects the lower barriers to ASHPs, including their wider applicability and the modular nature of the technology. We also took into account the much larger air conditioning markets of South East Asia that are driving technical development and providing volume in the market. A growth rate of 30 percent also is consistent with the sustained rate of growth observed in other countries, as noted above.

This projection implies industry sales of 100,000 units per year by 2020, with average between 2015 and 2020 of 60,000 units. By 2020, just over 300,000 units are installed, of which 90 percent (270,000) are in the domestic sector. The implied output heat output is 3.5 TWh in the domestic sector and 11 TWh in the non-domestic sectors, for a total of 14 TWh. Figure C.5 shows the implied trajectory for sales and total number of installed systems.

Figure C.5
Central Growth Scenario for Air-Source Heat Pumps



C.2.3.2.3. Summary of scenarios

The number of ASHP units and implied renewable heat output in different growth scenarios are summarised in Table C.5. As noted, the “higher” growth scenario represents potential between the central and stretch scenarios.

Table C.5
Summary of ASHP Growth Scenarios

Year	Domestic sector: Units (thousand)	Domestic sector: Heat output (TWh)	Non-domestic sector: Units (thousand)	Non-domestic sector: Heat output (TWh)
Stretch growth scenario				
2015	81	1.0	9	3.1
2020	720	9.3	80	28.0
Central growth scenario				
2015	59	0.8	7	2.3
2020	270	3.5	30	11.0
Higher growth scenario				
2015	88	1.1	10	3.4
2020	410	5.3	46	16.0

C.2.4. Ground source heat pumps

To estimate potential growth scenarios for ground-source heat pumps (GSHPs) we first consider the current rate of deployment and the character of the applications for the technology. Based on this information and an assessment of the barriers to the use of GSHPs, we then estimate a trajectory that represents a stretch (maximum possible) and central (feasible) growth rate for their deployment. As in the other growth scenarios, we consider supply potential given a situation where the RHI and other conditions make the use of GSHPs a financially viable option.

C.2.4.1. Number of installed systems and recent growth trends

There is currently no organisation collecting data on UK GSHP installations. There is therefore no definitive number. From reviewing the range of estimates available, our best estimate for the number of GSHP installations in England & Wales installed by 2008 is approximately 3,500 systems. As part of a further project AEA is undertaking stakeholders were consulted to produce a best estimate for 2009. This gave a range of estimates up to 10,000 systems, with an average of around 8,000 systems. Based on these estimates, the increase between 2008 and 2009 is thus around 4,500 systems. This is similar to estimates given at the ‘Geothermal Live’ 2009 conference, citing a current installation rate of 4,000 systems per year. It was also stated that GSHPs are an "immature market, but not a cottage industry".

The graph below shows data on the installation rate in the period 2000-2008. The pattern is approximately exponential, with an initial slow and steady installation rate giving way to higher levels of growth from 2004. This is consistent with a market emerging from an introductory phase into a growth phase. The implied year-on-year growth rates are shown in the table below the figure.

Figure C.6
Estimate of UK GSHP Market Growth Since 2000

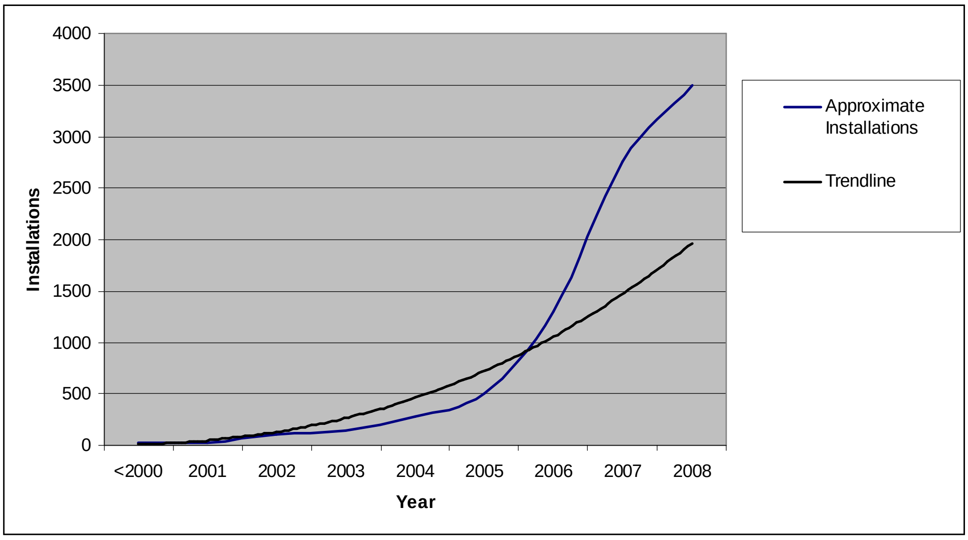


Table C.6
Estimated Annual UK GSHP Market Growth Rates, 2000-2010

Year	Estimated Annual Growth rate from Figure 1
2000 - 2001	50%
2001 - 2002	233%
2002 - 2003	40%
2003 - 2004	96%
2004 - 2005	82%
2005 - 2006	160%
2006 - 2007	112%
2007 - 2008	27%
2008 - 2009	83%
2009 - 2010	50%
2010 - 2011	51%

The Ground-Source Heat Pump Association (GSHPA) considers that a steady year-on-year growth rate in installed units of 50 percent may be achievable as the market expands during the growth phase. This corresponds with National Energy Foundation estimates indicating that in the 2004/5–2005/6 period a 60% increase in installations took place.[33]

[33] The discrepancy between these numbers and he data in Figure 1 or Table 1 is due to the fact that these years were the bridge between the two data sets used to construct the graph. NEF estimates 800 installations in 2006 while the EHPA estimated 1,800. We used an average of these in the figure and table. .

C.2.4.2. Split between domestic, commercial and industrial sectors

The installers we contacted estimate that 70-95 percent of all installations are in the domestic sector. The significant majority of the rest are commercial / public sector units and although it was agreed that recently the number of these scale system installations has increased, proportionally domestic scale installations still dominate. Opinion on industrial GSHP installations varied from there being none e.g. "not much seen in the way of industrial applications, nearest example would be business parks and retail" (Earth Energy), to a maximum of 1-2 percent of all installations.

In constructing the projections, we therefore split the market using the following assumptions for the market breakdown:

- Domestic: 90%
- Commercial / Public: 9.5%
- Industrial Scale: 0.5%.

In the absence of data to the contrary we would assume this split would continue throughout the period to 2020.

The most important reason for the dominance of domestic units in the early stages of market development may be that most of the subsidy available for GSHPs has been directed at the domestic market through the Clear Skies programme, the Low Carbon Building Programme, the Carbon Emissions Reduction Target the Microgeneration Certification Scheme, Code for Sustainable Homes, and the Scottish Community and Householder Renewables Initiative. Incentives in the non-domestic sectors have been more limited, although the Merton Rule in now stimulating the new-build section of the commercial market.

CERT is having an increasing impact and utilities can subsidise the domestic market heavily. Strategic alliances between specialist suppliers and utilities are being formed as in the biomass heating market and this is expected to continue and drive growth through CERT programmes and/or the RHI. Such alliances have historically played a strong role in the development of GSHP markets in other European nations such as Austria and Switzerland where GSHPs are a key service offering of regional utility companies.

Possible additional reasons for the predominance of domestic-scale system include:

- Higher numbers of new build homes (more suited to GSHP systems[34]) as opposed to commercial or public sector buildings.
- Greater difficulty in retrofitting internal heat distribution systems within larger scale buildings.
- Lower associated cost of small-scale domestic units that only require a slinky coil ground loop, whereas larger units require more expensive borehole collectors.

[34] Due to lower disruption and easier installation of low temperature heat distribution systems

The division between sectors will be affected by demand-side considerations, including the impact of the RHI. Nonetheless, we consider that the most robust approach is to use the current market structure as an approximation of the development of future supply potential.

To construct the projections, we use the following representative unit sizes:

§ Domestic: 5 kWth

§ Commercial / Public: 100 kWth

§ Industrial Scale: 1 MW

The largest scheme currently in construction in the UK is circa 5.5MW capacity. There has been an increase in installations with capacity between 100–300 kW.

C.2.4.3. Projections of future deployment

We have checked various projections of potential future deployment of GSHPs. These are summarised in Table C.7. At the high end, the GSHPA suggests it would be feasible to reach an annual installation rate of 200,000 systems. Estimates of the total number of systems range between 300,000 and 1 million. Some modelling estimates are significantly lower, although this is likely reflects demand-side considerations, notably competition with other technologies receiving similar levels of subsidy.

Table C.7
Projections of GSHP Installations by 2020

Source	Projection
GSHPA	At least 200,000 p.a. installation rate reached with between 1 and 7 million systems installed by 2020, with 50% penetration in commercial buildings.[35]
Geothermal International	300,000 systems
Reading University (Rayner Mayer)	1m units
BERR[36]	If renewable heat met 11% of overall heat demand, this could result in approximately 100,000 householders using heat pump technology
DTI[37]	'The potential for Micro-generation' (2005) suggests that 28,000 heat pumps will be installed by 2012
BSRIA	15,600 GSHPs installed by 2012
Calorex	With the adoption of a renewable heat incentive subsidy policy over 850,000 heat pumps (all types) could be installed by 2020
Bouma JWJ[38]	In the UK that an achievable sales target would be 15,000 heat pump systems per year" with GSHP systems accounting for a significant proportion of these systems.
Renewables Advisory Board (RAB)	Estimates for GSHPs in 2020 range from 615,000 (bottom up) to 950,000 (top down)[39].

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35 It is not stated whether this relates to all commercial buildings or just new builds

36 BERR Renewable Energy Strategy Consultation Document (June 2008)

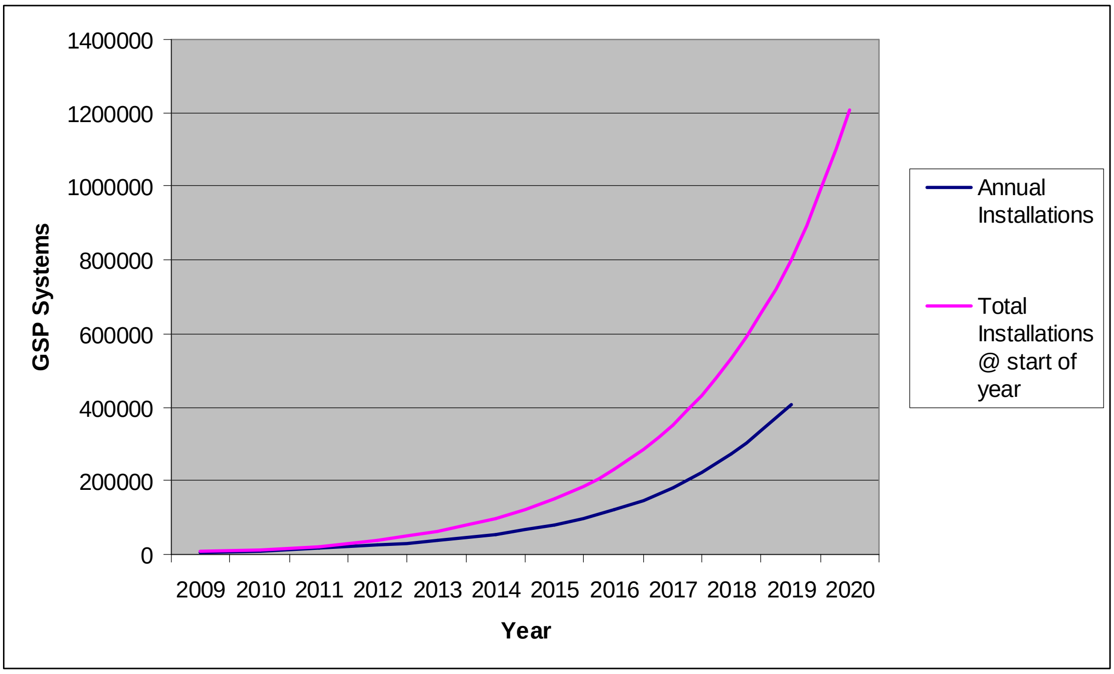
37 Department for Trade & Industry, now BERR

38 Achieving Domestic Kyoto Targets with Building Heat Pumps in the UK, 2002

C.2.4.4. Stretch growth scenario

The stretch growth scenario takes a starting point the 8,000 systems estimated to be in place in 2009 and annual installation rate of 4,000 installations per year. We ramp up the installation rate by 50 percent until 2011, after which it increases further to 60-65 percent upon the introduction of the RHI. After 2014 we assume that a steady growth of 50 percent increases in annual installations can be achieved. The graph below outlines the annual installation rate and total installed systems until 2020 under this scenario.

Figure C.7
Stretch Scenario Growth Projections for GSHPs



The annual number of systems installed reaches an average of 200,000 per year in five years leading up to 2020, with a peak of approximately 400,000 systems in 2019. The total number of systems reaches approximately 1.2m units by 2020.

Using the indicative sizes of systems and market splits indicated above, this corresponds to installed capacity of 33 $GW_{th,}$ producing in the region of 50-60 TWh of heat

Checking this against the projections discussed above, it is higher than most but within the range of projections made by others. We would expect the growth rate to diminish after 2020 to reach market saturation after 2030.

[39] Top down based on GSHPs providing 0.81 Mtoe as part of 5 Mtoe from all renewable sources and an average energy production per annum of 10 MWh (small domestic) bottom up based on 15% of the 3.9m homes estimated to be off the gas grid, + 2% of 1.5m gas boiler replacements made annually.

C.2.4.5. Central growth scenario

The central growth scenario takes the same starting point as the stretch scenario, with 14,000 units in 2010. There is an initial rapid ramp-up of supply capacity to around 35,000 units per year by 2015, but then slower growth in capacity to around 45,000 by 2020. The growth in the total number of units therefore more resembles linear growth, in contrast to the explosive exponential growth in the stretch case. This trajectory is consistent with one in which the various barriers constrain growth.

The cumulative number of units installed grows from 115,000 in 2015 to some 330,000 in 2020, and average annual growth thus is in the region of 25 percent per year. The associated total heat output in 2020 is just over 15 TWh.

C.2.4.6. Summary of scenarios

The number of units and implied renewable heat output in different growth scenarios are summarised in Table C.8. As noted, the "higher" growth scenario represents potential between the central and stretch scenarios.

Table C.8
Summary of GSHP Growth Scenarios

	Domestic sector		Non-domestic sector	
Year	Units	Heat output	Units	Heat output
	thousand	TWh	thousand	TWh
Stretch growth scenario				
2015	140	1.7	15	5.3
2020	1,100	14.0	120	42.0
Central growth scenario				
2015	100	1.3	12	4.1
2020	290	3.7	32	11.0
Higher growth scenario				
2015	160	2.0	17	6.1
2020	440	5.6	48	17.0

C.2.5. Biogas

In this section we present growth rate scenarios for biogas. We begin with a review of the German biogas market, which is the most developed in the EU, as a preliminary to analysing what might be feasible in the UK. We then consider a stretch growth scenario for biogas production, and the partition of biogas between electricity generation, heat generation, and injection into the gas grid. Next, we discuss a central growth scenario, followed by a review of factors that may limit growth. Finally, we discuss the potential for bio synthetic natural gas (SNG).

C.2.5.1. Experience in the German biogas market

Our basic premise is that the German experience is so exceptional that replicating the growth in the latter phases represents a stretch scenario for the UK. In this section we therefore present the basic features of the German biogas market.

German AD installations rely largely on revenue from electricity generation. Most installations are classed as CHP but much of the heat is used internally. Heat only and grid gas projects are built but there are few as yet. This will change in the next decade as gas supply companies open their networks to biogas producers in response to a new law passed in 2008. This law, in addition to paying a premium rate, gives biogas producers priority access to the network and places most of the costs of connection on the network operator.

The table below provides the number of agricultural AD plants in EU countries and their electricity generation capacities in 2005. It is clear from the table that there are a number of European countries in which the uptake of AD, either on-farm or centralised (CAD), by the agricultural sector has been much greater than it has in the UK. It is also clear that Germany is quite exceptional.

Table C.9
Numbers of Electricity-Producing Biogas Plants in EU-Countries

Country	Number of agricultural AD plants	Installed generating capacity MW_e
Austria	159 +150 to end 2007	29 + 40 to end 2007
Belgium	6	12.3
Denmark	58 on-farm 20 CAD	40
France	3	n/a
Germany	> 3000	550
Great Britain	<20	<2
Ireland	5	0.2
Italy	80	62
Netherlands	12	3.8
Switzerland	71	n/a

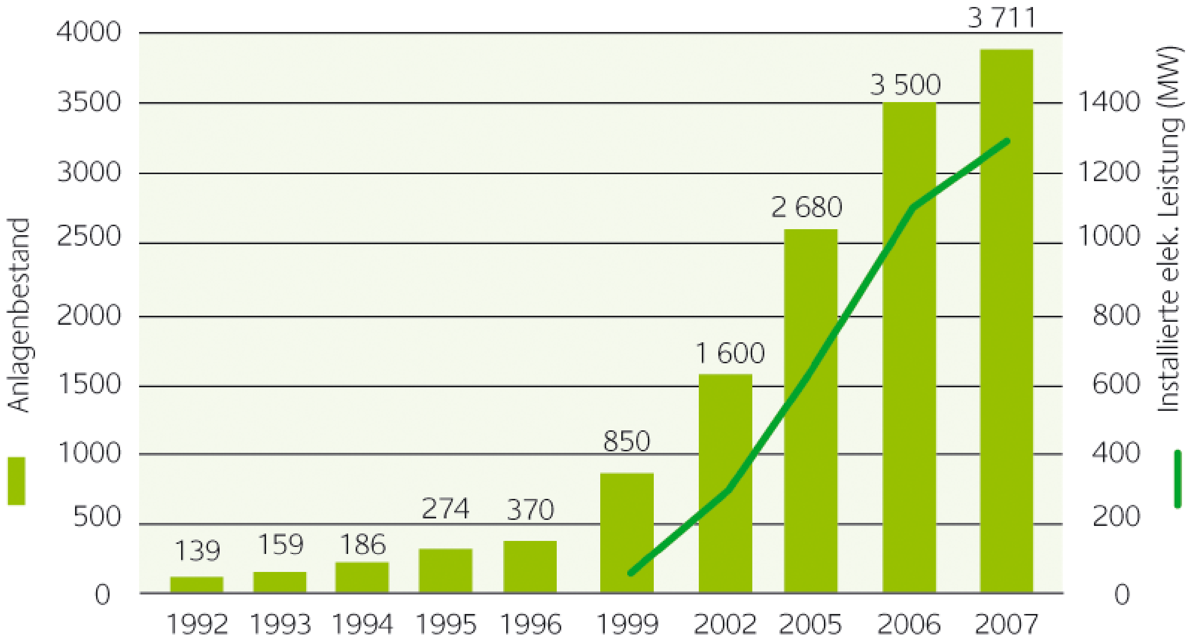
Source: Michael Köttner, November 2005.

The incentives system of producing renewable electricity in Germany has largely favoured the uptake of on-farm AD systems by farmers seeking to enhance their income. The scale of operation is increasing, however, and there are reports of very large plants being built specifically for injection.

For small-scale AD the additional tariff offered for electricity production is nearly twice that of renewable obligation certificates in the UK, with extra available for CHP and for cultivated biomass feedstock. Driven by this market, technological advances made in Germany enable dry fermentation and co-digestion with energy crops, increasing the potential for biogas production. The industry is also backed up by a large number of suppliers and good technical support.

Germany produces by far the most biogas in the EU at 2.4 Mtoe per year [40]. In 2007 71 percent of the biogas was produced by on-farm units. By the end of 2007, 3,700 units were in operation across Germany and equipment suppliers were exporting to the rest of the EU. The annual increment has slowed in the past year from 800 units per year in 2006 to 250 per year in 2007. This slowing is felt to be due to higher energy crop prices and equipment costs.

Figure C.8
German Biogas Capacity, 1992-2007



Source: German Biogas Association
Notes: The left-hand axis ("Anlagenbestand") shows the number of units, while the right-hand axis ("Installierte elek. Leistung") shows installed capacity measured in MW.

The growth in capacity is projected by German Energy Agency (DENA) to continue, and estimates suggest that by 2020, capacity in Germany will exceed 3,000 MW"[41],.

There is a significant market for auxiliary services connected with AD in Germany. Over 200 companies are offering services in connection with biogas technology, such as consulting, planning, design, manufacturing, delivery of parts and components (pumps, stirrers, engines, tanks), and servicing. It is estimated that together with the operating staff 8,000 jobs are depending on the services revolving around biogas technology.

If we consider the growth rates implied by the graph above we can see that the cumulative number of installations has grown steadily at between 6 percent and 47 percent per year, with

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40 Biogas Barometer – July 2008

41 http://www.renewables-made-in-germany.com/en/biogas/

typical growth rates between 20 and 30 percent per year over the period. The growth in the number of installations installed in each year has been less even, with peaks and troughs reflecting the impacts of incentives.

Table C.10 shows summary data for the German biogas market

Table C.10
Summary Data for German Biogas Market

Year	Percent annual growth of cumulative total number of installations	Percent annual growth of cumulative Mwe installed	% growth of annual increment Installations (Turnover)	Cumulative installations	Cumulative Mwe	Calculated average size of all installations kWe	Gross gas production GWh pa	Net gas production if all gas were for heat or injection GWh pa
1992				139				
1993	14%			159				
1994	17%		35%	186				
1995	47%		226%	274				
1996	35%		9%	370				
1997	35%		35%	500				
1998	35%		35%	675				
1999	26%		0%	850	50	59	1200	799
2000	29%	166%	26%	1071	133	124	3192	2126
2001	23%	62%	26%	1349	216	160	5184	3453
2002	19%	39%	-10%	1600	300	188	7200	4795
2003	23%	39%	19%	1898	416	219	9984	6649
2004	18%	28%	19%	2250	532	236	12768	8503
2005	16%	22%	22%	2680	650	243	15600	10390
2006	31%	69%	91%	3500	1100	314	26400	17582
2007	6%	18%	-74%	3711	1300	350	31200	20779

C.2.5.2. Stretch growth scenario

In considering limitations to the expansion of biogas in the UK, the limiting barriers are related to the production of methane gas, as we discuss further below. By contrast, the use of the gas in heat or power generation, or as substitute natural gas, is unlikely to impede progress provided incentives are in place and there is access to the relevant networks. We therefore discuss growth and deployment in terms of the production of methane gas in GWh per year.

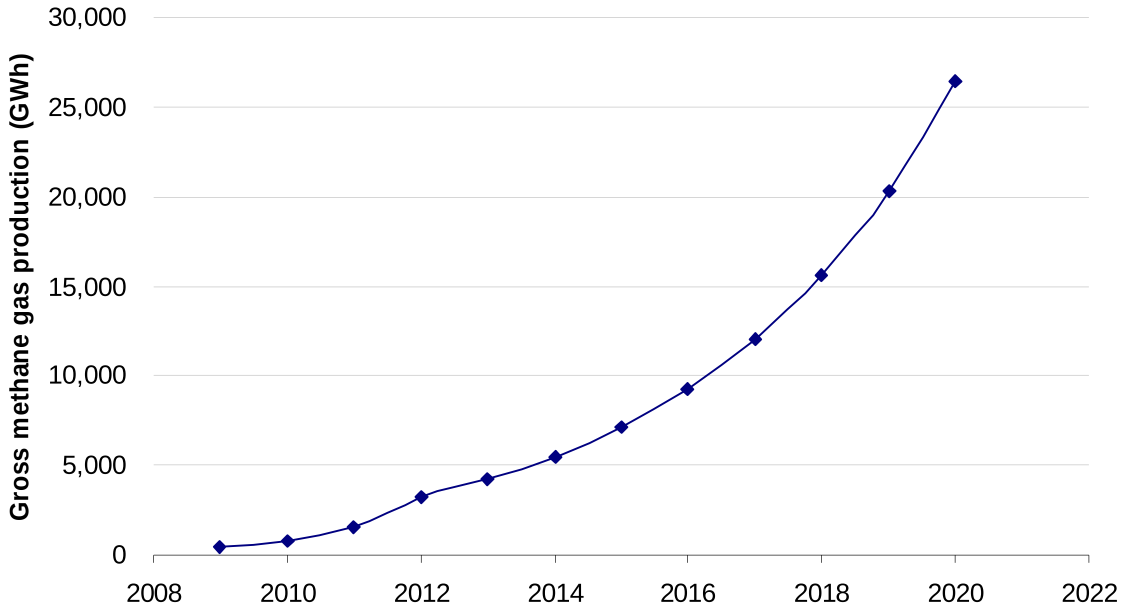
C.2.5.2.1. Gross gas production

Our premise is that the German experience represents a stretch scenario for what could be achieved in the UK. Based on German experience we suggest a growth rate in the supply of anaerobic digestion installations as follows

- Initial three years – 100% year on year
- Thereafter – 30% year on year growth in annual sales.

We are aware of 42MWe in planning or financing which if we assume that all of these go ahead would give us a starting point of 404 GWh/year in 2010. These assumptions gives the growth profile shown below. The total amount of gas produced reaches just over 7,000 GWh by 2015, and grows to just over 26,000 GWh by 2020. This refers to gross biogas generation before it is converted to heat or other uses.

Figure C.9
Stretch Scenario Biogas Production



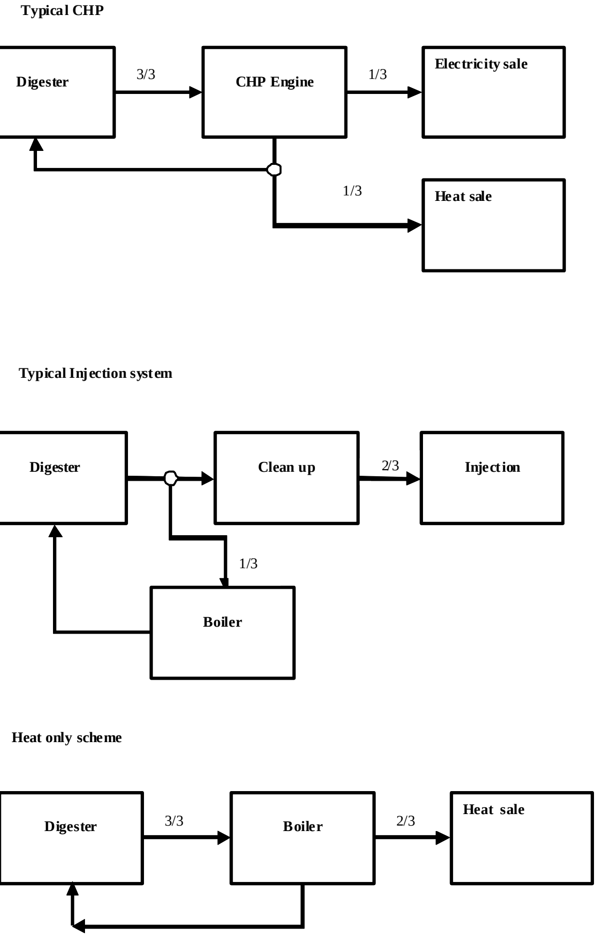
We consider the most likely installation to be a relatively large-scale operation (see discussion below). With an average of 2 MW gas generating capacity, the above implies the construction of 1,000 units by 2020. With the above gradual ramp-up pattern, an average of some 150 units per year would need to be built after 2015. This illustrates why the stretch scenario represents a highly challenging roll-out of AD, involving the creation of a substantial industry and build-up of expertise.

C.2.5.2.2. Net gas production for export

The above numbers refer to gross gas production. Not all of the energy in the methane produced in a digester is available for other uses, but approximately 1/3 is used to keep the digester at its required operating temperature. In a CHP installation using a reciprocating engine this heat is supplied from the engine cooling jacket and exhaust, which reduces the amount of heat for sale. Where the gas is supplied for injection a proportion needs to extracted before the gas is upgraded, and used to generate the energy supplying heat to the digester.

These factors are illustrated in the figure below. If the gas is used in a CHP unit one third will be converted to electricity and one third to heat, with the remaining third used to heat the digester and lost through flue losses. Similarly, If the gas were used for grid injection or heat-only generation, approximately one third of the gas would be needed to keep the digester at the correct temperature and thus be unavailable for other uses.

Figure C.10
Schematic Representation of Gas Use in CHP / Grid Injection



This means that the total amount of gas available by 2020 for heat or electricity production in the stretch case is reduced from 26 TWh to just under 18 TWh.

C.2.5.2.3. Allocation between grid injection, heat-only, electricity-only, and CHP generation

Outside some specialist cases in the food industry it seems unlikely that installations would choose heat-only operation if they could access either the gas or electricity networks. The networks offer a low-risk customer for the product capable of taking the output at all times of year, allowing for high load factors of operation. By contrast, most heat loads are much more limited.

The questions are therefore:

§ What proportion of the AD capacity will be built as gas injection?

§ What proportion will be built as CHP?

§ What proportion of the heat from the CHP can be sold as useful heat.?

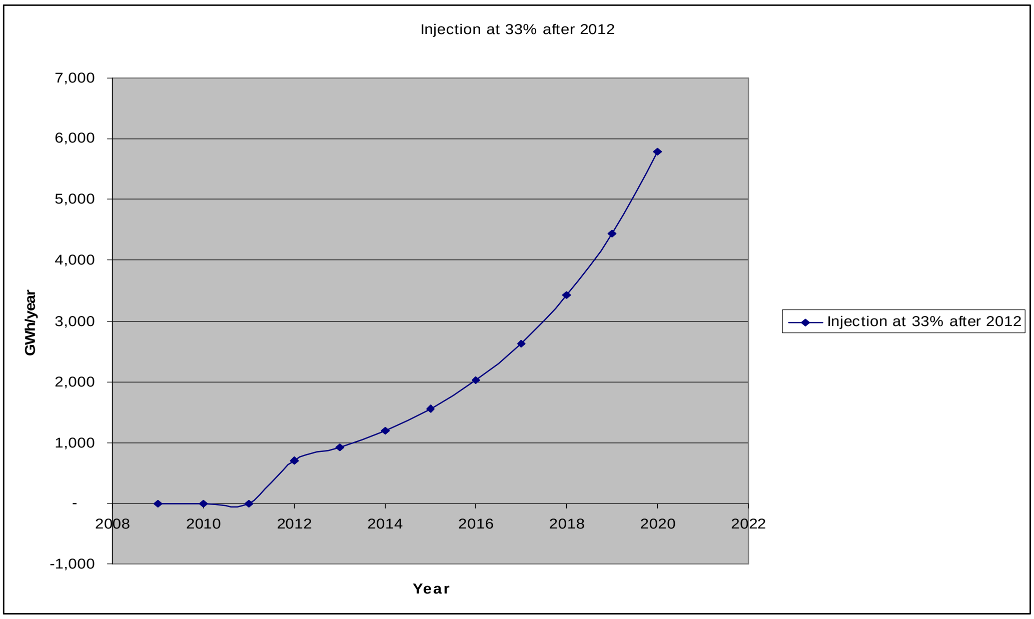
Grid injection

The electricity network is far more widespread than the gas network and access is relatively trouble-free. Electricity generation also is technically less complex, and benefits from a head start under the current regime of incentives. We therefore think it likely that independent operators will choose this route, unless financial incentives make gas grid injection more attractive by a reasonable margin to cover the additional cost and risk.

Not all operators are independent, however, so a proportion of gas may nonetheless be available for injection. For the purpose of this exercise, we have assumed that one-third of the gas available for export will be directed to grid injection. This number is uncertain, and depends on the balance of incentives between electricity and heat production and other factors.

The assumption that one-third of gas will be used for injection results in a potential of just under 6 TWh per year by 2020. The full trajectory is shown in Figure C.11

Figure C.11
Stretch Scenario Biogas Available for Injection



Heat from CHP

We make the following assumptions when considering the relationship between heat generation and biogas used for CHP:

First, there will be a gradual ramp-up of heat-capable installations. At present all projects are financed on the basis of electricity-only operation. This seems unlikely to change with in the next few years but the export of heat could then ramp up under the influence of the RHI. Consistent with the stretch target assumptions of no or very low barriers to renewable heat production, we assume that all electricity installations are built heat capable.

Second, not all of the heat produced can be usefully employed. The temperature of the heat available from AD gas is only suitable for space heating and low grade process heating. These types of heat load typically are seasonal (whereas the AD unit would be running at all times). To account for this we have assumed that 25 percent of the heat available could be used for heat production.

These two factors result in a gradual ramp-up from practically no heat generation, to 25 percent as developers develop plant to take better advantage of the RHI.

Table C.11 shows our assumptions for this ramp-up.

Table C.11
Assumptions about Uses of Heat from Biogas CHP

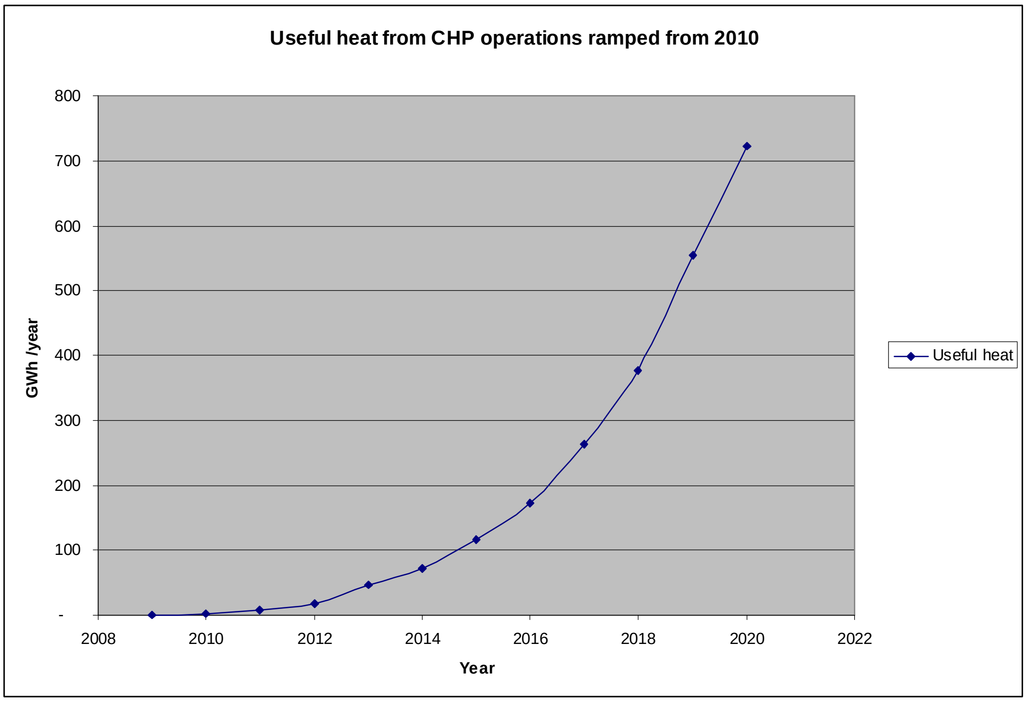
Year	Percent of available heat usefully employed
2009	2%
2010	3%
2011	5%
2012	10%
2013	12%
2014	15%
2015	17%
2016	20%
2017	22%
2018	25%
2019	25%
2020	25%

A third factor is that not all facilities will be located where there is a suitable heat load. Exporting heat is relatively straightforward and if they have sufficient advance information about incentives installations could be located in suitable places. Nonetheless, not all places will be suitable. We assume that half of installations are suitable.

Finally, we assume that the heat-to-power ratio of the CHP generation is such that the heat available corresponds to half of the energy content of the gas used.

Accounting for these four factors, we obtain the below trajectory for heat generation from biogas CHP. The total is just over 0.7 TWh by 2020.

Figure C.12
Heat from Biogas CHP



C.2.5.2.4. Check against feedstock availability

We have checked the above trajectory for gas production against available feedstock. The technical gas generating potential of household, commercial, and industrial (PPC returns and other) food waste amounts to approximately 26 TWh. Manures could add another 13TWh of technical potential, with the large majority of this from egg laying poultry. For the purposes of the stretch scenario, however, it is sufficient to note that if barriers can be overcome feedstock availability is not going to be a limiting factor to the above trajectory for gas production. Towards the latter part of the trajectory there will be increasing pressure to add other feedstock to maintain adequate margin between supply and demand. These are most likely to be crops grown specifically for digestion as is increasingly done in Germany.

C.2.5.3. Central growth scenario

The central scenario took a more UK-based view of development.

C.2.5.3.1. Feedstock considerations

To consider a scenario that accounts for barriers that are likely to apply in the UK, it is necessary to consider the feedstock that would be used for AD. Based on AEA knowledge of the sector we feel that a growth in AD will be driven largely by the availability of (consumer and processing) food wastes. These have the advantage of high methane generating potential, and also reduce costs by enabling AD operators to charge a gate fee for disposal. Other types of feedstock can be used depending on location and season. However, we do not think they will drive the growth.

We do not consider manures a likely feedstock for AD used to produce gas for grid injection. Manures are rural in origin, and AD plants using this type of feedstock would have limited access to locations suitable for grid injection. Facilities using manures therefore are more likely to be CHP, or more probably electricity-only, installations. (We did allow for a small number of small, "on farm" digesters supplying larger rural properties with heat only; however, this represents a trivial amount of capacity.)

Given this, we calculated the bio-methane potential for the central growth scenario by assuming that waste authorities will initiate separate food waste collection to meet Landfill Directive targets. The total amount of household food waste is around 8.3 million tonnes, [42]corresponding to methane generating potential of around 9.2 TWh. If somewhat over half of this could be made available for anaerobic digestion by 2020, the corresponding methane generating potential could be in the region of 5 TWh could be made available for anaerobic digestion by 2020. This would corresponds to a significant change in household waste handling from current practice. Limiting factors could include the need for and difficulties of coordination between waste authorities, pre-existing commitments other uses for the relevant waste streams (such as composting or energy from waste), and potential political or popular opposition to the introduction of food separation. To this potential can be added an equal quantity or somewhat larger quantity of commercial and industry waste. The total potential under these assumptions scenario would be around 11 TWh of gas generation, representing some 30 percent of the available food waste plus a minor contribution from dairy farming and egg production. This we would regard as feasible given current pressures to reduce landfill.

C.2.5.3.2. Construction of AD capacity

This potential needs to be cross-checked against the feasibility of building a supply industry to build, operate and support the required AD facilities. We consider the most likely model for AD to be large-scale units capable of achieving the required economy of scale. Units with of 2 MW capacity would require feedstock from two or more waste authorities, and thus require co-ordination. This adds complexity to the rollout of AD but may not be an insurmountable obstacle.

To achieve economy of scale waste authorities will co-operate to build larger installations than would be possible for one authority**.**

11 TWh of gas generating potential would correspond to 400 units of 2 MW net gas export capacity by 2020. We consider this a possible but challenging scenario, accounting for the various barriers (as noted above, the stretch case corresponds to some 1,000 units of size by 2020). Given a similar trajectory to that for the stretch case (100 percent growth for three years, then year-on-year growth at a steady rate until 2020), this would require an average installation rate of around 40 units per year towards the end of the period. This number would need to be still higher if the initial ramp up were slower.

11 TWh of raw gas production corresponds to 7 TWh of gas available for export once digest heat consumption is accounted for. With the same partitioning between grid injection and electricity / CHP generation, the amount of gas available for injection by 2020 would be 2.3 TWh, while the heat from CHP would be 0.3 TWh.

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[42] Hogg. D, Barth. J, Schleiss. K, and Favoino. E , 2007, Dealing with Food Waste In the UK, Eunomia Research and Consulting for WRAP

C.2.5.3.3. Summary of central and stretch growth scenarios

The below tables summarises the key numbers associated with different growth scenarios. As noted, the "higher" growth scenario represents potential between the central and stretch scenarios.

Table C.12
Summary of Biogas Growth Scenarios

Year	Units	Net capacity	Gross gas output	Net gas output	Gas for injection	CHP heat
		GW	TWh	TWh	TWh	TWh
Stretch growth scenario						
2015	270	0.5	7.1	4.7	2.1	0.1
2020	1,000	2.0	26.0	18.0	5.9	0.7
Central growth scenario						
2015	190	0.4	5.0	3.4	1.1	0.1
2020	400	0.8	11.0	7.0	2.3	0.3
Higher growth scenario						
2015	290	0.6	7.6	5.0	1.7	0.1
2020	600	1.2	16.0	11.0	3.5	0.4

C.2.5.4. Potential limiting factors and additional considerations

C.2.5.4.1. Digestate disposal

It appears that the most serious threat to wide scale deployment and the potentials described above would be the limitation imposed by finding suitable sites for digestate disposal.

Centralised AD plants, in particular, are likely to receive other agro-industrial residues, which after co-digestion with livestock slurries will increase both the volume and nutrient content of the digestate available for application to land. This may have implications in high livestock density areas within Nitrate Vulnerable Zones, where insufficient land may be available locally to accommodate the nutrient loading. Even in areas where nutrient-loading ceilings would not be an issue, the increased volumes of digestate to be spread by farmers would likely mean an increase in on-farm storage capacity to ensure that application rates and timings are agronomically sensible and that pollution risks are minimised.

A recent report [43] identifies a potential problem in finding sufficient land that is not subject to restrictions on nitrate content or topographical concerns. The problem is made worse by the increasing use of composting facilities by Local Authorities to treat green wastes, again the only viable outlet appears to be agricultural land disposal.

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[43] ENDS Report 404, September 2008, pp 30-33

C.2.5.4.2. Leakage of methane and nitrous oxides can negate benefits

We also wish to bring to your attention that a high growth rate and overcompensation of the energy output can lead to deterioration in the GHG mitigation performance of the overall system. We have heard anecdotally that feedstock can be processed too quickly through the unit to maximise generation and continue to produce methane in the digestate storage tank and beyond. Methane is a powerful greenhouse gas and if it leaks to atmosphere it will offset many of the benefits gained by energy generation.

Nitrous oxide is formed when nitrogenous fertilisers are applied to land. This is a very powerful greenhouse gas with a global warming potential of 320. The situation with digestate is poorly understood but it is possible that nitrous oxide would be emitted to the detriment of the overall GHG mitigation balance.

C.2.5.5. Analysis of Bio Synthetic Natural Gas

Bio synthetic natural gas (SNG) processes first break up the biomass into simple molecules of hydrogen, carbon monoxide and carbon dioxide which are then recombined to form methane.

We reviewed current activities, and activities in the related field of the production of renewable transport fuels using thermal gasification and Fischer Tropsch synthesis, and came to the conclusion that commercial deployment at any scale is unlikely before 2020. The likely outcome of current development activities is a demonstration plant built in approximately 5 years time, probably in Germany or Sweden with the first commercial full scale plant some years after this. Optimistically, one of these may be in the UK.

The formation of methane results in the emission of large quantities of heat at the reaction temperature of 350 degrees C. This temperature is ideal for the production of good quality process steam. The equipment is based around derivations of coal gasification and petrochemical processes and so is necessarily large scale. The production of high quality heat would also favour a large scale industrial location where it could be used to best advantage. For the purposes of our calculations we have therefore sized the installation at 700MW gas output which matches the heat demand of a typical petrochemicals installation.

In an assessment of the potential for biogas, National Grid (2009) took a different approach, assuming several smaller gasifiers distributed around the country to match the distribution of the waste resource used as feedstock. This may be equally valid. However, we feel that the potential over the period considered here would not differ greatly, as it is limited chiefly by the need to develop the technology.

The bio-SNG process operates at high pressure and we have assumed that further compression would not be required. Gas cleaning is also inherent in the process.

A large scale SNG plant is capable of treating a wide range of materials including waste derived fuels so we have assumed a mix of feedstock comprising half low cost waste derived fuels such as waste woods and recovered fuel, and half clean, more expensive fuels such as forestry residues, clean recycle wood energy crops etc.

There is little data on what the operating costs of a bio-SNG might be. In the absence of other data, we have assumed that they would be similar to those of a large biomass power plant.

On the basis of these assumptions, and provided the technology can be sufficiently developed, it appears Bio-SNG could be a cost-effective way of delivering renewable heat to consumers on the gas grid but it is unlikely to make a contribution before 2020.

A summary of our analysis is given in the below table.

Table C.13
Summary of analysis of costs for Bio-SNG plant

Plant life	**40**	Years
Major plant life	15	Years
Biomass In	1173	MWf
SNG production capacity	773	MWSNG
SNG annual production	6,180,313	MWh_{SNG}
Total plant cost	**£783,150,307**	£
Total operating cost	**£107,870,548**	£ p a
Capital Cost per MW sng installed	1,013,735.45	£/MW_{SNG}
Gasification efficiency	83%	LHV
Methanation efficiency	79%	
SNG production	772.5	MW_{SNG}
By-product heat	400.0	MW_T
Industrial Waste Heat capacity available to host site	**360**	**MW_T**
Industrial Waste Heat available to host site per year	**2880000**	**MWh_T**

C.2.5.5.1. References for Bio – SNG analysis

Exploration of the possibilities for production of Fischer Tropsch liquids and power via biomass gasification. M.J.A. Tijmensen et al, Biomass and Bioenergy 23 (2002) 129 – 152

US Dept of Energy report GEFR-00568 (DE82019167),METHANATION PLANT DESIGN FOR HTGR PROCESS HEAT By C. R. Davis, September 1981

National Grid PLC, Renewable Gas Project Assumptions Booklet (unpublished)

The potential for **Renewable** Gas in the UK, A paper by National Grid, January 2009

C.2.6. Solar Thermal

Solar thermal differs from the other renewable heat technologies in that it is a discretionary purchase and is decoupled from the need to replace existing equipment at the end of its economic life. This means that deployment can expand in response to financial incentive until it is constrained by the availability of equipment or manpower.

A central scenario was developed based on that developed by Enviros (2008)[44], but with a reduced 2020 deployment.[45] This was because felt the basic methodology was sound but we were unable to reconcile the 2020 target with the projected manpower and resource use assumed by Enviros. We therefore calculated the 2020 figure on following basis:

We considered the manpower availability assumptions Enviros had made on solar panel manpower requirements and availability projections. These are based on 4 man-days/installation by 10,000 plumbers working 220 days/year, and further assuming that these installers currently are available 25 percent of time (55 days/year) but that this could rise to 100 percent by 2015. We consider these assumptions to be reasonable and conclude that it is consistent with the projection of heat output of 2.2 TWh/year from cumulative installed capacity by 2015. However, the projection of cumulative output of 19.4 TWh/year is much higher than we find with these assumptions, and we have reduced it to 5.4 TWh/year. The reduction is due in part to the revision of assumptions about the output per unit, but we have not been able to verify precisely the reasons for the difference.

With the adjusted 2020 figure the required growth rate in cumulative output would be 44 percent in the period 2010-15, and 20 percent in 2015-20. We consider these possible in the light of the barriers identified.

With the adjusted 2020 figure the required average annual growth rate would be 44% in the period 2010-15 and 20% in 2015-20. (For comparison, Enviros's 2020 projection would require an average annual growth rate of 55% from 2015-2020.)

We further assumed that around 15 percent of the capacity would be in non-domestic applications, and the remaining 85 percent would be in the domestic sector. The implied number of installations and output by sector is shown in Table C.14. The total number of implied units is just under 4 million in 2020, with the large majority in the domestic sector.

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44 Enviros Consulting (2008a)

45 We have not develop a stretch growth or higher growth scenario for solar thermal, as the modelling assumptions (notably, limiting the subsidy payments to £100 / MWh heat output) mean this technology does not contribute significantly to the renewable heat mix.

Table C.14
Summary of Solar Thermal Growth Scenario

Year	Domestic sector		Non-domestic sector	
	Units (thousand)	Heat output (TWh)	Units (thousand)	Heat output (TWh)
2015	1,600	1.9	59	0.3
2020	3,900	4.6	140	0.8

Note: Calculations of the implied number of units assume output from domestic units of 1.2 MWh / year, and output from non-domestic units of 5.9 MWh / year.

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