Ofgem's
Future Insights Series
The Decarbonisation of Heat

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Abstract:

The decarbonisation of heat is arguably the biggest challenge facing UK energy policy over the next few decades.

In this paper we consider the nature of heat demand and supply today and some of the decarbonisation options that are presently being discussed by policy makers. We also discuss how decisions might be made and potential consumer and regulatory implications.

Some of the potential options are already known and deployed to some extent, but their role in the future will partly depend on cost-effectiveness. Others, such as use of hydrogen, are at an earlier stage. The challenge for policy, compared to decarbonisation of electricity for example, is not limited to technological developments, new business models and system integration, but also extends to consumer acceptance of changes within their property, often on a mandatory basis. Coordinating decisions on a regional basis may require new governance arrangements and longer-term decisions to reduce the extent to which individual choices are superseded.

This paper is the second in our series of "Future Insights" publications and outlines the key challenges involved with the decarbonisation of heat. The paper has developed from our **Insights for Future Regulation** project, launched in Spring 2016.

The views expressed in this paper are emerging thinking from the project and do not represent established Ofgem or Gas and Electricity Market Authority positions.

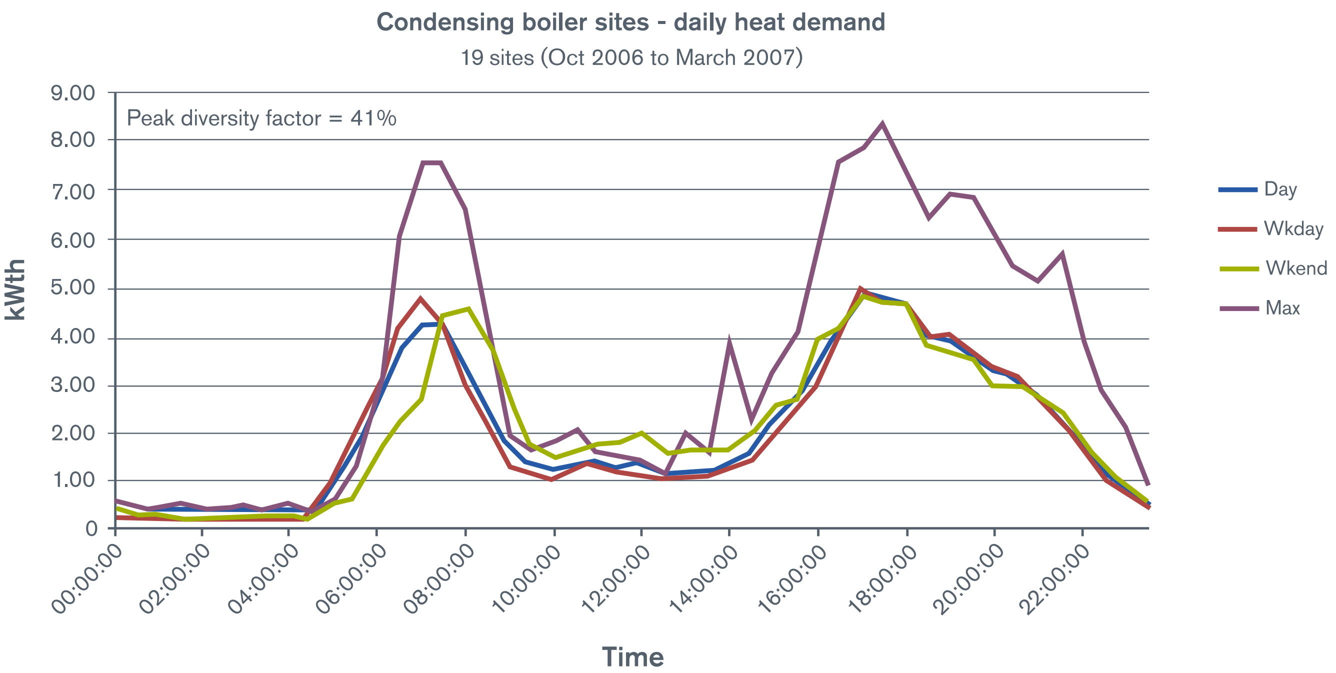
The nature of heat demand and supply today:

Demand

Almost half of the final energy consumed in the UK is to provide heat (760 TWh)[i] – more than that used to produce electricity or for transport. Around 57% of this heat (434 TWh) goes towards meeting the space and water heating requirements of our homes[ii]. This means that decarbonising domestic buildings, many of which are connected to the gas grid, forms a key part of the challenge of reducing greenhouse gas emissions.

At approximately 300GW, aggregate peak demand for heat is roughly 5 times greater than that for electricity[iii]. This is driven by the technology we currently use – predominantly gas condensing boilers providing heat on demand (see figure 1 below) and our gas infrastructure having the capability to meet this demand. But our underlying need for comfortable temperatures is less peaky. If we switched to provide heat from electricity, the costs of providing a peak of 300GW would be excessive, but the same level of comfort could be provided with somewhat less peaky energy use. Nonetheless, it would still represent a dramatic increase in capacity requirements.

Figure 1: Heat demand profile for gas condensing boiler



Source: Robert Sansom (2014) Decarbonising low grade heat for a low carbon future

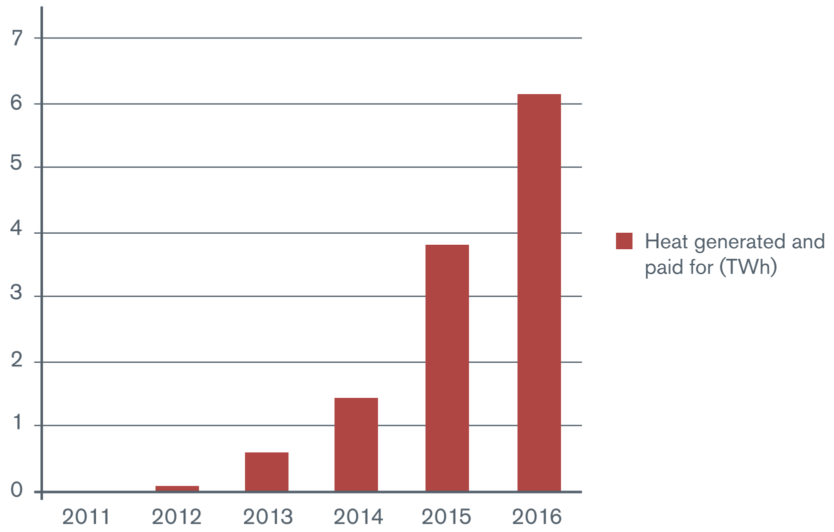
Cooling presently accounts for roughly 0.5% of overall energy demand[iv]. There is currently little demand for air conditioning outside of the commercial sector but this could change in the long term. Consideration of future cooling requirements will need to form a part of decarbonisation decisions.

Supply

Most of our heat energy currently comes from burning natural gas – over 70% across the domestic, industry and service sectors[v]. The remainder is made up of a combination of electric heating (direct and heat pumps) and non-gas fuels (oil, solid fuel, bioenergy and waste). It is estimated that heat delivered by heat networks meets around 2% of building heat demand[vi].

The Renewable Heat Incentive (RHI) is the key policy driver currently incentivising uptake of heat from renewable sources. The RHI has led to the installation of biomass boilers in off-grid locations, to the introduction of biomethane into the gas grid and to some electrification of heating through heat pumps. However, whilst increasing year-on-year, the overall contribution of renewable heat under the RHI in 2015 was less than 5 TWh[vii]. This shows the scale of the challenge in decarbonising a heating supply centred on natural gas. Latest estimates put 5.64%[viii] of heating energy coming from renewable sources, compared to the UK's indicative target for 2020 of 12%.

Figure 2: Renewable heat generated and paid for (TWh) under Non-Domestic RHI



Source: BEIS (2016) Non-Domestic RHI and Domestic RHI monthly deployment data: September 2016

Notes: An additional estimated 1.2 TWh of heat was produced under the Domestic RHI between April 2014 and September 2016. 2016 data extrapolated from heat generated Jan to Sep 16.

The nature of heat

One of the key things about heat is that typically the generation of heat takes place within our homes and businesses. This means that changing fuel sources often requires changes to appliances within buildings. In this sense, contrasting with the electricity sector for example, we start with heat generation already decentralised and see some opportunities for change to a more centralised basis – e.g. locally with district heating.

Changes to the way in which heat is delivered to UK buildings could have a major impact on households and businesses. Energy efficiency upgrades, new heat emitters and changes to heat generation and distribution systems all involve some disruption to end-users. The opportunity to deliver these changes in accordance with natural behaviour patterns such as boiler replacement is not straightforward. For example, the current lifespan of a gas boiler is approximately 10 to 15 years, with the vast majority replaced upon breakdown.

New-build properties provide an important opportunity to deliver low-carbon heating systems. The past five years have seen an average of around 143,000 new dwellings in the UK completed each year[ix]. However given that about 25 million existing homes will still need to be heated in 2050[x], intervention in the existing stock is essential for significant decarbonisation. Experience shows that more centrally determined change processes can be quite intrusive. The smart meter roll-out is a current example where significant efforts are being made to address concerns over cost, security and privacy and health, and ultimately this is not a mandatory switch. Given the additional physical disruption that might be involved with converting heating systems, the task could prove extremely challenging. We have to go back to the 1970's conversion from town gas to natural gas for a comparable change.

However recent successful retrofit projects such as the Wyndford Estate district heating project in Glasgow[xi] have shown that well-designed intervention on an area-based level can be successful and potentially more efficient than targeting individual households. A clear framework for delivering change at local, regional and national levels will be critical to the different decarbonisation options discussed in this paper.

Decarbonisation options:

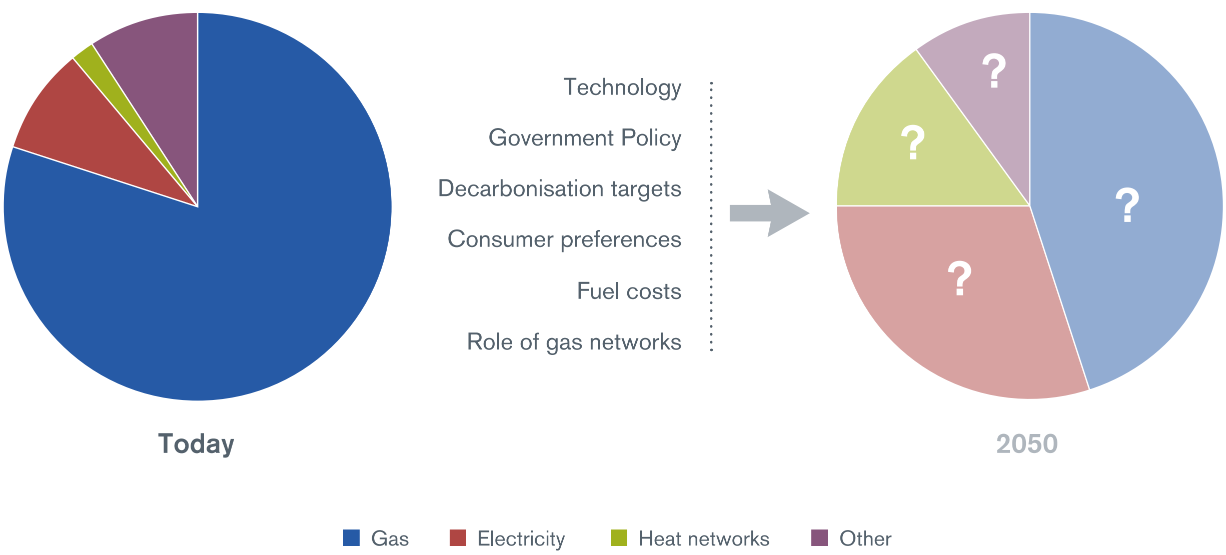
In this section we describe some of the main options for decarbonising heat to provide a context for consideration of consumer and regulatory implications later in the paper. The list is not intended to be exhaustive and the descriptions are not comprehensive. Further information can be found in a range of other publications including the Committee on Climate Change (CCC) report – 'Next steps for UK heat policy' and the Imperial College Centre for Energy Policy and Technology publication – 'Managing Heat System Decarbonisation'.

Options for decarbonising heat include:

- Improved energy efficiency;
- Adaptation of natural gas networks through blending in lower carbon gas;
- Electrification of heating through heat pumps;
- Further development of heat networks; and
- Hydrogen networks.

These options are all based on current technology. The most efficient approach to decarbonisation will depend on the rate of future cost reduction, which is inherently uncertain. By 2050, it is quite possible that other technologies not currently available will be important – we should expect technological developments to surprise us.

Figure 3: How will demand for heat in 2050 be met?



Energy Efficiency

Improving the energy efficiency of existing buildings and setting high standards for the performance of new-builds is a necessary, low-regret component in lowering emissions from the heat sector. It can also help to reduce bills, tackle fuel poverty and improve health and wellbeing.

Loft, cavity wall insulation, double glazing and smart sensors are relatively cheap means to decarbonise buildings and can improve the effectiveness of low carbon technologies such as heat pumps. While substantial progress has been made in some of these areas, there is still more to do. Tackling older homes with solid walls will involve greater disruption and cost.

A reduction in base heat demand through improved energy efficiency will be crucial to the successful decarbonisation of heat. Where possible, opportunities for improved energy efficiency and switching to low carbon fuels should be coordinated in order to minimise disruption to end users. This may be best achieved by moving delivery routes away from the current reliance on electricity and gas suppliers.

In the longer term, changes in average temperatures, technology and consumer preferences may lead to new or alternative means of providing 'comfort' to our homes that challenge traditional notions of space heating.

Gas Networks

The UK gas grid currently reaches around 80% of UK buildings[xii]. For households connected to the grid, gas-fired boilers and appliances are used to meet central heating, hot water and cooking needs. The chemical content and characteristics of natural gas in the grid are maintained within certain limits[xiii] to ensure that gas burns cleanly and to protect supply pipework from contaminants.

The injection of biomethane produced from organic matter into the gas supply pipeline is allowed, provided that the gas stays within technical limits. Under the RHI, attempts to diversify the current blend of natural gas through the injection of biomethane have seen some success. As of 2015 the energy contribution of biomethane injected to the grid stood at approximately 2.5TWh per annum[xiv]. No changes to networks or household appliances are required; this is a relatively lower cost means to partly decarbonise supply.

The volume of greener gases such as biomethane that might be produced in the longer term is not clearly known but some studies suggest it is limited to around 5% of total UK gas demand and 10% domestic gas demand by 2035[xv]. There are also potentially other uses for these gases such as in transport and industry.

Further decarbonisation of gas supply could be achieved by the introduction of hydrogen at levels above the 0.1% currently permitted. The HyDeploy[xvi] submission to the Gas Network Innovation Competition proposes to explore increasing the permissible proportion of hydrogen in natural gas up to 10% (or higher) as is currently seen in other European countries such as Germany.

Building in a degree of flexibility to adapt to different future gas blends may be particularly valuable, especially given that compositions may change over time as technology develops. The gas quality and system entry requirements for new sources of gas such as biogas and shale will also need to be explored.

The current cost of gas as a heating fuel is also a consideration for decarbonisation options. Generally, gas-fired heating is cheaper than using other fuel sources so Ofgem has supported extension of the gas grid as protecting the interests of consumers. Under the Fuel Poverty Network Extension Scheme, further households will be connected to the gas grid out to 2021 where it is the best solution for the customer. Beyond this period, we will need to consider whether this approach remains appropriate, compared to alternatives such as switching off-gas households towards heat pumps.

Electrification

There are two main ways to electrify heating: heat pumps and direct electric heating. The extent to which this contributes to decarbonisation depends on the carbon intensity of the electricity sector, which is expected to continue to fall substantially. Widespread electrification of heat would require significant network reinforcement and new generation to meet increased overall demand for electricity and higher peak loads, mitigated through spreading the load over time. On grounds of efficiency and ongoing cost levels, we focus on heat pumps here.

Heat pumps use electrical input to upgrade low temperature heat from sources such as the air, ground and water. For off-gas grid buildings they can provide an efficient means of fuel-substitution away from more carbon intensive non-gas fuels.

Given the spatial requirements and higher up-front costs of ground-source systems, air-source heat pumps are likely to be the preferred model for domestic buildings. At roughly £5,000 to £10,000, the cost of an air-source heat pump is typically over twice as much as a new gas boiler. This cost and unfamiliarity with the technology has led to slow overall uptake.

Improved building efficiency is often necessary for the lower flow temperatures provided by heat pumps to provide comfortable levels of heating. Opportunities for coordinating energy efficiency improvements at the same time as installing heat pumps should therefore be explored.

Hybrid gas/electric heat pump systems are a further option for buildings connected to the gas grid that wish to maintain a back-up supply and can switch fuels depending on cost and to meet peak heating requirements. Wider interactions across gas and electricity that can drive more efficient system outcomes in meeting demand for heating, cooling and power are likely to be increasingly important to our future energy system. For example, heating systems have the ability to absorb surplus electricity through heat pumps, electric heaters and thermal storage, shifting heating load and creating additional demand flexibility.

Heat Networks

Supplying heat through a network from a centralised plant in areas of concentrated demand may offer significant carbon savings where it enables lower carbon fuels and sources of waste heat to be used.

Heat networks can utilise numerous sources of heat including biomass and biogas fuelled boilers, heat pumps and energy from waste facilities. Converting a fuel to heat and power simultaneously – combined heat and power (CHP) – improves efficiency and provides additional value.

At present the majority of heat networks use gas as their fuel. However, once the network of pipes supplying end-users is in place then generation technologies may be changed over time to utilise lower carbon fuels i.e. permitting a switch from gas to biomass.

Many Local Authorities are becoming active in developing heat networks, giving planning permission and coordinating with customers such as leisure centres, schools and social housing developments to provide a baseload of heat demand. The BEIS National Heat Map is a set of electronic maps that display heat demand across buildings in England. It provides a useful starting point for Local Authorities in the development of area-based solutions that may incorporate district heating schemes. £320 million of funding is currently in place to support low-carbon heat networks until 2021 through the Heat Networks Investment Partnership. In Scotland the Heat Network Partnership has a target of connecting 40,000 homes by 2020.

The high capital costs of projects and need to secure a baseload of customers have led to difficulties in securing the required investment for widespread take-up. The spatial requirements of distributing hot water through large insulated pipes overlay further complexity for potential retrofit of heat networks to existing buildings. Potential options around the policy and regulatory regime for heat networks are discussed later in this paper.

Hydrogen

One alternative to burning natural gas (methane) for heating would be to burn hydrogen. Unlike natural gas, this does not produce carbon dioxide on combustion.

The H21 Leeds City Gate project[xvii] has assessed the potential to use the same network we use today for natural gas to pipe hydrogen into our homes and businesses. They have found that the polyethylene pipes increasingly used in gas distribution networks can safely transport hydrogen. That is not true for the entire gas transportation network and new hydrogen transmission pipelines would be required to connect to medium pressure distribution networks and inter-seasonal storage facilities. Changes would also be required to appliances at the points of end use.

Industrial scale hydrogen production typically falls into one of three categories – by electrolysis, steam methane reforming (SMR) or as a by-product from chlor alkali plants or refineries. Electrolysis and SMR are the ways to generate significant volumes of hydrogen. Electrolysis requires greater use of electricity so works better with very cheap electricity (e.g. power that would otherwise be curtailed), and depends on the costs of the required network reinforcement and storage. SMR currently appears to be the preferred option. For large scale conversion via SMR, natural gas would be required in significant quantities as the feedstock for hydrogen production, releasing carbon dioxide in the process. However if done in centralised locations it is much more realistic to envisage the use of Carbon Capture and Storage (CCS) technology than today where natural gas is burnt in millions of dispersed locations.

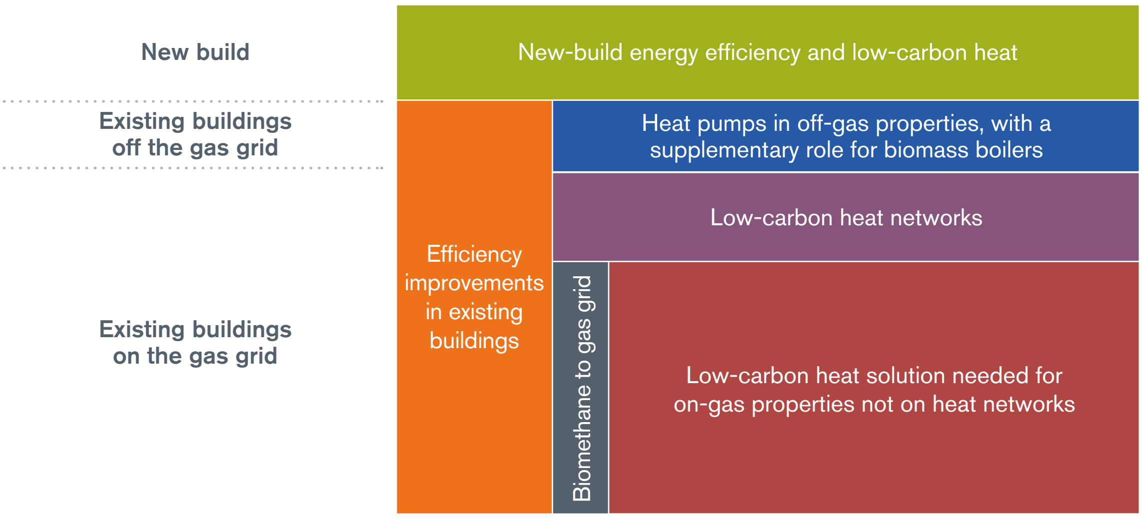
Due to the inherent similarities between hydrogen and natural gas, heating with hydrogen would perhaps require less change for consumers versus a switch to heat pumps or district heating. However rigorous appliance and safety testing will be needed to allay any potential safety issues. This could be greatly aided by pilot projects that can demonstrate the safe introduction and use of hydrogen within the gas grid by consumers and that generate further information on the potential challenges of retrofits. Given the scale of the retrofit challenge that would be involved with a local, regional or national conversion, consumer acceptance will be a huge challenge, especially given that remaining connected to natural gas would not be an option in areas of hydrogen conversion.

The availability of low-cost hydrogen at scale could also unlock the potential for hydrogen vehicles and use of fuel cells in local CHP units.

Decision points and pathways:

The current consensus is that decarbonisation of heat in the 2030s and 2040s will involve a mix of the above options. These have different strengths and weaknesses which means that – based on today's knowledge – different ones are likely to prevail in different circumstances. One way in which to consider the best option is by drawing a distinction between buildings connected to the gas grid and those that are not, and between new build and existing stock, as set out clearly in the diagram below from the CCC.

Figure 4: Decarbonisation options for new build and existing buildings off and on the gas grid



Source: Committee on Climate Change (2016) Next steps for UK heat policy

Notes: The sizes of the blocks broadly reflect the scale of emissions reduction, but do not do so precisely. Some potential for heat networks will be in new-build and off the gas grid, rather than all on-grid as presented. Biomass for heat may also play a role in hard-to-insulate rural properties.

However, we don't know enough about the future costs of different options – particularly the full supply chain for hydrogen and CCS – to be confident in setting a path now. These costs will include not only financial costs but also the cost of public acceptability. This makes a policy of trialling different options to uncover additional information seem attractive. Of course, we can also learn from projects in other countries and there would be value in further work to capture the lessons from such projects and, in particular, explicitly consider (and design trials to test) the extent to which they might be applicable in Britain.

Uncoordinated uptake risks

There is a risk that future decisions could run counter to decarbonisation attempts that are being taken in the near term – especially those by individual consumers.

For example, we can envisage a scenario where a consumer installs an air-source heat pump (choosing to retain their connection to the gas grid as a back-up) only for a subsequent connection to a hydrogen or district heating network to be mandated. Alternatively, a new efficient gas boiler could be installed by a customer when their old one breaks down, however conversion of the gas grid to hydrogen the following year leads to this appliance needing to be changed again.

An understanding of the likely direction of travel for policy will be crucial in mitigating situations such as these. In the short term this may mean that it is better to focus changes to lower carbon sources on individual households where community or regional scale solutions seem less likely.

Who decides?

At present, most heat technology decisions are taken at an individual property level, with the exception of district heating networks. With the right tools and expertise, Local Authorities can play a role in identifying appropriate solutions and coordinating connections. This will be particularly important for district heating retrofit schemes and recent examples show that this is possible. Government policy also has a key role in building and appliance standards, labelling, planning permission and financial support.

The roll out of a hydrogen network could be trialled at a local level but to be an important part of the decarbonisation of heat it will need to be at a regional level. It is not clear today who would make such decisions. In practice such a roll-out would likely require government backing as legislation may well be needed, or at least a funding model that would ensure that network development, hydrogen production and potentially CCS would all be delivered in a coherent timescale. Alongside this would be the need for a programme of changing appliances in every property currently using natural gas.

The developer of the new infrastructure and the regulator would need to be closely involved, but ultimately legitimacy is likely to require decisions to sit with elected politicians. Other bodies such as the National Infrastructure Commission could potentially play a particularly valuable role in developing proposals.

Regulatory implications:

Ofgem's primary duty is to protect the interests of existing and future consumers in the electricity and gas markets in Great Britain. This does not currently extend to direct responsibility for customers on district heating networks. We consider that our responsibilities would apply to customers on hydrogen gas networks, but would not extend to hydrogen production or CCS facilities. In this section we do not attempt to describe in detail the current regulatory model, but offer comments on what might be appropriate to best protect the interests of consumers more generally.

Consumer protection

The current approach for natural gas involves direct regulation of networks by capping revenues and requiring or incentivising outputs and quality of service. Alongside this we have competitive supply markets supported by specific licence requirements and other important arrangements such as the ombudsman scheme. Safety is regulated by the HSE and is not considered further here.

For electrification of heat, new regulatory issues may be relatively limited as electricity is already regulated.

For heat networks, there is likely to be a single provider for each individual scheme. It may be possible for an individual household to opt out, but this will often be undesirable in terms of cost and efficiency for area-based solutions. Customers may expect to receive similar (or better) protection and rights than on natural gas networks.

Citizens Advice has noted increased levels of complaints from heat network customers[xviii]. The launch of the Heat Trust, an industry-led voluntary consumer protection scheme, and the Heat networks: Code of Practice for the UK, have been positive steps in this regard. However the voluntary nature of the Heat Trust scheme, lack of incentives to join and certain exclusions on participation have limited its overall powers and reach. Such schemes cannot address some of the regulatory protections that might be desirable but require statutory backing, such as arrangements to protect customers if a scheme operator becomes insolvent.

For hydrogen networks, we could potentially see retail competition among suppliers in a broadly similar way as we do for natural gas today once deployment reaches sufficient scale. Initially, it is likely to be a single supplier per network, which may be more like a heat network. To the extent that increased use of hydrogen is the driver for CCS, this also raises questions of how CCS will be regulated.

If any of these technologies grow in scale, and arguably heat networks have already reached a critical mass, there appears to be a case for a more comprehensive approach to ensuring customer protection appropriate for an essential service. For service quality such as billing and metering, we consider that clear standards of service and an ombudsman arrangement should be a priority, with a regulatory backstop to address systematic failures. Our current work on principles based regulation for retail will likely make it easier to read across arrangements from electricity and gas.

Possible arrangements to cover charges and funding are considered in the following section.

Funding

The difficulties in securing investment in heat networks and a baseload of customers are well documented. District heating projects currently have a higher risk profile than those across gas, electricity and water.

It has been suggested that a Regulated Asset Base (RAB) model should be adopted. We would not rule out such an approach, but it may be useful to set out some of the issues we think would need to be considered in deciding whether to move in that direction.

In designing an appropriate regulatory framework, it is necessary to understand the problems it is intended to address. Regulation of prices is generally intended to prevent abuse of a monopoly position, and to give confidence to consumers that their interests are protected. In the case of heat networks, and prospectively for hydrogen, another motivation appears to be the perceived riskiness of projects. So what are these risks and how can they be addressed?

The main risks are around the level of development and construction costs, take-up or demand risk, ongoing operating risk (fuel costs, operating and maintenance/repair costs and service levels) and the risk of being superseded or stranded (e.g. if electric heating becomes very cheap). With a fixed price contract, these risks sit with the scheme developer. Most, if not all, are fundamental risks that can only be reallocated rather than avoided entirely. Instead of leaving them with the developer, options could include transferring them to other customers of the scheme or socialising more broadly across all heat consumers (on other networks) or taxpayers. Some risks, such as take-up risk, can be mitigated – for example through contracting in advance of deciding to invest, where this is practicable.

A RAB based model could provide a means to reallocate risks to other customers of the same scheme (or other schemes operated by the same licensee), in the same way that for existing electricity and gas networks, revenues are set across the whole licensed area. However, it is not clear that this is desirable. Particularly for operators starting out (without lots of other schemes), it risks putting up prices significantly to their first customers, who could then be discouraged and potentially seek to withdraw. Some sharing of risks between the developer and customers may be suitable, which could be implemented either through contract or through regulation. There may be an argument for socialisation of some risks more generally (i.e. involving other consumers or taxpayers), but that is not achievable through regulation alone – it is likely that legislation would be required, as in other parts of the energy sector where this approach has typically been taken forward through a levy.

So before debating particular regulatory solutions, it is important to be clear on the appropriate allocation of risk. Following on from that, we would also want to consider whether other regulatory approaches which we have adopted in circumstances that are arguably more similar to heat or hydrogen networks might be useful.

For heat networks, perhaps the closest parallel in the current electricity and gas regulatory framework is with independent gas transporters (IGTs) and independent distribution network operators (IDNOs). They are licensed entities, subject to price caps which typically involve requirements that they do not charge more than the local incumbent network. This avoids detailed assessments of their costs and rates of return. They are subject to some of the same requirements and provisions as the incumbent networks such as standards of service. A parallel would be a regime which ensures customers on district heat or hydrogen networks are charged no more than customers on natural gas networks.

Another potential parallel in infrastructure that is open to new project development is that of electricity interconnection. Here we have a regulatory framework which provides for a range of revenues that the developer can earn, depending on how used and valuable the asset turns out to be. A third example is through tendering for development and ownership of new infrastructure.

Each of these models provide incentives for efficient development and capital costs, and reward the developer for making good decisions. They all involve ongoing regulation, some with explicit incentives to ensure continued service availability. They are all subject to special administration regimes to ensure customers are protected in the event of insolvency.

Our current regulatory models rely on financial incentives which typically share the benefits of efficiency or service improvements between consumers and shareholders. We would need to consider whether this is appropriate for public sector organisations. We also make increasing use of reputational incentives (ratings or rankings) which could apply well to community based schemes.

Implications for current gas and electricity networks

Some of the above options clearly raise the possibility of declining use of current gas networks or of switching to alternative use, and of increased use of electricity networks. This implies that the economic asset life of gas networks is lower than their technical life and suggests that potential decommissioning may need to be considered. We do not see particular barriers to considering such issues – we have sufficient flexibility in how we consider price controls and within the RIIO framework.

As highlighted in our Overview paper, where consideration is given to alternative future pathways, it is important to consider economic choices based on future costs rather than past, and to ensure charging arrangements do not distort choices. In particular, the scale of past investment should not drive future decisions. Decisions about the best approach to a decarbonised heating future should be based on future not past costs.

In terms of charging, it is important not to load the costs of previous investments on one option but allow them to be evaded through choice of an alternative – when such a choice cannot change costs that have been incurred already. For example, if there is a choice between re-use of current natural gas networks for hydrogen or switching to electric heating, that choice could be distorted if future (hydrogen) gas customers were asked to bear all the sunk costs of the natural gas network but electric customers had no such requirement.

In the nearer term, there is clearly uncertainty around future gas demand scenarios given the potential impact of improved energy efficiency and the adoption of electric and district heating. Network companies will need to work with their stakeholders to justify assumptions in their business plans, and to develop contingency plans to prepare for the situation that assumptions which are adopted may turn out not to occur.

Conclusion:

There is a rapidly growing literature on the future of heat. Shifting our supply away from natural gas raises interesting questions regarding cost and choice for future consumers.

In general, we support the conclusion from the recent CCC report that the near term steps should focus on active experimentation, not on a wait and see approach.

We will be considering the implication of different future pathways for our core regulatory functions. We are keen to engage with government and other stakeholders and ready to work on regulatory solutions for heat supply more broadly. However given the interactions, we consider it is not sensible for us to take forward work in this area in isolation. We will therefore continue to liaise with BEIS and other stakeholders and seek to contribute to future work.

[i] DECC (2015) Energy Consumption in the UK, 2013 data

[ii] DECC (2015) Energy Consumption in the UK, 2013 data

[iii] Robert Sansom (2014) Decarbonising low grade heat for a low carbon future

[iv] DECC (2012) The Future of Heating: A strategic framework for low carbon heat in the UK

[v] DECC (2015) Energy Consumption in the UK, 2013 data

[vi] DECC (2013) 'The Future of Heating: Meeting the Challenge'

[vii] BEIS (2016) Non-Domestic RHI and Domestic RHI monthly deployment data: September 2016

[viii] BEIS (2015) Digest of UK Energy Statistics (DUKES)

[ix] DCLG (2016) Table 209: permanent dwellings completed, by tenure and country

[x] Imperial College (2016) Managing Heat System Decarbonisation – Comparing the impacts and costs of transitions in heat infrastructure

[xi] SSE: Learning from the impacts of the Wyndford Estate district heating project

[xii] DECC (2013) 'The Future of Heating: Meeting the Challenge'

[xiii] Under the Gas Safety Management Regulations 1996 (GSMR),

[xiv] REA (2016) REVIEW: The Authoritative Annual Report on the UK Energy Sector

[xv] National Grid (2015) Future Energy Scenarios

[xvi] See HyDeploy submission to Gas Network Innovation Competition.

[xvii] See H21 Leeds City Gate project details on ENA Smarter Networks Portal

[xviii] Citizens Advice (2016) Response to the consultation on the Heat Networks Investment Project

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