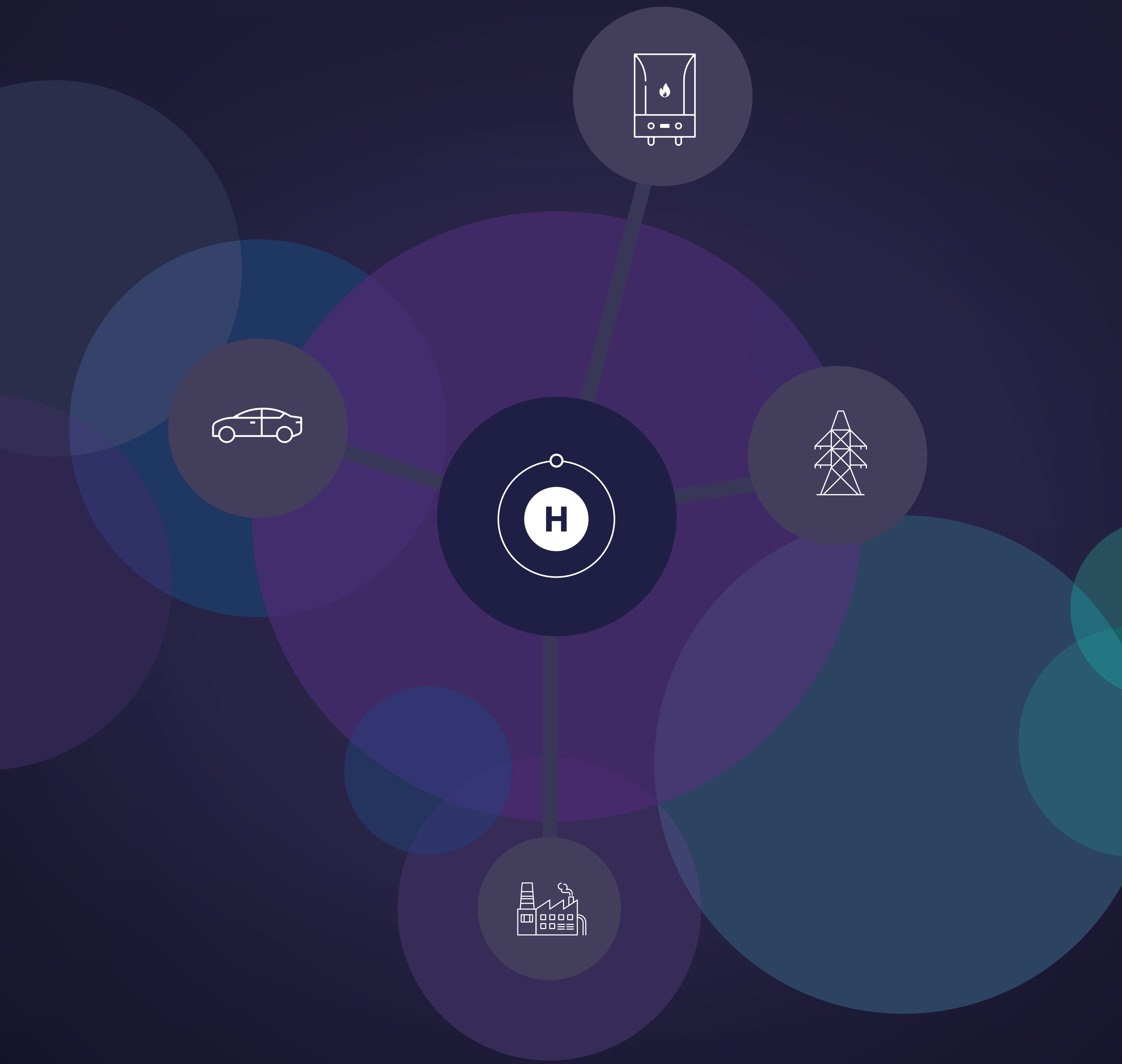
Hydrogen in a low-carbon economy

Committee on Climate Change
November 2018



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A wide range of stakeholders who participated in our workshops, engaged with us or met with the Committee bilaterally.

Contents

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Executive Summary

The emissions reductions required by 2050 under the Climate Change Act mean that energy will need to be supplied almost entirely carbon-free. That points to a large role for electricity, for which several low-cost zero-carbon production technologies are already available. It could also mean a role for hydrogen, which can be produced in low-carbon ways from electricity or with carbon capture and storage (CCS).

Alternatives to carbon-based fuels will be required across the energy system: not just in electricity generation, but also in our buildings, industry and transportation. Now is the moment for the UK to move decisively beyond the successful decarbonisation of electricity into a broader strategy for these sectors. Emissions can be cut from these sectors while growing the economy and at minimal overall cost to energy consumers.

The UK's commitments under the Paris Agreement further emphasise the imperative for zero-carbon energy. This will require government to make strategic decisions on energy infrastructure and the use of available energy resources. The Committee has undertaken this Hydrogen Review in parallel with reports on *Biomass in a low-carbon economy* and on *land use*. The insights in these reports will feed into our new appraisal of the UK's long-term climate targets, due in spring 2019.

A combination of energy efficiency and electrification based on zero-carbon electricity can take the UK a great deal of the way towards near-full decarbonisation of the whole energy system. But it is a strategy that, alone, is not enough. Producing hydrogen in low-carbon ways and using it to meet challenging demands (e.g. for heat in industrial processes, for heating buildings on colder winter days and for heavy transport) is likely to be an important part of the next stage of the UK's energy transition.

Our key messages in this report are:

- **Hydrogen can be a strong complement to electrification.**
  - The possibility of producing hydrogen by a low-carbon route and storing it at scale makes it a potentially valuable complement to electrification in reducing emissions from energy use to a very low level, cost-effectively, by 2050. Production of low-carbon hydrogen at scale will rely on deployment of carbon capture and storage (CCS).
  - Used selectively, alongside widespread electrification and improvements to energy efficiency, hydrogen has potentially valuable roles in replacing natural gas (e.g. for heating buildings on colder winter days, industrial process heat and back-up power generation) and liquid fuels (e.g. in heavy transport). With a planned approach, it is likely that the use of hydrogen will enable UK emissions to reach lower levels by 2050 than could be achieved without it.
- **The need for action on hydrogen.** If hydrogen is to play a substantial long-term role, progress towards deployment of low-carbon hydrogen at scale must start now. Deployment of hydrogen should start in a 'low-regrets' way over the next decade, recognising that even an imperfect roll-out is likely to be better in the long term than a 'wait-and-see' approach that fails to develop the option properly.
- **The need for a heat decarbonisation strategy.** The largest potential for hydrogen to contribute to decarbonisation is as a low-carbon fuel for heat in buildings and/or industrial processes. These uses will also determine hydrogen infrastructure requirements, for example relating to the future of gas distribution networks. Hydrogen's future role therefore rests on strategic certainty about how the decarbonisation of heat will be delivered in the UK. It also relies on the implementation of CCS, given its importance for low-carbon hydrogen

production at scale. A commitment should be made now to develop a fully-fledged UK strategy for decarbonised heat within the next three years, including clear signals on the future use of the gas grid in the UK.

- **Costs.** Deployment of hydrogen can provide a cost-effective option to displace fossil fuels in applications where emissions reductions would otherwise be impractical and/or expensive. This will be important in reaching near-full decarbonisation of the whole energy system. As part of a package - alongside energy efficiency, cheap low-carbon power generation and electrification of transport - hydrogen can contribute to deep decarbonisation of energy at lower costs than we have previously estimated.

Where hydrogen can add value

Hydrogen is often seen as an easier or cheaper way of achieving long-term decarbonisation, but it is important to draw such conclusions on the evidence over the role that hydrogen can play (Box 1).

Box 1. Evidence on the potential role of hydrogen

In engaging with stakeholders for this review, the Committee heard a range of views about the potential role of hydrogen in decarbonisation. The evidence and analysis presented in this Review allow us an improved understanding of hydrogen's potential role:

- **The existing gas grid does not preclude other solutions for heat decarbonisation.** The sunk costs of having an extensive gas grid do not automatically mean that it will be lower cost to switch it over to hydrogen and use it in boilers as we do with natural gas at the moment. Our analysis finds that the costs of a range of pathways for heat decarbonisation are similar (see Figure 1), including those in which the gas grid has a much reduced role or is decommissioned.
- **'Surplus' low-carbon power is limited.** While there is some opportunity to utilise some 'surplus' electricity (e.g. from renewables generating at times of low demand) for hydrogen production, our modelling shows that the quantity is likely to be small in comparison to the potential scale of hydrogen demand. Producing hydrogen in bulk from electrolysis would be much more expensive and would entail extremely challenging build rates for zero-carbon electricity generation capacity.
- **Hydrogen from fossil fuels with CCS is low-carbon but not zero-carbon.** Gas reforming with CCS has a potentially important role, especially in scaling up a hydrogen industry. However, it is low-carbon rather than zero-carbon, providing lifecycle emissions savings of 60-85% relative to natural gas use in boilers. If hydrogen from gas with CCS is deployed in very large quantities, the emissions savings may be insufficient to meet stretching long-term emissions targets.
- **Imports are uncertain.** International trade in low-carbon hydrogen[1] may develop over time. However, it is not a certainty that it will and the costs may be no lower than that of domestic low-carbon hydrogen production. It would therefore not be sensible for decisions taken now on the UK's energy infrastructure to rely on large-scale imports.

We therefore conclude that hydrogen is best used selectively, where it adds most value alongside widespread electrification, improvements to energy and resource efficiency, and use of CCS in industry and on bioenergy. This means using hydrogen where the alternative is continuing to burn unabated fossil fuels or where there are limits to feasible electrification.

[1] It currently appears that converting hydrogen to ammonia as a means of transporting it over long distances would have lower costs than transporting it as hydrogen.

While production and use of hydrogen is generally less efficient than electrification, hydrogen is more readily storable than electricity at very large scale. This means that hydrogen has particular value as a low-carbon replacement for natural gas (and potentially oil) in applications where full electrification is very difficult, disruptive and/or expensive:

- **Buildings.**
  - Hydrogen could play a valuable role as part of a heating solution for UK buildings, primarily in combination with heat pumps as part of 'hybrid heat pump' systems. Our assessment is now that heat pumps, powered by increasingly low-carbon electricity, offer the potential to provide heat efficiently for most of the time, with hydrogen boilers contributing mainly as back-up to meet peak demands on the coldest winter days.
  - Deployment of this combination of hydrogen and heat pumps could almost completely displace fossil fuel use in buildings. While not without challenges, this solution would enable the energy system to reach very low emissions, with greater feasibility and public acceptance than is likely with strategies for the full electrification of heat or the full use of hydrogen as a like-for-like replacement for natural gas as we use it today.
- **Industry.** New evidence indicates that hydrogen has an important potential role in reducing emissions from industrial heat, especially where the flame (and subsequent combustion gases) needs to come into direct contact with the material or product being produced (e.g. in furnaces and kilns). Hydrogen also appears to be well suited to decarbonisation of more distributed sources of CO_2 emissions (e.g. from the food and drinks sector), which would be impractical and costly to capture.
- **Power.** By 2030, the UK is likely to have a very low-carbon electricity system, with renewables and nuclear backed up by flexible thermal plants – mainly natural gas plants. There is an opportunity for hydrogen to replace natural gas cost-effectively in this back-up role, potentially enabling power system emissions to get close to zero by the 2040s. This would be helped if new gas plants can be made 'hydrogen ready', including being well-sited with respect to potential hydrogen supplies.
- **Transport.** While battery electric vehicles are now well placed to deliver the bulk of decarbonisation for cars and vans, hydrogen fuel cell vehicles could play an important role for heavy-duty vehicles (e.g. buses, trains and lorries) and potentially for longer-range journeys in lighter vehicles, where the need to store and carry large amounts of energy is greater. There is also a potentially important role in decarbonising shipping, especially if an international market in low-carbon hydrogen or ammonia develops.

Repurposing gas distribution networks to contribute to buildings decarbonisation would mean that low-carbon hydrogen is widely available, enabling it to play a wider role within other sectors. However, this is not a precondition for adoption of hydrogen technologies and there will be an important period before any gas grids are switched over to hydrogen. Even without a decision to switch grids to hydrogen, dedicated infrastructure solutions mean hydrogen can still play important roles in industry, heavy transport and the power sector.

The need for deployment

Hydrogen has been recognised as an option to reduce emissions for a long time, but it has yet to justify its deployment at scale within the UK energy system. Currently, hydrogen is not commercially competitive in most potential applications. This is likely to continue unless and until costs can be driven down, including through deployment at scale, and incentives for its use become stronger.

Continuing an incremental approach that relies on isolated, piecemeal demonstration projects may lead to hydrogen remaining forever an option 'for the future'. The longer it takes for hydrogen to become a proven option, the smaller the role it will be able to play by 2050.

The UK does not currently produce significant amounts of low-carbon hydrogen, nor does it have technologies in place that would provide a market for that hydrogen. One of the key challenges for hydrogen technologies is to get a foothold in the energy system, overcoming this 'chicken and egg' barrier.

A priority for the 2020s should therefore be to demonstrate hydrogen's value by deploying hydrogen technologies in a way that breaks this cycle of inaction:

- Hydrogen production should start at scale as part of a CCS cluster, for use in a range of ways that would not initially require major infrastructure changes (e.g. use in buses, power generation, industry or blending at small proportions into the natural gas supply).
- Hydrogen-ready technologies (e.g. boilers, turbines) should be developed in parallel and their deployment supported by policy.
- Effective policy mechanisms should be put in place that drive adoption of hydrogen technologies where they add most value, as hydrogen's long-term role in the energy system becomes clearer.

A strategic approach to heat decarbonisation

Heating buildings is one of the areas where the challenge in achieving deep emissions reductions by 2050 is greatest. We have previously recommended low-regret measures that the government should pursue now, including much high levels of energy efficiency and some deployment of low-carbon heat especially off the gas grid (Box 2). However, we identified that displacing natural gas heating will be difficult given its low costs, familiarity and convenience and the need for strategic decisions by the mid-2020s on the respective long-term roles of hydrogen and electrification in decarbonising heat for buildings on the gas grid.

Making strategic decisions on the future of heat provision and the gas grid will be difficult for any government. It requires the acceptance of higher short-term costs and a long-term outlook, beyond the standard Parliamentary timetable. Nevertheless, as an infrastructure issue with long lead-times, it must be addressed with strategic decisions in the 2020s if we are to meet the 2050 target under the Climate Change Act.

Analysis for this report shows that a range of pathways to 2050 for heat decarbonisation, based on hydrogen and/or electrification, have similar costs. These conclusions are similar to those of the National Infrastructure Commission.[2] New analysis for this report shows that these pathways include a 'Hybrid Hydrogen' pathway in which hydrogen boilers provide back-up to heat pumps on colder winter days.[3]

[2] National Infrastructure Commission (2018), *National Infrastructure Assessment*.

[3] The modelling undertaken for the Committee by Imperial College initially analysed three heat decarbonisation pathways: full electrification; full deployment of hydrogen; and 'hybrid' heat pumps backed-up by boilers using natural gas and biomethane. We subsequently asked them to model a pathway with hybrid heat pumps backed-up by hydrogen boilers. Imperial College (2018) *Analysis of alternative UK heat decarbonisation pathways*.

When taking decisions on how to decarbonise it is therefore sensible to consider a range of factors other than cost, including public acceptability and the feasibility of delivering near-full decarbonisation of heating for buildings by 2050. On each of these considerations, pathways based on full electrification and full hydrogen face considerable challenges.

- **Public acceptance.** New research has highlighted that the public is unaware both of the need to move away from natural gas heating and of what hydrogen or heat pump alternatives would entail. Making decisions by the mid-2020s to pursue either option as the primary solution for heat decarbonisation carries with it the possibility that the chosen solution will be rejected.
- **Delivering near-full decarbonisation by 2050.**
  – **A 'full hydrogen' pathway** would require large volumes of hydrogen. Depending on how this demand is met, this would lock-in to significant residual emissions and/or mean extremely challenging build rates for low-carbon energy infrastructure.
    - Producing large volumes of hydrogen from natural gas with CCS could lock the UK into a path with insufficient emissions reductions by 2050 – this route offers a reduction in lifecycle emissions of 60-85% compared to natural gas boilers, so could leave residual emissions of 20-70 Mt. It also depends heavily on both deployment of CCS at very large scale and gas imports at around double today's levels.
    - While production of hydrogen through electrolysis from 'surplus' renewables and/or nuclear could be a cost-effective niche, the size of this opportunity is small in comparison to potential demands for hydrogen. Producing hydrogen in bulk from electrolysis would be much more expensive and would entail extremely challenging build rates for electricity generation capacity.
    - Although it may become possible to import hydrogen from low-cost production elsewhere in the world, in making strategic infrastructure decisions in the near term it would not be sensible to rely on an international market in low-carbon hydrogen emerging over the coming decades.

  – **A full electrification pathway** would also entail major challenges, relating to how widely heat pumps can be deployed and how to meet the peak of electricity demands of the coldest winter days, which strain local grid capacity and are challenging to meet through low-carbon supply alone. Batteries alone cannot provide the scale of energy storage required to meet seasonal swings in energy demand.

Given the imperative for early decisions and the evidence currently available, it is not prudent to plan now on achieving the necessary emissions reductions by 2050 only from hydrogen (i.e. using hydrogen in boilers as we use natural gas now) or via full electrification.

Recent developments in the Committee's modelling of future energy system scenarios mean that our assessment of the most feasible approach to decarbonising heat for buildings has changed (Box 2):

- The path to near-full decarbonisation by 2050 now entails near-term deployment at scale of 'hybrid' heat pumps in buildings on the gas grid, alongside substantial improvements in energy efficiency, low-carbon new-build and other 'low-regrets' heat decarbonisation deployment.
- A hybrid heat pump can be retrofitted around the existing boiler, making it part of an upgraded, smart heating system. This retrofit can be done alongside improvements to

energy efficiency of the building, leading to dramatic cuts in both emissions and fossil fuel consumption while retaining high performance and potentially improving comfort levels.

- Retaining the boiler means that the heating system would provide equivalent performance to existing heating systems, and would not require changes to radiators. This more incremental approach to switching to heat pumps is likely to be considerably more acceptable to the public than replacing the boiler with a heat pump.
- Deploying hybrid heat pumps would lead to greater reductions in near-term emissions from buildings, and provide greater confidence that very low levels of emissions can be reached by 2050. This would keep open the option of switching the remaining gas supply to hydrogen at a later date, and would reduce the volume of hydrogen that would be needed in that scenario by around 70% for heating and by around 50% across the energy system.
- This would reduce concerns over whether sufficient low-carbon energy supplies can be delivered. Hydrogen from gas reforming with CCS and from electrolysis could play significant roles as part of a mix, potentially with production from sustainable biomass with CCS.

This approach would retain the value of the gas grid to the energy system, while both cutting emissions and the scale of gas consumption more quickly, and reducing the scale of the challenge to move to full decarbonisation by 2050.

Box 2. A near-term strategy for emissions reductions from buildings

In combination with a set of actions on heat decarbonisation that we have already recommended, deployment of hybrid heat pumps alongside low-cost renewable power generation provide a further means to reduce emissions from buildings in the near term:

- **Energy efficiency.** Regardless of the approach to heat decarbonisation, effective policies must be developed to deliver on the government's Clean Growth Strategy commitment to improve the efficiency of the existing stock of homes to EPC Band C by 2035. Achieving this will help to reduce people's bills, increase comfort levels and reduce the costs of heat decarbonisation. New buildings should be built with a high level of energy efficiency and designed for low-carbon heating systems, enabling them to be low-carbon from the outset.
- **Hybrid heat pump deployment.** Hybrid heat pumps can make a substantive difference if deployed at scale (e.g. 10 million hybrid heat pumps by 2035 in on-gas buildings). Retrofitting a hybrid heat pump system at the same time as implementing energy efficiency improvements to a building would minimise overall disruption and sharply reduce its emissions. As demonstrated by the Freedom project, these can be operated smartly, with the ability to fall back on gas (or ultimately hydrogen) boilers when necessary. This would add considerably to the responsiveness of electricity demand, helping it to operate with higher proportions of less flexible generation (i.e. renewables and/or nuclear).
- **Deployment of low-cost renewable electricity generation.** The dramatic reductions in the costs of renewable electricity generation have created an opportunity for more cost-effective earlier use of heat pumps. Deploying wind and solar will already be cheaper than building fossil power generation in the 2020s at current carbon prices, so the addition of flexible demand from heat pumps (i.e. that can be shifted smartly by a few hours or switched to gas boilers if necessary) should be accompanied by the addition of corresponding amounts of additional low-cost renewable electricity generation.
- **Other low-regrets solutions for heat decarbonisation.** The government should also pursue the range of low-carbon heating solutions we described as low-regrets in our 2016 report on *Next Steps*

Box 2. A near-term strategy for emissions reductions from buildings

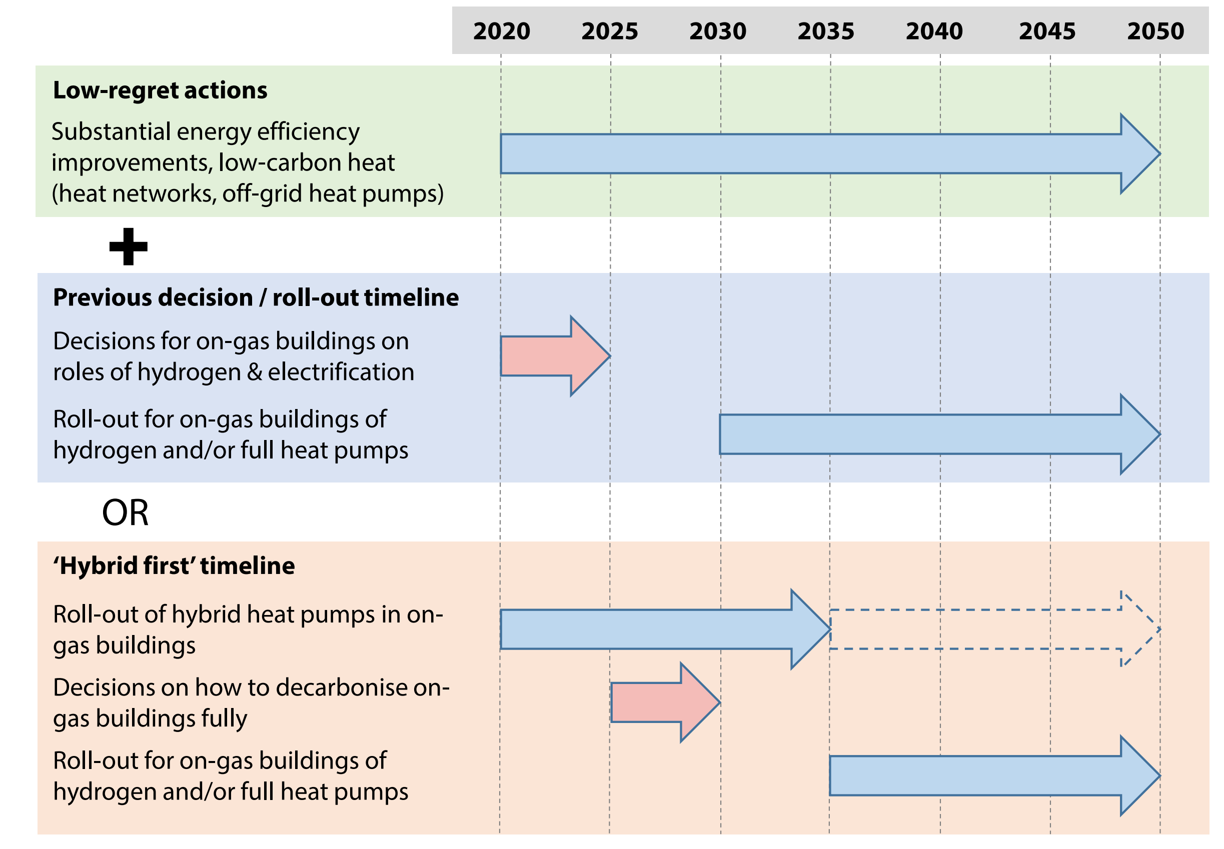
for UK Heat Policy: deployment of low-carbon heat networks in heat-dense areas; heat pump deployment off the gas grid; and increasing levels of biomethane injection into the gas grid.

These actions, would lead to homes being more comfortable and having significantly lower emissions in the nearer term. It would also make near-full decarbonisation of heat in the long term more achievable, if the hydrogen option is developed in parallel:

- Delivery of these measures, including hybrid heat pumps, would cut gas demand substantially by the 2030s, making any subsequent switchover of gas grids to hydrogen more deliverable by reducing the volume of low-carbon hydrogen required.
- Hybrid heat pump deployment would also help develop a full electrification pathway, increasing public familiarity with heat pumps via an incremental solution with less disruption (e.g. in replacing radiators as may be required for non-hybrid heat pumps).

By taking the first part of the decision over how to decarbonise heat fully for on-gas properties now, the second part - on how to reduce emissions from the considerably lower residual natural gas use - could potentially follow slightly later than we had previously set out (Figure B2).

Figure B2. Pursuing a 'hybrid first' approach alongside other low-regret actions



Notes: 'Low-regret' actions are those that the Committee recommended in 2016 should be pursued immediately, with subsequent decisions to be made by the mid-2020s on the respective roles of hydrogen and electrification in on-gas buildings outside heat network areas, for roll-out between 2030 and 2050 (shown the middle section of the diagram). The 'hybrid first' timeline would entail pursuing the low-regret actions now alongside deployment of hybrid heat pumps in on-gas properties, with decisions on achieving full decarbonisation able to come slightly later.

The costs of decarbonising heat, power and surface transport

Parliament has already accepted that meeting the targets under the Climate Change Act will have some costs, which we have previously assessed as being 1-2% of GDP. We estimate that costs of near-full decarbonisation heat for buildings, through hydrogen and/or electrification, will be up to 0.7% of GDP in 2050. That the costs of heat decarbonisation are such a significant proportion of the total costs reflects its importance and the challenge in achieving the necessary emissions reduction overall by mid-century.

However, the dramatic recent falls in the costs of renewable electricity generation and batteries mean that we now expect low-carbon power and transport to cost less by 2050 than their high-carbon equivalents today, offsetting some of the costs of decarbonising heat (Figure 1). The lower costs of low-carbon power generation also reduce the costs of electrified heat. This means that our overall assessment of the costs of decarbonising the energy system are considerably lower than previously estimated. We will take this into account when providing advice in spring 2019 on the implications of the Paris Agreement for the UK's emissions targets.

There remain important questions over how to pay for heat decarbonisation, especially in the case that this is achieved in different ways or at different rates in different parts of the UK. The distribution of the costs of heat decarbonisation is a policy choice for government.

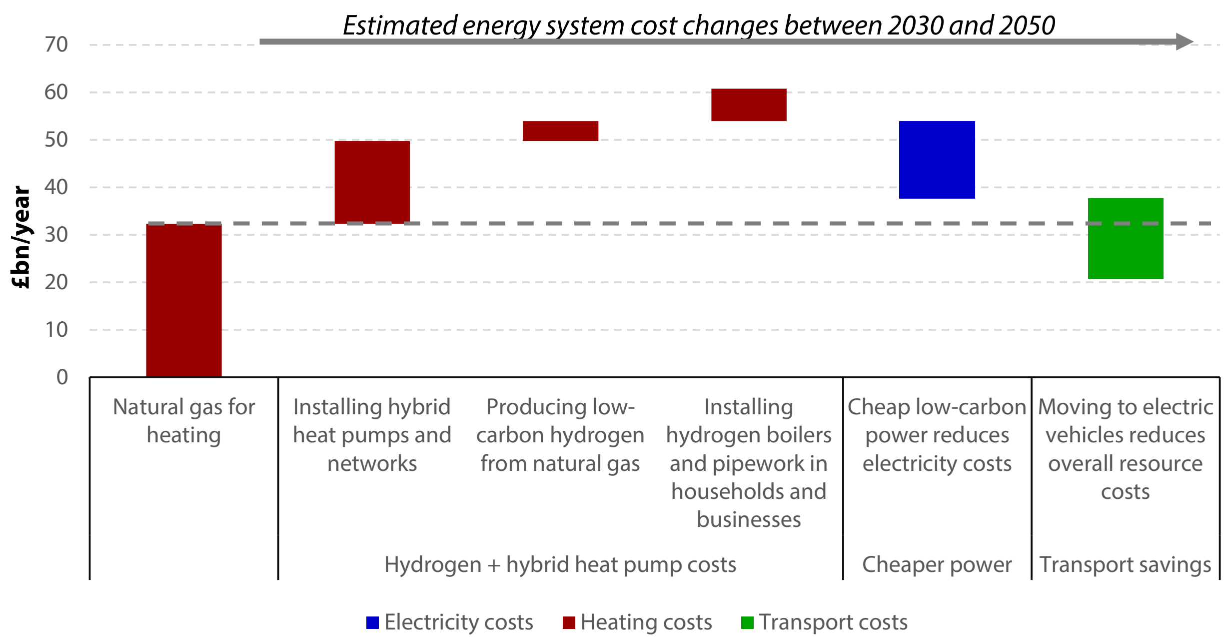
In developing a Heat Strategy, the government should consider how to ensure that the costs of heat decarbonisation are spread fairly, without exacerbating fuel poverty. This should include:

- Addressing the current imbalance between electricity and gas prices, which causes households that rely on electric heating to pay disproportionately towards the costs of environmental and social policies,[4] and distorts incentives in a way that increases the costs of moving away from fossil fuel heating.
- Consideration of how to introduce hydrogen in industry, given that it would increase costs relative to the use of fossil fuels it would displace and that there are likely to be significant barriers to uptake.

The costs relating to a potential switch of heat in buildings from natural gas to hydrogen would be appreciably reduced by the development and roll-out of hydrogen-ready boilers, if this is achieved on a timescale that would enable them to comprise a significant fraction of the boiler stock. This would also reduce the disruption associated with a switchover.

[4] Analysis for our 2017 *Energy Price and Bills* report showed that policy costs comprise 13% of energy bills for households with gas heating and 23% for those with electric (e.g. storage) heating.

Figure 1. Costs of heat decarbonisation are largely offset by a cheap low-carbon electricity by 2050



Source: CCC analysis based on Imperial College (2018) *Analysis of alternative UK heat decarbonisation pathways*.
Notes: Transportation savings are pre-tax and do not relate to the fact that electric vehicles in the UK currently don't pay fuel duty.

Recommendations

In order for hydrogen to become an established option for decarbonisation during the 2020s, the Committee recommend the following range of actions on strategy, deployment, public engagement, demonstration, technology development and research:

- **Heat decarbonisation strategy.** A key use of hydrogen is as a decarbonised fuel for heat in buildings and/or industry. This requires strategic certainty on how decarbonisation of heat will be delivered in the UK. In order to create the necessary signals for commercial investment, a commitment should be made now to develop a fully-fledged UK strategy for decarbonised heat within the next three years, including clear signals on the future use of the gas grid and supporting requirements for carbon capture and storage (CCS) in the UK.
- **Strategy for decarbonising heavy goods vehicles (HGVs).** By 2050 it will be necessary for HGVs to move away from combustion of fossil fuels and biofuels to a zero-emissions solution. Decisions about how to achieve this will be required in the second half of the 2020s. This will necessitate small-scale trial deployments of hydrogen HGVs in a variety of fleets prior to this, in the UK or elsewhere.
- **Energy efficiency improvements.** Regardless of the approach to heat decarbonisation, effective policies must be developed to deliver on the government's Clean Growth Strategy commitment to improve the efficiency of the existing stock of homes to EPC Band C by 2035. Achieving this will help to reduce people's bills, increase comfort levels and reduce the costs of heat decarbonisation. New buildings should be built with a high level of energy efficiency and designed for low-carbon heating systems, enabling them to be low-carbon from the outset.

- **Hydrogen deployment.** We have previously recommended that two CCS clusters are developed in the 2020s, in order to establish a CCS industry and enable deployment at scale from 2030. We now recommend that significant volumes of low-carbon hydrogen should be produced at one of these clusters by 2030, and be used in applications that would not require major infrastructure changes (e.g. applications in industry, power generation, injection into the gas network and depot-based transport).
- **Identification of low-regret hydrogen deployment opportunities.** The government should assess the range of near-term opportunities for hydrogen use across the energy system and set a strategic direction for low-regret use of hydrogen in the 2020s.
- **Public engagement.** Currently the general public has a low awareness of the need to move away from natural gas heating, and what the alternatives might be. There is a limited window to engage with people over future heating choices, understand their preferences and factor these into strategic decisions on energy infrastructure. This is especially important if solutions to heat decarbonisation could differ in different parts of the UK.
- **Demonstration.** In order to establish the practicality of switching to hydrogen, trials and pilot projects will be required for buildings, industry and transport uses. It is also necessary to demonstrate that hydrogen production from CCS can be sufficiently low-carbon to play a significant role:
  - Before any decision to repurpose gas grids to hydrogen for buildings heat, pilot schemes will be necessary to demonstrate the practical reality of such a switchover. These must be of sufficient scale and diversity to allow us to understand whether hydrogen can be a genuine option at large scale.
  - Hydrogen use should be demonstrated in industrial 'direct firing' applications (e.g. furnaces and kilns).[5]
  - Depending on international progress in demonstrating hydrogen HGVs, the Department for Transport should consider running trials in the early 2020s, in order to feed into a decision in the second half of the 2020s on the best route to achieving a zero-emission freight sector.
  - A substantial role for hydrogen produced from natural gas with CCS depends on delivering emissions savings towards the higher end of our estimated range of 60-85% on a lifecycle basis. This means demonstrating that it is feasible to achieve very high CO_2 capture rates (e.g. at least 90%) at reasonable cost from gas reforming.
- **Technology development.** There are technologies that are not yet deployable at scale but could play important roles within hydrogen use in the energy system by 2050. These include hydrogen-ready technologies, such as boiler and turbines, as well as hydrogen HGVs and biomass gasification. It is important that these are a focus for government support, in order to create a sufficiently wide range of pathways to achieve long-term emissions targets.
- **Further research** is required in a number of areas to establish the feasibility and desirability of using hydrogen in a range of applications:
  - This report identifies a key opportunity for hydrogen to provide low-carbon energy at peak times, performing a role currently played natural gas. Key to this will be the ability

[5] Direct firing refers to combustion-based heating processes (such as furnaces and kilns) where the combustion gases come into direct contact with the product that is being heated.

to deliver large quantities of hydrogen in a short space of time. It is therefore important to establish how the various options to store hydrogen perform with the patterns of operation that appear in models.

- Research and development is required on hydrogen technologies for industrial heating applications, especially where there may be technical barriers to use of hydrogen.
- The implications of hydrogen combustion for NOx emissions must be established – compared to fossil fuels and to any low-carbon alternatives – across applications in buildings, industry and power. This includes identifying potential technologies that can mitigate these NOx emissions.
- The feasibility of hydrogen use in gas turbines for power generation should be established, with consideration given to making new gas-fired capacity 'hydrogen ready'.
- The most cost effective way to produce and distribute hydrogen in order to supply a nationwide refuelling network for heavy-duty vehicles should be assessed, in consideration of hydrogen purity requirements and how these can be met.
- It will be important to complete the work currently underway to establish the safety of hydrogen use, and to understand the implications of this for hydrogen deployment.
- Further work is required to establish whether and to what degree hydrogen acts as an indirect greenhouse gas if emitted to atmosphere.

We will continue to bring together and develop the evidence on how deep emissions reductions can be achieved and the respective roles of different solutions, as an input to our advice on the UK's long-term targets in spring 2019.

Chapter 1: Hydrogen for heat in buildings and industry

The emissions reductions required under the Climate Change Act by 2050 mean that, to a very large extent, energy will need to be delivered to end-users carbon-free: as electricity, as hot water via heat networks, and potentially as hydrogen. Unabated use of carbon-based fuels will need to be almost entirely eliminated across the energy system: not just for electricity generation, but also for the buildings, industry and transport sectors.

There is no single technological route to achieving this, as the ways in which energy is used across the economy vary, as do the opportunities for decarbonisation. In meeting the challenge for near-full decarbonisation, it is likely to be necessary to deploy a range of different solutions.

Achieving these emissions reductions will require major improvements to energy efficiency and the application of decarbonised electricity to areas in which fossil fuels are currently used. However, there are likely to be limits to how far energy demand can be reduced and how far electrification can feasibly be taken (e.g. due to infrastructure challenges or inefficient use of electricity).

This chapter introduces hydrogen and sets out how hydrogen from low-carbon sources could be used for heat in the UK buildings and industry, and how it compares to other ways of decarbonising energy. The key messages are:

- **Buildings.**
  - Hydrogen could play a valuable role as part of a heating solution for UK buildings, in combination with heat pumps as part of a 'hybrid' system. Based on new modelling, our assessment is now that heat pumps offer the potential to provide heat efficiently for most of the time, with hydrogen boilers contributing mainly to meet peak demands on the coldest winter days.
  - Deployment of this combination of hydrogen and heat pumps could almost completely displace fossil fuel use in buildings. While not without challenges, this solution would enable the energy system to reach very low emissions, with greater feasibility and public acceptance than is likely with strategies for the full electrification of heat or the full use of hydrogen as a like-for-like replacement for natural gas as we use it today.
- **Industry.** New evidence indicates that hydrogen has an important potential role in reducing emissions from industrial heat, especially where the flame (and subsequent combustion gases) needs to come into direct contact with the material or product being produced (e.g. in furnaces and kilns). Hydrogen also appears to be well suited to the decarbonisation of more distributed sources of CO_2 emissions (e.g. from the food and drinks sector), which would be impractical and costly to capture.

The rest of this chapter is set out in five sections:

1. Hydrogen use today

2. Characteristics of hydrogen

3. Heat for buildings

4. Hydrogen use in industry

5. Blending of hydrogen into the gas grid

The subsequent chapters then cover hydrogen use for applications in power and transport (Chapter 2), how hydrogen could be produced to meet these demands (Chapter 3), scenarios for hydrogen deployment across the energy system (Chapter 4), implications for the costs of energy system decarbonisation (Chapter 5) and our conclusions and recommendations (Chapter 6).

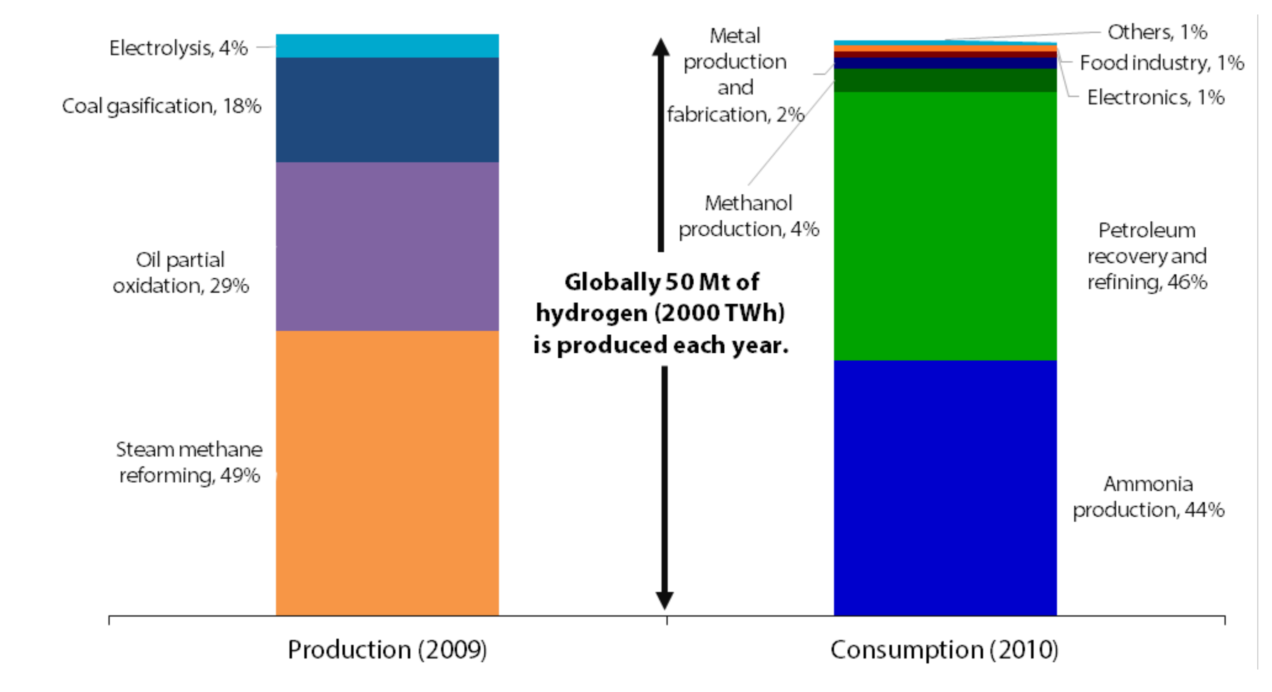
1. Hydrogen use today

Currently around 50 million tonnes (50 Mt, or around 2,000 TWh of energy equivalent) of hydrogen is produced globally each year, of which the UK produces around 0.7 Mt (27 TWh).[6] The majority of this is produced from either steam methane reforming (49%) or from partial oil oxidation (29%). The remainder is produced from coal gasification (18%) or electrolysis (4%) (Figure 1.1). If used for energy, this would be equivalent to less than 1% of global primary energy demand.

- Just under half of current hydrogen consumption is in the petroleum refining and recovery industry, where hydrogen is used to crack heavier oils into lighter oils for use as petroleum and petroleum products.
- The second largest use of hydrogen is in producing ammonia for fertilizers, where hydrogen is combined with nitrogen as part of the Haber-Bosch process.
- The remaining 10% of hydrogen use is across the food, methanol, metals and electronics industries.

Evidence suggests that these demands for hydrogen are likely to remain steady into the future.[7] If demand for low-carbon hydrogen for decarbonisation were to emerge, estimates suggest this could add anywhere between 300-19,000 TWh to global annual hydrogen production by 2050 (see section 3c).

Figure 1.1. Global hydrogen production and consumption



Source: Arup (2015) *A five minute guide to hydrogen*.
Notes: Production figures are for 2009, consumption figures are for 2010.

[6] Energy Research Partnership (2016) *Potential Role of Hydrogen in the UK Energy System*. UK production is from about 15 sites. About half is a by-product, mainly from the chemical industry, which is either used on site or sold as chemical feedstock, with a small percentage vented.
[7] Hydrogen Council (2017) *Hydrogen scaling up*.

The vast majority of hydrogen currently produced is not low-carbon. Hydrogen produced by Steam Methane Reforming (SMR) has an emissions intensity of around 285 gCO_2/kWh, and coal gasification around 675 gCO_2/kWh.[8] For these processes to be low-carbon it is essential that carbon capture and storage (CCS) technology is deployed.[9]

The only current method for producing hydrogen that is potentially low-carbon is electrolysis, if using a low-carbon supply of electricity (Box 3.1). However, electrolysers connected to the UK grid in 2017 would have had an average emissions intensity of around 395 gCO_2/kWh.

2. Characteristics of hydrogen

Hydrogen can be a complementary solution to energy efficiency and electrification, as it has a number of helpful characteristics:

- Hydrogen can be produced in a range of low-carbon ways and its use, whether through combustion or an electrochemical reaction in a fuel cell, produces no Kyoto greenhouse gas emissions.[10]
- In a fuel cell, use of hydrogen produces no local air pollutant emissions - the only by-product is water. This will significantly reduce impacts on air quality compared to the fossil fuels it displaces.
- Combustion of hydrogen can generate high temperatures, meaning that it can be used as a replacement for fossil fuels (e.g. natural gas) where higher-temperature heat is required, for example in industrial applications (see section 3). But as it burns at a higher temperature, nitrous oxides (NOx) - which are a harmful pollutant - may be a problem.
- Although hydrogen is significantly less energy-dense than fossil fuels, when compressed it has a significant higher energy density than batteries.[11] Hydrogen can be stored in large volumes, at quantities that can last for months rather than hours or days.
- As a compressible gas, hydrogen can be delivered at a high rate through pipelines. Potentially this could include use of polyethylene natural gas distribution pipes that have replaced older pipes under the Iron Mains Replacement Programme (see section 3).
- As an energy carrier that can be produced in a variety of ways, hydrogen is not resource-constrained in the same way as some other decarbonisation options (e.g. bioenergy).

Hydrogen as an energy vector is in some ways similar to electricity: both have to be generated rather than occurring in a useful, extractable form as for fossil fuels. It can be produced in a range of low-carbon ways: either through electrolysis based on low-carbon electricity or through application of carbon capture and storage combined with gasification or reformation of hydrocarbons (e.g. biomass, natural gas). We set these options out in Chapter 3.

[8] This is for emissions produced directly from the process. We report on the supply chain emissions associated with supplying feedstocks to these processes in Chapter 3.
[9] We do not consider partial oil oxidation a potential future low-carbon source of hydrogen due to low efficiencies, high costs and the carbon intensity of the process.
[10] Hydrogen isn't itself a significant greenhouse gas, but emissions of hydrogen may have an indirect greenhouse effect through extending the lifetime of methane emissions in the atmosphere.
[11] At Standard Temperature and Pressure (STP) a litre of hydrogen would contain just 0.09g of hydrogen by weight, whereas a litre of natural gas would contain 0.66g, being significantly more energy-dense.

However, use of hydrogen has potential disadvantages and challenges:

- Hydrogen is a smaller molecule than methane, so may leak more easily than natural gas. Different combustion characteristics could also make it more of a safety risk. Like natural gas, a hydrogen flame is colourless and odourless, so may require the addition of colourants and odourants in order to make it visible and detectable (Box 1.1).
- The energy density of hydrogen is lower than that of incumbent fossil fuels across a range of potential applications. This presents challenges in displacing use of these fuels where energy storage density is important, for example in transport applications, although it may have better characteristics in this respect than alternative low-carbon solutions (e.g. battery electric vehicles).
- In many cases the use of hydrogen is likely to have relatively low efficiency, when considering the whole energy chain, from primary resources to service demand. This implies a greater requirement for primary energy input to meet a given energy service demand, which has implications for cost, for whether enough low-carbon capacity can be built in the available time and for the import dependency of the UK energy system (see Chapter 4):
  - Most sources of zero-carbon energy (e.g. wind, solar, nuclear) are primarily harnessed through electricity generation rather than hydrogen production. The use of this electricity for hydrogen production would therefore entail use of electrolysis, leading to some energy loss in the conversion process.
  - Furthermore, in many applications (e.g. electric vehicles, heat pumps) electricity can be used with greater end-use efficiency than is possible with hydrogen. For example use of electric vehicles and heat pumps can deliver 75% and 270% more energy services respectively compared to fuel cell vehicles and hydrogen boilers in equivalent applications (see Figures 1.2 and 2.2) for a given input of zero-carbon electricity.
  - Hydrogen production with carbon capture and storage (CCS) also comes with a significant energy penalty relative to the use of fossil fuels if used with the same end-use efficiency (e.g. in a boiler). Producing hydrogen from natural gas incurs an efficiency penalty of around 65-80%.
- Other factors affect the costs of supplying energy alongside the implications of efficiency. Although costs of end-use appliances may be significantly lower than those using electricity (e.g. hydrogen boilers are expected to be substantially cheaper than heap pumps), as well as higher energy input costs the extra conversion step also has an associated cost of the electrolyser, reformer or gasifier. The costs of building CO_2 pipeline and storage infrastructure and of repurposing or increasing the capacity of energy infrastructure are also important.
- When hydrogen is combusted (e.g. in a boiler or turbine), this may lead to some formation of nitrogen oxides (NOx). Further research is required on the NOx emissions associated with hydrogen combustion in different applications. In considering NOx emissions from hydrogen combustion it is important to compare them to the fossil fuel being displaced, but also to consider whether low-carbon alternatives (e.g. electrification) would reduce NOx to a greater extent.

These advantages and disadvantages play out differently depending on the potential application of hydrogen. There are some areas where hydrogen may be the first choice route for decarbonisation, due to its storability (e.g. for heavy transport) or a continued need for high-temperature heat (e.g. some parts of industry). In other areas, hydrogen and electrification are alternatives and potentially complementary (e.g. in residential heating). Even where electrification is clearly the preferred solution, hydrogen can offer a back-up option should barriers to electrification prove too great.

This chapter considers the areas where hydrogen could be an important low-carbon energy vector and considers the different challenges it presents compared to the alternative decarbonisation options in buildings and industry.

Box 1.1. Hydrogen safety

Hydrogen

Hydrogen has similar safety characteristics to methane (natural gas): it's flammable, and produces a colourless, odourless flame. Blended hydrogen was previously used widely in domestic premises in the UK, in the form of 'town gas' (around 50%), which was phased out in the 1960s and 1970s and replaced by natural gas (Box 1.3). Recently, interest in blending hydrogen into natural gas networks has increased (see section 4).

Like natural gas, colourants and odourants can be added to reduce the safety risk associated with using the gas. However, hydrogen also has different properties to natural gas - such as leakage issues, ignition temperature and NOx, which could make it more hazardous than natural gas, if solutions weren't available to address these different characteristics:

- **Air quality.** Like methane, combustion of hydrogen produces nitrogen oxides (NOx), which causes air quality issues and can be dangerous for human health. It will be important to ensure that ways are identified, and implemented, to minimise the emission of NOx from hydrogen combustion.
- **Visibility.** Hydrogen, like natural gas, burns with an almost invisible flame, and could require a colourant to be added to ensure it is visible for use in common applications. BEIS's Hy4Heat programme is aiming to identify a solution for colourants in hydrogen.
- **Odour.** Hydrogen, like methane, is odourless and would require chemical odourants to make leaks detectable. Some types of odourants could contaminate fuel cells, so it will be important either to use one that avoids this problem or to filter it out before some end-uses. This is currently being considered in SGN's 'Hydrogen 100' project.
- **Leakage.** Hydrogen is a smaller molecule than natural gas, so could leak more easily. This could be a particular issue where a leak of hydrogen causes a build-up of hydrogen concentration in an enclosed space (though hydrogen's tendency to leak makes it harder to build up high concentrations). Both hydrogen and methane ignite at 4-5% concentration by volume, but whereas methane would not ignite above 15%, hydrogen will ignite up to 75%. At about 30% hydrogen the energy required to ignite it is about a tenth of natural gas, which could be a small spark. Detection and management of leaks and ventilation requirements need to be clearly defined to prevent significant build ups.
- **Heat radiation.** Hydrogen flames produce less radiative heat than natural gas, so close proximity to a hydrogen flame won't necessarily feel hot.

None of these properties makes hydrogen inherently less safe than other fuels (e.g. natural gas), but does require that safety protocols are appropriate for its characteristics.

Hydrogen energy carriers

Ammonia and Liquid Organic Hydrogen Carriers (LOHCs) have both been proposed as 'energy carriers' for hydrogen, as, unlike hydrogen, they are liquid at (or close to) room temperature and atmospheric pressure. Each comes with safety issues:

Box 1.1. Hydrogen safety

- **Ammonia.** Ammonia is a toxic chemical that requires safe storage and handling.
    - Exposure to very high concentrations of gaseous ammonia can result in lung damage and death. Storing ammonia in liquid form (at -33ºC or at pressure of 10 bar) reduces the risk of ammonia leaking as a gas.
    - Like hydrogen and natural gas, the direct combustion of ammonia will also lead to NOx emissions.
- **Liquid Organic Hydrogen Carriers.** LOHCs can store hydrogen at room temperature and atmospheric pressure, in similar conditions to petrol or diesel. Like petrol or diesel LOHCs are flammable, and would need to be stored appropriately.

It will be essential for the safety of hydrogen and any alternative carriers to be proven prior to their use at scale. The BEIS Hy4Heat programme is currently undertaking a programme of work to ensure that hydrogen safety case is fully supported by the necessary evidence. This will need to be completed prior to any decisions on large-scale hydrogen roll-out.

Source: National Physical Laboratory (2017) *Measurement needs within the hydrogen industry*. Energy Research Partnership (2016) *Potential Role of Hydrogen in the UK Energy System*. BEIS (2018) *Hy4Heat*.

3. Heat for buildings

Near-full decarbonisation of heat for buildings is one of the biggest challenges in reducing emissions from the energy system to near zero by 2050. This challenge is arguably greatest for existing buildings on the gas grid, where use of gas boilers is convenient and cheap relative to low-carbon alternatives.

In our 2016 report on *Next Steps for UK Heat Policy*, the Committee identified five low-regret routes to reducing emissions from heating buildings that the government should pursue immediately: energy efficiency improvements to existing buildings; ensuring that new buildings are efficient and low-carbon from the outset; installation of heat pumps in buildings off the gas grid; roll-out of low-carbon heat networks in population-dense urban areas; and injection of biomethane into the grid (Box 1.2). While these can make a significant contribution to reducing emissions from buildings, they still leave a substantial challenge over what to do about existing buildings on the gas grid (outside of heat network areas).

The two primary routes to reducing emissions in this remaining segment are to electrify heat provision using heat pumps and/or to repurpose gas distribution grids to carry 100% hydrogen rather than natural gas. We said in 2016 that strategic decisions will be required on the respective roles for hydrogen and electrification in the first half of the 2020s, in order for widespread roll-out to occur between 2030 and 2050. We also said that the government should make active preparations for those decisions.

Since then, BEIS has commissioned a wide range of studies on heat decarbonisation and committed to publishing a summary of the evidence in 2018. These studies, alongside wider emerging evidence, have helped to develop our view further.

The need for strategic decisions does not necessarily imply that chosen solutions need be the same everywhere. Some parts of the country may be better suited to one solution (e.g. where hydrogen can be supplied at lower cost due to access to CO_2 infrastructure). We consider this further in Chapter 4 on scenarios for hydrogen deployment.

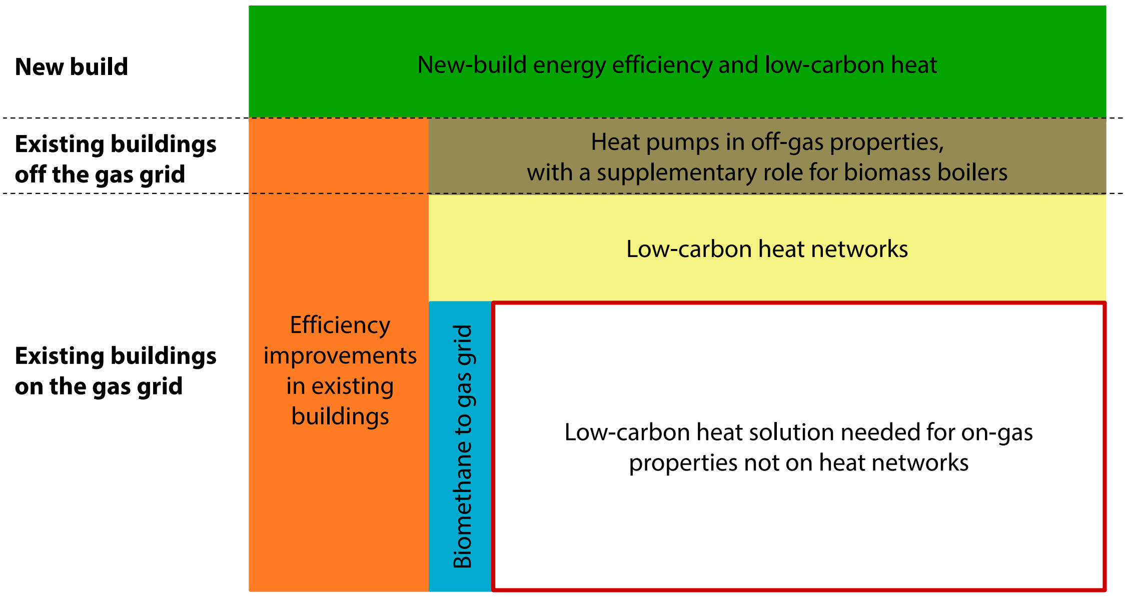
Box 1.2. Low-regret actions for buildings decarbonisation

In our 2016 report, *Next Steps for UK Heat Policy*, the Committee identified five low-regret routes to reducing emissions from heating buildings that the government should pursue immediately:

- **Energy efficiency improvement to existing buildings.** There is considerable potential to improve the energy efficiency of buildings at reasonable cost. Our scenarios include around a 15% reduction in energy used for heating existing buildings by 2030 through efficiency improvements, requiring insulation of about 7 million walls and lofts in homes, and heating controls and other insulation measures in homes and non-residential buildings.
- **New-build.** Buildings constructed now should not require retrofit in 15 years' time. Rather, they should be highly energy efficient and designed to accommodate low-carbon heating from the start, meaning that it is possible to optimise overall system efficiency and comfort at building level.
- **Heat pumps in buildings not on the gas grid.** Heat pumps are the leading low-carbon option for buildings not connected to the gas grid. Together with new-build properties, installation of heat pump in buildings off the gas grid can help create the scale needed for supply chains to develop, potentially in advance of accelerated heat pump roll-out in on-gas grid properties after 2030.
- **Low-carbon heat networks.** District heating schemes require a certain density of heat demand in order to be economic, which means that they are suited to urban areas, new-build developments and some rural areas. Low-carbon heat sources can include waste heat, large-scale (e.g. water-source) heat pumps, geothermal heat and potentially hydrogen.
- **Biomethane.** Injecting biomethane into the gas grid is a means of decarbonising supply without requiring changes from consumers, and provides a route for capture and use of methane emissions from biodegradable wastes. However, its potential is limited to around 5% of gas consumption.

While these can make a significant contribution to reducing emissions from buildings, they still leave a substantial challenge over what to do about existing buildings on the gas grid (Figure B1.2).

Figure B1.2. Low-regret measures and remaining challenges for existing buildings on the gas grid



Source: CCC (2016) *Next Steps for UK Heat Policy*.
Notes: The sizes of the blocks broadly reflect the scale of emissions reduction, but not precisely. Some potential for heat networks will be in new-build and off the gas grid, rather than all on-grid as presented.

Hydrogen and heat pumps

Hydrogen and heat pumps are both potentially viable routes to decarbonise heat at scale, and have similar costs (see Box 1.6). As well as providing heat at the building scale, each could also contribute via heat networks (e.g. through large-scale water- or sewage-source heat pumps, hydrogen boilers or combined heat and power units).

Heat pumps are a highly efficient way of producing low-carbon heat for buildings, although they have relatively high capital costs and they face challenges in terms of public acceptance (see section below) and in meeting demands for heat on the coldest days:

- **Efficiency and use of low-carbon electricity.** Heat pumps use electricity to produce heat efficiently by extracting it from the air, ground or water, producing several units of heat for each unit of electricity input.[12] They can use low-carbon electricity, the costs of which have fallen significantly in recent years.
- **Public acceptability.** Heat pumps are not a technology with which most people are familiar. The characteristics of the technology, extracting heat from (potentially already cold) surroundings, are also not immediately intuitive. As they produce heat at relatively low temperatures, they may also require installation of larger radiators, adding to the cost and disruption of installation.
- **Capital costs.** Heat pumps have significantly higher capital costs than gas (or hydrogen) boilers, and depending on whether changes to radiators are required, there may be other associated up-front costs of installation.
- **Peak demand.** Smart control systems can be used that enable heat pumps to 'pre-heat' a building, using the building itself to store energy, with or instead of hot water storage, so as to smooth out electricity demand or allow it to follow variations in generation. This is likely to be more effective in managing within-day demand variations than those on the timescale of a week or a month:
  - Heat pumps operate most efficiently when the temperature of the air (or ground) is not too far below the internal temperature of the building. Because the capital costs of heat pumps increase with their capacity, there is advantage in using hot water storage and/or smart control systems (e.g. by pre-heating the building ahead of need) to smooth out their output within the day to ensure higher utilisation of a smaller heat pump capacity.
  - However, on the coldest days when demand for heat is greatest, the larger gap in temperatures between the inside and outside of the property means that the efficiency of the heat pump falls. This efficiency drop compounds the increase in heat demand to produce a large increase in electricity consumption. These spikes in electricity demand provide challenges for the wider electricity system, both for local distribution networks and generating capacity.
  - This is less of an issue in non-domestic buildings, where there is less instantaneous heat demand (i.e. for hot water).

Using the existing gas grid to deliver hydrogen has significant advantages in terms of meeting peak demand, due to the possibility of storing gas for long periods of time and delivering it rapidly at peak times.

[12] The range for the ratio of heat out to electricity in is 2-4 for air-source heat pumps, and anything up to 8 for ground-source heat pumps if using things like phase-change materials and ground recharge over the winter.

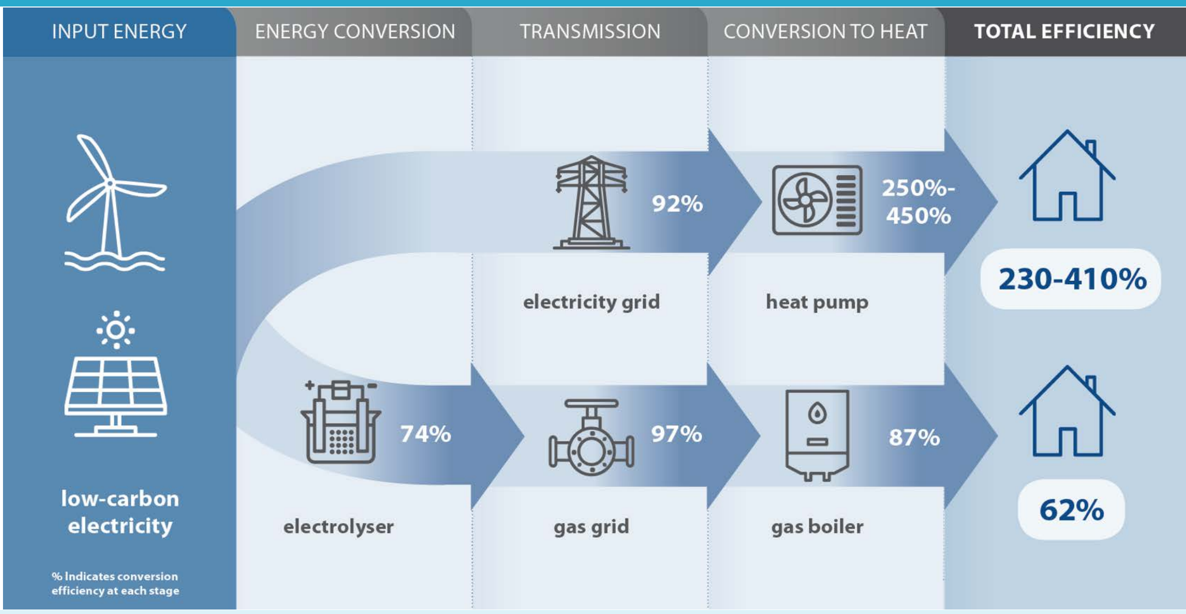
Hydrogen boilers are expected to have relatively low capital costs, comparable to gas boilers. However, their energy costs will be significantly higher (see Chapter 3), because the full hydrogen chain, from production to end-use, has a number of inefficiencies (Figure 1.2). There are also unresolved questions over the implications for nitrogen oxide (NOx) emissions from burning hydrogen in boilers.

Rather than burning hydrogen in boilers, it is possible instead to use hydrogen in fuel cell systems for combined heat and power generation at the building level (i.e. micro-CHP):

- Fuel cells have a high electrical efficiency of up to 60%[13] and generate energy through electro-chemical reaction rather than combustion, avoiding NOx emissions.
- Analysis undertaken by Imperial College indicates that fuel cell costs would have to come down considerably from the assumed cost of around £2500/kW in order to be able to compete on cost with a system based on hydrogen boilers.
- Widespread use of stationary fuel cells, generating both heat and power, would imply greater consumption of hydrogen than use in boilers alone, raising questions over feasibility of hydrogen supply at this scale, import dependence and residual greenhouse gas emissions (see Chapter 4).

For our analysis, we have assumed that hydrogen piped to buildings will primarily be used in hydrogen boilers.

Figure 1.2. Relative efficiency of heating: electricity in heat pumps vs. electrolytic hydrogen in boilers



Source: CCC analysis.
Notes: The diagram shows the indicative efficiency of using a given amount of zero-carbon electricity in delivering heat for buildings. Whilst in practice each of the efficiency numbers could vary, this would not be sufficient to change the conclusion that heat pumps provide a much more efficient solution for providing heat from zero-carbon electricity than use of electrolytic hydrogen in a boiler.

[13] U.S. Department of Energy (2013) *Comparison of Fuel Cell Technologies.*

Public acceptability

It is difficult to know quite how acceptable hydrogen will be for heating homes at this stage - although it is likely to be no more dangerous than natural gas (see Box 1.1), there is a difference between actual safety and perceptions of safety.

Work we have commissioned from Madano on public acceptability of hydrogen and heat pumps shows that there is currently very limited public understanding of these heating options. This could present challenges for public support of widespread roll-out, and for enabling informed contributions to any democratic decisions on future heat provision on a local basis:

- The public view tackling climate change as an important issue, but have limited awareness of the need to switch to low-carbon heating technologies and what this would entail.
- For both heat pumps and hydrogen, acceptability is limited by a perceived lack of tangible user benefits relative to their existing heating system.
- People also raised concerns about any time that households would spend without a gas supply in a switchover to hydrogen.
- When faced with a choice between hydrogen and heat pumps, preferences were not fixed - respondents were influenced by how the information was presented, preferring options with the least disruption and with little change compared to their existing system.

This indicates that there is a lot to do if the public are to contribute significantly to making strategic decisions on the future of heat in buildings. Alternatively, if decisions are made without significant public engagement there appears to be a significant risk that a stark 'hydrogen-only' or 'heat pump-only' choice could provoke a negative reaction, based on people's current preferences and understanding of the options.

Hydrogen at large scale

Opting for hydrogen boilers as a like-for-like replacement for natural gas boilers in buildings would imply a very large demand for hydrogen. Due to the low overall efficiency of producing electrolytic hydrogen and then burning it in a boiler (Figure 1.2), this implies a scale of supply of low-carbon hydrogen that probably goes beyond what can be produced in the UK from electrolysis (see Chapter 3).

Implicit in widespread use of hydrogen for heating therefore is a large role for carbon capture and storage (CCS) in producing low-carbon hydrogen in the necessary volumes (see Chapter 3). This also raises questions over whether the hydrogen production, CO_2 infrastructure and household switchover could be completed in the 20 years from 2030.[14] While the 'town gas' to natural gas switchover was achieved more quickly than this (Box 1.3), the greater number of appliances and the challenges relating to hydrogen production means that even two decades may be insufficient.

We consider challenges relating to how quickly energy generation capacity can be built, together with the import dependence of a 'widespread' hydrogen scenario, in Chapter 4.

Hydrogen cannot be carried in all types of pipeline, as some materials are prone to embrittlement and the gas can leak. However, the UK is now over halfway through the Iron

[14] 2030 is probably the earliest hydrogen conversion could start given the need to make well-evidenced decisions by the mid-2020s and the lead-times from those to starting conversion (e.g. in establishing low-carbon hydrogen supplies).

Mains Replacement Programme (IMRP), a 30-year programme that started in 2002 to switch gas distribution pipework from iron to polyethylene pipes to reduce gas leaks. This means that by the early 2030s gas distribution networks will have pipes well suited to carrying hydrogen. It is anticipated that any conversion of the existing gas grid to carry 100% hydrogen would be limited to distribution networks, with dedicated new hydrogen transmission pipelines being added where required.

The possibility of converting gas distribution networks to 100% hydrogen has been examined in detail by the H21 projects led by Northern Gas Networks, initially for Leeds and now across the North of England (Box 1.4).

Box 1.3. Town gas to natural gas conversion

Natural gas (methane) has been used for heating and cooking in UK homes since the 1960s, when indigenous gas sources were discovered in the North Sea. Before this, 'town gas' was widely used, produced from gasification of coal and distributed locally. Between 1967 and 1977, 13 million homes, and 0.5m business and industrial gas users in Great Britain were switched from using town gas to natural gas, alongside the development of a natural gas transportation network.

- Town gas contained around 50% hydrogen (H_2), as well as smaller quantities of carbon monoxide (CO) and methane (CH_4). The CO was poisonous, with leaks of the gas resulting in death. Town gas was produced in or around large urban centres, reducing the need for widespread transportation infrastructure.
- Between 1967 and 1977, the UK Gas Council undertook a conversion programme which switched 40m appliances from town gas to natural gas. During this process, neighbourhoods were disconnected from town gas networks and connected to new natural gas networks on a street-by-street basis.

Estimates suggest that a national switchover to hydrogen use in buildings would now cost up to £50-100 bn[1] for a similar conversion (excluding network costs, which are expected to be low due to the networks already being converted to be suitable for hydrogen use), at a cost of £2,000-4,000 per household.

- The wide range of costs represents uncertainty around the need for pipework upgrades in the home and conversion of additional gas appliances. Costs could be reduced by around £1,500 per household (around £36 bn) if 'hydrogen-ready' natural gas boilers could be installed as part of regular boiler replacement cycles (Chapter 5).
- A switchover to hydrogen today would be more complex, due to the increase in households over the past 50 years (including more appliances per household), the privatisation of the energy supply and distribution industries and the challenges involved in producing hydrogen (rather than extracting natural gas directly from a gas field).

Source: CCC calculations based on Imperial College (2018) Analysis of alternative UK heat decarbonisation pathways, Dodds and Demoullin (2013) *Conversion of the UK gas system to transport hydrogen* suggests. Northern Gas Networks (2016) *H21 Leeds City Gate.*
Notes: 1. Dodds and Demoullin (2013) suggest a conversion cost of £25bn, but this doesn't include new boilers, or any pipework/other gas appliances.

Box 1.4. The H21 studies

In 2016, Northern Gas Networks (NGN) undertook a study to examine how the low-pressure gas network in Leeds could be converted to 100% hydrogen. Their H21 Leeds City Gate study demonstrated that the existing network has sufficient capacity for conversion to hydrogen.

It set out that this would entail converting the gas grid in stages over three years, with each customer disconnected from the gas grid for less than a week during the summer months. As with the conversion of the gas grid from town gas to natural gas (Box 1.3), it would be necessary for technicians to visit each property and replace gas-burning appliances with hydrogen-compatible ones, which would operate in a similar fashion.

The H21 report produced cost estimates for the full switch from natural gas to hydrogen in Leeds, including technical changes to the pipe network, the need for new hydrogen appliances in buildings and hydrogen supply infrastructure, based on hydrogen production (via gas reforming with CCS). It also outlined further work that would need to be undertaken before a decision to convert, including a detailed engineering design study, demonstration of hydrogen appliances (e.g. boilers), development of standards and field trials.

This report is being followed by a further H21 report, by NGN in partnership with Equinor, on conversion of gas networks to hydrogen across the north of England.

Source: Northern Gas Networks (2016) *H21 Leeds City Gate*.

Decisions and options for decarbonising heating

Decisions on whether to repurpose gas distribution grids to carry hydrogen will have knock-on implications for provision of hydrogen for other end-uses, as a hydrogen grid could open up non-heat uses (see Chapter 4). However, these decisions will need to be made on the basis of the need to decarbonise heating, given that this is the primary use of these networks currently.

The choice to be made is not simply between conversion to hydrogen of every gas network or complete electrification of heat everywhere. Indeed, given the barriers and uncertainties in each case, choosing either would entail significant risks of non-delivery. Different solutions might be appropriate to different areas, either because of public preferences or local circumstances (e.g. the building stock or cheaper supply of hydrogen or electricity in particular areas).

Furthermore, it is important to consider the role of hybrid heat pumps, which have been successfully trialled in 75 homes in Bridgend as part of the Freedom project (Box 1.5), which use a heat pump to meet the bulk of heat demand, while retaining the gas network and boilers to provide heat on colder winter days (Figure 1.3). They have a number of attractions:

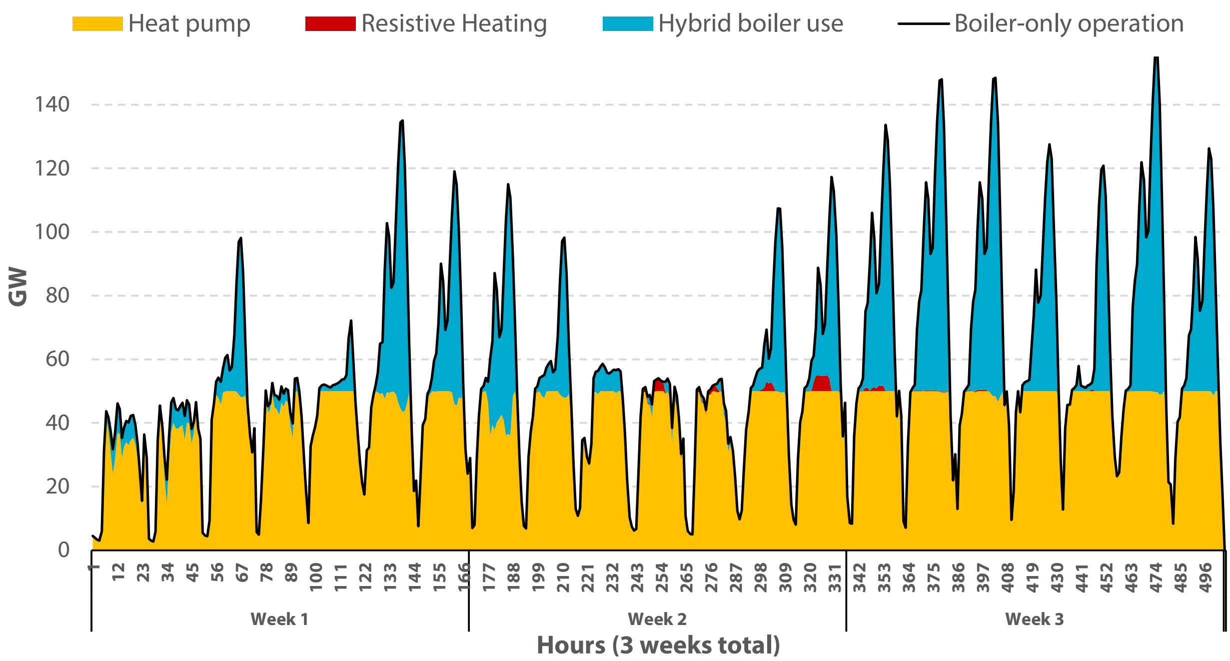
- **Capacity and operation.** Heat pumps can use zero-carbon electricity and are highly efficient under normal operating conditions. However, on the coldest winter days they perform less well: heat demand will be higher on these days, while the efficiency of the heat pump will be reduced and it may be difficult to generate extra electricity from low-carbon sources. A hybrid system enables the heat pump to provide the bulk of the heat, but the more responsive gas boiler to provide the back-up, contributing when demand is highest. This enables the heat pump to have a lower capacity than it would need to be to meet all heating demand, reducing its cost.
- **Public acceptability.** Unlike a shift straight to an electric heat pump, a switch to hybrid heat pumps would enable people to experience unchanged characteristics of the heating service

they receive and avoid disruption (e.g. by replacing radiators), while reducing emissions substantially and increasing familiarity with the technology. It could also make a switchover to hydrogen easier, as there would be a back-up heat source.

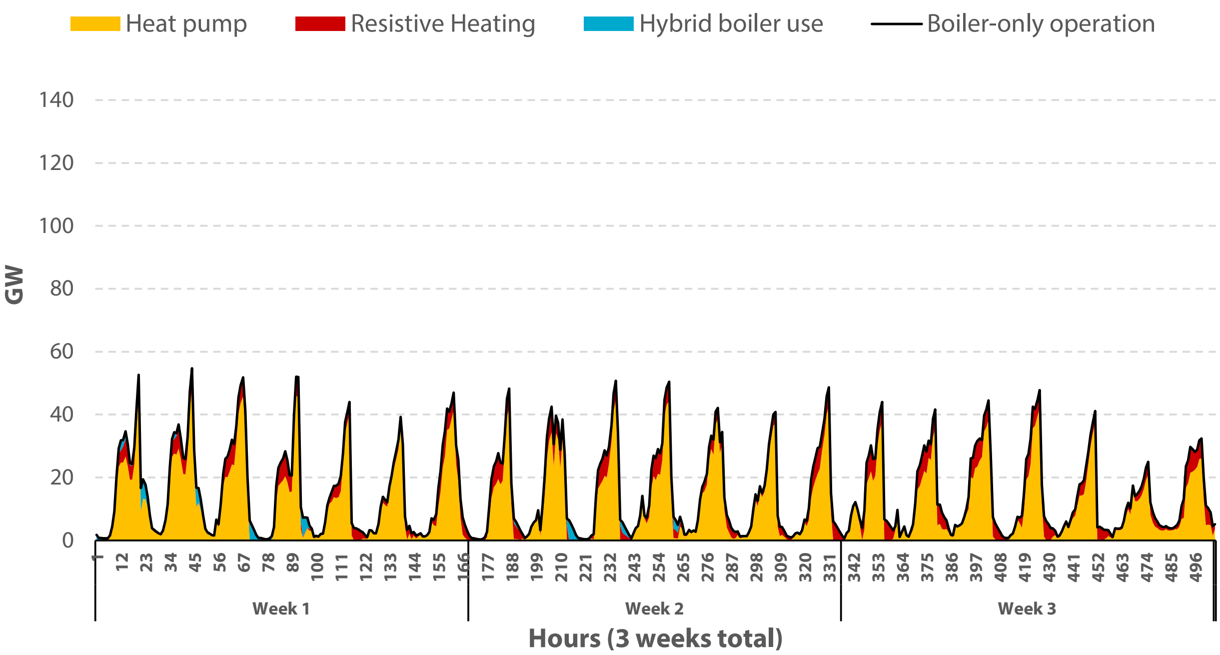
- **Supply chains.** Deployment of hybrid heat pumps at scale in the 2020s, alongside the installation for fully heat pump systems off the gas grid and in new-build properties, would help to develop heat pump supply-chain capacity, which could be important for further roll-out beyond 2030.
- **Electricity system operation.** Use of smart control systems mean that heat pumps can 'pre-heat' a building, using the building itself to store energy so as to smooth out electricity demand or allow it to follow variations in generation.
  - While this provides some benefit in making demand more flexible even in heat-pump-only systems, the requirement to meet all heat demand electrically does limit this flexibility.
  - Hybrid heat pumps have the further potential for the demand to be switched to the back-up boiler if necessary (Figure 1.3). This creates an additional value of flexibility to the electricity system, especially in managing an electricity system with a high proportion of inflexible generation. This demand-side flexibility potentially enables more low-cost renewables to be added to the system in the 2020s.
  - By limiting the spikes in electricity demand on the coldest days, hybrid heat pumps are likely to entail fewer upgrades to electricity grids to ensure that there is sufficient capacity. Furthermore, the ability to adjust the operation of the hybrid systems enables them to be installed without any grid upgrades initially, potentially implying a lower proportion of heat coming from the heat pump at first, but then to increase the operation of the heat pump if and when the grid is subsequently upgraded.
  - Hybrid systems will not be the best heat pump solution for all buildings - for some building types (e.g. flats, non-domestic buildings with air-conditioning) it may be lower cost and more straightforward to fit a non-hybrid heat pump.

Figure 1.3. Operation of hybrid heat pumps in a low-carbon energy system

Boiler use across three winter weeks



Boiler use across three summer weeks



Source: Imperial College (2018) Analysis of alternative UK heat decarbonisation pathways.
Notes: Chart shows aggregate heat demand for both domestic and non-domestic premises. Pattern of use could be expected to be similar on individual premises. Chart is for heat output, rather than energy input. 'Boiler only operation' is shown as a comparator, and is not expected to be in addition to the boiler in a hybrid system.

Box 1.5. The Freedom project

The Freedom project, a joint initiative by Wales and West Utilities, Western Power Distribution and PassivSystems, trialled 75 hybrid heat pumps in residential properties in Bridgend in South Wales. These hybrid systems were retrofitted around households' existing boilers, adding a heat pump to take on the bulk of the space heating load.

The system is controlled via an app that allows people to determine the comfort levels they want, enabling the smart control system to optimise how to achieve this. The systems have been able to operate flexibly in two key ways:

- **Flexible use of the heat pump.** As the heat pump provides heat at a lower rate than the boiler, in order for it to contribute fully to comfort levels the heat pump can commence operation earlier in order to provide sufficient warmth, pre-heating the home (e.g. starting in the early hours, several hours before people wake up). This ensures that people have the comfort they need from the heat pump, whilst not attempting to operate it like a boiler.
- **Switch to the boiler.** When the heat pump is unable to provide all of the space heating needed (e.g. on colder winter days), the boiler can switch on to provide boosts of heat to the system, supplementing the output of the heat pump. This could be useful not only to cope with colder days with higher heat demand, but also to respond to economic signals around the relative prices of electricity and gas and potentially to infrastructure constraints (e.g. ensuring electricity demand does not exceed local grid capacity).

The project demonstrated successfully that the hybrid systems could maintain comfort levels without any wider changes to the heating system (e.g. radiators), across a range of household types.

Energy system modelling of heat decarbonisation pathways

In order to explore the costs and infrastructure implications of alternative heat decarbonisation pathways, we commissioned Imperial College to model three alternative energy systems for 2050: full electrification of heat for buildings, full deployment of hybrid heat pumps (with methane as the residual gas) and full conversion of gas grids to hydrogen for use in boilers. The results indicated that the costs of all three are similar (Box 1.6):

- Although the capital costs of heat pump installation and electricity grid upgrades are significant in the pathways based on heat pumps, the costs of energy are considerably higher in the hydrogen scenario.
- The savings from reusing existing gas distribution grids, although helpful in limiting costs, do not give the hydrogen scenario a decisive advantage.

We have undertaken further analysis with Imperial, to examine the costs of a scenario with hybrid systems that combine a heat pump with a hydrogen boiler. The overall cost of this 'Hybrid Hydrogen' scenario is similar to those of the other decarbonisation pathways (see Figure B1.6).

The combination of hydrogen and electrification would offer the potential for full decarbonisation, and avoid some of the pitfalls and delivery challenges of achieving such low emissions pursuing either solution alone:

- A full electrification pathway would have demands for electricity from heating that are very peaky, creating challenges in having sufficient capacity to generate and deliver power on the coldest days. Modelling suggests that additional 'back up' electricity generation capacity in excess of 100 GW - roughly equivalent to the size of today's electricity system - could be required to meet electrified heat demand during peak periods.

- A pathway instead based on a wholesale switchover of gas grids to hydrogen - used in boilers as natural gas is currently - would imply a very large demand for hydrogen. This volume of hydrogen demand would have challenges around reliance on natural gas imports and on CCS, if produced from natural gas reforming with CCS (see Chapters 3 and 4). Alternatively, making the hydrogen zero-carbon rather than low-carbon would come with high costs (see Figure B1.6) and major delivery challenges (see Chapter 4). In either case, there are questions over whether full decarbonisation of heating can be achieved.
- A hybrid heat pump pathway based on methane as the residual gas has lower costs than other decarbonisation pathways based on the results of the Imperial College optimisation modelling. However, achieving the necessary degree of decarbonisation (e.g. in the 10 Mt scenario) relies on reducing gas demand to very low levels, and a substantial fraction of this being met from biomethane. The ability to do this rests on two significant assumptions:
  – The modelling of hybrid heat pumps backed up by methane boilers leads to an optimal result that the heat pump part of the hybrid system would deliver 86% of heating in the 10 Mt scenario. In the event that such a high proportion cannot be achieved in practise, this would lead to higher emissions. For example, residual gas use would be twice as high at an electric heat proportion of 72%.
  – This scenario has a very widespread deployment of heat pumps that may not be achievable in practice. As a gas boiler has around seven times the gas consumption assumed for the hybrid heat pump systems, a shortfall in heat pump deployment would lead to significantly greater unabated gas use in boilers, leading to higher emissions.
  – It is therefore plausible that only say 18 million instead of 24 million hybrid systems can be installed, with 72% electric heating instead of 86%. In combination, this would see much higher residual gas use at 180 TWh in 2050, over three times the 55 TWh in the Imperial modelling results. This equates to extra emissions of 23 $MtCO_2$ in 2050.
- Significantly higher residual gas use, due to a shortfall in hybrid heat pump deployment and/or a lower share of electric heat from the installed hybrid system, would take gas demand well beyond the available resource for biomethane production via anaerobic digestion at a national scale, which we estimate at 21 TWh. While there may be an opportunity for biomethane to meet the residual gas demand in some parts of the country, especially where residual gas demand is lower, in other parts a larger low-carbon gas supply would be required.
- It is not appropriate to plan for use of bio-synthetic natural gas (bio-SNG) to fill this gap. The 'best use of biomass' analysis in our parallel report on *Biomass in a low-carbon economy* shows that production of biofuels, even with CCS, is only one of the best uses of the finite sustainable bio-resource if the fossil fuels it displaces cannot otherwise feasibly be displaced (e.g. use of biomass to produce aviation biofuels with CCS). Given the opportunity to meet this gas demand via hydrogen, the plan should be for any significant residual demand for gas in a hybrid scenario to be met through hydrogen rather than bio-SNG by 2050.

Overall, a pathway that combines hydrogen and hybrid humps would moderate the challenges around meeting peak electricity demands in winter, with a lower reliance on bulk hydrogen supply (e.g. from gas with CCS - see Chapters 3 and 4) than under a 'full hydrogen' pathway and with greater confidence that unabated fossil fuel use can be reduced to near zero in a manner consistent with best use of bioenergy resources.

Therefore, although the results of the Imperial modelling for this scenario suggest that the costs are towards the higher end of the range across the decarbonisation pathways, it provides greater confidence that near-full decarbonisation of heating can be achieved in practice.

Box 1.6. Imperial College energy system modelling for a range of heat decarbonisation pathways

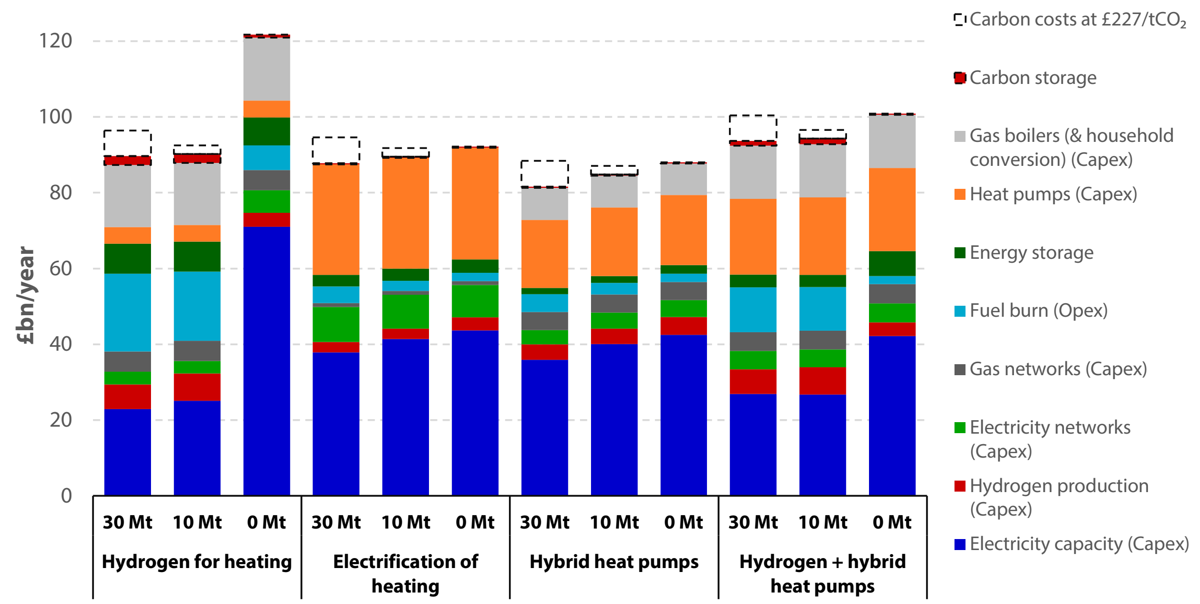
Imperial College evaluated the technical feasibility and overall system costs of four decarbonisation pathways across the electricity and gas systems in the UK: hydrogen, electrification, hybrid heat pumps with natural gas boilers and hybrid heat pumps with hydrogen boilers. This analysis found that:

- The total system costs for decarbonisation pathways based on hydrogen, heat pumps, and hybrid heat pumps, are broadly similar across a range of emissions constraints: the costs of all the scenarios are within around 10% of each other, for a given emissions constraint.[15] This is in line with findings of work for the National Infrastructure Commission. However, it is very expensive to reach the most stringent emissions constraint in the widespread hydrogen case. Unless emissions savings from fossil hydrogen production with CCS can be improved, this requires all hydrogen to be produced via electrolysis (see Chapter 4).
- Given the option, the model consistently chooses to install a hybrid solution in consumer premises. In a scenario with large levels of electrification then a heat pump is installed alongside resistive heating, rather than installing a larger heat pump, where the additional heat pump capacity is only used at times of peak demand. In a hybrid heat pump scenario the model installs a gas boiler (which could burn natural gas or hydrogen) in place of resistive heating.
- Gas is used to meet peak winter heat demands in all pathways, demonstrating the value of the gas grid.
  - In an electrification scenario gas is used in back-up power generation capacity, and electricity networks need to be upgraded to ensure electricity can reach users during these periods.
  - In a hybrid heat pump pathway gas boilers use gas more efficiently to meet peak heat demand, and avoid these network constraints.
  - In a hydrogen pathway peak gas demand is provided from the gas grid, as well as dedicated hydrogen storage.
- Regional hydrogen-only deployment within an otherwise national hybrid heat pump pathway could be similar cost to other pathways, particularly where hydrogen can be produced close to CO_2 storage facilities (reducing the need for onshore networks) and consumed in dense urban areas (avoiding electricity network upgrades).
- Significant uncertainty remains across all the pathways, particularly for:
  - Household conversion requirements and costs across all pathways,
  - The amount of electricity demand that can be shifted away from peak periods in the electrification scenarios,
  - The need for and operation of dedicated hydrogen storage alongside a hydrogen gas grid.
  - The extent to which gas demand can be reduced in hybrid heat pump pathways.

[15] With the exception of the hydrogen zero emission scenario, where producing significant volumes of hydrogen from electrolysis increase costs significantly (see Chapter 4).

Box 1.6. Imperial College energy system modelling for a range of heat decarbonisation pathways

Figure B1.6. Annualised system costs for alternative heat decarbonisation pathways.



Source: Imperial College (2018) *Analysis of alternative UK heat decarbonisation pathways* and follow-up analysis by Imperial College.
Notes: Chart shows total electricity and gas system costs, not costs compared to a counterfactual.

The way forward on decarbonising heating for buildings

Our results indicate that the costs of the pathways do not differ dramatically. This supports taking into account a range of considerations beyond cost alone, including feasibility of delivery, public acceptability, energy security and retaining options over how we decarbonise in the long term.

Given similar costs, there is an argument for deploying a range of solutions for heat decarbonisation, with solutions potentially varying by region across the UK depending on local resources, infrastructure and, potentially, preferences of the local population. However, some coordination will be required to ensure that infrastructure solutions are viable. This also raises the question of how the choice of different solutions would be arrived at for different geographical areas, and how heating is paid for in the case that different areas have different low-carbon solutions and some areas stay on natural gas for longer than others.

We recommend that hybrid heat pumps be deployed at scale in the near term. This would enable significant near-term emissions reductions to be made without significant initial changes to existing infrastructure, would help increase public familiarity with heat pumps without concern over compromising their comfort, and would provide a flexible market for additional low-cost renewables. It would also actively develop options for near-full decarbonisation of heat by 2050 without locking out important contributions from hydrogen and fully heat pump systems by 2050.

Given the possibility of heat pump use for the bulk of heat for buildings, the value of low-carbon gas in heat decarbonisation lies especially in meeting demand in a low-carbon way at peak times (i.e. during the coldest periods). At a building level, the proportion of electric heat could be very high (e.g. 85%[16]). Limits to deployment of heat pumps mean that overall the proportion could be significantly lower, with correspondingly greater need for low-carbon gas. Preferentially, this gas should be hydrogen rather than biomethane, due to the relatively small available resource for biomethane and its potential value elsewhere in the energy system (e.g. in combination with carbon capture and storage).

As with a full switch to hydrogen boilers, the costs of switching the residual gas consumption to hydrogen would arise from the combination of higher costs of hydrogen compared to natural gas, plus the upfront costs of switching the infrastructure and appliance stock to be hydrogen-compatible:

- With a like-for-like switch of natural gas heating to 100% hydrogen using boilers, the incremental costs are dominated by the higher costs of the gas that flows through the network. The higher cost of hydrogen compared to natural gas accounts for 75% of the incremental cost, with the upfront costs of switching the pipework and appliances contributing 25%.
- At lower volumes of gas consumption the upfront costs of a hydrogen switchover would be relatively more important. These could potentially be reduced if hydrogen-ready heating appliances could be introduced and diffuse significantly through the stock prior to a switchover. There also remain uncertainties over the need to change pipework within buildings.

As the need for hydrogen, if it were focused on meeting peak demands, would be substantially lower than providing all heat to on-gas properties, the challenges relating to hydrogen supply would be significantly reduced.

Near-term pursuit of hybrid heat pumps would not necessarily lead to a long-term solution of hybrid heat pumps with hydrogen boilers. A widespread near-term deployment of hybrid heat pumps would lead to a much better public understanding of heat pumps as a heating option. In turn, this could increase the acceptance of full heat pump solutions, making the subsequent roll-out from 2035 more achievable than it is likely to be in the nearer term.

We discuss the implications of these possible solutions for strategic decisions on long-term heating solutions and the future of the gas grid in Chapter 6.

4. Hydrogen use in industry

The predominant demand for hydrogen today is as an industrial feedstock, although hydrogen used in these processes does not currently come from low-carbon sources (see section 1).

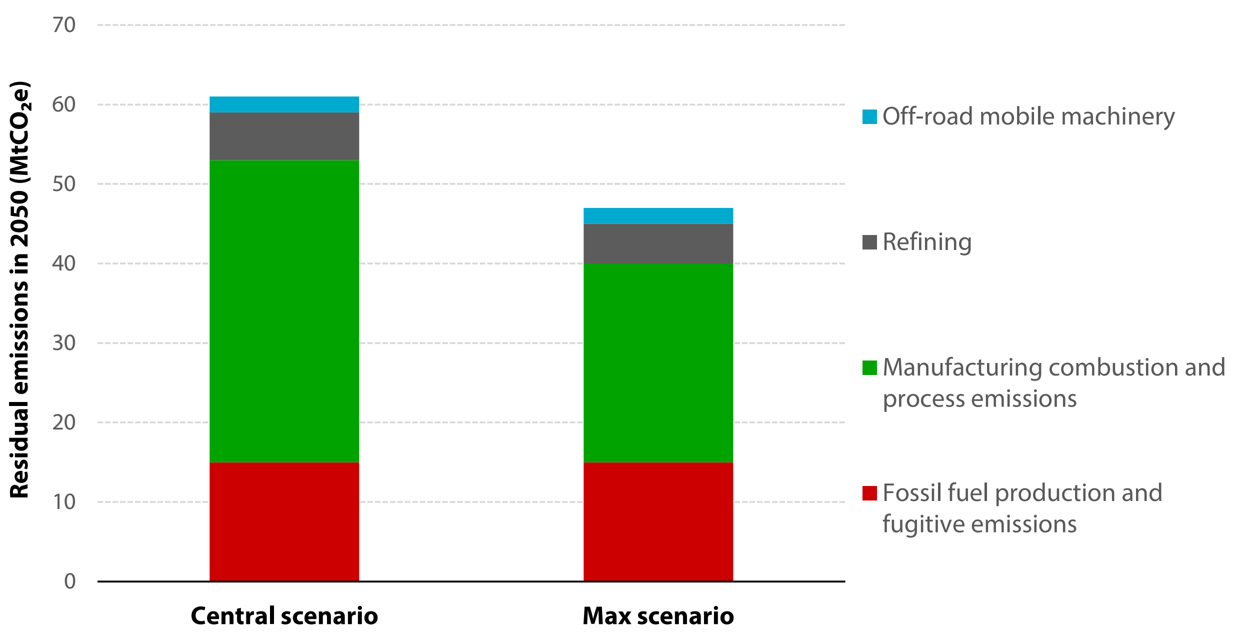
In previous analyses of long-term decarbonisation, industry has been one of the sectors with significant remaining emissions in 2050 (Figure 1.4), even with full deployment of identified measures to reduce emissions (the 'Max' scenario). This is partly due to a poor characterisation of opportunities to reduce emissions in industry. Evidence has also been lacking on the potential and costs of using low-carbon hydrogen to reduce UK industry emissions. For example, use of

[16] Modelling for the Committee by Imperial College indicates that around 85% of a building's heat could be met by the heat pump part of a hybrid heat pump system.

hydrogen was specifically excluded from the development of the £1m industry decarbonisation roadmap studies produced jointly by industry and government in 2015.

The scenarios that underpinned our advice on the fifth carbon budget[17] were therefore cautious with regard to the future role of hydrogen in industry, with no hydrogen deployed in the Central scenario. An 'Alternative' scenario, based upon a combination of results from the industry decarbonisation roadmaps and work we commissioned from E4tech and UCL,[18,19] did include significant quantities of hydrogen use for high-temperature heat, but this was not costed.

Figure 1.4 Residual emissions from industry in 2050 in the CCC Central and Max scenarios



Source: CCC analysis from CCC (2016) *UK Climate Action Following the Paris Agreement*.

Potential to use hydrogen in industry

Recent analysis commissioned by BEIS from Element Energy and Jacobs has examined the potential for fuel switching away from fossil fuels to hydrogen, electricity and biomass (without CCS) in a range of industry sub-sectors. The scope of the study covers just over half of fossil fuel use in manufacturing (i.e. around 120 TWh out of a total of 215 TWh).[20]

This analysis indicates that hydrogen has significant technical potential for deployment, is applicable in some processes where there is no alternative low-carbon option and, based on our

[17] CCC (2015), *Sectoral scenarios for the fifth carbon budget*.
[18] DECC (2015) *Industry Decarbonisation and Energy Efficiency Roadmaps to 2050*.
[19] E4tech et al (2015) *Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target*.
[20] This excluded consideration of switching fossil fuels used for: industrial combined heat and power plants; producing steam at external sites; unclassified industrial energy uses; as well as the option to switch the fuels that produce 'internal fuels' such as blast furnace gas and coke oven gas. The study also doesn't cover fuel use in fossil fuel production, which is outside of the manufacturing sector, but inside our definition of the industry sector.

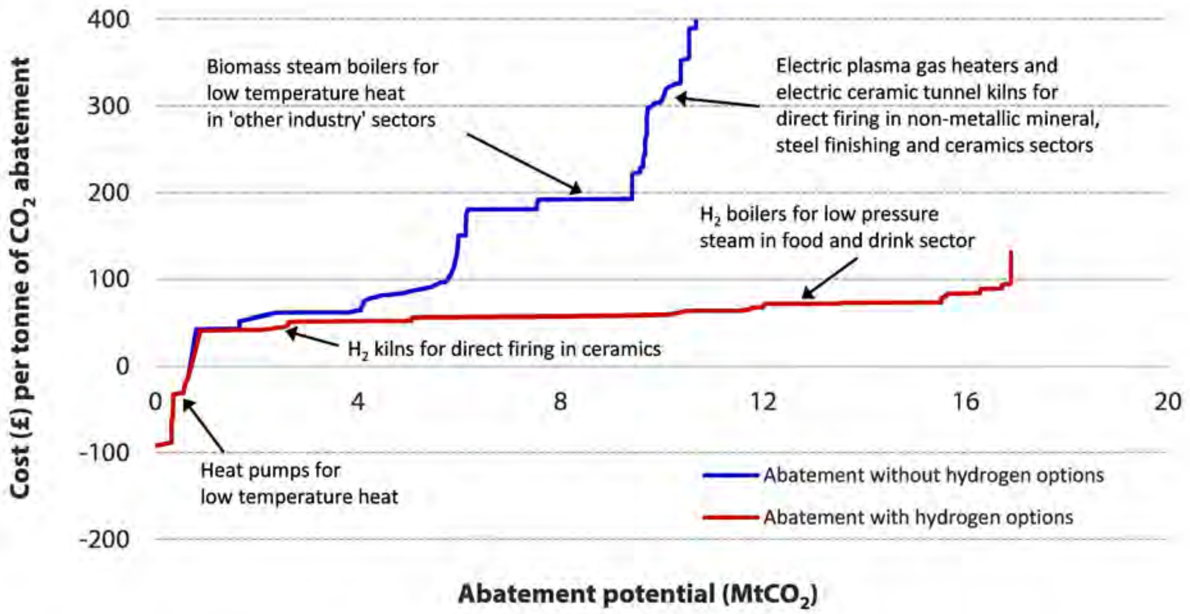
projections of future biomass use and prices, will be cost-competitive with other fuel switching[21] options for most applications (Figure 1.5):

- The new analysis identified 90 TWh of current industry fossil fuel consumption that could be switched to hydrogen by 2040.
  - For around 15 TWh of this demand it was the only option available - this demand was all for direct firing,[22] for which biomass and electrification are rarely technically suited.
  - The study found that hydrogen technologies are expected to become available at different rates in different sectors, and that some of the fuel switching technologies may not be available until around 2035, particularly hydrogen heaters and kilns outside of the chemicals and refining subsectors.
  - No potential was identified to switch fuels for the remaining 30 TWh of fuel use, due to potential limitations on the capacity of fuel switching technology units and on how much fossil fuel could be displaced. For example, the study estimated that there is likely to be a limit of 25% on how much fossil fuel used for reduction in blast furnaces can be replaced by hydrogen by 2040. This could be conservative if transformational technologies such as direct reduced iron are successfully developed and demonstrated (see Box 1.7).
- Based on our projections of fuel costs, we estimate that hydrogen will be the most cost-effective fuel switching option for the majority of the demand considered in the Element Energy and Jacobs study:
  - This includes fuel switching for all of the main industrial fuel consuming processes: steam production, high- and low-temperature heating (both direct and indirect heating), and reduction processes. Alongside this, the study identified some potential for low-cost electrification, using heat pumps for space heating in industrial buildings.
  - Our assessment differs from the results of the Element and Jacobs study under their central fuel cost assumptions, where biomass technologies were identified as being more cost-effective than hydrogen technologies for around half of demand considered because of different fuel cost assumptions. As set out in the Committee's parallel report on *Biomass in a low-carbon economy*, our wider analysis shows that bioenergy can be more valuably used for decarbonisation in other applications (e.g. use of bioenergy with carbon capture and storage – BECCS), implying a greater value of the bio feedstock than assumed in the Element analysis.

[21] Electrification and biomass; excludes CCS and BECCS.

[22] Direct firing refers to combustion-based heating processes (such as furnaces and kilns) where the combustion gases come into direct contact with the product that is being heated.

Figure 1.5. Costs and potential of fuel switching options in industry (excludes CCS)



Source: CCC analysis based on Element Energy and Jacobs, *Industrial Fuel Switching Market Engagement Study* (draft).

Notes: Costs exclude the cost of capital. Abatement costs are for 2040. These curves only consider the costs of hydrogen, biomass and electric technologies; post-process BECCS and CCS are not considered. Long run variable costs assumed for hydrogen 3.5p/kWh and biomass 3.7p/kWh. Scope of combustion emissions considered limited to those from combined heat and power, unclassified industrial sectors, those resulting from combustion of onsite-derived fuels (such as blast furnace gas) and those from the fossil fuel production sectors. Emissions from reduction in the pig iron sector are considered.

Box 1.7. Direct Iron Reduction

In 2016, three Swedish companies announced their plans to develop a method to decarbonise iron production process known as 'direct reduction', by using hydrogen as the reducing gas. Their concept is called Hydrogen Breakthrough Ironmaking Technology (HYBRIT). Direct reduction of iron is currently used for about 5% of global primary steel production, with the remaining 95% using blast furnaces.

Existing direct reduction of iron uses a reducing gas derived from natural gas or coal, neither of which are widely available in Sweden. HYBRIT will use hydrogen as the sole reducing gas, which will produce water as a by-product instead of CO_2.

The resulting 'direct reduced iron' (DRI) can then be made into steel using electric arc furnaces, in the same way as traditional DRI is used.

Source: Åhman, M. et al. (2018) *Hydrogen steelmaking for a low-carbon economy: A joint LU-SEI working paper for the HYBRIT project*; HYBRIT (2018) *HYBRIT - Fossil-Free Steel: Summary of Findings from HYBRIT Pre Feasibility Study 2016–2017*; World Steel Association (2017) *World Steel in Figures 2017*.

There is also significant further potential for deployment of hydrogen in parts of industry outside the scope of the Element Energy and Jacobs analysis:

- Hydrogen could be used instead of fossil fuels for industrial combined heat and power (CHP).
- There may also be some potential to reduce emissions from industrial energy (mainly oil) use that is currently not classified into a particular industrial use, which stood at 36 TWh in 2016. However, this is less clear as available data on 'unclassified' fossil fuel use lack detail.

Cost-effectiveness of hydrogen use in industry

The potential use of carbon capture and storage (CCS) in industry is likely to be a key competitor to the use of hydrogen in many industrial applications. There is considerable overlap between the decarbonisation potential from switching away from fossil fuels to hydrogen and from continuing to use fossil fuels and instead capturing and storing the resultant CO_2 emissions. There is also overlap with the potential use of biomass with CCS to achieve negative emissions. Given the likely major role for CCS in bulk hydrogen production (see Chapter 2), these options are effectively 'pre-process' and 'post-process' forms of CCS (Figure 1.6):

- **Pre-process CCS.** Use of hydrogen produced predominantly from CCS to remove the carbon before use in industrial processes, including combustion and reduction, is a means of decarbonisation that can be used across a wide range of industrial applications. It is likely to be well suited to smaller sources of emissions and those further from CO_2 networks, for which fitting CO_2 capture equipment and connecting to a CO_2 network are likely to be more difficult and expensive.
- **Post-process CCS.** Direct application of CCS to industrial sites is well suited to large point-sources of CO_2, especially those located close to CO_2 networks. An advantage of this approach over the use of hydrogen is that the CCS can be used to reduce emissions from industrial processes that do not use fuel, such as calcination in the cement sector, in addition to fuel-using processes (i.e. combustion and reduction).

The optimal balance between the deployment of hydrogen and direct application of CCS (including BECCS) in industry is not yet clear and will depend on risk profiles and the way that investment decisions are made in industry, as well as costs and CO_2 savings (e.g. due to different rates of CO_2 capture between the two approaches).

In combination, we estimate that there could be a cost-effective contribution to industry emissions reduction from some balance of hydrogen use and direct CCS of around 27 $MtCO_2e$ by 2050:

- This estimate is based on our latest whole-system analysis using the ESME model, which suggests that 10 $MtCO_2e$ could be avoided through hydrogen use and 17 $MtCO_2e$ reduced through CCS and BECCS.[23] The potential may be higher, as this analysis excluded consideration of hydrogen or CCS use (a) in most of the 'unclassified' industrial sector (b) on emissions arising from internal fuel use, such as blast furnace gas and (c) in fossil fuel production or on fugitive emissions.
- We estimate that without hydrogen the cost-effective potential to reduce emissions from industry would be 9 $MtCO_2e$ lower.[24] Although there are some opportunities to reduce

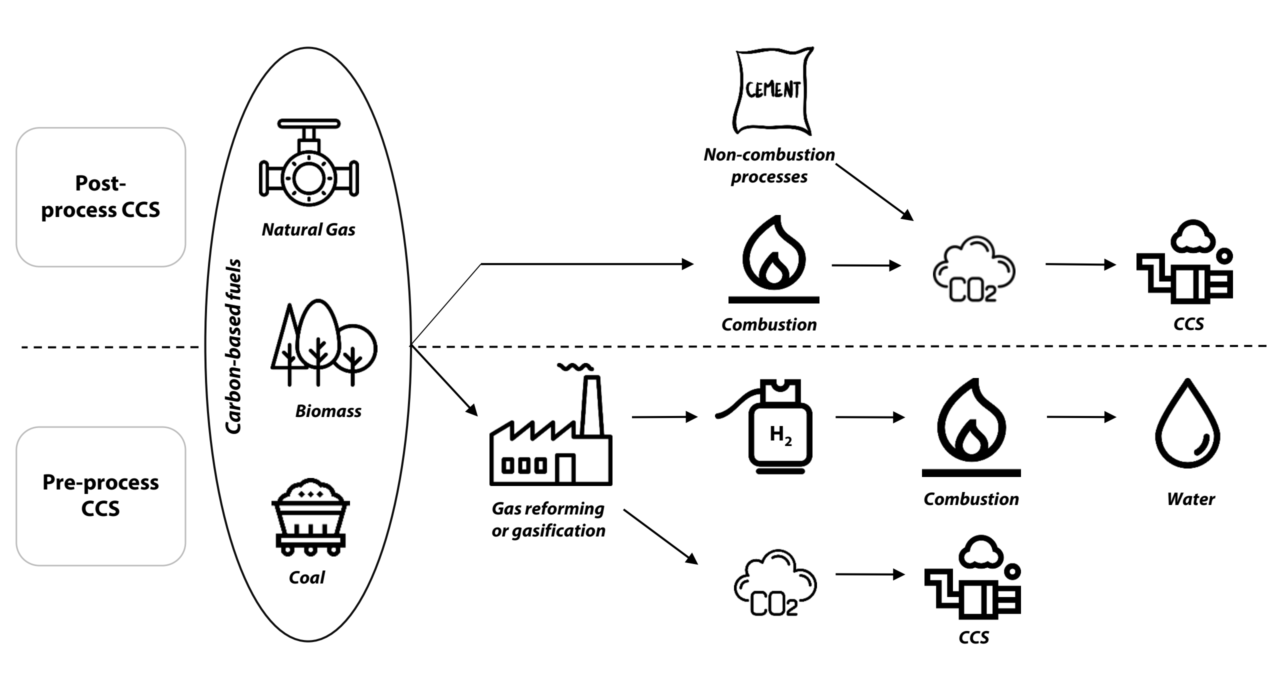
[23] This is comprised of 12 $MtCO_2$ stored and 5 $MtCO_2$ avoided through bioenergy use.
[24] At the government's target-consistent carbon values in 2050.

emissions through other means (e.g. some forms of electrification), the costs of these appear prohibitively expensive.

The large combined contribution of pre-process and post-process CCS underlines the importance of CCS in achieving the long-term decarbonisation required under the Climate Change Act and the Paris Agreement.

The additional abatement potential identified of up to 9 $MtCO_2e$ is significant relative to the residual manufacturing and refining emissions that remained in our Central and Max scenarios for 2050 that we presented in 2016, of 46 and 32 $MtCO_2e$ respectively.[25]

Figure 1.6. 'Pre-process' and 'post-process' forms of CCS for industry



Potential deployment of hydrogen in industry

Given the uncertainty in our analysis, it is not clear what is the precise level of hydrogen use that would achieve the necessary decarbonisation at least cost. This uncertainty is reflected in our modelling in Chapter 4.

Infrastructure development to support hydrogen use in industry is likely to take a staged approach, both in terms of where in the country hydrogen use occurs and at which pressure tier of the pipeline network.

Regional deployment of hydrogen to industry

Initial pathways for hydrogen use in industry may involve regional industrial clusters being converted for hydrogen use, potentially co-located with industrial CCS. For example, Cadent has proposed an industrial hydrogen cluster in the north-west of England (Box 1.8).

25 It is likely that the 9 $MtCO_2$ abatement will reduce these residual emissions, although we will assess the exact extent further for our upcoming advice on long-term targets. The Central and Max emissions for industry as a whole were 61 $MtCO_2$ and 47 $MtCO_2$ respectively.

Box 1.8. The HyNet North-West project

HyNet North West is a proposed regional hydrogen cluster based around Liverpool Bay being developed by Cadent and Progressive Energy, along with other local asset owners. The project proposes to build an (autothermal reforming) hydrogen production plant, with the hydrogen being used mainly in an industrial cluster, but also being blended into the natural gas network, for use by domestic and commercial users. The project may also supply hydrogen for use as a transport fuel.

The industrial cluster would involve converting 10 large industrial sites to using 100% hydrogen, which will require modifications to boilers, kilns and furnaces. New pipelines to transport the hydrogen to the industrial sites would also be built.

Carbon capture would be fitted on the hydrogen production plant, with CO_2 being stored in the Liverpool Bay oil and gas fields. In addition, 0.35 $MtCO_2$ from an ammonia plant would also be stored as part of the project.

The total potential for annual emissions reduction from the project is estimated to be 1.1 $MtCO_2$ at a cost of £920 million. Longer term expansion of the overall hydrogen cluster could involve use of hydrogen for power production and storage of hydrogen in underground salt caverns in Cheshire to balance swings in hydrogen demand.

Source: Cadent (2017) *HyNet North West: From Vision to Reality Project Report*. Cadent (2017) *The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project*.

If the cluster pathway is taken, the initial hydrogen clusters would likely be best placed in regions that have attributes suited to hydrogen use:

- **Regions with large industrial demand.** Regions with large industrial fuel demands that are suited to hydrogen use would likely benefit from economies of scale. The main industrial clusters include Grangemouth, Teesside, Humberside, South Wales, Grangemouth and Humberside.

- **Regions with potential for CO_2 storage.** Coastal regions with nearby offshore underground geology suitable for CO_2 storage would likely be better suited. They would likely be able to store the CO_2 produced from hydrogen production from CCS at a lower cost than regions without nearby CO_2 storage. Regions with access to existing infrastructure (e.g. gas pipelines) that could be repurposed for CO_2 use could also have lower CO_2 transportation costs.

- **Regions with existing hydrogen plants that have spare production capacity.** Spare capacity in existing industrial steam methane reforming (SMR) hydrogen production plants could be used to establish initial hydrogen supply, whether for use in industry or other sectors. This may help in establishing a first cluster. If this approach is taken, the SMR hydrogen production should be fitted with CCS.

- **Regions with other large hydrogen demands.** Initial industry hydrogen cluster locations could be driven by the proximity of significant demand from other sectors such as residential and commercial buildings. Factors that may affect the location of demand for hydrogen for buildings heat could include local public acceptability or the potential for hydrogen storage. Areas with potential for onshore or offshore hydrogen storage (e.g. in salt caverns) would be better able to manage the large swings in hydrogen demand from buildings.

If an initial regional approach is taken, follow-on stages would be required to enable hydrogen use in industry outside of these initial regions. A challenge may be supplying hydrogen to users that are not either (a) located near to large industrial clusters of hydrogen demand or (b) near to a region of hydrogen demand from buildings or transport and an associated hydrogen gas network. In this case, residual hydrogen demand may need to be met by truck.

Options for distributing hydrogen to industry

A key challenge for hydrogen deployment in industry will be providing an infrastructure for hydrogen supply, based on existing and some new pipelines. The Iron Mains Replacement Programme (IMRP) is converting low pressure gas distribution pipes from iron to plastic for health and safety reasons by 2032 (see section 3); these new pipes in the gas distribution network will be able to transport hydrogen.

However, some components may still need conversion in the distribution network (e.g. steel pipes that distribute gas at intermediate pressure, monitoring systems, compressors). New pipelines for hydrogen transmission may well be necessary – discussions with the gas industry suggest these need not be much more expensive than natural gas equivalents.[26]

Infrastructure changes for hydrogen in industry could take a number of pathways:

- **The gas distribution network is converted to hydrogen, with transmission pipes built in parallel to the existing transmission network.** This pathway would also allow widespread use of hydrogen. Building new hydrogen pipes parallel to gas pipes would incur a capital cost for the new pipework but parallel placement would minimise additional costs (e.g. land access rights). Industries that are connected to the gas transmission network and that would be unable to switch to hydrogen would be able to maintain their natural gas supply.
- **Only the gas distribution network is converted to hydrogen.** This pathway would have a relatively low capital cost post-2032 following the completion of the IMRP. Hydrogen could be fed into the distribution network from nearby hydrogen plants; this would not require compression of the hydrogen. However, this would not supply all of industrial demand as many large industrial gas users are connected directly to the transmission network. Those industries would maintain a natural gas supply, although as larger consumers of natural gas they may be well placed to decarbonise using carbon capture and storage (CCS).
- **Neither network is converted to carry hydrogen.** This pathway would allow for hydrogen blending at up 7% by energy (20% by volume) - see section 4. This would require the lowest capital spending and use existing pipework. However, this would lead to much smaller emissions savings. This pathway could be useful in establishing low-carbon hydrogen supplies in the near term.

It is also conceivable that in the long term, the natural gas network might be fully switched to hydrogen, enabling wider use of hydrogen. However, it would have a high capital cost as the transmission network would need pipe upgrades to prevent embrittlement and gas losses, and any industries that are unable to switch to hydrogen would lose their piped natural gas supply and would need to use other natural gas delivery methods.

[26] Although hydrogen pipelines may require more expensive materials, the cost of the pipeline itself is estimated to be only around one third of the total cost of laying a new pipeline. The overall cost of the pipeline is therefore relatively insensitive to the pipeline material cost.

Next steps for hydrogen use in industry

Despite the uncertainty about future levels of hydrogen use, there are a number of low-regrets actions that can be taken now to progress the option of using hydrogen for industrial decarbonisation. As such, we recommend that the government should:

- **Support the demonstration of hydrogen use for industrial direct firing applications in industries with small point sources.** Hydrogen appears to be the only realistic route to decarbonising these emissions sources and the government should ensure that this option is developed.
- **Target research and development spending into hydrogen technologies for industrial heating applications where there may be technical barriers to use of hydrogen.** This should sit alongside further research on BECCS applications in industry (see our parallel report on *Biomass in a low-carbon economy*).

To support the development of hydrogen use technologies (across the economy), the government should support low-carbon hydrogen production as part of a CCS cluster (as discussed in Chapter 6). The government should ensure that existing spare hydrogen production capacity in industry is considered for this low-carbon hydrogen production (through the application of CCS).

Longer-term and larger-scale industrial hydrogen use and broader industrial decarbonisation will require a clear mechanism to help support investment in industrial decarbonisation. The development of such a mechanism will need to tackle the risk of carbon leakage, while taking advantage of industrial opportunities. The Clean Growth Strategy set out a commitment to develop a framework to support the long-term low-carbon development of energy-intensive processes, but a year on there has not been further detail about this framework. This is needed urgently.

5. Blending of hydrogen into the natural gas supply

At present the specification for gas that can be transported through the UK gas network is closely linked to the composition of natural gas produced in the North Sea. It is likely that blending a small proportion of hydrogen into the natural gas supply could be done safely and without any changes to end-use appliances (e.g. boilers or cookers).

The HyDeploy project at Keele University is in the process of examining what proportion of hydrogen could be blended into the gas network (Box 1.9). It is thought that up to 7% hydrogen by energy[27] could be injected into gas supplies, but this study will develop an improved evidence base.

Blending of hydrogen into the gas grid at 7% would reduce the greenhouse gas footprint of grid gas by 4-6% if the hydrogen were produced from natural gas reforming with CCS, with potentially slightly greater savings from electrolytic hydrogen depending on the carbon intensity of the electricity used.

Although limited in potential, blending of hydrogen into the gas supply avoids some of the costs associated with switching to 100% hydrogen, including adjustments to the gas network infrastructure, swapping out household-level appliance and potentially changing the pipework inside buildings. It therefore reduces greenhouse gas emissions at a lower unit cost.

[27] As hydrogen is less energy-dense than natural gas, this equates to 20% hydrogen by volume.

Our cost estimates suggest that it could reduce emissions at a cost of £56-114/tonne, depending on the source of the low-carbon hydrogen. However, the potential is limited by the extent to which hydrogen can be blended before expensive and disruptive upgrades of natural gas appliances would be required.

Blending of hydrogen is not a key stepping stone on the way to full conversion to hydrogen, as it fails to tackle key challenges associated with higher proportions of hydrogen supply (i.e. costs and disruption of conversion at the household level, public acceptability of hydrogen as a fuel). Blending of hydrogen with natural gas and repurposing the gas grid to 100% hydrogen are quite separate things, with blending providing some benefits in a transition phase:

- The possibility to blend small proportions of hydrogen into the natural gas supply offers an option to use low-carbon hydrogen to reduce emissions without significant infrastructure changes.
- Production of low-carbon hydrogen for a range of uses, including potentially blending into the gas supply, would enable hydrogen supply chains to develop. This would provide a platform for subsequent wider deployment of hydrogen.

We consider the value of blending hydrogen into the gas grid as part of a transition to wider hydrogen use in Chapter 6.

Box 1.9. The HyDeploy project

The HyDeploy project is investigating the potential to increase the limit of hydrogen blending into natural gas supplies without changes to behaviour or existing gas appliances.

The project will test blends at up to 7% hydrogen by energy (20% by volume), the level below which previous studies have indicated that there gas appliances and customers are not affected. It is also slightly below the level at which gas appliances manufactured since 1993 have been designed to operate (8% by energy).

In November 2018, the project was given permission by the Health and Safety Executive to proceed to a live trial during 2019, which will test blends of hydrogen and natural gas for around 130 homes and buildings on the Keele University private gas network.

Chapter 2: Hydrogen use elsewhere in the energy system

Hydrogen's role in heat decarbonisation will determine whether or not gas grids are repurposed to hydrogen. Hydrogen can also play a role in the power and transport sectors irrespective of decisions over the gas grid, although they may affect the extent of hydrogen use and how it is delivered.

This chapter's key messages are:

- **Power.** By 2030, the UK is likely to have a very low-carbon electricity system, with renewables and nuclear backed up by flexible thermal capacity – mainly natural gas plants. There is an opportunity for hydrogen to replace natural gas cost-effectively in this back-up role, potentially enabling power system emissions to get close to zero by the 2040s. This would be helped if new gas plants can be made 'hydrogen ready', including being well-sited with respect to potential hydrogen supplies.
- **Transport.** While battery electric vehicles are now well placed to deliver the bulk of decarbonisation for cars and vans, hydrogen fuel cell vehicles could play an important role for heavy-duty vehicles (e.g. buses, trains and lorries) and potentially for longer-range journeys in lighter vehicles, where the need to store and carry large amounts of energy is greater. There is also a potentially important role in decarbonising shipping, especially if an international market develops in low-carbon hydrogen or ammonia (see Chapter 3).
- **Synthetic fuels.** Production of synthetic hydrocarbon fuels using zero-carbon hydrogen and captured CO_2 is technically feasible, but faces major challenges in contributing to decarbonisation in a cost-effective way. Inclusion of synthetic fuels within near-term policy mechanisms is not a priority.

The rest of this chapter is set out in three sections:

1. Managing the electricity system
2. Transport
3. Production of synthetic fuels

1. Managing the electricity system

Just as hydrogen and electricity can be used in complementary ways in end-use applications for sectoral decarbonisation, there is also potential to manage their supplies in ways that can provide benefits in managing the overall energy system.

The value of storable fuels in the power sector

The challenge in decarbonising electricity is to produce electricity from low-carbon sources - including variable renewable electricity - and to match demand and supply at all times. Although electricity can be stored in batteries, thermal stores and pumped-hydro storage, electricity storage in very large quantities over long periods of time is not cost-effective. Despite improvements in battery technology, there is likely to remain a role for storable fuels – such as natural gas or potentially hydrogen - in meeting peak electricity demand.

- Peak electricity demand occurs in winter, and fossil fuel power stations currently ensure that enough electricity is generated to meet this demand. In the future, electrification of heat for buildings will increase seasonal variation in electricity demand. Factoring in electrification in other sectors, peak demand could increase by up to four or five times by 2050 under a 'Full Electrification' pathway compared to today.[28]
- Whilst battery storage and thermal energy storage have large roles to play, they can largely help to manage intra-day and inter-day peaks in energy demand. It is likely that the UK grid will continue to rely on a storable fuel (e.g. natural gas or hydrogen) in order to meet peak electricity demand in the winter.
  - Developments in other forms of energy storage, such as flow batteries[29] and long-duration thermal energy storage, could reduce the role for storable fuels, though fuels such as gas are likely to remain important into the foreseeable future.
  - A transition of the UK's car fleet from fossil-fuelled vehicles to electric vehicles could provide up to 125 GW (1.7 TWh) of additional electrical storage capacity.[30] However, charging patterns (and possibly battery degradation through increased cycling) may limit the availability of this capacity to help balance the UK's electricity system. Even if these constraints can be resolved, vehicles are unlikely to provide a form of long-term storage.
  - As outlined in Chapter 1, hybrid heat pump systems would add a flexible load to the electricity system, able to be moved by a hours within the day or to switch to the boiler if necessary.
- In a heavily electrified system there is a potentially important role for the seasonal storage that is currently provided by natural gas, in order to meet peak electricity and heat demands in winter (see Box 1.6). There is potential for hydrogen to perform a similar role in a low-carbon way.

If electricity generation exceeds electricity demand at certain times of the year (e.g. at times of high renewable generation), this 'surplus' electricity could potentially be converted into hydrogen whether to re-generate electricity, or for use in other sectors. However, the scale of this surplus electricity is not likely to be significant and the role for electrolysis in converting it

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[28] See Imperial College (2018) *Alternative UK heat decarbonisation pathways*.
[29] A flow battery is a type of rechargeable battery with electrical charge provided by chemicals stored in two tanks. Tanks can be sized to contain large volumes of liquids, increasing storage compared to Li-ion batteries.
[30] Assuming 42m cars, 40 kWh battery, 3kW charger.

into hydrogen is likely to be limited by its economics relative to those of other forms of power system flexibility such as demand-side response and battery storage (Box 2.1).

We set out the economics of producing hydrogen via electrolysis and low-carbon electricity in Chapter 3, and consider its role in the context of the whole energy system in Chapter 4.

Box 2.1. Electrolysis and grid-balancing services

Increasing penetration of variable renewable energy into the UK's electricity system provide a need for more electricity grid services - such as balancing services and frequency response - to ensure that variable supply can match electricity demand at all times, and power quality can be maintained. Several options are available to provide this 'system flexibility', including flexible generators, battery storage, interconnection and demand-side response.

Electrolysers could be helpful in managing an electricity system with variable supply, by absorbing 'surplus' grid power (which would be low cost), by providing frequency management services, or by locating in areas where grid constraints limit the amount of power that can be transferred from one part of the electricity system to another. This role will be determined by the uptake of alternative system flexibility options, which have greater energy throughput and therefore lower costs. There may be a greater role for electrolysers in grid-constrained areas.

- Electrolysers are already providing system flexibility services to the UK grid. ITM Power's 3 MW electrolyser in Birmingham is able to contract for both frequency response and demand management contracts from National Grid, the UK's electricity system operator.
- Imperial College modelling (Box 1.6) suggests that more cost-effective methods for balancing the grid, such as demand-side response (e.g. shifting demand for electric heating via thermal storage in domestic premises or electric vehicle charging) are likely to play a greater role in providing electricity system flexibility than electrolysis:
  - The modelling suggested electrolysis would be limited to managing around 1% of grid electricity, producing around 1% of the hydrogen supplied in a scenario with high hydrogen demand.
  - If it were not possible to shift significant amounts of electrified heat and/or transport demand away from peak periods, there could be a greater role for electrolysis in providing grid balancing.

Electrolysers could play a useful role in producing energy in areas without electricity grids, or that are unable to export the electricity produced to an area of demand. This could be particularly relevant to Scotland, where onshore wind can be produced cheaply but upgrades to the electricity transmission system have been required in order to send electricity south of the border.

Source: Imperial College (2018) *Analysis of alternative UK heat decarbonisation pathways*. Grid Change Agent (2018) *ITM Power installing grid balancing hydrogen bus refuelling station in Birmingham*.

Using hydrogen in the power sector

Use of hydrogen for electricity generation can eliminate direct CO_2 emissions from the UK's power sector, though there may be indirect emissions associated with the production of the hydrogen being used. A zero-carbon power system can be a cost-effective contribution to meeting the UK's 2050 target. This could make sense especially where low-carbon H_2 is being produced anyway and stored for other applications (e.g. for use in industry or buildings).

- Technically, hydrogen can be used to generate electricity as a direct fuel in new gas turbines or some existing ones, as part of a pre-combustion gas CCS plant or a fuel for CHP plant, producing no carbon emissions at the point of combustion. Ammonia (NH_3) is a hydrogen-rich liquid that could be used as an alternative or complementary fuel to direct hydrogen use in power stations.[31]
- Hydrogen burnt in power plants can play a role in providing long-duration energy storage in order to meet seasonal peaks in electricity demand, as well as providing important system services – such as system balancing, inertia and voltage control – to help accommodate variable renewable energy within the system.

Technical feasibility

It appears technically possible that new power stations could be built to burn hydrogen, ammonia or a combination of the two, at limited additional cost. Modest retrofits to some existing power stations could also make burning these zero-carbon fuels viable. It is possible to already burn these fuels in engines. Further research is required to determine the technical capability, performance efficiencies and air quality implications of burning hydrogen in power stations. Additionally, burning hydrogen in power stations is only likely to be viable if there is a low-cost route to getting sufficient volumes of fuel to the power stations:

- Discussions with leading power equipment manufacturers suggest that hydrogen and ammonia could both be combusted in new gas turbines, with similar overall efficiency to today's combined cycle gas turbines (CCGTs).[32] New CCGTs built with diffusion burners - which are able to burn lower calorific gases - could be 'hydrogen ready', by burning natural gas initially before switching to burn hydrogen at a future date.[33]
- A trial by Siemens in Oxfordshire demonstrates that wind power can be used to produce low-carbon ammonia, for subsequent power generation via combustion of an ammonia-hydrogen blend in an engine.[34]
- It is likely that retrofitting existing CCGTs to burn hydrogen and/or ammonia would be possible, although suitability would be determined on a case-by-case basis. This is because turbine configurations may be space-constrained, and may not have room for additional pipework required for higher volumes of gas (per unit of energy), and the Selective Catalytic Reduction (SCR) technology that may be required to manage emissions of nitrogen oxides (NOx).
- Hydrogen could be also used in fuel cells for small-scale distributed electricity generation. These offer efficiency benefits compared to small gas generators, but are expected to be more costly at up to £2500/kW compared to £300/kW.[35]

[31] As ammonia is rich in nitrogen, there are risks that burning it directly could increase emissions of NOx - a harmful pollutant. This is also an issue for direct hydrogen combustion, as nitrogen in the air is involved in the combustion process. Reducing the flame temperature (i.e. by adding ammonia to a hydrogen fuel mix), or installing Selective Catalytic Reduction technologies are two options to help mitigate this.
[32] Efficiencies are assumed to be around 53% HHV for both technologies.
[33] US DOE also has a programme of development for an efficient hydrogen turbine. See ETI (2015) *Hydrogen - The role of hydrogen storage in a clean responsive power system*.
[34] Siemens (2016) *Green Ammonia*.
[35] BEIS (2016) *Electricity Generation Costs*; Fuel cell costs are domestic scale from Imperial College (2018) *Alternative heat decarbonisation pathways*. There could be significant cost reductions from economies of scale.

- In practice, the use of hydrogen for power generation may be constrained by the availability of the fuel. In scenarios where the gas grid isn't converted to hydrogen, combustion of hydrogen for power generation would be limited to power plants located near hydrogen production facilities, or using smaller volumes of fuel, that can easily be transported or stored. This may favour larger-scale gas plants.

The government should investigate the technical feasibility of burning hydrogen fuels for power, as well as the possibility of ensuring that new fossil-fired power plant being deployed in the UK is 'hydrogen ready', both in its ability to burn hydrogen at a later date and in siting new plants near to possible future hydrogen production facilities (e.g. near to CCS hubs).

The economic case for hydrogen in power

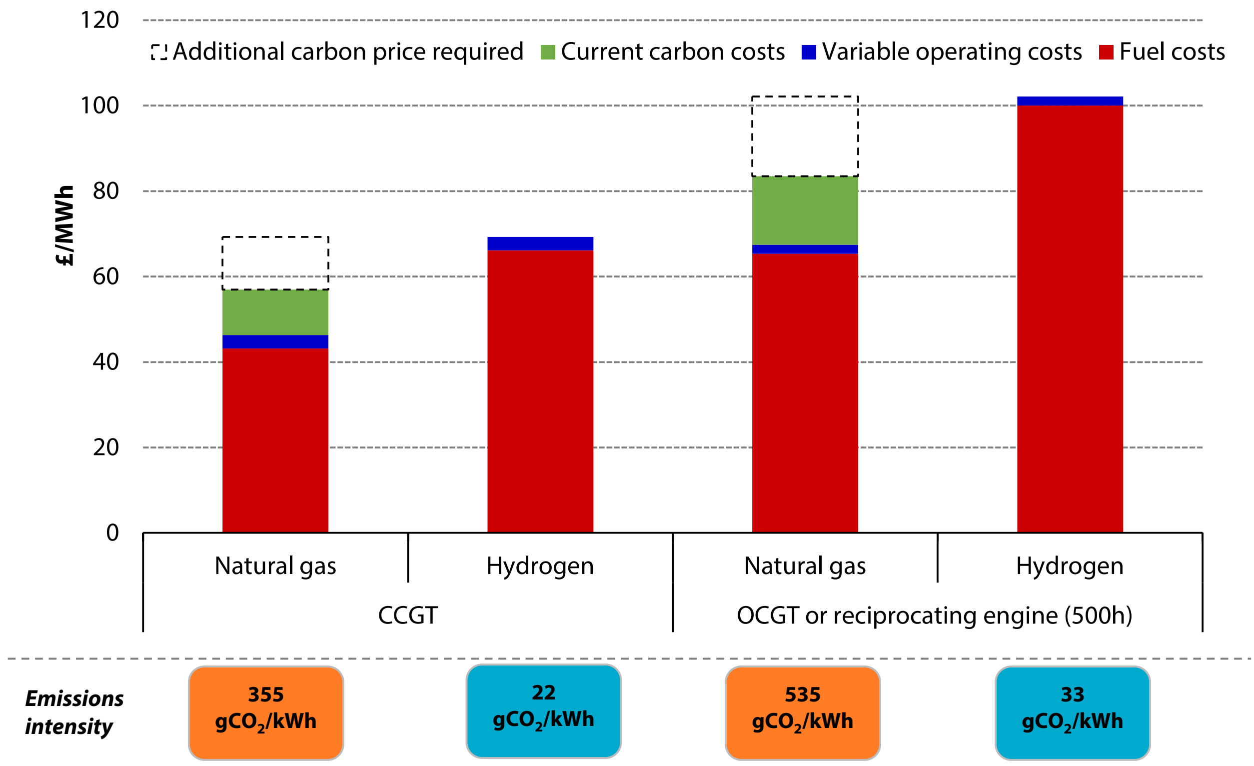
If hydrogen and/or ammonia can be combusted (at high efficiency) in gas power stations to produce electricity, then it is likely this could play a similar role to natural gas power plants today: providing capacity, flexible generation and a range of essential power system services such as inertia, and frequency response.

As carbon prices rise, the economics of burning low-carbon gas for power generation improve. We estimate that burning hydrogen in power stations will be cost-effective against the government's carbon values in the 2030s (Figure 2.1):[36]

- **Fuel switching.**
  - Forecast natural gas prices range between £13-28/MWh (39-83p/therm). If gas is burned in a high efficiency CCGT (53% higher heating value) power can be produced at a cost of £25-54/MWh.
  - If natural gas is reformed into hydrogen it could cost £27-46/MWh (see Chapter 3). Burning hydrogen in the same power station would produce power at £51-87/MWh.
  - Burning hydrogen instead of natural gas can reduce emissions by 60-85% when including lifecycle emissions (Chapter 3).
    - The emissions intensity of gas-fired power generation is around 355 gCO_2/kWh, in addition to lifecycle emissions from natural gas of around 30-135 gCO_2/kWh.
    - Hydrogen would produce no direct CO_2 emissions, but could incur emissions of around 20-23 gCO_2/kWh during the hydrogen production process (and emissions of 30-165 gCO_2/kWh associated with supplying the natural gas for this process).
  - Natural gas power plants currently pay around £11/MWh for their CO_2 emissions, at a carbon price of £30/tCO_2. Carbon prices would have to rise to around £70-100/tCO_2 to encourage switching to a lower-carbon fuel. This would be cost-effective against the government's carbon values from around 2030 onwards.
- **New-build fossil plant.** For all types of gas plant being built from 2030 onwards, it looks as or more cost-effective to build the gas plant to be able to burn either hydrogen or ammonia, instead of natural gas, against the government's carbon values.
- This logic also applies to fuel cells, which could be used to displace mobile power generation such as small-scale gas and diesel generators, as well as off-road mobile machinery. However, the costs of fuel cells would have to fall significantly in order to compete on cost with small fossil power generators.

[36] Assuming hydrogen engines and turbines have the same capital cost and efficiency as natural gas equivalents.

Figure 2.1. Projected operating costs of gas plants in 2040



Source: HMT (2018) *Green Book supplementary guidance: valuation of energy use and greenhouse gas emissions for appraisal*, BEIS (2016) *Electricity Generation Costs*.
Notes: Switching from using natural gas to using hydrogen becomes cost-effective at carbon prices of between £70-100/tCO_2. Assuming hydrogen is produced via gas-reforming at a cost of £35/MWh and an emissions intensity of 12 gCO_2/kWh. Current carbon prices are around £30/tCO_2. Emissions intensity excludes supply chain emissions which could add 30-135 gCO_2/kWh for natural gas CCGT and 30-165 gCO_2/kWh for a hydrogen CCGT.

System implications

In our 2016 report on *UK Climate Action following the Paris Agreement* we suggested that direct emissions from the power sector would be 6 MtCO_2 in 2050 under our Central scenario, compared to around 72 MtCO_2 in 2017. Use of hydrogen in the power sector could displace residual emissions from gas plant and gas CCS plant, providing the opportunity to reduce direct emissions from power generation to zero. Residual emissions from hydrogen production would depend on the source of the hydrogen, but would likely be lower than 5 MtCO_2.

Use of hydrogen in the power sector doesn't just depend on cost and emissions, but also relies on getting the hydrogen to power stations. Therefore its use in power could depend on hydrogen use in other sectors with potentially larger demands for hydrogen, such as buildings and industry.

- Current gas power stations use natural gas from the UK's transmission and distribution systems. Gas plants that connect to the transmission network would require dedicated hydrogen pipes from nearby hydrogen production facilities in order to switch to hydrogen. Converting the gas distribution networks to hydrogen use could allow direct use of hydrogen in smaller gas power stations. This demonstrates the importance of the gas grid offering system flexibility across both heat and power applications.

- In scenarios where the gas grid is not converted to hydrogen use, hydrogen power stations could be limited to locations near sources of hydrogen, or to smaller volumes that could be easily transported.
  - For example, in scenarios where hydrogen isn't used for heat but is used in industry, power stations may need to be located close to industrial clusters in order to access a source of low-carbon hydrogen.
  - Separately, if hydrogen could be transported in small volumes, then it has the potential to displace small-scale uses such as distributed power generation or off-road mobile machinery.

2. Transport

While battery electric vehicles have made a lot of progress, there is a question as to whether they are suited to all forms of road transport. The energy density by volume of hydrogen, whilst lower than that of diesel and petrol, is far greater than that of batteries. Refuelling a hydrogen vehicle is similar in speed to refuelling a diesel or petrol vehicle, whereas battery electric vehicles can take longer to charge.

Hydrogen fuel cell vehicles are electric vehicles that generate electricity on board at relatively high efficiency, avoiding or reducing the need for electricity storage in batteries. As such, fuel cell vehicles will have electric drive trains, and will benefit from improvements in electric vehicles.

Use of fuel cells for buses or trains could have relatively limited hydrogen infrastructure requirements, due to the potential for 'return to base' fuelling. By contrast, long-distance road transport, in cars, vans and/or trucks, would imply the development of a UK-wide network of hydrogen refuelling stations. This would depend to some extent on decisions made elsewhere in the energy system - if the gas grid is converted to hydrogen, it may be possible to use it to distribute hydrogen to refuelling stations.

Use of the gas grid to distribute hydrogen may mean that impurities are introduced into the hydrogen, either from the grid itself or from the addition of odorants and colourants to ensure the hydrogen can be safely used in homes for heating:

- To enable a long lifetime of the fuel cell, hydrogen entering it must be free of contaminants. Whilst it is possible that vehicles will include onboard purifiers, it is likely that the refuelling stations would need to provide hydrogen with a purity of a set standard.[37] Cadent Gas and the National Physical Laboratory (NPL) are currently collaborating on a project to assess the likely purity of hydrogen in the gas network and the purity requirements for fuel cell applications, to identify how feasible it will be to use hydrogen from the gas grid in hydrogen vehicles, with a focus on heavy goods vehicles (HGVs).[38]
- Whilst the costs of purification are uncertain, it is not clear whether converting the gas grid to hydrogen will support a transition to hydrogen in the road transport sector as, if

[37] Currently hydrogen refuelling stations need to be compatible with ISO 14687 standards for hydrogen purity, mandated at the EU level.
[38] Cadent (2018) *NIA Project Registration and PEA Document: Hydrogen Grid to Vehicle (HG2V); Network Purity for Transport.*

purification and transportation costs are above around £15/MWh (see Chapter 3), it may be cheaper to produce hydrogen on-site from electrolysis. The likely requirements for, and costs of, purifying hydrogen would be a useful area for further research.

In this section, we first consider the role for hydrogen in long-distance road transport, before considering other surface transport and then international transport.

Long-distance road transport

Cars

For passenger cars regularly travelling long distances exceeding the range of a battery electric vehicle, hydrogen cars provide the ability to travel further on a single tank of fuel and refuel more quickly than battery electric vehicles. However, the costs of electric vehicles are falling more rapidly than for hydrogen fuel cell cars and increasingly fast charging technologies are being developed.

Compared to battery electric vehicles, there are fewer models of hydrogen vehicle available and limited fuelling infrastructure:

- The number of hydrogen fuel cell car models available on the market is low, with only two models currently available in the UK: the Toyota Mirai and the Hyundai ix35.[39] This compares with more than 50 models of electric car.
- Hydrogen fuelling opportunities are also significantly more limited than for electric vehicles:
  – 13 hydrogen refuelling stations are operational across the UK.[40] The UK H_2Mobility consortium recommended that 65 stations should be installed by 2020 to support the development of an early market of 10,000 vehicles, rising to 1,100 stations by 2030 to enable a wider roll-out of the vehicles.[41]
  – Opportunities to charge electric vehicles are considerably greater. Alongside charging at home and at workplaces, there are now 11,000 public electric vehicle chargers in 7,000 locations.[42] With new 150kW and 350kW chargers being rolled out in the next few years, the time stopped to charge for an electric vehicle driver will be roughly equivalent to (or less than in the case of 350kW chargers) the recommended rest breaks in the Highway Code of 15 minutes every 2 hours of driving.[43]

The UK's Hydrogen for Transport Programme was launched in 2017 by the Office for Low Emission Vehicles (OLEV):

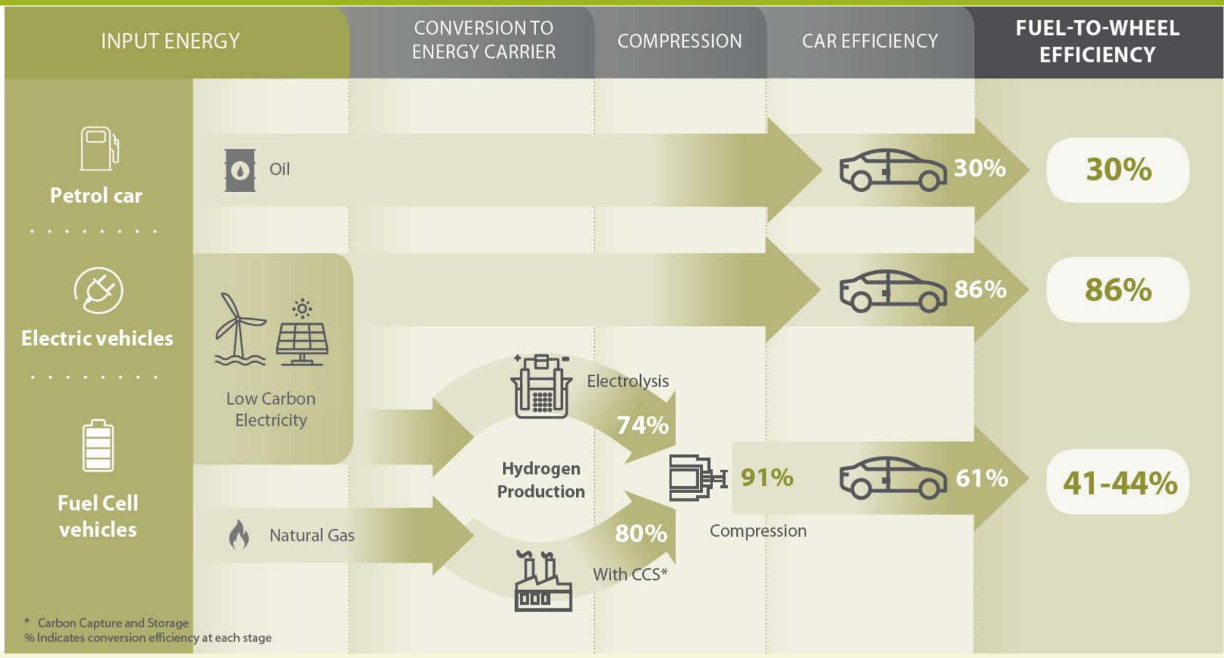
- Stage 1 will help fund four new hydrogen refuelling stations in Derby and Birmingham (opening early 2019) and two in London. Over 190 fuel cell vehicles will also be deployed, the majority of which will operate in London. Users will include Green Tomato Cars (a car service with an environmentally focused approach) and the Metropolitan Police. The London Fire Brigade and British Transport Police will also trial vehicles.

[39] Availability of the fuel cell version of the Honda Clarity is currently unclear in the UK as it seems to be available only for limited trials.
[40] Zap-map.com
[41] UK H_2Mobility (2013) *Phase 1 Results*.
[42] Zap-map.com
[43] Department for Transport (2018) *The Highway Code*.

- Stage 2 aims to fund up to ten hydrogen refuelling stations as well as associated fleets and commits up to £14m.[44]

While hydrogen fuel cell vehicles are around twice as efficient as petrol and diesel vehicles, they are less efficient than battery electric vehicles, and the overall energy efficiency of fuel cell vehicles is reduced by inefficiencies in the rest of the energy chain (Figure 2.2).

Figure 2.2. Relative efficiency of battery electric vehicles vs. electrolytic hydrogen fuel cell vehicles



Source: CCC analysis.
Notes: The diagram shows the indicative efficiency of using a given amount of zero-carbon electricity in powering a car. Whilst in practice each of the efficiency numbers could vary, this would not be sufficient to change the conclusion that electric vehicles provide a much more efficient solution for powering vehicles than use of electrolytic hydrogen in a hydrogen fuel cell vehicle.

Fuel cell vehicles are electric vehicles that generate power onboard, so it is possible that hydrogen cars could in the longer-term be hydrogen plug-in hybrids (i.e. combining a battery and a fuel cell):

- The vehicle could have a smaller fuel cell, alongside a battery similar to those in other plug-in hybrids. This would enable the user to benefit from cheaper energy through the greater efficiency of charging the battery, when convenient, whilst for longer journeys it would have greater range enabled by the hydrogen storage.
- It could also reduce concern over coverage of hydrogen refuelling stations, especially in the initial stages, given the possibility to fuel with hydrogen or recharge the battery.

Overall, battery electric vehicles are well placed to deliver the bulk of decarbonisation in light-duty transport, but hydrogen would be a useful option in some cases.

[44] Ricardo (2018) *Hydrogen for Transport Programme (HTP).*

Heavy goods vehicles (HGVs)

Long-haul heavy goods vehicles are challenging to decarbonise, as they require a large payload capacity. It is important to aim to decarbonise heavy-duty transport by switching to hydrogen and/or electricity, rather than continuing to use hydrocarbon fuels:

- As set out in our parallel report on *Biomass in a low-carbon economy*, use of biofuels is not the best use of finite bio-resources where applications can be shifted to carbon-free energy, given alternative uses and the potential to sequester the bio-carbon with carbon capture and storage (CCS).
- Synthetic fuels are unlikely to contribute significantly to cost-effective emissions reductions (see section 3).

The aim should therefore be to move HGVs to zero-carbon energy (i.e. electricity and/or hydrogen) where feasible by 2050.

In principle, hydrogen fuel cell vehicles would be well suited to providing the necessary power and range, but they are currently projected to be more expensive than electric trucks:

- Hydrogen trucks are currently being used in demonstration projects across the world, including several projects in California. However, these are generally for urban delivery and short distance routes.
- Currently, there are no long-haul hydrogen fuel cell HGVs being demonstrated, although the start-up Nikola has announced work towards a hydrogen truck with a range of 500-1000 miles and a 15-minute refuel time.
- Toyota unveiled a second iteration of its hydrogen truck in July this year, with a range of 300 miles. The first iteration of this truck has been operating at the Ports of Long Beach and Los Angeles, completing nearly 10,000 miles of testing and real operations.[45] Port operations offer a significant opportunity for low emission trucks, as many are located in areas of poor air quality and the trucks are required to do relatively short trips between the port and the distribution centre.

However, hydrogen is not the only potential solution for heavy trucks – electrification could be feasible, either with battery electric trucks or by installing infrastructure that charges the vehicles as they drive:

- **Battery trucks.** Volume and weight constraints on the vehicle mean that for larger battery electric trucks to become feasible, the energy density of the battery would need to improve compared to batteries available on the market today. Lighter electric trucks manufactured by Arrival and Daimler are already being trialled on urban routes by companies including UPS, DPD, Hovis and Wincanton.
  - Pure battery electric trucks could successfully operate on urban routes or predictable regional routes with lighter loads, but require charging infrastructure to enable to them to charge either overnight at the depot, whilst loading and unloading goods or during the driver's rest time. Local electricity grids would likely need to be upgraded to accommodate these vehicles, or the charging infrastructure could be paired with large on-site stationary batteries.

[45] Toyota (2018) *Press release: Toyota Doubles-Down on Zero Emissions Heavy-Duty Trucks.*

– Tesla have released specifications for a fully electric tractor trailer truck with an estimated range of between 200 and 300 miles, indicating that there is potential for electric trucks to service longer routes assuming certain developments in battery technologies.

- **Motorway charging.** Technologies that charge electric trucks whilst they drive can enable longer journeys and reduce the size and weight of batteries required, allowing larger payloads. However, installing this infrastructure on major roads is likely to be expensive and disruptive to road users (Box 2.2).

Given the large number of HGVs travelling between the UK and the rest of Europe, suitable infrastructure must be available in all countries that UK HGVs travel from, to and through. The UK cannot therefore consider decarbonisation of long-distance haulage in isolation from other countries. International coordination will be needed to ensure that countries across Europe transition towards the same low-carbon solution and reduce the potential need to install infrastructure to service trucks with multiple different power-trains.

Box 2.2. Electrification of motorways

Given the issues with installing sufficient batteries to enable trucks to travel long haul and to remove the need for potentially long recharging periods, options to recharge the truck as it drives along the road are being explored. A number of recharging options have potential, including overhead catenaries, dynamic inductive recharging embedded into the road and conductive on-road strips. The large infrastructure costs and disruption involved in installing these technologies mean that they are likely to be restricted to heavily used freight corridors.

Scania and Siemens are currently partnering to develop 'E-highway' technology, using overhead catenaries to recharge the trucks, with ongoing trials in Sweden and Germany showing that the project is technically feasible:

- In Sweden, overhead electric wires will be used to electrify a 2-km stretch of motorway north of Stockholm. Two electric trucks developed by Scania will be used to test the system.
- In Germany, three field trials of the technology are planned to start operation in 2019.
- In the US, Siemens have electrified 1-mile of highway in California between the ports of Los Angeles and Long Beach. Three trucks are currently being used to test the system.

In 2015, Highways England commissioned a feasibility study from the Transport Research Laboratory looking at installing dynamic inductive charging for cars, vans and HGVs on England's major roads.

- As part of this study, a survey of industry stakeholders stated that they would be more likely to purchase an electric vehicle if it were possible to use on-road charging on equipped sections of major roads, but that a return on investment on the vehicles of 18-36 months would be required.
- Dynamic charging installation on the motorways was found to have positive monetary benefits when modelled as being used by light vehicles (including cars and vans) and heavier vehicles (including HGVs and coaches). The study highlighted that at that time there were no systems that could supply the two different levels of power required by the two different vehicle types.

Highways England planned an 18-month trial of this technology but have paused the project whilst they wait for results of trials in other countries, including the FABRIC project that aims to test installing coils under the road surface to charge various types of vehicles in Italy, France and Sweden.

Sources: Siemens (2016) *Siemens builds first eHighway in Sweden*; Siemens (2017) *Siemens builds first eHighway in Germany*; TRL for Highways England (2015) *Feasibility study: Powering electric vehicles on England's major roads* and FABRIC project (2014) *FABRIC project leaflet*.

Infrastructure and strategic decisions for decarbonisation of road freight

In order for the HGV fleet to have turned over fully to ultra-low-emission vehicles (ULEVs) by 2050, this would require 100% of sales to be ULEVs by the mid-to-late 2030s given the lifetimes of these vehicles.

In turn, for a hydrogen solution this would means rolling out infrastructure from the late 2020s:

- Assuming a similar number of refuelling stations would be required for hydrogen HGVs, as has been estimated for a natural gas fleet,[46] 350-400 refuelling stations would be required by the mid-to-late 2030s to support the development of a hydrogen HGV fleet.[47]
- Modelling for the UK H_2Mobility project indicates that it is feasible to roll-out this number of stations in around a decade when starting from an initial 65 stations.[48]

Given large uncertainties over which technology option will prove most cost effective, it is important to consider the likely roll-out speeds of alternative technologies, if the electrification of road freight proves a more cost-effective option compared to the use of hydrogen fuel cell trucks (Box 2.3).

Given the current evidence on lead-times for infrastructure and the time taken to turn over vehicle stocks, the government would need to make a decision on the choice of ULEV solution(s) in the second half of the 2020s.

The Department for Transport should consider running larger-scale trials to assess these technologies in the early 2020s, after learning from the results of the ongoing international trials. This should feed into a decision on the best route to achieving a zero-emission freight sector in the second half of the 2020s.

Prior to this decision, it will also be important to improve understanding of the likely journeys of freight vehicles, by collecting data on lengths of trips, actual payloads and volumes of freight carried and the proportion of each trip spent on major roads. This can inform a full assessment of the different technology options (which may include hybrid hydrogen-electric trucks).

In the near term, the government should continue to focus on developing hydrogen refuelling station and vehicle technology, by building an initial network to allow wider roll-out later in the 2020s. Government funding in support of hydrogen refuelling stations should prioritise those bids which allow a variety of vehicles, including HGVs or buses, to refuel. This will enable SMEs and manufacturers to develop the early market for hydrogen HGVs.

Box 2.3. Timelines for non-hydrogen HGV solutions

Whilst cars and, to a lesser extent, vans are increasingly electrifying, the additional weight and space required to add sufficiently large batteries has proven difficult for electric trucks which carry heavier loads.

- According to the Continuing Survey for Road Goods Transport in 2017, the average length of haul for a domestic articulated truck was 85 miles, which implies a battery size of at least 270 kWh,

[46] Energy Technologies Institute (2017) *Natural Gas Pathway Analysis for Heavy Duty Vehicles.*

[47] Assuming a gradual ramp up of hydrogen HGV sales, starting from the late 2020's and rising rapidly to nearly 100% of new sales by the late 2030's, resulting in 30-35% of the HGV fleet being hydrogen vehicles in the late 2030s.

[48] UK H_2Mobility (2013) *Phase 1 Results.*

Box 2.3. Timelines for non-hydrogen HGV solutions

which could weigh 1.3 tonnes. Assuming the truck will be at the depot for 30 minutes, a 550 kW charger would be required to recharge the truck before it needs to leave again.

- There will be a significant proportion of trips that will be much longer than this. Transport and Environment estimate that a fully electric truck with a range of 190 miles could cover 50% of trips across the EU, potentially implying a 600 kWh battery, adding 3 tonnes of weight to the truck in 2025. Recharging this battery in 30 minutes would require a 1200 kW charger.

In both cases, there would be an impact on the payload of the truck. Fast chargers will increasingly be required if the pure battery electric truck is to become a viable option without some sort of on-road charging. However, given that 350 kW chargers are soon to be available, relatively minor improvements in charging speed could allow the use of electric trucks on shorter routes.

Alternatively, given the lower costs of running an electric truck, fleet operators may be willing to adjust working patterns to allow slightly longer stops at depots to recharge. Improvements in battery energy density, even when excluding the possibility of completely new types of batteries, could significantly improve the impact on payload as well.

It is reasonable to expect HGVs with lower payloads on regional routes to switch to electrification from the early 2020s. To support development of battery electric HGVs, it would therefore be sensible to ensure that HGVs parking in motorway service areas have access to chargers. Additionally, ensuring that all motorway service areas have sufficient spare capacity in their grid connection would allow easy installation of high-powered charging points in future, whilst also supporting the electrification of passenger transport.

Battery electric trucks could also be supported by some form of on-road charging, which could involve inductive charging placed under the road, catenaries with overhead electrified lines that HGVs can attach to and on road inductive charging:

- Given a decision to pursue this option in the mid-2020s, in the Bundesverband der Deutschen Industrie (BDI) report 'Climate Paths for Germany' it was assumed 400km of roads could be fitted with overhead electrified lines by 2028. Assuming a similar roll-out pace, the UK's motorways could be fitted with the lines by the late 2030s if a decision was made in the mid-2020s.
- This pace may seem ambitious compared to the slower pace of railway electrification. However, unlike railway electrification, HGVs travelling on the road network will need alternative power sources for travelling when not on major roads, such as diesel, batteries or hydrogen. Therefore, if difficult stretches of motorway are encountered (e.g. multiple low bridges), a HGV can run on the alternative power source for this stretch, avoiding the need to install the infrastructure in this area.

Sources: Energy Systems Catapult (2018) *ESME v4.4 Dataset*; Element Energy for the Energy Technologies Institute (2017) *HDV – Zero Emission HDV Database*. BCG and Prognos for BDI (2018) *Klimapfade für Deutschland*. Transport and Environment (2017) *Electric trucks' contribution to freight decarbonisation*.

Buses and trains

There are hydrogen fuel cell buses already operating in the UK, including fleets in London and Aberdeen and plans in Birmingham and Dundee. Costs remain higher than for electric models, but the buses can offer a longer range between stops to refuel.

Buses offer an important potential early market for hydrogen fuel cell vehicles:

- Depot-based bus fuelling limits the hydrogen refuelling infrastructure required, enabling buses to be a lead market while hydrogen refuelling infrastructure is not widespread.

- Operation of buses occurs predominantly in cities, where air quality is a particular problem. Deployment of ultra-low-emission buses in place of diesel buses is therefore attractive in improving urban air quality, especially where local authorities have the power to make this happen. For example, the Mayor of London's Environment Strategy[49] requires that all new double-deck buses will be hybrid, electric or hydrogen from 2018 and that all new single-deck buses will be electric or hydrogen from 2020.

The future balance between hydrogen fuel cell and battery electric buses remains to be seen, with choices based not only on cost but also potentially on local circumstances (e.g. route lengths and practicalities over charging and hydrogen refuelling infrastructure).

There is potential to use hydrogen in trains. Whilst electrification can significantly decarbonise the emissions from rail, the business case for electrification is strongest only on the busiest and high-speed lines. The main barriers to further electrification of the railway network are the cost and lengthy construction times of the electrical infrastructure. Hydrogen trains could offer an alternative for lines without this infrastructure, as refuelling can occur at rail depots (Box 2.4).

Box 2.4. Zero emission train technologies

In February 2018, the then Transport Minister Jo Johnson set an ambition to ensure that in 2040 no diesel-only trains will be operating within the UK. The Rail Safety and Standards Board were due to report on the feasibility of this goal in September 2018, but this report has not yet been released.

The German government has approved the use of hydrogen trains on their railway networks, and Alstom signed a contract to run hydrogen trains in Lower Saxony, commencing operation in late 2018. However, the energy density of hydrogen may represent a barrier to rolling out hydrogen trains across the whole railway network, as space constraints on the trains mean it is difficult to store sufficient hydrogen to service especially busy, high-speed routes and to transport heavy-duty freight. The Institute of Mechanical Engineers have released a report refuting the argument that there is no longer a need to commit to further rail electrification in England and Wales, stating that electrification offers major opportunities to reduce the unit costs of train operation and maintenance, as well as providing improved capacity, journey times and reliability, while also producing significant environmental benefits.

Both the introduction of hydrogen trains and further electrification of the railway network can offer improved air quality, a significant issue in stations where trains operate in enclosed areas.

Source: Institute of Mechanical Engineers (2018) *A breath of fresh air: New solutions to reduce transport emissions*.

Shipping and aviation

The shipping and aviation sectors currently depend entirely on liquid hydrocarbon fuels - overwhelmingly fossil fuels - for propulsion. Given long journey lengths, electrification using batteries is likely to be limited for long-haul travel in these sectors. However, some electrification of short-haul travel is likely to be feasible in both aviation and shipping, particularly if there are further significant improvements in battery energy density. Hydrogen use in shipping is also potentially feasible (Box 2.5).

Use of hydrogen - or another energy carrier based on it (e.g. ammonia) - for international transport faces considerable challenges in ensuring that refuelling infrastructure and low-carbon

[49] Mayor of London (2017), *London Environment Strategy*.

fuel is available in every country to which the craft might travel. In the case of shipping, the potential development of an international market in hydrogen (e.g. as ammonia) shipped from countries with low costs of low-carbon hydrogen production (see Chapter 3), does raise the possibility of this being the primary way of supplying low-carbon fuel for refuelling at ports.

Hydrogen use in aviation carries a further complication that it would lead to increased emission of water vapour at altitude, where it enhances the greenhouse effect, compared to continued use of kerosene. There does not therefore appear to be a role for hydrogen in decarbonising aviation.

Box 2.5. Hydrogen and ammonia in shipping

International shipping currently comprises 2% of global CO_2 emissions, and relies on Heavy Fuel Oil (HFO), a tar-like fossil fuel with substantial air quality impacts resulting from its high sulphur content and black carbon emissions. In April 2018, the International Maritime Organisation (IMO) agreed to reduce total annual GHG emissions by at least 50% by 2050 compared to 2008. This highlighted the need for rapid advancements in decarbonisation options for shipping such as electrification, hydrogen and ammonia (see Chapter 3). Use of biofuels in shipping does not represent the best use of finite sustainable biomass resources. Any biofuels produced are better used in aviation, due to the lack of other decarbonisation options.

Hydrogen and ammonia can power ships through fuel cells, internal combustion, or dual fuel or hybrid combinations. Low-carbon ammonia can be made directly from electrolysis, or by adding nitrogen to low-carbon hydrogen with renewable energy in the Haber Bosch process. There is a trade-off between hydrogen and ammonia; while low-carbon ammonia is more expensive than low-carbon hydrogen, hydrogen ships will have higher capital costs due to the difficulties associated with on-board storage. Storing hydrogen is more difficult as in its gaseous room temperature form, on-board storage tanks would take up a huge amount of space. Storage is more feasible if it is liquefied, but this requires cryogenic conditions which are expensive to run and take up space on the ship, displacing cargo. Ammonia is easier to store as a liquid than hydrogen, with a boiling point of -33°C instead of -253°C, so requires less expensive, bulky storage equipment and less cargo is displaced.

More work is needed to look at the profitability and emissions savings of different decarbonisation options, and how they will impact the global refuelling infrastructure. Work is also required to ensure that ammonia can be used safely as a shipping fuel (see Chapter 1, Box 1.1).

Source: Lloyd's Register; UMAS (2018) *Zero Emissions Vessels, what should be done?*; IEA (2017) Tracking Clean Energy Progress.

3. Production of synthetic fuels

There has been considerable interest in the production and use of synthetic hydrocarbon fuels as 'carbon-neutral' drop-in replacements for fossil fuels. In effect, this seeks to reverse the process of fossil fuel combustion: taking useful energy and CO_2 as inputs and ending up with a hydrocarbon. Consequently, the thermodynamics of such routes are poor – in addition to CO_2 they generally require a large amount of zero-carbon energy (in the form of hydrogen) to produce a significantly smaller amount of hydrocarbon energy. The CO_2 is then released to the atmosphere on combustion of the fuel.

In order for the production of such fuels not to reduce other opportunities for emissions reduction, and therefore for them to be genuinely carbon-neutral, the CO_2 used as an input must either be captured from the air or from a source of emissions that would otherwise have gone to atmosphere:

- **'Direct air capture' (DAC)** is potentially deployable in a relatively wide range of locations, but is likely to have high costs.
  - To date, DAC has only been demonstrated on a pilot and small commercial scale.
  - There is a wide range of estimates for what large-scale DAC might cost, but further work is required to understand expected costs under widespread commercial use.
  - Work is also needed to understand the challenges relating to scaling up DAC to a point where it could achieve meaningful amounts of CO_2 capture, in order to be a potential substantive source of carbon for synthetic fuels.
- **'Carbon capture and use' (CCU).** CO_2 can be captured from point-sources of emissions, either for sequestration (i.e. CCS) or for re-use. This is likely to be mainly in locations where CCS is not viable and it is difficult to avoid the CO_2 emissions in another way.
  - Where CO_2 can be sequestered via CCS, this is preferable as once the CO_2 has been captured, the costs for its transportation and storage can be relatively low relative to the cost of capture.
  - Alternatively, in many cases it is likely to be more feasible to switch away from unabated fossil fuel use (e.g. using renewables), removing the source of CO_2 emissions.
  - Remaining sources of CO_2 potentially available for CCU are therefore those in areas in which CO_2 storage is not viable, based on sources of CO_2 that cannot otherwise feasibly be abated (i.e. fossil fuel use that cannot be switched and/or produce CO_2 emissions as part of an industrial process).

Given the poor thermodynamic efficiency of synthetic hydrocarbon routes, in order to make a potentially sensible and cost-effective contribution to emissions reduction, it would require low-cost energy inputs. Therefore in order for synthetic hydrocarbon fuel production potentially to be viable, it would require the following to be available at the production location:

- Suitable volumes of CO_2 available for capture at relatively low cost; and
- Large volumes of very low-cost hydrogen based on zero-carbon energy sources.
  - Local production of zero-carbon hydrogen requires large amounts of available zero-carbon electricity, additional to that required for decarbonisation of electricity system (e.g. 'stranded' renewables – those that otherwise cannot access a market).
  - It also requires availability of large amounts of water from which to produce the hydrogen.

Whilst, in principle, the CO_2 or the zero-carbon hydrogen could instead be transported (e.g. shipped) from elsewhere, this transportation would add to costs (see Chapter 3), further undermining the economics of production.

However, even were all of the above conditions to be met production of synthetic fuels may still not be optimal. It would still be better to undertake DAC where the CO_2 can be sequestered geologically (i.e. DAC to CCS), leaving CCU as the primary route to synthetic fuels:

- **DAC to synthetic fuels.** Even if direct air capture of CO_2 were to turn out to be economic at scale and if routes to synthetic fuels were to be potentially viable, this does not mean it is sensible to capture atmospheric CO_2 for synthetic fuel production.

- An alternative that appears clearly preferable is to locate DAC instead in locations in which CCS is viable, directly sequestering the carbon rather than recycling it inefficiently, while continuing to use fossil fuels where hydrocarbon use is unavoidable.
- This has the same emissions outcome as the DAC-to-synthetic-fuels route, but avoids much of the costs associated with the large zero-carbon energy supply required and the production facilities to produce first hydrogen and then the synthetic fuel.

- **CCU to synthetic fuels.** CCU routes look more sensible for synthetic fuel production, given the location-specific nature of the CO_2 source and the lack of potential alternative ways of avoiding its emission to atmosphere. But given the poor fundamental characteristics of going from CO_2 to hydrocarbon fuels, the economics are likely to be highly challenging. Furthermore, the alternative of shipping the captured CO_2 to a site where it can be permanently sequestered (as for DAC above) is likely to be preferable where this is viable.

Therefore although there is a large technical potential for synthetic fuels from stranded CO_2, the challenges of finding sites that have the necessary characteristics, and of overcoming the very difficult economics relative to alternatives, make synthetic fuels a speculative option at this point.

Inclusion of synthetic fuels within near-term policy mechanisms is not a priority, and could potentially result in perverse outcomes (e.g. production using grid electricity, with a potentially very large carbon footprint).

Chapter 3: Hydrogen supply

Use of hydrogen in the UK depends on low-carbon hydrogen being available at acceptable cost. This chapter sets out the evidence on the costs and emissions implications of producing hydrogen at scale in the UK, the infrastructure requirements associated with its supply. It also considers the potential for the UK to meet some its hydrogen demand via a global low-carbon hydrogen market.

The chapter's key messages are:

- **Fossil fuels with CCS.** Production of hydrogen from fossil fuels with CCS (e.g. via reformation of natural gas) is not resource-limited in the same way. Fossil hydrogen production with CCS can be low-carbon, but cannot get to zero carbon due to residual emissions both from the production of the fossil fuel and incomplete capture of CO_2 in the process of producing hydrogen.
- **Electrolysis.** Use of electrolysers to soak up excess low-carbon power generation can provide a useful form of flexibility to the electricity system, and provide low-cost electricity for hydrogen production. However, the size of this opportunity is small in the context of the overall energy system (e.g. up to 44 TWh a year in 2050, less than 10% of buildings gas consumption). Beyond this niche in helping to manage the electricity system, the low overall efficiency of electrolysis and the relatively high value of using electricity as an input mean that the costs of producing bulk electrolytic hydrogen within the UK are likely to be high. Large-scale hydrogen production from electrolysis in the UK would also imply extremely challenging build-rates for low-carbon electricity capacity between now and 2050.
- **Bioenergy with CCS (BECCS).** Our parallel report on *Biomass in a low-carbon economy* reaffirms that within the energy system, the best use of finite sustainable biomass resource in contributing to meeting long-term emissions targets is to use it in conjunction with CCS, in order to maximise the overall emissions savings. Although BECCS can be done in several ways, our analysis indicates that production of hydrogen with CCS, sequestering almost all of the bio-carbon, could be a favoured route if there is demand for this hydrogen. However, given finite supplies of sustainable biomass globally and potentially strong competing demands for it, this limits the potentiall role of BECCS in hydrogen production.
- **Hydrogen infrastructure.** The current programme that is replacing existing iron gas distribution pipes with plastic ones will make the networks 'hydrogen ready'. This presents an opportunity for hydrogen to be widely used in the UK, but significant new infrastructure - in the forms of new hydrogen and CO_2 networks, and hydrogen storage - may be required for hydrogen production and consumption at scale in the UK.
- **Hydrogen imports.** The availability of low-cost energy resources in some parts of the world - both natural gas and renewable electricity - could mean that international trade in hydrogen develops. This hydrogen could potentially be imported to the UK at similar cost to producing hydrogen directly in the UK, even when including the costs of conversion and transportation. However uncertainty around the costs and availability of these imports implies a minimum role for domestic hydrogen production across all future scenarios. Strategic decisions should not be made in the near term that rely on high levels of future hydrogen imports.

The rest of this chapter is set out in three sections:

1. Technologies for producing low-carbon hydrogen
2. Hydrogen storage, transportation and infrastructure costs
3. Importing hydrogen to the UK

1. Technologies for producing low-carbon hydrogen

Table 3.1. Key characteristics of hydrogen production technologies

	Current global supply (TWh)	Key inputs	Efficiency estimates (%)		Cost estimates (£/MWh H_2)		CO_2 intensity (gCO_2/kWh)	CCS required	Other considerations
			Current	Future	2025	2040			
Gas reforming									
Steam methane reforming+CCS	965	Natural gas	65%	74%	£44/MWh (£32-50/MWh)	£45/MWh (£34-57/MWh)	45-120	Yes	Exposure to natural gas price.
Advanced gas reforming +CCS	N/A	Natural gas, oxygen	N/A	81%	£39/MWh (£28-45/MWh)	£44/MWh *(£27-46/MWh)*	29-99	Yes	Exposure to natural gas price.
Electrolysis									
Proton exchange membrane electrolysers	< 1	Low-carbon electricity , water	67%	74-81%	£89/MWh	£73/MWh *(£48-80/MWh)*	0-325	No	Water use / desalination.
Alkaline electrolysers	79	Low-carbon electricity , water	67%	74-81%	£92/MWh	£77/MWh *(£52-84/MWh)*	0-325	No	Water use / desalination.
Solid oxide electrolyser	N/A	Low-carbon electricity , water, low-carbon heat	N/A	92%	£90/MWh	£72/MWh *(£54-79/MWh)*	0-288	No	Water use and availability of low-carbon waste heat.
Gasification									
Coal gasification +CCS	355	Coal	54%	54%	£68/MWh	£61/MWh *(£53-72/MWh)*	112-186	Yes	Land footprint.
Biomass gasification + CCS	N/A	Sustain-able biomass	N/A	46-60%	£106/MWh	£93/MWh *(£64-127/MWh)*	Potential to achieve negative emissions	Yes	Sustainable supply of biomass feedstock.

Source: CCC analysis based on draft outputs in Element Energy (2018) *Hydrogen for heat technical evidence project*, and SGI (2017) *A Greener Gas Grid*.
Notes: All conversion efficiencies are on a HHV basis.

a. Gas-reforming (with CCS)

Gas reforming involves taking a stream of natural gas (CH_4) and reacting this with steam (H_2O) at high temperature to create hydrogen (H_2). During this process the carbon in the natural gas is separated as carbon dioxide (CO_2), allowing it to be captured for storage or use. This is necessary for gas reforming to be low-carbon:

- Steam Methane Reforming (SMR) is currently the most widely used gas reforming technology and has been used commercially for many decades. Steam methane reforming is currently deployed in the UK, with the largest plant at run by BOC Linde in Teesside.[50] SMR units that capture around 60% of their CO_2 emissions are in operation in Texas, Canada and Japan.[51]
- Alternative gas reforming processes take place within chemical production processes around the world (e.g. methanol production). Proposals to focus these technologies on hydrogen production, alongside gas-heated reformers could achieve higher hydrogen production efficiencies than SMRs by reusing heat produced during the process and introducing a stream of oxygen into the reforming process. They could also achieve higher CO_2 capture rates than SMRs. However, advanced reformers are not currently deployed at commercial scale and so their potential real-world performance is more uncertain.
  - CO_2 at process pressure is easier to capture than CO_2 at ambient air pressure, as it has a higher concentration of CO_2 and so requires less energy to capture.
  - The SMR process produces two streams of CO_2: one at process pressure (about 60% of the CO_2) and one at ambient air temperature, when CO_2 is sent through the flue. In contrast, advanced gas reforming technologies produce higher volumes of CO_2 at process pressure. Advanced gas reformers are therefore likely to achieve higher CO_2 capture rates than SMR technologies.
- The gas reforming process produces a stream of relatively pure hydrogen, but some impurities will remain in the hydrogen.[52] These contaminants could limit its use in some applications, such as fuel cells, but it would likely be suitable for many end-uses, such as burning for domestic or industrial heat. End-uses that require higher purity hydrogen could use purification technology, at additional cost.

Efficiencies and carbon intensity

Gas reforming technologies currently achieve around 65% conversion efficiency.[53,54] However, conversion efficiencies have the potential to increase significantly through future technological development to up to 85%. Those technological developments, and the addition of CCS technology, could reduce carbon intensities from the CO_2 emitted during the production process from today's levels of around 285 gCO_2/kWh to between 11-25 gCO_2/kWh:

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[50] E4tech and Element Energy (2014) *Tees Valley and North East Hydrogen Economic Study.*

[51] The plants capture 90% of the emissions from the process, but vent the flue gas, meaning overall carbon captured is around 60%. Capture rates in some ammonia production facilities may be higher than this.

[52] Gas reforming can produce hydrogen with around 99.8% purity. However, fuel cells for transport may require 99.999% hydrogen purity.

[53] All conversion efficiencies in this report are on a Higher Heating Value (HHV)/Gross Calorific Value (GCV) basis.

[54] Sustainable Gas Institute (2016) *A greener gas grid.*

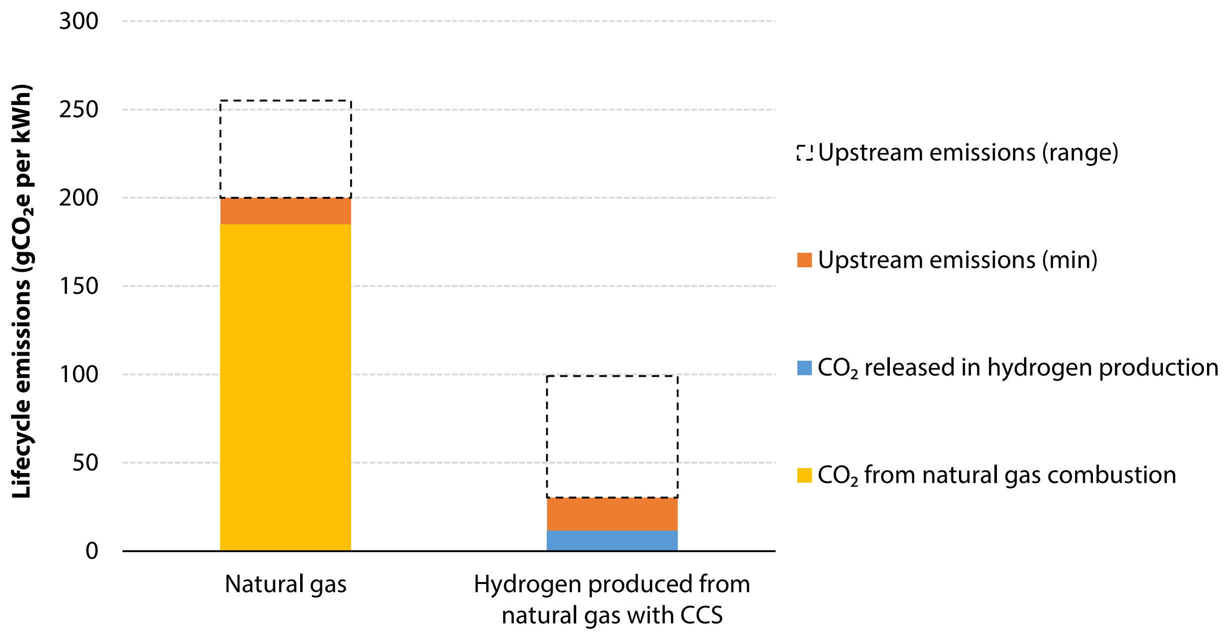
- SMRs currently achieve around 65% conversion efficiency. Evidence suggests that future technological developments and learning could increase this to around 74%.[55]
- Successful deployment of advanced gas reforming technologies could increase efficiencies to between 75-85%.
- CO_2 capture rates of at least 90%, and potentially close to 100%, could be achieved, with the upper end of this range more likely to be achieved by advanced reforming technologies. This would lower the emissions intensity of hydrogen produced from SMRs to around 25 gCO_2/kWh, and hydrogen produced from more advanced methods to around 11-15 gCO_2/kWh.

Extraction and delivery of natural gas also leads to greenhouse gas emissions. When factoring in these 'upstream' emissions, hydrogen production from gas reforming with CCS can reduce emissions relative to unabated natural gas use by 60-85% on a lifecycle basis. The remaining emissions are split between uncaptured CO_2 from the hydrogen production process and 'upstream' emissions from gas supply (Figure 3.1):

- **Uncaptured CO_2 from hydrogen production.** Depending on assumptions around the efficiency of natural gas reforming and the proportion of the CO_2 that would be captured and stored, these residual emissions could be 6-14% of the combustion emissions from natural gas.
- **Upstream emissions from natural gas supply.** As hydrogen production from gas reforming loses energy in the conversion process, a switch from natural gas to gas-based hydrogen supply would actually increase natural gas consumption and therefore 'upstream' emissions from natural gas production. We use a range for upstream emissions from natural gas production of 15-70 gCO_2e/kWh:
  - There is a wide range of estimated emissions relating to natural gas supply, reflecting uncertainty both in the sources of natural gas available in the long term and a current lack of knowledge over the upstream emissions from natural gas supplies, particular relating to imported liquefied natural gas (LNG). In our 2016 report on *Onshore Petroleum*, we presented a range of upstream emissions for LNG of 15-70 gCO_2e/kWh.
  - The range of 15-70 gCO_2e/kWh is similar for UK shale gas production across the full range of potential regulatory regimes, although if shale gas production is to be compatible with UK carbon budgets the regulatory regime will need to ensure that the emissions are towards the lower end of this range.

[55] Based on draft outputs in Element Energy (2018) *Hydrogen for heat technical evidence project*.

Figure 3.1. Lifecycle emissions of natural gas compared to hydrogen from natural gas reforming



Source: CCC analysis based on Element Energy (2018) *Hydrogen for heat technical evidence project*, CCC (2016) *Onshore Petroleum*.
Notes: Assuming 80% HHV efficiency for hydrogen production and a 95% CO_2 capture rate, with upstream emissions from natural gas production ranging from 15-70 gCO_2e/kWh.

Costs

Building a new steam methane reformer in the UK today could cost around £32-50/MWh, with the majority of costs coming from fuel costs (£16-34/MWh) and carbon costs (£9/MWh).[56] Advanced gas-reforming facilities could improve the efficiency of the hydrogen production process, reducing costs, although some of these cost reductions would be offset by paying for CCS. This could produce hydrogen at a cost of around £38/MWh by 2050, based on a gas price of 67 p/therm[57] (Figure 3.2):

- The majority of costs for a gas-reforming plant are fuel and carbon costs, which comprise around 80% of overall costs; capital costs are low, at around 12% of overall costs.
- Future efficiency gains, deployment of advanced reformers, and capital cost reductions could decrease costs to around £38/MWh (Figure 3.3).
  - Estimates suggest that overall process efficiency could reduce by around five percentage points with the addition of CCS, increasing costs by £2-5/MWh. Additionally, the capital costs of CO_2 capture could increase costs by around £3/MWh,[58] with payments for CO_2

[56] Assuming gas-reforming facilities receive a 70% allocation of free allowances under the EU Emissions Trading Scheme, so only pay 30% of their carbon costs. Future gas-reformers that produce hydrogen for non-industrial uses may not receive this free allocation.
[57] BEIS (2018) *Energy and Emissions Projections*.
[58] CCC calculations based on IEAGHG (2017) *Techno-Economic Evaluation of SMR Based Standalone Hydrogen Plant with CCS*.

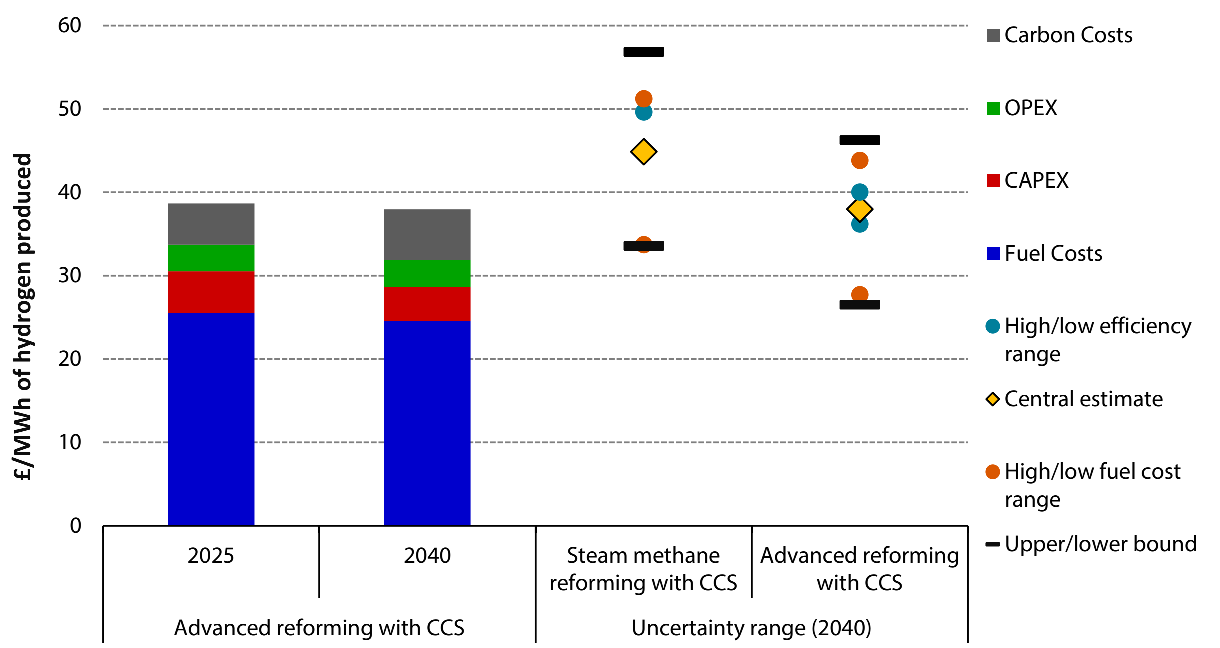
transport and storage infrastructure another £3/MWh (at £15/tCO_2). However, savings from avoided emissions due to application of CCS could be valued at around £50/MWh at government carbon values.

– Future efficiency gains from more advanced reformers could reduce costs by around £7/MWh. Reductions in the capital costs of building gas reformers, both from deployment at scale and from future innovations, could further reduce costs.

– Costs of gas reforming in 2040 could vary by around £17/MWh, depending on where gas prices turn out within the full range of current forecasts.

- Some countries have access to significantly cheaper natural gas than the UK.[59] There is therefore potential for them to produce hydrogen from gas reforming at lower costs. However, this hydrogen would then need to be shipped, or piped, to the UK, which would come at additional cost (see section 3). It may also be difficult to validate that the hydrogen was produced using low-carbon technologies.

Figure 3.2. Levelised costs of gas reforming with CCS (2025 and 2040)



Source: CCC analysis based on draft outputs in Element Energy (2018) *Hydrogen for heat technical evidence project*, SGI (2017) *A greener gas grid: what are the options?*, Ecofys and E4Tech (2018) *Bioenergy Heat Pathways to 2050 Rapid Evidence Assessment*, pending publication, BEIS (2018) *Energy and Emissions Projections*, Imperial (2018) *Analysis of alternative UK heat decarbonisation pathways*.
Notes: The upper/lower bound data points represent the compound uncertainty of both high efficiency and low fuel prices, or low efficiency and high fuel prices. Costs of capital is assumed to be 10%, and a 3.5% discount rate is applied to future costs. Load factors are assumed to be 90%, and a 95% CO_2 capture rate is assumed. Carbon prices rise to £227/tCO_2 by 2050. Gas prices: 39p/th, 67p/th, 83p/th.

[59] Aurora (2018) *Aurora's Long-term Outlook*, references Qatar and Russia as two low-cost natural gas producers.

b. Electrolysis

Electrolysis is the process of using electricity to split water (H_2O) into hydrogen (H_2) and oxygen (O_2). Electrolysers are modular technologies, with unit sizes up to 10 MW, and are therefore well suited to small-scale on-site hydrogen production. Larger plants could be built by "stacking" many smaller electrolysers together. Some types of electrolyser are technologically mature, but emerging variants could lead to significant performance improvements relative to current technologies:

- Alkaline electrolysers are a mature technology and produce the vast majority of global electrolytic hydrogen. Proton Exchange Membrane (PEM) electrolysers are currently at the demonstration stage of technological deployment, with around 50 MW of capacity currently deployed around the world.[60]
- Solid-oxide electrolysers (SOE) are an emerging technology which utilise heat from other sources to increase the efficiency of production significantly. However, in order for these efficiency gains to be realised in a low-carbon way the heat sources would also have to be low-carbon (e.g. heat that would otherwise be wasted). Moreover, if this low-carbon heat was not waste heat but had to be generated for the electrolyser, this would significantly reduce the overall efficiency of the process. These factors may limit the role that SOE electrolysers could play in producing significant quantities of hydrogen in the UK.
- Electrolysis produces pure hydrogen with very low levels of contaminants (99.999% hydrogen purity).[61] This makes it more suitable for end uses such as fuel cells in vehicles (see Chapter 2).

Efficiencies and carbon intensity

Current efficiencies for hydrogen production from electrolysis, using PEM and Alkaline electrolysers, are around 67%.[62] Depending on future technological developments electrolyser efficiencies could increase to 74-82%.

The load factor[63] that an electrolyser is run at has a significant effect on its efficiency, as do rapid changes in output. Therefore, efficiencies could be significantly lower if the electrolyser is run at low load factors or required to increase or decrease production regularly.

- For example, if an electrolyser is used in combination with intermittent generation, such as a wind turbine, efficiencies could be lower.
- Current evidence suggests that PEM electrolysers are best able to handle an intermittent supply of electricity, and may be best suited to changing load factors (Box 3.1).

The commercial deployment of solid-oxide electrolysers could lead to them having a higher efficiency (e.g. up to 92%) in converting electricity to hydrogen, if there is sufficient input of low-carbon waste heat.

Whilst no CO_2 emissions are produced directly from electrolysis, there are indirect emissions from the input electricity. At current UK electricity grid intensities, a future electrolyser could see

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[60] Element Energy (2018) *Hydrogen for heat technical evidence project (draft outputs).*

[61] Element Energy (2018) *Hydrogen for heat technical evidence project (draft outputs).*

[62] Sustainable Gas Institute (2017) *A greener gas grid: what are the options?*

[63] The load factor of a generation technology is given by actual generation divided by potential generation over a given period of time.

emissions of around 288-358 gCO_2/kWh, however in a largely decarbonised electricity grid in 2050 these are likely to be very low around at around 11-14 gCO_2/kWh.

- Alongside hydrogen, electrolysis also produces a stream of oxygen. There are potential synergies and savings available from using this oxygen with other low-carbon technologies (oxygen can cost around £15-30/tonne to produce).[64] For example, advanced gas reforming technologies require an oxygen input and so could be run in combination with electrolysis.

Costs

Current estimates of levelised costs for hydrogen production from electrolysis are around £89-92/MWh, but could fall to around £75-78/MWh due to efficiency improvements.[65] Further reductions in costs could come from capital costs, but electricity prices are likely to remain the largest input cost (Figure 3.3). The cost of producing hydrogen from electrolysis could be even lower in countries where solar electricity can be produced at very low cost. However, this hydrogen would still need to be transported to the UK at additional cost (see section 3):

- The majority of the cost of producing hydrogen via electrolysis is the cost of the input electricity (80-86%), rather than capital or operating costs. Capital costs are a small proportion of an electrolyser's costs, limiting the impact of further capital cost reductions.
  - Electrolysers are a modular technology, so could benefit from cost reductions through repeated deployment, in a similar way to that seen to date with solar PV, where costs have fallen 12% per doubling of capacity.[66] For electrolysis, this 'learning rate' has been estimated at around 7%[67] per doubling of globally installed capacity.
  - However as capital costs are expected to remain a small overall proportion of an electrolysers cost, the impact of further cost reductions in this area is likely to be limited.
- With future efficiency gains, and capital cost reductions the costs of production could decrease to between £72-77/MWh in the UK. The lower part of the range would only be achieved with the deployment of SOE electrolysers.
  - Cost of production from PEM and Alkaline electrolysers are likely to fall by around £8-13/MWh through efficiency gains.
  - Future efficiency gains from deployment of SOE electrolysers could reduce costs by an additional £3-5/MWh, provided that adequate low-carbon waste heat is available.
- Combining an electrolyser directly with low-cost renewable generation (at £30/MWh) could see costs of electrolysis in the UK reduce further to £48-60/MWh, although this may affect its load factor, increasing capital cost requirements (Box 3.1).
- Countries with more sun and accessible wind resource can produce electricity at lower cost and higher load factors than in the UK. This could lower the cost of hydrogen production from electrolysis. For example, solar PV can be produced in the Middle East, Mexico and Chile

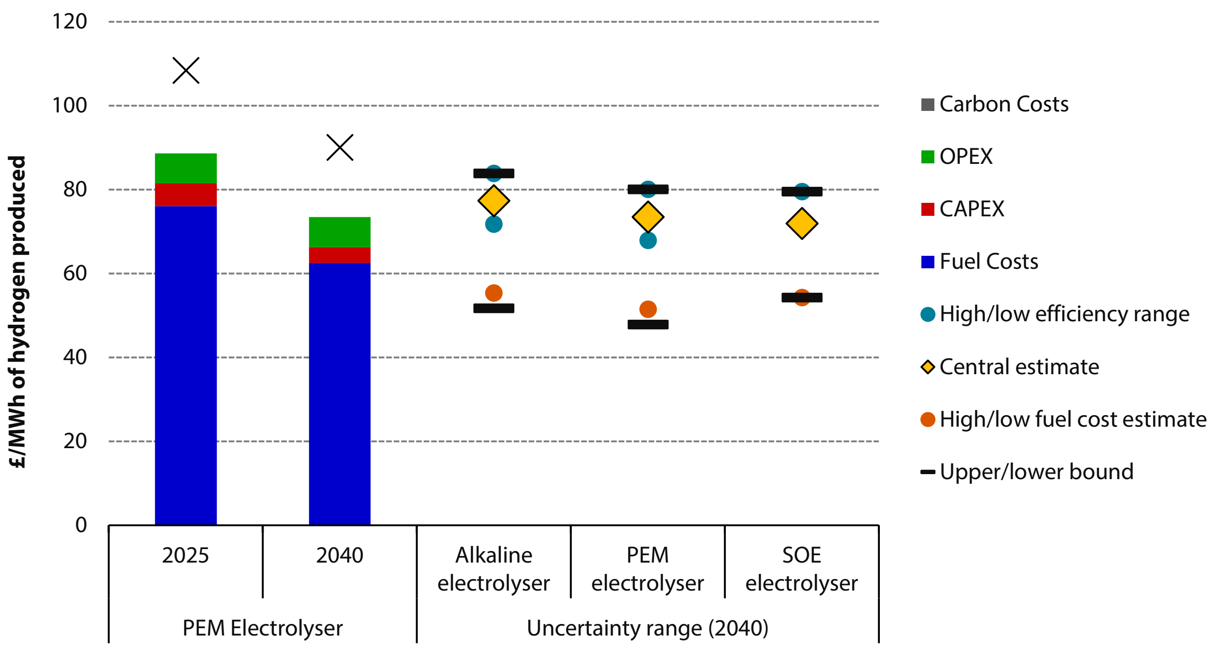
[64] U.S. Department of Energy (2016) *Oxygen Production.*
[65] Assuming an electricity price of £51/MWh. Higher electricity prices would significantly increase the costs of electrolysis. For example, an electrolyser consuming electricity at a retail electricity price of £150/MWh would produce hydrogen at a cost of £195-214/MWh. We have not considered this further in this analysis, due to the high cost.
[66] Newbery (2017) *How to judge whether supporting solar PV is justified.*
[67] Element Energy (2018) *Hydrogen for heat technical evidence project.*

at around £10-15/MWh,[68] electrolytic hydrogen could then be produced from this at around £26-32/MWh. This would still need to be shipped to the UK at additional cost (see section 3).

- The high costs of electrolysis in the UK, compared to alternative hydrogen production options, may limit the technology to specific applications or situations, particularly where the gas grid isn't converted to hydrogen:
  - The use of hydrogen in HGVs could require up to 400 hydrogen refuelling stations in the UK. As these are likely to be spread around the country it could make sense for hydrogen to be produced directly onsite, rather than transported to the station. However, given the cost difference between gas-reforming and electrolysis, the cost of the transportation of hydrogen from a gas-reforming facility, as well as any additional purification requirements, would have to be above around £15/MWh to make onsite electrolysis a cheaper option (assuming electrolysis can produce hydrogen onsite at £48/MWh).
  - In areas where electricity output from renewables is curtailed due to electricity network constraints, electrolysis could be used to convert electricity to hydrogen for other uses. This could be particularly useful where there is both network constraints and local demand for hydrogen (e.g. in Scotland, particularly for islands). However wind curtailment due to transmission constraints was just 1.5 TWh (3% of total wind production in 2017.[69]
  - Analysis presented in Chapter 2 (Box 2.1) suggested that the role for electrolysers in providing electricity system services is likely to be limited.

[68] See, for example: Bloomberg (2017) *Saudi Arabia Gets Cheapest Bids for Solar in Auction*.
[69] Policy Exchange (2018) *Fuelling the Future*.

Figure 3.3. Electrolyser cost projections for 2025 and 2040



Source: CCC analysis based on draft outputs in Element Energy (2018) *Hydrogen for heat technical evidence project*, SGI (2017) *A greener gas grid: what are the options?* Ecofys and E4Tech (2018) *Bioenergy Heat Pathways to 2050 Rapid Evidence Assessment* – pending publication, BEIS (2018) *Energy and Emissions Projections*, Imperial (2018) *Analysis of alternative UK heat decarbonisation pathways*.

Notes: The upper/lower bound data points represent the compound uncertainty of both high efficiency and low fuel prices, or low efficiency and high fuel prices. Costs of capital is assumed to be 10%, and a 3.5% discount rate is applied to future costs. Load factors are assumed to be 90%. X on the chart shows the effect of reducing load factors to 30%, which adds £17-20/MWh. Electricity prices: £30/MWh, £46/MWh, £53/MWh.

Box 3.1. Pairing electrolysis with renewables

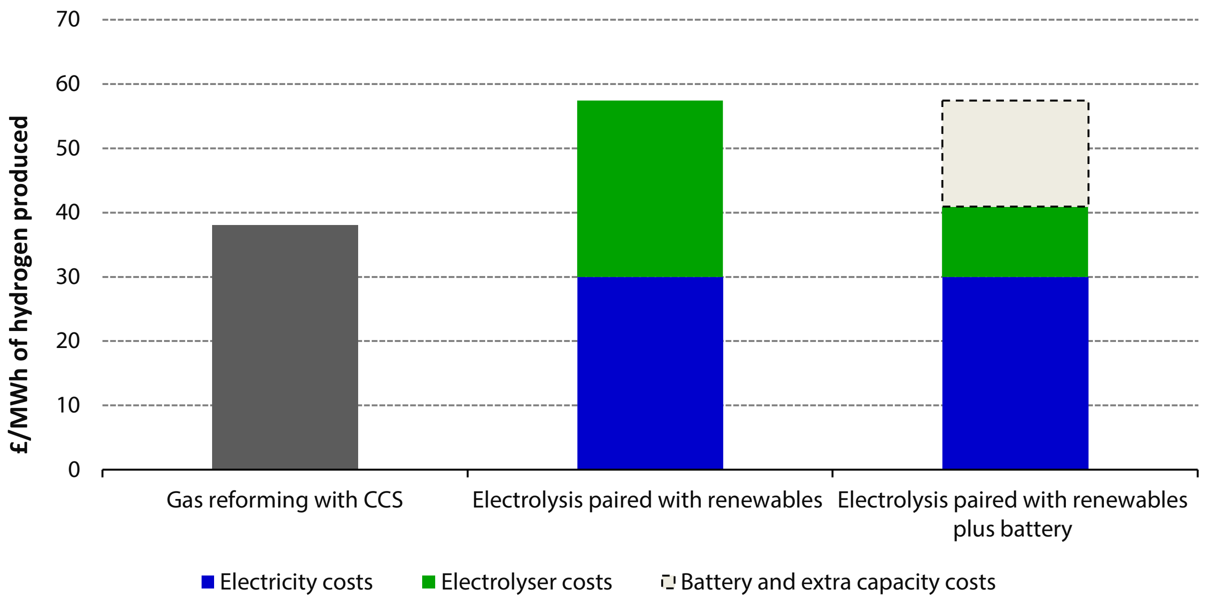
It is possible to build dedicated renewables for the sole purpose of supplying low-carbon electricity for an electrolyser to produce low-carbon hydrogen, or 'pairing' renewables with an electrolyser. In the UK this would likely involve building a wind turbine to pair with an electrolyser due to the less favourable profile of UK solar generation over the year. Whilst this would ensure that the hydrogen produced was low-carbon and may have a role in small-scale distributed production, it is likely to be prohibitively expensive for bulk hydrogen production:

- Projected costs of electricity from onshore and offshore wind turbines for the 2020s are around £40-60/MWh. If the costs of electricity from wind could fall to around £30/MWh by 2050, the costs of the input electricity alone for an electrolyser is likely to be around the costs of the hydrogen produced from gas reforming in 2050 (our central estimate is £38/MWh).
- If an electrolyser was paired directly with a wind turbine, it could only generate hydrogen when the wind turbine was generating. Estimates for annual load factors of wind turbines range from 32% to up to 55%, implying the electrolyser would only generate for this portion of the year. It would be possible to combine a wind turbine with a battery, in order to suppling the electrolyser with a more constant stream of electricity, however a battery would have to cost less than £15/MWh over its lifetime to make this a viable proposition. Current battery cost estimates for similar applications are significantly higher than this.[1]

Box 3.1. Pairing electrolysis with renewables

- Rapid and regular changes in wind output may also reduce the efficiency of the electrolyser, increasing the overall costs of production.
- Therefore, hydrogen produced from electrolysis paired with renewables in the UK would cost around £53-64/MWh (Figure B3.1), significantly higher than our central estimate for gas reforming.
  - For hydrogen produced from this method to be cheaper than our central estimate for gas reforming the costs of wind generation would need to fall to less than £10/MWh.
  - To the extent that other revenue streams are available, such as payments for flexibility services (Box 2.1), or transportation costs were saved (see section 2), this could improve the economics of production.

Figure B.3.1 Cost of producing hydrogen from renewable electricity, compared to gas-reforming



Source: CCC analysis based on draft outputs in Element Energy (2018) *Hydrogen for heat technical evidence project*, BEIS (2018) *Energy and Emissions Projections*.
Notes: Costs of capital is assumed to be 10%, and a 3.5% discount rate is applied to future costs. Load factors are assumed to be 90% for gas reforming, and 55% for electrolysis. A 95% capture rate is assumed for gas reforming.

Notes: 1. See, for example, Lazard (2017) Lazard's *Levelized cost of storage analysis - Version 3.0*.

c. Gasification of coal, biomass, waste

Gasification heats a hydrocarbon-rich feedstock,[70] such as coal or biomass, at high temperatures to produce a syngas rich in hydrogen (H_2), which also contains carbon monoxide (CO) and carbon dioxide (CO_2). The syngas can then be upgraded, separating out the hydrogen from other molecules and converting the carbon monoxide to CO_2 and more hydrogen (via the water-gas shift reaction[71]). This allows the carbon to be separated and sequestered, which is essential for gasification to be a low-carbon hydrogen production technology.

- Gasification of coal is a mature technology that has been used for many decades. For example, coal gasification was used to produce 'town gas' in the UK until the 1960s - however this was a carbon intensive and highly polluting process (Box 1.3).
- Gasification of biomass, including waste, to produce hydrogen is a more novel emerging technology which is currently at the research and demonstration phase of technological development. The process functions in a similar way to coal gasification, but there are additional requirements for pre-processing the feedstock (e.g. drying), and more effort is required to clean the syngas to remove contaminants before upgrading it to hydrogen. Therefore, there remains some uncertainty around whether biomass gasification can be deployed at scale in a commercially viable way.
- Gasification can produce a stream of hydrogen of similar purity to that produced from gas reforming (i.e. 99.8 % purity).[72] However, if a diverse range of feedstocks (e.g. wastes) is used there is a higher risk of contaminants entering the gas.

Efficiencies and carbon intensity

Current efficiencies for hydrogen production from coal gasification are over 60%, but are estimated to reduce to around 52% with the inclusion of CO_2 capture technologies.[73] As coal gasification is a mature technology, it is unlikely that there would be significant future increases in efficiency. Hydrogen production from coal gasification has a carbon intensity of around 675 gCO_2/kWh, the addition of CCS would likely lower this to around 27-34 gCO_2/kWh if a 95% CO_2 capture rate can be achieved.

Biomass gasification with CCS is not currently commercially deployed, so efficiencies are less clear although evidence suggests they could be between 46-60%. Bioenergy used with CCS to produce energy and sequester CO_2 has been identified as a key technology, as it maximises the emissions reductions from finite sustainable bio-resources. The Committee's parallel report on *Biomass in a low-carbon economy* identifies bio-gasification to produce hydrogen as a high value use of sustainable bioenergy, and given uncertainty around current costs and efficiencies, recommended demonstration of the technology.

Extracting/harvesting and transportation of coal/biomass also leads to greenhouse gas emissions. When factoring in these 'upstream' emissions, hydrogen production from coal gasification with CCS can reduce emissions relative to unabated natural gas use by 7-56% on a lifecycle basis. Sustainably sourced biomass can reduce emissions by more than 100% compared to unabated natural gas:

[70] Containing mostly hydrogen and carbon, as well as some oxygen and potentially some sulphur.
[71] The water-gas-shift converts carbon monoxide (CO) and water (H_2O) to hydrogen (H_2) and carbon dioxide (CO_2).
[72] Element Energy (2018) *Hydrogen for heat technical evidence project (draft outputs)*.
[73] E4Tech (2015) *Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target*.

- Lifecycle emissions from coal are in the range of 86-153 gCO_2/kWh[74], in addition to emissions of 27-30 gCO_2/kWh from the gasification process (if 95% of the CO_2 can be captured and sequestered).
- Lifecycle emissions from biomass can vary substantially depending on supply chain practices, and any changes in land-carbon stocks attributable to the harvested biomass (see the *Biomass in a low-carbon economy* report). Sustainable and low-carbon harvested biomass has the potential for overall 'negative emissions' to offset residual emissions in hard-to-decarbonise sectors, when used with CCS.

Costs

Building a new coal gasification plant in the UK today would cost around £68/MWh, including the costs of CCS. Future savings from economies of scale could reduce this, putting our central estimate of future coal gasification costs with CCS at around £61/MWh (Figure 3.4).

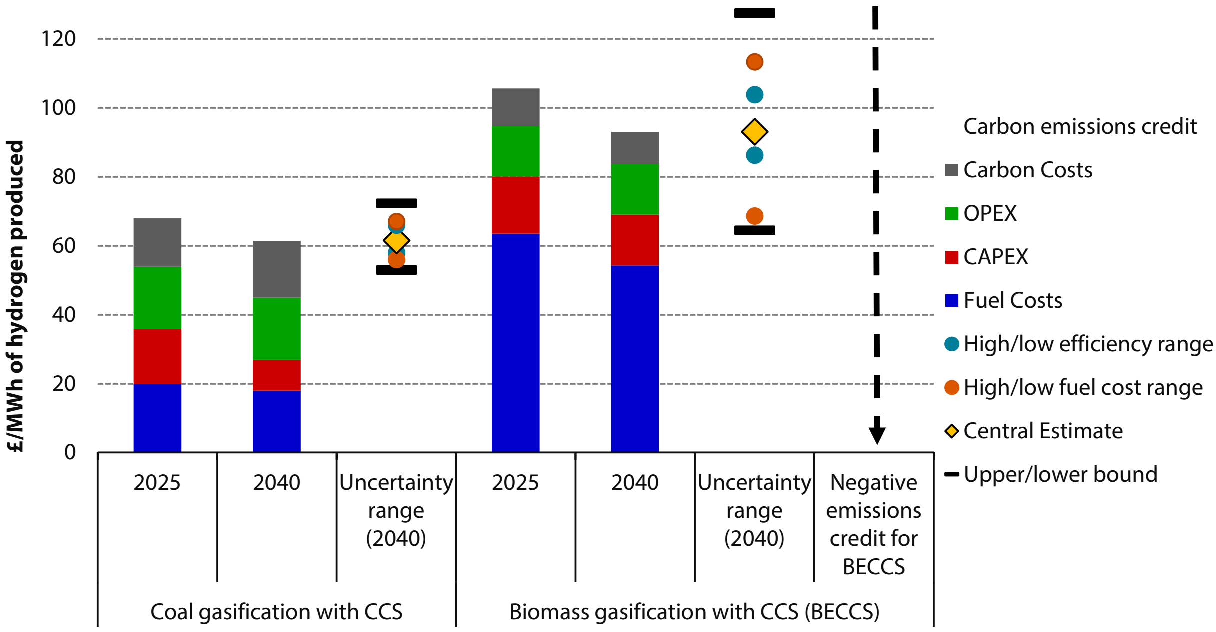
- Capital and running costs are a significant part of overall costs (53-59%). As this is a mature technology there is limited room for further technical improvements to reduce costs.
- Savings from building larger-scale coal gasification plants are significant, with estimates suggesting that capital costs roughly half for every doubling of plant size.[75] This contrasts with other hydrogen production technologies which can be deployed effectively at much smaller plant sizes.
- Costs of coal gasification in 2050 could vary by £12/MWh depending on coal price forecasts.

Hydrogen from biomass gasification with CCS could cost between £64-127/MWh in 2040. This depends on successful commercialisation and deployment, future capital and operating costs reductions being realised, and the costs of the biomass resource.

- Capital costs make up around 12-23% of overall costs, with fuel and operating costs making up the rest.
- Against the full range of forecast biomass prices costs of biomass gasification in 2050 could vary by £44/MWh.

[74] Based on a report for the CCC by Ricardo AEA (2013) Current and future lifecycle emissions of key low-carbon technologies and alternatives.
[75] Element Energy (2018) *Hydrogen for heat technical evidence project (draft outputs).*

Figure 3.4 Coal and biomass gasification cost projections for 2025 and 2040



Source: CCC analysis based on Element Energy (2018) *Hydrogen for heat technical evidence project*, SGI (2017), *A greener gas grid: what are the options?* Ecofys and E4Tech (2018) *Bioenergy Heat Pathways to 2050 Rapid Evidence Assessment* – pending publication, BEIS (2018) *Energy and Emissions Projections*, Imperial (2018) *Analysis of alternative UK heat decarbonisation pathways*.
Notes: The upper/lower bound data points represent the compound uncertainty of both high efficiency and low fuel prices, or low efficiency and high fuel prices. Costs of capital is assumed to be 10%, and a 3.5% discount rate is applied to future costs. Load factors are assumed to be 90%, and a 95% capture rate is assumed across both technologies. Carbon prices rise to £227/tCO_2 by 2050. Carbon costs for biomass are just CCS infrastructure costs. Gas prices: 39p/th, 67p/th, 83p/th. Coal prices: £48/t, £67/t, £90/t.

d. Other considerations

Our technology assessments also consider land and water footprints of the technologies, emissions of pollutants other than CO_2:

- **Land footprint**. Deployment of a large-fleet of hydrogen production technologies is likely to have a similar land footprint to the UK's thermal power generation fleet, or the UK's current petrochemical processing sites.
  - Gasification technologies require more land than gas-reforming technologies due to the need for onsite fuel storage of coal or biomass.[76]
  - Electrolysers would require additional low-carbon generation capacity to be installed in the UK. If this was from renewable sources this would significantly increase their overall land footprint.
- **Water footprint**. Electrolysers would require potable water to produce hydrogen, gas-reforming technologies require water as part of the chemical process, and for cooling.

[76] 0.8-2.5 m^2 kW H_2, compared to 0.05-0.16 m^2 kW H_2 for gas-reformers and 0.07-0.14 m^2 kW H_2, compared for electrolysers (not including electricity capacity)

Gasification technologies also require water for cooling, similar to the UK's current thermal power stations.

- Electrolysers require around 0.5 litres potable water per kWh of hydrogen.[77] For comparison, nuclear power plants consume around 1.5-2.7 litres of water for cooling purpose per kWh of electricity produced (though this water can be of lower quality).[78] This could pose some constraint on electrolysis, depending on where they are located in the UK. Sea water could be desalinated but this would incur a small additional cost.
- Gas-reforming and gasification technologies require around 0.1-0.3 litres of non-potable water per kWh H_2 as part of the reforming or gasification process. In addition, both require 0.1-30 litres of water for cooling.[79]

- **Air quality.** Gas reforming and gasification produce nitrogen oxides (NOx). Gasification can also produce particulate matter emissions. Both can pose serious health risks. These can be mitigated by fitting filter technology, such as Selective Catalytic Reduction technologies and electrostatic precipitators to the plants.

There are also implications for the potential scale of CO_2 infrastructure required and for energy imports. We consider these in Chapter 4.

e. Summary

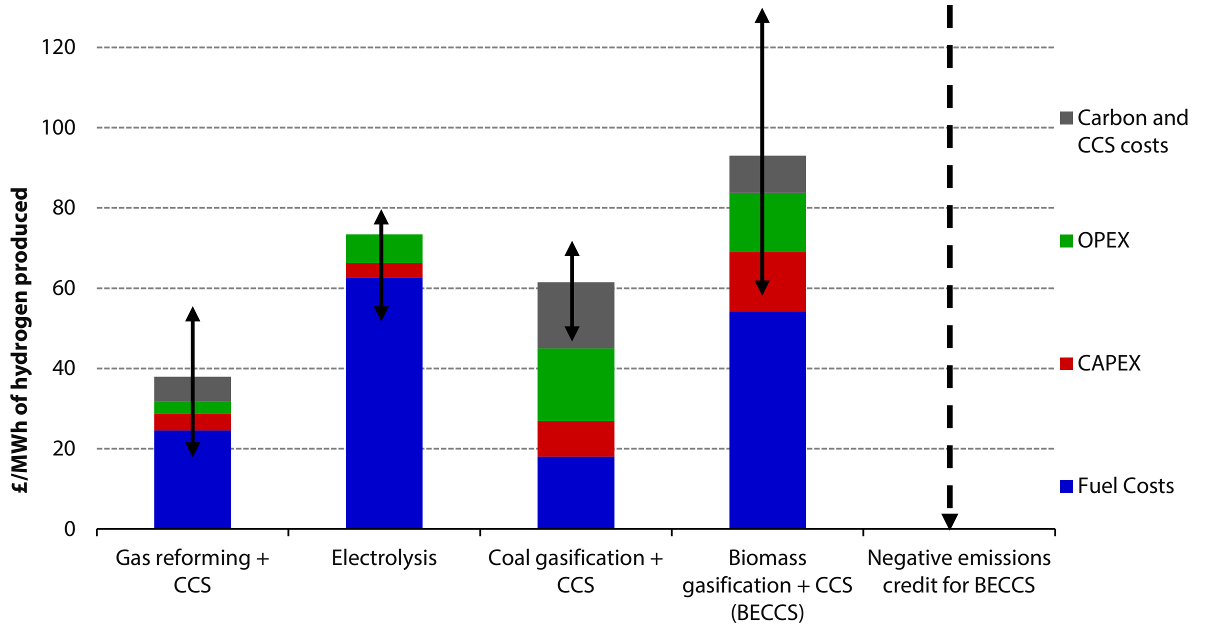
Our assessment considers the potential and costs of producing low-carbon hydrogen at scale in the UK. For scenarios with hydrogen demands in excess of 100 TWh/annum, gas-reforming with CCS is likely to be the lowest cost means of producing low-carbon hydrogen, although producing large volumes of hydrogen in this way could result in significant residual emissions (Figure 3.5, Figure 3.6). Other technologies are likely to play a more niche role, limited by amount of sustainable feedstock (BECCS), costs and the impacts of the technology on the electricity system (electrolysis), and emissions (coal gasification):

- Gas-reforming with CCS looks like the cheapest option for hydrogen production in the UK, with costs of between £27-46/MWh, reducing emissions by 60-85%, on a lifecycle basis, compared to natural gas. Although there is no real technical deployment limit to producing hydrogen via gas-reforming, in practice the deployment of this technology is likely to be limited by feasible build rates, availability of gas imports and the level of residual emissions from this technology is a decarbonised energy system.
- The potential for bio-gasification with CCS to be deployed at scale is limited by the amount of sustainable bioenergy available, but the technology offers one way of using bioenergy with carbon capture and storage (BECCS) to maximise emissions reductions from finite sustainable bio-resources. Deployment of bio-gasification will depend on the amount of sustainable bioenergy available. Scenarios in our parallel report on *Biomass in a low-carbon economy* suggest that 94-550 TWh/annum could be available, which could be used to produce 55-330 TWh of hydrogen.

[77] Element Energy (2018*) Hydrogen for heat technical evidence project (draft outputs)*.
[78] Woods (2006) *Water requirements of nuclear power stations*.
[79] Element Energy (2018*) Hydrogen for heat technical evidence project (draft outputs)*. Lower bound is using a cooling tower, upper bound is using sea water.

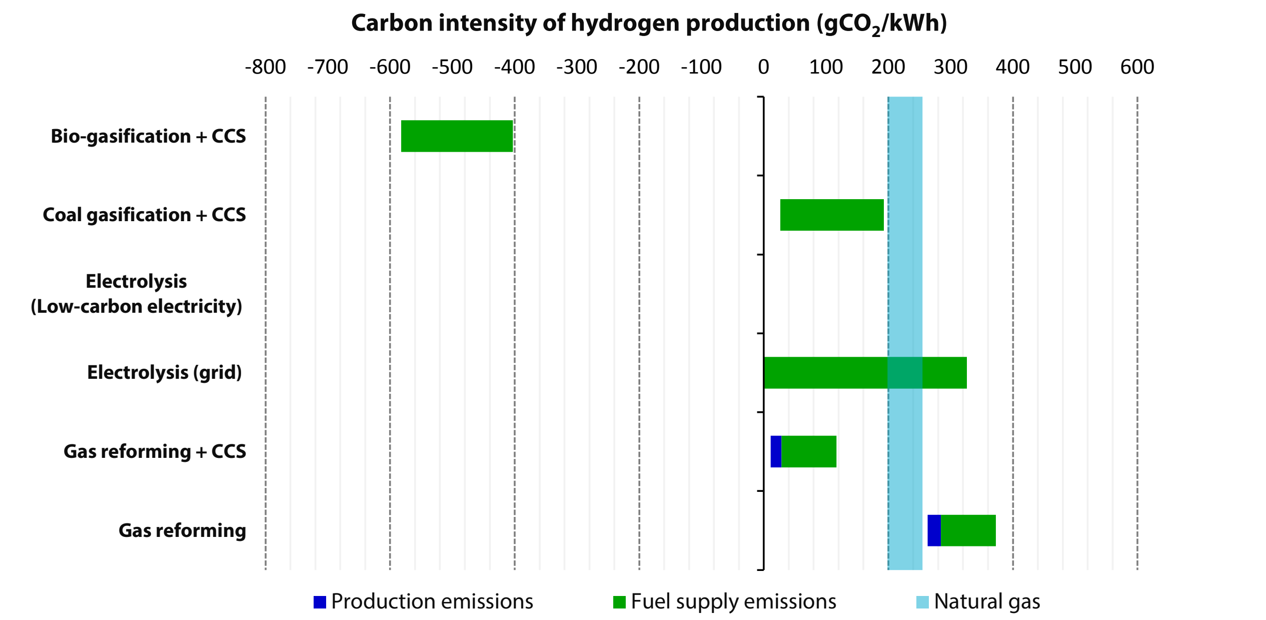
- Coal gasification is expected to be more than double the cost of gas-reforming, and only offer emissions savings of 7-56% compared to natural gas. Therefore we do not consider coal gasification to be a viable means of low-carbon hydrogen production in the UK.
- Electrolysis is expected to be higher cost than gas reforming, but could be zero-carbon. Cost reductions in electrolysers can reduce costs, but the cost of electricity will remain the most important factor. The cost of electricity would have to be less than £10/MWh for electrolysis to be the same cost as gas reforming in the UK.
- Other means of producing hydrogen may become commercialised, but given their current state of development, they are unlikely to be deployed at significant scale by 2050 (Box 3.2).

Figure 3.5. CCC central estimates for levelised costs of low-carbon hydrogen production technologies



Source: CCC analysis based on draft outputs in Element Energy (2018) *Hydrogen for heat technical evidence project*, SGI (2017), *A greener gas grid: what are the options?* Ecofys and E4Tech (2018) *Bioenergy Heat Pathways to 2050 Rapid Evidence Assessment* - pending publication, BEIS (2018) *Energy and Emissions Projections*, Imperial (2018) *Analysis of alternative UK heat decarbonisation pathways.*
Notes: The black arrow shows the uncertainty range for the overall levelised cost of hydrogen for each technology. Costs of capital is assumed to be 10% across all technologies, and a 3.5% discount rate is applied to future costs. Load factors are assumed to be 90% across all technologies. Carbon prices rise to £227/tCO_2 by 2050. Carbon costs for biomass are just CCS infrastructure costs. Gas prices: 39p/th, 67p/th, 83p/th. Coal prices: £48/t, £67/t, £90/t. Electricity prices: £30/MWh, £46/MWh, £53/MWh. Negative emissions credit: biomass gasification could provide negative CO_2 emissions, and receive payments for this reflecting the value of the carbon abated.

Figure 3.6. Lifecycle carbon intensities of hydrogen production technologies, compared to natural gas



Source: CCC analysis based on draft outputs in Element Energy (2018) *Hydrogen for heat technical evidence project*, SGI (2017), *A greener gas grid: what are the options?* Ecofys and E4Tech (2018) *Bioenergy Heat Pathways to 2050 Rapid Evidence Assessment* – pending publication, BEIS (2018*) Energy and Emissions Projections*, Imperial (2018) *Analysis of alternative UK heat decarbonisation pathways.*
Notes: We assume a supply chain emissions intensity for biomass of up to around 70 gCO_2/kWh on a primary energy basis. Biomass is assumed to not cause any change in land carbon stocks. A 95% capture rate is assumed across all technologies with CCS.

Box 3.2. Novel hydrogen production technologies

Several novel hydrogen production technologies are currently being researched and developed. Progress in these technologies could see them play a role in hydrogen production. However due to the lack of development, and robust data on costs, we do not include them in our scenarios:

- **Pyrolysis of hydrocarbons:** Hydrocarbons can be heated at high temperature in the absence of oxygen, a process known as pyrolysis, to produce a stream of hydrogen and a residual solid carbon.
- **Downhole conversion of fossil fuels with CCS:** Coal can be gasified underground, before it is mined and extracted, to produce hydrogen. If this process was fitted with carbon capture and storage technology it could produce low-carbon hydrogen. However, this is unlikely to be deployed at scale as it has a low efficiency and there are potential environmental issues.
- **Microwave technologies:** Hydrogen can be produced from novel emerging microwave techniques, which expose hydrocarbons and electricity to microwaves in the presence of catalysts to produce a high quality stream of hydrogen and residual solid by-products. A source of low-carbon electricity would be required for this hydrogen to be low-carbon.
- **Microbial conversion:** There are various emerging technologies that can produce hydrogen from a fermentation process. These tend to be part of a wider biological refining process, such as anaerobic digestion, and the hydrogen is therefore produced alongside other products. Whilst

Box 3.2. Novel hydrogen production technologies

these technologies could play some role in optimising yields from existing biological processes, it is unlikely these could be scaled-up to produce significant quantities of hydrogen.

- **Solar-to-fuel technologies:** Similarly to electrolysis, solar to fuel technologies split water into hydrogen and oxygen – but do so using solar energy directly. The main difference is that the fuel production occurs in the same device that is capturing the solar energy. Currently this had led to lower efficiencies than a combination of solar PV and electrolysis but could, in the future, be less costly and easier to build.

Source: The Royal Society (2018) *Options for producing low-carbon hydrogen at scale*.

2. Hydrogen storage, transport and infrastructure costs

a. Hydrogen infrastructure

Onshore networks

The UK has an extensive network of energy transmission and distribution infrastructure that has been built up over decades in order to transport oil, natural gas and electricity.

- The electricity and gas networks are separated into tiers, according to the flows of energy that they are able to deliver. Gas networks are split into multiple pressure levels, while electricity networks are split by voltage.
- Higher tiers are known as the transmission system, whereas lower tiers are grouped under 'distribution networks'; both are owned by separate private companies and regulated by Ofgem.

All levels of electricity networks will continue to be used – and require upgrading – far into the future. However, questions have been raised about the future of gas distribution networks given the need to decarbonise heat and alternative pathways for doing so. If heat demand can be switched to low-carbon hydrogen then gas networks will play a key role:

- The UK's existing gas distribution networks are expected to be suitable for transporting hydrogen at all lower pressure tiers.[80] However, use of hydrogen as an energy carrier at scale in the UK is likely to involve building a new transmission network, at a cost of around £0.5bn/year.[81] If hydrogen is produced inland, away from coastal CO_2 stores, some hydrogen transmission costs could be avoided, however additional onshore CO_2 networks could then be required at a cost of around £0.8 bn/year.
  - As a small molecule, hydrogen can diffuse into other compounds, causing embrittlement and fracturing. This is unlikely to be a problem in the gas distribution system - once

[80] The UK's Iron Mains Replacement Programme, currently being undertaken by the UK's gas network companies and due to be completed in the early 2030s, is replacing old iron pipes with plastic ones that are suitable for carrying hydrogen.
[81] Total network length could be less than the natural gas transmission network, which was developed to link gas fields and imported gas to centres of gas demand. See Imperial College (2018) *Alternative UK heat decarbonisation pathways*.

converted to polyethylene - but could be an issue if hydrogen were to be transported through the steel gas transmission infrastructure.

  - In some cases there may be opportunities to repurpose parts of the natural gas transmission system for transportation of CO_2, or potentially hydrogen, although this will be limited by both the feasibility of conversion[82] and any continued use of the transmission system for natural gas.
  - The potential to transport hydrogen via the existing gas distribution networks from the early 2030s provides an opportunity to deliver low-carbon gas to residential and commercial consumers.
  - However, investment in gas networks is just 5% of the annual costs of a decarbonised energy system (Box 1.6), so does not in itself determine the optimal heat decarbonisation pathway.
- In scenarios where heat is fully electrified, there may be a case for decommissioning the gas distribution networks. The gas transmission system could continue to remain useful in order to provide natural gas to power stations or industrial users (e.g. for use in combination with carbon capture and storage).

Alternative hydrogen transportation options

As well as pipelines, hydrogen can also be transported via lorries or ships (see section 3), which may play a greater role in scenarios where the gas grid isn't converted to hydrogen use:

- Hydrogen is currently transported in 'tube trailer' lorries to bus depots in the UK, carrying around 1,000 kg (or 39 MWh) per trip, enough for 25,000 bus-kms. This could increase to 1,500-5,000 kg per trip in the future if pressurisation is increased, although transportation of compressed hydrogen has higher costs than liquefied hydrogen or ammonia.
- Costs of transporting hydrogen via trucks could be in the range of £1-2/MWh. Tube trailer distribution is well suited to smaller volumes of hydrogen, but economies of scale favour transportation of hydrogen via pipelines at higher volumes. Beyond the cost implications of hydrogen distribution, transporting it by road in significant volumes would also add to congestion, given the relatively low volume transported per tube trailer.

These infrastructure considerations are reflected in our scenarios in Chapter 4.

b. Requirements and options for hydrogen storage

As well as delivering gas on demand, the UK's gas networks provide much of the storage services to the network as 'linepack',[83] enabling it to buffer large swings in energy demand over a period of hours or days. Following a conversion to hydrogen, these networks could play a similar role in buffering demand and supply, supplemented by hydrogen production capacity and hydrogen storage facilities (e.g. salt caverns) to ensure that the system can meet seasonal swings in heating demand:

[82] Current evidence suggests the existing gas transmission networks in the UK are unlikely to be able to accommodate significant amounts of hydrogen. See POST (2017) *Decarbonising the Gas Network*.
[83] The term linepack is used to represent the contribution to storage from the use of gas pipelines, due to the ability to operate them at a range of pressures. The effective storage potential comes from the difference in the quantity of gas held in the pipeline at maximum pressure compared to minimum operating pressure.

- The 'Beast from the East' in March 2018 highlighted the challenge of heating UK homes during an extended cold period. Most of this heat was provided by natural gas via the UK's gas networks, which supplied an extra 120 GW of demand over a 3-hour period.[84] Modelling for the Committee by Imperial College was able to replicate these conditions for alternative energy system configurations based on low-carbon heating (see Box 1.6).
- Conversion of the UK's gas distribution system for hydrogen use, alongside a new hydrogen transmission system, would enable significant amounts of hydrogen to be stored within the pipeline system as linepack at very low cost. This can be particularly useful in smoothing out short-term (e.g. within-day) demand fluctuations. The existing natural gas transportation system contains enough capacity to meet peak demand periods in cold winters, as well as sufficient flexibility to operate a lower flow levels during summers, when demand is low.[85] However, as hydrogen takes up greater volume per unit of energy (and therefore requires more pipeline pressure), there may be a need for additional storage in order to maintain flows through the networks and meet peak demand.
- Hydrogen can also store energy across longer time horizons (e.g. seasons). Salt caverns offer a promising option for long-term storage, and evidence suggests losses in hydrogen storage are minor and not time-dependent.[86] Such storage facilities could be used to help balance hydrogen demand and supply, reducing the required investment in hydrogen production capacity, and increasing its utilisation. For example, winter heating demand can be met in part from salt cavern storage, with production therefore spread out over the year, while peaks can be met in part from linepack, allowing steady production over days/weeks.[87]
  - Hydrogen production facilities are large chemical processes that require multiple hours, or even days, to start up or shut down, so are run most efficiently if operated continuously. Modelling suggests that the optimal way to deal with this constraint may be to have two fleets of hydrogen production facilities: one operating year-round, and the other operating continuously over the winter.
  - Hydrogen storage in salt caverns can provide reserves of energy for use over winter periods, when hydrogen demand peaks (Box 3.3). However dispatching large volumes of hydrogen from salt caverns over a short period of time could damage the cavern, with estimates suggesting a limit of 10% of a cavern's volume can be exported over a 24-hour period. This may limit the ability of salt caverns to meet intra-day swings in demand.
- The optimal mix of hydrogen storage solutions will depend on the volume and seasonality of hydrogen demand, availability and costs of alternative hydrogen storage options and the role of imported hydrogen in meeting seasonal swings in hydrogen demand.
  - Scenarios with lower and/or less seasonally variable demands for hydrogen (e.g. transport) are likely to require less investment in seasonal hydrogen storage than those with greater and/or more seasonally variable demands (e.g. buildings heat).

[84] UKERC (2018) http://www.ukerc.ac.uk/publications/local-gas-demand-vs-electricity-supply.html. This demand is equivalent to 15 million UK households turning their heating from zero to max over three hours, all at the same time.
[85] UK gas network operators are required to be able to supply gas against a probability of a '1-in-20' year winter period occurring. See Ofgem (2017) *Gas Transporters Licence: Standard Conditions*.
[86] Element Energy (2018) *Hydrogen for heat technical evidence project*.
[87] Storing 10 TWh of hydrogen seasonally would require 77500 of the Tesla megabattery (129 MWh), which was recently installed in South Australia.

– Alternative hydrogen storage options include underground storage of hydrogen in oil and gas fields, storage of hydrogen in pressurised tanks, storage of hydrogen in liquid form as ammonia, methanol or Liquid Organic Hydrogen Carriers (see Box 3.4 in section 3), or solid state storage of hydrogen in hydrides.[88]

In recent years the UK's natural gas system has dealt with reduced domestic gas storage through the availability of imported gas during peak demand periods.[89] If imported hydrogen could play a similar role, then the need for (and cost of) UK hydrogen storage could be reduced.

Box 3.3. Hydrogen storage

Salt Cavern storage

- Natural gas has been stored underground since 1916, and much of this experience is relevant to hydrogen. For example, Sabic Petrochemicals currently operates three hydrogen salt cavern stores in the Tees Valley.
- Although salt caverns provide a useful means of storing hydrogen, they are limited by the amount of hydrogen they can release at any one time, as importing/exporting hydrogen from the salt cavern too quickly can lead to fracturing and fragmentation of the salt formations. The Energy Technologies Institute (ETI) estimate a safe limit to be around 10% of the total hydrogen storage capacity, over a day.
- The costs of storing hydrogen in underground salt caverns are expected to be significantly higher than storage in existing gas networks, at an annuitised cost of around £200/MWh/annum (compared to £34/GWh/annum).[1] These cost estimates imply developing a storage facility ten times the size of the required peak daily dispatch over the year. Avoiding this constraint, or finding alternative means of storing hydrogen could significantly reduce storage costs.
  - The ETI suggest that options could be available to alleviate this constraint.[2]
  - Alternative underground storage options for hydrogen (e.g. storage in aquifers or old oil and gas fields) could reduce both this cost and constraint. However, current evidence suggests that residual contaminants in these fields (e.g. sulphur compounds, hydrocarbons), may render these unsuitable for hydrogen storage.
  - Importing hydrogen during peak periods could reduce the need for UK storage, but may imply other infrastructure costs.

Imperial College modelling

Imperial College modelled hydrogen flows through the UK's gas networks (Figure 3.3a), in order to determine whether additional volumes of hydrogen, which is less dense that natural gas, could be accommodated in existing networks, and to determine the need for any additional storage. Their conclusions included:

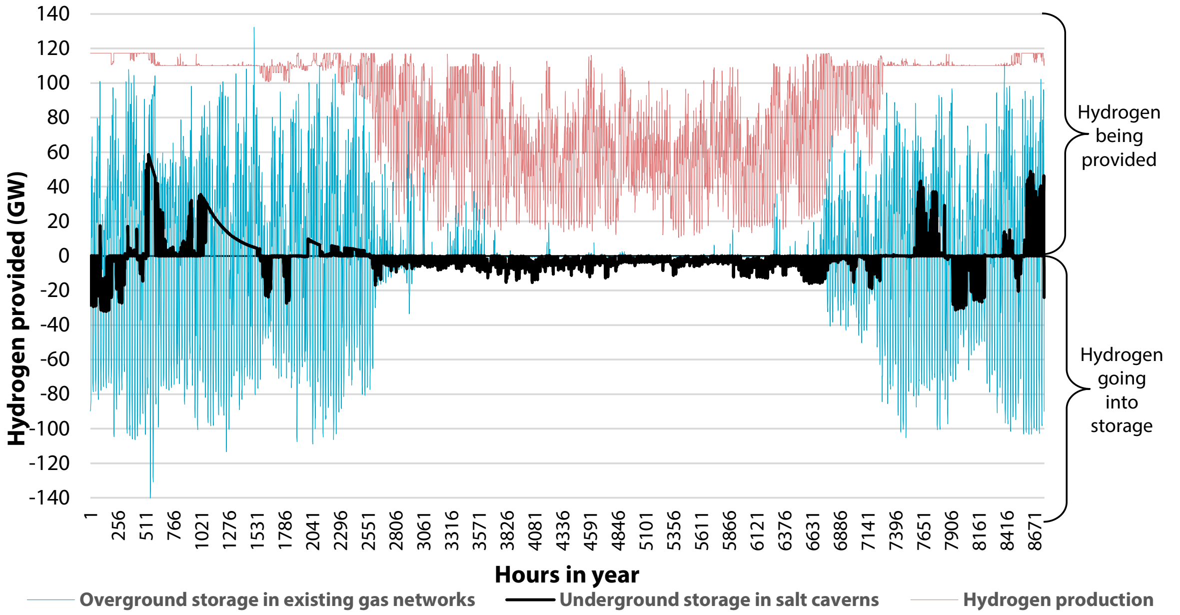
- 'Linepack' storage in existing medium pressure networks is largely sufficient to meet seasonal swings in demand, alongside scheduled seasonal output from hydrogen production facilities (Figure B3.3b)

[88] Hydrogen can also be stored in solid form, via metal hydrides.
[89] The UK's largest natural gas storage facility, 'Rough' in the Irish Sea, recently closed. Increasingly interconnected gas markets (both to Europe, and Asia) have limited the business case of storing gas on a seasonal basis in order to meet peak demands.

Box 3.3. Hydrogen storage

- Additional storage could be required to meet peak demands in peak winter weeks, at costs of around £6bn/year for 20 TWh of hydrogen storage. This storage is installed at high cost despite low utilisation over the year. Around 90% of this cost is oversizing hydrogen production capacity for instantaneous dispatch of large volumes of hydrogen.
- Some limited additional localised gas storage to help flows through the network at times of peak demand, at an additional cost of £0.3-0.6bn/year.

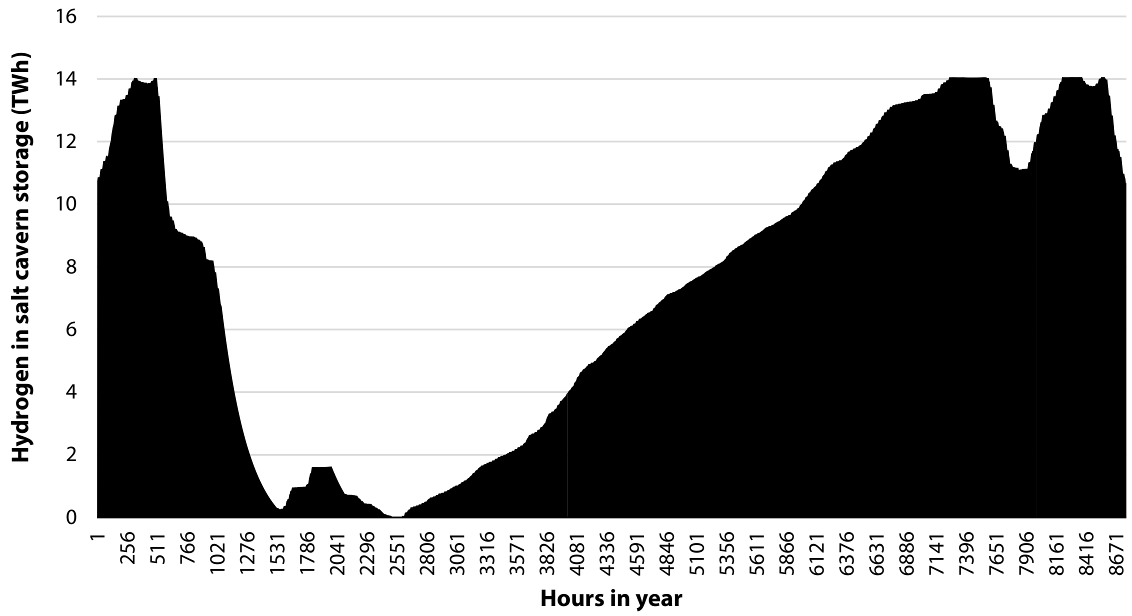
Figure B3.3a. 'Linepack' storage in existing networks can provide 90% of hydrogen storage needs across the year



Source: Imperial College (2018) *Analysis of alternative UK heat decarbonisation pathways*.
Notes: Peak demand for hydrogen is 261 GW in hour 594, equivalent to 6pm on a January weekday evening. Hour 1 is midnight to 1am on January 1st.

Box 3.3. Hydrogen storage

Figure B3.3b. Salt cavern storage can be used as a seasonal store of energy



Source: Imperial College (2018) *Analysis of alternative UK heat decarbonisation pathways*.
Notes: Hydrogen storage is gradually filled over the summer in order to supply hydrogen during winter periods at the beginning and end of the year. Hour 1 is midnight to 1am on January 1st.

Source: Imperial College (2018) *Analysis of alternative UK heat decarbonisation pathways*.
Notes: 1. Storing hydrogen underground is still expected to be cheaper than storing hydrogen above ground, which is expected to cost around £1200/MWh/annum. See Element Energy (2018) *Hydrogen for heat technical evidence project*.
2. ETI (2015) The role of hydrogen storage in a clean responsive power system.

3. Importing hydrogen to the UK

Hydrogen could be produced elsewhere, and piped or shipped to the UK. Indeed there are many countries with energy supplies that more plentiful and/or have lower costs than the UK. This suggests the cost of producing both electrolytic and gas-reformed hydrogen could be significantly cheaper than the cost of producing it in the UK (Figure 3.7).[90]

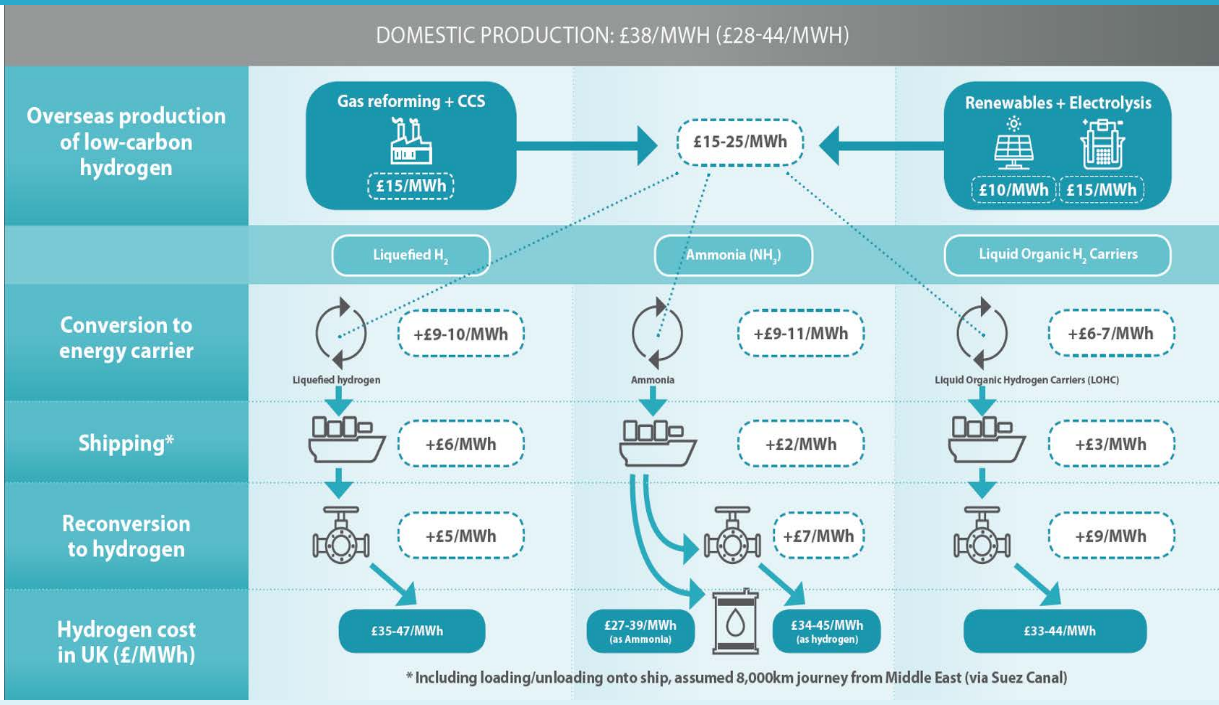
Hydrogen could be produced at low cost at locations outside of Europe (e.g. from gas reforming in the Middle East, or from solar power near the equator). This would need to be imported via ships, either as hydrogen or another energy carrier such as ammonia (Box 3.4). If a UK hydrogen market does develop, rules and governance will be required to ensure supplies are genuinely low-carbon.

- Low-carbon hydrogen could be produced at a cost of around £15-25/MWh in countries with cheap gas and renewable resources. However, transporting this hydrogen to the UK is likely to add around £20/MWh to the cost of hydrogen.
  - This is a similar cost range to the costs of producing hydrogen in the UK, implying that imported hydrogen could play a complementary role to - but is not necessarily cheaper than - domestic hydrogen production.
  - For end-uses where ammonia can be used directly,[91] imported ammonia (where hydrogen doesn't have to be removed from the energy carrier) could be cheaper than domestically produced ammonia (where nitrogen would have to be added to hydrogen to produce ammonia).
- Importing large quantities of hydrogen via ships would affect the required UK hydrogen infrastructure, but could also reduce the need for UK-based seasonal hydrogen storage.
  - Modelling by Imperial College suggested that without imports, domestic storage costs could be up to £6bn/year (Box 3.3). Importing hydrogen could reduce the need for these storage facilities.
  - Meeting all of the UK's hydrogen demand via sea-borne imports could require around 80 ocean-going vessels.[92] This compares to around 4,000 large oil or chemical tankers around the globe today, of which the UK effectively uses around 95 vessels.
- Importing hydrogen over large distances requires additional energy - to convert the hydrogen to an easily transportable form, and transport it - compared to domestically produced hydrogen. There are opportunities for low-carbon energy to be used at most stages of this process in order to ensure emissions are minimised, but rules would need to be put in place ensure this happens.
  - Transporting large volumes of hydrogen via ships is unlikely to materially increase the overall emissions of the energy feedstock, as ships are able to transport large volumes of energy in a single journey.[93]
  - Furthermore, ships transporting low-carbon fuels may have the opportunity to use these low-carbon fuels as a source of propulsion, reducing these emissions.

[90] Both solar PV and natural gas in the Middle East are around 20% of the costs of their costs in the UK.
[91] This could include use in industry or power, or potentially in fuel cells.
[92] Based on the Hydrogen Council report. Unclear if these are dedicated vessels or journeys.
[93] At an emissions intensity of 5 gCO_2/tonne/km, transporting hydrogen from the Middle East would increase emission by around just 1 gCO_2/kWh of hydrogen.

The UK's share of a global hydrogen market will depend on competition between the costs of producing hydrogen domestically, versus producing it at lower cost elsewhere, and shipping it to the UK. Both hydrogen produced in the UK and elsewhere would have to demonstrate it is low-carbon. This could require an agreed universal definition or standard for low-carbon hydrogen, or alternative mechanisms to appropriately recognise the carbon content of the hydrogen being consumed.

Figure 3.7. Potential hydrogen import routes and costs



Source: CCC analysis based on Mizuno et al. (2017) *Economic analysis on international hydrogen energy carrier supply chains*, Aurora (2018) *Aurora's Long-Term Outlook*, draft outputs in Element Energy (2018) *Hydrogen for heat technical evidence project*.
Notes: Natural gas price of 15p/therm. Assumed cost of £10/MWh for solar PV. Low-cost hydrogen could also be transported to the UK via pipeline at a transportation cost of under £5/MWh.

Importing hydrogen via pipelines is more economic over shorter distances, so would only be an economically viable option for hydrogen produced in other European countries. Norway has access to both cheap gas, and abundant hydroelectricity, as well as gas interconnectors to the UK. Iceland has low cost geothermal power, which could be used to produce electrolytic hydrogen. Hydrogen produced from natural gas in Norway, or via electrolysis from low-carbon electricity in Norway and Iceland, could potentially compete on cost with UK domestic production, although transporting this hydrogen to the UK will depend on, cost, volumes and technical feasibility:

- Pipeline transportation of natural gas is considered more economic than liquefied natural gas (LNG) over distances of up to 3,000-4,000 km.[94] This is likely to be similar for hydrogen, given the expected costs of converting hydrogen into alternative energy carriers. If production in these places becomes sufficiently low-cost, this could justify the building of

[94] See CSIRO (2018) *National Hydrogen Roadmap*, and Cornot-Gandolphe et al (2003) *The challenges of further cost reductions for new supply options (pipeline, LNG, GTL)*.

new hydrogen pipelines between these markets, at a cost of under £5/MWh. However, new long-distance natural gas pipelines in Europe have had capacities of around 200-600 TWh of gas per year, so new pipelines are only likely to be justified by high export volumes to the UK.[95]

- The UK currently has natural gas interconnectors to Norway, Holland, Belgium and Ireland. It is not clear that these would be able to be converted to hydrogen, as embrittlement issues could mean that conversion wasn't possible.

Box 3.4. Hydrogen-based energy carriers

Most global hydrogen consumption occurs near to the point of production, or is traded via products such as ammonia which contain large proportions of hydrogen. Hydrogen itself is therefore not a globally traded commodity, although research and development is ongoing into multiple energy carriers that could be used to transport hydrogen internationally:

- **Liquefied hydrogen (LH_2).** Hydrogen, like natural gas, can be liquefied in order to be transported at volume via sea and without pressurisation, although liquefying hydrogen requires temperature of -253C and is therefore energy-intensive, increasing costs. Additionally, once the gas reaches its destination country it needs to be regasified before being used, adding further cost. A project is under development in Australia to export liquefied hydrogen to Japan.
- **Ammonia (NH_3).** Ammonia is a traded global commodity, produced from synthesising hydrogen with nitrogen, and is shipped via sea in liquid form. Ammonia is a liquid fuel at temperatures of below -33C or a pressure above 10 atmospheres, and is therefore easier and less costly to transport than LNG or LH_2. There is currently an energy loss of about 15-25% when cracking ammonia back into hydrogen, which could favour the use of ammonia, rather than hydrogen in certain sectors. A project where ammonia could be exported from Saudi Arabia to Japan is under consideration.
- **Liquid Organic Hydrogen Carriers (LOHC).** Liquid Organic Hydrogen Carriers can be an option for transporting hydrogen at ambient temperature and pressure, although this is more of a novel process than liquefied hydrogen or ammonia. Hydrogen can be extracted after transportation, and the energy carriers re-used. As the hydrogenation process is exothermic, and the dehydrogenation process is endothermic, both could be a good pairing for technologies that require or produce waste heat. A project is under development in Brunei to export hydrogen to Japan using LOHCs. All these energy carriers need to resolve safety issues around flammability, toxicity and safe storage of the materials in order to be viable options for transporting and storing hydrogen at scale.

Source: Reuters (2018) *Australia's AGL to host coal-to-liquid hydrogen export trial for Japan's Kawasaki Heavy*; Ammonia Energy (2018) *Japan, Saudi Arabia Explore Trade in Hydrogen, Ammonia*; Ammonia Energy (2017) *Japan-Brunei MCH Energy Carrier Demonstration*.
Notes: Metal and non-metal hydrides can be used to store hydrogen in either liquid or solid form, but weren't considered in this analysis.

Increasing global interest in low-carbon hydrogen

Several countries besides the UK are considering the potential for using low-carbon hydrogen in the decarbonisation of energy. However, scenarios point to low-carbon hydrogen remaining a relatively niche global energy source to 2050 - providing around 1% of global primary energy demand by 2030 and up to 8% in 2050 (Box 3.5).

[95] The new Nord Stream pipeline from Russia to Germany can export up to 600 TWh/year. Blue Stream (2005) and Langeled (2006) are each up to 200 TWh/year.

Genuine interest in low-carbon hydrogen suggests that a global hydrogen market could emerge over the next few decades. It is likely that hydrogen can be produced in the UK at similar cost to importing hydrogen from overseas, though imports of hydrogen could complement UK production. However uncertainties around the costs, scale and potential UK share of any global hydrogen market, imply a *de minimis* role for UK hydrogen production in any future hydrogen scenario.

- Global interest in low-carbon hydrogen, and opportunities for low-cost hydrogen to be produced and shipped around the world suggest that a global trade in low-carbon hydrogen could emerge over the period to 2050, although there is significant uncertainty over its size. Despite genuine interest in the trade of low-carbon hydrogen, the most ambitious scenarios for hydrogen use by 2050 comprise just 8% of global energy demand. Any internationally traded market in low-carbon hydrogen would be smaller than this, and could take decades to scale up.
  - Furthermore, imported hydrogen would have to demonstrate that it is produced via genuine low-carbon processes, in order to be a viable low-carbon fuel for the UK.
  - Opportunities for lower cost hydrogen production outside of the UK suggest that it is unlikely that the UK would ever be a large-scale exporter of hydrogen.
- Estimates of the potential costs of hydrogen imports to the UK are comparable to the costs of hydrogen production in the UK. Lower costs of production elsewhere suggest that any UK role as a hydrogen exporter would be limited.
- Given the costs and uncertainties of the potential for a globally traded market in low-carbon hydrogen to emerge, it is likely that any large-scale UK demand for hydrogen would have to be met, at least initially, by domestic production.

Box 3.5. Potential global supply and demand of low-carbon hydrogen

Current forecasts for global hydrogen demand vary widely, from 35-1,100 TWh per annum in 2030 (up to 1% of global primary energy demand), scaling up to 300-19,000 TWh per annum by 2050 (0.1-8%) (Figure B3.5).

There are some real-world developments in low-carbon hydrogen production for export. However the scale of these developments to date is small, and insufficient to stimulate large scale global trade of hydrogen:

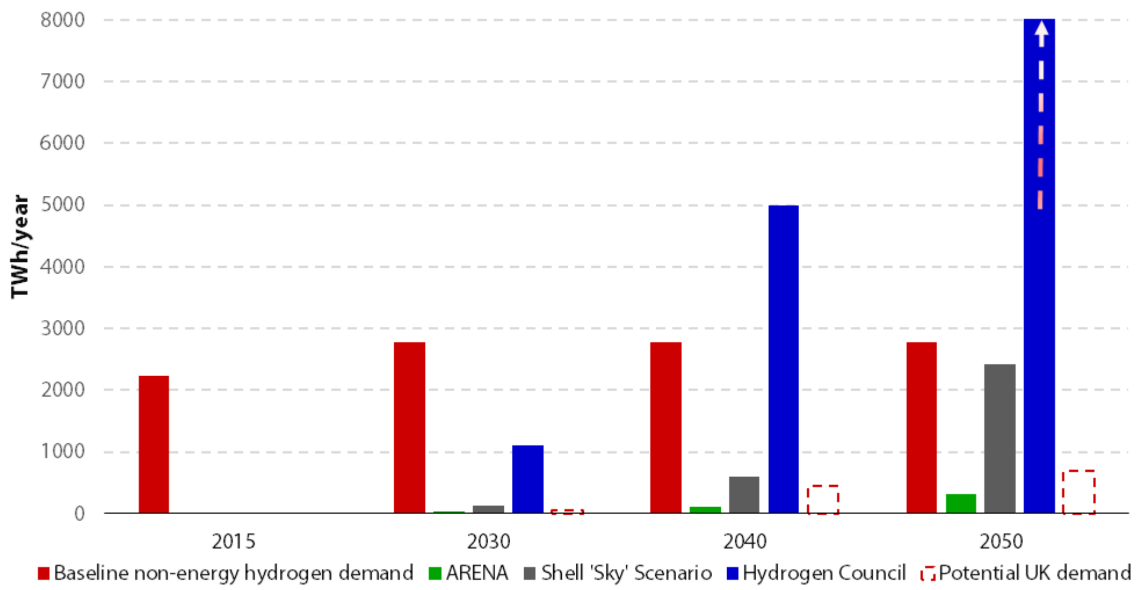
- In 2017 the Japanese Government released a 'Basic Hydrogen Strategy', outlining its plans to import around 0.2 TWh by 2020, rising to 12 TWh by 2030, as well as research and investments into international hydrogen supply chains and end-use technology.
- Australia is currently building a coal gasification plant in Victoria with the intention of shipping the hydrogen to Japan. Unless CCS is fitted, this would be high-carbon hydrogen. Australia is also exploring potential for exports of low-carbon hydrogen via coal gasification plant with CCS, and renewables with electrolysis. Total export potential is envisaged as 5 TWh per annum from 2025, rising to 55 TWh per annum by 2040.
- Norway, France and Saudi Arabia are also considering the potential for hydrogen supply and use.

If future global hydrogen trade followed a similar scale up to LNG, this would imply a limited role for imports of low-carbon hydrogen to the UK:

Box 3.5. Potential global supply and demand of low-carbon hydrogen

- Natural gas was originally consumed near to low-cost centres of production (e.g. North Sea, Russian gas in Europe). As the market matured and demand increased, new, low-cost sources of gas were discovered, though not necessarily near large centres of demand (e.g. Qatar, US Shale). It was therefore exported as LNG, with the global LNG market increasing from 80 TWh/annum (40 MTPA) in 1990 to over 600 TWh/annum (300 MTPA) today, around 1.6% of the global gas market.
- Even if global volumes of traded hydrogen could reach the size of today's LNG market, the total volume of globally traded hydrogen would be lower than total potential UK hydrogen demand, implying that the bulk of UK hydrogen would need to be produced domestically.

Figure B3.5. Potential global demands for hydrogen to 2050, compared to potential UK demand



Source: Hydrogen Council (2017) *Scaling up*; Shell International B.V (2018) *Sky Scenario*; ARENA (2018) *Opportunities for Australia from hydrogen exports.*
Notes: Potential UK demand is based on the 'Full Hydrogen' scenario presented in Chapter 4. IRENA (2018) *Hydrogen from renewable power* assessed economic potential for 2050 to be 8 EJ (or 2200 TWh).

Source: Reuters (2018) *Australia's AGL to host coal-to-liquid hydrogen export trial for Japan's Kawasaki Heavy, Hydrogen Strategy Group (2018) Hydrogen for Australia's future, METI (2017) Basic Hydrogen Strategy, IGU (2018) 2018 World LNG Report, BP (2018) Global Energy Outlook.*

Chapter 4: Scenarios for hydrogen use

Having identified how hydrogen might sensibly be used in a highly decarbonised energy system (Chapters 1 and 2), and how hydrogen could be produced in a low-carbon way (Chapter 3) it is necessary to understand what a sensible infrastructure might look like to connect the two, and how this fits with the rest of the energy system.

Our Conclusions in this chapter are:

- A 'Full Hydrogen' scenario would be very difficult to deliver, whatever the primary production method. The required capacity to service this scenario looks implausibly large, especially given the relatively short timeframe to roll it out, and it brings further challenges in import dependency and potentially insufficient emissions reductions.
- We therefore do not recommend that a Full Hydrogen pathway be pursued. Instead we recommend that a smaller role for hydrogen is pursued for buildings decarbonisation, focused on the colder periods of winter which it may otherwise be particularly difficult to decarbonise at reasonable cost. Limiting the use in light vehicles - cars and vans - where electric alternatives are available will also help to reduce the required low-carbon capacity.
- Given likely limits to hydrogen production from electrolysis and bioenergy with carbon capture and storage (BECCS), there is an important role for low-carbon hydrogen production from gas reforming with CCS. However, this is a low-carbon rather than zero-carbon route for hydrogen production, reducing emissions on a lifecycle basis by 60-85%. Keeping overall hydrogen to a more manageable level (e.g. the Hybrid or Niche scenarios) would limit reliance on natural gas imports and CCS, and would limit residual emissions from hydrogen supply.

We set out this chapter in seven sections:

1. Our scenarios
2. Hydrogen demands in our scenarios
3. Meeting hydrogen demands
4. Could we build enough low-carbon capacity?
5. Implications for energy imports
6. Regionally-varying solutions

1. Our scenarios

The biggest infrastructure question regarding hydrogen is whether or not to repurpose gas distribution networks to carry hydrogen rather than natural gas. These decisions primarily relate to decarbonisation of heat, given the role of these gas networks today.

We therefore define scenarios in which this does or does not occur nationally. We then further distinguish between a hydrogen network that is used similarly to the current gas network with heavy use of hydrogen in boilers, as against one in which it plays a back-up role (Figure 4.1):

- **Full Hydrogen.** In this scenario, gas networks are repurposed to hydrogen, which is used in boilers in a similar way to natural gas today, requiring that strategic decisions are taken by the mid-2020s for the wholesale switch to hydrogen for heating. Widespread availability of a hydrogen grid means low-carbon hydrogen supplies being available for other applications.
- **Hybrid Hydrogen.** In this scenario, gas networks are also repurposed to hydrogen. However, the near-term focus for decarbonising existing on-gas properties is deployment of hybrid heat pumps, leading to sharper near-term reductions in emissions. Gas demand would be significantly lower in this scenario, enabling a slightly later switch of gas networks to hydrogen due to a lesser challenge in producing sufficient low-carbon hydrogen by 2050. Again, widespread availability of a hydrogen grid means low-carbon hydrogen supplies will be available for other applications.
- **Niche Hydrogen.** This is a scenario in which gas grids are not switched to hydrogen, with heat decarbonisation for on-gas buildings relying primarily on electrification through full and hybrid heat pump systems. Despite this, the potentially high value of hydrogen in other sectors means that some deployment does occur, focused on areas in which the value of hydrogen is greatest and where infrastructure barriers can be overcome more readily.

These scenarios are intended to be illustrative and make assumptions about the levels of hydrogen use not only for buildings heat but elsewhere in the energy system. It is also possible to pursue different strategies in different parts of the UK.

The quantitative analysis presented here is primarily from internal modelling undertaken using the Energy System Catapult's ESME energy system model, updated with our assumptions. This modelling has been undertaken jointly for this report and our parallel report on *Biomass in a low-carbon economy*. Papers on both will be published following this report. Where appropriate, we also draw on modelling done for us by Imperial College on heat decarbonisation scenarios.

Both models perform optimisation on the costs of meeting energy service demands under a range of scenarios with differing roles for hydrogen. As we are interested in how large a role hydrogen could potentially play, we have used assumptions on technology costs and performance (e.g. efficiencies and CO_2 capture rates) that are relatively optimistic.

In general our analysis assumes that hydrogen demand within the UK energy system will be met through domestic production rather than relying on imports, due to uncertainties over whether an international market in low-carbon hydrogen (e.g. as ammonia) will develop and be able to provide hydrogen at a lower cost than UK production. It is therefore possible that some of the hydrogen supply, especially closer to 2050, might come from imports if this turns out to be cheaper than domestic production.

2. Hydrogen demands in our scenarios

The Full Hydrogen scenario

The widespread repurposing of gas grids to hydrogen over the period 2030 to 2050, for use in hydrogen boilers, implies very rapid growth in low-carbon hydrogen supplies during this period, as well as building-by-building switchover (e.g. by replacing gas boilers with hydrogen ones).

Even allowing for uses elsewhere in the energy system, enabled by having access to hydrogen networks, demand for hydrogen in this scenario is dominated by buildings (Figure 4.1):

- **Buildings.** Under this scenario, we assume that strong policy is implemented to drive significant improvements in energy efficiency as under our cost-effective path for reducing emissions. Remaining heating demand is largely switched to hydrogen. This results in a demand for hydrogen in 2050 of 470 TWh, with conversion of networks assumed to occur at a consistent rate over the period from 2030 to 2050.
- **Industry.** As outlined in Chapter 1, hydrogen can play an important role in industry decarbonisation, alongside energy and resource efficiency improvements, product substitution and the use of CCS and BECCS. Here we assume that the full cost-effective potential of hydrogen is taken up, reaching 82 TWh by 2050.
- **Transport.** The case for hydrogen use in surface transport is less clear-cut, even in a scenario with abundant low-carbon supplies available. We assume that hydrogen is used for most HGVs, including urban delivery trucks. Cars and vans are assumed to switch to hydrogen only when needing to regularly travel long distance journeys, given that battery electric vehicles are likely to be lower cost.
- **Power.** Given limited end-user considerations, we allowed the model to optimise the use of hydrogen to support a decarbonised power system. We assumed that the costs and efficiencies of hydrogen combined-cycle and open-cycle gas turbines (CCGTs and OCGTs) are the same as for equivalent natural gas plants.

The Hybrid Hydrogen scenario

It is in the buildings sector where the Hybrid Hydrogen scenario differs from the Full Hydrogen scenario. In this scenario, hydrogen consumption is limited to playing a back-up role in a system with widespread hybrid heat pumps (see section 2 of Chapter 1).

This reduces hydrogen consumption in buildings under the Hybrid Hydrogen scenario by around 75%, and overall hydrogen consumption by around 50% relative to the Full Hydrogen scenario.

Outside the buildings sector, hydrogen demands in this scenario follow those in the Full Hydrogen scenario.

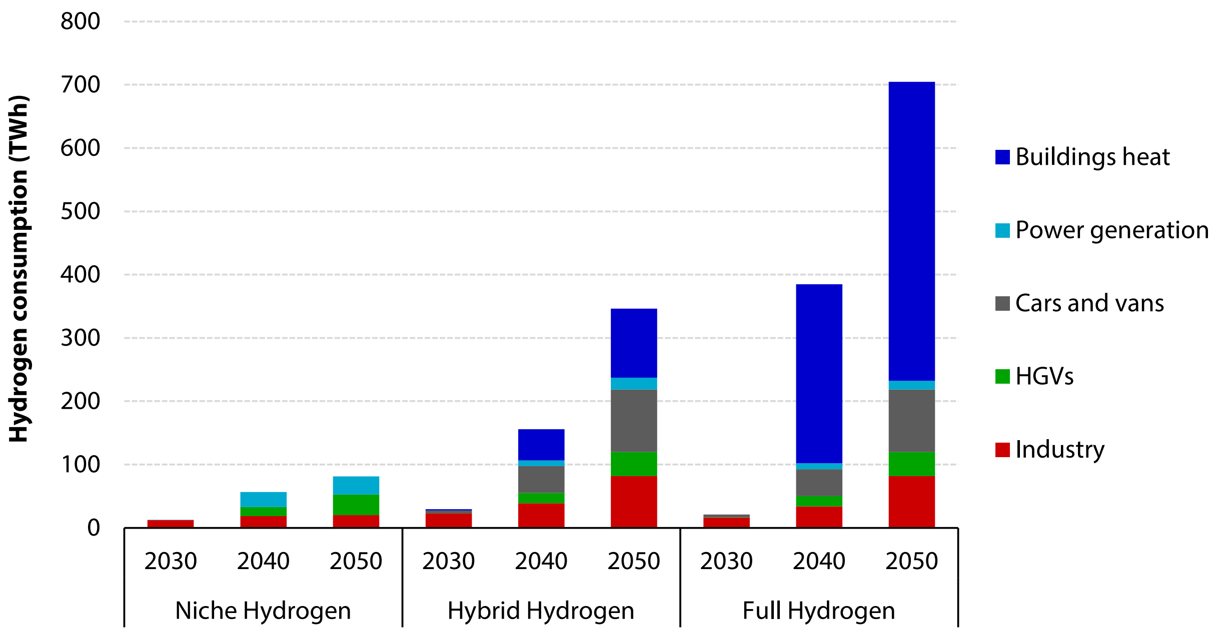
The Niche Hydrogen scenario

Under the niche scenario, gas grids are not repurposed to hydrogen, meaning that hydrogen is not used for heat in buildings and also that, unlike in the Full and Hybrid scenarios, a piped supply of hydrogen is not available for other sectors.

Hydrogen can still offer decarbonisation in other sectors, even without conversion of the gas grid, but potentially at lower levels given the greater barriers and higher cost of low-carbon hydrogen provision in such a scenario. The use of hydrogen outside of heat in buildings will depend on its value in offering decarbonisation solutions in these sectors that go beyond what can be offered by other available options or at lower costs, and the ease of ad-hoc infrastructure solutions:

- **Industry.** We have assumed a smaller role in industry, focused on applications in which decarbonisation is likely to be infeasible without hydrogen. We have assumed that hydrogen is not deployed where there are overlaps with other potential cost-effective abatement options (e.g. CCS).
- **Transport.** Hydrogen may still be deployed in HGV fleets, mainly in the long-haul sector. A nationwide refuelling infrastructure to serve these HGVs will be required, which will depend on electrolysis sited at or near refuelling stations. For cars, vans and HGVs operating on shorter regional and urban routes, battery electric vehicles are the preferred option, given the lower costs of vehicles and fuel.
- **Power.** We again allowed the model to optimise the use of hydrogen to support a decarbonised power system.

Figure 4.1. Demands in the Full Hydrogen, Hybrid Hydrogen and Niche Hydrogen scenarios (2030-50)



Source: CCC runs of the Energy System Catapult's ESME model with data and assumptions updated by the CCC.
Notes: Hydrogen consumption in buildings and transport was fixed at the values shown above for the ESME runs for all scenarios. For power generation, the model was free to select the cost-optimal level of consumption in all scenarios. For industry: for the niche scenario, the model could use hydrogen only where CCS or electrification options were not available; for the Hybrid and Full scenarios, hydrogen is assumed to be deployed wherever feasible.

3. Meeting hydrogen demands

Whilst there are some potential opportunities to supply hydrogen from a mix of sources, the contributions of each of biomass gasification with CCS (BECCS) and electrolysis could be limited, given high costs and/or limits to sustainable supplies:

- **Electrolysis.** The use of electrolysers to utilise excess low-carbon power generation can provide a useful form of flexibility to the electricity system, and as such when this occurs we would expect the electricity to be very low cost. However, the volumes of hydrogen that can be expected to be produced using very low-cost electricity are small in the context of the overall energy system (e.g. up to 44 TWh in 2050,[96] around 6% of consumption in the Full Hydrogen scenario). Beyond this niche in helping to manage the electricity system, the low overall efficiency of electrolysis and the relatively high value of using electricity as an input mean that the costs of producing bulk electrolytic hydrogen within the UK are likely to be high.
- **Bioenergy with CCS (BECCS).** Our parallel report on *Biomass in a low-carbon economy* reaffirms our position that within the energy system, the best use of finite sustainable biomass resource in contributing to meeting long-term emissions targets is to use it in conjunction with CCS, in order to maximise the overall emissions savings. However, given finite supplies of sustainable biomass globally and potentially strong competing demands for it, we estimate that the UK might have access to around 94-550 TWh of biomass in 2050. Allowing for important uses elsewhere (e.g. use of wood as a construction material) and for the energy losses in hydrogen production this might be sufficient to produce 55-330 TWh of hydrogen.

Beyond these sources, the remainder of low-carbon hydrogen supply would be expected to come from gas reforming with CCS, although there is potential for hydrogen imports to supplement this. A focus therefore on supplying large volumes of low-carbon hydrogen at the lowest cost is likely to entail a heavy reliance on natural gas reforming with CCS (Figure 4.2).

The evidence presented in Chapter 3 suggests that although gas reforming with carbon capture and storage (CCS) is the lowest-cost way of producing low-carbon hydrogen, its residual emissions are significant:

- Bulk production of hydrogen from gas reforming with CCS can reduce emissions relative to unabated natural gas use by 60-85% on a lifecycle basis, with the remaining emissions being from a combination of uncaptured CO_2 from the hydrogen production process and 'upstream' emissions from gas supply.
- Achieving the upper end of the potential emissions savings (i.e. an 85% lifecycle emissions saving against natural gas) would require sourcing of very large quantities of natural gas with proven low upstream emissions (e.g. at or below around 15g CO_2e/kWh), high efficiency of gas reformation and very high CO_2 capture rates (e.g. at least 95%).

We project around 470 TWh of gas demand from buildings alone in 2050 allowing for growth in the number of buildings and delivery of strong energy efficiency policy. This implies that a switch to a hydrogen supply based fully on gas with CCS would achieve an emissions reduction

[96] Imperial College modelling of heat decarbonisation pathways selected up to 44 TWh of electrolysis in pathways with less stringent emissions constraints (i.e. 30 $MtCO_2$ and 10 $MtCO_2$). The ESME model tends to select less than this, but it has a less detailed temporal resolution than the Imperial College model.

for buildings from 87 $MtCO_2e$ in 2017 to around 5 Mt from un-captured CO_2 from hydrogen production in 2050, alongside a further 8-41 $MtCO_2e$ from upstream natural gas supply.[97]

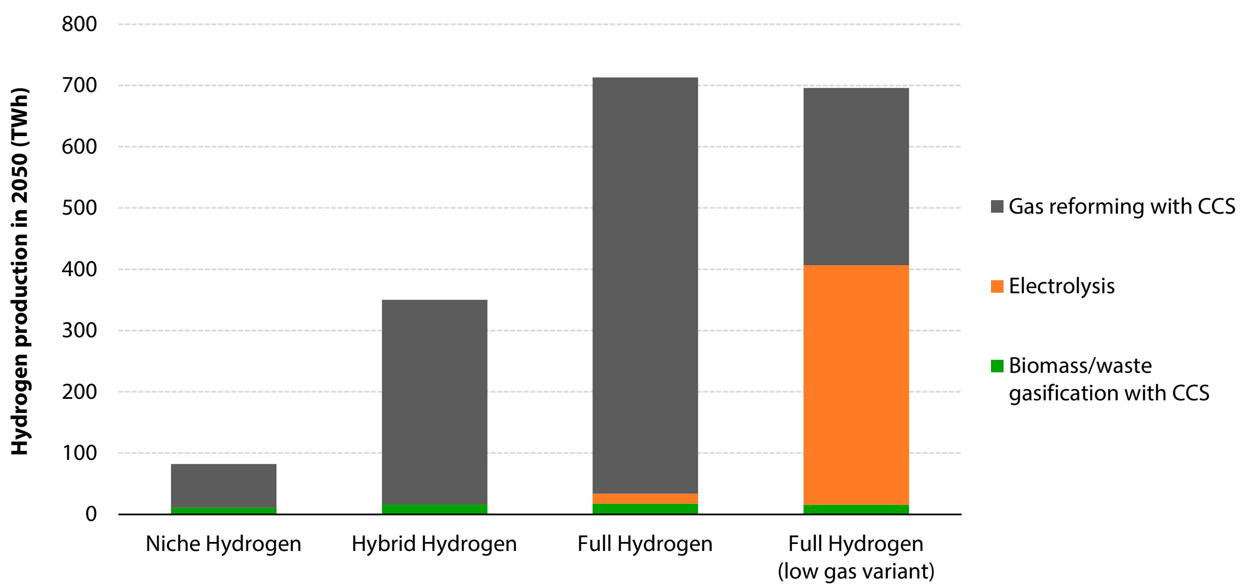
Gas reforming at very large scale would also place a heavy reliance both on CCS and on natural gas imports (see section 4).

The lower levels of hydrogen consumption in the Hybrid and Niche scenarios would place less reliance on gas reforming with CCS, both due to the lower overall hydrogen demand and because the contributions of the more volume-limited sources of hydrogen (i.e. electrolysis and BECCS) would form a greater share of production (Figure 4.2).

Depending on the need to minimise residual emissions, further electrolysis could be undertaken to reduce the production from natural gas, although this would significantly increase both costs and challenges over delivery of the necessary capacity (see section 4).

Overall volumes of hydrogen production in the Niche Hydrogen scenario would be a fraction of the Full Hydrogen scenario. A lack of widespread hydrogen infrastructure means that hydrogen production would likely need to be produced nearer to points of demand. Production for industry could be based on CCS (i.e. based on natural gas and/or bioenergy) as part of industrial clusters, while use in transport is likely to be dominated by electrolysis.

Figure 4.2. Hydrogen production in the Full, Hybrid and Niche scenarios (2050)



Source: CCC analysis using the Energy System Catapult's ESME model with input data updated by the CCC.
Notes: The ESME model tends to select low levels of electrolysis, but has a less detailed temporal resolution than the Imperial College model which chooses slightly more. For the 'low gas variant' of the Full Hydrogen scenario, deployment of gas reforming with CCS plant was restricted and production via gas reforming and biomass gasification without CCS were made unavailable.

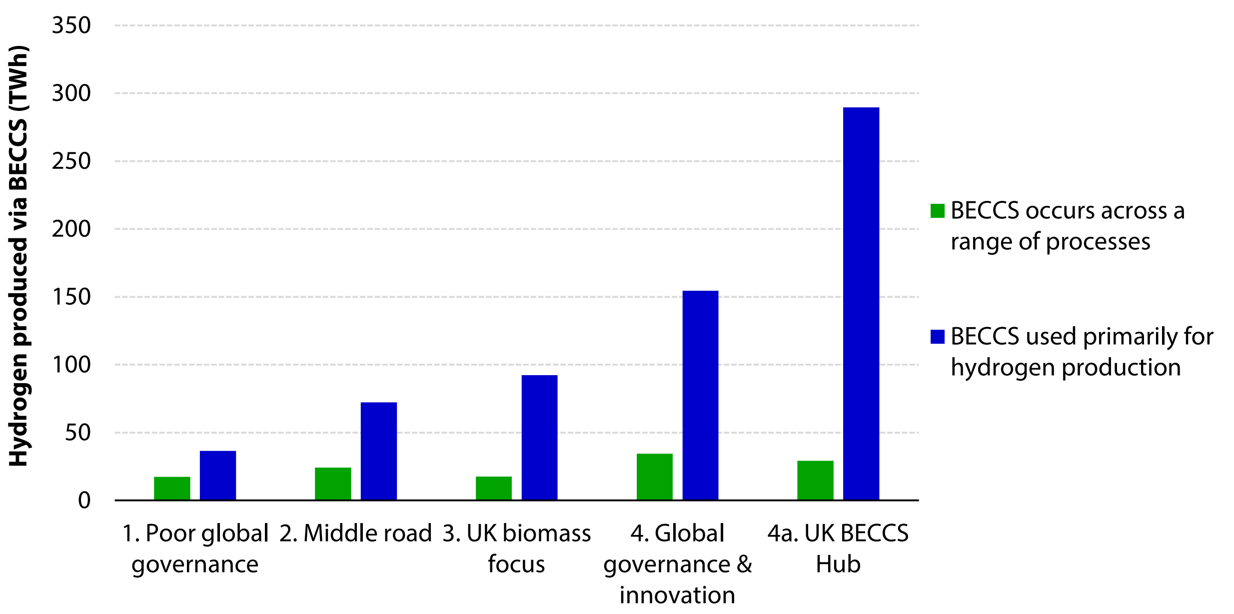
[97] Some of the upstream emissions from natural gas supply would occur overseas and would therefore not be counted towards UK carbon budgets.

Whilst the contribution of BECCS to hydrogen production is small in Figure 4.2, this is under a lower biomass supply scenario, and where only a fraction of the UK's available bio-resource goes to hydrogen production with CCS. There is potential for this to be considerably higher:

- The finding in our parallel report on *Biomass in a low-carbon economy* is that by 2050 any biomass used in the energy system should be used with carbon capture and storage (CCS) where feasible, in order to maximise the emissions savings from the finite supply of sustainable biomass.
  - This combination of bioenergy with CCS (BECCS) could take a number of forms, including electricity and hydrogen production. In these cases virtually all of the bio-carbon would be sequestered, and the resultant energy provided in a zero-carbon form for use in the energy system.
  - Alternatively biomass could be used with CCS to produce hydrocarbon fuels that displace otherwise irreducible demand for fossil fuels (e.g. in aviation), providing emissions savings from both fossil fuel displacement of and carbon sequestration with CCS.
  - The optimal choice of BECCS application in 2050 is currently highly uncertain, depending on the costs and CO_2 capture rates of the range of BECCS processes. If hydrogen can be produced at reasonable cost with a high rate of CO_2 capture, it may be the most effective use of the finite sustainable biomass resource by 2050.
- The quantity of biomass available to the UK energy system is also uncertain. We have developed four supply scenarios to reflect this uncertainty, taking into account varying levels of domestic production plus imported biomass based on an 'equal share' of the global sustainable resource, which itself is likely to vary considerably. It is possible that both UK production and the global resource will be higher than that shown above. It is also possible that the UK could access a greater share of the global resource in a 'UK BECCS hub' scenario:
  - Figure 4.2 assumes an increase in UK sustainable bioenergy resource of about 40% from around 145 TWh today to around 200 TWh in 2050. This could be met by an ambitious 'UK bioenergy focus' scenario where the UK prioritised domestic production of biomass, or through a balance of domestic production and imports.
  - Under certain conditions it may be possible for the UK to access higher levels of sustainable resource, up to around 300 TWh in total in 2050, with around half of this coming from imports.
  - Furthermore, it may be that the UK accesses a different share to the 'fair share' we have assumed (e.g. as a result of being an early mover on BECCS deployment). In a 'UK BECCS hub' scenario we assume that the UK might be able to access 550 TWh of biomass by 2050, and could accommodate this with manageable implications for ports and other infrastructure.

The range for potential UK hydrogen production from BECCS based on biomass gasification is therefore very wide. At one end of the range it could be very low, based on low availability of sustainable biomass and hydrogen production getting a small share of this. At the other end, if the UK were to become a BECCS hub and use BECCS primarily for hydrogen production it could provide a substantial proportion of hydrogen consumption by 2050 (Figure 4.3).

Figure 4.3. Potential contribution of hydrogen production from bioenergy with CCS (BECCS) in 2050



Source: CCC analysis using the Energy System Catapult's ESME model with input data updated by the CCC.
Notes: The five scenarios for biomass supply are those presented in our parallel report on *Biomass in a low-carbon economy*. Deployment of different types of BECCS is very sensitive to assumptions on their CO_2 capture rates – where capture rates are assumed to be equal across applications, the model chooses a range of BECCS applications, with relatively little hydrogen production. However, with slightly higher CO_2 capture rates for BECCS hydrogen production than other BECCS applications, the model chooses a lot more hydrogen production.

4. Could we build enough low-carbon capacity?

Production primarily from natural gas

Producing the volume of hydrogen required under the Full Hydrogen scenario within the UK would be challenging. If produced very largely from natural gas reforming with CCS, it would require:

- Up to 90 GW of hydrogen production capacity, installed over a period of little over 20 years. This is around three times the capacity of the existing gas CCGT power station fleet.
- Very large volumes of carbon capture and storage (CCS) would be needed, with deployment for hydrogen production reaching annual levels of over 140 $MtCO_2$ by 2050 out of a total of over 190 Mt (Figure 4.4). This would mean a heavy level of reliance on CCS deployment at very large scale by 2050, especially considering the lack of progress to date on CCS commercialisation. It is not clear that CCS could be scaled up to reach these levels from our recommended deployment levels of 10 Mt per annum by 2030 and 20 Mt per annum by 2035, implying a potential need for greater near-term ambition on CCS.
- Substantial development of UK infrastructure, including a new hydrogen transmission network and hydrogen storage capacity (e.g. salt caverns).

It would also have large implications for the level of total gas consumption, and therefore for the level of gas imports (see section 5).

Production primarily from electrolysis

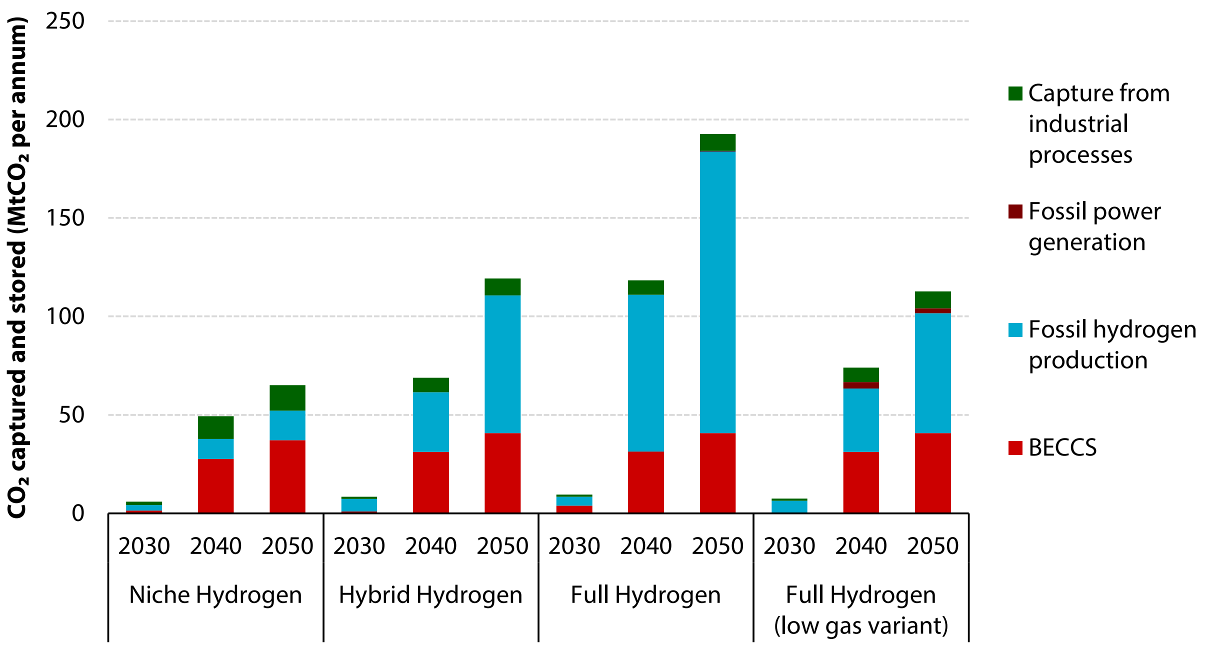
Use of hydrogen at very large scale while limiting the contribution of gas reforming is likely to imply a very large contribution from electrolysis (see Figure 4.2). However, given the build rates of zero-carbon electricity generating capacity that supplying this quantity of electrolytic hydrogen would imply, and the costs that it would entail, meeting the Full Hydrogen scenario hydrogen demands predominantly through electrolysis is unlikely to be feasible or sensible:

The electrolysis process leads to energy losses and requires additional decarbonised electricity to be generated. This would have very high costs (see Figure B1.6) and would mean extremely challenging build rates for low-carbon electricity capacity:

- This would require more than 300 TWh additional zero-carbon electricity generation by 2050 compared to all of the other scenarios, increasing the requirement for decarbonised electricity by 50%-130% compared to the other hydrogen scenarios in 2050 and by over 175% compared to our High Low-Carbon scenario for 2030 (Figure 4.5).
- This would require very major additional capacity build, for example an additional 31 GW of nuclear capacity compared to the Niche Hydrogen scenario, which is scenario with the next highest electricity consumption.
- It would also require over 100 GW of electrolyser capacity, the operation of which can follow the profile of wind and solar generation, with hydrogen storage used to buffer supply and demand (Figure 4.6).

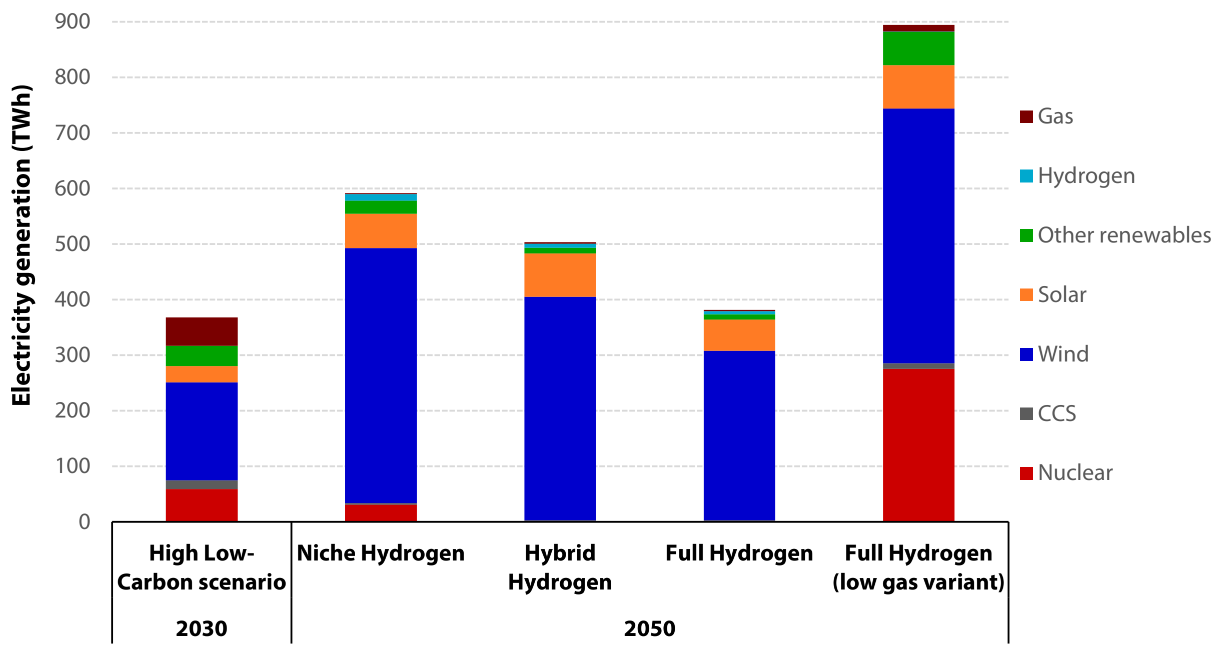
As we conclude in section 7, these levels of production make a Full Hydrogen scenario look very challenging, and point towards a preference for lower levels of hydrogen use.

Figure 4.4. CCS deployment in the Niche, Hybrid and Full Hydrogen scenarios (2030-2050)



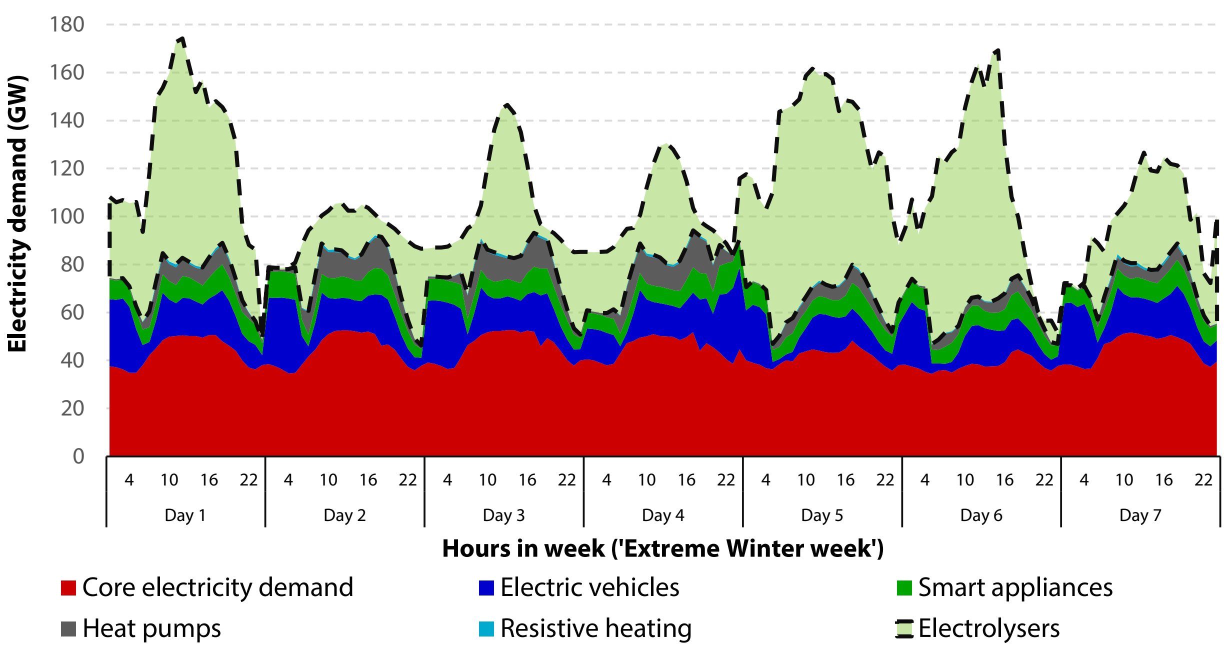
Source: CCC analysis using the Energy System Catapult's ESME model with input data updated by the CCC.
Notes: 'Capture from industrial processes' covers all industrial CCS, including use of biomass (BECCS). 'BECCS' covers all BECCS use to produce biofuels, hydrogen, power and synthetic natural gas, except in industry.

Figure 4.5. Electricity generation in the Niche, Hybrid and Full Hydrogen scenarios (2050)



Source: CCC analysis using the Energy System Catapult's ESME model with input data updated by the CCC.
Notes: CCC scenario for 2030 is the High Renewables scenario from CCC (2018) *Progress Report to Parliament*; the scenarios for 2050 are results from the ESME model.

Figure 4.6. Electrolysers could add over 100 GW to peak electricity demand



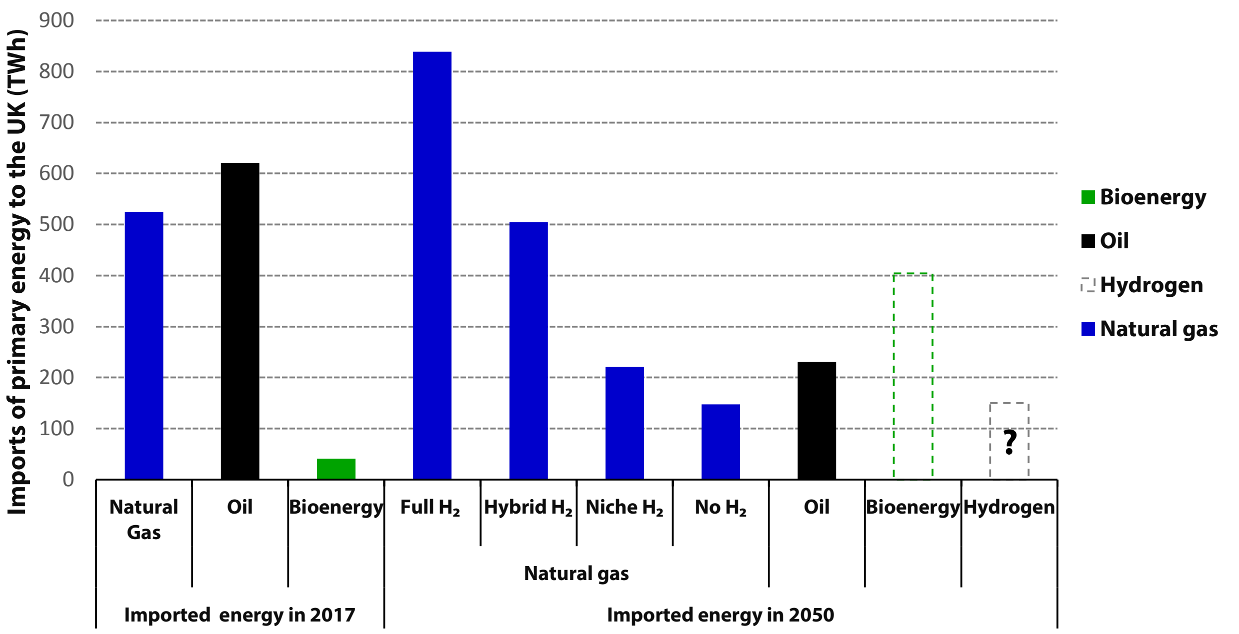
Source: CCC analysis based on Imperial College (2018) *Analysis of alternative UK heat decarbonisation pathways*.
Notes: The shape of total demand is driven by inflexible sources of generation, especially variable renewables. The peaks in total demand and utilisation of electrolysers coincide with high renewable generation.

5. Implications for energy imports

A widespread hydrogen scenario where hydrogen is produced predominantly via gas reforming would likely increase the UK's import dependence, through both increased imports of gas, and potentially bioenergy (Figure 4.7).

- The UK imported 60% of the natural gas it consumed in 2017. As production of oil and gas in the North Sea continental shelf declines in the UK, our import dependence will tend to rise, unless the consumption of fossil fuels can be made to decline more quickly than North Sea production.
- Widespread use of hydrogen could exacerbate this import dependence, either by increasing dependence on natural gas for domestically produced hydrogen via gas reforming (which requires more units of natural gas per unit of hydrogen produced), or by importing hydrogen directly.
- The level of biomass imports by 2050 will depend on the extent to which it has been possible to scale up global sustainable supplies of biomass, and the fraction of the 'tradable' resource that the UK accesses. Our scenarios for sustainable biomass supply also include a substantial contribution from UK-grown feedstocks (see our parallel 2018 report on *Biomass in a low-carbon economy* for more details).

Figure 4.7. UK import dependency



Source: BEIS (2018) Digest of UK Energy Statistics. CCC (2018) The Bioenergy Review. CCC ESME analysis.
Notes: Imported bioenergy in 2050 could range from zero to 400 TWh per year. Range for hydrogen imports is illustrative.

6. Regionally-varying solutions

The role of hydrogen as a low-carbon fuel need not be nationally determined, but could be driven by regions where hydrogen is a strong decarbonisation option. This could be due to public acceptability of hydrogen as a heating solution, clusters of industrial activity, proximity to carbon storage, and grid upgrades in urban areas:

- Regions where gas delivered via the gas grid is already the dominant heating source will have the greatest opportunities for using hydrogen.
- Public acceptability that favour hydrogen over alternative heat decarbonisation options in certain areas could lead to a regional push for hydrogen conversion.
- Estimates suggest that economies of scale available for large centralised hydrogen production technologies such as gas reformers could reduce costs by up to 20% compared to smaller-scale equivalents. [98] This could favour large-scale centralised production of hydrogen.
- Siting hydrogen production in coastal areas near to CO_2 storage facilities could avoid the need for building new onshore CO_2 transportation infrastructure. Most CO_2 stores in the UK are in proximity to North East or North West England, or North East Scotland. This could also offer overlap with salt cavern storage, and industrial CCS clusters:
  - As identified in Chapter 1, decarbonising heavy industry in the UK is likely to involve a combination of hydrogen and CCS technologies. Four out of five of the UK's industrial clusters are in areas in proximity to identified CO_2 storage facilities,[99] presenting potential opportunities for infrastructure sharing between hydrogen production facilities and industrial decarbonisation efforts.
  - Studies suggest significant overlap between areas where hydrogen could be stored in salt caverns, and potential for geological storage of CO_2, particularly in North West and North East England.[100] These synergies could reduce the costs of a hydrogen energy system.
- The cost of upgrading electricity networks in urban areas is estimated to be up to three times as expensive as rural upgrades.[101] A hydrogen heating pathway could make use of existing gas networks, and avoid electricity network upgrades, potentially favouring dense urban areas where hydrogen can be consumed for heat, as an alternative to electrification.

For example, the H21 North of England study, led by Northern Gas Networks, will set out a vision for how hydrogen could be deployed on a widespread basis in the North of England.

[98] Element Energy (2018) *Hydrogen for heat technical evidence project*.
[99] CCTF (2018) *Delivering Clean Growth*.
[100] Element Energy (2018) *Hydrogen for heat technical evidence project*.
[101] Imperial College (2018) *Alternative UK heat decarbonisation pathways*

Chapter 5: Energy system cost implications

In setting the targets under the Climate Change Act, Parliament has already accepted that meeting them will have some costs. We have previously assessed the cost of meeting the existing 2050 target as being 1-2% of GDP.

Low-carbon heating is very likely to remain more expensive than burning natural gas in boilers (and allowing the CO_2 emissions to escape for free to the atmosphere). We estimate that costs of near-full decarbonisation of heat for buildings, through hydrogen and/or electrification, will be up to 0.7% of GDP in 2050. This estimate is for a degree of decarbonisation that may go beyond what is required to meet the existing 2050 target for an 80% reduction under the Climate Change Act, although this depends on sufficient emissions reductions being made elsewhere in the economy.

However, the dramatic recent falls in the costs of renewable electricity generation and batteries mean that we now expect low-carbon power and transport to cost less by 2050 than their high-carbon equivalents today, offsetting some of the costs of decarbonising heat. The lower costs of low-carbon power generation also reduce the costs of electrified heat.

This assessment of the costs of buildings decarbonisation is consistent across pathways for decarbonisation involving electrification, hydrogen use and hybrid heat pumps (and therefore applicable to the Full, Hybrid and Niche hydrogen scenarios outlined in Chapter 4). This reflects the analysis undertaken for us by Imperial College, which finds that the costs of a range of heat decarbonisation pathways for buildings have similar aggregate costs. This is also in line with the conclusions of the National Infrastructure Commission, based on analysis by E4tech and Element Energy.[102]

In this Chapter, we outline the costs of decarbonising heating using the deployment under a Full Hydrogen scenario to illustrate where the costs fall.

Costs of heat decarbonisation in buildings

In a Hybrid Hydrogen scenario, emissions from heat in buildings could be reduced from around 83 Mt/year today to around 5 Mt/year at a cost of around £28 bn/year. This would be occurring alongside cost reductions for the electricity and light-duty transport sectors between 2030 and 2050 even as these sectors decarbonise, as they switch to zero-carbon options that have lower costs than fossil fuel technologies. Together, this could result in no increase in overall costs and therefore in theory could be managed without increasing consumer bills.

The additional costs come from producing hydrogen and removing the carbon from natural gas (£4 bn/year), installing heat pumps and upgrading electricity networks (£17 bn/year), and installing appliances and changing pipework in consumer premises (£7 bn/year). Alternative options for heat decarbonisation are likely to incur similar costs, including hybrid heat pump and full electrification scenarios, although the distribution of these costs between households and energy production will differ.

- Currently, use of natural gas for heating costs around £30 billion annually. That is largely the cost of buying and burning the gas, plus the cost of replacing gas boilers at the end of their lives (on average every 10-15 years).
- Decarbonising heat that is currently provided by natural gas is likely to incur additional costs of around £28 bn/year.

[102] National Infrastructure Commission (2018), *National Infrastructure Assessment*.

- In a Hybrid Hydrogen scenario, using natural gas to produce hydrogen via gas reforming, and capturing and sequestering the carbon will increase costs compared to just using natural gas. Building and running the hydrogen production capacity and network capability to transport hydrogen to consumer premises at all times could add around £4bn/year to the costs of heat.[103]
- Installing heat pumps in consumer premises, installing low-carbon electricity generation to meet new heat demands, and upgrading electricity networks is expected to add £17 bn/year to the cost of heat.
- In addition to this, installing hydrogen boilers and converting consumer premises to be able to use hydrogen could increase costs by around £7bn/year.[104]
- There remains uncertainty over the infrastructure requirements for a hydrogen world. Theses cost estimates include the cost of converting pipework and other (non-boiler) gas appliances. Those conversions may not prove necessary if pipework in consumer premises could safely carry hydrogen without needing upgrading, and if gas appliances in the home - such as cookers or fires - could be switched to electric equivalents, or made 'hydrogen-ready' in anticipation of a hydrogen conversion. In that case, costs of up to £4bn/year could be saved, reducing total heat decarbonisation costs to £24 bn/year instead of £28 bn/year. BEIS's Hy4Heat programme is investigating the requirements for consumer premises to be able to use hydrogen for heat and other purposes.
- Separately, there is uncertainty around the need for seasonal hydrogen storage. System modelling suggests that significant investment in salt cavern storage could be required for both a Full Hydrogen and Hybrid Hydrogen scenario, at a cost of up to £6bn/year. Improved understanding the need for, and operating characteristics of, geological hydrogen storage could significantly reduce overall costs.

• Under hybrid heat pump and electrification scenarios the total costs incurred would be similar to a hydrogen heating scenario,[105] although the balance of costs would shift, as heat pumps are more expensive upfront, but cheaper to run than hydrogen boilers.

These cost numbers assume a reduction in average household heating consumption from around 14 MWh per annum today to around 10 MWh per annum in 2050, due to an increase in the average efficiency of the housing stock. This is through new-build efficiency improvements and insulation of existing properties. A failure to deliver these savings would imply higher costs for a decarbonised heating system.

[103] CCC estimates based on Imperial College (2018) *Analysis of alternative heat decarbonisation pathways*.
[104] Costs are annualised over the lifetime of the technology using a simple interest approach at a 3.5% discount rate. Capital costs for households are also assumed to be low, at 3.5%, reflecting a world where government action reduces barriers and costs to installing low-carbon technologies in consumer premises.
[105] Imperial College (2018) *Analysis of alternative heat decarbonisation pathways* concluded the costs of heat decarbonisation pathways across a range of emissions reduction scenarios (except for a hydrogen scenario with a strict zero emissions target) - see Box 1.6
[106] CCC (2017) *Energy prices and bills: impacts of meeting carbon budgets*.

Costs when including the power sector and cars

In 2017 the Committee published an assessment of how energy bills are and would be affected by the transition to a low-carbon electricity supply.[106] We concluded that whilst the unit cost of electricity has increased, this has been more than offset by reductions in energy use as energy efficiency has improved. Household energy bills were therefore lower in 2016 than in 2008 when the Climate Change Act was passed. Looking to 2030, we expected the effects of energy efficiency to continue offsetting increased costs of low-carbon electricity and the carbon price.

Beyond 2030, electricity costs should fall, both on a unit basis and in aggregate:

- Renewables are now being contracted at a price lower than the cost of new gas generation (e.g. the latest offshore wind contracts were signed at £57.50/MWh).
- Future projects could be cheaper still as innovation and learning continues and if more established technologies are also offered contracts (e.g. onshore wind and solar).
- Many renewable projects will keep operating beyond their contract lifetimes, potentially providing power even more cheaply (e.g. contracts are for 15 years, whereas project lifetimes are expected to be up to 25).
- Higher payments to legacy projects will cease as their contracts come to an end. Payments under the Levy Control Framework are due to peak at around £9 billion per year in the mid-2020s.[107] These payments to legacy projects will then fall to below £1 billion by 2050.
- Further savings should also be available from energy efficiency, as lights and appliances continue to be replaced by more efficient models.

In total we expect an annual saving from lower costs in the power sector of up to £16 billion per year between 2030 and 2050. All consumers, including commercial and industrial consumers, will be able to benefit from lower costs.

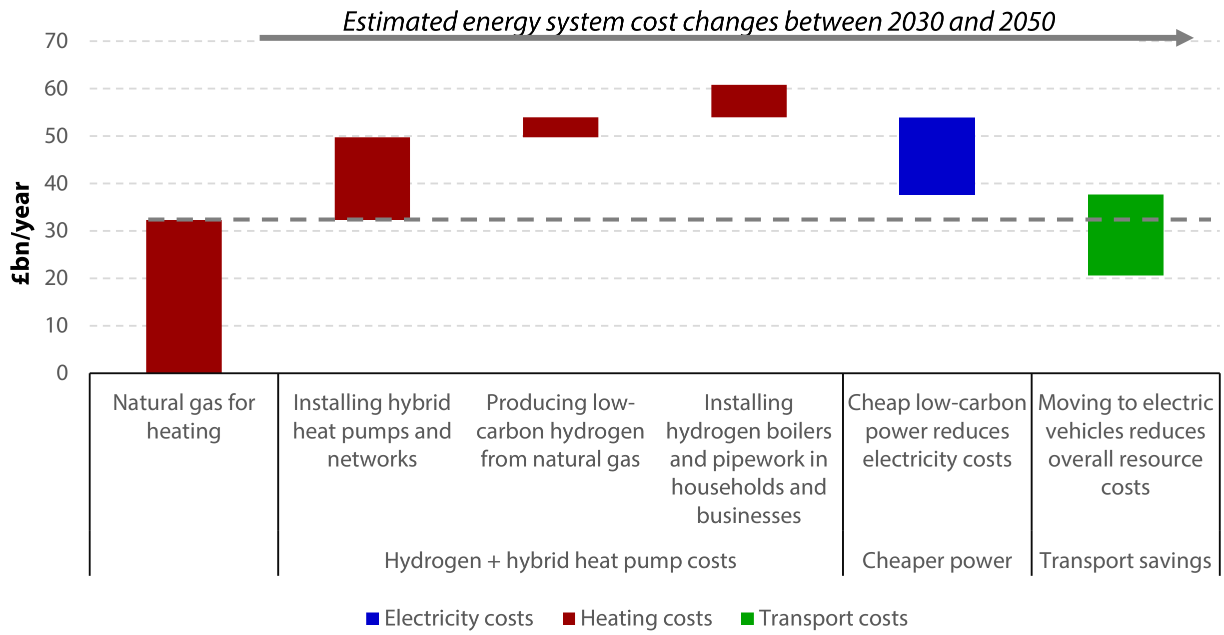
Further savings are available from the transport sector as electric vehicle costs continue to fall:

- At present the total cost of ownership (TCO) of electric vehicles is greater than their internal combustion engine (ICE) equivalents; the premium varies across different vehicle types and categories. This is due to the higher up-front costs of most electric vehicles, even after government support.
- The cost of electric vehicles is expected to steadily decrease in the coming years, as battery costs decline and manufacturing methods improve. Market projections suggests that EVs could reach price parity with ICEs by the mid-2020s.[108]
- Providing the energy for electric vehicles will be significantly cheaper than use of petrol and diesel on a pre-tax basis (i.e. ignoring the fuel duty differential), especially as reduced costs of electricity generation feed through into lower consumer prices.

In total this suggests a saving of up to £17bn/year saving in switching away from diesel and petrol vehicles towards low-carbon transport. Combined with the reduced costs for the electricity sector these savings more than offset the costs of decarbonising the heating sector.

[107] HMT (2017) *Control for Low Carbon Levies*.
[108] Bloomberg New Energy Finance (2018) *Electric Vehicle Outlook*, HM Government (2017) *The Clean Growth Strategy*.

Figure 5.1. Switching to low-carbon heating increases costs but will be occurring alongside cost savings in transport and the power sector



Source: CCC analysis based on Imperial College (2018) *Analysis of alternative UK heat decarbonisation pathways*.
Notes: Transportation savings are pre-tax and do not relate to the fact that electric vehicles in the UK currently don't pay fuel duty.

Distribution of costs and savings

However, the costs of decarbonising heating and savings from power and transport will not automatically fall to the same consumers:

- Households with higher than average heating consumption will be more affected by heating cost increases.
- Some consumers may have more opportunities for energy efficiency to offset these costs than others.
- The benefits of cheaper transport will be skewed towards those who travel most often. Currently a quarter of UK households do not own a car, while over a third of households own more than one.
- Lower power prices over this period will benefit all electricity consumers, including non-domestic consumers.

A challenge for government is to design policies in a way to drive the required changes but without creating too many winners and losers. That will require a joined-up approach and could include:

- Maintaining the Levy Control Framework at its peak level, but redirecting funds to pay for low-carbon heat investments (e.g. the upfront cost of installing a heat pump).

- Rebalancing policy costs between electricity and gas (Box 5.1):
  - Electricity consumption is subject to a carbon price under the EU Emissions Trading System (ETS) and the Carbon Price Floor in the UK, whereas there is no carbon price on domestic gas consumption.
  - Low-carbon support costs are currently higher on electricity as they include the costs of decarbonising the power sector (through subsidies such as the Renewables Obligation and Contracts for Difference).
- Using carbon price income from residual fossil fuel use to help finance the transition. For example, in 2015 the UK's carbon prices (i.e. the EU ETS and the carbon price underpin) raised £2.3 billion, while the Exchequer spent £0.6 billion on the Renewable Heat Incentive and payments to reduce energy costs for heavy industry.
- Shifting tax on vehicle use from a tax on fuel to a tax per mile. In theory the overall tax take could be increased within the same overall cost of motoring, with extra funds redirected to pay for heat decarbonisation.
- It is not for the Committee to dictate these choices and it is not necessarily the case that the goal should be to minimise the change from the current distribution of costs.

There will also be challenges in the regional distribution of costs. Certain areas, regions or customers will move to low-carbon heating solutions before others. Policy will need to be carefully designed to ensure that these consumers are not penalised for switching earlier.

Opportunities to reduce the costs of heat decarbonisation

Government and regulators have opportunities to reduce the costs of the transition to low-carbon heating by reducing investment risk, developing standards for low-carbon heating appliances and developing funding instruments to reduce the cost of capital.

- **Cost of capital.** Modelling by Imperial College for this report identifies savings of up to £16bn/year that could be made by reducing the cost of capital available to developers of hydrogen production facilities from 10% to 3.5%. Whilst it may not be possible to reduce the cost of capital to that extent, this illustrates the importance of reductions in investment risk, and of government developing funding instruments to support hydrogen production in a low-risk way. This principle can be applied to any capital-intensive technologies, including heat pumps.
  - As a comparator, long-term contracts (i.e. Contracts for Difference)[109] for low-carbon electricity generators have demonstrably reduced the cost of capital for project developers.[110] A recent report by Frontier Economics for BEIS suggested that other options for reducing risk could include implementation agreements, Government underwriting of debt and cap-and-floor type regulatory mechanisms.[111]
  - The capital-intensive equipment required for low-carbon heating - such as hydrogen production facilities, heat pumps, or new networks - may not require long-term contracts

[109] Contracts for Difference provide guaranteed revenue streams to low-carbon electricity generators, by offering fixed payments above an electricity price, with the payments (and associated risk) spread over consumer bills.
[110] CCC (2018) *Progress Report to Parliament*.
[111] See Frontier Economics (2018) Market and regulatory frameworks for a low-carbon gas system. In an implementation agreement the Government would guarantee some recovery of development spend if a future Government decision meant that the project could no longer proceed.

in the same way that electricity generators do, but the importance of avoiding unnecessary policy risk remains.

- **Hydrogen-ready appliances.** Development of regulation and standards for hydrogen-ready appliances could reduce costs in a transition towards a hydrogen economy.
  - If 'hydrogen-ready' boilers can be developed at limited additional cost, then they could be installed as part of the regular boiler replacement cycle, and avoid the need for old boilers to be swapped out as part of a future hydrogen switchover, saving costs. If a hydrogen switchover didn't occur then the 'wasted' cost associated with this foregone option would be small, assuming that hydrogen-readiness comes at limited additional cost.
  - Similarly, there will be benefits in making other gas-fired investments hydrogen-ready, such as gas turbines for power stations (Chapter 2), as well as cooking equipment and gas fires.
  - However if deploying 'hydrogen-ready' appliances did incur a significant additional cost, this could result in wasted costs if such boilers were never used for hydrogen. If this cost for hydrogen-readiness is judged worth paying it will be important to ensure that a later switch to hydrogen is feasible. This means hydrogen-ready boilers and power stations being deployed in locations where a switch to hydrogen is potentially feasible (i.e. with potential access to a low-carbon hydrogen supply).
- **Energy efficiency.** Reduced energy consumption through energy efficiency will reduce the costs of all heat decarbonisation pathways.

Developing hydrogen-ready appliances with low additional costs would be a valuable innovation goal. Policies to decarbonise heat and develop a UK supply of low-carbon hydrogen should be designed to keep costs of capital as low as possible.

During the transition to low-carbon heating in the UK, there are several other issues relating to prices and cost recovery, not least the current absence of carbon pricing (Box 5.1).

Box 5.1. Price and cost recovery in a transition to low-carbon heating

Currently low-carbon policies are paid through a mixture of taxation and energy bills. Decisions by Government and regulators will need to be taken on the appropriate means of paying for the costs and savings of the energy transitions, and policy-makers have an opportunity to manage these costs in an equitable way. This will require a joined up approach.

- Switching to low-carbon heating is made more costly by the fact that the carbon costs of gas are not reflected in its price:
- Electricity consumption is subject to a carbon price under the EU Emissions Trading System (ETS) and the Carbon Price Floor in the UK, whereas there is no carbon price on domestic gas consumption (business and industrial gas consumers pay the Climate Change Levy on their gas consumption).
- Low-carbon support costs are significantly higher on electricity as they include the costs of decarbonising the power sector (through subsidies such as the Renewables Obligation and Contracts for Difference). These costs are likely to largely disappear from electricity bills by 2040.
- Both electricity and gas prices include support costs for low-carbon and fuel poverty energy efficiency schemes, at 0.6 p/kWh on electricity and 0.2 p/kWh on gas.
- Longer-term, introducing a carbon price for heat in homes would reduce the cost of low-carbon heat compared to conventional alternatives, and make energy efficiency more cost-effective.

- Fuel duty is currently collected from sales of diesel and petrol, and raised £28bn in revenue for the Exchequer in 2017/18. A transition away from fossil-fuelled to electric and/or hydrogen vehicles - which are currently exempt from fuel duty - will reduce tax revenue, unless fuel duty is extended to include low-carbon vehicles, or alternative mechanisms are introduced.

Additionally, all forms of heat decarbonisation will require a change in the regulatory framework around how consumers currently pay for gas:

- As gases of different calorific values, such as biomethane or hydrogen, enter the gas grid, billing procedures will have to change to ensure that customers are billed according to the amount of useful energy they consume, regardless of the calorific value of the gas in their network.
- Certain areas, regions or customers will move to low-carbon heating solutions before others. As the cost of low-carbon heating is likely to remain higher than the cost of gas heating, the costs of supporting low-carbon heating should be distributed amongst all users, rather than falling on those that reduce heating emissions earliest.
- The Iron Mains Replacement Programme is paid by UK gas customers via their energy bills, with payments for this programme projected to continue beyond 2050. Funding for this programme will need to continue regardless of what happens with gas use, as costs are paid for over a 45-year period.

Source: CCC (2017) *Energy prices and bills: impacts of meeting carbon budgets*, Northern Gas Networks (2018) *H21 North*.
Notes: By volume, hydrogen contains less energy than natural gas - a lower 'calorific value'. Consumers are currently billed according to the estimated calorific value of their energy, by multiplying the amount of gas consumed at a meter point by the UK's standard for 'calorific value of gas'.

Chapter 6: Conclusions and Recommendations

Hydrogen demand and supply

Hydrogen is not a new solution for reducing emissions - for example, fuel cell buses have been running on our roads for the past 15 years. However, hydrogen does not currently make a significant contribution to reducing greenhouse gas or local pollutant emissions in the UK.

The preceding chapters highlight the opportunities that hydrogen offers in reaching the very low levels of emissions from the energy system that will be required in the long term, complementing the roles of electrification, improvements to energy efficiency and carbon capture and storage (CCS):

- **Buildings.** Hydrogen could potential play a valuable role in decarbonisation of buildings heat, especially in meeting the peaks in heat demand on colder winter days:
  - The latest evidence indicates that the costs for decarbonisation pathways based on hydrogen and/or electrification through heat pumps are similar (see Chapter 3). The balance between these solutions should therefore not be primarily determined by cost but by a range of considerations, feasibility of delivery, public acceptability, import dependence and retaining options over how we decarbonise in the long term.
  - Full conversion of the UK's gas distribution networks to hydrogen, and its like-for-like use in boilers as is done today, would lead to a very high demand for hydrogen by 2050 (e.g. 470 TWh even allowing for substantial improvements to buildings energy efficiency). Given the relatively low efficiency of hydrogen energy chains, this requires more energy input than some other pathways, raising questions over feasibility of delivery, import dependence and residual emissions (see below).
  - By focusing the role of hydrogen more narrowly, concerns over delivery, residual emissions and imports can be reduced, while retaining an important role for hydrogen where it would provide the greatest value: in meeting peaks in heat demand in winter months and/or only in particular parts of the country where low-carbon hydrogen can be sourced at lower costs (e.g. due to access to CCS or 'stranded' renewable electricity).
- **Industry.** New evidence indicates that hydrogen has an important potential role in reducing emissions from industrial heat, especially where the flame (and subsequent combustion gases) needs to come into direct contact with the material or product being produced (e.g. in furnaces and kilns). Hydrogen also appears to be well suited to the decarbonisation of more distributed sources of CO_2 emissions (e.g. from the food and drinks sector), which would be impractical and costly to capture.
- **Power.** By 2030, the UK is likely to have a very low-carbon electricity system, with renewables and nuclear backed up by flexible thermal capacity – mainly natural gas plants. There is an opportunity for hydrogen to replace natural gas cost-effectively in this back-up role, potentially enabling power system emissions to get close to zero by the 2040s. This would be helped if new gas plants can be made 'hydrogen ready', including being well-sited with respect to potential hydrogen supplies.
- **Transport.** While battery electric vehicles are now well placed to deliver the bulk of decarbonisation for cars and vans, hydrogen fuel cell vehicles could play an important role for heavy-duty vehicles (e.g. buses, trains and lorries) and potentially for longer-range journeys in lighter vehicles, where the need to store and carry large amounts of energy is greater. There is also a potentially important role in decarbonising shipping, especially if an international market develops in low-carbon hydrogen or ammonia.

Hydrogen is already produced at scale, globally and in the UK - for example in fuel desulphurisation at refineries and for ammonia production. However, the vast majority of hydrogen is currently produced in a high-carbon way, from fossil fuels without CCS. This will need to change for hydrogen to contribute to decarbonisation.

There are three main routes to producing hydrogen in a sufficiently low-carbon way for it to contribute by 2050: electrolysis using low-carbon electricity, bioenergy with CCS and fossil fuels with CCS. The first two of these are likely to be limited by resource availability and/or economics, while there is a question over the size of a role for fossil fuels with CCS due to their residual emissions:

- **Electrolysis.**
  - The use of electrolysers to soak up excess low-carbon power generation can provide a useful form of flexibility to the electricity system, and as such when this occurs we would expect the electricity to be very low cost. However, the infrequency and relatively small size of this opportunity is such that the volumes of hydrogen that can be expected to be produced using very low cost electricity are small in the context of the overall energy system (e.g. up to 44 TWh a year in 2050, less than 10% of buildings gas consumption).
  - Beyond this niche in helping to manage the electricity system, the low overall efficiency of electrolysis and the relatively high cost of using electricity as an input mean that producing bulk electrolytic hydrogen within the UK is likely to be expensive. Large-scale hydrogen production from electrolysis in the UK would also imply extremely challenging build-rates for low-carbon electricity capacity between now and 2050.
- **Bioenergy with CCS (BECCS).**
  - Our parallel report on *Biomass in a low-carbon economy* reaffirms our position that, within the energy system, the best use of finite sustainable biomass resource in contributing to meeting long-term emissions targets is to use it in conjunction with CCS, in order to maximise the overall emissions savings. Although BECCS can be done in several ways, our analysis indicates that production of hydrogen with CCS, sequestering almost all of the bio-carbon, could be a cost-effective route if there is demand for this hydrogen.
  - However, given finite supplies of sustainable biomass globally and potentially strong competing demands for it, we estimate that the UK might have access to around 150-300 TWh of biomass in 2050. Allowing for uses elsewhere (e.g. use of wood as a construction material and other forms of BECCS) and for the energy losses in hydrogen production this might be sufficient to produce up to 150 TWh of hydrogen, although it could be much less.
- **Fossil fuels with CCS.** Production of hydrogen from fossil fuels with CCS (e.g. via reforming of natural gas) is not resource-limited in the same way. Fossil hydrogen production with CCS can be low-carbon, but cannot get to zero-carbon due to residual emissions both from the production of the fossil fuel and incomplete capture of CO_2 in the process of producing hydrogen.
- **Imports.** There is substantial interest in hydrogen globally, which may lead to international trade in low-carbon hydrogen, or an equivalent energy carrier such as ammonia, produced at low cost from cheap energy resources (e.g. wind and solar) that otherwise cannot access a market. Whilst the scope to import low-carbon hydrogen at a competitive cost against domestic production is valuable for the long term, there are risks around reliance on such a

market emerging when taking decisions in the 2020s on the extent to which we repurpose existing gas networks to hydrogen.

- **Storage.** There is significant uncertainty over the extent to which hydrogen storage facilities will be needed alongside the 'linepack' storage in pipelines, and over which types of hydrogen storage will be best suited to help balance the system at least cost.

How big a role should hydrogen play by 2050?

Widespread repurposing of gas distribution grids across the entire UK to hydrogen, and its use as a like-for-like replacement for natural gas in boilers, would entail a very high level of hydrogen consumption in 2050.

This raises questions over the feasibility of delivery of a wholesale shift to hydrogen for heating and, depending on how the hydrogen is produced, its implications for the level of residual emissions that would result if the hydrogen production is low-carbon rather than zero-carbon and for dependence on energy imports:

- **Feasibility of delivery.** A switchover of this scale would entail a very large-scale build out of hydrogen production plants, as well as a programme to switch households over to hydrogen, which would be challenging to achieve even in 20 years across the whole gas grid:
  - Switching all buildings on the gas grid to hydrogen, starting in 2030, would entail scrapping the natural gas boilers and cooking appliances present. While it may be possible to roll out hydrogen-ready appliances over time, the need to start a switchover as early as 2030 means that there would be quite a limited opportunity for these to diffuse through the stock by the time the switchover occurs, especially for areas that convert earlier on.
  - However it is produced, this scale of hydrogen production would require a very large build programme for hydrogen capacity, along with major implications for carbon capture and storage (if production is primarily from natural gas) or zero-carbon electricity generation capacity (if primarily via electrolysis).
- **Residual emissions.** Large-scale production of hydrogen from fossil fuels with CCS by 2050 would lead to some residual emissions, both from a small proportion of CO_2 being released during the hydrogen production process and from emissions relating to production and supply of the fossil fuels themselves. As hydrogen produced from natural gas with CCS can reduce emissions by 60-85% relative to natural gas, it is low-carbon but not close to being zero-carbon. Its widespread use would lead to higher residual emissions than deployment of zero-carbon technologies where this is feasible.
- **Import dependence.**
  - As we outlined in Chapter 4, a very high level of hydrogen consumption means that its production would depend heavily on fossil fuels - most likely natural gas - combined with carbon capture and storage. This would imply very high levels of natural gas consumption in 2050, including a high reliance on gas imports.
  - Decisions on buildings heat for this scale of hydrogen deployment would need to be committed to in the mid-2020s, well before we can be confident that imported low-carbon hydrogen will be able to meet a significant fraction of our long-term needs. A decision to pursue hydrogen at this scale should therefore not rely on an import market emerging in the longer term.

- **NOx emissions.** There remain questions over the emissions of nitrogen oxides (NOx) associated with combustion of hydrogen and therefore impact on air quality from its widespread use. More work is required to identify the size of this potential problem and options to mitigate it.

It is therefore prudent to plan for hydrogen to have a smaller, more focused role in the decarbonisation of heating, playing to its strengths alongside other solutions. This could mean a national role for hydrogen that provides the capacity to meet peak heat demands in winter but meets relatively small proportion of total heating, with hybrid heat pumps meeting much of the 'baseload' demand. There may also be some role for larger amounts of hydrogen deployment more in certain geographical areas.

There remain questions about the size of hydrogen's contribution and about how the UK's energy infrastructure will change over the coming decades. The next decade will be very important in developing the hydrogen option sufficiently for it to make an important contribution by 2050. Rather than a wait-and-see approach, this means making key strategic decisions, taking action to develop the hydrogen option and developing key technologies.

Strategic decisions

Infrastructure and strategic decisions for decarbonisation of road freight

In order for the heavy goods vehicle (HGV) fleet to have turned over fully to ultra-low-emission vehicles (ULEVs) by 2050, this would require 100% of vehicle sales to be ULEVs by the mid-to-late 2030s given the lifetimes of these vehicles. In turn, for a hydrogen solution this would means rolling out infrastructure from the late 2020s.

Given large uncertainties over which technology option will prove most cost-effective, it is important to consider the likely roll-out speeds of alternative technologies, if the electrification of road freight proves a more cost-effective option compared to the use of hydrogen fuel cell HGVs (Box 2.3).

Given the current evidence on lead-times for infrastructure and the time taken to turn over vehicle stocks, the government would need to make a decision on the choice of ULEV solution(s) in the second half of the 2020s.

The Department for Transport should consider running larger-scale trials to assess these technologies in the early 2020s, after learning from the results of the ongoing international trials. This should feed into a decision on the best route to achieving a zero-emission freight sector in the second half of the 2020s.

Prior to this decision, it will also be important to improve understanding of the likely journeys of freight vehicles, by collecting data on lengths of trips, actual payloads and volumes of freight carried and the proportion of each trip spent on major roads. This can inform a full assessment of the different technology options (which may include hybrid hydrogen-electric lorries).

In the near term, the government should continue to focus on developing hydrogen refuelling station and vehicle technology, by building an initial network to allow wider roll-out later in the 2020s. Government funding in support of hydrogen refuelling stations should prioritise those bids which allow a variety of vehicles, including HGVs or buses, to refuel. This will enable SMEs and manufacturers to develop the early market for hydrogen HGVs.

Strategic decisions on heat decarbonisation

The potential use of hydrogen for heating requires strategic decisions, as a wholesale shift away from natural gas for heating can be expected to take around 20 years.

- We have previously set out[112] that decisions on the respective roles of hydrogen and electrification in heating buildings will be required by the middle of the 2020s, in order to allow for these solutions to be rolled out between 2030 and 2050. This means actively preparing for these decisions over the intervening period, by understanding better the challenges and potential solutions relating to each of hydrogen and heat pumps.
- BEIS has commissioned useful and important work in the two years since we set out this decision timeline, which has occurred alongside other analysis and pilots. The latest evidence indicates that the costs for decarbonisation pathways based on hydrogen and/or electrification are similar (see Chapter 1).
- It also suggests a more important role than we had previously considered for hybrid heat pumps by 2050. We had previously been concerned that they would lead to insufficient levels of decarbonisation by 2050. However, the latest evidence suggests that higher proportions of electric heat can be achieved than we had assumed. The latest analysis suggests that the remaining gas demand can be decarbonised with hydrogen, with potentially some contribution from biomethane.
- Solutions for heat decarbonisation may differ across the UK, without significant implications for the overall costs of decarbonisation. However, currently public understanding of heating their homes with hydrogen or heat pumps is far from where it would need to be in order to contribute to making the decisions that will be required in the early 2020s.

We recognise the difficult nature of the decisions around the heat decarbonisation and the future of the gas grid. There may well be a strong temptation politically to 'kick the can down the road' by sticking with natural gas for longer, given the higher costs of the low-carbon alternatives and the lack of end-user benefit that a switch would bring.

This is one of the areas where the challenge is greatest in reducing the UK's emissions to very low levels by 2050. But failing to take the necessary actions and decisions will not significantly reduce size of the challenge and would put at risk the ability of the UK to meet its commitments under the Climate Change Act and the Paris Agreement.

Targeting a smaller role for hydrogen in providing buildings heat, focused where it can provide most value, would raise a question over whether a different approach to can be taken on decisions over future heating and gas grids. The decision could be split, with a part of the decision made soon to drive near-term deployment of hybrid heat pumps at scale, which would also deliver nearer-term decarbonisation. Doing this would also create the option for different kinds of heating solutions by 2050, on which decisions could be made slightly later.

This approach would have lower risks of regret than near-term decisions to pursue hydrogen or full electrification as the primary route for decarbonisation (Box 6.1).

Were a near-term decision made to pursue hybrid heat pumps, it may be possible to defer the second part of strategic decisions on energy infrastructure for heating. However, this would require concerted near-term action to deploy energy efficiency, hybrid heat pumps, low-cost renewable power generation and hydrogen:

112 CCC (2016) *Next Steps for UK Heat Policy*.

- **Energy efficiency.** Regardless of the approach to heat decarbonisation, it is essential that effective policies are developed urgently to deliver on the government's Clean Growth Strategy commitment to improve the efficiency of the existing stock of homes to EPC Band C by 2035. Achieving this will help to reduce people's bills, increase comfort levels and reduce the costs of heat decarbonisation.
- **Hybrid heat pump deployment.** Retrofitting a hybrid heat pump system at the same time as improving energy efficiency in a building would minimise disruption and dramatically reduce its emissions. The scale of deployment should be such that hybrids are widely used by 2035 (e.g. in 10 million homes), reducing the later challenge of tackling residual gas use.
- **Deployment of low-cost renewables.** The dramatic reductions in the costs of wind and solar generation have not only reduced the costs of power sector decarbonisation but also created an opportunity for more cost-effective and earlier electrification of other sectors. As deploying wind and solar will already be cheaper than fossil power generation in the 2020s, the addition of flexible loads to the electricity system should be accompanied by the addition of corresponding amounts of additional low-cost renewable generation.
- **Developing the hydrogen option.** It is likely to be considerably easier and quicker to switch the remaining gas supply to hydrogen once hydrogen has been deployed at scale and become a mainstream option, including establishment of low-carbon hydrogen supplies.
- **Hydrogen-ready heating appliances.** Whilst not essential to a switch to hydrogen, the deployment of hydrogen-ready boilers or fuel cells would reduce the costs and disruption of switching to hydrogen by avoiding scrappage of natural gas boilers. Depending on the development of hydrogen-ready appliances and the cost premium over natural gas boilers, the government should consider mandating hydrogen-ready heating appliances by the mid-2020s similar to the successful mandation of condensing boilers in 20 years earlier.
- **Other low-regrets actions to reduce heating emissions.** It remains necessary to pursue the range of actions we described as low-regrets in our 2016 report on *Next Steps for UK Heat Policy*: deployment of low-carbon heat networks in heat-dense areas; ensuring that new buildings are efficient and low-carbon from the outset; heat pump deployment off the gas grid; and increasing levels of biomethane injection into the gas grid.

Being able to split the approach to deciding on the long-term future of heating and the gas grid relies on the government ensuring good progress in the areas set out above. This would enable decisions to be taken more gradually, over the period to 2030, as the implications of different pathways become clearer. However, should less progress be made in some or all of these areas it might be necessary to intervene at an earlier stage in order to ensure that the buildings sector can be fully decarbonised by 2050. We will keep progress under review.

Deployment of hybrid heat pumps would offer an additional way of reducing emissions in the 2020s, beyond those set out in the Clean Growth Strategy, helping to meet and outperform the fourth and fifth carbon budgets (covering 2023-27 and 2028-32). This progress would also reduce the risks, and potentially the costs, relating to meeting long-term emissions reduction goals. However, it will also come with some increased costs in the 2020s - mainly the capital costs of the hybrid heat pumps.

There remain important questions over how to pay for heat decarbonisation, especially in the case that this is achieved in different ways or at different paces in different parts of the UK (see Chapter 5). We have not attempted to address these questions in detail in this report, but they will be an essential part of any strategy to decarbonise heating.

Box 6.1. Near-term deployment of hybrid heat pumps could develop options for full decarbonisation

A large deployment of hybrid heat pumps together with much improved energy efficiency across the building stock by the mid-2030s would reduce emissions very substantially from properties on the gas grid. A key advantage of hybrid heat pumps is that they can be retrofitted around existing heating systems, retaining the existing radiators and also the existing boiler (although its utilisation would be much decreased). This means that the retrofit could sensibly be done together with improvements to the energy efficiency of the building. In combination, these changes could reduce a household's gas consumption by over 80% and reduce energy bills.

In sharply reducing gas demand and increasing public awareness of heat pumps, it would also help to develop more deliverable solutions relating to full heat pumps and hydrogen to 2050:

- **Hybrids then full heat pumps.** A widespread deployment of hybrid heat pumps would lead to a much better public understanding of heat pumps as a heating option. In turn, this could increase their acceptance of full heat pump solutions, making their widespread roll-out more achievable than it is likely to be in the nearer term. If from a certain date (e.g. 2035), hybrid systems at the ends of their lifetimes were replaced with full heat pump solutions, then over the following 15 years this stock could be very largely turned over. In this way hybrids could end up being an enabler to a widespread switch to full heat pumps by 2050.
- **Hydrogen hybrids.** Near-term deployment of hybrid heat pumps, together with making new gas heating appliances hydrogen-ready, could make a switch to a hybrid solution of hydrogen plus heat pumps more achievable and potentially reduce the costs of doing so:
  - If the deployment of energy efficiency and hybrid heat pumps is successful in reducing gas demand sharply, this would reduce the challenge of switching remaining natural gas consumption to hydrogen. Overall gas consumption in buildings could be reduced by around 75%, which would in turn reduce the challenge in supplying the necessary volumes of hydrogen and could reduce the time needed for the switch.
  - The other key challenge in switching from natural gas to hydrogen is the disruption and costs at the household level. If there were a sufficiently large stock of hydrogen-compatible heating appliances - either boilers or fuel cells - by the time of a switchover to hydrogen there would be many fewer boilers that need to be scrapped. This would reduce the costs significantly and increase the public acceptability of a switch to hydrogen. This could potentially be achieved by deploying hydrogen-ready heating appliances sufficiently early (e.g. from the mid-2020s) as part of the standard boiler replacement cycle, so that these would be able to build up in the stock by the time the switch occurs.

It remains to be seen what the right balance between hydrogen and full electrification will be in the long term, but the aim should be to eliminate all direct use of hydrocarbon fuels for heating buildings by 2050 through low-carbon energy delivered through a combination of hydrogen, electrification and heat networks. In the case that some areas of the gas network are particularly difficult to switch to hydrogen and these buildings cannot switch to fully electric solutions, the small amount of residual fuel demand could potentially be met through biomethane from anaerobic digestion.

We intend to commission further analysis to look at how accelerated deployment of flexible electricity demands (e.g. electric vehicles, hybrid heat pumps) could help to manage an electricity system with an increasing proportion of variable renewables and, in turn, how cheap renewables can help cost-effective earlier decarbonisation of heat and transport.

A potential shift of approach, to deployment of hybrid heat pumps in the near term, also brings into focus the imbalance in the respective retail prices of electricity and gas:

- Electricity prices have historically been increased significantly relative to gas prices due to the way costs relating to policies both to reduce emissions and to achieve social objectives were levied,

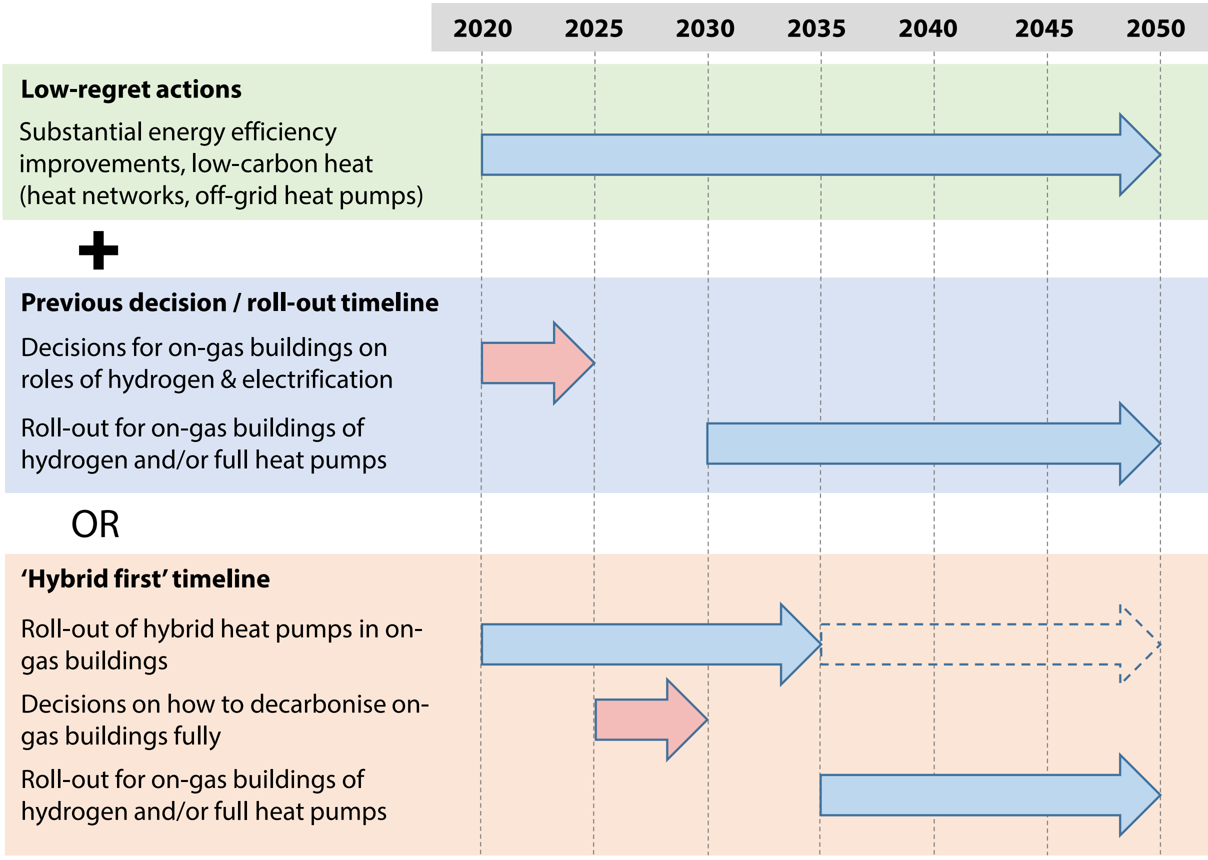
Box 6.1. Near-term deployment of hybrid heat pumps could develop options for full decarbonisation

paid for through consumer electricity bills. By placing these costs primarily onto electricity prices, households off the gas grid that rely on electric heating paying disproportionately towards the costs of these policies.

- It has also made it significantly more costly to move from fossil fuel heating to electric heating, and distorts the operational incentives over when a hybrid system should be operated on electricity rather than fossil fuel.

Rebalancing the relative costs of electricity and gas would make the introduction of hybrid heat pumps more achievable and provide appropriate signals so that they achieve high proportions of electric heat, as well as reducing the burden of policy costs on electricity-only households.

Figure B6.1. Pursuing a 'hybrid first' approach alongside other low-regret actions



Notes: 'Low-regret' actions are those that the Committee recommended in 2016 should be pursued immediately, with subsequent decisions to be made by the mid-2020s on the respective roles of hydrogen and electrification in on-gas buildings outside heat network areas, for roll out between 2030 and 2050 (shown the middle section of the diagram). The 'hybrid first' timeline would entail pursuing the low-regret actions now alongside deployment of hybrid heat pumps in on-gas properties, with decisions on achieving full decarbonisation potentially coming slightly later.

Coordination and action

At the moment, hydrogen is not commercially competitive in most potential applications. This is likely to continue unless and until costs can be driven down, including through deployment at scale. Continuation of an incremental approach that relies on isolated, piecemeal demonstration projects may lead to hydrogen continuing to remain forever an option 'for the future'.

The UK does not currently produce significant amounts of low-carbon hydrogen nor does it have technologies in place that would provide a market for that hydrogen. One of the key challenges for hydrogen and its associated technologies is to get a foothold in the energy system, overcoming this 'chicken and egg' barrier.

- This could be done through taking a highly coordinated approach, ensuring that hydrogen demand and supply infrastructure develop in parallel. It is likely that this coordination would need to be led by government, due to the range of policy levers it has on both the demand and supply sides, and given the funding that would be required.
- The need for active coordination can be lessened, however, by taking actions that break the interdependence of supply and demand. This could be achieved, for example, through establishing low-carbon hydrogen supplies that can be accommodated within the existing energy infrastructure (e.g. through blending of hydrogen into the gas grid and/or generation of power from the hydrogen produced) and/or deploying technologies that can be switched over to hydrogen when supplies become available (e.g. hydrogen-ready boilers or gas turbines).

Without taking near-term action to deploy hydrogen, it is difficult to see how the infrastructure and costs challenges will be addressed to enable it to play an important part in decarbonisation by 2050. This means starting deployment of hydrogen in a 'low-regrets' way in the 2020s, recognising that even an imperfect start is likely to be better in the long term than a 'wait-and-see' approach that fails to develop the option properly.

Key technologies

Whilst hydrogen can be produced in a range of ways and used in a variety of applications, there are several technologies that are of strategic importance in enabling hydrogen to play a substantial role in a highly decarbonised energy system:

- **Carbon capture and storage (CCS).** As we outlined in Chapter 3, there are three main routes to producing hydrogen in a sufficiently low-carbon way for it to contribute by 2050: electrolysis using low-carbon electricity, bioenergy with CCS (BECCS) and fossil fuels with CCS. A large role for hydrogen within the energy system will entail an important role for CCS:
  - While the electrolytic route can help to manage a low-carbon electricity system, the amount of hydrogen it can produce in the UK at reasonable cost is likely to be relatively small. Beyond this, due to low efficiency of this energy chain, it is likely to be expensive and imply extremely challenging build rates of low-carbon electricity.
  - Without CCS therefore, hydrogen is likely to be limited to niche applications unless a large-scale international market in low-carbon hydrogen (e.g. carried as ammonia) emerges. Such an international market cannot be relied upon and is unlikely to occur in the next 10-15 years, during which time key decisions on the role of hydrogen must be made.

- Infrastructure decisions relating to repurposing parts of the gas grid to hydrogen must therefore be taken on the basis that sufficient low-carbon hydrogen can be produced domestically. This means establishing CCS as a credible pathway by the time these infrastructure decisions are taken in the first half of the 2020s.

- **Biomass gasification.** Hydrogen production has been identified in our analysis as a key potential use for finite bioenergy resources in conjunction with CCS. Biomass gasification is a key technology that would open up a range of potential pathways for using bioenergy with CCS (BECCS), including hydrogen production but also routes to production of synthetic fuels for use where the use of hydrocarbons cannot be eliminated completely (e.g. aviation fuels). However, biomass gasification is not yet proven at scale, and it should be priority to do so.

- **Hydrogen-ready heating appliances.** The development of hydrogen-ready heating appliances, whether boilers or fuel cells, at reasonable cost would open the possibility to reduce significantly the costs of, and barriers to, switching buildings heat to hydrogen.
  - This would depend not only on the hydrogen-ready technologies being available at a sufficiently small premium relative to natural gas boilers but also that they are rolled out as part of the normal boiler replacement cycle in time to comprise a large proportion of the stock of heating appliances by the time any grid switchover to hydrogen occurs.
  - This implies that hydrogen-ready appliances would need to be available - and probably mandated - in areas earmarked for switching the gas grid to hydrogen, during the 2020s to allow for substantial turnover of appliances by say 2040 in areas where the switch to hydrogen does not occur in the 2030s.

- **Hydrogen-ready turbines.** Emerging evidence, and discussions with leading equipment manufacturers, suggest that burning hydrogen and/or ammonia as a low-carbon fuel for power generation is possible in new – and in some cases existing – turbines and engines.
  - Work should be done to improve the evidence and understanding of this, with particular focus on the ability to develop 'hydrogen-ready' turbines that can be installed in new natural gas CCGTs, opportunities for retrofitting existing turbines and engines to burn low-carbon fuels, and solutions that can reduce emissions of NOx during the combustion process.
  - Consideration should also be given to the opportunities to site gas plants near to a supply of low-carbon hydrogen, so that a transition to switch turbines to using hydrogen is more feasible.

- **Hydrogen HGVs.** Use of hydrogen fuel cell vehicles is a key option for the decarbonisation of heavy-duty transport, including HGVs. There is emerging interest in developing hydrogen HGVs internationally – the UK should support these efforts, including demonstration of these technologies where appropriate.

Recommendations

In order for hydrogen to become an established option for decarbonisation during the 2020s, the Committee recommend the following range of actions on strategy, deployment, public engagement, demonstration, technology development and research:

- **Heat decarbonisation strategy.** A key use of hydrogen is as a decarbonised fuel for heat in buildings and/or industry. This requires strategic certainty on how decarbonisation of heat will be delivered in the UK. In order to create the necessary signals for commercial investment, a commitment should be made now to develop a fully-fledged UK strategy for decarbonised heat within the next three years, including clear signals on the future use of the gas grid and supporting requirements for carbon capture and storage (CCS) in the UK.
- **Strategy for decarbonising heavy goods vehicles (HGVs).** By 2050 it will be necessary for HGVs to move away from combustion of fossil fuels and biofuels to a zero-emissions solution. Decisions about how to achieve this will be required in the second half of the 2020s. This will necessitate small-scale trial deployments of hydrogen HGVs in a variety of fleets prior to this, in the UK or elsewhere.
- **Energy efficiency improvements.** Regardless of the approach to heat decarbonisation, effective policies must be developed to deliver on the government's Clean Growth Strategy commitment to improve the efficiency of the existing stock of homes to EPC Band C by 2035. Achieving this will help to reduce people's bills, increase comfort levels and reduce the costs of heat decarbonisation. New buildings should be built with a high level of energy efficiency and designed for low-carbon heating systems, enabling them to be low-carbon from the outset.
- **Hydrogen deployment.** We have previously recommended that two CCS clusters are developed in the 2020s, in order to establish a CCS industry and enable deployment at scale from 2030. We now recommend that significant volumes of low-carbon hydrogen should be produced at one of these clusters by 2030, and be used in applications that would not require major infrastructure changes (e.g. applications in industry, power generation, injection into the gas network and depot-based transport).
- **Identification of low-regret hydrogen deployment opportunities.** The government should assess the range of near-term opportunities for hydrogen use across the energy system and set a strategic direction for low-regret use of hydrogen in the 2020s.
- **Public engagement.** Currently the general public has a low awareness of the need to move away from natural gas heating, and what the alternatives might be. There is a limited window to engage with people over future heating choices, understand their preferences and factor these into strategic decisions on energy infrastructure. This is especially important if solutions to heat decarbonisation could differ in different parts of the UK.
- **Demonstration.** In order to establish the practicality of switching to hydrogen, trials and pilot projects will be required for buildings, industry and transport uses. It is also necessary to demonstrate that hydrogen production from CCS can be sufficiently low-carbon to play a significant role:
  - Before any decision to repurpose gas grids to hydrogen for buildings heat, pilot schemes will be necessary to demonstrate the practical reality of such a switchover. These must be of sufficient scale and diversity to allow us to understand whether hydrogen can be a genuine option at large scale.

- – Hydrogen use should be demonstrated in industrial 'direct firing' applications (e.g. furnaces and kilns).[113]
  – Depending on international progress in demonstrating hydrogen HGVs, the Department for Transport should consider running trials in the early 2020s, in order to feed into a decision in the second half of the 2020s on the best route to achieving a zero-emission freight sector.
  – A substantial role for hydrogen produced from natural gas with CCS depends on delivering emissions savings towards the higher end of our estimated range of 60-85% on a lifecycle basis. This means demonstrating that it is feasible to achieve very high CO_2 capture rates (e.g. at least 90%) at reasonable cost from gas reforming.
- **Technology development.** There are technologies that are not yet deployable at scale but could play important roles within hydrogen use in the energy system by 2050. These include hydrogen-ready technologies, such as boiler and turbines, as well as hydrogen HGVs and biomass gasification. It is important that these are a focus for government support, in order to create a sufficiently wide range of pathways to achieve long-term emissions targets.
- **Further research** is required in a number of areas to establish the feasibility and desirability of using hydrogen in a range of applications:
  – This report identifies a key opportunity for hydrogen to provide low-carbon energy at peak times, performing a role currently played natural gas. Key to this will be the ability to deliver large quantities of hydrogen in a short space of time. It is therefore important to establish how the various options to store hydrogen perform with the patterns of operation that appear in models.
  – Research and development is required on hydrogen technologies for industrial heating applications, especially where there may be technical barriers to use of hydrogen.
  – The implications of hydrogen combustion for NOx emissions must be established – compared to fossil fuels and to any low-carbon alternatives – across applications in buildings, industry and power. This includes identifying potential technologies that can mitigate these NOx emissions.
  – The feasibility of hydrogen use in gas turbines for power generation should be established, with consideration given to making new gas-fired capacity 'hydrogen ready'.
  – The most cost effective way to produce and distribute hydrogen in order to supply a nationwide refuelling network for heavy-duty vehicles should be assessed, in consideration of hydrogen purity requirements and how these can be met.
  – It will be important to complete the work currently underway to establish the safety of hydrogen use, and to understand the implications of this for hydrogen deployment.
  – Further work is required to establish whether and to what degree hydrogen acts as an indirect greenhouse gas if emitted to atmosphere.

We will continue to bring together and develop the evidence regarding how deep emissions reductions and the respective roles of different solutions, as an input to our advice on the UK's long-term targets in spring 2019.

[113] Direct firing refers to combustion-based heating processes (such as furnaces and kilns) where the combustion gases come into direct contact with the product that is being heated.

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