Bagdonaite, Dovile

From:	Wightman, Stuart
Sent:	04 May 2016 18:27
To:	O'Neill. Brian
Cc:	Hughes, Seamus; Woods, Michael (DETI); Mills, John (DETI)
Subject:	RE: RHI
Attachments:	Annex A - RHI Economic Analysis - Feb 2012.PDF

Brian

I can confirm that the Consultants were asked to revisit the assumptions in their economic assessment following the Department's public consultation and subsequent responses. The attached Addendum was completed in 2012 which formed the basis for the initial tariff of 5.9p. The table on p15 of the business case shows the two different sets of tariffs.

Unfortunately, I can't explain the statement made in the business case that '*Tiering is not included in the NI scheme because in each instance the subsidy rate is lower than the incremental fuel cost"* as the business case shows biomass to be only 0.47p/kwh more expensive than oil yet the reduced tier would be higher than this.

I'll come back on your other points asap.

Thanks, Stuart

From: O'Neill. Brian
Sent: 04 May 2016 16:25
To: Wightman, Stuart
Cc: Wilkinson, Tomas
Subject: RHI

Stuart
From looking at the initial report from the consultants on 28 June 2011, page 65 of this report suggests a tariff level of 4.5p. The business case then seems to suggest a tariff of 5.9p (page 17 and 104) and the final agreed tariff was 6.4p.
Why did these rates change and why were the rates recommended by the consultants not used?

Also the consultants recommended that the GB tariff rates were used in the scheme – why did this not happen?

There is also a comment in the business case (page 17) which states that "Tiering is not included in the NI scheme because in each instance the subsidy rate is lower than the incremental fuel cost" when it seems that this was not the case?

Also in relation to the role of OFGEM auditing the scheme, has the Department any input into how many applications should be audited and how often these audits should be carried out, what work is required in each audit and at what stage is the Department provided with results/ concerns.

Grateful if you could also provide confirmation of the application numbers for both schemes and costs involved per my previous request.

We'd like to issue the report to Andrew McCormick next week – prior to this, we'd like to meet with you to discuss some of the issues – myself and Tomas are available any time on Monday afternoon, Tuesday afternoon or Wednesday afternoon.

Please let me know when suits to meet and discuss.
Happy to clarify any of the requests above.
Many thanks

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Regards
Brian

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A Renewable Heat Incentive for Northern Ireland
Addendum

16 February 2012

Submitted by:

Cambridge Economic Policy Associates Ltd and AEA Technology Limited

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EXECUTIVE SUMMARY

On 20 July 2011, DETI launched a public consultation on the development and implementation of a Northern Ireland Renewable Heat Incentive (RHI). The overall objective of the Northern Ireland RHI was to support the achievement of 10% renewable heat by 2020. The proposals outlined in the consultation were largely informed by CEPA and AEA's economic appraisal[1] of various options for incentivising the Northern Ireland renewable heat market.

The consultation closed on 3 October 2011. Seventy-eight responses were received; these can be found on DETI's website[2].

We understand from DETI that there was widespread support for the introduction of a Northern Ireland RHI, as well as an acknowledgement that it is important that a Northern Ireland approach is taken in relation to support for the renewable heat market. However, we also understand that there were a number of areas where consultees were not fully in agreement with the current DETI proposals, including:

- the proposed level of tariff rates (with evidence provided to suggest alternative pricing assumptions);
- the appropriateness of the existing banding; and
- the interaction between DETI policies on the extension of the gas network and renewable heat, specifically in relation to policy on supporting large industrial sites.

As a result, DETI asked CEPA and AEA to reconsider their assumptions, in the light of the new evidence presented. We were asked to revisit and, where appropriate, update existing cost assumptions and banding methodology and consider the resulting implications for tariffs and overall costs.

We have reviewed the new evidence, and updated our cost assumptions for biogas injection and for wood chip. We have also included ongoing barrier costs for renewable heat, as in the GB RHI. In addition, we have included cost assumptions for geothermal, which was not considered in our previous work. Finally, we have adjusted the tariff bandings for biomass and ground source heat pumps (GSHPs), and modified our economic model so that it always chooses a reference installation in 2011 or 2012. Following these changes, we have re-run the model with the new assumptions.

The high level results are shown in Table 1 below, which sets out the revised tariff levels and banding that we propose. We have shown the tariffs from our original report[3] for ease of reference.

[1] CEPA/ AEA for DETI, *Renewable Heat Incentive For Northern Ireland*, June 2011, available at: http://www.detini.gov.uk/economic_appraisal_into_the_northern_ireland_rhi_-_june_2011.pdf

[2] www.detini.gov.uk

[3] Table 5 in that report

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Table 1: Implications of updated assumptions for tariffs (all figures in p/kWh and based on quarterly payments)

Technology size band	Size range (kW)[4]	Tariff in original report	Updated tariff[5]	Notes
ASHP – Small	0-45	3.3	4.0	Increase due to inflation and switch to 2011/12 reference installation
ASHP – Medium	45+	-		
Biogas injection – All	All	2.5	3.0	Change to assumption on gate fee
Biomass boilers – domestic	0-20	4.5	6.2	Increase due to inflation, switch to 2011/12 reference installation and inclusion of ongoing barrier costs
Biomass boilers – small	20-100	4.5 (<45kW) 1.3 (45kW+)	5.9	Intermediate tariff based on 50kW boiler. Increase due to inflation and inclusion of ongoing barrier costs
Biomass boilers – medium	100-1,000	1.3	1.5	Increase due to inflation and switch to 2011/12 reference installation
Biomass boilers – large	1,000+	-		
GSHP – domestic	0-20	4.0	8.4[6]	Change to the reference installation means a higher tariff
GSHP – small	20-100	4.0 (<45kW) 0.9 (45kW+)	4.3	Intermediate tariff based on 30kW pump
GSHP – large	100+	0.9	1.3	Increase due to inflation and switch to 2011/12 reference installation
Geothermal	All	n/a	1.6	Indicative tariff only[7]

[4] The range should be read as including the lower end, but not the upper end. For example, the range 20-100 includes 20kW boilers but not 100kW boilers – the latter are covered by the 100-500 range.

[5] Includes inflation, and effect of changes to technology costs and tariff bands

[6] This tariff reflects a deeming approaching for the domestic sector. If a metered approach was introduced a tiered tariff would be more appropriate. This would be 9.3p/kWh for the first 1314 hours and then 4.9p/kWh after that.

[7] This tariff is based on geothermal primarily displacing domestic heating. The tariff is dependent on the assumption about the type of heating being displaced, and depending on which assumption is chosen, a tariff of between 1.6 and 4.6p could be appropriate.

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Technology size band	Size range (kW)[4]	Tariff in original report	Updated tariff[5]	Notes
Liquid biofuels – small	0-45	1.5	1.6	Increase due to inflation and switch to 2011/12 reference installation
Liquid biofuels – medium/ large	45+	-		
Solar Thermal	All	8.5		

As can be seen, the tariffs have changed for all technologies. In some cases, these changes are quite significant (e.g. heat pumps, because of a shift in our assumption about technology costs). In many cases, however, the changes are very small and explained by inflation and a slight shift in reference installation. A new (indicative) tariff has been added for geothermal, although given the very small number of potential installations in Northern Ireland between now and 2020, some other form of support is likely to be more appropriate, such as some form of administered grant, most likely with provisions for clawback in the event of high performance.

Comparing the tariffs directly to those in Great Britain is difficult, since the tariff bands are different. However, in general our proposed tariffs are lower. The main reason for this is as set out in our previous report – that is, the higher cost of oil heating in NI compared to gas heating which predominates in GB. This is less the case for heat pumps, since they use electricity which is relatively more expensive in Northern Ireland than in GB.

Comparisons of specific tariffs are in Table 2 below.

Table 2: Comparison of NI and GB RHI rates[8]

Technology size band	Size range (kW)	Proposed NI tariff	Nearest GB equivalent
Biogas injection – All	All	3.0	6.5
Biomass boilers – small	20-100	5.9	7.6 for the first 1,314 hours and then 1.9
Biomass boilers – medium	100-1,000	1.5	4.7 for the first 1,314 hours and then 1.9
Biomass boilers – large	1,000+	-	1.0
GSHP – small	20-100	4.3	4.3
GSHP – large	100+	1.3	3.0
Geothermal	All	1.6	3.0[9]

[8] Not all technologies are shown since in some cases there is not a GB equivalent.
[9] Deep geothermal can receive the same tariff as large GSHPs.

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Technology size band	Size range (kW)	Proposed NI tariff	Nearest GB equivalent
Solar Thermal	All	8.5	

The high-level impact of these new tariffs, and other minor changes that DETI has asked us to make[10], is shown in Table 3 below.

Table 3: Impact of RHI in 2020, including baseline and viable installation[11]

	Renewable Heat delivered (% of total 2020 heat demand)	Lifetime subsidy spending in present value terms (£m)
Before changes	11.14%	334
After changes	11.10%	445

In summary, the changes have a minor impact on renewable heat deployed, but noticeably increase the costs (because of the higher tariffs). The total subsidy spending is still constrained by the annual budget limits in our previous report[12].

As noted in our previous report, we recommend a review of tariffs after two to three years.

[10] Such as delaying ASHP and bioliquids tariffs until 2013

[11] Assuming long-term funding - £25m to 2014/15, with an additional £5m per year from 2015/16. This assumes no geothermal before 2020.

[12] £2m in 2011, £4m in 2012, £7m in 2013, £12m in 2014 and increasing by £5m per year thereafter until 2020.

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1. INTRODUCTION

CEPA and AEA Technology have been asked by the Department of Enterprise, Trade and Investment (DETI) to perform additional analysis on a possible Renewable Heat Incentive (RHI) for Northern Ireland. This follows our previous report, which was published alongside DETI's consultation on the RHI.

Since that report was published, further information has become available. The purpose of this addendum to our previous report is to consider that information, and other issues that have arisen as a result of DETI's consultation, and provide additional analysis on tariffs and the wider impacts of an RHI. Further details on the background to this project are in the next section.

1.1. Background and context

In this section we very briefly set out the context for the analysis discussed in later sections. We start with our previous report for DETI, which this work follows on from.

1.1.1. Previous report

Our previous report for DETI looked at "*...the most appropriate form of [an RHI] for Northern Ireland*"[13]. It set out an RHI that while similar to the GB RHI in many ways, differed on the subsidy levels and on the technologies supported. We noted that previous work[14] had shown that a GB RHI would be sub-optimal for Northern Ireland. In particular, it would not achieve the 10% renewable heat target, whereas our analysis suggested that the rates we proposed could achieve that target.

The report was published as part of DETI's consultation[15] on the RHI. As part of the responses to that consultation, DETI has received additional material, which we now turn to.

1.1.2. New material received in response to consultation

We understand from DETI that there was widespread support for the introduction of a Northern Ireland RHI, as well as an acknowledgement that it is important that a Northern Ireland approach is taken in relation to support for the renewable heat market. However, we also understand that there were a number of areas where consultees were not fully in agreement with the current DETI proposals, including:

- the proposed level of tariff rates (with evidence provided to suggest alternative pricing assumptions);
- the appropriateness of the existing banding; and
- the interaction between DETI policies on the extension of the gas network and renewable heat, specifically in relation to policy on supporting large industrial sites.

[13] ibid, page 5.

[14] AECOM/ Pöyry, 2010, *Assessment of the Potential Development of Renewable Heat in Northern Ireland: Final Report*

[15] http://www.detini.gov.uk/consultation_on_the_development_of_the_northern_ireland_renewable_heat_incentive

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In particular, responses were received on the technology costs and banding for biomass, biomethane, bioliquids, GSHPs and geothermal.

Technology costs are a major factor in determining the RHI tariffs that we suggested in our report. We have therefore been asked by DETI to review our assumptions on technology costs, in the light of the new information received, and update tariffs if appropriate. This and the other specific tasks assigned by DETI, are discussed below.

1.1.3. Terms of reference from DETI for extension

Our first task has been to update the technology costs, and where appropriate tariffs, for the following technologies: biomass, bioliquids, biomethane and ground source heat pumps. We have also been asked to consider what a tariff for geothermal might look like. Our results have been set out in a form agreed with DETI (see Annex A, for details of the tariffs, and Annex B for details of overall impact).

DETI has also asked us to consider at a high level the possible impact on gas demand of providing a tariff for large scale biomass and the potential for a shift to the use of biomass in the large industrial sector.

1.2. Structure of report

Following this introduction, our report is structured as follows:

- Section 2 outlines the methodology that we have used for this analysis;
- Section 3 sets out our results and conclusions;
- Annex A includes tables showing technology cost assumptions, and the breakdown of each tariff by capital, operating and fuel costs; and
- Annex B includes a table summarising key impacts of the policy, such as CO_2 emissions saved and renewable heat delivered per year.

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2. METHODOLOGY

Much of our work for this report involves applying elements of our methodology from our previous report. We briefly summarise this below. Where the requirements involve a new methodology or approach, we have given more detail.

2.1. Technology costs and tariff bands

AEA has reviewed all the consultation responses received from DETI, and compared it with other data sources available to it. This included publically available sources of information released since the original report such as recent fuel prices.

As well as revisiting technology costs, DETI has also asked us to revisit the banding for biomass and GSHPs. Specifically, it was felt that there needed to be finer-grained banding for both technologies. We have reviewed the views of consultees, and the GB approach, in coming to our recommendations.

2.2. Tariff setting

Changes to costs and tariff bands require us to recalculate tariffs for some technologies. Our basic methodology for doing so is as in our previous report. We briefly summarise it here. Further details can be found in Annex E of that report.

Our approach to setting the NI RHI tariffs can be summarised as: first, identify the required subsidy level, in pence per kWh that just covers the additional cost of a *reference* renewable heat installation compared to a conventional oil boiler. For example, suppose that over its lifetime, an oil boiler costs 5p per kWh of heat produced, and a reference biomass boiler of similar size costs 7p per kWh. The subsidy is therefore 7p-5p=2p per kWh.

This leads to two questions: (i) what is a reference installation; and (ii) how is the average lifetime cost of a boiler or renewable heat installation calculated?

Following the GB RHI approach, we say that the reference installation for a particular technology size is the one with the average[16] cost for that technology size over all the sites where it could be installed. One change from our previous approach is that, at DETI's request, we have adjusted the model so that it always uses a reference installation from 2011/12 rather than allowing one from any year. The previous approach set tariffs based on expected future technology cost improvements, which was felt to be unnecessary given the planned regular reviews of the tariffs.

An additional change is that we have included on-going barrier costs, following the GB RHI approach and costs. In many cases, there is not a direct GB RHI equivalent. For example, there are no costs quoted for ASHPs or for domestic installations for any technologies.

For ASHPs, we have used the figures for GSHPs. For domestic installations, we have taken the assumed cost for the smallest commercial sites under the GB RHI and scaled this to reflect the

[16] More precisely, the median.

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different value of time assigned to domestic (£15/ hour) and commercial/ industrial (£70/ hour)[17] users.

In most cases, these ongoing barriers make little difference to the tariffs, because they are small in comparison to the other costs. However, they do noticeably increase the tariffs for small biomass.

To calculate the average lifetime cost, we calculate the annual operating and fuel cost, and add this to the annuitized cost of the upfront capital, installation and barrier costs[18]. We then divide this cost per year by the average annual heat produced to obtain a figure for cost per unit of heat.

2.3. Delays to tariffs

At DETI's request, we have delayed the tariffs for ASHPs and bioliquids until 2013 (tariffs for other technologies start in 2012). We have also removed the small number of installations originally expect to take up renewable heat in the model in 2011. These changes have only a very small impact.

[17] Hourly rates are sourced from: NERA and AEA (2009), *The UK Supply Curve for Renewable Heat*, paragraph 2.4.4.3

[18] Barrier costs divide into two types – upfront and ongoing costs. Upfront costs are determined as a number of days required to install the new equipment, times an assumed hassle cost per day (following the approach used for the GB RHI). Ongoing costs are taken from those used in the GB RHI.

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3. RESULTS

This section presents the results of the analysis that we performed, using the methodology from the previous section. To recap, DETI asked us to update technology costs and tariffs, and look at the impact on renewable heat delivered, carbon dioxide emissions, costs and gas demand.

3.1. Changes to banding

As noted in Section 3, we have updated the banding for biomass and ground source heat pumps (GSHPs). The new bands are set out below.

3.1.1. Biomass banding

The biomass bandings (less than 45kW and above 45kW) have been criticised by respondents to the consultation as being too broad. Respondents requested the same or similar biomass banding as in place in GB.

The GB biomass banding between small and medium non-domestic is set at 200kW. The rationale used for this banding is that that boilers above 200kW tend to predominantly run on wood chips compared to wood pellets and that load factors generally increase for larger boilers[19]. However, it should be recognised that in reality there is no specific point where the £/kW decrease dramatically. The net result of this is that any banding mechanism will result in 'gaming' where consumers look to undersize boilers where possible.

Recommendation:

Whilst many respondents would like to see the same tariffs as GB, the average boiler size in Northern Ireland is expected to be smaller than in GB. Therefore a tailored tariff to reflect the Northern Ireland market could be beneficial to consumers. We propose the banding in Table 3.1 below.

Table 3.1: Proposed biomass boiler bandings

Band size	Comments
0-20kW	Based upon 11kW biomass boiler
20-100kW	Based upon 50kW size biomass boiler (original 20kW)[20].
100-1,000kW	Based upon 200kW boiler. This would encompass the majority of the 'large commercial/public'. Upper limit adjusted to 1,000kW to match GB.
1,000kW+	Requires consideration of how GB was treated under the EU State Aid Regulations. The large scale biomass tariff had to be reduced to 1.0p/kWh following intervention from the EU.

[19] AEA (2011) Review of technical information on renewable heat technologies

[20] In reality 20kW is very small for a non-domestic boiler and many of the installations are likely to be larger i.e. 50kW+. In a very small office it would probably not be practical from a load factor perspective that biomass would be viable. It is also likely that small office premises may be connected to larger biomass boiler heating a either one larger building with several different businesses or via a small district heat network such as holiday lets/farm business.

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3.1.2. Ground Source Heat Pump banding

Consultation responses have questioned the current tariff boundaries of less than and greater than 45kW. The differences in tariff between the lower and upper bands were also questioned during the consultation as being too large. Such a dramatic step change in project costs does not exist and therefore the tariff boundaries need revising to reduce this significant difference.

One issue is that a 60kW installation will cost more per kW than a 200kW installation. The reasons for this are the use of smaller heat pump modules and that fixed drilling costs (that is, getting drilling contractors and rig set up on site) are not spread over a larger number of borehole. The step change between bands needs revisiting as it is quite significant in Northern Ireland at 3.1p/kWh compared to 1.2 p/kWh in GB. This issue has arisen largely from the size of the reference installation.

Recommendation:

Our recommendation is to introduce what is in effect a domestic tariff; this will be based upon the existing 11kW boiler size. Further, we recommend using a 30kW GSHP size for small commercial installations, instead of 11kW. We consider that it is more likely that small commercial installations will be by landlords installing heating systems to serve multiple small businesses, rather than each business in a building installing its own heating systems. We have therefore proposed a reference size which would cover the demand from two or three small businesses, rather than just one. The 30kW reference size will also act as an interim point between domestic and large commercial installations (reference size 200kW).

This gives us the proposed bandings in Table 3.2 below.

Table 3.2: Proposed GSHP bandings

Band size	Reference size
0-20kW	11kW
20-100kW	30kW (original 11kW)
100kW +	200kW

3.2. Updated cost assumptions

In this section, we describe the new information received on technology and fuel costs, and what we have concluded as a result. Each technology that we have reviewed (biomass, biomethane, bioliquids, GSHPs and geothermal) is described below.

3.2.1. Biomass

Apart from concerns over bandings, which we addressed in the previous section, respondents' main concern was that the biomass fuel prices used for Northern Ireland were too low. In particular, it was raised several times that the local biomass price for Northern Ireland is higher than that for England. This is claimed to result from the lower levels of domestic biomass resource and the high demand encouraged by the Republic of Ireland (ROI) carbon tax of 15 €/ tonne CO_2. One stakeholder claimed that biomass wood chip was 40% more expensive in

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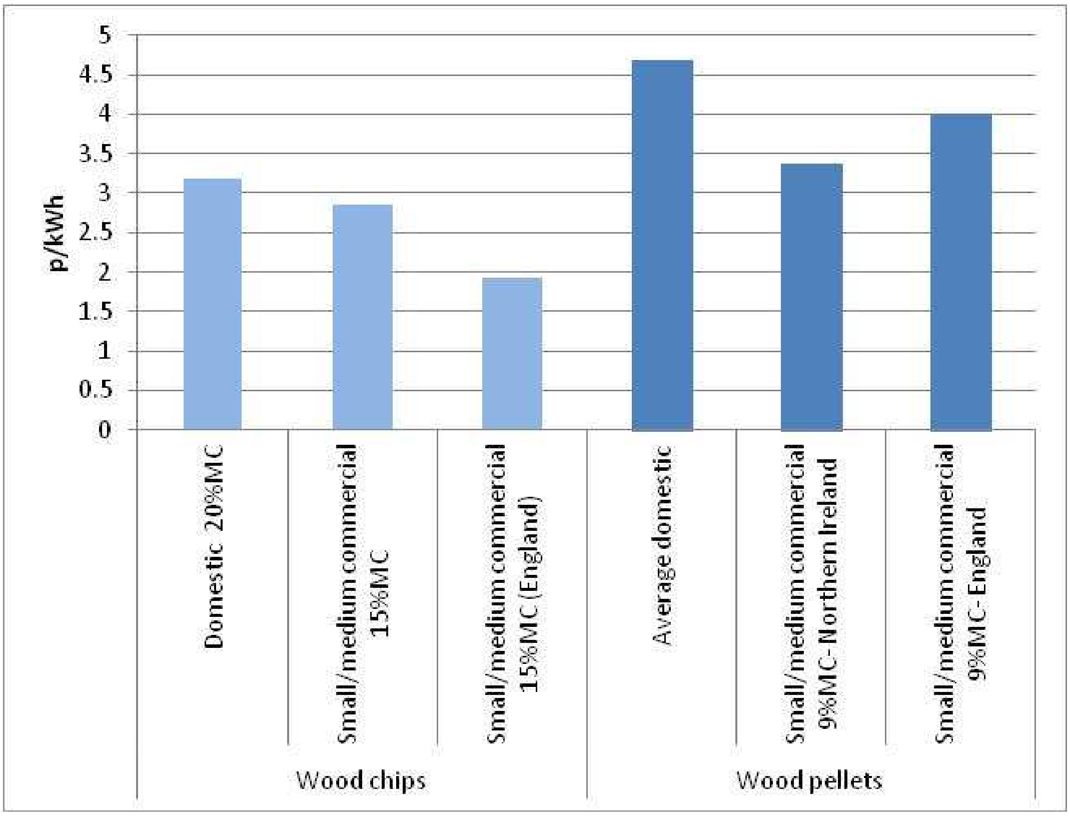
Northern Ireland compared to GB. Following these concerns AEA have evaluated the prices provided to DETI and also undertaken additional analysis by reviewing publically available chip and pellet prices from distributors in Northern Ireland and England. The findings are presented in Table 3.3 below.

Table 3.3: Biomass chip and pellet prices evaluated in January 2012

	Sector	£/t	£/GJ	p/kWh
Wood chips	Domestic 20%MC- Northern Ireland	130	8.9	3.19
	Small/medium commercial 15%MC- Northern Ireland	125	7.9	2.85
	Small/medium commercial 15%MC (England)	85	5.4	1.94
Wood pellets	Average domestic Northern Ireland	223	13.0	4.69
	Small/medium commercial 9%MC- Northern Ireland	160	9.4	3.37
	Small/medium commercial 9%MC- England	190	11.1	4.00

The p/kWh figures are shown graphically in Figure 3.1 below. As is clear from this and from the table, prices for pellets are higher than prices for wood chips, across all customer groups.

Figure 3.1: Northern Ireland biomass prices in p/kWh (delivered)



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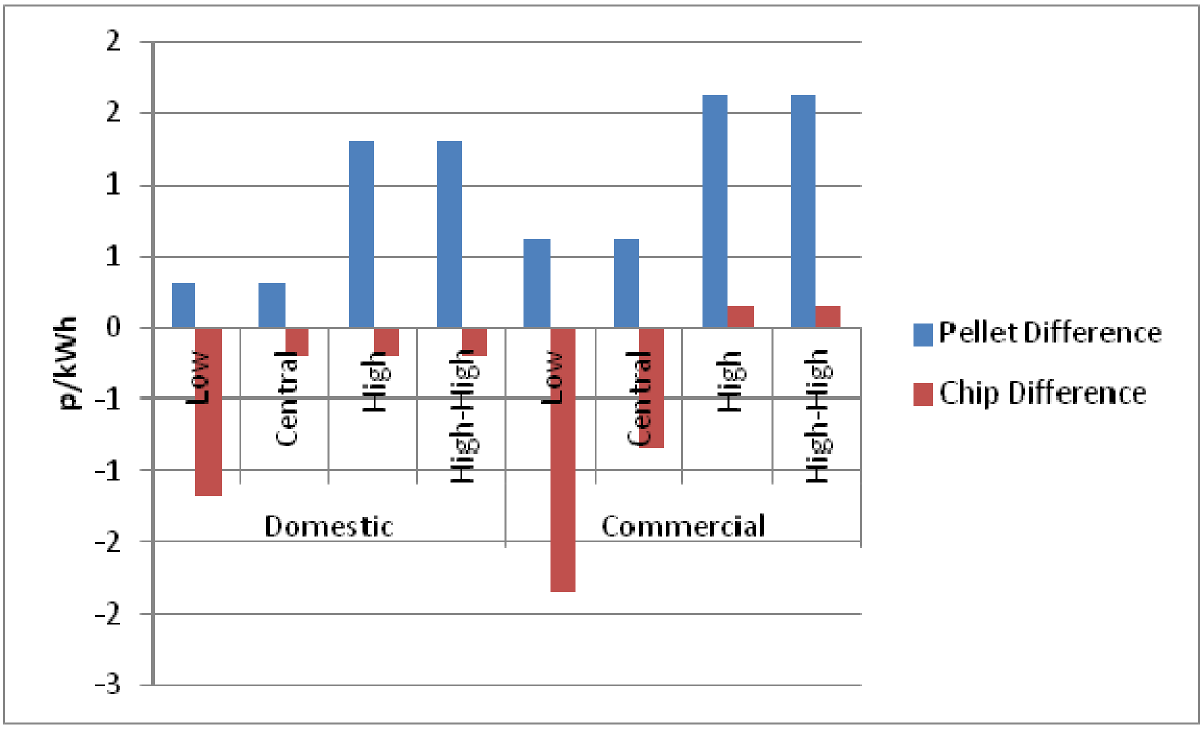
The analysis suggests that Northern Ireland prices are higher than in GB for wood chip. Wood pellet prices fluctuate dramatically depending upon location; however, it would appear that in general pellets prices may be marginally cheaper in Northern Ireland compared to England and certainly not more expensive. One of the reasons for this is the slightly more mature nature of the market in terms of suppliers and distributors in Northern Ireland such as Balcas.

Further analysis shown in Figure 3.2 below of the difference between the prices compared to the prices in our original report suggests that as a general trend the pellet prices were about right or slightly generous whilst the chip prices were slightly under.

Figure 3.2: Comparison of difference between fuel prices reviewed Jan 2012 and assumptions in previous report



The issue of fuel price inflation was also raised. This is highly uncertain for many reasons. However, respondents suggest that the inflation for biomass fuels through to 2020 was too low and that the ROI carbon tax of €15/t or potentially €30/t would significantly drive up the Northern Ireland biomass price.

On the first point, biomass inflation is unlikely to be as high as that of heating oil and therefore in the absence of better data the inflation rates remain as proposed. It is recommended that DETI reassess biomass prices at review points to determine whether the overall tariff level is still appropriate.

On the second point, the ROI carbon tax, the UK also has a carbon price floor, expected to be set at £16/t from 2013[21]. While this only applies to electricity generation and not heat, it is likely to increase the demand for biomass for electricity generation which can be expected to have a

[21] Source: HM Treasury, 2011, *Carbon price floor consultation: the Government response* http://www.hm-treasury.gov.uk/d/carbon_price_floor_consultation_govt_response.pdf

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knock-on effect on the supply of biomass available for heating. Given this, the degree to which the Northern Ireland market will experience an exceptional demand for biomass that is not occurring in GB is questionable. It should however be noted that the comparative £/MWh values used for heating oil[22] show no dramatic inflation on heating oil prices.

Recommendation

Our recommendation, therefore, is to use our existing central case for pellet prices (i.e. leave them unchanged), but to use our previous high case for chip prices. This gives the prices shown in Table 3.4 below.

Table 3.4: Pellet and woodchips prices to 2040 (£/kWh)

Segment/ Scenario	2010	2015	2020	2025	2030	2035	2040
Pellets							
Domestic	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Commercial	0.04	0.04	0.05	0.05	0.05	0.05	0.05
Industrial	0.04	0.04	0.05	0.05	0.05	0.05	0.05
Woodchips							
Domestic	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Commercial	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Industrial	0.03	0.03	0.03	0.03	0.03	0.03	0.03

In fact, it turns out that our economic model uses a pellet boiler as the reference installation for all technology sizes (except large industrial). This means that it uses the (higher) pellet prices to determine tariffs, rather than the (lower) woodchip prices. This is likely to produce a higher tariff than using a woodchip boiler as a reference installation. However, since the pellet prices used for our current tariffs are the same as those for the previous tariffs, there is no change to tariffs as a result of fuel prices[23].

It will also be noted that in our tariff tables, we recommend no tariff for large (>1MW) biomass boilers. In arriving at this recommendation, we have used the same methodology as for other technologies. This indicates that large industrial biomass should be viable without subsidy, taking into account current technology costs and current and expected oil and biomass costs. In particular, the low price of woodchips relative to oil, when coupled with the high load factor of an industrial boiler, more than outweighs the higher capital cost of a biomass boiler.

There are two caveats to this conclusion. The first is that it depends on our assumption about woodchips – both their price, and that they are the fuel of choice for industrial biomass. If the price were to increase in future, or industrial customers were to shift to using mostly pellets, this could argue for revisiting our conclusion.

[22] See table C.3 in our previous report.

[23] Note that the model takes account of expected increases in fuel prices over time, as shown in the table, when determining tariffs. It does not solely base the decision on the price in the current year.

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3.2.2. Biomethane

Following our review, we have updated our estimate of the annual operating cost to £350 per kW. It was previously £600 per kW. We have also changed our estimate of the efficiency to 85%. These changes were made following a review of additional evidence made available from SKM/Enviros[24] in their report to DECC published May 2011. Finally, we have revisited our assumption on fuel input, and have assumed a 50:50 split between waste and fuel crops.

Recommendation

We recommend making the three changes to assumptions noted above, but keeping other figures the same as before.

3.2.3. Bioliquids

For this technology, AEA has re-considered both fuel prices and capital costs (capex).

The fuel price of 60 pence per litre (ppl) used in the original modelling aligns with updated figures provided during the consultation. This information indicated that through May 2010-May 2011 prices ranged between 45ppl and 65ppl.

On capital costs, the original assumption was a boiler cost of £220/kW for a 20kW domestic boiler running on B30 biofuel blend. This equates to a total capital cost of £4,392 installed. The correspondence provided during the consultation does not suggest that any modifications to the current modelling values should be made.

Recommendation

Our recommendation, therefore, is to retain both the existing fuel prices and the existing capital cost figures.

3.2.4. Geothermal

DETI have been provided with cost and performance information by respondents to the consultation. This is generally the same information that has been provided to DECC and reviewed as part of the GB RHI.

The most comprehensive information relates to a deep geothermal scheme recently completed in Pullach-Im-Isartel, south of Munich, Germany. Cost and performance information provided by respondents to DETI and DECC has been consolidated into Table 3.5 below:

Table 3.5: Deep geothermal cost and performance information

CAPEX £/kW	OPEX £/kW	Size (kW)	Efficiency[25]	Lifetime	Load factor	CAPEX	Heat output MWh
3,415	39	5,000	1,500%	30	55%	17,075,000	24,090

[24] http://www.decc.gov.uk/assets/decc/11/meeting-energy-demand/renewable-energy/2711-SKM-enviros-report-rhi.pdf

[25] Estimated based on a co-efficient of performance (CoP) of 15.

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As highlighted to DETI by the consultation responses, other policy issues exist which would need to be overcome such as primary legislation defining the ownership of geothermal resources in Northern Ireland. Given the policy issues highlighted and the fact that deep geothermal is not an 'established' UK heating technology there is a risk that no project would be completed by 2020.

Other barriers to geothermal include the potential uses for the heat generated. For example, because of the relatively low temperatures in the ground underneath NI (at 2,500m), the heat from geothermal is not suitable for high-temperature industrial uses. Use for small commercial premises or households would typically require some form of district heating system, which does not yet exist to any significant extent in NI. As the technology is largely dependent upon the presence of a district heating network we have included the costs for this within the capital costs.

Note that while we quote indicative figures below, the counterfactual costs for geothermal (and the costs of district heating) are quite site-specific. Therefore, what is an appropriate tariff for one site may be insufficient or overly generous for another. This is one of the reasons that we recommend that DETI considers carefully whether an RHI tariff is the best support option for geothermal (rather than, say, a capital grant paid on completion of construction, with provisions for clawback in the event of financial out-performance). It is also the reason that we quote a range of indicative tariffs rather than a single figure. At one end of the range, we have taken as the counterfactual a group of houses, and at the other a group of small commercial premises. As can be seen, the choice of counterfactual can make several pence difference to the tariff.

An additional barrier facing Deep Geothermal is that the area with the greater resource; that is, the Rathlin basin, is not well aligned with areas of high heat density. A district heating network capital cost of £1,415/kW has therefore been assumed. This figure is based upon the typical heat density in urban areas within the Raithlin basin, using Ballymoney as an example. The capital expenditure is higher than for normal district heat networks as outside of Belfast and Londonderry, Northern Ireland does not generally have a high heat density.

Further, we have assumed that consumers need to be incentivised to connect to a district heating network, rather than continue with their existing stand-alone oil or gas boiler. We have therefore applied a discount factor of 20% to the current cost of gas, to represent the counterfactual fuel cost. The counterfactual technology is assumed to be gas boilers, because we understand that the geothermal sites in Northern Ireland are typically in areas that the gas network has already reached.

Putting these barriers and concerns aside, we have calculated an indicative tariff of 1.6p for geothermal. This is on the same basis as for other technologies. We should note that this tariff is highly dependent on the assumption about the counterfactual.

3.3. Changes to tariffs

In summary, we propose changes to the tariffs for all technologies, although in some cases these changes are very small. We have proposed an indicative tariff range for geothermal (but see the caveats above).

The implications of these changes on our proposed tariffs are shown in Table 3.6 below.

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Table 3.6: Implications of updated assumptions for tariffs (all figures in p/kWh)

Technology size band	Size range (kW)[26]	Tariff in original report	Updated tariff[27]	Notes
ASHP – Small	0-45	3.3	4.0	Increase due to inflation and switch to 2011/12 reference installation
ASHP – Medium	45+	-		
Biogas injection – All	All	2.5	3.0	Change to assumption on gate fee
Biomass boilers – domestic	0-20	4.5	6.2	Increase due to inflation, switch to 2011/12 reference installation and inclusion of ongoing barrier costs
Biomass boilers – small	20-100	4.5 (<45kW) 1.3 (45kW+)	5.9	Intermediate tariff based on 50kW boiler. Increase due to inflation and inclusion of ongoing barrier costs
Biomass boilers – medium	100-1,000[28]	1.3	1.5	Increase due to inflation and switch to 2011/12 reference installation
Biomass boilers – large	1,000[29]+	-		
GSHP – domestic	0-20	4.0	8.4	Change to the reference installation means a higher tariff
GSHP – small	20-100	4.0 (<45kW) 0.9 (45kW+)	4.3	Intermediate tariff based on 30kW pump
GSHP – large	100+	0.9	1.3	Increase due to inflation and switch to 2011/12 reference installation
Geothermal	All	n/a	1.6	Indicative tariff only

[26] The range should be read as including the lower end, but not the upper end. For example, the range 20-100 includes 20kW boilers but not 100kW boilers – the latter are covered by the 100-500 range.
[27] Includes inflation, and effect of changes to technology costs and tariff bands
[28] We have widened this band to be consistent with GB.
[29] Our figures show that a typical industrial installation using wood chip fuel could be expected to make savings over its lifetime, compared to a corresponding oil installation. We therefore propose no subsidy. This conclusion should be revisited if there is a significant shift in the relative cost of wood chips and oil, and if there is a significant shift to the use of pellets for large industrial sites.

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Technology size band	Size range (kW)[26]	Tariff in original report	Updated tariff[27]	Notes
Liquid biofuels – small	0-45	1.5	1.6	Increase due to inflation and switch to 2011/12 reference installation
Liquid biofuels – medium/ large	45+	-		
Solar Thermal	All	8.5		

3.4. Implications for renewable heat delivered and for cost

In the work for our previous report, our model suggested that an NI RHI could deliver around 11.14% of NI's heat demand from renewables, at a subsidy cost of £334m in present value terms[30]. We have re-run our economic model to show the impact of the changes discussed earlier in this section. The results are in Table 3.7 below. At DETI's request, an annual breakdown of these figures is also provided (see Annex B).

Table 3.7: Impact of RHI[31] in 2020, including baseline and viable installation, before and after changes

	Renewable Heat delivered (% of total 2020 heat demand)	Lifetime subsidycost in present value terms (£m)
Before	11.14%	334
After	11.10%	445

In summary, the changes have almost no effect on renewable heat delivered. They do however increase costs significantly, because of the higher tariffs offered for many technologies.

3.5. Implications of industrial biomass for the gas network

DETI has a stated objective, set out in statute[32], to promote the development and maintenance of an efficient, economic and coordinated gas industry in Northern Ireland. To this end, DETI has recently consulted[33] on the potential extension of the existing gas network. It has therefore asked us to consider the implications for gas demand of the proposed changes to the RHI – in particular, support for large biomass boilers that might be used on industrial sites.

3.5.1. Industrial sites suitable for biomass

Our previous report looked at the potential for large industrial sites to switch to biomass. We classified the 15[34] such sites in Northern Ireland into three categories: "not suitable", "less likely" and "potential". This is shown in Table 3.8 below, which is a copy of Table 2.11 in our previous report.

[30] Source: CEPA/ AEA, 2011, op. cit., chapter 7
[31] Assumes long term funding of £25 m to 2014/15 and an additional £5m/ year from 2015/16
[32] Article 14 (1) of the Energy (Northern Ireland) Order 2003
[33]http://www.detini.gov.uk/consultation_on_the_potential_for_extending_the_natural_gas_network_in_northern_ireland
[34] The previous AECOM/ Pöyry report identified 17 such sites. Since that report, one site has closed and another (Balcas) is already using biomass.

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Table 3.8: Summary of industrial renewable heat potential in Northern Ireland

Category	Sites	Heat demand in GWh per year
Not suitable[35]		2,654
of which	*Quinn Cement*	
	Lafarge Cement	
	Quinn Glass	
Less Likely[36] (near/on gas)		537
of which	*Bombardier Aerospace*	
	Michelin Tyre plc	
	Armaghdown Creameries	
	Pritchitts	
	Gallaher Ltd	
	Huhtamaki (Lurgan) Ltd	
	Glanbia Cheese Ltd	
	Ulster Farm Byproducts Ltd	
Potential sites		**527**
using coal	*Invista (Coal CHP)*	
using oil[37]	*Dalefarm Ltd*	
	TMC Dairies	
	Moy Park Ltd - Dungannon	
TOTAL		**3,718**

The question is then which of the sites in the "potential" or "less likely" categories might switch to biomass.

The factors that drive individual sites to take up biomass (or not) can be quite specific to that site. Our uptake model is designed to look at the decision that individual homes or businesses might make in choosing between an oil or gas boiler and renewable heat. In particular, our model looks at the relative costs of the two options. In any such decision, there are many factors that come into play, which might mean that for an individual home or business, our model's conclusion is incorrect. However, when considering a large number of homes or businesses, we

35 Because of their very high temperature requirement, which cannot be met by biomass.
36 We assume that these sites are less likely to switch because they are either already on gas or are near the gas network. Reasons for this include the fact that those on the network are likely to have relatively new gas boilers.
37 Note that this was incorrectly labelled "using gas" in our previous report.

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would expect those factors to tend to cancel out, and in this case our model's conclusions would be expected to be reasonably representative of what might happen in reality.

The key phrase in the preceding paragraph is "...when considering a large number of homes or businesses". When we consider a relatively small number of sites (such as the 16 large industrial sites), it is statistically less likely that the various factors specific to individual sites will cancel out. Our model is therefore likely to be further from reality in that case.

The best approach (which is outside the scope of this study) would be a full site-by-site analysis – and even this of course could not hope to predict accurately the individual commercial decisions of the firms. In this study, we have taken the approach of looking at the range of possible outcomes, on the spectrum from no sites adopting renewable heating to all possible sites adopting it, and considered the implications of both ends of that spectrum.

At the lower end of the uptake spectrum, no site switches to biomass. This might be because of concerns regarding the supply chain or wider business drivers that mean that a switch to biomass is not seen as a sufficient priority. Clearly, in this scenario, the impact is zero.

At the upper end, in theory every site in the "potential" or "less likely" categories could switch. In practice, this is very unlikely because of constraining factors such as the biomass supply chain, that many of those installations are likely to have installed gas boilers within the last ten years, meaning that they are less likely to be considering a boiler replacement of any type and so on. We also need to account for the fact that Invista is currently on coal rather than gas. But the industrial sites could, technically, produce around 1,064GWh of heat from biomass per year.

A more likely although still extreme scenario is that all the "potential" sites switch to biomass. In this case, industry would produce 527GWh of heat from biomass per year.

Now that we know the approximate scale of the possible shift to biomass, we can consider the possible impact on the gas network.

3.5.2. Implications for the gas network

We start by assuming that those sites in the "potential" category are unlikely to have the option of connecting to gas by 2020. In this case, there would be no impact on the gas network of these sites switching to biomass. There may of course be impacts longer term if the gas network is rolled out to near these sites post-2020, but this is both beyond the scope of this project and sufficiently far in the future to be highly uncertain and so not amenable to analysis.

Any impact on the gas network would come from those sites in the "less likely" category. These generate a total of 527 GWh per year. We start by comparing this to annual gas consumption in Northern Ireland, which in 2008/09 was 16,650 GWh[38]. However, the vast majority of this was for power generation - 4,161 GWh was distributed to non-power consumers[39].

The *potential* impact on non-power gas demand of a switch to industrial biomass is therefore up to 12.5%. The actual impact is likely to be significantly lower, as the decision to switch to biomass would be driven by a number of factors, of which the precise costs of biomass, gas and

[38] Source: CER/ NIAUR (2010): Gas capacity statement

[39] ibid

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coal would be only one. For example, there are significant costs and risks associated with moving to a new system for generating heat on a well-established industrial site, not least the temporary disruption any move would cause.

As well as the impact on the gas network, we can ask what the impact would be on subsidy costs and renewable heat delivered. This is discussed in the next section.

3.5.3. Implications for cost

We do not propose any subsidy for large industrial biomass, based on the relative costs of oil and biomass. However, the case for such subsidy might change in future if those costs change. For example, if DETI were to move to the subsidy levels seen in GB (1p/kWh[40]), the total annual subsidy to industrial sites would be as in Table 3.9 below.

Table 3.9: Potential subsidy requirements from industrial biomass use

Scenario	Annual cost (£m)
No switching	0
All "potential" sites	5.27
All "potential" and "less likely" sites	10.64

For comparison purposes, the annual subsidy under the NI RHI is capped at £12m in 2014/15. Available funding would therefore note be a barrier to all industrial sites taking up biomass, but that take-up would significantly reduce the subsidy available to smaller businesses and to domestic consumers.

On the other hand, it would significantly help to achieve the renewable heat target. If all the "potential" sites above switched to biomass, this would deliver 527GWh at a cost (assuming GB subsidy rates) of just over £5m. By comparison, our preferred subsidy rates from our previous report delivered up to 580 GWh per year of renewable heat. This reinforces the point that renewable heat on industrial sites is significantly more cost-effective than that on smaller commercial, or domestic, sites.

[40] This is the current figure for the GB RHI for 1MWth and over. http://www.ofgem.gov.uk/e-serve/RHI/Documents1/RHI%20leaflet.pdf

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ANNEX A: TARIFF TABLES

In this section we set out the technology assumptions, and proposed tariffs, for each technology, in a format agreed with DETI. This includes those technologies where we do not consider that subsidy is required. In those cases, we have shown why the average cost of energy from the renewable heat technology is less than that from oil.

We do not show any tables for solar thermal. This is because the tariff for solar thermal was set on the same basis as the corresponding tariff for the GB RHI, i.e. at the cost of offshore wind, rather than using the same basis as for other technologies. See our previous report for more details.

Please note that in the tariff calculation tables, the figures are all on an annual basis except the final figure which for consistency with the GB RHI and our previous report is on the basis of quarterly payments. As in our previous report, we have converted to quarterly payments by multiplying the annual figure by 0.96. We have also increased all tariffs in line with 2011 inflation of 4.8%[41].

Note that cost figures have been rounded to the nearest pound (except where otherwise noted or for small sums) and tariff figures to the nearest 0.1p. Totals may therefore not add exactly.

Please also note that while our approach produces results close to that for the GB RHI, it is not quite the same. In particular, we consider future changes in fuel costs in our tariffs. More details are in Section 2 of this report, and Annex E of our previous report.

Air Source Heat Pumps – small

The tables below set out the technology costs for small (under 45kW) air source heat pumps, and compare them to an oil counterfactual. As for most renewable technologies we consider, the capital costs are relatively high, but the operating costs are in fact lower than the oil counterfactual.

Table A.1: Air Source Heat Pumps (small) – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)[42]	Upfront barrier costs (£)[43]	Ongoing barrier costs (£/year)[44]

[41] Source: December 2011 RPI figure, Office of National Statistics
http://www.ons.gov.uk/ons/rel/cpi/consumer-price-indices/december-2011/stb---consumer-price-indices---november-2011.html
[42] Note that this is the fuel cost in 2012. The model takes account of expected future fuel costs in determining tariffs.
[43] Calculated following the GB RHI approach (i.e. a number of days times an assumed hassle cost per day). It does not include the cost of a heat meter.

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Air Source Heat Pump	650	3.88	260%	15%	14	20	14.44	605	3.40
Oil	183	9.41	93%	10.5%	20	15	5.11	0	0

The tables below reinforce the importance of capital costs, with the total difference in cost between technologies almost entirely driven by the capital cost.

Table A.2: Air Source Heat Pumps (small) – technology resource costs in £ per year

	Annuitised Capital cost at 16[45]%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Air Source Heat Pump	1,535	54	1,019	102	3.40
Oil	657	188	1,004	0	0
Difference	878	-134	15	102	3.40
Sum of difference	865				

Table A.3: Air Source Heat Pumps (small) – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	4.4
Operating costs	-0.7
Fuel costs	0.4
TOTAL	**4.0**
Convert to quarterly basis[46]	**3.9**

[44] We have taken the GB RHI figures for ongoing costs associated with a 30kW commercial GSHP (no figures are given for ASHP) and scaled this to reflect the different costs of time assumed in e.g. NERA (2009). The costs are £15 per hour for domestic customers and £70 per hour for commercial or industrial.
[45] Since the reference installation is domestic, we assume a discount rate of 16% to reflect a typical consumer discount rate.

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Adjust for inflation	**4.0**

Air Source Heat Pumps – medium

The tables below show the technology costs for medium (above 45kW) ASHPs. As for the smaller heat pumps, capital costs are higher than the counterfactual oil boiler, but in this case operating costs are also higher.

Table A.4: Air Source Heat Pumps (medium) – technology parameters

	Capex (£/kW)	**Opex (£/kW/year)**	**Efficiency (%)**	**Load Factor (%)**	**Size (kW)**	**Lifetime (years)**	**Fuel cost (p/kWh)**	**Upfront barrier costs (£)**	**Ongoing barrier costs**
Air Source Heat Pump	446	3.45	400%	36%	200	20	12.14	3,951	£66[47]
Oil	68	1.47	89%	20%	360	15	4.86	0	0

The tables below show the impact of these technology costs. The key difference from the smaller heat pumps is the very substantial savings in annual fuel costs compared to an oil boiler. This saving is enough to outweigh the additional capital costs, and means that the technology is economic. This is driven by the higher efficiency of the larger ASHP (400%, compared with 260% for the sub-45kW boiler).

Table A.5: Air Source Heat Pumps (medium) – technology resource costs in £ per year

	Annuitised Capital cost at 12%	**Annual operating costs**	**Annual fuel costs**	**Annuitised Upfront barrier costs**	**Ongoing barrier costs**
Air Source Heat Pump	11,942	690	19.148	529	66
Oil	3,594	529	34,479	0	0
Difference	8,348	161	-15,331	529	66
Sum of difference	-6,227				

[46] Following the GB RHI approach, we multiply annual tariffs by 0.96 to calculate quarterly tariffs. This is to reflect the benefit to consumers of not having to wait a full year for payments under the RHI.
[47] Sourced from the on-going barrier costs for the GB RHI, as set out in the Impact Assessment. No figure is given for ASHPs, so we have used that for the equivalent GSHP.

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Table A.6: Air Source Heat Pumps (medium) – tariff breakdown, in pence per kWh

Subsidy for	**Amount**
Annualised capital and barrier costs	No subsidy required
Operating costs	
Fuel costs	
TOTAL	
Convert to quarterly basis	

Ground Source Heat Pumps – domestic

The table below shows the technology cost assumptions for domestic GSHPs. The pattern is similar to that for small ASHPs – a relatively high capital cost but low operating costs.

Table A.7: Ground Source Heat Pumps (domestic) – technology parameters

	Capex (£/kW)	**Opex (£/kW/year)**	**Efficiency (%)**	**Load Factor (%)**	**Size (kW)**	**Lifetime (years)**	**Fuel cost (p/kWh)**	**Upfront barrier costs (£)**	**Ongoing barrier costs (£/ year)**
Ground Source Heat Pump	1,480[48]	4.94	325%	19%	11	20	14.4	605	3.40
Oil	183	9.41	93%	10.5%	20	15	5.11	0	0

This gives the relative resource costs in the table below. Again, capital cost dominates.

[48] This is the figure for an urban installation, since our reference installation is in an urban area. The corresponding figure for an urban installation is £940.

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Table A.8: Ground Source Heat Pumps (domestic) – technology resource costs in £ per year

	Annuitised Capital cost at 16%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Ground Source Heat Pump	2,746	54	815	102	3.40
Oil	657	188	1,004	0	0
Difference	2,089	-134	-189	102	3.40
Sum of difference	1,872				

Table A.9: Ground Source Heat Pumps (domestic) – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	9.9
Operating costs	-0.7
Fuel costs	-0.8
TOTAL	**8.4**
Convert to quarterly basis	**8.0**
Adjust for inflation	**8.4**

Ground Source Heat Pumps – small commercial

The picture for small commercial GSHPs is similar to that for the medium size ASHPs, as the table below shows. Capital and operating costs are higher, but fuel costs are lower because of the very high efficiency (360%).

Table A.10: Ground Source Heat Pumps (small commercial) – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)	Ongoing barrier costs (£/ year)
Ground Source Heat	1,228	7.00	360%	29%	30	20	12.14	3,951	16

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	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)	Ongoing barrier costs (£/ year)
Pump									
Oil	97	3.45	93%	17%	50	15	4.86	0	0

However, as the tables below show, this lower fuel cost is not enough to outweigh the high capital and operating costs, and so small commercial GSHPs require subsidy to be economic.

Table A.11: Ground Source Heat Pumps (small commercial) – technology resource costs in £ per year

	Annuitised Capital cost at 12%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Ground Source Heat Pump	4,932	210	2,526	529	16
Oil	710	173	3,902	-	0
Difference	4,222	37	-1,376	529	16
Sum of difference	3,428				

Table A.12: Ground Source Heat Pumps (small commercial) – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	5.5
Operating costs	0.0
Fuel costs	-1.3
TOTAL	**4.3**
Convert to quarterly basis	**4.1**
Adjust for inflation	**4.3**

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Ground Source Heat Pumps – larger commercial

The very largest ground source heat pumps do well on operating costs, and on fuel costs, but the capital cost is still very high compared to conventional oil boilers, as the table below shows.

Table A.13: Ground Source Heat Pumps (larger commercial) – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)	Ongoing barrier costs
Ground Source Heat Pump	900	1.05	360%	36%	200	20	12.14	3,951	66
Oil	68	1.47	89%	20%	360	15	4.86	0	0

The implications of the table above is that the lower fuel costs of a larger GSHP almost outweigh the higher capital costs, leading to a low level of subsidy requirement, as the tables below show.

Table A.14: Ground Source Heat Pumps (larger commercial) – technology resource costs in £ per year

	Annuitised Capital cost at 12%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Ground Source Heat Pump	24,098	209	21,276.	529	66
Oil	3,594	529	34,479	-	0
Difference	20,504	-320	-13,203	529	66
Sum of difference	7,576				

Table A.15: Ground Source Heat Pumps (larger commercial) – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	2.9
Operating costs	-0.1

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Subsidy for	Amount
Fuel costs	-1.6
TOTAL	**1.3**
Convert to quarterly basis	**1.2**
Adjust for inflation	**1.3**

Geothermal

The relative costs and characteristics of an indicative geothermal plant are shown below, compared to a notionally equivalent oil boiler (in fact, the combination of over a thousand typical domestic boilers).

Table A.16: Geothermal – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)
Geothermal	3,415	39	1,500%	55%	5,000	30	13.8	0[49]
Oil	183	9.41	93%	10.5%	26,251[50]	15	4.86	0

The most important factor to note in the table above is the extremely high efficiency (1,500%). This means that the annual electricity (fuel) cost for geothermal is very low, and the benefit of this low cost very nearly outweighs the high initial capital cost. This is illustrated in the next two tables.

[49] Costs such as the requirement to install a district heating network are included in the capex figure.
[50] This represents around 1,300 small domestic boilers (around 20kW each).

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Table A.17: Geothermal – technology resource costs in £ per year

	Annuitised Capital cost at 12%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs
Geothermal	2,119,753	195,000	221,634	-
Oil	705,490	247,114	1,317,802	-
Difference	1,414,263	-52,114	-1,096,167	-
Sum of difference	255,981			

Table A.18: Geothermal – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	6.4
Operating costs	-1.0
Fuel costs	-3.8
TOTAL	**1.6**
Convert to quarterly basis	**1.5**
Adjust for inflation	**1.6**

Bioliquids – small

The costs and characteristics for bioliquids, compared to an oil boiler, are shown below. Many of the figures are the same or very similar, reflecting the similar technology.

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Table A.19: Bioliquids (small) – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)	Ongoing barrier costs (£/ year)
Liquid biofuels – small	220	9.41	93%	10.5%	20	15	5.22	908	0
Oil	183	9.41	93%	10.5%	20	15	5.11	0	0

The tables below illustrate the basic cost differences between the two boilers – a higher capital and upfront barrier cost and a slightly higher on-going fuel cost. These translate into a small subsidy requirement of 1.6p/kWh.

Table A.20: Bioliquids (small) – technology resource costs in £ per year

	Annuitised Capital cost at 16%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Liquid biofuels	788	188	1,027	133	0
Oil	657	188	1,004	0	
Difference	131	-	23	133	0
Sum of difference	353				

Table A.21: Bioliquids (small) – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	1.3
Operating costs	0
Fuel costs	0.2
TOTAL	**1.6**
Convert to quarterly basis	**1.5**
Adjust for inflation	**1.6**

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Biomass – domestic

The table below shows the relative costs of domestic biomass and oil boilers. Costs are higher across the board for biomass.

Table A.22: Biomass (domestic) – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)	Ongoing barrier costs (£/ year)[51]
Biomass	662	19	85%	17.5%	12	20	5.54	908	177
Oil	183	9.41	93%	10.5%	20	15	5.11	0	0

The higher costs for capex, opex and fuel in the table above translate into a requirement for subsidy for all three, as shown in the two tables below.

Table A.23: Biomass (domestic) – technology resource costs in £ per year

	Annuitised Capital cost at 16%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Biomass	1,339	230	1,196	153	177
Oil	657	188	1,004	0	0
Difference	682	42	192	153	177
Sum of difference	1,246				

Table A.24: Biomass (domestic) – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	4.8
Operating costs	0.2

[51] Takes from the figure used in the GB RHI for 107kW commercial biomass boilers, scaled to reflect the assumed difference in the cost of time between domestic (£15/ hour) and non-domestic (£70/ hour) consumers.

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Subsidy for	Amount
Fuel costs	1.2
TOTAL	**6.2**
Convert to quarterly basis	**6.0**
Adjust for inflation	**6.2**

Biomass – small commercial

The picture for small commercial biomass is slightly different to that for domestic, in that the fuel is marginally cheaper than oil, as shown in the table of costs below.

Table A.25: Biomass (small commercial) – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)	Ongoing barrier costs (£/ year)
Biomass	608	4.60	85%	17%	50	20	4.39	3,951	828[52]
Oil	97	3.45	93%	17%	50	15	4.86	0	0

The slightly lower fuel cost is though outweighed by the significantly higher capital cost in particular, translating into a tariff almost identical to that for domestic biomass. This is shown in more detail in the two tables below.

Table A.26: Biomass (small commercial) – technology resource costs in £ per year

	Annuitised Capital cost at 12%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Biomass	4,073	230	3,868	718	828

[52] Source: GB RHI impact assessment

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	Annuitised Capital cost at 12%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Oil	710	173	3,902	-	0
Difference	3,362	58	-34	718	828
Sum of difference	4,932				

Table A.27: Biomass (small commercial) – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	5.9
Operating costs	0.2
Fuel costs	-0.1
TOTAL	**5.9**
Convert to quarterly basis	**5.6**
Adjust for inflation	**5.9**

Biomass – larger commercial

The picture for larger commercial biomass boilers is similar to that for smaller boilers, although the capital cost gap has narrowed somewhat. In addition, the higher load factor for a biomass boiler means that it can be of a smaller size, reducing the capital cost gap further.

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Table A.28: Biomass (larger commercial) – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)	Ongoing barrier costs (£/ year)
Biomass	486[53]	4.60	81%	36%	200	20	4.4	5,364	878[54]
Oil	68	1.47	89%	20%	360	15	4.86	0	0

The impact of these cost differences is illustrated in the tables below. As for most renewable technologies, most of the requirement for subsidy comes from the capital cost difference. Operating and fuel costs are similar for the technologies.

Table A.29: Biomass (larger commercial) – technology resource costs in £ per year

	Annuitised Capital cost at 12%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Biomass	13,031	920	34,185	718	878
Oil	3,594	529	34,479	-	0
Difference	9,437	391	-486	718	878
Sum of difference	11,130				

Table A.30: Biomass (larger commercial) – tariff breakdown, in pence per kWh

Subsidy for	**Amount**
Annualised capital and barrier costs	1.5
Operating costs	0.1
Fuel costs	-0.1

[53] This is the figure for our reference installation, which is in a rural building. The corresponding figure for an urban installation is £508.80.
[54] Source: GB RHI Impact Assessment

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Subsidy for	Amount
TOTAL	**1.5**
Convert to quarterly basis	**1.4**
Adjust for inflation	**1.5**

Biomass – industrial

For this segment, the crucial points to note are the lower fuel price for biomass, compared to oil, and the high load factor. This serves to outweigh any additional capital cost, such that no subsidy is required.

Table A.31: Biomass (industrial) – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)	Ongoing barrier costs (£/ year)
Biomass	316	14,38	81%	82%	16,086	20	2.52	5,364	878
Oil	31	0.23	89%	82%	16,086	20	4.77	0	0

This is illustrated in the table below, which shows that the benefit of lower fuel costs is around four times the increased capital cost, on an annuitized basis. There is therefore no requirement for subsidy to make industrial biomass economic.

Table A.32: Biomass (industrial) – technology resource costs in £ per year

	Annuitised Capital cost at 12%	Annual operating costs	Annual fuel costs	Annuitised Upfront barrier costs	Ongoing barrier costs
Biomass	681,375	231,341	3,613,079	718	878
Oil	67,574	3,701	6,226,764	0	0
Difference	613,801	227,639	-2,613,686	718	878
Sum of difference	-1,770,650				

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Table A.33: Biomass (industrial) – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	No subsidy required
Operating costs	
Fuel costs	
TOTAL	
Convert to quarterly basis	
Adjust for inflation	

Biogas (biomethane)

The table below shows the technology costs for the production of biomethane for injection into the gas grid. One point to note is that fuel costs are shown as negative. This is because some of the fuel for biomethane production is waste, which has a negative cost (a "gate fee").

Also, the counterfactual for biogas is conventional wholesale gas. The viability of biomethane is therefore assessed based on its cost per kWh against the 2.9p per kWh we assume for wholesale gas prices.

Table A.34: Biomethane – technology parameters

	Capex (£/kW)	Opex (£/kW/year)	Efficiency (%)	Load Factor (%)	Size (kW)	Lifetime (years)	Fuel cost (p/kWh)	Upfront barrier costs (£)	Ongoing barrier costs (£/ year)
Biomethane	4,600	350[55]	85%	93%	1,000	20	-4.1	0[56]	0
Wholesale gas	-	-	-	-	-	-	2.9		-

[55] Note that this figure is lower than that used in the GB RHI. AEA have received additional information on biomethane opex since the last review, notably SKM's report to DECC. This has been taken into account and reflects the lower opex compared to that previously reported

[56] Source: GB RHI Impact Assessment. Biomethane is assumed under the GB RHI to have no upfront or ongoing barrier costs.

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The tariff cost for biomethane is shown in the table below. Note that the fuel cost figure is higher than might be expected from the figures in the previous table (a fuel cost difference of 4.1+2.9=7.0p/kWh). This is because the subsidy figure is per unit of heat produced, while the fuel cost is per unit of heat in the fuel. There are losses in converting from the fuel to heat (as shown by the efficiency factor) which means that the subsidy figure per unit of heat produced is higher than the difference in the cost of the input fuel.

Table A.35: Biomethane – tariff breakdown, in pence per kWh

Subsidy for	Amount
Annualised capital and barrier costs	6.7
Operating costs	4.3
Fuel costs	-8.1
TOTAL	**3.0**
Convert to quarterly basis	**2.9**
Adjust for inflation	**3.0**

Solar Thermal

Our approach to solar thermal is as set out in our previous report. In that report, we said[57] that:

"*Our [tariff setting] methodology gives a raw subsidy figure of 32.5p per kWh for solar thermal. This is clearly very high, compared to that for other technologies. Subsidy at this level for solar thermal could divert funding away from more cost-effective technologies, and our analysis shows this happening in the Funding 3 scenario. On the other hand, in the Funding 2 scenario with an RHI, not all funding will be taken up without some deployment of solar thermal. But this deployment is very expensive: the analysis shows 13GWh at a cost of £175 million – over £10 per kWh.*

[57] Section 6.7.3 of our previous report

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Our conclusion is that DETI should, depending on funding, subsidise solar thermal but set it at a lower level than our methodology suggests; the same level as the GB RHI would be appropriate. DECC has decided to set the solar thermal tariff '...at a level which is roughly equivalent, in terms of financial support per unit of energy output, to the level allocated to what is currently considered to be the marginal cost effective technology required to deliver the UK's 15 per cent renewable target, offshore wind'".

The tables presented for other technologies are therefore not appropriate for explaining the solar thermal tariff of 8.5p/kWh.

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ANNEX B: HIGH LEVEL IMPACT OF POLICY

The tables in this annex show the high level impact, by year, of the RHI on key measures such as renewable heat delivered, carbon emissions reduced and subsidy paid. The tables assume a rising level of funding to 2020 ("Funding 2", from our previous report).

We start by showing how the table would have looked based on the tariff levels in our previous report.

Table B.1: Overall impact of previously proposed RHI rates

Year	Total CO_2 emissions displaced (millions of tonnes)	Additional renewable heat resource (GWh)	Number of installations	Subsidies paid (£m, 2010 prices)[58]
2012	0.01	31	721	0.98
2013	0.02	84	2,230	2.43
2014	0.03	156	4,190	4.36
2015	0.05	242	6,814	6.89
2016	0.07	334	9,557	9.53
2017	0.09	438	12,946	12.75
2018	0.12	558	17,173	16.73
2019	0.16	701	22,496	21.68
2020	0.20	871	29,248	27.94
2021	0.20	871	29,248	27.94
2022	0.20	871	29,248	27.94
2023	0.20	871	29,248	27.94
2024	0.20	871	29,248	27.94

[58] Note that, as we stated in our previous report: "*...deployment constraints, and the fact that the rates used in the RHI options set out above may not be sufficient to incentivise all the potential for each technology, mean that not all available funding will be taken up. In practice of course, the ability to deploy renewable heat could increase, given a long-term, credible, funding stream, and so our results need to be considered with this in mind*" (CEPA/ AEA, 2011, section 7.6.1)

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Year	Total CO_2 emissions displaced (millions of tonnes)	Additional renewable heat resource (GWh)	Number of installations	Subsidies paid (£m, 2010 prices)[58]
2025	0.20	871	29,248	27.94
2026	0.20	871	29,248	27.94
2027	0.20	871	29,248	27.94
2028	0.21	871	29,248	27.80
2029	0.21	871	29,248	27.66
2030	0.21	871	29,248	27.53
2031	0.22	871	29,248	27.39
2032	0.22	840	28,527	26.28
2033	0.22	787	27,018	24.83
2034	0.23	716	25,057	22.90
2035	0.23	629	22,434	20.37
2036	0.24	537	19,690	17.86
2037	0.24	433	16,302	14.78
2038	0.24	313	12,074	10.94
2039	0.25	171	6,752	6.12
2040	0.25	0	0	0

Table B.2 below shows the impact of the changes described in this report.

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Table B.2: Overall impact of RHI given changes

Year	Total CO_2 emissions displaced (millions of tonnes)	Additional renewable heat resource (GWh)	Number of installations	Subsidies paid (£m, 2010 prices)
2012	0.01	46	754	1.61
2013	0.03	111	2,290	3.77
2014	0.05	185	4,256	6.41
2015	0.08	272	6,880	10.00
2016	0.11	364	9,623	13.59
2017	0.15	466	12,971	17.89
2018	0.19	581	17,123	23.07
2019	0.23	712	22,329	29.38
2020	0.27	872	29,081	37.54
2021	0.27	872	29,081	37.54
2022	0.27	872	29,081	37.54
2023	0.27	872	29,081	37.54
2024	0.27	872	29,081	37.54
2025	0.27	872	29,081	37.54
2026	0.27	872	29,081	37.54

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Year	Total CO_2 emissions displaced (millions of tonnes)	Additional renewable heat resource (GWh)	Number of installations	Subsidies paid (£m, 2010 prices)
2027	0.28	872	29,081	37.54
2028	0.28	872	29,081	37.40
2029	0.28	872	29,081	37.26
2030	0.28	872	29,081	37.12
2031	0.29	872	29,081	36.98
2032	0.29	826	28,327	35.23
2033	0.29	761	26,791	33.08
2034	0.30	687	24,824	30.43
2035	0.30	600	22,201	26.84
2036	0.30	508	19,457	23.39
2037	0.30	406	16,110	19.23
2038	0.31	291	11,957	14.20
2039	0.31	160	6,752	8.02
2040	0.31	-	-	-

Apart from differences in 2013 (due to a delay in ASHPs and bioliquids) the major differences are in carbon saved (more with the updated tariffs) and the higher subsidies paid (due to the higher tariffs).

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