Preface

The Sustainable Gas Institute (SGI) is a unique academic-industry partnership, and a ground-breaking collaboration between the United Kingdom and Brazil. The Institute is multidisciplinary and operates on a global open innovation model, based at Imperial College London, and collaborating with leading universities in Brazil. The Sustainable Gas Institute manages, leads and delivers world class research with global partners across the spectrum of science, engineering, economics and business.

The aims of the Institute are to:

• Examine the environmental, economic and technological role of natural gas in the global energy landscape;
• Define the technologies and develop energy systems models that could explore the role of gas and other energy sources;
• Help to advance technology roadmaps to support future industry R&D investment decisions; and
• Address the global challenge of how to mitigate climate change.

The White Paper Series

The aim of the Sustainable Gas Institute (SGI) White Paper Series is to conduct systematic reviews of literature on topical and controversial issues of relevance to the role of natural gas in future sustainable energy systems. These white papers provide a detailed analysis on the issue in question, along with identifying areas for further research to resolve any shortcomings in our understanding. The reviews also examine key future technologies and provide a critique of assessment processes.

To download the papers and find out more about the White Paper Series:
http://www.sustainablegasinstitute.org/white_paper_series/
Acknowledgement

The Sustainable Gas Institute was founded by Imperial College London in partnership with BG Group (now Royal Dutch Shell). The authors of this report would also like to acknowledge the contribution of the expert advisory group; a group of independent experts who have offered valuable comments and guidance on both the scoping of the project and the final report. The expert advisory group comprises Chris Andreou (National Grid), Philip Cohen (Department of Business, Energy and Industrial Strategy), PaulDodds (University College London), David Joffe (Committee on Climate Change), Stephen Marland (National Grid), Dan Sadler (Northern Gas Networks) and Goran Strbac (Imperial College London). It should be noted that any opinions stated within this report are those of the authors.

Units

Unless otherwise stated:

- All energy and efficiency expressed as Higher Heating Value (HHV)
- All emissions in CO₂eq. including supply chain emissions
- All costs normalised to 2016 pounds or pence sterling
- All pressures in bar gauge unless otherwise stated

The energy units used in this report are watt-hours. To convert any of these data to gas volume (m³) or gas weight (kg) please multiply by the relevant correction factor.

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Note: Conversions in Standard Temperature and Pressure (STP)
Executive Summary

The future for gas networks is uncertain and contested, mainly due to the carbon dioxide (CO₂) and methane emissions associated with natural gas systems. Gas networks are used in many countries to deliver natural gas to industrial, commercial and domestic consumers, supplying energy for a range of services, including space heating, water heating and cooking.

Existing gas networks are extensive, with an estimated 2.8 million kilometres of gas transport pipelines globally. Low pressure gas networks deliver a significant amount of energy annually to commercial and domestic consumers (8,158 terawatt-hours globally) with a large proportion of this used for heating in buildings. However, unabated natural gas use in the domestic and commercial sectors is unlikely to be compatible with climate change goals. The carbon emissions created by burning natural gas in modern gas boilers is in the range of 230 to 318 gCO₂eq/kWh heat, including supply chain methane emissions.¹

The carbon dioxide and methane emitted by natural gas systems and the difficulty in capturing emissions at domestic, commercial, and many industrial end-uses, is a problem for global carbon reduction ambitions. Country-level scenarios show a reduced role for gas networks in the future, often preferring electricity and heat pumps to decarbonise domestic and commercial energy services. However, there are significant technical, economic and consumer barriers to electrifying heat, which have made widespread uptake of electric heat challenging. Given these concerns there is a growing argument that decarbonised gas networks could play a significant role in the future energy system and contribute significantly to decarbonisation. The aim of this white paper is to review the evidence on options for the future use of gas networks, including the use of biomethane and hydrogen, focusing on their technical potential, carbon intensity and costs.

While much of the evidence is from a small number of countries, implications for other countries are explored. The study examines how these options compare to each other and to the electrification of heat via heat pumps.

¹. This assumes 90% boiler efficiency (1) for a modern domestic condensing boiler, UK 2015 natural gas combustion emissions of 184 gCO₂eq/kWh (2) and supply chain emissions of 47 to 134 gCO₂ eq/kWh.
Key Findings

1. Gas networks have the potential to play an important role in decarbonising the future energy system and therefore should not be discounted in energy scenarios.

   • A number of options exist to decarbonise gas networks. A significant proportion of consumers could be converted to low-carbon gas where suitable networks exist. There are also significant benefits to decarbonising and maintaining these networks.

These include:

   • utilising the value of existing assets;
   • the inherent flexibility of gas vectors;
   • consumer preference for gas based appliances; and
   • the relative low cost and ease of installing gas-fired heating systems in existing dwellings.

   • However, there are still significant uncertainties around the technical capabilities of existing networks, the level of decarbonisation achievable and the resulting costs. Improving the evidence around these issues is therefore a key priority for future work.

2. The storage potential of low carbon gas offers a significant advantage over electricity networks, providing relatively low cost flexibility, particularly for seasonal fluctuations in energy demand.

   • The fluctuations in gas demand are significant, though natural gas currently handles this challenge well. Future decarbonised gas options will have similarly flexible properties whereas for an electricity system, flexibility is more technically challenging and expensive.
   • For example, per kilowatt-hour the cheapest forms of electricity storage are approximately four times more expensive the highest cost estimates for hydrogen storage in salt caverns.
   • However, the value of this flexibility is unclear and dependent on a number of factors including the future balance of decarbonised gas and electricity demand, and the future costs and potential of all technologies that can provide system flexibility. Improving our understanding of the value of low carbon gas flexibility is therefore important.

3. The options for producing decarbonised gas have a range of different positive characteristics, but there is no ‘best option’.

   • Biomethane is most compatible with existing gas networks and may deliver negative emissions. Electrolysis has the potential to deliver very low carbon hydrogen from renewable energy without the need for carbon capture, and steam methane reformers (SMR) are scalable at relatively low cost.
However, these options also have limitations. For example, there are limitations on the future availability of biomass, and there will be competition for these resources. Electrolysis is currently expensive relative to other methods to produce hydrogen, although cost reductions are anticipated. Using natural gas to generate hydrogen in steam methane reformers could increase gas demand of 15% to 66% per unit of energy delivered to consumers relative to direct use of natural gas.

4. The range of CO₂ emissions estimates for the different methods to produce low carbon gas is extremely large; -371 to 642 gCO₂eq/kWh for hydrogen (Figure ES1), and -50 to 450 gCO₂eq/kWh for biomethane.

- The highest and most variable emissions come from fossil fuel routes to produce hydrogen that do not include carbon capture and storage (CCS). These technologies are likely to produce carbon intensities greater than current gas networks. Any fossil fuel routes to hydrogen production must therefore include carbon capture and storage to avoid a higher carbon intensity than the natural gas system it replaces.

- Emissions estimates for steam methane reformers with carbon capture and storage typically lie in the range of 23 to 150 gCO₂eq/kWh, while CO₂ emissions from electrolysis range from 25 to 178 gCO₂eq/kWh for renewable electricity sources. The carbon intensity of heat might be between 26 and 167 gCO₂eq/kWh for methane based hydrogen and 27 to 198 gCO₂eq/kWh for hydrogen from electrolysis, assuming a 90% efficient hydrogen boiler. Heat pumps with 250% efficiency using the same electricity might deliver heat with CO₂ intensity of 10 to 71 gCO₂eq/kWh.

2. This includes embodied emissions of renewable generation manufacturing.
Supply chain emissions are an important aspect of decarbonised gas life cycles, particularly as emissions from decarbonised gas production decrease.

Supply chain emissions include the methane and carbon dioxide emissions in the natural gas supply chain, the embodied carbon dioxide emissions in electricity generation, and the negative emissions associated with biomass cultivation.

The supply chain emissions for hydrogen production from both steam methane reforming and electrolysis are the most important source of total emissions due to the relatively low emissions in the hydrogen production process. In both cases supply chain emissions are expected to decrease as emissions in gas production and transportation are reduced, and as decreasing electricity carbon intensity feeds back into the manufacturing of electricity generating technologies.

Biomass gasification emissions are characterised by large negative supply chain emissions and large positive hydrogen production emissions. Small percentage improvements in biomass gasification emissions could therefore have relatively large impact on total emissions.

5. The cost estimates for different decarbonised gas options vary significantly. The retail price achievable based on these costs might be 4.4 to 13.6 p/kWh (average 8.1 p/kWh) for biomethane compared to a hydrogen price estimate of 4.9 to 18.4 p/kWh (average 9.3 p/kWh). 3

These prices exclude the costs of converting gas users to hydrogen compatible systems. Estimates can be compared to the EU average retail price of natural gas, 5.4 p/kWh, and the EU average retail price of electricity, 17p/kWh (both in 2015).

If the future efficiency of methane or hydrogen fired boilers is 90%, the costs of delivered heat ranges from 4.9 to 15.1 p/kWh heat for biomethane and 5.4 to 20.4 p/kWh heat for hydrogen. For comparison, at heat pump efficiencies of 250%, a retail electricity price of 17 p/kWh, heat pumps could produce heat for 6.8 p/kWh.

The additional cost of converting consumers to hydrogen gas networks may be over £3,000 per household including appliances and supporting equipment such as meters and domestic service pipes. This can be compared to the cost of installing air source heat pumps at between £4,000 to £11,000 or ground source heat pumps at £13,000 to £20,000.

3. These prices include costs for gas generation, transportation, storage, and assumptions regarding tax, profit and other additional costs.
6. Countries with mature gas networks such as the Netherlands, the UK and the USA may find gas network decarbonisation options attractive given the value of their existing assets.

- Existing low pressure gas networks are compatible with biomethane, and the cost of converting existing low pressure gas networks to carry hydrogen is expected to be small relative to total system costs.
- Countries with gas networks connected to less than 50% of gas consumers may continue to develop low pressure networks and may have opportunities to design those assets to be compatible with potential hydrogen conversion in the future.
- Where low pressure gas distribution networks are very small or non-existent the cost of building them may be significant, but not necessarily prohibitive. For example, to build a new hydrogen low pressure distribution network similar in length to the networks existing in the UK or Japan might cost £145 billion. Spread over 20 million domestic gas consumers (approximate number of UK gas consumers) this is £7,250 per household, which is within the order of costs associated with other types of domestic heat decarbonisation such as installing air source or ground source heat pumps. This can be compared to an estimated cost for repurposing an existing natural gas network of the same length to transport hydrogen of £2 billion or £10,000 per km.
7. There is limited real-world evidence on the capability of low pressure gas networks to transport 100% hydrogen gas streams effectively. Improving our understanding in this area will be key to making future investment decisions.

- A number of studies exploring the decarbonisation of gas networks are designed around the transportation of hydrogen through existing low pressure gas infrastructure. However, there are a number of potential issues associated with this, including the increased potential for gas leaks.

- Several studies have considered, and tested, the durability, integrity and safety of existing low pressure gas distribution infrastructure in a small number of countries. They found increased but manageable gas leakage rates and safety concerns. However, this evidence often focusses on hydrogen/methane blends and not on 100% hydrogen gas streams. The diversity of materials and variable quality and age of existing low pressure gas networks is an issue for extrapolating these findings to real-world gas systems.

8. Key considerations for policy include:

- **Setting gas decarbonisation standards**
  The carbon intensity of decarbonised gases differs due to a range of factors. If decarbonised gas networks are pursued then policy should ensure these systems are sufficiently low carbon. A number of policy approaches are possible, including a standard for low carbon gas or a market based mechanism. It is important that any policy measures used should ensure decarbonisation at the network level, and encourage the lowest possible carbon intensities.

- **Developing consumer awareness approaches for network conversion**
  Choosing areas of the existing gas network to convert to hydrogen will be a significant policy consideration. Consumers in these areas will not have the option to continue using natural gas. This will raise related questions including what rights do these consumers have, how do you ensure equity between all gas network consumers and what does this mean for competitive energy markets.

- **Advancing the evidence base and standards around hydrogen safety**
  Establishing the safety of hydrogen networks is an important first step before more significant gas network investment decisions are made. There is evidence that the safety of hydrogen networks is not a barrier. However, there is, currently, little demonstration evidence. An extensive and robust evidence base on safety issues should be developed before significant commitments are made on hydrogen networks. In 2017 the Department of Business Energy and Industrial Strategy announced a £25 million programme investigating hydrogen standards and the development and testing of hydrogen appliances in domestic buildings. Efforts should be made to coordinate these projects with existing activities.
9. There are a number of opportunities for future research. These include the development of practical demonstration projects, and new whole-system modelling research that incorporates evidence from practical experience and quantifies the system-wide impacts.

- Future projects should be coordinated to ensure findings from practical demonstrations inform modelling efforts, and vice versa.

Priorities for practical demonstration of gas network decarbonisation options include:

- Examining the main gas network options to understand real world efficiencies, carbon intensities and costs achievable;
- Testing of hydrogen safety, in households, commercial consumer premises and in the existing low pressure gas network; and
- Analysis of the consumer and system-level impacts associated with new technologies such as hybrid gas/electric heat pumps, fuel cells or gas heat pumps.

Better whole-systems modelling analysis is needed, grounded in the practical reality of gas network decarbonisation options, to provide a stronger evidence base for decision makers. This includes:

- Spatially resolved and fine timescale whole-system modelling examining the conditions and locations under which gas networks may be competitive options;
- Modelling the interactions between gas, electricity and other energy infrastructures to better quantify the system value of gas flexibility and the optimal balance of energy system options to maximise this value while taking advantage of the positive characteristics of other energy system options; and
- Quantifying the economic costs and benefits of different gas network decarbonisation options to establish the conditions needed for a positive business case for investment in these options.
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<tr>
<td>AD</td>
<td>Anaerobic Digestion</td>
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<tr>
<td>ASHP</td>
<td>Air Source Heat Pump</td>
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<td>ATR</td>
<td>Autothermal Reforming</td>
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<td>BECCS</td>
<td>BioEnergy with Carbon Capture and Storage</td>
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<td>BEIS</td>
<td>UK Department for Business, Energy &amp; Industrial Strategy</td>
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<td>BioSNG</td>
<td>Bio-synthetic Natural Gas</td>
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<tr>
<td>CH(_4)</td>
<td>Methane</td>
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<tr>
<td>CO(_2)</td>
<td>Carbon Dioxide</td>
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<td>CO</td>
<td>Carbon Monoxide</td>
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<td>CHP</td>
<td>Combined Heat and Power</td>
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<td>CCC</td>
<td>Committee on Climate Change (UK)</td>
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<td>CCS</td>
<td>Carbon Capture and Storage</td>
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<td>EASEE</td>
<td>European Association for the Streamlining of Energy Exchange-gas</td>
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<td>ETI</td>
<td>Energy Technologies Institute</td>
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<td>GHG</td>
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<td>GSHP</td>
<td>Ground Source Heat Pump</td>
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<td>GWP</td>
<td>Global Warming Potential</td>
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<td>H(_2)</td>
<td>Hydrogen</td>
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<td>HHV</td>
<td>Higher Heating Value</td>
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<td>IEA</td>
<td>International Energy Agency</td>
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<tr>
<td>IGCC</td>
<td>Integrated Gasification and Combined Cycle</td>
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<td>LTS</td>
<td>Local Transmission System</td>
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<td>LUC</td>
<td>Land-Use Change</td>
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<td>Micro Combined Heat and Power</td>
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<td>NTS</td>
<td>National Transmission System</td>
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<td>Ofgem</td>
<td>The Office of Gas and Electricity Markets</td>
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<td>PSA</td>
<td>Pressure Swing Adsorption</td>
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<td>Proton Exchange Membrane</td>
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<td>SNG</td>
<td>Synthetic Natural Gas or Substitute Natural Gas</td>
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<td>Seasonal Performance Factor</td>
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<td>UCTE</td>
<td>Union for the Coordination of the Transmission of Electricity (UCTE) in Germany</td>
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<td>UK Energy Research Centre</td>
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<td>World Energy Outlook</td>
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1. Introduction

The future for gas networks is uncertain and contested. Gas networks are used in many countries to deliver natural gas to industrial, commercial and domestic consumers, supplying energy for a range of end-uses including power generation, industrial heat and chemicals, building heat and transport. However, current use of natural gas by domestic and commercial consumers is unlikely to be compatible with climate change goals in a number of countries. The carbon dioxide (CO\(_2\)) produced by natural gas combustion, and the difficulty in capturing CO\(_2\) at domestic and commercial end-uses, are problems for carbon reduction ambitions [3, 4]. Country level emissions abatement scenarios show a smaller role for gas networks in the future, often preferring electric routes to the decarbonisation of domestic and commercial energy services [5-7]. However, there are significant technical, economic and consumer barriers to electrifying heat, which may make deep penetrations of electric heat challenging [8-10].

Given these concerns there is a growing argument that decarbonised gas networks (carrying hydrogen or biomethane for example) can play a significant role in the future energy system and that their characteristics are of value to future energy system decarbonisation [3, 8, 9, 11].

The Sustainable Gas Institute (SGI) at Imperial College London has conducted a systematic review of the available evidence surrounding the options for gas network decarbonisation to bring clarity to the difficult issues of this debate. This white paper examines the evidence surrounding gas network decarbonisation options, including the technical characteristics, associated costs and implications for carbon emissions and wider environmental impacts. The paper focusses on the options for local gas distribution networks and the associated infrastructure required, presenting findings in the context of the alternative option; using electricity and heat pumps. While much of the evidence arises from countries where the use of gas networks is common (e.g. UK, Netherlands), implications for these options in other countries are also explored.

1.1. Context

There is an estimated 2.8 million km of natural gas transport pipelines worldwide [12].\(^1\) In 2015 gas provided 21% of global primary energy, and is expected to provide 24% by 2040; this is equivalent to 39,300 TWh in 2015 rising significantly to 57,000 in 2040 [13].\(^2\) Networked gas is expected to play

\(^1\) Major transport lines only (high pressure production, supply and transmission), not including local transmission or distribution (data collected 2010-2013).

\(^2\) The World Energy Outlook (WEO) 2016 New Policies scenario has been used for energy projections unless otherwise stated [13]. This is the International Energy Agency's central scenario.
an ongoing role in power generation where it may displace coal, decarbonise through carbon capture and storage (CCS), and provide flexibility to support increasing quantities of intermittent renewable electricity generation [13-15]. Power generation is forecast to drive gas demand in the future [14], contributing 34% of global gas demand growth by 2040 [13]. Global industrial gas demand growth is expected to contribute a similar proportion (45% of gas demand growth by 2035) as it displaces coal in the developing world where energy demand is growing rapidly [16]. Power generation and industrial gas use are typically supplied by the higher pressure tiers of gas networks.

Domestic and commercial use of natural gas, typically connected to the distribution system (lower pressure gas network tiers), is dominated by the provision of heat. Total gas use in 2013 in these sectors was 8,158 TWh, with the majority of this used for heating of buildings [17]. However, the future of this end-use is in question. Modern domestic gas boilers produce around 230 to 318 gCO2eq/kWh heat, including supply chain methane emissions. In many of the countries that use network gas for space heating, carbon targets require significant reduction in this carbon intensity. The International Energy Agency (IEA) 450 scenario requires a 20% reduction in emissions from heating buildings by 2040, despite an increasing population and demand for space and water heating [13].

The requirement to decarbonise energy services currently connected to gas networks is reflected in decarbonisation plans developed by many countries in the last decade. For example, in developing policies in the UK Climate Change Act [18] a number of modelling and scenario studies were used to demonstrate the achievability of an 80% decarbonisation target with known technologies [5-7]. A common theme in these assessments is the use of electricity to deliver energy for space heating, and the resulting diminished role for networked natural gas. This is a result of the relatively high decarbonisation potential in the use of electric heat pumps connected to low carbon electricity. This, along with the planned electrification of private transport, became known as the ‘all-electric future’ and was reflected in emerging UK energy policy [19].

The implication of an increase in electrification is that networked gas will have a significantly diminishing role in the energy systems of countries with high gas heating demand. Given the costs of operating and maintaining gas networks and the mechanisms for paying this cost, the diminished role for networked gas brings into question the continued existence of gas networks [20]. Since the development of decarbonisation goals much of the rhetoric around the future of natural gas has focused on promoting its transitional role. It is the lowest carbon fossil fuel, which can be used until renewable and other low carbon technologies are developed and deployed [21]. However, more recently, studies have highlighted the value of maintaining gas networks in the longer term [3, 8, 9, 11].

3. This assumes 90% boiler efficiency [1] for a modern domestic condensing boiler, UK 2015 natural gas combustion emissions of 184 gCO2eq/kWh [2] and supply chain emissions of 47 to 134 gCO2eq/kWh.
4. IEA 450 Scenario is based on a 50% probability of limiting the average global temperature increase in 2100 to 2 °C above pre-industrial temperatures [13].
This narrative has focussed on the following key points:

- The technical potential to significantly decarbonise the gas delivered by gas networks;
- The inherent storage potential of the gas network relative to the daily and seasonal variation in gas demand;
- The relative low cost of delivering such a decarbonised gas network; and
- The relative challenge for electricity to deliver these services in parallel with wider electrification aspirations.

1.2. Aim and Scope

The aim of this white paper is to review the evidence on options for the future decarbonisation of gas networks, focusing on their technical potential, carbon intensity and costs. The options include the use of biomethane or hydrogen, including the range of different technologies that can be used to produce either. The analysis presented in this report focusses on the following questions:

- What is the current state of gas networks globally;
- What are the options for these networks in the future, including:
  - What is the technical potential of these options;
  - What is their potential for decarbonisation and the wider environmental implications;
  - What are the costs of these options; and
- How do these options compare, both to each other and to the electric alternative?

This report focusses on the decarbonisation of low pressure gas network assets. The distinction between different aspects of the gas network is more clearly defined in Section 2. The low pressure local distribution network has the most uncertain future as higher pressure network assets are likely to be needed to deliver natural gas to power generation and industrial consumers in the medium to long term. However, many of the gas network decarbonisation options require the modification of the existing assets at both transmission and distribution scales. Therefore, the report scope includes these aspects.

The scope of the study focusses on the use of gas networks to service domestic and commercial energy demands. However, the use of decarbonised gas may also have implications for industrial consumers.

The study excludes transport as an end use of gas delivered through the gas network. In the future there may be benefit in supplying transport refuelling services with decarbonised gas. This potentially includes the use of both biomethane and hydrogen.

The white paper scope is not geographically constrained. However, the nature of gas network experience means that much of the existing evidence arises in the small number of countries with the most extensive use of gas networks. The report indicates the nature of gas distribution networks globally, and the implications for gas network decarbonisation options.
1.3. Methodology

This comprehensive review of academic, industrial and governmental literature has drawn on the methodology created by the UK Energy Research Centre (UKERC) Technology and Policy Assessment (TPA) theme and refined by the Sustainable Gas Institute for the White Paper Series. The methodology uses systematic and well-defined search procedures to document the evidence review, providing clarity, transparency, replicability and robustness to the analysis. An external expert advisory panel is appointed with a broad range of perspectives to consult on the initial framing and specification of the review procedure, as well as providing additional comments on the emerging analysis. The research outputs have been reviewed by an expert panel prior to publication. The assessment process carried out is presented in Figure 1.

<table>
<thead>
<tr>
<th>Scope the project</th>
<th>Solicit expert input</th>
<th>Review the literature</th>
<th>Synthesis and analysis</th>
<th>Prepare the draft report</th>
<th>Expert panel review and refine</th>
<th>Publish and promote</th>
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<tbody>
<tr>
<td><strong>TASKS</strong></td>
<td>• Write a scoping note, outlining aims and search and review protocols</td>
<td>• Appoint expert panel</td>
<td>• Apply protocol to literature search</td>
<td>• Write preliminary draft report</td>
<td>• Solicit expert panel comments on draft report</td>
<td>• Design and format report</td>
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<tr>
<td>• Appoint expert panel</td>
<td>• Solicit expert panel comments on scoping note</td>
<td>• Detailed and transparent ‘trawl’</td>
<td>• Apply protocol for evaluation and synthesis of literature</td>
<td>• Revise draft report</td>
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<td>• Finalise aims and search and review protocols</td>
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<td><strong>OUTPUT</strong></td>
<td>• Submit scoping note to expert panel</td>
<td>• Expert panel review of scoping note</td>
<td>• Literature database</td>
<td>• Draft report</td>
<td>• Expert panel review of report</td>
<td>• Publish report</td>
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FIGURE 1
Diagram of the systematic review methodology. Adapted from UK Energy Research Centre [22].
1.4. Structure

The remainder of the white paper is structured as follows:

- Section 2 presents the **current state of gas networks** including their fundamental structure and technical characteristics, geographical extent, current use, and current carbon intensity in the context of carbon targets;
- Section 3 presents a **range of options** for future decarbonisation of the existing local gas distribution network, examining their technical aspects and potential;
- Section 4 presents the **costs** associated with the future gas network options;
- Section 5 examines the **CO₂ and environmental impacts** of the options;
- Section 6 analyses and compares the evidence on **gas network decarbonisation to electricity networks and heat pumps**;
- Section 7 presents the findings, **conclusions**, policy implications and future research priorities.
2. The current state of gas networks

Existing gas network infrastructures are valuable and strategic assets capable of delivering significant quantities of energy, in the form of natural gas, to a wide variety of consumers. They are also capable of doing this flexibly on daily and seasonal intervals in a manner difficult to replicate with other energy infrastructures. However, the future use of gas networks will depend to a significant extent on their ability to decarbonise sufficiently to be consistent with climate targets. To understand gas networks potential to decarbonise requires an understanding of their structure and the way in which they are currently used.

This section lays out the current status of global gas networks, focusing on:

• their structure and function;
• the geographical characteristics of gas production and consumption, and where changes are likely to occur in the future; and
• the climate implications of natural gas systems.

2.1. What are gas networks: form and function

Gas networks consist of several distinct stages, from high pressure transmission pipelines that connect sources of gas to a number of cascading tiers of a distribution network at different pressures (Figure 2). Gas networks also include compressors, metering and regulating stations, storage facilities, and a range of other ancillary equipment [23, 24]. The pressure and pipeline diameters generally decrease as gas gets closer to the consumer. The network is illustrated in Figure 2, structured around the following gas network stages:

• production and supply pipelines;
• transmission networks including seasonal storage;
• local transmission networks including intra-day storage; and
• local distribution networks.

Figure 3 shows the kilometres of gas pipeline infrastructure in selected countries, broken down by pressure tier. This figure shows the significant extent of infrastructure, and the variation in pressure tier seen in different countries. Pipeline diameter varies depending on the flows required. Supply and transmission pipelines can be between 500 mm and 1,400 mm in diameter. Low pressure distribution pipelines to individual streets can have diameters as small as 100 mm, though 150 mm diameter is typical [25-27].
FIGURE 2
Simplified view of a whole gas system (based on the UK gas network).
Source: [11, 24, 28] Note: Pressures are approximate, with some variation between national networks

FIGURE 3
Approximate total pipeline length of gas networks in The Netherlands, the US, UK and Japan.
Source: [3, 29-34]
2.1.1. Production and supply pipelines

Natural gas is extracted from multiple wells, and then gathered and piped to gas processing facilities for conditioning to meet product specifications (Box 1). Natural gas of suitable purity is then piped and injected into the gas transmission network, or delivered to liquefied natural gas (LNG) terminals.

High pressure pipeline transportation from production sites supplies is around 89% of worldwide demand, while the rest is traded either as LNG transported by ship (10%) and 1% is by rail or truck [14]. Major transnational supply pipelines connect countries to gas supplies across long distances, mostly over land. They are large in diameter (up to 1,400 mm) and made of thick carbon steel, with coatings and electrochemical cathodic protection, which is used to inhibit corrosion [35]. For example, an 800 km Norway to Belgium supply line is 1,067 mm in diameter, made of 75 mm thick carbon steel, operating at a pressure of 190 bar, providing 240 terawatt-hour-per-year of gas capacity (TWh/y) [36].

In LNG transportation, natural gas is liquefied at -160 °C, reducing its volume by 600 times, and then carried by ship to be regasified and injected into the gas network at its delivery destination. LNG allows the transport of smaller volumes across longer distances to more varied locations.

Box 1. Network gas quality specifications

Gas produced from natural gas reservoirs or produced from biomass contains a mixture of other components and may need to be processed to meet the gas network quality standards. These components include heavier hydrocarbons, water, CO₂, hydrogen sulphide, nitrogen and other trace components such as siloxanes.

Gas quality standards set the legal allowable ranges for the gas composition on a network to which all suppliers must adhere [37-39]. These are set at country level and differ between jurisdictions. However, there are efforts to harmonise across European countries [38].

Specifications are needed to ensure quality and to protect network equipment. Removing water and sulphur compounds prevents corrosion, whilst particles and siloxanes are removed to prevent damage to compressors. Gas interchangeability constraints (including Wobbe index⁴ and composition) ensure that the gas burns correctly in appliances. Adding an odorant for domestic users ensures that residential leaks can be detected.

Calorific value constraints are set by the network operator to ensure standard energy content across all gas sources. For example, biomethane producers inject propane to increase its calorific value to be in line with the gas already on the network.
2.1.2. Transmission system

The high pressure transmission system delivers gas from supply points to power generation sites, industrial consumers, interconnectors and the lower pressure local distribution network. Gas is injected into the transmission system from supply pipelines or LNG terminals, which then supply gas across regions through its interconnected network of pipelines (up to 1,200 mm in diameter). Compressor stations are needed at approximately 60 to 160 km intervals across the network [24] to boost supply pressures and therefore flows. These compressor stations consume around 0.5% to 8.6% of the energy transported [47] and can be electrically or gas turbine driven. There may also be interconnector pipelines to connect transmission systems to other countries. On the transmission system entry and exit points, metering stations measure volumetric flow in conjunction with temperature, pressure and gas composition.

2.1.3. Local transmission and distribution network

Once gas has flowed from the high pressure transmission system onto the distribution network it is stepped down through a number of pressure tiers until it reaches consumers. The following pressure tiers relate specifically to the UK network.

Local transmission system - high pressure distribution
(UK system: 38-7 bar)
The local transmission system is operated in a similar way to the national transmission network but controlled regionally. Small industrial and large commercial consumers may take gas at intermediate pressures found on the local transmission system. Biomethane production plants inject gas at this level or below, where pipelines have capacity to receive this gas.

Odorant is often added to natural gas between the national transmission system and local transmission system (LTS), so that gas leaks can be detected well below flammable limits [11].

5. The Wobbe Index is a standardised indicator of fuel gas interchangeability.
Intermediate (UK system: 7-2 bar) and medium pressure distribution (UK system: 2 bar - 75 mbar)
As gas enters the distribution network at the ‘city gate’ station, pressure is stepped down and the flow is measured. Pressure reduction stations are required at large pressure reduction steps similar to that between transmission and distribution, where the gas is also heated (to offset the cooling effect of gas expansion). To ensure reliable supplies multiple city gates supply a single distribution area.

Low pressure distribution (UK System: <75 mbar)
Residential and small business consumers receive gas at the lowest pressure branches of the network, which in the UK is regulated between 19 and 75 mbar [48]. Pressure regulators are used to prevent surges and dips as consumer load varies over time. The low pressure network pipework length can be very long compared to the upstream networks (Figure 3). Pipework is typically either polyethylene, steel or iron, though other plastics and materials can be used. Polyethylene is the most versatile of these materials, being compatible with natural gas, biomethane, or hydrogen.

Box 2: The UK Iron Mains Replacement Programme
The UK is in the process of a 30-year Iron Mains Replacement Programme (IMRP) whereby all iron gas pipes within 30 m of a building are replaced by polyethylene to reduce the risk of pipe failure leading to gas leaks and explosions [49]. This affects the below 7 bar gas distribution network and the new pipe can be replaced or inserted directly inside the old mains. The total extent of mains to be replaced is estimated at 107,000 km [49]. A total of 19,500 km of mains were replaced between 2002/2003 and 2009/2010 costing £4.8 billion (2009/2010 prices) [49]. This replacement programme will provide efficiency and environmental benefits as fugitive emissions are reduced [49]. This also benefits any future transition to hydrogen in the gas network (Section 3.1.1) as the replaced polyethylene pipework is more robust to hydrogen [11].

2.1.4. Gas storage
Demand for gas is highly variable across multiple time-scales, particularly for countries that require gas for heating buildings such as the UK, as shown in Figure 4. Storage facilities operate on either daily or seasonal timescales. Inter-seasonal storage typically involves saving gas produced in the summer season so it can be used for the winter heating season. A large storage capacity provides a steady additional base-load across several months [24].

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6. In hot countries, using gas predominantly for power generation may instead see peak demands in summer due to building cooling demands. The US exhibits a large winter heating peak and a smaller summer peak for gas-fired power for space cooling.
Figure 5 illustrates how storage facilities can supplement supply in the heating season, based on a US system. Inter-seasonal storage reservoirs are large scale. For example, UK storage accommodates around 10% of annual demand and the UK’s seasonal storage facility, Rough, has a storage capacity of up to 36 TWh (approximately 4.6% of UK gas demand in 2016) [51-53]. This capacity is small by European standards, with countries such as Germany maintaining a working gas storage capacity approximately five times the size of the UK’s [54]. The closure of the UK’s Rough facility was announced in June 2017, with the implications for UK gas storage unclear at time of writing. Storage capacity is influenced by a number of market and geopolitical factors such as export/import balance and attitudes to supply security and risk. There is potential for further storage requirements in Europe post-2020 if flexible gas-fired power generation is used as a back-up to intermittent renewables [55].
Depleted gas reservoirs are the preferred option for inter-seasonal storage. This is because they are well-understood geologically, with a proven capacity to store gas. They also have existing infrastructure in place and do not require initial pressurisation with gas which will be unrecoverable [24]. In comparison, salt caverns can be expensive to construct but can have a higher rate of gas withdrawal into the gas network making them more suitable for providing responsive gas supply [24].

Short-term peak shaving or peak load facilities are designed to meet short duration intra-day demand peaks of high magnitude (in the morning and afternoon), and can send large gas flows onto the network at very short notice. These often use above ground tank storage of LNG or gas.

The pipeline network itself has an amount of inherent storage capacity which can be exploited by adjusting the pressure within allowable boundaries. The ‘linepack’ is the quantity of gas in the system at any one time, acting as buffer capacity. System pressure can be increased in advance of expected demand within a short intra-day time frame. Unlike the electricity system, supply is not required to meet demand on a moment-to-moment basis. In the UK, the national and local transmission systems are operated to increase linepack overnight with pressure being drawn down throughout the day. Figure 6 shows the UK National Transmission System (NTS) is able to provide around 200 GWh/d in flexibility through management of linepack [57]. Linepack capacity in lower pressure networks is limited due to network leakage rates which increase with increasing pressure. However, plastic pipework may provide sufficiently low leakage rates to allow increased linepack capacity. Decarbonising gas networks may therefore have the double benefit of providing safer networks while also increasing the inherent flexibility of gas systems.

![Figure 6](image-url)

**FIGURE 6**
UK National Transmission System Linepack capacity in energy stored, on an hourly basis for one day (on 18 Jan 2017). Source: [50]
2.2. Global use of natural gas and gas networks

Natural gas currently contributes 21% of total global primary energy supply, equivalent to 39,300 TWh [58]. Increased natural gas production is forecast in the medium-term as unconventional gas resources become economically recoverable. The IEA estimate that global natural gas demand will continue to grow, reaching between 44,000 TWh and 57,000 TWh⁷ by 2040 across their range of scenarios [13].⁸

The production of and demand for natural gas are highly variable across regions, due to differences in availability, cost and existing infrastructure. Gas demand varies significantly across countries, depending on quantity of domestic gas reserves, the historical context of energy system development, and the energy policy context. Demand is expected to grow in most regions except Russia. Growth will predominantly come from developing countries led by China (Figure 7) [13].

Natural gas is used for many applications: power generation, industrial heat and chemicals, building heat and transport. The power sector consumes 39% of global gas demand [13]. Around 21% of gas is used for space heating, water heating and cooking within buildings [13]. Industry (25%) and transport (4%) make up the majority of remaining demand. Demand in all sectors is projected to increase to 2040, with power and industrial sectors making up most (67%) of this growth (Figure 8) [13].

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7. All conversions from gas volumes to energy units assume a gross calorific value of 39.4 MJ/m³.
8. Based on IEA New Policies scenario to 2040 unless otherwise stated. This is their central scenario whereby, in addition to those already in place, new energy and climate policies are introduced to meet the Intended Nationally Determined Contributions (INDCs) as published prior to the UNFCCC Paris Agreement (COP21 climate pledges).
Demand for gas in the buildings sector is projected to increase by 3,000 TWh to 2040, with a third from China as it plans to expand its gas distribution networks [13]. Where there is limited natural gas distribution, domestic and commercial heat demand is served in other ways, including electricity (through heat pumps or resistive heating), solar thermal or bottled liquid petroleum gas (LPG) [13]. Domestic and commercial natural gas demand is not expected to grow in developed countries given that heat demand is largely saturated, energy efficiency of homes and appliances is improving and there is increasing competition from non-gas energy vectors such as electricity and solar thermal heat systems [13].

2.2.1. Gas networks

Local distribution networks serve residential and commercial end-users. The use of low pressure distribution networks varies significantly between countries. This is shown in Figure 9, which presents estimates of the proportion of households connected to the low pressure network in a number of gas consuming countries. Broadly, low pressure networks are more developed in countries with:

- high domestic natural gas production;
- high population density;
- limited availability of alternative resource;
- high demand for heating in buildings; and
- high level of economic development.
The Netherlands has the most comprehensive and dense gas network with 96% of households connected [59, 63] followed by the UK with 86% [60, 80]. Both countries have been producing large indigenous sources of natural gas and developing their networks since the 1960s. Gas production is correlated with gas network development. Countries that have relatively high per capita gas production tend to demonstrate relatively high proportions of domestic consumer connections to the gas network (Figure 10) [81].

The United States, Australia, Russia, Canada, Bolivia and China are also large producers but have relatively lower household connection levels (Figure 10). This may be due to lower population densities in these countries (Figure 11).
**FIGURE 10**
Percentage of households connected to the gas grid against domestic annual production of natural gas per capita for 32 countries. 
Source: [12, 33, 59-79, 82]

**FIGURE 11**
Household connection compared to population density in 32 countries. 
Source: [12, 33, 59-65, 67-79, 82]
Geography and spatial distribution of energy demand are likely to be strong determinants of gas network development [83]. Costs per customer can be high in countries with a low population density spread over difficult terrain. Equally, in some countries population may be concentrated in particular areas, making high level metrics like national population density less indicative of the gas network costs and subsequent potential. Figure 11 shows the proportion of homes connected to the gas network against population density for 32 gas consuming countries. This shows the expected relationship, with high population density countries typically having a higher percentage of domestic gas network connections. Outliers include Australia, Canada and Russia, where population density is highly regional. Singapore, also an outlier, operates a town gas network, and has declining gas consumption domestically and an order of magnitude greater population density than any other country compared [84]. Competing energy vectors also have a strong impact on gas network development. For example, the large nuclear energy fleet in France may have limited gas-fired power generation and gas network growth, alongside policies which have lowered the relative cost of electricity to consumers [81]. Countries that feature towards the right in both Figure 10 and Figure 11 have both relatively high domestic gas production and relatively high population density. This could indicate scope for development of domestic and commercial gas network connections in these countries in the future.

![Figure 12](chart.png)

**FIGURE 12**
Country-specific data for households connected to the natural gas network compared to those not connected (but within economic reach of the network).

Source: [81]
Figure 12 presents estimates from Fawcett et al. [81] suggesting that in Europe there is significant potential to increase the number of consumers connected to gas networks given the proximity to existing infrastructure. However, this data is somewhat dated, with updates difficult to obtain given the level of spatial detail needed.

Based on research by Evans & Farina [14] and Fawcett et al. [81], countries may be divided into several broadly defined categories in terms of the current status and future potential of their gas networks: mature markets; intermediate markets; and developing markets.

**Mature gas markets** have developed significantly over time, with a high proportion of households connected to the gas network (> 50%). New assets may still be under construction, although this is relatively small compared to the scale of the existing network. Such countries include the UK, Netherlands, Italy, Belgium and the United States [81]. Gas use is high and consumers are used to working with gas appliances so there may be some inertia in wanting to switch to a different heating technology [85].

**Intermediate gas markets** have experienced increasing market penetration and more households are being connected to the gas network (25% to 50%). The main high and medium pressure gas network has been installed although there is still significant potential for new household connections at the low pressure tiers. Such countries include Germany, Spain, Portugal and the Republic of Ireland [33, 81, 86].

**Developing gas markets** are those with potential for rapid market expansion with major new investment in gas networks in the coming decades, and significant potential for future gas production. These countries include China [13], India [87] and Brazil [88].

A number of countries do not fall into any of these categories due to their limited development of gas network infrastructure. These countries do not rely on gas today to deliver energy services and are unlikely to do so in the future. This includes countries such as Sweden and Finland, where low population density, low domestic gas production, and the use of heat pumps and district heating networks to deliver large proportions of domestic and commercial heat load are likely to act as barriers to gas network development [89, 90].

There is potential to provide repurposed decarbonised gas networks for mature and intermediate gas markets, and potential to design new gas networks suitable for decarbonisation for developing markets, but this is likely to be at an increased cost. The comprehensive infrastructure associated with mature markets means that decarbonisation could make a material contribution to climate targets and uptake could be swift. For intermediate markets, the capital-intensive infrastructure is new and there may be political drive to make good use of this asset. For developing markets, although natural gas demand may drive development in the near term, new infrastructure could be “future-proof” designed to ensure the possibility of using low carbon gas in the future.
Box 3. Gas demand in key gas consuming countries and regions

**United States** is the largest consumer of natural gas globally (8,300 TWh in 2014), with around one third used for power generation, one third used in buildings and over one fifth used in industry [13]. Demand continues to rise, driven by low gas prices and the development of domestic shale gas production. Gas is projected to become the largest primary energy type in the US by the early 2030s [13]. Demand will also grow in the chemicals and transport sectors [13]. The US is expected to become a net gas exporter [13].

**China**'s gas demand growth is expected to be the highest globally due to economic growth and residential heating, rising from 2,000 TWh in 2014 to around 6,600 TWh in 2040 [13]. Growth is expected in all sectors, driven in part by air quality and climate policies [13]. Gas distribution networks are set to expand, with consumption from buildings growing by more than 900 TWh by 2040, with a 20% growth across all sectors [13, 17]. Domestic gas production is likely to increase, though imports will likely also increase from both pipeline and LNG to meet growing demand [13].

**European Union** gas demand has fallen in recent years; though it is expected to rise again from around 4,600 TWh (2014) to nearly 5,000 TWh (2040) [13]. This growth is mainly from new gas-fired power generation as coal plants are retired although policies and the impact of falling renewable costs are a major source of uncertainty in this area [13]. Domestic production is set to decline by 45% by 2040 compensated by pipeline imports from Russia, the Middle East and Caspian countries and LNG from Qatar, North America and Africa feeding into the currently underused import terminals [13].

**Russia** uses natural gas to supply 55% (4,900 TWh) of its primary energy, but demand is not expected to grow significantly [13, 17]. Net exports will increase as Asian markets are reached via LNG and pipeline infrastructure in development [13].

**The Middle East** is the major gas exporting region and holds almost 40% of the world’s proven gas reserves [13]. High gas demand growth over the last decade has been driven by economic and population growth, and subsidies leading to low consumer prices [17]. Demand in this region is driven by power generation (particularly in combination with desalination) and industry [13]. There is little need for building space heating and so there is limited development of comprehensive low pressure distribution grids [13, 91].

**India** projections see demand quadruple to around 2,100 TWh in 2040, with half this growth from the power sector, met by increasing domestic production and LNG imports [13].

In **Southeast Asia** gas demand may grow by 40% between 2013 and 2040 [13], mostly from the industrial sector with half of that growth in Indonesia [17]. This region is expected to become a net importer in the 2030s [13].
Box 3. continued...

Canada will see a marked demand growth from 1,100 TWh to 1,800 TWh as gas replaces coal power stations, and gas is used in tight oil extraction; Canada is expected to remain a net exporter despite demand for US imports falling due to shale gas development [13].

Africa’s gas production is set to double by 2040 as Tanzania and Mozambique add to production from Egypt, Nigeria, Algeria and Angola, exporting 1,400 TWh [13]. Demand is forecast to grow rapidly in the region, although residential gas demand is not expected to drive this growth [13].

Australia’s LNG market growth is expected to plateau, with reducing development of new facilities [13]. Most of the gas produced is converted to LNG for export although the eastern side of the country has greater domestic demand, with connections to buildings for heat in the South Eastern states [92].

Latin America has the potential to exploit its large natural gas reserves, two thirds of which are unconventional resources [13]. Venezuela, Peru and Brazil have expanded production in recent years, whereas Bolivia and Argentina saw falling production [73].

In Brazil, gas consumption grew from 0.5 million consumers using 11 TWh to 2.44 million consumers using 360 TWh between 1990 and 2013, and is projected to climb to around 570 TWh by 2025 [73]. This growth was encouraged by regulated low gas prices [88]. Its current production (320 TWh in 2014) is insufficient to meet demand, despite its gas reserves being twice that of the UK [73]. In the long-term, further production is expected from the development of fields in the pre-salt blocks off Brazil’s southeast coast [73]. A large proportion of gas production is consumed upstream (180 TWh): most is generated offshore as associated gas with oil and re-injected or flared, used in gas processing or refining and fertiliser production [73]. Brazil’s domestic consumption is relatively low overall, although it did grow 10.4% per year (2000-2013) after Bolivian pipeline imports were introduced [73]. The residential market is small and concentrated in the southeast around Rio de Janeiro and Sao Paulo (94% of consumers) [73]. Brazil’s infrastructure is relatively limited with 9,240 km of national transmission pipeline and only 25,066 km of local transmission and distribution pipelines [73].

2.3. Greenhouse gas emissions and climate targets

Given the complexity of the natural gas supply chain, emissions of methane and CO₂ from the supply chain are highly variable and sometimes large in magnitude. However, the main source of greenhouse gas (GHG) emissions associated with natural gas is from end-use combustion. Combustion emissions from natural gas are 184 gCO₂eq/kWh, which is significantly lower than other fossil fuels, as shown in Figure 13 [93].
Estimates of supply chain emissions are typically between 47 and 134 gCO$_2$ eq/kWh, including both CO$_2$ and methane emissions [47, 94, 95]. Supply chain emissions include all processes from the point of extraction, processing and purification, as well as transmission, storage and distribution networks. The main contribution to supply chain emissions is from methane leaks and vents, as well as from fuel usage associated with processing facilities and gas compression. Methane is a much stronger greenhouse gas (GHG) than CO$_2$, 34 times more on a mass basis over a 100 year time horizon. Consequently, small emissions have a large impact, particularly in the short term.

Combining the supply chain emissions with those from combustion, the range becomes 230 – 318 gCO$_2$ eq/kWh. Supply chain emissions are likely to decrease in response to emissions targets and other regulations. However, gas appliances will increase these emissions further, depending on their efficiency. Efficiencies associated with gas boilers are around 90% (higher heating value [HHV]) for modern efficient boilers [96].

Whilst natural gas has a lower carbon intensity per unit of energy delivered than other fossil fuels, unabated natural gas use must still be reduced significantly in order to meet climate targets [97]. To limit climate change to less than 2 °C relative to pre-industrial levels, atmospheric CO$_2$ concentrations must be kept below 450 ppm by 2100 [98]. The scenarios that achieve these targets require a halving of global emissions by 2050 relative to 2010 and to nearly zero by around 2070. The following section outlines a number of options for decarbonising natural gas networks along with their feasibility and supply potential.
3. What are the options for the future gas network?

Reducing greenhouse gas emissions associated with gas distribution networks may involve decarbonising the gas in the network or reducing the use of natural gas sufficiently to remain within emissions targets. The latter may involve using gas only during peak demand through hybrid gas/electric heat pumps or other gas/electric hybrid systems at domestic or district scales. There is only limited evidence for this option. There is, however, an evidence base focused on the decarbonisation of gas, and the implications for gas networks.

This section discusses the technical and practical aspects of gas decarbonisation options, and is structured in the order of the gas supply chain. It covers:

- the gas generation options for both hydrogen and biomethane;
- the network issues arising from these options, including what new infrastructure or reinforcement may be needed; and
- the consumer implications of gas network decarbonisation.

3.1. Generating decarbonised gas

3.1.1. Hydrogen

Hydrogen can be used for heat or electricity generation, or as a transport fuel. The key benefit of hydrogen over natural gas is that there are no CO\textsubscript{2} emissions from combustion. Alternatively hydrogen can be used in fuel cells using electrochemical conversion, with no direct CO\textsubscript{2} emissions.

Hydrogen’s zero-emission combustion represents a significant advantage over natural gas combustion. However, it has a more complex supply chain, resulting in reduced efficiency and potentially greater supply chain emissions. Additionally, differences in the physical properties of hydrogen and natural gas mean that some modifications are required in the way hydrogen is transported and used (see Box 4 for further details).
Box 4. Properties of hydrogen versus methane

The physical properties of hydrogen are different to those of methane (see Table 1). These differences mean that they are not perfectly interchangeable for each demand service and may require adaptation of some existing infrastructure.

<table>
<thead>
<tr>
<th>Property</th>
<th>Methane</th>
<th>Hydrogen</th>
</tr>
</thead>
<tbody>
<tr>
<td>Chemical formula</td>
<td>CH₄</td>
<td>H₂</td>
</tr>
<tr>
<td>Molecular weight (g/mol)</td>
<td>16</td>
<td>2</td>
</tr>
<tr>
<td>Density (kg/m³)</td>
<td>0.668</td>
<td>0.084</td>
</tr>
<tr>
<td>Energy density (MJ/kg)</td>
<td>55.5</td>
<td>142</td>
</tr>
<tr>
<td>Energy density (MJ/m³)</td>
<td>37.3</td>
<td>12.0</td>
</tr>
<tr>
<td>Flame speed (m/s)</td>
<td>0.39</td>
<td>3.06</td>
</tr>
<tr>
<td>Low flammability limit (% vol)</td>
<td>5.3%</td>
<td>4%</td>
</tr>
<tr>
<td>High flammability limit (% vol)</td>
<td>15%</td>
<td>75%</td>
</tr>
<tr>
<td>Flame temperature (adiabatic) (°C)</td>
<td>1,953</td>
<td>2,107</td>
</tr>
<tr>
<td>Flame colour (complete combustion)</td>
<td>Blue</td>
<td>None</td>
</tr>
<tr>
<td>Auto-ignition temperature (°C)</td>
<td>600</td>
<td>560</td>
</tr>
</tbody>
</table>

The net calorific value per normal cubic metre of hydrogen is around 30% of that of natural gas on a volumetric basis [100]. The flow rate of hydrogen must therefore be greater to deliver the same quantity of energy [100]. As the flame speed is higher for hydrogen, the velocity of hydrogen through the burner must also be greater to prevent flame flashback to the air-fuel mixing point, extinguishing the flame. An extinguished flame risks build-up of hydrogen, creating a safety risk.

Hydrogen has a high flammability range, but is much less dense than methane and air, which means it disperses in open spaces very quickly [101]. However, without ventilation hydrogen plumes could develop at high points within buildings [100].

Due to the small molecular size of hydrogen, there is also a greater potential for equipment leaks. In addition to being a safety concern, greater leakage also increases cost and environmental impact.

Hydrogen flames are difficult to detect with the naked eye as they are colourless [100]. This represents a potential hazard and may also be off-putting to consumers for such services as stove-cooking where a blue methane flame is visible.
3.1.2. Hydrogen from natural gas

Steam methane reforming (SMR) is the most common method of bulk hydrogen production, with over 500 operational SMR plants globally [11].\(^9\) The core of the process involves reacting methane with steam at high temperature to form hydrogen and carbon monoxide [107, 108]:

\[
\text{CH}_4 + \text{H}_2\text{O} \rightarrow \text{CO} + 3\text{H}_2
\]

High temperatures are required to maintain the reaction, typically 800 °C [108] at approximately 30 bar [109], using excess steam (3-to-1 steam to carbon ratio) and a nickel catalyst [110]. Another reaction, known as the water-gas shift, reacts the produced carbon monoxide with steam to produce more hydrogen and generate CO\(_2\) in the following reaction:

\[
\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2
\]

\(^9\) There are other routes to reform natural gas to hydrogen not discussed in detail in this report, including partial oxidation and autothermal reforming, though these typically involve lower efficiencies at larger scales [106].
Production rates are typically 150 – 250 MW and up to 340 MW [11]. Estimates of overall energy efficiency are between 60 and 90% [111-114], but typically ~70% [108, 111-118]. These values do not include the efficiency of carbon capture and the higher rates assume any excess steam is fully used, for example in an additional CCS process. The addition of CCS is expected to reduce overall efficiency by 5-14% [119-121].

3.1.3. Reducing CO₂ from steam methane reforming with CCS

In order for hydrogen, derived from fossil fuels, to deliver climate benefits over natural gas, the CO₂ must be separated and stored using CCS. The literature reviewed in this report estimates between 71% and 92% of the carbon in the SMR process can be captured [11, 122]. There are a variety of technological options for capturing, transporting and storing CO₂ [123, 124]. With respect to capture, the most suitable options are ‘pre-combustion’ or ‘post-combustion’ in conjunction with the SMR system, which are described below [11].

Pre-combustion capture is the capture of CO₂ before burning fuel in the reformer furnace used to heat the SMR process. Indeed, pre-combustion requires reforming gas to hydrogen. Pre-combustion techniques involve separation of the CO₂-rich gas stream (Figure 15). Due to the high CO₂ concentration and high pressures in the SMR/gas shift exit streams, physical solvents such as glycol are suitable to absorb the CO₂.

Post-combustion capture is used to capture CO₂ after the SMR by-products have been burnt in the reformer furnace and consequently has a low CO₂ concentration. Whilst the final product has not been combusted in the SMR process, post-combustion capture is used in the flue gas stream from the fuel used to heat the SMR unit (Figure 16). CO₂ can be separated from CO₂-lean flue gases at low pressures using amine-based absorbents. The reacted amine is then sent to a heated regenerator tower, converting the reacted amine to remove CO₂ back into their original states. The former is sent back to the absorber tower, where it is reused.
The preferred capture technology depends upon specific process parameters and the desired capture rate. Typically pre-combustion gives a higher capture fraction, but post-combustion may be preferable as a retrofit solution [125]. Once captured, the CO₂ stream must be dehydrated and compressed for transport and storage. A significant number of studies examine transportation and storage of carbon, relating to the CO₂ captured in power generation and the issues discussed are likely to be the same as for captured carbon in hydrogen production [126-128].

### 3.1.4. Potential for hydrogen from SMR with CCS

The potential for hydrogen from SMR with CCS to replace natural gas is dependent on the:

- availability of the natural gas feedstock;
- availability of CO₂ transport infrastructure and proximity to storage location; and
- efficiency and cost of reforming/CCS

The efficiency loss associated with converting natural gas to hydrogen with CCS means significantly more gas input would be required to supply the same energy demand (Figure 17). At an SMR energy efficiency of between 60% and 90%, this would increase total gas demand by between 15% and 66%. Relative to EU residential gas demand in 2013 [129] this means a gas demand for hydrogen production of between 1,400 TWh and 2,100 TWh. This is approaching half the total EU gas demand in 2015 of 4,700 TWh.
The storage capacity for CO₂ is also a factor that affects the potential for hydrogen and should be considered when planning the location and development of SMR with CCS. Global CO₂ storage capacity is estimated to be ten times larger than the size of discovered fossil fuel reservoirs [97]. However, this does not take any economic, regulatory or local factors into account, which would significantly lower the estimation of economically viable storage sites. A modelling exercise examining the sensitivity of CCS to the availability of CO₂ storage sites found that halving estimates of global CO₂ storage capacity had little impact on global CCS deployment rates but had an important effect on regional CCS deployment rates [133]. For example, the storage capacity of Japan fell from 13 GtCO₂ in the reference scenario to 2 GtCO₂, and China risked running out of storage space after 2050 [133]. The geological storage of CO₂ is not yet well established [123, 134]. Therefore, large-scale storage demonstrations are needed if CCS is to play a meaningful role in the decarbonisation of gas networks.

There are several ways to increase SMR process energy efficiency, for example enhancing reforming by the addition of calcium oxide or replacing the furnace with a chemical looping combustion process. This would lead to the natural separation of CO₂ from the tail gas stream, with one study suggesting a possible increase in the efficiency of hydrogen production to around 85% [130].

3.1.5. Hydrogen from oil

The second largest source of hydrogen (30%) is from steam reforming of oil at refineries. This hydrogen is typically used onsite as a chemical feedstock for processes such as desulphurisation and hydrocracking [135]. The process is much the same as for natural gas reforming described previously, but with longer chained hydrocarbons and consequently higher emissions. Due to its typical use as a chemical feedstock rather than an energy carrier [136], oil reforming is not typically considered in the literature around hydrogen for decarbonisation.
3.1.6. Hydrogen by electrolysis

Another route for hydrogen production is via electrolysis of water. Approximately 4% of global hydrogen production is from electrolysis processes [137, 138], typically small scale production. Electrolysis of water dissociates hydrogen and oxygen by the application of electricity using an electrolysis cell. The cell is composed of an anode, cathode, electrolyte and membrane. The specific make-up of the cell depends on the type of electrolyser, of which there are three main types: alkaline; proton exchange membrane (PEM); and solid oxide electrolysers (SOE). Details of the main electrolysis technologies are presented in Figure 18, Table 2 and Figure 19. Generally, PEM electrolysers are more suited to a variable electricity supply associated with intermittent renewable electricity generation [139]. Higher temperature SOEs are suited to being combined with nuclear power or other thermal plants with large waste heat production.

![Diagram of electrochemical reactions associated with three types of electrolysis cell: a. alkaline; b. proton exchange membrane (PEM); and c. solid oxide electrolysers (SOE). Source:[140]](image)

<table>
<thead>
<tr>
<th>Type of Electrolysis</th>
<th>a. Alkaline</th>
<th>b. Proton exchange membrane (PEM)</th>
<th>c. Solid oxide electrolysis (SOE)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electrolyte</td>
<td>Potassium hydroxide (KOH) of typically 25 - 35% w/w [137, 138, 141]</td>
<td>Thin polymer, (approximately 0.2 mm) such as perfluorosulfonic acid (PFSA) polymers [141]</td>
<td>Zirconium dioxide (ZrO₂) with 8 mol % of Yttria-stabilized zirconia (YSZ) [142]</td>
</tr>
<tr>
<td>Operating pressure</td>
<td>35 bar [138]</td>
<td>10 to 30 bar</td>
<td>10 bar [143]</td>
</tr>
<tr>
<td>Operating temperature</td>
<td>80 to 140 °C [137, 138, 144]</td>
<td>20 to 80 °C</td>
<td>650 to 1,000 °C</td>
</tr>
<tr>
<td>Output capacity</td>
<td>Up to 2.5 MW</td>
<td>100 kW [144] (1.5 MW proposed [145])</td>
<td>Up to 150 kW [146]</td>
</tr>
</tbody>
</table>

**TABLE 2**

Details of the three main electrolysis technologies.
3.1.7. Efficiency of electrolysis systems

The efficiencies of electrolysers are variable and are dependent on factors such as temperature, capacity and the age/condition of electrolyser. Estimates of electrolyser efficiency are shown in Figure 19, ranging from 50% to 90%. Variation in efficiencies reflect differences in technologies, system boundaries and the type of efficiency estimated. However, system efficiency must also allow for the energy and resource requirements of the ancillary equipment and processes, for example water purification, gas/liquid separation and gas compression equipment (Figure 20). This total efficiency is likely to be towards the lower end of the presented range.

The lifetime of electrolysers also has an impact on the efficiency of hydrogen production. Some studies suggest that PEM electrolysers have a short lifespan of a few years using typical materials and conditions [103]. Alkaline electrolysers may have a longer lifespan, in the order of 10 to 15 years [139]. Since SOE are not commercially available, their lifespan is unknown. However, given the high temperature of SOE operation, the lifespan as well as the maintenance requirement are likely to be important technical factors.
3.1.8. Electrolysis Supply Potential

Feasible limits to hydrogen electrolysis are likely to be governed by economic costs and constraints on building electricity generating capacity. Figure 21 shows the electricity needed to produce hydrogen using an electrolysis system with conversion efficiency of between 50% and 90%. For context, this is compared to total European electricity generation and European residential gas demand. To supply the quantities of hydrogen equivalent to European residential gas demand, significant amounts of electricity must be generated, in addition to existing electricity demand. To meet European residential gas demand in 2013 of 1,280 TWh using hydrogen would require between 1,450 TWh and 2,600 TWh of electricity depending on the efficiency of electrolysis. This can be compared to total European electricity generation of approximately 3,000 TWh. In order to ensure sufficiently decarbonised hydrogen, new generating capacity supplying this electrolysis should be low carbon.
What are the options for the future gas network?

3.1.9. Power to Gas (PtG)

Power to Gas (PtG) is the conversion of electricity to a gas energy vector, typically either hydrogen or methane. Renewable energy generators are subject to ‘curtailment’, where generation exceeds a network’s capacity to accept electricity. In PtG systems this very low or negative priced electricity can be used to produce hydrogen through electrolysis, which can be injected into the gas network. Current gas quality standards in a number of countries limit hydrogen blending in natural gas grids to 0.02% to 0.10% (molar) \[37, 39\]. However, there is evidence to suggest that gas networks are capable of handling significantly higher concentrations of hydrogen without technical issues arising, as high as 17% by volume for some natural gas networks \[40\]. Allowing for these levels of hydrogen blending will require changes to regulations and gas standards due to the restrictive rules currently in place in many gas networks.

At very high penetrations of renewables evidence suggests that some regions may benefit from PtG as part of a deeply decarbonised system \[39\]. However, it does not appear to be the lowest cost option to integrating deep penetrations of renewable energy \[39\]. This means that system design may tend towards reducing the quantities of excess electricity generation and handling remaining excess electricity in a fashion that precludes the need for PtG. These cost aspects are discussed further in Section 4 and the decarbonisation potential of PtG is discussed further in Section 6.

---

10. Hydrogen can be converted to methane, avoiding blending limits. However, this involves extra chemical processing and additional costs.
3.1.10. Hydrogen from coal or biomass gasification

Coal gasification is a mature process with over 100 plants in operation and a combined capacity of 43,000 MW [151]. Gasification produces syngas, which consists mainly of hydrogen, carbon monoxide and CO₂. Syngas can be used for electricity production in integrated gasification and combined cycle (IGCC) power generation plants.

Conventional gasification techniques are based on high temperature pyrolysis of carbon based materials. The total process includes: combustion to add heat; drying to remove moisture; pyrolysis to produce tar and char; cracking to reduce the hydrocarbon chain lengths; and reduction to partially reverse combustion and increase calorific value. The main reactions involved are:

$$C + CO_2 \leftrightarrow 2CO$$

$$C + H_2O \leftrightarrow CO + H_2$$

There are a host of other reactions which also occur, which are driven by temperature, pressure and input composition [152]. In order to increase the concentration of hydrogen, the water-gas shift process described previously with the natural gas SMR process is typically employed. Syngas is currently used as a feedstock for many industrial chemical and fuel production processes such as methanol and ammonia and is used as an intermediate energy fuel [153].

Due to the high carbon intensity of coal, this option is considered unfavourable compared to alternatives. However, the impact of CCS on total emissions alongside a low coal cost increases its favourability (see Section 6). Depending on the specific gasification process, additional equipment and processes may include an air separation unit to provide oxygen to the gasifier, an acid gas separation unit and a ‘Claus’ plant to remove and purify sulphurous compounds, and a pressure swing adsorption process to purify the hydrogen [155].
An alternative option is to use solid biomass such as wood and dried municipal solid waste for the same gasification process [156]. Gasification of biomass follows broadly the same process as gasification of coal, where biomass is treated with steam and oxygen under high temperatures (typically 700 to 1,200 °C) [156]. There are several examples of plants switching from coal to co-fired coal and biomass gasification [155-157].

Biomass gasification of municipal solid waste has been proposed as having the double-benefit of providing a low carbon source of energy, while providing a waste disposal alternative to landfill [158]. This also provides biomass routes to decarbonised gas with a significant resource, significantly increasing the resource constrained potential. The production of bio synthetic natural gas (BioSNG) from municipal solid waste is discussed in more detail in this section.

However, the formation of tar during gasification of biomass is a significant issue that has been investigated in recent years [156, 159]. Tars are a thick liquid hydrocarbon that are formed during gasification and may be transferred to downstream processes. It can cause blockages and reduce the efficiency of equipment and the quality of the product gas. There are various methods to reduce tar production, such as reforming or cracking or incorporating catalysts, but all add complexity and cost to the process.

The incorporation of CCS with biomass gasification is one route toward negative GHG emissions, given that the cultivation of biomass removes CO2 from the atmosphere. This is discussed further in Section 5.

The potential contribution of coal with CCS or biomass to hydrogen production may be very large. Coal currently is the primary energy source for 18% of hydrogen production, and global reserves of coal are abundant and relatively cheap [157]. Restrictions on the use of coal is likely to be based on carbon budget restrictions, due to the high carbon intensity of coal. Typical gasification plant sizes may be up to 250 – 500 MW for integrated gasification combined cycle plants for electricity generation [160]. Similar order of magnitude capacity plants are expected for biomass gasification.

Biomass is also distributed across different regions, currently providing around 10% of the world’s primary energy supply. However, there are significant and multifaceted limitations to resource usage for biomass, including competing service demands. These are discussed further in the biomethane section.

3.1.11. Additional hydrogen production methods

There are a number of other emerging options for hydrogen generation that may make a contribution to production in the future. These options are outlined briefly here, but are not elaborated upon further.

**Plasma pyrolysis** uses methane to produce hydrogen but instead of co-producing CO₂, carbon black is produced instead [161]. This is a stable solid and therefore removes the need for CCS infrastructure [162]. Similar processes as those described for reforming and partial oxidation are carried out but at temperatures exceeding 2,000 °C, resulting in fast and efficient conversion
to hydrogen [102]. However, the process is energy intensive, due to the high temperatures required. Additionally, the process is typically low pressure, which results in an additional compression requirement for further transport or storage.

**Photoelectrolysis** is a method used to produce hydrogen, driven by electricity generated from a photoelectrochemical system harnessing solar energy [102].

**Thermochemical water splitting** has a similar reaction to that of electrolysis, in that water is dissociated into hydrogen and oxygen. However, thermochemical cycles use only heat for dissociation [102]. Given the high dissociation temperature of water (2,500 °C), catalysts such as copper-chlorine are added to lower the required temperature [163, 164].

### 3.1.12. Biomethane

One option to decarbonise the gas network is to produce low carbon methane from biomass, known as biomethane [165]. If biomethane is used then gas networks would need little modification, the network utilisation would be maintained and the carbon intensity of the network would be reduced. However, the extent to which this would reduce the carbon intensity, and the cost implication of such a change would depend upon the biomass source, conversion technology and resource availability.

The options for biomethane production are described in this section. This covers sources of biomass, biochemical processes and infrastructural requirements for each option. The carbon and wider environmental implications of these options, and the associated costs are also examined.

Biomethane is derived from organic feedstocks such as plant material and waste. Biomethane can be a direct substitute for natural gas with limited impact on the downstream infrastructure or consumers, as long as gas specifications are maintained. Biomethane can be produced from a variety of processes, but these are typically based on anaerobic digestion (AD) or methanation of biologically-sourced hydrogen.

### 3.1.13. Anaerobic digestion (AD)

Anaerobic digestion (AD) is the fermentation of organic material or waste in an oxygen-restricted environment to form biogas, which contains mainly methane, CO₂ and some heavier hydrocarbons [166]. The content depends upon the feed material and the processing conditions. AD occurs in sealed vessels, where digestion by microorganisms is controlled by managing temperature, pH, hydrogen and oxygen concentration and mixing. AD processes typically operate at slightly elevated temperatures (30 °C) and pressures (a few millibar) [167]. The process involves many different microorganism species and many reaction pathways (Figure 22).
There is a wide range of plant sizes, with smaller scale digesters in the order of 10 kW and larger digesters approaching megawatt capacities [173]. Raw biogas produced from AD requires further processing (sometimes referred to as upgrading) to produce biomethane that meets grid specification. The composition of raw biogas depends on the feedstocks and process conditions but typical compositions are shown in Table 4. The high CO₂ content of biogas is a primary contaminant that results in low energy density making it less efficient to transport as well as affecting combustion properties. Other contaminants such as hydrogen sulphide, siloxanes, particulates, carbon monoxide, water, ammonia and oxygen must also be removed to meet the gas specification and ensure that the mixture does not corrode or otherwise damage the pipeline assets or pose health risks [174].

### TABLE 4
**Typical biogas composition (data assumed to be mass percentage).**
Source: [174]

<table>
<thead>
<tr>
<th>Compound</th>
<th>Concentration (mass %)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Methane</td>
<td>40 to 75</td>
</tr>
<tr>
<td>Carbon dioxide</td>
<td>15 to 60</td>
</tr>
<tr>
<td>Water</td>
<td>5 to 10</td>
</tr>
<tr>
<td>Hydrogen sulfide</td>
<td>0 to 2</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>0 to 2</td>
</tr>
<tr>
<td>Ammonia</td>
<td>0 to 1</td>
</tr>
<tr>
<td>Oxygen</td>
<td>0 to 1</td>
</tr>
<tr>
<td>Halogenated hydrocarbons</td>
<td>0 to 0.6</td>
</tr>
<tr>
<td>Carbon monoxide</td>
<td>0 to 0.6</td>
</tr>
<tr>
<td>Siloxanes</td>
<td>0 to 0.02</td>
</tr>
</tbody>
</table>

As well as the biogas product, a digestate slurry of organic residue is also formed and may be used as a replacement for fertiliser (which helps to further reduce agricultural emissions).
3.1.14. BioSNG by methanation

Bio-synthetic natural gas (bioSNG) is biomethane formed by converting syngas from biomass gasification (described in Section 3) into methane via methanation (catalytic or biological) [153, 175]. This route to biomethane is often associated with gasification of municipal solid waste, which has the dual benefit of producing decarbonised gas while providing an alternative to landfill as a waste management solution.

Methanation is effectively the reverse of SMR and water-gas shift reactions, where hydrogen is reacted with CO$_2$ to form methane and steam by the Sabatier process [176]:

\[
H_2 + CO_2 \rightarrow CO + H_2O
\]

\[
3H_2 + CO \rightarrow CH_4 + H_2O
\]

The reaction uses a metal oxide catalyst at operating conditions of 50 to 200 bar and around 300 °C [177]. Although the Sabatier process was conceived in 1910, commercial realisation of bioSNG production will require technology improvements to increase efficiency and lower costs [178].

It is possible to use other waste CO$_2$ or atmospheric CO$_2$ for this reaction, although efficiencies of these systems with low CO$_2$ concentrations are unfavourable [178].

Biological methanation of hydrogen is an alternative route, where anaerobic hydrogenotrophic methanogen microbes produce methane in a strictly anaerobic atmosphere. This process can be combined with AD (described previously), as there is a CO$_2$ source and hydrogen is first produced by hydrogenic microbes before being consumed by methanogens [178].

National Grid’s bioSNG demonstration project is the first project of its kind to demonstrate all the bioSNG technologies in an integrated process. The process involves thermal gasification of waste in a fluidised bed gasifier followed by a plasma arc converter to produce syngas (carbon monoxide and hydrogen mixture). The syngas is then passed through a catalytic methanation process, and methane is purified using pressure-swing adsorption (PSA) to 97% methane [179].

Biomass gasification/methanation products will contain many of the same impurities as biogas, and so must similarly be treated before bioSNG meets the required standards. However, much of the contaminant removal may occur before SNG methanation in order to protect catalysts.

Grid specifications typically require purification to around 95 to 97% methane, with 1 to 3% CO$_2$ [174]. The economic costs associated with purification depend on the gas composition and can be important (Section 4).
Box 5: Synthetic Natural Gas (SNG)

Synthetic natural gas (SNG), also known as substitute natural gas, refers to methane based fuel gas that is produced using fossil fuels, biomass or water electrolysis [180, 181]. This white paper discusses the process of creating BioSNG, reflecting the importance of this route to SNG in the gas decarbonisation literature. However, the other routes to SNG could also provide methane rich gas for transport via gas networks.

SNG can be produced from any syngas or hydrogen fuel stream. Methanation processes can be used to convert hydrogen to methane [181, 182] providing the practical benefit of being compatible with existing gas networks. However, adding carbon to syngas or hydrogen via methanation undermines the decarbonisation benefits, particularly where these gases are used in domestic or commercial appliances where the capture of combustion CO₂ is impractical. There are also economic and technical challenges associated with methanation, which creates an additional cost and efficiency loss to gas production [181, 182].

3.1.15. Supply potential

Biomass currently provides around 10% of the world’s primary energy [183]. Both wastes and purpose-grown crops can be used as feedstocks for biomethane production, where typically wet feedstocks are suited to AD, whilst dry woody feedstocks are more suited to gasification. AD particularly can use very low and negative cost feedstocks such as food waste (i.e. the operator is paid to take the waste). This makes it more economical and an efficient waste management technique, and is able to reduce local air and water pollution as well as providing a nutrient-rich by-product known as digestate which can be used as organic fertiliser.

The availability of biomass for biomethane production is dependent on many things. For purpose-grown resources, there is competition for land with other uses including food production and production of other bioenergy and bio-products (e.g. liquid biofuels and bio-plastics). In addition to gasification and anaerobic digestion, other biomass to energy processes include pyrolysis, oil extraction and esterification, and carbohydrate fermentation to alcohols for liquid biofuel production; and solid biomass combustion for heat and power [153, 184]. Although synthesis of liquid fuels and solid products are usually more complex, they are expected to fetch higher prices than methane, and therefore biomethane production may be limited where economics favour these products.
The supply potential of the resource can be defined in several ways.

- **Ultimate theoretical** potential describes potential production according to physical and biological limits.
- **Technical potential** accounts for ecological and topographical constraints and technology limits which may change over time.
- **Economic potential** includes constraints due to financial feasibility based on production cost and market conditions.
- **Realisable potential** estimates production without causing negative socio-economic impacts and respecting market development and technology deployment issues.

Estimates of global bioenergy potential range from 100 to 1,100 EJ/yr [185], whilst global primary energy supply of all resources was around 500 EJ/yr in 2007. Estimates of potential vary due to different estimation methods, boundaries and data sources. Global primary bioenergy potential for 2050 ranges have been estimated by Haberl et al. (2011), at 64 to 161 EJ/yr, under various climate change, yield and diet scenarios based on a ‘food-first’ basis where food crops are prioritised over energy crops. The authors concluded that food requirements for a growing population, particularly crops for livestock fodder will strongly influence bioenergy availability [186]. On the basis of an analysis of the available biomass resources and competition for them, the Committee on Climate Change (CCC) estimate that 5% of UK gas consumption might be supplied using biomethane [10]. Alternatively, National Grid argue that municipal solid waste could be used to generate BioSNG, which could provide between 10% and 40% of UK gas demand in 2050 [158]. However, this assumes no competition for biomass resources.

### 3.2. Transmission, storage and distribution of decarbonised gas

The infrastructure that carries natural gas has the potential to carry other lower carbon gas vectors. However, this is limited by some technical and practical considerations. Biomethane is compatible with the existing natural gas network infrastructure. However, biomethane will be injected into the system at different locations requiring the installation of connection infrastructure and potentially upgrades to the existing assets to deal with capacity constraints. The case for transporting and storing hydrogen is more complicated and the relevant issues are discussed in this section.

#### 3.2.1. Transmission of decarbonised hydrogen

Existing high pressure gas transmission networks are likely unsuitable for hydrogen transport due to embrittlement issues associated with carbon steel (Section 3.2.3). It may be possible to retrofit transmission pipelines with plastic liners or other hydrogen resistant materials and this may be an important area of research in the future. However, these parts of gas networks are also likely to be needed in the future to deliver natural gas to electricity generation plants.
In the event of future hydrogen systems based on SMR, the transmission systems will also be useful to transport natural gas to SMR plants [11].

Hydrogen networks are likely to need some transmission infrastructure of their own if hydrogen production is centralised. For example, with centralised SMR hydrogen generation there are spatial issues associated with optimising plant location based on the location of CO₂ storage sites, infrastructure and centres of energy demand. Transmission infrastructure can link these sites, transporting the significant quantities of hydrogen at high pressure to maximise service while minimising cost. Since early installations in the late 1930s there has been an estimated ~3,000 km of hydrogen transmission pipework installed, including 1,640 km in Europe and 1,450 km in the USA and Canada, providing significant experience for future infrastructure development [11, 187].

3.2.2. Hydrogen storage

As described in Section 2, gas demand fluctuates significantly on a daily and seasonal basis. In order to deal with this, current natural gas systems rely on storage technologies to manage the balance between relatively inflexible gas production and highly variable gas demand. Natural gas also manages a significant proportion of this variation through its capacity to store gas within the gas network itself through increasing network pressure (known as linepack capacity). However, the capacity of hydrogen to do the same is considerably less. Biomethane can use the existing natural gas storage facilities but in a future hydrogen system dedicated storage facilities will be needed.

For example, Sadler et al. [11] assume that a hydrogen demonstration project in the UK would use onshore salt caverns in the North East of England to store hydrogen for both daily and seasonal hydrogen storage. Salt caverns are commonly used in gas storage and there are 30 salt caverns currently in use in the UK, which are used mainly for storing natural gas and to support industrial-scale chemical applications [188]. These storage options would be operated in a similar way to the natural gas storage (Section 2).

It is also possible to inject hydrogen in offshore salt caverns. However, their capital costs are twice as high [189], and the minimisation of hydrogen production costs requires SMRs to be located near inter-seasonal and intraday storage sites [11].

Alternative sites to store compressed hydrogen include depleted natural gas or oil reservoirs, aquifers and excavated rock caverns. However, there is little evidence of the feasibility of these options and questions remain regarding their costs, the integrity of their impermeable cap, and the potential for unwanted reactions or interaction with bacteria. The use of depleted gas reservoirs was examined by Amid et al. [190], which suggests that there are no insurmountable barriers associated with current technologies. A potential complication could be the presence of bacteria that could feed on hydrogen, and the study recommends that more tests be done before any injection of hydrogen takes place [190].
3.2.3. Local distribution of hydrogen

Existing local distribution systems are potentially compatible with hydrogen use, but this depends on the materials they are made with and the current capacity.

The greater volumetric throughput needed with hydrogen results in different pressure and velocity profiles across the same transmission and distribution pipework. Distribution pipework must be operated within design limits to maintain system safety and integrity. Such design limits are minimum/maximum allowable operating pressures and maximum allowable velocities. In typical design limits for low pressure distribution systems are between 0.02 and 0.075 bar with a maximum velocity of 40 m/s [11]. If the natural gas infrastructure were being operated close to its limits, it is arguable that a switch to hydrogen would require large infrastructural modification to ensure safe and effective operation. A three-fold increase in volumetric throughput forced through the same pipework (even with a much less dense fluid), will require greater pressure drops.

It may be the case that existing design limits are very conservative and could therefore be revised to accommodate increased velocities and pressure drops [11]. However, at a sensitive time when the consumer-perceived risk may be heightened due to a change in systems (i.e. the switch from methane to hydrogen), it is vital that there is no additional risk of incident.

Secondly, unprotected iron and carbon steel pipework suffers from embrittlement due to the diffusion of hydrogen into the material. Embrittlement results in a reduction of structural integrity and can potentially cause fracture. Therefore these materials are not suitable for hydrogen networks. However, plastic pipework (typically high-density polyethylene or medium-density polyethylene) and lined steel (polytetrafluoroethylene lined carbon steel) are suitable materials for construction. Many distribution networks are already materially suitable for this task, due to the progress made from the iron mains replacement programme (Section 2). However, higher pressure transmission networks (such as the National Transmission System and the Local Transmission System in the UK) are constructed primarily from carbon steel and are unsuitable for hydrogen transfer. Instead, new transmission pipework would be required from the point of production to the local distribution network, made of low-strength steel capable of withstanding hydrogen under transmission pressures of approximately 10 - 50 bar.

3.2.4. Storage and transport of biogas

A benefit in using biomass for gasification and for anaerobic digestion is the ability to store it efficiently with a relatively high energy density. However, biomass transport distance and transport mode has a significant effect on life-cycle emissions [191]. For energy crops and agricultural residues, harvested intermittently, large storage silos are necessary to maintain a year-round availability for energy conversion. These facilities add to the cost of the energy and good storage practices are needed to ensure the feedstock quality. Once processed and pressurised sufficiently, biomethane may be handled by the
existing gas infrastructure, negating additional requirements except grid connection.

3.3. Consumer transition

The use of biomethane in the gas network will have limited impact on consumers and the existing appliances connected. This is due to the current requirement for biomethane to be close in composition to natural gas. However, if gas networks were to transport hydrogen a number of compatibility issues will arise with consumer appliances. This would require either modification of existing appliances and systems or replacement of those appliances. In addition, it will be necessary to convert a large number of consumers almost simultaneously at once as gas networks will need to be converted (to hydrogen) on a local gas network basis. Consumers within that local network will not be able to choose to remain on the natural gas network. This presents a logistical challenge that may be difficult to follow without a high level of consumer acceptance, creating a policy challenge for governments.

3.3.1. Consumer appliances and systems

Due to the differing properties of hydrogen to natural gas, it will be necessary to modify or replace existing consumer appliances if the local gas network is converted to transport hydrogen. The higher flame speed\textsuperscript{11} of hydrogen relative to natural gas is one of the key differences, creating the safety risks for the combustion of hydrogen (flame lift-off or flashback\textsuperscript{[83, 192]} in appliances designed for natural gas\textsuperscript{[193]}. This would include gas boilers, gas fires and gas cookers. A modification of the gas burners in these appliances is theoretically all that will be required to address this issue. However, due to the variation in appliances and contracts across residential properties and companies for both boilers and cookers, it would perhaps be more viable and timely to replace whole appliances\textsuperscript{[115]}. This may create an issue of cost and inconvenience for consumers that may impact on the consumer acceptability of hydrogen gas networks (see Section 5).

Some types of existing consumer appliance design may be difficult to retrofit with hydrogen-compatible burners because of their design. However, it may be possible to regulate or incentivise the design of gas-fired appliances to be more easily retrofitted for hydrogen combustion\textsuperscript{[11]}. It may also be possible to design appliances that work with a range of gas mixtures from 100% methane to 100% hydrogen\textsuperscript{[193]}. The effort needed to convert natural gas boilers designed to be easily converted is estimated to be two hours per property, compared to six hours for a traditional combi boiler and eleven hours for a traditional system boiler\textsuperscript{[11]}.

\textsuperscript{11} Flame speed is the measured rate of expansion of the flame front in a combustion reaction.
An alternative to boiler retrofit is replacement with a hydrogen-fired boiler design. These boilers have been described as “functionally identical” to existing gas boilers, and are thought to have very similar operating efficiencies, in the order of 90% (higher heating value) [11, 194, 195]. This similarity to existing boiler characteristics may be an important factor in consumer acceptability as evidence suggests consumers have a preference for gas systems over other heat appliance types [85]. Another study examined the feasibility of developing the necessary supply chains to deliver hydrogen ready appliances, and found that there is no barrier to scaling up the manufacturing of boilers that operate in a similar way to existing natural gas boilers [196].

Hydrogen fuel cell micro combined heat and power (fuel cell microCHP) systems could also be employed to convert hydrogen to heat, with the additional benefit of generating electricity. A more detailed description of consumer fuel cell technologies and their characteristics can be found in a white paper by Dodds and Hawkes et al [194]. Heat led operation of these systems means that their electricity generation follows the electricity demand profile of high heat load countries such as the UK [194]. As a result fuel cell microCHP can potentially reduce the need for investment in centralised electricity generation and electricity network reinforcement needed to facilitate high levels of electrification expected in the coming decades [194]. In a simulation of the UK energy system it was estimated that every fuel cell microCHP system installed avoided 0.6 kW of peak electricity generating capacity, saving £240 per kW of power station investment and £100 to £300 per kW in infrastructure reinforcement costs [194]. Including operational efficiency improvement the total system cost saving might be £500 per kW [194].

The service pipes throughout the consumer dwelling and the existing gas meter may need to be addressed as part of the conversion to hydrogen. Existing pipework within the consumer dwelling may include pipe materials unsuitable for transporting hydrogen. Existing pipes may also need to be checked for leaks and potentially repaired due to hydrogen’s smaller molecular size and ability to leak at joints otherwise secure for natural gas [11]. Gas meters may also need attention as existing meters measure the energy content per volume which differs between natural gas and hydrogen. This may be addressed through monitoring and developing a correction factor or meters may require replacement [11].

3.3.2. Switchover period

There is a practical implication of converting existing gas networks to supply hydrogen for consumers connected to the existing natural gas network. Consumers will experience a switchover period where gas services will be disrupted and domestic appliances may be adapted or replaced. The switchover period may last days or weeks depending on the switchover procedure, with Leeds City Gate H21 recommending that this could be limited to five days [11]. In the UK, this is not seen as a significant impact as gas usage during summer months is relatively minimal [11]. However, the impact on commercial buildings is likely to be more disruptive.
The switchover period has often been compared to the UK’s conversion from town gas to natural gas, which was conducted between 1966 and 1977 [3, 11, 83]. This programme of conversion included changing ~ 40 million of appliances in 13 million homes. The roll-out began with isolated pilot schemes but also required new regulations and policies, institutional leadership, management strategies and the development of skills and expertise among consumers, industry engineers and technicians [197]. This programme was not without technical difficulty and issues, even though the town gas transition is still held as a successful example of transition. It is also comparable to the significant pace and scale commensurate with the challenge faced by a UK transition to a hydrogen network [11, 197]. More recently the Isle of Man transitioned from a gas network utilising liquid petroleum gas (LPG) /air mixtures to a natural gas system. This has been used as a comparator for the costs of both appliance conversion and the works required at street level [11, 118].

The Leeds City Gate H21 report proposes to reduce disruption to customers by transitioning consumers in discrete zones helping to minimise transition times. [11]. Within the summer period these zones will be isolated to areas of approximately 2,500 households, with conversion works carried out over a five day period for each household. In an extension of this proposal, the report suggests that a rolling programme of conversions in the major cities of the UK could successfully convert 30% of UK gas users. This programme would follow a similar process, with consumers experiencing five days of service interruption, and would take place between 2026 and 2052 [11].

### 3.3.3. Hydrogen safety

A transition to hydrogen raises questions of safety relative to natural gas. A number of studies have tried to address questions of hydrogen safety. The HyHouse project injected natural gas and hydrogen at different rates (8 - 64 kW low rate releases and high rate release of 200 kW) into a two story three-bedroom farmhouse in Scotland, in order to evaluate the risks associated with using hydrogen in a domestic setting [198]. The study measured the concentrations of these gases accumulating in the dwelling to establish the relative combustion risk of gas leaks in a residential setting [198]. The study found that the combustion risk from natural gas or hydrogen leaks in the house were broadly similar despite the differing properties of both gases [198]. To mitigate the impacts of such a leak excess flow valves could be fitted to gas systems, limiting the maximum flow rate in the event of a leak [11]. In addition, it is likely that odorants added to hydrogen would assist timely detection of leaks and prevent significant concentrations of hydrogen from accumulating [11, 83]. In most circumstances, hydrogen disperses more readily than natural gas [192]. It is therefore more difficult to build up dangerous concentrations of hydrogen [11].

There are also a number of considerations in the design of safe hydrogen appliances, including the development of sufficient safety standards and the training of gas engineers [196]. However, studies that have gathered evidence from appliance manufacturers and experts suggest that there is
significant confidence that appliances can be delivered at scale whilst meeting appropriate safety standards [196].

Hydrogen also provides some safety benefits as the combustion products from a hydrogen boiler do not contain carbon monoxide, a significant safety concern for existing natural gas appliances [83].

Despite emerging evidence it will be necessary to build on this safety evidence to increase consumer acceptability. Safety concerns should be sufficiently addressed before commitments to hydrogen network development are made. Safety is likely to be a significant concern to potential consumers and engagement with the public on issues of hydrogen safety is likely an important aspect of any hydrogen network development programme. Early academic work has already sought to develop public engagement on hydrogen issues through surveys and small-scale direct communication [83].

The Department of Business Energy and Industrial Strategy (BEIS) has announced a £25 million programme investigating hydrogen standards and the development and testing of hydrogen appliances in domestic buildings [199]. This programme compliments other relevant research projects, such as HyHouse [198], NaturalHy [41, 200, 201] and HyDeploy [202]. Efforts should be made to coordinate new projects with existing activities and the existing evidence base.

### 3.3.4. Hybrid heat pump systems

Hybrid gas/electric heat pump systems combine ground or air source heat pumps with a gas boiler and a control system that switches between these two sources of heat. These appliances can either be integrated units containing the complete hybrid system, or a heat pump and control unit retrofitted to an existing gas boiler [203]. These systems are a relatively recent consumer option and are currently underrepresented in the evidence base, though small demonstration projects are underway [203, 204]. The potential benefit that these hybrid systems could provide is that they take advantage of the inherent benefits of both gas and electricity and in doing so may mitigate the challenges associated with either vector exclusively.

Gas vectors are capable of supplying heat demands that vary significantly on both daily and seasonal timescales, although the carbon intensity of natural gas combustion at current levels is incompatible with climate change targets (Section 2). However, electricity is increasingly decarbonised in many countries and using heat pumps to convert electricity to heat is highly efficient [194, 205]. However, electricity systems are less capable of dealing with daily and seasonal fluctuations in demand, and the costs of reinforcing electricity networks to deal with increasing electrification of heat are likely to be significant.

Hybrid gas/electric heat pump systems are designed to operate for the majority of the time using electricity through the heat pump unit, maximising efficiency and minimising carbon emissions. However, in periods of low external temperatures and high heat demand a typical electric heat pump system efficiency would drop, increasing both operating cost and carbon
emissions. This has a significant impact on electricity system balancing and network operability, resulting in the need for the significant reinforcing costs discussed previously [206-208]. During these periods the gas boiler can be used to provide higher temperature heat, relieving the electricity network of a significant proportion of peak load and therefore reducing costs of network reinforcement, and back-up electricity generation costs [194]. If the period of gas boiler operation is sufficiently short throughout the year then this may reduce carbon emissions sufficiently to meet carbon reduction targets.

In addition it may be possible to further decarbonise the operation of the hybrid system by running the boiler on decarbonised gas when needed. This future option may require additional modification or replacement of the boiler unit, but could unlock further decarbonisation potential if it becomes available. The integration of gas and electricity systems has been investigated at the electricity and gas transmission scale [209]. However, further work on options at the low pressure distribution scale are needed [204].

Calculating the potential impact of hybrid heat pump systems is currently difficult for a number of reasons. First, there is a lack of data on the practical operation and operating efficiency of hybrid heat pump systems in homes [203]. Efficiencies of heat pumps must be measured over long periods in order to correct for the seasonal temperature effect on operating efficiency, and establish seasonal performance factors. This requires trial and demonstration projects with multiple sites to correct for site specific variation [203]. The efficiency of hybrid heat pumps will depend on the ratio of heat delivered by the heat pump against the gas boiler. This factor will be subject to design choices balancing the trade-offs between cost/energy efficiency and peak performance.

It is then necessary to apply emerging data on practical operating characteristics to system-level energy models, to establish the potential impact of hybrid systems on the need for backup-generation, system balancing investment and electricity network reinforcement [204]. System-level analysis will also be necessary to establish the practical and economic impacts on gas network operation of reducing the gas flow through the network. It is likely to become increasingly expensive per unit of delivered energy to maintain and operate the existing gas network if hybrid heat pumps replace existing gas boiler systems. Equitable and economically feasible ways of meeting these costs will likely require some attention and potentially market restructuring.

3.3.5. Gas-fired heat pumps

A number of gas-fired heat pump technologies may play an increasing role in future building heating, though these are not investigated in detail in this white paper. These include:

- gas adsorption heat pumps;
- gas absorption heat pumps; and
- gas driven heat pumps [210].
These technologies are at a relatively early stage of commercial development and there is little evidence of their performance and future role in gas systems. However, early findings suggest that domestic absorption heat pumps might provide energy savings of approximately 30% against domestic gas condensing boilers [210]. These technologies provide an advantage over electric heat pumps in their limited burden on the electricity grid. However, they are still subject to the relatively high installation costs and are large in size, factors that may limit widespread deployment [210].
4. Costs of gas network options

The options for gas network decarbonisation have a range of different costs, including cost of gas production, network and storage costs as well as different cost implications for the end user. The costs do not simply relate to the costs of network infrastructure, but with the wider supply chain implications of chosen options. However, the full system implications of particular options are difficult to estimate without the use of whole-system modelling tools given the interconnected nature of the impact on costs (see Section 6).

The ultimate cost to consumers includes: the cost of gas production; the cost of gas transportation through gas networks; the cost of end-user appliances and services, and the administrative, profit and tax costs throughout the supply chain. This section discusses six types of cost data, summarised in Table 5.

<table>
<thead>
<tr>
<th>Cost type</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas plant capital cost</td>
<td>£/kW (Sterling pounds per kilowatt)</td>
<td>The initial investment cost to build new gas production capacity.</td>
</tr>
<tr>
<td>Production cost</td>
<td>p/kWh (Pence Sterling per kilowatt hour)</td>
<td>Cost of producing gas, including the capital costs, operating cost but excluding profit margin (also known as unit cost).</td>
</tr>
<tr>
<td>Infrastructure investment cost</td>
<td>£m/km (Million pounds sterling per kilometre)</td>
<td>The initial investment cost to build fixed length of infrastructure pipeline.</td>
</tr>
<tr>
<td>Storage capital cost</td>
<td>£/kWh</td>
<td>The initial investment to build a fixed unit of gas storage capacity.</td>
</tr>
<tr>
<td>Retail price</td>
<td>p/kWh</td>
<td>Price of gas delivered to consumers including costs of gas generation, networks, taxes, profit and other obligations. Excludes consumer costs.</td>
</tr>
<tr>
<td>Consumer cost</td>
<td>£/household</td>
<td>The initial cost per household of investing in new appliances or equipment needed to use decarbonised gas.</td>
</tr>
</tbody>
</table>

The costs\textsuperscript{12}, and the various issues surrounding cost are discussed in this section, including:

- Decarbonised gas production;
- Transmission, distribution and storage of decarbonised gas;
- Consumer cost impacts of gas network decarbonisation.

\textsuperscript{12} All costs have been normalised to 2016 Great British Pounds. Where cost estimates in the literature do not clearly state the currency year the publication year is assumed and the cost inflated accordingly.
4.1. Gas production costs

As highlighted in the previous section, the two main gases that might be used to decarbonise existing gas networks are hydrogen and biomethane. The various processes and technologies used to generate these gases have different associated costs. A summary of cost estimates for hydrogen and biomethane generation are presented in Figure 23. This shows the significant range of cost estimates, driven by the differences in production technology, assumptions about plant scale, operating costs and age of estimates. The specific issues associated with producing hydrogen and biomethane are discussed in this section.

4.1.1. Hydrogen

A systematic review of literature uncovered a number of cost estimates across a range of countries, years and plant scales. These have been normalised in Figure 24, which shows hydrogen plant capital costs, and Figure 25, which presents costs per unit of hydrogen produced.
The average capital costs associated with hydrogen production technologies ranges from £315 per kW to over £2,000 per kW. SMR is one of the cheapest production technologies in capital cost terms, with the additional cost of CCS adding less than £100 (~30%) to the average cost. Biomass gasification with CCS appears the most expensive technology, at £2,030 per kW, though the very wide range of biomass gasification estimates includes estimates below £500 per kW. The average capital cost for electrolysis is less than £1,000 per kW, in the mid-range of cost estimates.

However, when examining the cost of hydrogen produced from these technologies coal and biomass gasification appear to be the cheapest technologies, while electrolysis becomes the most expensive. This is a function
of the difference in energy input costs assumed, with coal and biomass often assumed to be the cheapest fuels, while the electricity used in electrolysis is assumed the most expensive [212-214, 217] (Figure 26). Not all studies make transparent statements regarding energy input costs. This effect is likely exacerbated when using renewable electricity to further decarbonise electrolysis due to increasing costs. In the future, the relative costs of these energy inputs are likely to change, and future assessments of gas production costs may come to different conclusions as a result. In particular, the constrained nature of biomass availability may lead to significant future increase in traded biomass prices [229]. This highlights the need to revisit these research topics as changes in future energy input costs become apparent.

The possibility of taking advantage of negative electricity wholesale prices associated with renewables curtailment is a key driver behind the concept of PtG. However, no cost estimates reviewed in this white paper are based on negative energy input costs. The prospects for negative electricity wholesale prices are real, though negative prices will likely equilibrate through market forces. The likelihood of a large scale hydrogen economy based around negative electricity wholesale price is therefore questionable.

Another factor that influences cost is plant size. For example, Agnolucci et al [211] estimate a range of costs for SMR and electrolysis at different scales. The study found modest cost reductions with increasing scale for electrolysis but more significant cost reductions for SMR as plant scale increases. This trend is apparent when comparing a number of comparable estimates from the literature (Figure 27 and Figure 28), although the year in which estimates are made is a confounding factor. However, the number and comparability of available estimates is insufficient to provide a detailed analysis of the learning effects and cost reduction associated with these technologies.
A number of sources make statements about the future of costs for hydrogen production technologies, indicating some expectations for future cost reduction. For example, Hart et al. [118] estimate future cost reductions for a number of hydrogen production technologies based on the available literature estimates. A summary of this evidence is presented in Table 6. This evidence suggests some limited cost reduction potential for several technologies. Fossil fuel based technologies are expected to have limited cost reduction potential relative to the cost reductions estimated for electrolysis and biomass gasification (Table 6).
Finally, the costs associated with PtG as an option for gas network decarbonisation are discussed by de Joode et al [39] who model the role of PtG in the future energy system of the Netherlands. This work suggests that PtG is only likely to play a significant role where there is a need to meet deep decarbonisation targets (80% to 95% CO₂ reduction by 2050). This is driven largely by the cost of PtG relative to the costs of other options to mitigate intermittent renewables. These other options include:

- Temporary curtailment of intermittent generators;
- Interconnection of electricity networks with other countries;
- Demand side response to manage variable electricity demand;
- Use of dispatchable gas fired power stations as back-up generators (possibly with biomethane and CCS);
- Some types of electricity storage (compressed air or batteries in electric vehicles) [39]; and
- Heat storage, where electricity is used as the final energy carrier to provide the heat.

The study also mentions that the costs of PtG may appear expensive in comparison to other options, though positive business cases are likely to exist in particular geographical and system niches. A hydrogen wholesale price of 9.5 p/kWh is suggested necessary to achieve a supportive business case for PtG, which is not competitive with most of the range of production cost estimates presented in Figure 25, bearing in mind that the wholesale price also includes a profit margin.

### 4.1.2. Biomethane

The main routes to biomethane include anaerobic digestion (AD) and biomass gasification and methanation, both of which involve additional upgrading steps to produce sufficient methane purity to meet gas network standards. A number of cost estimates for AD routes to biomethane exist in the relevant literature. Relatively few cost estimates exist for biomass gasification. However, this process is already represented in the hydrogen production cost estimates discussed previously, though the costs of hydrogen methanation are additional to the initial gasification steps to produce hydrogen.

<table>
<thead>
<tr>
<th>£2016/kW</th>
<th>2014</th>
<th>2030</th>
<th>2050</th>
</tr>
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<tbody>
<tr>
<td>Steam methane reforming (SMR)</td>
<td>£453</td>
<td>£453</td>
<td>£453</td>
</tr>
<tr>
<td>SMR CCS</td>
<td>£817</td>
<td>£737</td>
<td>£696</td>
</tr>
<tr>
<td>Coal Gasification</td>
<td>£1,635</td>
<td>£1,622</td>
<td>£1,622</td>
</tr>
<tr>
<td>Coal Gasification CCS</td>
<td>£2,505</td>
<td>£2,505</td>
<td>£2,490</td>
</tr>
<tr>
<td>Biomass Gasification</td>
<td>£3,774</td>
<td>£2,465</td>
<td>£2,045</td>
</tr>
<tr>
<td>Biomass Gasification CCS</td>
<td>£4,989</td>
<td>£3,355</td>
<td>£3,337</td>
</tr>
<tr>
<td>Electrolysis</td>
<td>£1,237</td>
<td>£586</td>
<td>£568</td>
</tr>
</tbody>
</table>

**TABLE 6**

Estimates of capital cost reduction over time (£/kW).
Source: [118]
Note: Technologies with significant cost reduction estimates shaded grey.

The main routes to biomethane include anaerobic digestion (AD) and biomass gasification and methanation, both of which involve additional upgrading steps to produce sufficient methane purity to meet gas network standards. Relatively few cost estimates exist for biomass gasification. However, this process is already represented in the hydrogen production cost estimates discussed previously, though the costs of hydrogen methanation are additional to the initial gasification steps to produce hydrogen.

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Figure 29 and Figure 30 present illustrative cost estimates from the existing literature regarding first generation AD. Capital costs for AD methane production plants are approximately £1,800 per kW to £4,500 per kW. This is significantly more expensive than many of the hydrogen production technologies. The production costs of biomethane from AD plant is approximately 2 to 10 pence per kWh, with an average of ~5p/kWh. This range is closer to that seen for hydrogen production, reflecting the relatively low energy input costs (Figure 26), but more expensive than hydrogen production from the same primary energy source.

The costs of biomethane production from AD are influenced by the costs of upgrading biogas to a methane purity sufficient for gas network standards [233]. This is dependent on the type of upgrading process and choice of upgrading technology which can lead to a 3% variation in total biomethane production costs [217]. The greatest share of these costs, however, relate to the cost of biogas production, at approximately 75% of total biomethane production costs.

**FIGURE 29**
Capital cost of biomethane production technologies.
Source: [220, 223, 230-232]

**FIGURE 30**
Production cost for biomethane.
Source: [217-223]
production costs. The economic performance of AD is sensitive to biogas yield and biomass feedstock costs, with transmission and distribution of gas and electricity price having less influence [217].

The literature discussing gasification of biomass and methanation to biomethane has comparatively few cost estimates. As mentioned, the technology to gasify biomass is functionally the same for hydrogen production, though biomass gasification to biomethane requires methanation as an additional process. The IEA estimate that biomethane via gasification costs between 3.5 p/kWh and 5 p/kWh, including feedstock, the costs of gasification (35% of total costs) and cleaning and methanation (also 35% of total costs) [221]. This appears competitive with the range of cost estimates for biomethane production using AD (Figure 30). This is also comparable to the costs of biomass gasification to hydrogen presented in Figure 25.

4.2. Infrastructure and storage costs

While the focus of this white paper is on the repurposing of existing low pressure gas networks there are still costs associated with upgrading these assets to be compatible with new gases, and the supporting infrastructure to transport and store these gases. These costs are most significant for hydrogen, where new transmission and storage infrastructure is needed. However, there are also costs associated with injection and compression infrastructure to facilitate the use of biomethane.

The following section shows the range of cost estimates found in the literature, and covers the cost of supporting infrastructure needed for hydrogen repurposing of the gas network. This is followed by an examination of the network costs associated with use of biomethane.

4.2.1. Hydrogen infrastructure costs

The network costs associated with hydrogen gas networks are summarised in Figure 31. The average cost of new hydrogen ready high pressure transmission infrastructure is approximately £1.15 million per km. The infrastructure to distribute hydrogen at lower pressures is not specific to hydrogen, but existing literature estimates costs for distribution infrastructure averaging £740,000 per km.

This cost estimate does not reflect the granularity of pressure tiers in a network such as the one operated in the UK as many statements of infrastructure costs below transmission level infrastructure are aggregated. The real costs of hydrogen gas network repurposing will be subject to a more detailed differentiation of cost elements than the simple, transmission/distribution split reported in much of the literature.
Another confounding factor in these estimates is the assumed diameter of pipe. Pipe diameter is a key factor in pipeline capacity and the cost of gas infrastructure is a function of both the cost per distance of pipeline, and the capacity of the pipeline.

Figure 32 shows estimates of high pressure transmission and distribution capital costs as a function of pipe diameter in centimetres and length in meters. This shows average transmission capital costs of £27/cm/m and distribution pipeline capital costs of £24/cm/m.

**FIGURE 31**
Infrastructure costs associated with hydrogen gas networks as a function of pipeline length.
Source: [3, 11, 118, 187, 213, 217, 234-236].

**FIGURE 32**
Infrastructure costs associated with hydrogen gas networks as a function of pipe diameter and pipeline length.
Source: [11, 118, 187, 234, 237, 238]
The breakdown of costs will vary with specific locations. However, an illustrative breakdown of costs associated with constructing a 30 cm diameter hydrogen pipeline are presented in Figure 33. This shows the majority of costs associated with labour, which is similar to the cost breakdowns associated with natural gas and CO₂ pipelines [187].

![Figure 33: Breakdown of cost components associated with constructing a 30 cm diameter hydrogen pipeline. Source: [187]](image)

The estimates of distribution network costs assume those assets are new. However, the existing distribution networks in some countries are already capable of transporting hydrogen (Section 2 and 3). As a result, a number of studies have discussed the possibility of repurposing the existing UK gas network to transport hydrogen [3, 11, 83]. In some cases studies assume no cost associated with this repurposing. One of these studies estimated that the necessary upgrading and reinforcement of the gas distribution network in Leeds, UK was approximately £10,000 per kilometer with a total cost of approximately £5,000,000 [11]. This is significantly cheaper than the cheapest estimates of gas network replacement costs in Figure 31. In addition, this area is urban, and likely to cost in the order of five times more to install new assets than costs for rural areas, increasing the relative value of the existing assets [237]. However, the low costs of repurposing the low pressure local distribution network is offset by the costs associated with providing new high pressure transmission and local transmission infrastructure. Total gas network infrastructure costs needed to provide Leeds with hydrogen were estimated at £235 million [11].

The costs of delivered hydrogen are influenced by the spatial distribution of demand, because of the per distance costs of gas networks. The influence of diffuse demand has been estimated to increase delivered hydrogen costs by 10% [211]. This suggests that urban locations are likely to provide optimal cost conditions for hydrogen network development.
The flow rate of gas also influences the impact of infrastructure costs on delivered hydrogen. Pipes that carry more energy can spread capital costs, resulting in lower infrastructure costs per unit of energy. Damen et al [236] present evidence of the impact of hydrogen transmission infrastructure on hydrogen cost as a function of both distance and energy flow rate (Figure 34). Studies also suggests CO₂ infrastructure costs are less than hydrogen infrastructure costs, suggesting that plant location should be optimised to reduce the distance of hydrogen transport, relying on the cheaper cost of CO₂ transport to mitigate the greater distance between CO₂ capture and storage sites.

The impact of both distance and flow rate on gas infrastructure costs are important aspects to capture in any assessment of gas network options. However, cost optimisation models often used to perform whole energy system analysis tend to represent gas network costs only as a function of energy throughput. Dodds and Demoullin [83] note that the impact of geography and network design are likely to be a more significant driver of gas infrastructure costs than many models account for.

The costs of network infrastructure impacts on the competitiveness of hydrogen as an option for gas network repurposing. Dodds and Demoullin [83] examined the impact of increasing gas network costs on the competitiveness of a hydrogen repurposed gas network using the UK MARKAL whole-system energy model. The study showed that the role for hydrogen decreased with increasing network costs. It also showed that even with high network costs of hydrogen (equivalent to the costs of a new network infrastructure) the model provides 8.3 TWh of hydrogen per year to consumers, suggesting that network infrastructure costs are not a complete barrier to hydrogen adoption in gas networks.[83].

Schoots et al. [187] examine the historical development of hydrogen pipelines to establish a history of cost estimates and to examine the development of these costs over time as evidence of technological learning and resulting cost
reduction. This study examined the cumulative pipeline length constructed in Europe, the US and Canada since 1938, approximately 2,900 km [187]. The cost estimates associated with the cumulative pipeline construction data suggest (with a weak statistical significance) that a doubling of pipeline length results in a 20% reduction in infrastructure costs, demonstrating a cost reduction learning effect [187]. This indicates the potential for cost reductions in future hydrogen infrastructure projects. However, the ultimate impact on delivered hydrogen costs is also a subject of the flowrate through infrastructure as well as the pipeline distance. Again this highlights the challenges of optimising hydrogen network design to minimise delivered hydrogen costs.

4.2.2. Hydrogen storage

There are a number of cost estimates\(^\text{13}\) for hydrogen storage options in the existing literature (Figure 35). The most promising hydrogen gas storage option considered in the literature, on a cost and capacity basis, is salt cavern storage. This option therefore features in contemporary assessments of hydrogen network feasibility [11, 239]. A review of the literature identified that capital cost estimates of storage options vary, from less than £1/kWh to £28/kWh of hydrogen storage capacity, with an average of ~£5/kWh (Figure 35). This variation is a function of the different technologies considered, with bulk compressed gas storage representing the upper end of this range, and salt cavern storage representing the lower end. In addition this variation is driven by assumptions made about the storage capacity and storage time, and for salt caverns, the depth of injection, the operating pressure and the amount of hydrogen injected [188, 240]. For example, the Energy Technology Institute (ETI) [188] estimates that the CAPEX of salt caverns in Teesside (with a storage size of 70,000 m\(^3\), depth of 370 meters and operating pressure of 45 bar absolute pressure) is £130 million whereas it is only £27 million in East Yorkshire (with a storage size of 300,000 m\(^3\), depth of injection of 1,800 meters and operating pressure of 270 bar absolute pressure), assuming a 400 MWe gross capacity (in 2015 GBP).

Onshore salt caverns are most commonly discussed in the literature, but it is also possible to inject hydrogen in offshore salt caverns. However, their capital costs are significantly more expensive (possibly twice as high) [189], and the minimisation of hydrogen production costs requires SMRs to be located as near inter-seasonal and intraday storage sites as possible [11].

It may also be possible to store hydrogen in depleted natural gas fields [190]. This option is technologically possible but it is likely to be more costly, and issues remain regarding the long-term stability of such reservoirs [190].

\(^{13}\) Comparisons are made on a cost per kWh basis, to capture the pertinent issues for seasonal storage requirements. Seasonal storage is often considered most challenging for energy system costs. However, other metrics for energy storage costs, such as on a cost per discharge capacity, may be more relevant for particular questions.
4.2.3. Biomethane infrastructure costs

The existing gas network infrastructure is largely compatible with biomethane given its similarity to natural gas (Section 3). Additional infrastructure will, however, be required to inject biomethane into the network. There may also be requirement for new compression equipment or network reconfiguration to distribute gas which is being introduced at new points in the existing network. It is difficult to attribute the costs of these capital investments in a comparable way to the other costs discussed in Section 4. First, the costs of injection in many instances are carried by the biomethane producer [242]. This means that these costs are often included in the gas production costs. The costs of new compression equipment and network reconfiguration are new costs incurred by the network operator and are therefore not included in gas production costs. However, gas network operators routinely upgrade and reinforce their networks to accommodate connections for new consumers, changing demand patterns and changing sources of natural gas connected to the network. It is also likely that compressor upgrades will be needed to improve the flexibility of gas networks in conjunction with electricity system management and increased variation in flexible gas power plant demand [209]. It is therefore arguable that this type of cost is an ongoing cost for network operators and not an additional cost incurred as a function of the transition to biomethane.

The additional costs of biomethane injection relate to the infrastructure needed to link biomethane plants to the existing gas network. This includes pipework to cover the distance between locations and gas handling and monitoring equipment to facilitate connection to the existing network assets. The costs of connection are site specific. However, in 2010 the UK Waste and Resources Action Programme (WRAP) [243] presented an estimate of costs of connection to the UK gas grid at £880,000. A significant impact on this cost is thought to be the cost associated with gas monitoring equipment required by the UK Gas Safety (Management) Regulations 1996. There is an identified potential to reduce this cost to £470,000 by modifying regulations to reduce their cost burden. In addition, the existing literature includes calls for financial support for biomethane production and injection into the gas network [217, 244] and the amendment of regulations to equitably allocate gas network connection costs, incentivising connections [242].
4.3. Consumer costs

4.3.1. Consumer appliance and services upgrades

The use of biomethane requires no additional investment at point of end-use given its similarity to natural gas. The transition to a hydrogen network requires some form of consumer appliance upgrade or replacement in order to safely use hydrogen. This may mean either the use of hydrogen for combustion in modified or replaced boilers, cookers and fires or the use of hydrogen fuel cell based micro CHP systems. These options have different associated costs.

First, the cost of converting a household to hydrogen, including pipework, boiler modifications and meter replacement is estimated at between £3,000 and £3,600. These estimates derived either by analogy to the costs of converting homes on the Isle of Man from town gas to natural gas [194] or by ground up estimation including the labour and parts costs associated with hydrogen boilers, cookers, fires, hydrogen compatible service pipes and gas meters, and administrative/management costs [11]. A significantly lower cost for household conversion is presented by Dodds and Demoullin [83], though this cost reflects stakeholder estimates of the costs of appliance burner replacement only and does not cover more expensive appliance costs.

Alternatively, the household cost of various consumer appliances can be compared. Appliances capable of running on hydrogen include hydrogen boilers, fuel cell micro CHP and potentially gas heat pumps. The cost of
hydrogen boilers is estimated to be close to the current cost of natural gas boilers at £1,100 to £2,200 per household [11, 194]. A study to examine the challenges of manufacturing hydrogen boilers at sufficient scale to meet the challenges of converting national scale gas networks to hydrogen concluded that there were no unsurmountable barriers [248]. Manufacturing at volumes of between 10,000 and 100,000 units was estimated to be achievable at boiler costs in the region of 1.5 times current gas boiler costs [248]. The report also noted that cost will be subject to the level of nitrogen oxides pollution permissible, with more stringent limits on boiler emissions levels resulting in higher costs [248].

The cost of hydrogen fuel cell micro CHP appliances is significantly greater than the estimates of hydrogen boiler costs, at £13,000 to £24,000 per household. However, the rate of cost reduction in fuel cell micro CHP systems is significant, and extrapolating current cost trajectories in Japan and Korea suggests that system prices might reduce by 15% to 20% for every doubling of manufactured fuel cell micro CHP appliances [249]. At current rates of deployment this has meant an approximate halving of costs between 2007 and 2013 [249]. Cost estimates for gas fired micro CHP, gas fired heat pumps and gas/electric hybrid heat pumps appear in the mid-range of consumer appliance costs, at between £4,000 and £12,500 per household.

One cost benefit of micro CHP appliances is that electricity generated will offset the requirements for centralised generation. The extent to which this impacts total system costs is complex as the total need for generating capacity, and the transmission and distribution costs associated with centralised generation are dependent on a range of system variables. However, given that heat demand is highly correlated with electricity demand in many countries the impact of electricity system costs could be significant. Dodds and Hawkes [194] estimate that savings of £500/kW might be achieved due to the impact on reduced peak demand for centralised generation.

4.3.2. Final cost of gas to consumers

The final cost of decarbonised gas to the consumer (the retail price) is a function of a number of cost components including: the production cost of gas; the transportation and storage cost of gas to consumers; the cost of storing any captured CO2; any profit margin; and taxes, levies and administrative costs [11, 250]. Final gas price is also subject to the funding mechanism, with a regulated price control model proposed in some reports likely to yield different estimates of future price than estimates based on private capital financed approaches. For example Sadler et al [11] propose one option to spread incremental hydrogen development costs across all gas users. The proposal suggests that the burden will have minimal impact on the average consumer bill. However, this does raise questions over equity, particularly as consumers will have little agency over their access to hydrogen networks.

14. The Ex-Works costs (i.e. manufacturing costs with profit margin but excluding transportation costs, installation costs and reseller profit margin) were estimated to be between £700 and £1,100
Few studies present the impact of the cost components on the potential cost of decarbonised gas to consumers. Understanding the impact of the range of cost estimates presented in this white paper is therefore subject to a number of assumptions that vary across geographical location. Nevertheless examining the cost to consumers of decarbonised gas generation provides useful context as to the economic impact of gas decarbonisation.

Sadler et al. [11] present an estimate of hydrogen retail price based on cost of gas production, and the additional price impacts associated with network operation, environmental levies, administrative costs, taxes and profits. These additional costs are presented in Figure 37, and are estimated to be 35% of gas production costs. This estimate includes the costs of hydrogen storage and high pressure hydrogen transmission, as well as the additional costs of upgrading work to the low pressure gas network as costs added to the gas production costs. This can be compared to estimates of the composition of the gas retail price in the UK, presented in Figure 38 [250, 251].

**FIGURE 37**
The components of consumer price of hydrogen as calculated in the H21 Leeds City Gate report.
Source: [11]
Note: Gas production costs also include the costs of hydrogen network infrastructure and storage.

**FIGURE 38**
Composition of UK gas retail price.
Source: [250, 251]
The costs of biomethane production (Figure 23) can be added to the costs presented in Figure 38 (minus wholesale gas cost) to give an indicative estimate of biomethane retail price. Since biomethane can use existing gas network assets there is a limited need for new gas network infrastructure, and therefore little impact on retail price. The cost estimates for biomethane production presented in Figure 23 are estimated in different countries. The addition of UK profit margins, taxes and levies is therefore not a fair comparison. However, it does give a closer illustration of the magnitude of costs likely to be experienced by the consumer. This includes the range of uncertainty in gas production, transportation and storage cost estimates in the existing evidence base. This retail price estimate is shown in Figure 39.

Figure 39 also presents an estimate of the retail price of hydrogen. This is based on: the range of costs of hydrogen generation presented in Figure 23 for SMR with CCS; the costs of hydrogen transportation and storage presented in Figure 32 and Figure 35; and the addition of current UK gas network operating costs, tax and administrative costs based on regulator estimates (Ofgem) [250].

The figures for SMR with CCS are used for comparability with other similar studies [8, 11]. However, other technologies discussed in this paper could also contribute to future hydrogen production, with their varying costs impacting on the resulting retail price of hydrogen. The approximate composition of these ranges of retail costs are presented in Table 7.

The potential hydrogen retail price is not just a function of hydrogen production costs but also the costs of new or upgraded gas network assets. The estimates of gas infrastructure costs in this section are difficult to compare with the per kWh cost estimates for other costs without assumptions on the length and capacity of pipelines and on the volume of gas it will transport annually. In addition, the hydrogen storage, transmission and distribution upgrade costs (Figure 37) are calculated within the gas production costs, and only the costs associated with using the existing gas network are itemised within the additional costs.

The estimates of retail price in Figure 39 demonstrate the additional impact of hydrogen infrastructure, which have increased the retail cost of hydrogen above that of biomethane. This is in contrast to the production costs presented in Figure 23. These estimates also demonstrate the impact of the significant range of estimated gas production, transmission and storage costs. The resulting wide range of retail price estimates makes analysis of the future for decarbonised gas difficult. A priority for future investigation is therefore the development of demonstration projects that can provide increased certainty around the costs of decarbonised gas options.

In a real system these costs will be dependent on the location, design and utilisation of the gas system, among other variables. This will create opportunities to optimise costs based on system design. However, a significant proportion of the estimated retail price (40 to 50%) is in the cost of gas production. Opportunities to minimise decarbonised gas price should therefore begin minimising production and infrastructure costs. Given the range of technical efficiencies presented for SMR in Section 3 (60 to 90%), and
the efficiency penalty associated with CCS (5 to 10%), maximising efficiency may be a first point of focus in cost reduction.

**FIGURE 39**
Estimate of retail price (in pence sterling) of decarbonised gas based on the composition of current UK gas retail price.
Note: Based on the cost ranges presented in Figure 23 (for SMR with CCS only), Figure 32 and Figure 35 and the Ofgem analysis of gas retail price composition. Cost estimates scaled to [11]. Cost of capital and asset lifetime based on [11].

**TABLE 7**
Composition of retail price estimates for biomethane and hydrogen average case.
Note: Numbers in the hydrogen column total over 100% due to rounding.
5. Carbon impacts of gas network options

The primary driver for assessing the role of gas networks in future energy systems is to consider their role in achieving climate targets that avoid an average global temperature rise of 1.5 - 2 °C. Therefore, a thorough assessment of the greenhouse gas emissions associated with gas decarbonisation options is necessary. It is important that technological options offer a reduced climate impact, as well as allowing for deeper decarbonisation options in the future.

This section reviews the environmental impacts associated with the gas decarbonisation options considered in Section 3. Evidence of the GHG emissions for each technology is summarised and compared. The analysis examines each technologies’ overall life cycle to assess total contributions to emissions. The impact of supply chain emissions is also examined.

5.1. Greenhouse gas emissions: hydrogen production

There are several estimates of GHG emissions for the mature routes of hydrogen production, from natural gas methane reforming [112, 113, 117, 122, 125, 137, 149, 252-255], coal gasification [122, 137, 255-257], electrolysis from renewables [137, 148, 149, 253, 255], biomass gasification [137, 258, 259] and nuclear [137, 255]. Estimates of overall life cycle GHG emissions are provided in Figure 40 for each category, given in gCO₂ eq/kWh higher heating value (HHV) of hydrogen production. The current carbon intensity of natural gas for heating is approximately 230 to 318 gCO₂ eq/kWh and is also shown in the figure.

The studies examined in this report were from a wide spectrum of literature sources and therefore use a variety of different estimation methods, study boundaries, product qualities and feedstocks, thus causing a large variation in the results. These differences are described in the following sections for each technological category.

The overall range of emissions across the technologies is extremely large, from -371 to 642 gCO₂ eq/kWh. The highest and most variable estimates are associated with natural gas and coal based hydrogen production without the use of CCS. The lowest estimates are typically associated with electrolysis using wind generation and biomass gasification. As shown in Figure 40, reductions in GHG emissions can only occur with hydrogen production using a low carbon source and/or with CCS. However, many estimates associated

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15. 184 gCO₂/kWh from combustion, plus 30 to 75 gCO₂/kWh supply chain CO₂ emissions, plus 17 to 58 gCO₂ eq/kWh supply chain methane emissions (0.8% to 2.6% of total production)
with supposedly low carbon systems give only a 40% reduction, which alone is unlikely to contribute sufficient emissions reductions to meet climate targets.

5.1.1. Hydrogen from reforming natural gas

Estimates of GHG emissions associated with hydrogen production from natural gas reforming are 23 to 401 gCO₂eq/kWh as shown in Figure 41, although estimates below 71 gCO₂eq/kWh exclude supply chain emissions [117, 252]. Estimates are 23 to 150 gCO₂eq/kWh for reformers with CCS, or 288 to 347 gCO₂eq/kWh for those without CCS. The average impact of CCS is to reduce total emissions by approximately 75%. These estimates assume carbon capture rates of 71% to 92% [113, 122, 125, 137].
For estimates that do not include CCS, emissions are typically 75% from the reforming operation and 25% from the natural gas supply chain. As the fuel used to obtain the temperatures and pressures required is sourced from the natural gas itself, the efficiency is a key parameter, expressed as the energy contained within the hydrogen product versus the energy contained within the natural gas input. Estimates of efficiency are between 60% and 90% for all reforming technologies [111, 112, 117, 125] and depend on: the technological reforming option considered; assumptions regarding the exporting of excess steam generation; and whether CCS is included.

There are a number of technological options within this reforming category, as outlined in Section 3 which are steam reforming, partial oxidation, autothermal and autocatalytic decomposition. Almost all emissions estimates are for the most mature and commercialised system, steam reforming. There are a small number of estimates for the others, but all are within the range. Efficiencies for steam reforming are typically slightly higher at 60% to 90%, compared to 60% to 75% for the others [111-114].

Overall in the reforming and gas shift processes, excess steam is produced. The steam may be used for another process, in which case this may be an avoided burden (negative emission) by replacing another steam-raising duty. The suitability of this duty is site specific and dependent on other process requirements, but may account for approximately 7 gCO₂eq/kWh according to Spath and Mann [112]. The H21 report suggests that an efficiency gain of up to 11.2% can be made by using excess steam [125]. A conservative assumption would be to assume this steam is wasted (i.e. zero avoided burden), whereas the best environmental result is where the excess steam is fully utilised and replaces a high emitter (e.g. coal or liquid fuels). An obvious route to use excess steam is for a CCS heat requirement. The H21 report [125] indicates that the excess steam is sufficient to satisfy the heat requirements of the capture process, although specific figures are not mentioned.

When CCS is included in emissions estimations, total emissions are reduced by approximately 75%, with SMR and CCS emissions representing approximately 50% of the total, with upstream emissions contributing 40% and hydrogen transport and storage contributing the remaining 10% [113, 122, 125, 137]. Adding carbon capture to a reforming process may represent only a small efficiency loss due to the use of excess steam.

There is likely to be a trade-off in the capture process between maximising capture rate and minimising energy penalty. Capture rates are typically assumed to be 85% to 90% [97, 126], but most CCS projects have lower capture rates [260]. For example, the Quest project aims at retrofitting three SMRs with CCS, and capturing 80% of their CO₂ emissions, or around one million tCO₂ per year [261]. Higher capture rates can be achieved by greater absorption/adsorption rates or multiple stages, but this increases the energy penalty. The energy penalty of CCS on SMRs was estimated to be 5% to 14% [119-121]. Future CO₂ capture plants are expected to capture up to 95% of CO₂ emitted [123]. No research was found that investigates the effect of capture rate and energy penalties on life cycle GHG emissions and cost, but this would be needed to determine optimum cost/environmental impacts.
5.1.2. Hydrogen from electrolysis

Estimates of GHG associated with electrolysis are widely variable, between 24 and 788 gCO₂eq/kWh [137, 148, 149, 255]. However, the upper limit is an estimate using grid electricity (using a German/UCTE grid mix from 2012 [137]). When only low carbon sources are considered, the range is reduced to between 24 to 178 gCO₂eq/kWh as shown in Figure 43.

GHG emissions associated with electrolysis are primarily governed by the electricity source and the electrolysis efficiency [262]. There is a large difference between solar PV and wind estimates, with wind consistently at the lowest end of estimates. Emissions associated with solar PV are highly variable due to the difference in efficiencies associated with PV energy conversion in different regions. Wind electrolysis estimates are approximately 25 gCO₂eq/kWh, whereas solar PV estimates are 51 to 178 gCO₂eq/kWh. Note that wind electrolysis estimates are all derived from the same inventory [147], hence the lack of variation. Emissions in renewable electrolysis typically arise in the manufacturing stage of the renewable generation technologies, including process energy requirements and the embodied emissions in raw materials [149]. The use of lower carbon fuel sources to replace electricity and diesel usage during the production of raw materials and manufacturing is likely to reduce supply chain emissions significantly.

The different types of electrolysers considered are alkaline, PEM and SOE, as described in Section 3. The efficiency of electrolysis differs across the technologies, with estimates of 50 to 85% for alkaline, 48 to 83% for PEM and 60 to 90% for SOE [103, 111, 137, 138, 143, 144, 147-150]. However, efficiency, as well as life span, of electrolysers may be significantly affected by the use of an intermittent electricity supply. As mentioned in Section 3, PEM electrolysers are more suited to variable loads, though some evidence suggests lifespans are limited [103,139].
Estimates of GHG emissions typically only consider alkaline electrolysers with different types of renewable electricity generation, primarily solar PV or wind. No sufficiently detailed environmental life cycle assessments on hydrogen production using PEM or SOE from renewables were discovered. Therefore, there is no useful comparison of emissions from different electrolysers. The efficiency, use of exotic catalysts and life span of the electrolyser may have a significant impact on environmental emissions and should be investigated further. Currently, data on the resource requirements for different electrolysers are very poor. Only two studies were found which detailed an inventory of resource for electrolyser manufacture [147, 263].

Emissions associated with the fuel usage in compressing hydrogen to the appropriate pressure may be significant, although this depends on the pressure requirement and this is also true for the other hydrogen production options [264]. It is also dependent on the fuel source of compression, as it may be the hydrogen itself, or grid electricity which would result in higher GHG emissions.

5.1.3. Hydrogen from coal and biomass gasification

Estimates of coal gasification emissions are 50 to 642 gCO₂eq/kWh [122, 137, 255, 257]. The largest impact is whether CCS is accounted for: estimates are 50 to 180 gCO₂eq/kWh with CCS and 270 to 642 gCO₂eq/kWh without CCS.

![FIGURE 43](image)

**FIGURE 43**
Greenhouse gas emission estimates of hydrogen from coal and biomass gasification.
Source: [122, 137, 255, 257-259, 265-273]

Given that there is no environmental benefit associated with hydrogen production from coal without CCS, only coal gasification with CCS is considered here. GHG emissions arise from coal extraction (methane and CO₂), fuel usage during gasification and residual CO₂ emissions that are not captured. Deep-mined coal extraction yields greater methane emissions than for surface-mined coal, contributing to total GHG emissions [122]. Emissions associated with coal gasification with CCS are comparable to those from reforming natural gas with CCS (50 to 180 gCO₂eq/kWh versus 29 to 151 gCO₂eq/kWh from natural gas).
Estimates of GHG emission from biomass gasification are lower but more variable, -371 to 504 gCO₂eq/kWh [258, 259, 265-275]. Key factors associated with emissions estimates include the source of the biomass feedstock, how the carbon sink associated with biomass growth is included, as well as whether CCS is within the scope. Much of the source of CO₂ emissions from the gasification and upstream processes is biogenic, in that carbon dioxide was taken from the atmosphere to grow the biomass. Consequently, combustion of the biomass yields low overall emissions. Some studies account for the carbon-sink, whereas others account for different levels of soil carbon uptake [276].

Combined with the allowance of biogenic carbon, incorporating CCS should yield net-negative emissions. Indeed, this is the motivation behind research into the use of electricity from bioenergy with carbon capture and storage (BECCS). Hydrogen from biomass gasification using CCS is one route to produce negative life cycle GHG emissions in gas production. One study provides an estimate of hydrogen production from biomass gasification using CCS of -371 gCO₂eq/kWh hydrogen [268]. This estimate is comparable to estimates for electricity generation from biomass combustion with CCS, suggesting that hydrogen production from biomass with CCS will be relevant in the second half of this century, when negative emissions become increasingly important [277].

The impact of biomass gasification depends largely on the source of the biomass feedstock, in particular the energy density of the biomass and whether it is a residue or an energy crop [275]. Waste products are likely to yield significantly better environmental credentials as there are no associated agricultural impacts. However, waste is likely to give limited potential in terms of providing enough hydrogen to significantly reduce national emission profiles.

Land-use change (LUC) also impacts GHG emissions of decarbonised gas where energy crop biomass is used as feedstock. These issues are discussed in Section 5.2.

5.1.4. Hydrogen from reforming biogas

Reforming biomethane would be identical in process to reforming natural gas. Consequently, the emissions profiles associated with this step would be similar. Thus, the difference in emissions associated with hydrogen from reformed biogas would be the upstream emissions, which are described in the following section on producing biogas.

5.2. Greenhouse gas emissions: biomethane

Estimates of GHG emissions associated with biomethane production from anaerobic digestion span several orders of magnitude, representative of the broad range of feedstocks, processes, uses and estimation methods. Estimates range from slightly negative (not accounting for combustion) to 450 gCO₂eq/kWh methane [15, 274, 278-280].
Given that direct CO₂ emissions associated with biomethane consumption are mostly biogenic, they are often considered to be balanced by CO₂ uptake from soil during cultivation and are assumed to be zero. However, the indirect emissions associated with plant construction and diesel usage for agricultural machinery are examples of non-trivial supply chain CO₂ emissions, whilst nitrous oxide (N₂O) emissions from fertiliser usage may be significant (given that their global warming potential is around 300 times that of CO₂). The main source of GHG emissions associated with anaerobic digestion is often considered to be methane emissions from the open storage of digestate [274, 275, 280]. However, digestate may be reused as fertiliser, which results in an avoided burden of reduced fertilizer production [274, 275, 280].

A potentially important source of emissions associated with AD methane production is methane emissions from the storage and application of any digestate that is formed. This can be effectively minimised, but there is a risk of significantly increased emissions if it is not adequately addressed [275].

Generally waste crops are preferred to energy crops in AD, as the emissions associated with crop cultivation are entirely avoided. Whiting et al. [280] estimate that using maize as an energy crop for AD combined heat and power (CHP) electricity and heat generation results in 10% higher GWP emissions. However, it has been suggested that maize crops perform extremely well due to the high yields achieved [275]. Whiting et al. [280] also estimate that using biogas from farm wastes to replace natural gas (in their case in a combined heat and power plant) reduces GHG emissions by 34%.

The consideration of direct and indirect land-use change (LUC) also has a significant impact on GHG emission estimates. Where energy crops are cultivated on cleared forestry land for example, the change in land-use is likely to change the amount of carbon ‘sink’ available. The soil organic carbon (SOC) sequestration is an important part of the carbon cycle, where estimates of life cycle GHG emissions including direct and indirect LUC are sometimes worse than their fossil alternatives [281, 282]. Note that the impact of LUC is highly region-specific and the majority of GHG estimates associated with biomethane production do not allow for this contribution.
5.3. The role of supply chain emissions

All routes to gas decarbonisation have emissions in their supply chain. These emissions vary significantly and have a range of different relative impacts on total GHG emissions estimates, as discussed in this section. Table 8 presents the balance of supply chain and hydrogen production or methane combustion emissions for a number of hydrogen production methods.

There are significant differences in the sources of supply chain emissions between the different routes to hydrogen. Emissions in natural gas boilers or the SMR with CCS supply chain arise due to CO₂ and methane emissions in the production and transportation of natural gas. The supply chain emissions in electrolysis arise due to the carbon intensity of electricity and the embodied emissions arising from the manufacturing of electricity generation technologies (e.g. solar panel or wind turbine manufacture). Biomass routes to hydrogen involve supply chain emissions from the cultivation of crops, transportation of biomass and potential emissions resulting from LUC.

Only two studies present disaggregated data for SMR with CCS showing supply chain emissions of 36.5 [11] and 41.2 gCO₂eq/kWh [122]. This range is significantly lower than existing estimates of natural gas supply chain emissions, presented here as 47 to 134 gCO₂eq/kWh [47]. Emissions estimates for SMR with CCS could therefore be underestimated in the literature reviewed in this white paper.

For the studies that estimate environmental impacts of biomethane production, the approach is to assume combustion emissions of biomethane are zero, balanced by the carbon uptake associated with crop growth [274, 275, 279, 280]. Whilst this is an appropriate approach, it is not comparable with the data presented in Table 8.

On examining the impact of supply chain emissions there are a number of important issues:

- The majority of emissions associated with hydrogen from SMR with CCS arise in the natural gas supply chain, in particular methane emissions. These emissions are highly variable and are amplified by the efficiency loss and energy penalty associated with SMR and CCS processes. Given this amplification, minimising methane emissions is an increasingly important aspect in reducing total emissions.

- Supply chain emissions have a disproportionately large impact on total emissions for electrolysis routes to hydrogen, given the lack of emissions in the hydrogen production stage. This gives rise to some of the counterintuitively large emissions seen in some electrolysis estimates.

16. This is a constrained range based on analysis of the broader range represented in Balcombe et al [47].
• There is scope for reduction of supply chain emissions for all technologies. Production and transportation emissions in gas are reducing over time in response to environmental regulation. The CO₂ intensity of electricity is expected to decrease as the carbon intensity of electricity decreases, reducing the embodied energy in manufacturing these generation technologies. The scope to reduce supply chain emissions for biomass gasification is less clear given variation in feedstock and feedstock processing.

• Whilst supply chain emissions decrease under future decarbonisation scenarios, embodied emissions in imported generating technologies will be dependent on the emissions of the exporting country. Since decarbonisation pathways vary significantly across regions, the country of origin will become an important factor in determining life cycle emissions of decarbonised gas routes.

• The emissions from biomass gasification (with and without CCS) are characterised by significant negative emissions in the supply chain due to carbon uptake in biomass cultivation and significant positive emissions in the gasification process. As a result, relatively small percentage improvements in aspects such as CCS capture rate or process efficiency will have relatively large impacts on total emissions. The large range of supply chain emissions is heavily influenced by the biomass source, and as such there is relatively less potential to improve supply chain emissions without limiting resource availability.

<table>
<thead>
<tr>
<th>Supply chain emissions</th>
<th>Hydrogen production/ methane combustion</th>
<th>Total</th>
<th>Hydrogen production efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>gCO₂ eq/ kWh</td>
<td>gCO₂ eq/ kWh</td>
<td>gCO₂ eq/ kWh</td>
</tr>
<tr>
<td>Natural gas</td>
<td>47 to 135</td>
<td>184</td>
<td>230 to 318</td>
</tr>
<tr>
<td>Natural gas SMR + CCS</td>
<td>37 to 41</td>
<td>40 to 77</td>
<td>23 to 150</td>
</tr>
<tr>
<td>Renewables electrolysis</td>
<td>25 to 178</td>
<td>0</td>
<td>25 to 178</td>
</tr>
<tr>
<td>Biomass gasification</td>
<td>-786 to -288</td>
<td>571 to 786</td>
<td>-45 to 504</td>
</tr>
<tr>
<td>Biomass gasification + CCS</td>
<td>-832</td>
<td>461</td>
<td>-371</td>
</tr>
<tr>
<td>Coal gasification</td>
<td>8 to 30</td>
<td>278 to 684</td>
<td>279 to 642</td>
</tr>
<tr>
<td>Coal gasification + CCS</td>
<td>8 to 30</td>
<td>40 to 162</td>
<td>50 to 181</td>
</tr>
</tbody>
</table>

Note: Estimates in “Total” column represent total estimates in literature and not the sum of estimates for supply chain emissions and hydrogen production/methane combustion. Lowest total SMR + CCS emissions estimates do not include supply chain emissions. Biomass gasification + CCS based on single study, with the increased supply chain emissions reflecting the energy penalty of CCS.
6. Analysis of the options

Decarbonised gas networks are one set of options that can reduce the emissions impact of energy services currently supplied by natural gas. However, there are other options to provide this decarbonisation, including electrification of energy services and the development of heat networks. These options can be compared to each other in terms of cost, emissions, and system flexibility, among other metrics. However, it is an oversimplification to compare options competitively, and there is significant scope for these options to be deployed together in a complementary way, maximising the benefits of each. Understanding the optimal suite of options is therefore an important aspect of gas network decarbonisation, though the existing evidence at energy system-level is currently lacking. It is therefore key to identify the extent of knowledge of decarbonised gas systems, how they compare to other options, and what emerging system-level questions should be a priority.

This section begins by comparing the previous analysis with cost and carbon emissions estimates from use of electric heat pumps. The section then briefly discusses issues regarding whole-system modelling of gas networks and specifically modelling the current options for gas network decarbonisation. Finally, the relevance of the report’s findings for different countries, is discussed, based on their current use of gas and gas networks.

6.1. Comparison of costs

6.1.1. Cost of gas vectors

The costs of gas network decarbonisation options can be compared to the costs of electricity and heat pumps at various stages in the energy supply chain. First, recent gas and electricity wholesale prices can be compared to the estimates of hydrogen or biomethane production costs (Figure 45). This comparison shows that, while all hydrogen and biomethane production costs are greater than wholesale prices of gas, in a small number of estimates hydrogen or biomethane production costs are lower than current wholesale electricity prices. However, it is important to note that producers of hydrogen or biomethane would add a profit margin to hydrogen production costs, while the wholesale prices of electricity and natural gas presented in Figure 45 already account for this margin. This suggests that future hydrogen wholesale prices are likely to be higher than current electricity or gas vectors, regardless of the route to hydrogen or biomethane production.

In addition to the apparent uncertainty in future hydrogen and biomethane wholesale prices, future electricity prices are also uncertain. The increasing role for low carbon generation is likely to impact on future electricity wholesale and retail prices. Analysis of the impact of increasing renewable electricity generation is often conflicting. Some studies highlight the likelihood of longer
term price rises as the additional costs of decarbonisation are passed down to consumers [286], while other studies indicate wholesale price reduction relating to the addition of low marginal cost solar and wind generation [224]. This uncertainty is in part tied to the future demand for electricity, which is in turn tied to the role for competing energy vectors such as decarbonised gas. This illustrates the systemic nature of the problem, highlighting the need for careful and internally consistent modelling approaches to estimating the future impacts of different decarbonisation pathways.

6.1.2. Cost of infrastructure requirements

A significant component of retail energy prices arise in the transmission and distribution of energy vectors [224, 250]. As discussed in Section 4, the additional costs associated with transporting biomethane (or BioSNG) are minimal, while the costs of transporting hydrogen are likely to include the costs of new transmission infrastructure and the reinforcement and/or construction of lower pressure gas network infrastructure. The cost of gas network infrastructure and its impact on the cost of hydrogen to consumers is a function of the distances between gas supply and gas demand, and the scale of energy transported through the network. This means that optimising network design is key to minimising costs and that the ultimate costs of infrastructure to consumers are sensitive to consumer density and how much gas the infrastructure transports. As presented in Section 4, the proportion of infrastructure and storage costs in the final retail gas price might increase in a transition to hydrogen gas networks by 23% to 35%. However, it is more appropriate to compare infrastructure costs to the costs of other decarbonised energy vectors given the need to decarbonise the energy system.
The infrastructure costs associated with electrification of heating have been discussed in a number of studies and it has been noted that the costs of reinforcing electricity networks to accommodate electrification of heat are significant [10, 288, 289]. A report by the CCC examining the future of UK heat suggests that the additional costs of electricity infrastructure incurred through action to address climate change is £6.2 billion in the period to 2030 [10]. This scenario includes the addition of 7 million heat pumps. The report also estimates that demand side response measures over the same period might reduce this cost by £1.7 billion [10]. Another estimate by National Grid suggests that electricity network reinforcement costs might be in the order of £10 billion and that this cost might be equivalent to the infrastructure requirements to upgrade and inject a “technical potential” of 180 TWh of renewable gas into the UK gas network, representing two thirds of the UK 2020 renewables target of 15% of total energy [288].

In addition, electricity networks will require reinforcement to deal with electrification of other energy services including the growth in electric vehicles and the increasing quantity of distributed electricity generation in many countries [289]. The network reinforcement needed to accommodate electrification of heat and transport in the UK alone has been estimated at up to £36 billion over the period 2010 to 2050 [289]. To put these costs into context, roll-out of a hydrogen network to cover 30% of UK gas users by 2051 was estimated to cost £26 billion in capital costs, £24 billion in labour and appliance conversion costs and £2.8 billion in annual operating costs [11].

Any future role for decarbonised gas will be based on its value in providing not only decarbonised energy, but system benefits in terms of its inherent flexibility, and through integration across heat, power, and transport. There may also be resource constraints limiting the volumes of decarbonised gas. Therefore costs are not mutually exclusive choices but will likely play complimentary roles in energy system decarbonisation. The calculation of infrastructure costs of electricity networks and decarbonised gas networks therefore requires whole-system modelling approaches and very few comparable estimates exist in the literature [290]. Since the cost of infrastructure is likely to be non-linear, it is important to calculate these costs using internally consistent scenarios. Issues to be examined include the optimal share of technologies in the energy mix under various assumptions, the resulting capacity and the cost burden of the various required infrastructure upgrades. This highlights the need for new research effort in these areas to quantify the potential costs of future energy systems with varying contributions of decarbonised gas networks.

6.1.3. Cost of storage requirements

The relatively low cost of gas storage is often presented as a key benefit of decarbonised gas network options [8, 11, 239]. As mentioned in Section 2, interseasonal energy storage is a significant challenge and the costs of electricity storage are thought to be expensive in comparison to current gas storage costs. For example, MacLean et al [239] note that the cost of gas storage could be several orders of magnitude less than the cost of electricity storage. Figure 46 presents the range of hydrogen storage costs (presented
in Section 4) to transmission level electricity storage costs for some of the cheaper electricity storage technologies on a per energy basis [291]. This demonstrates a significant difference between gas and electricity storage costs. However, these technologies are not necessarily comparable on a seasonal storage basis and the storage requirements and options to mitigate energy storage needs are not equivalent between gas and electricity systems.

A number of factors will ultimately influence the total requirement for storage if electricity displaces gas for domestic and commercial heat. For example, heat pumps may be 2-3 times more efficient than hydrogen or methane based consumer appliances. This will translate as a lower energy demand and therefore a reduced requirement for electricity storage in energy terms [292]. Energy system design will also influence the requirement for storage. Demand-side response technologies, smart grids, integration of vehicle batteries storage capacity, interconnection and gas fired backup electricity generation may all play a role in mitigating the issues of variable consumer energy demand, both on daily and interseasonal timescales. Understanding the ultimate consumer energy demand profile and the optimal system design to minimise costs requires system modelling approaches that consider all energy vectors, appliance options and that can resolve on both spatial and fine temporal timescales.

The use of hybrid heat pumps offers the potential to take advantage of both the low storage costs and inherent flexibility of gas vectors and the significant decarbonisation potential of electric driven heat pumps (Section 6.2). This could potentially reduce the impact of variable heat demand on the reinforcement costs of electricity networks and the capital cost of building additional electricity generating capacity to meet peak heat demand. However, the appliance and system performance of these devices is unknown and some level of demonstration is needed to understand these factors [203]. Projects are underway that seek to answer these questions. It is therefore important for any future analysis of energy systems to incorporate the findings of these emerging demonstration projects in order to improve the representation of all energy system options [204].

![Figure 46](image-url)
6.1.4. Cost of energy and heat to the consumer

The retail price of delivered energy vectors is a more reflective measure of the total cost impact of gas network options. However, very few estimates of future hydrogen or biomethane retail prices exist, making systematic comparison difficult. To confuse matters further, the future retail price of networked gas may be a composite of several gas vectors where natural gas, methane and hydrogen may be blended together in different proportions [293]. Understanding future retail prices is therefore a ‘whole-system’ problem requiring appropriate quantitative approaches. However, the retail cost estimates presented Section 3 can be compared to existing energy prices, providing an illustration of the possible prices in context.

Figure 47 compares an estimate of the retail price for hydrogen and biomethane presented in Figure 39 (see Section 4.3.2) compared to current average retail prices for electricity and natural gas in the EU in 2015 [224]. This suggests that hydrogen and biomethane retail prices may lie somewhere between the current retail prices for electricity and natural gas. Reducing the wide range of price estimates is again a priority for future research, and the development of appropriately scaled demonstration projects will be a key step in providing this evidence.

The eventual costs of heat delivered to consumers is a function of the cost of energy as well as the efficiency of the consumer appliance used to convert energy to end-use service. For domestic and commercial consumers connected to the gas grid this largely means the conversion of gas or electricity to heat. Where gas is used domestically the likely appliances used for heat conversion will be efficient condensing boilers capable of handling hydrogen, with an efficiency approaching 90%, similar to current natural gas fired condensing boilers [8-11]. Heat pumps of some form may be used if electricity is the chosen energy vector, though modern storage heaters are also a potential heat appliance in some future domestic systems [8, 10]. Heat pumps are highly efficient appliances capable of converting one unit of electricity in several units of heat in optimal conditions. However, the achievable efficiency...
in real applications (known as the Seasonal Performance Factor [SPF]) is uncertain, and demonstrated mean efficiencies of these appliances in the UK climate typically lie in the range of 2 to 3, with ground source heat pumps typically performing better than air source models [294]. Given this range the final cost of heat to consumers can vary significantly. Figure 48 demonstrates this issue by comparing the cost of heat from a hydrogen boiler with the cost of heat from a heat pump as it changes with heat pump efficiency. This demonstrates that, within current assumptions of electricity and hydrogen prices, heat from hydrogen is likely to be more competitive at lower heat pump efficiencies, while heat pumps with higher efficiencies are likely to be more cost competitive, even with a relatively large difference between electricity and hydrogen prices.

6.2. Comparing carbon intensities of decarbonised gas

Section 5 presents a range of carbon intensities for hydrogen and biomethane, showing that a number of factors influence this large range. Reforming natural gas to hydrogen with CCS would produce embodied emissions to 23 to 150 gCO₂eq/kWh of hydrogen produced, compared to between 230 to 318 gCO₂eq/kWh for natural gas and condensing boilers. However, small methane leaks across the supply chain can cause carbon intensities to increase significantly. Reformer efficiency and CCS capture rates are important factors in reducing emissions further. A remaining question is how does this carbon intensity compare to other decarbonisation options, and how sensitive is this to methane leakage, CCS capture rate and consumer appliance efficiency.

Figure 49 presents the carbon intensity of heat from hydrogen (boiler efficiency 90%) generated using SMR with CCS as it varies with both the CCS capture efficiency and the leakage rate of methane in the natural gas supply chain. This is compared to the carbon intensity of heat from a natural gas boiler (efficiency 90%) and the carbon intensity of heat from a heat pump (SPF 2.5) running on electricity with a 50 g/kWh carbon intensity, which is the CCC 2030 goal for
power generation [295]. This demonstrates that while hydrogen boilers may deliver significant carbon reductions relative to current gas boilers, electric routes to heat delivery could significantly lower the carbon intensity of heat provided that electricity is sufficiently decarbonised. In terms of capture rate, there are clear benefits to maximising capture rate for the total emissions of SMR based hydrogen gas network. Increasing capture efficiency from 90% to 94% could reduce the carbon intensity of hydrogen based heat by over 10%. 

Figure 49 also presents the impact of increasing methane leakage in the SMR supply chain. This suggests that increasing leakage rates by 1% of gas demand might increase carbon emissions by 37%. This highlights the importance of minimising methane leakage given the very high climate forcing impacts of this gas relative to CO₂.

Notes: Natural gas and hydrogen boiler efficiency assumed 90%. 1.4% leakage rate based on [47]. 50 - 100 gCO₂/kWh intensity based on [295].

Other methods of hydrogen production offer similar life cycle emissions, such as coal gasification with CCS, solar PV electrolysis and biomass gasification without CCS. Each have different emissions profiles and vary significantly based on regional variations and conversion efficiencies. However, wind electrolysis, biomass gasification with CCS and reforming biogas with CCS can deliver significantly better greenhouse gas emissions, below 36 gCO₂eq/kWh and in the case of some biofuel processes, negative emissions. Such low carbon intensities will become increasingly important later in this century with the need to move the global energy system towards net zero emissions [296]. However, the resource availability of biomass and the costs of scaling up electrolysis are likely to limit the contribution that these technologies can make to future decarbonisation (Section 3 and Section 4).

Hydrogen via electrolysis is often assumed to be among the lowest carbon

17. Based on a methane leakage rate of 1.4%.
18. Based on 90% CCS capture efficiency.
routes to decarbonised gas, particularly when renewable energy is used. However, this assumption is highly sensitive to the type and location of electricity generation. As presented in Figure 42 the carbon intensity of hydrogen from solar electricity, for example, ranges from 50 g/kWh to 178 g/kWh, with average carbon intensity of 122 g/kWh. This is significantly more carbon intensive than estimates of future electric routes to heat in the UK (Figure 49). Using electricity from wind generation could be significantly lower carbon than this, with an average carbon intensity of available estimates at 25 g/kWh. At this carbon intensity, and assuming a hydrogen boiler efficiency of 90%, hydrogen based heat could have a carbon intensity of 28 g/kWh, competitive with electric heat pumps using 50 to 100 g/kWh electricity and a heat pump efficiency SPF 2.5. Future efficiency of electrolysis may improve carbon intensity over time, and the impact of supply chain emissions in the manufacture of renewable technology is likely to reduce in line with decarbonisation of electricity. Future quantification of potential hydrogen gas systems will require forward-looking estimates of hydrogen technology performance and supply chain emissions to capture these issues.

6.3. Examining the whole-system

Many aspects of future gas networks decarbonisation are difficult to measure or estimate without consideration of ‘whole-system’ level interactions. Issues such as the cost impact of new infrastructure, the cost burden of CCS, the decarbonisation potential and the future demand profile for primary and final energy are all interdependent, and estimating the role, cost and carbon intensity of gas networks requires a coherent understanding of many other aspects of the whole energy system. Energy research often uses scenario methods and whole-system modelling techniques to address this issue. However, these techniques are subject to the chosen scenarios, assumptions and model structures.

The scenario literature and whole-system energy modelling have explored a range of different options for energy system decarbonisation, with many of these examining reduced utilisation of gas networks [3, 301]. However, many models do not represent all the gas network decarbonisation options sufficiently. For example, Dodds [302] notes that UK energy policy in the decade to 2014 was underpinned by the UK MARKAL model [303]. However, a number of key aspects of the gas network and the residential energy sector are identified as needing modification, including:

- a more detailed disaggregation of dwelling types;
- the full representation of heat delivery infrastructure (district heat networks, radiators and underfloor heating systems);
- addition of several heat generation technologies including hydrogen boilers and ground source heat pumps; and
- addition of the option to deliver hydrogen through the gas network.

19. UK MARKAL is a multi-time period linear optimisation model that portrays the entire UK energy system.
These modifications highlight the extent to which currently discussed gas network decarbonisation options were absent from tools used to inform UK energy policy in the past.

Models used extensively in the development of current UK energy policy include UKTM and ESME [304, 305]. These models include an extensive list of energy technologies, including gas-fired technologies, from which the models develop least-cost optimised scenarios that meet specified carbon constraints. However, recent iterations of these models may not capture all technologies or the characteristics of energy infrastructures, limiting their ability to represent decarbonised gas options on a comparable basis with other energy vectors. Key aspects limiting these models include:

- the limited capacity to model hydrogen transportation in existing low pressure gas networks;
- the limited capacity to deal with temporal scales necessary to model flexibility options such as hybrid gas/electric heat pumps; and
- their treatment of gas networks as a cost per energy unit delivered, without the impact of pipeline length [306].

This highlights some limitations in examining gas network decarbonisation options. Other UK focused models capture some of the missing aspects described in this section, highlighting the value in incorporating findings from a range of models into policy evidence [209].

Whole-system models are also in need of real world performance data in order to characterise assumptions relating to things such as technology performance. Emerging research projects covering aspects of gas networks and heat provision are designed to provide this collaboration between technological trial projects and parameterisation of whole-system models [204]. Identifying important data gaps and developing demonstration projects in conjunction with whole-system model development will therefore be an important area for future research.

6.4. Global relevance

Section 2 examined the countries that use gas and categorised them in terms of their gas network maturity. Countries that might seek to take advantage of gas network decarbonisation options largely fall into three of these categories. These are discussed in turn in this section.

6.4.1. Mature gas network countries

Countries with ‘mature’ gas networks have the greatest incentive to use their existing infrastructure, and the least additional infrastructure cost associated with adopting decarbonised gas network options. Countries in this category

20. Future iterations of the model intend to include element of spatial characterisation.
also typically have challenging decarbonisation targets on a country or regional basis. These countries typically have a significant heat load, which is challenging to deliver via non-gas vectors. In order to use hydrogen the suitability of the existing network is dependent on the proportion of steel pipes and countries that have majority plastic low pressure networks are best prepared for this option.

Countries in the ‘mature’ category include the Netherlands, the UK, and the United States. They all have gas network connections to over 50% of households, high per capita demand for gas, and climate targets that require a significant decarbonisation of gas fired energy services.

6.4.2. Growing gas network countries

Countries with ‘intermediate’ gas networks have smaller networks with relatively fewer household connections. However, these countries have the potential to grow on the basis of having access to gas resources, relative population density and significant energy demand. The need to build additional network infrastructure to reach more consumers will result in increased costs relative to the costs associated with decarbonising mature gas markets. However, this also provides the opportunity to future-proof new gas network assets in preparation for future decarbonisation. This could include optimising the locations and structure of gas network infrastructure to minimise the additional costs of decarbonising the market at future dates.

Countries in the ‘intermediate’ category include Germany, Spain, Portugal and the Republic of Ireland. These countries have 25% to 50% of households connected to the gas network. There is also some historical evidence in some of these countries that a significant proportion of households might be within close proximity to existing gas network infrastructure, reducing the cost of significant increases in household connections.

6.4.3. Developing gas network countries

Countries described as ‘developing’ gas networks have smaller gas networks and relatively few connections to households. In order to use low carbon gas to decarbonise end-use energy services significant investment will be needed in transmission and distribution gas infrastructure. As detailed in Section 2 the distance of low pressure local gas distribution infrastructure is typically much longer than transmission infrastructure Figure 3 (Section 2.1). This, when combined with the costs presented in Figure 31 will translate to a significant cost burden for countries developing new gas networks. For illustration, to build a low pressure distribution network similar to the length of the networks currently existing in the UK or Japan, over 200,000 km of pipe would need to be constructed and installed. Based on the costs in Figure 31 this network might cost £145 billion,\(^{21}\) which can be compared to the cost of repurposing

\(^{21}\) Based on the average cost in Figure 31. Based on the minimum and maximum estimate this cost might be between £19 billion and £430 billion.
an existing 200,000 km natural gas distribution network of £2 billion,\textsuperscript{22} highlighting the value of existing infrastructure.

These costs are highly sensitive to site and country specific conditions. Capital costs are likely to be particularly sensitive to labour costs, the largest component of gas network infrastructure costs (Figure 33), with labour cost varying significantly by geographical location. However, countries in this category might still invest in gas networks due to a number of other influencing factors.

Countries in the ‘developing’ category include China, Brazil and India. These countries have growing economies, increasing gas supply through production, supply pipelines, and LNG terminals \cite{73, 81, 87, 299}. They are also developing energy infrastructure, including gas network infrastructure, at a significant rate. Their urban populations are significant and growing, creating centres of demand suitable for gas network infrastructure development. If these networks are built then this again provides an opportunity to build with future gas network decarbonisation in mind, potentially reducing the cost of this transition in the future.

6.5. Comparison of impacts to consumers

The impacts to consumers of switching from current use of natural gas networks vary significantly depending on the technologies that might replace current natural gas based systems. These impacts include the cost to consumers and the physical disruption associated with retrofitting new technologies. Evidence suggests that consumers are unlikely to change their existing gas energy appliances unless there are financial benefits, incentives or the appliance needs replacing due to age or failure \cite{85}. It is therefore important to examine the issues facing consumers that may influence future consumer decisions.

6.5.1. Costs for the end-user

The cost associated with gas network options incurred at the consumer end of the gas supply chain are discussed in Section 4. These can be classed as the total household conversion cost (including pipework, labour, meters etc.) or the cost of appliance conversion/new appliances. Figure 50 compares some of these costs to the cost of heat pump installation. This shows that the cost of both air source and ground source heat pump installations are likely to be higher than the costs of whole property hydrogen conversion. This is particularly the case for ground source heat pumps. However, the greater efficiencies of ground source heat pumps may help ensure that running costs are minimised. This will in turn have an impact on the payback period of a heat pump system over alternative gas vector options. However, the significant

\textsuperscript{22} Based on £10,000 per kilometre estimate for existing natural gas network repurposing including assumption that existing network is built using plastic pipework \cite{11}.
differential in costs between hydrogen and electric appliances and associated household conversion costs is likely to be a significant barrier to consumer uptake of heat pumps in the absence of significant incentives. The choice to replace gas boilers with electric heat pumps is impacted by this upfront cost, amongst other barriers [297]. Since the cost of converting a dwelling to hydrogen may be similar to the cost of replacing a gas boiler then this may prove a more popular option from a consumer perspective.

The cost of installing gas electric hybrid heat pumps appears less than the cost of dedicated electric heat pump installation. This is in part due to the lower capacity of the heat pump component of these hybrid installations, and the low relative cost of dedicated gas condensing boiler appliances. This may have an impact on the attractiveness of this option, though it is not currently a widely available option for consumers.

It is important to note that heat pump installation may need to be accompanied by investment in underfloor heating systems and improved insulation [246, 247]. These costs are not always transparent in quoted heat pump installation costs.
6.5.2. Issues of switching consumers

The relative impact to consumers of switching heat appliance is often discussed as an important factor in the tractability of different end-user decarbonisation options. The importance of considering the consumer in energy system planning has received increasing attention in the context of liberalised energy markets where consumers have significant control over which energy options are adopted [298]. Recent research has highlighted the reluctance of many consumers to change their energy appliances unless significant benefits are provided [85]. In truth, many of the future options to decarbonise gases or the end use services they provide actually present practical and economic costs to the consumer, in exchange for lower carbon. This is often cited as a key reason that progress on decarbonising heat has been relatively slow in many parts of Europe [85, 297, 298].

Table 9 considers a number of options for consumers and qualitatively estimates their relative burden to the consumer.

<table>
<thead>
<tr>
<th>Option</th>
<th>Potential building intervention</th>
<th>Time to switch</th>
<th>Other considerations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Biomethane in gas boiler</td>
<td>No need for new installation</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>Hydrogen fuelled boiler</td>
<td>Refit or replace appliances, gas meter, service pipework</td>
<td>5 days</td>
<td>Similar to natural gas boiler replacement</td>
</tr>
<tr>
<td>Air source heat pump</td>
<td>Electric consumer unit upgrade, internal water or air distribution system upgrade or installation.</td>
<td>1-3 days</td>
<td>Additional time for underfloor heating installation. Lower output temperatures and need for high building insulation. Potentially incompatible with smaller urban dwellings.</td>
</tr>
<tr>
<td>Ground source heat pump</td>
<td>Electric consumer unit upgrade, internal wet or dry system upgrade or installation, vertical or horizontal ground heat exchanger installation.</td>
<td>Ground heat exchanger: 1-2 days Heat pump: 1-3 days</td>
<td>Similar to air source heat pumps</td>
</tr>
<tr>
<td>Gas electric hybrid heat pump</td>
<td>Similar to air source heat pumps</td>
<td>Similar to air source heat pump</td>
<td>Similar to air source heat pumps</td>
</tr>
</tbody>
</table>

The impact of these installations is highly dependent on the nature of the building, with older, less well insulated buildings typically less suitable for heat pump installation. Many buildings in urban areas may not have the option to install ground or air source heat pumps and only houses connected to gas grids will have the option to use biomethane, hydrogen or gas/electric hybrid heat pump systems.

Due to the relatively low impact to consumers of the biomethane option, (and the relatively low impact further up the supply chain) biomethane blended in the existing gas network is sometimes referred to as a ‘low regrets’ option given its relatively low system costs and compatibility with existing
infrastructure [10]. However, the constrained nature of the resource will limit the extent to which biomethane can decarbonise gas fuelled consumer energy services (see Section 3). This raises questions of where biomethane should be used to maximise the value of this constrained resource.

The process of switching to hydrogen will likely be inconvenient for consumers, with a period of five days necessary to isolate sections of the gas network and conduct works in consumer properties. Much has been written about the similarities to the switchover programme when town gas was substituted with natural gas in the UK and other countries, a process that has only relatively recently happened in certain areas [39, 118, 300]. However, a significant benefit of hydrogen fired appliances from a consumer perspective is that those appliances can be operated in a very similar way to existing natural gas fired appliances. This includes using existing conventional radiators with higher water flow temperatures [11, 299].

For heat pumps the time to install systems is equivalent to the switchover period for a hydrogen based system. However, given lower output temperatures from heat pump systems it may be necessary in a number of homes to increase the surface area of the heat distribution system in order to reach suitable levels of thermal comfort in homes while maximising the efficiency of the device [203, 246, 247, 299]. This may mean increasing the size of radiators or installing underfloor heating [203, 246, 247, 299]. Heat pump operation is also unlikely to be as responsive as existing boiler technologies, or hydrogen boilers. This means that the consumer experience and consumer interaction with heat pump systems will be different, potentially contributing to consumers’ reluctance to change systems [85]. Decarbonised gas based options may therefore have an advantage over electric heat pumps from a consumer perspective, which may influence the rate at which decarbonisation of heat and other end-use energy services may proceed.
7. What does it all mean? Findings and Conclusions

7.1. Summary of main findings

7.1.1. Options for gas networks

There are a number of ways to decarbonise existing gas networks and maintain their relevance in future decarbonised energy systems. The main options are decarbonising gas in the network with either biomethane or hydrogen. Current low pressure gas network infrastructure is likely to be compatible with both biomethane and hydrogen in many countries. This network represents an extensive and valuable asset that should be considered in future decarbonisation pathways where it is available. There may be opportunities to reduce gas use significantly in order to reduce the carbon burden of gas networks by using hybrid gas/electric heat pump systems, but there is only limited evidence currently.

Biomethane production through either anaerobic digestion or biomass gasification with methanation both present opportunities for particular biomass feedstocks. However, the future potential of biomethane is limited by biomass availability and competition for biomass resources with other bioenergy routes such as liquid biofuels and biomass electricity generation. Estimates suggest that the biomethane contribution to UK gas demand might be limited to around 5% [165], though BioSNG from refuse may increase biomethane production significantly [158].

There are a number of routes to generate hydrogen from a range of different technologies and primary energy sources. One option commonly discussed is converting natural gas to hydrogen via SMR with CCS. This option is scalable, has an available resource and the potential to generate hydrogen while minimising CO₂. However, depending on the efficiency of the SMR plant, replacing natural gas with hydrogen from SMR might increase natural gas demand by 15% to 66%. A study of SMR with CCS roll out in the UK proposes to convert large UK cities to hydrogen networks by 2052. This raises the question of what technologies can decarbonise the rest of gas users in order to meet challenging 2050 carbon targets.

There are a number of electrolysis technologies that may be used to produce hydrogen at scale. They have the potential to produce low carbon hydrogen through renewable electricity. However, typical estimated efficiencies of these technologies are between 50% and 90%, and the electricity capacity needed to generate hydrogen at the scale of domestic gas demand are significant relative to current energy demand. For example, to meet EU residential gas demand with electrolysed hydrogen would require 1,600 to 2,600 TWh.
electricity. For context the EU produced 3,000 TWh electricity in 2013.

Both coal and biomass can be gasified to produce hydrogen. While coal gasification may be scalable given coal abundance, coal is likely to be a more carbon intensive source of hydrogen than other hydrogen production routes. Gasification of biomass could also produce low carbon hydrogen. Increasing the resource base to include municipal solid waste may significantly increase future biomass to hydrogen potential.

7.1.2. Costs of gas networks

There is a large range of cost estimates associated with all aspects of gas network decarbonisation options including costs of gas generation, costs of infrastructure and the costs of converting consumers’ homes. Gas generation and infrastructure costs, when combined with assumptions regarding profit, tax and other costs, results in a retail price estimate for biomethane of 4.4 to 13.6 p/kWh, with an average of 8.1 p/kWh. A similar retail price estimate for hydrogen is 4.9 to 18.4 p/kWh, with an average of 9.3 p/kWh. To put these estimates in context the EU average retail price of natural gas in 2015 was 5.4 p/kWh, and the EU average retail price of electricity in 2015 was 17 p/kWh [224]. These ranges are extremely large, and demonstration projects to develop real cost evidence are needed to help reduce this range.

The ability to repurpose existing low pressure gas network assets to transport hydrogen is a significant advantage for countries with extensive existing low pressure networks. There is limited evidence regarding the cost of repurposing local gas distribution networks, but one estimate suggests a cost of £10,000 per km. Replicating these networks in countries without existing assets will likely be much more expensive. For example, to build a hydrogen low pressure distribution network similar to networks existing in the UK or Japan might cost £145 billion. Spread over 20 million domestic gas consumers (approximate number of UK gas consumers); this is £7,250 per household, which is within the order of costs associated with other types of domestic heat decarbonisation such as installing air source or ground source heat pumps.

Hydrogen boilers are likely to be slightly more expensive than existing natural gas boilers and there are also other household costs relating to hydrogen conversion. However, fuel cell micro CHP systems, and various types of other microCHP or heat pump system are all likely to be more expensive initial investments per household. The cost of fuel cell microCHP systems have reduced significantly in the recent past (reducing by 15% to 20% per doubling of manufactured appliance capacity), and these systems may compete economically in the future, providing increased efficiency though combined production of electricity and heat. In the meantime the relatively low cost of hydrogen boilers, consumers’ preference for systems that operate similarly to existing gas boilers and difficulties in installing heat pumps in many building types are likely to be positive factors influencing consumer acceptability of hydrogen as a future domestic and commercial energy vector.

23. Based on the cost estimates for SMR with CCS.
The cost of heat delivered by hydrogen boilers is influenced by boiler efficiency. If efficiency reaches 90% then cost of heat delivered will increase slightly per kWh against the price of hydrogen. However, using electric heat pumps with efficiencies in the order of 250% greatly reduces the cost of heat delivered against the price of electricity, making electric heat economically competitive. On this basis the cost ranges above increase to 4.9 to 15.1 p/kWh heat for biomethane and 5.4 to 20.4 p/kWh heat for hydrogen. If future heat pump efficiencies are 250%, 17 p/kWh electricity will deliver 6.8 p/kWh heat. However, future electricity prices may increase in response to decarbonisation, impacting on the relative competitiveness of gas versus electric routes to heat services. A common argument for the value of gas networks is the capacity to meet the very challenging daily, and particularly seasonal variations in energy demand. This may be more expensive for electricity networks to provide, particularly as penetrations of renewables increase and as other energy services are electrified. This points to the potential value of hybrid systems, such as hybrid gas electric heat pumps that can take advantage of gas flexibility while delivering lower carbon heat throughout the rest of the year via an electric heat pump. However, the limited evidence of hybrid system performance precludes any stronger conclusions currently.

The difference in costs of storage between hydrogen and electricity illustrates the value of gas to some degree, with hydrogen storage costs likely to be many times less than the cheapest electricity storage technologies. However, electricity storage represents one of a number of approaches to manage interseasonal energy demand issues, and given heat pump efficiencies it is likely that electricity storage requirements will be significantly reduced in energy terms relative to hydrogen or natural gas. Understanding the ultimate storage costs for equivalent hydrogen or electricity systems is a whole-system energy question which might best be answered through appropriate modelling approaches.

### 7.1.3. Carbon emissions in decarbonised gas network options

The overall range of emissions across technologies is extremely large, from -371 to 642 gCO₂eq/kWh. The highest and most variable emissions come from fossil fuels routes to hydrogen without CCS, with average carbon intensities greater than current gas networks. Fossil routes to hydrogen production must therefore include CCS, without which a hydrogen system will have a higher carbon intensity than the natural gas system it replaces. Emissions estimates for SMR with CCS lie in the range of 23 to 150 g/kWh including supply chain emissions, with CCS typically reducing CO₂ emissions by 75%.

The CO₂ emissions from electrolysis range from 24 to 178 gCO₂eq/kWh for renewable electricity sources. Electrolysis from solar PV electricity defines the upper end of this range, approximately 72 to 144 gCO₂eq/kWh and varies significantly by geographical region, with less efficient regional PV conditions resulting in greater CO₂ emissions per unit of hydrogen produced. Wind electricity to hydrogen results in the lowest CO₂ emissions at approximately 25 gCO₂eq/kWh.
Biomethane CO₂ emissions range from -50 to 450 gCO₂eq/kWh. Direct emissions are often assumed to be zero, with the majority of emissions assumed to arise from indirect sources such as methane leakage, plant construction and agricultural emissions. The climate benefits of biomethane are significantly influenced by the choice of feedstock, crop location and digestate treatment. These cause high variation in the life cycle carbon intensity of produced biomethane given the dominant role of indirect emissions in estimates of biomethane CO₂ intensity.

The carbon intensity estimates for hydrogen and biomethane production can be compared to electricity and heat pumps. The UK for example, is likely to seek carbon intensity of electricity of around 50 to 100 g/kWh in order to meet system-level carbon targets. If this electricity is used in heat pumps the CO₂ intensity of the resulting heat will be in the order of 20 to 40 g/kWh. This is significantly lower than most estimates for decarbonised gas network options.

The impact of supply chain emissions is a significant factor in total emissions estimates and varies considerably across different routes to hydrogen. Given the relatively low emissions in hydrogen production from both SMR with CCS (40 to 77 gCO₂eq/kWh) and electrolysis (0 gCO₂eq/kWh) the range of potential supply chain emissions is a significant proportion of total emissions (Table 8). Biomass gasification is characterised by very large negative emissions in the supply chain and very large positive emissions in the gasification process. This suggests that improvements in total emissions could be relatively large if even relatively small improvements to gasification emissions can be made, either through process efficiency or CCS capture rate.

7.1.4. Global perspective

While gas networks are valuable assets in many countries, they are not universally used due to a range of factors including: importance of domestic natural gas production, population density, availability of alternative resources, demand for space heating in buildings and the level of economic development. Countries with mature gas networks such as the Netherlands, the UK and the United States may find gas network decarbonisation options attractive given the extent of their existing assets. Existing low pressure gas distribution networks using plastic pipework are largely compatible with decarbonised gases such as biomethane or hydrogen, and the costs of repurposing existing low pressure gas networks is likely to be small relative to total system costs. The value of existing gas networks in those countries is therefore significant. Countries with gas networks covering less than 50% of gas consumers may continue to develop low pressure networks and may have opportunities to design those assets to be compatible with potential hydrogen conversion in the future. However, where low pressure gas distribution networks are very small or non-existent the cost of developing them is likely significant, though not necessarily prohibitive.
7.2. Implications for policy

Many studies suggest that SMR with CCS is the most likely technology to deliver low carbon hydrogen at scale in the near term. SMR with CCS does have both relatively low costs and relatively low carbon emissions based on the options reviewed in this white paper. Therefore, it may be the favoured technology until costs for electrolysis or other gas decarbonisation options reduce. If hydrogen networks are pursued policy support for CCS is therefore necessary to ensure that carbon networks and storage facilities are available at scale and in time. There is an existing literature base surrounding policy support for CCS with regards to electricity generation, and much of this analysis is likely relevant to hydrogen network development. CCS should be a necessary part of any gas network repurposing proposals that rely on fossil fuels and proposals that do not guarantee the transport and storage of carbon risk creating more carbon emissions than the existing gas network.

Converting gas networks will likely need amendments to existing gas network regulations, standards and specifications. There may also be a need for modifications to market arrangements to facilitate and encourage injection of biomethane or hydrogen. The gas network regulation landscape spreads across a number of different organisations and may therefore take some effort to modify. However, there appears to be no significant barriers preventing the adaptation of gas network regulation to decarbonised gases.

Choosing areas of the existing gas network to convert to hydrogen and establishing consumer rights within these areas will be another policy consideration if hydrogen network repurposing is pursued. Consumers in the area of conversion will not have the option to continue using natural gas. A number of policy considerations will arise as a result, including: who decides what areas are to be converted and how; who pays for appliance replacement; and what rights do consumers have if they do not want hydrogen?

The issue of hydrogen safety, and public perception of safety, will also create issues for policymakers. First, while there is evidence suggesting that safety of hydrogen networks is not a barrier to hydrogen network development, it will be necessary to develop an extensive and robust evidence base on hydrogen related safety issues before significant commitments to hydrogen network development are made. It will be necessary to conduct a coordinated programme of work in order to ensure a structured and comprehensive evidence base, and a clear understanding of the safety issues. Communication of these issues will also have a significant impact on consumer opinion and acceptability of hydrogen networks. The Department of Business Energy and Industrial Strategy has announced a £25 million programme investigating hydrogen standards and the development and testing of hydrogen appliances in domestic buildings. Efforts should be made to coordinate these projects with existing activities to ensure a comprehensive evidence base.
7.3. Future research

There is a clear need for new research to provide evidence for a number of questions arising in gas network decarbonisation, both in practical demonstration of technologies, and in whole-system modelling of the impacts of these technologies. Coordinating this research to allow demonstration project findings to feed into the development of system models and vice versa will be important to maximise the value of this research.

A large proportion of the evidence of costs and carbon emissions discussed in this white paper is subject to assumptions. Practical demonstration of the technological options discussed in Section 3, is an important next step in developing the evidence base on a number of gas network decarbonisation options. For example, practical demonstration of hydrogen repurposing of low pressure gas networks will answer a number of questions regarding the suitability of these networks for hydrogen and the costs of upgrading these networks where needed. Similarly a demonstration of SMR with CCS linking to new high pressure hydrogen and CO₂ networks will provide evidence for the practical feasibility, efficiency, costs and carbon emissions, all of which are currently uncertain given available evidence.

The safety aspects of gas network decarbonisation also requires additional research effort, particularly repurposing the gas network to carry hydrogen. Some existing research explores issues of gas safety in homes. However, a more comprehensive evidence base is needed, covering the safety issues at all stages of a potential hydrogen supply chain. This includes research into the safety of domestic and commercial hydrogen boiler systems, the integrity of the existing gas network for carrying hydrogen and the safety impact of hydrogen leakage in the full range of locations where future hydrogen infrastructure will exist.

New consumer appliances such as hybrid gas/electric heat pumps also require demonstration research given the relative lack of evidence currently. The lab efficiencies of hybrid heat pumps are likely to be better than their seasonal performance in situ. In addition, the impact of aggregate hybrid heat pump operation on the profile and magnitude of gas and electricity demand is an important and currently uncertain factor. Practical demonstration will be necessary to improve the evidence base in this regard.

Understanding the whole-system impacts of gas network decarbonisation, and the system interactions with other energy vectors such as electricity, will require additional whole-system modelling research. This should include fine spatial and temporal resolution, interactions between different energy infrastructure (including gas and electricity networks), and representation of all gas network decarbonisation options, including the conversion of existing low pressure networks to hydrogen. The emerging evidence from demonstration and practical experience should also be incorporated into whole-system modelling work where and when available, and collaborative projects that explicitly capture the interaction between practical experience and modelling.
should be encouraged. Finally, research and development focusing on electrolysis systems could help to improve system efficiency and reduce system costs, both of which are critical to the future competitiveness of this technology.

7.4. Conclusion

Gas networks are valuable assets with a range of technological options that may keep them relevant in the future low carbon energy system. However, there are a range of uncertain factors that will ultimately impact the extent to which existing networks can contribute effectively to decarbonisation. Given the various limitations on biomethane and hydrogen production, replacing gas networks entirely with any other solution is problematic.

Decarbonising an entire gas network is logistically challenging and may not be able to deliver the deepest possible decarbonisation at a satisfactory cost. The electrification of heat also has limits given increasing costs and technical challenges associated with building generating capacity, balancing supply and demand and reinforcing it to deal with increasing loads. The important question is therefore how to establish the optimal balance of energy system options. While the costs and emissions associated with decarbonised gas networks is still uncertain, the value of gas networks in providing flexibility and sharing the burden of decarbonisation is potentially significant. Quantifying this in future system-level research should therefore be a priority.
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