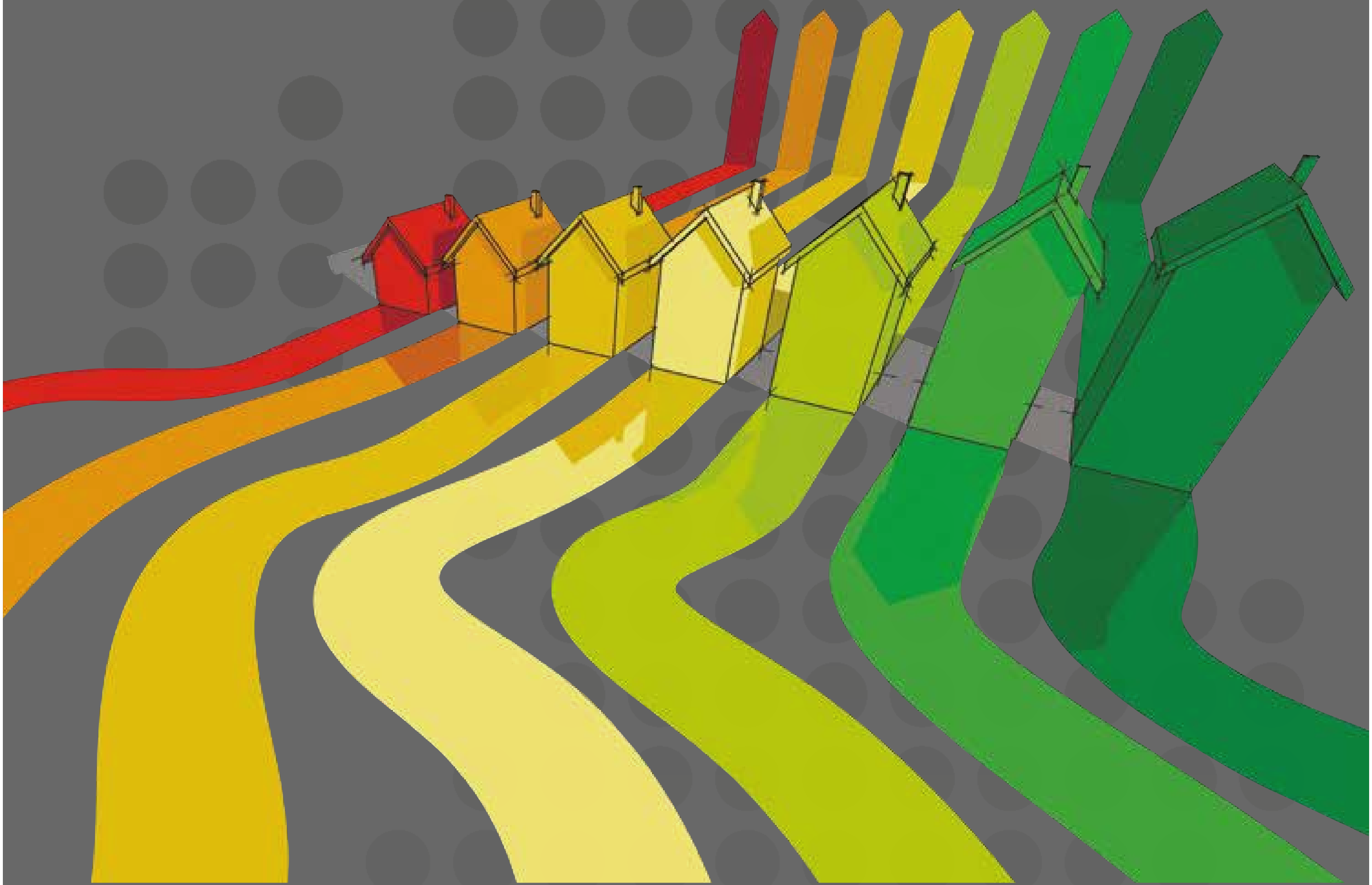
October 2017 Energy Research Partnership

The Transition to Low-Carbon Heat



The Energy Research Partnership

The Energy Research Partnership is a high-level forum bringing together key stakeholders and funders of energy research, development, demonstration and deployment in Government, industry and academia, plus other interested bodies, to identify and work together towards shared goals.

The Partnership has been designed to give strategic direction to UK energy innovation, seeking to influence the development of new technologies and enabling timely, focussed investments to be made. It does this by (i) influencing members in their respective individual roles and capacities and (ii) communicating views more widely to other stakeholders and decision makers as appropriate. ERP's remit covers the whole energy system, including supply (nuclear, fossil fuels, renewables), infrastructure, and the demand side (built environment, energy efficiency, transport).

The ERP is co-chaired by Prof John Loughhead, Chief Scientific Advisor at the Department of Energy and Climate Change and Dr Martin Grant, CEO Energy, Atkins. ERP is supported through members' contributions.

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ERP Reports provide an overarching insight into the development challenges for key low-carbon technologies. Using the expertise of the ERP membership and wider stakeholder engagement, each report identifies the challenges for a particular cross-cutting issue, the state-of-the-art in addressing these challenges and the organisational landscape (including funding and RD&D) active in the area. The work seeks to identify critical gaps in activities that will prevent key low-carbon technologies from reaching their full potential and makes recommendations for investors and Government to address these gaps.

Contents

This project was guided by a steering group, listed below. The views in this report are not the official point of view of any organisation or individual involved and do not constitute government policy.

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Summary: The Transition to Low-Carbon Heat

If the UK is to meet its carbon targets in 2050 of 80% reduction in Greenhouse Gas Emissions, and beyond, we will have to change how we heat our homes and buildings, and the energy used for industrial heat. Supplying Natural Gas or oil directly into homes will no longer be possible and will have to be replaced by either a decarbonized alternative such as hydrogen or bio-gas, or by an electric heating option or heat network.

But it is not a simple choice of one option or the other, as each option presents challenges, which could limit the extent they can be deployed and where. A combination of options is likely to be required, as one option may not dominate in the way that Natural Gas currently does.

The scale of the challenge should not be underestimated. Each of the heating options, and combinations of options, will affect how the energy system operates and how the energy networks are configured, or need reinforcing. Almost all households and buildings will be affected, requiring appliances to be changed and possibly the internal pipework. Measures to reduce overall energy demand in buildings will be an essential part of delivering a cost-effective transition.

The social aspects of the transition are likely to be as challenging as the technical. The capital investment in the transition means that most of the available options will be at a higher cost than the current gas system. Each choice available to a consumer will have a different cost profile, and may affect the energy networks, potentially adding to the costs. Changes to the gas supply means that consumers risk having to scrap an appliance they only recently installed.

Timing is crucial and preparations need to begin now for an efficient transition, to enable investments and develop business models, over the next thirty years. Long investment cycles mean that industry needs clear signals as to where to apply its resources.

Preparing now to deliver an efficient transition

The transition to a decarbonised heat system, will require coordinating and enabling investments in homes and across the energy sector, whilst avoiding unnecessary costs. Clear long-term plans and signals will be needed to enable informed decisions. Understanding the potential to decarbonise the gas network should be a priority, but until there is clarity about the feasibility, costs and availability of Carbon Capture and Storage (CCS), it presents several risks, which could make the transition considerably more expensive. Reducing these risks requires supporting investments now, in order to develop and deploy a range of options. Some are 'no regrets' that can already be deployed, such as in off-gas areas, others will provide options that could reduce costs and mitigate risks.

Early engagement with the public will be vital to help design policies, products and communication programmes. A clear, national narrative will be needed that brings together the various aspects of the transition, including the overall need to move to new heating systems, operational concerns, and financing mechanisms. A combination of regulatory and financial packages will need to be developed to encourage consumer uptake and ensure timely upgrading of the energy networks and infrastructure. A trustworthy advisory service will be needed to provide consumers with an independent source of information.

A decision-making framework will be required to determine which options should be deployed across the country and where. Investment decisions will need to be aligned with local and national interests and with other energy sectors. Synergies or competition for resources may come from changes in the transport sector and industry. Optimising the design of networks and the energy system, and securing investment, will require long-term planning, supported by clear policy guidance.

Conclusions and Recommendations

The report makes recommendations on three key aspects of the transition, that will need to be addressed to reduce the risks and costs, and deliver an effective and coordinated decarbonisation of heat.

1. Several low-carbon heating options need to be pursued in parallel now. Early in 2020s, critical actions and decisions will need to be taken, by Government, to avoid closing-off options, undermining their potential, or increasing their costs.

- **Determining the extent to which hydrogen could be used to decarbonise the gas system, is critical. In addition to the regulatory aspects, understanding is needed of deployment rates, skills and costs.**
- **Carbon Capture and Storage (CCS) is essential to enable the deployment of hydrogen. Government needs to address barriers to enable a CO_2 transport system and suitable storage sites to be secured.**
- **A Government supported programme to demonstrate and trial key technologies is needed now, to better understand their technical, social and operational aspects. Public and private sectors innovation funding is needed to trial hybrid heat pumps, bio-Synthetic Natural Gas (bio-SNG), heat storage technologies and new retrofit energy efficiency measures.**
- **No and low-regrets options should be supported now, particularly in off-gas areas where fewer options are available.**
- **High efficiency standards for new-buildings need to be set and enforced by Government. Very low energy bills offer a quick pay-back and the buildings will require no further modification to decarbonise.**
- **Government needs to develop a robust retrofit energy efficiency programme for existing buildings to reduce the overall cost of the transition.**

A priority for heat is to determine the extent to which the gas network can be decarbonized by 2050, using hydrogen, bio-SNG and/or bio-methane. Critical to this is understanding the resource availability of bio-SNG and bio-methane, as well as the potential and costs of hydrogen, including the regulatory and safety aspects, the logistical challenges of converting all appliances, building the production, storage and import facilities, and identifying future sources of zero-carbon hydrogen. The investment by BEIS of £25 million to investigate its potential and run trials, is an important step towards informing an early decision.

CCS will be essential to secure investment in the widespread deployment of hydrogen. Equally, large-scale hydrogen production could provide a cost-effective and practical means to enable CCS. A CO_2 transport network will be needed and storage sites de-risked, to take the carbon emissions from producing hydrogen from natural gas. Hydrogen could be produced from electricity, but it currently presents higher risks, as the costs and volumes produced are uncertain. CCS will also benefit other options, including power generation and potentially delivering negative emissions when used with bio-energy. The absence or delay of CCS will radically change which options can be deployed, and could lead to increased costs and greater disruption to services.

However, waiting for a decision on hydrogen, and understanding the extent to which the gas system can be decarbonized, is not an option. Other ‘no regrets’ options can be deployed now that will not conflict with the potential decarbonisation of the gas system, including energy efficiency measures and deploying low-carbon options in off-gas areas.

Trials of other heating systems need to be supported, to provide options for the future energy system. These need to explore not only the operational aspects, but, importantly, provide better understanding of the social, financial and logistical challenges of deployment.

Availability of bioenergy for heating needs to be better understood. Demands from the power, transport and industry sectors, driven by best-use hierarchy could significantly reduce the potential of this option.

New-buildings are likely to represent 10-25% of properties in 2050[1], and should be designed so they do not need to be connected to the gas network. Enforcing high efficiency standards now, will allow low-cost heating and hot water options to be installed and avoid expensive retro-fits over the next 30 years. The overall cost and payback times are likely to be lower than for a heat pump or for connecting to a gas or heat network.

A demand reduction programme will make all options easier. The challenge is to reduce costs so that deeper reductions in energy demand can be cost effective, with business models for deploying it, and developing techniques to make it quicker and easier to install. The business case should consider the total cost to the owner/consumer, as an improved thermal performance can not only reduce the amount of energy consumed, but may allow an alternative, lower-cost heating system to be used.

Intra-day thermal storage (available now) could be co-ordinated to reduce winter peak demand; inter-seasonal thermal storage (being developed) could reduce required network capacity and use of high-price winter fuel.

[1] ERP 2016 Heating Buildings & National Grid FES 2017 – depends on build rate and population growth

2. Addressing the social aspects of the transition needs to be a priority and requires early engagement with the public, alongside the development and coordination of financial policies, incentives, regulations and business models. These need to facilitate informed choices, deter inefficient decisions, and to distribute costs appropriately between customers and over time.

- **Engagement with the public will be crucial and needs to start now, to inform the development and deployment of each option and to inform the development of finance policies and business models.**
- **The narrative on providing heating and hot water needs to change to recognise that costs will increase, whether paid for by tax or energy bills.**
- **Energy efficiency should be pursued to deliver cost-effective emissions reductions, and promoted to customers as a means of controlling the costs of options, especially those with higher fuel costs.**
- **Government should decide how to address distributional impacts of cost differences.**
- **Government and Ofgem should prioritise the design of new financing mechanisms and market structures to manage costs.**

  The cost of providing heat will increase, either directly through costs of fuel and equipment, or indirectly through the need for ancillary services (energy storage, communication and control system), system upgrades (networks, transmission and generation) or demand reduction (insulation and energy efficiency measures). Demand reduction measures will be important to manage the overall cost of the transition.

  Costs are likely to differ geographically/regionally, with customers potentially facing substantial increases in costs. Policies and financial incentives may have to be area focused to enable uptake, facilitate informed choices, deter inefficient decisions and avoid choices that could be disruptive to the energy networks. Failure to do so could lead to additional costs through upgrading of other energy networks as well.

  Industrial and commercial customers are also likely to be affected by cost distribution issues. Local and national policies will need to be aligned to address these issues.

  Temporal distribution of costs will also need to be addressed. For example, where hydrogen replaces natural gas in the gas network, the first customers to transition will bear the higher costs for longer than the last movers; a customer on one network may convert 15 years before another network. Socialising these costs would reduce the impact, but decisions would have to be made as to how this should be done and who would bear the costs. This is distinct from the current costs inequities between on-gas and off-gas customers; for the latter, the options are limited and the cost of extending the gas network prohibitive.

  Variations in the cost profiles for each option means decisions will be need as to how the costs will be co-ordinated (e.g. through policy instruments, incentives, energy bills), recovered (e.g. taxation, regulated network costs, or competitive retail energy costs) and distributed (e.g. at-cost to each customer or socialised).

3. A long-term strategy is needed for how the transition will be managed, which engages with the public and brings together and coordinates the diverse range of interested parties, and sets out a clear decision-making framework.

- **The strategy needs to integrate decisions on energy for heat with those for transport, industry and power generation.**
- **A heat delivery body should be formed to facilitate the decision-making processes and coordinate national, local and commercial decision making.**
- **Early engagement with the public will be crucial – as will a clear narrative**

  A heat delivery body would help align the regulatory requirements, local and national priorities and mobilise the commercial and industrial investment. Regulators, DNOs, GDNs, TSO, appliance industry, local and regional government, central and devolved governments and NIC need to be coordinated and adequately resourced to enable effective delivery of a heat strategy. An uncoordinated approach could lead to costly duplication of effort, delays in meeting targets and undermine the confidence of industrial investment.

  A heat strategy needs to integrate with strategies for buildings (new and retrofit), transport, industry and wider energy policy. Determining best use will be important for constrained energy supplies, such as bioenergy. Benefits will also derive from coordinated development and upgrading of energy infrastructure and networks, to meet the demands of both heat and transport.

  Consumers will need to be involved at an early stage in the transition to inform and enable planning as to appropriate measures to take and to develop the marketing for the various options. In areas where hydrogen is introduced, consumers could purchase appliances that become stranded, if ‘hydrogen ready’ boilers are not available in advance. A lack of early information in an area designated for hydrogen, could mean consumers choose to make a large investment in a low-carbon option, for example a heat pump supported by the RHI, only to find that a simpler, low cost alternative was being provided. The cost of these stranded assets could also be significant. A trustworthy advisory body will also be required to provide independent advice on the various options and their costs.

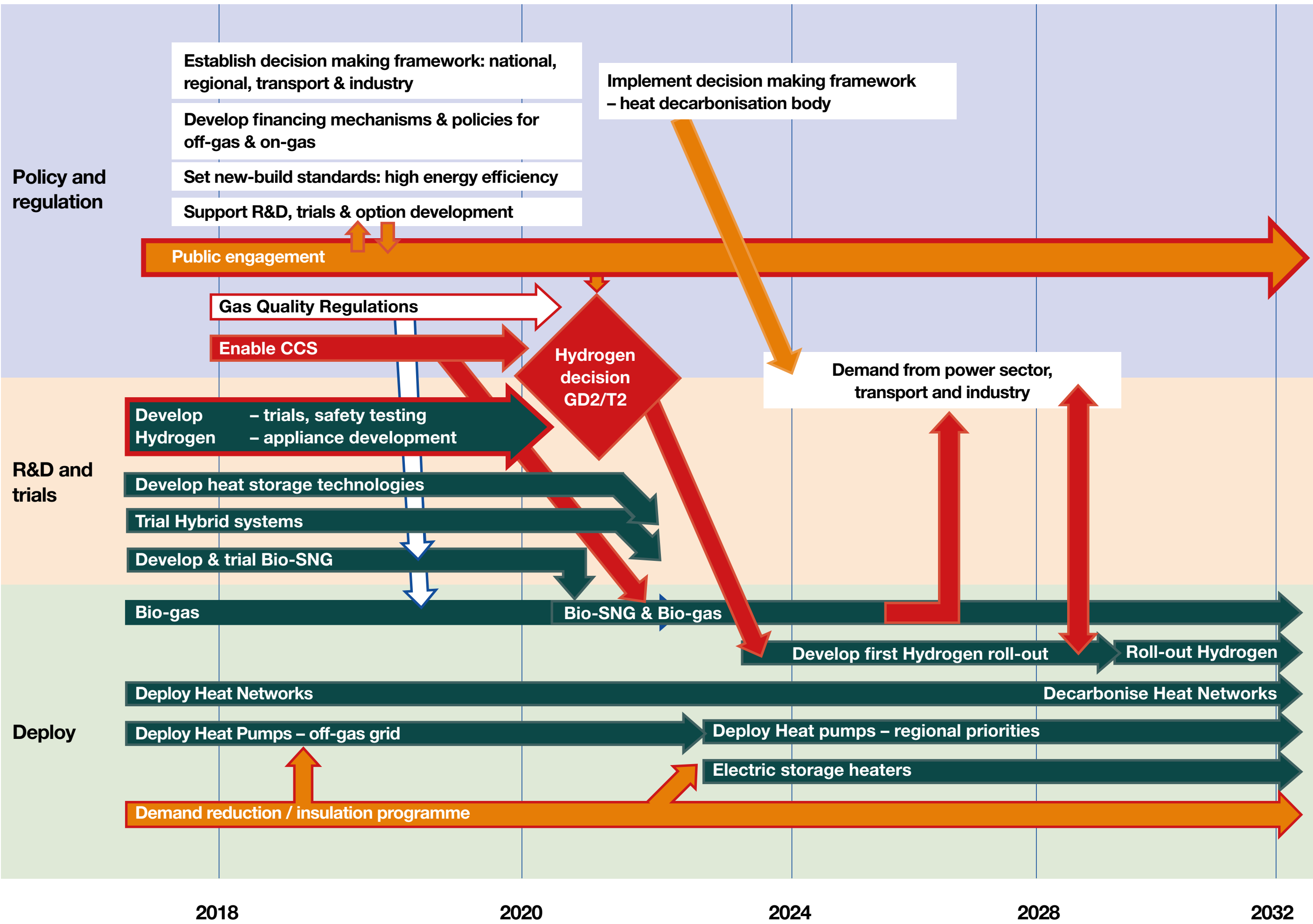

Figure S1 Roadmap for decarbonising heat. Several options will need to be deployed to achieve the objectives. Clarity about the potential of hydrogen is needed in the early 2020's as it will define how the energy system develops. Policy and regulatory decisions (white boxes) are needed to enable the transition. Key enabling actions (orange boxes) will improve decision making and reduce costs. Other heat options (green arrows) need to deploy and develop in parallel.

1 Introduction

Domestic and commercial heat account for about a quarter of UK emissions. The Committee on Climate Change (CCC) advises that if the UK is to meet its 2050 target of 80% reduction in Greenhouse Gas emissions, it will be almost impossible without the near complete decarbonisation of heat[2]. This will mean that Natural Gas, which provides heating for over 85% of homes will have to be replaced with either a decarbonized gas, or an electric heating option.

A range of options to decarbonise heat are available or in development. However, the practicalities and implications of delivering these are becoming increasingly clear, along with recognition that the social and financial aspects of the transition will be an important factor in its success. The expectation that electric heat pumps will be the primary technology, as proposed by the 2013 Heat Strategy, is being challenged, as the expense and practicalities of deploying them are being realised.

Heat networks are being rolled out, offering a potentially efficient means of delivering heating for areas with sufficient population density. Efficiency could improve further if a Combined Heat and Power (CHP) unit is used, as long as the energy supply can be decarbonized. However, social factors affect their uptake in residential heating, with the need to ensure the customer is getting a competitive price. Retrofitting heat networks will also require a guaranteed market, but would also require digging up roads and new pipe work into customer's homes.

Other options that are in development and coming to the fore, particularly hydrogen and bio-gas[3], which could play significant roles, but gaps remain in our understanding of them. For bio-gas, questions remain about overall supply, and its best use in the energy system, and how to capture its potential to deliver negative emissions[4]. Uncertainties about the safety of hydrogen is being addressed by the BEIS funding, and subsequent trials and developments will clarify deployment rates and logistics, and costs[5]. It may therefore be early 2020's before there is clarity about their potential.

Tentative investments are being made by parts of the industry to help inform the developments of hydrogen and biogas. But this uncertainty about their potential is creating a hiatus in policy on heat, leaving the industries involved uncertain as to the technologies and infrastructure to invest in. In off-gas regions, hydrogen will not be an option, so other options will need to be deployed. Heat networks, preferably with CHP units, could be deployed without being incompatible with the decision on hydrogen. With a risk that there may be limits on the extent that hydrogen or bio-gas could be deployed, keeping other options open would reduce the future costs.

The transition to decarbonised heat will occur alongside other major changes in the energy system. Transport, industry and the power sector will be looking at similar energy sources, and changes in the way electricity is generated, with increasing variability, will place additional pressures on how the system is configured.

This report explores the timelines for the transition to decarbonised heat and sets out the issues that need to be addressed to enable timely investments, engage the public and reduce the costs.

1.1 The scale of the challenge

One of the biggest challenges for the transition is developing a system that can deliver the scale and flexibility of energy supply provided by the current gas system at an affordable cost and an acceptable level of disruption in terms of street-works and in homes. The nature of heating means it requires huge variations in hourly and seasonal energy demand (see Text Box). Gas, and other liquid fuels, are easily stored to respond to these changes.

The scale of energy used, often only at peak times and for only half the year, presents challenges to all the options. With winter gas demand about five times that of summer, inter-seasonal energy storage requirements are huge. Apart from gases and solid fuels, storing energy is expensive, with electricity considerably more than heat.

Nearly all consumers will be affected by the transition, over the next 30 years and are likely to require a new appliance and possibly make improvements to the fabric and insulation of the building. Some options will change how and when heat is used in the home, which will require managing consumer awareness and expectations. The exception could be for new build properties, if building standards are improved now, it will remove the need for expensive retrofitting in the next couple of decades. Regulations and incentives will be required to deliver the changes and manage the costs of some options. For example, upgrading the current housing stock – in particular for solid walled properties - is likely to require a government support programme given the significant costs, which few customers will be able or willing to pay for without. Such a programme will also need to address the impact on the aesthetics of buildings, which many customers are attached to.

[2] CCC Sectoral Scenarios for 5th Carbon Budget Box 3.14

[3] Carbon Connect 2017, Next Steps for the Gas Grid, Future Gas Series: Part 1

[4] CCC Bioenergy Review 2011

[5] www.gov.uk/government/publications/funding-for-innovative-approaches-to-using-hydrogen-gas-for-heating

TEXT BOX: The challenges of supplying heat

It is not just the overall quantity of energy that is needed to provide heat that makes decarbonising heat challenging, low-carbon heating options will also need to address the huge variations in demand over a few hours. The main challenges are:

- **Peak demand** – Across the UK, residential peak demand for heat is about 300 $GW_{thermal}$ [thermal demand rather than energy], currently largely met by gas. Delivering this with electric heating will be challenging; although heat pumps can be considerably more efficient, the highest peaks are when it is cold outside, which is when heat pumps are least efficient. Additional generation capacity and network reinforcement will be needed, the scale of which will depend, to a degree, on the extent of fabric improvements to buildings to reduce heat loss.
- **Load-shifting** – Unlike transport, where electric vehicles can be charged during off-peak periods, heat demand is hard to shift, as storing useful amounts of heat requires large stores. Reducing heat loss from buildings will allow greater flexibility, as the heat input will be easier to interrupt.
- **Rate of demand change** – At peak periods demand can change by 100GW over an hour.[6] This flexibility is currently largely met by gas stored in the pipes.
- **Inter-seasonal storage** – Heat demand is highly seasonal, with summer peak half-hourly demand for heat dropping to less than a fifth of winter (~$50GW_{th}$),[7] With nearly all the energy demanded during the winter months, storing this volume of energy between seasons can only realistically be provided by gaseous or energy dense solid fuels. To put it in context, the combined total energy that could be stored in the 13 million domestic hot water tanks could provide 80 GWh of heat energy storage.[8] However, the trend is towards combination gas boilers, with hot water tanks being removed to free up space. While this can be more efficient, reducing heat loss from the tank, it will be hard to reclaim that space for a heat store; new technologies with higher energy densities, such as phase change materials, would reduce the space requirements.
- **Hot water** – instantaneous demand of energy is largely met by natural gas. This increase in demand is easy to buffer through gas storage in pipes. Without hot water tanks, managing these peaks with electricity will be much harder.

Fabric improvements to building, such as insulation and draft excluding could reduce heat loss and therefore help manage peak demand. But, the cost of installing these measures has to be balanced against the payback and the non-financial gains, including comfort.

Efficiency measures, such as condensing boilers and heating controls mean that overall heat demand has been declining over recent years, and could decline further. This may reduce peak gas demand, and be beneficial for decarbonised gas solutions, but improvements to the fabric of the building will be required to impact non-gas heating options.

Future climate

The weather will affect heat demand and summer cooling. Inevitable climate change will mean that winters in 2050 are likely to be on average be 1-2°C warmer than current, although this does not rule out the possibility of periods of very cold weather. Similarly, summer temperatures are expected to be higher, which may increase demand for air conditioning. This could be met using reversible heat pumps, but they would require an air-to-air heat-pump system or cooling units added to the wet-system. Insulation measures for winter warmth will also help manage summer overheating.

Mix of housing stock

Choice of heating option may be restricted by the heat demand of the building, which may be too high for some systems to work efficiently. For example, a heat pump in a large, poorly insulated property would either run very inefficiently or would require a bigger unit that may exceed the rated supply to the building, requiring an expensive upgrade to the wiring.

The physical size of some heating options will make them hard to install in some buildings, with some two or three times the size of a standard gas boiler, which would make them hard to install in some buildings, such as hybrid heat pumps. The need to add a water tank for some systems would increase the challenge, as would the need for external heat exchangers.

[6] Sansom 2014
[7] Sansom 2014
[8] Low Carbon Futures 2012

1.2 A range of options are being proposed

A range of heating options could be used, with some offering greater potential than others. Some, such as hydrogen, are still in development. with their potential dependent on key aspects being better understood. Whilst it is possible to analyse and model the deployment potential of a technology, how it could perform and how the energy system needs to be configured to support it, there are various social and financial factors that could affect the extent to which they can be deployed. It is possible that no single technology will dominate in the same way that gas currently does.

If one option proves harder to deploy than expected then a greater onus will be put on other options, along with changes to how the energy system is configured. The likely outcome is therefore that the transition will see the development of a combination of options, which will require a firm understanding of the decision making and financing to avoid unnecessary costs and conflicting developments.

1.3. Governance aspects

The overall objectives of the transition are to meet the 2050 carbon emission targets through the long-term decarbonisation of heat and avoid unnecessary costs. Numerous organisations, local authorities and businesses will need to make decisions about their investments and priorities, and about 30 million households will make changes to their heating systems, and the fabric of their buildings. Network companies and appliance manufacturers will need guidance to develop business plans to make timely investments and develop the necessary technology and skills.

The various options available are driven by different actors. In new-build properties the purchaser 'buys into' the heating system that is installed. In existing buildings, the owner will be involved in the change, except where bio-methane is used,[9] which may require only minor changes to appliances. The decision to introduce hydrogen into an area will be more complex, and is likely to involve the local authorities and the network companies, but will also require customer buy-in. The local authority agenda will be driven by several factors including air quality, fuel poverty and provision of services to local businesses. Consumers may wish to opt out, but they will be required to decide at the point of transition. Where there is no gas network, the choice of heating option is made by the consumer, with decisions to switch led by incentives or regulation or mandating of appliances.

Switching from gas to electricity or biomass, is currently made by the consumer, assisted by national policies, such as the Renewable Heat Incentive (RHI). The timing, location and rate of transition is therefore determined by consumers 'opting-in'.

The decision-making framework is important for the success of the transition, and the current lack of clear allocation of roles and responsibilities across decision makers and a lack of coordination could lead to problems[10]. Local solutions need to be coordinated with national objectives and the wider system implications understood, but to do this they will need to be given responsibility and access to resources. Coordination is also needed across policy objectives, such as how to treat fuel poverty where reducing heat demand may be more effective in the long term than switching to the energy vector that is currently the lowest cost.

[9] low blends of hydrogen may also not affect appliances, although it is not a long-term option as it will have limited impact on full decarbonisation.
[10] Frontier Economics 2016 Regulation of Gas Grid for CCC

1.4 Historical comparators

To help understand the complexity of the transition to low-carbon heat it is worth comparing it with other major transitions (see Text Box). These are often cited to demonstrate the ease with which the UK can decarbonise heat. However, decarbonising heat will be more challenging in all aspects, as none was as large or required the coordination of as many stakeholders and technologies: the low-carbon heat transition will require arguably unprecedented preparation and facilitation.

Furthermore, low-carbon options are likely to be more expensive, as with the conversion to natural gas in the 1970s, but it is unclear if they can provide the same utility currently provided by natural gas. Convincing the public to undertake the inevitable disruption, and of the benefits and safety of the available options may be much harder.

TEXT BOX: Historical Comparators

Switch from Town Gas to North Sea Gas (1960-70s)

This is often used to highlight the potential ease of converting the gas network to hydrogen. The number of homes that will need converting per year is comparable, but the scale of conversion could be more challenging. The market structure and public attitudes were very different. In the 1970s, each home had fewer gas appliances, with few using gas central heating. Modifications were quicker and cheaper, with appliances requiring only parts to be changed rather than the whole unit.

Public acceptance was easier to win: there was a more trusting relationship between government, state-owned companies and the public, and North Sea gas and the introduction of central heating were regarded as a definite improvement, despite – it is argued – that natural gas was more expensive. Co-ordination was simple, and delivered by a vertically-integrated company; and most homes were occupied during the day.

Power sector decarbonisation (1990s onwards)

This is separable from the demand-side, i.e. electricity can be decarbonised by changing the generation equipment. By contrast, heat can be produced from several different energy vectors, each requiring specific distribution systems and heating technology, so supply-side changes to energy vectors necessitate changes to the distribution and / or heating systems.

Digital TV switch over (2000s)

The programme showed good customer engagement and communications, but only involved replacing or adjusting a few appliances in each building, with no changes to building infrastructure, and assistance was available. So, it was much simpler than decarbonising heating, and had fewer consequences for anyone who missed a deadline.

Diesel replacing petrol for cars and vans (2000s)

Whilst the lifespans of heat sources and road vehicles are both about 10-15years (although each vehicle stays with an owner for typically 5-10 years), customers can easily switch road fuels because both are already distributed to fuelling stations, whereas their buildings are unlikely to have access to an alternative energy vector (except electricity, although the capacity may not be large enough).

2 Options, resources and constraints

How heat will be decarbonised is currently unclear, but broad, high-level pathways to 2050 can be distinguished. These differ depending on whether the building is currently on the gas network (see Figure 2.1) and affect mainly residential and commercial properties. Options for industrial users will be affected by the impact decarbonisation has on the energy networks.

The 15% of residential properties that are off the gas grid, are likely to continue to utilise a diversity of options. Fuels may be decarbonised, for example bio-oil, with minor changes to appliances. Better insulated buildings could switch to electric heat pumps and storage heaters.

New-build could amount to 10-25% of all properties by 2050[11]. Building with low-carbon options now will prevent them having to be retrofitted in the next couple of decades, at additional cost to the consumer and the energy system. High insulation standards should be prioritised, with building designs enabling low-cost heating options to be utilised. The additional costs to the build is likely to be small and quickly recouped by the occupier, through significantly reduced energy bills.

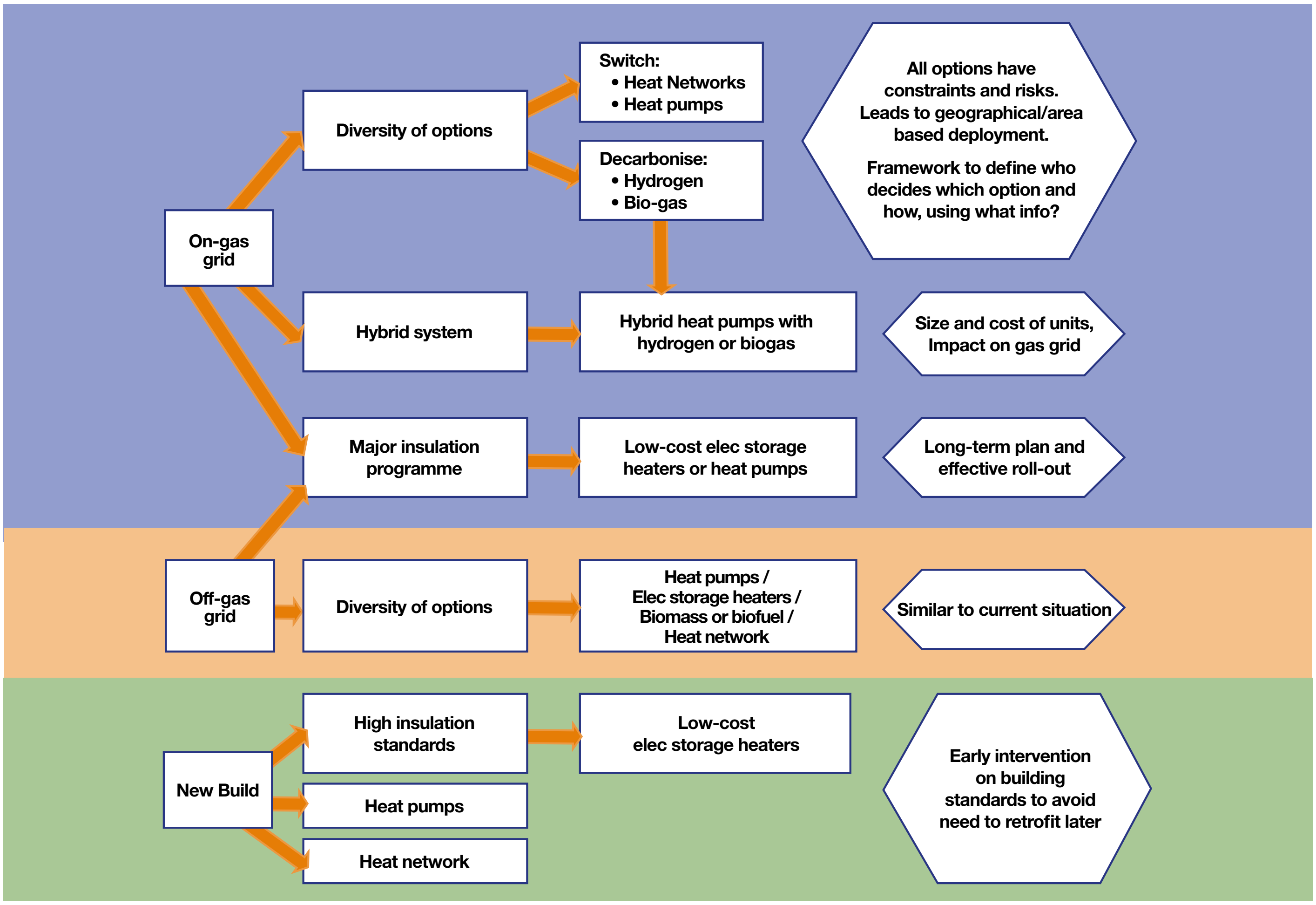

Figure 2.1: The options to reduce carbon emissions from heating depend on whether the building is currently on or off the gas grid or is a new build. Each sector has a choice of long-term pathways, which will lead to a different set of heating technologies being used, which in turn has implications for how the transition will be delivered. The default pathways are likely to be towards a diversity of options.

For the 85% currently supplied by (fossil) natural gas, three main pathways are available. A major programme of building fabric improvements to reduce energy demand of each property, enabling low-cost electric storage heaters to be installed; a diversity of options, with some homes switching to electricity or heat networks, with the remainder supplied by decarbonised gas, such as hydrogen or bio-gas; or, a hybrid system, with an electric heat pump delivering a majority of heat demand, but switching to gas to manage the challenges of meeting peak demand.

All of these pathways present significant challenges. Each would lead to very different configurations of the energy networks and infrastructure, in order to deliver a secure and resilient system, and would be developed alongside increasing demand for low-carbon energy from transport. In all cases, a national insulation programme will be essential to help manage the transition and enable the various heating options to provide cost-effective solutions. The costs and implications of these changes are explored in subsequent sections.

[11] ERP 2016 Heating Buildings & National Grid 2017 Future Energy Scenarios – depends on build rate and population growth

2.1 Options and constraints

Much of the focus has been on how to develop and bring individual options forwards. However, the extent that each option will contribute to meeting heat demand in 2050 is dependent on factors that will affect their deployment, limiting the scale at which they can deliver or the location and where they can be deployed.

Table 1 outlines the constraints and issues for the main options. Some are available now, such as biogas, electric heat pumps, demand reduction and heat networks. Others need further understanding and testing, before they can be deployed, such as hydrogen.

Heating option		Constraint / issue
Decarbonised gas supply	Hydrogen	CCS availability Regulatory cost / safety Public acceptance Conversion logistics (build rate of infrastructure) End-user appliances Extensive inter-seasonal storage capacity Early competition from other energy sectors Long-term GHG emissions – zero-carbon hydrogen supply
	Biogas / BioSNG	Limits on feedstock availability Competition from other energy sectors and best-use (potential for negative with CCS in other sectors) GHG emissions and role of CCS Need for inter-seasonal storage
Decarbonised Heat Networks	CHP (new build & residential retrofit)	Supply of decarbonised energy – relies on decarbonised gas supply? Retrofit requires minimum uptake threshold to be viable
	Ambient heat	Geographical constraint – distance to heat source
	Waste Heat	Long-term reliable heat source Location of heat source
Electrification with heat pumps and hybrid systems	Heat pumps	Suitability of building Size of units – inside and outside building Social acceptance – noise, unfamiliar operation Infrastructure – network & generation capacity
	Storage Heaters	Highly insulated building Social acceptance – unfamiliar operation
	Hybrid systems	Decarbonised gas supply Commercial models – high capital cost Gas network operation – low gas flows
Niche technologies	Biomass	Feedstock availability – conflict with food security
	Solar Thermal	Limited, seasonal energy supply
	Micro-Combined Heat & Power (mCHP)	Decarbonised gas supply Commercial models Control protocols Electricity network configuration

Table 1 Overview of main heating options and the constraints and issues that may affect their deployment.

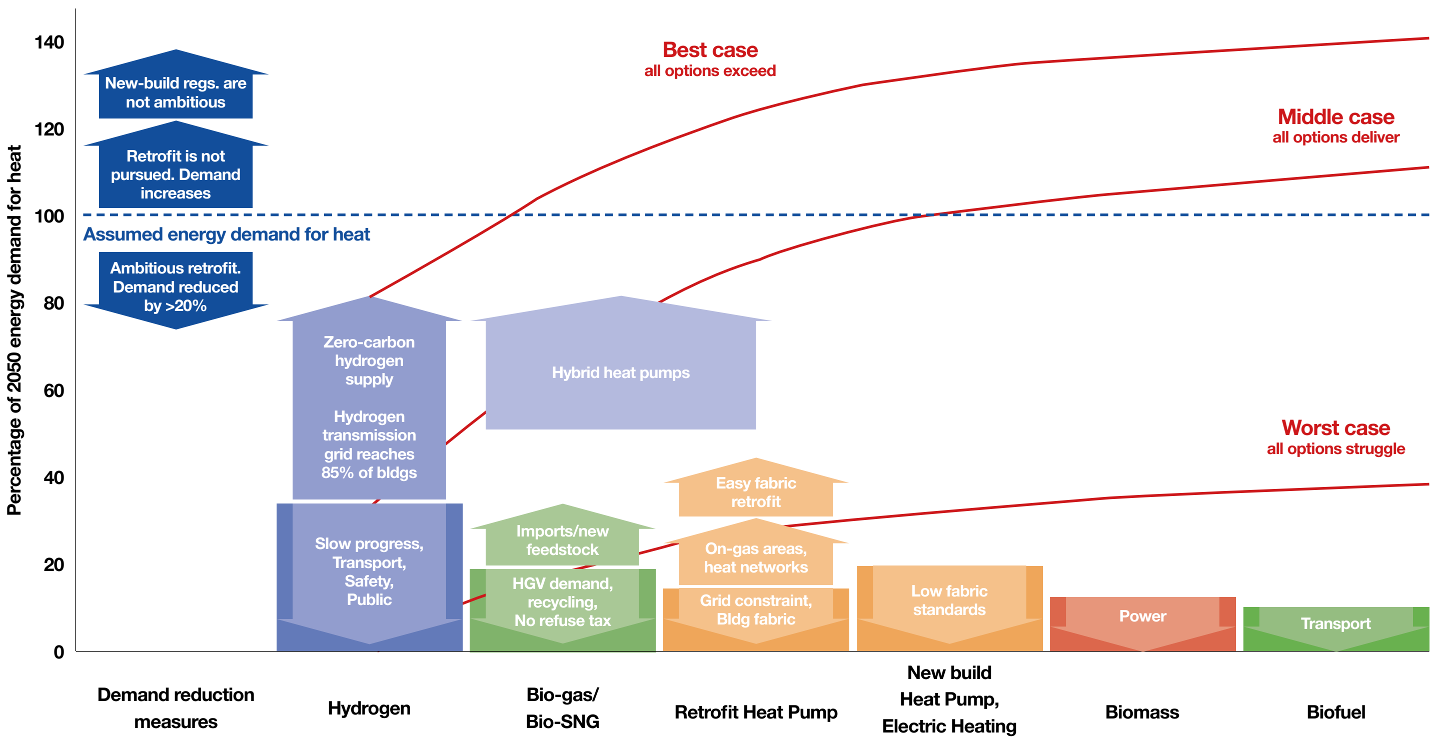

Figure 2.2 Percentage contribution to heat energy demand in 2050 by different energy sources. Various factors (text in arrows) increase or decrease contribution from each option. Red lines show cumulative supply from all energy sources under three scenarios. Blue dashed-line shows expected annual demand. Blue arrows indicate demand may increase or decrease depending on energy efficiency measures imposed. Hybrid heat pumps could be widespread and woud reduce the overall demand for decarbonised gas. Demand from other energy sectors may be important, e.g. competing for bio-gas and hydrogen. Note, some options interact, e.g. hydrogen could displace biogas in the gas network, or biomass for bioSNG converted to hydrogen.

Figure 2.2 illustrates best estimates and sensitivities for the potential options. It suggests that there is likely to be sufficient energy supply available to meet the expected heat demand from residential buildings, if demand is controlled (see text box). However, it suggests that no one option will dominate and a mix of options will be required. Alternatively, substantial effort could be put into deploying specific options, to increase their contribution and offset the risk of one of the other options not delivering. If the constraints proved significant across all options, then any shortfall will continue to be delivered by natural gas, which will be the default supplier of energy for heating, but with associated greenhouse gas emissions.

2.2. Demand levels in 2050

Several studies suggest that demand from residential properties in 2050 will be similar to current demand, with the increase in numbers of homes offset by high insulation standards in new-build and further insulation measures for existing homes. Failure to implement high fabric standards on new-build properties and/or retrofitting existing homes will increase overall energy demand, placing unnecessary pressure on limited resources and threatening the UK's ability to decarbonise (Figure 2.2).

Deeper demand reduction could be more cost effective than previously assessed, and could lead to demand levels in 2050 lower than current[12]. Ambitious targets could reduce heat loss from homes and buildings enough to enable a low-cost electric heating option to be used, which will have a long-term impact on lowering consumer's energy bills, reducing CO_2 emissions and improving energy security. The challenge is how to enable it.

A strong policy commitment will be required that defines retrofitting as a national infrastructure programme, with investment in new techniques that can deliver effective demand reduction with reduced disruption and quicker delivery. It will also require developing appropriate skills and standards to ensure high quality work.

[12] UKERC/CEID 2017 Policy Briefing, Unlocking Britain's First Fuel: The potential for energy savings in UK housing

TEXT BOX: Impact of demand reduction measures

For the consumer

Insulating buildings reduces the rate of heat lost from the building and therefore the rate at which heat must be supplied to maintain the desired temperature. Lowering the amount of heat that needs to be supplied has several effects. It has direct impact on the fuel bill, as heat demand is lower and the appliance providing the heat can work more efficiently. Heat pumps work best in well insulated properties, delivering efficiencies averaging about 300%. In large, 'leaky' buildings a bigger heat pump unit will be required, which may put excessive demands on the electricity networks, particularly in cold weather when the efficiency drops.

High insulation measures could allow an entirely different heating system to be installed, that has a lower capital and maintenance cost and cheaper to run. For example, a high cost heat pump could be replaced by low-cost electric storage heaters.

As heating demand reduces, the energy needed for hot water becomes more significant. The higher temperature and instantaneous demand means it is more likely to determine the size and type of appliances, or a separate unit. Heat storage systems may be beneficial, but will require space provision.

At a system level

Low heat loss will allow some smart management of heating, with units switching off temporarily in response to stresses on the electricity system. Storage heaters could provide additional benefits, during winter months, of being able to provide services to the grid, 'charging' when there is surplus generation on the system.

Reducing overall demand means that the supply of energy can be distributed across a wider number of customers. This reduces the need for additional generation capacity. It also reduces the impact on the energy transmission and distribution networks, potentially avoiding the need for expensive upgrades and reinforcement.

See Section 3 for details of the economic implications of insulation.

2.3. Greenhouse gas emissions

Most of the heating options available are not fully decarbonised. While most are zero-carbon at point of use, upstream emissions from the production of the energy vector will need to be addressed to remove any emissions. Additional infrastructure will be required towards 2050 to manage upstream emissions, along with decisions about best use of bioenergy resources. This may not present an issue for achieving the 2050 targets of an 80% reduction in emissions, but the expectation that the UK will set a zero-carbon target by 2070/2080, in line with global ambitions, means that infrastructure built towards 2050 will need to be compatible with these increasingly tough targets.

For heat pumps, this means tackling emissions from power generation. For hydrogen, emissions from production using Steam Methane Reforming (SMR) and gas extraction will mean large volumes of hydrogen will need to be sourced from renewable energy. Limited domestic resources will mean developing an international trade in hydrogen and building import facilities.

TEXT BOX: Overview of constraints

Energy resource and Greenhouse Gas Emissions

- Limits to availability of primary energy supply, such as bio-energy feedstocks.
- Whole system GHG emissions: upstream emissions e.g. from gas extraction for hydrogen production from SMR; alternative best-use – potential negative emissions from bio-energy.
- Competition between energy sectors, e.g. transport and industry for bio-gases and hydrogen
- Increase in primary energy consumption.

Logistical and physical constraints

Deployment rate: Over the next 30 years, 16,000 homes per week need to be converted (assuming new-build standards are raised, so they do not need to be revisited). By comparison, over 5,000 boilers are currently fitted each day, but the scale of intervention to each property is likely to be larger.

- New skills and training programmes will be needed.
- Disruption to roads: Retrofitting heat networks to install pipes. Electricity reinforcement for heat pumps (and electric vehicle charging) may lead to new wires being laid down streets.
- Changes to properties: new appliances; changes to internal pipe work – heating system, gas pipes. Heat networks – new pipework inside and outside the buildings. Electric heat pumps – may need new radiators and possibly insulation.
- Suitability of home or building: physical size of appliances; high heat demand from 'leaky' buildings; noise of heat pumps; need for a heat store.

Dependencies

Delays in bringing a technology to market could constrain its potential, reducing deployment time.

- Infrastructure – early, low-cost hydrogen production is dependent on CCS being available.
- R&D – delays in developing and trialling options.
- Regulatory constraints – gas quality regulations required for bio-gas, bio-SNG and hydrogen.
- Investment in appliance development: including test appliances for trials.
- Certain options, such as heat networks, require a minimum uptake threshold to be viable, which if retrofitted in a residential area would require regulatory tools to enable.

Geographical factors

Geographical factors may affect some options affecting where they can be deployed and their extent; in the same way, options available to off-gas grid customers are determined.

- Access to a CO_2 pipe network for storage: Hydrogen production from SMR.
- Access to storage: large-scale inter-seasonal salt-cavern stores for hydrogen and bio-gases, which are produced year-round. Short-term storage for hydrogen to balance gas in the networks. Growth of a hydrogen transmission network will reduce the constraint.
- Heat networks –constrained by available decarbonised heat source: hydrogen or biogas network, ambient heat pump or waste heat. Customers in the network area are likely to be expected to connect to the heat network to make it economically viable.

Financial and social (further details in sections 3 and 4)

- Large variations in costs of appliances and fuel prices between options.
- Public acceptance: support for the transition, unfamiliar operation, safety concerns.
- Financial inequities – costs difference of options and between first and last mover.

2.4. Development delays and dependencies

Delays in developing and proving a technology, and defining regulations could also constrain its potential, by reducing the time available to deploy the option. Logistical constraints will affect the rate of deployment of an option and assumptions in the literature are subject to wider variation.

The Leeds H21 project proposed repurposing the gas network to take 100% hydrogen[13]. Trials and regulatory testing for safety standards are being put in place to better understand the potential of this option and to develop the appliances. They will also seek to address the logistical challenges of how to deploy hydrogen and a more detailed understanding of system operation and costs.

'Hydrogen-ready' boilers, which are in development, would simplify the requirement to change all the appliances on the conversion day – although it would still require the necessary hydrogen production infrastructure to be built along with CCS to manage the emissions from SMRs. The Leeds H21 programme suggests that if bulk supplies of low-carbon hydrogen can be produced by 2026, 19 cities could be converted by 2050 (about 35% of housing). This figure could be higher if build out rates for production and conversion can be increased. Any delays in establishing the first project could restrict the number of projects that could be deployed.

2.5. Opportunities and risks – interactions with other parts of the energy system

Developing a strategy for heat deployment needs to be coordinated with decarbonisation efforts in other energy sectors. Various options are being explored to decarbonise industry, particularly the energy intensive sector. Developments in the transport sector could provide synergies in how the energy networks are developed and used that deliver cost savings. However, these sectors could develop demands on the energy sources being considered for heating, which could lead to competition for limited sources, or act as a driver for developing supplies, such as hydrogen.

Industrial energy use

A proposal by Cadent in Merseyside could see a hydrogen production facility, with CCS connected to the East Irish Sea, operational by the mid-2020s. The project, which is in development, aims to supply an industrial cluster with 100% hydrogen. Surplus hydrogen would be injected into the gas network supplying the local residents with a blended gas, up to the safe limit of 20%[14]. Further developments could link into local salt cavern storage in Cheshire and expand the supply to local gas system.

Developments such as these will bring forwards learning about the options, which will help inform their larger roll-out, and, in the example of the Cadent project, will raise awareness of the emerging hydrogen economy, and understanding of the risks of using 100% hydrogen, to inform the wider safety case.

Failure to ensure that the CO_2 transport network and storage components of CCS are available in time could create a significant risk to the development of a decarbonised gas system. If successful, the Cadent project would be valuable to de-risk CCS investment.

Transport energy use

Transport decarbonisation could also play a role, either driving the reinforcement of local electricity networks or competing for limited bioenergy or hydrogen resources.

Home charging of electric vehicles may stress distribution networks, which could be complimentary to heat pump deployment. Although, unlike demand for heating where demand from consumers tends to coincide, the charging of EVs is more diverse and is likely to be easier to shift to off-peak times. Similarly, repurposing the gas network for hydrogen could accelerate the deployment of hydrogen refilling stations, and the uptake of hydrogen cars; although the hydrogen would need to be purified before it can be used by vehicles, because of the sensitivity of their fuel cells.

Supplies of bio-energy are estimated to be about 100 TWh of bio-methane/bio-SNG[15], which could be used for heat. Energy demand from Heavy Goods Vehicles (HGV) is a similar order of magnitude, and if they opted for the compressed bio-gas route, could easily utilise all the available supplies. Hydrogen is also being explored for HGVs, which may create a valuable new market for hydrogen, but could also compete for energy supplies. However, best-use of bio-energy indicates that scarce resources would be best deployed in the power sector with CCS, delivering negative emissions.

These developments risk emerging ahead of an overarching national strategy that could bring together, and optimise, industrial and energy objectives. But, perhaps more importantly, the strategy needs to set out how the public will be engaged in the transition. This will need to provide the narrative for the transition and address the financial aspects that are likely to emerge.

[13] Leeds City Gate 2016 H21
[14] HSE 2015 Injecting hydrogen into the gas network – a literature search
[15] Cadent 2016, The future of gas: Supply of renewable gas

3 Finance: Costs of heating options

A critical issue to the success of the transition is how the economics of heating options is addressed and the information is presented and impacts on individual customers. Our analysis indicates that the different cost profiles and total costs of each heating option has impacts for customers, network companies and energy supplies, and in turn has implications for funding and deployment. Network and fuel costs affect the consumers' bills, but the capital cost of appliances and installing them will have implications for the policies to encourage uptake, and for implementing energy efficiency measures.

An important aspect is how to make the costs reflective so that consumers can make appropriate decisions, and balance this with the risk of negative social impacts. Furthermore, low-carbon heating options are likely to increase the cost of heating, so measures will be needed to address the temporal financial inequities between first and last movers[16].

3.1 Total cost of ownership

Alternatives to natural gas are likely to be more expensive (potentially over 40% more for some options), although applying a carbon price would reduce the difference. Calculating the cost of different heating options is complex, requiring assumptions about how each option will affect how the energy system is configured and operated, developments in other energy sectors and the future price of fuels. Hence, the figures in this section are largely illustrative and subject to many variables.

Figure 3.1 illustrates a simple comparison of the total cost of ownership of each option, broken down by current charging arrangements for billing. For a household currently using natural gas, with average energy consumption, the key points are:

- Biogas (not shown in Figure 3.1) is likely to be the cheapest option, with little change in the cost of appliances or fuel.
- Average spend on all fuels is likely to be higher than for gas: heat pumps 30% higher, hydrogen 20%[17], and direct electricity more than double (with no additional insulation).
- Capital cost of heating appliances over 30 years (including modifications to the building fabric) varies between the options. Gas and hydrogen boilers account for about 15% of total costs, but for several options appliance costs amount to 25-30%.
- Disconnecting from the gas network reduces the annual energy bill by about 10%. Large numbers of consumers doing so would concentrate the fixed network costs on fewer customers, which may lead to a gas disconnection fee, offsetting some of the savings.

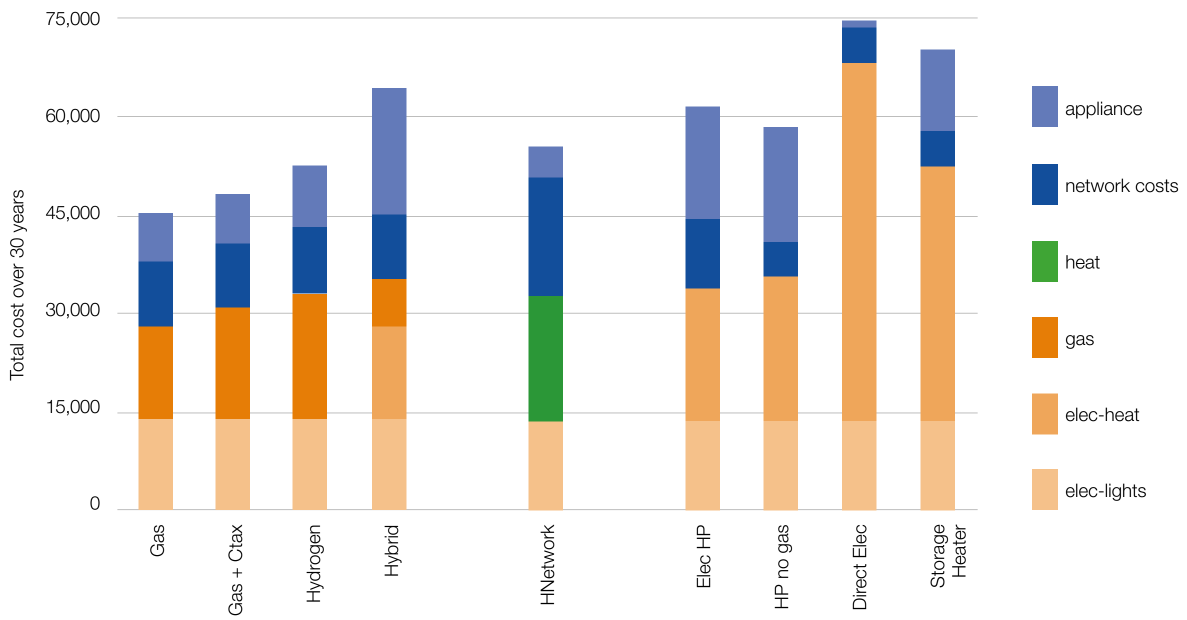

Figure 3.1: Total cost of ownership over 30 years – energy bills and capital expenditure payments. Fuel prices as of 2017 – carbon tax on gas of £49/tCO_2[18]; first installation includes any heating system modifications; electric heat pumps include building changes to ensure an average efficiency of 3.0 (Coefficient of Performance (COP)); appliances are replaced after 16 years. For heat networks it is assumed that the network bears the cost of the appliance, shifting appliance costs to network costs.

[16] NEA 2017, Heat decarbonisation: Potential impacts on social equity and fuel poverty

[17] BEIS Updated short-term traded carbon values March 2017

[18] Hydrogen fuel is expected to be about 30-40% higher, but electricity consumption is not expected to change.

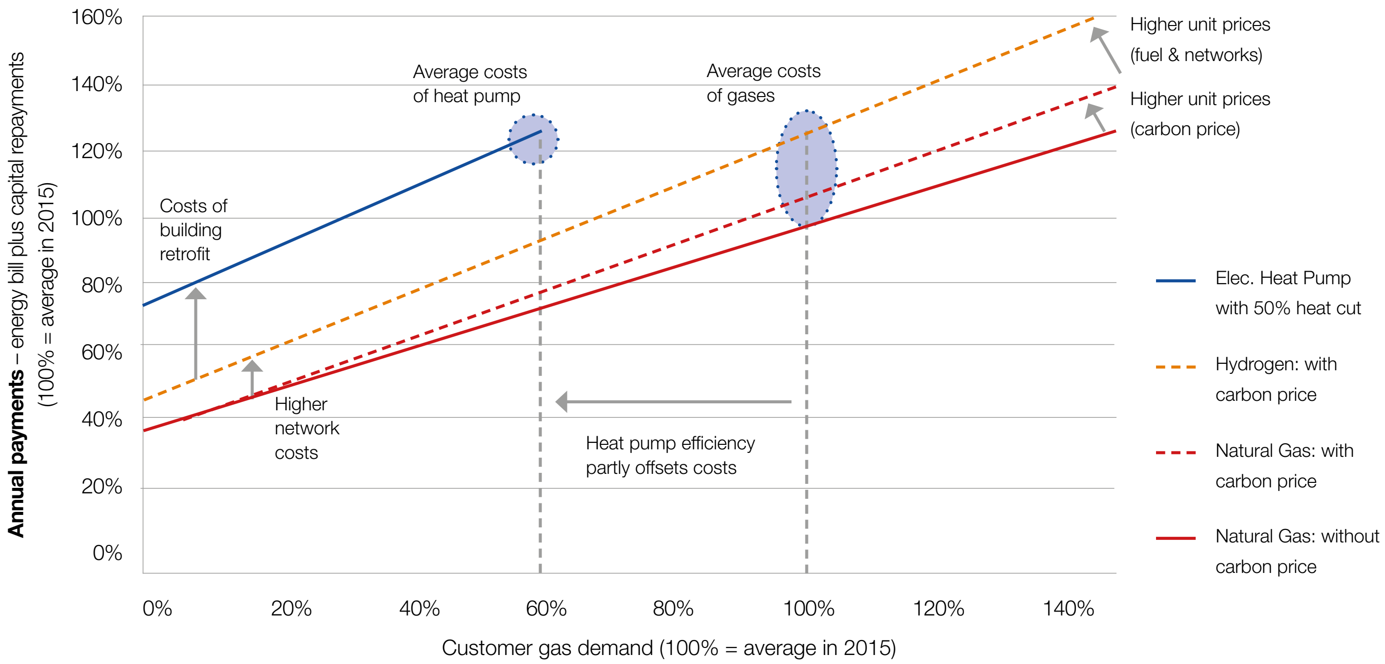

Figure 3.2 Total annual costs of alternative heating options, showing changes to fixed payments and unit rates. Note: hot water provides a 'back-stop' 20% of gas demand, so a 50% cut in heat is a 40% cut in gas. Additional insulation added to building for the heat pump, reducing heat demand by 50% (total gas reduced by 40%) and increasing the efficiency of the heat pump.

Average consumption figures hide a range of heating behaviours and energy use, even for identical buildings. Figure 3.2 illustrates how annual bill payments change across a range of heating demands, under the current charging arrangements, and the effect of switching to a different option. Fabric energy efficiency measures are included for heat pumps, to ensure efficient operation, but are not included for the gas options. For heat pumps, it assumes that only a few are installed i.e. not enough to impact upon gas grid costs (see Section 3.3).

Increasing the costs of appliances, building modifications and network investment raises the annual payments, even for all users (point at which lines cross the vertical axis). While switching to a heat pump and disconnecting from the gas network saves the standing charges, it is offset by the cost of the appliance.

Under current charging arrangements only part of the capital cost of the energy networks is recovered in the standing charge, the remainder is recovered by increasing the unit cost of the fuel. Raising the unit cost of energy, to recover capital costs, or through a carbon tax on methane or switching to hydrogen, increases the steepness of line. The impact of that is that above-average energy consumers pay a greater proportion towards the network capital costs.

With costs expected to change in future, there are pros and cons to retaining current charging arrangements:

- Assigning more costs to the unit rate can be seen to penalise high users that have genuine need (as opposed to profligacy), but it gives a higher incentive for energy efficiency i.e. every unit of demand reduction, gives a larger reduction in the bill.
- Moving more costs into the standing charge would be seen to penalise low users, and encourage wasteful high use, but it would help high users that have genuine need.

ERP recommends:

- **Engagement with the public will be crucial and needs to start now, to inform the development and deployment of each option and to inform the development of finance policies and business models.**
- **The narrative on providing heating and hot water needs to change to recognise that costs will increase, whether paid for by tax or energy bills.**

3.2 Cost profiles of each option

The cost profile of the options, and who it affects, is as important as the annual and overall costs. This is most significant for the consumer, who has fewer options for financing capital purchases compared to network companies, who have access to low cost finance and can spread capital costs over 40 years, with low-interest finance available. Figure 3.3 illustrates the cost profile over a 30 year period (two average life-cycles of a heating appliance). Key points are:

- Installation of appliances, and ongoing replacement, has a significant impact on costs. Who pays for them will be important – whether the network will be expected to pay (as could be the case with hydrogen and Heat Networks), or the consumer (as currently with electric heat pumps, aided by policy incentives). Other factors affect 'willingness to install', such as disruption to the property and having the space for the appliance and possible heat store.
- For network and infrastructure companies the ad hoc roll-out of heating technologies could increase costs, e.g. if heat pumps necessitate reinforcements, part of the cost can be passed on to the consumer responsible. However, as units are not always registered when installed (and without smart meters), finding the person responsible and charging them retrospectively is difficult. Planning will also be harder, requiring additional engineers to be available to respond to any unplanned issues. A planned conversion programme, could allow the cost of a gradual conversion to be included in the regulatory settlements for network companies.

ERP recommends:

- **Government should decide how to address distributional impacts of cost differences.**
- **Government and Ofgem should prioritise the design of new financing mechanisms and market structures to manage costs.**

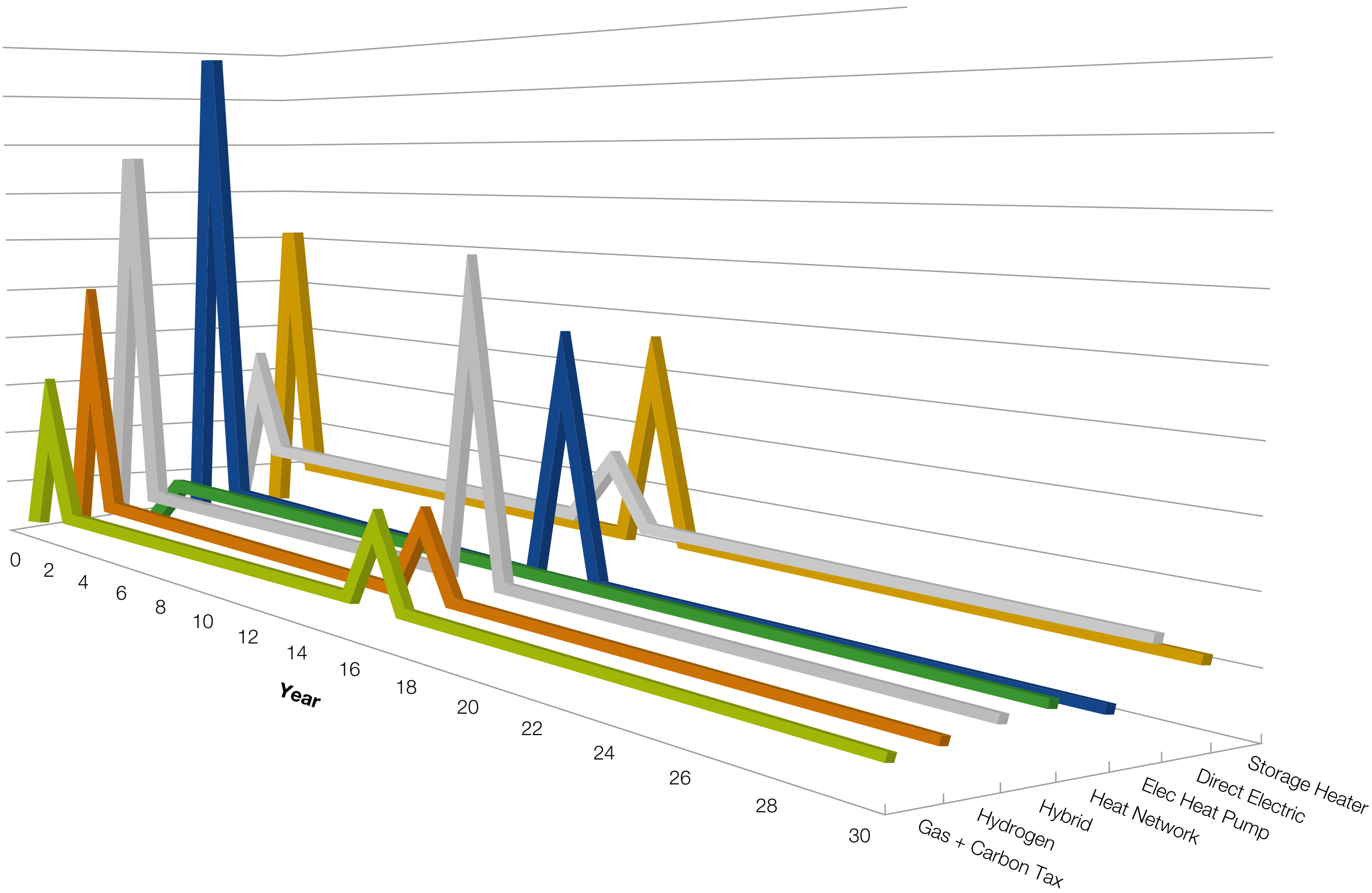

Figure 3.3 Indicative annual expenditure for different heating options. Cost profiles for different options may impact their uptake. Peaks in year 1 are higher as it includes cost of first installation, such as pipe or electrical work or insulation, especially for heat pumps. For heat networks, installation costs are covered by the network company. Height of flat lines indicates annual fuel, maintenance and network costs. It is assumed that appliances are replaced after 16 years. It is unclear how much these costs will reduce over time.

3.3 Impacts of demand reduction

Demand reduction can be due to energy efficiency (i.e. providing the same comfort but with less waste) or disconnections (e.g. leaving the gas grid in favour of an alternative heating option). Both have impacts upon bills, some of which customers might find counter-intuitive.

- **Gas customers reducing their demand:** Fixed payments will increase if capital expenditure was needed e.g. building fabric improvements. Unit price will rise (because fixed network costs are shared between fewer units), offsetting some of the cost savings from lower consumption, so their bills will not fall by as much as they expected. In the longer term, unit price will fall as lower demand will reduce the need for investment in network reinforcements.
- **Customers disconnect from the gas grid** in favour of an alternative heating option: Unit price and standing charges will rise (because fixed network costs are shared between fewer units). The remaining gas customers will be presented with higher bills.

Figure 3.4 and Figure 3.5 illustrates several 'customer bill journeys' for what would occur if gas demand in an area fell by 40% over five years, either due to gas disconnections or an energy efficiency programme.

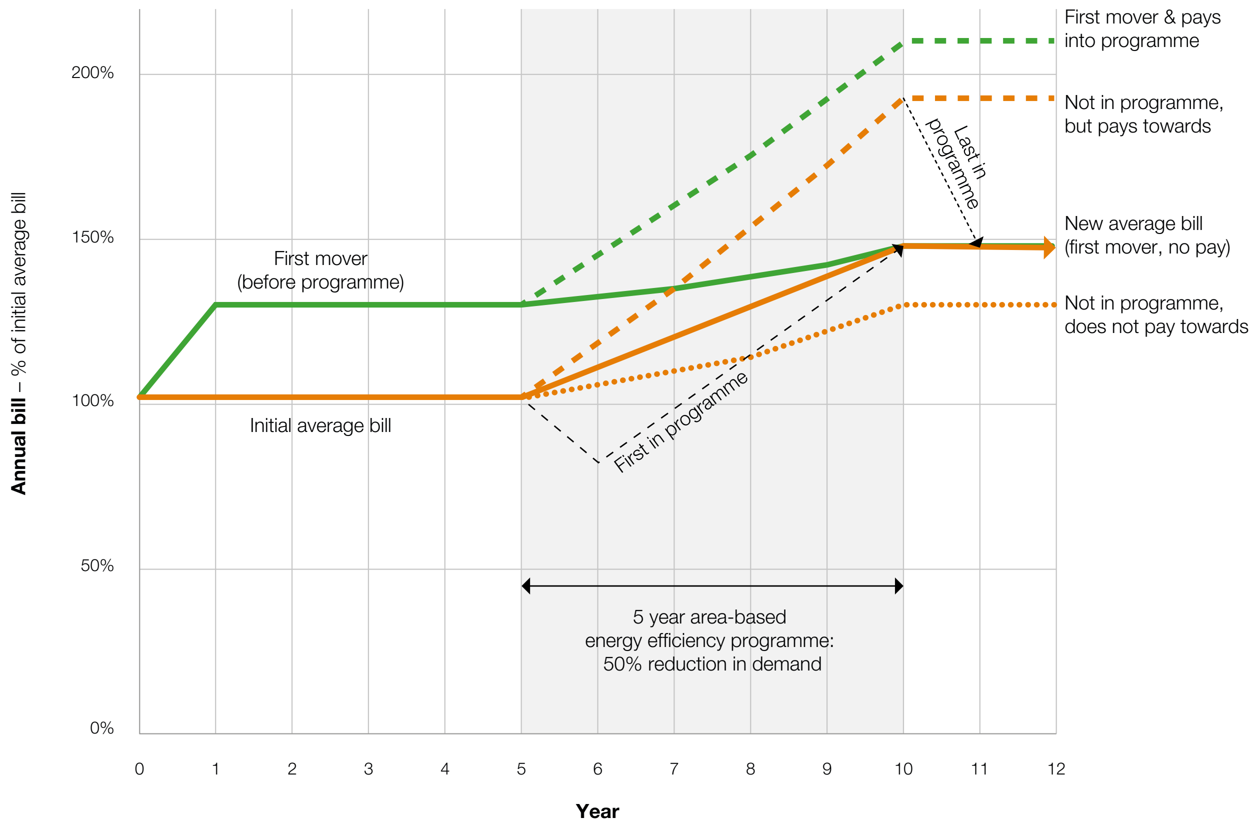

Figure 3.4 Annual gas bills for different customers affected by a five-year energy efficiency programme (greyed-out area) that reduces local gas demand by 40%. This is equivalent to a 50% reduction in space heating demand, as demand for hot water does not decrease. The average bill for all customers rises due to the capital cost of the programme and the increasing unit energy cost, required to cover network costs.

For energy efficiency programme (Figure 3.4), 50% heat demand reduction, funded by all customers):

- **First mover**: Makes change of own volition. Energy bill falls due to lower demand, but net payments rise due to retrofit repayments. Payments rise during programme, as reduced demand increases energy unit price to either: 1) the new average bill, if first mover is exempt from funding wider programme, or 2) a higher level, if not exempt – pays for retrofit twice.
- **First in programme**: Payments fall at start of programme, rise to new average bill at end of programme as unit rate rises, due to cumulative programme costs.
- **Average payments**: Rise during programme because demand reduction is exceeded by costs of programme and unit price rises. Rises to new average at end of programme due to increases in programme cumulative costs and unit price.
- **Last in programme**: Payments above average during programme; fall at end to new average.
- **No change**: For customers not in the programme, payments rise during programme: if funding programme, follows last mover, but remains high afterwards ('no gain, but pays'); or, if exempt from funding programme, rises (due only to unit price rises) to lower level than new average ('no gain, no pay').

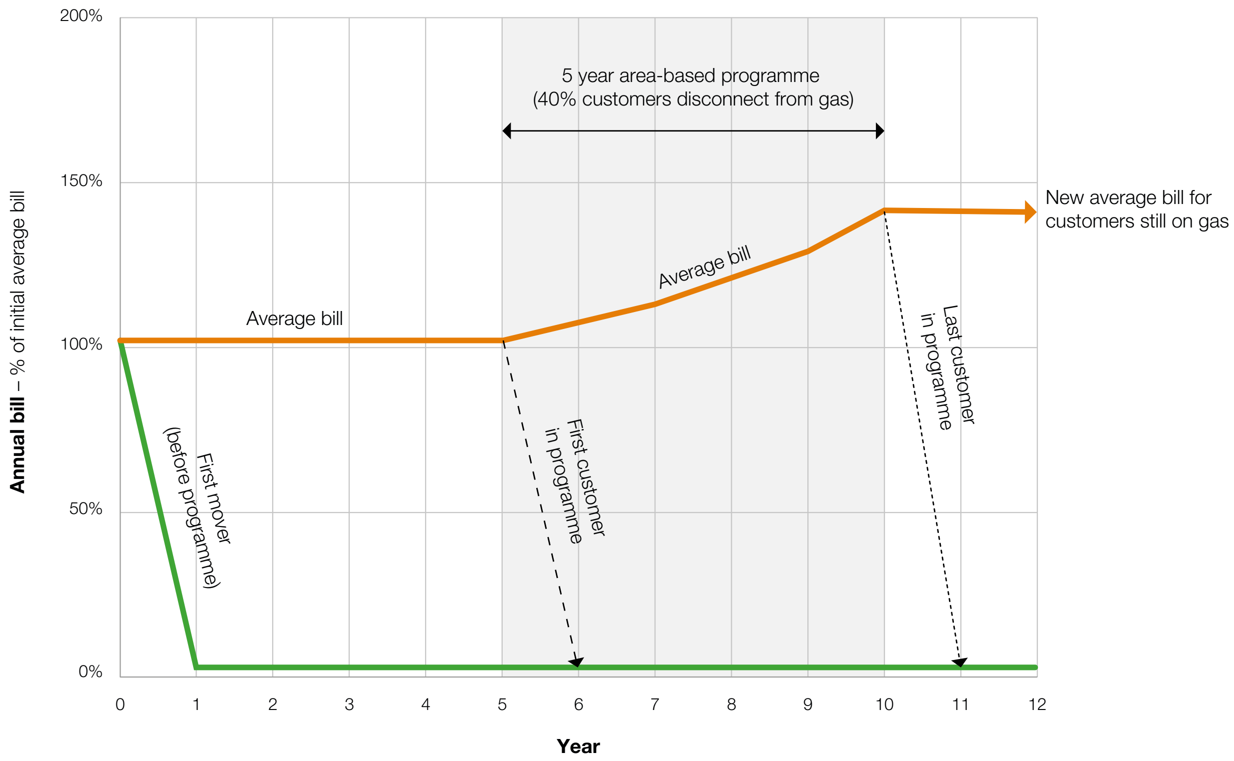

Figure 3.5 Annual gas bills for different customers if gas demand falls by 40% due to customers disconnecting from the gas grid over five years (greyed-out area). Average bill increases as unit of energy rises as sunk network costs are paid across fewer units of energy.

For disconnections (Figure 3.5), where 40% of customers move to non-gas heating: if charged a disconnection fee but it is not enough to cover fixed costs incurred previously on their behalf, the unit rates and standing charges will rise for all remaining customers.

These examples raise questions about fairness in the transition, in addition to those in the earlier example without retrofit costs. First movers that have funded their own retrofit should perhaps be exempt from funding the wider programme. The last to be helped by a wider programme should perhaps not pay towards programme costs until they are benefitting. The same is true for non-movers, so long as they are contributing an equivalent level of decarbonisation and not just enjoying lower costs for higher carbon heating than those that are in the energy efficiency programme.

ERP recommends:

Government and Ofgem should prioritise the design of new financing mechanisms and market structures to manage costs.

3.4 Encouraging energy efficiency

Figure 3.6 and Figure 3.7 build on the analysis above to illustrate the cost of retrofit. Instead of simply moving up or down the straight line of 2015 gas demand and bills, a first mover (i.e. before demand reduction shifts increases the unit rate) can move left along the curve that includes retrofit's demand reduction and costs (points mark heat demand cuts of 25%, 50%, 75%). Any reductions in costs will deepen the curves and allow for larger cost savings (or deeper cost-effective demand reduction), so it is desirable to have:

- **Cheaper retrofit products and installation**: For average demand in an average home, clearly the low retrofit difficulty allows deeper cost-effective retrofit.
- **Cheaper financing** e.g. VAT at 5%, down from 20% currently; low interest on loans; and long repayment terms on loans. These figures suggest the need for new, low-risk financing, perhaps through energy service business models that are linked to the building through energy bills or mortgages, without being off-putting for buyers (e.g. as the Green Deal was said to be).

Another key point is that higher unit rates make the retrofit cost curves steeper and deeper, i.e. customers have a stronger incentive to undertake retrofit to reduce demand. Hence, more expensive fuels will give customers a natural incentive for efficiency.

ERP recommends:

- **Energy efficiency should be pursued to deliver cost-effective emissions reductions, and should be promoted to customers as a means of controlling the costs of options especially those with higher fuel costs.**
- **Government and Ofgem should prioritise the design of new financing mechanisms and market structures to manage costs.**

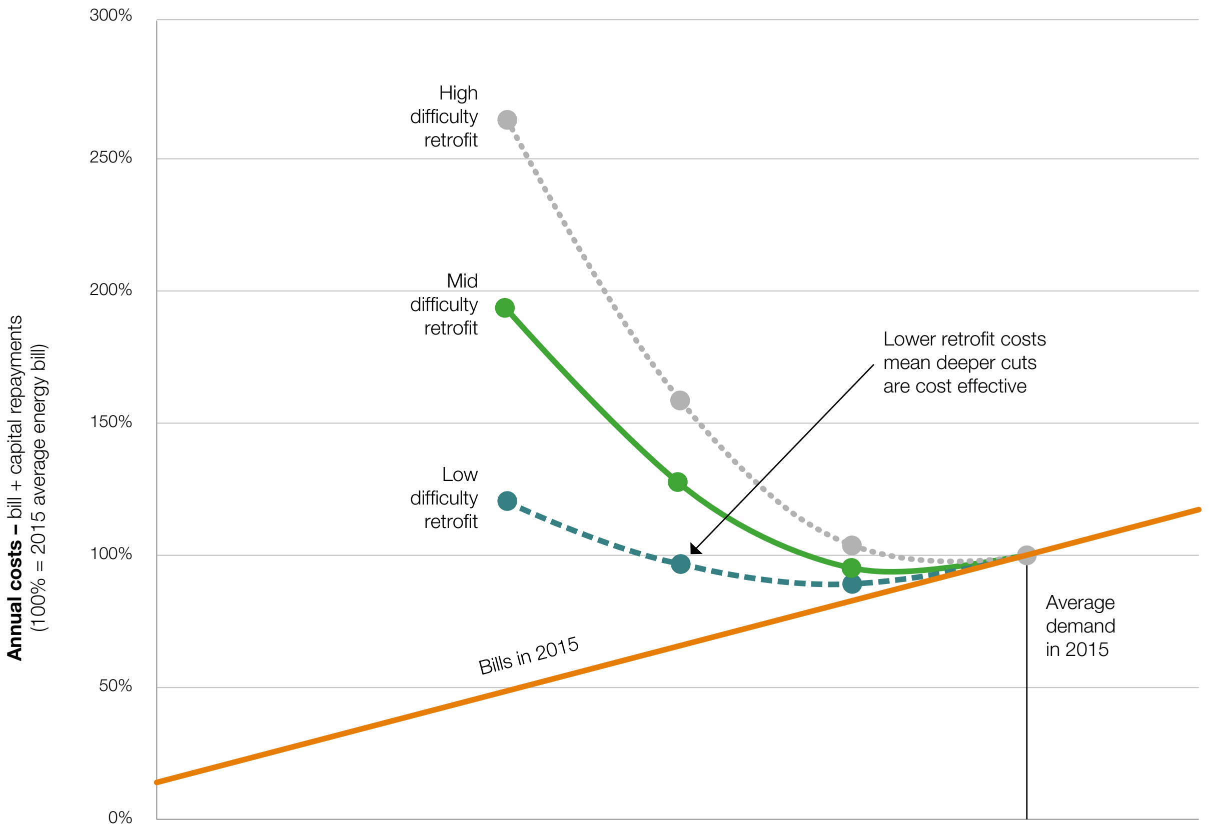

Figure 3.6 Annual costs (energy bill plus capital repayments) for retrofit at different degrees of difficulty. Easier retrofit is lower cost and delivers greater reductions for same investment. Costs rise unevenly as unit cost of energy increases to sunk network costs.

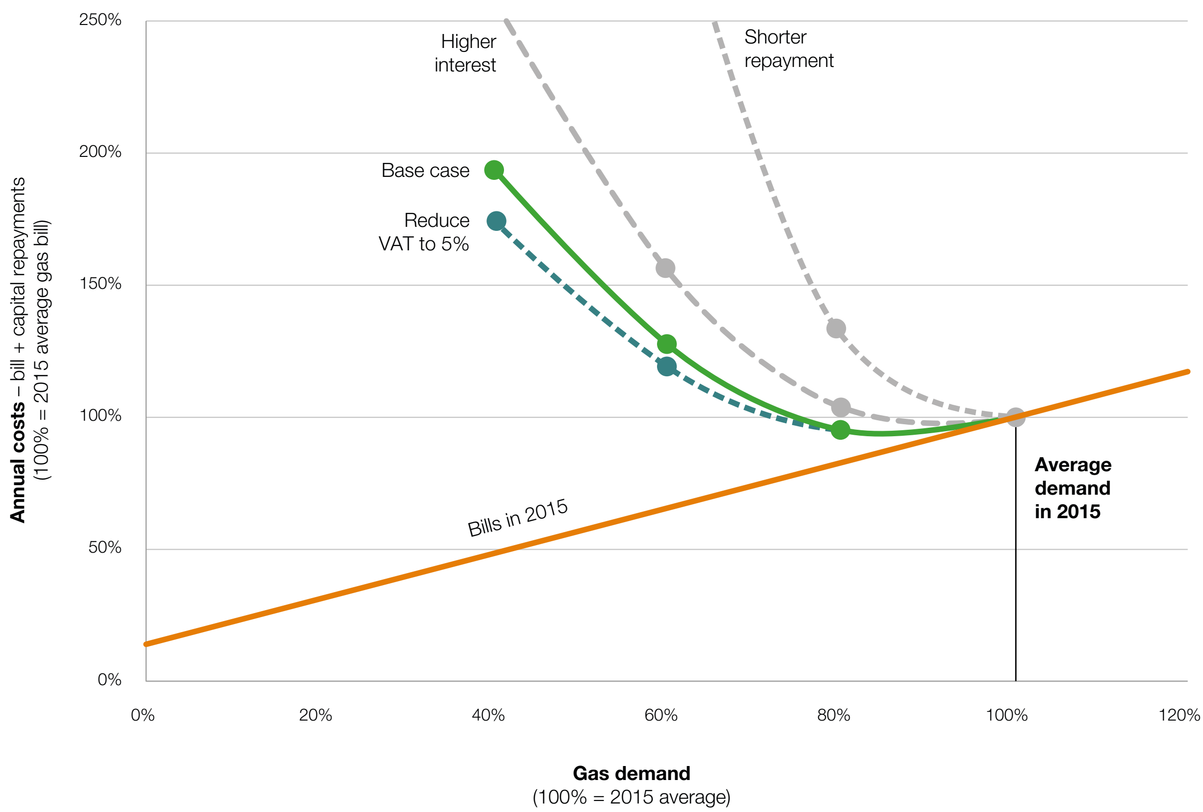

Figure 3.7 Impact on annual payments from different retrofit financing options, including lowering VAT on retrofit to 5%, repayments over a shorter term and higher interest rate on capital loan. Greater demand reduction increases the annual payments. Low cost finance (e.g. reducing VAT) reduces the extent of increase in annual payments and could encourage greater demand reduction. High cost of financing makes even small retrofit investments expensive.

4 Governance

Developing a decision-making framework will be important for the success of the transition. The current lack of clear allocation of roles and responsibilities across decision makers and a lack of coordination could lead to problems.[19] A strategy is needed for how the transition will be managed, which brings together and coordinates the diverse range of interested parties, including the public, and sets out clear decision-making frameworks.

Local solutions need to be aligned with overall national constraints, and coordination is needed across policy objectives (e.g. fuel poverty, industrial strategy, etc.). This section considers questions about who decides which options to use, and potential complications and conflicts that might arise.

4.1 Overview of decision makers

Numerous different organisations and around 30 million households and businesses all have some role in decarbonising the UK's heating. Figure 4.1 summarises broad objectives at national, local and customer levels, along with their decision-making powers at present and how these powers might change in the future. National and local decisions will need to be aligned to create policies and incentives that avoid conflicting with broader objectives. Key points include:

- Central government should set out the strategy and incentives for the efficient allocation of low-carbon energy across the economy, and its interaction with other energy-related policies. Energy efficiency should be promoted as a no-regret option and funded accordingly, with benefits to the consumer and to the wider economy.
- Local level proposals should be developed for deploying appropriate option or options. These will need to be well informed and resourced, taking account of local and national constraints, while managing costs for customers (both switching networks and staying put).
- Customers should be properly involved in the local processes, to minimise the numbers declining the proposed option and hence harming its cost-effectiveness.

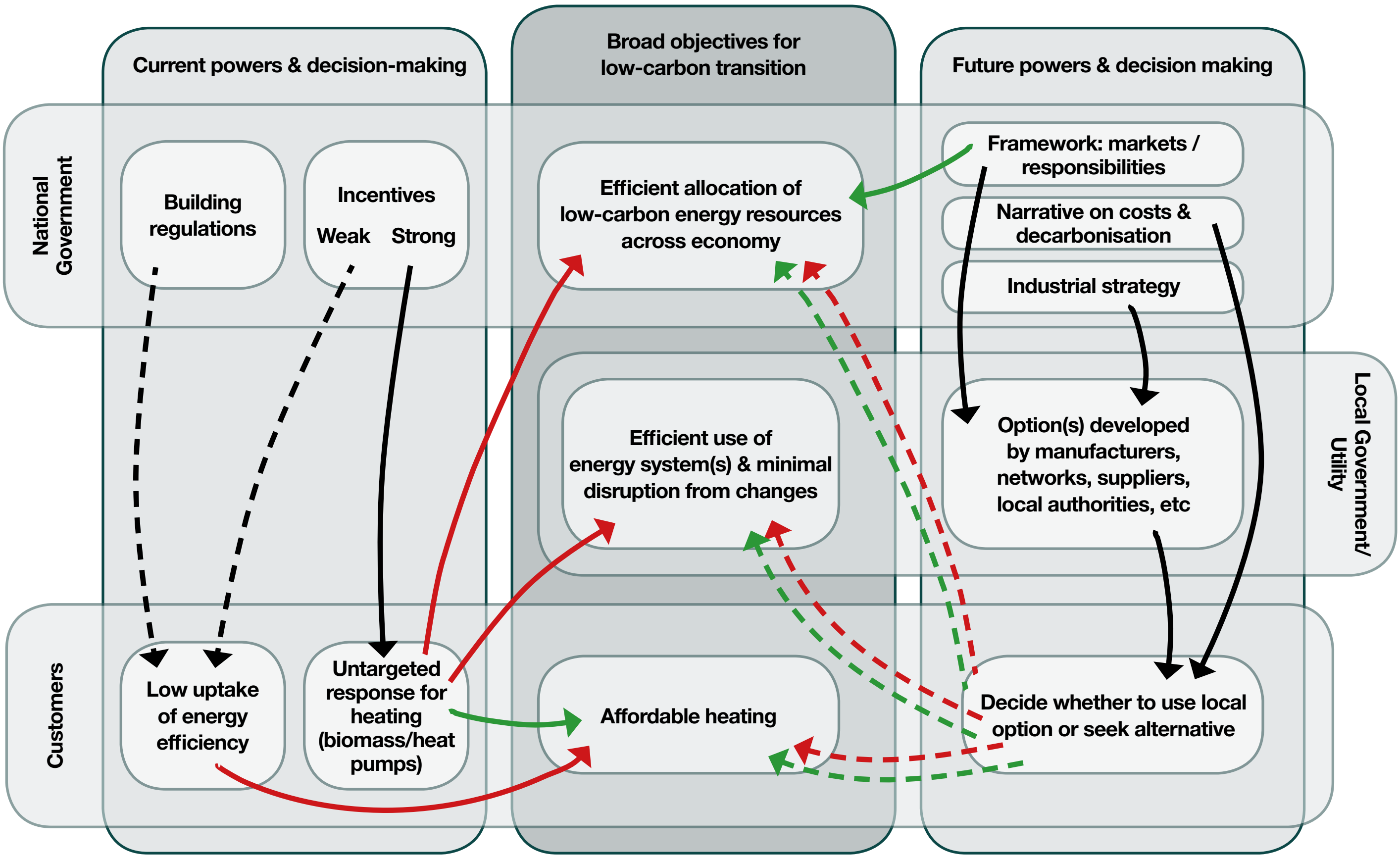

Figure 4.1 Future powers and decision-making roles for national government, local actors and customers (right) need to be aligned with the broad objectives of transition (middle). The current policies (left) risk (red arrows) conflicting with the objectives. Future coordination increases opportunity of meeting objectives (green arrows).

[19] Frontier Economics 2016 Regulation of Gas Grid for CCC

4.2. Integration with wider decarbonisation and other policies

Managing the interactions between the critical requirements of the heat system and other sectors, and wider policy objectives, will be vital to enabling an effective transition to low-carbon heat.

Industrial strategy

Heat strategy should seek to influence (and align with) industrial strategy that could impact upon availability of fuels or feed-stocks in certain areas. Industries that can switch to hydrogen would strengthen the case for using hydrogen for heating in their areas. Industrial sites that emit large quantities of unused heat could become sources for heat networks (or for charging inter-seasonal thermal stores);[20] industrial strategy could provide confidence that these sources would remain.

Export opportunities for UK-manufactured heating technologies, or its leading expertise in system integration, should be supported. Opportunities may be limited for existing heating options (e.g. heat pumps), but new technologies such as hydrogen could offer scope, drawing on the UK's leading expertise and companies building electrolysers and fuel cells. Early development of hydrogen appliances could open an international market to other countries considering using 100% hydrogen, although manufacturers might reassign existing factories in each country rather than develop an international trade in appliances. Hydrogen for industrial and commercial heating could be more significant, leading to opportunities to export expertise and equipment.

Energy security

Switching to low-carbon energy is likely to lead to net imports of energy, raising questions about energy security. Replacing gas with 100% hydrogen will increase gas imports initially, as most hydrogen will be produced from methane. While the supply risk is reduced by the diversity of sources, it is still exposed to price volatility. In the long term, decarbonising hydrogen will mean it producing it from renewable sources. Extensive use, will mean gas will be replaced by hydrogen imports; the diversity of supply will depend on global uptake and scale of international trade.

UK energy production is seen as a more secure resource, but all of the options face challenges: indigenous shale gas will not be acceptable due to unavoidable methane emissions during extraction; and the availability of bio-energy feedstocks is uncertain.

Allocation of low-carbon energy resources

Government incentives for using bio-energy for transport, power and heating have been likened to a 'bidding war' between departments; a clear process is needed to define best use of this limited resource.[21] A suitable carbon price would help with allocation and inform customers of the true cost of high-carbon fuels: at present a carbon price is charged on gas for power generation but not for use in buildings.

Non-area-based incentives (e.g. Renewable Heat Incentive (RHI)) can add infrastructure issues, e.g. heat pumps used in areas with grid constraints or not used in areas with spare capacity and spare renewable power.

Social policies

Some health issues can be addressed by improvements to heating systems and energy efficiency, e.g. 'boilers on prescription'. Fuel poverty is inextricably linked with energy policy, but debates about the affordability of energy bills will become sharper as costs increase (due to carbon pricing for gas and costs of low-carbon options). Arguably the issues should be addressed separately, but any targeted programme needs to be coordinated with heat policy so the distributional impacts of higher standing charges or unit rates do not negate the benefits of the scheme.

Promoting energy efficiency

Improving energy efficiency is a no-regrets option: almost all buildings could deploy measures that would pay back over a few years, along with further, more ambitious improvements, which would pay back given appropriate long-term financing. It also reduces the overall UK heat load (and hence also peak load), reducing the strain on low-carbon energy sources and on network capacity, making the transition easier.

The Government should assign improving the energy efficiency of building as a national infrastructure programme. Such a programme would need robust incentives that encompass hard to treat buildings, delivering solid wall insulation, where the high costs are a barrier to deployment.

Over 90% of existing homes (and 65% of workplaces) will still exist in 2050. The first step to reducing their emissions should be to apply cost effective demand reduction (e.g. by improving the fabric of the building). Levers that are not fully used include: building regulations that apply when undertaking renovations and extensions; regulations and finance for the private rental sector, without the get-out of 'no upfront cost'; access to finance for social housing providers; and incentives for home-owners e.g. lower taxation or mortgage rates.

New-build poses a risk to the UK's decarbonisation aims, but offers the easiest step to implement and justify, if build standards are improved now, avoiding unnecessary strain on low-carbon resources. If fabric energy efficiency standards for new-build are improved and enforced, heat demand would rise by only ~3% by 2050[22] (with minimal or zero impact on house prices[23]). While current standards would lead to an increase of 10-20% in heat demand, or require alterations which would add to logistical and financial pressures of the transition.

[20] Inter-seasonal thermal storage is still at the development stage, but there are plans for trials to charge stores at industrial sites, transport the stores to commercial buildings, and release the heat later.

[21] See Committee on Climate Change bioenergy hierarchy, Bioenergy Review 2011

[22] Homes currently account for ~75% of building floor area (workplaces ~25%), growing by over 25% by 2050 (30% in housing, 15% in workplaces). 2016 new-build regulations allow a specific heat demand of ~45kWh/m^2 per year – about one third the average for the UK's existing stock (hence ~10% increase in demand). Most buildings do not perform according to design (hence the potential 20% increase). By comparison, Passivhaus standards are 15kWh/m^2 per year (hence a ~3% increase). Proper enforcement of standards would be needed.

[23] See discussion in: ERP 2016, Heating Buildings

New-build affects heating system options. Customers could be frustrated if they assumed (understandably) that new buildings with gas are ready for the future, but then face making changes. New-build offers an opportunity to 'show case' low-carbon options, e.g. heat networks, electric resistive heating (cheaper and sufficient with good insulation) or electric air-source heat pumps (synergies with ventilation in draught-proofed buildings). But, installing gas limits this exposure, which could make it harder to persuade customers about alternatives.

Installing a low-carbon option from the outset is arguably lower risk, removing the need for future changes. While a new-build using gas could simply transition to a low-carbon gas, it relies on those gases delivering. Over the next few years, before there is clarity about the role of hydrogen, between 500,000 and 1,000,000 new homes will have been built; in the event that hydrogen cannot deliver, these new buildings add to the challenge of implementing an alternative.

ERP recommends:

- **The heat decarbonisation strategy needs to take account of wider policies, including allocation of low-carbon energy resources for transport, industry and power generation.**
- **Government needs to develop a robust retrofit energy efficiency programme for existing buildings to reduce the overall cost of the transition. High efficiency standards for new-buildings need to be set and enforced.**

4.3. Developing and delivering options

There is debate about the balance between planning and markets (e.g. whether resources should be allocated strategically or first-come-first-served), and between national and local decision making (e.g. whether local options should be guided by a national framework). However, the question is rather who should undertake these tasks, as some issues will need to be decided nationally, and, at the very least, local plans will be developed to seek economies of scale or to manage disruption.

Local Authorities are often cited as being best-placed to understand the needs and opportunities of the local area and to co-ordinate activities. In addition to their various roles and powers, having the ambition to lead local heat decarbonisation requires:

- resources, which are patchy across the UK;
- sufficient powers to co-ordinate action, or at least add weight to other decision makers e.g. Ofgem;
- greater fund-raising rights to facilitate their part in any local plans;
- access to data from many sources e.g. electricity Distribution Network Operators (DNOs) and Gas Distribution Network (GDNs) companies.

Energy companies (producers, networks, suppliers, ESCOs, heat networks, etc.) are leading some of the main research and demonstration projects, and will be delivering major projects, but greater clarity is needed as their future role in decision-making. Energy network companies have the best overall view of the network assets and their operation, which will be enhanced as smart meters are rolled out. Network companies will play an important role in developing regional strategies, in order to utilise and plan their networks efficiently.

From a technical perspective, DNOs and GDNs are well-placed to determine optimal local options for using or expanding existing infrastructure, but some form of 'arbitration' would be needed to ensure that wider perspectives are incorporated and to reconcile any conflicting views.

The critical step is to win support from customers. It would be a step-change in network companies' relationship with customers, to move from being largely invisible, to promoting major changes. Energy service companies (ESCOs) are a growing business model that could potentially bridge the gap between technical expertise and customer engagement.

Given the national constraints and interplay with other policies, no individual areas should propose options in isolation. And given the complex mix of roles, no single organisation can propose and deliver local heat options. This all points to the need for a national body to oversee the heat transition, providing a national strategy for using low-carbon energy resources and potentially assisting organisations to co-ordinate their activities for local delivery.

ERP recommends:

A heat delivery body should be set-up to facilitate the decision-making processes and coordinate national, local and commercial decision making.

4.4. Public / customer engagement

Customer decisions are important at present and will be important during the widespread transition; as such, public engagement is a critical part of the national strategy and local options.

First-movers

Action by customers ahead of the main transition to low-carbon heat is positive in that it can bring immediate benefits and reduce the future challenge. However, it could be undertaken in a more co-ordinated manner to increase benefits and reduce issues, e.g. RHI does not currently take account of wider issues (see section 4.2). As noted in the Finance section, first movers for energy efficiency (albeit there are not many, owing to limited incentives) will reduce their energy bills, but would have to pay the cost of the retrofit. But they would miss out on economies of scale that other customers would enjoy if an energy efficiency programme came to the area. Furthermore, there would be the distributional question of whether first movers should contribute to paying for the wider programme. Similarly, having made investments to significantly reduce their own heat demand, customers could undermine a local plan by being reluctant to invest in high-cost technology, such as heat networks or network upgrades, thereby reducing the case for network changes. The area-wide option that is most likely to remain viable is to reduce heat load, i.e. following first-movers.

Widespread transition

The transition will be facilitated by more than just rules, and to treat it as a legal exercise risks a public backlash: it has to involve honest engagement in advance with the public about the motivations, costs and benefits, as well as ongoing engagement about challenges and concerns. Examples of legal and engagement issues (most of which apply to a transition from any system to any other system) include:

Before

- Which organisation(s) would be seen as impartial and hence be more likely to win customers' support for change?

During

- If a customer resisted a proposed change in their building, could they be compelled to allow it, and could they appeal?
- Who would advise the customer on alternatives and their impacts?
- Would a network company have the right to disconnect them (applicable to gas)?
- Conversely, could there be any circumstances in which a network had to be kept in operation to service a small number of customers, e.g. in a local community?

After

- If a customer was disconnected from gas, would anyone have a duty to provide temporary alternative services (heating, hot water and cooking)?
- Would anyone have a duty to provide the customer with a long-term solution?
- If a subsequent owner of the building wanted the heating option that the previous owner refused, would they be charged the full incremental cost of the one-off work? Would that full cost naturally be reflected in the sale/rental price?

Even if the transition progresses well, such that the majority of the public agrees to changes to their buildings and heating systems, there will almost certainly be some that do not and who would have to move to an option that was not favoured in their area. Moving to biomass would add to pressure on that limited resource; moving to an electric heat pump could trigger upgrades that a local plan sought to avoid; and rejecting all low-carbon options and moving to coal or oil would ultimately lack financial logic as carbon pricing came to bear.

ERP recommends:

Early engagement with the public is crucial, combined with a clear narrative about energy costs and decarbonisation.