element energy

E4tech
Strategy | Energy | Sustainability

Cost analysis of future heat infrastructure options

Report for

National Infrastructure Commission

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1 Executive Summary

1.1 Summary of study objectives

Element Energy and E4tech have been commissioned by the National Infrastructure Commission (NIC) to undertake an **analysis of the cost of decarbonising the UK's heat infrastructure, specifically space heating and hot water**. The NIC intends that this work is able to inform the debate surrounding the deployment and operating cost of the various low carbon heating pathways, and helps to define their response to the infrastructure challenges associated with heating the UK in an ultra-low carbon future.

This analysis suggests that space heating and hot water provision currently accounts for approximately 100 $MtCO_2$ / yr, a contribution that is likely to be **required to fall below 10 $MtCO_2$/yr by 2050** to be compatible with the UK's economy-wide 2050 carbon emissions target.

A variety of pathways to very low levels of carbon emissions from the UK heat sector are available, including electrification of heat, decarbonisation of the gas grid with biomethane, and repurposing of the gas grid to deliver low carbon hydrogen, or a combination of these approaches. In each case, there is likely to be a key role for a set of supporting measures and technologies, including energy efficiency, heat networks and bioenergy.

The technologies studied include:

- Heat pumps (Air-source, Ground-source and Water-source)
- Direct electric resistive/Electric storage heating
- Hybrid gas-electric heating
- Hydrogen networks
- Heat networks (including the utilisation of waste and secondary heat)
- Biomethane for grid injection
- Biomass combustion

This study aims to provide a clear and transparent assessment of the likely **costs** of decarbonising UK heat using different pathways, whilst highlighting the **impact of uncertainties** and practical barriers on the feasibility of implementing the different pathways. A particular ambition of the project is to assess all heating options using a common methodology incorporating not just the direct costs of the pathway, but also the indirect costs for the wider energy system including the associated network and generation level costs.

1.2 Key findings and conclusions

Cost of heating is highly likely to rise, but the transition presents economic opportunities

All heat decarbonisation options studied are significantly more costly than the Status Quo under all scenarios. The **cumulative additional cost to 2050 versus Status Quo** (discounted at 3.5%) is **in the range £120-300 bn** under the Central cost assumptions. Under the Best case assumptions, the corresponding range is £100-200 bn and in the Worst case assumptions £150-450 bn. The **average annual cost of heating per household is found to be £100-300 higher in 2050** than in the Status Quo.

In the context of the expected growth in GDP, however, the additional cost can be seen to be manageable. Assuming an average real GDP growth of 2.3% per annum over the period 2016-2050, such that GDP in 2050 is over 200% of that in 2015, as in the NIC's central assumption, the total **cost of heating represents a substantially smaller share of GDP than in 2015 under all scenarios**. This is supported by the table below, which compares an estimate of the cost of heating as a share of GDP in 2015 with the cumulative cost of heating to 2050 in the decarbonisation scenarios as a share of cumulative GDP to 2050. Nonetheless, the increase in heating costs will have significant distributional impacts which will be a key challenge for any heat decarbonisation pathway.

Cost of heating as a fraction of GDP in 2015	*Cumulative cost of heating to 2050 as a fraction of cumulative GDP to 2050*[1]			
	Electrification (heat pumps)	**Electrification (direct electric)**	**Hybrid gas-electric**	**Hydrogen grid**
1.2%	0.9%	0.9%	0.8%	0.9%

The transition will, however, bring the potential for substantial economic opportunities, and a variety of additional factors would be expected to bring indirect economic benefits. The focus of this study is an analysis of the infrastructure costs of the heat decarbonisation pathway options, and we do not model in detail the wider economic benefits (or costs) of the transition. Such wider economic impact should, however, be incorporated into any policy decision on low carbon heat. A non-exhaustive list of the potential wider benefits would include the potential health and productivity improvements resulting from greater energy efficiency in the home and workplace. In certain cases, the skills and supply chains developed through implementation of the transition could present an opportunity for the UK to become world leaders in the sector and to export this capability. It appears that this may be particularly relevant in the case of hydrogen heating, where the UK's highly developed gas grid represents a greater driver for this option than in most (though not all) countries. To some extent, a similar logic applies to the CCS technologies that would be needed to support this.

In the case of electrification of heat, the use of waste heat and to some extent bioenergy, there is also an opportunity to increase energy security by reducing the reliance on imported gas, providing that the required investment is made to generate the increased electricity or biomass indigenously and/or through closer integration with the energy systems of neighbouring countries.

A range of no regrets or low regrets options are identified

Energy efficiency, including enhanced efficiency standards for **new buildings** and a substantial share of the remaining potential for **retrofit** is among the no regrets or low regrets options identified. It is found that implementation of efficiency measures defined here as 'Low cost' measures, bringing savings of nearly 30 TWh / yr (around 6% of heat demand) reduces the overall system cost across all decarbonisation pathways. These no regrets measures include more than 10 million loft top-ups, nearly 4 million remaining cavity walls (including some hard-to-treat cavities), more than 1 million solid walls and more than 6 million floor insulation measures.

The implementation of further efficiency measures defined here as 'Medium cost', reducing heat demand by nearly 100 TWh / yr in total (21% of heat demand), presents an opportunity for further decarbonisation, but the economics of these measures depends on the decarbonisation pathway taken. In scenarios with relatively high heating fuel costs, such as direct electric heating and hydrogen heating, these measures can be cost-effective. For a heat pump-led pathway, these deeper efficiency retrofits, dominated by further solid wall and floor insulation measures, will be a pre-requisite to render up to 4 million buildings suitable for heat pump heating. However, under scenarios with lower heating fuel costs, such as for hybrid heat pumps, these measures lead to an increase in discounted system cost unlikely to be justified by the additional carbon emissions savings.

Heat networks are also identified as a low regrets option with the potential to reduce carbon emissions at low or negative cost as part of any pathway, particularly through the utilisation of waste and environmental heat. We find that between 10% and 25% of the UK's heat demand could be met through heat networks with a net reduction in system cost irrespective of the decarbonisation pathway taken, leading to carbon emissions reductions of up to 10 $MtCO_2$ / yr.

Biomethane grid injection using the lowest cost feedstocks, primarily including municipal solid waste (MSW), landfill gas and other waste sources, is also found to be a low regrets option in all scenarios as long as the natural gas grid remains in use. There is considerable uncertainty surrounding the availability of low cost

[1] Assuming cumulative GDP to 2050 of £145 trillion based on NIC central assumption.

biomethane resource, and on its most appropriate uses, but at least 10 TWh / yr of biomethane grid injection appears likely to be cost-effective. It is noted that MSW is a potential feedstock for both Energy-from-Waste plants (generating electricity and heat for heat networks) and for biomethane (or biohydrogen) plants injecting into the gas grid.

Off-grid biomass heating offers a further low regrets opportunity, given that more than 100 TWh / yr of sustainable potential could be available, with much of this biomass potentially available at a lower cost (in fuel cost terms) than the counterfactual of oil or direct electric heating. The key question here is over the most appropriate use for this biomass resource, including potential uses in high temperature industrial heating, power generation and/or in combination with CCS to provide negative emissions (see later). While off-gas biomass heating is found to be a cost-effective option when the lower cost resource is available to the heat sector, careful consideration should be given to the best use of this resource.

Beyond the no regrets options, important decisions on the future of the UK's energy infrastructure will need to be taken

All heat decarbonisation options will require substantial investment in the UK's energy generation and distribution infrastructure over the next 30 years, of the order £120-300 bn in discounted terms. **Beyond the no regrets and low regrets options**, the majority of the heat demand which remains – associated in particular with the share of the >22 million existing buildings on the gas grid in areas less well-suited to heat networks – will need to be decarbonised through other means. This will require **decisions to be made** on whether the demand will be met through a **low carbon electricity grid**, a **low carbon gas network** or a **combination** of the two in a hybrid approach. This decision will have an important impact on the nature of the future electricity system, and on the ongoing viability of the gas distribution system.

An important finding of the work is that, in some scenarios, a **large share of the required infrastructure investment occurs at the building level** – this is highest in the case of heat pumps, and lowest in the case of hydrogen heating, with energy efficiency an important component to reduce costs in all scenarios. This suggests a need to **view infrastructure not only in terms of multi-billion pound investments**, but also in terms of millions of smaller investments, and to recognise that delivering this investment will require a range of very different approaches to financing.

Comparison of main pathway options

All the main pathway options studied – electrification through heat pumps and other electric heating, a hybrid approach involving electric heating supported by gas heating during peak periods, and repurposing of the gas grid to deliver low carbon hydrogen – represent potentially viable pathways to deep decarbonisation of a large fraction of the UK's heat demand.

A summary of the potential for the main pathway options described above to contribute to deep decarbonisation of the UK heat sector is provided in Table 1-1, and figures presenting the range of uncertainty in the cumulative discounted system cost of each option to 2050 are presented in Figure 1-1 to Figure 1-4.

Figure 1-1: Uncertainty in cumulative additional system cost to 2050 – Heat pumps

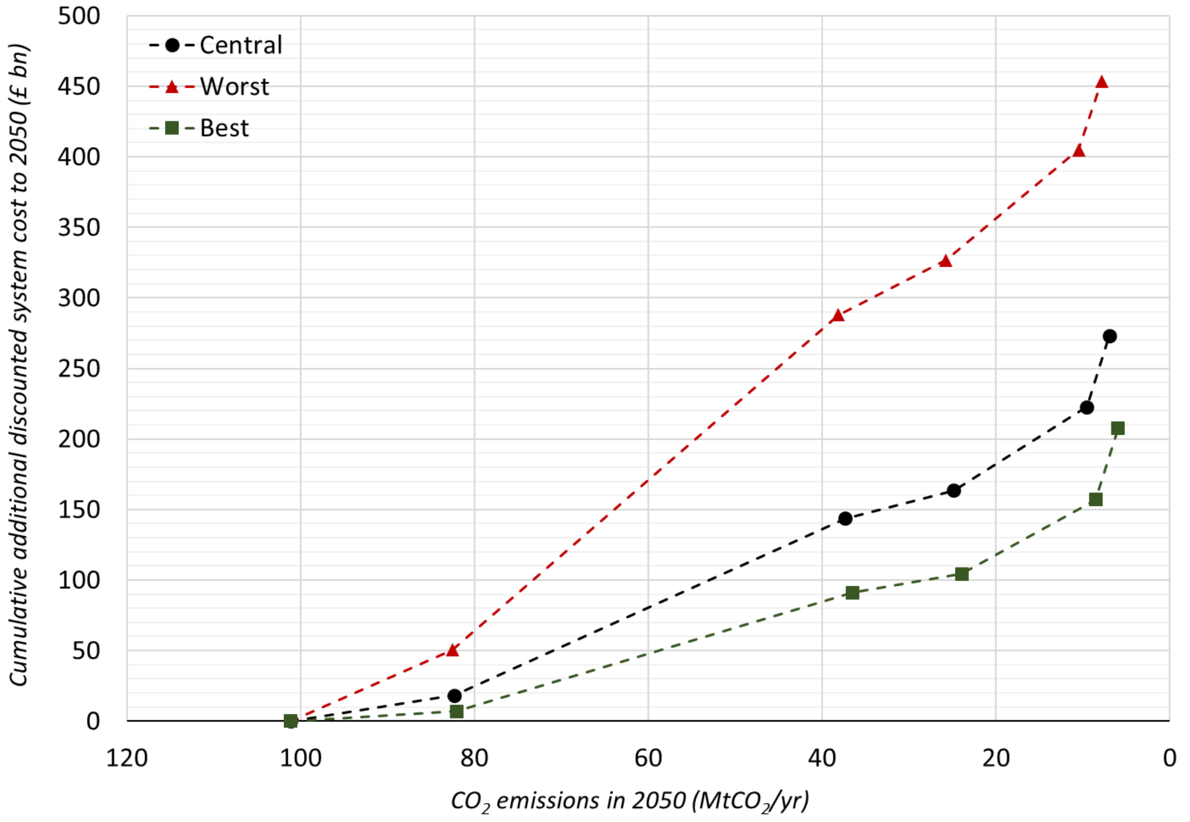


Figure 1-2: Uncertainty in cumulative additional system cost to 2050 – Direct electric heating

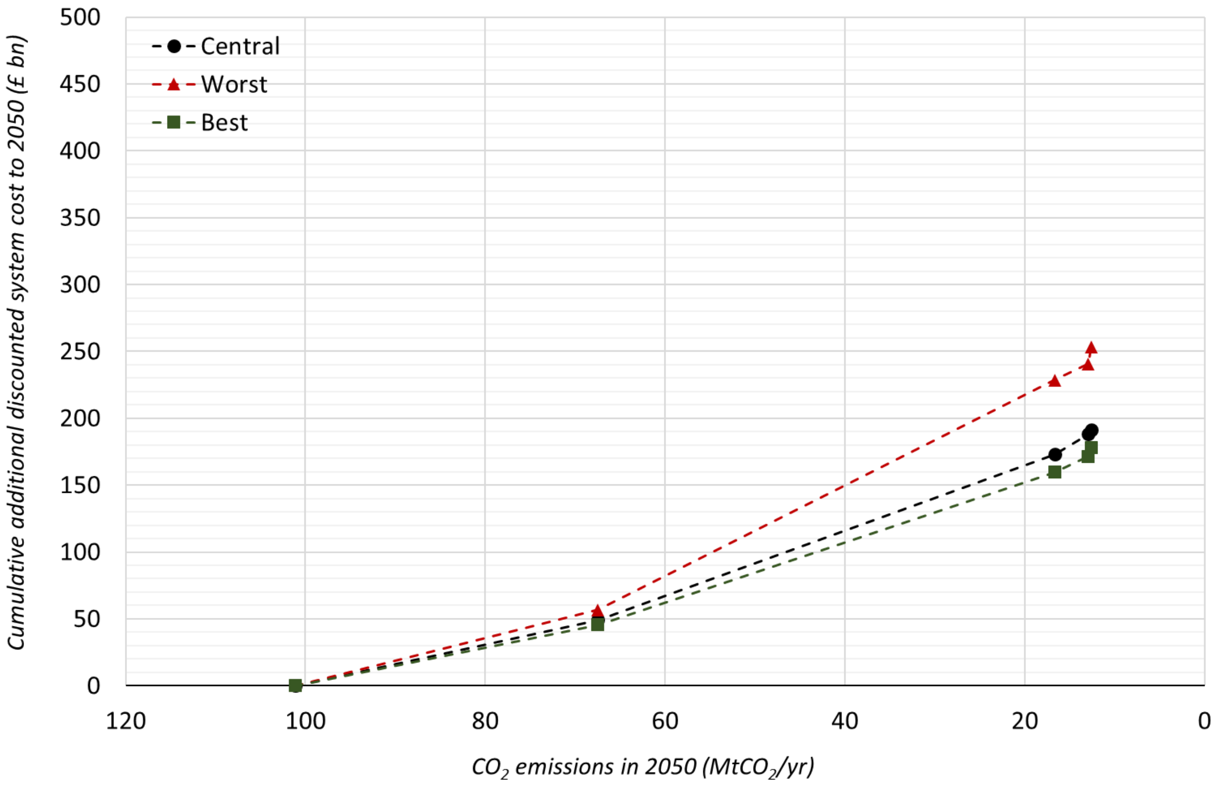


Figure 1-3: Uncertainty in cumulative additional system cost to 2050 – Hybrid heat pumps

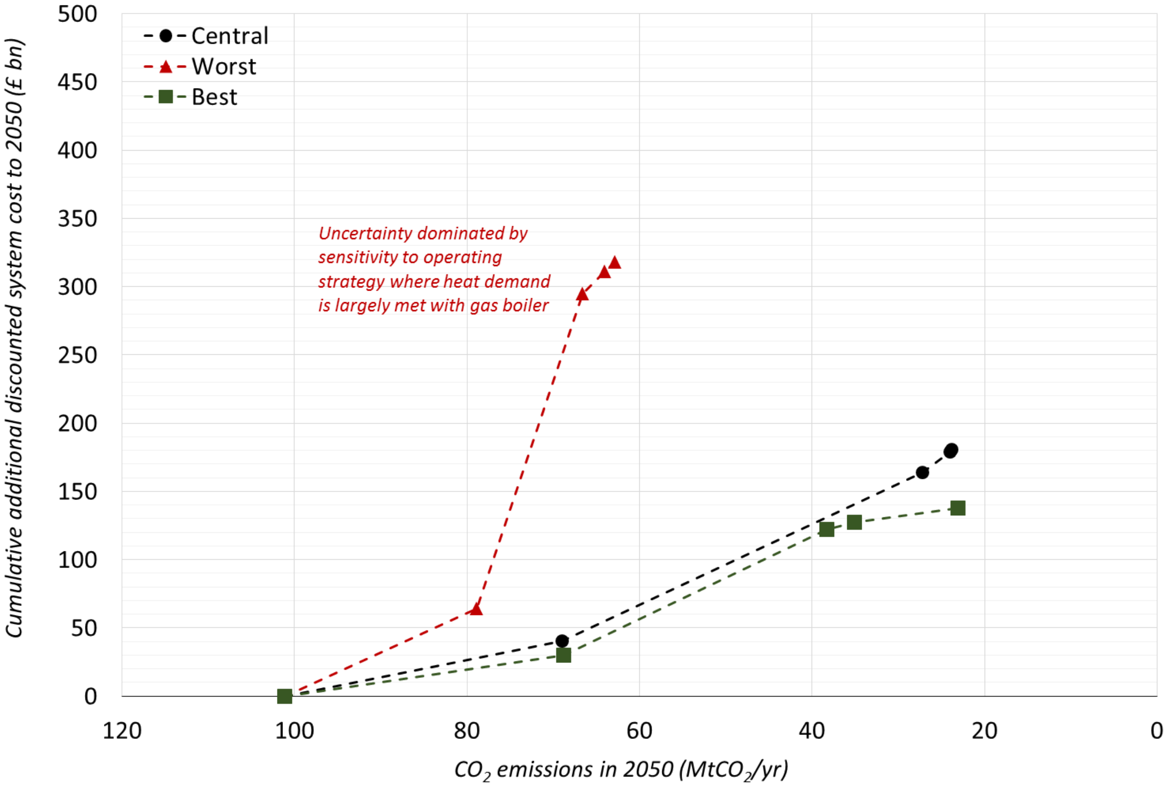


Figure 1-4: Uncertainty in cumulative additional system cost to 2050 – Hydrogen heating

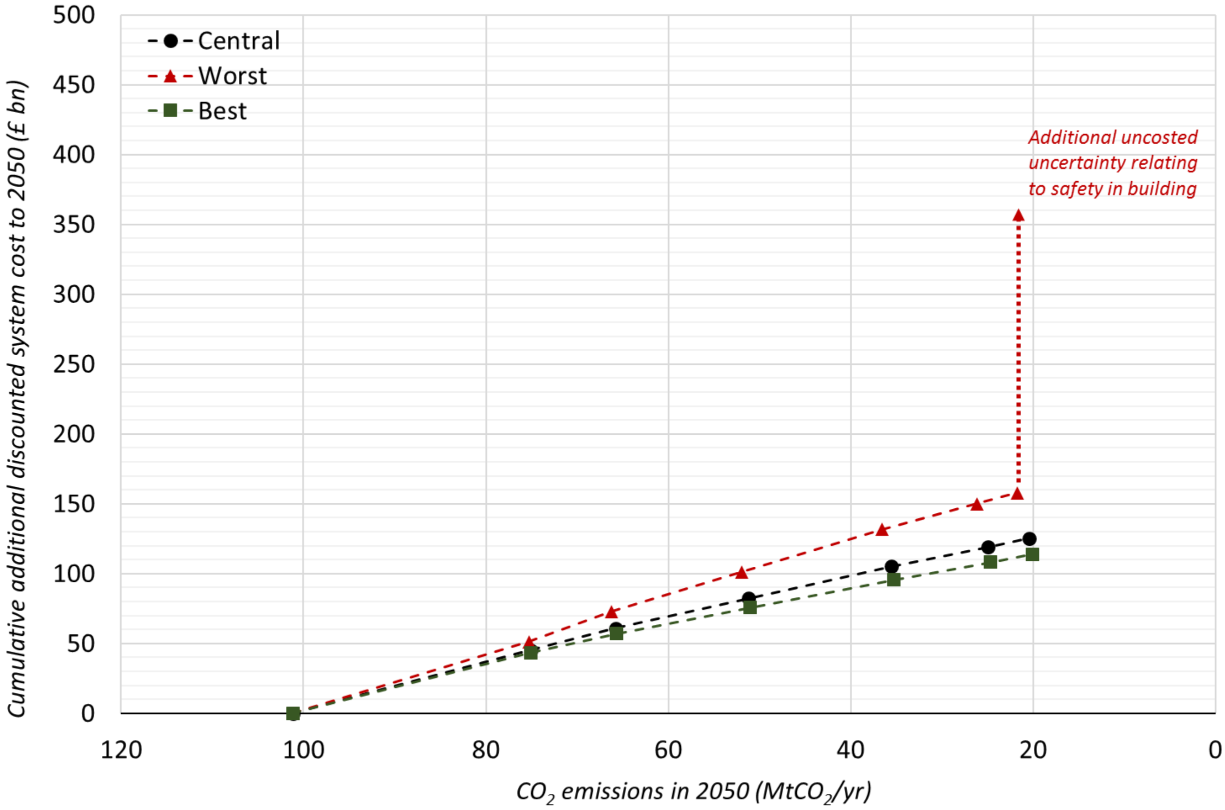


Table 1-1: Comparison of main pathway options

	Electrification (heat pumps)	**Electrification (direct electric)**	**Hybrid gas-electric**	**Hydrogen grid**
Suitable building stock segments	• On- and off-gas • Suitable for efficient buildings – maximum deployment requires widespread retrofit	• On- and off-gas • Suitable for all building efficiency levels	• On-gas only • Suitable for all building efficiency levels	• On-gas only • Suitable for all building efficiency levels
Achievable level of heat decarbonisation at maximum deployment	**5-10 $MtCO_2$** (Limited by grid CO_2)	**10-15 $MtCO_2$** (Limited by grid CO_2)	No green gas: **20-25 $MtCO_2$** With green gas: **15-20 $MtCO_2$** (Limited to on-gas)	**20-25 $MtCO_2$** (Limited to on-gas and 90% CCS capture)
Cumulative additional cost vs Status Quo to 2050 at maximum deployment (discounted at 3.5%)	Central case: **£270 bn** Range: **£210-450 bn**	Central case: **£190 bn** Range: **£180-250 bn**	No green gas: Central case: **£180 bn** Range: **£120-320 bn** With green gas (40 TWh): Central case: **£210 bn** Range: **£150-350 bn**	Central case: **£130 bn** Range: **£110-160 bn**
Annualised costs in 2050	Capital costs: **£21 bn** Operating and fuel costs: **£19 bn**	Capital costs: **£5 bn** Operating and fuel costs: **£33 bn**	Capital costs: **£15 bn** Operating and fuel costs: **£25 bn**	Capital costs: **£8 bn** Operating and fuel costs: **£28 bn**
Key uncertainties	Heat pump unit cost, requirement for energy efficiency retrofit, grid reinforcement cost	Electricity fuel cost, grid reinforcement cost, heating system unit cost	Heat pump unit cost, actual emissions reduction strongly dependent on consumer behaviour, potential contribution of green gas	Safety case, in-building retrofit cost, consumer acceptability, readiness and cost of CCS
Deployment timescales	• Ready to deploy • Consistent with long-term CO_2 budget	• Ready to deploy • Consistent with long-term CO_2 budget	• Ready to deploy • Only consistent with long-term if near-fully green gas (also need off-gas solution)	• Unlikely before 2030s • Consistent with long-term CO_2 budget (also need off-gas solution)

A comparison of the main pathway options finds that re-purposing the gas grid to deliver **low carbon hydrogen** – if this option can be delivered safely and at scale – is the lowest cost option under most scenarios studied. However, there is greater uncertainty over the hydrogen option compared with the electrification and hybrid options. This is not simply an uncertainty in cost terms but a 'stop-go' uncertainty, since the safe delivery of hydrogen to millions of buildings remains, as yet, unproven. Cost-effective hydrogen heating is highly likely to be reliant on carbon capture and storage (CCS), which is also as yet unproven, and carries substantial cost uncertainty. Furthermore, the hydrogen option would require the highest level of state intervention and central planning of all the options.

Nonetheless, given that the cost of this pathway could be more than £100 bn lower in discounted system cost than, for example, the heat pump electrification pathway, there is a strong case to invest in research and trials of the associated supply chain technologies, including hydrogen appliances, building and network level re-purposing, hydrogen storage and CCS. This is crucial to gain a better understanding of the true cost of the pathway, its risks and regulatory requirements.

Any deep **electrification** option will lead to an additional peak electricity demand of at least 45 GW, representing an additional two-thirds of the current UK electricity generating capacity. The capability to generate[2] and distribute this additional electricity demand would represent a major infrastructure investment over the next 30 years, including around £20 bn associated with the distribution network.

Heat pump heating is found to be the most costly of the main pathway options under most scenarios. Despite the substantial electricity network upgrade costs (in the region of £20 bn), the largest share of the cumulative discounted system cost (exceeding £200 bn) is associated with investment at the building level, in the heat pump unit itself and the accompanying energy efficiency and building renovation work required in many cases. Despite the relatively mature market for heat pumps (outside the UK), there is the potential for significant reduction in installed heat pump costs. Given the dominance of the heat pump unit costs in this pathway, this leads to a relatively large uncertainty over the total cost of this pathway.

Storage heating is an alternative electrification option to heat pumps, with a quite different cost profile. While the capital cost of the installation is substantially lower, the ongoing electricity cost is much larger due to the lower efficiency. The lower efficiency also means that this option requires greater investment in electrical grid reinforcement and electrical generation than the heat pump option, and also that a lower level of decarbonisation is reached for the same level of deployment. For the Central cost assumptions, the total cumulative discounted system cost is, however, lower than in the heat pump case, at £190 bn as compared with £270 bn. In the Worst case for electricity production cost, the trend is preserved, although the difference between the scenarios is reduced.

Despite the higher system cost than the hydrogen heating option in most scenarios, electrification of heat through heat pumps and/or other electric heating is a proven technology and is the most likely outcome in the majority of homes in the absence of substantial heat infrastructure planning.

A further option involves heating using both the electricity and gas infrastructure, through the application of **hybrid heat pumps.** We find that, in all scenarios (excluding hybrid heat pumps in combination with biomethane grid injection – see below), this is more cost-effective than full electrification using heat pumps due to a reduction in costs incurred both at the building level (since much of the building renovation associated with pure electric heat pumps can be avoided) and at the electricity network/generation level (since the peak heat demand can be met through the gas network). The main drawback in cost terms of this option is the requirement to maintain both electricity and gas infrastructure. This could present a challenge in particular for the gas grid given that the

[2] Note, this report does not consider the cost of additional power generation capacity required to meet this increased peak demand (e.g. the per kW capital cost of peaking plant required), and instead assumes a fixed annual average cost for electricity (starting at 6 p /kWh in 2015, reaching 8 p / kWh in 2025 and dropping to 7 p / kWh from 2035 onwards – see Section 6.1 for a detailed explanation of these costs). These assumptions will be updated for key scenarios by the power sector modelling exercise currently underway at the National Infrastructure Comission.

volume of gas demand is likely to be much reduced, and the operating costs would be spread over a smaller customer base. Furthermore, in the absence of decarbonisation of the gas grid, this option achieves a lower level of heat decarbonisation than full electrification due to the ongoing use of natural gas – and there would be substantial uncertainty over the level of decarbonisation that would be achieved since this would be dependent on the behaviour of consumers operating the hybrid systems and via the share of heating provided by the gas boiler. In this case, hybrid gas-electric heating offers only an interim option on the path to deeper decarbonisation.

Biomethane grid injection offers a route to deeper decarbonisation using the hybrid heating approach. At least 7 TWh / yr of biomethane could be produced at negative overall cost, based on waste feedstocks. Beyond this, to achieve a level of remaining GHG emissions from heating approaching 15 $MtCO_2$ / yr, the cost of producing biomethane is expected to increase significantly. In the Central case, we find that a level of remaining emissions of 17 $MtCO_2$ / yr can be achieved for a cumulative discounted system cost of £220 bn, but a further reduction to 15 $MtCO_2$ / yr would require a total discounted cost of more than £300 bn. There is considerable uncertainty over the available resource for biomethane, and it is clear that the technology can play a role at least in the interim period. However, on the basis of this analysis it is unlikely to be cost-effective to reach deep levels of decarbonisation in the long-term using a hybrid approach due to the high penetration of biomethane required and the associated cost of large amounts of relatively costly imported biomass.

Biomass gasification to hydrogen with CCS offers the opportunity to achieve negative emissions from the heat sector. This analysis finds that the production of 47 TWh / yr of biohydrogen, combined with CCS, could lead to an emissions reduction of 24 $MtCO_2$ / yr by 2050, and potentially net negative emissions from the heat sector overall. This should be viewed as an upper limit, however, as various other sectors are likely to compete for the underlying feedstocks required to produce the biohydrogen. Nonetheless, this could provide a relatively low cost alternative to other hard-to-reduce emissions.

Local circumstances are likely to mean that – to some extent – a mix of options will occur

It is meaningful and important to compare the cost of the main pathway options since, in many cases, policymakers will need to make decisions on whether to invest in order to ensure technology readiness and cost reductions through learning (such as for hydrogen heating, CCS and heat networks, for example) and, in some cases, to make decisions on the most appropriate pathway for a given region (particularly in the case of hydrogen heating).

However, this is not to suggest that there will be a single optimum pathway across all buildings and regions. Indeed, this report sets out to inform which segments of the stock are more or less suitable for decarbonisation through the various pathway options. In some cases this is obvious – for example, decarbonised gas solutions will only be feasible for on-gas buildings. Beyond that, however, there will be heat-dense regions located near sources of low carbon heat, well-suited to heat networks, and rural off-gas regions well-suited to heating using biomass. Millions of new and well-insulated existing buildings will be well-suited to heating with heat pumps. **Specific local circumstances** relating to the electricity or gas grid, and the presence of local renewable sources of energy, **will provide particular constraints and opportunities**, which could lead to regions with distinct differences in **energy pricing** and time-of-use differentials. This is likely to result in a mix of heating options being deployed.

In some cases, it may be appropriate and beneficial for the public sector – most likely through the local authority – to develop '**heat zoning**' policy to incentivise and/or regulate the use of different heating and other energy technologies, where market failures persist or where substantial benefits can be gained through coordinated behaviour. Given such factors, it is highly likely that a mix of heat decarbonisation options will occur across different regions and building types. The analysis presented in this report that all these options provide a viable decarbonisation approach, but also indicates the level of infrastructure investment that will need to be made under the deployment of each option at scale.

CCS is identified as a critical enabling technology in most scenarios

Carbon capture and storage (CCS) is a **pre-requisite for the hydrogen heating pathway**, in order to support the application of steam methane reformation (SMR) for hydrogen production, as it is highly unlikely that electrolysis could provide sufficient hydrogen for a national rollout of hydrogen heating at reasonable cost.

However, the challenge of achieving sufficiently deep decarbonisation via any pathway – including electrification of heat – suggests that CCS is likely to be required to enable cost-effective decarbonisation of power and, potentially, negative emissions in combination with biomass. Without CCS, heat decarbonisation is likely to require near-complete decarbonisation of the electricity grid using renewable and battery storage – the cost of achieving this is not well-understood but could be higher than the cost of the alternatives. An ongoing study by the NIC aims to provide further insight into the comparative cost of power sector decarbonisation with and without CCS[3].

1.3 Analysis of Mixed scenarios for deep decarbonisation of the UK heat sector

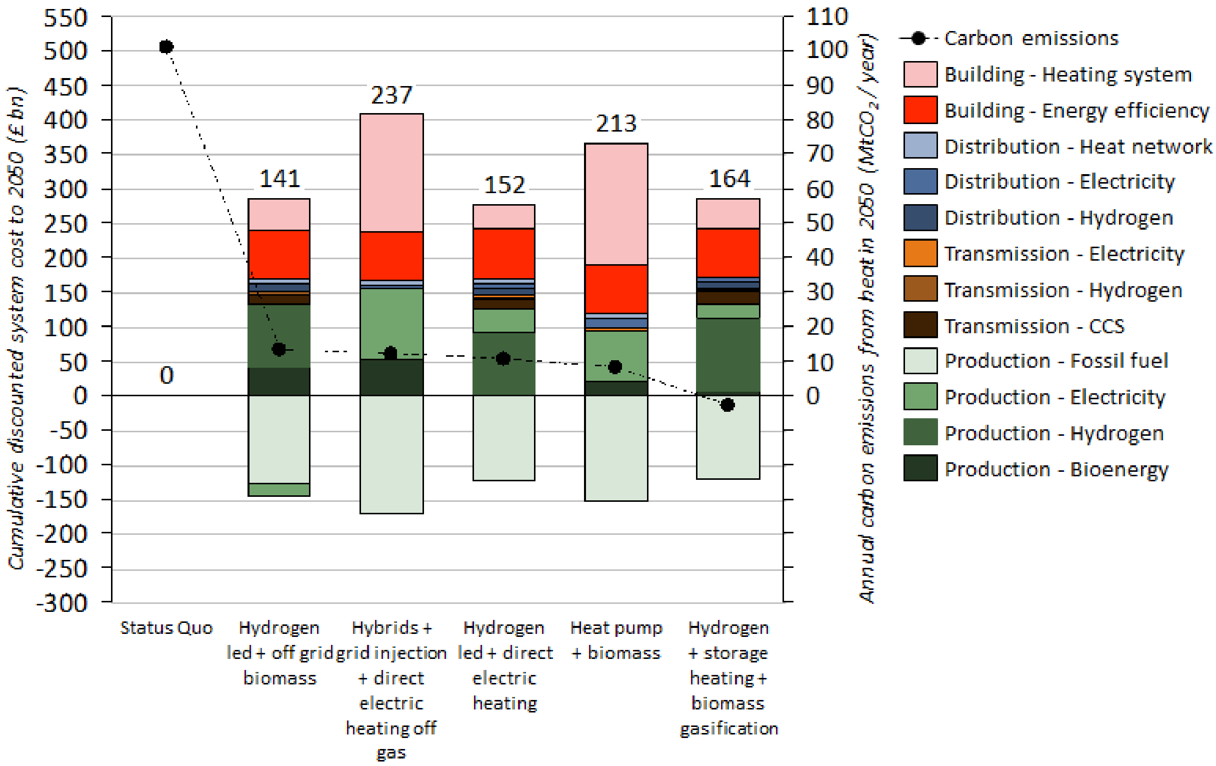
On the basis of the results of the analysis of individual heat decarbonisation options, a series of coherent 'Mixed' scenarios were defined with the potential to provide a deep level of carbon emissions reduction across the stock – with remaining emissions in 2050 approaching or falling below the approximate 'target' defined here of 10 $MtCO_2$ / yr – and the likely range of costs associated with each were compared. The following scenarios are considered:

1. **Hydrogen led + biomass off-gas** – the UK gas grid is repurposed to carry low carbon hydrogen, and low cost biomass is installed in off-gas buildings, displacing oil and electric based heating.
2. **Hybrid gas-electric + grid injection + direct electric heating off-gas** – hybrid heat pumps are installed in all on-gas buildings, and low carbon biomethane is injected into the gas grid. In order to fulfill this grid injection demand, almost all low cost available bioenergy feedstocks are required, so electric heating is used as an off-gas solution.
3. **Heat pumps + bioenergy in hard-to-insulate buildings** – all Low and Medium cost energy efficiency measures are applied across the stock, and heat pumps are applied in all buildings in the high efficiency band. The remaining buildings that are insufficiently insulated to be suitable for a heat pump use a biomass solution.
4. **Hydrogen led + direct electric heating off-gas** – the UK gas grid is repurposed to carry low carbon hydrogen with direct electric heating in off-gas buildings.
5. **Hydrogen led + biomass gasification with CCS + direct electric heating off-gas** – hydrogen is produced by a mix of SMR and biomass gasification (both implemented in conjunction with CCS). Direct electric heating systems are applied to all off-gas buildings.

The cumulative additional system cost to 2050 of each Mixed scenario relative to the Status Quo scenario, and the associated level of CO_2 emissions in 2050, are shown in Figure 1-5.

[3] National Infrastructure Commission (pending 2018)

Figure 1-5: Cumulative additional system cost and CO_2 emissions in 2050 – Mixed scenarios



The Mixed scenarios achieve a range of levels of decarbonisation of the heating sector, with remaining emissions in 2050 in the range -3 to 13 $MtCO_2$ / yr. It is notable, therefore, that several of these options fail (just) to reduce carbon emissions below the approximate 'target' for space heating and hot water of 10 $MtCO_2$ / yr suggested by the high-level analysis above. This is due to one or more of the factors including a remaining level of gas boiler heating (in the hybrid heat pump case), remaining emissions from the electricity grid (of 30 gCO_2/kWh as assumed here) or the emissions associated with hydrogen produced using SMR with incomplete capture of the CO_2 using CCS (the emissions intensity of hydrogen with a 90% CO_2 capture rate is approximately 24 gCO_2/kWh). It should be noted that this analysis does not account for other GHG emissions indirectly related to the provision of heat in these scenarios, such as the upstream emissions associated with gas production including methane leakage (relevant in the hydrogen scenarios, and any electrification scenario with remaining gas-based electricity generation, even with CCS).

It can be seen that the cumulative discounted cost of the scenarios to 2050 versus the Status Quo ranges from £141 bn for the "Hydrogen led + biomass off-gas" scenario, to £237 bn for the "Hybrids + grid injection + direct electric off-gas" scenario. The estimated level of sensitivity in the cost figures to technology cost and performance is presented in Figure 1-6.

Figure 1-6: Uncertainty in cumulative additional system cost to 2050 – Mixed scenarios

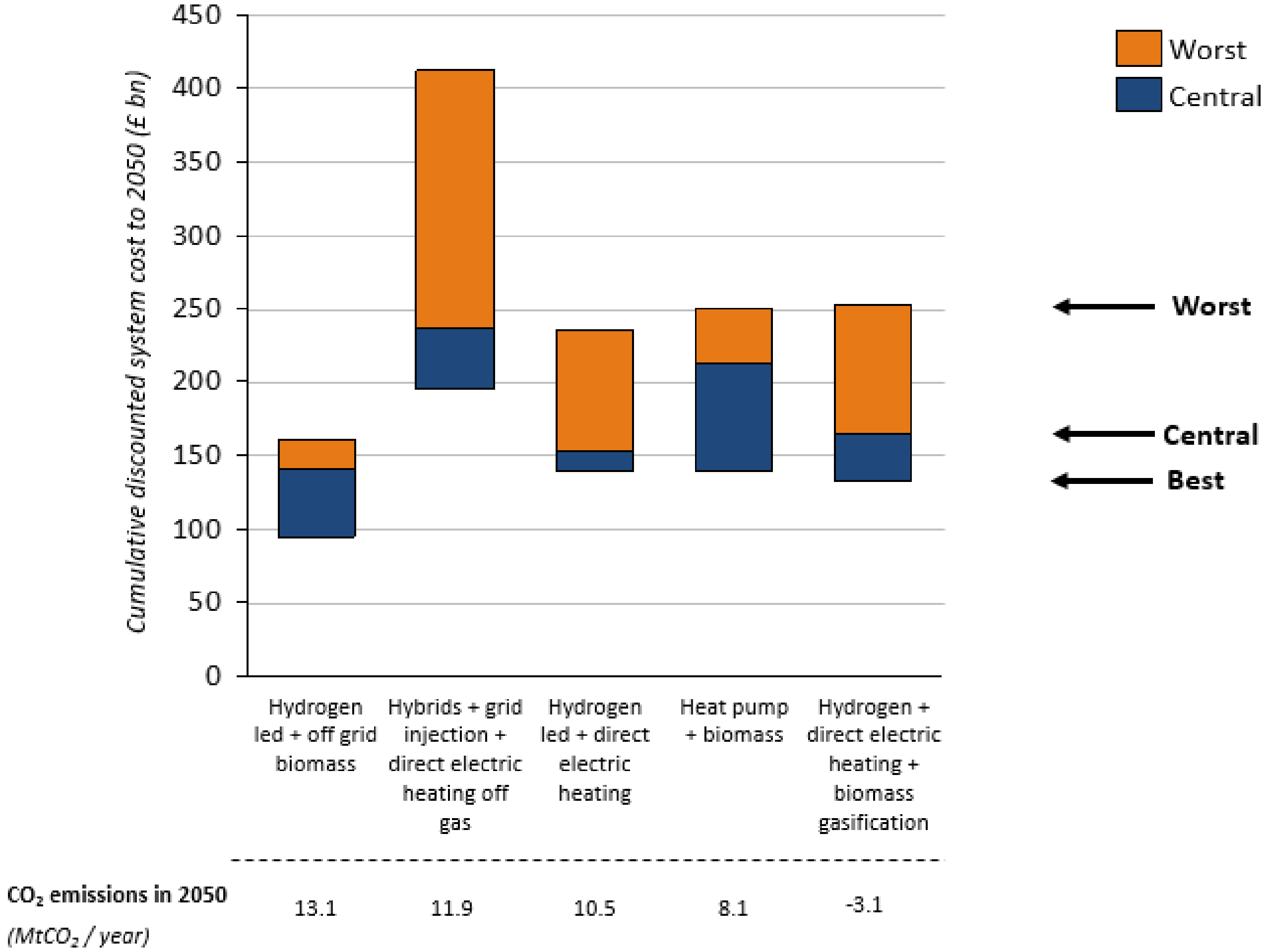


Figure 1-6 shows a substantial variation between the Best and Worst cases for all scenarios, in some cases larger than the difference between the Central cases for the different scenarios. It is notable that there is considerable overlap between each of the scenarios. This suggests that on the basis of the analysis undertaken here, while there are clear indications that certain pathways are likely to be lower cost than others, no pathway can definitively be ruled the lowest cost option.

Nonetheless, the results of most scenarios suggest that a hydrogen-led heat decarbonisation pathway could be lower in cost by several tens of billion pounds than an electrification-led or hybrid gas-electric. This finding is sufficient to justify a concerted level of effort and investment at the national policy level to further develop the readiness of all technologies implicated and to trial these at scale, in order to better inform decision-making over the UK's heat decarbonisation pathway.

2 Introduction

2.1 Context

Meeting the UK's legally-binding, carbon emissions reduction goals will require deep decarbonisation of all sectors of energy use. As heat currently accounts for around half of the UK's energy consumption, transitioning to low carbon heating will be a key aspect of an ultra-low emission future.

A wide range of options for decarbonising heating exist and the different pathways will lead to quite different energy systems in the UK. One of the most frequently considered options is the electrification of heating demands via high efficiency heat pumps and/or storage heating, which together with efforts to decarbonise electricity supplies could reduce emissions in this sector. Other approaches to reducing emissions from heat include substituting traditional heating fuels (mainly gas and to a lesser extent oil) with biomass of different types, and supplying heat networks, mainly in urban areas, with environmental and secondary sources such as geothermal, water source and waste heat. In recent years, new concepts have emerged to continue the use of the gas transmission and distribution infrastructure using either injection of low carbon synthetic methane (derived from biomass) or the injection/substitution of methane using low carbon hydrogen.

None of these solutions is without its drawbacks and challenges. Heat pumps are not suitable in all building types (as their efficiency decreases with increasing temperature of heat delivery) and place additional strains on electricity networks that are seeing growing demands from other uses (e.g. transport). Biomass resources are limited, and combustion of wood can lead to undesirable local environmental impacts such as increased particulate emissions, while heat networks remain a niche solution in the UK with significant barriers to wider uptake. The hydrogen option remains subject to significant uncertainty over the costs, consumer acceptability and the practicality of implementation.

In this context, there is a considerable challenge for those planning the UK's future infrastructure for heat. There is uncertainty over the practicality and also a lack of data on the relative costs of these very distinct pathways. The Committee on Climate Change[4], for example, recognises this uncertainty and proposes a number of low regrets measures to help decarbonise heat. These will have a limited impact, however, and still leave open the broader decisions on the most appropriate low carbon heating pathway for the majority of the existing building stock.

2.2 Objectives of this study

Element Energy and E4tech have been commissioned by the National Infrastructure Commission (NIC) to undertake an **analysis of the cost of decarbonising the UK's heat infrastructure, specifically space heating and hot water**.

The NIC intends that this work is able to inform the debate surrounding the deployment and operating cost of the various low carbon heating pathways, and helps to define their response to the infrastructure challenges associated with heating the UK in an ultra-low carbon future.

This study aims to provide a clear and transparent assessment of the likely costs of decarbonising UK heat using different pathways, whilst highlighting the impact of uncertainties and practical barriers on the feasibility of implementing the different pathways. A particular ambition of the project is to assess all heating options using a common methodology incorporating not just the direct costs of the pathway, but also the indirect costs for the wider energy system including the associated network and generation level costs.

Heating technologies

The technologies studied include:

[4] Committee on Climate Change, *The infrastructure needs of a low-carbon economy prepared for climate change* (2017) https://www.theccc.org.uk/wp-content/uploads/2017/03/The-infrastructure-needs-of-a-low-carbon-economy-Committee-on-Climate-Change-March-2017.pdf

- Heat pumps (Air-source, Ground-source and Water-source)
- Direct electric resistive/Electric storage heating
- Hybrid gas-electric heating
- Hydrogen networks
- Heat networks (including the utilisation of waste and secondary heat)
- Biomethane for grid injection
- Biomass combustion

2.3 Summary of approach

Stock model of UK heat demand

The suitability, cost and practicality of each heat decarbonisation option varies widely across different ‘segments’ of heat demand – that is, across the building stock. For example, options requiring the delivery of decarbonised methane or hydrogen to buildings are only suitable for on-gas buildings, which applies to around 86% of the UK’s domestic buildings. Heat networks will be cost-effective only in densely-populated areas, where the capital-intensive distribution infrastructure is justified by a high volume of heat sales. Heat pumps are likely to be suitable only in buildings with a minimum level of thermal efficiency, and hence the cost of this option is dependent on the depth of energy efficiency retrofit required to render the building suitable. There is also a geographical element to the suitability of the decarbonisation options. This is particularly relevant for the rollout of a hydrogen grid, which is likely to develop from one or more geographical centres suitable for large-scale low carbon hydrogen production with close proximity to CO_2 storage sites and presence of waste heat and/or other low cost energy sources.

Figure 2-1: Illustration of the rationale for segmentation of the UK heat demand (adapted from the Committee on Climate Change[5])

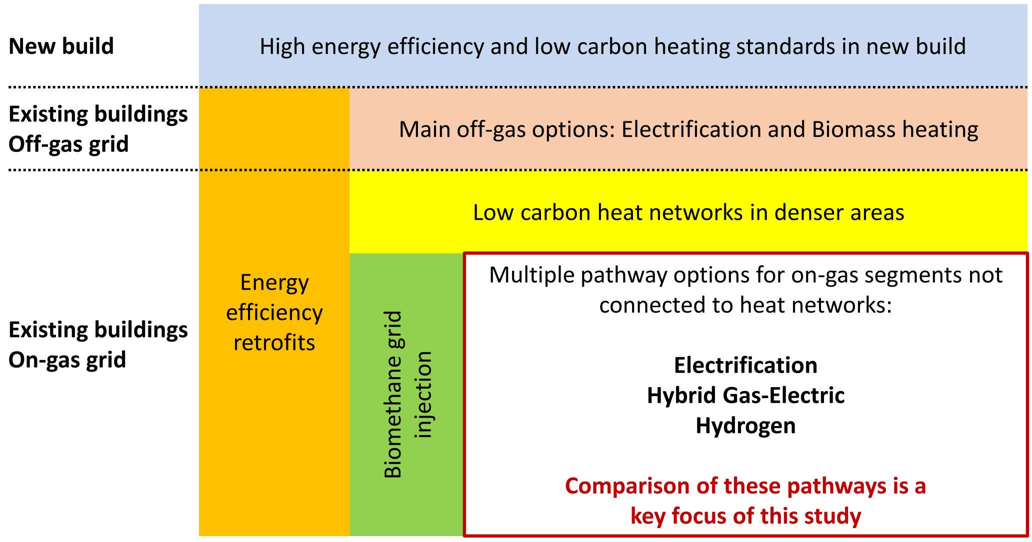


Figure 2-1, adapted from the Committee on Climate Change, indicates the impact of some of these factors on the suitability of different heat decarbonisation for different heat demand segments.

The analysis undertaken for this study aims to capture the most material factors influencing the suitability and cost of the heat decarbonisation options, and hence to determine the heat demand segments in which each option may be more (or less) suitable, and to assess the impact of this on the overall cost of each pathway. This has been achieved through the development of a stock model of the UK space heating and hot water demand.

[5] Committee on Climate Change, *Next steps for UK heat policy* (2016)

Table 2-1: Description of variables used to segment UK heat demand and groups defined

Variable	Rationale	Segments defined in analysis
On- or off-gas and incumbent heating system	• Off-gas properties would not be able to take up hybrid gas-electric or hydrogen heating • Incumbent heating system influences the cost (and likelihood) of installing an alternative heating option • Electric, oil or solid fuel heating homes may not have central heating, which would represent an additional cost	• Gas, Electric, Other
Heat demand density and geographical region	• Cost of district heating is strongly dependent on the density of the area; this relates mainly to the cost of the required distribution-level infrastructure • Rollout of a hydrogen grid is likely to develop from one or more geographical centres, influenced by population density, proximity to CO_2 storage sites and presence of waste heat and/or other low cost energy sources • Suitability of biomass heating also depends on area density (urban vs rural)	• 12 heat density groups defined based on MSOA level data • Geographical information recorded in the model to allow application of technologies to specific regions
Building type	• Suitability of heating technologies varies by building type; for example, hybrid heat pumps will not be suitable for all apartments due to space constraints • Building type also determines the cost of building-level infrastructure, and the annual average and peak fuel demand per building	• Domestic: Small (Apartment), Medium (Semi-detached/ Terraced), Large (Detached) • Non-domestic
Thermal efficiency level	• Suitability of heating technologies varies by thermal efficiency level • The key examples is that heat pumps are not suitable for thermally inefficient buildings • Ease of insulation is important in determining the cost of bring the building up to a suitable level of thermal efficiency; e.g. easy-to-treat vs hard-to-treat walls • Thermal efficiency level also used to define the annual average and peak fuel demand per building	• Existing buildings: three levels of building thermal efficiency • New buildings

Table 2-1 describes the variables used to segment the heat demand, the rationale for doing this, and the segments defined in the analysis. Information on the characteristics of the UK domestic building stock, including building type, thermal efficiency level and incumbent heating system, was based on Element Energy's Housing Energy Model. The characteristics of the non-domestic building stock were based on BEIS's Building Energy Efficiency Survey[6]. The geographical description of the heat demand was based on BEIS's Sub-national gas and electricity consumption datasets[7], used to develop an MSOA-level energy demand map and calibrated to the overall national heating and hot water demand according to BEIS's *Energy Consumption in the UK* data[8].

[6] https://www.gov.uk/government/publications/building-energy-efficiency-survey-bees (Accessed November 2017)
[7] https://www.gov.uk/government/collections/sub-national-gas-consumption-data (Accessed November 2017)
[8] https://www.gov.uk/government/collections/energy-consumption-in-the-uk (Accessed November 2017)

Scenario development

A model has been developed to construct and compare a range of heat decarbonisation pathways. Scenarios are constructed by defining the level of deployment of each heating technology at 5-yearly time intervals between 2015 and 2050, with the deployment defined separately for the different heat demand segments and/or geographical regions indicated in Table 2-1.

Figure 2-2: Summary of the input parameters and cost outputs associated with each system level

Level	Building level	Distribution level	Transmission level	Generation level
Inputs	• **Deployment** of heating options across stock • **Cost per building** of building-level technologies • **kWh/yr** and **kW peak** demand per building for each fuel	• **kW peak** per fuel type (aggregated across stock) • **Cost per kW** of distribution level new build, reinforcement, and maintenance	• **kW peak** per fuel type (**aggregated** across stock) • **Cost per kW** of transmission level new build, reinforcement and maintenance	• **kW peak** per fuel type (**aggregated** across stock) • **kWh/yr** per fuel type (aggregated across stock)
Cost outputs	• **Energy efficiency** retrofit • **Building-level heating system** (boilers, HPs) • **Heat transfer unit + heat meter** (DH) • **Fuel storage** (Biomass) • Building-level **thermal storage**	• **Distribution networks** for electricity, gas, hydrogen and heat • **Network-level heating plant for DH** (e.g. large HPs, CHP)	• **Transmission networks** for electricity, gas, hydrogen • No transmission network assumed for heat	• **Production cost** of gas, electricity, H_2 production, bioenergy

The infrastructure required to support the deployment scenarios defined is then assessed. As shown in Figure 2-2, the analysis includes infrastructure across all levels of the energy system. At the building-level, the number and capacity of all relevant components are determined, including heating systems (boilers, heat pumps etc.), energy efficiency measures, fuel and thermal storage, heat transfer units and heat meters (for heat networks).

The annual and peak demand of each fuel type (electricity, gas, hydrogen, bioenergy) for each building is derived, and these demand values are then aggregated across the stock (including the effect of diversity) to determine the additional annual and peak demand of each fuel nationally. Based on the increase in peak demand for each fuel type, any additional distribution, transmission and generation level infrastructure for each fuel is determined.

The capital and operating cost of all required infrastructure components is then calculated for each five-yearly interval between 2015 and 2050, along with the production cost of all associated fuels. The annual demand for each fuel is also used to determine the carbon dioxide emissions trajectory associated with each scenario at the same five-yearly intervals.

3 Status Quo scenario and the 2050 CO_2 target

3.1 Status Quo scenario

A Status Quo scenario has been developed, with an associated cost and CO_2 emissions trajectory between 2015 and 2050, to provide a baseline against which to compare the heat decarbonisation pathways. The Status Quo scenario, as for all scenarios presented in this study, incorporates all infrastructure and resource inputs associated with the provision of space heating and hot water.

In the Status Quo scenario, existing buildings are assumed to retain the same heating system type between 2015 and 2050 (replacement of these systems at end-of-life is included), and no new energy efficiency measures are assumed to be applied to existing buildings. A demolition rate is assumed, which has the effect of removing some existing buildings from the stock, and a construction rate is applied to add new buildings to the stock. By 2050 this results in the demolition of 454,000 domestic buildings, and the construction of 4,476,000 buildings. The new buildings are assumed to be highly energy-efficient, but are served by gas boilers. The Status Quo scenario is thus intended to be a 'blank canvas' to which heat decarbonisation pathways are applied, rather than a representation of current policies or 'business-as-usual'.

Total system costs over time in the Status Quo scenario are shown in Table 3-1. The cumulative undiscounted[9] system cost in five-year periods to 2050 in the Status Quo scenario is shown in Figure 3-1. The cumulative discounted system cost is shown in Figure 3-2. The table indicates that there is a significant rise in annual undiscounted costs towards the 2031 – 2035 period, which subsequently level off. This is driven by a projected increase in the underlying cost of gas (from 2.4 p / kWh in 2015 to 3.1 p / kWh from 2035 onwards) and electricity (from 6 p / kWh in 2015 to 7 p / kWh in 2035). The cumulative discounted system cost of this pathway is found to be £561 bn, comprising the costs of fossil fuels and electricity used for heating (£307 bn), costs related with the electricity and gas distribution and transmission networks (£35 bn, £32 bn of which is associated with the ongoing cost of operating the gas network, £3 bn of which is associated with network upgrades required for the electricity network) and the costs of replacing the heating systems at end-of-life (£220 bn). On an undiscounted basis, the annual system cost of heating from 2050 is expected to be £840 / building / yr.

Table 3-1: Total system cost and annual carbon emissions to 2050 under the Status Quo scenario

Five-year period	**2016-2020**	**2021-2025**	**2026-2030**	**2031-2035**	**2036-2040**	**2041-2045**	**2046-2050**	***2016 - 2050***
System cost in five year period *£bn (undiscounted)*	116	127	142	150	151	153	157	***996***
System cost in five year period *£bn (discounted)*	106	99	92	82	70	60	51	***561***
Annual carbon emissions from heat (end of period) *Mt CO_2 / yr*	99	98	98	98	98	100	101	***3,459***

[9] Both discounted and undiscounted costs are shown extensively in this report. If not stated, costs should be assumed to be undiscounted.

Figure 3-1: Five year total system cost to 2050 in the Status Quo scenario

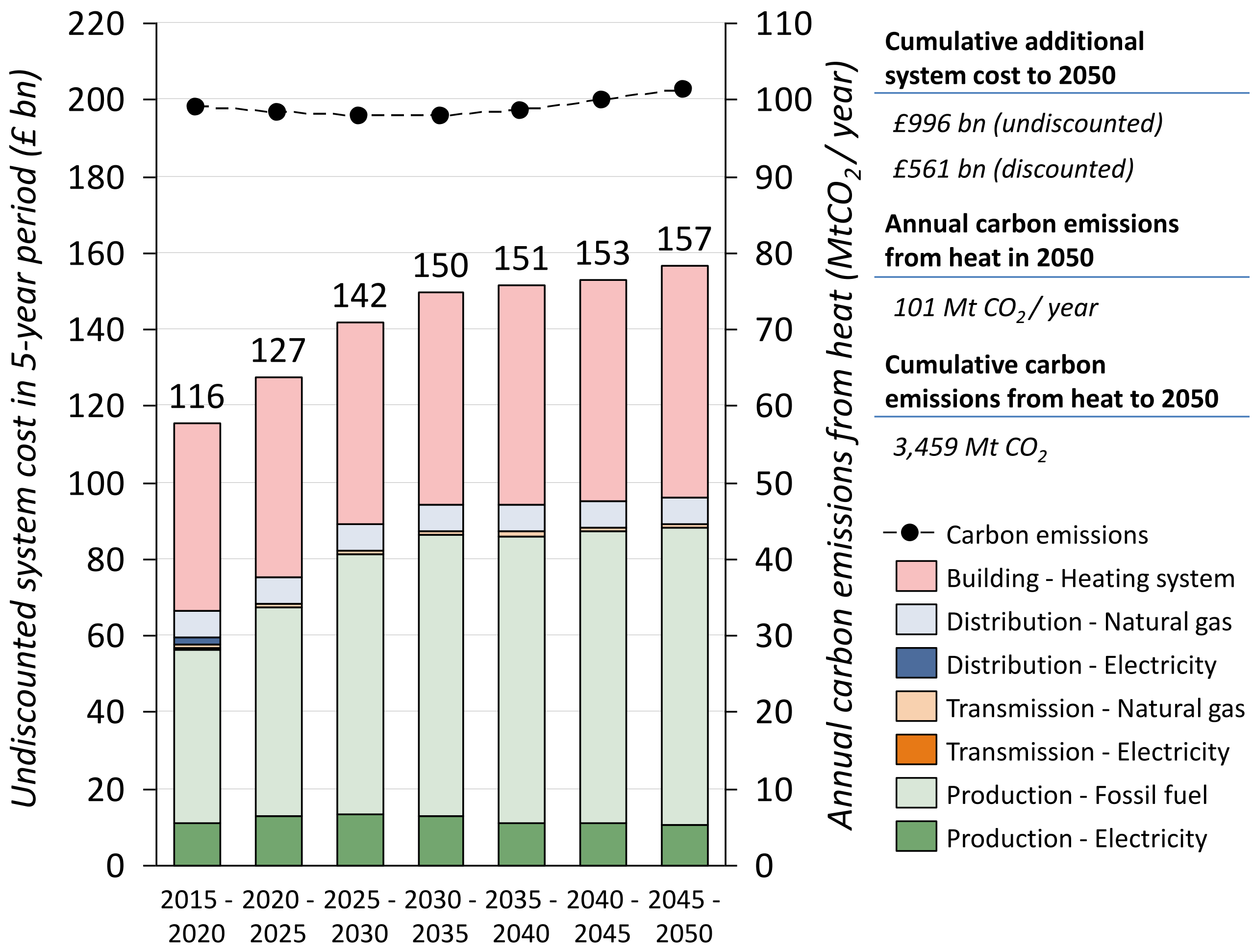


Figure 3-2: Cumulative discounted system cost to 2050 in the Status Quo scenario

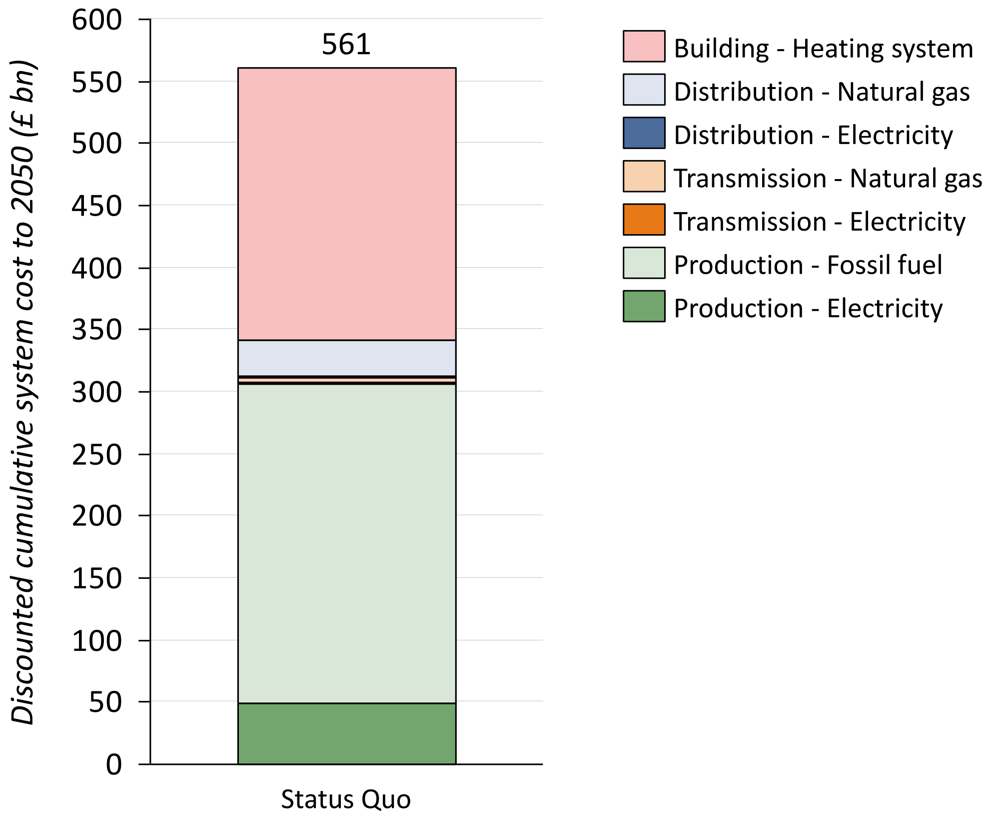
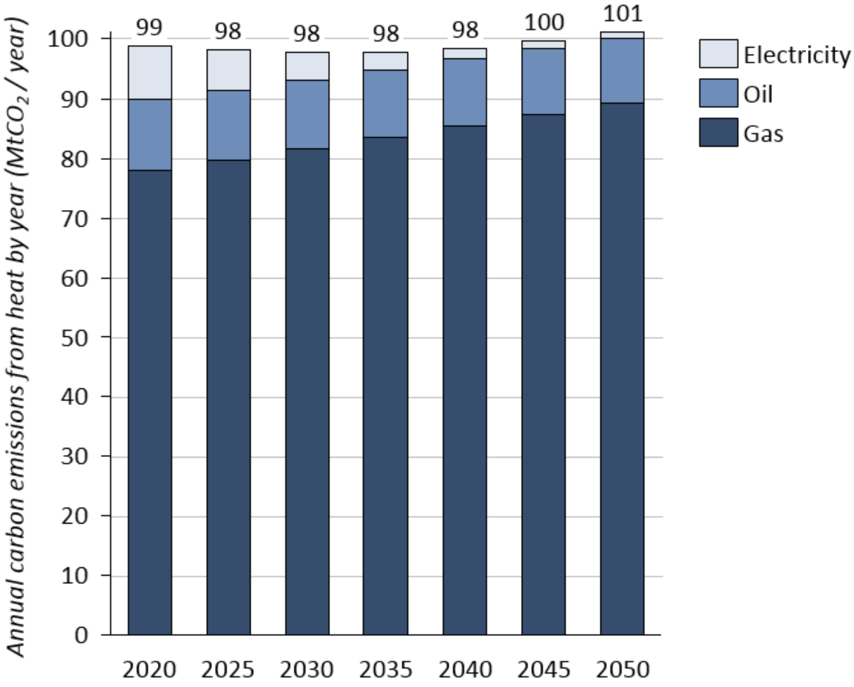


Figure 3-3 shows the annual CO_2 emissions by year in the Status Quo scenario. The annual CO_2 emissions are relatively flat over the time period, increasing from 99 $MtCO_2$ / yr in 2015 to 101 $MtCO_2$ / yr in 2050. The relatively constant level of emissions reflects the definition of the Status Quo scenario, in which no energy efficiency or heat decarbonisation measures are applied. Some variation in the level of emissions is apparent. In particular, the carbon intensity of the electricity grid is assumed to decrease (from 240 gCO_2 / kWh in 2020 to 30 gCO_2 / kWh by 2050). Some emissions reduction is also observed as existing buildings are demolished and replaced by new, more energy-efficient buildings, but beyond 2030 this is offset by the overall increase in the number of buildings implied by the construction rate.

Figure 3-3: Annual CO_2 emissions 2015-2050 in the Status Quo scenario



3.2 Defining a CO_2 target for the heat sector

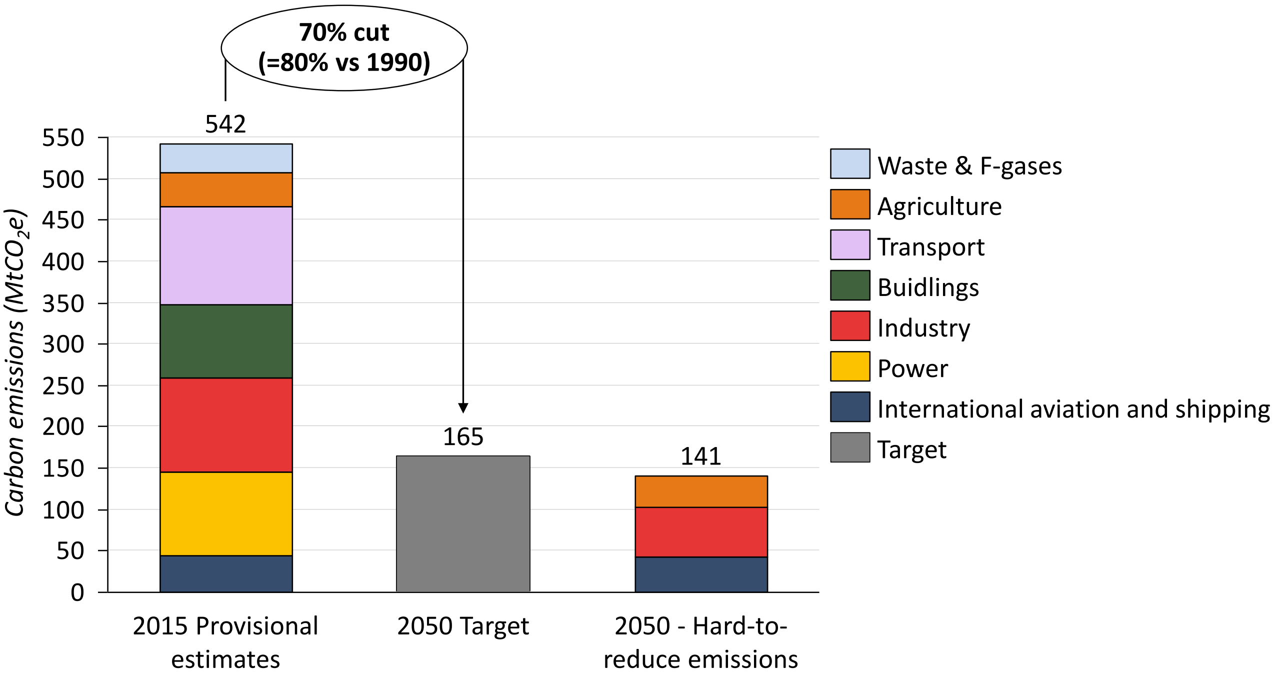
According to this analysis, space heating and hot water provision in the UK currently accounts for emissions of approximately 101 $MtCO_2$ / yr.[10] According to analysis by the Committee on Climate Change (CCC),[11] the UK's economy-wide 2050 target of an 80% reduction in CO_2 emissions versus 1990 levels implies a total carbon budget for 2050 of 165 $MtCO_2$ / yr.

The same analysis suggests that a simple application of the economy-wide target (that is, a reduction of 80% versus 1990 levels) will not be sufficient for the heat sector. A tranche of 'hard-to-reduce' emissions were identified, associated with the industry, agriculture and international aviation and shipping sectors. The CCC estimates that around 140 $MtCO_2$ / yr of the total 165 $MtCO_2$ / yr carbon budget may be required for these sectors, given a lack of cost-effective emissions reduction options. Accordingly, a near-total decarbonisation of heat, and other sectors including transport and power, is likely to be required. A high-level analysis, based on the current share of emissions in the heat, transport and power sectors, suggests that remaining carbon emissions from space heating and hot water provision are likely to be required to fall below 10 $MtCO_2$/yr.

In view of this, the scenarios presented in this study are broadly directed towards identifying pathways leading to very low levels of emissions associated with space heating and hot water, and it is highlighted where pathways are inconsistent with this level of ambition.

[10] This figure includes carbon emissions, but not other greenhouse gas emissions.
[11] Committee on Climate Change, *Next steps for UK heat policy* (2016)

Figure 3-4: Hard-to-reduce sectors and the 2050 target (adapted from CCC[12])



[12] *Ibid*.

4 Heat decarbonisation options

In this section, a range of single technology options with the potential to lead to substantial decarbonisation of the UK heat sector are presented. The options presented include:

- Energy efficiency
- Electrification of heating using heat pumps
- Electrification of heating using direct electric heating/electric storage heating
- Hybrid gas-electric heating
- Hydrogen heating
- Heat networks (including utilisation of waste heat sources)
- Bioenergy

The technology options presented include those that could provide the main component of a heat decarbonisation pathway for the UK (electrification, hybrid gas-electric heating, hydrogen heating), and others that are more likely to form a minority component of a pathway (energy efficiency,heat networks, bioenergy). Each option has some associated limit in terms of its capacity to deliver decarbonisation. For example, hydrogen and hybrid heat-pumps are only realistically practical in the 85% of buildings in the UK on the gas network; the depth of decarbonisation of heat pumps is dependent on the decarbonisation of the electricity grid; energy efficiency, while capable of delivering substantial savings in the building stock, cannot completely displace CO_2 emissions.

Accordingly, the technology options are studied individually in this section in order to elucidate the key features of the option, in particular:

- How deep a level of decarbonisation can the technology option deliver?
- Which segments of heat demand can be decarbonised using the technology option?
- How does the cost of decarbonisation through the technology option change across the different segments of heat demand, and for varying depths of decarbonisation?

In the next section, the individual technology options are combined into ‘Mixed’ scenarios, aiming to achieve near-total decarbonisation across all segments of heat demand.

4.1 Energy efficiency

By reducing overall heat demand, energy efficiency leads to fuel savings, with associated cost savings and carbon emissions reduction. The capital cost of energy efficiency measures varies widely depending on the type of intervention (and the building type and size), with the lowest cost measures such as draught proofing, easy-to-treat cavity wall and loft insulation each typically costing several £100s per household, high efficiency glazing typically several £1,000s per household and the highest cost measures such as external wall insulation often more than £10,000 per household.

The value of fuel cost savings also varies widely by intervention and building type, and also depends on the heating fuel displaced. This leads to a wide distribution of cost-effectiveness of energy efficiency measures across the building stock. For the most cost-effective measures, the fuel cost savings over the measure lifetime exceed the capital cost of the measure. Less cost-effective measures may not lead to payback over the measure lifetime.

For the purposes of this analysis, three bands of cost-effectiveness of energy efficiency measures are defined, namely Low cost, Medium cost and High cost measures. The total remaining potential heat demand savings associated with the three bands across the UK building stock, based on Element Energy datasets[13], is tabulated in Table 4-1.

Table 4-1: Total remaining potential heat demand savings across the UK building stock

Cost-effectiveness band	Cost effectiveness range (£ / tCO_2 abated)	Total energy savings potential – domestic (TWh / yr)	Total energy savings potential – non-domestic (TWh / yr)
Low cost	<0	23	5
Medium cost	0-200	66	2
High cost	200-1,000 (domestic) 200-5,000 (non-domestic)	92	17
Total		***180***	***24***

The implementation of the total potential for each cost effectiveness band implemented in a give year can be defined, allowing the impact of applying sequentially less cost-effective measures to be determined. Four scenarios have been studied including the impact of energy efficiency alone

Table 4-2: Scenarios presented for Energy efficiency

Scenario	Description
Low cost EE	Low cost energy efficiency measures only applied
Medium cost EE	Low and Medium cost energy efficiency measures applied
High cost EE (Domestic only)	Low and Medium cost energy efficiency measures applied in Domestic and Non-domestic sectors, High cost measures applied in Domestic sector only)
High cost EE (All)	Low, Medium and High cost energy efficiency measures applied in Domestic and Non-domestic sectors

The deployment rate of the energy efficiency cost-effectiveness bands, where included in the scenario, is shown in Table 4-3. The number of energy efficiency measures installed by 2050 is shown, by measure category, in Table 4-4.

[13] '*Review of potential for carbon savings from residential energy efficiency*', report by Element Energy and EST for the CCC, 2013, https://www.theccc.org.uk/wp-content/uploads/2013/12/Review-of-potential-for-carbon-savings-from-residential-energy-efficiency-Final-report-A-160114.pdf

Table 4-3: Deployment of energy efficiency measures if included in scenario (fraction of total potential)

Cost-effectiveness band	2020	2025	2030	2035	2040	2045	2050
Low cost	30%	60%	90%	100%	100%	100%	100%
Medium cost	30%	60%	90%	100%	100%	100%	100%
High cost	20%	40%	60%	80%	100%	100%	100%

Table 4-4: Number of domestic measures installed by 2050 in energy efficiency scenarios (millions)

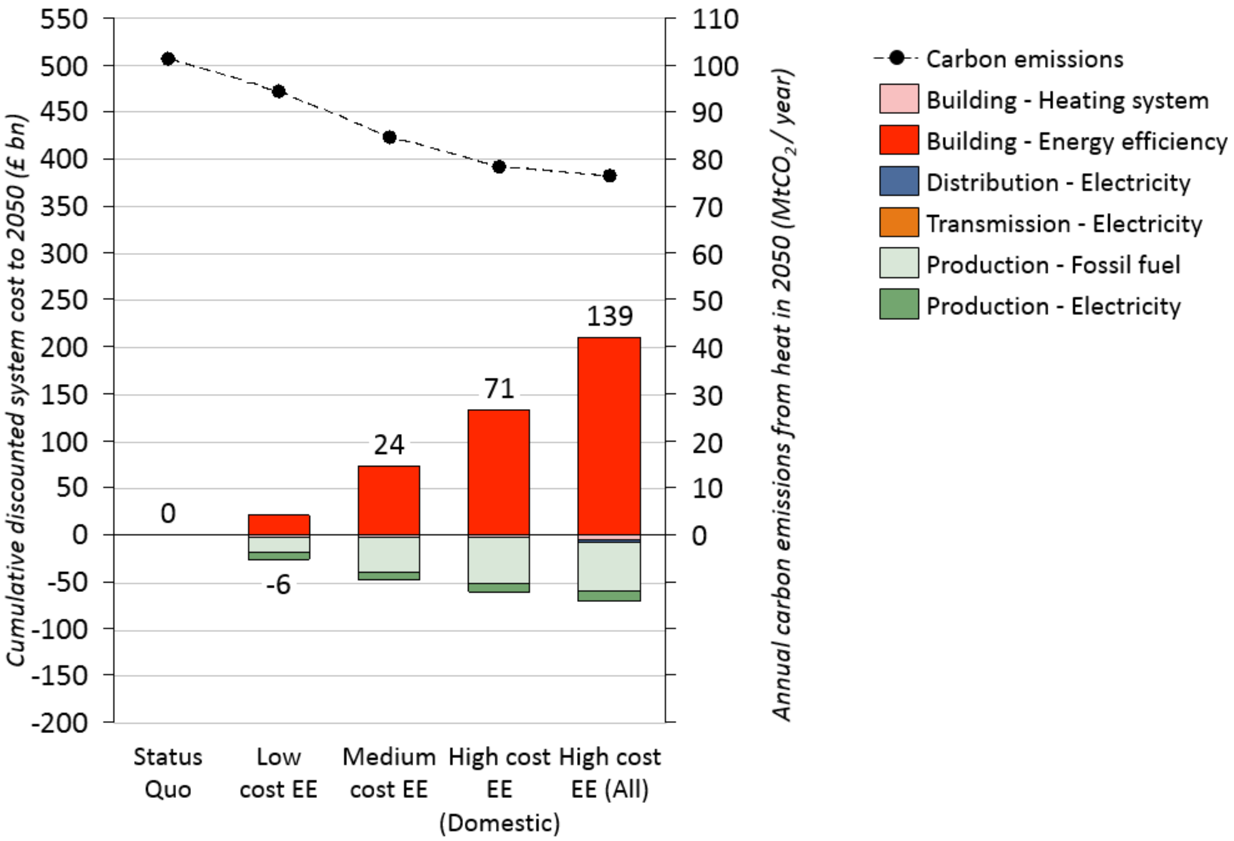
Measure category	Scenario		
	Low cost EE	Medium cost EE	High cost EE
Solid wall insulation	1.1	5.8	7.1
Cavity wall insulation	3.5	4.7	5.2
Loft insulation	10.2	10.2	10.5
Floor insulation	6.4	19.9	19.9
High efficiency glazing	0.1	0.6	17.1

The cumulative additional system cost to 2050 in each scenario, compared to the Status Quo scenario, and the associated carbon emissions in 2050, is shown in Table 4-5 along with Low and High cost sensitivity values. The cost breakdown shown in Figure 4-1 correspond to the undiscounted costs 'Central' case. Under the maximum deployment of energy efficiency measures, in the High cost EE (All) scenario, corresponding to 204 TWh of heat demand savings across the domestic and non-domestic sectors, carbon emissions from heat fall to 76 $MtCO_2$ / yr by 2050. Since the annual carbon emissions in 2050 in the Status Quo are 101 $MtCO_2$ / yr, the High cost EE (All) scenario corresponds to a 24 $MtCO_2$ / yr reduction versus the Status Quo, a reduction of 25%.

Table 4-5: Cumulative additional system cost versus Status Quo and annual carbon emissions in 2050 in energy efficiency scenarios

Scenario	Parameter	Low cost EE	Medium cost EE	High cost EE (Domestic)	High cost EE (All)
Central	2050 Carbon emissions ($MtCO_2$/ yr)	94	85	78	76
	Undiscounted additional cost (£ bn)	-24	2	65	158
	Discounted additional cost (£ bn)	-6	24	71	139
Best	2050 Carbon emissions ($MtCO_2$/ yr)	91	84	78	76
	Undiscounted additional cost (£ bn)	-29	-11	37	129
	Discounted additional cost (£ bn)	-6	15	52	119
Worst	2050 Carbon emissions ($MtCO_2$/ yr)	95	86	78	77
	Undiscounted additional cost (£ bn)	-20	15	100	192
	Discounted additional cost (£ bn)	-4	32	95	162

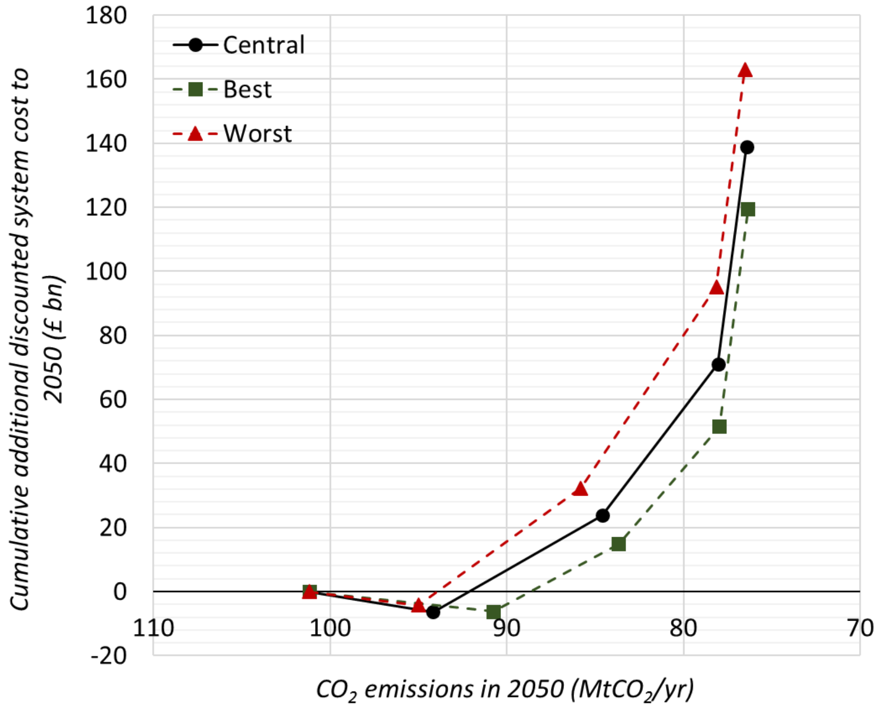
Figure 4-1: Cumulative additional system cost and CO_2 emissions in 2050 – Energy efficiency only



However, the chart shows that only part of this emissions reduction potential provides an overall reduction in system cost to 2050. In the Low cost EE scenario, which achieves a carbon emissions reduction of 7 $MtCO_2$ / yr by 2050, there is a reduction in the discounted cumulative system cost to 2050 versus the Status Quo of £6 bn (£24 bn on an undiscounted basis). The breakdown of the cost components in the chart show that, in this scenario, the cumulative fuel savings to 2050 more than offset the capital cost of the efficiency measure. In the Medium cost EE scenario, a carbon emissions reduction of 17 $MtCO_2$ / yr by 2050 is achieved with a net *increase* in cumulative system cost of £24 bn (£2 bn on an undiscounted basis). For the High cost EE (Domestic only) and High cost EE (All) scenario a deeper level of decarbonisation is achieved, but this comes with an increase in discounted cumulative system cost of £71 bn and £139 bn respectively. The figures presented here correspond to energy efficiency reducing the heating demand met by (mainly) gas boilers in the Status Quo scenario; the cost-effectiveness of energy efficiency would be expected to be different in scenarios where heating is met by other, low carbon, technologies, where the economic benefit of demand reduction would be different. The impact of energy efficiency in scenarios dominated by low carbon heating technologies is presented in Section 4.8.

The estimated uncertainty in the analysis is presented in Figure 4-2. The chart shows the dependence of the cumulative additional system cost to 2050 as a function of the CO_2 emissions from heat in 2050. The Central case estimates, corresponding to the cost values shown above in Figure 4-1, are shown as black circles. The Best case cost estimates are shown in green squares, and the Worst case estimates in red triangles. The main contribution to the uncertainty in cost shown here relates to the capital cost of the energy efficiency measures. For the Low cost measures, corresponding to a level of annual carbon emissions in the range 91-95 $MtCO_2$ / yr, the additional system cost to 2050 is found to be negative in all cases. For the Medium cost measures, corresponding to annual carbon emissions in the range 84-86 $MtCO_2$ / yr, the Central and Best cases show a positive additional discounted cost of £23 bn and £15 bn respectively, and the Worst case shows an additional cost of £32 bn to 2050. The additional cost of the High cost EE measures, corresponding to annual emissions of approximately 75 $MtCO_2$ / yr, is large and positive in all cases, from £119 bn to £163 bn.

Figure 4-2: Uncertainty in cumulative additional system cost to 2050 – Energy efficiency only



Box 1 – Energy efficiency: Key findings

- Carbon emissions savings of up to 24 $MtCO_2$ / yr can be achieved by 2050 through energy efficiency.
- In the Central cost estimate, energy efficiency measures alone can lead to carbon emissions savings of up to at least 7 $MtCO_2$ / yr by 2050 (Low cost EE scenario) with a net reduction in cumulative discounted system cost to 2050.
- Total savings of 17 $MtCO_2$ / yr by 2050 can be achieved (Medium cost EE scenario), although in a scenario dominated by gas boiler heating, in discounted cost terms, this leads in a net increase in cumulative system cost to 2050 of £24 bn.
- Energy efficiency is expected to be more cost-effective in most scenarios dominated by low carbon heating options, rather than gas boilers, since the low carbon heating options are expected to entail higher heating fuel costs than gas heating. This is studied later in Section 4.8.
- The Medium cost EE scenario would require the insulation of more than 10 million walls (roughly 6 million solid walls and more than 4 million remaining uninsulated cavity walls), more than 10 million lofts and up to approximately 20 million homes overall.

4.2 Electrification using heat pumps

The electrification of heating demand using heat pumps, which can operate with high energy efficiency, brings the potential to achieve very low levels of CO_2 emissions in the presence of a decarbonised electricity grid. A key challenge for heat pumps is the comparatively high capital cost relative to a gas boiler, and the associated need to minimise the size of the heat pump (in kW terms) whilst remaining able to serve the heat demand of the building. Heat pumps operate more efficiently at lower output temperatures, and are therefore less suitable in thermally-inefficient buildings where high temperature heating may be required during cold periods.

These factors mean that heat pumps are effectively suitable only in buildings of a sufficiently high thermal efficiency. The threshold for heat pump suitability is not clear-cut, and depends on the heat distribution system within the building, how appropriately the system is designed and installed, and the way in which the heat pump is subsequently operated by the user. However, the requirement for sufficient building thermal efficiency is a key factor which will influence the cost and practicality of a heat electrification pathway, as widespread deployment of heat pumps is likely to require the renovation of millions of buildings with energy efficiency measures and, in many cases, new heat distribution systems. Such a scenario would also require a behavioural change in the millions of consumers switching to heat pumps, to ensure appropriate system operation.

An additional challenge for a high electrification scenario is the impact on the electricity distribution, transmission and generation system, through the associated increase in peak demand. This impact is studied as part of the cost analysis presented here.

In order to reflect the constraint on heat pump suitability in sufficiently thermally-efficient buildings only, the existing domestic building stock has been divided into three segments based on the building specific heat demand (in kWh/m^2). The three segments, High efficiency, Medium efficiency and Low efficiency, are defined in Table 4-6 below. The number and type of buildings in the stock within each thermal efficiency segment is based on the Element Energy Housing Energy Model. The threshold between the High and Medium efficiency level was selected such that almost all buildings in the High efficiency band include at least wall insulation and (where relevant) loft insulation – analysis of the building stock found this threshold to correspond to a space heating and hot water demand of approximately 120 kWh/m^2. The threshold between Medium and Low efficiency buildings was set to 180 kWh/m^2.

In this analysis, it is assumed that heat pumps are only installed in High efficiency buildings – that is, buildings with wall insulation and loft insulation where relevant, as a minimum. New buildings are also assumed to be suitable for heat pumps. Application of energy efficiency measures to the stock can be used to improve the efficiency level of a building, thereby increasing the number of buildings in the stock suitable for a heat pump (note that many of the Low, Medium and High Cost EE measures are applied in buildings that already fall into the category 'High-efficiency'). Table 4-6 also shows the number of domestic buildings in each thermal efficiency segment in 2050 under the various energy efficiency scenarios presented in Section 4.1.

Table 4-6: Building thermal efficiency segments

		Number of domestic buildings in segment in 2050 under various energy efficiency scenarios (millions)			
Building thermal efficiency segment	**Heat demand (kWh / m^2 / yr)**	**Status Quo**	**Low Cost EE**	**Medium Cost EE**	**High Cost EE**
High efficiency	0 – 120	16.6	22.0	25.8	26.7
Medium efficiency	120 – 180	8.5	5.0	2.2	1.3
Low efficiency	180+	2.9	1.0	0.1	0.1

In the scenarios presented here, the air-source heat pumps are deployed across a majority of the building stock; ground-source heat pumps are also assumed to be deployed in a smaller share of the building stock, to reflect the suitability of this option particularly in larger and more rural (often off-gas) buildings. The deployment rate for heat pumps assumed in the scenarios presented in this section are shown in Table 4-8.

A range of scenarios with varying depths of heat electrification have been studied. Due to the heat pump suitability constraint limited to High efficiency buildings, there is an interaction between the deployment of energy efficiency and the number of heat pumps that can be deployed. Table 4-9 presents the scenarios studied, and shows the actual number of heat pumps assumed to be deployed by 2050 in each scenario. More than 16 million existing buildings are found to be suitable for heat pumps without further energy efficiency measures, and 22 million existing buildings would be rendered suitable in total if Low cost EE measures were applied to all buildings. The majority of existing buildings, at nearly 26 million, can be rendered suitable for heat pumps with the application of Medium cost energy efficiency measures[14].

Table 4-7: Scenarios presented for Electrification using heat pumps

Scenario	Description
New build only	Heat pumps in new build only
New and Existing (No EE)	Heat pumps in new build and existing buildings suitable for heat pumps with no new energy efficiency measures applied
New and Existing (Low cost EE)	Heat pumps in new build and existing buildings suitable for heat pumps after all Low cost energy efficiency measures applied
New and Existing (Medium cost EE)	Heat pumps in new build and existing buildings suitable for heat pumps after all Medium energy efficiency measures applied
New and Existing (High cost EE)	Heat pumps in new build and existing buildings suitable for heat pumps after all High cost energy efficiency measures applied

Table 4-8: Deployment rate of heat pumps assumed in scenarios presented

Building segment		2020	2025	2030	2035	2040	2045	2050
Existing buildings	**Domestic (if suitable)**	10%	20%	40%	70%	100%	100%	100%
	Non-domestic	10%	20%	40%	70%	100%	100%	100%
New build	**Domestic**	100%	100%	100%	100%	100%	100%	100%
	Non-domestic	100%	100%	100%	100%	100%	100%	100%

Table 4-9: Heat pump uptake assumptions and resultant 2050 installations

Electrification scenario		New build only	New + Existing (No EE)	New + Existing (Low cost EE)	New + Existing (Medium cost EE)	New + Existing (High cost EE)
Heat pumps deployed in 2050 (millions)	Domestic (existing)	0	16.6	21.1	25.9	27.1
	Non-domestic (existing)	0	1.7	1.7	1.7	1.7
	Domestic (new)	4.5	4.5	4.5	4.5	4.5
	Non-domestic (new)	0.7	0.7	0.7	0.7	0.7
Heat pumps deployed in 2030 (millions)	Domestic (existing)	0	6.7	8.3	10.1	10.4
	Non-domestic (existing)	0	1.0	1.0	1.0	1.0
	Domestic (new)	1.8	1.8	1.8	1.8	1.8
	Non-domestic (new)	0.2	0.2	0.2	0.2	0.2

[14] The uptake scenarios assumed here are relatively aggressive compared to other analyses such as '*Pathways to high penetration of heat pumps*', report by Element Energy and Frontier Economics for the CCC, 2013, https://www.theccc.org.uk/wp-content/uploads/2013/12/Frontier-Economics-Element-Energy-Pathways-to-high-penetration-of-heat-pumps.pdf

The cumulative additional system cost to 2050 of each scenario relative to the Status Quo scenario, and the associated level of CO_2 emissions in 2050, are shown in Figure 4-3.

As expected, the analysis indicates that heat pumps can achieve a significant reduction of CO_2 emissions. In the scenarios shown here, the grid electricity CO_2 emissions intensity follows the trajectory defined in the HMT Green Book *Reference Scenario*[15], falling to 100 gCO_2/kWh in 2030, 60 gCO_2/kWh in 2035 and 30 gCO_2 by 2050, remaining at that level subsequently.

Figure 4-3: Cumulative additional system cost and CO_2 emissions in 2050 – Heat pumps

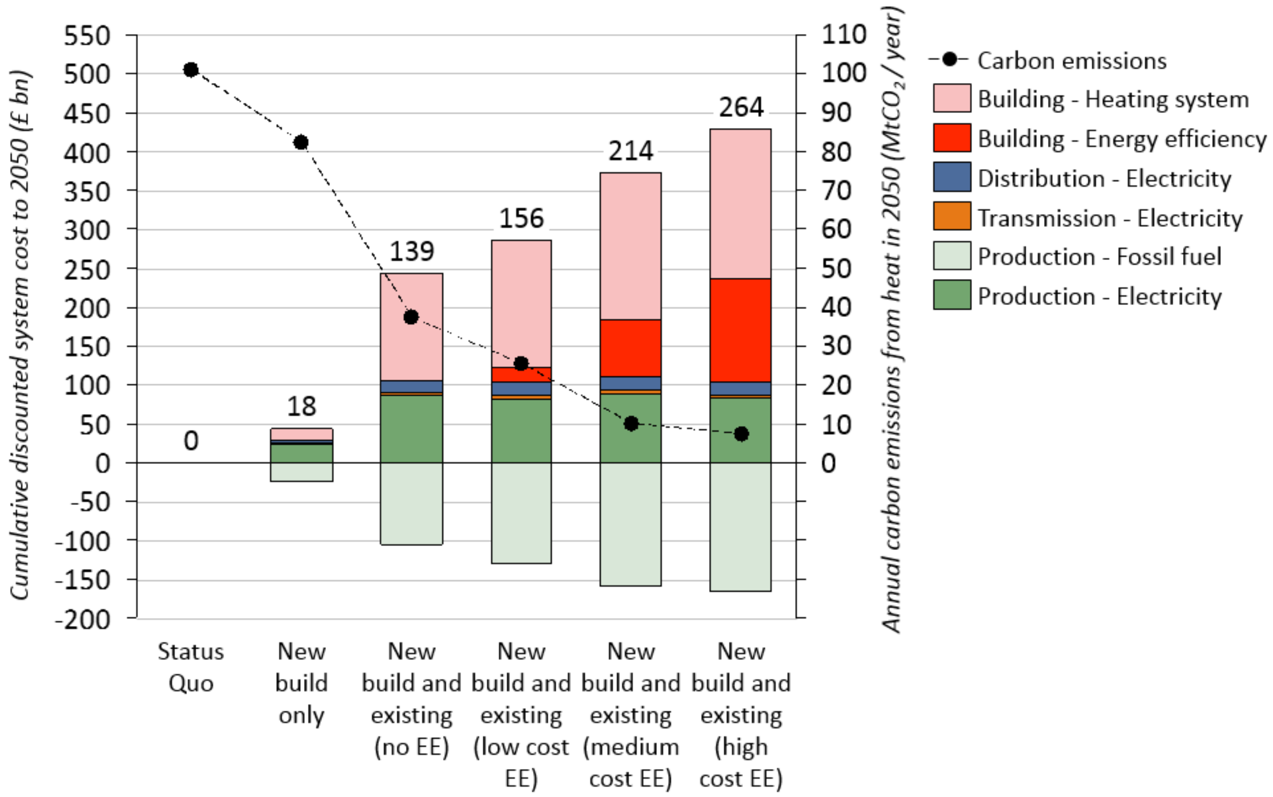


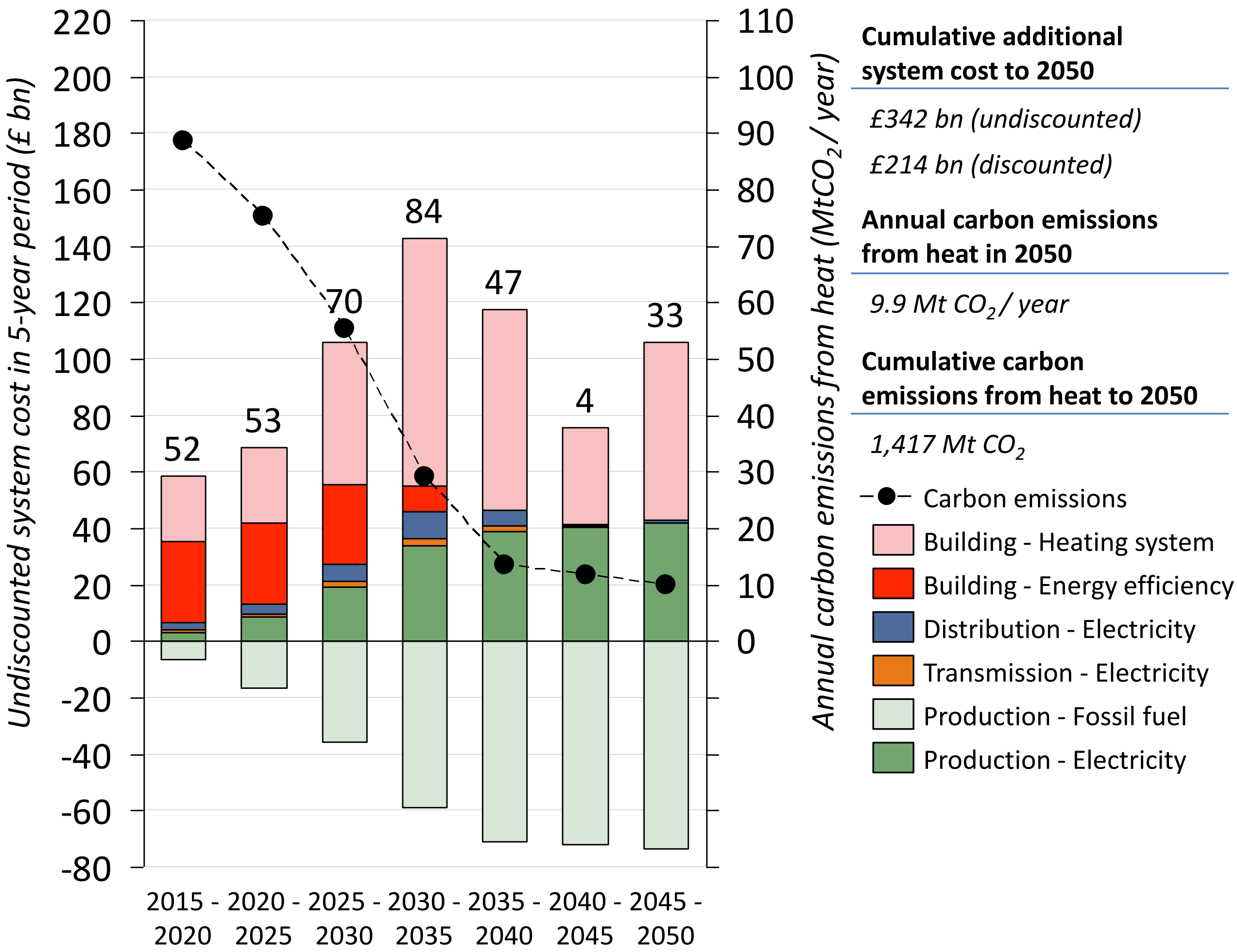
Table 4-10 and Figure 4-4 show the costs and emissions in the New build and existing (medium cost EE) scenario on a five-yearly basis. These show that the majority of investment under this pathway takes place before 2040, with a high level of additional costs incurred between 2026 and 2035 (£154bn, or 45% of the total cost). This is due in part to the investments in energy efficiency which are necessary to prepare much of the stock to be suitable for a heat pump described in the previous section, which occur between 2016 and 2030. This is also due to the fact that, since heat pumps are a relatively well-developed technology they can be deployed relatively early in the period to 2050. By 2040, the annual carbon emissions are reduced to roughly 13% of the Status Quo scenario, dropping further to 10%, partly driven by a decreasing electric grid emissions factor. Therefore in this scenario, the reduction in overall carbon emissions to 2050 is significant, resulting in 1,400 $MtCO_2$, or 40% of the cumulative emissions estimated in the Status Quo scenario.

15 *Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal (March 2017)* https://www.gov.uk/government/publications/valuation-of-energy-use-and-greenhouse-gas-emissions-for-appraisal

Table 4-10: Additional system cost and annual carbon emissions to 2050 for electrification with heat pumps in the medium cost energy efficiency scenario

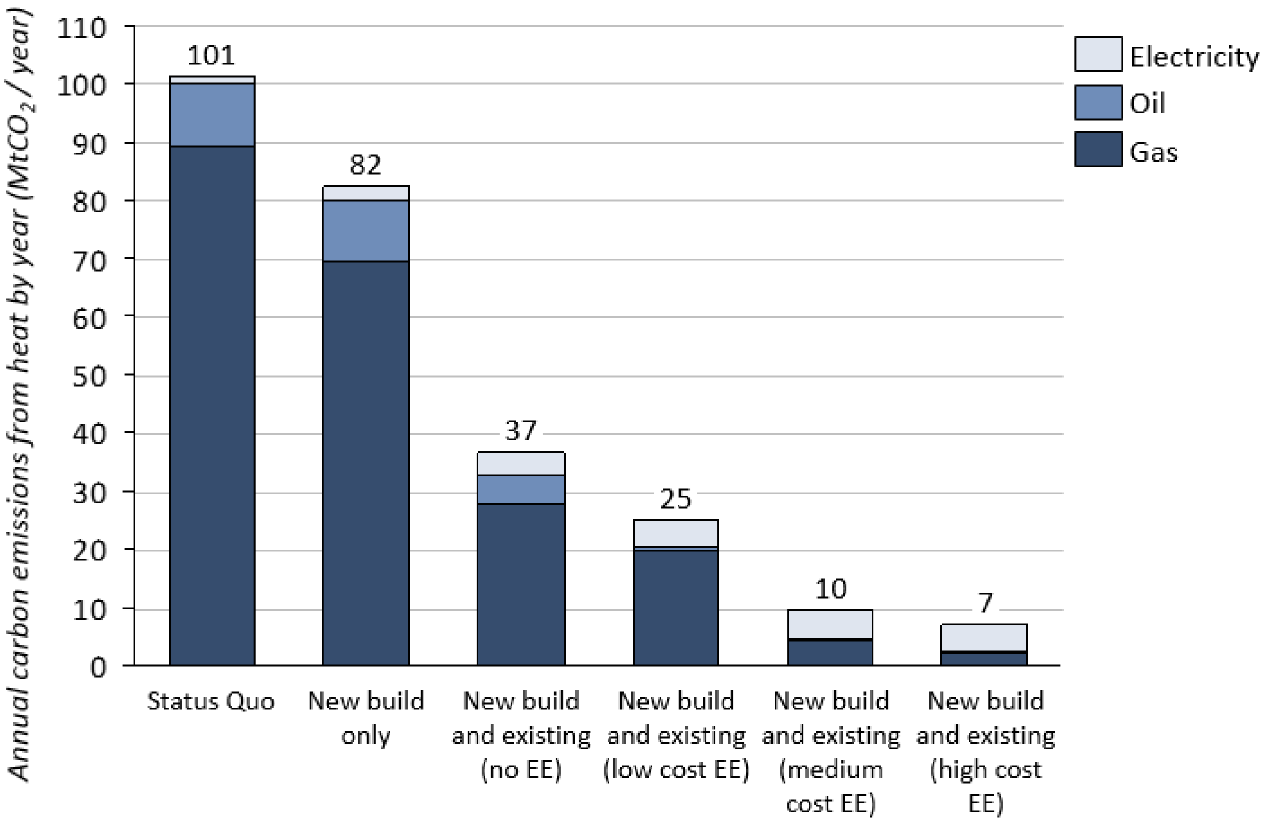
Five-year period	2016 - 2020	2021 - 2025	2026 - 2030	2031 - 2035	2036 - 2040	2041 - 2045	2046 - 2050	*2016 - 2050*
Additional system cost *£bn (undiscounted)*	52	53	70	84	47	4	33	***342***
Additional system cost *£bn (discounted)*	48	40	46	46	22	1	11	***214***
Annual carbon emissions from heat *Mt CO_2 / year*	89	75	55	29	13	12	10	***1,417***

Figure 4-4: Five year undiscounted additional system cost to 2050 for electrification with heat pumps in the medium cost energy efficiency scenario



In the maximum heat pump deployment scenario shown, the New + Existing (High cost EE) scenario, CO_2 emissions in 2050 are reduced by 94 $MtCO_2$ / yr versus the Status Quo scenario to 7 $MtCO_2$ / yr. The remaining emissions are due mainly to the residual carbon intensity of grid electricity, and also to a small number of existing domestic buildings which do not reach a sufficient level of thermal efficiency to be suitable for a heat pump even after deployment of all High cost energy efficiency measures. These components are illustrated in the breakdown of CO_2 emissions in each scenario by fuel type, as shown in Figure 4-5.

Figure 4-5: Annual CO_2 emissions in 2050 in the electrification scenarios



The cumulative additional system cost to 2050 is positive in all scenarios. In the case where all Low cost energy efficiency is applied, and heat pumps are deployed in the 21 million suitable domestic buildings over the period 2020-2040, as well as in all new buildings from 2020, carbon emissions are reduced to 25 $MtCO_2$ / yr for an additional discounted system cost of £156 bn. Applying all Medium cost EE measures and deploying heat pumps in the 26 million suitable buildings, as well as in all new buildings, achieves a carbon emissions level of 10 $MtCO_2$ / yr for an additional discounted system cost of £214 bn. In the maximum deployment case, achieving an emissions level of 7 $MtCO_2$ / yr, the additional discounted system cost to 2050 is £264 bn.

The largest contribution to the additional system cost across all scenarios is the additional building level cost associated with the transition from (mainly) gas boilers to heat pumps. The building level costs assumed in the Central cost estimate include the cost of the heat pump unit and of new large-area emitters to support the lower delivery temperature provided by the heat pump (the cost of new emitters is avoided in the case of new build). For a typical semi-detached house, in 2030, this corresponds to a capital cost of £6,700 for a 6kW HP and £1,800 for the new emitters. The analysis assumes a 15 year lifetime for the heating system, so most buildings require a replacement before 2050 (emitters are not assumed to need a second replacement).

There is also a large cost contribution from the capital cost of energy efficiency measures. As shown in the previous section, the Low cost energy efficiency measures applied in a scenario dominated by gas heating result, on a discounted basis, in an overall reduction in the system cost to 2050, as the fuel production cost savings offset the capital cost of the efficiency measures. The Medium cost EE measures, however, result in a small increase in overall discounted system cost. A similar result applies here in the heat pump heating scenarios. Figure 4-3 shows that, in discounted terms, the fuel production costs for the Low cost energy efficiency scenario are decreased by £28 bn versus the No EE case, an amount of savings greater than the additional cost of the efficiency measures in that scenario of £20 bn. In the Medium cost EE scenario, however, the discounted fuel production cost savings, at £70 bn, are smaller than the discounted capital cost of the efficiency measures, at £72 bn.

The similar level of cost-effective energy efficiency in the heat pump and gas boiler cases reflects the similar cost of heating modelled in the two cases, where the higher cost of electricity than gas is approximately offset by the higher efficiency of the heat pump. In the Central case, an average heat pump efficiency of 250% is assumed (though the Ground source heat pump is assumed to have an average efficiency of 290%). Fuel costs for the heat pump would therefore be expected to be lower than for an 90% efficient gas boiler for an electricity-to-gas production cost ratio below 2.7. For the Central assumption on electricity and gas production costs, it can be seen that this ratio falls from 3.2 in 2016 to 2.4 from 2035 onwards, providing a small amount of fuel cost savings for the heat pump relative to gas heating from that time onwards.

While the Medium cost EE measures do not lead to an overall reduction in discounted system cost, they are a pre-requisite for the most extensive heat pump rollout scenarios. To recap, more than 21 million domestic buildings are expected to be suitable for heat pumps with no efficiency measures or only Low cost efficiency measures applied. A further 5 million buildings, however, are expected to require Medium cost efficiency measures to be rendered suitable for a heat pump.

It is worth noting that the requirement for substantial energy efficiency retrofit is likely to provide an additional challenge in a high heat pump deployment scenario in terms of developing an attractive consumer proposition to incentivise uptake of efficiency, or application of other (potentially regulation-based) interventions to achieve this outcome.

An increase in the system cost is also observed associated with the electricity distribution and transmission networks. Figure 4-6 presents the increase in peak electrical load under each of the electrification scenarios, versus the Status Quo scenario. The additional peak load is estimated to reach 49 GW in the New build + Existing (Medium cost EE) scenario, corresponding approximately to an additional 1.4 kW per heat pump installed. This figure accounts for diversity across the stock and assumes favourable consumer behaviour to avoid a more severe impact on the grid; the case of a more severe impact is included in Worst case sensitivity below. This is estimated to lead to an additional discounted system cost of £21 bn associated with distribution and transmission grid reinforcement, with the distribution grid reinforcement accounting for £16 bn of this total.

Figure 4-6: Contribution to peak load electricity in 2050 under electrification via heat pump scenarios

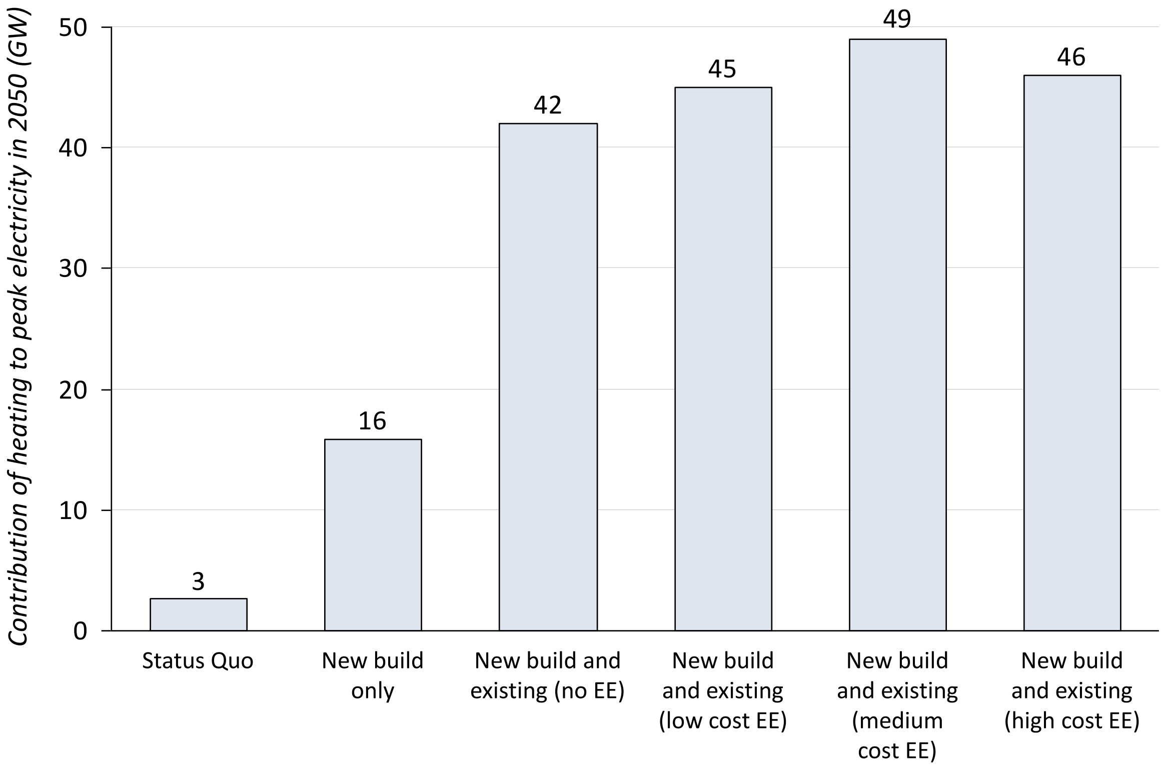
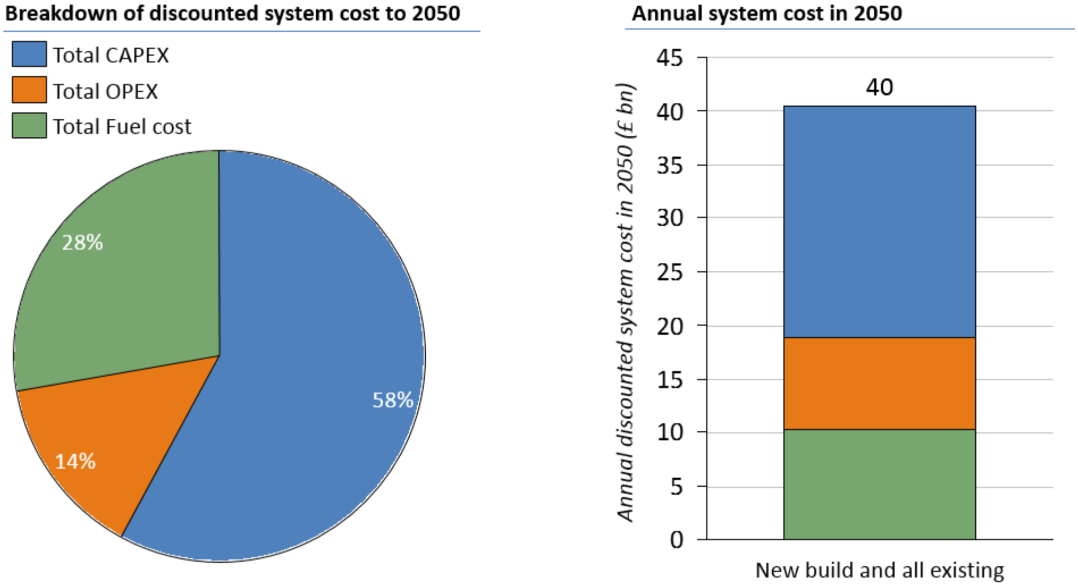


Figure 4-7 presents a breakdown of the discounted costs to 2050 and the ongoing annual system costs in 2050 for the New build + Existing (High Cost EE) scenario. The plots show the contribution of capital costs (including the cost of building level heating systems, energy efficiency measures and network upgrades), fixed opex (including the costs of operating the gas grid, and maintaining building level heating systems) and the fuel production costs. The breakdown of costs to 2050 shows that capital costs are the major component of the total system cost in the high heat pump scenario, accounting for 58% of the total discounted cost to 2050. The operating costs account for 14% of the total, while the fuel production costs contribute 28%.

Figure 4-7 also shows that the annual system cost from 2050 is dominated by capital costs. This is mainly associated with the life-cycle replacement cost of heat pumps every 15 years, and amounts to £22 bn / yr. There is a further £10 bn / yr of fuel production costs (dominated by electricity). Finally, there is a cost of £8 bn / yr for (non-fuel) operating costs. Overall, this amounts to an ongoing heating cost of £1,070 / building / yr in 2050. Compared with the annual cost estimated in the Status Quo scenario (£840 / building / yr), this is an increase of £230 / building / yr.

Figure 4-7: Breakdown of discounted system costs to 2050 and annual system costs in 2050 – Electrification using heat pumps



The estimated uncertainty in the cost analysis is presented in Figure 4-8. A large potential range in the additional system cost versus the Status Quo is found. For the New + Existing (Medium cost EE) scenario, achieving an emissions level of 6-8 $MtCO_2$ / yr, the cumulative discounted cost versus the Status Quo scenario ranges from £199 bn in the Best case to £453 bn in the Worst case. This relates to several underlying uncertainties modelled here. In particular, there is substantial uncertainty over the capital cost of heat pumps; in the Central case, the unit cost is assumed to fall by around 25% between 2015 and 2040, whereas in the Worst case the unit cost is assumed to fall by less than 5% over the same period. An additional cost of £1,200 at the time of conversion for switching from gas-burning cookers to electric cookers (i.e. assuming that on-gas buildings switch to electric heating) is included in the Worst case scenario only. The Worst case also assumes a reduced heat pump efficiency of 210% versus 250% in the Central case, and a larger increase in peak electricity demand due to less favourable consumer behaviour[16], resulting in higher peak load contributions than those shown in Figure 4-6. This leads to total discounted distribution and transmission reinforcement costs of £62 bn. The Best case assumes a higher heat pump efficiency of 320% and a greater decrease in heat pump unit costs.

[16] The central case assumes a 2.4 diversity factor for heat pumps, whereas the Worst case assumes a factor of 1.0.

Figure 4-8: Uncertainty in cumulative additional system cost to 2050 – Heat pumps

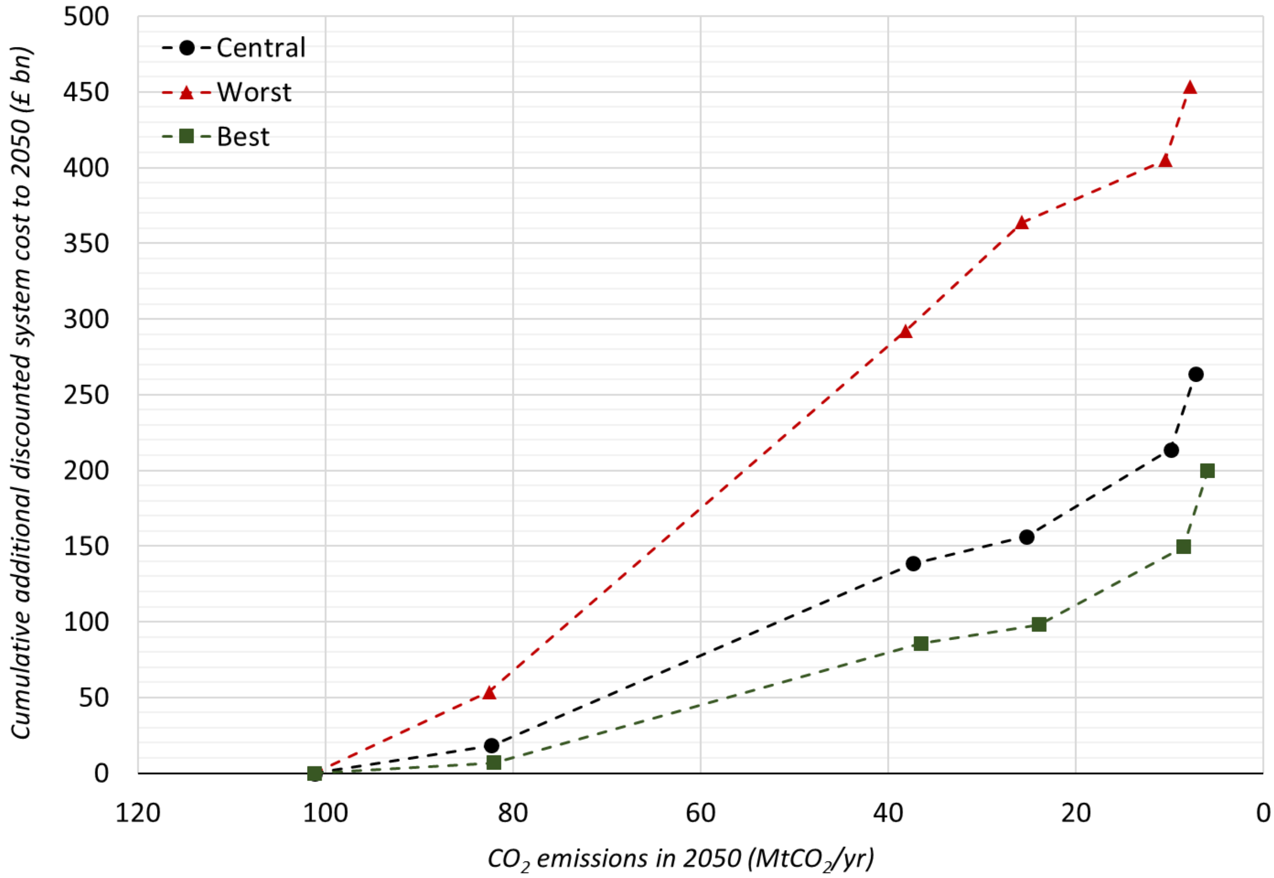


Figure 4-9 shows a cost component level breakdown of the results of two sensitivity analyses for the New build and Existing (High cost EE) scenario described above. The first, the technology cost and performance sensitivity, is the same analysis as presented in Figure 4-8 for the relevant scenario. This demonstrates that the dominant uncertainty is associated with the capital cost of the heat pump (£114 bn additional cost in the Worst case, and a relative reduction of £36 bn in the Best case). Other significant uncertainties include the varying electricity network upgrade costs (resulting in a potential increase of £44 bn between the transmission and distribution networks). Another sensitive factor is the varying electricity fuel production costs that could arise from the uncertainty in the heat pump efficiencies and the cost of network upgrades described above (+£22 bn, -£24 bn).

The second sensitivity shown relates to uncertainty in fuel production cost, based on the High prices and Low fuel price scenarios set out in BEIS projections[17]. The cost of electricity in 2050 varies by +1 p/kWh in the Worst case and -1 p/kWh in the Best case (versus a Central case assumption of 9 p/kWh), and the gas price varies by +0.3 p/kWh in the Worst case and -0.8 p/kWh in the Best case (versus a Central case assumption of 3.3 p/kWh). Due to the relatively minor share of fuel costs in the heat pump heating scenario (see Figure 4-7 above), the additional cost is less sensitive to variations in fuel production cost than variation in technology cost and performance, varying by +£25 bn and -£33 bn in the Worst and Best cases respectively.

It can also be seen that there is a contribution to the reduction in cost in the Best case associated with the capital cost of energy efficiency. This is related to a small shift between efficiency measure cost categories as the fuel costs are varied, in this case with a small subset of the Medium cost EE (for some building types)

[17] *2016 Updated Energy & Emissions Projections* BEIS (Accessed 2017)

moving into the High cost EE category as the value of fuel savings is reduced, meaning those measures are no longer applied in the Best case scenario.

Figure 4-9: Sensitivity to technology cost and performance and fuel cost – Electrification using heat pumps

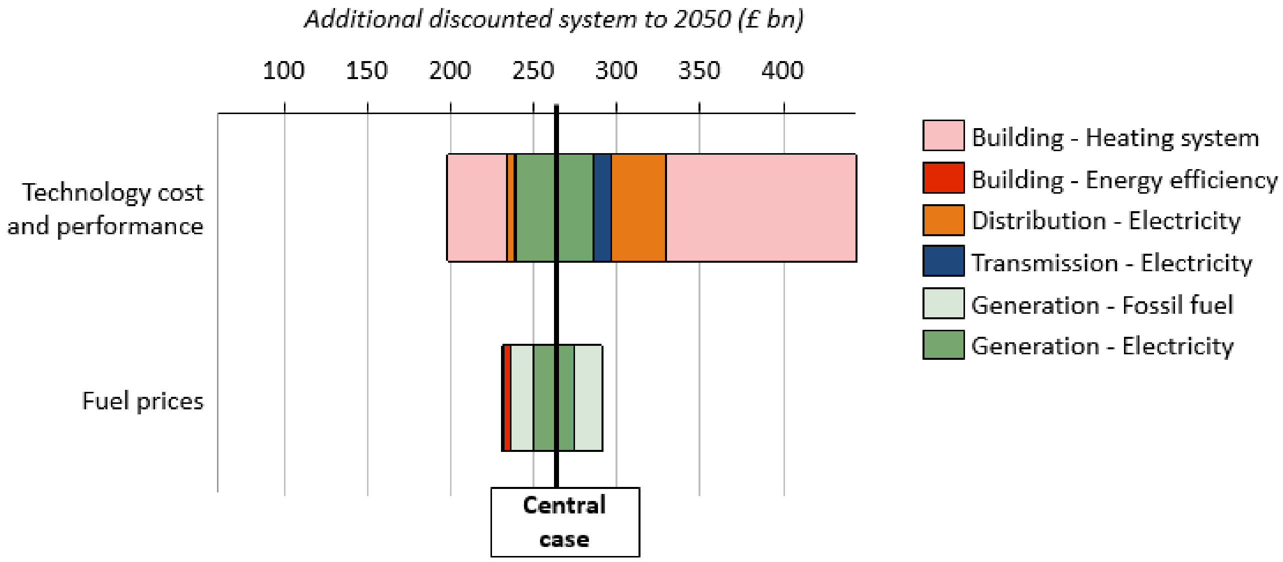


Table 4-11: Summary of technology cost and performance and fuel prices sensitivity – Electrification using heat pumps

Parameter	Sensitivity	Best	Central	Worst
Additional discounted system cost to 2050 *£ bn*	Technology cost and performance	199	264	453
	Fuel prices	231	264	289
2050 carbon emissions *Mt CO_2 / year*	Technology cost and performance	6	7	8
	Fuel prices	7	7	7

Box 2 – Electrification using heat pumps: Key findings

- Electrification using heat pumps can lead to deep decarbonisation by 2050, and is a solution that can be applied using only proven, mature technology – albeit that heat pumps currently have a very low level of deployment in the UK.
- In the Central case studied here, where the grid carbon intensity falls to 30 gCO_2/kWh by 2050, carbon emissions from heat are reduced by more than 90% versus the Status Quo in the maximum heat pump deployment scenario. Further reduction in emissions could be achieved through deeper decarbonisation of the electricity grid.
- Heat pumps are suitable only in buildings with a sufficient level of thermal efficiency, while other buildings will require some level of energy efficiency retrofit alongside installation of a heat pump. This analysis estimates that more than 10 million buildings would require an energy efficiency intervention before a heat pump would be suitable.
- However, the analysis also suggests that for the majority of the buildings, the required energy efficiency would result in a net reduction in cumulative system cost due to the fuel cost savings, and would therefore be desirable in any case. Widespread uptake of energy efficiency is, however, likely to involve significant challenges relating to consumer participation.
- The cumulative discounted additional system cost to 2050 in a high heat pump scenario is substantial, at £214 bn in the Central case, targeting buildings requiring only Low or Medium cost efficiency measures.
- The dominant contribution to the additional cost is that of the heat pump itself and the cost of replacing the heat distribution system, where required, which amount to £192 bn (discounted) in the same scenario.
- Fuel costs are reduced substantially due to the energy efficiency measures; beyond those savings, the fuel costs are similar on a per kWh basis to the (predominant) gas heating counterfactual, as the higher heating efficiency is approximately offset by the difference in fuel production cost.
- There is also a significant contribution of £23 bn in the same scenario associated with reinforcement of the distribution and transmission grid to meet the additional peak electricity demand of 49 GW.
- An advantage of the heat pump option is that it is applicable to off-gas grid buildings, and could be a key option for this segment even in a scenario dominated by an alternative heating technology.

4.3 Electrification using direct electric heating

Electrification using highly efficient heat pumps was considered in Section 4.2. Under the assumption of a low carbon electricity grid this can lead to a very deep level of decarbonisation. However, the comparatively high capital cost of a heat pump compared to a gas boiler leads to significant building-level capital costs. This section considers an alternative, where direct electric heating (potentially in the form of storage heating) is installed in a large number of buildings.

Direct electric heating is generally less efficient than heat pumps (direct electric heaters are assumed here to be 100% efficient, whereas an air-source heat pump was assumed to be 250% efficient in the Central case). Unlike air-source heat pumps, the efficiency of the electric heating considered here is not strongly dependent on supply temperature. Therefore, direct electric heating is expected to applicable across most of the UK building stock without requiring extensive efficiency upgrades.

At present, many electric heaters (roughly two thirds of the current electric heating stock) are storage heaters. In this case, direct resistive heating is used to heat ceramic blocks within the heating unit, typically overnight when electricity is cheaper (buildings with storage heating typically operate on the economy 7 or economy 10 tariff), releasing the heat on request during the day. As a result, storage heaters do not currently contribute to the national peak electrical load (which occurs during the early evening), hence the capability to use lower cost (and potentially lower carbon) electricity.

In some of the scenarios set out here, a very large uptake of electric heating is modelled, leading to an additional electrical load (at whatever time of day heating is carried out) of the 10s of GWs. This would quickly saturate the benefits of peak avoidance – for example, an additional 30 GW of electricity demand at night would be likely to lead, hypothetically, to a new peak during the night. In this case, any electricity pricing differentials would adapt accordingly with the objective of redistributing demand. Thus, in these scenarios the impact on the electricity distribution, transmission and generation system due to peak demand increase is found to be a significant challenge.

The scenarios considered are described in Table 4-12: and the deployment rates (used in all scenarios) are set out in Table 4-13. In all cases, the Medium cost energy efficiency measures are applied. In all cases, it is assumed that direct electric heating is suitable for all building types and for all thermal efficiency levels.

Table 4-12: Scenarios presented for Direct electric heating

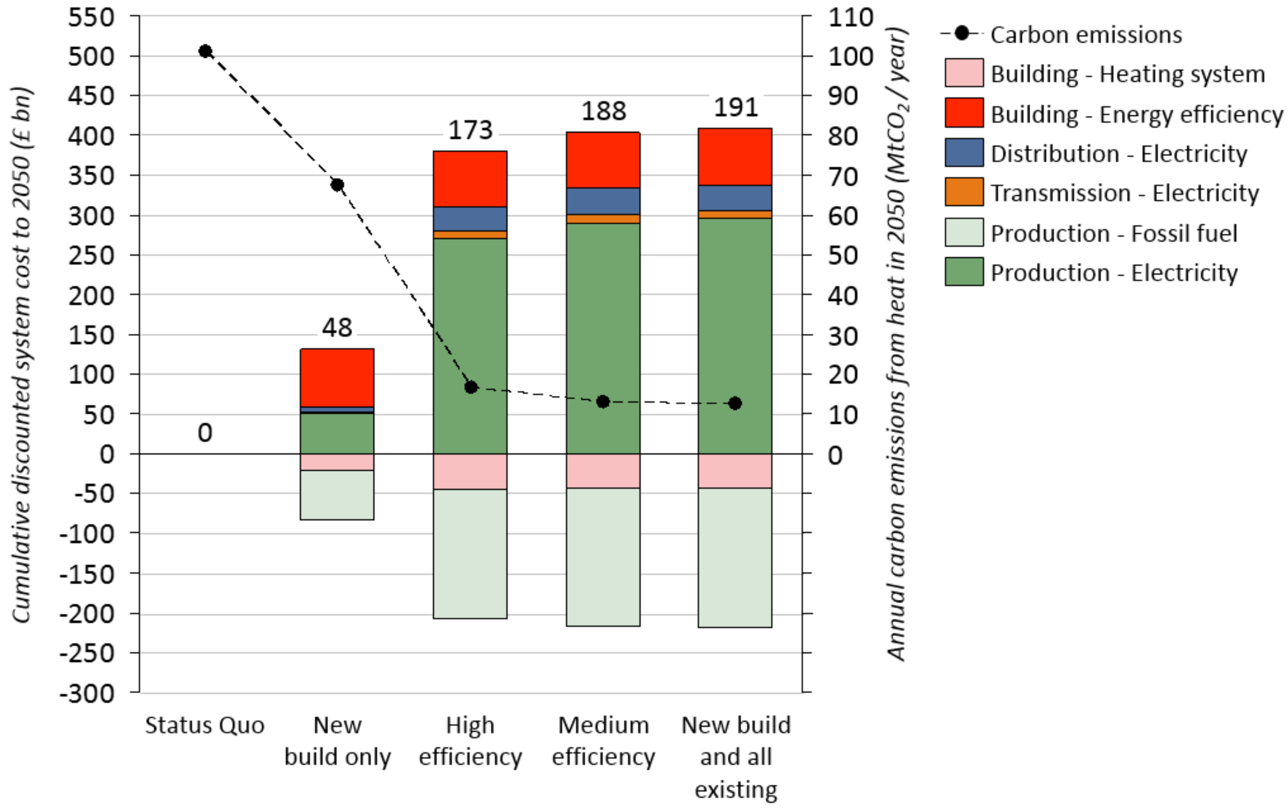
Scenario	Description	Energy efficiency
New build only	Electric heating in new build only	Medium cost energy efficiency measures applied
High efficiency	Electric heating in all new build and High efficiency buildings	
Medium efficiency	Electric heating in all new build, High and Medium efficiency buildings	
All	Electric heating in all buildings	

Table 4-13: Deployment rate of direct electric heating assumed in scenarios presented

Building sector		2020	2025	2030	2035	2040	2045	2050
New build	Domestic + Non-domestic	100%	100%	100%	100%	100%	100%	100%
Existing	Domestic	10%	30%	50%	70%	90%	100%	100%
	Non-domestic	10%	30%	50%	70%	90%	100%	100%

Figure 4-10 shows the total additional discounted system cost to 2050 for each of these scenarios relative to the Status Quo scenario, along with the estimated level of carbon emissions in 2050.

Figure 4-10: Cumulative discounted additional system cost and CO_2 emissions in 2050 – Direct electric heating



Under the Central case shown in Figure 4-10, deployment of direct electric heating across all buildings in the stock leads to annual carbon emissions of 13 $MtCO_2$ per year by 2050. Additional costs and emissions for the highest deployment scenario, where electric heating is installed in all buildings are shown below in Table 4-14 and Figure 4-11 on a 5-yearly basis.

The additional cost increases from £40 bn in the period 2016 – 2020, to £63 bn in the period 2026 – 2030 (where the electricity system is upgraded to support electricity demand and energy efficiency measures installed), falling to £31 bn between 2046 and 2050.

Since the CO_2 emissions savings potential of direct electric heating is lower than for heat pumps (as a result of their lower efficiency), the cumulative emissions to 2050 are substantially higher than those seen in the heat pump case, with net emissions to 2050 of 1,699 $MtCO_2$, or 49% of those in the Status Quo scenario).

Table 4-14: Additional system cost and annual carbon emissions to 2050 for electrification with Direct electric heating in New build and all existing buildings

Five-year period	2016 - 2020	2021 - 2025	2026 - 2030	2031 - 2035	2036 - 2040	2041 - 2045	2046 - 2050	2016 - 2050
Additional system cost *£bn (undiscounted)*	40	58	63	47	39	36	31	**315**
Additional system cost *£bn (discounted)*	37	44	41	26	18	14	10	**191**
Annual carbon emissions from heat *Mt CO_2 / year*	94	83	64	43	26	17	12	**1,699**

Figure 4-11: Five year undiscounted additional system cost to 2050 for electrification with Direct electric heating in New build and all existing buildings

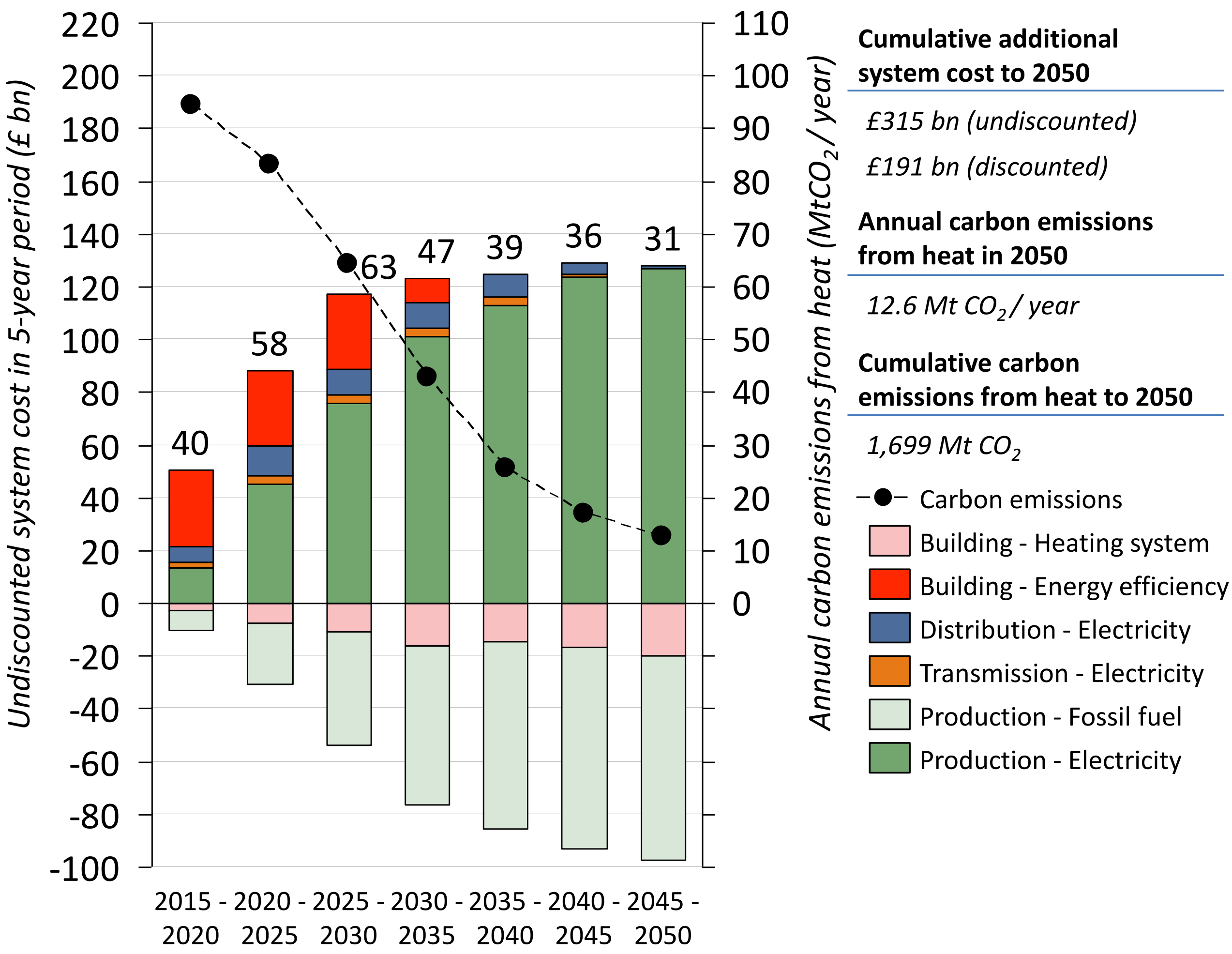
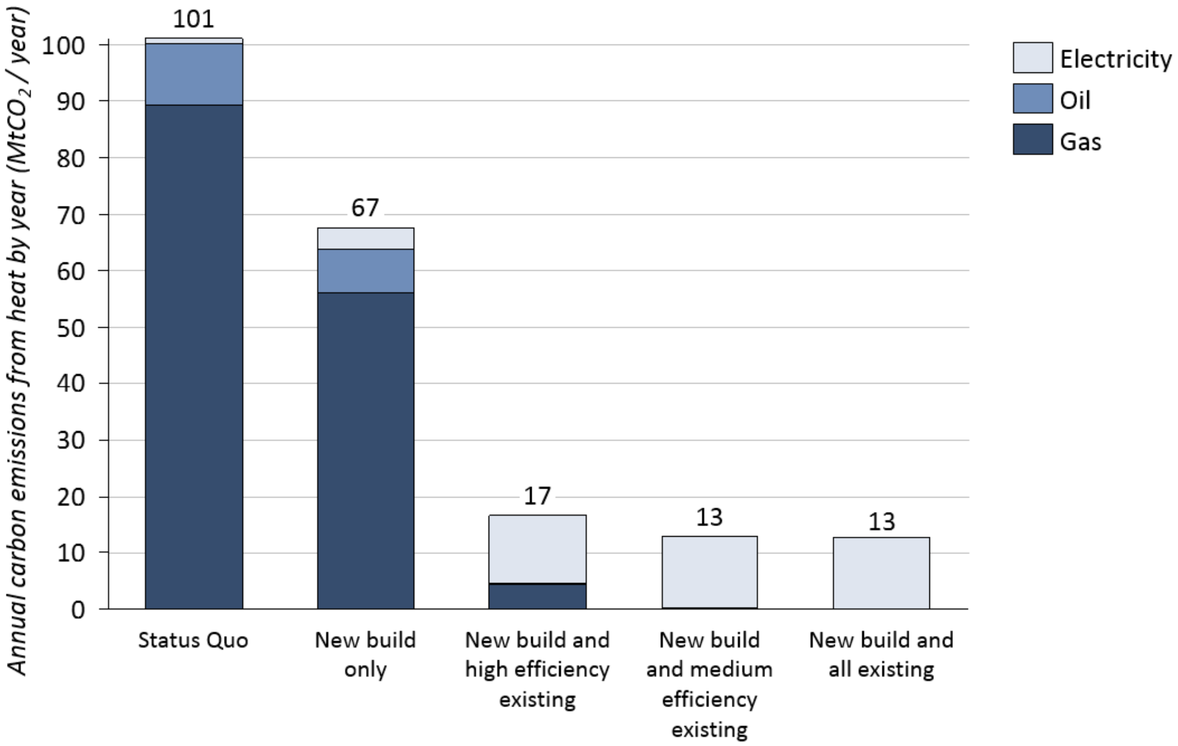


Figure 4-12 shows that under this scenario heating in all buildings is electrified, and so the residual emissions result solely from electricity. In comparison to the deepest heat pump electrification scenario (7 $MtCO_2$ / yr), the final emissions shown here are roughly 6 $MtCO_2$ / yr higher. This is despite the fact that all buildings shift to electric heating, where a small number of buildings in the heat pump scenario are not electrified (as they remain unsuitable even after High cost efficiency measures are applied), and is due to two main factors. First, the lower application of energy efficiency measures across the stock, resulting in the 2050 heat demand in the direct electric heating scenarios being ~90 TWh / yr higher than in the deepest heat pump electrification scenario. Second, the higher efficiency of heat pumps compared to direct electric heating. As is the case in all scenarios, by 2050 the carbon intensity of the electric grid is assumed to be 30 gCO_2 / kWh, therefore more extensive decarbonisation of the electricity system could act to enhance the decarbonisation potential of direct electric heating.

Figure 4-12: Annual CO_2 emissions in 2050 in the direct electric heating scenarios



In the most extensive deployment case – where all buildings are reached – the cumulative additional system cost to 2050 reaches £191 bn. The most significant component of this increase in fuel production cost of £121 bn, resulting from the large additional cost of electricity production, at £295 bn, relative to the fuel cost savings from the counterfactual (mainly gas) at £174bn. In contrast to the heat pump based electrification scenarios, however, a net decrease in the building level heating system cost is seen. This is due to a marginally lower capital cost of an electric heating system compared to a conventional oil or gas boiler when installed in high efficiency buildings.

Another significant component of the cost increase estimated in this analysis is associated with reinforcement of the electricity distribution and transmission networks. The increase in peak electrical load under the different scenarios is shown in Figure 4-13. This indicates a peak load increase of 82 GW by 2050 in the highest decarbonisation scenarios, equivalent to an additional peak of 2.2 kW per building. This is expected to be a relatively conservative estimate, based on an assumption of continuous heating throughout the day. Nonetheless, this is significantly higher than the peak observed in the electrification via heat pumps scenarios, at up to 49 GW, due mainly to the lower efficiency of direct electric heating than heat pumps. Taken together, the total additional discounted cost to 2050 of upgrades to the distribution (£32 bn) and transmission system (£10 bn) reach £42 bn for scenarios where electric heating is installed in all buildings.

Figure 4-13: Contribution to peak load electricity in 2050 under electrification direct electric heating scenarios

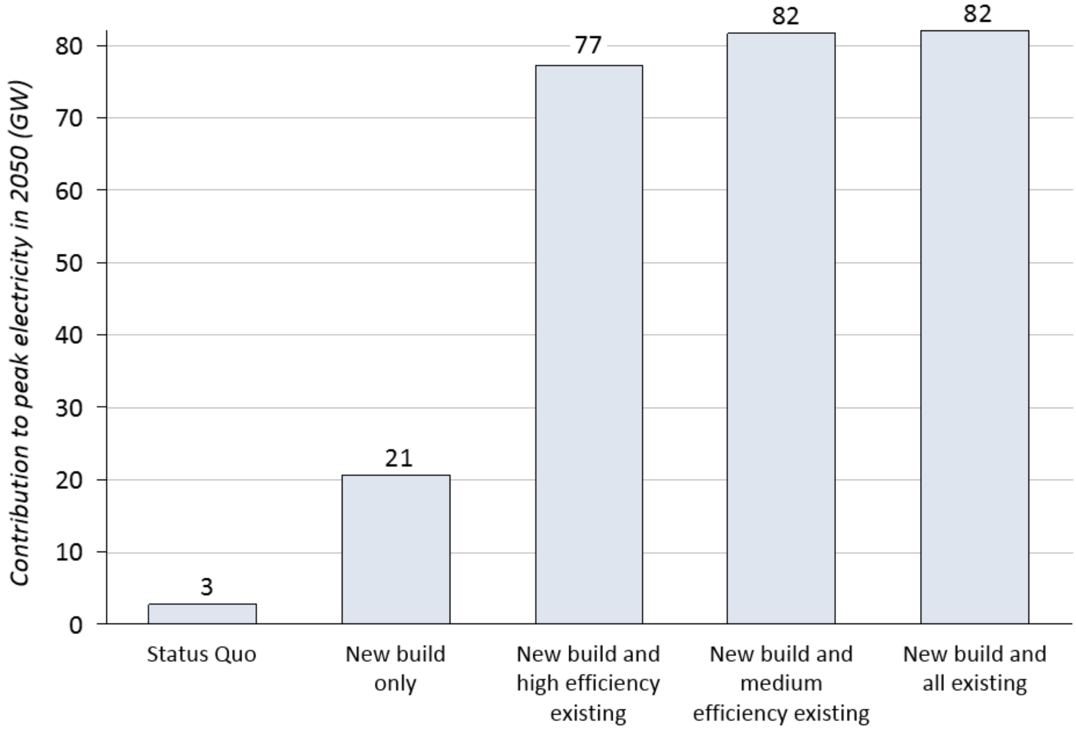


Figure 4-14 presents a breakdown of the total discounted system costs to 2050 and the ongoing annual system costs in 2050 in the direct electric heating case, for the New build and all Existing buildings scenario. This indicates that the major contribution to costs to 2050 are the additional fuel costs associated with displacing (mainly) gas with more expensive electricity, without a substantial efficiency increase as in the heat pumps case. Overall, the fuel costs account for 59% of the discounted system costs. The capital costs (associated with replacing heating systems and network upgrades) account for 30%, and the ongoing operating costs contribute 11% of the total.

The dominant component of the annual system cost from 2050, as shown in Figure 4-14, is the cost of electricity, accounting for £28 bn of the £38 bn total. The operating and replacement capital costs each contribute £5 bn / yr. Taken together, these represent an ongoing heating cost of £1,020 / building / yr in 2050. In comparison with the £840 / building / yr estimated for the Status Quo scenario, this is an increase of £180 / building / yr.

Figure 4-14 Breakdown of discounted system costs to 2050 and annual system costs in 2050 – Electrification using direct electric heating

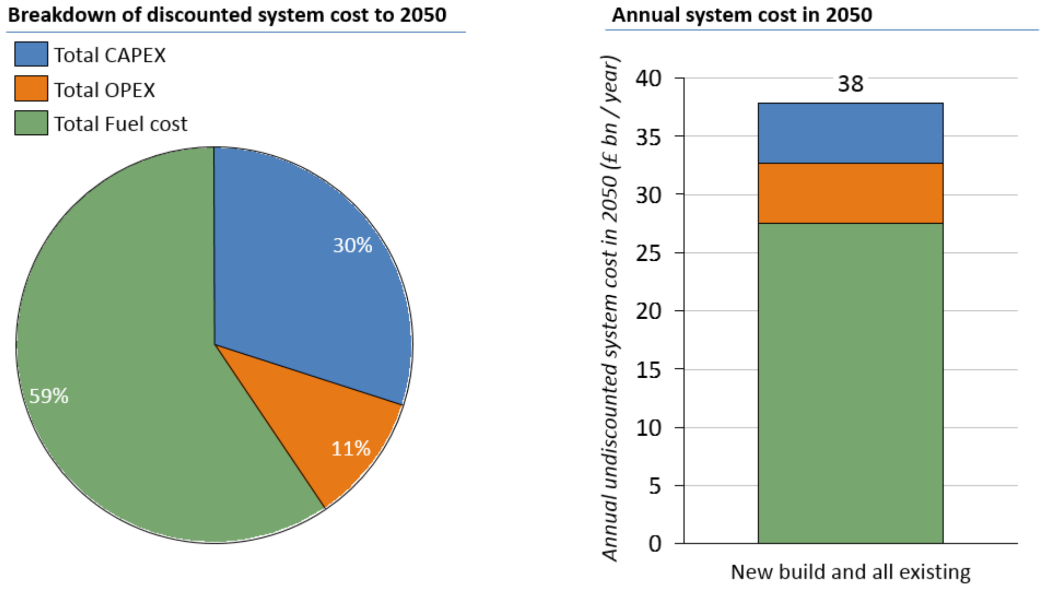
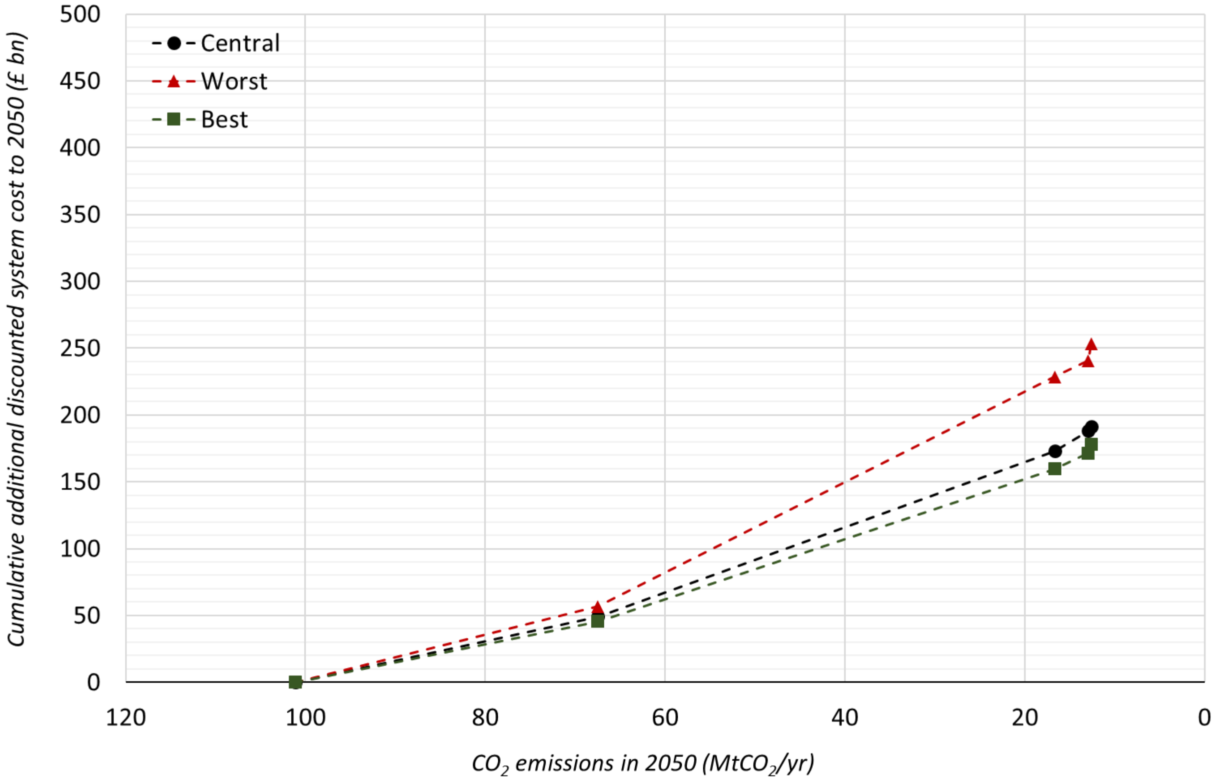


Figure 4-15 shows the estimated uncertainty in the cost analysis for the direct electric heating scenarios – excluding uncertainty in the fuel production cost (which is presented below). The range in costs shown here is relatively low, owing to the relatively low uncertainty in the cost and performance of direct electric heating as an already well-established technology. The range in costs shown here is relatively low, owing to the relatively low uncertainty in the cost and performance of direct electric heating as an already mature technology. As for the case of electrification using heat pumps, an additional cost of £1,200 at the time of conversion for switching from gas-burning cookers to electric cookers (i.e. assuming that on-gas buildings switch to electric heating) is included in the Worst case scenario only. The cumulative discounted cost compared to the Status Quo scenario ranges from £178 bn in the Best case scenario to £253 bn in the Worst case.

Figure 4-15: Uncertainty in cumulative additional system cost to 2050 – Direct electric heating



For the case where direct electric heating is installed in all buildings, the cost components of the above uncertainty analysis are broken down in Figure 4-16, along with the sensitivity of the results to fuel production cost. The most significant components of the technology cost and performance are the costs of increased electricity transmission and distribution upgrades required, as well as the variation in building level heating system costs (which reflects the range of costs for electric heaters currently seen in the market).

A strong dependence is found of the cost of the scenario on the electricity production cost. Due to the low contribution of gas fuel costs in this scenario (which are non-zero since the cost is cumulative over the transition to 2050), the sensitivity to the gas production cost is smaller. Overall, in the Best case fuel production cost scenario, a reduction in additional discounted cost of £53 bn is found, with an increase of roughly £45 bn in the Best case.

Figure 4-16 Sensitivity to technology cost and performance and fuel costs – Direct electric heating

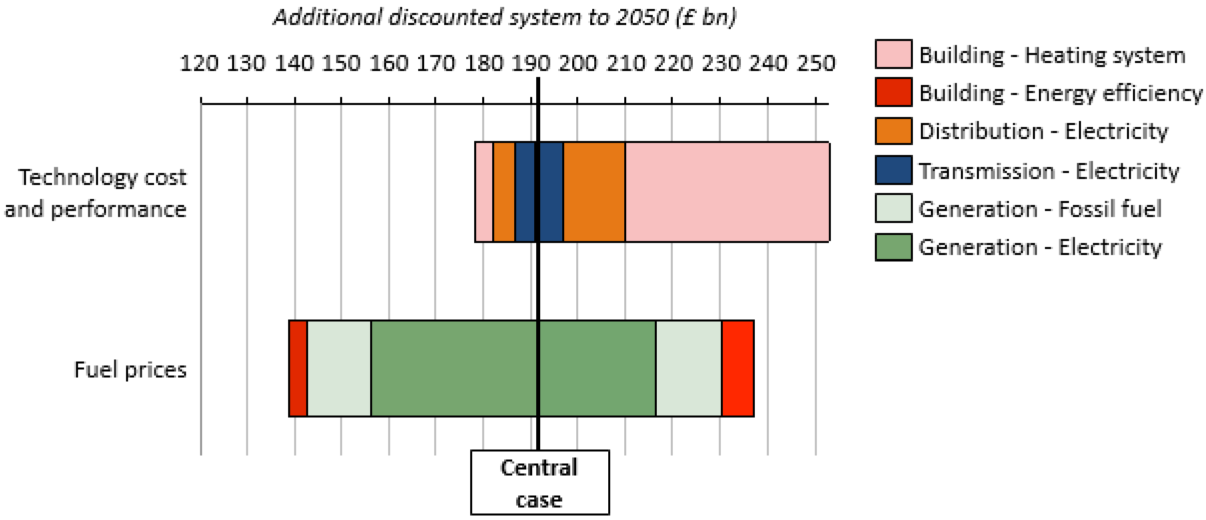


Table 4-15 Summary of technology cost and performance and fuel prices sensitivity – Direct electric heating

Parameter	Sensitivity	Best	Central	Worst
Additional discounted system cost to 2050 *£ bn*	Technology cost and performance	178	191	253
	Fuel prices	138	191	236
2050 carbon emissions *Mt CO_2 / yr*	Technology cost and performance	12	12	12
	Fuel prices	12	12	12

Box 3 – Direct electric heating: Key findings

- Direct electric heating represents an option used by a large number of buildings today, and unlike heat pumps is assumed to be suitable across the stock without energy efficiency upgrades.
- Although this pathway results in significantly higher fuel consumption than the heat pumps case, these costs are offset by the lower capital costs of the equipment at the building level.
- Ultimately, the decarbonisation potential of this option is limited by the carbon intensity of the electricity grid. Moreover, because of their lower efficiency compared to heat pumps, direct electric heaters cannot reach the same level of decarbonisation even for the same level of electricity grid carbon intensity.
- In the maximum direct electric heating deployment scenario, where all buildings switch to direct electric heating, carbon emissions are reduced to 12 $MtCO_2$ / yr, with an associated increase in discounted cumulative system cost to 2050 of £191 bn in the Central case.
- This is dominated by the costs of producing additional electricity for the systems, resulting in a total increase in fuel production cost of £121 bn.
- Another significant component of the increased costs corresponds to the required upgrades to the electricity distribution network (£32bn), and the transmission network (£10bn).
- A key advantage of direct electric heating is that it can be applied in off-gas buildings, and could therefore be an important option in this segment in scenarios led by decarbonisation of the gas-grid using low carbon hydrogen and/or biomethane.

4.4 Hybrid electric-gas heating

Sections 4.2 and 4.3 considered 'purely' electric heating through the deployment of heat pumps and direct electric heating. The heat pump analysis highlighted the large additional costs associated with the heat pump and a compatible heat distribution system, as well as the substantial cost of electricity grid reinforcement. Conversely, the analysis of direct electric heating suggested a significant increase in cost related to producing and transporting electricity.

Hybrid heat pumps have been proposed as a potential alternative to mitigate some of the negative impact of each of these factors. By installing a heat pump alongside a gas boiler within a single building, hybrids present the opportunity to meet the majority of annual heat demand using the heat pump, but applying the gas boiler during the coldest periods (and potentially the bulk of the hot water heating demand). The potential benefits of this approach are several: that a smaller heat pump could be installed, since it is not required to meet peak demand, reducing the system cost; that emitter replacement could be avoided, as the gas boiler can be used to provide the high heating temperatures when required, where a lower temperature would be sufficient for most of the year; and that much or all of the additional peak electricity demand can be mitigated since the gas boiler could be used alone during peak periods. Hybrid heat pumps could be perceived by some consumers as more likely than pure electric heat pumps to guarantee the desired level of performance and comfort; however, the potential added complexity and space requirements may be a barrier for others.

The key disadvantage of the hybrid approach versus the pure electrification approach is that a less deep level of decarbonisation is achieved insofar as gas remains in use to meet some fraction of the heating demand. The approach is also strongly dependent on consumer behaviour, and the ability of 'smart' controls to influence this behaviour, to ensure that the share of the heat demand is met by the gas boiler is not larger than necessary under 'optimal' operation (however defined) and that the benefits of reduced electrical peak load are achieved.

The deployment potential of hybrid heat pumps is also (effectively) limited to on-gas buildings. The potential for hybrid gas-electric heating to reduce carbon emissions could be enhanced through the application of biomethane grid injection. A key consideration in this regard is the potential availability of biomethane for grid injection, and hence what fraction of the remaining gas demand in a hybrid scenario could be low carbon.

Case A: No Biomethane injection into the gas grid

This section considers the deployment of hybrid heat pumps in the case of no decarbonisation of the gas grid. The scenarios presented are described in Table 4-16, and the deployment rates (which apply to all scenarios) are set out in Table 4-17. In all cases, the Medium cost energy efficiency measures are applied; it is assumed that hybrid heat pumps are suitable for buildings of all thermal efficiency levels, so no further efficiency retrofits are required to increase hybrid heat pump deployment.

Table 4-16: Scenarios presented for Hybrid gas-electric heating

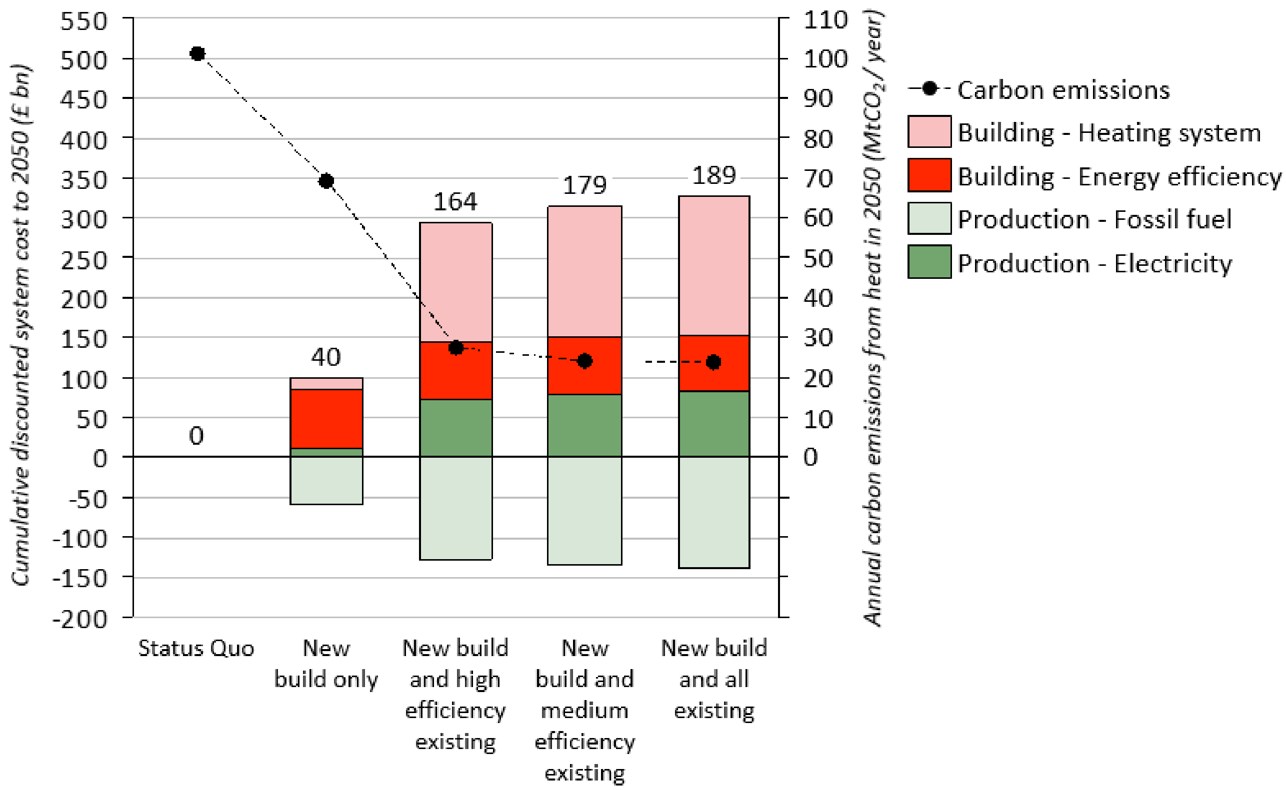
Scenario	Description	Energy efficiency
New build only	Hybrid heat pumps in new build only	Medium cost energy efficiency measures applied
On-gas (High efficiency)	Hybrid heat pumps in all High efficiency on-gas buildings	
On-gas (Medium efficiency)	Hybrid heat pumps in all High and Medium efficiency on-gas buildings	
On-gas (All)	Hybrid heat pumps in all on-gas buildings	

Table 4-17: Deployment rate of hybrid heat pumps assumed in scenarios presented

Building sector		2020	2025	2030	2035	2040	2045	2050
New build	**Domestic + Non-domestic**	100%	100%	100%	100%	100%	100%	100%
Existing	**Domestic**	20%	40%	60%	70%	100%	100%	100%
	Non-domestic	20%	40%	60%	70%	100%	100%	100%

The discounted cumulative additional system cost to 2050 of each scenario relative to the Status Quo scenario, and the associated level of CO_2 emissions in 2050, are shown in Figure 4-17.

Figure 4-17: Cumulative discounted additional system cost and CO_2 emissions in 2050 – Hybrid heat pumps



In the Central case, the maximum deployment of hybrid heat pumps – across all on-gas buildings – leads to carbon emissions of 24 $MtCO_2$ / yr by 2050. A key assumption underlying this result is that, for buildings with hybrid heat pumps, 85% of the heating demand is met by the heat pump, and the remaining 15% is met by the gas boiler. This assumption is based on recent analysis undertaken by Element Energy on hybrid heat pumps for BEIS[18]. The impact of sensitivities on this and other assumptions are presented below.

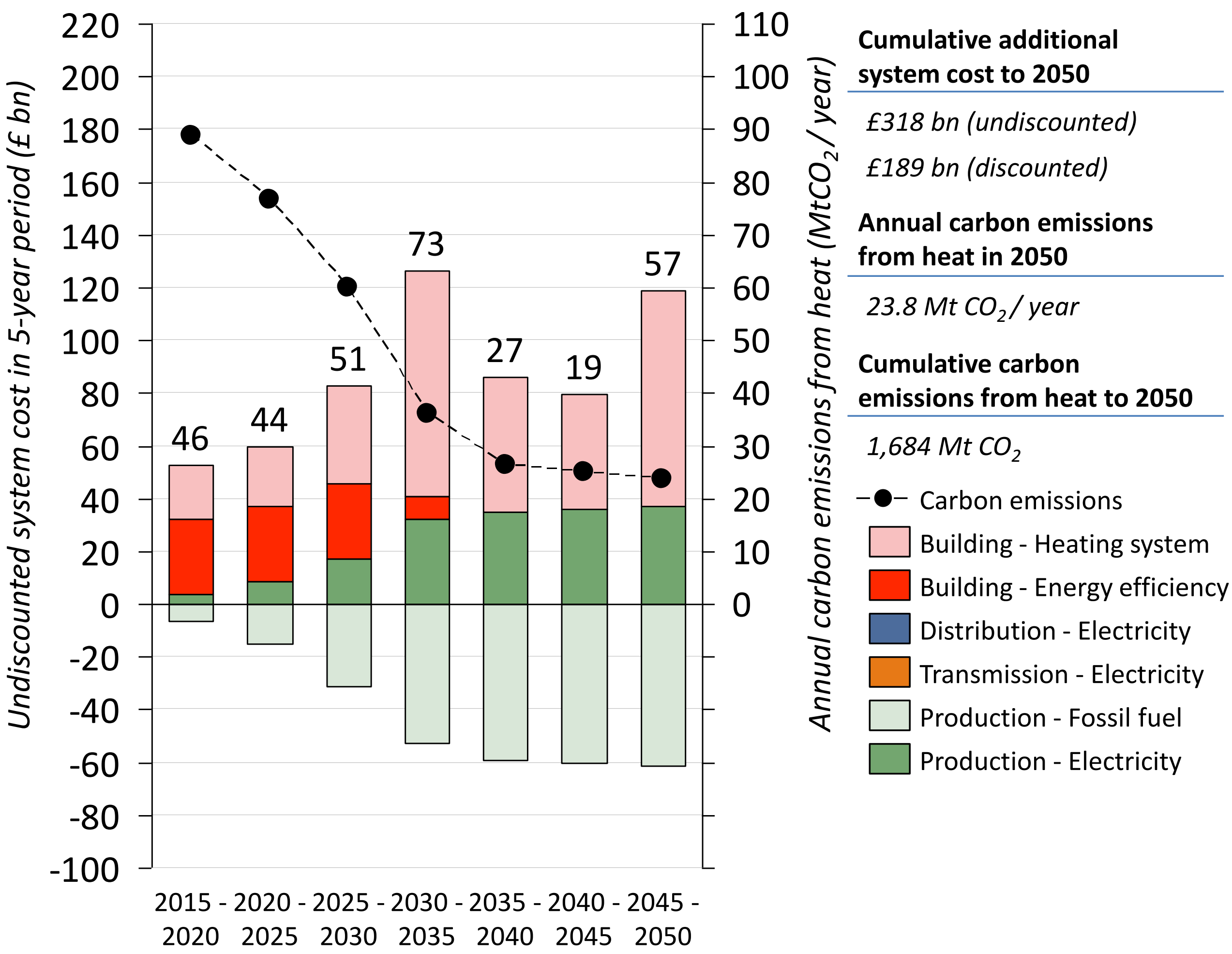
Table 4-18 and Figure 4-19 set out the additional system costs and emissions due to heating in the New Build and all existing scenario.

Table 4-18: Additional system cost and annual carbon emissions to 2050 for the hybrid electric heating in New build and all existing buildings scenario

Five-year period	2016 - 2020	2021 - 2025	2026 - 2030	2031 - 2035	2036 - 2040	2041 - 2045	2046 - 2050	2016 - 2050
Additional system cost *£bn (undiscounted)*	46	44	51	73	27	19	57	***318***
Additional system cost *£bn (discounted)*	42	34	33	40	12	8	19	***189***
Annual carbon emissions from heat *Mt CO_2 / year*	89	77	60	36	26	25	24	***1,684***

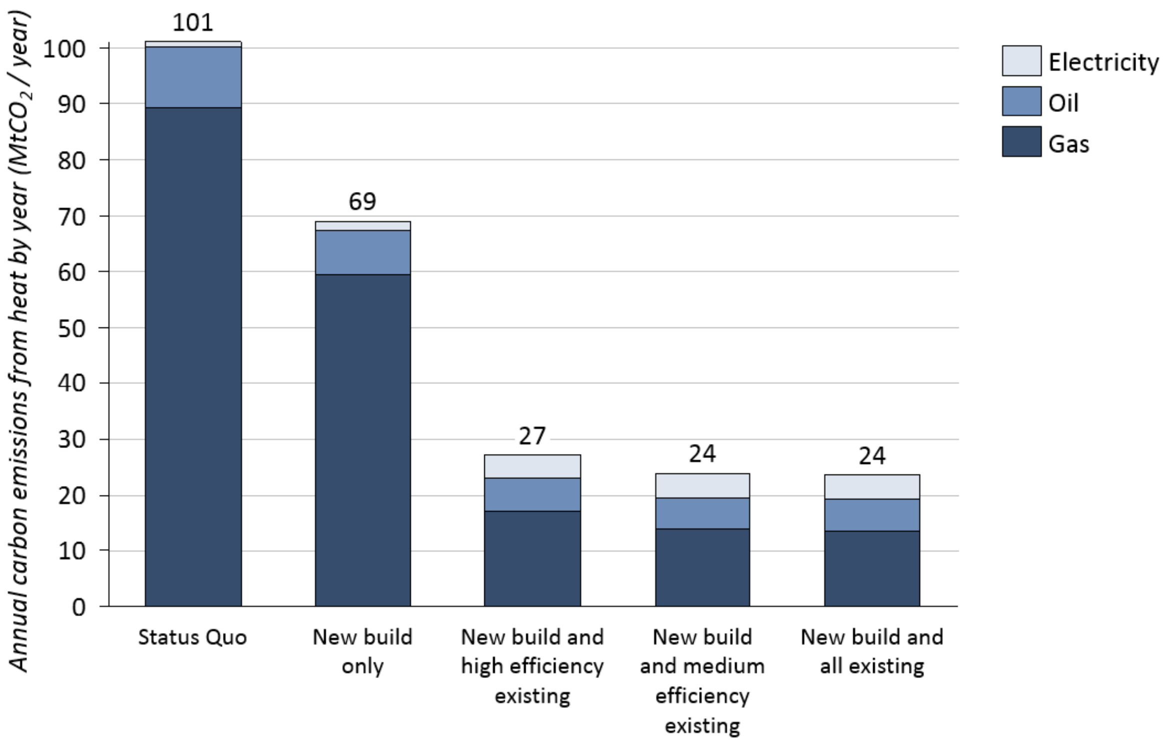
[18] Element Energy for BEIS, *Hybrid Heat Pumps study* (2017) (pending publication)

Figure 4-18: Five year undiscounted additional system cost to 2050 for the hybrid electric heating in New build and all existing buildings scenario



A further limit to the depth of decarbonisation possible in the hybrid gas-electric case is that the option can only be applied to on-gas buildings. In the scenarios presented here, the off-gas buildings (corresponding to roughly 15% of the domestic building stock) remain on the counterfactual heating system, a mixture of electric resistive and oil heating. Figure 4-19 shows the breakdown of carbon emissions by fuel type to 2050, indicating an associated reduction in gas-related emissions, a small increase in electricity-related due to the shift to heat pumps (mostly offset by the decarbonising grid) and no change in the oil-related emissions except a small reduction associated with energy efficiency.

Figure 4-19: Annual CO_2 emissions in 2050 in the hybrid gas-electric scenarios



The cumulative discounted additional system cost to 2050 increases to £189 bn in the maximum hybrid heat pump deployment case, reaching all on-gas buildings. Similarly to the heat pump based electrification scenarios, the most significant component of the additional cost to 2050 is the building-level cost. However, these are significantly lower for the hybrid heat pump case than for the heat pump case, due to the somewhat reduced cost of the smaller heat pump, and the avoided cost of the replacement heat distribution system (large-area emitters). For a typical existing semi-detached building, this is estimated to bring savings of around £2,300 for the hybrid heat pump relative to the heat pumps.

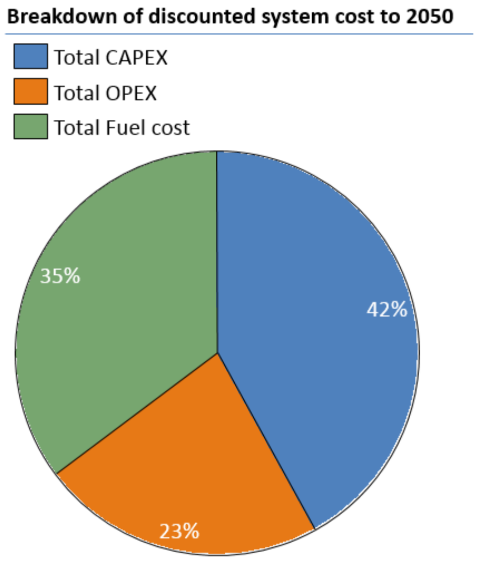
Furthermore, in the Central case, hybrid heat pumps are assumed not to lead to an increase in peak electricity demand, since gas boilers could be used exclusively during peak periods. In the maximum heat pump deployment case, electricity grid reinforcement led to an additional system cost of £23 bn, which is not incurred in the central hybrid gas-electric case.

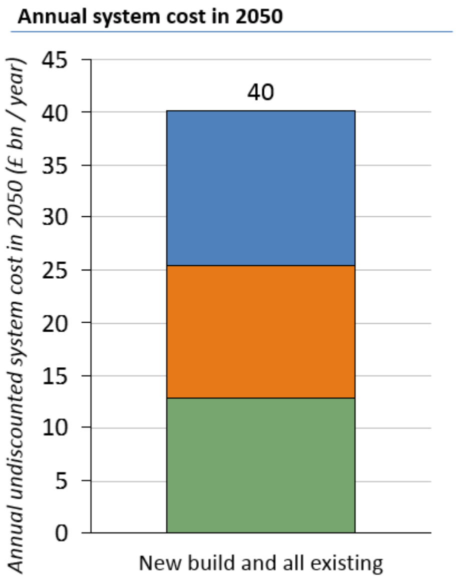
A comparison of the hybrid gas-electric scenario with the electrification scenario is not quite like-for-like, since the hybrid heat pump deployment is limited to on-gas buildings, and an alternative solution would be required for off-gas buildings. With this in mind, a high-level comparison can nonetheless be made between the scenarios. The maximum heat pump deployment scenario achieves carbon emissions savings of 94 $MtCO_2$ / yr by 2050 with a cumulative additional system cost of £264 bn; the maximum hybrid deployment scenario achieves savings of 77 $MtCO_2$ / yr by 2050 (82% of the maximum heat pump case) with a cumulative additional system cost of £189 bn (72% of the maximum heat pump case).

A breakdown of the total system costs to 2050 and the ongoing 2050 annual system costs for the New build and all existing scenario is presented in Figure 4-20. In comparison to the pure electrification scenarios, the discounted total system cost to 2050 is relatively evenly distributed between capital costs (42%, including the building level heating system and energy efficiency costs, as well as network upgrades), fuel costs (35%) and operating costs (23%, comprised of the costs of maintaining building level heating systems and ongoing operation of the gas grid).

The annual system cost in 2050 is similar to the two pure electrification cases, at £40 bn / yr. The largest component of this is the capital costs (£15 bn / yr), with the fuel costs (£13 bn / yr) and the operating costs (£12 bn / yr) representing a similar share. This represents an annual cost of £1,070 / yr / building, representing an increase of £230 / building / yr compared to the Status Quo scenario.

Figure 4-20: Breakdown of discounted system costs to 2050 and annual system costs in 2050 – Hybrid gas-electric heating





In terms of cumulative investment required to 2050 (though not annual cost from 2050 onwards), the hybrid gas-electric option can be seen to be less costly than the pure-electric heat pump option. However, it is also substantially more limited in terms of the potential depth of decarbonisation. This analysis relates to the case of no biomethane grid injection; in the next section, the potential to achieve deeper levels of decarbonisation through hybrid gas-electric systems, using biomethane, is considered.

The estimated uncertainty in the cost analysis is presented in Figure 4-21. The key contributing factors to the uncertainty range are the reduction in heat pump cost over time, the heat pump efficiency and – specific to the case of hybrid gas-electric heating – the relative use of the gas and electric components due to consumer behaviour. While the Central scenario assumes that the heat pump meets 85% of a building's annual heat demand, the Worst case assumes the heat pump only provides 39% of a building's heat demand, with the remainder met by the gas boiler[19]. These factors lead to a range in the cumulative additional system cost versus the Status Quo for the maximum hybrid heat pump deployment scenario of £131 bn to £325 bn, and a large range in the resulting level of emissions in 2050 of between 23 and 63 $MtCO_2$ / yr.

Figure 4-22 presents the breakdown of the technology cost and performance sensitivity, along with the sensitivity on fuel production cost.

[19] The Worst case is based on analysis undertaken in: Element Energy for BEIS, Hybrid Heat Pumps study (2017) (pending publication) and relates to a case where the user operates the hybrid system in a 'sub-optimal' manner with a strongly bimodal heating pattern, rather than a more continuous heating pattern as appropriate for a heat pump. This reduces the potential contribution of the heat pump.

Figure 4-21: Uncertainty in cumulative additional system cost to 2050 – Hybrid heat pumps

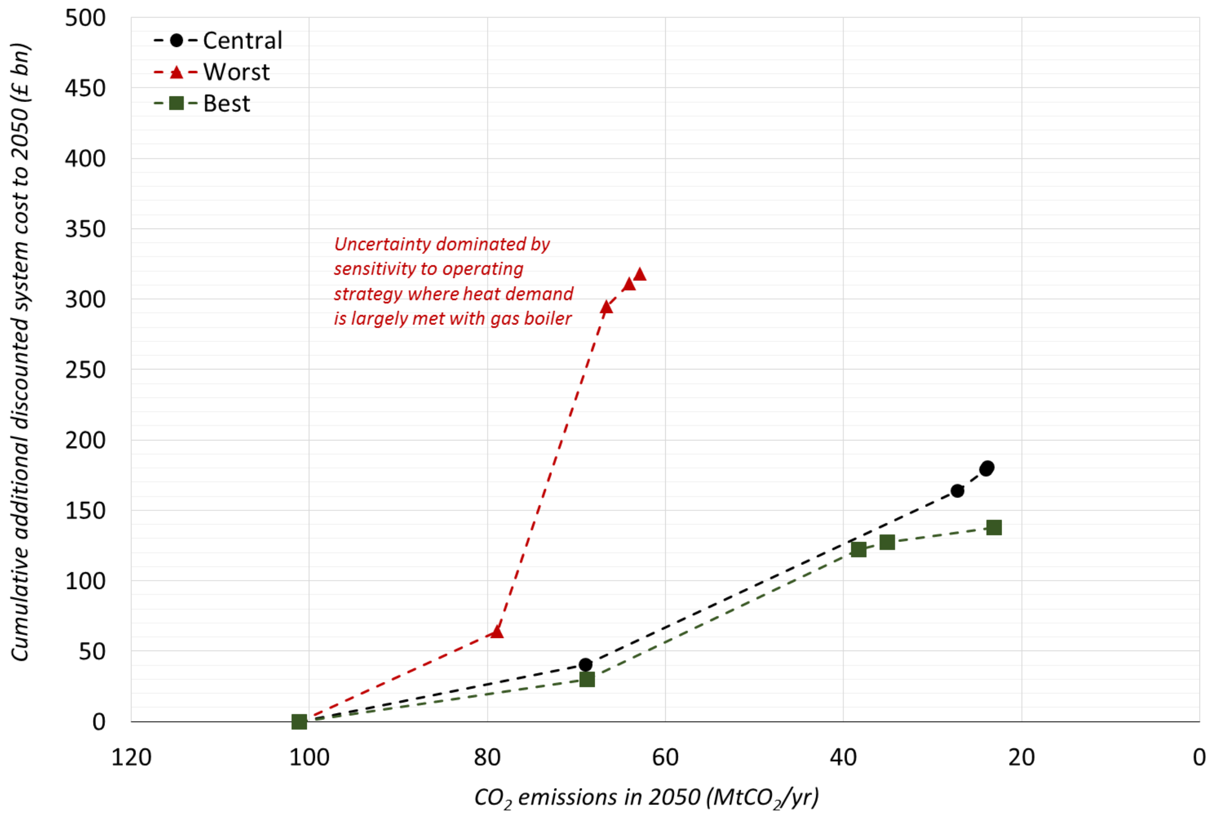


Figure 4-22: Sensitivity to technology cost and performance and fuel costs – Hybrid gas-electric heating

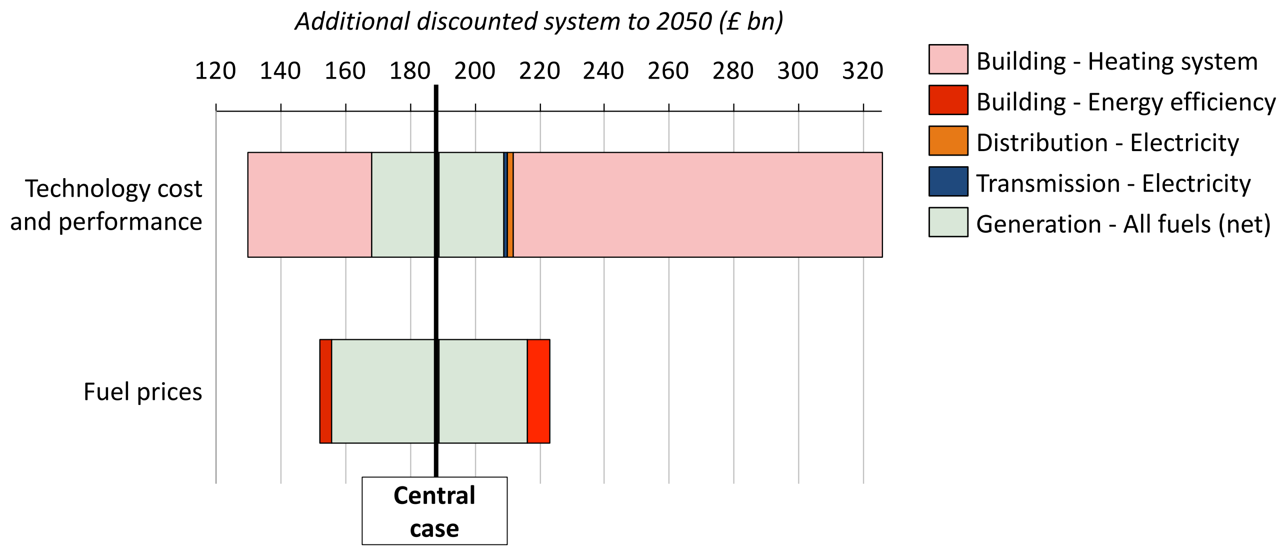


Table 4-19: Summary of technology cost and performance and fuel prices sensitivity – Hybrid gas-electric heating

Parameter	Sensitivity	Best	Central	Worst
Additional discounted system cost to 2050 *£ bn*	Technology cost and performance	131	189	325
	Fuel prices	152	189	222
2050 carbon emissions *Mt CO_2 / year*	Technology cost and performance	23	24	63
	Fuel prices	24	24	24

Case B: Biomethane injection into the gas grid

In Case A, the potential of hybrid heat pumps to reduce the total CO_2 heat related emissions was limited in part by the use of gas to provide 15% of the heating demand. Deeper decarbonisation could be achieved through the injection of low carbon biomethane into the gas grid.

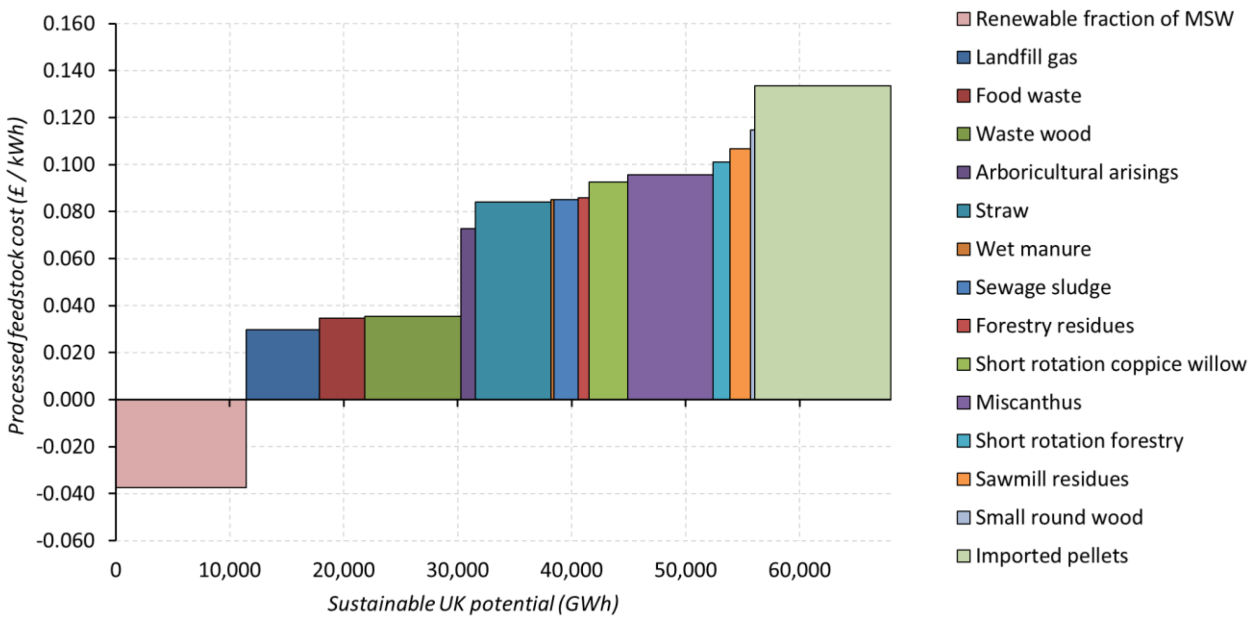
The assumptions underlying this analysis, as shown in Figure 4-23, indicate that by 2050, up to 67 TWh / yr of biomethane could be produced and injected into the gas grid. It should be noted that there is substantial uncertainty over this potential, and other recent studies[20] have indicated a potential for bio-synthetic natural gas (Bio-SNG) grid injection in the UK of up to 100 TWh / yr and further potential of 40 TWh / yr from anerobic digestion.

It is also important to note that it is highly unlikely that, in a hybrid gas-electric scenario, space heating and hot water would account for the majority of remaining gas demand. In fact, other end-uses such as high temperature industrial processes, power generation and natural gas-fuelled vehicles would likely account for much of the remaining gas demand in such a scenario. Notwithstanding the potential for greater amounts of biomethane grid injection shown here, therefore, the figures shown should be considered an upper limit for the potential of biomethane to decarbonise space heating and hot water provision.

Figure 4-23 suggests that the processed feedstock cost of the biomethane potential varies from a negative cost of -4 p/kWh for municipal solid waste (MSW), to less than 4 p/kWh for landfill gas, waste wood and food waste, and up to nearly 14 p/kWh for the most costly potential based on sawmill residues, small round wood feedstocks and imported wood pellets. In addition to the processing of the feedstocks into biomethane, the costs shown in the figure include an additional 2 p/kWh associated with distribution in the gas grid.

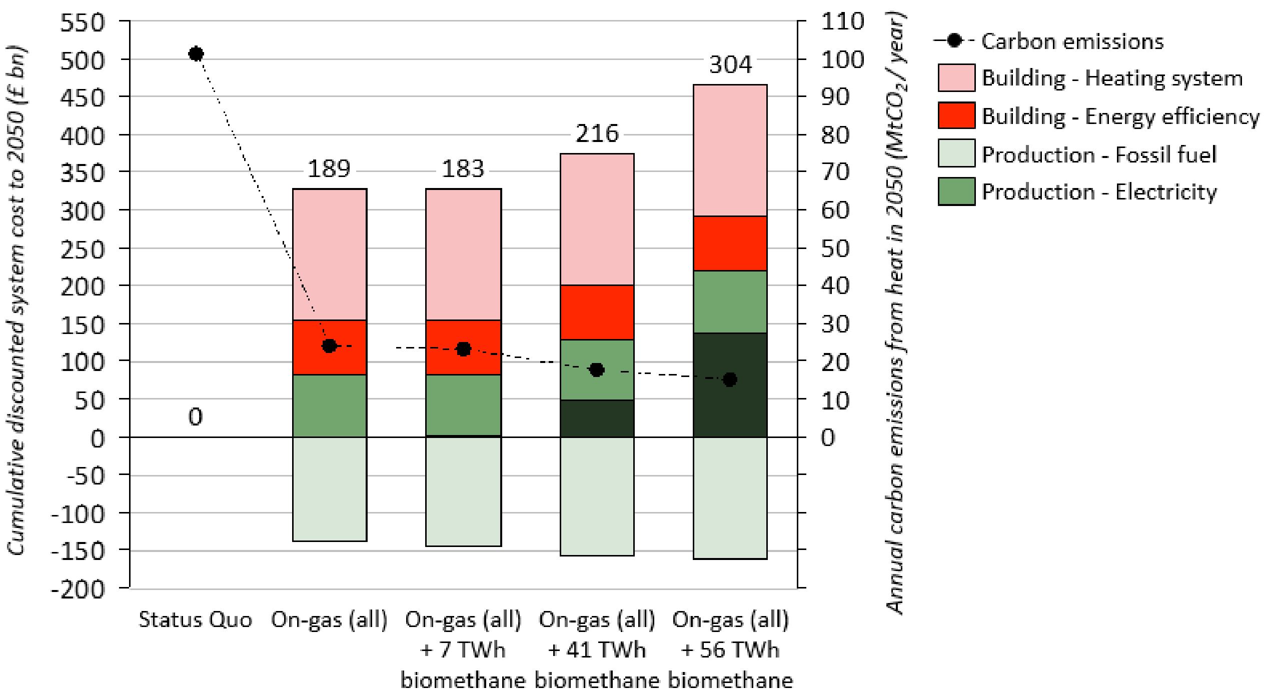
[20] Anthesis and E4Tech for Cadent, *Review of Bioenergy Potential: Technical Report* (2017)

Figure 4-23: Processed feedstock cost of sustainable biomethane potential in 2050



The potential impact of biomethane grid injection on the level of carbon emissions reduction that could be achieved in the hybrid gas-electric scenario, and on the cumulative additional system cost to 2050, is shown in Figure 4-24.

Figure 4-24: Cumulative additional system cost and CO_2 emissions in 2050 – Hybrid heat pumps with biomethane grid injection



It is reiterated here that, under the assumptions on biomethane potential applied in this analysis, these scenarios represent an upper bound for the potential of biomethane to decarbonise space heating and hot water, as a range of other end-uses (high temperature industrial heating, power, transport) are likely to account for a share of this potential.

The figure demonstrates that up to 9 Mt CO_2 / yr of carbon emissions could be abated in the hybrid gas-electric heating scenario through the injection of 56 TWh of biomethane, with a net increase in cumulative discounted system cost reduction of £115 bn compared to the case of no biomethane. This includes, however, the most costly feedstocks. For a lower level of biomethane injection, more cost-effective emissions savings are achievable. For example, with the injection of 7 TWh / yr of biomethane as shown here, a net reduction in total system cost of £6 bn is observed, assuming use of the negative and low cost potential from MSW and landfill gas. However, this results in a relatively low carbon emissions reduction of roughly 1 $MtCO_2$ / yr. As more expensive feedstocks such as miscanthus, short rotation forestry, and ultimately imported pellets are used, more extensive emissions reductions can be achieved, with decreasing cost-effectiveness.

Box 4 – Hybrid gas-electric heating: Key findings

- Hybrid gas-electric heating provides an alternative to full electrification with a number of potential benefits in terms of system cost relating to the ability to use gas heating during peak heating periods.
- This includes the ability to avoid the cost of replacing the building's heat distribution system and the ability to install a somewhat smaller heat pump, as well as the potential to avoid much of the electricity grid upgrade cost associated with full electrification.
- However, the decarbonisation potential of the hybrid gas-electric option is limited by the ongoing use of gas for a share of the heating, unless the gas supply is decarbonised through biomethane grid injection.
- A further limit to the hybrid gas-electric option versus full electrification is that it can be deployed only in on-gas buildings, and an alternative solution will be required for off-gas properties.
- In the maximum hybrid heat pump deployment scenario, with no biomethane grid injection, carbon emissions are reduced to 24 Mt CO_2 / yr, with an associated increase in discounted cumulative system cost to 2050 of £189 bn in the Central case.
- The maximum hybrid heat pump deployment case therefore achieves 80% of the emissions reduction in the maximum heat pump case with 72% of the additional system cost.
- The injection of 7 TWh / yr of biomethane into the gas grid could achieve emissions savings of a further 1 Mt CO_2 / yr with a net reduction in cost, assuming use of the lowest cost feedstocks.
- Injection of up to 56 TWh / yr of biomethane could lead to a further reduction in carbon emissions of up to 9 Mt CO_2 / yr with a net increase in system cost of £115 bn. However, this potential should be viewed as an upper limit, since it is highly likely that gas demand in other sectors including industry and power would account for a share of the overall biomethane potential.

4.5 Hydrogen grid

An alternative heat decarbonisation strategy for the UK is to continue to meet the majority of space heating and hot water demand through the existing low-pressure gas grid, repurposing it to deliver hydrogen produced from low carbon sources. In this scenario, gas boilers (and other gas-burning appliances) would be replaced or adapted to use hydrogen. The potential advantages of this approach would be that the value of the existing gas infrastructure would be maximised, the need for additional electricity network and generation capacity could be minimised, and little change in consumer behaviour would be required.

The most cost-effective source of bulk low carbon hydrogen is likely to be steam methane reformation (SMR) with carbon capture and storage (CCS), although electrolysis using low-carbon electricity and various methods of hydrogen production using bioenergy could play a more limited role.

There remains, however, significant uncertainty around the cost and practicality of this option. In particular there is uncertainty regarding consumer acceptability, the cost of safely distributing hydrogen and its use within buildings, and the readiness and cost of CCS. A multi-million pound research and demonstration project on the hydrogen for heating option funded by BEIS is about to commence, which aims to reduce the uncertainty around the feasibility of the hydrogen for heat option, particularly concerning the costs and practicalities of safely using hydrogen within buildings. In parallel, the gas distribution network companies are developing innovation projects to trial the use of hydrogen within isolated parts of the gas distribution network.

Element Energy has recently undertaken research for BEIS on the cost of hydrogen for heating across the supply chain[21], including production, transmission and distribution and at the appliance level. The analysis undertaken here is based largely on the datasets developed as part of that work.

The components of the hydrogen for heating system included in this analysis are outlined below.

Production

Hydrogen can be produced through various methods including:

1. Fossil fuel based conversion
    a. Steam methane reformation (SMR)
    b. Coal gasification
2. Biomass gasification
3. Electricity based conversion
    a. PEM electrolysers
    b. Alkaline electrolysers
    c. Solid oxide electrolysers

For the scenarios presented in this study, two options for hydrogen production are assumed. In *'Case A'* SMR is assumed to be used to meet all hydrogen demand, as this is found to be the lowest levelised lifetime cost option. '*Case B'* considers hydrogen production via biomass gasification. Though much of the UK biomethane potential is more expensive than natural gas, and the biomass gasification to hydrogen pathway is less efficient than SMR, the absorption of CO_2 by bioenergy feedstocks can be significant, thereby leading to considerable negative emissions.

A hypothetical rollout of the hydrogen network has been specified, with SMR plants assumed to be located in Aberdeen, Liverpool, Stockton-on-Tees and London. These sites are favourably located near existing infrastructure of shoreline terminals, as well as being close to regions of high population density and heating demand. Nonetheless, these sites are only some among a wider group of potentially suitable locations, and are intended to represent an illustrative example of how a national rollout could proceed.

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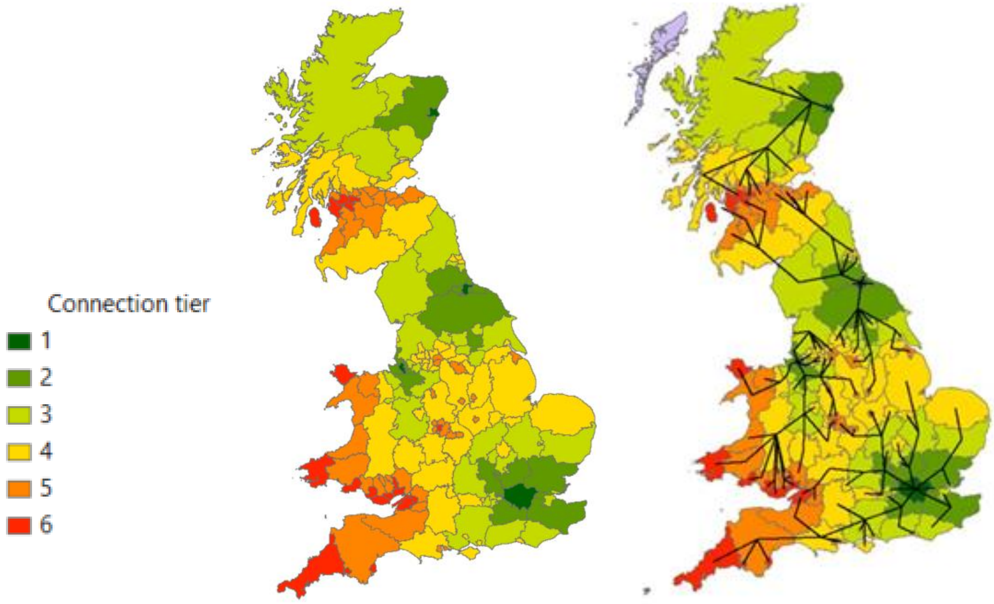
[21] *Hydrogen for heat technical evidence and modelling project,* (2017), a report by Element Energy, Jacobs and BGS for BEIS)

Transmission

Hydrogen generated at the four production sites is assumed to be transmitted initially across the country using a new hydrogen transmission network. Existing (gas) National Transmission System (NTS) and Local Transmission System (LTS) are assumed still to be required to provide gas to regions and/or installations that have not converted to hydrogen, such as power plants and industry, as well as to provide gas to SMR facilities.

Figure 4-25: Visualisation of the hydrogen rollout scenario assumed in the analysis



In this analysis, the hydrogen transmission pipelines are assumed to connect the production sites to the regions of demand using a simplified radial network, in which each county is connected to its nearest upstream county as shown in Figure 4-25. In the figure, Tier 1 comprises the four counties with SMR production facilities (dark green), Tier 2 comprises all the counties neighbouring Tier 1, and so on up to Tier 6 (red), at which point all counties in Great Britain have been connected. In the scenarios presented, the six tiers are assumed to connect between 2035 and 2045, as shown in Table 4-20.

It should be noted that the simple radial network assumed for the hydrogen transmission grid is not intended to represent an optimal network layout, but rather to provide an upper bound for the length of such a network.

Table 4-20: Rollout of hydrogen assumed in the scenarios

Tier	Connection date
1	2035
2	2035
3	2040
4	2040
5	2045
6	2045

Storage

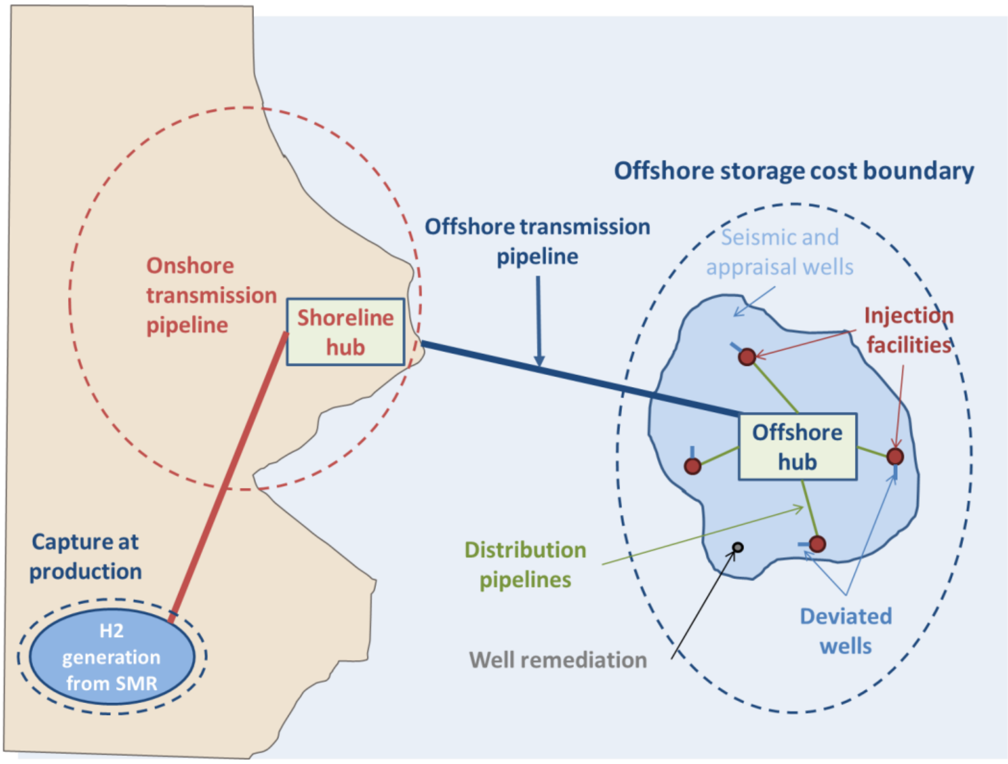
Hydrogen storage allows the installed capacity of the SMR facilities to be lower than the peak hydrogen demand for heating, thus improving the load factor of production facilities and reducing costs. However, SMR facilities have a high response time and slow ramp up/down rates. Therefore, it is assumed that the SMR facilities are sized to the average winter demand and are able to ramp down to the corresponding seasonal average demand.

Salt cavern facilities are assumed to provide the storage mechanism, as this is expected to provide the lowest cost option.

CCS

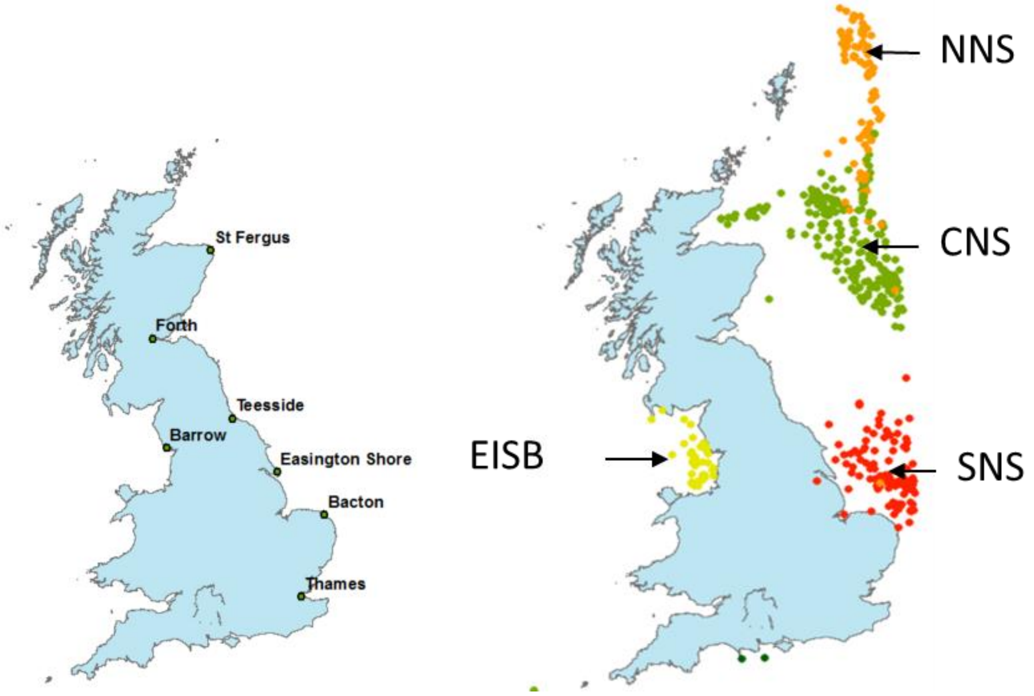
Hydrogen production from SMR leads to CO_2 emissions which can be captured relatively easily. Capture facilities are assumed here to remove 90% of the CO_2 emissions from the flue gas. These are then transmitted to the shoreline terminals, compressed and transmitted via offshore pipelines to the offshore storage sites. The system boundary for the CCS analysis is illustrated in Figure 4-26. The offshore CO_2 storage sites have been grouped into four regions, as shown in Figure 4-27, and average lifetime cost of CO_2 storage (£/tCO_2) calculated for each of these based on previous Element Energy analysis for BEIS[22].

Figure 4-26: Carbon capture and storage (CCS) system boundary for costing



[22] Element Energy for BEIS, *Hydrogen for heat* (2017)

Figure 4-27: Shoreline terminals and offshore CO_2 storage regions



Distribution

The existing gas distribution network is assumed to be repurposed to deliver hydrogen. This includes measures to replace pipelines that are not suitable for hydrogen such as iron-based pipes. However, it is assumed that most of these will be replaced through the Iron Mains Replacement Programme (IMRP), and hence the cost is not included here. Additional costs of replacing ancillary equipment such as district governors, isolation valves and other low integrity components, as well as installing new hydrogen compliant gas meters, are included.

Heating technologies

New hydrogen boilers (assumed to quickly reach cost parity with a gas condensing boiler) are assumed to be needed for domestic and non-domestic heating demand provision. This equipment is included within the model.

In summary, the full breakdown of cost elements included in the hydrogen scenario is as follows:

1. SMR (capex, opex and fuel consumption)
2. CO_2 capture (capex, opex)
3. Transmission pipeline (capex, opex)
4. Hydrogen storage (capex, opex)
5. CO_2 onshore pipeline (capex, opex)
6. CO_2 offshore pipeline (capex, opex)
7. CO_2 offshore storage (levelised lifetime cost)
8. Distribution pipeline repurpose (capex)
9. Hydrogen boiler (capex, opex)

A detailed breakdown of all cost components can be found in the Annex in Section 6.3.

Case A: Hydrogen production by SMR only

The scenarios presented in this analysis are described in Table 4-21, and are selected to illustrate the impact of implementing a progressively more extensive hydrogen grid serving the six tiers defined.

Table 4-21: Scenarios presented for Hydrogen heating

Scenario	Description	Energy efficiency
Tier 1	All on-gas buildings in Tier 1 counties using hydrogen heating	Medium cost energy efficiency measures applied
Tier 2	All on-gas buildings in Tier 1-2 counties using hydrogen heating	
Tier 3	All on-gas buildings in Tier 1-3 counties using hydrogen heating	
Tier 4	All on-gas buildings in Tier 1-4 counties using hydrogen heating	
Tier 5	All on-gas buildings in Tier 1-5 counties using hydrogen heating	
Tier 6	All on-gas buildings in Tier 1-6 counties using hydrogen heating	

The cumulative additional system cost to 2050 of each scenario relative to the Status Quo scenario, and the associated level of CO_2 emissions in 2050, are shown in Figure 4-28.

Figure 4-28: Cumulative additional system cost and CO_2 emissions in 2050 – Hydrogen heating

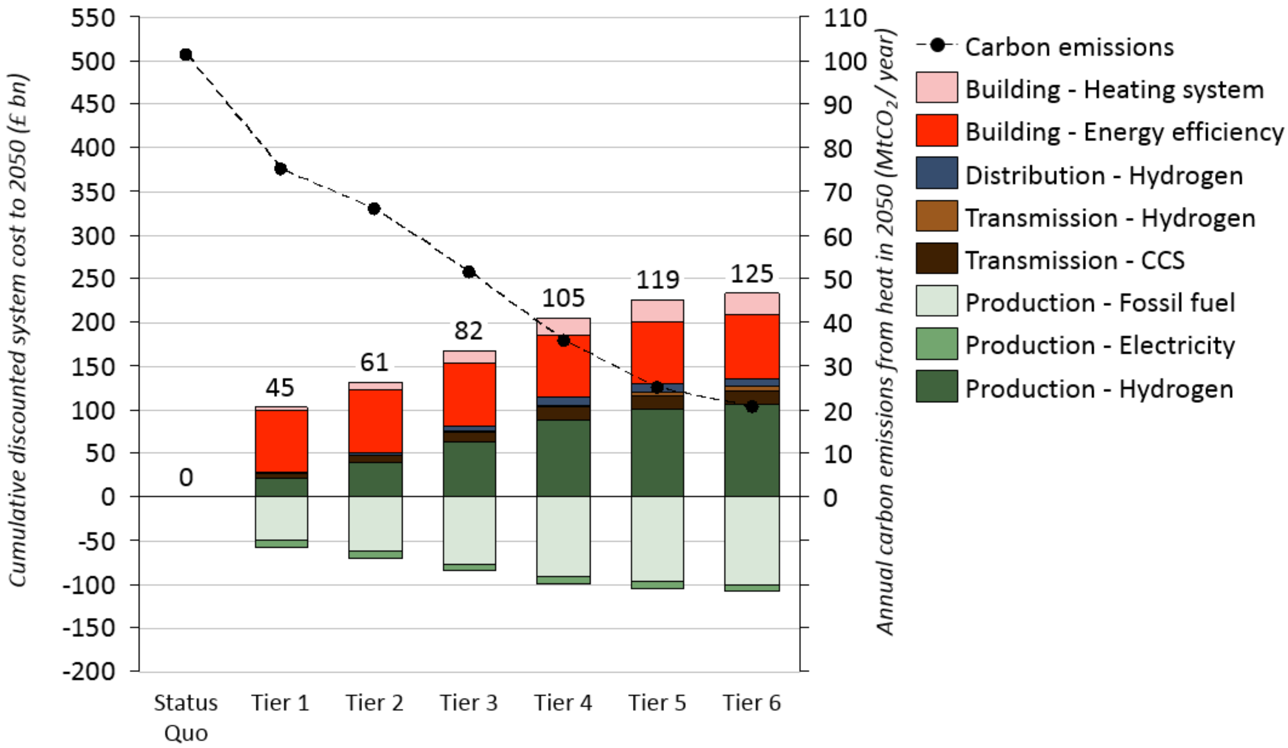


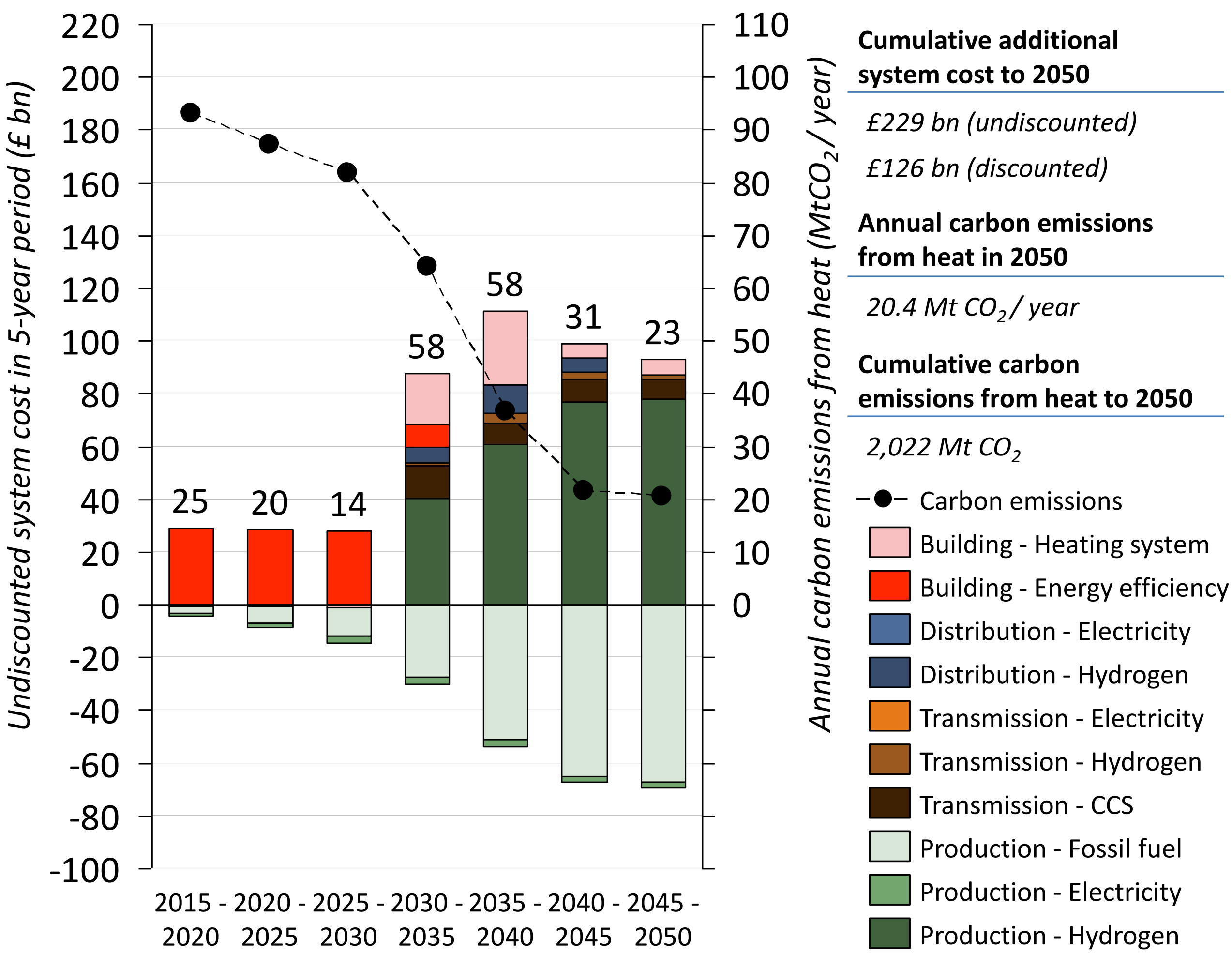
Table 4-22 and Figure 4-29 show the costs and emissions in the Tier 6 scenario on a five-yearly basis. Since the hydrogen gas grid is rolled out between 2030 and 2045 in this scenario, a large proportion of the additional costs (£154bn, or 67% of the total undiscounted cost) falls within this period. Beyond 2045, the additional costscost are comprised principally of the additional hydrogen fuel cost (£8bn undiscounted), the ongoing cost of CCS (£8 bn undiscounted), hydrogen transmission operational costs (£1bn) and additional costs of heating system replacement (£6 bn).

Since the rollout of the hydrogen grid occurs later than the rollout of heat pumps and direct electric heating in the electrification scenario, and since the transition to hydrogen heating is limited to on-gas buildings, the cumulative emissions to 2050 are higher than in those scenarios. In the heat pump based electrification scenarios, for example, cumulative CO_2 emissions to 2050 are 1,400 $MtCO_2$ (or 40% of the Status Quo). In the Tier 6 hydrogen scenario, the cumulative CO_2 emissions to 2050 are over 2,200 $MtCO_2$ (or 64% of the Status Quo).

Table 4-22: Additional system cost and annual carbon emissions to 2050 in the Hydrogen gas grid Tier 6 Scenario

Five-year period	2016 - 2020	2021 - 2025	2026 - 2030	2031 - 2035	2036 - 2040	2041 - 2045	2046 - 2050	*2016 - 2050*
Additional system cost *£bn (undiscounted)*	25	20	14	58	58	31	23	*229*
Additional system cost *£bn (discounted)*	23	15	9	32	27	12	8	*126*
Annual carbon emissions from heat *Mt CO_2 / year*	93	87	82	64	37	22	20	*2,022*

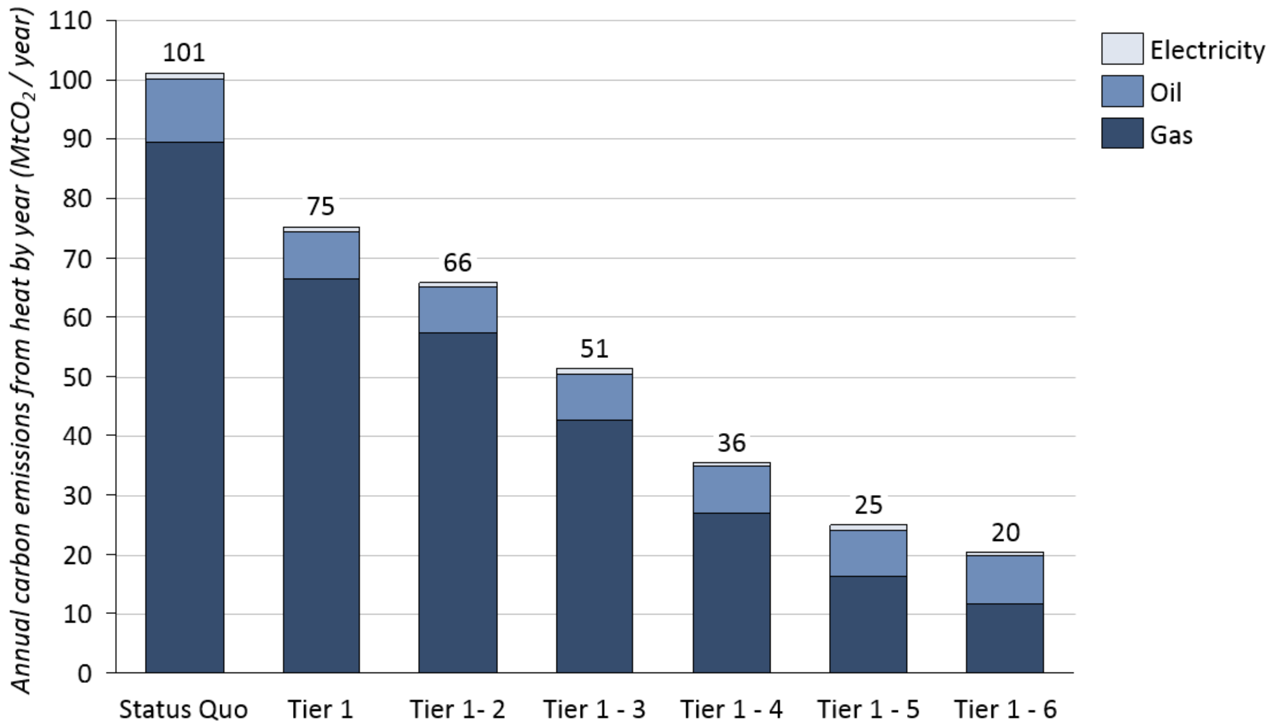
Figure 4-29: Five year undiscounted additional system cost to 2050 in the Hydrogen gas grid Tier 6 scenario



As shown in Figure 4-30, the hydrogen heating scenarios do nonetheless achieve substantial reductions in carbon emissions by 2050, with the maximum deployment (Tier 1-6) achieving a level of 20 $MtCO_2$ / yr by 2050. This is limited by two factors: first, that the rollout is only able to reach on-gas buildings, with the off-gas buildings (around 15% of the domestic building stock) assumed to remain on the counterfactual electricity and oil heating systems; second, that the CO_2 capture rate in the hydrogen production process is assumed in the Central case to be 90%.

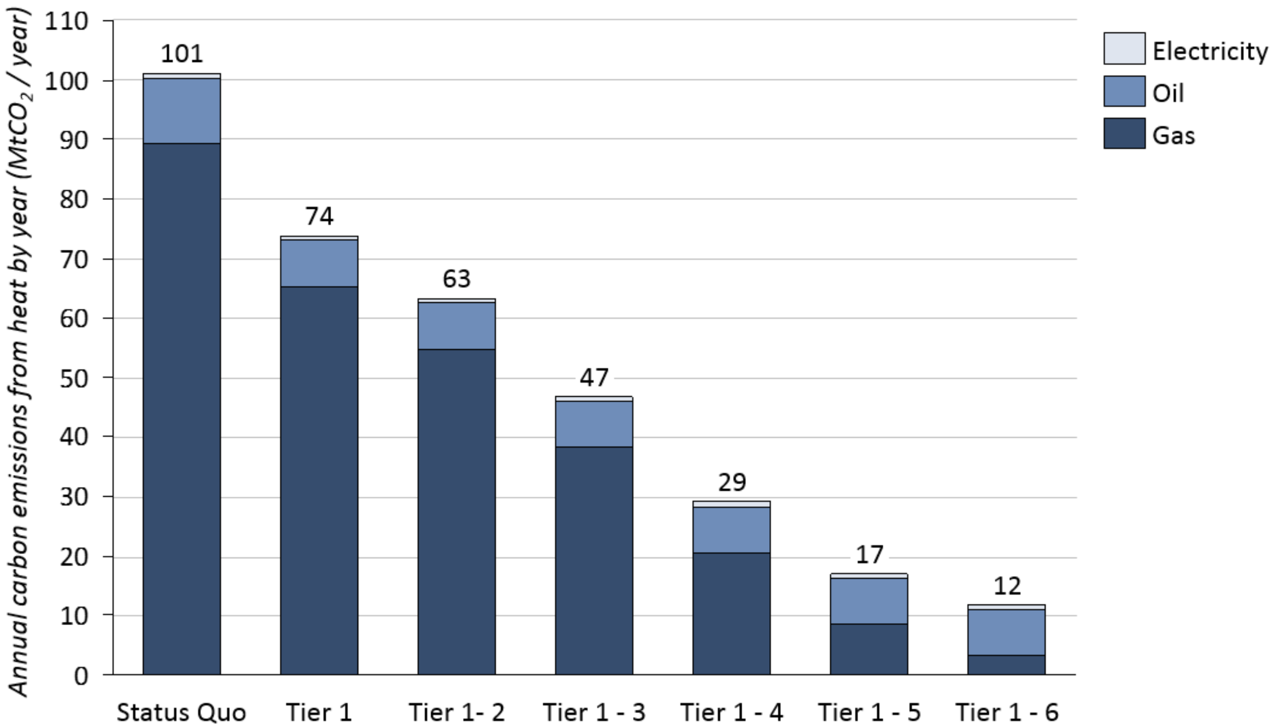
A higher capture rate could potentially be feasible, allowing a deeper level of decarbonisation. Some analysts have argued that next generation capture technologies deployed alongside SMR could reach capture rates nearing 100%[23]. However, since many of these technologies are at an early stage of development, there is considerable uncertainty over their cost. Figure 4-31 shows the impact on CO_2 emissions if a 100% capture rate could be achieved. In the most highest decarbonisation scenario, annual carbon emissions of 12 $MtCO_2$ / yr can be achieved, with the majority of residual emissions arising from oil-fuelled heating in off-gas buildings, with small contributions from electrically-heated off-gas buildings and a small number of on-gas buildings in Northern Ireland, where the gas grid is assumed here not to have been converted to hydrogen.

Figure 4-30: CO_2 emissions by fuel for each hydrogen gas grid scenario assuming a 90% capture rate



[23] *Hydrogen for heat technical evidence and modelling project,* (2017), a report by Element Energy, Jacobs and BGS for BEIS)

Figure 4-31: CO_2 emissions by fuel for each hydrogen gas grid scenario assuming a 100% capture rate



The maximum deployment of hydrogen heating across Tiers 1-6 entails a cumulative additional discounted system cost to 2050, in the Central cost estimate, of £125 bn versus the Status Quo scenario. The main contribution to the additional cost is the cost of hydrogen production and associated cost of carbon capture and storage. The transition of all on-gas buildings away from gas heating, including the impact of the Medium cost energy efficiency measures, results in (non-net) gas production savings of £100 bn to 2050. The production of hydrogen to meet the demand of all on-gas buildings reaches nearly £105 bn to 2050. It is important to note that this includes the benefit of energy efficiency savings – the increased fuel production cost in the hydrogen heating case versus the Status Quo can therefore be seen approximately to 'cancel out' the efficiency savings[24]. The additional cost of fuel production relates to the lower efficiency of conversion of gas to heat in the hydrogen scenario relative to gas boiler heating. Most importantly, the SMR conversion efficiency is assumed to be 85%, leading to a nearly 20% higher demand for gas in the hydrogen case (446 TWh / year in 2050 in the Tier 6 case compared to 380 TWh / year in the Status Quo + Medium Cost EE scenario). Overall, the result is a net increase in fuel production costs versus the Status Quo of £5 bn. A further £39 bn of additional cost is incurred to 2050 associated with CCS, which could be considered as part of the overall hydrogen production cost.

The repurposing of the gas distribution grid to carry hydrogen is estimated, in the Central case, to bring an additional discounted cost of £10 bn (an additional cost of £22 bn on an undiscounted basis), and the new hydrogen transmission network is estimated to entail an additional discounted cost of £4 bn (£5 bn on an undiscounted basis).

In contrast to the electrification scenarios, however, the building level costs are not significantly increased relative to those in the Status Quo scenario. This is because it is assumed in the Central case that, once produced at scale, hydrogen boilers can be installed for the same cost as a gas boiler (approximately £2,000 for a typical domestic building). Nonetheless, an additional cost increase of £26 bn associated heating systems

[24] The cost of the hydrogen scenario in the absence of energy efficiency is studied later in Section 4.8.

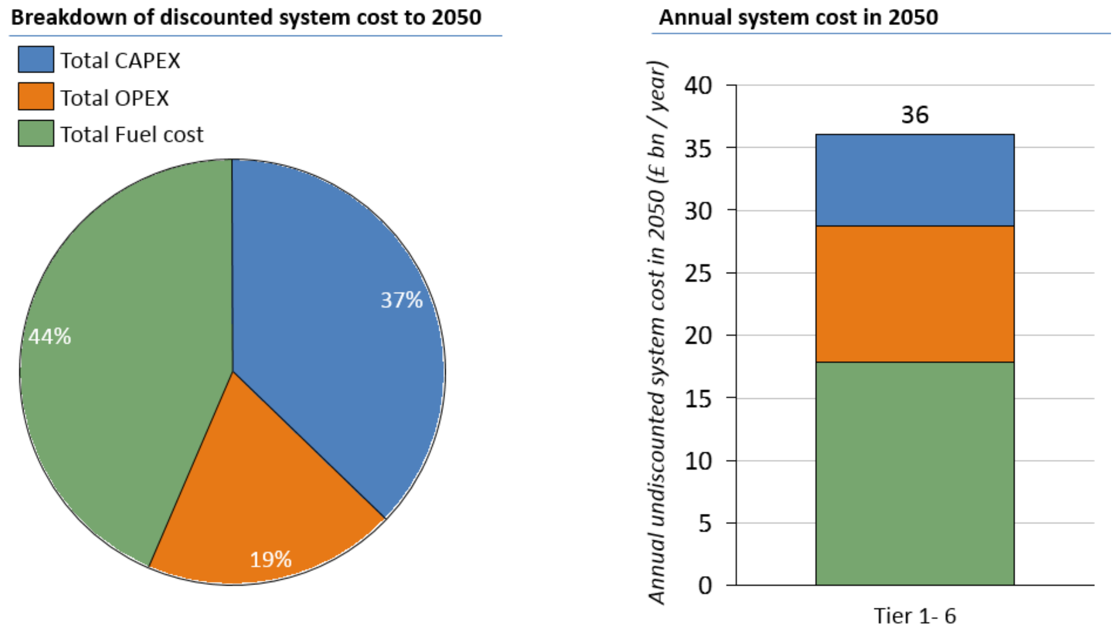
can be seen in the most extensive scenario, since a regional rollout of hydrogen is likely to lead to early replacement of many systems.

The absence of a large additional building-level cost in the hydrogen scenarios means that the additional system cost of these scenarios to 2050 is found to be significantly lower than for the electrification scenarios reaching a similar level of decarbonisation. For comparison, the heat pump deployment case applying Low cost energy efficiency measures achieves a level of 25 $MtCO_2$ / yr for a cumulative discounted cost of £163 bn, compared with the maximum hydrogen deployment case, which achieves a level of 20 $MtCO_2$ / yr for a cost of £125 bn.

A breakdown of the total discounted system cost of the maximum hydrogen deployment scenario to 2050 is shown in Figure 4-32, along with the total annual system cost from 2050. This indicates that the largest component of heating related costs to 2050 is the cost of fuel (44%), owing to the increased gas consumption under this scenario. Capital costs, including the cost of the hydrogen production and distribution infrastructure, as well as carbon capture and storage infrastructure, also make up a significant share (37%). The remaining 19% of the cost relates to operating costs (maintenance cost of the plant).

The annual system cost in 2050 is found to be £36 bn, slightly lower than for the electrification and hybrid gas-electric options. This is dominated by fuel costs, found here to be £18 bn per year, with operating costs contributing £11 bn per year, and the capital cost of replacement of heating systems and infrastructure amounting to £8 bn per year. Fuel costs are again the dominant component due to the additional gas consumption associated with the hydrogen conversion process versus direct combustion of gas. The relatively low contribution of capital costs to the ongoing annual cost from 2050, compared to the cumulative costs to 2050, arises because by the end of a transition to a hydrogen grid, the major capital costs (pipeline costs, SMR plants etc.) have been incurred and these only need to be replaced after a long lifespan. On a per-building basis, the ongoing annual total system cost from 2050 amounts to £970 / building / yr, representing an increase of £130 / building / yr compared to the Status Quo scenario.

Figure 4-32: Breakdown of discounted system costs to 2050 and annual system costs in 2050 – Hydrogen grid



There is substantial uncertainty over the cost of the hydrogen heating option, as presented in Figure 4-33, associated with all aspects of the hydrogen heating supply chain. In the Best case, the potential reduction in cost is mainly associated with a lower cost of hydrogen production and CCS. In the Worst case, a large share of the higher potential cost is associated with a higher in-building cost. In the Worst case shown, this cost is associated with the replacement of other gas-fuelled appliances such as cookers and hobs in each domestic dwelling (estimated to be £1,200 per dwelling).

However, there are wider uncertainties around the feasibility of delivering hydrogen safely within the home. Since these uncertainties are difficult to quantify in cost terms, these are considered here as 'stop-go' uncertainties – this reflects a possible outcome that the costs of ensuring safe delivery of hydrogen in the home are prohibitively high, resulting in the hydrogen option simply not being viable. This is indicated on the chart with a red dotted arrow and associated annotation.

In the maximum hydrogen deployment case, incorporating all costed uncertainties, the cumulative additional discounted system cost versus the Status Quo ranges from £113 bn to £158 bn.

Figure 4-33: Uncertainty in cumulative additional system cost to 2050 – Hydrogen heating

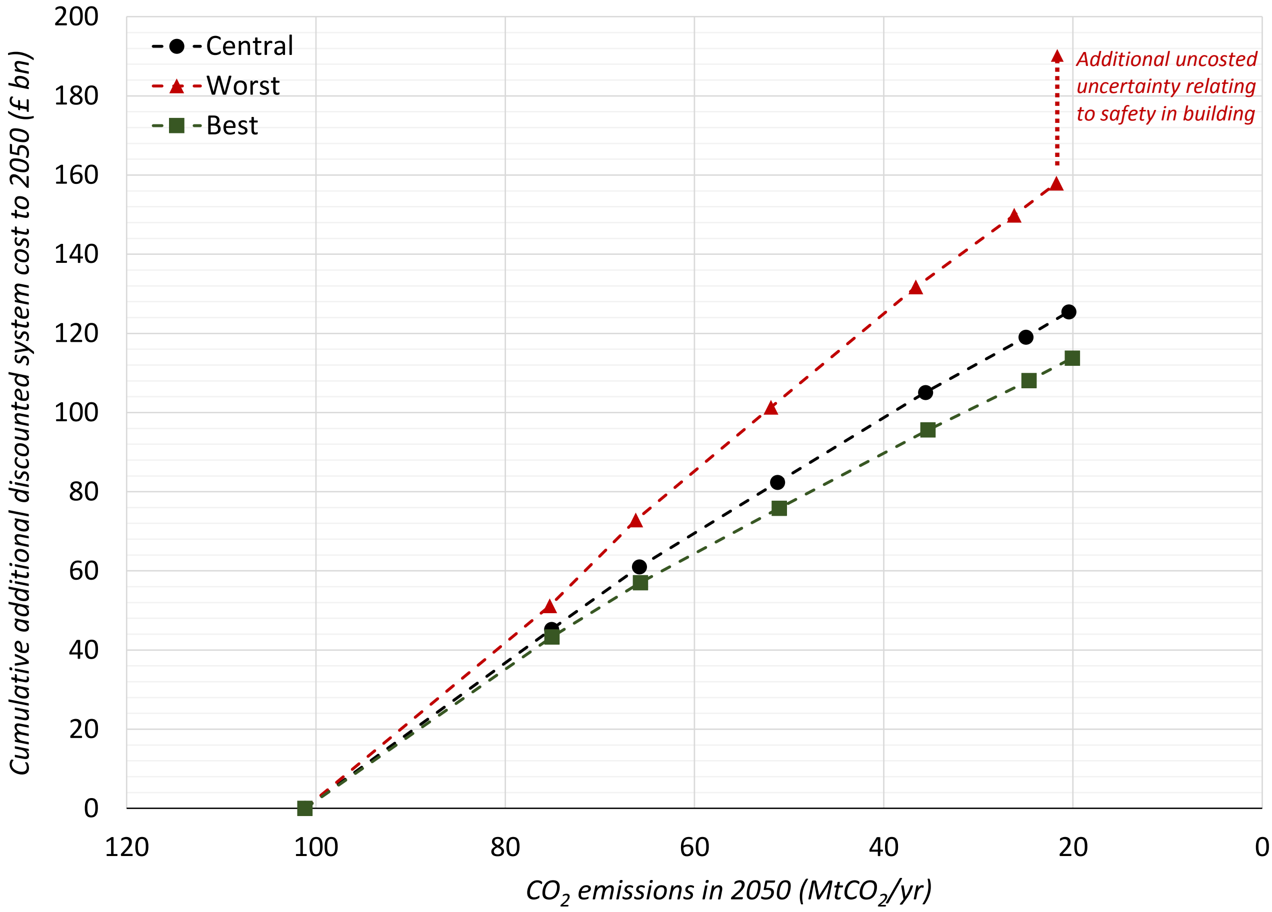


Figure 4-34 presents the sensitivity of the system cost in the Tier 1-6 hydrogen deployment scenario to technology cost and performance, and to the fuel production cost. Under the technology cost and performance scenario, the most significant factor is the additional building-level cost of installing additional hydrogen-compatible appliances (contributing £15 bn in the Worst case scenario to the additional discounted costs). Another significant uncertainty relates to the hydrogen generation costs. In the Central case scenario, the SMR is assumed to convert natural gas to hydrogen at an efficiency of 85%. The Worst case assumes an efficiency of 74% and results in an additional discounted cost contribution of £13 bn. Conversely, the Best case, which assumes an efficiency of 90%, results in a reduction in hydrogen generation cost of £4 bn.

The fuel production cost sensitivity suggests a strong dependence of the overall system cost in the hydrogen scenario to the gas production cost. This is due to the large increase in gas consumption in the hydrogen scenario versus the Status Quo, due to the conversion losses in the SMR process.

Figure 4-34: Sensitivity to technology cost and performance and fuel costs – Hydrogen grid

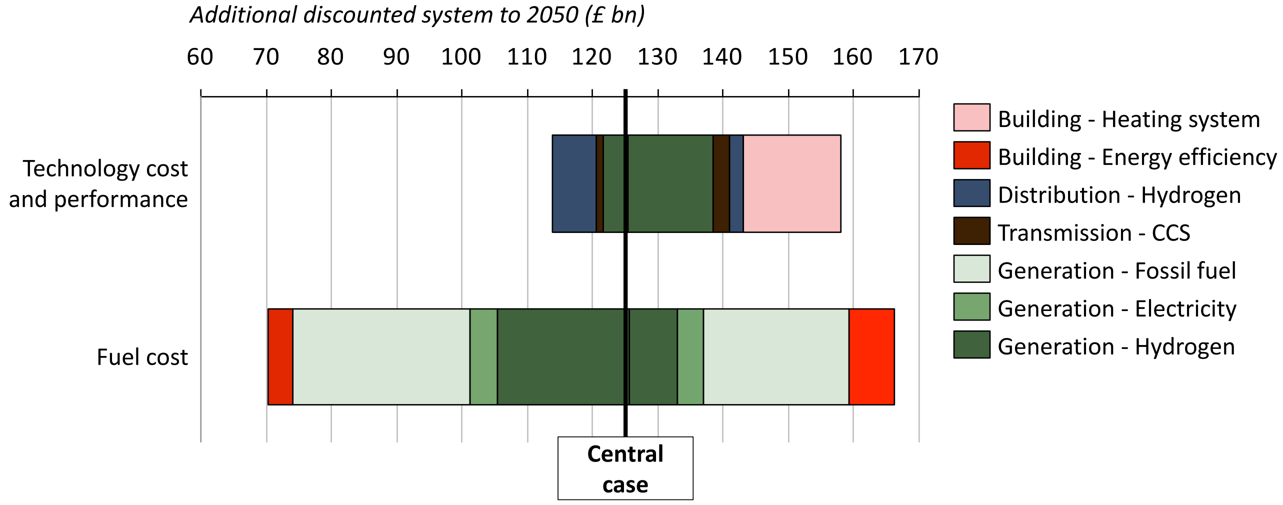


Table 4-23: Summary of technology cost and performance and fuel prices sensitivity – Hydrogen grid

Parameter	Sensitivity	Best	Central	Worst
Additional discounted system cost to 2050 *£ bn*	Technology cost and performance	114	125	158
	Fuel prices	70	125	166
2050 carbon emissions *Mt CO_2 / yr*	Technology cost and performance	20	20	22
	Fuel prices	20	20	20

It is worth highlighting again, as described above, that there is also a ‘stop-go’ uncertainty associated with the hydrogen for heating option, in relation to the safely delivering hydrogen within the home, and the consumer acceptability of the option. The range of costs of the pathway shown here should be considered to represent a case in which these barriers have been addressed successfully.

Case B: Hydrogen production by SMR and biomass gasification

In Case A, the potential of repurposing the existing natural gas network to carry low carbon hydrogen in order to reduce the UK’s CO_2 emissions was considered. The use of hydrogen production using biomass gasification in conjunction with CCS could result in further decarbonisation. This is due to the potential of such a technology to remove carbon from the atmosphere over time. Since the carbon absorbed from the atmosphere by the biomass over its lifetime is captured rather than being re-emitted during processing (in this case gasification to produce hydrogen rather than direct combustion), the overall process results in a net reduction in carbon in the atmosphere.

This analysis assumes that by 2050 up to 50 TWh / yr of hydrogen could be produced via biomass gasification. As is the case for biomethane injection potential, there is considerable uncertainty over this estimate. In particular, there may be consumption of the underlying feedstocks for other sectors, and in other countries, reducing this potential in the heat sector.

Figure 4-35: Processed feedstock cost of sustainable biohydrogen potential in 2050

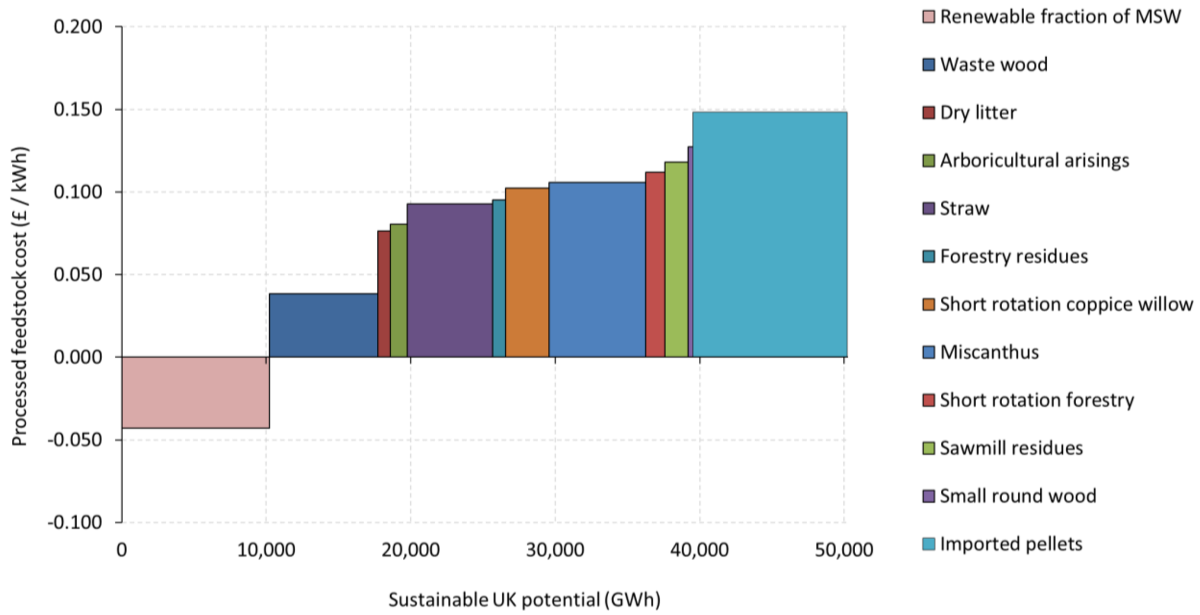


Figure 4-35 presents the processed cost of hydrogen injected into the gas grid depending on the pathway considered. This varies from approximately -5 p/kWh for hydrogen derived from renewable MSW, to around 10 p/kWh for straw- and miscanthus-derived hydrogen, with the most expensive biohydrogen produced from imported pellets at an estimated cost of 15 p/kWh. In addition to the raw feedstock cost and all processing costs, the figures include an additional raw feedstock transportation cost of 2 p/kWh for in-grid transportation of the hydrogen. It is assumed that for each kWh (LHV) of hydrogen produced, 446 gCO_2e could be captured.

Figure 4-36: Cumulative additional system cost and CO_2 emissions in 2050 – Hydrogen heating with SMR and biomass gasification

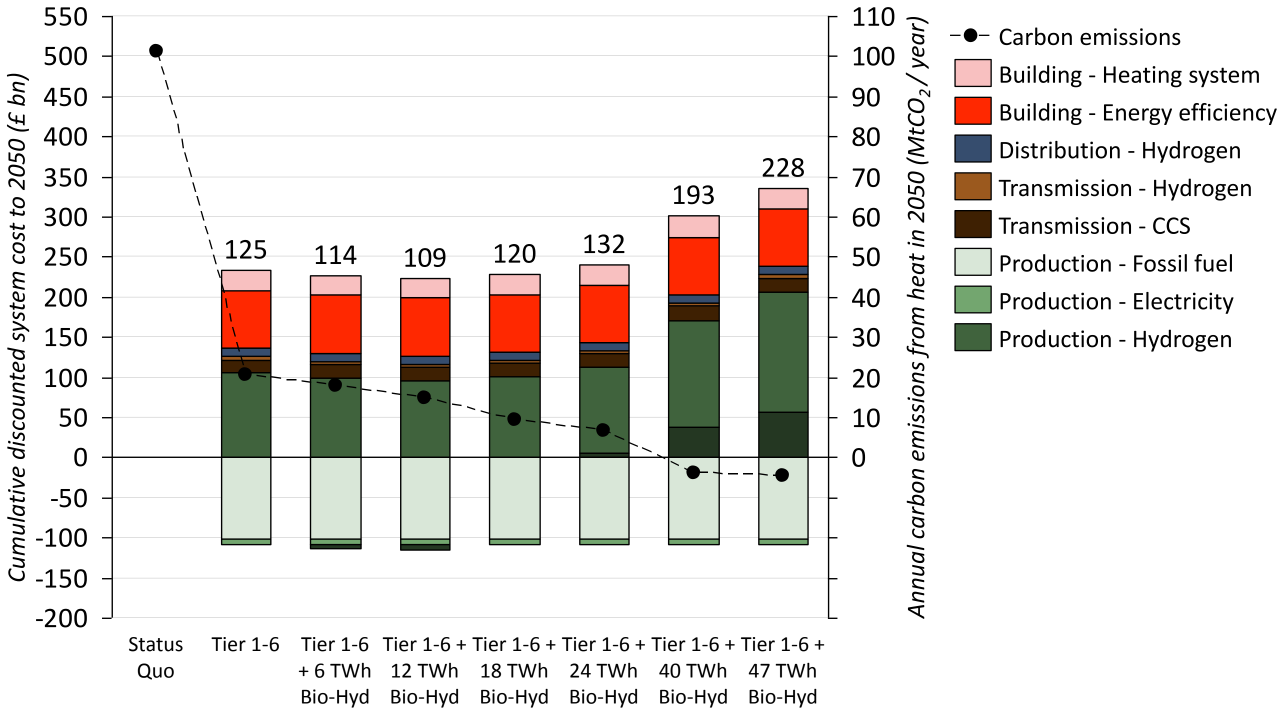


Figure 4-36 presents the cumulative discounted additional system cost to 2050 under varying levels of hydrogen production via biomass gasification with CCS. In each case, it is assumed that hydrogen has been rolled out across all 6 tiers, and the remaining hydrogen requirement not met by biomass gasification is met by SMR + CCS (SMR remains the dominant production method by a large margin in all cases). As in the case of biomethane injection, it should be noted that under the assumptions made here, the above figures represent an upper bound on the potential for biohydrogen to lower the carbon emissions of space heating and hot water, as the underlying biomass feedstocks are likely to be applicable in other sectors (e.g. power generation, industrial processes).

This suggests that, due to the capture of additional carbon, up to 24 $MtCO_2$ / yr of carbon emissions reductions could be achieved – which would lead to negative net emissions from the heat sector. Alternatively, for a lower level of biohydrogen production (i.e. corresponding to the lowest cost feedstocks only), this can even lead to a net reduction in costs. For example, for injection of 18 TWh of biohydrogen, using the lowest cost resources available, a net reduction of £5 bn in the cumulative discounted system cost is achieved. Further reductions in carbon emissions using more costly feedstocks, however, lead to significantly higher overall costs. For example, to achieve reductions of 24 $MtCO_2$ / yr and negative net heating sector emissions of -5 $MtCO_2$ / yr through the injection of 47 TWh / yr of biohydrogen (nearly the full potential according to Figure 4-35), the resulting increase in cumulative discounted system cost is £103 bn compared to the Tier 1-6 hydrogen scenario with no biohydrogen production.

Box 5 – Hydrogen heating: Key findings

- In a hydrogen heating pathway, the majority of the UK's heat demand would continue to be met through the existing gas grid, but this would be repurposed to deliver hydrogen produced from low carbon sources.
- The potential advantages of this option would be that the value of the existing gas infrastructure would be maximised, the need for additional electricity network and generation capacity could be minimised, and little change in consumer behaviour would be required.
- This analysis finds that hydrogen heating rollout across the country over the period 2030-2050, with production of hydrogen through SMR with 90% capture of CO_2 emissions, could achieve a nearly 80% reduction in carbon emissions from heating to 20-22 $MtCO_2$ / yr.
- The discounted cumulative additional system cost to 2050 versus the Status Quo for that scenario has been estimated in the range £114 bn to £158 bn, with a Central case estimate of £125 bn.
- The additional cost is associated predominantly with an increase in the cost of producing the heating fuel (a discounted increase of £50 bn), the cost of CCS (£17 bn) and the investment required to repurpose the gas distribution network (£10 bn) and construct a new hydrogen transmission grid (£4 bn).
- Around half of the remaining emissions in that scenario would be associated with the off-gas building stock, for which the hydrogen options is not applicable, and an alternative solution would be required to achieve further decarbonisation.
- There remains, however, significant uncertainty around the cost and practicality of this option, particularly in terms of consumer acceptability and the cost of safely distributing hydrogen to end-users and the readiness and cost of CSS. These are considered here as 'stop-go' uncertainties rather than uncertainties than can be captured through cost ranges.
- In order to achieve further reductions in carbon emissions – potentially even negative net emissions from the heat sector – the production of hydrogen from bioenergy resources, in conjunction wiith CCS could be employed.
- This analysis finds that the production of 47 TWh / yr of biohydrogen, combined with CCS, could lead to a further reduction of 24 $MtCO_2$ / yr by 2050, and therefore net negative emissions from the heat sector of -5 $MtCO_2$ / yr. This should be viewed as an upper limit, as various other sectors are likely to compete for the underlying feedstocks required to produce the biohydrogen.

4.6 Role of heat networks

Heat networks distribute heat in the form of hot water or steam (and sometimes cooling in the form of cool water) from one or more large-scale, centralised sources through a network of pipes, to serve multiple end-users. Heat networks can refer to such systems limited to a single apartment block, but can also be city-wide systems serving thousands of customers. A potential advantage of heat networks over individual building-level heating systems is the ability to benefit from economies of scale and the diversity of heat demand across multiple end-users to bring cost savings for the heat generation plant. Furthermore, heat networks provide the opportunity to make use of multiple sources of low carbon heat that would otherwise not be possible, including waste heat from industry and power stations, and environmental sources of heat including water sources. Where these sources of heat are not high enough in temperature to serve the heat demand directly, they can be supplied to a water-source heat pump to raise the temperature with high efficiency.

A key limit to the applicability of heat networks is that they are typically only cost-effective in areas of high heat demand density. This is due to the high capital cost of the heat distribution infrastructure (pipes), requiring sufficient revenue from the sale of heat per unit length of heat network to justify the capital outlay. As such, large-scale heat networks are typically only suitable in dense urban areas.

Prior work by Element Energy for the Committee on Climate Change[25] has studied the potential for heat networks to contribute to heat decarbonisation in the UK, and developed several scenarios for heat network deployment. The Barriers and Central scenarios studied in that work found that heat networks could provide between 39 TWh and 80 TWh of heat demand by 2050, leading to CO_2 emissions savings of 7 to 15 $MtCO_2$ / yr relative to a gas heating counterfactual. In the Central scenario, this included the use of 11 TWh of waste heat from industry and power stations, and a further 4 TWh from Energy-from-Waste plants, with more than half of the heat demand provided in 2050 supplied by water-source heat pumps. The data collected and analysis undertaken in that study were applied in the current work.

Given the importance of heat density in determining the cost-effectiveness of heat networks, a segmentation of the UK heat demand by heat density was developed. Using BEIS's Sub-national gas and electricity consumption datasets[26], an MSOA-level energy demand map of the UK was constructed, and the overall energy demand calibrated to the national space heating and hot water demand according to BEIS's *Energy Consumption in the UK* data[27]. This map was used to define ten heat density 'bands', as shown in Table 4-24. The number of MSOAs and amount of heat demand associated with each band is shown in the same figure. It can be seen that the three most heat dense bands account for 11 TWh of heat demand (3% of the total), the most dense five bands 42 TWh of heat demand (10%), and so on.

[25] Element Energy and Frontier Economics for the Committee on Climate Change, *District heating and localised approaches to heat decarbonisation* (2015)
[26] https://www.gov.uk/government/collections/sub-national-gas-consumption-data (Accessed November 2017)
[27] https://www.gov.uk/government/collections/energy-consumption-in-the-uk (Accessed November 2017)

Table 4-24: Heat density band ranges and total heat demand and number of MSOAs in each band

Band	Heat density range (kWh/m^2)	Heat demand in band (TWh)	Cumulative heat demand (TWh)	Number of MSOAs in band	Cumulative number of MSOAs
1	150+	5	5	15	15
2	125 – 150	2	7	14	29
3	100 – 125	4	11	19	48
4	75 – 100	9	20	88	136
5	50 – 75	22	42	290	426
6	40 – 50	20	61	274	700
7	30 – 40	41	103	564	1,264
8	20 – 30	84	187	1,613	2,877
9	10 – 20	92	279	2,362	5,239
10	0 – 10	146	425	3,588	8,827
Total			***425***		***8,827***

As part of the prior project for the CCC, Element Energy developed a spatial map of the largest sources of waste heat from industry and power in the UK, and the typical distance that would be required to connect these sources to regions of high heat demand. There is considerable uncertainty around the applicability of this analysis for the period to 2050, as the amount of heavy industry and thermal power generation could change substantially over that time – but also because any new sources of waste heat arising could be located strategically in proximity to regions of high heat demand to enable their usage. Nonetheless, this analysis gives an indicative view of the potential for waste heat to serve heat networks.

This analysis determines the availability of waste heat as a function of distance for each heat density band. For example, the analysis finds that more than 11 TWh of waste heat is located within 15 km of MSOAs heat density bands 1-6.

Table 4-25: Waste heat sources within 15 km of at least one MSOA withinin groups of progressively less dense heat density bands

Bands	Minimum heat density included (kWh/m^2)	Supply of Waste Heat Potential within 15 km of MSOAs in heat density bands (TWh / yr)
1-3	100	2.4
1-4	75	4.2
1-5	50	7.0
1-6	40	11

A further 4 TWh of waste heat from Energy-from-Waste facilities is assumed; in this case, it is deemed likely that the facilities could be sited strategically to allow effective use of the heat in heat networks.

The same study used data from BEIS Water-source Heat Map[28] to develop an estimate of the potentially useful water-source heat. That analysis found that up to 232 TWh of water-source heat is located within 1 km of urban areas, and that 73 TWh of this potential is coincident with heat demand and hence could be considered useful.

The scenarios presented in this analysis are described in Table 4-26. The scenarios have been chosen to demonstrate the impact of heat networks in two different counterfactuals: first, the gas heating counterfactual; second, the hydrogen heating counterfactual. This is to test whether heat networks offer carbon emissions reduction potential in both cases.

[28] https://www.gov.uk/government/publications/water-source-heat-map-layer (Accessed November 2017)

Table 4-26: Scenarios presented for Heat networks

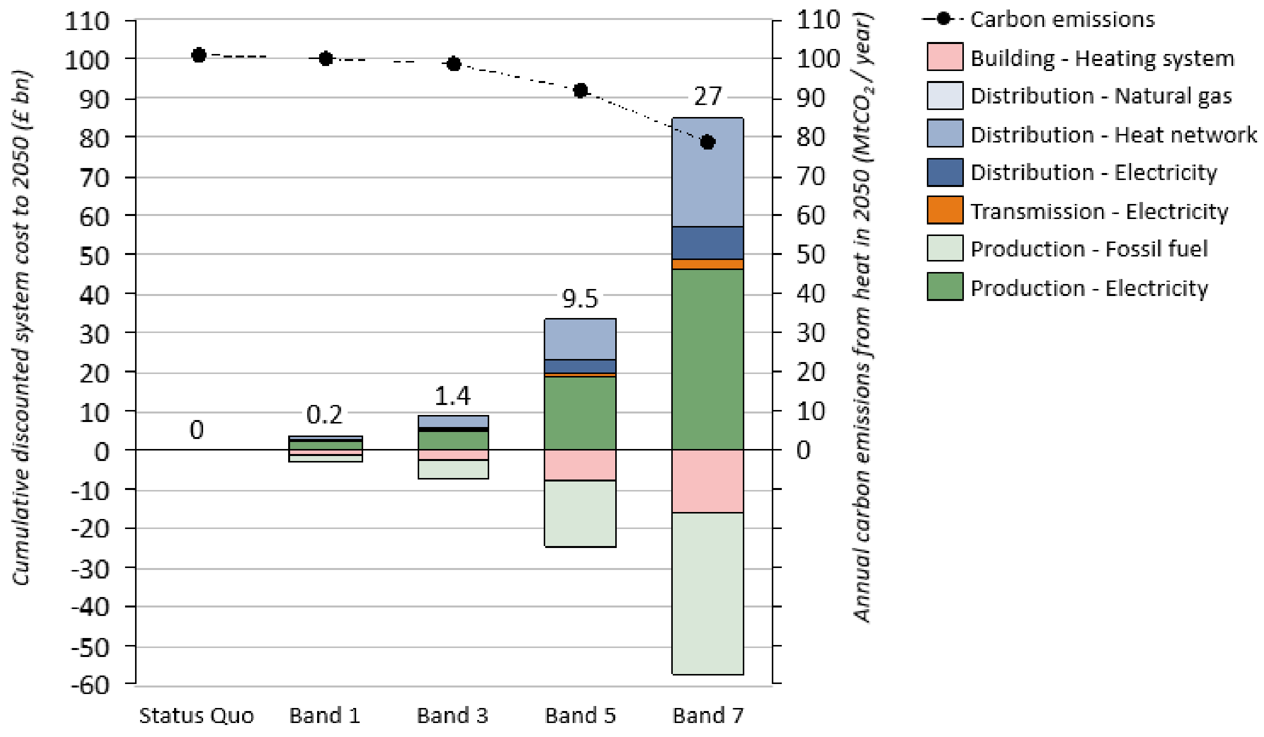
Scenario category	Scenario	Description	Heat source
Gas heating + Heat networks (No EE applied in all cases)	Band 1	100% of buildings in Band 1 MSOAs connected to heat networks	Heat network served by the waste heat potential available to the relevant bands, and the remainder using water-source heat pumps
	Band 3	100% of buildings in Bands 1-3 MSOAs connected to heat networks	
	Band 5	100% of buildings in Bands 1-5 MSOAs connected to heat networks	
	Band 7	100% of buildings in Bands 1-7 MSOAs connected to heat networks	
Hydrogen heating + Heat networks (Hydrogen Tier 1-6 rollout, Medium cost EE applied in all cases)	Band 1	100% of buildings in Band 1 MSOAs connected to heat networks	
	Band 3	100% of buildings in Bands 1-3 MSOAs connected to heat networks	
	Band 5	100% of buildings in Bands 1-5 MSOAs connected to heat networks	
	Band 7	100% of buildings in Bands 1-7 MSOAs connected to heat networks	

The cumulative additional system cost to 2050 relative to the Status Quo scenario, and the associated level of CO_2 emissions in 2050, are shown for the Gas heating + Heat networks scenarios in Figure 4-37. The figure shows that, in the case of heat network rollout across Bands 1-7, carbon emissions savings of 23 $MtCO_2$ / yr are achieved, due to the shift in heating from gas to waste heat and water-source heat pumps.

The cumulative discounted additional system cost of the Heat network scenarios versus the Gas heating + Medium cost EE (no heat network) scenario is positive for all Heat network scenarios studied. In the Band 7 Heat network scenario, the cumulative discounted system cost increases by £27 bn. However, comparison with the other low carbon heating scenarios above suggests that savings of 23 $MtCO_2$ / yr for £27 bn to 2050 is among the most cost-effective options.

In the Band 7 Heat network scenario, an additional discounted cost of £28 bn is incurred associated with the capital cost of the heat distribution network. Savings of £16 bn in building-level costs are achieved. This is due to the lower cost of building-level infrastructure, including heat interface units and heat meters, required in the heat network case, assumed to be £1,500 for the typical domestic building, compared with £2,000 for a gas boiler. The reduced fuel costs associated with mainly gas boiler heating is approximately offset by the increase in electricity fuel cost associated with water-source heat pump heating. A further £10 bn is also found to be required to reinforce the electricity distribution and transmission grid to meet the increase peak demand due to the use of water-source heat pumps to serve the heat networks.

Figure 4-37: Cumulative additional system cost and CO_2 emissions – Gas heating + Heat networks



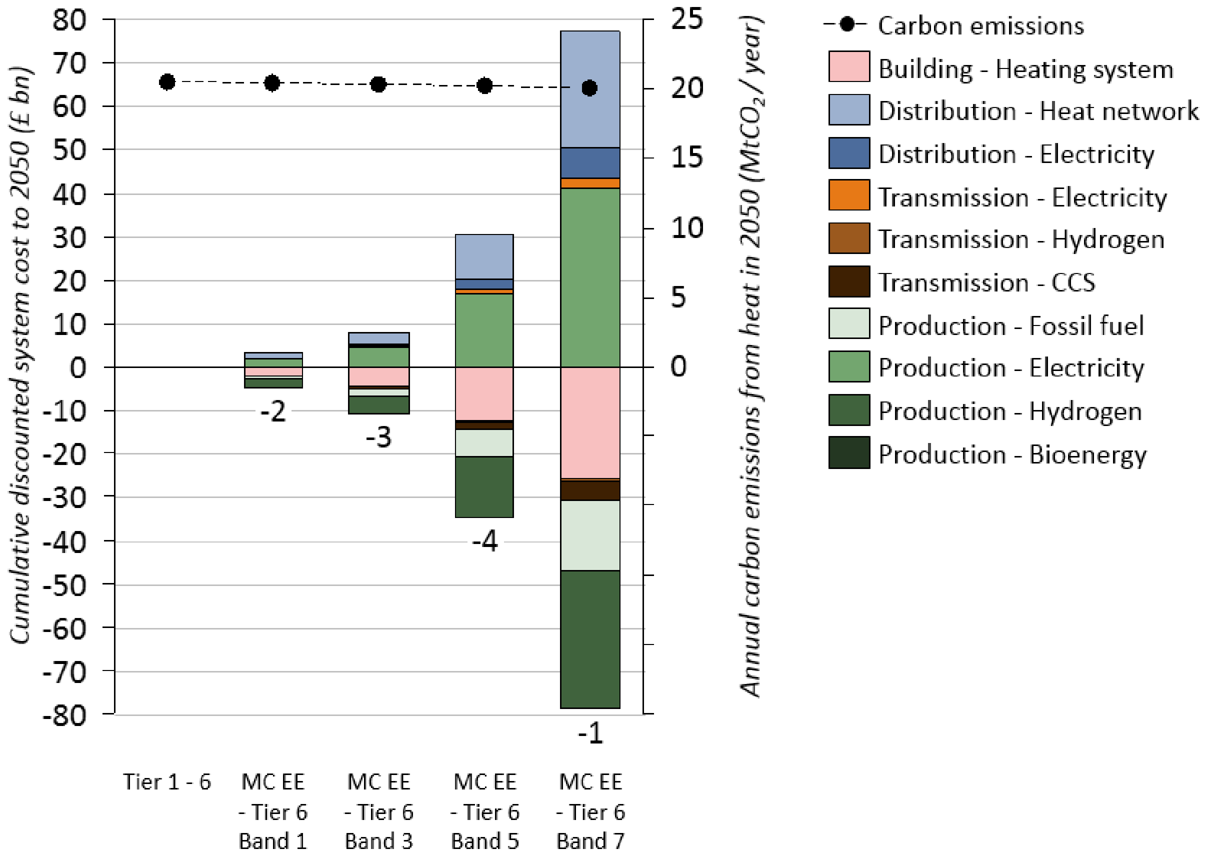
The corresponding results for deployment of Heat networks in the hydrogen Tier 1-6 scenario are shown in Figure 4-38. Carbon emissions in all four heat network scenarios are marginal given the relatively high level of decarbonisation already achieve through the use of hydrogen, but are nonetheless positive in all cases. This indicates that even when hydrogen heating is the dominant counterfactual, the application of heat networks using waste heat and low carbon heat pumps offers an opportunity to decarbonise further (or at least not to increase emissions).

In terms of cost, Figure 4-38 indicates that deployment of heat networks in sufficiently heat dense areas can lead to substantial cost reductions in the hydrogen heating scenario. The cumulative reduction in discounted system cost to 2050 in the Band 5 Heat network scenario amounts to £9 bn. This contrast to the gas heating case is due to two main factors. First, the presence of a more costly counterfactual heating fuel, i.e. hydrogen rather than gas. When the avoided cost of CCS is included, this leads in the Band 5 Heat network scenario to net savings of £4 bn to 2050. Secondly, there is a substantial avoided cost of early replacement of building-level heating systems (as occurs in the hydrogen scenario), since much of the transition to heat networks occurs before hydrogen rollout – this leads to a larger reduction in building-level heating system costs than in the case of heat networks replacing gas heating.

Deployment of heat networks up to Band 7 results in a small overall decrease in cumulative discounted system cost of £1 bn to 2050. This reflects the worse economic case for heat networks in less heat dense areas, as the majority of cost of the heat network infrastructure is no longer offset by the reduction in fuel and building-level costs. In the hydrogen scenario, therefore, this analysis suggests that up to approximately 20-25% of the UK's heat demand (i.e. up to approximately Band 7) could be met using low carbon heat networks with overall cost savings.

Taken together, the analysis above indicates that heat networks served by waste heat and low carbon heat pumps, if deployed in sufficiently dense areas, can be viewed as a low or no regrets measure. When compared against the lowest cost counterfactual of gas heating, deployment of 40-100 TWh of low carbon heat networks is likely to result in relatively inexpensive carbon savings. Compared against a low carbon counterfactual of hydrogen heating, a similar level of deployment of low carbon heat networks is likely to lead to substantial cost savings, whilst maintaining or slightly improving upon the level of decarbonisation.

Figure 4-38: Cumulative additional system cost and CO_2 emissions – Hydrogen heating + Heat networks



Box 6 – Heat networks: Key findings

- Heat networks benefit from economies of scale and the diversity of heat demand across multiple end-users, potentially leading to a more cost-effective heat supply in areas of high heat demand density.
- Importantly, they provide the opportunity to make use of multiple sources of low carbon heat that would otherwise not be possible, including waste heat from industry and power stations, and environmental sources of heat including water sources.
- More than 10 TWh of waste heat from the industry and power sector could be available within 15 km of the regions making up this 40 TWh demand, representing a viable low carbon option. A further 4 TWh of waste heat from Energy-from-Waste facilities could be utilised, if those facilities were located strategically in close proximity to the demand areas.
- Water-source heat pumps could provide much of the remainder of the heat demand for heat networks (our analysis suggests a potential of up to 73 TWh nationally). Biomass heating represents a low carbon alternative, and could also play a role.
- This analysis suggests that 40-100 TWh of heat networks could provide low-cost carbon emission reduction measured against a gas heating counterfactual, and a substantial net reduction in cost measured against a hydrogen heating scenario.
- Within any deep decarbonisation scenario, a similar level of deployment of heat networks is likely to bring cost savings, as they displace more costly counterfactual fuels and/or heating systems.
- This indicates that heat networks served by waste heat and low carbon heat pumps, if deployed in sufficiently dense areas, can be viewed as a low or no regrets measure.

4.7 Role of biomass

A key question is the most appropriate use of the available sustainable bioenergy resource. This issue has been studied in detail by the Committee on Climate Change[29] and others. In broad terms, it is suggested that the optimal use for a majority of the available bioenergy resource would be in combination with CCS in order to achieve negative carbon emissions, to offset hard-to-reduce emissions in other sectors. This would be most appropriate (somewhat dependent upon the type of bioenergy) as part of large facilities providing power and/or heat generation, producing hydrogen or biofuels for aviation and shipping. If CCS is not available, the optimal use of bioenergy would be in sectors where no cost-effective low carbon alternative is available, such as high temperature industrial processes and to produce biofuels for aviation and shipping.

Most relevant for the scope of this study – aside from the potential for biomethane to displace natural gas, or to be used to produce hydrogen in conjunction with CCS as described in earlier sections – is the potential for biomass heating in buildings and to serve heat networks. Biomass heating involves burning woody materials – typically wood pellets, chips or logs, but potentially also other crops such as straw or miscanthus – in a boiler, to serve a central heating system (or heat network) and provide hot water, or to directly heat a room.

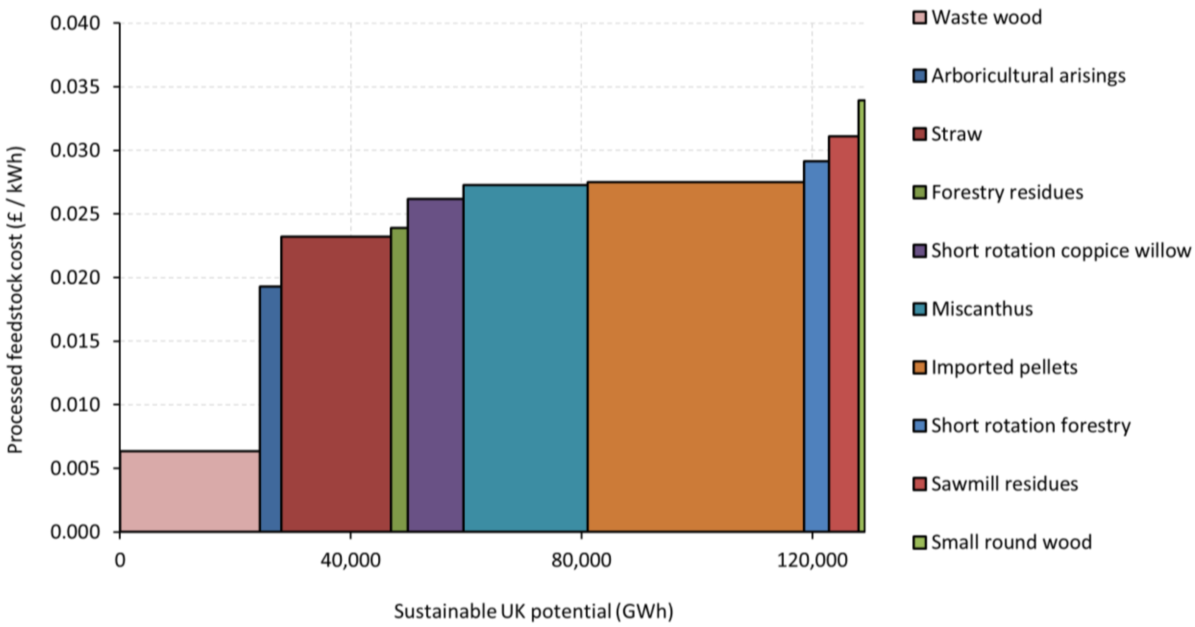
In this section, we study the potential for biomass heating in off-gas domestic buildings, as a potential supporting solution in a scenario with a decarbonised gas grid (such as the hydrogen and hybrid gas-electric scenarios). The biomass heating option may be most relevant for the hard-to-insulate buildings in which full electrification using heat pumps has been shown above to be a more costly option. It is important to note that there are drawbacks of biomass in terms of air quality, as relatively high levels of particulate emissions and nitrogen oxides can result from biomass combustion. This supports the use of biomass limited to rural (as for most off-gas regions) and industrial areas.

The deployment of biomass is ultimately limited by the sustainable UK production (and import) potential of the relevant feedstocks, but as a result of the multiple competing uses described above, there is substantial uncertainty over the available resource for building-level heating using biomass. In order not to overestimate the biomass potential available to the heat sector, in the Central case it is assumed that only 40%[30] of the potential biomass supply is available for space heating and hot water provision, and is applied to the off-gas buildings.

[29] Committee on Climate Change, *Bioenergy Review* (December 2011)

[30] The rationale for this assumption is simply that space heating and hot water heating account for roughly 40% of industrial commercial and domestic final energy consumption – the sensitivity is not intended to represent a judgment on the optimal allocation of biomass potential, which is not within the scope of this study.

Figure 4-39: Processed biomass feedstock cost and sustainable UK potential in 2050 – feedstock suitable for the Domestic sector only



Biomass heating in individual domestic buildings typically uses pelleted biomass, as pellet boilers are easier to control and can operate in a similar way to gas and oil boilers. Figure 4-39 presents a 'resource curve' of the main feedstocks that can be used to produce pelleted biomass, indicating the estimated processed feedstock cost and sustainable UK potential in 2050, as used in this analysis[31]. This data has been provided by E4tech, based on prior work undertaken for BEIS[32], the Energy Technologies Institute[33] and others.

This suggests that over 130 TWh per year of sustainable biomass potential, in the form of biomass pellets, could be available in the UK by 2050. This exceeds the current demand from off-gas buildings in the domestic sector, estimated at 59 TWh. The available potential could also be substantially higher under an assumption of greater biomass imports into the UK.

The resource curve suggests that the majority of the biomass pellet resource (128 TWh) could be available, in 2050, at a delivered feedstock cost of less than 3 p/kWh, with the lowest cost 25 TWh available at less than 1 p/kWh. It can therefore be seen that the average biomass feedstock cost is lower than the gas production cost in 2050 assumed in this analysis, of 3.3 p/kWh.

A single scenario is studied for off-gas biomass heating, in which all off-gas buildings are served by biomass boilers, while all on-gas buildings are served by the hydrogen grid, as shown in Table 4-27.

Table 4-27: Scenario for off-gas biomass heating

Scenario	Description
Hydrogen Tier 6 + Biomass off-gas	All off-gas buildings served by biomass heating, while all on-gas buildings are served by the hydrogen network

[31] Note – a separate resource curve for biomass in chip form, suitable for non-domestic boilers, accounting for a smaller potential also underlies this analysis
[32] E4tech for BEIS, *Bioenergy heat pathways to 2050 and Innovation Needs Assessment for Biomass Heat* (2017)
[33] E4tech and Imperial College for Energy Technologies Institute, *Bioenergy Value Chain Model* (2012)

Figure 4-40: Cumulative additional system cost and CO2 emissions in 2050 – Biomass off-gas

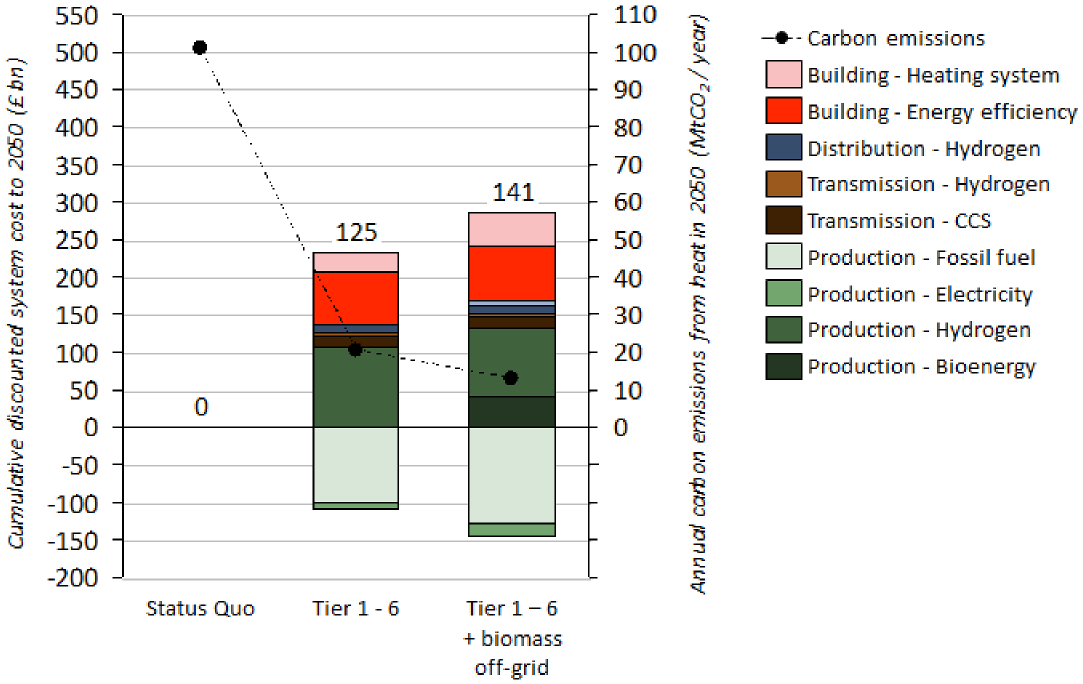


Figure 4-40 shows the cumulative discounted additional system cost to 2050 relative to the Status Quo scenario, and associated level of CO_2 emissions in 2050, of the Hydrogen Tier 6 + Biomass off-gas scenario. The Hydrogen Tier 6 scenario (with counterfactual off-gas heating) is shown for comparison.

The figure shows that applying biomass heating in all off-gas buildings results in additional CO_2 emissions savings of 7 $MtCO_2$ / yr relative to the hydrogen heating scenario with counterfactual off-gas heating, leading to remaining annual emissions in 2050 of 13 $MtCO_2$ / yr. The remaining emissions are associated both with the biomass heating – biomass carbon intensity is low but non-zero, between 2 gCO_2/kWh and 61 gCO_2/kWh depending on the feedstock – and with the 10% of natural gas derived CO_2 emissions not captured in the hydrogen production process.

The cumulative discouted additional system cost to 2050 of installing biomass heating in all off-gas buildings is only £16 bn relative to the hydrogen heating scenario with counterfactual off-gas heating, leading to a total additional discounted cost relative to the Status Quo scenario of £141 bn in the Hydrogen Tier 6 + Biomass off-gas scenario. With the additional of off-grid biomass heating there is a substantially increased building-level heating system cost of £21 bn in discounted terms to 2050. The biomass boiler is considerably more costly than a typical oil boiler counterfactual (for example); in the Central estimate, a typical large off-gas domestic building is assumed to incur a cost of £9,300 for a 15 kW biomass boiler in 2030, including biomass fuel storage, versus £2,000 assumed for an oil boiler. Maintenance costs are also higher in the biomass boiler case, due to the additional need for system cleaning and ash disposal, among other factors. There is, offsetting most of this increase, an overall reduction in fuel production costs of £13 bn in discounted terms, as the £41 bn in biomass fuel cost is more than offset by a cost reduction of £37 bn associated with the oil and electricity demand of the off-gas counterfactual heating systems. This effect is particularly marked given that the off-gas heating fuels, oil and electricity, are substantially more costly than gas. Overall, a smaller increase in discounted system cost to 2050 results. It should be noted once more that this analysis assumes that the off-gas heat sector is able to make use of the lowest cost biomass resources where, in reality, there is likely to be competing demand from other sectors for the same resource. As such, the cost analysis here could be seen as a lower bound.

Given that the most likely off-grid alternative to biomass heating is electrification, a comparison of these technologies in the off-grid context is of interest. This will be included in the following section, where several Mixed decarbonisation scenarios are studied.

Box 7 – Biomass heating in off-gas buildings: Key findings

- The potential for biomass heating to serve off-gas grid buildings has been studied as a potential supporting solution in a scenario with a decarbonised gas grid (such as the hydrogen and hybrid gas-electric scenarios).
- The biomass heating option may be most relevant for the hard-to-insulate buildings in which full electrification using heat pumps has been shown above to be a relatively costly option.
- As a result of multiple competing, potentially more appropriate, uses for biomass – including in the industrial sector, and in combination with CCS to produce power, or hydrogen, with net negative CO_2 emissions – there is substantial uncertainty over the available resource for building-level heating using biomass.
- This analysis suggests that over 130 TWh per year of sustainable biomass potential, in the form of biomass pellets, could be available in the UK by 2050, an amount which exceeds the current demand from off-gas buildings in the domestic sector of 59 TWh. This should be viewed as an upper limit, given the competing demands noted above, although greater biomass imports could also contribute to a higher overall resource availability.
- The majority of the biomass pellet resource could be available, in 2050, at a processed feedstock cost of less than 3 p/kWh.
- This analysis finds that applying biomass heating in all off-gas buildings results in additional CO_2 emissions savings of 7 $MtCO_2$ / yr relative to counterfactual off-gas heating. In combination with a hydrogen heating rollout across all on-gas buildings, this leads to remaining annual emissions in 2050 of 13 $MtCO_2$ / yr.
- The cumulative discounted additional system cost to 2050 of installing biomass heating in all off-gas buildings could be as little as £16 bn, under the assumption that the off-gas heat sector has access to the lowest cost biomass resources. Nonetheless, the high cost of off-gas heating fuels means that biomass heating even using the higher cost feedstocks could be an economic option.
- The cost increase is mainly due to the increased building-level heating system cost associated with biomass boilers and fuel storage units, and the increased maintenance costs of the biomass heating option. This is despite an overall reduction in fuel production costs, due to the lower assumed production cost of biomass pellets relative to the counterfactual oil and electric resistive heating.
- Since biomass heating and electrification of heat are the most likely heat supply technologies in the off-grid context, these options will be studied in the Mixed scenarios presented in the next section.

4.8 Role of energy efficiency

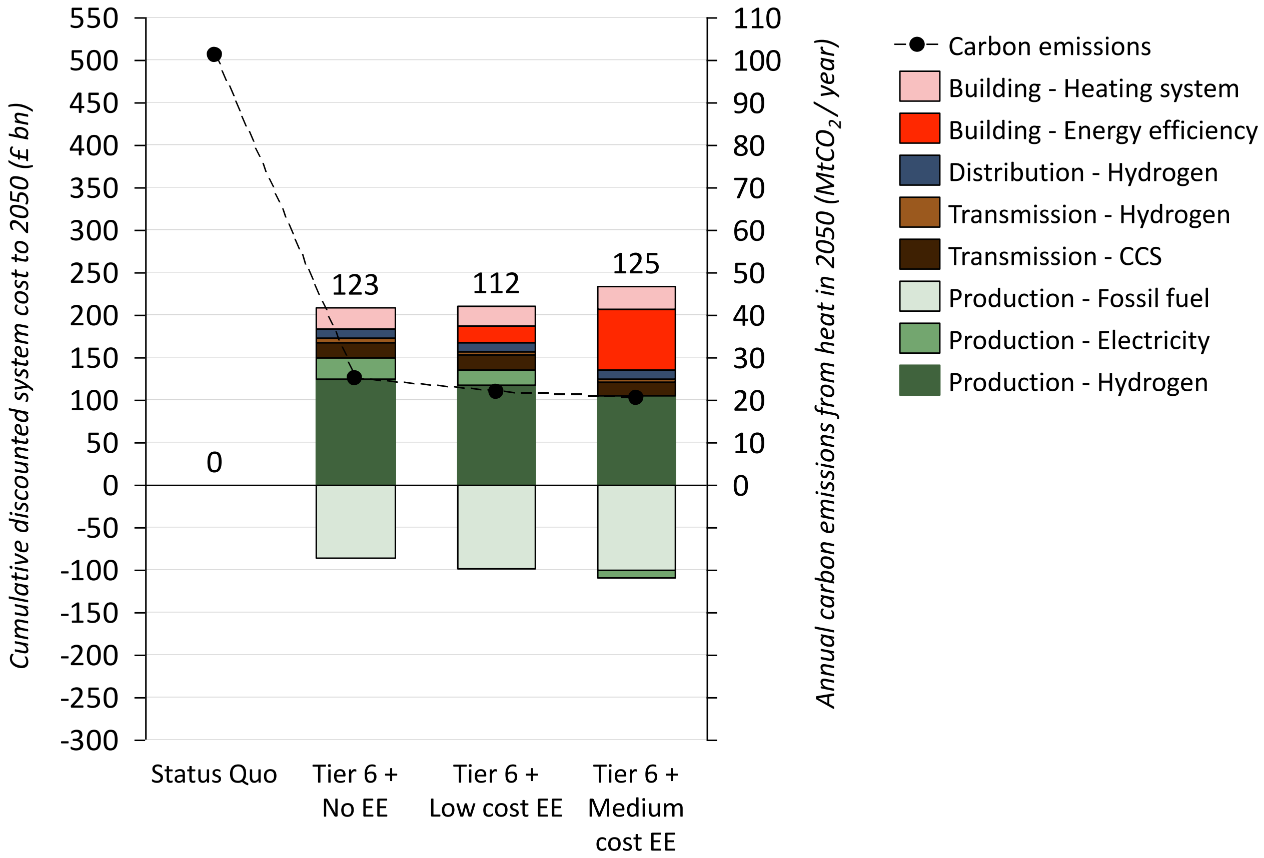
Section 4.1 set out the effect of implementing energy efficiency against the counterfactual of the Status Quo scenario. It was found that implementing Low cost measures is likely to result in a reduction in cumulative discounted cost to 2050, whereas the deployment of Medium cost energy efficiency measures is likely to lead to a small net increase in discounted costs, albeit resulting in substantially increased carbon emissions.

The categorisation of these measures set out previously is based on their cost-effectiveness when using a counterfactual fuel. This means that, when a more expensive fuel such as electricity or hydrogen is used in a building, energy efficiency can offset higher fuel costs, thus proving more cost-effective. In this section, assess how the cost of the various low carbon heating pathways compares under the implementation of no energy efficiency measures, Low cost EE measures and Medium cost EE measures. The exception to this is the heat pump pathway, whose uptake is contingent upon the deployment of energy efficiency.

In all cases the uptake rates for energy efficiency set out in Table 4-3 of Section 4.1 are assumed in the following analysis.

Figure 4-41 shows the impact on the cumulative discounted cost to 2050 of implementing the various levels of energy efficiency for the Tier 6 hydrogen heating scenario. Implementing no energy efficiency results in annual 2050 CO_2 emissions of 25 $MtCO_2$ / yr; implementing Low cost EE measures results annual emissions of 22 $MtCO_2$ / yr; Medium cost EE measures result in emissions of 20 $MtCO_2$ / yr. The Low cost EE measures result in a net reduction in discounted cost to 2050 of £11 bn relative to implementing no energy efficiency measures. The Medium cost EE measures result in an increase in discounted system cost of £13 bn to 2050 versus the Low cost EE case – achieving further CO_2 emissions reductions of nearly 2 $MtCO_2$ / yr versus the Low EE measures case.

Figure 4-41: Cumulative additional system cost and CO_2 emissions in 2050 – Hydrogen grid with varying levels of energy efficiency



Since the electricity production cost assumed in this analysis is significantly higher than the production cost of hydrogen, the benefit of energy efficiency is more pronounced for the case of direct electric heating. Section 4.3 presented the additional discounted cost to 2050 of implementing direct electric heating in all buildings as £191 bn. Figure 4-42 shows that for the case of direct electric heating implemented in all buildings, implementing increasing levels of energy efficiency leads to a significant decrease in discounted system cost. The cumulative discounted cost falls from £287 bn in the case of no energy efficiency measures, to £270 bn with Low cost EE, to £191 bn in the case of Medium cost EE.

Figure 4-42: Cumulative additional system cost and CO_2 emissions in 2050 – Direct electric heating with varying levels of energy efficiency

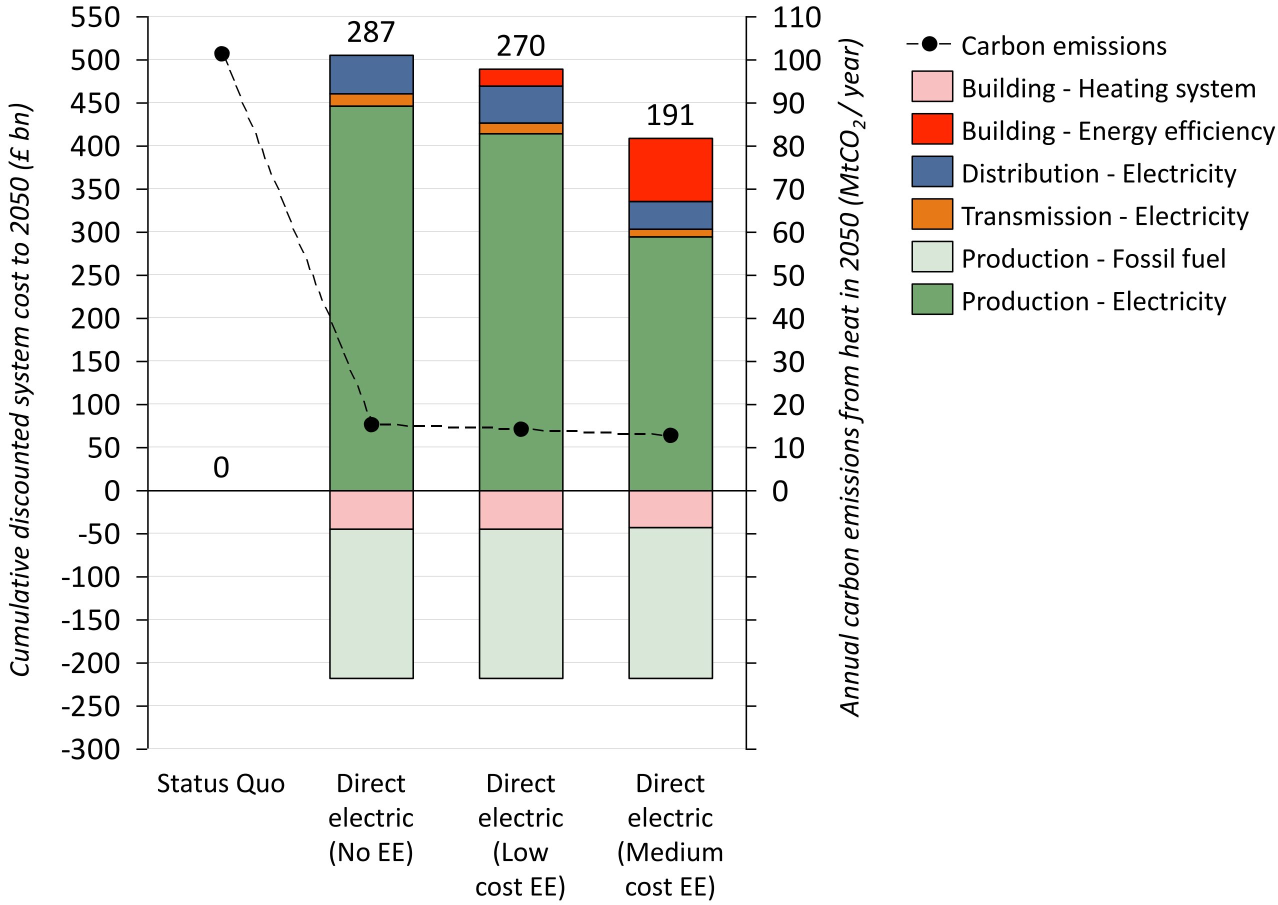
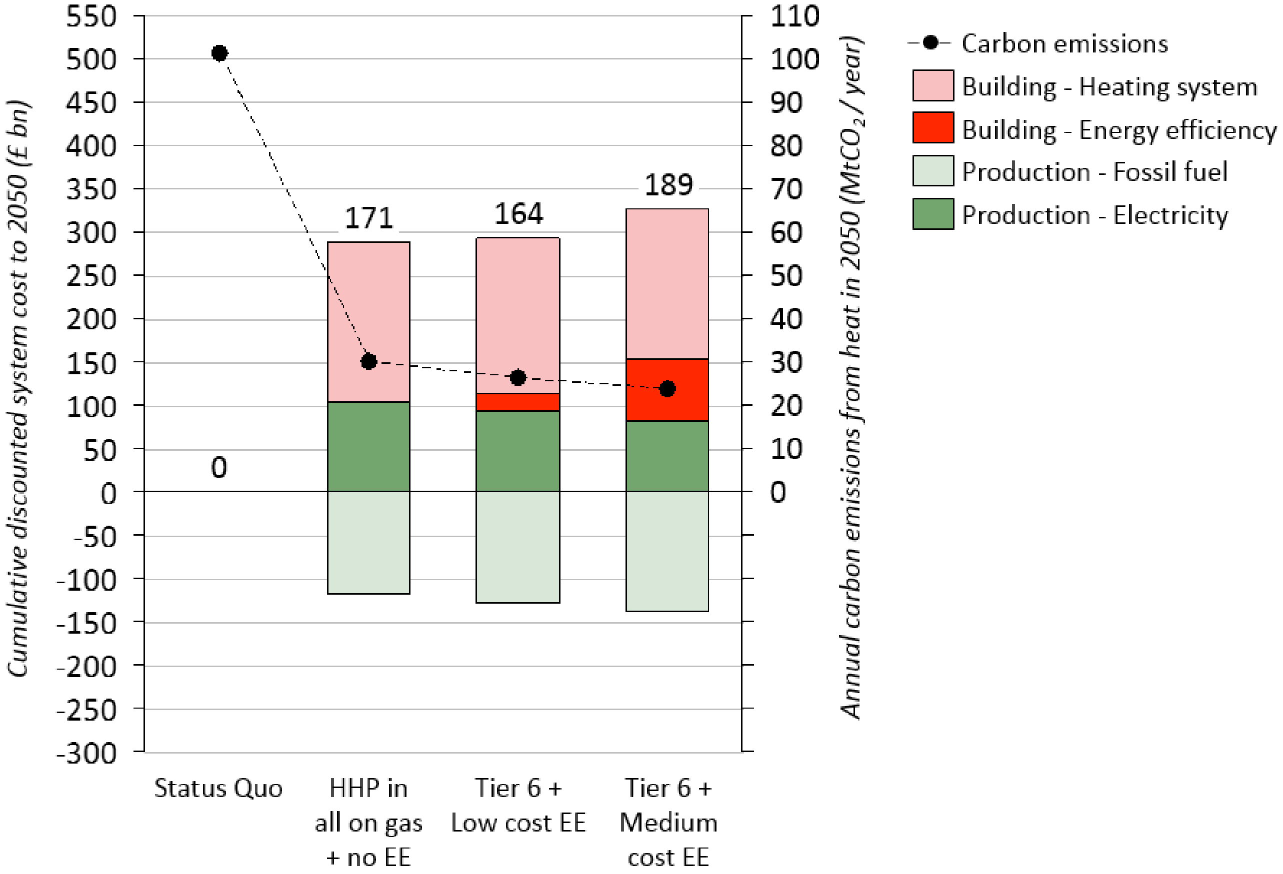


Figure 4-43 presents the corresponding analysis for the case of hybrid gas-electric heating. This indicates that while Low cost EE measures again result in a decrease in cumulative discounted cost to 2050 (£7 bn versus the no efficiency case), the Medium cost EE measures result in an increase in cost (£17 bn versus the Low cost EE case) – albeit providing a further 3 $MtCO_2$ / yr emissions savings. This is due to the lower fuel production cost in the hybrid case, where the cost of both the gas heating component and the heat pump heating component is substantially lower than in the hydrogen and direct electric heating cases.

Figure 4-43: Cumulative additional system cost and CO_2 emissions in 2050 – Hybrid gas-electric with varying levels of energy efficiency



Box 8 – Energy efficiency in combination with low carbon heating scenarios: Key findings

- The impact of energy efficiency applied as part of the main decarbonisation pathways has been studied.
- In all cases, the Low cost energy efficiency measures lead to a reduction in cumulative discounted system cost to 2050, as well as carbon emissions savings.
- The economic outcome for the Medium cost efficiency measures varies between scenarios.
- In the cases with higher cost fuels – including direct electric heating and to a lesser extent hydrogen – the Medium cost efficiency measures can achieve further cost savings or at least low cost emissions reduction.
- In the cases with lower fuel production costs – including gas or heat pump heating, and hence in the hybrid heat pump case – the Medium cost efficiency measures lead to an increase in discounted system cost. In these cases, the additional carbon emissions savings provided by the Medium cost measures are relatively costly.
- In the heat pump case, to recap, Low and Medium cost energy efficiency measures are required to render some buildings suitable for heat pumps – while nearly 17 million buildings are estimated to be suitable with no further efficiency measures, a further 5 million require Low cost EE measures and a further 4 million Medium cost EE measures to become suitable.
- Overall, therefore, the Low cost efficiency measures – including more than 10 million loft top-ups and 3.5 million cavity wall measures, as well as more than 1 million solid walls and more than 6 million floor insulation measures – can be seen as no regret measures, leading to cost and carbon savings in all scenarios.
- However, the Medium cost efficiency measure, dominated by further solid wall and floor insulation measures, should be considered on a case-by-case basis, as the cost-effectiveness of these is dependent upon the heat decarbonisation pathway taken.

5 Mixed decarbonisation scenarios

The previous section presented the potential role of a range of heat decarbonisation options for the UK, including:

- Energy efficiency
- Electrification of heating using heat pumps
- Electrification of heating using direct electric heating/storage heating
- Hybrid gas-electric heating
- Hydrogen heating
- Heat networks (including utilisation of waste heat sources)
- Bioenergy

The analysis presented in that section provided insight into the depth of decarbonisation each option could deliver, and any limits to this; the likely range of costs associated with deployment of the option; and, thereby, the most appropriate segments of the UK heat demand in which to deploy each option.

In Section 3.2, an indicative carbon 'budget' for space heating and hot water was suggested, based on prior analysis by the Committee on Climate Change which outlines the likely remaining emissions in 2050 associated with 'hard-to-reduce' sectors including industrial processes, agriculture and aviation and shipping. This evidence indicates that the remaining carbon emissions from space heating and hot water provision are likely to be required to fall below 10 $MtCO_2$ / yr.

In this section, we use the findings above to combine the heat decarbonisation options into coherent 'Mixed' scenarios with the potential to provide a deep level of carbon emissions reduction across the stock – with remaining emissions in 2050 approaching or falling below 10 $MtCO_2$ / yr – and compare the likely range of costs associated with each. The Mixed scenarios presented are illustrative, and it is likely that the eventual mix of technologies will be more diverse than any of the above scenarios.

The following scenarios are considered:

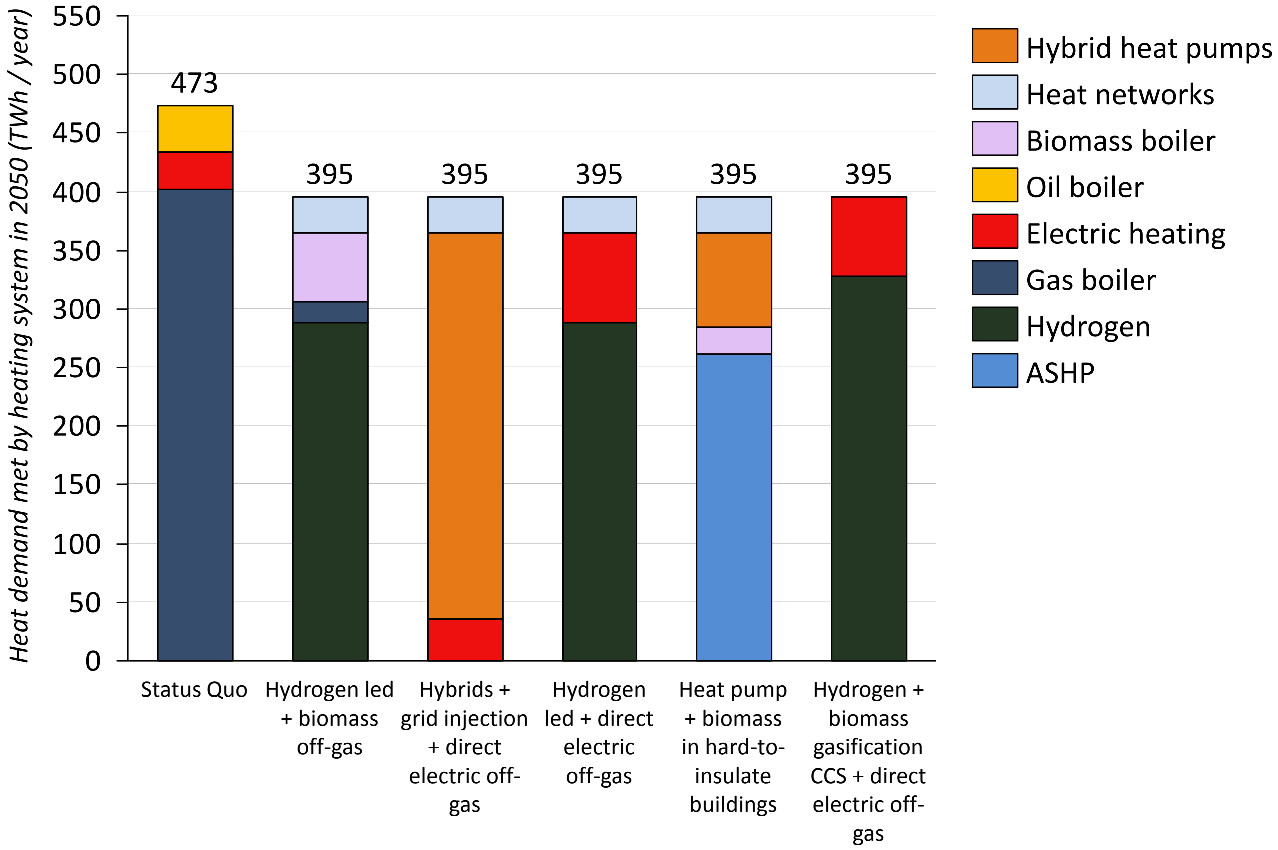
6. **Hydrogen led + biomass off-gas** – the UK gas grid is repurposed to carry low carbon hydrogen, and low cost biomass is installed in off-gas buildings, displacing oil and electric based heating.
7. **Hybrid gas-electric + grid injection + direct electric heating off-gas** – hybrid heat pumps are installed in all on-gas buildings, and low carbon biomethane is injected into the gas grid. In order to fulfill this grid injection demand, almost all low cost available bioenergy feedstocks are required, so electric heating is used as an off-gas solution.
8. **Heat pumps + bioenergy in hard-to-insulate buildings** – all Low and Medium cost energy efficiency measures are applied across the stock, and heat pumps are applied in all buildings in the high efficiency band. The remaining buildings that are insufficiently insulated to be suitable for a heat pump use a biomass solution.
9. **Hydrogen led + direct electric heating off-gas** – the UK gas grid is repurposed to carry low carbon hydrogen with direct electric heating in off-gas buildings.
10. **Hydrogen led + biomass gasification with CCS + direct electric heating off-gas** – hydrogen is produced by a mix of SMR and biomass gasification. Direct electric heating systems are applied to all off-gas buildings.

The assumptions underlying these Mixed scenarios are summarised in Table 5-1. A breakdown of the heat demand met by each heating system type in 2050 in each of the Mixed scenarios, and comparison with the Status Quo scenario, is shown in Figure 5-1.

Table 5-1: Level of implementation of different heating technologies the Mixed scenarios

Scenario	Energy efficiency	Heat pumps	Direct electric heating	Hybrid gas-electric heating	Hydrogen heating	Heat networks	Bioenergy
1. Hydrogen led + biomass off-gas	All low and medium cost measures	None	None	None	Implemented in all on-gas buildings	Implemented in heat density bands 1-5	Biomass boilers implemented in off-gas buildings
2. Hybrids + grid injection + direct electric heating	All low and medium cost measures	None	Implemented in all off-gas buildings	Implemented in all on-gas buildings	None	Implemented in heat density bands 1-5	41 TWh / yr of biomethane injected into the gas grid
3. Heat pumps + biomass in hard-to-insulate	All low and medium cost measures	Air source heat pumps in high efficiency buildings	None	None	None	Implemented in heat density bands 1-5	Biomass boilers implemented in hard to insulate buildings
4. Hydrogen led + direct electric heating off-gas	All low and medium cost measures	None	Implemented in all off-gas buildings	None	Implemented in all on-gas buildings	Implemented in heat density bands 1-5	None
5. Hydrogen led + biomass gasification with CCS + direct electric heating off-gas	All low and medium cost measures	None	Implemented in all off-gas buildings	None	Implemented in all on-gas buildings	None	24 TWh / yr of biohydrogen injected into the gas grid

Figure 5-1: Heat demand met by heating system in 2050 in the Mixed scenarios

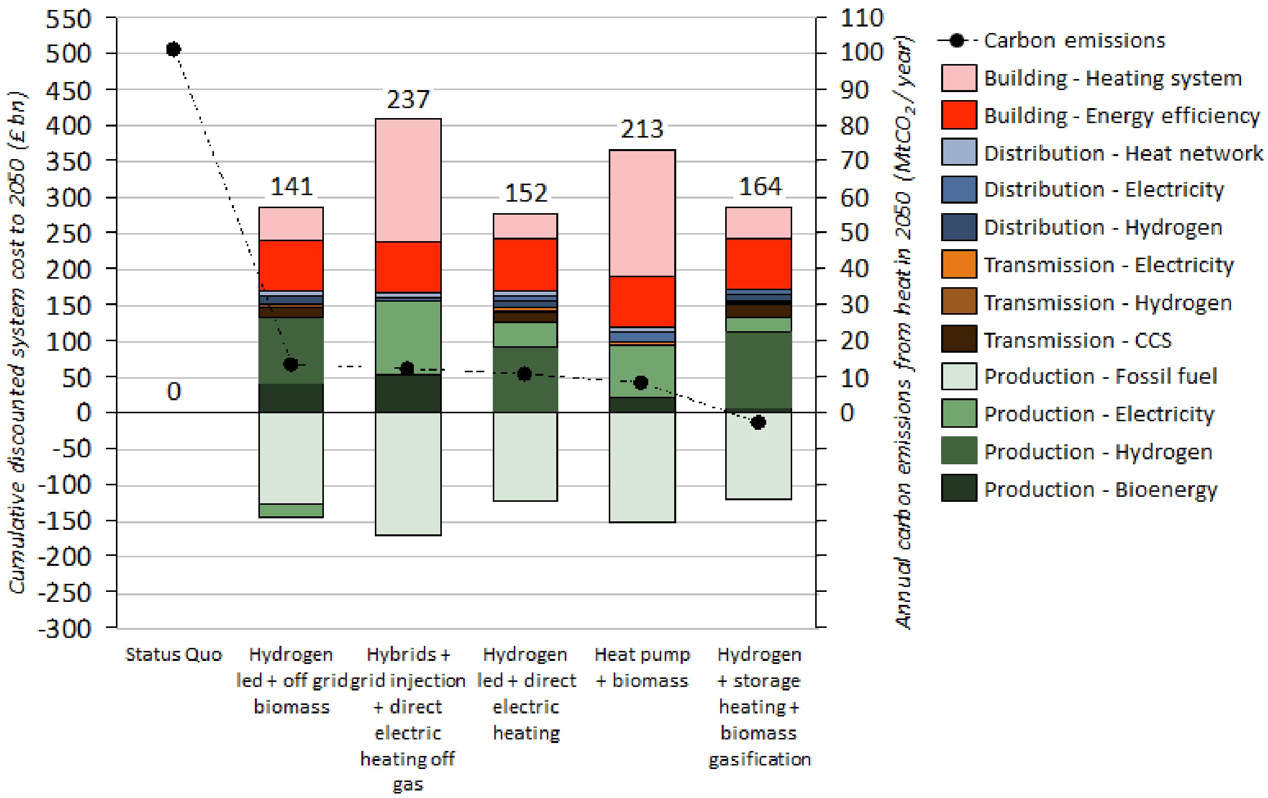


The cumulative additional system cost to 2050 of each Mixed scenario relative to the Status Quo scenario, and the associated level of CO_2 emissions in 2050, are shown in Figure 5-2.

The Mixed scenarios achieve a range of levels of decarbonisation of the heating sector, with remaining emissions in 2050 in the range -3 to 13 $MtCO_2$ / yr. It is notable, therefore, that several of these options fail (just) to reduce carbon emissions below the approximate 'target' for space heating and hot water of 10 $MtCO_2$ / yr suggested by the high-level analysis above. This is due to one or more of the factors including a remaining level of gas boiler heating (in the hybrid heat pump case), remaining emissions from the electricity grid (of 30 gCO_2/kWh as assumed here) or the emissions associated with hydrogen produced using SMR with incomplete capture of the CO_2 using CCS (the emissions intensity of hydrogen with a 90% CO_2 capture rate is approximately 24 gCO_2/kWh). It should be noted that this analysis does not account for other GHG emissions indirectly related to the provision of heat in these scenarios, such as the upstream emissions associated with gas production including methane leakage (relevant in the hydrogen scenarios, and any electrification scenario with remaining gas-based electricity generation, even with CCS).

It can be seen that the cumulative discounted cost of the scenarios to 2050 versus the Status Quo ranges from £146 bn for the "Hydrogen led + biomass off-gas" scenario, to £237 bn for the "Hybrids + grid injection + direct electric off-gas" scenario. The high cost of that scenario is largely due to the large required uptake of biomethane grid injection to achieve sufficient decarbonisation, involving the more costly feedstocks. The "Hydrogen led + direct electric off-gas" scenario entails a cost of £152 bn, somewhat higher than the "Hydrogen led + biomass off-gas" scenario. However, the caveat should be noted again that the biomass off-gas cost analysis assumes the lowest cost biomass resource is available to the heat sector. The "Heat pump + biomass in hard-to-insulate buildings" scenario entails a cost of £211 bn, several tens of million pounds greater than the Hydrogen-led cases. Finally, the "Hydrogen led + biomass gasification CCS + direct electric off-gas" scenario achieves net negative emissions for a cost of £164 bn versus the Status Quo.

Figure 5-2: Cumulative additional system cost and CO_2 emissions in 2050 – Mixed scenarios



The estimated sensitivity to cost and performance in the cumulative additional system cost for the Mixed scenarios is shown in Figure 5-3 and the sensitivity to fuel costs is shown in Figure 5-4. The charts show a substantial variation between the Best and Worst cases for all scenarios, in some cases larger than the difference between the Central cases for the different scenarios. It is notable that for the cost and performance the Best case result for the “Heat pump + biomass in hard-to-insulate buildings” scenario entails a cost within £15 bn of the Central case for the lowest cost scenario, the “Hydrogen led + biomass off-gas” scenario. This suggests that on the basis of the analysis undertaken here, while there are clear indications that certain pathways are likely to be lower cost than others, no pathway can definitively be ruled the lowest cost option.

Figure 5-3: Sensitivity to technology cost and performance in cumulative additional system cost to 2050 – Mixed scenarios

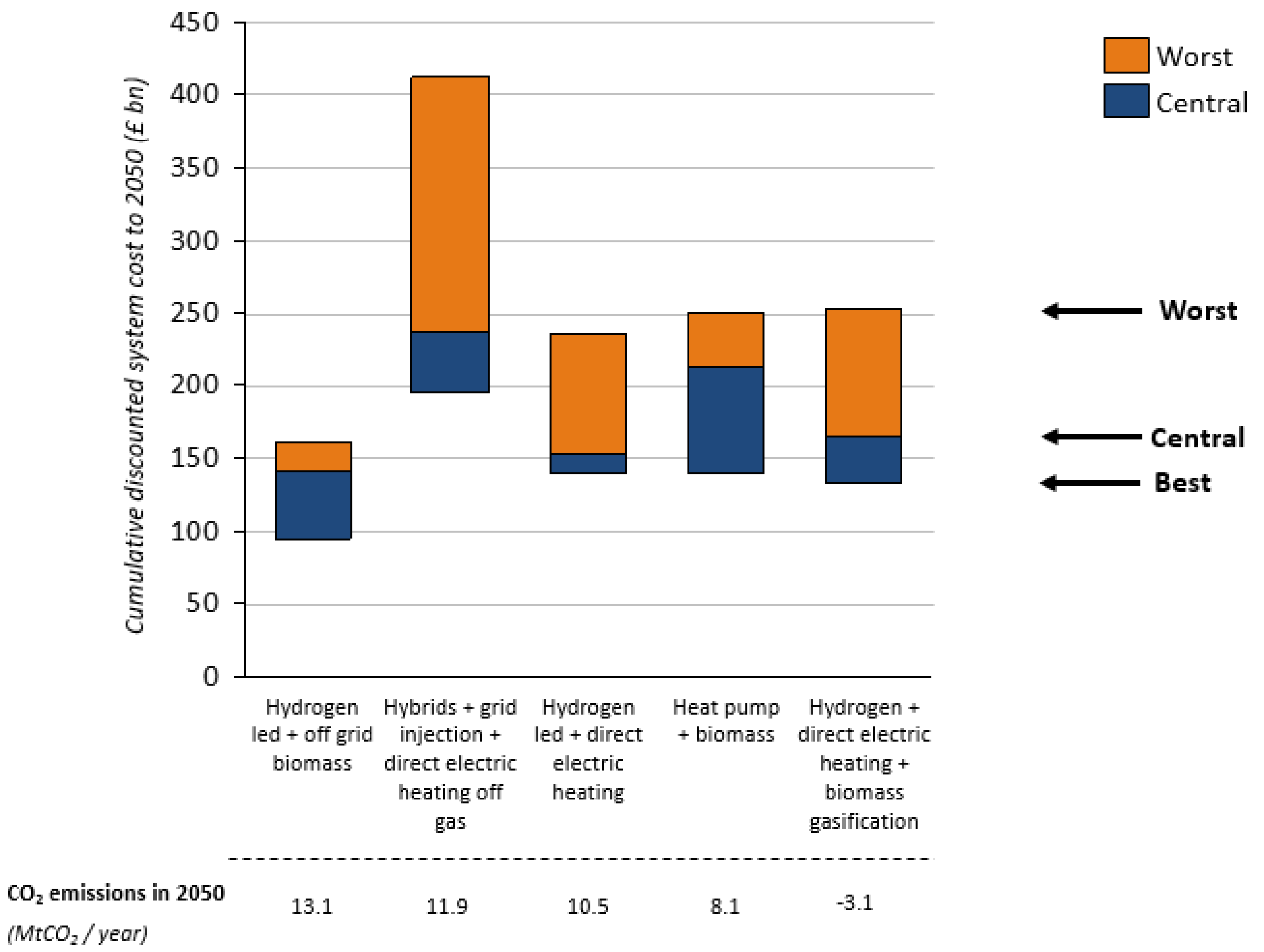
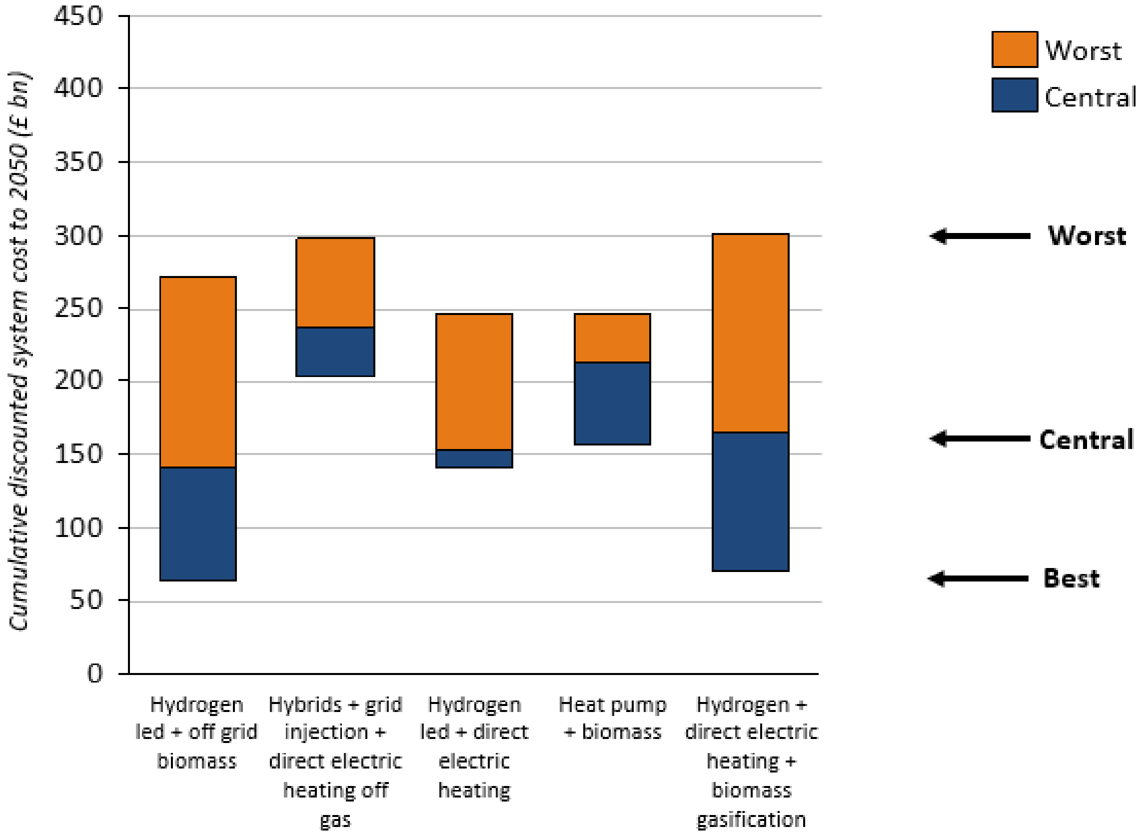


Figure 5-4: Sensitivity to fuel costs in cumulative additional system cost to 2050 – Mixed scenarios



CO_2 emissions in 2050 *($MtCO_2$ / year)*	13.1	11.9	10.5	8.1	-3.1

6 Annex – Assumptions

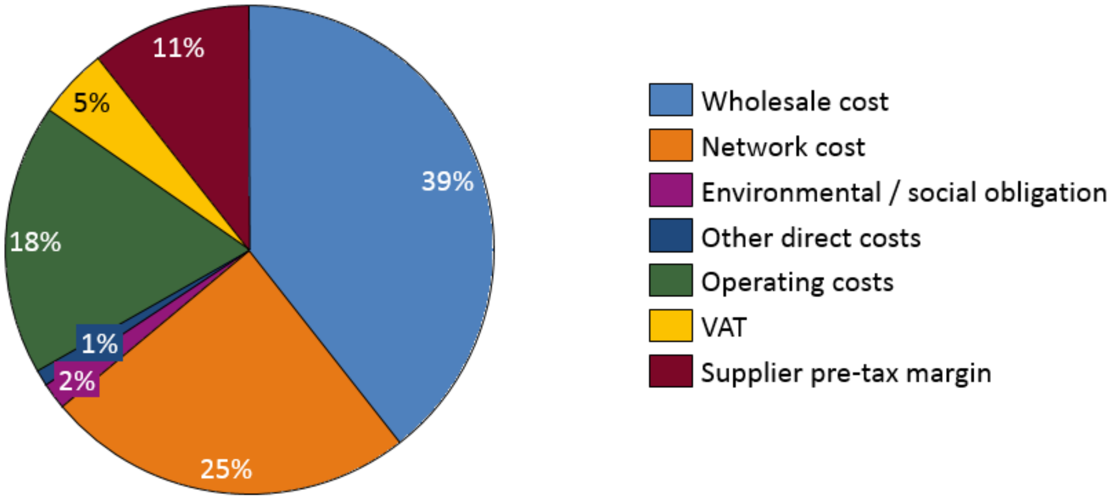
6.1 Energy costs

A series of energy cost assumptions underly the analysis set out in this report. This section summarises the methodology for developing costs for different raw forms of energy / fuels used here.

Gas

The cost of gas bill paid by an end consumer is made up of a series of components. Ofgem estimates of the breakdown of an end-consumer gas bill are set out below in Figure 6-1:.

Figure 6-1: Breakdown of a domestic consumer gas bill[34]



This report is concerned primarily with infrastructure costs, and the 'resource' costs of importing and producing fuel. Therefore, only some components of the consumer gas price should be included in the analysis. For the purposes of this analysis, Wholesale costs and Operating costs are included as components of the gas production cost varying by gas production volumes (that is, varying in p/kWh terms). The Network cost is assumed here not to vary substantially with gas production volume, and so is assumed to be incurred in all scenarios. The other components of the consumer gas price are assumed outside the scope of this cost analysis.

BEIS's Energy and Emissions Forecasts (2016) suggest that the wholesale cost of gas in the UK is expected to vary significanty over the coming decades. In order to reflect this, the following approach to constructing electricity costs has been adopted:

1. The Operating cost component, totalling 18% of the 2015 domestic gas price or 0.65 p/kWh, is assumed to be constant over time in p/kWh terms.
2. This is added to the Wholesale cost taken from BEIS's Energy and Emissions Forecasts (2016) for each year out to 2035 (when the forecast ends) to derive the gas production cost used in this analysis.
3. From 2035 the gas production cost is assumed to be constant.

The resulting gas costs used in the model set out in below in Table 6-1. In addition to this, a CO_2 content of natural gas of 0.20 $kgCO_2$ / kWh (HHV) is assumed.

[34] Ofgem, *Bills, prices and profits* (2017) https://www.ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits

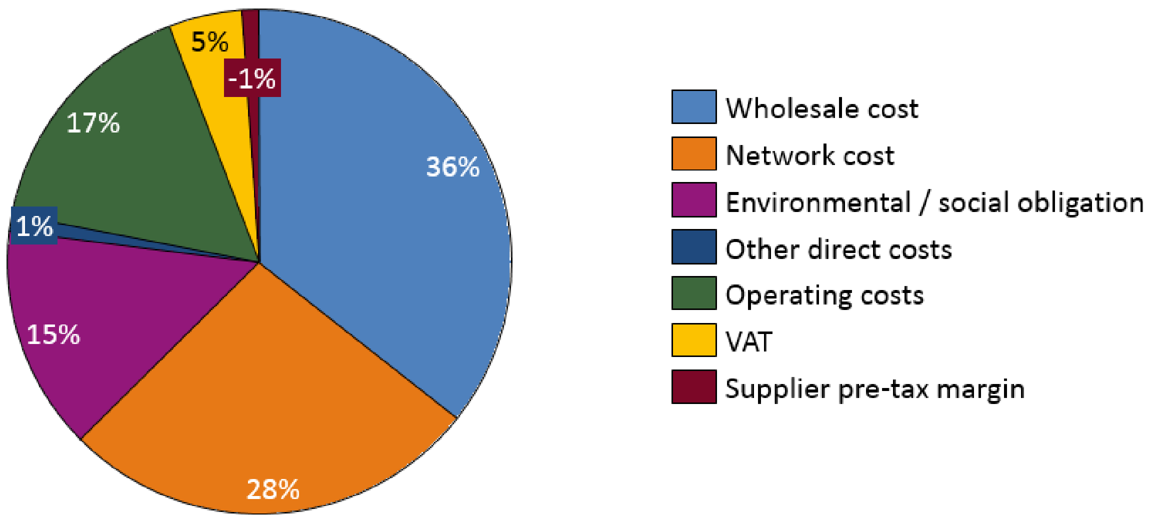
Table 6-1: Gas production costs assumed in this analysis

Year	Cost (£ / kWh – HHV)
2015	0.024
2016	0.020
2017	0.021
2018	0.021
2019	0.021
2020	0.021
2021	0.022
2022	0.023
2023	0.024
2024	0.025
2025	0.026
2026	0.027
2027	0.028
2028	0.029
2029	0.030
2030	0.031
2031	0.031
2032	0.031
2033	0.031
2034	0.031
2035	0.031

Electricity

Ofgem estimates of the breakdown of domestic electricity tariffs are shown in Figure 6-2 below.

Figure 6-2: breakdown of a domestic consumer electricity bill[35]



Using a similar argument as that used to derive the gas production cost, the electricity production cost used for the purposes of this analysis are assumed to include the Wholesale cost of electricity and the Operating costs.

The Network costs associated with the maintenance of the existing electricity network is assumed to be fixed and incurred in all scenarios, so is excluded from the scope of this analysis (noting that the capital and operating cost of any additional investment in the electricity network is costed explicitly elsewhere in our analysis). Therefore, of the above components, Wholesale costs and Operating costs are included.

The approach taken to derive the electricity production cost is then:

1. The Operating cost component, totalling 17% of the 2015 domestic electricity price or 2.6 p/kWh, is assumed to be constant over time in p/kWh terms.
2. This is added to the Wholesale cost taken from BEIS's Energy and Emissions Forecasts (2016) for each year out to 2035 (when the forecast ends) to derive the electricity production cost used in this analysis.
3. From 2035 the electricity production cost is assumed to be constant.

The resulting electricity production costs are set out in Table 6-2. Also included is the CO_2 intensity of grid electricity as forecast in BEIS: Energy and Emissions Forecasts 2016.

[35] Ofgem, *Bills, prices and profits* (2017) https://www.ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits.

Table 6-2: Electricity production costs and emissions factors assumed in this analysis

Year	Cost (£ / kWh)	Carbon intensity (kg CO_2 / kWh)
2015	0.06	0.35
2016	0.06	0.35
2017	0.06	0.30
2018	0.06	0.29
2019	0.06	0.27
2020	0.06	0.24
2021	0.06	0.21
2022	0.07	0.20
2023	0.07	0.17
2024	0.08	0.18
2025	0.08	0.17
2026	0.08	0.15
2027	0.08	0.15
2028	0.08	0.12
2029	0.08	0.11
2030	0.08	0.10
2031	0.08	0.10
2032	0.08	0.09
2033	0.08	0.08
2034	0.07	0.08
2035	0.07	0.06

Electricity grid reinforcement

Additional costs are assumed for reinforcing the electrical grid to support increasing peak electricity supply at the transmission and distribution levels are also included. These are modelled on an increased cost per kW of electricity demand basis and are set out in Table 6-3.

Table 6-3: Peak load reinforcement costs for the electricity distribution and tranmission systems

Scenario	Transmission network reinforcement cost (£ / kW_{peak})	Distribution network reinforcement cost (£ / kW_{peak})
Worst case	271	772
Central case	200	650
Best case	98	484

Oil

The costs of oil used in this analysis are based on the industrial cost projections set out in BEIS: Energy and Emissions Forecasts 2016. A CO_2 content of 0.25 $kgCO_2$ / kWh is assumed for oil. The cost assumptions are assumed constant beyond 2035 and are set out in Table 6-4

Table 6-4: Oil production costs assumed in this analysis

Year	Cost (£ / kWh)
2015	0.04
2016	0.03
2017	0.03
2018	0.03
2019	0.03
2020	0.04
2021	0.04
2022	0.04
2023	0.04
2024	0.04
2025	0.04
2026	0.04
2027	0.05
2028	0.05
2029	0.05
2030	0.05
2031	0.05
2032	0.05
2033	0.05
2034	0.05
2035	0.05

Bioenergy feedstocks

The following feedstocks are in scope of the study:

- Domestic
  - Perennial energy crops (Miscanthus, SRC willow)
  - Forestry & forestry residues
  - Straw and Dry litter
  - Waste wood, Renewable fraction of residual MSW
  - Wet wastes for AD (Food waste, Manure, Sewage sludge)
  - Landfill gas
- Imported woody biomass pellets

The UK sustainable resource potential of each feedstock for bioenergy uses changes over time to 2050, as shown in Table 6-5. Best/central/worst scenarios are derived from the BEIS "UK and global biomass reosurces model" (Ricardo, 2017). Price independent non-bioenergy demands are already excluded from these values (e.g. certain fractions of feedstocks are recycled, composted or used for animal bedding).

Imported woody pellet availability also uses the Best/Central/Worst range from Ricardo (2017). In the central and worst scenarios, availability falls over time based on a decreasing % of global surplus, that reaches 1.5 – 3.0% of the net global surplus supply in 2050. However, the UK currently imports ~43% of internationally traded biomass pellets[36], and new scenarios for BEIS also assume more of this global surplus could be imported than just 3%. We have therefore assumed a Best scenario that takes the Central scenario import potential value in 2020 and holds this value fixed to 2050 (no decrease as in the Central scenario), to denote the UK maintaining a less modest market share over time.

The biomass resources considered in this study do not have any spatial differentiation or mapping, since the Ricardo model does not consider different UK regions. Other spatially explicit models (such as the ETI's Bioenergy Value Chain Model) only consider a subset of the UK feedstocks in scope, and sourcing and repurposing the underlying GIS data (if ETI had allowed this) would have taken significantly more time than available in the study.

Delivered cost and GHG emission ranges for each unprocessed feedstock are derived from Ecofys & E4tech (a 2017 project for BEIS), as shown in Table 6-5. These delivered feedstock costs and GHG emissions values do not change over time, due to lack of forecasts. All values include cultivation & harvesting (or only collection if the feedstock is a waste/residue), and indicative truck transport to a conversion plant (often ~£15/tonne) unless the feedstock is used onsite (e.g. landfill gas, sewage sludge). Several of the waste feedstocks have a negative feedstock cost, due to attracting a gate fee for their disposal.

Imported woody pellets use a landed port price range from Argus (2017), and then transport within the UK is added on top. There are currently no international supply-cost curves available (we understand that a BEIS project on this topic is currently ongoing).

Table 6-5: Costs and GHG emissions factors of unprocessed feedstocks

Feedstock	Scenario	Feedstock cost (£ / kWh)	GHG emissions factor (kg CO_2e / kWh)
Arboricultural arisings	Best	0.006	0.003
Arboricultural arisings	Central	0.008	0.007
Arboricultural arisings	Worst	0.011	0.011
Dry litter	Best	0.003	0.003
Dry litter	Central	0.006	0.007
Dry litter	Worst	0.0013	0.011
Food waste	Best	(0.035)	0.001
Food waste	Central	(0.017)	0.002
Food waste	Worst	0	0.003
Forestry residues	Best	0.009	0.003
Forestry residues	Central	0.012	0.007
Forestry residues	Worst	0.025	0.011
Imported pellets	Best	0.032	0.025
Imported pellets	Central	0.040	0.061
Imported pellets	Worst	0.048	0.115
Landfill gas	Best	0	0.000
Landfill gas	Central	0	0.000
Landfill gas	Worst	0	0.000
Miscanthus	Best	0.009	0.007
Miscanthus	Central	0.018	0.018
Miscanthus	Worst	0.028	0.029

[36] FAO (2017) "FAOSTAT", available at: http://www.fao.org/faostat/en/#data/FO

Renewable fraction of MSW	Best	(0.047)	0.013
Renewable fraction of MSW	Central	(0.025)	0.033
Renewable fraction of MSW	Worst	(0.010)	0.053
Sawmill residues	Best	0.013	0.003
Sawmill residues	Central	0.019	0.007
Sawmill residues	Worst	0.028	0.011
Sewage sludge	Best	-	0.000
Sewage sludge	Central	-	0.000
Sewage sludge	Worst	-	0.000
Short rotation coppice willow	Best	0.010	0.004
Short rotation coppice willow	Central	0.019	0.009
Short rotation coppice willow	Worst	0.029	0.014
Short rotation forestry	Best	0.014	0.005
Short rotation forestry	Central	0.020	0.012
Short rotation forestry	Worst	0.030	0.020
Small round wood	Best	0.015	0.003
Small round wood	Central	0.022	0.007
Small round wood	Worst	0.032	0.011
Straw	Best	0.009	0.008
Straw	Central	0.018	0.020
Straw	Worst	0.027	0.032
Waste wood	Best	(0.008)	0.002
Waste wood	Central	(0.004)	0.004
Waste wood	Worst	0	0.006
Wet manure	Best	0	0.000
Wet manure	Central	0.016	0.001
Wet manure	Worst	0.032	0.001

Table 6-6: Unprocessed feedstock availability by year and scenario (TWh/yr)

Year	Scenario	Imported pellets	Misc-anthus	Short rotation coppice willow	Short rotation forestry	Small round wood	Forestry residues	Sawmill residues	Arbori-cultural arisings	Waste wood	Straw	Dry litter	Wet manure	Sewage sludge	Food waste	Renew-able fraction of MSW	Landfill gas
2020	Central	252	0.4	0.2	0.0	0.1	0.4	2.4	3.7	26	15	2.2	0.3	3.9	6.3	25	11
2025		238	2.1	1.0	0.0	0.6	1.0	3.4	3.7	26	15	2.2	0.3	4.1	7.1	18	10
2030		189	6	2.9	0.0	0.9	1.5	4.2	3.8	26	15	2.2	0.3	4.2	7.9	19	10
2035		138	10	4.4	0.0	0.9	1.3	4.0	3.8	26	18	2.6	0.3	4.3	8.4	22	10
2040		105	14	6.3	0.5	0.9	1.5	4.1	3.8	26	21	3.0	0.4	4.4	9.0	25	9
2045		60	18	8.3	2.9	0.9	1.8	4.1	3.8	26	21	3.0	0.4	4.5	9.5	28	9
2050		37	23	10.6	3.1	0.5	1.3	3.4	3.9	26	21	3.0	0.4	4.6	10.0	32	9
2020	Best	376	0.8	0.4	0.0	1.1	0.6	3.8	6.3	26	17	2.5	2.6	4.0	8.4	30	11
2025		376	3.7	1.7	0.0	1.8	1.6	5.0	6.3	26	17	2.5	2.7	4.1	8.9	20	10
2030		376	10	4.6	0.0	2.3	2.3	6.0	6.3	26	17	2.5	2.7	4.3	9.5	21	10
2035		376	14	6.1	0.5	2.2	2.0	5.7	6.3	26	19	2.7	2.8	4.4	10.1	24	10
2040		376	18	7.9	4.8	2.2	2.3	5.8	6.3	26	21	3.0	2.8	4.4	10.7	28	9
2045		376	20	9.2	4.8	2.2	2.6	5.7	6.3	26	21	3.0	2.8	4.5	11.2	31	9
2050		376	23	10.6	5.7	1.7	2.0	4.9	6.3	26	21	3.0	3.2	4.6	11.8	36	9
2020	Worst	125	0.1	0.1	0.0	0.0	0.1	0.0	1.2	21	13	1.9	0.0	3.6	2.9	20	11
2025		107	1.2	0.5	0.0	0.0	0.3	0.8	1.4	21	14	1.9	0.0	3.8	3.8	14	10
2030		85	4.4	2.0	0.0	0.1	0.5	1.5	1.6	21	14	2.0	0.0	4.0	4.8	16	10
2035		65	8.7	3.9	0.0	0.1	0.4	1.3	1.6	21	17	2.5	0.0	4.1	5.1	19	10
2040		48	14	6.3	0.0	0.2	0.5	1.3	1.6	21	21	3.0	0.0	4.1	5.3	22	9
2045		25	17	7.8	0.5	0.1	0.6	1.3	1.6	21	21	3.0	0.0	4.2	5.6	25	9
2050		17	21	9.6	2.9	0.0	0.4	0.7	1.6	21	21	3.0	0.1	4.3	5.9	28	9

Bioenergy technologies

The following pre-treatment technologies are in scope of the study:

- Chipping
- Pelleting

The following bioenergy conversion technologies are in scope of the study:

- Pellet biomass boilers to heat only – at a range of different scales
- Chip biomass boilers to heat only – at a range of different scales (non-domestic buildings only)
- Biomass combined heat and power (CHP), at a range of scales, and for district heating
- Anaerobic digestion (AD) to biomethane for grid injection – with/without CO_2 capture
- Landfill gas upgrading to biomethane for grid injection – with/without CO_2 capture
- Biomass gasification to synthetic natural gas (BioSNG) for grid injection – with/without CO_2 capture
- Biomass gasification to hydrogen ($BioH_2$) for grid injection – with/without CO_2 capture

For each technology, we have provided capex, fixed opex, variable opex (including costs of key input/output materials or energy), plant efficiency, lifetime and availability data. This is summarised in the following technology tables. Building-level combustion boilers are provided at a range of domestic & commercial scales, based on the kW heat demands in each building type.

These costs and efficiencies include gas clean-up to grid quality for bio-methane or hydrogen injection, and CO2 capture where selected. Costs and efficiencies generally improve over time with innovation and scale-up, with best/central/worst ranges given from Ecofys & E4tech (2017 project for BEIS).

Distribution or transmission costs for the (methane) gas or hydrogen grid, or for captured CO_2 transport, are not included in the biomass-specific data. These costs and GHG emissions impacts are included elsewhere in the model.

The final bioenergy vector GHG emissions, including any credit for CCS, are calculated based on the EU's Renewable Energy Directive rules. This assumes a LHV basis throughout, energy allocation between any co-products, and no use of feedstock counterfactuals (e.g. avoided landfill). This allows the model to add the GHG emissions from the feedstock, the truck diesel used, electricity and chemicals consumed, plus wastes and ashes produced during pre-treatment or conversion, into an overall supply chain GHG emissions value for either the biomass heating supplied to a building ($gCO2e/kWh_{th}$), or the biomethane or biohydrogen injected into the gas grid ($gCO2e/kWh_{th}$). These are the limits of the bioenergy system boundary assumed in the study.

Importantly, not every feedstock can be used in every conversion technology. Some conversion technologies require the unprocessed feedstock to have undergone pre-treatment (such as domestic pellet boilers only being able to use pellets). If pre-treatment is required, the model adds the costs, efficiency and GHG emissions of the pre-treatment step into the supply chain GHG emissions and costs. The impact of chipping is very low, but pelleting is more significant in terms of costs and energy use.

Table 6-7: Feedstock processing and allowable end use pathways (green = feasible, grey = not feasible)

	UK pre-processing	Domestic boilers (pellets)	Commercial boilers (pellets)	Commercial boilers (chips)	Biomass CHP	AD to bio-methane	Landfill gas upgrading	Gasification to bioSNG	Gasification to bioH2
Imported pellets	None								
Perennial energy crops	Pellet								
	Chip								
	None								
Short rotation forestry	Pellet								
	Chip								
Small round wood	Pellet								
	Chip								
Forestry residues	Pellet								
	Chip								
Sawmill residues	Pellet								
	Chip								
Arboricultural arisings	Pellet								
	Chip								
Waste wood	Pellet								
	Chip								
Straw	Pellet								
	None								
Dry litter	None								
Wet manure	None								
Sewage sludge	None								
Food waste	None								
Renewable fraction of MSW	None								
Landfill gas	None								

Note that these cost datasets do not include the other inputs/outputs to each technology – i.e. the variable opex values given in these tables are only for non-characterised inputs/outputs or labour costs related to operating hours. The inputs and outputs that are characterised separately within the model vary by technology, as shown below:

- Chipping: Diesel input, Rejects output
- Pelleting: Diesel, Electricity and Binder inputs, Rejects output
- Biomass boilers (heat only): Electricity input, Ash output
- Biomass CHP: Electricity, Diesel and Water inputs, Ash and waste water outputs
- Anaerobic digestion: Electricity input (particularly with CO_2 capture), Digestate and Methane slip outputs, plus CO_2 if captured
- Landfill gas upgrading: Electricity input (particularly with CO_2 capture), Methane slip output, plus CO_2 if captured
- Gasification to synthetic natural gas (bioSNG): Ash and (small) methane slip outputs, plus CO_2 if captured
- Gasification to hydrogen: Ash output, plus CO_2 if captured

Table 6-8: Anaerobic digestion for grid biomethane injection cost and performance assumptions

Year	Scenario	Marginal capex (£/kW)	Marginal opex (£/kW/y)	Variable opex (£/kWh)	Availability factor (%)	Lifetime (years)
2020	Best	1720	160.05	0	0.86	30
2020	Central	2457	228.64	0	0.86	30
2020	Worst	3195	297.23	0	0.86	30
2025	Best	1711	159.23	0	0.86	30
2025	Central	2445	227.47	0	0.86	30
2025	Worst	3178	295.72	0	0.86	30
2030	Best	1703	158.42	0	0.86	30
2030	Central	2432	226.31	0	0.86	30
2030	Worst	3162	294.2	0	0.86	30
2035	Best	1694	157.6	0	0.86	30
2035	Central	2420	225.14	0	0.86	30
2035	Worst	3146	292.68	0	0.86	30
2040	Best	1685	156.78	0	0.86	30
2040	Central	2407	223.97	0	0.86	30
2040	Worst	3129	291.17	0	0.86	30
2045	Best	1676	155.97	0	0.86	30
2045	Central	2395	222.81	0	0.86	30
2045	Worst	3113	289.65	0	0.86	30
2050	Best	1668	155.15	0	0.86	30
2050	Central	2382	221.64	0	0.86	30
2050	Worst	3097	288.13	0	0.86	30

Table 6-9: Bio synthetic natural gas for grid injection cost and performance assumptions

Year	Scenario	Marginal capex (£/kW)	Marginal opex (£/kW/y)	Variable opex (£/kWh)	Availability factor (%)	Lifetime (years)
2020	Best	1123	44.22	0.002	0.8	30
2020	Central	1604	63.18	0.002	0.8	30
2020	Worst	2086	82.13	0.003	0.8	30
2025	Best	1097	43.19	0.001	0.8	30
2025	Central	1567	61.71	0.002	0.8	30
2025	Worst	2037	80.22	0.003	0.8	30
2030	Best	1071	42.17	0.001	0.8	30
2030	Central	1530	60.24	0.002	0.8	30
2030	Worst	1989	78.31	0.003	0.8	30
2035	Best	1055	41.55	0.001	0.8	30
2035	Central	1507	59.36	0.002	0.8	30
2035	Worst	1960	77.16	0.003	0.8	30
2040	Best	1039	40.93	0.001	0.8	30
2040	Central	1485	58.47	0.002	0.8	30
2040	Worst	1930	76.02	0.003	0.8	30
2045	Best	1029	40.52	0.001	0.8	30
2045	Central	1470	57.89	0.002	0.8	30
2045	Worst	1911	75.25	0.003	0.8	30
2050	Best	1019	40.11	0.001	0.8	30
2050	Central	1455	57.3	0.002	0.8	30
2050	Worst	1892	74.49	0.003	0.8	30

Table 6-10: Biomass gasification to hydrogen for grid injection cost and performance assumptions

Year	Scenario	Marginal capex (£/kW)	Marginal opex (£/kW/y)	Variable opex (£/kWh)	Availability factor (%)	Lifetime (years)
2020	Best	1116	42.91	0.006	0.91	30
2020	Central	1594	61.3	0.009	0.91	30
2020	Worst	2072	79.69	0.012	0.91	30
2025	Best	1067	41.03	0.006	0.91	30
2025	Central	1524	58.61	0.009	0.91	30
2025	Worst	1981	76.19	0.011	0.91	30
2030	Best	1018	39.14	0.006	0.91	30
2030	Central	1454	55.92	0.008	0.91	30
2030	Worst	1890	72.7	0.011	0.91	30
2035	Best	983	37.79	0.006	0.91	30
2035	Central	1404	53.98	0.008	0.91	30
2035	Worst	1825	70.18	0.01	0.91	30
2040	Best	947	36.43	0.005	0.91	30
2040	Central	1353	52.05	0.008	0.91	30
2040	Worst	1759	67.66	0.01	0.91	30

2045	Best	924	35.53	0.005	0.91	30
2045	Central	1320	50.76	0.007	0.91	30
2045	Worst	1716	65.99	0.01	0.91	30
2050	Best	900	34.63	0.005	0.91	30
2050	Central	1286	49.47	0.007	0.91	30
2050	Worst	1672	64.31	0.01	0.91	30

Table 6-11: Landfill gas upgrading for grid injection cost and performance assumptions

Year	Scenario	Marginal capex (£/kW)	Marginal opex (£/kW/y)	Variable opex (£/kWh)	Availability factor (%)	Lifetime (years)
2020	Best	340	29.25		0.9	30
2020	Central	486	41.79		0.9	30
2020	Worst	632	54.33		0.9	30
2025	Best	338	29.1		0.9	30
2025	Central	483	41.58		0.9	30
2025	Worst	628	54.05		0.9	30
2030	Best	337	28.95		0.9	30
2030	Central	481	41.36		0.9	30
2030	Worst	625	53.77		0.9	30
2035	Best	335	28.8		0.9	30
2035	Central	478	41.15		0.9	30
2035	Worst	622	53.49		0.9	30
2040	Best	333	28.66		0.9	30
2040	Central	476	40.94		0.9	30
2040	Worst	619	53.22		0.9	30
2045	Best	331	28.51		0.9	30
2045	Central	473	40.72		0.9	30
2045	Worst	615	52.94		0.9	30
2050	Best	330	28.36		0.9	30
2050	Central	471	40.51		0.9	30
2050	Worst	612	52.66		0.9	30

Table 6-12: Chipping cost and performance assumptions

Year	Scenario	Marginal capex (£/kW)	Marginal opex (£/kW/y)	Variable opex (£/kWh)	Availability factor (%)	Lifetime (years)
2020	Best	4.87	1		0.32	15
2020	Central	6.95	1		0.32	15
2020	Worst	9.04	1		0.32	15
2025	Best	4.84	1		0.32	15
2025	Central	6.92	1		0.32	15
2025	Worst	8.99	1		0.32	15
2030	Best	4.82	1		0.32	15

2030	Central	6.88	1		0.32	15
2030	Worst	8.94	1		0.32	15
2035	Best	4.79	1		0.32	15
2035	Central	6.85	1		0.32	15
2035	Worst	8.9	1		0.32	15
2040	Best	4.77	1		0.32	15
2040	Central	6.81	1		0.32	15
2040	Worst	8.85	1		0.32	15
2045	Best	4.74	1		0.32	15
2045	Central	6.77	1		0.32	15
2045	Worst	8.81	1		0.32	15
2050	Best	4.72	1		0.32	15
2050	Central	6.74	1		0.32	15
2050	Worst	8.76	1		0.32	15

Table 6-13: Pelleting cost and performance assumptions

Year	Scenario	Marginal capex (£/kW)	Marginal opex (£/kW/y)	Variable opex (£/kWh)	Availability factor (%)	Lifetime (years)
2020	Best	116.87	6		0.85	20
2020	Central	166.96	8		0.85	20
2020	Worst	217.04	11		0.85	20
2025	Best	116.28	6		0.85	20
2025	Central	166.12	8		0.85	20
2025	Worst	215.95	11		0.85	20
2030	Best	115.99	6		0.85	20
2030	Central	165.7	8		0.85	20
2030	Worst	215.41	11		0.85	20
2035	Best	115.7	6		0.85	20
2035	Central	165.28	8		0.85	20
2035	Worst	214.86	11		0.85	20
2040	Best	115.4	6		0.85	20
2040	Central	164.86	8		0.85	20
2040	Worst	214.32	11		0.85	20
2045	Best	115.11	6		0.85	20
2045	Central	164.44	8		0.85	20
2045	Worst	213.77	11		0.85	20
2050	Best	114.81	6		0.85	20
2050	Central	164.02	8		0.85	20
2050	Worst	213.23	11		0.85	20

6.2 Stock projections

Table 6-14: Domestic and Non-domestic demolition rate

Year	Annual demolition rate - Domestic (%)	Annual demolition rate - Non domestic (%)
All years	0.04%	1.0%

Table 6-15: Domestic new build rate

Year	Annual new build
All years	135,627

Table 6-16: Non-domestic new build rate

Year	Annual new build floor area (m^2)	Annual new build
2018	5,908,030	19,058
2019	5,921,323	19,101
2020	5,934,696	19,144
2021	5,948,149	19,188
2022	5,961,683	19,231
2023	5,975,298	19,275
2024	5,988,994	19,319
2025	6,002,773	19,364
2026	6,016,635	19,408
2027	6,030,579	19,453
2028	6,044,608	19,499
2029	6,058,720	19,544
2030	6,072,918	19,590
2031	6,087,200	19,636
2032	6,101,568	19,682
2033	6,116,022	19,729
2034	6,130,563	19,776
2035	6,145,192	19,823
2036	6,159,908	19,871
2037	6,174,712	19,918
2038	6,189,605	19,966
2039	6,204,588	20,015
2040	6,219,660	20,063
2041	6,234,823	20,112
2042	6,250,077	20,162
2043	6,265,422	20,211
2044	6,280,859	20,261
2045	6,296,390	20,311
2046	6,312,013	20,361
2047	6,327,730	20,412

2048	6,343,541	20,463
2049	6,359,447	20,514
2050	6,375,449	20,566
2051	6,391,546	20,618
2052	6,407,740	20,670
2053	6,424,032	20,723
2054	6,440,421	20,776
2055	6,456,908	20,829

6.3 Hydrogen cost breakdown (undiscounted)

Hydrogen production

The Hydrogen Tier 6 scenario with maximum rollout of hydrogen to all of the on gas network requires a total SMR capacity of 91.9 GW, resulting in a capex of £18.6 bn, cumulative opex of £44.9 bn and cumulative fuel cost of £188.5 bn to 2050. These SMR are sized to meet the average winter day demand and modulate the output to meet the lower demands of other seasons, with storage being used to meet the peak demand.

Hydrogen transmission

Hydrogen transmisison pipelines are sized to meet the peak demands of each local authority via a radial network that connects each SMR generation plant to all of its downstream connected loac authorities. This results in a total transmission pipeline network of around 6,300 km with average diameter of 16 inches at a capex of £5.0 bn and cumulative opex of £4.2 bn to 2050.

Hydrogen distribution

Hydrogen distribution network repurpose requires replacement of any segments of the gas network not already covered under the Iron Mains Replacement Program, as well as costs for replacing network componenets for compatibility with hydrogen. The total cost of this repurpose of network, as well as any in building changes (e.g. new gas meters, additional gas detectors) is a capex of £22.2 bn.

Hydrogen storage

Hydrogen storage in large salt caverns are used to provide buffer as the SMR runs continuously and also provides discharge for meeting the peak demand. Daily operational profile of storage is assumed, as this requires only 4.5 kWh of storage for every kW of SMR capacity displaced. However, nearly 700 kWh of storage would be needed for interseasonal storage for every kW of SMR capacity displaced which is not cost effective at the current costs of storage relative to SMR. This results in a total storage capacity requirement of 0.32 TWh with a capex of £6.5 bn and cumulative opex of £5.7 bn.

CO_2 transmission

CO_2 transmission pipelines transport the captured CO_2 to shoreline terminals and then to the offshore storage sites. Total CO_2 flows of 81 $MtCO_2$/y are captured by 2050, requiring onshore CO_2 pipelines with capex of £3.9 bn and cumulative opex of £0.3 bn to 2050, while for offshore CO_2 pipelines capex of £6.3 bn and cumulative opex of £0.9 bn to 2050 is required.

CO_2 storage

Depleted hydrocarbon storage sites and aquifers in the Northern North Sea are used for storing the captured CO_2. This results in a cumulative infrastructure investment of £17.4 bn for a total cumulative storage requirement of 1040 $MtCO_2$.

Figure 6-3: Hydrogen network cumulative undiscounted cost to 2050 by category

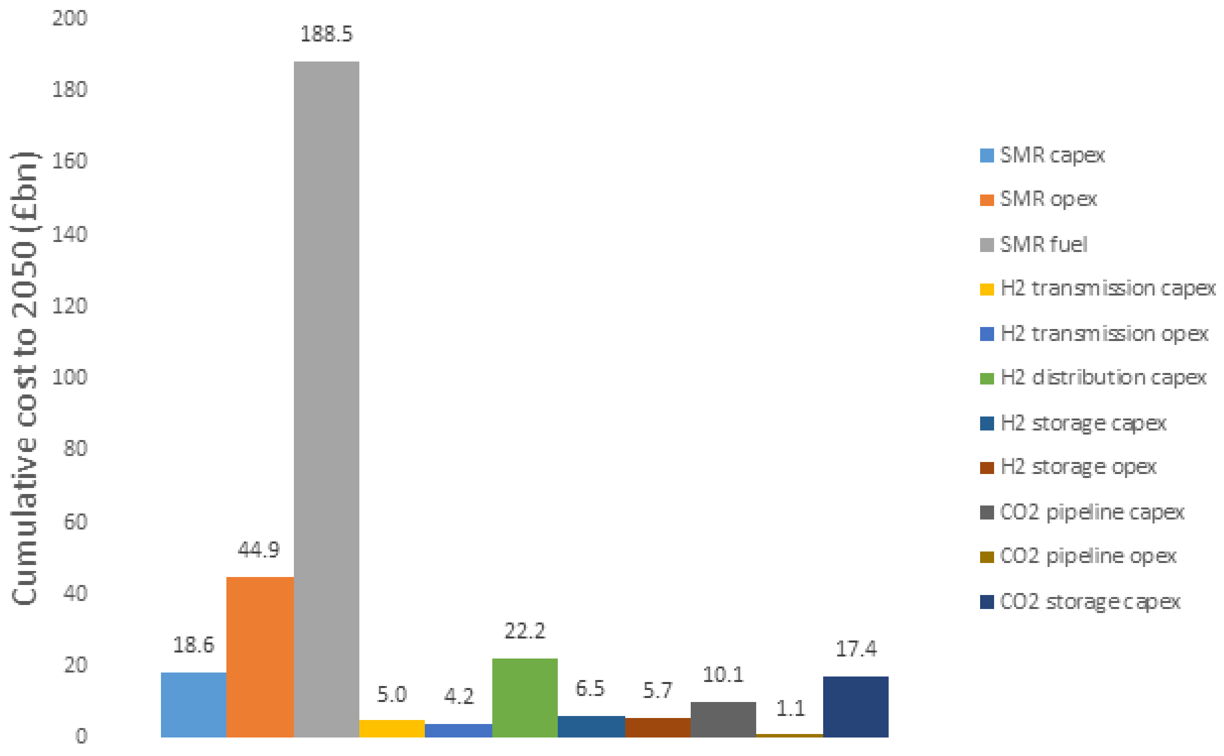


Figure 6-4: Share of hydrogen network cumulative undiscounted cost to 2050 by category