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# Quantitative Evaluation of Financial Instruments for Renewable Heat

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# Contents


| | | |
|---|---|---|
| **Acknowledgments** | | **i** |
| **Executive Summary** | | **ii** |
| **1.** | **Introduction** | **1** |
| 1.1. | Structure of This Report | 2 |
| **2.** | **Modelling Inputs and Approach** | **3** |
| 2.1. | Potential for Renewable Heat | 3 |
| 2.2. | Technology Cost | 7 |
| 2.3. | Other Input Costs and Relevant Parameters | 8 |
| 2.4. | Costs of Overcoming Supply-Side Barriers | 13 |
| 2.5. | Costs of Overcoming Demand-Side Barriers | 14 |
| 2.6. | Monitoring and Metering Costs | 15 |
| 2.7. | Other Administrative Costs | 16 |
| 2.8. | Approach to Modelling of “Deeming” | 17 |
| 2.9. | Summary: Policy Features and Differences | 18 |
| **3.** | **Results** | **21** |
| 3.1. | Cost Curves for Renewable Heat | 21 |
| 3.2. | Headline Modelling Results | 26 |
| 3.3. | Detailed Modelling Results | 28 |
| 3.4. | Distribution of Subsidies and Rents | 34 |
| 3.5. | Sensitivity Analysis | 41 |
| **4.** | **Summary and Suggestions for Further Research** | **52** |
| 4.1. | Summary of Findings | 52 |
| 4.2. | Suggestions for Further Research | 54 |
| **5.** | **References** | **56** |
| **Appendix A.** | **Cost Curves by Technology / Sector** | **60** |
| **Appendix B.** | **Cumulative Headline Results to 2030** | **62** |
| **Appendix C.** | **Technology Cost Assumptions** | **63** |
| **Appendix D.** | **Deeming Assumptions** | **65** |

# List of Tables

Table 2.1 Target Output Scenarios for Renewable Heat in 2020 3
Table 2.2 Impact of uncertainty about future support level on cost 19
Table 3.1 Modelling Headline Results for 2020 27
Table 3.2 Impact of Fuel Prices on RHO Modelling Results (2020) 44
Table 3.3 Impact of Fuel Prices on RHI Modelling Results (2020) 47
Table 3.4 Impact of Barrier and Policy Costs on Modelling Results (2020) 51

# List of Figures

Figure 3.1 RHO and RHI Cost Curves for Renewable Heat in 2015, 2018 and 2020 22
Figure 3.2 2020 Cost Curves under Different Fuel Price Assumptions 24
Figure 3.3 2020 Cost Curves with Different Administrative and Barrier Costs 25
Figure 3.4 Composition of Additional Renewable Heat Technologies in 2020 29
Figure 3.5 Split of Renewable Heat Output by Sector and Technology in 2020 31
Figure 3.6 Split of Renewable Heat Output by Technology and Sector in 2020 32
Figure 3.7 Distribution of Resource Cost by Technology and Sector in 2020 33
Figure 3.8 Distribution of Inframarginal Rents Accruing to Sectors and Technologies (2020) 35
Figure 3.9 Distribution of Inframarginal Rents per-MWh Accruing to Sectors and Technologies (2020) 39
Figure 3.10 Impact of RHO "Banding" of Biomass on Subsidies and Rent (2020) 40
Figure 3.11 Impact of Discount Rate Assumptions on Modelling Results (2020) 43
Figure 3.12 Impact of Fuel Prices on Selected RHO Modelling Results (2020) 45
Figure 3.13 Impact of Fuel Prices on Selected RHI Modelling Results (2020) 47
Figure 3.14 Categories of Renewable Heat Resource Cost (2020) 50

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NERA Economic Consulting ("NERA") prepared the report. NERA is a firm of more than 450 consulting economists with 22 global offices that has extensive experience in the design and evaluation of emissions trading programs in Europe, the United States and elsewhere. The main authors of the report are Daniel Radov and Per Klevnas. NERA relied on various inputs from Enviros Consulting for this report, as described in the text, as well as inputs from BERR.

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# Executive Summary

This is the second of two reports by NERA for BERR presenting analysis of financial instruments to support the use of renewable heat in the UK. These reports were prepared in parallel with two companion reports produced by Enviros Consulting, addressing the non-financial barriers to renewable heat and the prospects for the future use of bio-gas. NERA's Phase I report (NERA 2008) provided a qualitative analysis and evaluation of a range of potential support mechanisms, and working with the BERR Steering Group selected a short-list of policies for further analysis—referred to as a Renewable Heat Obligation ("RHO") and Renewable Heat Incentive ("RHI"). This Phase II report presents the results of a quantitative assessment and cost-benefit analysis of these policies. The analysis relies on input from Enviros regarding the cost of renewable heat technologies and the costs of overcoming barriers to the widespread use of these technologies.

## Summary Findings

The following are a summary of the main findings of this study.

§ The study calculates costs and benefits associated with reaching a share of renewables in heat consumption of 7, 11, and 14 percent by 2020.

§ Reaching a 7 percent share of renewables in heat generation by 2020 (42 TWh) is relatively inexpensive given the assumptions used in our modelling, and if electric heating could be replaced by renewables may incur little or no additional resource cost provided barriers to renewable heat demand and supply are actually overcome at the costs estimated by Enviros.

§ Reaching a renewable share of 11 percent by 2020 (67 TWh / year) would incur a resource cost under the RHI of £1.0bn per year in 2020, with costs increasing to £3.1bn with a 14 percent share (90 TWh / year). With the higher discount rates that we assume under an RHO, the costs would increase to £1.3bn and £3.9bn in 2020, respectively.

§ These costs capture the higher technology cost of renewables, as well as the time and transaction costs of policy compliance and administration; and costs of overcoming barriers to the rapid increases in the demand and supply of renewable heat implied by the target. The administrative and barrier costs constitute a significant share of the total resource cost, at around 50-65 percent of the total, depending on the level of output.

§ The dominant renewable heat technology is biomass, which accounts for more than two-thirds of renewable heat output at the 11 percent target, and half in the 14 percent target. Heat pumps also are relatively cost-effective but appear to have limited installation potential based on Enviros's assessment. At higher output levels, large amounts of costlier solar heat and biogas are necessary to reach the target level of output.

§ The opportunities for renewable heat are concentrated in the domestic sector, which accounts for around two-thirds of renewable heat output, but only around half of total UK heat demand. The opportunities in industry are limited by the difficulty of using renewable heat for many process heating applications.

- The use of 11 percent renewables for heating would reduce $CO_2$ emissions by an estimated 17 $MtCO_2$ in 2020, while the 14 percent target corresponds to an emissions reduction of 24 $MtCO_2$ in 2020. Renewables would displace natural gas and non net-bound fuels (coal, oil, and LPG) by similar amounts, each corresponding to 40-45 percent of the energy displaced (with the remainder displacing electricity).

- At the 14 percent share, total subsidies to renewable heat under the RHO reach nearly £10bn per year. This corresponds to an increase in annual energy bills of some £200 per household by 2020. Increases for other sectors are proportionate to energy consumption.

- The cost of renewable heat varies significantly by sector, technology, and fuel displaced. Under policies where all sources of renewable heat are paid the same per-MWh subsidy the total payments therefore are significantly higher than net resource costs. The resulting "rents" may amount to as much as £3.6-4.3bn for the 11 percent target, and £5.2-6.0bn for the 14 percent target.

- Under either the RHO or the RHI, support could be "banded" to reduce rents. Under one indicative example, offering biomass technologies just half the level of support available to other technologies could reduce rents by around 35 percent. However, banding is likely to increase resource costs because of the uncertainties associated with setting the appropriate level of support. (Banding also could complicate efforts to link a UK scheme to a potential pan-European trading scheme for renewable energy certificates.)

- Much of the information developed for this study is highly uncertain. There is limited experience with the promotion of renewable heat in the UK, and therefore limited understanding of the potential for, barriers to, and cost of widespread renewable heat use. In particular, assumptions about the availability of biomass (both domestic and imported) have a very significant impact on our modelling results, and would benefit from further research. Future developments of key parameters (e.g., fossil fuel prices) are also uncertain, adding to the uncertainty about the costs of renewable heat. Other sources of uncertainty include the feasibility of the rapid acceleration in renewable heat use and the efficacy of the policies—either to reduce risks to developers and end-users or to promote uptake.

- The policies perform differently under uncertainty. We find that the cost of meeting a fixed target of renewable heat under an RHO is sensitive to various modelling assumptions. Higher fossil fuel prices could reduce significantly the estimated cost of meeting the targets. Additionally, different assumptions about the costs of overcoming barriers or about the efficacy of the policy could have a significant impact on the results.

- In contrast, under an RHI the amount of output could vary significantly with input assumptions. Adverse conditions for renewable heat could cause the output target to be missed, while more favourable conditions would lead to higher output and commensurately higher subsidy payments. The RHI therefore offers much less certainty about meeting a target level of output than an RHO with a strict quantity target.

The remainder of this Executive Summary provides additional details on these findings, with a more complete account in the main body of the report.

## Overview of this study

The Phase I work identified two main categories of financial instrument for quantitative analysis:

§ A Renewable Heat Obligation ("RHO"). This policy would require a party in the heat supply chain (e.g., fossil fuel suppliers, or distribution network operators) to present on a regular basis certificates demonstrating that a quantity of renewable heat had been produced. This would, in effect, correspond to an obligation to support the generation of a minimum quantity of renewable heat. Certificates would be tradable and the price of certificates determined in a market.

§ A Renewable Heat incentive ("RHI"). This policy would offer a fixed support level per unit of output from eligible renewable heat projects. The finance could be offered through different arrangements, including obligations on parties in the heat supply chain to pay the RHI, or through a central purchasing agency. The level of the subsidy would be determined through regulation.

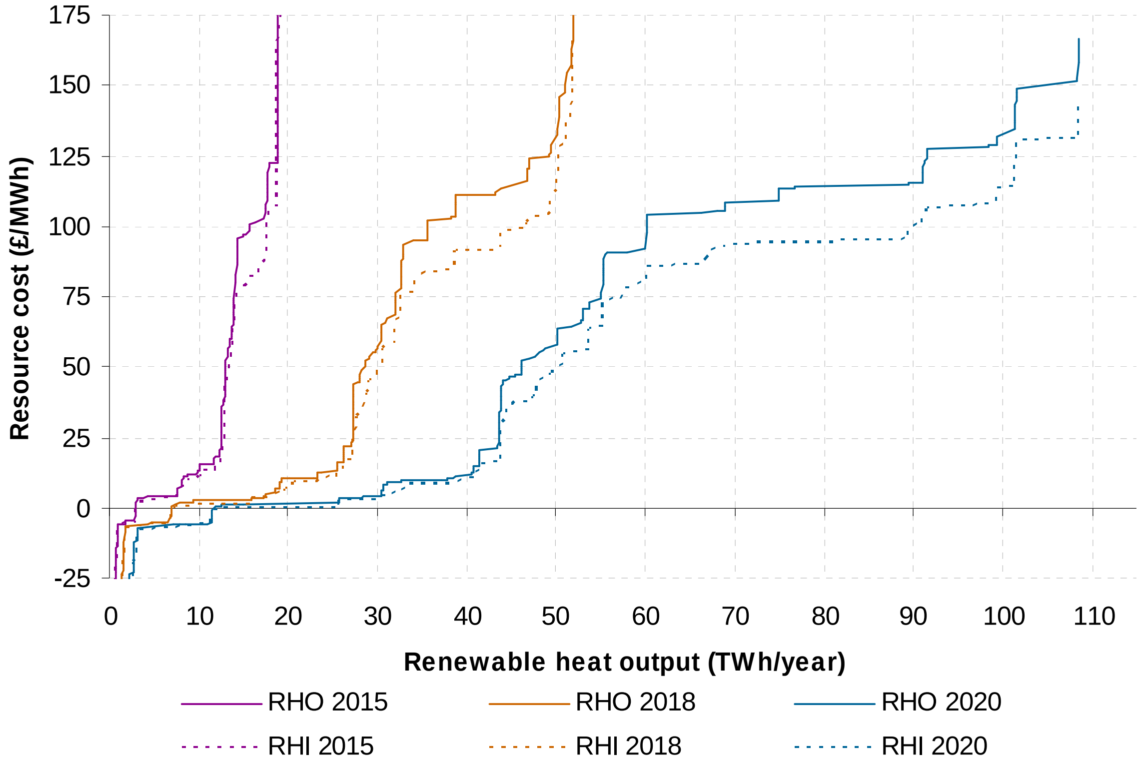
BERR requested that we model support mechanisms in place over the 2010-2020 period, and resulting in total renewable heat output of 41 TWh, 67 TWh, and 90 TWh in 2020. For each output scenario we have estimated the most cost-effective composition of renewable heat output, and calculated the associated costs and benefits. The assessment has aimed to provide as complete as possible an account of the costs and benefits of renewable heat. In addition to the (generally) higher technology cost of renewables relative to conventional heating technologies, the modelling incorporates various other costs associated with implementing the policies. This includes supply-side barriers (such as the need for new infrastructure, or qualified installers), demand-side barriers (such as the additional cost of project appraisal), and administrative costs of policy implementation (such as the time costs of monitoring, reporting, and verification). Data on the potential for renewable heat from different technologies and in different sectors, as well as on the cost of overcoming barriers, have been provided by Enviros Consulting, with more detail available in Enviros (2008a) and Enviros (2008b).

The Phase I report highlighted various differences between an RHO and RHI, many of which relate to the feasibility of implementation of the policies and the potential contractual and administrative arrangements that would be necessary under each policy. For this assessment, we have assumed that either an RHI or RHO is in place and is successful in providing subsidy of renewable heat projects. We incorporate into the modelling various differences between the RHO and RHI, with the chief distinguishing factor being a risk premium for investments undertaken under the RHO compared to the RHI, reflecting the greater uncertainty in subsidy levels under a certificate scheme than under the fixed-support arrangements of the RHI.

## Headline modelling results

The assessment of these costs allows the construction of a cost curve for renewable heat for each year in the 2010-2020 period. Figure ES-1.1 shows cost curves in the central scenario for RHO and RHI in the years 2015, 2018, and 2020. The costs represented include the barrier and administrative costs

**Figure ES-1.1**
**RHO and RHI Cost Curves for Renewable Heat in 2015, 2018 and 2020**




***Note**: The private discount rates used for the RHO are 9 percent for the domestic sector and 12 percent for the non-domestic sectors. For the RHI, the corresponding rates are 7 and 10 percent.*

The cost curves show several features implied by the data about renewable heat supply under these policies. First, the cost of renewable heat varies significantly between different projects (sectors, technologies, and fuel counterfactuals). Some projects are available at low cost or even a cost saving, while others cost in excess of £175 / MWh. Second, achieving the targets by 2020 requires a very significant ramp-up of renewable heat potential. Enviros (2008a) projects that much of the increase in renewable heat use would be in the last few years before 2020. The need for very rapid growth in capacity and output is a source of high costs of overcoming barriers to supply and demand.

Third, the assumption of lower discount rates results in a cost for a given output level under the RHI lower than the cost under the RHO. However, there is a possibility that the RHO would have other advantages that could lead to lower costs, discussed in the Phase I report but not modelled here. These include the possibility of making less use of a "deeming" approach to measuring heat output (which introduces some inefficiency and leads to higher subsidies). It also is possible that it would be easier to put in place contractual arrangements for upfront financial support, which could make more projects viable than would be under the RHI. These qualitative aspects of policies are not captured in the comparison of costs of the RHO and RHI in the cost curve above, nor in the modelling results presented below.

Table ES-1 shows headline results for 2020 for each of the three target scenarios under the RHO and RHI, assuming no "banding" is used to differentiate support to different renewable heat technologies (we discuss banding and its implications for the quantitative results below).

Total costs (in real 2008 prices) to achieve the Scenario 2 target amount to £1.0-1.3 billion in 2020, rising to £3.1-3.9 billion for Scenario 3.[1] Support levels vary from £73-89 per MWh in Scenario 2 to £95-113 per MWh in Scenario 3, and aggregate subsidies paid thus amount to £4.6-5.6 and £8.3-9.9bn, respectively. Either policy would lead to $CO_2$ savings of 17 $MtCO_2$ per year in Scenario 2 and 24 $MtCO_2$ per year in Scenario 3.

**Table ES-1**
**Modelling Results for 2020 – No Banding**

| | | RHO | | | RHI | | |
|---|---|---|---|---|---|---|---|
| **Variable** | **Units** | **Scn 1** | **Scn 2** | **Scn 3** | **Scn 1** | **Scn 2** | **Scn 3** |
| Renewable heat output | TWh | 42 | 67 | 91 | 42 | 67 | 90 |
| Resource cost | £bn | -0.1 | 1.3 | 3.9 | -0.1 | 1.0 | 3.1 |
| *Technology cost* | *£bn* | *-0.2* | *0.4* | *1.9* | *-0.2* | *0.2* | *1.3* |
| *Supply-side barrier cost* | *£bn* | *0.0* | *0.5* | *1.2* | *0.0* | *0.4* | *1.0* |
| *Demand-side barrier cost* | *£bn* | *0.1* | *0.4* | *0.7* | *0.1* | *0.3* | *0.6* |
| *Administrative costs* | *£bn* | *0.0* | *0.1* | *0.2* | *0.0* | *0.1* | *0.2* |
| Subsidy | £bn | 0.4 | 5.6 | 9.9 | 0.3 | 4.6 | 8.3 |
| Rents | £bn | 0.5 | 4.3 | 6.0 | 0.5 | 3.6 | 5.2 |
| Certificate price or incentive | £/MWh | 12 | 89 | 113 | 9 | 73 | 95 |
| Resource cost per MWh | £/MWh | -2 | 22 | 47 | -4 | 17 | 37 |
| CO2 savings | MtCO2 | 11 | 17 | 24 | 11 | 17 | 24 |
| *Outside EU ETS* | *MtCO2* | *8* | *11* | *17* | *7* | *11* | *17* |
| *Within EU ETS* | *MtCO2* | *3* | *6* | *7* | *3* | *6* | *7* |
| Number of installations | million | 0.4 | 4.2 | 8.9 | 0.4 | 4.3 | 9.3 |

***Note**: The private discount rates used for the RHO are 9 percent for the domestic sector and 12 percent for the non-domestic sectors. For the RHI, the corresponding rates are 7 and 10 percent.*

The results imply that the level of renewable heat output associated with Scenario 1 could be achieved at a net cost saving. This results because some renewable heat options appear to entail a cost saving, even accounting for the various barrier and other costs described above. We believe that this finding should be treated with caution, as it may be inconsistent with the observation that current use of renewable heat is relatively low, and may arise because barriers to the use of renewable heat in some segments of the market are not fully represented. The quantity of "cost-saving" renewable heat potential is a small proportion of the total in Scenarios 2 and 3 and therefore has only a limited impact on the results for these scenarios.

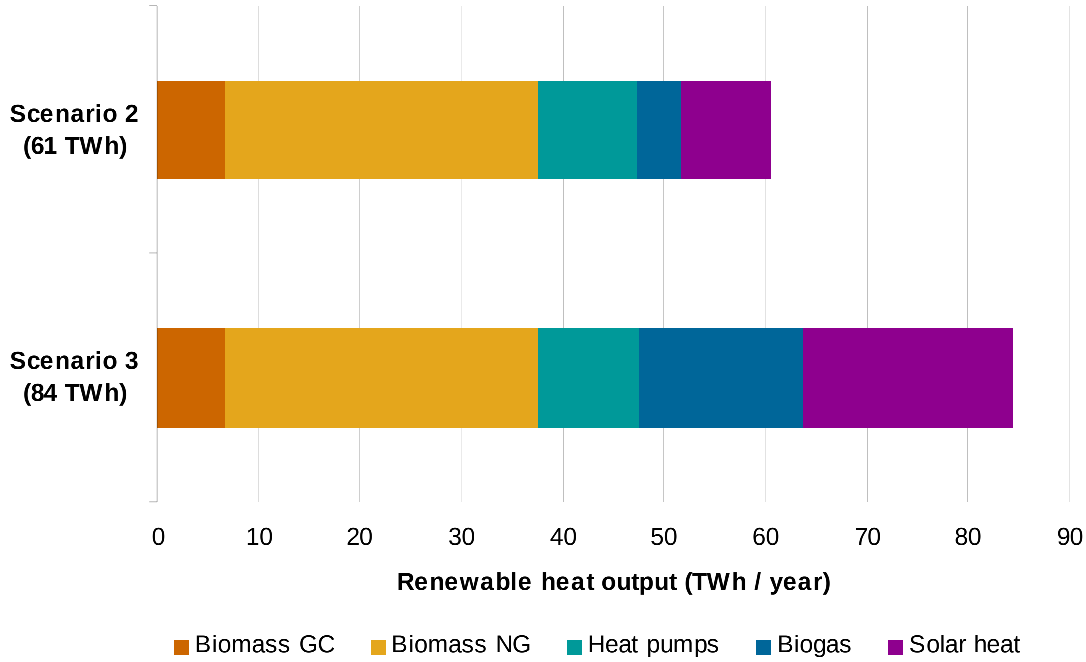
## Composition of renewable heat output

Figure ES-1.2 shows the composition of renewable heat by technology in Scenarios 2 and 3. Biomass is the dominant technology, followed by solar heat. Much of the increase in output from Scenario 2 to Scenario 3 is accounted for by solar heat and biogas, both of which make a significant contribution at higher output levels. By contrast, the amount of biomass and heat pump output does not increase from Scenario 2 to Scenario 3, even though subsidy levels increase. The constant level of biomass is due to a constraint on the amount of biomass assumed by BERR to be available for heat (limited to a share of that available for

[1] If these costs, which will be incurred in 2020 but which are expressed in real terms, were *discounted* to 2008 at the social time preference rate of 3.5 percent, the range of costs would be £0.7-0.9bn for Scenario 2 and £2.1-2.6bn for Scenario 3.

UK consumption – see Box 1). We believe that if the supply curve provided by BERR is accurate, increasing the support level for biomass heat to the levels modelled here would result in more biomass coming to market, whether from additional UK sources of biomass or through biomass imports. This modelling constraint thus may lead to an overestimate of the cost and subsidy levels required to meet UK targets, and to inaccurate estimates of the likely composition of renewable heat that would result under the policies.

**Figure ES-1.2**
**Composition of Additional Renewable Heat Technologies in 2020**




***Note**: GC = "Grid Connected" (district heating); NG = "non-Grid Connected". The figure shows results for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively (the default RHO scenario). Results differ only slightly with lower discount rates of 7 and 10 percent (the default RHI scenario).*

The modelling indicates that opportunities for renewable heat are greater in the domestic sector than in the commercial and industrial sectors, with the domestic sector accounting for 60-65 percent of total renewable heat output in 2020 (compared to around 54 percent of heat demand). The use of renewable heat also leads to reduced demand for fossil fuels and electricity. We find that the energy displaced by renewables is split relatively evenly between natural gas and non net-bound fuels (coal, oil, and LPG) at 40-45 percent each, with the remainder displacement of electricity—although there is significant uncertainty about these findings.

## Distributional effects and impact of "banding"

The steep supply curve—and the resulting need to use more expensive technologies to reach the higher output levels—leads to total levels of subsidy that are significantly higher than the resource cost when all technologies are paid the same level of support. This results in a net transfer from fossil energy consumers (who would pay higher energy prices) to beneficiaries of subsidies under the policies. Under the results above, in which no attempt is made within the policy to reduce such transfers, payments in excess of cost ("rents") correspond to as much as 60-75 percent of the total subsidy, depending on the level of output.

There are various reasons why this measure may overstate the significance of these rents, however. For one, some households that benefit from these "rents" – notably those that install heat pumps or solar thermal technology – are likely to have some residual use of fossil fuel, and therefore will face higher costs for these fuels that will offset some proportion of any rents they may receive. Moreover, to the extent there are "behavioural" barriers to renewable heat that can be overcome without net costs to consumers, rents would be overestimated. Finally, rents could be smaller under the RHO to the extent that obligated parties were able to price discriminate and pay different subsidies to different policies.

In addition, either the RHO or the RHI could be designed explicitly to limit rents, by building price discrimination into the support policy through "banding". Banding support levels would provide different subsidies to different types of renewable heat projects. Under the RHO, this would take the form of awarding different quantities of certificates to different categories ("bands") of projects; whereas under the RHI, the level of subsidy offered per MWh could be varied by band. For illustration, offering biomass half the number of certificates awarded to other technologies would reduce rents by around 35 percent.

However, banding also gives rise to a trade-off, as it risks increasing total resource costs. Under the RHO, if the band were set so that some otherwise cost-effective projects received less support than they would require in order to be taken up, other more expensive projects would have to be undertaken instead to reach the target level of output. This would increase total resource costs. Under similar circumstances with the RHI, the level of output would be lower, and the cost of achieving that level of output higher, than it would be without banding. We illustrate this effect by modelling an indicative band for biomass that provides insufficient support to all of the biomass that would be needed to meet the target output levels at lowest cost. Under this banding design, resource costs are higher than the no-banding case, even though rents are lower. We emphasise that these results are illustrative only; detailed consideration of banding parameters would require analysis outside the scope of this project.

## Sensitivity of results to input assumptions

The input data used for this project are subject to uncertainty. We have analysed the sensitivity of the results to a range of different parameters, including the following:

- **Discount rate assumptions.** We consider that 7 percent cost of capital in the domestic sector, and 10 percent in the non-domestic sectors, are reasonable baseline assumptions. Nonetheless, there are several uncertainties associated with this important input into the model:
  - The "risk premium" associated with the RHO may not be as large as the 2 percentage-point spread indicated above. With a 1 percentage-point spread the apparent cost disadvantage of the RHO would be roughly halved, to 13-16 percent more than in the RHI (not accounting for other potential differences between the policies).
  - Other risks to both policies may mean that the relevant discount rate should be higher. This could include various risks associated with the use of renewables compared to other heating technologies (e.g., uncertainty about the future availability of suppliers

and services, or the risk associated with production or heating service disruptions). For illustration, if the appropriate domestic and non-domestic cost of capital were 10 and 13 percent instead of the 7 and 10 percent used in the central case, then social costs would increase by as much as 40-45 percent and subsidies by 25-30 percent.

§ **Fossil fuel prices**. Renewables become more attractive with higher fossil fuel prices. In the "high-high" fuel price scenario used in BERR's Updated Energy Projections (UEP) the social resource cost of using renewables to reach the Scenario 2 target would be close to zero, while costs would be reduced by 50 percent in Scenario 3, compared to the central case. The impact on total subsidies would be smaller but still substantial, with a 20-25 percent reduction in both scenarios. Conversely, in the UEP "low" fuel prices scenario costs would be 15-35 percent and subsidies 5-10 percent higher then the central case, respectively. Changes in fuel prices would have a negligible effect on the level of rents.

§ **Admin and barrier costs.** These costs are a significant proportion of the total, making up as much as 50-65 percent of total cost in the central scenario, depending on the level of output. However, the cost to end-users associated with rapidly overcoming barriers to the extent required by the targets is very uncertain. If administrative and barrier costs were 50 percent lower cost would be reduced by 30-35 percent, depending on policy. If these costs were 50 percent higher would raise costs by 25-30 percent.

## Implications of uncertainty for policy performance

The uncertainty about net costs and subsidies associated with reaching the renewable heat targets has different consequences under the RHO and the RHI. Under the RHO, there is a risk that higher costs of renewables over their fossil fuel-fired alternatives would lead to higher certificate prices for a given quota. As noted above, the additional subsidy required to meet the targets could vary by some -25 / +10 percent with the high-high / low fuel prices, compared to the central case. In a scenario where both fuel prices and barrier costs were less favourable than expected, the required subsidy could increase significantly more.

Under the RHI, by contrast, higher fuel prices would result in ***higher*** overall subsidies. This is because the lower net cost of renewable heat makes additional projects viable, leading to more output and thus overall payments for a fixed per-unit payment. For example, in Scenario 2 subsidies (and heat output) would increase by 37 percent under high-high fuel prices, compared to the central case, whereas the low fuel price scenario would cause the RHI to miss the target by some 5 / 13 percent in Scenario 2 / 3. As there are many other sources of uncertainty besides fuel prices it may be difficult to use the RHI mechanism to achieve a target level of output. The difficulty could be alleviated by more detailed data on the cost and potential of different technologies. It also could be reduced if it were possible to adjust the subsidy level over time in response to developments (e.g. mimicking a "contract for differences" structure of payments), but this is likely to be complex.

## Suggestions for further research

The next step towards developing a financial support mechanism for renewable heat would benefit from additional investigation of areas that are uncertain in the analysis presented here.

We suggest that the following would be important areas for further research to strengthen the quantitative assessment provided here:

§ Qualitative properties of support mechanisms. As highlighted in the Phase I report, achieving a working policy through either an RHO or RHI could be complex, and many issues would need to be clarified in consultation with stakeholders before the policy could be developed further. This in turn would clarify aspects that would be relevant to the quantitative assessment presented in this report.

§ Potential for renewable heat. The estimates of the potential for renewable heat could be improved by further analysis, taking into account the findings of this study about the relative cost-effectiveness of different options. It also could be improved by considering alternative scenarios for the availability of biomass, which is an important constraint on the current modelling.

§ Barriers and potential by fuel counterfactual. There currently is only limited data available about how the potential for renewable heat may be distributed between different fuel counterfactuals, and which barriers may be faced by different segments of current users of gas, non net-bound, and electricity for heat.

§ Risks from missing energy reduction targets. The scenarios investigated here rely on a sharp improvement in energy efficiency and thus reduction in overall energy use until 2020. If energy efficiency were not increased at this rate, costs of reaching the renewable heat targets of 11 or 14 percent would increase.

§ Details of banding. The quantitative analysis could be refined use to reflect different approaches to banding, including different definitions of banding categories and levels of support for each band.

§ Linking to the Renewables Obligation. It would be possible to develop a joint certificate scheme for heat and electricity. This would raise several issues for the quantitative analysis, including the implied “exchange rate” for certificates for the two types of energy.

§ Impact of volatility and safety valve arrangements. The RHO may require the use of a “safety valve” to avoid spikes in the certificate price. Different mechanisms would be available, including “buy-out” arrangements, international trading, and the use of intertemporal trading in the form of banking / borrowing.

# 1. Introduction

This report is the second part of NERA's analysis for the Department of Business, Enterprise and Regulatory Reform (BERR) of financial instruments that could be used to promote renewable heat. It builds on the qualitative analysis developed in the Phase I report to develop a quantitative analysis of the policies short-listed there. The analysis presented here draws on parallel work undertaken by Enviros Consulting on the costs of renewable heat technologies, including the costs of overcoming barriers to the expansion of renewable heat.

The Phase I report of this project considered and evaluated qualitatively a range of financial mechanisms and incentives that could be put into place to promote the use of renewable heat in the UK. Based on the evaluation criteria provided by the project Steering Group, two main categories of policy were taken forward for detailed analysis:

§ A Renewable Heat Obligation ("RHO"). This policy would require a party in the heat supply chain (e.g., fossil fuel suppliers or distribution network operators) to present on a regular basis certificates demonstrating that a quantity of renewable heat had been produced. This would, in effect, correspond to an obligation to support the generation of a minimum quantity of renewable heat. Certificates would be tradable, the price of certificates determined in a market.

§ A Renewable Heat incentive ("RHI"). This policy would offer a fixed support level per unit of output from eligible renewable heat projects. The finance could be offered through different arrangements, including obligations to pay the RHI on parties in the heat supply chain, or through a central purchasing agency.

These policies are similar to tradable green certificate schemes and feed-in tariffs that have been used to promote electricity generation from renewables, respectively.

The quantitative assessment in this report takes as given that either an RHI or RHO is put in place and is effective in providing a subsidy to renewable heat projects. In addition to the higher technology cost of renewable heat, we model administrative costs, costs of overcoming supply- and demand-side barriers. We also models scenarios to explore potential through quantitative modelling some of the differences between the policies, such as the level of risk faced by participants, or the ability of the policies to provide certainty about meeting policy objectives.

However, we emphasise that the quantitative assessment in this report should be considered alongside the discussion in the Phase I report for a fuller picture of the feasibility and implications of different policy designs. The Phase I report highlighted that both types of support system for heat could raise several complications. Key issues include the likely need for up-front support to encourage uptake; the need to ensure light-touch monitoring and other administrative procedures; the requirement for contractual arrangements between market participants to underpin long-term investment decisions and reduce policy and other risk; and the risk that complexity may undermine policy effectiveness. These issues are not amenable to quantitative evaluation and are not fully represented within the modelling results presented in this report. The detailed design of policy, as well as the overall evaluation of which policy is best suited to the promotion of renewable heat, would require additional work and input from stakeholders.

## 1.1. Structure of This Report

The remainder of this report is structured as follows. Section 2 provides details of the modelling framework as well as the inputs and assumptions used for key modelling parameters. This includes the potential for renewable heat, the technology cost of renewable heat technologies, assumptions about fuel prices and other key input parameters—as well as the cost of administration and of overcoming supply- and demand-side barriers.

Section 3 presents the results of the modelling, including cost curves for renewable heat and headline results including the overall cost, distribution of subsidies, composition of renewable heat, and $CO_2$ implications of the scenarios. The subsequent sections explore the sensitivity of the results to input assumptions such as fuel prices and discount rates. This includes the different implications of the RHO and RHI for certainty about reaching targets, and also the potential implications of mechanisms to reduce the transfers ("rents") generated by the policy through "banding" or other mechanisms.

Section 4 presents conclusions and recommendations for future research.

# 2. Modelling Inputs and Approach

This chapter describes the data and assumptions used for the modelling.

## 2.1. Potential for Renewable Heat

### 2.1.1. Scenarios for renewable heat

The modelling in this project is carried out for three target levels of renewable heat output in 2020, provided by BERR and analysed by Enviros Consulting as part of a project to quantify the supply- and demand-side constraints on renewable heat supply. The resulting scenarios are shown in Table 2.1. Total heat output in 2020 is assumed to be 637 TWh, and the BERR projection of baseline renewable heat output is that it remains at current levels of 6 TWh / year, or 1 percent of 2020 heat demand. The three higher output scenarios correspond to the use of renewables to meet 6.5, 10.5, and 14.1 percent of total 2020 renewable heat demand. The corresponding total renewable heat output levels are 42, 67 and 90 TWh, respectively. This corresponds to 35, 61, and 84 TWh of additional renewable heat output over the baseline level. Further details of the scenarios and underlying assumptions are available in Enviros (2008a)

**Table 2.1**
**Target Output Scenarios for Renewable Heat in 2020**

| Scenario | Total heat demand (TWh) | Share of heat demand from renewable energy (%) | Total enewable heat output (TWh) | Additional renewable heat output (TWh, over baseline) |
|---|---|---|---|---|
| Baseline | 637 | 1.0% | 6 | - |
| Scenario 1 | | 6.5% | 42 | 35 |
| Scenario 2 | | 10.5% | 67 | 61 |
| Scenario 3 | | 14.1% | 90 | 84 |

***Source**: Enviros Consulting (2008a) and BERR*

These scenarios were used by Enviros to develop scenarios for renewable heat output, assess the barriers to renewable heat use that would need to be overcome, and thus to develop estimates of the potential for renewable heat. We describe below the nature of the information provided to us by Enviros and our use of these data in our modelling. More details of the approach taken by Enviros and the nature of the data are available in Enviros (2008a).

### 2.1.2. Modelling categories: technology, sector, and counterfactual heating technologies

The methodology used by Enviros to assess supply-side barriers entailed projecting the uptake of renewable heat potential from among five renewable heat technologies by four end-user sectors, and then calculating the cost of overcoming the relevant barriers in each technology/sector segment as necessary to reach that level of output. For each target level scenario this approach results in 20 technology/sector segments, each with an associated potential for renewable heat and total cost of overcoming barriers.

#### 2.1.2.1. Renewable heat technologies

The five basic technologies and fuels in the Enviros projections are biomass, biogas, heat pumps, geothermal energy, and solar thermal. In addition, the biomass category distinguishes between district heating ("grid-connected") and other heat ("non-grid-connected"). As agreed with BERR, the potential for geothermal heat assumed to be is minimal in all scenarios, at all points representing less than half a percent of the total potential. To simplify the modelling we therefore have excluded this technology from the analysis.

#### 2.1.2.2. End-use sectors

Enviros further has split each technology band into four end-user sectors: industrial, domestic, and small and large commercial / public sectors.[2] These technology/sectors segments differ in important respects, including the cost of heat generation capacity, load factors, and other technology and market characteristics, as discussed below. We also adapt the model in various ways to account for differences between likely size and other characteristics of the renewable heat installations in the sectors, including the feasibility of metering, administrative implications, and demand-side barriers associated with the uptake of renewable heat technologies.

#### 2.1.2.3. Counterfactual heating technologies

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. The modelling requires that the potential within each technology and sector combination is 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).

### 2.1.3. Potential by modelling category

For each of the three scenarios Enviros has provided trajectories (over the period 2010-2020) for heat production from each sector/technology combination, such that the total corresponds to the respective target level of renewable heat output for 2020. In addition, Enviros provided projections for a fourth scenario with the maximum feasible renewable heat output that could be made available by 2020, which was judged to be 114 TWh per year.

Enviros has assessed the barriers within each technology/sector category of achieving the renewable heat levels implied by the four scenarios. Both supply-side barriers (such as the availability of overall renewable resource, supply chain infrastructure, or qualified installers) and demand-side barriers (such as lack of awareness of technologies, the additional "hassle" or time costs of using renewable heat, or air quality regulations) have been accounted for in the analysis. A premise for the analysis was that financial constraints were not a barrier to

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2 Enviros's study uses the following sectors: commercial, domestic, industrial, and public. However, for the purposes of the policy evaluation at hand in this study we deemed it more important to distinguish between large and small heat loads than between commercial and public sector heat demand. Enviros has translated the data from their analysis into this categorisation by assigning some of the public sector potential to the commercial / public sector, and some (mostly civic district heating schemes) to the domestic sector.

the use of renewable heat, and the barriers thus do not include considerations about the relative technology cost of renewables and conventional heating technologies.

To make use of these data in the modelling we have combined the four sets of initial projections produced by Enviros into a single cost curve. This is done by treating each *incremental* quantity of heat supply represented by each technology and sector in each scenario as a separate segment in the overall supply curve. For each technology/sector, the potential thus is split into four "tranches": the first tranche reflecting the amount of heat potential in Scenario 1; the second tranche reflecting the difference between Scenario 2 and Scenario 1; the third tranche reflecting the difference between Scenario 3 and Scenario 2; and the final trance reflecting the difference between the maximum feasible output level and the Scenario 3 projections. To ensure that the barriers to expanding output from the level in one scenario to another are reflected, we associate with each tranche the incremental cost of overcoming barriers implied by the different output level and cost combinations across the four scenarios provided by Enviros (see discussion below). This procedure permits the model to use potential for a given technology/sector combination from different initial projection scenarios, if our modelling data indicate that it would be cost-effective to do so (taking into account the additional costs of overcoming barriers estimated by Enviros).

This constitutes the first attempt to create a barrier-consistent supply curve for renewable heat in the UK, and the detailed consideration of barriers to renewable heat that it embodies is likely to provide a significant improvement over a supply curve only incorporating technology costs and available renewable resource. It incorporates information reflecting the trade-off between barrier costs and differences in technology costs between different renewable heat technologies and sectors. The approach also implicitly improves the granularity of the modelling, by accounting for the costs of different sub-category within each broad technology category. (For example, the barrier costs to the use of biogas for centralised district heating plants are very different to those of on-farm anaerobic digestion facilities, and some of these differences are reflected in different supply-side barrier costs between different tranches, even though the modelling has a single "biogas" technology category.)

The accuracy of the estimates could be improved through an iterative procedure that reassessed the likely barrier costs associated accounting for the output scenarios and technology mix implied by the modelling output (which are likely to differ from the initial scenarios constructed by Enviros). The supply curve also could be improved by increasing the granularity of barrier cost assessment to more than four projections and tranches.

### 2.1.4. Constraints on the availability of biomass

The potential for renewable heat depends on the total renewable resource available, which has been analysed by Enviros as part of the investigation of supply-side barriers to renewable heat. In the case of biomass it also is necessary to assess what proportion of the resource will be available for heating rather than other potential uses, including the use of biomass for electricity generation and biofuels for transport. BERR has requested that both Enviros's and NERA's analysis proceed on the assumption that a maximum of 44 TWh of the total estimated UK biomass resource of around 96 TWh is available for heat generation by 2020.

Of the total biomass resource available for heat, 4.6 TWh currently are being used and thus are in the baseline projections. A source of uncertainty in this split is the use of biomass for combined heat and power generation (CHP). Enviros finds that it may be possible to use up to 5 TWh additional biomass for heating if electricity-only generation were converted to CHP generation. The total theoretical maximum therefore is 44 TWh *additional* biomass output. Box 1 provides additional background on BERR's biomass assumptions.

**Box 1**
**BERR Biomass Market Assumptions**

BERR's assumptions about the biomass supply curve were based on current information of the available UK resource as set out in the Renewable Energy Strategy ("RES") consultation document, and on an initial assessment of how the market might develop in the medium to longer term. As noted, there is considerable uncertainty about the future development of the biomass market, both within the UK and internationally. Currently the UK biomass market is relatively small and disparate, relying largely on locally sourced suppliers but with some imports mainly for large scale electricity or dedicated biomass plant. Under one scenario considered by BERR, the market would continue to operate in a similar fashion, with some expansion of output and use of different sources as demand rose. Under this scenario, imports would be limited due to supply constraints in other countries or sustainability issues. Another scenario considered by BERR is that biomass products could become internationally traded, with the price set by international demand and supply conditions – where supply costs would reflect transport costs to the UK. Under this scenario, supply to any one (relatively small) country would be constrained only by the international price, and all countries would be price-takers. These two scenarios could lead to very different modelling results.

BERR intended the assumptions underlying the biomass supply curve that they provided to us are to be between these two scenarios. Initially the market is dominated by local supply conditions, but over time international trade expands. By 2020 the prices reflect assumptions that the market is more international, although the assumptions for 2020 are not intended to reflect a perfectly liquid and competitive global commodity market. BERR considered a range of costs for each type of biomass product to allow for uncertainty. Because the heat and electricity sectors' contribution to the RES target were modelled separately, BERR split the predicted quantity of available biomass between the two sectors to avoid double-counting. (BERR determined the allocation of the biomass resource to the two sectors with reference to previous modelling work by Pöyry (2008), selecting what that study suggested would be the most cost-effective split between the two sectors.) The volume of biomass available in our modelling of the heat sector was restricted by this "rationing" assumption.

### 2.1.5. Potential by counterfactual fuel use

In addition to the segmentation into renewable heat technologies and end-user sectors, the modelling requires information about the heating technology that would be displaced by renewable heat. The starting point used by Enviros to estimate the split between counterfactual fuels is the current patterns of energy consumption for heating reported in DUKES published statistics. This default split has been modified as part of Enviros analysis of demand-side barriers to account for reasons that the potential for renewable heat may deviate from this default division of potential. The modifications fall in two main categories. First, Enviros notes that obstacles to the use of biomass in the domestic sector are significantly smaller for premises in the non net-bound customer segment (which already has a need for bulk storage of fuels and are more likely to have the space required for domestic biomass heating) than they are for customers on the gas grid. The potential for biomass use in the domestic sector therefore is concentrated in the non net-bound segment.

Second, some of the theoretical potential to replace electric heating with renewables that is implied by the DUKES default split has been reassigned to other fuels. The rationale for this adjustment is that electric heating is likely to be used in specialised applications that may not be easily substituted by these renewable heat technologies (e.g., flash process heating). More generally, electric heating typically is significantly more expensive than direct-fired heating using fossil fuels, and some of the current significant share of electric heating therefore is likely to correspond to circumstances where various barriers prevent the easy application of other heating options, including renewable heat. While Enviros has not investigated this in detail, as a conservative assumption the potential to replace electric heating therefore has been reassigned to the replacement other fuels in some cases. Specifically, this has been done for biomass in the industrial and commercial sectors, as well as for biogas in the domestic and industrial sectors. However, Enviros has indicated that without more in-depth analysis and data to understand the current pattern of electric heating there is no *a priori* reason to assume that at least some of the electric heating in other sectors / for other technologies could not be replaced. Except for the modification mentioned, the share of potential for renewable heat represented by replacement electric heating therefore corresponds to the share in current consumption as indicated by DUKES data.

Enviros has carried out sense checks to ensure that the uptake rates of renewable heating technologies implied by the above approach are plausible given expected heating equipment replacement rates and developments of heating demand in the sectors.

## 2.2. Technology Cost

### 2.2.1. Cost of Renewable Heat Technologies

Data on the cost of renewable heat have been collected from a range of sources on the cost of each renewable heat technology in each sector, including Pöyry (2008), Element Energy (2005), Ernst & Young (2007), and EEE (2005). The numbers used in the modelling have been sense-checked by Enviros, which have led to some significant revisions of the numbers in Pöyry (2008). This includes revisions to reflect the higher resolution of the model in differentiating between sectors and customer segments.

Fixed costs comprise capital expenditure, including installation cost, and fixed operating expenditure, including maintenance and renewal costs. We have converted these to levelised costs on a per-MWh basis for each sector and technology band based on the lifetime of the relevant equipment and using sector-specific discount rates. Variable costs are fuel or electricity costs, which are calculated from assumptions about load factors, equipment efficiency, and assumptions about input prices. Fuel and electricity prices are discussed further in section 2.3.

We also allow for reductions in fixed costs over time. The starting point for this is the specification in Pöyry (2008), consisting of a combination of “learning rates” and linear reductions in cost. These numbers, too, have been sense-checked and in some cases modified by Enviros.

### 2.2.2. Cost of counterfactuals

As noted, to calculate the resource cost of renewable heat we compare the levelised cost of renewable heat technologies with the relevant counterfactual heating technology. The three counterfactual technologies used are electric heating, oil-fired boilers, and gas-fired boilers. These in turn vary across different sectors, resulting in different numbers for the size, lifetime, efficiency, capital expenditure, and operating expenditure. Enviros has provided assumptions for each of these aspects for the modelling, based on its own experience and published data.

## 2.3. Other Input Costs and Relevant Parameters

### 2.3.1. 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 2010-2020 have been provided by BERR based on recent Updated Energy Projections (UEP) model runs and other modelling. The projections include four scenarios—referred to as low, central, high, and “high-high” scenarios—for petroleum, natural gas, coal, and electricity.

The prices used in the model differ for the domestic, commercial (large and small), and industrial sectors, as well as for the electricity, natural gas, and non net-bound counterfactual fuel segments. 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.

The variable cost of technologies differs by year to reflect future fuel prices at the point of investment. We assume that investors make decisions on the basis of future input prices, which are discounted using sector-specific discount rates and the lifetime of the relevant equipment (typically 15 years). This calculation requires price projections beyond 2020. In the absence of projections for this period, we have assumed that long-term fuel prices stay constant at 2020 levels in real terms.

Details of the fuel price assumptions for each of the low, central, high, and high-high scenarios and by end-user sector were provided to us by BERR.

### 2.3.2. $CO_2$ and certificate 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 BERR, and are constant for the modelling period. Coverage of the EU ETS is assumed to extend to the industrial sector, as the closest approximation to actual coverage feasible given the resolution of the model. This may overestimate coverage by industrial heat use, some of which is not in the EU ETS; on the other hand, it does not account for some of the public and commercial sector heat use that is covered.

$CO_2$ allowance price assumptions were provided by BERR.

### 2.3.3. Biomass prices

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 (e.g., in agriculture or 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 also linked to the price of counterfactual fuels.

The prices we use in the modelling are broadly based on a combination of assumptions in Pöyry (2008), data on UK biomass resources provided by BERR, and data on current prices collated by Enviros. We do not have biomass price projections until 2020 and have not undertaken an analysis of biomass markets, nor has Enviros. We follow guidance from BERR and assume a central wholesale price of £5.5 / GJ (£19.8 / MWh), with low and high scenarios 20-30 percent higher and lower.[3] Based on input from BERR, and in the absence of detailed price projections, we assume constant prices in real terms for the relevant modelling horizon.[4]

Biomass prices are likely to vary between different end-user segments. In particular, the domestic sector and small commercial sectors are likely to pay higher prices, both because of the need for highly standardised and non-bulky products (e.g., pellets) and because smaller volumes incur higher delivery costs. Information provided to us by Enviros suggests that current prices are around three times higher in the domestic sector than for bulk delivery in the non-domestic sector. This gap may close if domestic UK supply to the residential sector were developed. In the absence of further analysis, we assume that prices paid by the small

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[3] These assumptions are used for consistency with other policy assessments carried out for BERR and we understand that they have been derived from detailed analyses of the future potential supply curve for biomass fuels in the UK. We have not attempted an analysis of the future availability or likely price of biofuels in the UK but note that current prices of biomass in more developed markets can be significantly higher than the prices in the central scenario used here.

[4] There is considerable uncertainty about the potential developments in biomass markets in response to increased demand for renewable energy to meet 2020 targets throughout Europe. Possibilities include both increasing prices as suitable supply becomes scarcer, and increasing correlation with other fuel prices if biofuels increasingly become substitutes for fossil fuels. 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.

commercial and domestic sectors are £2/GJ (£7.2/MWh) higher than those in wholesale markets. The large commercial and industrial sectors are assumed to pay the wholesale price.

### 2.3.4. Discount rates and cost of capital

Discount rates are used in the model to calculate levelised costs of the different technologies, including levelised upfront costs and the weight put on future variable costs when switching to a technology. Capital costs also are incurred by parties investing in the renewable heat supply chain, and we use the non-domestic discount rate to levelise the supply chain costs of overcoming barriers, as calculated by Enviros. Finally, we also use discount rate to model the trade-off between up-front costs to overcome demand-side barriers and subsequent benefits.

It is a common observation that the discount rates *implied* by economic decisions about energy consumption often are very high. For example, several econometric studies have found implied discount rates in excess of 100 percent for a wide range of appliances and situations. Similarly, it is a common observation that service-sector companies often use rough payback criteria of 1-3 years for energy consumption decisions, implying discount rates of 33-100 percent. Such discount rates pose a difficulty for analysis of social costs, as they exceed the cost of capital that it can reasonably be expected that households or companies incur. One approach to resolving this apparent discrepancy is to assume that the high rates arise because not all costs are captured, and that there are (large) “hidden and missing” costs in addition to the observed capital costs. An alternative approach is to assume that the high rates arise because “behavioural” considerations or market failures give rise to the apparently high discount rates. There is evidence that individuals’ decision-making over time is not successfully captured through a discounting framework (Frederick et al., 2002). To this can be added issues such as split incentives within organisations, or various considerations arising from transaction costs economics, that serve to inflate the implied discount rates above the cost of capital (Sorrel et al., 2006).

For transparency, we do not use the high rates derived from empirical studies or simple payback rules, but use discount rates intended only to reflect capital costs and any risk premium associated with uncertain future revenues or utility. This helps clarify the elements of the decision-making that truly have a time dimension, and allows for the investigation of potential impact of policies that may raise the cost of capital. Hidden and missing costs are accounted for instead through explicit costs associated with demand-side “barriers” (discussed below).

We use 7 percent as the central (real) cost of capital for the household sector. This is intended to reflect real interest rates on types of financing likely to be used by households for decisions to purchase heating capital equipment. The rate is higher than the real return on savings, similar to interest rates on asset-backed borrowing, and lower than some forms of debt used by consumers (e.g., credit cards) but which are unlikely sources for purchases of heating capital equipment.[5] For the non-domestic sector the cost of capital can differ significantly between different sectors and industries, and the appropriate number depends on

[5] As an additional consideration, it is possible that households prepared to incur capital costs to use renewable heat have access to cheaper capital than does the average household.

where renewable heat would be deployed. We use a rate of 10 percent as an indicative average.[6]

To the extent the variability of support offered by the RHO leads to higher costs of capital and therefore higher private discount rates, the costs of the quantity-based policy will be higher than that of the fixed-price arrangements under RHI. However, it remains a somewhat open question to what extent uncertain support would in fact lead to higher implicit cost of capital to participants as assumed in this modelling scenario. As an alternative scenario, it is possible that administrative and institutional arrangements under the RHO – both the use of deeming and pre-contracting with obligated parties – would serve to shield consumers, heat producers, equipment installers, and fuel suppliers from much of the risk associated with variable certificate prices. We discuss these issues in the Phase I report of this project.

Nonetheless, to investigate the potential impact of this uncertainty on the modelling results we use discount rates in the RHO case that are 2 percentage points higher than the central case of 7 and 10 percent that is used to model the RHI. This is similar to the difference in discount rates used in some studies contrasting green certificate schemes and feed-in tariffs in the context of electricity (e.g., Ragwitz et al, 2007), although other studies suggest that the relevant difference could be smaller (e.g., Redpoint, 2008). While the 2 percentage-point difference is intended to capture the greater uncertainty faced by investments undertaken under RHO compared to the RHI we have not undertaken an analysis of the implications of the stochastic properties of potential certificate prices for the cost of capital. This aspect of the modelling therefore is best seen as an indicative scenario, and we use further sensitivity analysis (presented in section 3.5.1) to explore the implications of other discount rates for the results.

In the below discussion we refer to assumptions about discount rates by giving first the domestic then the non-domestic discount rate; i.e., discount rates of 7 / 10 correspond to a rate of 7 percent for the domestic sector and a 10 percent rate for the commercial and industrial sectors.

### 2.3.5. Costs of time

An important category of cost arising from any regulation or policy is the 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. This contains estimates of the value of time placed by individuals and businesses as revealed through the choice of means of transport. These are used to calculate the costs of complying with the administrative requirements of the RHO and RHI, and also have been used by Enviros to assess the cost of demand-side barriers.

#### 2.3.5.1. Domestic sector value of time

The TAG "non-work" estimate of the value of time is £5.6 per hour in 2007 real terms. This is an average across all modes of transport for non-work purposes but including travel to

[6] 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).

work. We use a higher number for our estimates, based on two considerations. First, the TAG guidance notes that significantly higher time values are implied for some activities; for example, walking to or waiting for transport has a time value 2.5 times as large as the basic estimate. It is unclear what value of time is placed on decisions about energy consumption, but circumstantial evidence suggests that it may be more similar to the higher than the lower TAG estimates.[7]

Second, other things being equal, the experience with the Energy Efficiency Commitment ("EEC") and Carbon Emissions Reduction Target ("CERT") indicates that there is s significant difference in uptake and the required level of subsidy depending on the income and other characteristics of the household. For example, households in the CERT "priority group" (comprising some 11 million out of the total 26 million households) require a 90 percent subsidy for the uptake of cavity wall insulation, whereas the non priority-group households require a subsidy of less than 50 percent (Defra, 2008). We expect that those installing renewable heat measures are likely to be higher-income, "able-to-pay" consumers. Their value of time therefore is likely to be higher, both because the opportunity cost of foregone earnings are higher, and because the amount of leisure time is likely to be smaller in this group (because it includes more individuals in full-time employment and fewer pensioners and part-time or unemployed individuals) and the marginal value placed on leisure therefore higher. As a rough judgement reflecting these considerations, we use the higher number of around 2.5 times the basic rate, resulting in an estimate of £15 per hour.

#### 2.3.5.2. Non-domestic value of time

The TAG "work" estimate of time is £27.5 per hour in 2007 real terms. This is based on data on gross wages and national insurance, pensions and other costs which vary with the number of hours worked. Like in the case of the domestic sector we use a larger number than the value in the TAG. This reflects the fact that the parties making decisions about energy (engineers, energy managers, and similar) are likely to have higher wages than the average transport user. Consistent with previous studies where time has been explicitly valued in the context of "hidden and missing costs" and policy evaluation we use a number of £70 per hour (Enviros, 2005; NERA-Enviros, 2006).

### 2.3.6. 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

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7 For example, it is difficult to reconcile the level of subsidy required to induce the uptake of energy efficiency measures under EEC / CERT with a low time value (see discussion in section 2.5). Similarly, the continued presence of unrealised gains from switching of energy supplier may suggest that switching costs, of which time costs are likely to be a significant component, may be higher than this.

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 CCGT plant will remain the marginal baseload entrant 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.

### 2.3.7. Social cost of carbon and discount rates

Present-value calculations of benefits and costs are calculated using the 3.5 percent social discount rate recommended by the Treasury Green Book. However, the private cost of capital is accounted for before such discounting, turning all capital costs into a stream of payments over time, which subsequently is discounted at the recommended social discount rate.

For the valuation of the social benefit of emissions reductions we use social cost of carbon numbers provided by BERR for emissions reductions outside the EU ETS. For emissions reductions by facilities assumed to be covered by the EU ETS we follow the current practice for appraisal within the Government Economic Service of using the price of EU ETS allowances to estimate social benefits.

## 2.4. Costs of Overcoming Supply-Side Barriers

As noted above, for each scenario for renewable heat potential Enviros has calculated the aggregate cost of overcoming supply-side barriers, by technology band and sector. These costs need to be reflected in the full cost curve for a more complete representation of the costs of renewable heat and uptake of technologies for a given policy and incentive provided.

Enviros has provided costs to overcome barriers on a per-year basis. However, many of the actions required to develop the supply chain constitute investment decisions, with initial costs (e.g., of training, construction of infrastructure, etc.) recouped through subsequent demand for the relevant services (e.g., installation, fuel supply, etc.). To reflect this, we convert the costs into levelised costs using the discount rate assumed for the commercial sector in the overall modelling. As discussed above, there may be reasons that the appropriate discount rate should vary between policies, and we reflect these considerations when considering investment in the supply chain.

We assume that the cost of developing the renewable heat supply chain will be recouped through charges to end-users of the associated renewable heat technology (but then offset by the relevant policy support). To calculate this impact, we assume the total cost of overcoming barriers results in an aggregate cost to the relevant end-users of the same magnitude. Concretely, we calculate the per-MWh cost of overcoming barriers associated with each scenario, and assume that this cost is incurred equally by all relevant end-users. We distinguish between the scenarios, as the per-MWh cost is not constant with the volume of supply, but for most sectors and technologies the incremental cost per unit of renewable heat increases with additional levels of supply. A different barrier cost therefore is associated with each "tranche" of renewable heat supply described above. [8]

## 2.5. Costs of Overcoming Demand-Side Barriers

In addition to the above supply-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.

As discussed in the Phase I report of this project, 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.

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, as described in section 2.3.4. 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 subsumes 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 either up-front costs or as future risks of non-performance.

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8 This is a simplifying assumption, as actual costs to end users would depend on the characteristics of the individual markets associated with each barrier (and thus may involve infra-marginal rents that result in higher cost to end-users). It also is likely to be relevant to distinguish between fixed and variable costs to end users. For example, the lack of trained engineers and installers would result in higher installation costs, which would lead to higher fixed costs of installation faced by renewable heat end-users. By contrast, a shortage of biomass supply infrastructure would lead to an increase the price of biomass to the point where it became economically viable to invest in new infrastructure, which corresponds to an increase in variable cost. It has not been possible to account for these considerations within the scope of this analysis.

A third approach, which we adopt here, is to explicitly account for demand-side barriers through bottom-up estimates of time input or risk premiums, which in turn can be entered into the model as fixed or ongoing costs associated with particular technologies. We rely for this on estimates of costs produced Enviros. 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. A final cost category estimated by Enviros is campaigns to raise awareness about renewables to encourage uptake. We have assumed that costs in this latter category would not be paid for by end-users of renewable heat. Further details of the costs to overcome demand-side barriers are found in Enviros (2008b).

We understand from Enviros that the accelerated depreciation of existing heating equipment need not be a significant cost under any of the scenarios estimated, but that the demand could be met largely from new build and end-of-life replacement. Enviros' estimates also do not include the estimate of any risk premiums associated with the use of renewable heat, such as the risk of disruption of activity, or of inadequate performance or delays to project delivery.

## 2.6. Monitoring and Metering Costs

We assume different approaches to monitoring of heat will be used in different market segments and for different technologies. We assume that heat consumption will be directly metered for all end-users where heat is provided through district heating, whether from biomass or biogas. We also assume that output from non-grid biomass and heat pumps in the large commercial and industrial sectors would be metered directly.

Of the remaining sectors, we assume that monitoring will take the form of input metering for non-grid biomass in the small commercial and domestic sectors. As discussed in Phase I, the absence of ongoing monitoring could lead to a risk of gaming or reversion to the use of fossil fuels. For the remaining technologies—heat pumps in the small commercial sector and solar thermal in all sectors—we model a "deeming" approach to estimating output.

Direct heat metering would entail costs of metering equipment, including metering equipment cost, billing and administration, and maintenance and replacement costs. We calculated the implied levelised cost per MWh using sector-specific discount rates and the relevant equipment lifetime. With the exception of domestic sector district heating, the cost of direct metering is insignificant for the instances where direct metering is used. Input metering leads to small administrative costs of sending proof of input use (likely fuel bills) to the relevant scheme regulator. Finally, in the case of deeming no monitoring costs arise except for the upfront costs of registering the installation of the relevant equipment; however, deeming has other consequences for the efficiency of the policy, which we discuss in the next section.

## 2.7. Other Administrative Costs

As discussed in the Phase I report, we consider that either an RHO or RHI system would function well only if it involved low administrative effort for heat market participants. In all cases, we assume that there is no legal requirement for consumers to undertake administrative activity, but that requirements associated with certification, monitoring, reporting, and verification would be undertaken by installers of equipment, fuel suppliers (both of whom may act as "representative agents"), and / or the fossil fuel suppliers or other parties on whom an obligation is imposed under the policy.

The starting point for our cost estimates is therefore the assumption that costs will be borne by suppliers (of renewable heat or conventional energy sources). As an initial guide, we have referred to the estimates of "indirect costs" incurred by energy suppliers that have been developed by Defra in relation to the CERT (Defra 2008) – the administrative requirements of which are likely to be similar to those feasible under a renewable heat support policy. For larger customers, we have also drawn on estimates of administrative costs developed in conjunction with the analysis of the Carbon Reduction Commitment for large non-energy-intensive industry (NERA and Enviros 2006a).

We allow some administrative time for heat consumers in the large commercial and industrial sectors, who may wish to understand the context of the subsidy implicitly received, or any legal issues arising from indirectly availing themselves of support offered under the policy. (Most commercial and legal issues would already be accounted for under the terms of a conventional heat supply contract, and therefore would not be considered additional costs here.) Also, there may be a need to provide other parties with more detailed information for a verification "evidence pack", although we consider that most of this information is likely to be developed anyway as part of the appraisal of the project (time for which is allocated under the demand-side barrier cost, above). We allow for up to a day of time for very large projects in the large commercial / public and industry sectors.

Equipment installers or fuel (biomass) suppliers are likely to incur further costs in addition to those incurred by their customers. Upfront activities include understanding and keeping abreast of scheme rules as they apply to the relevant technology. There also is likely to be a need to submit various forms of information registering the installation of heating equipment or the supply of biomass fuel as necessary for certification. For larger projections, fossil fuel suppliers or other obligated parties also may demand additional information on project characteristics necessary to demonstrate that there will be a future revenue stream of certificates. The amount of time allowed for these and associated activities vary between less than an hour for the most standardised procedures (e.g., domestic solar thermal) to up to 1.5 days for the largest biomass developments.

Finally, the parties with an obligation under the policy are likely to incur some administrative cost when they process documentation received from equipment installers or fuel suppliers, and preparing evidence packs for the scheme regulator. We allow less than an hour for the smallest projects, but up to two days of work for very large projects where the parties with the obligation may take a more active role in negotiations.[9] Overall, we assume significant returns to scale in these activities.

As discussed above, it is uncertain how the policies would work in practice, and therefore also what administrative time requirements would arise under the respective policy designs. We investigate the impact of this uncertainty through sensitivity analysis, the results of which are presented in section 3.5.3.1.

## 2.8. Approach to Modelling of "Deeming"

As noted in the Phase I report, it is likely that an RHO or RHI would need to make use of a "deeming" approach to heat monitoring, whereby heat output is estimates through standardised protocols based on easily observable characteristics of heat projects, rather than through direct or indirect metering of heat output. Potential advantages of deeming include substantially reduced monitoring costs, and also the ability to provide certificates upfront for the lifetime of a measure to help overcome high initial capital costs. However, deeming also has drawbacks, as it provides a less precise correspondence between the number of certificates issued and the amount of renewable heat generated. We discuss below the impact on policies to promote renewable heat, and the approach to representing this in the modelling.

### 2.8.1. Impact on functioning of policy

The use of deeming leads to a situation where the scheme regulator uses a standardised methodology to attribute the same amount of output to a group of potential projects that in fact have different output levels. These discrepancies between deemed and actual output may arise for a number of reasons, such as differences in heat demand and utilisation of equipment (e.g., because of differing energy efficiency of premises), differences in local physical circumstances that influence the effectiveness of the technology (e.g., the suitability for solar heating or heat pumps), or different load patterns from the deeming reference group.

This situation can be understood in part as a problem of asymmetric information, where the scheme regulator can only imperfectly observe information that is available to the heat end-user and producer. This can be basic information, such as total heat load (e.g., size of gas bill), and need not necessarily imply a sophisticated consumer. From the point of view of the consumer, the deemed amount manifests itself as a fixed level of subsidy, and the consumer is then faced with appraising whether this is sufficient to cover the cost associated with the heat technology and usage patterns they expect from the equipment.

As deeming can result in both over- and under-estimates of actual heat output, one consequence of deeming is likely to be "adverse selection" of projects. Projects where actual heat output is significantly higher than the deemed level may not be undertaken, even if they would be cost-effective if compensated at the actual (rather than deemed) level of output. This means that, for a given level of per-unit subsidy, some cost-effective potential is

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[9] For comparison, information on "indirect costs" (including administrative, marketing, and search costs) in the CERT illustrative mix (Defra, 2008) indicates that total indirect costs may be around £70 for measures with a cost of £400. This corresponds to around an hour's time for suppliers at the time costs used in our modelling.

foregone. Similarly, projects where the level of output is overestimated may lead to projects being undertaken even though they would not be cost-effective if subsidised at the level of actual (rather than overestimated, deemed) output. The overall effect of these mechanisms is to reduce the cost-effectiveness of the policy. Moreover, adverse selection also would lead to a higher level of subsidy over and above cost (infra-marginal rents) for a given level of output. This ensues because projects with large rents are undertaken in greater proportion than ones with small rents.

A second potential impact is that the lack of continued monitoring leads to a risk that the end-user / heat producer receives an upfront payment (or continues to receive ongoing subsidy) even where no renewable heat is produced (moral hazard). The most prominent example of this could be biomass boilers, which in some cases could be either disused or converted for use of fossil fuels. For this reason, we assume that all biomass use will include at least some element of monitoring either output or inputs. The risk would be smaller where variable costs are relatively small (such as solar thermal or heat pumps).

### 2.8.2. Model implementation of deeming uncertainty

We model deeming by assuming that the extent of over/underestimation has a probability distribution around the true level of output.[10] For a given level of support, we then calculate the proportion of each category of renewable heat projects that are undertaken, based on the difference between the level of subsidy and the cost of the project, and the probability of over/underestimating the output level given the probability distribution for the error of measurement implied by the deeming. We then calculate the implicit support offered to the project potential that is undertaken, based on the ***actual*** level of output.[11]

We do not model the possibility that failure to monitor ongoing activity will lead to a problem of reversion to the use of fossil fuel-fired heat. The main reason for this is that we assume that metering will be used either as an alternative or a supplement to deeming in most cases where reversion could be a realistic prospect, notably for biomass heat.

Appendix D shows the technologies and sectors for which we assume that deeming applies under different scenarios.

## 2.9. Summary: Policy Features and Differences

In summary, for the purposes of modelling the quantitative impacts of the two policies, we assume very similar policy implementations. This reflects our assessment, set out in our Phase I report, that in practice the RHO and RHI would need to have many features in common to be effective – reflecting the nature of the heat markets and of the specific technologies likely to be required to meet the government's renewable targets.

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[10] Concretely, we assume that the extent of deviation from the true level of output follows a normal distribution, where the standard deviation is a modelling parameter. For the analysis here, we assume a standard deviation of one-quarter of the mean, implying a two percent chance of under-estimating (or over-estimating) output by half.

[11] Technically, this is carried out by integrating the product of the probability distribution and the level of support, to arrive at the total payment necessary to achieve a given proportion of the total output.

For both policies, we assume that the full levelised cost of the marginal technology is fully compensated through the support mechanism. We do not make any explicit assumptions about the timing of this support, only that it is sufficient to compensate the marginal technology. We assume no systematic differences between the RHI and the RHO apart from the discount rate. As discussed in the Phase I report, there may be differences between the RHO and RHI with regard to the need for or desirability of deeming, and in terms of the extent to which they are actually able to incentivise uptake and overcome the barriers identified by Enviros (2008a). We do not attempt to reflect any of these potential differences in our modelling.

Even so, there are several ways in which the outcome of RHO and RHI may differ that we do try to capture in our modelling. We outline our approach to reflecting these potential differences below.

First, the more uncertain level of future support under the RHO can cause market participants to require higher returns when undertaking the various investment decisions necessary to deploy renewable heat under the policy. Table 2.2 summarises the impact of this consideration on different elements of the cost of policies to support renewable heat. We reflect the influence of these considerations by using a higher opportunity cost of capital rate to calculate levelised costs under the RHO than under the RHI. This is intended to capture the risk premium associated with the policy and results in higher costs.

**Table 2.2**
**Impact of uncertainty about future support level on cost**

| Cost element | Impact of uncertainty about future support level |
|---|---|
| Fixed capex and opex of heating equipment | Reluctance to incur upfront costs with uncertain prospect of future compensation from certificates. |
| Variable cost of heat generation | Shorter implied payback period leads to greater implied weight on near-term prices. |
| Supply-side barriers | Less investment in supply chain with uncertain future return, and resulting higher barrier costs for given level of output. |
| Administrative cost | Lower willingness to incur upfront administrative cost with uncertain future revenue. |
| Demand-side barriers | Greater weight attached to initial time requirements, inconvenience, and other barriers |
| Metering costs | Upfront costs given greater weight with uncertain future payback. |

Second, although our default policy design assumes that some deeming would be used under both the RHO and RHI, it may not be necessary to use deeming to the same extent under the RHO. (As discussed in the Phase I report, fossil fuel suppliers or other parties with an obligation may simply provide up-front payments to customers or renewable heat providers, even if they do not receive certificates in advance.) This could help eliminate some of the adverse impact of deeming. We estimate the potential benefits this might provide by modelling a scenario where deeming only applies to solar thermal technologies (where input metering is not possible and output metering is likely to be prohibitively expensive). The results of this sensitivity scenario are discussed in section 3.5.3.3.

Third, a major difference between the two policies is the impact of uncertainty associated with fixing prices vs. fixing quantities. For a fixed price (or level of renewable support), the quantity of renewable heat and $CO_2$ emissions avoided depend on the cost of renewable heat compared to other technologies, which in turn depends on the development of capex costs, fuel prices, and other factors. Conversely, for a given quantity, the total subsidy, resource cost, and infra-marginal rents vary with the various factors that influence costs. We model this through scenario analysis, as described below.

Fourth, it is possible that the policies would have different administrative costs, and we therefore model scenarios with different levels of administrative cost.

# 3. Results

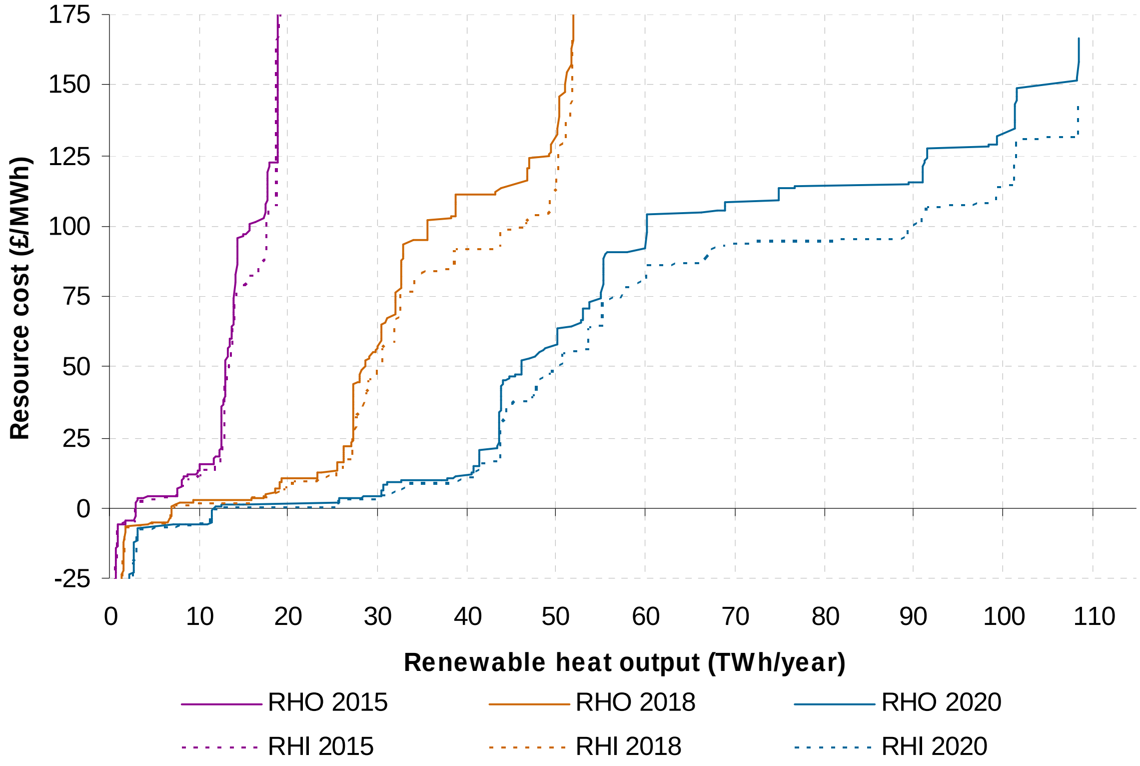
This section presents the results of the modelling detailed in the previous section. The first subsection illustrates the data in the previous section in the format of cost curves and discusses some of the key features of the potential for renewable heat supply in the UK. The subsequent subsections presents more detailed headline results of the modelling, including cost and composition of renewable heat output for the RHO and RHI policies. The last subsection shows the result of sensitivity analysis of key input parameters and modelling assumptions.

## 3.1. Cost Curves for Renewable Heat

Figure 3.1 shows the cost curves calculated for RHO and RHI for three different years: 2015, 2018 and 2020. The horizontal axis of the figure indicates total ***additional*** output of renewable heat per year from all technologies and sectors, 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. The resource cost reflects the costs of both renewable and conventional heat technologies, and also the costs associated with administration, metering and monitoring, supply-side barriers, and demand-side barriers.

The maximum additional amount of renewable heat that could be achieved by 2020 is 108 TWh per year. At this level of output, the most expensive renewable heat technologies would cost in excess of £150 per MWh more than conventional heating technologies. The increase in potential between years (horizontal extent between the curves) reflects the growth rates used by Enviros in the projections of the renewable heat scenarios. As Enviros (2008a) notes, the targets indicated by BERR for 2020 are very ambitious. One corollary of the assumption of exponential growth is that a significant proportion of the assumed 2020 potential becomes available only towards the end of the period; for example, around half of the total potential becomes available in the years 2018-20. The figure shows that the RHI is able to achieve a higher level of output for a given level of subsidy. This is due to our assumption that private discount rates under the RHI would be lower than those under the RHO, as discussed in section 2.3.4.

**Figure 3.1**
**RHO and RHI Cost Curves for Renewable Heat in 2015, 2018 and 2020**




***Note**: The private discount rates used for the RHO are 9 percent for the domestic sector and 12 percent for the non-domestic sectors. For the RHI, the corresponding rates are 7 and 10 percent.*

In earlier years, the data show costs increasing quickly. However, the cost curve flattens out significantly over time, and by 2020 large increases in output can be achieved at relatively modest increases in marginal cost (e.g., the segment of 60-90 TWh in 2020). However, the output potential shown for 2020 is dependent on achieving the high rates of growth set out in Enviros's underlying projections.

One notable feature of these cost curves is the suggestion that a proportion of the new renewable heat potential (around 10 TWh by 2020) could be available at no additional or resource cost (indeed, the figures imply cost savings). These "negative costs" of course are dependent on the technology, fuel price, and other assumptions underlying the analysis. As noted above, the data include the cost of overcoming demand-side and supply-side barriers to renewable heat, and are intended to reflect the full cost of using renewable heat. One interpretation of these data therefore is that the use of renewable heat may increase even without subsidy. One factor that may explain this result is that the price of $CO_2$ emissions allowances under the EU Emissions Trading Scheme is expected to be higher than it has been to date. This would increase the cost of conventional fossil fuel and electric heating for covered installations, and therefore promote the adoption of renewable heat technologies. Another factor contributing to the greater attractiveness of renewable heat is the assumption that the cost of renewable heat technologies declines in the period to 2020.

Despite these contributing factors, we believe there are a number of reasons to treat the negative cost results with a degree of caution, and not to assume that they imply increased use of renewable heat without further policy intervention. The first reason is that the aggregate cost of overcoming barriers, which is reflected in the per-MWh cost of the cost curves, has been estimated in the context of scenarios where widespread deployment of renewable heat is achieved. It may cost more to overcome these barriers (e.g., to establish reliable supply chains) without the large-scale use of renewable heat technologies implied by these scenarios.

Second, the large majority of the negative-cost potential consists of the replacement of electricity heating by biomass heating. Aggregate data on heat use suggests that a significant proportion of current heat supply in the commercial and industrial sectors in particular is derived from electric energy, even though this typically would be expected to be significantly more expensive than heating technologies relying directly on fossil fuels. It is possible that this heat consumption could be converted to alternative energy sources – including renewable heat. However, as noted in section 2.1.5, it also is possible that the current use of electric heating reflects specific constraints or barriers that make alternative heating technologies unsuitable or expensive, and that switching (either to renewable heat or to other technologies) would incur "hidden and missing" costs which are not represented in the cost curves. Further research therefore may identify additional barriers specific to such switching that would reduce the amount of negative-cost potential that currently is indicated by the cost curve.

Additional renewable cost curves showing the technology and sector classifications for different segments are presented in Appendix A.

### 3.1.1. Impact of fuel price and barrier cost assumptions on cost curves

The net resource cost curves presented above are specific not only to a given year, but also to other input assumptions. Figure 3.2 indicates the impact of different fossil fuel / conventional energy prices on the 2020 cost curve.[12] The figure shows that the impact of fuel price assumptions is significant. For example, the marginal cost of measures necessary to achieve 60 TWh of output may is £30 more per MWh in the "low" fuel price scenario than in the "high-high" scenario. In addition to the effect shown here, changing fuel prices may also affect the composition of renewable heat technologies used to meet a given target, as the relative ordering of different options depends on both absolute and relative fossil fuel prices.

The "negative-cost" element of the cost curve increases significantly with higher fuel prices. The caveats discussed above apply to much of this negative-cost potential. Nonetheless, the data indicate that significant renewable heat capacity – including switching from fuels other than electricity – may become economically viable if fossil fuel prices rise sufficiently. The cost curve indicates that some additional 30 TWh of output per year could be viable in 2020 in the "high-high" scenario, compared to the "central" scenario – again, assuming that the various efforts to overcome existing demand- and supply-side barriers were undertaken.

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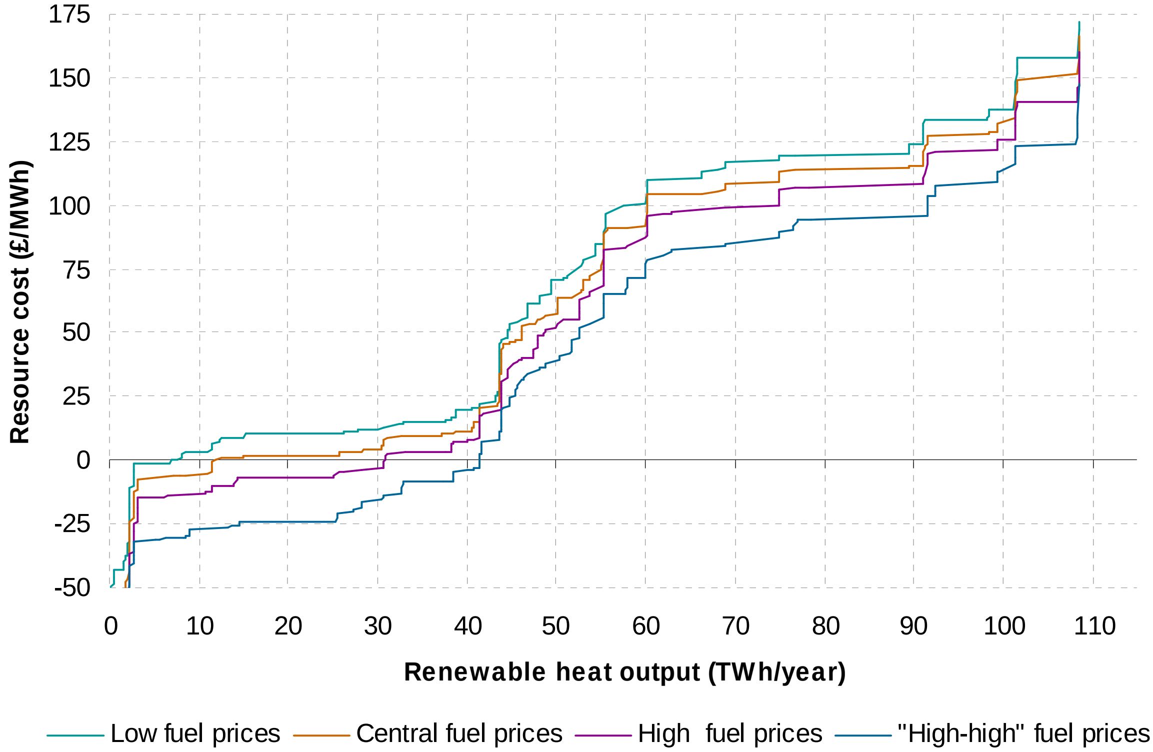
12 All of the supply curves shown in Figure 3.2 assume a private discount rate of 9 / 12 percent, which is the rate assumed for the RHO. The absolute levels of the curves would change if we used rates of 7 / 10 percent (the one that we have assumed for the RHI), but the relative position of the curves under different fuel price assumptions would not be materially different.

**Figure 3.2**
**2020 Cost Curves under Different Fuel Price Assumptions**

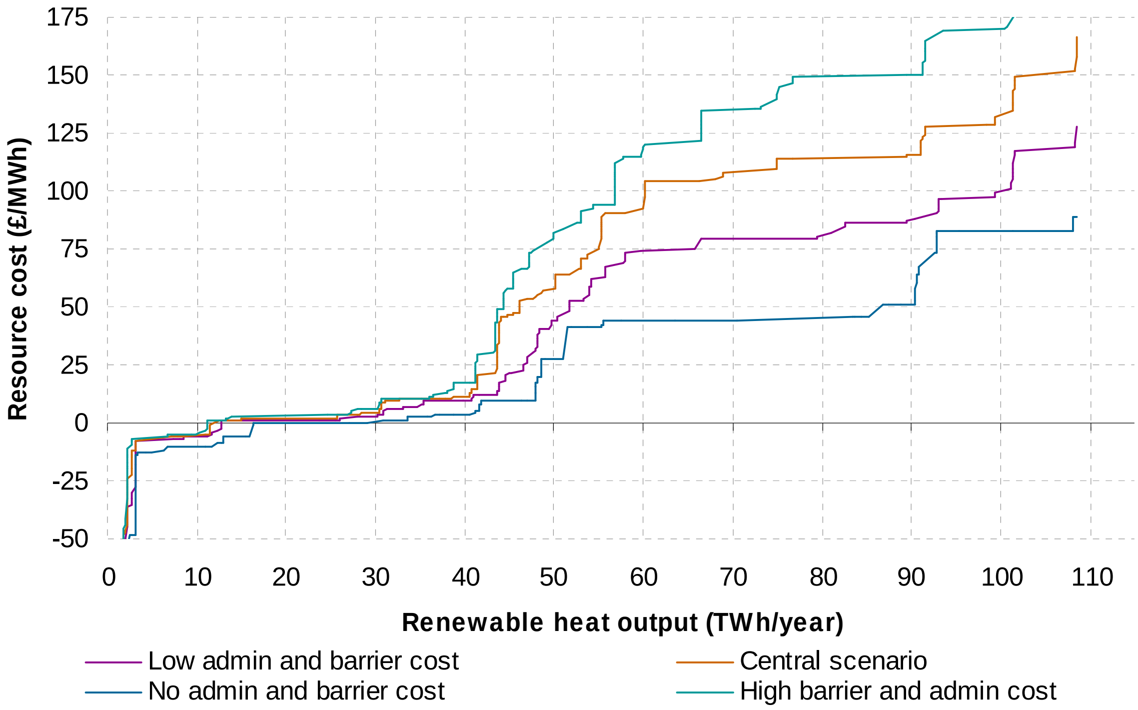



***Note**: The figure shows cost curves for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively (the default RHO scenario). Results differ only slightly with lower discount rates of 7 and 10 percent (the default RHI scenario).*

The next figure (Figure 3.3) illustrates the impact on the 2020 cost curve of different assumptions about administrative and barrier costs.[13] These costs include a wide range of different cost categories – described in sections 2.4 to 2.8 above – from the cost of new infrastructure to individuals' time cost.

13 Again, for the purpose of illustration, we show the cost curves corresponding to a private discount rates of 9/12 percent (domestic / non-domestic), the same ones we used in our central scenario of the RHO.

**Figure 3.3**
**2020 Cost Curves with Different Administrative and Barrier Costs**




***Note**: The figure shows cost curves for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively (the default RHO scenario). Results differ only slightly with lower discount rates of 7 and 10 percent (the default RHI scenario).*

The lowest of the four curves shows the net resource costs assuming no policy and barrier costs. The remaining three show the central scenario as well as costs 50 percent lower and 50 percent higher than the central case. For a significant proportion of the potential more than half of the total resource cost is associated with administration and the need to overcome barriers to supply and demand. Failure to take these costs into account therefore could result in a significant underestimate of the true resource costs of renewable heat.

Both policy (administrative) and barrier costs per MWh vary significantly between technologies. (This is reflected in the fact that the shape of the curve without administrative and barriers costs is different from the shape of the curves that include these costs.) Many aspects of policy and barrier costs are fixed and are incurred regardless of the technology or installation size, so small installations typically have higher costs on a per-MWh basis. Also, biomass generally has lower policy and barrier costs than does biogas (which faces significant supply-side barriers) or heat pumps and solar heat (which generally are relatively small in scale). The figure also shows that the negative- and low-cost technologies are attractive in part because they have lower policy and barrier costs than the more costly technologies.

As noted above, the policy and barrier costs have been built up through analysis on a sector- and technology basis. However, the estimates are highly uncertain. The projections underlying the barrier cost calculations imply a very rapid expansion in the use of renewable heat, and there is little current experience on which to draw for estimates of the cost of achieving these very high implied take-up rates and diffusion for renewable heat technologies in the UK.

### 3.1.2. Implications for policy design and objectives

The above figures illustrate that the potential for renewable heat available at a given level of subsidy varies significantly by year, as well as with input assumptions such as fuel prices and policy and barrier costs. These assumptions have implications for the selection between the policy approaches to supporting renewable heat. With a steep cost curve, even small deviations from a fixed target under the RHO could lead to large changes in the cost of certificates. At these levels, regulation by setting a fixed quantity therefore is likely to risk high (or low) costs. Conversely, with a flat cost curve, large differences in quantity could result from slight differences in (or uncertainties about) fixed levels of support under the RHI – with a risk that output targets could be missed. Adding to the uncertainty here, however, is the dynamic uncertainty associated with the roll-out of any policy. The rapid change in the shape of the cost curves from year to year – and thus in *both* the output that could be expected from a given level of subsidy, ***and*** the cost associated with a given fixed target – means that applying these considerations to practical policy making is likely to be difficult. We investigate these issues further in section 3.5.2.

Another important aspect of the cost curves is that the marginal cost of renewable heat varies very significantly across a number of dimensions: between sectors, between the conventional heating technologies displaced, and between technologies. The projections provided by Enviros indicate that it may be necessary to use relatively expensive renewable heat options in order to achieve the ambitious targets for renewable heat output envisaged by Government by 2020. As discussed above, however, some potential renewable heat projects appear to be on the verge of commercial viability even without additional support. If a single level of subsidy were provided on a per-MWh basis to all sources of renewable heat, the cheaper, “infra-marginal” technologies therefore could earn significant rents, i.e., payments over and above their resource cost. We return to this issue in greater detail in section 3.4

## 3.2. Headline Modelling Results

The headline results (shown in real terms using 2008 prices) for the three target levels of renewable heat and for the two policy categories (RHO and RHI) are shown in Table 3.1. The certificate price required to reach an RHO quota of 42 TWh (Scenario 1) is £12 per MWh. As noted above, the cost curve for renewable heat is relatively steep, and the required subsidy therefore rises sharply to £89 and £113 per MWh in Scenarios 2 and 3, respectively. The lower discount rate used to model the RHI leads to lower costs for the same levels of output. The subsidy is £9 per MWh in Scenario 1, increasing to £73 per MWh and £95 per MWh in Scenarios 2 and 3.

The total subsidy payments associated with these per-unit costs increase correspondingly, from £0.4bn per year in Scenario 1 to £5.6bn and £9.9bn per year, respectively under the RHO. Results for the RHI are lower by 15-20 percent in all cases, reaching £4.6bn in Scenario 2 and £8.3bn of total subsidy in Scenario 3. As discussed in section 2.3.4, these differences between the RHO and the RHI are entirely due to different assumptions about the appropriate private discount rate to use to assess investor behaviour under each policy.

Resource cost are just under zero in Scenario 1, reflecting the availability of low- or negative-cost measures at low output levels. However, the impact of "negative-cost" measures on the overall results is small at higher output levels, and net resource costs under RHO / RHI are £1.3bn / £1.0bn in Scenario 2 and £3.9bn / £3.1bn in Scenario 3, respectively.[14] There thus is a large disparity between resource cost and subsidy levels, and the difference is the amount of "rents". These rents represent transfers from those making payments for certificates or incentives (heat customers and potentially also suppliers and owners of energy companies) to beneficiaries of the policy undertaking renewable heat projects. For both policies, rents thus amount to some 75 percent of the subsidy payments in Scenario 2, and just over 60 percent in Scenario 3. Rents are as high as £5-6bn in Scenario 3, depending on the policy. We discuss potential mechanisms for limiting rents, and their implications for the results, in section 3.4.

**Table 3.1**
**Modelling Headline Results for 2020**

| | | RHO | | | RHI | | |
|---|---|---|---|---|---|---|---|
| **Variable** | **Units** | **Scn 1** | **Scn 2** | **Scn 3** | **Scn 1** | **Scn 2** | **Scn 3** |
| Renewable heat output | TWh | 42 | 67 | 91 | 42 | 67 | 90 |
| Resource cost | £bn | -0.1 | 1.3 | 3.9 | -0.1 | 1.0 | 3.1 |
| *Technology cost* | *£bn* | *-0.2* | *0.4* | *1.9* | *-0.2* | *0.2* | *1.3* |
| *Supply-side barrier cost* | *£bn* | *0.0* | *0.5* | *1.2* | *0.0* | *0.4* | *1.0* |
| *Demand-side barrier cost* | *£bn* | *0.1* | *0.4* | *0.7* | *0.1* | *0.3* | *0.6* |
| *Administrative costs* | *£bn* | *0.0* | *0.1* | *0.2* | *0.0* | *0.1* | *0.2* |
| Subsidy | £bn | 0.4 | 5.6 | 9.9 | 0.3 | 4.6 | 8.3 |
| Rents | £bn | 0.5 | 4.3 | 6.0 | 0.5 | 3.6 | 5.2 |
| Certificate price or incentive | £/MWh | 12 | 89 | 113 | 9 | 73 | 95 |
| Resource cost per MWh | £/MWh | -2 | 22 | 47 | -4 | 17 | 37 |
| $CO_2$ savings | $MtCO_2$ | 11 | 17 | 24 | 11 | 17 | 24 |
| *Outside EU ETS* | *$MtCO_2$* | *8* | *11* | *17* | *7* | *11* | *17* |
| *Within EU ETS* | *$MtCO_2$* | *3* | *6* | *7* | *3* | *6* | *7* |
| Number of installations | million | 0.4 | 4.2 | 8.9 | 0.4 | 4.3 | 9.3 |

***Note**: The private discount rates used for the RHO are 9 percent for the domestic sector and 12 percent for the non-domestic sectors. For the RHI, the corresponding rates are 7 and 10 percent. Values are expressed in real terms using 2008 prices; see footnote 14 for additional information.*

These modelling results (in particular, the differences between the RHO and the RHI) are highly sensitive to the private discount rate used to represent the opportunity cost of capital faced by investors. As noted in the foregoing discussion, it is uncertain how great any additional risk under the RHO would be, and which market participants would be required to accept this. We investigate the sensitivity of the results to other discount rate assumptions in section 3.5.1 below.

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[14] If these costs, which will be incurred in 2020 but which are expressed in real terms, were ***discounted*** to 2008 at the social time preference rate of 3.5 percent, the range of costs would be £0.7-0.9bn for Scenario 2 and £2.1-2.6bn for Scenario 3. As a rule, any of the monetary values presented in this report indicating costs for 2020 can be expressed in terms of their ***discounted*** present value (in 2008) by multiplying them by a discount factor of 0.662

The use of renewable heat reduces $CO_2$ emissions, amounting to emissions reductions of 11 $MtCO_2$ per year in Scenario 1, and rising to 17 and 24 Mt $CO_2$ per year in Scenarios 2 and 3. These include reductions inside and outside the EU ETS. The *average* resource cost per tonne of $CO_2$ abated is £78 / £60 (RHO / RHI) per $tCO_2$ in Scenario 2, rising to £165 / £131 per $tCO_2$ in Scenario 3.[15]

Finally, the number of renewable heat installations differs somewhat between RHO and RHI. This results because the different costs of capital in the two policy scenarios lead to a slightly different composition of renewable heat projects (across technologies and sectors). The larger number of installations in the RHI chiefly reflects the greater attractiveness of solar thermal, which has high upfront costs as a proportion of lifetime costs, and which also produces less output per installation than do the other renewable heat technologies. We discuss the composition of renewable heat output across sectors and technologies in more detail in the next section.

## 3.3. Detailed Modelling Results

In this section we present more detailed modelling results on the composition of renewable heat output and cost. Except where otherwise noted, we present results assuming private discount rates of 9 / 12 percent (for domestic / non-domestic sectors, respectively). We focus on Scenarios 2 and 3, corresponding to total renewable heat output of 67 and 90 TWh, because these are the ones that most consistent with the target levels identified by Government as being consistent with the UK's overall 2020 renewable energy target (BERR 2008d).

### 3.3.1. Composition of renewable heat output

Figure 3.4 shows the composition of *additional* renewable heat technologies for Scenario 2 and Scenario 3 (over and above the baseline level of 6 TWh / year). Biomass (the two left-most segments in the bars, representing "grid" and "non-grid" biomass installations) is the dominant technology, accounting for some 60 percent of output in Scenario 2 and 45 percent in Scenario 3. Biomass is followed by solar heat, biogas, and heat pumps.

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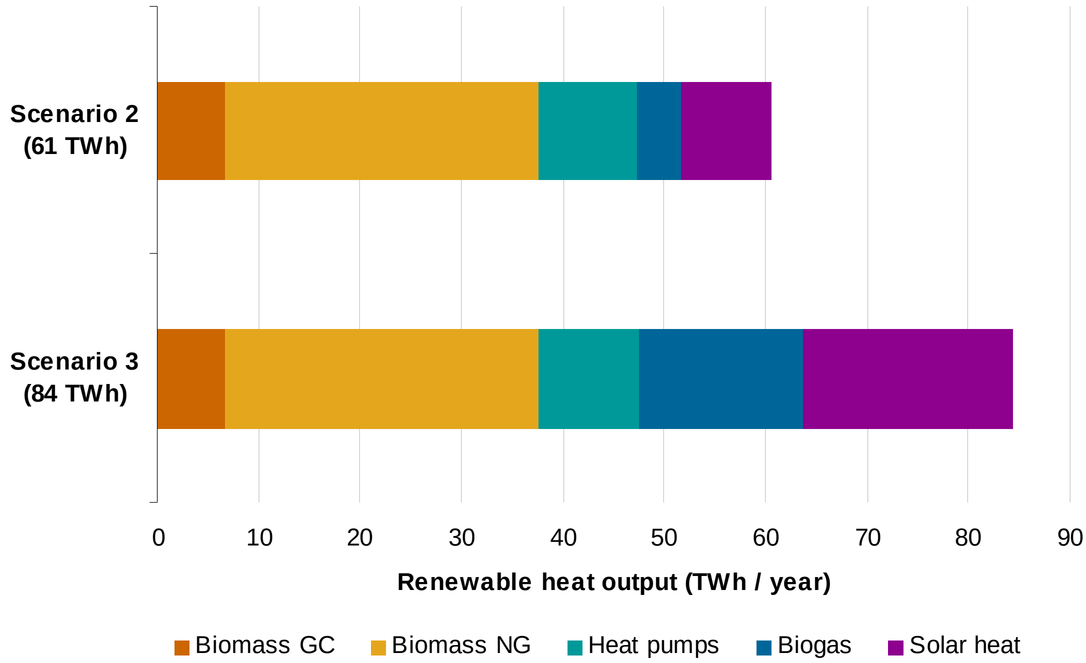
[15] The *marginal* cost of $CO_2$ abated as a result of the incremental unit of renewable heat supplied is not particularly meaningful in this case because of the different emissions intensities of the conventional heating source displaced. Also note that all reported resource costs account for the cost-*savings* associated with emissions reductions within the EU ETS – such reductions free up EU ETS Allowances for use elsewhere. Finally, note that the *subsidy payment* per $tCO_2$ reduction is far higher than the resource cost, rising to over £400 / $tCO_2$ in Scenario 3. This difference between resource cost and subsidy cost per $tCO_2$ is also a feature of policies like the CERT. In general, the level of the subsidy payment per tonne of emissions reduction should not be used to assess the cost-effectiveness or efficiency of a given abatement policy or measure.

**Figure 3.4**
**Composition of Additional Renewable Heat Technologies in 2020**




***Note**: The figure shows results for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively (the default RHO scenario). Results differ only slightly with lower discount rates of 7 and 10 percent (the default RHI scenario).*

One notable feature of these results is that the amount of biomass is the same in both scenarios, at just under 40 TWh per year. The constant level of biomass is due to a constraint on the amount of biomass assumed by BERR to be available for heat, as discussed in section 2.1.4. The certificate price / incentive payment in Scenario 2 is £89 / MWh, which is sufficient to support all of the available biomass. Increasing the subsidy to £113 / MWh in Scenario 3 therefore does not lead to an increase. We believe that increasing the support level for biomass heat would result in more biomass coming to market, whether from additional UK sources of biomass or through biomass imports (which are expected to be a major source of fuel in recently announced UK biomass power plants[16]). To the extent that BERR's assumption underestimates the amount of available biomass, the modelling results are likely to overestimate the cost of achieving higher output levels of renewable heat. This has important implications for some of our results, as we discuss below.

Figure 3.4 also shows that the amount of output from heat pumps does not increase between Scenarios 2 and 3. Again, this reflects the input assumptions provided to NERA, in this case by Enviros. Enviros's assessment of the maximum feasible output from heat pumps in 2020 is 10 TWh.[17] The cost data indicate that this technology option is relatively attractive

[16] For example, the recently announced Port Talbot and Stallingborough biomass–fired power stations both expect to rely on fuel imported from continental Europe and North America.

[17] 10 TWh is the amount of heat pump output in Enviros's Scenario 4, which is a projection of the maximum available potential for each renewable heat technology. As discussed in section 2.1.3, we have combined Enviros's scenarios 1-4 into a single heat supply curve with tranches corresponding to each scenario, accounting for the relevant costs of barriers to reach each scenario. Because heat pumps appear relatively cost-effective, the full potential for heat pumps

compared to other technologies and the full 10 TWh of heat pumps therefore contribute to meeting the 61 TWh target in Scenario 2. Because the total potential is deployed at this level, there is no increase in the results for Scenario 3. As with biomass, it seems plausible to believe that increasing the level of support available would spur the uptake of more heat pumps. However, there may also be significant barriers to the uptake of heat-pumps beyond this level because of physical constraints on their applicability.

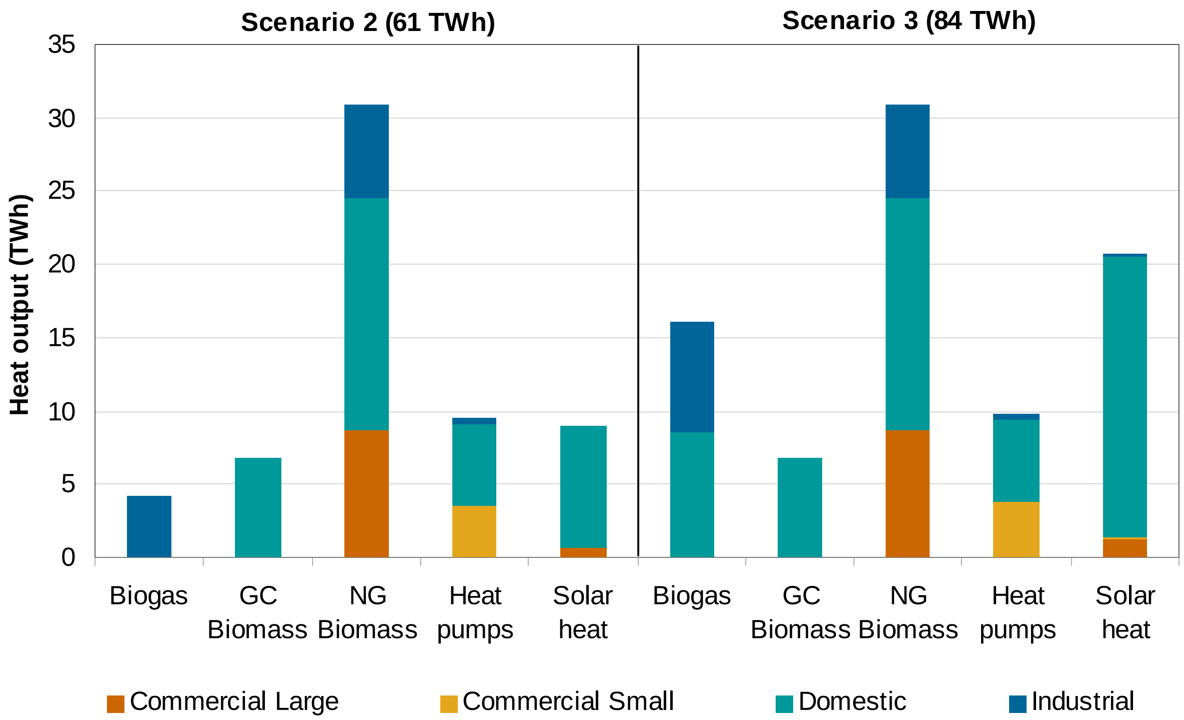
### 3.3.2. Heat output by technology and sector

In this section we provide further details about the sectors in which each of the technologies above are taken up, as well as the distribution across different renewable heat technologies.

The split of the output data by technology and sector is shown in Figure 3.5. As noted, "non-grid" biomass (corresponding to individual boilers not connected to a district heating system) provides a very large share of the output (around 50 percent in Scenario 2), and is spread across the domestic, large commercial, and industrial sectors. Grid-connected biomass is limited to district heating schemes serving the domestic sector. Biogas is used in industrial CHP in Scenario 2, and in Scenario 3 comprises on-farm anaerobic digestion and additional district heating schemes in the domestic sector. Heat pumps are used mostly in the small commercial sector and domestic sectors, while solar heat is overwhelmingly used in the domestic sector. The figure also shows that the additional 23 TWh by 2020 in Scenario 3 come mainly from very significant expansion of biogas and solar thermal in the domestic sector, as well as some additional biogas in the industrial sector. As discussed above, there is no increase in biomass or heat pump output between the two scenarios.

indicated by Enviros's Scenario 4 is used to meet the Scenario 2 target in our model, but no further output from this technology is available at higher overall output levels of the Scenario 3 target

**Figure 3.5**
**Split of Renewable Heat Output by Sector and Technology in 2020**



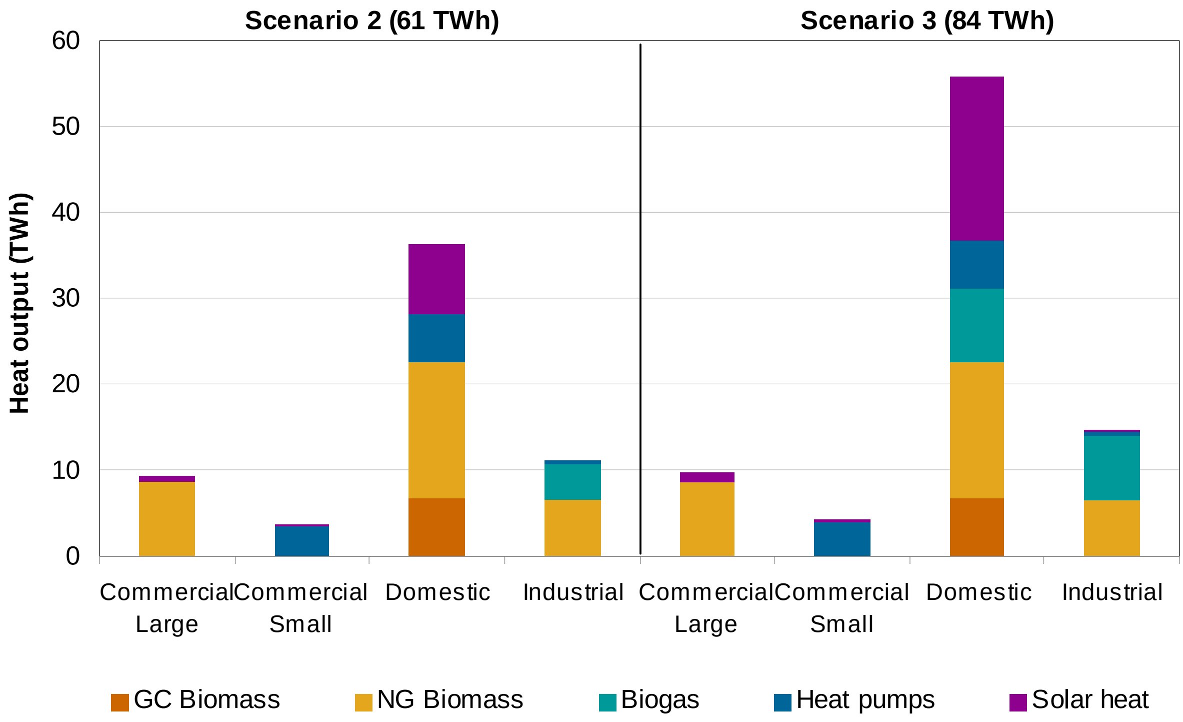

***Note**: The figure shows results for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively (the default RHO scenario). Results differ only slightly with lower discount rates of 7 and 10 percent (the default RHI scenario).*

In addition to the five technologies discussed above, Enviros also has provided an indication of which categories of heat output may be provided through combined heat and power (CHP) generation. Enviros (2008a) assumes (for simplicity in the modelling) that all district heating and industrial use of non-grid biomass would be CHP; that around half the use of biogas in the domestic sector (chiefly through civic district heating schemes) could be CHP; and that around one-quarter of the use of biomass in the large commercial sector could be CHP. Combining these assumptions with the results of our modelling suggests that some 15 TWh of the total additional output of 61 TWh in Scenario 2 would be accounted for by CHP, rising to 20 TWh out of 84 TWh in Scenario 3. In both scenarios, around one-quarter of heat output thus is generated using CHP.

These numbers are indicative of the quantity of CHP that may be expected given the assumptions and technology mix indicated by the modelling results. However, the amount of CHP that is used for a given amount of renewable heat is likely to be sensitive to various factors affecting the attractiveness of CHP compared to the use of boilers to serve heat load. Among the modelling parameters discussed above, relative fuel prices (and especially the spark spread) influence the viability of CHP. Its attractiveness also can be influenced by the on the price of $CO_2$, with higher allowance prices generally making CHP more attractive than separate electricity and heat generation. Depending on *relative* fuel prices, higher energy costs also are likely to make CHP more attractive. However, CHP also faces many other influences on overall profitability. Notably, CHP depends on the coincidence of heat and electricity demand, and the load factor that can be expected from a particular CHP project depend on the patterns of highly local demand for heat. In the absence of a supply curve for biomass and biogas CHP, the amount of CHP output that can be expected for a given set of parameters cannot be investigated in more detail.

Figure 3.6 shows the same information on the composition of renewable heat output as presented above, but organised with one column for each sector. The domestic sector accounts for 60 percent of renewable heat output in the modelling results for Scenario 2, increasing to 66 percent in Scenario 3. For comparison, the sector accounts for just over half of total current heat demand, and the results thus suggest that opportunities for renewable heat are better in this sector than in the other sectors. By contrast, the industrial sector has a lower share of renewable heat than its current share in heat demand. This reflects, among other things, the fact that a large proportion of industrial heat demand is process (rather than space or hot water) heating that may be more difficult to serve from renewable energy (e.g., because it requires a steadier or higher temperature than can be achieved from renewable heat). As noted by Enviros, there is a lack of comprehensive, up-to-date and reliable data on the amount or nature of current heat consumption by sector, which limits the accuracy with which the potential can be split by sector.

**Figure 3.6**
**Split of Renewable Heat Output by Technology and Sector in 2020**




***Note**: The figure shows results for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively (the default RHO scenario). Results differ only slightly with lower discount rates of 7 and 10 percent (the default RHI scenario).*

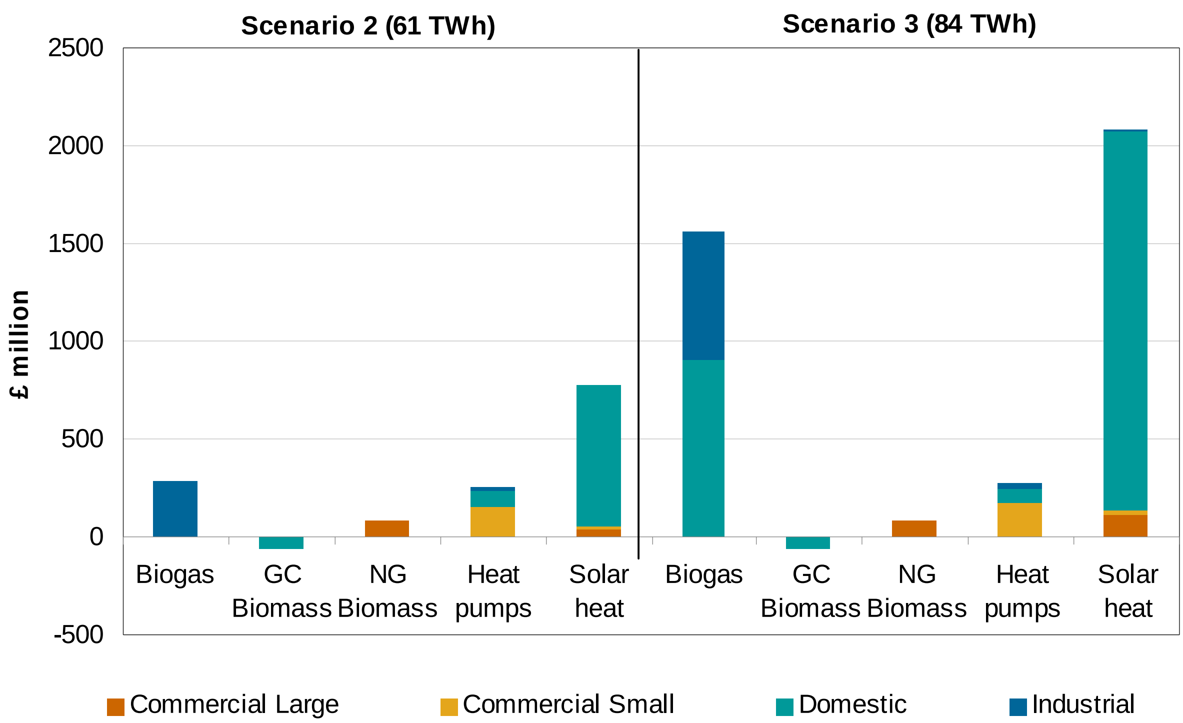
The use of renewable heat also leads to reduced demand for fossil fuels and electricity. The modelling results indicate that the counterfactual fuels are divided evenly between natural gas and non net-bound fuels, each account for around 40-45 percent of total energy displaced by renewables in Scenarios 2 and 3. By contrast, non net-bound fuels account for some 17 percent of total current heat use. There thus is a concentration of opportunities for renewables in the non net-bound segment of the market. This reflects in part the greater attractiveness of using biomass (which accounts for a large share of renewable heat output ) where gas is not available, particularly in the domestic sector. The methodology used to estimate the fuels displaced depends on the assumptions presented in section 2.1.5. A more refined picture of the fuels displaced would require addition research, including of the barriers to renewable heat that attach to displacing different fuel counterfactuals for each sector and technology combination.

### 3.3.3. Distribution of cost

The distribution of the resource costs between technologies and sectors is shown in Figure 3.7. As this shows, a very large share of total cost is accounted for by solar heat and, in Scenario 3, biogas. As noted above, these technologies account for much of the expansion in output from Scenario 2 to Scenario 3, but their share of total cost is significantly larger than their share of output. By contrast, biomass has a very low resource cost (and in the case of grid-connected biomass there is a net resource benefit to switching).

One implication of this pattern of costs is that, if other technologies could become available in greater quantity, and targets could be met without recourse to a large quantity of (expensive) biogas and solar heat, then the costs of meeting the target level of output could be significantly lower. The pattern of costs also has implications for rents, which we discuss in section 3.4.

**Figure 3.7**
**Distribution of Resource Cost by Technology and Sector in 2020**




***Note**: The figure shows results for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively (the default RHO scenario). The distribution of costs differs only slightly with lower discount rates of 7 and 10 percent (the default RHI scenario), although the* level *of resource costs differs more.*

## 3.4. Distribution of Subsidies and Rents

Under both the RHO and the RHI subsidy payments would be financed through obligations on energy suppliers or distribution network operators, which in turn would be expected to recoup the additional cost largely through higher energy bills for their customers.[18] The size of increased energy bills could be significant. For example, with a simplified assumption that costs would be recouped in proportion to heat consumption, so that households paid half of the total subsidy amount, each household would pay £170-200 per year by 2020 to finance half of the £8-10bn of subsidy required to reach the additional 84 TWh of heat output under Scenario 3 (with businesses and other non-domestic organisations paying the remaining £4-5bn in proportion to their heat consumption).

A large share of these subsidy payments would be "rents", i.e., payments to renewable heat output in excess of that required to make it financially viable compared to the relevant counterfactual conventional heating technology. If rents could be reduced, the cost to consumers of fossil fuels and electricity also would be lower. Based on the observation that rents account for three-quarters of the total subsidy, completely eliminating rents would reduce the average cost to households to only £60-80 per year.

The net distributional impact of the rents under an RHO or RHI would be a transfer from consumers using fossil fuels or electricity for heating to other consumers that switch to renewable heat and to producers of renewable heat equipment and suppliers of renewable fuels. Insofar as they benefit consumers rather than suppliers, the rents are more similar to those that arise under the CERT (where there is a transfer from the general consumer to those undertaking energy efficiency measures) than those arising under the RO (where any rents accrue to owners of renewable generation assets). Figure 3.8 shows the distribution of rents by sector and technology. Most rents are earned on heat supplied to the household sector, and the majority of these are in relation to consumers who switch to biomass. Concretely, this is likely to mean a net transfer from households on the gas grid to those off the gas grid, which have more opportunities for the use of renewable heat. In the non-domestic sectors rents would accrue chiefly in locations and applications with opportunities for the use of biomass and to some extent heat pumps.

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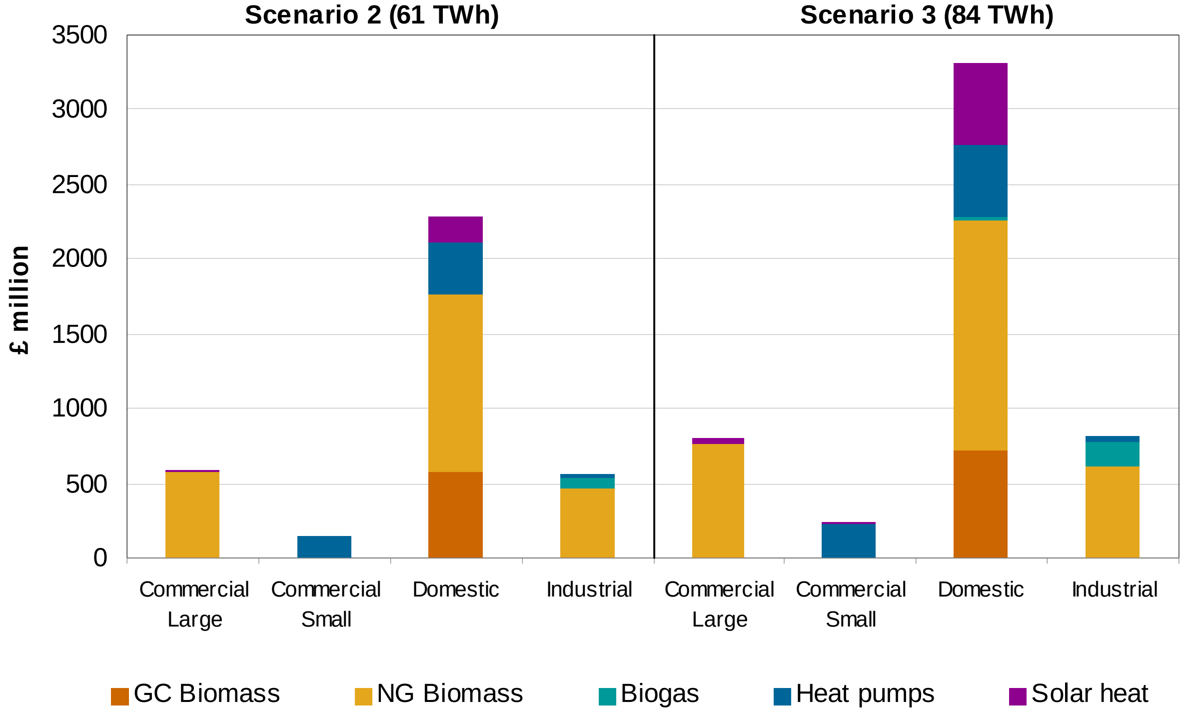
[18] As discussed in the report on Phase I of this project (NERA 2008), the nature of the obligation on energy suppliers or DNOs could influence the exact distribution of price increases necessary to pay for the subsidies

**Figure 3.8**
**Distribution of Inframarginal Rents Accruing to Sectors and Technologies (2020)**




***Note**: The figure shows results for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively (the default RHO scenario). The distribution of rents differs only slightly with lower discount rates of 7 and 10 percent (the default RHI scenario), although the* level *of rents differs more.*

### 3.4.1. Factors affecting uncertainty of estimates of rents

There are several complications that arise when attempting to judge how significant rents would be in practice, and there are reasons that actual rents could deviate from the above estimates.

First, rents accruing to solar heat installations (and to some extent heat pumps) may be inflated as these technologies are not used to cover all heat demand. For example, a household using solar heat may cover around half of hot water demand from this technology, whereas a heat pump user is likely to serve (some or all of) space heating but not hot water demand. This means that these users will continue to use fossil fuel, and therefore also pay the higher energy prices that finance the subsidies. The net rents therefore would be smaller than indicated by the above numbers. Rents accruing to these types of technologies are not a large proportion of the total in all scenarios, but they represent around 30 percent of the rents in the domestic sector in Scenario 3, so this offsetting effect within individual households could be significant.

Second, the estimate of rents (as well as of cost) is affected by the constraints on the input data discussed in section 3.3.1. Rents are high in large part because it is necessary to use costly technologies to achieve the output target. If the constraints (notably, the restrictions on the availability of biomass) were relaxed, and a greater quantity of less expensive renewable heat became available, rents would change—although they could either increase or decrease. The net impact would depend on how much certificate prices fell / incentive payments were reduced (i.e., the *marginal* cost of renewable heat) compared to the impact on the overall cost (i.e., the *average* cost of renewable heat). Clarifying this issue would require modelling using alternative biomass potential and cost input data.

Third, the actual size of rents would depend on how demand-side barriers should be regarded. As noted in section 2.5, our interpretation of the inputs and the modelling results is that all payments made to encourage the required uptake of renewable heat (the demand-side barrier costs) are real social costs. Also, we assume that the "hidden and missing" cost demand-side barriers (such as the cost of time) do not include the possibility of "behavioural" barriers (e.g., "inertia") that could cause heat consumers to fail to take up renewable heat even though they would be genuinely better off by doing so. The belief that "behavioural" barriers are important has been one motivating factor behind energy efficiency policy. If such barriers exist for renewable heat this could mean that our approach has ***under***estimated the extent of rents.[19]

Fourth, we have already discussed the negative net resource costs associated with some of the renewable heat technologies considered, and have suggested that they be viewed with caution. These negative-cost technologies result in higher calculated rents, so if they in fact did not have negative costs, the rents associated with them would be lower.

Finally, there is a possibility that rents also may be lower than suggested by the modelling because procurers of renewable heat – whether energy suppliers, DNOs or a central procurement agency under one version of the RHI – could be able to price discriminate. That is, they may be able to offer different levels of subsidy to different categories of projects. Price discrimination would be less likely if there were a liquid and active certificate market, where project developers would be able to undertake projects without the need for direct engagement with energy suppliers / DNOs. In the case of renewable heat, however, there are reasons to believe that the emergence of a liquid and independent certificate market is unlikely to emerge (see the report on Phase I of this project for discussion of this issue). We have not attempted to assess the possible scope for price discrimination or the reduction in rents that could result from it. However, we do investigate the quantitative impact of "banding" support in the next section, which is likely to have similar effects.

### 3.4.2. Other distributional impacts

The policies considered here also would have uneven impacts on different suppliers in the heating supply chain. Our modelling results suggest that the high targets for renewable heat would lead to large-scale replacement of some non-net bound fuels such as heating oil, coal, and LPG, with negative consequences for suppliers of those fuels. Whether these suppliers

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[19] If "behavioural" barriers exist they imply an underestimate of rents *whether or not* Enviros has included them in their demand-side barriers. In the case where Enviros's demand-side barrier estimates reflect some "behavioural" barriers, then our interpretation of them as reflecting real social costs overestimates the actual social costs. The payments associated with overcoming them therefore correspond to additional rents to renewable heat. On the other hand, if Enviros's demand-side barrier estimates only reflect real social costs, but there are "behavioural" barriers that they have not quantified, this would mean that our modelling under-estimates both the total subsidy required to incentivise the desired levels of renewable heat, as well as the rents that would accrue to its production.

also bore the direct costs of supplying renewable heat, or benefited from the policy subsidies, would depend on the details of policy design and their ability to adapt their business.

This report has not analysed the potential for rents in the auxiliary markets that would support the increase in renewable heat use. The rapid growth in supply chain infrastructure and installer services that would be required to meet renewables targets could result in scarcity that would drive up prices, with corresponding "scarcity rents" for current providers or early entrants to the industry. (Of course, like in other markets, the prospect of profits – or at least return on initial investment and compensation for risk – is a prerequisite for entry, and it is not clear that such potential rents should be seen as "undesirable".) Moreover, these rents are in part due to the potential savings on heating costs for consumers in this segment, and therefore do not necessarily all accrue to equipment producers, fuel suppliers, or others in the renewable heat supply chain. The actual distribution of the benefits implied by these rents would depend on the arrangements agreed between different supply chain participants and consumers.

Finally, our modelling of distributional impacts does not reflect the potential feedback interaction due to the increased costs to consumers of fossil fuels resulting from the renewable heat policy. In terms of social cost-benefit accounting these increased costs would be similar to a tax, and therefore are most appropriately treated as a transfer from "conventional" energy consumers and producers to renewable consumers / producers. Thus, these costs would not be expected to change either the overall resource costs associated with the renewable heat policy or the choice of individual renewable heat technologies.[20] However, these costs would affect consumers' willingness to shift from fossil technologies to renewable technologies at a given renewable support level, because the burden of the policy is borne by fossil energy users. In practice, this is likely to mean that the level of the certificate price or incentive payment required to achieve the target would be less than it would be in a case where the cost of the policy was not borne entirely by energy consumers. It would not, however, change rents – because these are a function of the difference between the most expensive and the least expensive renewable heat technology, in terms of real resource costs, excluding taxes / transfers.[21]

### 3.4.3. Quantitative analysis of "banding"

One way to reduce rents is to provide different levels of support for different eligible projects, often referred to as "banding" of support. Rents arise because some of the projects required to reach a target level of output (whether through RHO or RHI) have a significantly higher cost than do others. By reducing the per-MWh subsidy offered to projects known or thought to have lower costs, the overall level of payment can be reduced. However, banding also gives rise to a trade-off: because the cost of a particular project cannot be known with

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[20] The only exception to this rule would be if there were differences in the relative cost increases faced by different types of "conventional" energy consumers, and these differences were significant enough for the "marginal" renewable heat technology that they resulted in certain more expensive technologies being taken up than would otherwise have been used. We have not attempted to model the possibility of such a skewing of the incentives for taking up the least cost renewable heat technologies, but it seems unlikely that they would have a significant effect on the choice of technologies.

[21] Again, rents could be affected if there were differences in the incidence of the cost increase on different forms of conventional energy.

certainty, there is a risk that some projects which would be cost-effective (for a given target) are offered lower support than required for them to be undertaken.

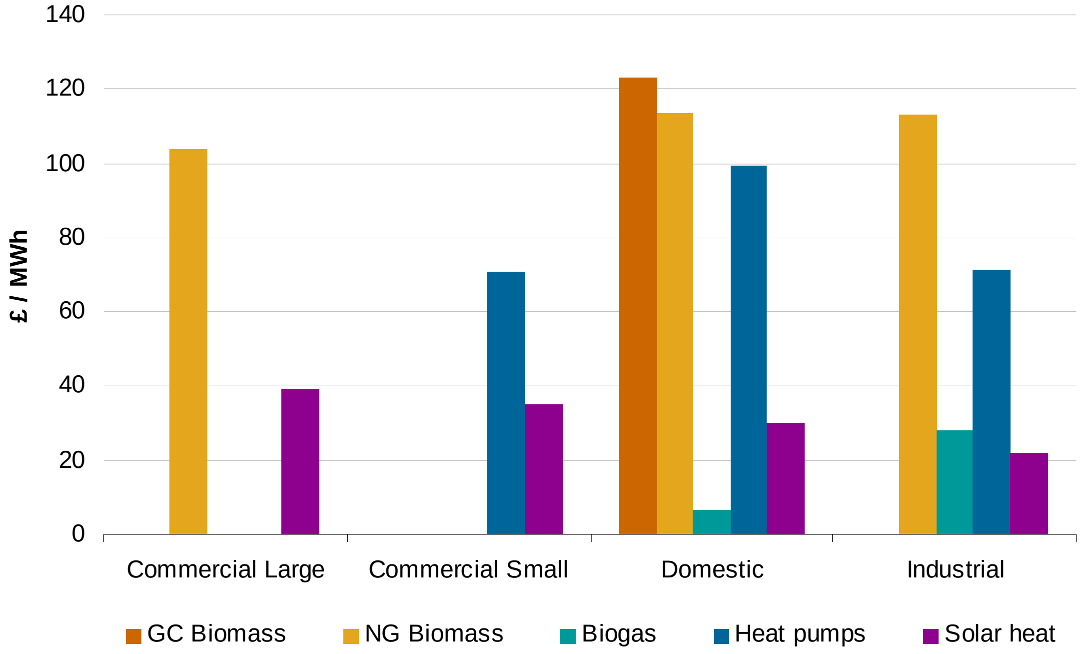
In a world where the costs and future output of every renewable heat project were known with certainty, it would be possible to set support levels (in the form of certificates or incentives) to match each project's requirements perfectly. Even in a world with uncertainty, it might still be possible to estimate the relative costs of particular technologies, and try to set the bands so they provided only the necessary level of support to each technology. (In this case, the necessary level of support would be just sufficient to make it profitable to invest in the last "tranche" of capacity in each technology to meet the desired target.) In practice, there is substantial uncertainty about the per-MWh costs of renewable heat – of individual projects but also even of classes of technologies. The present study represents an initial attempt to quantify these costs for the relevant technologies, but without much more information and experience, a great deal of uncertainty will remain.

This uncertainty means that if bands are set to provide the level of support that is *believed* to be required for each technology, there is a risk that this support will be insufficient to meet *actual* requirements. Where this is true for technologies that are relatively low cost, fewer projects using these technologies will be taken up than in a case without banding, and more expensive technologies (qualifying for higher bands) will be used instead.

Our implementation of banding varies for the RHO and RHI, in keeping with the specific character of each policy. Under the RHO, the level of support depends on developments in the certificate market, and it is not possible to determine the absolute level of support in advance. Instead, it is possible to vary the number of certificates awarded per MWh of output, and therefore the relative levels of support offered to different categories of projects. Under the RHI, by contrast, the absolute level of support is under direct political control, and banding can be more precise.

As a starting point for considering options for banding it is useful to see how rents are distributed on a per-MWh basis. This is shown in Figure 3.9 for Scenario 3. As it shows, rents per MWh can be very substantial for a number of technologies, with the highest rents for biomass. Biomass is followed by heat pumps, although as seen in Figure 3.8 (above) these correspond to much smaller absolute rents, because the output from this technology is much smaller than that from biomass.

**Figure 3.9**
**Distribution of Inframarginal Rents per-MWh Accruing to Sectors and Technologies (2020)**

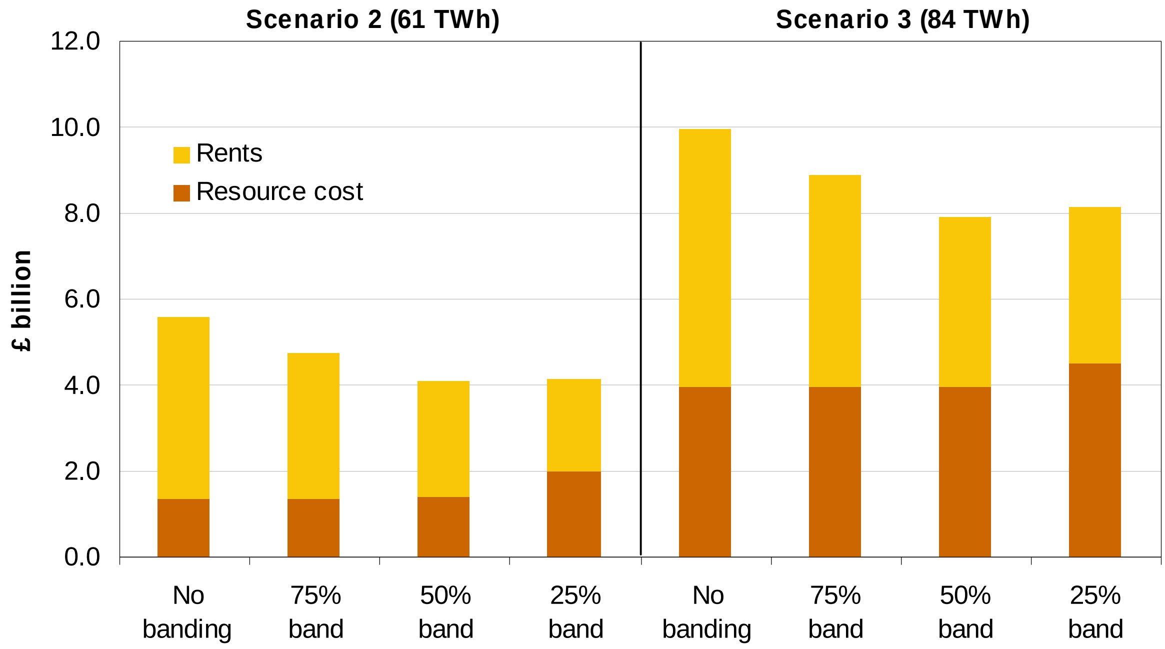



***Note***: *The figure shows results for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively.*

We illustrate the potential trade-off between reducing rents and minimising cost by creating a separate band for biomass, which is responsible for the largest contribution to total rents. We consider policy designs in which biomass receives different levels of support – ranging from a full certificate per MWh (which is equivalent in this case to there being no banding), to just one quarter of one certificate per MWh. Figure 3.10 shows the results for four different banding levels. The figure shows how reducing the number of certificates awarded to biomass heat can reduce rents. For example, in our central scenario, if biomass receives 50 percent of the certificates awarded to other technologies, this reduces total rents by £1.5bn in Scenario 2 and by £2bn in Scenario 3, with only very limited effects on total resource costs. However, if support for biomass is reduced to 25 percent of the support offered to other technologies the outcome is somewhat different. Although rents continue to be reduced relative to the other banding (and non-banding) cases, total costs increase. As a consequence, in both Scenarios 2 and 3 total subsidy payments and resource costs start to increase as the support for biomass is reduced.[22]

[22] The trade-off occurs because in the case where biomass receives just 25 percent of a certificate per MWh, marginal biomass projects that would have been less expensive than other renewable heat projects do not receive sufficient support to make them profitable. If the Government knew that these projects would be required to meet their target at the minimum cost and knew what their cost and output levels would be, the Government would be expected to set the banding level sufficiently high to ensure that these projects were deployed. However, governments do not have perfect information, and our assumption that in some cases the band could be set below the minimum support requirement is intended to reflect this.

**Figure 3.10**
**Impact of RHO "Banding" of Biomass on Subsidies and Rent (2020)**




We emphasise that the above modelling results are illustrative only, and should not be taken as a guide to the appropriate level of bands. We do not consider that the information available for this project is sufficiently detailed and certain to be suited to detailed policy design—including determining the appropriate level of banding, or the details of how banding categories should be defined.

Determining appropriate bands for renewable heat is likely to be more difficult than it has been for renewable electricity. The potential disadvantages with banding arise because of heterogeneity within banding categories and because of uncertainty about costs. Both of these are likely to be greater for renewable heat than for electricity. In particular, the state of knowledge about cost and potential typically is much better for renewable electricity. Past policies (notably, the NFFO auctions) have provided opportunities to develop detailed information about costs for particular technologies. Also, costs of more centralised projects for electricity generation are easier to observe, and are less likely to depend on site-specific costs of overcoming barriers that arise in more dispersed and smaller renewable heat project. It seems likely that detailed information about the actual cost of renewable heat will become available only after some time, when the outcome of the policy can be observed. As noted, if the policy is introduced but the information underlying the bands is inaccurate there is a risk that (potentially large) portions of the potential for renewable heat would not be taken up, leading to higher costs.

### 3.4.4. Additional qualitative aspects of banding

As discussed in the Phase I report, banding under an RHI allows more control over the absolute level of support that is provided to different technologies. On the other hand, the relative bands under an RHO would adjust automatically to circumstances that change the cost of using renewables in general, such as rising fossil fuel prices. Under neither policy is it straightforward to adjust bands after they have been introduced. In general, it might be necessary to commit to (administratively complex) "grandfathering" support in order not to risk introducing uncertainty for investors. Moreover, to avoid incentives to delay investments, any increases in support that are made available for new installations of particular technologies would likely also need to apply to existing installations. These considerations mean that revisions to bands over time can be complex.

The use of banding also has implications for the certainty of reaching a target level of output under the RHO. Without banding the level of output can be controlled by requiring energy suppliers or other obligated parties to hold a given number of certificates. However, with banding all certificates are equally valid for compliance but correspond to different amounts of additional heat output. The total amount of heat output achieved therefore depends on the composition of renewable projects that are undertaken, which cannot be known with certainty before the policy is implemented.[23]

Finally, as we note in our suggestions for further research (section 4.2), the introduction of banding is likely to have implications for the ease of implementing an international trading system for renewable certificates. Banding could make participation in such a system more difficult. This would be another instance in which banding offers the possibility of reducing rents but simultaneously risks imposing higher overall costs.

## 3.5. Sensitivity Analysis

The discussion in section 3.1 above showed that the resource cost of renewable heat is highly dependent on input assumptions. Key inputs include fuel price assumptions and the cost of overcoming barriers, both of which are subject to considerable uncertainty. This section investigates how the results in previous sections may vary with different inputs, and how sensitive the main findings are to different assumptions.

Sensitivity analysis also allows for the investigation of one of the main differences between the RHO and RHI policies, *viz.*, regulation through quantities or through prices. It is a standard observation that the properties of these types of regulation differ when there is uncertainty. Provided enforcement is feasible and credible, the RHO can provide certainty about the level of output, but the price of certificates required to meet targets is uncertain. The impact of different fuel prices scenarios therefore is to change the prices of certificates as well as the overall cost and subsidy payments. By contrast, the sensitivity of the RHI to fuel price assumptions is investigated by keeping the same certificate prices as in the headline results in section 3.2, and investigating the impact on output levels and other key modelling outputs.

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[23] As we discuss in the Phase I report on this project, there may in any case be a need under an RHO to make use of safety valve arrangements to prevent prices from rising above acceptable levels. The use of such mechanisms also introduce uncertainty about meeting a target level of output.

### 3.5.1. Impact of discount rate assumptions

Section 3.2 presented key results for the RHO and the RHI. As noted above, the differences between the results shown are due entirely to the different discount rate assumptions used. For the RHO, we assumed domestic / non-domestic private discount rates of 9 / 12 percent, and for the RHI we assumed corresponding rates of 7 / 10 percent.[24] The higher rates for the RHO reflect the assumption that uncertainty about future levels of support leads to a higher cost of capital or risk premium when considering future revenues from switching to renewable heat. As noted, the precise way the policies would function – including the distribution of risk between different market participants – is highly uncertain, and although it seems likely that the RHI would involve less uncertainty it is unclear exactly how this would affect discount rates used in private decision-making (and whether the 2 percent "RHO premium" is appropriate).

Also, although the lower discount rates used for the RHI by construction lead to lower costs than for the RHO, this should not be taken as an indication that the RHI policy automatically would be more desirable than the RHO. The fixed-price support RHI carries different kinds of policy risk than the RHO (notably, the risk of not meeting renewable heat output targets), as we discuss in the next subsection. Also, there are important other considerations that are not captured in the quantitative estimates – notably, the complexity, feasibility of contractual arrangements, and other aspects of policy workability of a fixed-support mechanism in the heat sector, as discussed in detail in the Phase I report of this project.

The true discount rates or capital costs relevant to private decisions about renewable heat investments under the support mechanisms also would be influenced by sources of risk other than certificate price volatility. Examples of relevant sources of risk may include the (perceived) reliability of renewable heat technologies, the reliability of fuel or equipment supply chains, or the availability of qualified installation or repair services. These all may have effects on discount rates similar to those of certificate price uncertainty. The appropriate discount rate to use for the modelling therefore also is uncertain.

To investigate these considerations we model different scenarios for discount rates, and the results for seven sets of discount rate assumptions are shown in Figure 3.11. The lowest discount rate assumptions (5/8 for domestic / non-domestic) are two percentage points lower than our central RHI assumptions, while the highest set uses 14/17, respectively (these ranges have been chosen to reflect the ranges existing in other studies of discount rates used for private decisions about renewable heat). The figure shows that assumptions about the opportunity cost of capital is very important for the results. As noted, the premium associated with additional uncertainty under the RHO relative to the RHI may be smaller than the 2 percentage points used for the above results.

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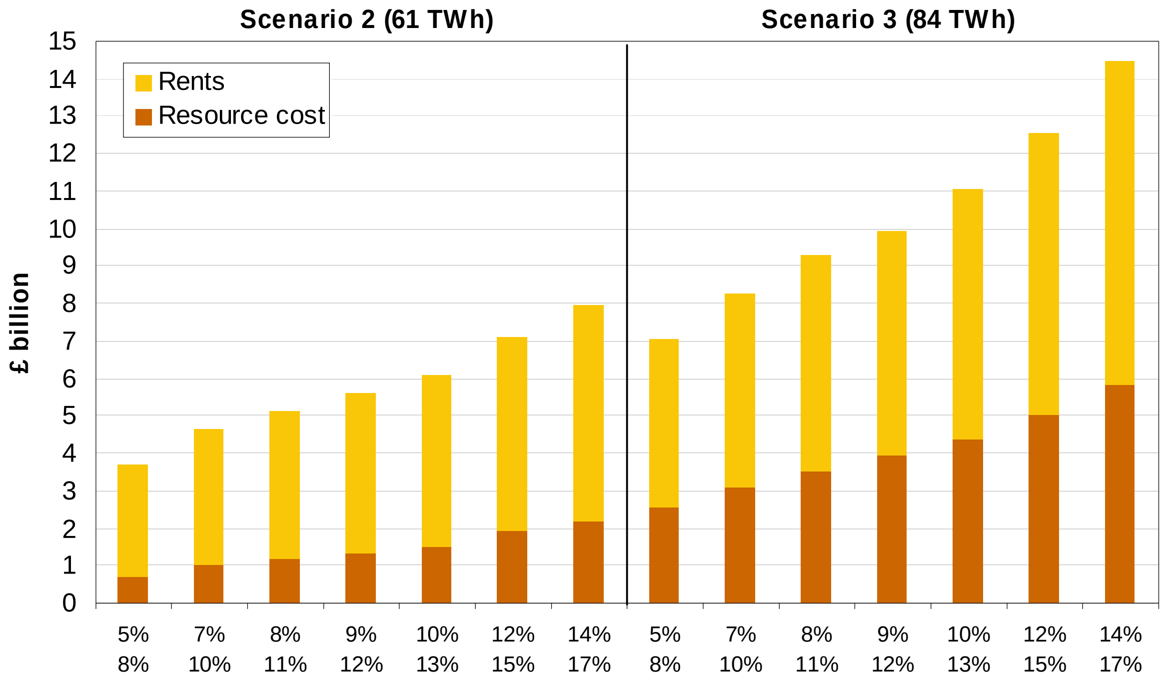
[24] If under the RHO or RHI, the costs of providing renewable heat in individual households are not paid directly by those households, but by companies in the renewable heat supply chain, there may be some justification for using the non-domestic discount rate even for domestic installations of renewable heat technologies. Using the non-domestic rates for all installations would result in higher overall resource costs and higher rents. Individual households might be expected to invest in renewable heat technologies themselves if they believed they could save (or earn) money from doing so. Their potential to earn money from adopting renewable heat in turn depends on the extent to which rents are split between companies and households. To avoid making assumptions about "profit-sharing" between companies and households and the potential implications for calculations of levelised resource costs, we simply apply the domestic discount rate to domestic installations of renewable heat.

**Figure 3.11**
**Impact of Discount Rate Assumptions on Modelling Results (2020)**




If, on the other hand, discount rates were higher than assumed in the central case, costs could increase substantially. With rates of 12 / 15 percent (a 5% percentage-point increase on the central RHI assumptions), costs increase by 90 percent in Scenario 2 and 60 percent in Scenario 3, and in both Scenarios total subsidy payments increase by around 50 percent. Some studies, such as AEA (2007b), have suggested that rates of 15 percent are appropriate, although it is not clear to what extent this is intended to reflect risk premiums or perhaps hidden and missing costs (which are accounted for elsewhere in the modelling undertaken here). As noted in section 2.3.4, we regard discount rates this large as unlikely in the absence of very significant risk to participants.

## 3.5.2. Impact of fuel prices

This section presents modelling results for a number of fuel price scenarios that differ from the central ones presented above. We consider how the key modelling outputs vary with the level of fuel and biomass prices for Scenarios 2 and 3. We first model the RHO, and consider how different fuel prices affect the certificate price required to reach a given output level. We then model the RHI and assess by how much the target would be over- or under-achieved with different price assumptions. (Details of the fuel price scenarios used for the modelling were provided by BERR.)

### 3.5.2.1. RHO modelling sensitivity to fuel prices

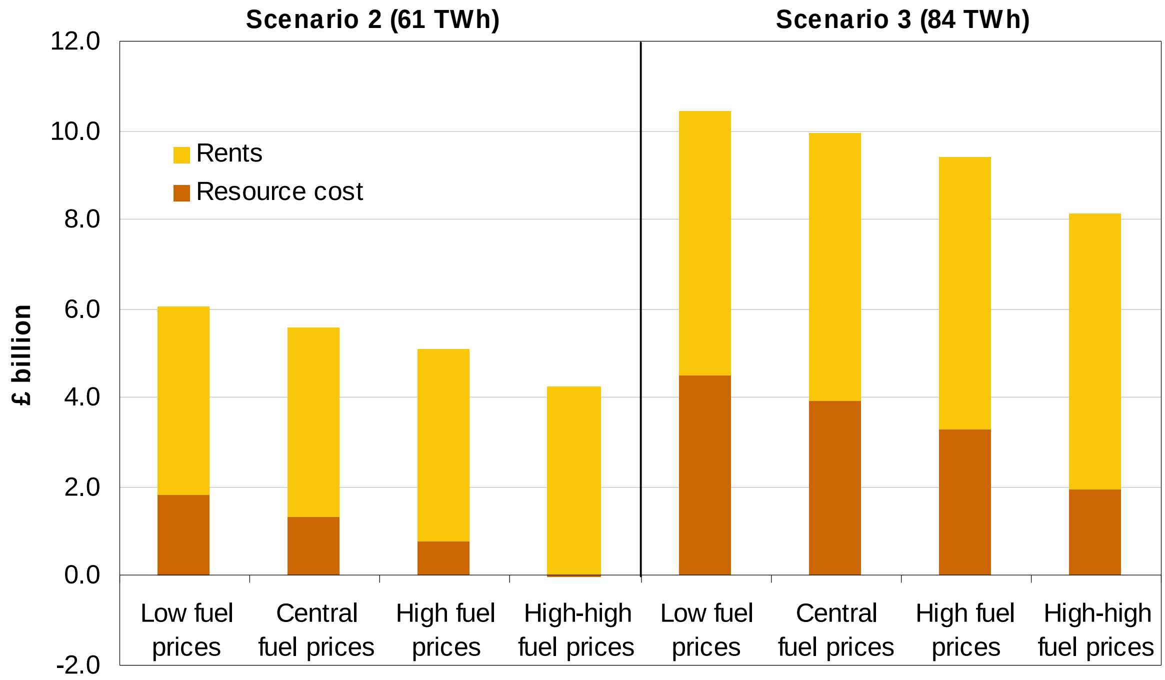
The impact of fuel prices on the 2020 headline results for the RHO in is shown in Table 3.2 below, while Figure 3.12 shows the distribution of total subsidies, rents and resource cost across the different fuel price scenarios. Four sets of fuel prices are shown for each of Scenarios 2 and 3. As suggested by the cost curves in section 3.1, assumptions about fuel prices have a substantial impact on the cost of achieving the renewable heat targets. For example, net resource costs under Scenario 3 amount to £4.5bn in the low fuel price scenario (compared to £3.9 in the central scenario) but fall to £2.0bn in the high-high fuel price scenario. In Scenario 2, the highest fuel price scenario leads to a zero overall net resource cost because a significant proportion of the heat output would be generated at "negative cost". Even so, the certificate price required in this case is £67 / MWh. The results also show that rents are largely unaffected by fuel prices, staying more or less constant just over £4bn for Scenario 2 and around £6bn in Scenario 3. This is because the different fuel price scenarios tend to shift the renewable heat supply curve up and down vertically, but do not result in much re-ordering of the curve. As a consequence, the area between the certificate price and the supply curve – which represents rents – does not change much, while the total area under the supply curve (which represents resource costs) does change significantly. The ratio of rents to cost thus also increases with higher fuel prices.

**Table 3.2**
**Impact of Fuel Prices on RHO Modelling Results (2020)**

| | | **Scenario 2** | | | | **Scenario 3** | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Variable** | **Units** | Low | Central | High | High-high | Low | Central | High | High-high |
| Renewable heat output | TWh | 67 | 67 | 66 | 67 | 90 | 91 | 91 | 90 |
| Resource cost | £bn | 1.8 | 1.3 | 0.8 | 0.0 | 4.5 | 3.9 | 3.3 | 2.0 |
| *Technology cost* | *£bn* | *0.9* | *0.4* | *-0.1* | *-1* | *2.4* | *1.9* | 1.2 | 0.0 |
| *Supply-side barrier cost* | *£bn* | *0.5* | *0.5* | *0.5* | *0* | *1.2* | *1.2* | 1.2 | 1.1 |
| *Demand-side barrier cost* | *£bn* | *0.4* | *0.4* | *0.4* | *0* | *0.7* | *0.7* | 0.7 | 0.7 |
| *Administrative costs* | *£bn* | *0.1* | *0.1* | *0.1* | *0* | *0.2* | *0.2* | 0.2 | 0.2 |
| Subsidy | £bn | 6.0 | 5.6 | 5.1 | 4.2 | 10.4 | 9.9 | 9.4 | 8.2 |
| Rents | £bn | 4.2 | 4.3 | 4.3 | 4.2 | 5.9 | 6.0 | 6.1 | 6.2 |
| Certificate price or incentive | £/MWh | 95 | 89 | 82 | 67 | 119 | 113 | 107 | 94 |
| Resource cost per MWh | £/MWh | 30 | 22 | 13 | -1 | 54 | 47 | 39 | 24 |
| CO2 savings | MtCO2 | 17 | 17 | 17 | 17 | 24 | 24 | 24 | 24 |
| *Outside EU ETS* | *MtCO2* | *11* | *11* | *11* | *11* | *17* | *17* | 17 | 17 |
| *Within EU ETS* | *MtCO2* | *6* | *6* | *6* | *6* | *7* | *7* | 7 | 7 |
| Number of installations | million | 4.3 | 4.2 | 4.0 | 3.4 | 8.8 | 8.9 | 9.0 | 9.2 |

***Note:*** *Values are expressed in real terms using 2008 prices; see footnote 14 for additional information.*

**Figure 3.12**
**Impact of Fuel Prices on Selected RHO Modelling Results (2020)**




The above modelling shows the results for 2020 of modelling with systematically different fuel price trajectories throughout the modelling period 2010-2020. They therefore are not immediately an indication of how certificate prices would respond to changes in fuel prices over time.[25] Nonetheless, the fact that the cost of renewable heat generation is highly sensitive to fossil fuel prices suggests that certificate prices for renewable heat could be volatile. This volatility would depend on the design of the scheme, including whether banking was allowed and the length of the banking periods.

We have also investigated the impact of different fuel prices on the composition of renewable heat output. The results show only very modest changes, with some substitution from solar heat to biogas at high fuel prices.

The above modelling scenarios investigate the impact of changes to fuel prices alone. In reality, there may be reasons why the cost of renewable heat generation would change alongside changes in fossil fuel prices. For example, if biomass increasingly becomes a substitute for fossil fuels in heat and electricity generation (as well as through biofuels in transport), then biomass and fossil fuel prices may start to show a greater degree of correlation than historically has been the case. In addition, the prices of inputs into some forms of biomass production (e.g., energy crops) depend on the price of fossil fuels. More generally, the greater attractiveness of renewables under high fossil fuel prices may lead to greater demand and therefore higher prices, although the magnitude of this feedback may be

[25] They also do not incorporate other influences on short-term price variations, notably the risk of price spikes in the event the supply of renewable heat did not respond sufficiently quickly to the demand for certificates.

limited if the extent of demand depends chiefly on policy intervention rather than on the relative costs of different heat technologies.

As noted, the model does not explicitly model the CHP output resulting under different scenarios. It is likely that higher fuel and $CO_2$ prices would make CHP more attractive, other things being equal, though this would depend on how relative fuel / electricity prices (and particularly the spark spread) developed. Investigating the choice between CHP and dedicated boiler technologies under different fuel prices would require a separate cost curve for CHP that is beyond the scope of the current study.

#### 3.5.2.2. RHI sensitivity to fuel prices

The sensitivity analysis for the RHI policy option is carried out by keeping the subsidy per MWh at the same level as presented in the headline results above (£76 / MWh for Scenario 2 and £99 / MWh for Scenario 3). This provides some insight into the policy risk associated with fixing the support level for renewable heat. The results are shown in Table 3.3 and Figure 3.13 below.

The figure shows the same quantities as the corresponding figure for RHO, above, and in addition shows on the right-hand axis the level of renewable heat output in each modelling run (indicated by the blue triangles in the figure). The results show that the amount of renewable heat output can vary very significantly depending on fuel prices, between 58-83 TWh per year by 2020 in Scenario 2, and 72-95 TWh in Scenario 3. Whereas the total subsidy under the RHO decreases as fossil fuel prices increase, the total subsidy payment under the RHI *increases* significantly with higher fuel prices, because the incentive payment per MWh remains constant while total output expands.

The resource cost under the RHI has a more complex relationship to fuel prices than the total level of subsidy. For Scenario 2, total resource cost with either low or high-high fuel prices is somewhat ***higher*** than it is in the central scenario. This reflects two opposing effects: on the one hand, low (high) fuel prices raise (reduce) the net resource cost of renewable heat; on the other hand, low (high) fuel prices reduce (raise) output levels. The net effect thus depends on whether the increased (reduced) cost per MWh outweighs the impact of lower (higher) output levels, or vice versa. In Scenario 3, the relationship is similarly complex, but the balance of factors leads to the reverse relationship between the fuel price scenarios – the central scenario has the *highest* resource costs, followed by the high, then the low, and then the high-high fuel cost scenario.

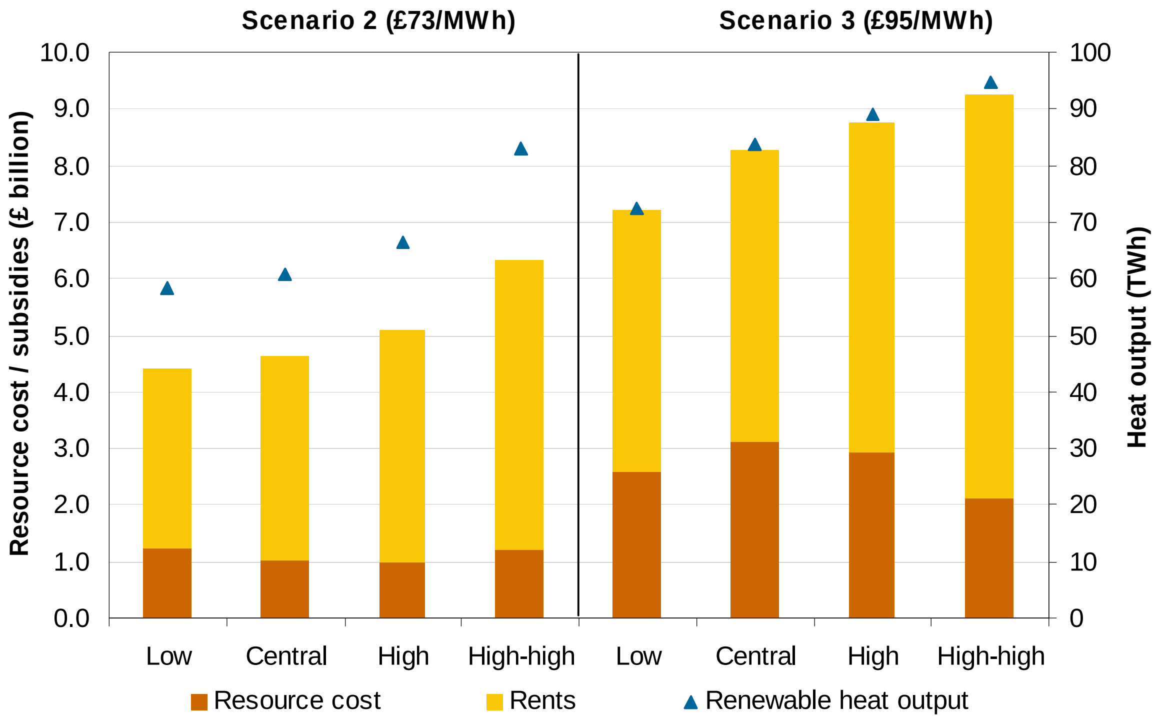
**Table 3.3**
**Impact of Fuel Prices on RHI Modelling Results (2020)**

| Variable | Units | Scenario 2 Low | Scenario 2 Central | Scenario 2 High | Scenario 2 High-high | Scenario 3 Low | Scenario 3 Central | Scenario 3 High | Scenario 3 High-high |
|---|---|---|---|---|---|---|---|---|---|
| Renewable heat output | TWh | 64 | 67 | 73 | 89 | 79 | 90 | 95 | 101 |
| Resource cost | £bn | 1.2 | 1.0 | 1.0 | 1.2 | 2.6 | 3.1 | 2.9 | 2.1 |
| *Technology cost* | *£bn* | *0.5* | *0.2* | *-0.1* | *-1* | *1.2* | *1.3* | 0.8 | -0.4 |
| *Supply-side barrier cost* | *£bn* | *0.4* | *0.4* | *0.5* | *1* | *0.7* | *1.0* | 1.2 | 1.4 |
| *Demand-side barrier cost* | *£bn* | *0.3* | *0.3* | *0.4* | *1* | *0.5* | *0.6* | 0.7 | 0.8 |
| *Administrative costs* | *£bn* | *0.1* | *0.1* | *0.1* | *0* | *0.2* | *0.2* | 0.2 | 0.3 |
| Subsidy | £bn | 4.4 | 4.6 | 5.1 | 6.3 | 7.2 | 8.3 | 8.8 | 9.3 |
| Rents | £bn | 3.2 | 3.6 | 4.1 | 5.1 | 4.6 | 5.2 | 5.8 | 7.1 |
| Certificate price or incentive | £/MWh | 73 | 73 | 73 | 73 | 95 | 95 | 95 | 95 |
| Resource cost per MWh | £/MWh | 21 | 17 | 15 | 14 | 36 | 37 | 33 | 22 |
| CO2 savings | MtCO2 | 16 | 17 | 19 | 24 | 20 | 24 | 25 | 27 |
| *Outside EU ETS* | *MtCO2* | *11* | *11* | *13* | *17* | *14* | *17* | 18 | 19 |
| *Within EU ETS* | *MtCO2* | *6* | *6* | *6* | *7* | *6* | *7* | 7 | 7 |
| Number of installations | million | 3.3 | 4.3 | 5.7 | 9.1 | 7.9 | 9.3 | 10.7 | 12.9 |

***Note:*** *Values are expressed in real terms using 2008 prices; see footnote 14 for additional information.*

This variation in resource costs and overall subsidy payments means that there is wide variation in the level of rents under the RHI depending on fuel prices. As discussed in section 3.4, the level of rents could be reduced by setting different levels of support for different technologies.

**Figure 3.13**
**Impact of Fuel Prices on Selected RHI Modelling Results (2020)**



The variability in the amount renewable heat taken up under different fuel price scenarios suggests that it would be difficult to hit a target level of output with the RHI, even if other parameters (such as renewable heat technology costs) were known with a high degree of certainty. It also would be difficult to control the impact on end-user energy bills, as the total subsidy would be uncertain. As we discuss in the report on Phase I of this project, these risks could be mitigated by adjusting the level of payment offered under an RHI over time to reflect new information and changing circumstances. As the Phase I report notes, however, it could be difficult to make such changes while also preserving investor confidence. Any changes to the level of absolute payment would need to apply only to new investments, not existing ones, to avoid the introduction of uncertainty for investors that the RHI is designed to eliminate. Such "grandfathering" would be administratively complicated, and also could be difficult given the significant variable cost subsidy required to ensure delivery of biomass heat.

Another potential way to reduce the uncertainty about the total level of subsidy would be to design a "contract for differences" support mechanism similar to those in use for the electricity sector. A "contract for differences" approach would be difficult to define in the context of heat supply, however, because it would require a widely accepted index against which to calculate subsidy levels. It is not clear that such an index exists or could be developed.

#### 3.5.2.3. Impact of biomass prices

As noted in section 2.3.3, there is considerable uncertainty about the level of biomass prices that will be available to UK heat consumers. Given the large proportion of renewable heat potential that is accounted for by this technology, biomass prices are likely to be an important determinant of the cost reaching renewable heat targets.

Modelling results for scenarios with higher and lower biomass prices confirms that they have a large effect on resource cost. The impact of biomass prices on other aspects of the results is less pronounced than may be expected, however, because of modelling assumptions and constraints already discussed. Even at high biomass prices the technology remains infra-marginal, so changes to the price therefore do not affect the certificate price or incentive required to reach the output targets in Scenarios 2 and 3. This outcome is in part a result of the fact that biomass appears very cost-effective compared to some other technologies (notably, solar heat and the more expensive tranches of biogas heat), and partly because of the absolute constraint on available biomass, which means that no additional biomass heat results as the level of subsidy is increased.

These factors mean that the currently available data do not allow for comprehensive testing of the implications of different biomass supply and price scenarios. We suggest that this is an important area for further research.

### 3.5.3. Other sensitivity analysis

In addition to fuel prices we have tested the sensitivity of the modelling results to other key parameters, including policy administrative costs, demand- and supply-side barrier costs, and the impact of "deeming" on the results.

#### 3.5.3.1. Policy administrative costs

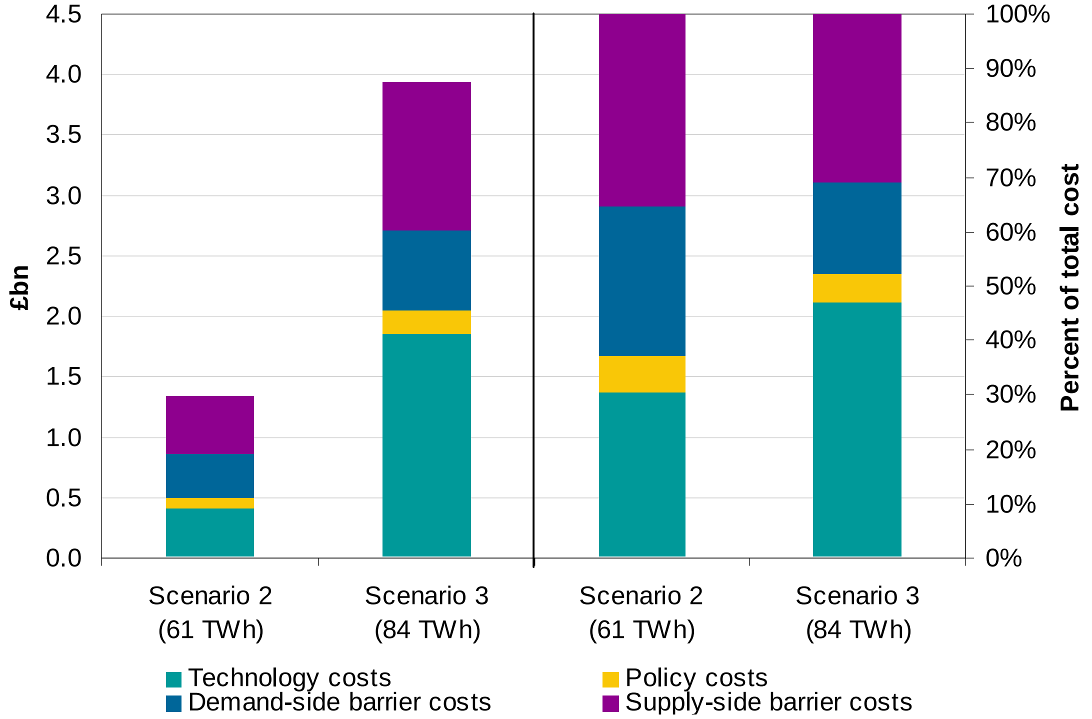
The policy design outlined in the report on Phase I of this project indicated that a very light-touch approach to administrative requirements would likely be necessary to ensure take-up. The approach suggested for both the RHI and RHO was more similar to the CERT than to the RO in key respects, including the elimination of reporting and other administrative requirements for the small commercial and household sectors, and a light-touch approach to other sectors.

Reflecting the discussion for the Phase I report the policy costs—i.e., costs such as fees to regulators or the time costs of complying with reporting or other requirements necessary under the policy—consequently are relatively low. To investigate the sensitivity of the results to this parameter, we model a scenario with administrative costs three times as high as in the central case. The results show that the price of certificates increases by £6-13 per MWh, while total resource cost increases by 7-13 percent, depending on scenario, with much of the increase arising from small installations – notably of solar thermal – for which administrative costs constitute a proportionately larger share of the total. We consider the scenario with tripled administrative costs an extreme assumption, and it appears from the modelling that the influence of uncertainty about this parameter is relatively small compared to the other uncertainties in the model.

#### 3.5.3.2. Barrier costs

The analysis of cost curves in section 3.1.1 shows that barrier costs constitute a large share of total cost for some of the renewable heat technologies and sectors. The split between technology costs, policy costs, and demand- and supply-side barrier costs is shown in Figure 3.14, where the left-hand panel shows the absolute amount and the right-hand panel the percentage accounted for by each cost category. As the figure shows, combined policy and barrier costs constitute 75 percent of costs in Scenario 2, but just over 50 percent in Scenario 3, because technology costs grow faster than barrier and policy costs as the output level increases (solar thermal and biogas, which make up much of the difference between the two scenarios, have high technology costs). Supply-side barrier costs are larger than demand-side barriers, while policy costs are small relative to barrier costs.

**Figure 3.14**
**Categories of Renewable Heat Resource Cost (2020)**




***Note**: The figure shows results for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively.*

The figure illustrates that assumptions about barrier costs are a very important input into the modelling. Our understanding of Enviros's underlying research is that the true cost of barriers to the large increase in renewable heat use implied by the targets is very uncertain, especially as it is uncertain that barriers could be overcome at the speed required to meet the targets by 2020.

To investigate the significance of uncertainty in barrier costs for our results we model scenarios with all barrier and policy costs 50 percent higher and 50 percent lower than those in the central scenario. Table 3.4 shows the results for these assumptions as well as for the central level of costs. In Scenario 2 the higher costs lead to a 20 percent increase in both overall subsidies and resource costs, raising the required subsidy from £92 / MWh to £111 / MWh. The increase in Scenario 3 is still higher, with an increase in certificate prices or incentive payments from £113 / MWh to £145 / MWh and total resource cost reaching almost £5bn. With lower costs, subsidies and resource costs are reduced by some 30 percent and 20 percent in Scenarios 2 and 3, respectively.

**Table 3.4**
**Impact of Barrier and Policy Costs on Modelling Results (2020)**

| | | Scenario 2 | | | Scenario 3 | | |
|---|---|---|---|---|---|---|---|
| **Variable** | **Units** | **Low Cost** | **Central Cost** | **High Cost** | **Low Cost** | **Central Cost** | **High Cost** |
| Renewable heat output | TWh | 67 | 67 | 67 | 90 | 91 | 90 |
| Resource cost | £bn | 0.9 | 1.3 | 1.7 | 2.7 | 3.9 | 4.9 |
| *Technology cost* | *£bn* | *0.4* | *0.4* | *0.5* | *1.6* | *1.9* | *1.9* |
| *Supply-side barrier cost* | *£bn* | *0.2* | *0.5* | *0.6* | *0.6* | *1.2* | *1.8* |
| *Demand-side barrier cost* | *£bn* | *0.2* | *0.4* | *0.5* | *0.4* | *0.7* | *1.0* |
| *Administrative costs* | *£bn* | *0.0* | *0.1* | *0.1* | *0.1* | *0.2* | *0.3* |
| Subsidy | £bn | 4.0 | 5.6 | 6.7 | 7.9 | 9.9 | 12.7 |
| Rents | £bn | 3.1 | 4.3 | 5.0 | 5.1 | 6.0 | 7.8 |
| Certificate price or incentive | £/MWh | 63 | 89 | 108 | 91 | 113 | 145 |
| Resource cost per MWh | £/MWh | 14 | 22 | 28 | 33 | 47 | 58 |
| CO2 savings | MtCO2 | 17 | 17 | 17 | 23 | 24 | 24 |
| *Outside EU ETS* | *MtCO2* | *11* | *11* | *11* | *16* | *17* | *17* |
| *Within EU ETS* | *MtCO2* | *6* | *6* | *6* | *7* | *7* | *7* |
| Number of installations | million | 4.2 | 4.2 | 3.3 | 11.1 | 8.9 | 8.7 |

***Note**: The figure shows results for discount rates of 9 and 12 percent for the domestic and non-domestic sectors, respectively. Values are expressed in real terms using 2008 prices; see footnote 14 for additional information.*

### 3.5.3.3. Use of metering instead of deeming in RHO

As noted in section 2.8, the use of simplified protocols for monitoring heat output, including "deeming", can lead to some inefficiency because installations may be offered higher or lower levels of subsidy per MWh than would be the case if output could be accurately observed. This impact is incorporated in the central modelling scenarios presented above, taking into account the parameter assumptions described in section 2.8.2 above.

As an illustration of the impact of deeming, we have modelled the same scenarios without any deeming. The results for non-deeming scenarios indicate that deeming may raise the cost of renewable heat by some 5-7 percent per MWh. Note however, that this result does not increase monitoring costs to reflect the absence of deeming and therefore represents a lower bound on the costs of a non-deeming scenario.

It also is possible that there would be less need for the use of deeming under an RHO than under an RHI. Using deeming only for solar heat but not for other technologies lowers the cost of the central RHO scenario by a small amount, but this is not sufficient to offset the disadvantage of a 2 percentage-point risk premium on discount rates that is associated with the RHO in the central scenario. (Appendix D provides details of the deeming assumptions for specific technologies under different scenarios.)

These numbers are indicative only, and it is not possible to judge whether the degree of cost and output heterogeneity that our deeming parameter assumptions reflect correspond to what would be relevant under the actual implementation of deeming in future policy. More accurate and precise estimates of the effects of deeming would require better information about the range of different output levels and costs for the different renewable heat technologies as well as more realistic deeming methodologies.

# 4. Summary and Suggestions for Further Research

## 4.1. Summary of Findings

The following are a summary of the main findings of this study.

§ The study calculates costs and benefits associated with reaching a share of renewables in heat consumption of 7, 11, and 14 percent by 2020.

§ Reaching a 7 percent share of renewables in heat generation by 2020 (42 TWh) is relatively inexpensive given the assumptions used in our modelling, and if electric heating could be replaced by renewables may incur little or no additional resource cost provided barriers to renewable heat demand and supply are actually overcome at the costs estimated by Enviros.

§ Reaching a renewable share of 11 percent by 2020 (67 TWh / year) would incur a resource cost under the RHI of £1.0bn per year in 2020, with costs increasing to £3.1bn with a 14 percent share (90 TWh / year). With the higher discount rates that we assume under an RHO, the costs would increase to £1.3bn and £3.9bn in 2020, respectively.

§ These costs capture the higher technology cost of renewables, as well as the time and transaction costs of policy compliance and administration; and costs of overcoming barriers to the rapid increases in the demand and supply of renewable heat implied by the target. The administrative and barrier costs constitute a significant share of the total resource cost, at around 50-65 percent of the total, depending on the level of output.

§ The dominant renewable heat technology is biomass, which accounts for more than two-thirds of renewable heat output at the 11 percent target, and half in the 14 percent target. Heat pumps also are relatively cost-effective but appear to have limited installation potential, based on Enviros's assessment. At higher output levels, large amounts of costlier solar heat and biogas are necessary to reach the target level of output.

§ The opportunities for renewable heat are concentrated in the domestic sector, which accounts for around two-thirds of renewable heat output, but only around half of total UK heat demand. The opportunities in industry are limited by the difficulty of using renewable heat for many process heating applications.

§ The use of 11 percent renewables for heating would reduce $CO_2$ emissions by an estimated 17 $MtCO_2$ in 2020, while the 14 percent share corresponds to an emissions reduction of 24 $MtCO_2$ in 2020. Renewables would displace natural gas and non net-bound fuels (coal, oil, and LPG) by similar amounts, each corresponding to 40-45 percent of the energy displaced (with the remainder displaced electricity).

§ At the 14 percent share, total subsidies to renewable heat under the RHO reach nearly £10bn per year. This corresponds to an increase in annual energy bills of some £200 per household by 2020. Increases for other sectors are proportionate to energy consumption.

§ Under policies where all sources of renewable heat are paid the same per-MWh subsidy the total payments are significantly higher than total cost. The modelling indicates these "rents" may amount to as much as £3.6-4.2bn for the 11 percent share, and £5.2-6bn for the 14 percent share.

- Rents arise because all categories of renewable heat receive the level of payment necessary to make viable the highest-cost technology necessary to meet the required output level, while the cost of renewable heat varies significantly by sector, technology, and fuel displaced (and the potential for lower-cost measures is limited).

- Various factors may limit these rents, and thus the total subsidies paid. Under either the RHO or the RHI, support could be "banded" to reduce rents. Under one indicative example, offering biomass technologies just half the level of support available to other technologies could reduce rents by around 35 percent. However, banding (especially if based on limited data) is likely to increase resource costs because of the uncertainties associated with setting the appropriate level of support. (Banding also could complicate efforts to link a UK scheme to a potential pan-European trading scheme for renewable energy certificates.)

- Much of the information developed for this study is highly uncertain. This is both because the future developments of key parameters (e.g., fossil fuel prices) are uncertain and because knowledge about the potential for, barriers to, and cost of using renewables for heating is limited. In particular, assumptions about the availability of biomass (both domestic and imported) have a very significant impact on our modelling results, and would benefit from further research. Other sources of uncertainty include the feasibility of the rapid acceleration in renewable heat use and the efficacy of the policies—either in ensuring subsidies available to eligible renewable heat projects are taken up, or that risks to end-users are reduced (which otherwise could raise the cost of capital for investment therefore the resource cost of the policy).

- The policies perform differently under uncertainty. We find that the cost of meeting a fixed target of renewable heat under an RHO is sensitive to various modelling assumptions. Higher fossil fuel prices could reduce significantly the estimated cost of meeting the targets. Additionally, different assumptions about the costs of overcoming barriers or about the efficacy of the policy could have a significant impact on the results.

- In contrast, under an RHI the amount of output could vary significantly with input assumptions. Adverse conditions for renewable heat could cause the output target to be missed, while more favourable conditions would lead to higher output and commensurately higher subsidy payments. The RHI therefore offers much less certainty about meeting a target level of output than an RHO with a strict quantity target.

## 4.2. Suggestions for Further Research

We suggest that the following would be important areas for further research to strengthen the quantitative assessment provided here:

§ ***Qualitative properties of support mechanisms.*** As highlighted in the Phase I report, achieving a working policy through either an RHO or RHI could be complex, and many issues would need to be clarified in consultation with stakeholders before the policy could be developed further. This in turn would clarify aspects that would be relevant to the quantitative assessment presented in this report, including administrative costs and barriers.

§ ***Potential for renewable heat.*** The estimates of the potential for renewable heat could be improved by further analysis, taking into account the findings of this study about the relative cost-effectiveness of different options. It also could be improved by considering alternative scenarios for the availability of biomass, which imposes a very important constraint on the current modelling.

§ ***Barriers and potential by fuel counterfactual.*** There currently is only limited analysis of how the potential for renewable heat may be distributed between different fuel counterfactuals, and which barriers may be faced by different segments of current users of gas, non net-bound, and electricity for heat.

§ ***Risks from missing energy reduction targets.*** The scenarios investigated here rely on a sharp improvement in energy efficiency and thus reduction in overall energy use until 2020. If energy efficiency were not increased at this rate, costs of reaching the renewable heat targets of 11 / 14 percent would increase.

§ ***Details of banding.*** The quantitative analysis could be refined use to reflect different approaches to banding, including different definitions of banding categories and levels of support for each band.

§ ***Linking to the Renewables Obligation.*** It would be possible to develop a join certificates scheme for heat and electricity. This would raise several issues for the quantitative analysis, including the implied exchange rate for certificates for the two types of energy.

§ ***Impact of volatility and safety valve arrangements.*** The RHO may require the use of a “safety valve” to avoid spikes in the certificate price. Different mechanisms would be available, including “buy-out” arrangements, linking to other schemes, and the use of intertemporal trading in the form of banking / borrowing.

§ ***Potential for international trading to meet renewables targets and implications for policy design.*** It would be possible to link an RHO to similar systems in other countries, much as the EU ETS is being linked to other countries. Some trading of renewable certificates within Europe already occurs (governed by rules for Guarantees of Origin for Renewable Energy Certificates). It would be possible for the UK to participate in this market – either letting individual market participants buy and sell certificates from abroad or by taking a more active Government role in trading with other countries. Decentralised trading probably would be feasible only under the RHO, but various provisions of an RHO could complicate attempts to link with other countries' schemes – including banding and safety valves.[26] We have not attempted to model the prospects for or implications of international certificate trading here.

[26] With banding, each issued certificate potentially corresponds to a different amount of renewable energy. All countries would have to agree how certificates of each technology from each country would be treated before it would be possible to account for traded compliance. Moreover, from the perspective of renewable heat producers, if it were possible for a UK biomass heat facility (or household) to take advantage of higher incentives for biomass in *other* Member States through international trading, such facilities would have little incentive to offer their output for compliance within the UK – they would be better off selling the "green attributes" of their output to the international market. If this were allowed, it would be much more difficult to minimise the level of infra-marginal rents that could be earned by these producers, because they would simply receive the market price unless all countries banded certificates in the same way. Thus there is likely to be a trade-off between the potential savings in resource costs offered by international trading and the potential reductions in consumer costs that may be possible through banding.

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# Appendix A. Cost Curves by Technology / Sector

Figures Figure A.1 and Figure A.2 indicate the cost curve for the central case presented in section 3.1, indicating the segments represented by different technologies and sectors, respectively. The costs and potentials data are for 2020, and are net of levelised technology costs, administrative costs, and supply- and demand-side barrier costs.

**Figure A.1**
**Renewable Heat Cost Curve by Technology (2020)**

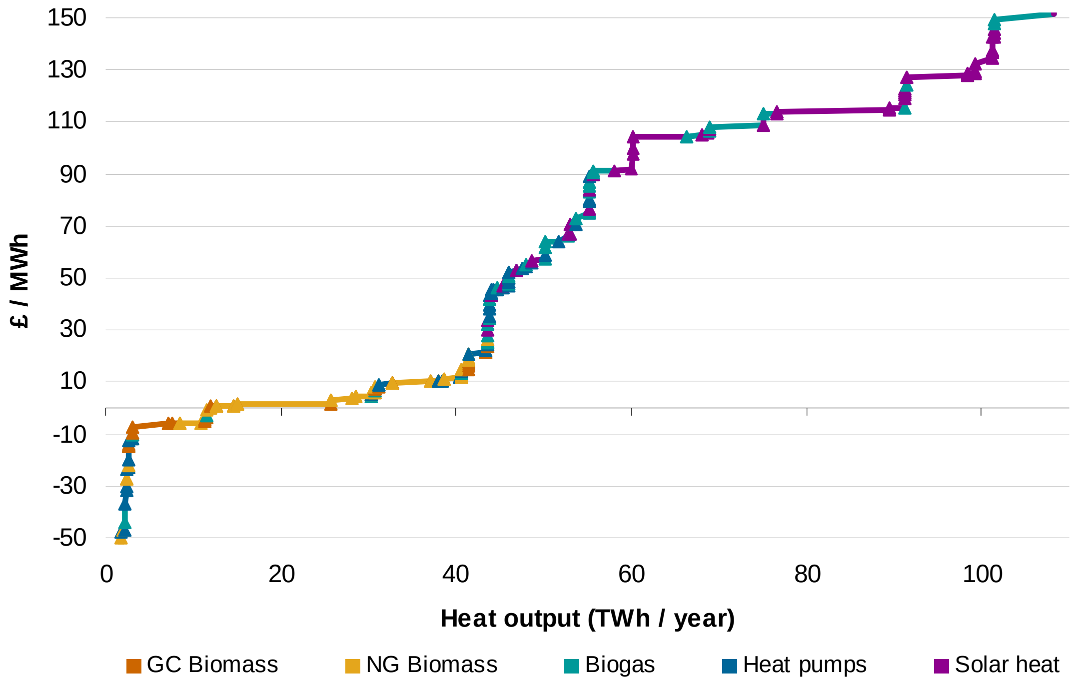
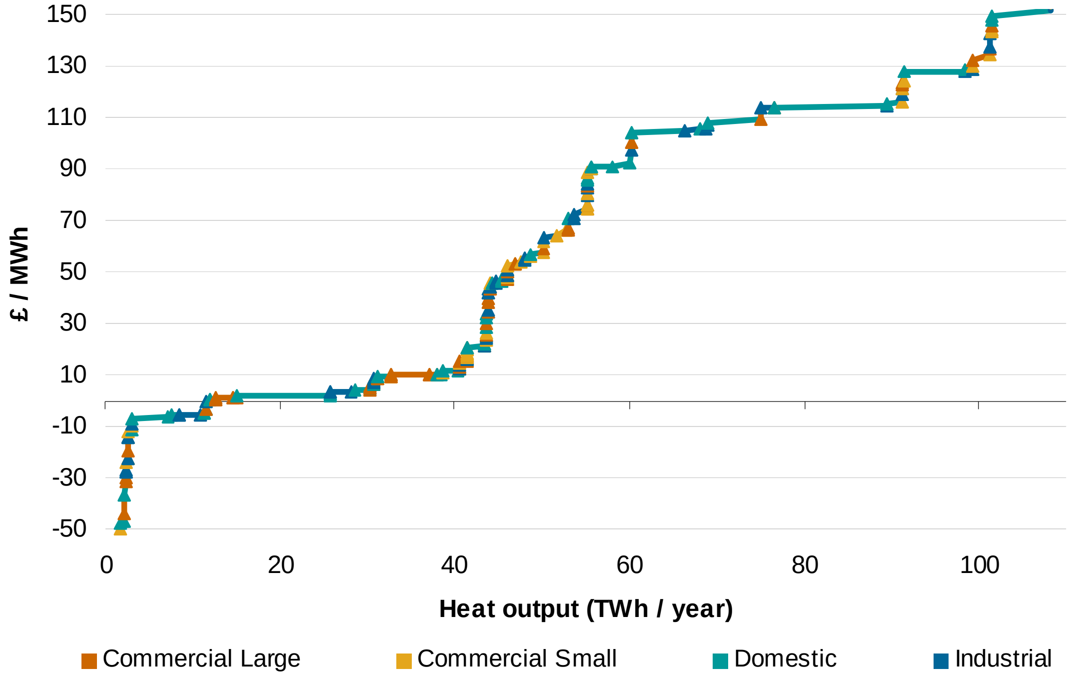


**Figure A.2**
**Renewable Heat Cost Curve by Sector (2020)**



# Appendix B. Cumulative Headline Results to 2030

Table B.1 and Table B.2 show headline modelling results cumulative over the period 2010-2030. Presenting these cumulative data gives rise to the question of whether some or all of the financial results (resource cost, subsidy, rents, certificate price or incentive, and resource cost per MWh) should be discounted. Costs arguably should be discounted if included in a social cost-benefit analysis. It is less clear that rents or subsidies (which are a transfer rather than a cost) should be discounted. For completeness, and to enable comparisons with estimates previously published by BERR and with other studies of the 2020 renewables target, we publish both undiscounted and discounted results. Table B.1 shows results without any discounting applied, whereas Table B.2 shows the same information using a discount rate of 3.5 percent per year for *all* financial results (heat output and $CO_2$ savings are not discounted).

**Table B.1**
**Headline Modelling Results Cumulative to 2030 (Not Discounted)**

| | | RHO | | | RHI | | |
|---|---|---|---|---|---|---|---|
| **Variable** | **Units** | **Scn 1** | **Scn 2** | **Scn 3** | **Scn 1** | **Scn 2** | **Scn 3** |
| Renewable heat output | TWh | 474 | 813 | 1,110 | 474 | 816 | 1,100 |
| Resource cost | £bn | -0.8 | 15.6 | 43.8 | -1.5 | 12.0 | 34.6 |
| Subsidy | £bn | 5.2 | 67.7 | 116.9 | 4.1 | 55.9 | 97.3 |
| Rents | £bn | 6.0 | 52.1 | 73.1 | 5.6 | 43.9 | 62.8 |
| Certificate price or incentive | £/MWh | 12 | 89 | 113 | 9 | 73 | 95 |
| Resource cost per MWh | £/MWh | -2 | 19 | 39 | -3 | 15 | 31 |
| CO2 savings | MtCO2 | 143 | 229 | 314 | 142 | 231 | 312 |
| Outside EU ETS | MtCO2 | 101 | 151 | 223 | 100 | 151 | 224 |
| Within EU ETS | MtCO2 | 42 | 79 | 91 | 42 | 79 | 87 |

**Table B.2**
**Headline Modelling Results Cumulative to 2030 (Discounted)**

| | | RHO | | | RHI | | |
|---|---|---|---|---|---|---|---|
| **Variable** | **Units** | **Scn 1** | **Scn 2** | **Scn 3** | **Scn 1** | **Scn 2** | **Scn 3** |
| Renewable heat output | TWh | 474 | 813 | 1,110 | 474 | 816 | 1,100 |
| Resource cost | £bn | -0.5 | 10.3 | 29.0 | -1.0 | 7.9 | 22.9 |
| Subsidy | £bn | 3.4 | 44.8 | 77.4 | 2.7 | 37.0 | 64.4 |
| Rents | £bn | 4.0 | 34.5 | 48.4 | 3.7 | 29.1 | 41.5 |
| Certificate price or incentive | £/MWh | 8 | 59 | 75 | 6 | 49 | 63 |
| Resource cost per MWh | £/MWh | -1 | 13 | 26 | -2 | 10 | 21 |
| CO2 savings | MtCO2 | 143 | 229 | 314 | 142 | 231 | 312 |
| Outside EU ETS | MtCO2 | 101 | 151 | 223 | 100 | 151 | 224 |
| Within EU ETS | MtCO2 | 42 | 79 | 91 | 42 | 79 | 87 |

# Appendix C. Technology Cost Assumptions

The three tables below show input assumptions about technology cost and other attributes for conventional and renewable heat technologies used in the modelling. These costs are shown in 2008 terms. The assumptions have been provided by Enviros Consulting, based on literature review and in-house expertise and experience. Note that the costs are only technology costs, and do not include other costs that may be associated with making a property suitable for installation, or other barrier costs. For more information please see Enviros (2008a), which contains discussion about the underlying assumptions.

**Table C.1**
**Cost and Technology Assumptions for Conventional Heating Technologies**

| Sector | Fuel | Capex | Fixed opex | Load factor | Efficiency (HHV ) | Lifetime |
|---|---|---|---|---|---|---|
| | | £/kW | £/kW/year | % | % | Years |
| Commercial Large | Electricity | 221 | 11 | 20% | 85% | 15 |
| Commercial Small | Electricity | 221 | 11 | 20% | 85% | 15 |
| Domestic | Electricity | 175 | 17 | 20% | 85% | 15 |
| Industrial | Electricity | 147 | 7 | 35% | 85% | 15 |
| Commercial Large | Gas | 60 | 3 | 50% | 85% | 15 |
| Commercial Small | Gas | 45 | 3 | 35% | 85% | 15 |
| Domestic | Gas | 50 | 5 | 6% | 85% | 15 |
| Industrial | Gas | 30 | 1 | 75% | 85% | 15 |
| Commercial Large | Non net-bound | 50 | 3 | 50% | 85% | 15 |
| Commercial Small | Non net-bound | 50 | 3 | 35% | 85% | 15 |
| Domestic | Non net-bound | 60 | 8 | 9% | 85% | 15 |
| Industrial | Non net-bound | 50 | 1 | 75% | 85% | 15 |

***Source***: *Enviros Consulting, based on literature review and other sources*

## Table C.2
## Cost and Technology Assumptions for Renewable Heating Technologies

| Technology | Sector | Capex<br>£/kW | Fixed opex<br>£/kW/year | Load factor<br>% | Efficiency (HHV )<br>% | Lifetime<br>Years |
|---|---|---|---|---|---|---|
| Biomass Heat Grid Connected | Commercial Large | 615 | 15 | 50% | 87% | 15 |
| Biomass Heat Grid Connected | Commercial Small | 615 | 15 | 50% | 87% | 15 |
| Biomass Heat Grid Connected | Domestic | 615 | 15 | 50% | 87% | 15 |
| Biomass Heat Grid Connected | Industrial | 615 | 15 | 50% | 87% | 15 |
| Biomass Heat Non Grid | Commercial Large | 313 | 18 | 30% | 87% | 15 |
| Biomass Heat Non Grid | Commercial Small | 368 | 18 | 30% | 87% | 15 |
| Biomass Heat Non Grid | Domestic | 528 | 18 | 30% | 87% | 15 |
| Biomass Heat Non Grid | Industrial | 274 | 18 | 70% | 87% | 15 |
| Ground Source Heat Pumps | Commercial Large | 800 | 9 | 25% | 400% | 20 |
| Ground Source Heat Pumps | Commercial Small | 1000 | 9 | 25% | 400% | 20 |
| Ground Source Heat Pumps | Domestic | 1200 | 9 | 25% | 400% | 20 |
| Ground Source Heat Pumps | Industrial | 800 | 9 | 25% | 400% | 20 |
| Air-source heat pumps | Commercial Large | 450 | 9 | 25% | 325% | 20 |
| Air-source heat pumps | Commercial Small | 600 | 9 | 25% | 325% | 20 |
| Air-source heat pumps | Domestic | 600 | 9 | 25% | 325% | 20 |
| Air-source heat pumps | Industrial | 450 | 9 | 25% | 325% | 20 |
| Solar Heat | Commercial Large | 800 | 4 | 11% | - | 20 |
| Solar Heat | Commercial Small | 1000 | 4 | 11% | - | 20 |
| Solar Heat | Domestic | 1000 | 4 | 11% | - | 20 |
| Solar Heat | Industrial | 800 | 4 | 11% | - | 20 |
| Biogas | Commercial Large | 1370 | 34 | 50% | - | 15 |
| Biogas | Commercial Small | 2819 | 70 | 50% | - | 15 |
| Biogas | Domestic | 2819 | 70 | 30% | - | 15 |
| Biogas | Industrial | 1370 | 34 | 30% | - | 15 |

***Source****:* *Enviros Consulting, based on literature review and other sources*

## Table C.3
## Capex Cost Indices for Renewable Heat Technologies (2010=100)

| Year | Biomass Heat Grid Connected | Biomass Heat Non Grid | Ground Source Heat Pumps | Biogas | Solar Heat |
|---|---|---|---|---|---|
| 2010 | 100 | 100 | 100 | 100 | 100 |
| 2011 | 99 | 99 | 97 | 99 | 99 |
| 2012 | 97 | 97 | 95 | 97 | 97 |
| 2013 | 96 | 96 | 93 | 96 | 96 |
| 2014 | 94 | 94 | 90 | 94 | 95 |
| 2015 | 93 | 93 | 88 | 93 | 93 |
| 2016 | 91 | 91 | 86 | 91 | 92 |
| 2017 | 90 | 90 | 84 | 90 | 91 |
| 2018 | 89 | 89 | 82 | 89 | 90 |
| 2019 | 87 | 87 | 80 | 87 | 89 |
| 2020 | 86 | 86 | 78 | 86 | 87 |

***Source****:* *Enviros Consulting, based on literature review and other sources*

# Appendix D. Deeming Assumptions

In all of the scenarios that we model, we assume that some form of deeming is used in both the RHO and the RHI. The reasons for this assumption are set out in our Phase I report on policy options to promote renewable heat. Table D.1 sets shows the technologies for which we assume that deeming will be used in most scenarios – these include non-grid biomass (because of the possible need to compensate equipment manufacturers and installers up-front), heat pumps, and solar heating technologies. The table also shows our assumptions for a reduced deeming scenario, designed primarily to test the sensitivity of the results to deeming. In this latter scenario, only solar heat is deemed, implying that heat from the other technologies would need to be measured in some way (possibly by proxy). For the reduced deeming scenario we do not attempt to reflect any additional costs that may result from the need to measure delivered heat.

**Table D.1**
**Deeming Assumptions Used in Modelling**

| Technology | Sector | Default Scenario | Reduced Deeming |
|---|---|---|---|
| Biomass Heat Grid Connected | Commercial Large | Not Deemed | Not Deemed |
| Biomass Heat Grid Connected | Commercial Small | Not Deemed | Not Deemed |
| Biomass Heat Grid Connected | Domestic | Not Deemed | Not Deemed |
| Biomass Heat Grid Connected | Industrial | Not Deemed | Not Deemed |
| Biomass Heat Non Grid | Commercial Large | Deemed | Not Deemed |
| Biomass Heat Non Grid | Commercial Small | Deemed | Not Deemed |
| Biomass Heat Non Grid | Domestic | Deemed | Not Deemed |
| Biomass Heat Non Grid | Industrial | Deemed | Not Deemed |
| Biogas | Commercial Large | Not Deemed | Not Deemed |
| Biogas | Commercial Small | Not Deemed | Not Deemed |
| Biogas | Domestic | Not Deemed | Not Deemed |
| Biogas | Industrial | Not Deemed | Not Deemed |
| Heat Pumps | Commercial Large | Deemed | Not Deemed |
| Heat Pumps | Commercial Small | Deemed | Not Deemed |
| Heat Pumps | Domestic | Deemed | Not Deemed |
| Heat Pumps | Industrial | Deemed | Not Deemed |
| Solar Heat | Commercial Large | Deemed | Deemed |
| Solar Heat | Commercial Small | Deemed | Deemed |
| Solar Heat | Domestic | Deemed | Deemed |
| Solar Heat | Industrial | Deemed | Deemed |

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