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PRODUCING LOW CARBON GAS

Future Gas Series: Part 2

“Low carbon gas has great potential to support the UK’s efforts to decarbonise its economy. This report is an essential guide to policy decisions in this area.”

James Heappey MP, Alistair Carmichael MP, and Dr Alan Whitehead MP,
Inquiry Co-Chairs, July 2018

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Foreword

Gas plays a fundamental role within the UK's energy system. The majority of buildings are heated by gas and it is used widely within industry for process heat and as a raw material. It is also a major source of electricity and even provides fuel for a small number of vehicles. Currently natural gas meets almost all of UK gas demand, but it releases greenhouse gas emissions when burnt.

In order to decarbonise our economy and meet our climate change targets we will need to make a dramatic shift away from using unabated natural gas in the coming years and decades. Low carbon gases like hydrogen and forms of biogas may be able to help us transition to a cleaner energy system.

In the UK heat for domestic, commercial and public buildings alone accounts for around 20% of UK greenhouse gas emissions. Replacing the natural gas currently used to heat buildings with low carbon forms of gas could be part of a long term solution. Transport amounts to around a quarter of UK greenhouse gas emissions. Low carbon forms of gas could also be utilised in this sector to reduce carbon emissions and air pollution, such as to fuel heavy goods vehicles (HGVs) and trains.

The *Future Gas Series Part 1* examined the gas grid, discussing the potential to transition to a low carbon gas grid. This report examines the 'upstream' questions related to where these low carbon gases could come from - their sources and production methods, summarising the evidence base and setting out how policymakers should approach this area.

Forms of biogas offer an exciting opportunity to redirect resources such as food and black bin waste from landfill to provide energy and contribute to meeting our climate change targets. The UK still exports waste material, which has energy value, and imports energy. While the role of hydrogen in the UK's future energy system is still an open debate, it is potentially useful both as a fuel and as a way of storing energy.

We are delighted to have co-chaired Part 2 of Carbon Connect's *Future Gas Series*, a process which has brought experts together with policymakers to consider challenges and come up with solutions. We would like to extend a thank you to everyone who gave their time and expertise to this inquiry and would especially like to thank the steering group for their valuable contributions. We are also grateful to IGEM and National Grid for sponsoring the inquiry. We hope this report helps to advance thinking in this area and provides ideas for next steps in the transition to a low carbon economy.

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Introduction

Carbon Connect's *Future Gas Series* project examines the opportunities and challenges associated with using low carbon gas - hydrogen and biogases - to help to decarbonise the UK economy. Part 1 of the *Future Gas Series* was entitled 'Next Steps for the Gas Grid' and detailed the issues related to the gas distribution network (the pipe system transporting gas to end users) and the potential to repurpose it to use low carbon gases.

This is the second report in the *Future Gas Series* and explores the 'upstream' questions related to the production of low carbon gas. It considers the different production technologies, the potential scale of deployment of each method, and the sources and feedstocks. It also discusses issues related to bulk transport and storage of gas.

The report is divided as follows. The Executive Summary provides an overview of the report and a summary of policy recommendations and next steps. This includes discussion of some cross-cutting issues which have relevance across the report.

Parts 1 and 2 of the report are divided between biogases (gases derived from biological sources) and hydrogen respectively. Part 1 has two chapters, one focusing on biomethane and anaerobic digestion, and one focusing on BioSNG (bio-synthetic natural gas). Part 2 has three chapters which are divided into the different ways of producing hydrogen: converting natural gas to hydrogen, electrolysis and alternative methods of production.

In Parts 1 and 2 each chapter has a similar structure - first outlining the method and potential scale of production, the evidence around cost, emissions reduction and practical implications, and then examining the challenges of developing these methods of production and how policymakers could approach them.

Part 3 of the report considers three crosscutting additional areas which are related to both Parts 1 and 2 but focus particularly on hydrogen. They are: storage and transport of low carbon gas, carbon capture and storage (CCS), and developing markets for low carbon gas.

This report examines low carbon gases specifically in order to provide a detailed assessment of the particular issues related to them and not because other decarbonisation solutions are considered to have no value. It is likely that decarbonisation will be achieved by a portfolio of techniques. Policy development designed to support the decarbonisation of the economy as a whole, or specific sectors like heat and transport, will clearly need to take account of a broader range of technologies.

Executive Summary

Alongside other decarbonisation solutions, low carbon forms of gas could make a significant contribution to the UK's efforts to reduce greenhouse gas emissions by at least 80% (from the 1990 baseline) by 2050. In order to realise this opportunity, however, the production of these gases will need to be developed further. This report summarises the evidence base around different sources of low carbon gas and identifies the challenges and trade-offs associated with producing and using them. It provides a guide to how policymakers can approach this area.

Low carbon gas – Affordable? Sustainable? Secure?

How affordable are low carbon gases to produce?

It is important to make a distinction between the current cost of producing a gas and the potential cost in the future. Some methods of producing low carbon gas are already in use in the UK and are thought to have relatively limited potential for cost reduction in the future, for example biomethane through anaerobic digestion. Other methods of producing low carbon gas are currently in use in the UK but are thought to have significant long term potential for cost reductions, such as hydrogen through electrolysis.

There are also methods of producing low carbon gas which are not yet used in the UK so it is difficult to be certain about the future costs, for example carbon capture and storage combined with the conversion of natural gas to hydrogen. The level of uncertainty in this area needs to be addressed, and is one of the reasons for modelling work by Department for Business, Energy and Industrial Strategy (BEIS), the National Infrastructure Commission and the Committee on Climate Change.

Whether a particular method of producing a low carbon gas is considered affordable can depend on the amount which is being produced and how it is used. For example, this inquiry heard that in a 'high hydrogen' scenario for heat - whereby consumers in numerous cities who are currently connected to the gas grid are converted from natural gas to 100% hydrogen - production is likely (at least initially) to be predominantly based on methods which convert natural gas rather than electrolysis, because electrolysis is at present less affordable at such scales. However, in the longer term producing hydrogen through electrolysis could be more affordable at this volume, and electrolysis can make immediate contributions on a smaller scale in some specific applications.

How sustainable are low carbon gases?

The carbon intensity (the amount of carbon dioxide released per unit of energy) associated with the gases discussed in this report varies significantly depending on factors like feedstocks and production method. For example, biomethane produced from food waste generally has a much lower emissions profile than biomethane produced from energy crops. Likewise, the carbon intensity of converting natural gas to hydrogen depends on the supply chain emissions from natural gas extraction and the capture rate of carbon capture technology.

This is an important issue for policymakers to consider. If further policies are brought forward to encourage the production of low carbon gases, a decision will need to be made about how low carbon these gases are required to be. There may be reasons for providing initial policy support to forms of gas produced in a way that has minimal carbon benefit, such as developing an early market for certain types of gas. However, there is a danger of providing support for supposedly 'green' technologies which make minimal or no contributions to the UK's climate change objectives.

There are also broader sustainability considerations in relation to low carbon gases. While biomethane and bioSNG (synthetic natural gas) do represent an opportunity to produce energy from waste that would otherwise go to landfill, it is important that this does not undermine the broader circular economy and waste policy objectives. Energy projects must use genuine waste and not work against ongoing efforts to reduce the amount of waste produced. There is also a wider, controversial debate around the sustainability of the bio-resources used as a feedstock for some low carbon gases. For example, this inquiry heard criticism of reallocating land for food production to provide feedstocks for energy. On the other hand, low carbon gases could support other environmental objectives such as improving air quality.

What security of supply issues are raised by low carbon gases?

An important test of the usefulness of low carbon gas to the UK's energy objectives is how securely they can be supplied. If hydrogen is to be used on a widespread basis to provide heat for buildings, it will be vital for suppliers to ensure delivery of sufficient amounts to consumers, including on the 'coldest day in mid-winter'. In the short term if attempts are made to build up a market for hydrogen through use in transport fleets or industrial processes, businesses and other users involved will need to have contingency measures in case of shortages in supply.

Planning around low carbon gases also has to take into account the level of contribution different forms of gas could actually make to the UK's energy demand. For example, limited availability of feedstocks such as food waste means that biomethane is expected to be able to make a much smaller contribution to the UK's future heat and transport needs than hydrogen produced through natural gas conversion potentially could.

If hydrogen is produced in the UK through natural gas conversion, sourcing the natural gas as a feedstock will raise similar security of supply issues as the use of natural gas currently does. There is likely to be a need for extensive international imports but this could be mitigated through continued diverse sources of supply and/or a domestic storage capacity. There is also the potential in the longer term for a large scale international hydrogen market not dissimilar to the current framework for liquefied natural gas but this is still very uncertain.

The costs, carbon intensity and potential production volumes of gases produced from various production methods are summarised in Table 1 and Chart 1.

Table 1: Summary of the Cost of Production and Carbon Intensity of Different Methods of Low Carbon Gas Production

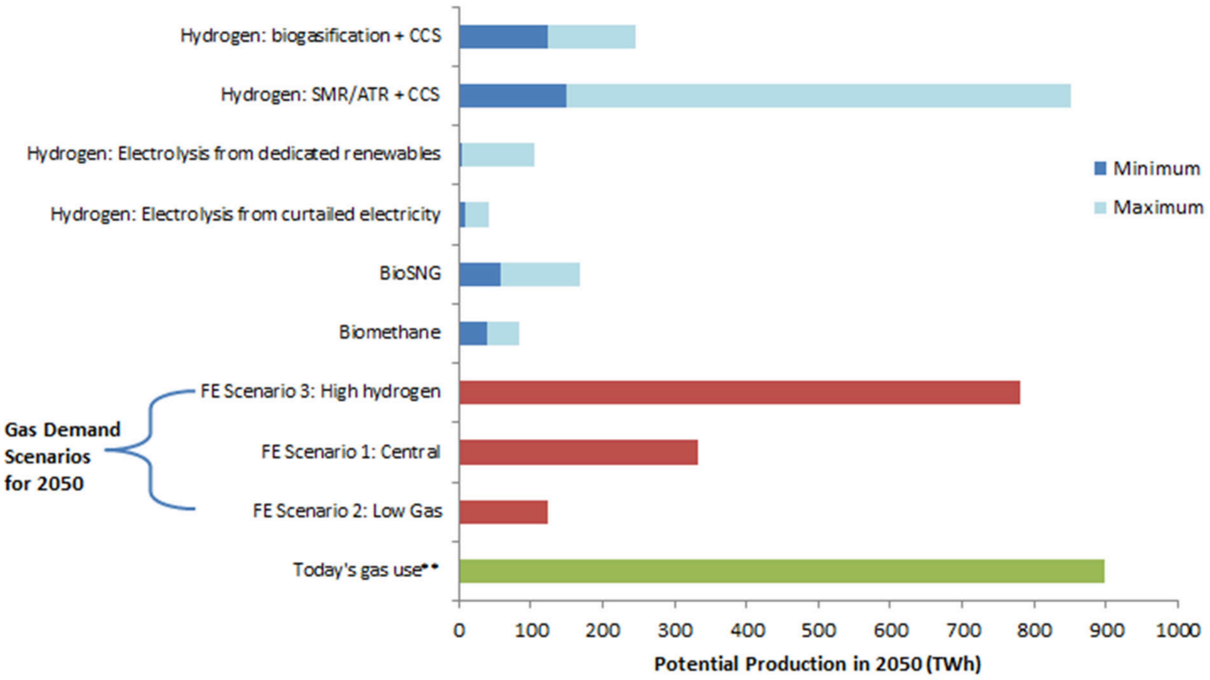
Production Method	Cost of production* (p/kWh)	Carbon intensity (gCO2eq/kWh)**
Biomethane	***Average: 5.5[1] with potential for 5% cost reductions per year up to 2020	-50 to 450[2] Depending on feedstock. To be eligible for the RHI, it must be under 125
BioSNG	***Average: 5[3]	-200 to 45 Depending if CCS is included[4]
Hydrogen: electrolysis using low carbon generation	Average: 7[5] Does not include the possibility of negative wholesale electricity prices	25 to 180[6] Depending on how electricity is generated
Hydrogen: SMR[7] + no CCS	Average: 3.3[8]	250 to 300[9]
Hydrogen: SMR + CCS at 90% capture rate	Average: 3.4[10]	30 to 40[11] Depending on the capture process utilised
Hydrogen: ATR[12] + CCS at 95-98% capture rate	Around 10% less than SMR and CCS[13]	5 to 15[14]
Hydrogen: biogasification + CCS at 90% capture rate	Average: 3.6[15]	Negative: as low as -370[16]
Hydrogen: biogasification + no CCS	Average: 3.4[17]	Average: 100[18] with a large range of -45 to 500
Alternative methods such as solar to fuel and microwave	Too early in development to estimate[19]	Too early in development to estimate
Current figures for Natural Gas	1.5 to 2[20] Average over Jan-Jun 2017 for a medium user	180 to 230[21]
Current figures for National Grid electricity	5.5 to 6[22] 2017 averaged price	Range of monthly averages in 2017: 225 to 324[23] We expect electricity to be 50-100 by 2030

* These figures are the current cost of production - not the retail cost - of a gas. The retail cost would be higher, as it includes the cost of infrastructure upgrades, network operating costs and taxes/profit margins. These costs come from a range studies, only the averages of these are above. These costs are a function of energy input costs and will change as the price of gas, electricity and biomass change.
** For carbon intensity figures involving natural gas (SMR/ATR) the lower limit of the carbon intensity is for emission from combustion only, while the upper limit includes lifecycle emissions including production and liquefaction, except for the figure for SMR with CCS, which just shows combustion emissions. The carbon intensity of electrolysis includes supply chain emissions for manufacturing renewable generation technologies. Biomethane, biogasification and BioSNG have a range of carbon intensities depending on feedstock, with waste lower than energy crops. Land use change and indirect land use change from energy crops are included in the upper limit of the figure for biomethane.
*** These figures do not include gate fee payments.

1 Sustainable Gas Institute (2017), A green gas grid: what are the options?' White Paper
2 Decarbonising the Gas Network', Houses of Parliament Postnote, November 2017
3 Ibid 1
4 Go Green Gas (2015), BioSNG Demonstration Plant Summary of Plant Design
5 Ibid 1
6 A greener gas grid: what are the options?' Energy Policy, 118 (2018) 291-297
7 Steam Methane Reformation
8 Ibid 1
9 Data heard from evidence for this inquiry
10 Ibid 1
11 Data heard from evidence for this inquiry
12 Autothermal Reformation
13 Data heard from evidence for this inquiry
14 Desk-based calculations based on 75% efficiency data and potential capture rates of 95-98%
15 Ibid 1
16 Ibid 6
17 Ibid 1
18 Ibid 1
19 'Options for producing low-carbon hydrogen at scale' Royal Society, January 2018
20 Ofgem (2018), Infographic: Bills, prices and profits, Available at: https://www.ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits
21 Decarbonising the Gas Network', Houses of Parliament Postnote, November 2017
22 BEIS, (2018), Average unit costs and fixed costs for electricity for UK regions, Available at: https://www.gov.uk/government/statistical-data-sets/annual-domestic-energy-price-statistics
23 MyGridGB data: http://www.mygridgb.co.uk/dashboard/

	A fairly certain figure - for example if the process is already operating on a commercial scale
	A figure with some uncertainties–for example if the process if operating at a demonstration scale with more than one plant
	An uncertain figure based mainly on desk-based research - for example, a process only in the development phase

Chart 1: Potential Production of Different Types of Low Carbon Gas in 2050, Compared to Different Gas Demand Scenarios for 2050*



* The scenarios shown by red bars in the chart above represent three different gas demand scenarios for 2050, as modelled by Frontier Economics for the Committee on Climate Change in 2016.[24] As these scenarios demonstrate, energy demand is expected to reduce by 2050 due to increased energy efficiency, and other decarbonisation routes may also reduce demand for gas. For example, in the 'Low Gas' scenario shown above, transport and heating are mainly electrified.
** Today's gas use is the figure for 2016, and comprises 36% for power generation, 34% for domestic heating, and 11% for industry.

[24] Frontier Economics for the Committee on Climate Change (2016), Future Regulation for the UK Gas Grid

Producing low carbon gas: next steps

Supporting biomethane

The Renewable Heat Incentive (RHI) has been relatively successful in supporting biomethane production to provide heat. The potential end to this support in 2021 is likely to disrupt its deployment. It is thought that the Renewable Transport Fuels Obligation (RTFO), which obligates fuel suppliers to source a minimum share of transport fuel from renewable sources, could provide a useful support for biomethane in the future. However, to date biomethane plants have only been supported through the RHI. Biomethane from waste should be a consideration in future policy development designed to help decarbonisation.

The most beneficial scenario for the deployment of biomethane would be that the RTFO proves successful in supporting biomethane production for use in transport and that the government offers a new support regime replacing the current RHI framework for low carbon heat beyond 2021. The future of heat policy post-2021 is still uncertain, however, and there are many wider considerations to this beyond just low carbon gas. Additionally, if post-2021 heat policy development places emphasis on support for decarbonising off-gas grid properties this may exclude biomethane. It would be sensible for the government to continue to look at the synergies between BEIS and the Department for Transport's (DfT) policies in this area.

In general any future support for biomethane should also be looking to drive cost reductions in technology and continue to incentivise the use of waste feedstocks over energy crops.

Joining up the Waste and Resources Strategy with the Clean Growth Strategy

The Department for Environment, Food and Rural Affairs (DEFRA) is expected to publish a waste strategy in autumn 2018. Alongside waste-specific issues, this strategy should seek to support the ambitions set out in BEIS' Clean Growth Strategy to reduce carbon emissions. Food waste in particular is a potentially very useful feedstock for biomethane production which in England is not widely collected separately and therefore often goes straight to landfill or is burnt for energy.

It is important that plans for energy policy do not run counter to attempts to reduce the amount of waste being produced. However, there is scope for a waste strategy which simultaneously supports government aims in waste policy - such as the UK achieving no food waste entering landfill by 2030 - and also aligns with attempts to decarbonise the UK economy in the short term.

The waste strategy could set out a clear direction of travel towards separate food waste collection in England. Mandating that all local authorities in England collect food waste separately is unlikely to be feasible, due to the additional cost involved. One more targeted option heard by this inquiry was the creation of a small, centrally-held (by DEFRA) pot of funding to which local authorities could apply to support the initial costs of changing to separate food waste collection. This could follow the models of BEIS' Heat Networks Investment Project (HNIP) and Heat Networks Delivery Unit (HNDU) which have provided advice, information and financial support to local authorities installing district heating.

Developing BioSNG and gasification

BioSNG can be produced through a process called gasification and used in a similar way to biomethane, but this technology is at an earlier stage of development than biomethane production. There is one commercial-scale demonstration plant in construction in the UK. Even with successful support now, it would be a number of years before further BioSNG plants would be producing gas for use in the UK. However, the flexibility of feedstocks which can be used in gasification plants and the different outputs it can produce, including methane and hydrogen, mean it offers significant opportunities for the decarbonisation of the UK economy.

Access to feedstocks is much less of an impediment to developing BioSNG than biomethane and the key challenge for its deployment is financing the development of the technology itself; an area where government policy could usefully play a role. It is thought that a scheme based on obligations (like the RTFO) or a direct grant would be most appropriate to develop BioSNG production - but the type of support available is likely to be bound up with wider considerations relating to the decarbonisation of heat and transport. It would be sensible for government to consider how it might proportionately integrate financial support for BioSNG into future policy development focused on decarbonisation.

Understanding hydrogen as a clean-tech opportunity for the UK

There is an ongoing debate about the potential to convert the gas grid from natural gas to 100% hydrogen in some parts of the country as a way to produce low carbon heat. This is a long term concept and the contribution hydrogen will make to decarbonising the heat in the UK is still uncertain. What is more certain, however, is that cleanly-produced hydrogen has many potential useful applications in the UK's energy system as decarbonisation continues.

Technologies which can produce hydrogen cleanly and affordably without compromising energy security should therefore continue to be considered for innovation and research funding. This should include projects developing new methods of hydrogen production as well as those which can help the optimisation and deployment of more established methods.

Developing a market for hydrogen

The key to developing and deploying hydrogen production is fostering a market for hydrogen which incentivises businesses to invest in it, encourages new businesses into the market and also builds up hydrogen demand by recognising those who use it.

This is not an easy task, not least due to the higher cost of hydrogen compared to carbon intensive fuels. An important challenge is the need to build up the low levels of hydrogen supply and demand simultaneously. The final chapter of this report examines this in more detail, however the four practical routes identified to build up hydrogen deployment are: blending it in the gas grid, supplying it to large industrial gas users, using it for transport such as large vehicle fleets or trains and a framework allowing hydrogen to be used in the electricity sector. Two considerations related to this merit particular focus: practical short term action and scale.

Finding immediate practical routes to develop hydrogen production

There is a trade-off between projects developing hydrogen production on a large scale, which will require larger investments and take longer to come to fruition, and smaller scale projects which require less investment and less time to develop.

This inquiry found that small-scale hydrogen projects, which are likely to deliver practical outcomes in the short and medium term, could help deploy production through electrolysis as well as create a market demand for hydrogen. One potential route to achieve this would be through local authorities converting transport fleets, such as buses, to run on hydrogen, which can help to combat air pollution and reduce carbon emissions. This has started to happen in some cities but could be rolled out more widely.

Providing sufficient scale of demand for hydrogen production with Carbon Capture and Storage (CCS)

If a 'high hydrogen' route for decarbonising heat through to 2050 is pursued, it is likely to require a production method which uses natural gas conversion with CCS. Hydrogen production in this way therefore may also provide a viable route to deploying CCS in the UK. However, deploying hydrogen production with CCS has an unavoidable need for scale. Small incremental uses of hydrogen, such as in bus fleets, are not likely to provide sufficient demand to support its deployment.

The additional cost of hydrogen compared to carbon intensive fuels implies a significant role for government to support investment on this scale. For example, blending a small proportion of hydrogen into the gas grid would provide only a limited contribution to decarbonising heat but could generate the scale of demand needed to develop hydrogen production with CCS, potentially leading to further projects and a route to using 100% hydrogen in the gas grid. This would be likely to require some form of policy support to produce the hydrogen.

Learning lessons from the power sector: deployment is key

The UK has made significant reductions in the emissions associated with power generation in recent years. Though there are different challenges in decarbonising sectors such as heat and transport, there is still learning which could be applied in these areas. One is of particular relevance here: it is only through the deployment of low carbon technologies, at sufficient scale to allow competitive supply chain development, standardisation and further innovation, that their costs are reduced and their potential is fully realised (as has been seen with both offshore wind and solar photovoltaic (PV)). There are other important options to provide low carbon heat and transport in the future not considered by this report. However, if the UK is to exploit the potential offered by low carbon gases in time to contribute to the 2050 decarbonisation targets it will need to further demonstrate and deploy production technologies in the near term.

Part 1

BIOGASES

A number of different gases sourced from biological materials fall under the term ‘biogases’, but in this report we look at two of particular interest: **biomethane** and **BioSNG**. While very similar in their composition and end-uses, their methods of production are different:

- Biomethane is made from a process called **anaerobic digestion** (AD), which converts the energy in ‘wet’ feedstocks (e.g. sewage, food waste) into methane.
- In contrast, BioSNG is made from a process called **gasification**, which can use the energy in both ‘wet’ and ‘dry’ sources of biomass (e.g. ‘black bag’ waste) as feedstock.

1. Biomethane and anaerobic digestion

FINDINGS

1. Biomethane can be produced from waste sources such as food waste and sewage and can be used as a low carbon alternative to natural gas.

2. The government's upcoming waste and resources strategy (responsibility of DEFRA) should join up with the UK's published Clean Growth Strategy (responsibility of BEIS). One area in which this could be done is in the removal of barriers to accessing food waste as a feedstock for biomethane.

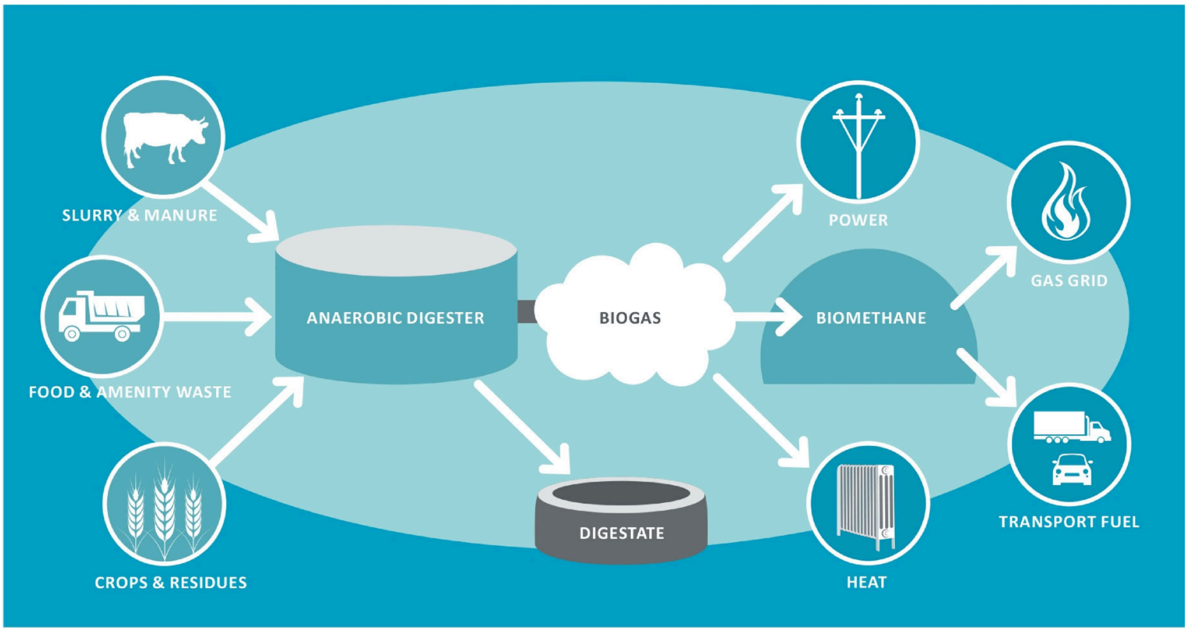
3. The production of biomethane is currently subsidised through the Renewable Heat Incentive which is due to close to new projects in 2021. If no new support regime is brought forward, this may prevent the commissioning of biomethane production plants after this point.

1.1 Overview - biomethane and anaerobic digestion

What is biomethane and how is it made?

Biomethane is a gas produced from biological sources which has a similar composition and properties to natural gas. Biomethane is derived from organic feedstocks such as plant material and organic waste such as sewage sludge. It is produced by anaerobic digestion (AD) - the fermentation of organic material or waste in an oxygen-restricted environment to form a product known as biogas.

Figure 1: Anaerobic Digestion and Biomethane Production



Source: NNFCC - the Official Information Portal on Anaerobic Digestion

The products of AD have many possible end uses. Biogas comprises 60% methane, 29% carbon dioxide, and other constituent gases such as hydrogen sulphide, oxygen, hydrogen and nitrogen,[25] and can be burnt to produce power or in a combined heat and power plant (CHP) to produce both power and heat.

Raw biogas can also be 'upgraded' or 'scrubbed' to produce biomethane in a process that removes impurities and carbon dioxide and increases the methane content to approximately 97% methane by volume. This makes it suitable to inject into the gas grid, where it can be used for heat in buildings, or as a transport fuel as compressed natural gas (CNG).

What emissions reductions can AD and biomethane achieve?

Accurately calculating the exact greenhouse gas emissions coming from individual sources of bioenergy is complicated, but in principle at least, all biogases can be considered a lower carbon alternative to natural gas.[26] The extent to which biomethane is 'low carbon' can vary considerably based on numerous factors including the nature of the feedstock used (waste sources are less carbon intensive than energy crops), processing and the accounting method used. In order to be eligible for the RHI, biomethane injected to the gas grid must be below 125 gCO_{2eq}/kilowatt hour (kWh) which is around half of the carbon footprint of natural gas.[27]

What does AD and biomethane in the UK look like at the moment?

AD is a well-established process. As of December 2017, there were 578 AD plants in the UK, producing 11.4 Terawatt hours (TWh) of biogas.[28] As of February 2018, 85 biomethane plants were accredited under the Renewable Heat Incentive, with a further 6 commissioned plants having applied but not yet been fully approved; 4.8 TWh of energy had cumulatively been produced by biomethane plants.[29]

How much do AD plants for biomethane cost?

This inquiry heard that a typical biomethane plant (40,000 Megawatt hours (MWh)) costs around £6-10m to construct, including the biomethane upgrader and grid connection. The Sustainable Gas Institute suggested that the capital costs for AD plants to make biomethane range from £1,800 to £4,500 per kilowatt (kW). When combined with operating costs, this results in a production cost (the cost of producing gas including capital and operating costs but excluding profit margin) of 2-10p per kWh, with an average of 5.5p per kWh.[30] This inquiry heard that, accounting for profit margins and feedstock costs, the levelised cost (the cost of generating, over the lifetime of a project, each unit of energy) of biomethane from AD is currently around 7.5p per kWh. Costs do vary depending on the site and feedstock arrangement.

Finding 1

Biomethane can be produced from waste sources such as food waste and sewage and can be used as a low carbon alternative to natural gas.

1.2 Key technical and policy challenges

Biomethane, sourced from waste feedstocks, has been identified by the Committee on Climate Change as a 'low regrets' option which can help the UK meet its greenhouse gas reduction targets.[31]

[25] IGEM (2012), Biofuels: analysis of the various biofuel types including biomass, bioliquids, biogas and bioSNG
[26] Welfle, A. *et al.* (2017), Generating low-carbon heat from biomass: life cycle assessment of bioenergy scenarios, *Journal of Cleaner Production* **149**: 448-460
[27] POST (2017), Decarbonising the gas network
[28] ADBA (2017), AD Market Report: November 2017
[29] BEIS (2018), RHI deployment data Feb 2018 Available at: https://www.gov.uk/government/statistics/rhi-deployment-data-february-2018
[30] Speirs et al. (2017), A greener gas grid: what are the options?
[31] Committee on Climate Change (2018), 'An Independent Assessment of the UK's Clean Growth Strategy'

Cost reductions

There is some evidence that the cost of biomethane plants has reduced since they started to be supported by the RHI.[32] The Anaerobic Digestion & Bioresources Association's Cost Competitiveness Taskforce suggested cost reductions could be facilitated by additional investment in research and innovation, greater access to food waste feedstocks, recognition of the uses of digestate, increased awareness of AD and policy certainty.[33] If the industry grows there are also likely to be minor reductions in overhead costs; for example if one head office runs numerous plants it will be more efficient to administrate.

Feedstocks

Food waste

There are two sources of food waste: waste collected by local authorities from households and some businesses, and commercial and industrial waste streams generally collected via commercial contracts.[34] Separately collecting food waste (much of which currently ends up in landfill) can provide a reliable feedstock for biomethane production which could reduce the risk surrounding investment in AD projects.

This inquiry heard that UK households currently produce around 7m tonnes of food waste per year in the UK. Around 60 per cent of this waste is avoidable, meaning the overall amount could be reduced - this would be the most sustainable approach. Businesses produced around 3m tonnes of food waste per year, around 60 per cent of which is avoidable. With typical AD plants requiring around 45-60,000 tonnes per annum this means there is significant potential feedstock for biomethane, even if the desired widespread reductions in food waste are achieved.[35]

Food waste is collected separately much more systematically in Scotland, Wales and Northern Ireland than in England, where less than 50 per cent of households have access to food waste collection - and even where they do, these are often mixed with garden waste which cannot be used as efficiently in AD.

There are financial benefits to separate food waste collection - primarily avoiding landfill tax (which is currently £88.95 per tonne)[36] and instead paying a much lower gate fee to the AD operator (on average £29 per tonne).[37] However, this cost differential is usually insufficient to offset the high cost of collecting food waste in the first place. Where local authorities currently provide weekly collections of residual waste they could repurpose these collections to provide fortnightly separate food waste collections without incurring additional cost or even achieve a cost saving.[38] If they do not already provide weekly collections, it will impose a cost upon them.

A key barrier to separate food waste collection in some areas therefore is the cost of collection. Evidence given to this inquiry suggests that the largest component of the cost is manpower and vehicles needed to perform collections, which can, for large local authorities, total millions of pounds a year. It would not be sensible for central government to mandate local authorities to act in this area without providing sufficient resource to enable them to do so.

Finding 2

The government's forthcoming waste and resources strategy (responsibility of DEFRA) should join up with the UK's climate change objectives and published Clean Growth Strategy (responsibility of BEIS). One area in which this could be done is through the removal of barriers to accessing food waste as a feedstock for biomethane.

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[32] NAO (2018), Low-carbon heating of homes and businesses and the RHI
[33] http://adbioresources.org/news/adba-unveils-cost-competitiveness-task-force
[34] Cadent (2017), 'Review of Bionenergy Potential'
[35] This inquiry heard about plants ranging from 2,000-200,000 tonnes per annum, however, so a 'typical' plant is a slightly contested concept.
[36] HMRC (2016), Landfill Tax: increase in rates Available at: https://www.gov.uk/government/publications/landfill-tax-increase-in-rates/landfill-tax-increase-in-rates
[37] WRAP (2017), Comparing the costs of waste treatment options
[38] REA (2016), Report shows that food waste "collected separately" can reduce costs for businesses and LA's Available at: https://www.r-e-a.net/news/report-shows-that-food-waste-collected-separately-can-reduce-costs-for-businesses-and-las

Table 2: Accessing Food Waste for Biomethane

Problem	Potential Solution
Lack of incentive for local authorities to collect household food waste separately.	Central government targets for separate food waste collections among local authorities.[39]
Lack of resources among local authorities to introduce separate food waste collections.	Additional resources from central government to support separate collections.
Lack of incentive for households to separate food waste and the 'ick' factor - where food waste is collected separately individuals can be reluctant to separate out their waste.	Remove the central government ban on local authorities in England implementing 'pay as you throw' schemes - originally planned to be trialled through the Climate Change Act 2008. Local authorities that collect food waste generally have separate small food waste bins (kitchen caddies) to reduce the hassle involved for individuals to separate their waste.
Commercial waste is charged for but businesses are not incentivised to separate food waste.	Separate collections for commercial food waste. If commercial waste was charged by weight rather per bag, this could encourage businesses to separate food waste for separate collections as it is generally heavier than other forms of waste. Incentives such as the landfill tax or mandated separate food waste collection could also drive further action on commercial food waste collection.
Much of commercial waste management is tied up in long term contracts.	Ensure future waste contracting does not unduly undermine opportunities to redirect food waste towards AD.

Slurries and sewage

AD can also utilise slurries and sewage as additional forms of feedstock. There are ten sewage treatment works with biomethane production in the UK. It is thought that these sources could provide feedstocks for further biomethane plants. Generally, farm slurries will be isolated sources which are not sufficient to support a plant big enough for gas grid injection and are also located in areas off the gas grid. In these cases the resource is generally more appropriately used for on-site combined heat and power units. Where these sources are available in suitable locations and quantities, however, they could provide useful feedstocks for AD for biomethane production.

Energy crops

Many of the existing AD plants used to produce biomethane rely heavily on crops as feedstock. There is a long-running and contentious debate over how sustainable and low carbon different sources of bioenergy are which is beyond the scope of this report to address. However, there are concerns around the use of energy crops - in particular the displacement of agricultural land which would otherwise be used for food production and the lifecycle emissions of energy from crops.

[39] As mentioned above, this would not be sensible without additional support to enable local authorities to do this.

Renewable Heat Incentive (RHI) and other forms of support

Subsidising AD and biomethane

AD plants producing biogas for power have generally been subsidised through the Feed-in-Tariff (FiT) but this is due to close for new registrations in 2019.

In theory biomethane plants could be supported through the RTFO but to date all plants have been supported through the RHI.[40] This inquiry heard that the RTFO may in the future prove accessible to biomethane production projects.

As of August 2017, the Government has spent £328m on biomethane production under the Non-Domestic RHI and has helped develop a biomethane industry.[41] The National Audit Office has suggested that RHI support for biomethane has delivered much more cost-effective carbon abatement when higher concentrations of food waste and sewage are used as feedstock. However, around 40-60% of AD plants may be using mostly crop based feedstock.[42]

The RHI

The RHI is currently open to new applicants until 2021. There is a risk that no new biomethane plants will be commissioned after this date due to the lack of support. This could damage the UK's effort to decarbonise its economy. There are a number of broader issues on how future support for low carbon heat is designed but biomethane should be one consideration within this. In addition to offering a similar scheme to the RHI after 2021, moving to a levy framework was raised by contributors as one option for funding future low carbon heat. Some contributors also raised the idea of following the RTFO model by placing obligations on suppliers of fossil fuels to provide low carbon sources of heat. On the other hand, if there is a focus on supporting heating solutions in off-grid properties after 2021 then this may make it harder to integrate biomethane into the policy support framework.

Finding 3

The production of biomethane is currently subsidised through the RHI which is due to close to new projects in 2021. If no new support regime is brought forward, this may prevent the commissioning of biomethane production plants after this point.

Landfill tax

The landfill tax increases the cost of sending material to landfill. It currently stands at £88.95 per tonne but has escalated over time.[43] Continuing this escalation could help to prevent resources such as food waste going to landfill by incentivising other uses, for example use in AD for biomethane. The gate fees, paid by local authorities to operators as an alternative to paying the landfill tax, help to make AD plants economical.

Improving access to the gas grid

As discussed in the *Future Gas Series: Part 1* '*Next Steps for the Gas Grid*', there are a number of potential steps which could be taken to help biomethane plants access the gas grid and thereby support its deployment. One significant challenge in some areas and at certain times, such as summer nights, is the capacity of the gas grid for biomethane, which is being produced.

RIIO price controls

Gas networks are organised through a system of price controls run by Ofgem which put a ceiling on the amount companies can earn from charges to users of the networks. RIIO (Revenue = Incentives + Innovation + Outputs) is Ofgem's performance-based framework to set the price controls.[44] The next suite of price controls, RIIO-2, will take effect in 2021. It could be possible to allocate some of the costs of producing biomethane to the gas networks under the next stage of price controls but this is a judgement for Ofgem. There are also questions over whether energy generation costs should be integrated into a framework for distribution.

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40 DfT (2012), Renewable Transport Fuel Obligation Available at: https://www.gov.uk/guidance/renewable-transport-fuels-obligation
41 NAO (2018), Low-carbon heating of homes and businesses and the RHI
42 Ibid
43 HMRC (2016), Landfill Tax: Increase in Rates, available at: https://www.gov.uk/government/publications/landfill-tax-increase-in-rates/landfill-tax-increase-in-rates
44 Ofgem (2018), Network regulation - the 'RIIO' model Available at: https://www.ofgem.gov.uk/network-regulation-riio-model

Future use of AD plants

In the long term (the 2030s, 2040s and beyond) AD plants producing biomethane for injection into the gas grid may no longer be useful in achieving the UK's policy objectives. For example, the energy resource may need to be diverted to support decarbonisation in other sectors. This should not be an impediment to encouraging biomethane production because it can provide immediate support to the UK's effort to meet its forthcoming carbon budgets. This inquiry heard differing views on how far it will be possible to repurpose existing biomethane plants for alternative uses in the future. There are options to do so but they are difficult to do at the small scales AD plants generally operate at in the UK.

The other issue with regards to the long-term future of AD plants is availability of feedstock. Best practice action on food waste is to reduce the amount being disposed of initially and this should be the priority for waste policy. It is also vital that UK energy policy does perversely lead to maintaining or increasing levels of 'waste' to feed AD plants. However, this inquiry heard that the sheer level of cultural change needed for the UK to achieve close to zero food waste means there are likely to be extensive sources of genuine food waste for the coming decades. Nonetheless, availability of feedstock should be factored into local and national planning of future AD plants.

2. BioSNG and gasification

FINDINGS

4. Bio-synthetic or bio-substitute natural gas (BioSNG) is generated by the gasification of biomass, and can be tailored to have a similar composition and properties to natural gas. Because gasification can process dry as well as wet feedstocks, it can produce greater volumes of gas from sustainable UK feedstocks than anaerobic digestion.

5. Gasification technology can be tailored to produce BioSNG or hydrogen according to demand and economic or environmental benefit.

6. Gasification to produce BioSNG is at an earlier stage of technological development and operates on a larger scale than AD. These differences render it less well suited to accessing the same support mechanisms as AD (primarily the Renewable Heat Incentive).

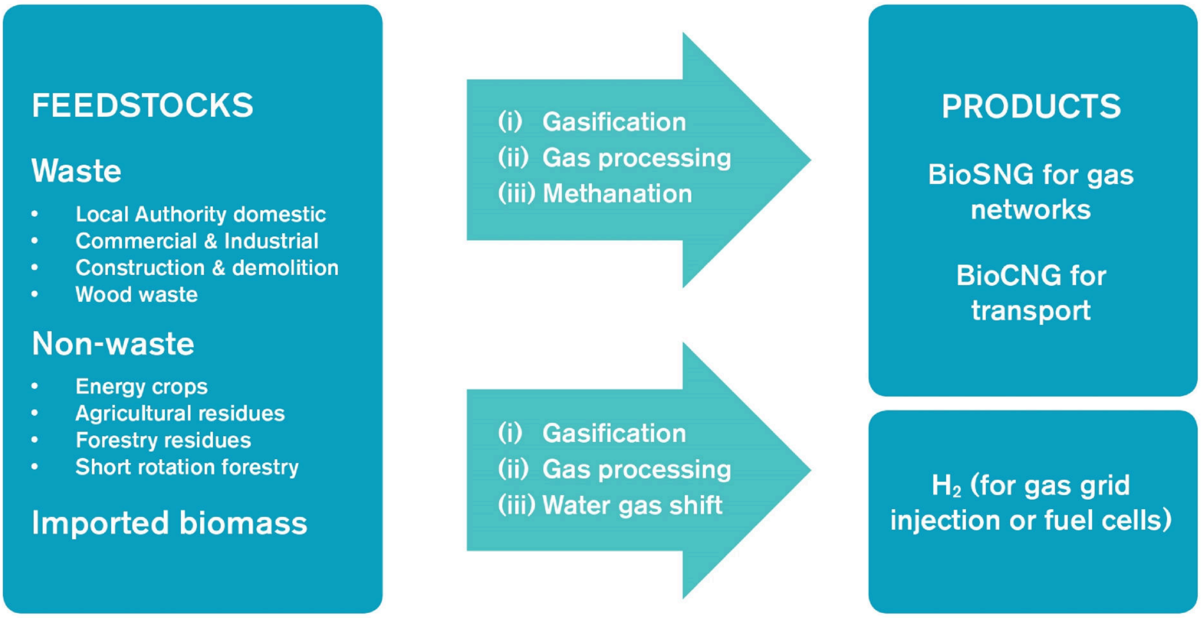
7. There is one commercial-scale demonstration BioSNG plant in the UK, currently under construction, which has adopted the Renewable Transport Fuels Obligation as a support mechanism. This support is predicated on the BioSNG produced being used as a transport fuel. In order to drive investment in BioSNG as a viable alternative to natural gas for heating, alternative support mechanisms would need to be developed.

2.1 Overview - BioSNG and gasification

What is BioSNG and how is it made?

SNG (synthetic or substitute natural gas) is a form of high-methane gas, much like natural gas, and is currently derived from the gasification of coal and other fossil fuels. A similar process can be used with waste and biological material rather than fossil-based feedstocks - creating BioSNG. Whilst waste material may well contain items of fossil-fuel origin (such as plastics), SNG produced from such feedstocks is still included within the definition of BioSNG as it is of lower carbon intensity and includes 'avoided emissions' compared to SNG from coal- or oil-gasification. BioSNG is generated using a process of gasification followed by methanation, rather than anaerobic digestion (AD; discussed in Chapter One). Although the process first creates hydrogen it then 'carbonates' it, adding carbon back in to create methane. This extra step allows the production of a gas almost indistinguishable from natural gas, which allows continued use of all network infrastructure and appliances, avoiding the costs and delays associated with the conversion to allow use of 100% hydrogen.

Figure 2: BioSNG Process



The gasification process is able to generate BioSNG from both 'wet' *and* 'dry' feedstocks (such as sustainable energy crops, waste wood, paper or textiles; however, 'wet' feedstocks may need to be dried first to improve process performance). Gasification can therefore create BioSNG from a much wider range (and thus greater volume) of feedstocks than AD. Of greatest current interest is the generation of BioSNG from residual 'black bag waste' - shredded and dried waste which would otherwise go to landfill. This has the dual benefit of producing a low carbon gas, while providing an alternative to landfill as a waste management solution.[45]

Finding 4

Bio-synthetic or bio-substitute natural gas (BioSNG) is generated by the gasification of biomass, and can be tailored to have a similar composition and properties to natural gas. Because gasification can process dry as well as wet feedstocks, it can produce greater volumes of gas from sustainable UK feedstocks than anaerobic digestion.

What emissions reductions can gasification achieve?

The carbon intensity of BioSNG from gasification depends on the type of feedstock used. BioSNG from residual black bag waste is likely to be less carbon intense than BioSNG from feedstocks such as imported wood pellets. This is because of the avoided methane emissions that would have otherwise occurred if the black bag waste had been sent to landfill, as well as avoiding any emissions incurred by processing and importing wood pellets. However, the level of mitigation achieved compared to natural gas will depend on the extent to which the black bag waste is composed of organic matter (e.g. food waste) rather than wastes such as fossil-derived plastics (e.g. packaging). There is also potential to use domestically grown sustainable energy crops such as miscanthus, willow or short rotation coppice.

[45] Speirs et al. (2017), A greener gas grid: what are the options?

Analysis based on the Advanced Plasma Power (APP) demonstration plant in Swindon has suggested that a commercial BioSNG plant will produce gas with a greenhouse gas footprint 80% lower than that of natural gas; this is similar to the performance of AD.[46] With CCS this could rise to 190% (i.e. negative emissions).[47]

What does gasification in the UK look like at the moment?

Gasification of biomass to BioSNG is still at demonstration level. In the UK, the APP BioSNG commercial-scale demonstration plant is currently under construction, and will gasify 10,000 tonnes of waste a year, aiming to produce about 22 GWh of BioSNG per annum from the end of 2018.[48] The Swindon-based plant intends to deliver gas to the grid, and will include a demonstration of carbon dioxide capture. Costing £30m, the plant received £11m from DfT's Advanced Biofuels Demonstration Competition in September 2015 and a further £6m from the Network Innovation Competition, run by energy regulator Ofgem. The remainder is funded by a consortium of partners.

Additionally, the Energy Technologies Institute (ETI) has invested £5m in a commercial demonstration waste gasification plant in the West Midlands, with match-funding from a US-based company. Once construction is complete, the project will convert around 40 tonnes a day of locally produced waste into a clean syngas which will be used to power a high-efficiency gas engine. Waste heat generated by the engine will be used to heat a local swimming pool.[49] Elsewhere in Europe, Engie has built a €60m BioSNG demonstration plant in Lyon.[50] There are a number of other gasification plants in operation in the UK already, however for economic reasons they are designed to generate electricity rather than low carbon gas.

How much does BioSNG from gasification cost?

There is relatively little information on the production costs of BioSNG from gasification, but estimates from the International Energy Agency (IEA) suggest that it could be competitive with the range of costs of producing biomethane from AD, at between 3-5p/kWh.[51] For comparison, natural gas had a price of 1.5p/kWh averaged over Jan-Jun 2017.[52]

According to the developers of the demonstration plant in Swindon, the capital cost of a first-of-a-kind BioSNG production plant would be around £100m for a plant converting around 136,000 tonnes of waste per annum (at an annual operating cost of £10m) into 315 GWh/yr BioSNG. They expect that later, larger plants (processing almost 300,000 tonnes of waste annually, and producing 665 GWh/yr of BioSNG) would cost around £150m, and about £16.5m per year to run.[53] Forecasts based on BioSNG production of 37 TWh/yr by 2030 price the fuel at 2.5p/kWh, similar to the anticipated price for fossil fuel equivalents at that time.[54]

The economics of BioSNG production are presently reliant upon two sources of funding. BioSNG plants using waste as a feedstock receive a gate fee, and policy support mechanisms such as the RHI or the RTFO can provide revenues on the gas produced, depending on its end use. Early stage BioSNG projects supported by the RTFO may be economically viable but support under the RHI is too low. The key to bringing gasification technology forward as a mature technology will be through improving its efficiency and reducing its costs. Biogasification to produce hydrogen is discussed in Chapter 5.

2.2 Key technical and policy challenges

Feedstocks

According to research by Anthesis and E4tech, some 59-169 TWh/yr of BioSNG could be available in 2050, of which around 39-46 TWh would come from waste feedstocks and the remainder from non-waste feedstocks such as energy crops, short rotation forestry and wood/forestry residues.[55] Sustainable international biomass

[46] The Renewable Energy Directive sets out a typical greenhouse gas saving of 80% for AD.
[47] Go Green Gas (2015), BioSNG Demonstration Plant Summary of Plant Design
[48] Ibid
[49] Energy Technologies Institute (2017), Targeting new and cleaner uses for wastes and biomass using gasification
[50] Gaya (2017), One mission, one biomethane, one industrial project for a new energy generation, Available at: nhttp://www.projetgaya.com/wp-content/uploads/2017/08/Gaya-AN-new_08_2017-4.pdf
[51] Speirs et al. (2017), Sustainable Gas Institute, Imperial College London, A greener gas grid: what are the options?
[52] Ofgem (2018), Infographic: Bills, prices and profits, Available at: https://ofgem.gov.uk/publications-and-updates/infographic-bills-prices-and-profits
[53] Ibid 47
[54] Cadent (2015), Commercial BioSNG Demonstration Plant; Advanced Plasma Power (2018)
[55] Cadent (2017), Review of Bioenergy Potential: Technical Report

supply chains could significantly augment this quantity. To put this into context, 510 TWh of natural gas was used by the domestic, public administration and commercial sectors in 2016.[56]

While these estimates are indicative of the total overall feedstock availability, they do not reflect the economics underlying the accessibility of these bioresources. Some waste feedstocks can receive gate fees - paid to a processor by a local authority to avoid the much higher landfill tax - making them economically attractive; by contrast, non-waste feedstocks such as energy crops incur a cost. This highlights the importance of differentiating between the physical resource availability and the affordability or commercial viability. These estimates are also based on assumptions that waste feedstocks end up entirely in renewable gas production, ignoring the competing demands for such resources.

However, gasification technology offers some flexibility in how the available waste biomass is used e.g. for BioSNG in the gas system for heating; hydrogen - either for heat or fuel cells; or BioCNG (bio-Compressed Natural Gas, used as a transport fuel for HGVs), amongst others. This avoids a trade-off between end-use demands; the gasification step is common to both BioSNG and hydrogen whilst the final step and end vector could be tailored according to the area of greatest demand or economic and environmental benefit.

Finding 5

Gasification technology can be tailored to produce BioSNG or hydrogen according to demand and economic or environmental benefit.

Commercialising gasification for BioSNG

BioSNG is not yet a fully bankable technology. To reach a point where it is commercially viable, there is a need for more early stage demonstration projects that scale up the size of gasification plants. Achieving this, and ensuring the availability of waste feedstock, will be essential to providing investors the confidence to invest in BioSNG production.

Evidence given to this inquiry has suggested that a pipeline of demonstrators, scaling up in size each time and demonstrating the use of different feedstocks, would have the potential to develop waste/biomass gasification to BioSNG as a mature commercial technology within 10 years - assuming suitable incentives and policy frameworks are in place to support this. Precisely what such a framework could look like remains debatable and the options to achieve this are reviewed below. Above all, it is important that policy is designed to finely balance the need to support individual early-stage projects as well as establish a pipeline of subsequent projects that would constitute the formation of a BioSNG market.

Policy options for BioSNG production

Gate fees are helpful for gasification projects; they are a stable source of income which has been useful support. For AD plants, current average gate fees in 2016 were just under £30 per tonne.[57] However, gate fees alone are insufficient to support gasification from waste to make BioSNG. Furthermore, using gate fees as support may disincentivise the drive to increase plant efficiency - the more waste that is used, the greater the income from gate fees. BioSNG is eligible to receive support under the RHI's biomethane to grid tariff; however BioSNG projects are not using this because including waste gasification in the same category as biomethane production fails to reflect the difference in their commercial maturity - the latter being far more technically mature. This is problematic because as AD has been rolled out more widely under the RHI, its tariff rate has reduced to a level that is considered by many as too low to support BioSNG projects.

The RHI's biomethane tariff is also tiered: the first 40,000 MWh of energy delivered to the grid receives a higher rate, which falls for the second 40,000 MWh, and decreases again beyond that. These tiers present an issue for BioSNG, as an individual BioSNG plant produces larger quantities of gas compared to smaller AD plants, and therefore most of the gas it produces receives only the lowest rate tariff. These factors combined

[56] BEIS (2017), Digest of UK Energy Statistics (DUKES): natural gas
[57] WRAP (2017), Gate fees report 2017: Comparing the costs of waste treatment options

mean that the RHI is unsuitable for supporting BioSNG production at present. It is unlikely that Government will adjust the RHI (which is due to close in 2021 anyway) to specially accommodate BioSNG given that the option of a bespoke tariff was explicitly ruled out as recently as 2014.[58]

Finding 6

Gasification to produce BioSNG is at an earlier stage of technological development and operates on a larger scale than AD. These differences render it less well suited to accessing the same support mechanisms as AD (primarily the Renewable Heat Incentive).

Policy instruments based around **obligations** rather than incentives could be more suited to drive forward gasification projects. The Renewable Transport Fuel Obligation (RTFO) requires transport fuel suppliers above a certain size to source a percentage of their fuel from renewable sources, implemented through a market-based certification scheme. The percentage obligation is currently at 7.25% for the period from April to December 2018, rising to a 2020 target of 9.75%, and 12.4% by 2032.[59] Moreover, within the RTFO is a "development fuel sub-target" of 0.5% by 2021, rising to 2.8% by 2032, specifically aimed at less commercially-mature technologies including gasification to make BioSNG.[60] Indeed, the RTFO has been the support mechanism adopted by the waste gasification demonstration plant under construction in Swindon (rather than the RHI) as it is more aligned to supporting this technology.

The RTFO puts pressure on fuel supplying companies to adopt new ways to source renewable fuels for transport. Some have suggested that a similarly designed obligation scheme for low-carbon heat could be pivotal in compelling gas supply companies to source low-carbon gases for use in the gas grid for heat consumption, creating demand for BioSNG production and providing the long-term revenue streams that financiers need for them to invest into waste gasification plants. Furthermore, the use of grants and similar direct state funding to support the development of renewable gas could both help meet our domestic carbon budgets whilst increasing indigenous gas production.

Finding 7

There is one commercial-scale demonstration BioSNG plant in the UK, currently under construction, which has adopted the Renewable Transport Fuels Obligation as a support mechanism. This support is predicated on the BioSNG produced being used as a transport fuel. In order to drive investment in BioSNG as a viable alternative to natural gas for heating, alternative support mechanisms would need to be developed.

The potential for **government grants** to support the commercialisation of the BioSNG market also merits exploration. Internationally, governments are providing capital funding to gasification plants for BioSNG, such as the Gaya project in France (with €18.7m of funding by the French Environment and Energy Management Agency)[61] and the GoBiGas project in Sweden, as well as the BioSNG demonstration plant in Swindon (with £11m provided by the DfT). Grant funding plays a large role in de-risking private investments in individual early-stage projects, and it is appropriate that government should provide capital to support such projects given that often no one individual investor captures sufficient benefits of gasification projects.

Recent research for Cadent sets out a series of possible support mechanisms for BioSNG, such as top-up payments (either variable or fixed) on top of the market price for gas, thus creating a stable total price per unit of BioSNG, and also fixed long-term cap and floor revenue streams whereby a minimum level of revenue is guaranteed.[62] These could be funded through general taxation, like the RHI, or through an obligation on fossil gas suppliers, like the RTFO. In the latter case thought will need to be given on how to protect households in fuel poverty from higher costs.

An alternative approach might be to allow low carbon heat generation to be brought into the regulated asset base of gas distribution companies. This approach would require some significant changes to the gas regulatory framework but may offer lower costs to consumers. It was discussed in some detail for low carbon electricity generation in the Dieter Helm review of the Cost of Energy.[63]

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[58] DECC (2014), RHI Biomethane Injection to Grid Tariff Review Government Response
[59] DfT (2018), Renewable Transport Fuel Obligation Guidance Part One Process Guidance
[60] Ibid
[61] Gaya (2017), Project report
[62] Cadent (2018), Options for stimulating investment in BioSNG
[63] Dieter Helm (2017), Cost of Energy Review

Regardless of which policy approach government thinks is best for BioSNG, it is imperative that although AD and BioSNG should be given comparative fairness in opportunity, this does not entail parity in support. BioSNG and AD may well be complimentary technologies, both suited to different constituents of the waste stream. However, BioSNG from waste gasification is not yet a commercially mature technology; AD for biomethane is. Policy ought to reflect this.

Part 2

HYDROGEN

The majority of global hydrogen production - some 95% - uses fossil fuels as a feedstock.[64] The dominant method for producing hydrogen is via conversion from natural gas, in a process known as steam methane reformation (SMR). Other technologies for hydrogen production include Auto Thermal Reforming (ATR; similar to SMR where natural gas is used as a feedstock), gasification (the thermal degradation of solid fuels, such as coal, biomass and wastes, to produce hydrogen gas; discussed separately in this report) and electrolysis (which uses electricity to split water into hydrogen and oxygen). Other novel early-stage technologies include solar-to-fuels and microwave separation from hydrocarbons. The main methods will be explored here and are summarised in Table 3.

[64] OECD/IEA 2017 Renewable Energy for Industry; cited in The Royal Society (2018), Options for producing low-carbon hydrogen at scale

Table 3: Summary of Hydrogen Production

Method	Summary
Converting natural gas to hydrogen	Steam Methane Reformation: combustion of natural gas (methane; CH_4) with steam to produce hydrogen. Generates carbon dioxide as a by-product, therefore not currently a low-carbon technology without CCS. A commercially viable technology already producing hydrogen on a large scale (nationally around 26.9 TWh/year) Autothermal Reforming: a variation on SMR, combusting methane and steam in the presence of oxygen to produce hydrogen. Already in operation but less suited to current market demand as a result of generally larger scale application than SMR unless carbon dioxide capture becomes a requirement.
Gasification	Gasification of fossil fuels is a mature technology but is not low carbon without CCS. 'Town gas', the forerunner of natural gas, was produced via gasification of coal and comprised a mixture of 50% hydrogen, 35% methane and 10% carbon monoxide. Gasification of biomass is in early stages of development (see Chapter 2), and could potentially be coupled with CCS.
Electrolysis of water	An electricity driven process to split water into hydrogen and oxygen. Commercial electrolysers are already available. The carbon intensity of the process depends on the source of the electricity; low to zero carbon hydrogen production is achievable using low carbon electricity.
Novel technologies	Includes (amongst others): • Pyrolysis of hydrocarbons • Downhole conversion of fossil fuels using shale gas as a feedstock • Microwave separation from hydrocarbons • Solar to fuel, using water as a feedstock • Fermentation • Nuclear power driven solid oxide electrolysis.

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

3. Converting natural gas to hydrogen

FINDINGS

8. If hydrogen is to be used extensively to help meet the UK's 2050 targets, the most likely method of production will be via steam methane reformation (SMR) or autothermal reformation (ATR) - both with CCS - using a natural gas feedstock.

9. SMR is the most commercially developed option for hydrogen production currently, and offers the fastest solution for production of hydrogen at scale in the medium term; however it cannot be recognised as low-carbon without either incorporation of CCS or use of biomethane as a feedstock. ATR offers a more cost-effective route once the costs associated with carbon capture are factored in and at larger scale application.

10. The use of 100% hydrogen in the gas grid would require a long term strategic plan. Scaling up from small demonstration projects to larger fully-operational systems can take a significant amount of time. If the UK is to move to low carbon hydrogen to help meet its 2050 targets, steps should be taken in the near term to encourage demonstration projects into its production.

3.1 Overview – converting natural gas to hydrogen

The most commonly used method for producing bulk hydrogen at present is the conversion of natural gas (predominantly methane; CH_4) to hydrogen through SMR, which reacts natural gas with steam at high temperatures and in the presence of a catalyst to generate hydrogen with carbon dioxide as a by-product.[65]

SMR of natural gas is responsible for 48% of current total hydrogen production worldwide (the remainder coming from a combination of the partial oxidation of oil, coal gasification and electrolysis) with over 500 operating units globally.[66, 67] It is a mature technology having been used in industry since the 1940s.[68] A large chemical process, SMR operates in units of the scale of 150-250MW,[69] (and sometimes larger, in the region of 500MW, when used for methanol production). Globally, the ammonia, methanol and oil refining industries consume some 90% of the hydrogen or 'syngas' (synthesis gas; generally a mixture of hydrogen, carbon monoxide and carbon dioxide) currently produced.[70]

ATR is fundamentally very similar to SMR, both processes reform natural gas with steam. The key difference is that ATR also adds oxygen via a catalytic process, and generates carbon dioxide by-product at temperatures and pressures that facilitate carbon dioxide capture.

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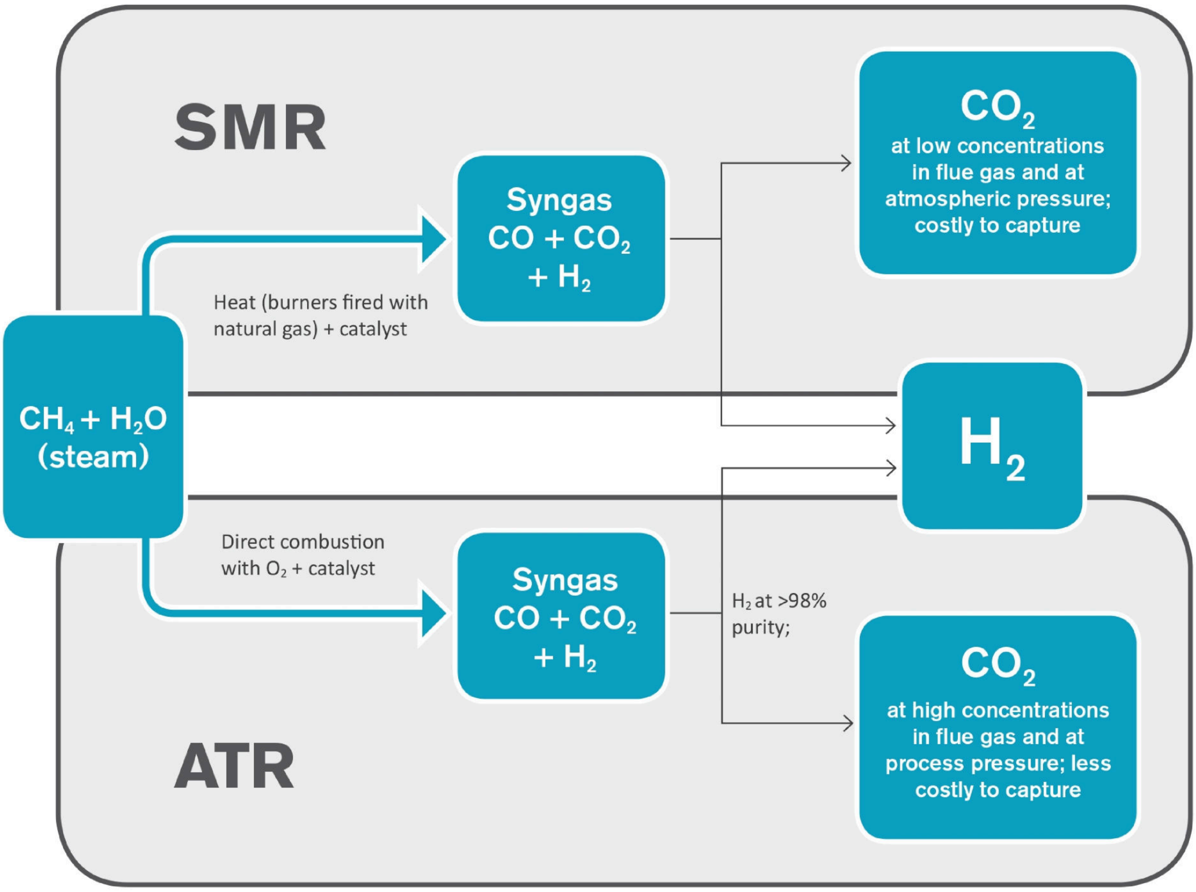
65 Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System
66 Ibid
67 E4tech (2016), Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target
68 Aqua Consultants (2017), Liverpool - Manchester Hydrogen Hub: Energy to Fuel the Northern Power House - A study for Peel Environmental
69 Ibid
70 Collodi, G. et al. (2017), Techno-Economic Evaluation of Deploying CCS in SMR Based Merchant H2 Production with NG as Feedstock and Fuel

Figure 3: SMR/ATR Process



Adapted from: Aqua Consultants (2017) Liverpool-Manchester Hydrogen Hub - Energy to Fuel the Northern Power House. A study for Peel Environmental

Because carbon dioxide is emitted as a by-product during hydrogen production, CCS is essential if the process is to offer carbon savings. This is discussed in greater detail later in this report.

Findings 8 & 9

8. If hydrogen is to be used extensively to help meet the UK's 2050 targets, the most likely method of production will be via steam methane reformation (SMR) or autothermal reformation (ATR) - both with CCS - using a natural gas feedstock.

9. SMR is the most commercially developed option for hydrogen production currently, and offers the fastest solution for production of hydrogen at scale in the medium term; however it cannot be recognised as low-carbon without either incorporation of CCS or use of biomethane as a feedstock. ATR offers a more cost-effective route once the costs associated with carbon capture are factored in and at larger scale application.

How much does SMR/ATR cost?

SMR is currently one of the cheapest hydrogen production technologies in terms of capital cost.[71] Estimates suggest the capital cost of steam methane reformation *with CCS* would be around £800 per kW of hydrogen production capacity - which could fall to around £700 per kW of hydrogen production capacity by 2040.[72] Scale also plays a factor in its cost - as plant scale increases, there are significant potential cost reductions for SMR.[73]

Currently, without CCS, SMR offers a more cost-effective production of hydrogen than ATR. However, because carbon dioxide emissions from ATR are contained at process pressure, carbon capture on an ATR is more cost effective than on an SMR, making ATR potentially more economically competitive should CCS become a requirement. The HyNet North West project proposes using ATR rather than SMR to generate hydrogen, due to its increased gas processing efficiency combined with reduced compression costs resulting from the hydrogen being produced at pressure.[74]

What are the greenhouse gas emissions of SMR?

SMR of natural gas has a carbon footprint in the region of 250-300 gCO_{2eq}/kWh, potentially reducing to 30-40 gCO_{2eq}/kWh when combined with CCS.[75] By comparison, natural gas has a carbon footprint of 180-230 gCO_{2eq}/kWh.[76,77]

The extent to which the production of hydrogen by SMR can contribute to the reduction of greenhouse gas emissions is determined by the rate at which carbon dioxide emissions from SMR are captured.[78] Currently, CCS technology is capturing some 90% (> 1 million t/y CO_2) of the carbon dioxide emissions of the product stream from two SMR plants in Port Arthur, Texas, USA,[79] (equivalent to around 60-65% of *total* plant emissions) where it is piped and used for enhanced oil recovery.[80]

How mature a technology is SMR/ATR with CCS?

Carbon dioxide capture from SMR plants is already a commercial operation and one of the main sources of global industrial and food grade carbon dioxide. However, to date only three SMR plants have demonstrated carbon dioxide capture with transport and storage.[81] CCS is a fundamental barrier to deployment - the need to develop CCS facilities and pipelines represents additional technical and economic burdens to the use of SMR,[82] adding around 30% to the capital cost, as well as additional operating costs.[83] There are no CCS projects in the UK at the moment, although a number are either proposed or at design stage. CCS is discussed in greater detail later in this report (see Chapter 7).

The low concentration of carbon dioxide in SMR flue gas makes ATR the more attractive option once the need to capture carbon is factored in. There are a number of ATR facilities operational within the chemical industry (e.g. used in syngas generation for methanol production) but it is not currently used solely for commercial hydrogen production. This is because there is not yet any economic benefit to capturing and storing carbon dioxide, rendering SMR the more cost-effective and lower risk hydrogen-production technology at the moment. HyNet North West - a hydrogen, energy and CCS project - proposes using ATR technology and anticipates being operational by 2026.

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[71] Speirs et al. (2017), A greener gas grid: what are the options?
[72] E4tech (2016), Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target; Ibid
[73] Ibid 72
[74] Cadent (2018), HyNet North West Project Report
[75] Ibid 72
[76] BEIS (2017), Greenhouse gas reporting: conversion factors 2017
[77] Ibid 72
[78] Energy Research Partnership (2016) Potential Role of Hydrogen in the UK Energy System, p.36
[79] IEA GHG (2015), Understanding the potential of CCS in hydrogen production. Presentation by Santos S to Joint IEA GHG and IETS workshop, March 2015; cited in ERP (2016) Potential role of hydrogen in the UK energy system
[80] Global CCS Institute
[81] IEAGHG (2017), Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS
[82] Ibid 73
[83] Ibid 72

Table 4: Comparison of SMR and ATR Thermal Technologies[84,85,86]

Steam Methane Reforming	Auto Thermal Reforming
Well proven H_2 generation technology but, to be classified as low carbon, carbon dioxide has to be captured from the flue gas. The flue gas is at atmospheric pressure and temperature and contains carbon dioxide at low concentrations so requires large columns and thus high CAPEX (capital expenditure).	Carbon dioxide is captured at process pressure and concentrations so carbon dioxide capture is well proven and comparatively cheap. Best suited to large installations.
74% efficient	>75% efficient
Cost of production (p/kWh): SMR no CCS = 1.4-5 (average of 3.3) SMR + CCS (@90%) = 1.6-5.2 (average of 3.4)	Around 10% less than SMR with CCS[87]
Carbon capture potential of 71- 92% (a higher cost is associated with higher capture rates)	Carbon capture potential of 95-98%
Carbon footprint (gCO_{2eq}/kWh): SMR no CCS = 250-300 SMR + CCS = 30-40[88] *(depending on the capture process utilised)* [For comparison, natural gas has a carbon footprint of 180-230 gCO_{2eq}/kWh][89]	Potential carbon footprint (with CCS) in the region of 5-15 gCO_{2eq}/kWh[90]

3.2 Technical challenges

Technology maturity

SMR today is generally optimised to maximise its hydrogen output, but to be as low carbon as possible, the process will need to be optimised for carbon dioxide capture as well. ATR can achieve high capture rates of above 95%, potentially in combination with gas-heated reforming (GHR)[91] and may offer a means to improve hydrogen production efficiencies and carbon dioxide capture rates, but - without the need for CCS - is currently the more expensive of the two technologies.

Feedstocks

Currently natural gas - a fossil fuel - is used in SMR/ATR processes. However, there is some potential to use biomethane from biogas production as a feedstock. This would lower the net CO_2 emissions relative to SMR/ATR from natural gas, and would, if used in combination with CCS, have the capacity to produce negative

[84] Johnson Mathey (2017), Options for Decarbonisation of Natural Gas
[85] POST (2017), POSTnote no. 565 Decarbonising the Gas Network
[86] Speirs et al. (2017), A greener gas grid: what are the options?
[87] Data heard from evidence to this inquiry
[88] Ibid
[89] BEIS (2016), Greenhouse Gas Reporting – Conversion factors 2016
[90] Calculations based on 75% efficiency data and potential capture rates of 95-98%
[91] Ibid 85

emissions. It is likely there will be difficulties producing the quantities of biogas required; the challenges around biogas production and feedstocks are explored in Chapter 2.

Supply chain emissions

Given that SMR and ATR use natural gas as a feedstock, there are inevitable supply chain emissions that contribute to the total GHG emissions of the process. Approximately half of carbon dioxide emissions associated with hydrogen from SMR with CCS could arise in the supply chain, through upstream emissions and in hydrogen transport and storage.[92] Although outside the scope of this report, there is a need to ensure that supply chain emissions - particularly methane leaks from the production and transportation of natural gas - are minimised in order to reduce the total emissions associated with clean hydrogen. Conversely, replacing natural gas with hydrogen in the gas network would reduce methane leakage in downstream distribution.

Consideration should also be given to the potential for hydrogen leakage. Currently any excess hydrogen produced from industrial processes is either burnt off or released directly into the atmosphere as there is no incentive to capture it. UK academic research has identified hydrogen as a secondary greenhouse gas. This means that, whilst hydrogen in itself has no Global Warming Potential (GWP), it drives reactions to increase the atmospheric burden of methane and ozone, both of which are potent greenhouse gases.[93] The report authors are clear that the climate impact of a hydrogen-based energy system would still be much less than its fossil-fuelled equivalent; however leakages are clearly something that should be avoided, not least from an economic and safety perspective.

Storage

The existing gas network already uses natural gas storage as a means to manage fluctuations in intraday and inter-seasonal demand. There are challenges associated with the capture and storage of hydrogen. The H21 Leeds CityGate project examined the potential for hydrogen storage and concluded that underground storage in salt caverns offered the most flexible and cost effective option (as opposed to storing H_2 gas in pressurised containers, or as a liquid in refrigerated containers). The report concludes that the costs of storage in underground salt caverns, in addition to a 1,025MW SMR facility costing £395m CAPEX, would be in the region of £77m CAPEX for intraday storage, plus £289m CAPEX for 700MWh$_{HHV}$ inter-seasonal storage.[94] There are already some examples of hydrogen storage in salt caverns in the UK. Storage potential is explored in Chapter 6.

3.3 Policy challenges

Carbon capture and storage (CCS)

Perhaps the primary barrier to low-carbon hydrogen production from natural gas is the need to develop CCS infrastructure. This is explored in further detail in Chapter 7, but will be crucial if thermal technologies such as SMR and ATR for hydrogen generation from fossil fuels are to be pursued.

Business models

A key challenge would be the need to secure investment in SMR/ATR *with* CCS projects. Investors will need confidence there will be a reliable demand for hydrogen, and in the long-term revenue streams of both hydrogen and CCS. Across the value chain, there is a need for all actors (producers, transporters, storage handlers) to have confidence that they will receive a sustainable income. This is discussed further in Chapter 8.

A number of models for support mechanisms merit further investigation. Examples include capital grant schemes, a low carbon gas obligation or certification scheme, and feed-in tariffs. Contracts for Difference, developed as part of the Electricity Markets Reform, could also offer a model to support investment in low carbon technologies for heat generation, of which hydrogen production facilities with CCS could be one.

Regulation and policy incentives

Government plays a key role through both the implementation of policy tools to drive and support low carbon heat, and via regulation. Realistically, using hydrogen to decarbonise the gas grid is a medium- to long-term option, but could be implemented via a staged approach through research into the safety and acceptability of

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92 Speirs et al. (2017), A greener gas grid: what are the options?
93 Derwent, R. et al. (2006), "Global environmental impacts of the hydrogen economy", Int. J. Nuclear Hydrogen Production and Application 1(1): 57-67.
94 Sadler et al. (2016), H21 Leeds City Gate report

hydrogen for heat, development of demonstration schemes, and also through increasing hydrogen blending in the existing natural gas network. Hydrogen blending is discussed in greater detail in our first report (*Future Gas Series: Part 1 'Next Steps for the Gas Grid'*) however there is a role for Government and Ofgem to play in amending the regulations in the short term to allow increased concentrations of hydrogen in the grid. Currently, only 0.1% is permitted, but research is being undertaken to establish the volume of hydrogen that could be safely blended - possibly up to 20% by volume (equivalent to 6-7% of energy) - with no change to existing infrastructure. This will, however require changes in regulation and consumer pricing to pay by energy density rather than gas flow, as currently.

Finding 10

The use of 100% hydrogen in the gas grid would require a long term strategic plan. Scaling up from small demonstration projects to larger fully-operational systems can take a significant amount of time. If the UK is to move to low carbon hydrogen to help meet its 2050 targets, steps should be taken in the near term to encourage demonstration projects into its production.

From a policy perspective, there are not yet any drivers to explicitly incentivise the production of hydrogen for heat; hydrogen is not incentivised under the existing Renewable Heat Incentive. Under recent amendments for the RTFO hydrogen is now eligible for Renewable Transport Fuel Certificates (RTFCs), providing that the hydrogen sold is of *non-biological origin.*[95] This could incentivise production of hydrogen from electrolysis i.e. splitting hydrogen from water using a renewable electricity source. Hydrogen derived from natural gas fuelled SMR/ATR, even with CCS, falls outside the RTFO due to its fossil fuel derived feedstock. Policy mechanisms to develop hydrogen production through ATR/SMR are discussed further in Chapter 8.

Energy security

Although there is some potential to use biogas as a feedstock, hydrogen production through SMR/ATR is primarily dependent on the availability of natural gas as a feedstock. Currently much of the UK natural gas supply comes either from domestic production from the North and East Irish Seas (43%) or imports via pipelines from Europe and Norway (44%). The remaining 13% comes into the UK as Liquefied Natural Gas (LNG) from overseas.[96] Hydraulic fracturing - 'fracking' - is another means of extracting domestic shale gas but is not without controversy.

Estimates suggest that using natural gas as a source of hydrogen could increase demand of natural gas by between 15% and 66% per unit of energy delivered, relative to direct use.[97] According to the Northern Gas Network's (NGN) H21 project, 47% more natural gas than current consumption would be needed if hydrogen was to solely meet consumer demand.[98] As discussed later in this report, gas reforming is not the only means of hydrogen production, with electrolysis and other technologies also likely to contribute over the longer term, but the use of natural gas for hydrogen generation does have potential implications for energy security, particularly if there is a global move to a hydrogen economy. For example, the increasing shift towards lower carbon transport, such as hydrogen fuel cell vehicles, may drive a further increase in demand for hydrogen production.

[95] Sadler et al. (2016), H21 Leeds City Gate report
[96] British Gas (Dec 2017), "The Source", Where does UK gas come from?
[97] Speirs et al. (2017), A greener gas grid: what are the options?
[98] H21 Leeds City Gate, Northern Gas Networks (2016); unpublished data suggests that this figure may be more in the region of 33% more feedstock gas, based on efficiencies of around 75%; personal communication from NGN H21 North of England

4. Electrolysis

FINDINGS

11. For the foreseeable future, it is unlikely that surplus electricity generated by renewables in the UK will produce enough hydrogen to support widespread deployment of electrolysers. Currently, the greatest potential for further deployment of electrolysers is through dedicated renewables.

12. Municipal vehicles fuelled by hydrogen, such as buses, could facilitate the development of a national hydrogen infrastructure and the decarbonisation of local transport. There are funding mechanisms in place to support this.

13. The biggest barrier to deploying further electrolysers is cost which prevents the competitive pricing of hydrogen. For example, for electrolysers powered by the grid, the cost of electricity is the biggest barrier.

4.1 Overview - electrolysis

What is electrolysis, and how does it make hydrogen?

Electrolysis generates hydrogen through an electrochemical cell by splitting water into hydrogen and oxygen using electricity.[99] It currently accounts for 4% of global hydrogen production.[100] There are three types of electrolysers:[101]

- **Alkaline** electrolysers are the most technically mature.[102] Individual units can have an output capacity of up to 2.5MW and plants with multiple units can have outputs of hundreds of MW.[103] They account for almost all the worldwide water electrolysis capacity.[104]
- **Proton Exchange Membrane** (PEM) electrolysers are developing rapidly and have recently surpassed 1MW of output capacity. They can also be constructed in a modular manner with outputs of 10MW and plans for 50MW. They are ideal for using with highly variable renewable power sources.[105]
- **Solid Oxide Electrolysers** (SOE) could be very efficient. They are currently at the pilot stage so need significant development. Their need for high temperatures could make nuclear energy suitable for powering them.[106]

4.2 How can electrolysis be deployed for hydrogen production?

Power-to-gas (P2G)

Power-to-gas (P2G) is the process of converting electricity into hydrogen gas with electrolysers where it can be used for transport, heating, industry or stored.[107] There is currently a focus on P2G taking advantage of the availability of 'surplus' or low cost renewable electricity. This can take two forms:

- **Constraint**: Where payments are made to generators to reduce their output because the network lacks sufficient capacity to transmit the electricity being generated, though there may be sufficient demand. Electrolysers near the generators could take advantage of this excess.

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[99] Royal Society (2018), Options for producing low-carbon hydrogen at scale
[100] Energy Research Partnership (2016), Potential Role of Hydrogen in the UK Energy System
[101] H2FC SUPERGEN (2017), The role of hydrogen and fuel cells in future energy systems
[102] Speirs et al. (2017) A greener gas grid: what are the options?
[103] SANTOS, Diogo M. F.; SEQUEIRA, César A. C. and FIGUEIREDO, José L., Hydrogen production by alkaline water electrolysis. Quím. Nova [online]. 2013, vol.36, n.8 [cited 2018-05-11], pp.1176-1193. Available from: http://www.scielo.br/scielo.php?script=sci_arttext&pid=S0100-40422013000800017&lng=en&nrm=iso
[104] E4tech, (2015), Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target
[105] Speirs et al. (2017), A greener gas grid: what are the options?
[106] Ibid 103
[107] ITM, (2017), Power to Gas Energy Storage. Available at: http://www.itm-power.com/sectors/power-to-gas-energy-storage

- **Curtailment**: Where plants are paid not to generate because there is not enough demand. Electrolysers could take advantage of this surplus and the low cost of electricity.

There is uncertainty about the availability of 'surplus' renewable generation. It is unlikely that surplus electricity would generate enough hydrogen to recuperate the large capital costs incurred. [108] Estimates suggest there may cumulatively be between 13-40 TWh of curtailed electricity[109] in the UK which would produce 10-32 TWh of hydrogen per year. [110] This is unlikely to make a significant contribution to meeting demand (which is projected to between 398-772 TWh by 2050).[111] Moreover, this surplus is spatially and temporally disaggregated, meaning many electrolyser assets would be operational infrequently (perhaps less than 15% of the year).

Furthermore, investment in transmission capacity[112] and connections to the grids of other EU countries[113] could reduce the number of low priced periods. There may also be demand-side technologies (e.g. electric vehicle charging)[114] which would compete for any surplus electricity.

The wholesale price of electricity must also be considered. If wholesale prices continue to fall, it could also put future renewable projects at risk [115] so it is in the market's interest to not let renewable prices drop too low, therefore the scope for P2G using surplus electricity may be further limited.

Competitive pricing of hydrogen could be supported by offering grid balancing services which could generate £50,000-£100,000 per MW per year. This, combined with capital savings, could reduce costs by 5-25%.[116] Encouraging greater co-ordination between network investments and generation infrastructure would avoid congestion and inefficient network development[117] and could encourage investment. This could be in conjunction with a review into how electro intensive companies can be supported with network costs.

Hydrogen generated from P2G could be injected into the gas grid to support the decarbonisation of natural gas. This type of blend is being investigated through the HyDeploy project.[118] There may also be niche uses such as powering forklift trucks in warehouses[119] or heating offices[120] such as TfL's Palestra Building. However for electrolysers to be economically sustainable we need to look at alternative methods of powering them.

Finding 11

For the foreseeable future, it is unlikely that surplus electricity generated by renewables in the UK will produce enough hydrogen to support widespread deployment of electrolysers. Currently, the greatest potential for further deployment of electrolysers is through dedicated renewables.

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108 Speirs et al. (2017), A greener gas grid: what are the options?
109 Ibid
110 Energy Research Partnership (2015), Managing flexibility whilst decarbonising the GB electricity system; ITM Power, National Grid, Shell, SSE, Scotia Gas Networks, Kiwa, et al. Power-To-Gas: A UK Feasibility Study. ITM Power Plc, Sheffield
111 National Grid (2017), Future Energy Scenarios. Available at: http://fes.nationalgrid.com/media/1253/final-fes-2017-updated-interactive-pdf-44-amended.pdf
112 Coates, Alan, (2014), Grounds for constraint
113 Poyry (2018), Fully decarbonising Europe's energy system by 2050. Available at: http://www.poyry.com/news/articles/fully-decarbonising-europes-energy-system-2050
114 Energy Research Partnership (2016), Potential Role of Hydrogen in the UK Energy System
115 Cornwall Insights (2018), Wholesale price "cannibalisation effect" puts economics of renewables at risk. Available at: https://www.cornwall-insight.com/newsroom/white-papers-and-industry-info
116 Ibid 115
117 Aldersgate Group (2018), Removing barriers to mature renewables key to lowering industrial electricity prices. Available at: http://www.aldersgategroup.org.uk/latest#removing-barriers-to-mature-renewables-key-to-lowering-industrial-electricity-prices
118 HyDeploy (2018), About HyDeploy, Available at: https://hydeploy.co.uk/
119 Ryan, J and Martin, C (2017), Amazon and Wal-Mart Finally Found a Use for Hydrogen Power. Available at: https://www.bloomberg.com/news/articles/2017-07-31/amazon-and-wal-mart-finally-give-hydrogen-power-a-reason-to-be
120 Hydrogen London, (2016), LONDON: a capital for hydrogen and fuel cell technologies. Available at: https://www.london.gov.uk/sites/default/files/exec_summary_-_london_-_a_capital_for_hfc_technologies.pdf

Table 5: How Much does P2G Cost?

Cost estimates by E4tech (2016) for water electrolysis[121]		2014	2030	2050
CAPEX	£/kW(H_2 out, HHV)	1,215	576	558
Fixed OPEX (Operational expenditure)	£/kW(el in)/year	33	22	22
Efficiency	% (el in /H_2 HVV out)	73%	81%	84%
Lifetime	Years	25	30	30
Hydrogen levelised cost[122]	p/kWh	10	9	8

Electrolysers are currently 50-75% efficient but this is expected to improve to 85%-95%.[123] However, the total system efficiency must account for the energy and resource needs of supporting equipment and processes. Therefore total efficiency may be at the lower end of the 50-90% range.[124] Thus electrolysis could double the cost of hydrogen should cheap electricity not be available. One study suggests a wholesale price of 9.5p/kWh to achieve a supportive business case for P2G.[125]

For electrolysis to be economical the total efficiency needs to be above 70%. Further research is being conducted on how to achieve this. It is estimated that electrolysers would need to operate for 1000 load hours at times when electricity costs were null[126] to produce hydrogen competitively. Even in this scenario, there are risks due to uncertainties about load factor and the costs associated with processing hydrogen.[127]

What emissions reductions can be achieved?

The emissions associated with P2G depend upon the carbon intensity of the electricity used to power the electrolysers. There is a large range in emissions generated by renewable powered electrolysis, depending on the generation technology used. Emissions from wind are low - around 10-25 gCO_{2eq}/kWh (carbon dioxide equivalent emissions per kilowatt hour) - whereas solar PV estimates are highly variable (around 50-180 gCO_{2eq}/kWh).[128] This is because PV energy conversion can be more efficient in certain regions. Some estimates also incorporate the emissions generated from manufacture of the renewable generation technology.

Dedicated renewables electrolysis

There is growing interest around coupling electrolysers with dedicated renewables as part of a diversified hydrogen production network. Renewable electricity, particularly offshore wind, has seen dramatic cost reductions in recent years with wind falling from £150 per MW/h to £57.50 per MW/h.[129]

There are a range of developed technologies that are already commercially employed and could support hydrogen production alongside SMR/ATR with CCS. This includes alkaline electrolysers which would offer clear projected costs for investors. Companies indicate they are ready to move into this market[130] at a large scale (up to 50 MW).[131]

This set up could meet the demand for hydrogen for transport, by basing a renewable-powered electrolyser at a refuelling station. Fuel cell technology is well developed but requires very pure hydrogen. The hydrogen generated from electrolysers meets this requirement and, unlike hydrogen from SMR/ATR, does not need to

[121] E4tech (2015), Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target
[122] Assumptions: Plant size = 1MW; Load factor = 80%; Output = 24 x 365 x 80% x 1,000kWh = 7,008,000kWhpa; Electricity price = £0.06/kWh
[123] Dodds, P, (2012), A review of hydrogen production technologies for energy system models Review of hydrogen production methods. Available at: http://www.wholesem.ac.uk/bartlett/energy/research/themes/energy-systems/hydrogen/WP6_Dodds_Production.pdf
[124] Speirs et al. (2017), A greener gas grid: what are the options?
[125] Ibid
[126] IEA (2017), Renewable Energy for Industry
[127] Ibid
[128] Ibid
[129] Ambrose, J, (2017), 'Offshore wind to power £17.5bn investment boom as costs halve'. Available at: https://www.telegraph.co.uk/business/2017/09/11/offshore-wind-power-175bn-investment-boom-costs-halve/
[130] Asahi Kasei (2017), The Role of "Power-to-Gas" in the coming Green Society and Asahi Kasei's Activity in Europe. Available at http://www.nedo.go.jp/content/100873096.pdf
[131] Nel (2017), The world's most efficient and reliable electrolyser. Available at: http://nelhydrogen.com/assets/uploads/2017/01/Nel_Electrolyser_brochure.pdf

be scrubbed.[132] Other transport, such as long haul HGVs, require development and improved economics but is a promising area where batteries are likely to be less suitable because of their weight. There is also exploration into marine and rail transport which are both at a demonstration stage, with UK universities and companies conducting research and expressing interest.[133] There are further opportunities for chemical industry processes which could lower their carbon intensity through the introduction of hydrogen from electrolysers.

Dedicated renewables are unlikely to ever meet all the potential domestic demands for hydrogen. Some scenarios estimate that if all home heating and water systems were fuelled by hydrogen, up to 445 TWh of electricity (about one and a half times total current electricity production) would be needed to generate enough hydrogen to meet the forecast demand by 2050.[134] However, in a high hydrogen scenario, it is likely there will be a need for hydrogen from electrolysis and so where it can be made efficiently and cost-effectively using renewable power, it should be considered.

How much could this cost?

Many studies point to electrolysis being an expensive way of producing hydrogen because it requires large amounts of electricity - which is relatively expensive compared to natural gas. This is especially applicable to the UK which has relatively high electricity prices and transmission/distribution fees.[135] It is estimated that electricity from wind could cost 5p/kWh in 2017 terms[136] (with hydrogen costing around £4/kg) but could be reduced to 4p/kWh by 2030 (making hydrogen around £2.50/kg), assuming a load factor of 35%.[137] SMR/ATR with CCS would still be cheaper at with natural gas costing 3p/kWh in 2030[138] (with hydrogen at £2/kg). However, the use of hydrogen for transport would add scrubbing costs on to SMR/ATR with CCS. This means hydrogen from electrolysis may be more competitive for use in transport than hydrogen from SMR/ATR.

What emissions reductions can be achieved?

Emissions generated from electrolysis powered by renewables range between 24-178 gCO_{2eq}/kWh.[139] This depends on the manufacturing process for the renewable technology and is far less than SMR/ATR without CCS. Currently, these estimates are only for alkaline electrolysers and the efficiency and life span of different electrolysers could impact emissions and needs to be investigated. However, several experts believe that the potential to store renewable electricity as a gas and decarbonise other energy sectors outweighs any emissions or toxicity impact associated with electrolyser manufacturing.[140]

4.3 Key technical and policy challenges

How can the technology be further developed?

Development of electrolysers is needed for commercial low carbon hydrogen to be feasible[141] and for a diversified network of hydrogen generation. To support this development, the challenge of reducing capital and operating costs needs to be tackled.

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132 Interview for report with Paul Dodd
133 E4tech (2017), Future Fuels for Flight and Freight
134 Energy Research Partnership (2016), Potential Role of Hydrogen in the UK Energy System
135 FCH (JU), (2014), Study on development of water electrolysis in the EU
136 Baringa (2017), An analysis of the potential outcome of a further 'Pot 1' CfD auction in GB
137 E4tech (2016), Hydrogen and Fuel Cells: Opportunities for Growth
138 Ibid
139 Speirs et al. (2017), A greener gas grid: what are the options?
140 O. Schmidt, A. Gambhir, I. Staffell, A. Hawkes, J. Nelson, S. Few, (2017), Future cost and performance of water electrolysis: An expert elicitation study, International Journal of Hydrogen Energy, Volume 42, Issue 52, Pages 30470-30492. Available at: http://www.sciencedirect.com/science/article/pii/S0360319917339435
141 E4tech (2015), Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target

How can we reduce the costs of electrolysis?

Scale: increasing the size of electrolysers

Production scale up is anticipated to have a greater impact on cost reductions than R&D.[142] Although the modular nature of many electrolysers means that currently making larger electrolyser plants does not significantly reduce costs, there are efforts to make larger individual electrolysers. Moving from 1MW scale to 100MW can reduce the unit cost (£ per MWh) by roughly half.[143]

Manufacturing automation and increased production rates could enable capital savings for all types of electrolyser. Savings could also result from the standardisation of manufacturing techniques for PEM electrolysers,[144] operating SOEs at lower temperatures[145] and new electrode coating methods on alkaline electrolysers.

However, for electrolysers powered from the grid, the price of electricity in the UK still poses an issue. As a result, the Sustainable Gas Institute (SGI) estimates that there are only modest savings with increasing scale for electrolysis[146] and hydrogen from SMR/ATR with CCS would still be cheaper.

For electrolysers powered by dedicated renewables, it is the capital cost that poses the greatest issue as there is the need to invest in the electrolyser and the renewable energy source.

Deployment: increasing the number of electrolysers being installed

Producing more electrolysers could reduce the need to invest in a large transmission network. It is expected that future gas generation will be more distributed and electrolysers could be deployed to support local demands and take advantage of constrained electricity. Widespread deployment could also reduce the perceived risk around electrolysers so may reduce borrowing costs. Whether an electrolyser is appropriate for the area will be based on factors including the geographical area, density of housing, what the hydrogen will be used for and how easily it can be stored. Below are two methods which involve increasing the deployment of electrolysers. Other practical routes to increasing deployment of electrolysers are discussed in Chapter 8.

Transport

A distributed model could support the development of hydrogen for transport. Hydrogen fuelled municipal large vehicles are a promising area and could be refuelled by local electrolysers. This could support bus networks and other municipal vehicles/fleets. Development of bus networks is already underway in Aberdeen,[147] Dundee[148] and Birmingham.[149] Development across the country could serve local needs, give a clear indication of future energy policy to upstream producers and provide grid balancing services to the National Grid, thereby creating another source of income.[150]

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[142] Schmidt el al. (2017), Future cost and performance of water electrolysis: An expert elicitation study
[143] Gathered during interview for report
[144] ITM (2016), 100MW ELECTROLYSER PLANT DESIGNS TO BE LAUNCHED AT HANNOVER Available at: http://www.itm-power.com/news-item/100mw-electrolyser-plant-designs-to-be-launched-at-hannover
[145] Speirs et al. (2017), A greener gas grid: what are the options?
[146] Ibid
[147] Aberdeen City Council (2017), The Aberdeen Hydrogen Bus Project. Available at: http://www.all-energy.co.uk/__novadocuments/30431?v=635060505159530000
[148] Air Quality News (2018), Dundee to deploy hydrogen buses. Available at: https://www.airqualitynews.com/2018/03/29/dundee-to-deploy-hydrogen-buses/
[149] Birmingham City Council (2017), Cleaner hydrogen buses to be given green light. Available at: https://www.birmingham.gov.uk/news/article/178/cleaner_hydrogen_buses_to_be_given_green_light
[150] Gridchangeagest (2018), ITM Power installing grid balancing hydrogen bus refuelling station in Birmingham. Available at: https://www.gridchangeagent.com/itm-power-installing-grid-balancing-hydrogen-bus-refuelling-station-in-birmingham/

Case Study: Aberdeen Hydrogen Project

What is it?

Aberdeen City Council has run a fleet of 10 hydrogen buses since 2015 - the largest fleet of this kind in Europe. This was done in an effort to improve air quality, reduce noise pollution and explore the possibilities of developing a hydrogen sector in Aberdeen.

How does it work?

Buses refill at two hydrogen refuelling stations situated in the north and south of the city. Hydrogen is produced on site by electrolysers, using electricity on a green tariff, and compressed and stored as a gas on site in tanks.

How was the project coordinated and funded?

A collaboration of Aberdeen City Council, Scottish Industry, the Scottish Government, the EU and two local bus operators provided £20m of funding. The Council led the implementation and running of the project, so it could be tailored to local needs.

What challenges have there been?

Challenges included the absence of a robust supply chain - there was a lack of parts and skilled technicians for maintenance of the hydrogen buses; the perception of the safety of hydrogen by the public; the cost of hydrogen; and hydrogen buses still not being competitive without subsidy. The council hopes a developing market for hydrogen bus fleets will make these projects more competitive.

What are the future possibilities?

This demonstration project has shown hydrogen buses work on scale. The learning and expertise developed on this project is being applied to Local Authorities around the UK, and the Council itself is looking to develop a longer term project with up to 30 hydrogen fuelled buses.

However, at current electricity prices, it is not economical to produce hydrogen from electrolysers on site. The Council is therefore looking into importing hydrogen from the EU, where tariffs mean it is cheap to produce, or shipping hydrogen in from Scottish offshore wind farms. Future refuelling facilities might include renewable generation on site to avoid transmission and storage costs. With the support of government policy, the costs of hydrogen and hydrogen technology should decrease, creating opportunities for transport and the Council.

Finding 12

Municipal vehicles fuelled by hydrogen, such as buses, could facilitate the development of a national hydrogen infrastructure and the decarbonisation of local transport. There are funding mechanisms in place to support this.

Heavy Industry

Electrolysers could also support heavy industry. Heavy industry generates a significant portion of global carbon emissions (the steel industry alone is responsible for 7% of global emissions).[151] Using renewably generated hydrogen could lead to significant emissions reductions in a variety of industries that use high temperatures including the cement, refractory, glass, refining and petro chemical industries. There are plans to trial using

[151] HYBRIT (2018), 20- Toward fossil-free steel. Available at: https://www.ssab.com/company/sustainability/sustainable-operations/hybrit

hydrogen in ore-based steel making in Sweden[152] with dedicated renewable resource and an electrolyser. Though currently 20-30% more expensive due to electricity prices, it is estimated that with costs falling for electricity and rising for carbon emissions, due to the emission cap of the EU Emissions trading scheme tightening, fossil-fuel free steel will be competitive in the future.

In the UK, public and private funding is needed for research, development and commercial deployment. Key industries would require specially designed furnaces, entailing significant capital costs. Previous scenarios do not envisage these applications being deployed in the UK before 2030.[153] Though progressing, the need for further development and cost uncertainty are key barriers for the use of hydrogen in heavy industry.

Reducing operating costs

For electrolysers powered by the grid, electricity costs make up the largest cost component of electrolysis.[154] The falling cost of renewables will entail reduced operating costs - so measures targeted at reducing the costs of renewables are essential for the affordability of electrolysis. This could be done in conjunction with offering grid balancing services mentioned above.

Measures could include reviewing how electro intensive companies can be supported with network costs. This could take the form of funding for research and development, support for large scale demonstration of electrolysers to support commercialisation, price guarantees for hydrogen or increasing the costs around producing emissions so hydrogen from electrolysis becomes relatively competitive.

Finding 13

The biggest barrier to deploying further electrolysers is cost which prevents the competitive pricing of hydrogen. For example, for electrolysers powered by the grid, the cost of electricity is the biggest barrier.

Opportunities for research and development

Below are areas this inquiry has identified where support for research and development would be most beneficial to support electrolysis and hydrogen:

- Reducing the costs of renewables for dedicated electrolysis
- Development of Solid Oxide Electrolysers to extend their lifetime
- Gathering evidence to examine what steps can be taken to manage the operational costs of electrolysis so that the hydrogen produced is competitive
- Support for research into hydrogen powered HGVs. There are concerns about the efficiency of fuel cells[155] and the costs around vehicles and hydrogen that need to be tackled.[156]

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152 Coyne, N. (2018), Vattenfall backs hydrogen to decarbonise heavy industry, eyes supply chain ownership. Available atL https://theenergyst.com/vattenfall-backs-hydrogen-to-decarbonise-heavy-industry-eyes-supply-chain-ownership/
153 E4tech (2016), Hydrogen and Fuel Cells Opportunities for Growth – Mini Roadmaps'
154 E4tech and Element Energy (2016), Hydrogen and Fuel Cells Opportunities for Growth – Mini Roadmaps
155 Shone, E, (2016), Hydrogen as fuel is 'a disaster' says Centre for Sustainable Road Freight. Available at http://freightinthecity.com/2016/11/hydrogen-as-fuel-is-a-disaster-says-centre-for-sustainable-road-freight/#SIRTvVCjWFkjH7AM.99
156 ICCT (2017), Transitioning to Zero-Emission Heavy-Duty Freight vehicles. Available at: https://www.theicct.org/sites/default/files/publications/Zero-emission-freight-trucks_ICCT-white-paper_26092017_vF.pdf

5. Alternative methods of hydrogen production

FINDINGS

14. Gasification of biomass and wastes could be an alternative method of hydrogen production that could be deployed to support meeting the 2050 carbon budget.

15. There are a number of technologies that are currently unlikely to create large volumes of hydrogen, but could offer routes to efficient, low carbon, hydrogen production beyond 2050. If they are to be developed, they will need to be supported.

Given the uncertainties around CCS and the availability and cost of electricity for electrolysis,[157] many studies recommend developing a diverse portfolio of resources.[158] The technologies detailed below could offer additional options for producing hydrogen in the future.

5.1 Gasification

The process of gasification is outlined in chapter 2. Producing hydrogen simply means leaving out the methanation step after gasification. 18% of global hydrogen production comes from coal gasification.[159] However, this is unlikely to continue due to its high emissions (approximately 500-700 gCO_{2eq}/kWh), even with CCS,[160] variable capital investment costs and low energy efficiency.

Cost of coal gasification with CCS

Capital costs for coal gasification with CCS are estimated at just under £2,500 per kW of hydrogen and operating costs at just over £120 per kW of hydrogen. No significant change in cost is expected by 2050.[161]

Biomass and wastes

For low carbon hydrogen from gasification, biomass and wastes must be used as feedstocks instead, producing ‘biohydrogen’. The process again involves gasification (detailed in 2.1) but without methanation. To achieve optimum yields, feedstocks need to be treated before the gasification process which adds complexity.[162]

Concerns for gasification of biomass are similar to those for BioSNG and focus on whether it is possible to deliver biohydrogen at scale at affordable cost. There is a particular issue around the formation of tar during this process that can cause blockages and reduce the efficiency of equipment. There are solutions, but these

157 ETI (2016), DECC Small Modular Reactor – Techno-Economic Assessment – Project 2
158 Policy Exchange (2016), Too Hot to Handle? How to decarbonise domestic heating
159 Energy Research Partnership (2016), Potential Role of Hydrogen in the UK Energy System
160 POST (2016), POSTnote no. 523 Carbon Footprint of Heat Generation
161 E4tech (2015), Scenarios for deployment of hydrogen in contributing to meeting carbon budgets and the 2050 target
162 Royal Society (2018), Hydrogen Production – Policy Briefing

add complexity and cost[163] and there is a lack of research that brings together expertise in biomass, gasification and CCS.[164]

Costs

The capital costs for biomass gasification with CCS are just under £5,000 per kW, but are expected to fall to £3,279 by 2050, with operating costs concomitantly falling from £343 per kW/year to £230. SMR with CCS is estimated to have a capital expenditure of £684 per kW by 2050 with operating costs around £27 per kW/year.[165] This means SMR with CCS is significantly cheaper.

Emissions

Using waste alongside CCS technology could result in hydrogen production with negative emissions. This has yet to be demonstrated but estimates are biohydrogen with CCS would generate carbon savings of 565 gCO_{2eq}/kWh.[166]

Technical challenges

Demonstration

A bioSNG plant was adapted in Swindon by Cadent.[7] All elements of biomass gasification were carried out apart from full CCS (some carbon dioxide was captured and utilised elsewhere). The results indicated this model was suitable for a larger scale operation. There are now plans to build a 45 MW plant.[167] However, due to issues with the availability of feedstocks and tar production, it is unlikely to make a major contribution to reaching the 2050 targets.

Policy challenges

- The efficacy of CCS needs to be demonstrated so that low and negative emissions scenarios can be better understood. This is important to build governmental and investor confidence.
- There is a need to understand the availability of feedstocks (detailed in chapter 2). Under optimistic scenarios, biomass could generate 123 TWh[168] which could significantly meet demand by 2050.[169] Work to understand the ability of industrial and commercial sectors to supply feedstocks could help mitigate the risks around competition for feedstocks.

Finding 14

Gasification of biomass and wastes could be an alternative method of hydrogen production that could be deployed to support meeting the 2050 carbon budget.

5.2 Alternative thermochemical processes

The report 'Hydrogen Production - Policy Briefing' by the Royal Society (2018) outlines a range of methods that use thermochemical processes to produce hydrogen. They may contribute to future hydrogen production but require further research and are unlikely to make a significant contribution to the UK meeting its 2050 targets.

Pyrolysis

Pyrolysis is where a fuel is thermally degraded in the absence of air/oxygen. It is currently used commercially to produce bio-charcoal and low volumes of hydrogen. If used for hydrogen production, the carbon could be collected. How to produce large volumes of hydrogen is currently at an early research stage.[170]

163 Speirs et al. (2017), A greener gas grid: what are the options?
164 E4tech & Ecofys (2018), Innovation Needs Assessment for Biomass Heat. Available at: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699669/BE2_Innovation_Needs_Final_report_Jan18.pdf
165 Policy Exchange (2016), Too Hot to Handle? How to decarbonise domestic heating
166 Ibid
167 Cadent (2017), Biohydrogen – Production of hydrogen by gasification of waste
168 Ibid 164
169 National Grid (2017), Future Energy Scenarios. Available at: http://fes.nationalgrid.com/media/1253/final-fes-2017-updated-interactive-pdf-44-amended.pdf
170 Royal Society (2018), Hydrogen Production – Policy Briefing

Downhole conversion of fossil fuels to hydrogen with carbon dioxide sequestration

Fossil fuels can be combusted underground in the presence of water. This has been used previously to generate a mixture of hydrogen and syngas, but due to environmental concerns and the low-calorific nature of the gas mixture compared to natural gas, it is no longer used. It would require CCS but could be used to unlock the hydrogen stored in shale gas. Further research is needed into the process and the economic and environmental consequences.

Microwave technologies

Microwave cracking with cheap and abundant catalysts (made from iron/nickel) can release large amounts of pure hydrogen (greater than 98%) from hydrocarbons such as diesel and wax. Unwanted by-products (methane and carbon dioxide) can be almost entirely suppressed, leaving almost exclusively solid carbon which can be easily separated and sequestered. This process could use the existing infrastructure for transporting and storing petrochemicals. Currently, this requires a low carbon source of electricity to produce the microwaves and the overall process still needs considerable development. Issues include competition for hydrocarbons and the large quantities of solid carbon that would need to be sequestered.

Fuel cells

Some fuel cell technologies - including molten carbonate fuel cells (MCFCs) - can operate in 'reverse' to produce hydrogen from various sources using electricity. MCFCs can use electrochemical hydrogen separation to produce hydrogen with low emissions and with low operating costs. The high temperatures required by MCFCs mean they can be difficult to deploy, but several companies, including Fuelcellenergy, are exploring the options for their deployment.

5.3 Solar to fuel

There are a range of production methods in which solar energy splits water into hydrogen and oxygen. This is a process similar to electrolysis which involves artificially replicating a process that naturally occurs in photosynthesis. The difference between solar to fuel and electrolysis is that solar to fuel technologies produce the fuel in an integrated single device rather than needing a separate remote renewable source of electricity.

There are several types of solar to fuel technologies. It is an active area of research globally, but significant development is still required, and competition for space may limit the scale of this technology. At this stage, it is difficult to make reliable cost projections for solar to fuel. This means it is likely to be decades before it can be deployed commercially and so it will not support us in reaching our decarbonisation 2050 targets.

5.4 Biological methods

Anaerobic digestion modification

AD can be modified to produce hydrogen. One of the biological steps for the production of methane from biomass (discussed in Chapter 1) involves producing hydrogen which is then converted to methane. By inhibiting the microorganism that converts hydrogen into methane, hydrogen can be produced.

The advantages of this process are the lower operating temperatures, the simple technology and that the modifications mean both wet and dry feedstocks can be used.[171]

Currently, this technology needs further development. Various issues need to be resolved, including increasing the yield of hydrogen, increasing the range and availability of feedstocks and making it easier to process feedstocks. Solutions are being researched at a number of UK universities.

[171] Royal Society (2018), Hydrogen Production – Policy Briefing

Other methods

Fermentation

There have been developments in producing hydrogen from by-products of fermentation. Organic acids can be converted to hydrogen using photo-fermentation or microbial electrolysis.[172] This maximises the energy use from biomass and can also produce other, high value, chemicals. The variety of processes means it is flexible and can be used with different yields and feedstocks (e.g. water, microorganisms or waste). It also requires minimal energy and does not produce airborne pollutants.

This process opens the possibility of fermentation enhancing current biological processes and making a small but valuable contribution to the hydrogen economy.

Hydrogen from oil/coal

Biological processes could be applied to oil or coal to extract hydrogen while preventing carbon emissions by keeping the carbon underground. It may be possible to replace methane from oil/coal with hydrogen by combining engineering and synthetic biology. However the process is slow and is accompanied by significant environmental risks that need to be resolved.

Challenges

The principle drawbacks with biological production methods are low efficiencies, high capital costs of bioreactors and large land area requirements. There are also challenges specific to each method (e.g. separating nitrogen from biomaterial prior to photo fermentation and toxic chemicals that could be produced from oil/coal).[173]

To succeed commercially, the energy yields of the micro-organisms and processes need to be improved. For this reason, genetic engineering of more resilient and productive micro-organisms is an active area of research. In the medium term, it needs to be demonstrated that these technologies can produce hydrogen on an industrial scale in a way that is also environmentally friendly.

5.5 Nuclear power

Nuclear powered electrolysis

Nuclear power, including Small Modular Reactors, could contribute to the production of carbon-free hydrogen through electrolysis.[174] The high temperatures generated in nuclear plants would be suitable for Solid Oxide Electrolysers (SOEs). Though currently not commercially viable, they offer an opportunity to generate hydrogen very efficiently at up to 90%.[175] Even if lower efficiency electrolysers were to be employed, reactors could support the production of hydrogen without carbon emissions.

Thermochemical cycles

Thermochemical cycles are chemical cycles which use high temperatures to split water into hydrogen and oxygen. Waste heat from nuclear reactors can be used, which has near zero emissions. It is currently being researched so the efficiency and durability of the materials involved in the reaction can be improved and is a technology that could be used in the future.[176]

5.6 Policy Challenges

The primary challenge for policy makers is that the above technologies are at such an early stage that it is too soon to prioritise funding for certain technologies. It is worth nurturing their development because of the possible efficiency gains and the possibility of the UK exporting this expertise. This could come from the 'Innovation Loans' proposed in the Industrial Strategy.[177]

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172 Ibid
173 Ibid
174 Policy Exchange (2018), Small Modular Reactors- the next big thing in energy
175 Speirs et al. (2017), A greener gas grid: what are the options?
176 U.S. Department of Energy (2018), Hydrogen Production: Thermochemical Water Splitting
177 BEIS (2017), Industrial Strategy: building a Britain fit for the future

5.7 Funding

Most of the funding available falls under the **Energy Innovation Programme,** worth £505m.[178] It aims to accelerate the commercialisation of innovative clean energy technologies and processes. All these funds have the potential to support the development of hydrogen production in different forms with some funding already allocated for investment in low carbon heating.[179]

Table 6: Breakdown of funding from the Energy Innovation Programme:

	Smart Systems	Transforming Construction Challenge Fund	Industrial Decarboni-sation	Nuclear Innovation	Renewables Innovation	Energy Entrepren-eurs and Green Finance	Hydrogen Supply Competition
BEIS funding (£m)	70	170	100	180	15	50[180]	20
Funding from UK Research and Innovati-on (£m)	102.5[181]		62	280	162		

[178] BEIS (2017), Energy Innovation. Accessible at: https://www.gov.uk/guidance/energy-innovation#beis-energy-innovation-programme
[179] BEIS (2017), Innovations in the built environment. Accessible at: https://www.gov.uk/guidance/innovations-in-the-built-environment
[180] There might be scope for more funding. So far £20m has been committed to investing in green technologies through green finance and £50m has been committed through the Energy Entrepreneurs fund with a further £10m available
[181] There may be £92.5m of additional funding according (see reference 179)

Table 7: Additional Funding Sources for Innovation Programmes

Name of fund	Amount	Description
Innovation Loans (Innovate UK)	£50m	A pilot scheme for late stage R&D projects that have not yet reached the point of commercialisation. Up to £10m will be available in each loan competition. This is only open to SMEs.
Community and Renewable Energy Scheme (CARES) - Scottish Government[182]		Financial support that is available for Scottish energy projects. It is broken down as follows: **CARES Enablement Grant** - Up to £25k to fund energy systems or renewable energy projects, investigation of shared ownership opportunities or work to maximise the impact from community benefit association with renewable energy projects. **CARES Development Loan -** Up to £150K (10% interest rate) can be provided for projects with a reasonable chance of success. **CARES Innovation Grant -** Up to £150K to either fund innovation activity or improve the viability of projects by grant funding elements of the project.
Ultra-low Emission Bus Scheme (DfT)[183]	£48m	Open to local authorities and bus operators in England and Wales to help with the purchase of ultra-low emission buses and supporting infrastructure, including hydrogen.
Hydrogen for Transport (DfT)	£14m	Seeks to increase the number of publicly-accessible hydrogen refuelling stations in the UK and the number of fuel cell-powered electric vehicles on UK roads.
Transforming Cities (DfT)[184]	£1.7bn	Aims to improve productivity and spread prosperity through investment in public and sustainable transport in some of the largest English city regions.

Finding 15

There are a number of technologies that are currently unlikely to create large volumes of hydrogen, but could offer routes to efficient, low carbon, hydrogen production beyond 2050. If they are to be developed, they will need to be supported.

[182] Scottish Government (2013), Scottish Government Community And Renewable Energy Scheme (CARES). Accessible at: http://www.gov.scot/Topics/Business-Industry/Energy/Energy-sources/19185/Communities/CRES
[183] Department for Transport (2018), Ultra-low emission bus scheme: application and guidance 2018. Accessible at: https://www.gov.uk/government/publications/low-emission-bus-scheme
[184] Department for Transport (2018), Apply for the Transforming Cities Fund. Accessible at: https://www.gov.uk/government/publications/apply-for-the-transforming-cities-fund

Part 3
KEY POLICY ISSUES

This part examines the various crosscutting challenges that exist for the methods outlined in parts 1 and 2 in detail. These are:

- The transport and storage of low carbon gas.
- Carbon Capture and Storage.
- Markets and regulation for low-carbon gas.

6. Transport and storage of low carbon gas

FINDINGS

16. The UK currently has many forms of energy storage across the energy systems, most of which are currently in the form of unabated fossil fuels. The UK will need to find replacements for these as it moves towards a decarbonised future, and consider the best balance for storage and generation capacity across the gas and electricity systems. On a large scale, interseasonal basis, low carbon fuels are expected to provide the most practical and cost-effective storage option.

17. Fundamentally, biogases and hydrogen can be stored and transported in the same way as natural gas - in underground reservoirs, tanks and pipelines in gaseous or liquid form.

18. Transporting hydrogen as a gas presents different challenges to transporting natural gas. Using ‘hydrogen carriers’ such as ammonia, or transporting hydrogen as a liquid could resolve some of these issues. Such methods require additional energy inputs or cause conversion losses - therefore they may only be suitable for longer distances, such as those required for imports and exports, rather than for domestic transportation.

6.1 Storing energy

Energy storage

A low carbon energy system must be able to meet the significant daily, weekly and seasonal variation in energy demand in the UK. The peak gas demand for heat in the winter can be 12 times the summer maximum and 5 or 6 times bigger than the peak for electricity.[185] The electricity demand is on average 36% higher on a winter day than in the summer.[186] The UK energy system must be sufficiently flexible to meet this variable demand, especially in an energy system dominated by intermittent renewable generation. One way of achieving this is by having various methods of storing energy.

Types of energy storage

Any decarbonised future will utilise a portfolio of storage methods depending on duration, purpose and quantity of energy which needs to be stored. The following summarises different storage types:

- **Chemical storage**: Fuels offer a good way to store energy over a long period: they have a high energy storage capability and do not lose energy over time. They are also cheap for large stores of energy; using gas to balance supply and demand of the natural gas system is between 1000-10,000 times cheaper than using electrical storage methods to balance the electrical system.[187] This suits their current role balancing the gas market on a daily basis.
- **Electrochemical storage**: Batteries are compact, deliver energy efficiently and quickly and can handle a range of loads. However, they have higher costs currently than chemical storage, which makes them suitable for shorter timeframes and smaller storage capacity. This suits their current role balancing the

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185 Imperial College London (2016), Managing Heat System Decarbonisation: comparing the impacts and costs of transitions in heat infrastructure
186 DECC (2014), Seasonal Variations in Electricity Demand
187 Imperial College London (2016), Managing Heat System Decarbonisation: comparing the impacts and costs of transitions in heat infrastructure

electricity market on a second by second basis. Common batteries, such as the lithium ion battery, also need periodic recharging to make up for parasitic losses of 0.1-0.3% a day.[188]

- **Mechanical storage**: Such as pumped hydro and compressed air. Pumped hydro has operated in the UK electricity system for decades. Both methods require certain geographical features and are therefore difficult to use on a nationwide scale in the UK,[189] although they are excellent for long term, large scale storage and have good roundtrip efficiencies.

Current UK energy storage

Until recently, the UK could store about 5% of the annual consumption of gas in underground storage.[190] However, since the Rough Storage facility has closed, this has fallen to 1.5%, which is around 15 TWh. The UK also has 25 GWh of storage for electricity production in pumped hydro, and a fraction of that in grid scale batteries. There is also some storage potential in the pipes of the gas transmission itself, known as 'line pack', which provides some intra- and inter- day storage.

Other than storage, a resilient energy supply can be secured through a diverse supply chain. Current gas suppliers include domestic North Sea production; interconnectors to Belgium and the Netherlands; imports of Liquid Natural Gas; and Norwegian supplies via pipelines. Both gas and electricity energy markets play an important role in deciding the most economic and efficient capacity of supply to meet demand, including the optimal amount of energy storage. The future energy system will need to be optimised across supply chain, storage and production.

Finding 16

The UK currently has many different forms of energy storage across the energy system, most of which is in the form of unabated fossil fuels. The UK will need to find replacements for these as it moves towards a decarbonised future, and consider the best balance for storage and generation capacity across the gas and electricity systems. On a large scale, interseasonal basis, low carbon fuels are expected to provide the most practical and cost-effective storage option.

6.2 Options for storing low carbon gas

Storing biomethane and BioSNG

Since biomethane and BioSNG are very similar to fossil fuel-derived natural gas, they can be stored in the same way as natural gas. Aspects of this are covered in the *Future Gas Series: Part 1 'Next Steps for the Gas Grid'*.

Storing hydrogen

Salt caverns have been manufactured to store hydrogen in the UK since the 1970s.[191] The UK has a number of naturally occurring salt fields onshore, principally around Teesside, Cheshire and Dorset.[192] Caverns can be up to 2000m deep and are a range of sizes - the largest caverns in the UK are 600,000 cubic metres. Existing onshore UK salt caverns alone could provide around 0.8 billion cubic metres of gas storage, enough to store around 3TWh hydrogen. Proposed new salt caverns have the potential to increase this capacity by an order of magnitude.[193]

Storing hydrogen in salt caverns is one option for the large volume of fuel required in interseasonal storage. The technology is well understood, and, compared to other types of non-fossil fuel energy storage, it is a relatively cheap method of large scale and long term energy storage. Across various different cavern depths and sizes, onshore hydrogen gas caverns have an average capital cost of £2-5/kWh, compared to £400/kWh for

188 Energy Technologies Institute with Baringa (2016), Energy Storage and Distribution
189 Renewable Energy Association with Energy Storage UK (2015), Energy Storage in the UK: An Overview
190 Sadler et al (2016), H21: Leeds City Gate
191 HyUnder (2013), Overview of all known underground storage technologies for hydrogen
192 British Geological Society (2017), Underground natural gas storage in the UK. Available at: http://www.bgs.ac.uk/research/energy/undergroundGasStorage.html
193 Desk-based calculations using data from: Energy Research Partnership (2016), Potential Role of Hydrogen in the UK Energy System

a lithium ion battery.[194] However, hydrogen's low volumetric density needs three times the pressure or volume to store the equivalent energy of methane,[195] so more caverns, or higher pressure caverns, are required to have the same energy capacity of gas salt cavern storage as the UK has now. Overall storage costs may therefore be higher than currently. On the other hand, installing enough hydrogen production capacity to meet peak demand without storage is also costly: for example, only having 11 TWh of hydrogen storage would require 80 GW of SMR capacity to be installed, some of which would be idle in summer months.[196] A balance between capacity of hydrogen production and hydrogen storage with lowest overall cost should be found.

6.3 Options for transporting low carbon gas

Transporting biomethane and BioSNG

Since biomethane and BioSNG are similar to fossil fuel-derived natural gas, they can be transported in the same way as natural gas. Issues relating to the injection of biomethane and BioSNG and constructing a biogas transport network are covered in Chapter 3 of the *Future Gas Series: Part 1 'Next Steps for the Gas Grid'*.

Transporting hydrogen

Hydrogen requires very high pressures and low temperatures to be liquefied and still has relatively low volume density compared to other fuels. This makes it challenging to transport over a long distance. Therefore, a 'hydrogen carrier' could be used to transport hydrogen. Two examples of this are provided below:

Ammonia

Ammonia has a high hydrogen density with respect to weight (17.8%),[197] can be stored as a liquid at low or ambient pressure and temperature, and contains no carbon. Globally, 150m tonnes of ammonia are produced per year, mostly through the energy intensive Haber Bosch process.[198] However, ammonia can also be produced by renewable powered electrolysis. While this is currently more expensive than the Haber process, it is anticipated that this route will be a cost effective method of producing hydrogen as a fuel for vehicles by 2030.[199] Hydrogen is recovered from ammonia by catalytic decomposition, which is possible on board a vehicle.[200]

Ammonia is already well understood. There is an extensive transport infrastructure for it in the form of shipping, tanks and pipes, and further potential for Liquid Propane Gas networks to be adapted for it.[201] However, ammonia is toxic and forms NO_x in the decomposition process if it is not burnt cleanly. This requires NO_x scrubbers of the sort used in diesel vehicles today to be fitted to exhaust pipes. There are also efficiency losses for transporting hydrogen in ammonia, which vary depending on how the hydrogen and ammonia is produced. This means that ammonia is only suitable for long distance transportation. It is therefore one option for how hydrogen will be imported or exported rather than how hydrogen will be domestically transported.

Metal Borohydrides

Metal borohydrides are a type of solid hydrogen storage. They have high hydrogen densities (between 18% by weight for lithium, and 10% for sodium) and can be safely stored on board a vehicle. However, more work is needed to develop this option to optimise reactions so they take place at temperatures compatible with vehicles, and are cost effective overall.[202]

Other methods of transporting hydrogen

Fuel tanks for liquefied hydrogen

The cost of pressurising hydrogen into liquid and making reinforced tanks is high: a 3.5 tonne container for liquid hydrogen might cost up to £1m.[203] However, this inquiry heard that prices may come down by the mid-

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194 The Hydrogen and Fuel Cell Research Hub (2017), The role of hydrogen and fuel cells in delivering energy security in the UK
195 Imperial College London (2016), Managing Heat System Decarbonisation: comparing the impacts and costs of transitions in heat infrastructure
196 Ibid 194
197 US department of Energy (2017), Future of Ammonia Production: improvement of Haber Bosch Process or electrochemical synthesis?
198 US Geological Survey (2018), Nitrogen Fixed: Ammonia, Mineral Commodity Summaries
199 Ian Wilkinson at the 'Hybrid and Integrated Energy Storage' seminar (2017), 'Green Ammonia',
200 Journal of the American Chemical Society (2014), Hydrogen production from ammonia using sodium amide
201 ACOLA (2017), Role of energy storage n Australia's future energy supply mix
202 Energies (2015), Recent Advances in the use of sodium borohydrides as a solid state hydrogen store
203 Evidence heard from this inquiry

2030s. This is especially being looked into in areas with high renewable energy resource, such as deserts, where the low costs of hydrogen production make the cost of liquefying worthwhile.

Findings 17 & 18

17. Fundamentally, biogases and hydrogen can be stored and transported in the same way as natural gas - in underground reservoirs, tanks and pipelines in gaseous or liquid form.

18. Transporting hydrogen as a gas presents different challenges to transporting natural gas. Using 'hydrogen carriers' such as ammonia, or transporting hydrogen as a liquid could resolve some of these issues. Such methods require additional energy inputs or cause conversion losses - therefore they may only be suitable for longer distances, such as those required for imports and exports, rather than what is required in domestic transportation.

Hydrogen Transmission Network

Suitability of the current National Transmission System for hydrogen

The National Transmission System (NTS) uses high pressure steel pipes to transport natural gas over long distances. There are questions over whether repurposing the NTS for hydrogen will be cost-effective,[204] because hydrogen can cause steel pipes to undergo 'embrittlement', making fractures more likely. There are a number of research projects underway to establish the safe percentage of hydrogen that can be blended into natural gas in steel pipeline systems. It is also expected that further innovation projects will look at options to repurpose steel pipes, potentially through innovation in sleeving or coatings, to allow higher levels or pure hydrogen to be transported.

The cost of building a new high pressure transmission network for hydrogen was estimated by the HyNet project - which proposes a hydrogen hub in the Northwest of England - to cost £1.65m per km of pipeline.[205] This project proposed a 109km pipeline at a cost of £178m.

Suitability of the current Gas Distribution Network for hydrogen

The Gas Distribution Network (GDN) transports natural gas at lower pressures from the NTS to end-users. It is two orders of magnitude longer than the NTS. Some parts of the GDN are expected to be suitable for hydrogen. This is because the Iron Mains Risk Reduction Programme (IMRRP - formerly IMRP) is replacing most of the iron pipes in the GDN which are below 7 bar with hydrogen-compatible polyethylene.

The cost of modifying the whole of the GDN below 7 bar so that it is suitable for hydrogen is relatively small. For example, the cost of retrofitting the existing GDN in Leeds to be compatible with 100% hydrogen has a total capital cost of £10,000 per km of pipeline,[206] which is ten times cheaper than the estimated costs of building a new distribution network for hydrogen.[207] This means hydrogen could be injected into the GDN in the near future with little extra capital than what has already been spent on the IMRRP to maintain gas infrastructure.

However, higher pressure parts of the GDN - between 7 and 30 bar - are not expected to be compatible with hydrogen. New pipes would need to be laid for injection of hydrogen into this part of the distribution system.

[204] Energy Technologies Institute (2015), The potential role of hydrogen for domestic heating
[205] HyNet Northwest (2018), Cadent
[206] Sadler et al (2016), H21: Leeds City Gate
[207] Speirs et al. (2017), A greener gas grid: what are the options?

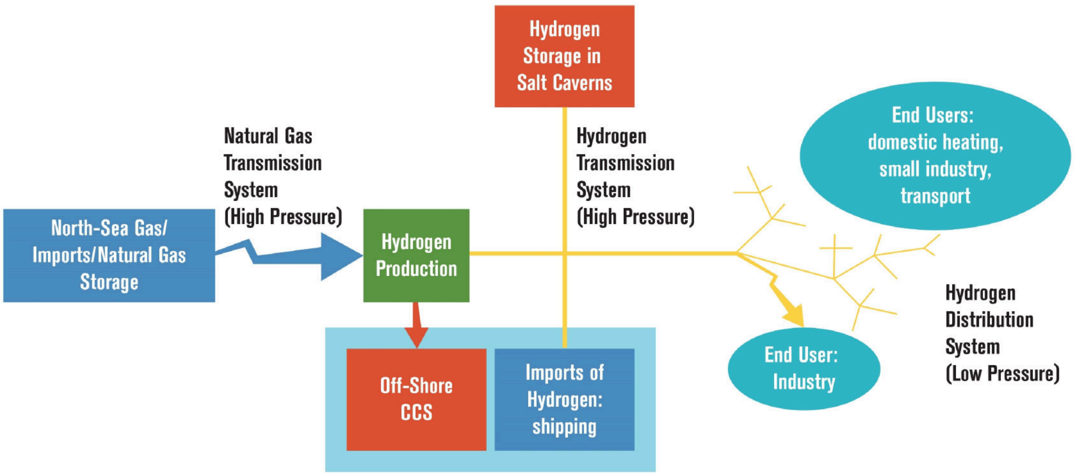
Imports of hydrogen

It is possible the UK could import hydrogen from an international market. A recent report for BEIS explored a scenario where 40% of hydrogen demand was met by international imports, using a similar shipping infrastructure currently in place for imports of natural gas.[208] However, the size and certainty of an international market for hydrogen is still very hard to predict, and this inquiry heard that widespread international trade of hydrogen is unlikely before the 2030s.

Configuration of a hydrogen transmission network

Any hydrogen transmission network would be optimised so there is a cost effective balance between hydrogen production capacity, length of hydrogen transmission network and hydrogen storage capacity. Below, consideration is given to how a hydrogen transmission network for different hydrogen production methods could function. For clarity they are presented as two diagrams - in reality any transmission network would be a combination of the two.

Figure 4: Hydrogen Transmission using Hydrogen from Steam Reforming



Hydrogen production capacity and hydrogen storage can be balanced to meet peak demand and limit excess production capacity.

The natural gas NTS could continue to be used to transport natural gas to hydrogen production facilities. The hydrogen production plant would then act as the interface between a NTS for natural gas and a low pressure hydrogen distribution network.

Natural gas supply to hydrogen production facilities could be varied to meet domestic demand. This, combined with storage in pipes known as 'linepack', could limit the amount of intra- and inter-day hydrogen storage which needs to be installed.

On the other hand, hydrogen storage in salt caverns can help to meet peak winter demand. This limits the need to build excess hydrogen production capacity to meet this peak demand, which would sit idle for other parts of the year. However, extensive hydrogen storage does mean that a new hydrogen transmission network would be required (covered below).

A new hydrogen transmission network will probably be needed, and some new pipes will be needed on high pressure parts of the Gas Distribution Network.

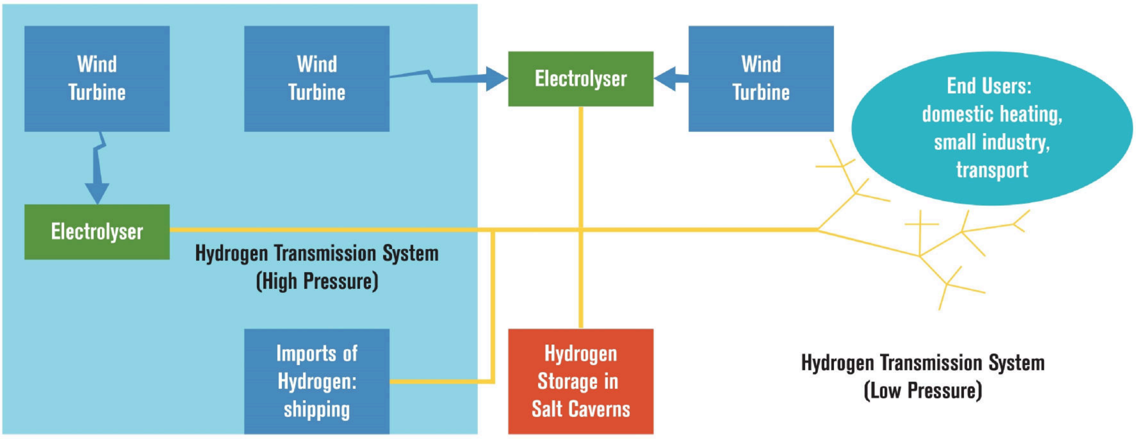
SMRs and ATRs will need to be situated relatively close to the coast to allow carbon emissions from the reforming process to be easily piped offshore for storage. They must also be within range of hydrogen storage facilities. The resulting geographical constraint means hydrogen will need to be transported over a relatively long distance under a high pressure, to move it between production facilities, storage facilities and end users. This means that a short hydrogen transmission network - at a pressure above 30 bar - will probably be needed.

[208] Frontier Economics for BEIS (2018), Market and regulatory frameworks for a low carbon gas system

Siting of hydrogen production facilities will depend on whether hydrogen or carbon dioxide is easier and cheaper to transport.

Furthermore, some new higher pressure hydrogen pipes would need to be built on the GDN to move hydrogen from the hydrogen production facility at a pressure of between 7 and 30 bar to the hydrogen-compatible lower pressure distribution system below 7 bar.

Figure 5: Hydrogen Transmission Using Hydrogen from Electrolysis



Electrolysis using on- and off-shore wind can provide decentralised hydrogen production close to renewable energy hotspots.

Wind turbines can power electrolysers to generate hydrogen, with particular potential in the UK from large offshore wind farms. Electricity from offshore wind can either be transmitted onshore to electrolysers via long distance cables; or it can be used to generate hydrogen from electrolysers offshore, pumping the hydrogen back to shore via a hydrogen transmission network. Over 80km, it may become more cost effective to pump hydrogen to shore - particularly if nearby natural gas infrastructure can be used.[209]

Since wind generation is intermittent, as much as three times more hydrogen storage is needed for periods of peak demand if only hydrogen from offshore wind is used, compared to hydrogen from methane reforming.[210] Production of hydrogen from wind powered electrolysis is also currently twice as expensive as that of reforming hydrogen. This is therefore an option to consider expanding in the future, when costs have reduced, or in areas with high wind capacity, such as Scotland, supported by baseline hydrogen production from natural gas.

As covered in Chapter 4, electrolysers may also be useful for providing on-site hydrogen for transport or heavy industry. In this scenario, electrolysers would not feed into a transmission system but would instead be delivered straight to end-users.

[209] World Energy Council Netherlands (2017), Bringing north sea energy ashore efficiently
[210] Statoil presentation to BEIS (2017), Clean Hydrogen for Heat

7. Carbon capture and storage

FINDINGS

19. Carbon Capture and Storage (CCS) is key in producing low carbon hydrogen from methane reforming; and important in meeting our national and international commitments limiting global temperature rise. Early projects for CCS with hydrogen/biogas which are incentivised now could support the Clean Growth Strategy ambition of deploying CCS at scale during the 2030s.

20. The UK has enormous carbon dioxide storage capacity offshore due to naturally occurring geological features. There are good opportunities to take advantage of this emerging market and to assume a leadership position in offshore storage.

21. CCS projects are likely to require significant government action to get early demonstration projects off the ground.

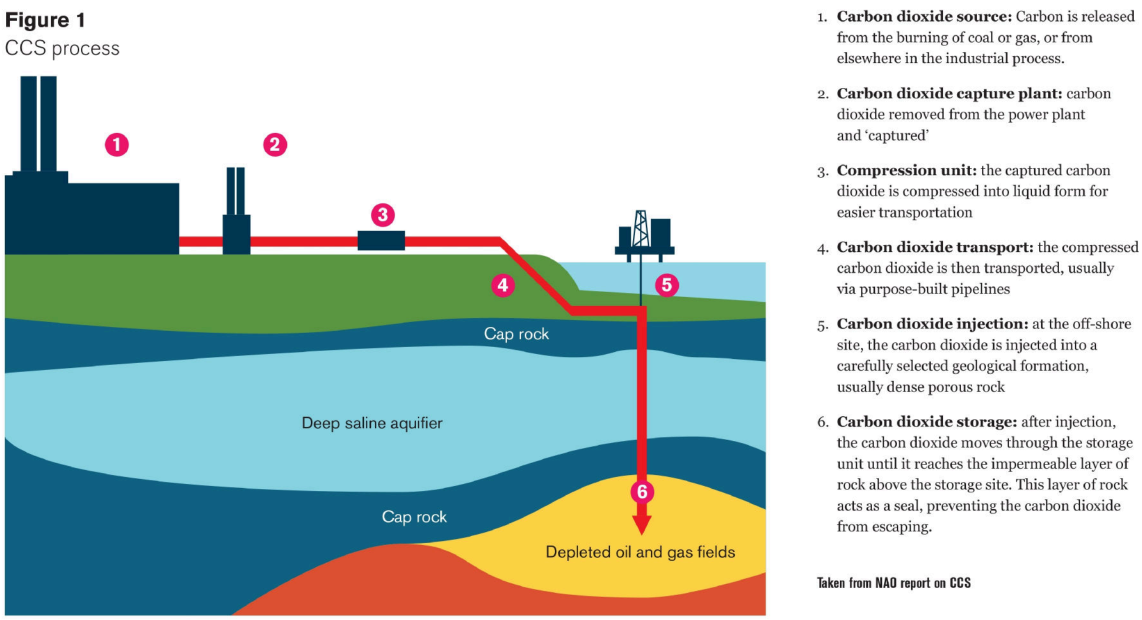
22. Carbon Capture and Utilisation could provide an early stage economic incentive to develop carbon capture infrastructure but it has limited climate change mitigation potential or large scale carbon capture potential.

7.1 Overview - Carbon Capture and Storage (CCS)

CCS is the process of capturing emissions of carbon dioxide, transporting it, and permanently sequestering it in order to avoid these emissions contributing to climate change.

Figure 6: CCS Storage

CCS?



Taken from NAO report on CCS

Why does CCS matter?

Without CCS, natural gas must be largely removed from the UK energy system by 2050.[211] Most heat decarbonisation routes rely on natural gas and therefore CCS to some extent, but CCS is particularly critical for producing low carbon hydrogen for heat, because emissions from the production of hydrogen from natural gas without CCS entails net greenhouse gas emission *increases*, not reductions.

CCS also has a wider importance beyond heat decarbonisation. The Committee on Climate Change (CCC) has argued the UK government should not plan to meet the national decarbonisation 2050 target without CCS,[212] as a strategy including CCS on industry, bioenergy and potentially some form of fossil generation offers the most cost-effective way to reduce national emissions. It is also currently one of the few viable ways for energy intensive industries - such as steel and cement - to decarbonise.

In order for hydrogen to deliver a meaningful contribution towards low carbon heat in the 2030s, this inquiry heard that 1 or 2 strategic CCS transport and storage hubs capable of storing several megatons of carbon dioxide per year must be in place during the 2020s. The Clean Growth Strategy aims to "*deploy CCUS at scale during the 2030s, subject to costs coming down sufficiently*".[213] However, the cost of CCS is expected to come down with deployment, and early projects will also need a number of years to develop. Early projects which are incentivised now can support the ambition of carbon capture utilisation and storage (CCUS) at scale during the 2030s.

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[211] McGlade et al. (2018), The future role of natural gas in the UK
[212] CCC (2018), An independent assessment of the UK's Clean Growth Strategy: from ambition to action
[213] BEIS (2018), Clean Growth Strategy. Available at: https://www.gov.uk/government/publications/clean-growth-strategy

Finding 19

Carbon Capture and Storage (CCS) is key in producing low carbon hydrogen from methane reforming; and important in meeting our national and international commitments limiting global temperature rise. Early projects for CCS with hydrogen/biogas which are incentivised now could support the Clean Growth Strategy ambition of deploying CCS at scale during the 2030s.

How much does CCS cost?

Carbon dioxide capture is already practised at industrial scale, so the costs associated with this are fairly certain. The full chain commercial transport and storage of carbon dioxide, on the other hand, is less well established, so costs are more unclear. These costs are explored in more detail below. It is important to note that it is generally agreed that while costs per tonne of carbon dioxide stored may be high in early projects, prices will come down as the technology develops and economies of scale can be guaranteed. The cost of inaction on CCS for the UK is estimated to be £1-2bn per year in the 2020s, rising to £4-5bn per year in the 2040s.[214]

Carbon capture technology cost

Carbon capture from the product gas of methane reforming is already widely deployed, with the captured carbon utilised to supply a global market for use in industry, chemicals and oil recovery'. Generally, the addition of CCS to an SMR plant increases the total capital cost of a plant by between £35-145m[215] on top of a base SMR plant cost of £150m, depending on the type of capture technology employed and the percentage of carbon captured. Most of this extra capital is due to the additional carbon dioxide capture and compression plant. Averaged across various studies CCS may add about 30% to the cost of SMR, taking it from around £315/kW to £415/kW, which would be a levelised hydrogen production cost of between 2-5p/kWh.[216]

Carbon dioxide transport and storage cost

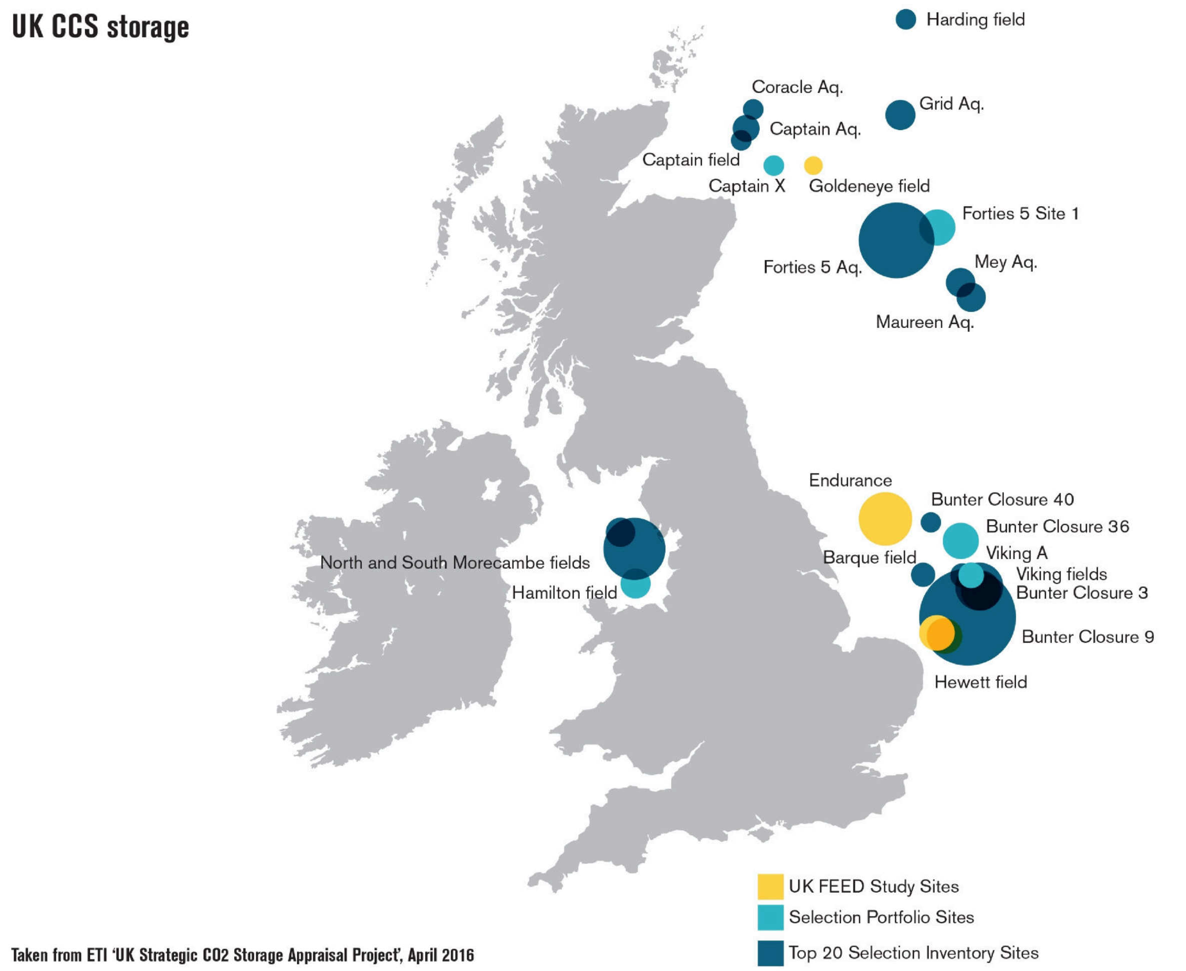
- **Initial investment includes Front End Engineering Design (FEED) studies, sites appraisal and the development of initial transmission network from an early stage hydrogen hub.** The cost of initial investment rises in line with the size of the project, and depends on whether the carbon storage facility has already been appraised or used previously. HyNet suggests £121m[217] will be needed for the carbon dioxide transport and storage infrastructure in their proposed hydrogen distribution system in the Northwest of England. The Committee on Climate Change, meanwhile, suggested the cost of developing and building initial transmission and storage infrastructure for an early hydrogen hub might cost £600m, including FEED studies on potential sites.[218] Another report suggests £200-300m is needed just for site appraisal and FEED studies on potential hub sites.[219]
- **Costs of building the whole infrastructure include the cost of building the transmission and storage network, operating costs over its lifetime, and decommissioning costs.** Various assessments found that the lifecycle cost for offshore transportation and storage of a significant carbon dioxide storage volume (60-300Mt) would range from £166-288m.[220] This is a levelised cost of storage - excluding capture, compression and onshore transport - of carbon dioxide of £12-18 per tonne;[221] although this inquiry heard that current estimates for the CCS in North England could be as low as £10 per tonne.

How much can we store?

The UK has a large carbon dioxide storage capacity of around 78 billion tonnes - about 30% of EU storage capacity for carbon.[222] About 7 billion tonnes of this is currently technically feasible and economically reasonable. The large storage capacity in the UK puts it in a good position to be an early adopter of CCS technology, and also - given the UK's expertise and experience in offshore drilling - offers the opportunity to take advantage of an emerging market in storing carbon.

[214] A strategic approach to carbon capture and storage: letter to DECC Secretary of State (2016) Committee on Climate Change
[215] IEAGHG Technical Report (2017), Techno-economic evaluation of SMR based standalone merchant hydrogen plant with CCS
[216] Speirs et al. (2017), A greener gas grid: what are the options?
[217] Cadent (2018), HyNet North-West: From Vision to Reality
[218] Committee on Climate Change Letter to Amber Rudd MP (2016) A Strategic Approach to Carbon Capture and Storage
[219] Parliamentary Advisory group on CCS (2016) Lowest cost decarbonisation for the UK: the critical role of CCS
[220] Pale Blue Dot (2016), Progressing the Development of the UK's Strategic Carbon Dioxide Storage Resource
[221] Ibid 219
[222] Ibid 219

Figure 7: Map of Possible UK CCS Sites



Taken from ETI 'UK Strategic CO2 Storage Appraisal Project', April 2016

Finding 20

The UK has enormous carbon dioxide storage capacity offshore due to naturally occurring geological features. There are good opportunities to take advantage of this emerging market and to assume a leadership position in offshore storage.

7.2 Key policy challenges

The Clean Growth Strategy sets out plans to invest up to £100m in CCUS technologies - although this is only a tenth of the £1bn CCS competition that was cancelled in late-2015. The Government has also established a CCUS Cost Challenge Taskforce to provide advice on the steps needed to reduce the cost of deploying CCUS. The Taskforce will report in summer 2018, and will inform the Government's CCUS Deployment Pathway, due by the end of the year.

CCS has struggled to develop in the UK, although the technology is mature. It is difficult to fund CCS as there is currently no proven business model for full-chain CCS in the UK. For private investment in CCS to come forward, appropriate financial mechanisms need to be in place that can enable a return on investment in transport and storage, and incentivise carbon dioxide capture in a variety of sectors. Some policy considerations which may help to develop CCS into a part of the national infrastructure are explored below.

Low carbon heat, power and CCS strategy development

CCS works most efficiently on a non-variable energy conversion process generating a pure stream of carbon dioxide at high pressure. Natural gas reforming can provide these conditions. Therefore, putting CCS on a hydrogen production facility and then burning the resulting hydrogen in dispatchable power stations is one way to provide low carbon flexible electricity.[223] Furthermore, using hydrogen to decarbonise heat is an efficient use of carbon transmission and storage infrastructure in terms of £CO_2 stored/kWh.[224] Therefore, hydrogen with CCS could provide a source of both low carbon dispatchable electricity generation and low carbon heat. This means that it makes sense for the strategy for decarbonising heat and power and the strategy for CCS to be developed in one coherent plan.

The role of the public and private sector in CCS

Decisions on how risk in early CCS projects is allocated between private and public entities must be made as soon as possible. The Oxburgh report suggested that the government should set up a state-owned, CCS Delivery Company. This would comprise of a power company and a transport and storage company, which would underwrite the risks of building transmission and storage infrastructure, take the long term carbon dioxide storage liability and provide funding for initial projects. Either company could later be privatised. Another report recently set out four business cases for CCS transmission and storage infrastructure, which included both public and private ownership.[225] These models will feed into the government's CCUS Deployment Pathway.

Scale of demand and policy certainty

Evidence for this report - and on-going work on hydrogen hubs such as HyNet[226] - suggests that committing to a hydrogen heat scenario would provide the scale required to underpin widespread CCS deployment, including the construction of transport and storage infrastructure. Economies of scale, when combined with appropriate treatment of long-term storage liability, minimises the cost and therefore the level of government support required. Long term policy certainty and scale of demand which is large enough to make CCS assets economical are therefore necessary in a successful CCS roll-out.

Get started with early projects

Early projects will provide evidence for policymakers and certainty for industry, so they should be supported in order to drive the cost reduction needed to deploy CCS at scale in the 2030's.

Finding 21

CCS projects are likely to require significant government action to get early demonstration projects off the ground.

Carbon Capture and Utilisation (CCU)

CCU refers to the capture of carbon dioxide from industrial processes, and its subsequent use in enhanced oil recovery or in the creation of materials and chemicals. While CCU could help to develop a market for carbon, which may help to stimulate early carbon capture, it is too small a market to mitigate any significant amount of carbon. Furthermore, much of the carbon still ends up in the atmosphere at a later date. It should not be considered as a long term climate mitigation strategy.

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223 Equinor (2018), available at https://www.equinor.com/en/news/evaluating-conversion-natural-gas-hydrogen.html
224 Sadler et al (2016), H21 Leeds City Gate Report
225 Pale Blue Dot for BEIS (2018), Carbon Dioxide Transmission and Storage Business Models: summary report
226 Cadent (2018), HyNet North-West: From Vision to Reality

What uses are available?

Carbon dioxide feedstocks have a wide variety of uses, including as a carbonating agent in drinks; to generate chemicals such as methanol, dimethylchlorine (DMC), and formic acid; to generate mineral carbonates such as magnesium carbonate; and in Enhanced Oil Recovery (EOR), whereby oil which is difficult to extract is released by mixing with liquid carbon dioxide, after which some of the carbon dioxide can then be permanently sequestered. Despite this wide range of uses, careful consideration needs to be given to the energetic and economic requirements of using carbon dioxide as a feedstock, compared to conventional feedstock options.[227] EOR presents the most economically promising option for CCU, having been used commercially for 40 years in onshore oil reserves in the US. One of the only commercial SMR with CCS plants, in Texas, uses the captured carbon in EOR.[228] In the UK, oil exploitation is mainly offshore, which means EOR costs will be substantially higher than in the US. Furthermore, EOR increases fossil fuel exploitation; robust regulation would be needed to ensure it stores more CO_2 than is released from the use of additional oil to make it useful from a climate mitigation perspective.

How much can we reuse?

The quantity of carbon which needs to be removed from the system is much higher than any carbon reuse market can absorb.[229] Evidence for this report put global market demand for carbon dioxide at 150-250 Mt per year, two orders of magnitude less than the 36 Gt[230] produced in 2017 globally. It is therefore highly unlikely that CCU will provide more than 1% of the global mitigation efforts, or between 4-8% if global scaled-up EOR is included.[231] CCS, on the other hand, was estimated to contribute up to 40% of the mitigation effort. CCU, therefore, will only provide a niche option in future climate change mitigation.

How green is it?

The environmental impact of CCU depends on what it is being used for. For example, utilising carbon dioxide for production of DMC can reduce the global warming potential (GWP) by 4.3 times compared to the conventional process; while EOR has a GWP 2.3 times lower than releasing carbon dioxide to the atmosphere.[232] On average, CCS reduces the global warming potential of processes more than CCU. This is partially because the carbon in products created from CCU are often then returned to the system after use anyway - and partially because using captured carbon decreases the overall efficiency of processes. Therefore, while CCU could be considered to incentivise the early building of CCS infrastructure, it should not be considered as a long term climate change mitigation strategy.

Finding 22

Carbon Capture and Utilisation could provide an early stage economic incentive to develop carbon capture infrastructure but it has limited climate change mitigation potential or large scale carbon sequestration potential.

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227 Journal of CO2 Utilisation (2015), Carbon Capture, storage and utilisation technologies: a critical analysis and comparison of their life cycle environmental impacts

228 MIT (2016), Port Arthur Fact Sheet: Carbon Dioxide Capture and Storage Project. Available at: https://sequestration.mit.edu/tools/projects/port_arthur.html

229 Parliamentary Advisory group on CCS (2016), Lowest cost decarbonisation for the UK: the critical role of CCS

230 Carbon Brief Analysis, available at https://www.carbonbrief.org/analysis-global-co2-emissions-set-to-rise-2-percent-in-2017-following-three-year-plateau

231 Nature Climate Change (2017), The role of CCU in mitigating climate change

232 Journal of CO2 Utilisation (2015), Carbon capture, storage and utilisation technologies: a critical analysis and comparison of their life cycle environmental impacts

8. Markets for low-carbon gas

FINDINGS

23. The UK is well-placed to be a global leader in low carbon gases, with extensive expertise in innovation in this area to date.

24. Low carbon gases will need some type of support to reach commercial maturity. There is a range of potential mechanisms that could be used to provide this. Regardless of which mechanism is chosen, launching demonstration projects and developing an enabling framework that both incentivises low carbon gas use and rewards its production will be important in growing a market for low carbon gas.

25. If the government seeks to further develop low carbon gas as a decarbonisation route, a decision must be made on whether to only support low carbon methods of production from the outset, or whether for pragmatic reasons, the government might initially support higher carbon production routes for early projects.

8.1 Market for low carbon biogases

Methane is already a traded commodity in the UK, so biogases such as biomethane and BioSNG already have a potential domestic market, most obviously through injection to the gas grid. Low carbon methane is currently more expensive than natural gas, and therefore requires a subsidy, obligation or incentive to allow it to compete. Some of these policy levers are explored in more detail later on in this section and in Chapters 1 and 2. In areas where low carbon biomethane is cost competitive with conventional fuels, there has already been growth: for example, sites dispensing low carbon compressed natural gas to HGVs have seen demand triple from 2017 to 2018, and has resulted in a 84% drop in emissions compared to the equivalent diesel vehicles.[233]

8.2 Markets for low carbon hydrogen

What demand for hydrogen will there be in the future?

The future demand for hydrogen depends on how different decarbonisation pathways are developed, as well as assumptions around efficiency gains and overall demand reduction. However, it is clear from estimates in the literature (see Table 8) that as much as several hundred TWh of hydrogen may be needed if hydrogen is adopted as the energy vector of choice in both heating and transport.

[233] Element Energy for Cadent (2017), Independent assessment of the benefits of supplying gas for road transport from the local transmission system

Table 8: Future Hydrogen Demand, from Selected UK-wide Studies

Description of 2050 Scenario	TWh	Source
30% of total gas demand met by hydrogen in 2050	154TWh	Frontier Economics/CCC Scenario 4 – Regional, 'Future Regulation of the gas grid', 2016
38% of industrial demand, 94% of domestic and commercial heating and 60% of cars are fuelled by hydrogen by 2050	176TWh	Aqua Consultants, 'Liverpool Manchester Hub', 2017
75% of total gas demand met by hydrogen in 2050 with 253 cities converted to hydrogen	587TWh	Frontier Economics/CCC Scenario 3 – National, 'Future regulation of the gas grid', 2016
62% of homes, 32% of industry, 56% of business and public sector heated by hydrogen by 2050. All cars and vans fuelled by hydrogen	700TWh	Clean Growth Strategy, Pathway 2 – Hydrogen, 2017

On an international scale, at the high end of estimates, hydrogen could have the potential to meet 18% of the world's energy demand by 2050,[234] which corresponds to over 55,000 TWh per year.

Current international market for hydrogen

Hydrogen is already a large market, valued at £115 billion USD in 2017 and forecast to grow to £154 billion USD by 2022.[235] Hydrogen is mainly used in the chemicals sector, but it has a growing application in the domestic sector: Japan in particular is strong in this area, with 180,000 homes heated by a fuel cell in 2017, and a target for 40,000 hydrogen fuel cell vehicles by 2020.[236] Both Norway and Australia are looking to export hydrogen produced by electrolysis to Asia, exploiting their naturally extensive renewable energy resources.[237]

The UK may import hydrogen as it does for natural gas. A recent report for BEIS set out a hydrogen scenario in which the UK imports 40% of its hydrogen from an international market.[238] However, an international market for hydrogen is still difficult to predict, and this inquiry heard that widespread international trade of hydrogen is unlikely before the 2030s. Nevertheless, given that the UK is currently a global leader in hydrogen production, with many firms experienced in innovation in hydrogen as an energy vector, there is significant potential for the UK to export skills, knowledge and technology in the clean hydrogen market in the future.[239]

Finding 23

The UK is well-placed to be a global leader in low carbon gases, with extensive expertise in innovation in this area to date.

[234] Hydrogen Council (2017), Hydrogen: a sustainable pathway for a global transition
[235] IEA Hydrogen (2017), Global Trends and Outlooks for hydrogen
[236] Hydrogen and Fuel Cell Research Hub (2017), The role of Hydrogen and fuel cells in future energy systems
[237] Energy Research Partnership (2016), Potential Role of hydrogen in the UK energy system
[238] Frontier Economics (2018), Market and regulatory frameworks for a low carbon gas system: a report for BEIS
[239] Ibid 236

8.3 Policy options in developing a market for low carbon gas

Possible government support mechanisms

Without an effective carbon price on gas use in heat and transport, low carbon gases will generally struggle to compete with fossil fuel cost-wise. There are a number of options for how the government can intervene if it wishes to support the production of low carbon gases, summarised in Table 9 below.

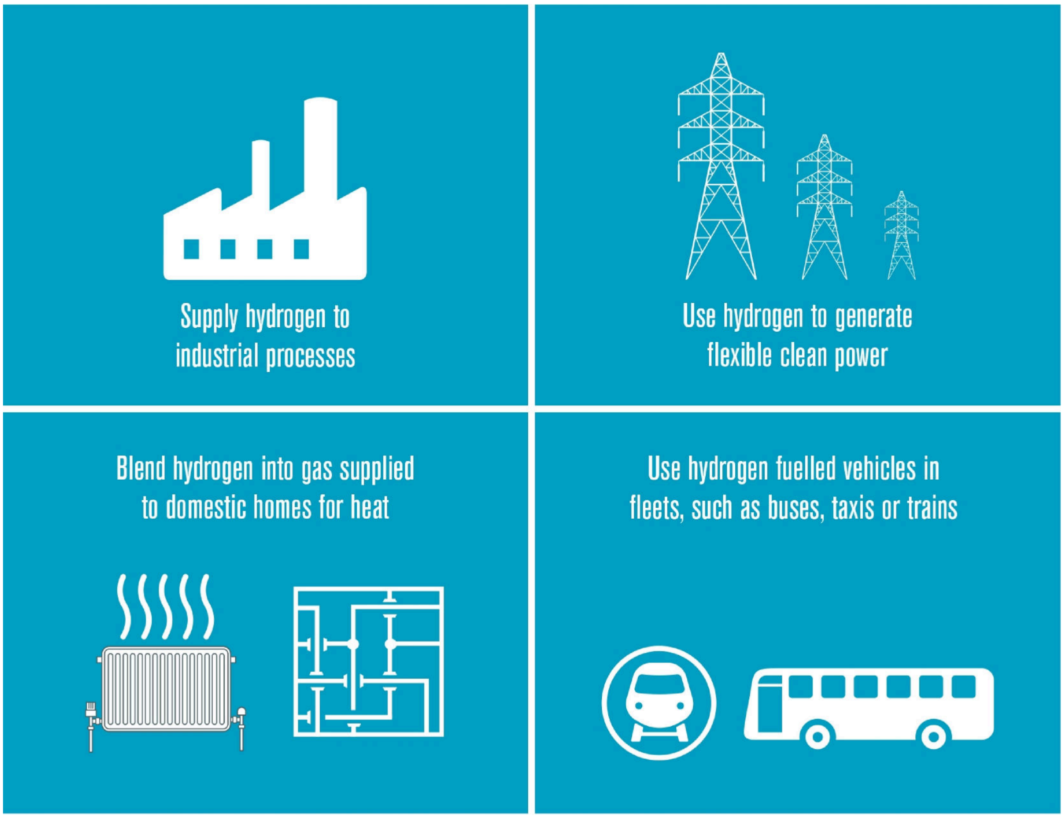
Table 9: Policy Mechanisms to Facilitate a Transition to Low Carbon Gases

Policy lever	Explanation
Obligation	The Government has successfully imposed obligations on industry in the past to achieve positive environmental outcomes. This has been used recently in the Renewable Obligation, where electricity suppliers were obliged to provide a certain proportion of electricity from renewable sources and in the Renewable Transport Fuel Obligation, where suppliers are obliged to provide a certain proportion of fuel from renewable sources.
Taxes and Contracts	The Government can use taxation to encourage or discourage behaviours, and also may enter into direct contracts with businesses to achieve desired outcomes. This has been used recently in Contract for Difference mechanisms to encourage the construction of low carbon electricity generation; and in the Carbon Price Support Mechanism, which effectively taxes fossil fuel use for electricity generation.
Incentives	The Government can make available capital and revenue support to business and individuals to incentivise the adoption of new, sustainable technologies, processes or behaviours. This has been used recently in Feed in Tariffs, where those with renewable energy generation technologies are rewarded per unit exported; and the Renewable Heat Incentive, where those who install renewable heating systems are rewarded for the green heat they generate.
Grants and Funds	Government can also award a particular sum of money to encourage and develop specific low carbon processes and technologies, both in Research and Development, and in commercialisation. This has been used recently in the Renewable Energy Innovation fund, and the Hydrogen Supply Competition.
Regulation and legislation	Regulation and legislation can be used to drive change and can lead to very effective changes in environmental performance. Examples include the Clean Air Act in 1993, which banned the use of coal for heating in urban areas; and in the Boiler Plus legislation in 2018, which has made it compulsory to have highly efficient boilers.

Developing a domestic hydrogen market

All low carbon gases will require some form of government intervention to compete with fossil fuels, but there is a particular issue with incentivising hydrogen production, since it cannot currently be used directly in the gas grid or in industry in the same way that biomethane and BioSNG can. In order to deploy hydrogen production in the UK it will be necessary to develop a market for its use. This requires building up levels of both supply and demand of hydrogen. There are various practical options which the government could take to do this, which are summarised below. Whichever the government chooses, an enabling market framework that both incentivises the use of low carbon gas and rewards its production will be important.

Figure 8: Practical Routes to Develop a Domestic Hydrogen Market



Supply hydrogen into gas supplied to industry

Supplying energy intensive industries - such as chemical, steel and glass making - with sustainable hydrogen lowers their carbon emissions. Modelling suggests that a blend of 60-100% hydrogen to industries in the Manchester and Liverpool region would have relatively small costs of conversion of furnaces or boilers - about £7.8m per industrial site.[240]

Use hydrogen to generate dispatchable clean power

Electricity from a hydrogen turbine could deliver dispatchable electricity. Evidence for this report heard that hydrogen electricity could be delivered at a price below £92/MWh: the strike price for Hinckley Point C nuclear plant, although this is not yet confirmed. Hydrogen production from methane reforming could also make more efficient use of CCS infrastructure than a corresponding Combined Cycle Gas Turbine.

Blend hydrogen into gas supplied to domestic homes for heat

Research is currently trailing whether it is feasible and safe to blend hydrogen into the current distribution system by up to 20% by volume (6% by energy) to supply domestic and commercial properties.[241] Should this work prove conclusive, this could prove a useful large scale option to develop a hydrogen market. There is currently no incentive for the use of hydrogen in heat.

Use hydrogen fuelled vehicles in fleets

Hydrogen fuel buses are already operating, with 83 across Europe, and fleets in London and Aberdeen. Rolling out other public sector fleets of hydrogen vehicles - including taxis, school buses and police cars - could be a practical way to build up a baseline demand for hydrogen. This could further be expanded to the fleets of private companies, which may include fleets of vans and HGVs.

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[240] Cadent (2018), HyNet Northwest: from vision to reality

[241] HyDeploy (2018), About HyDeploy. Available at: https://hydeploy.co.uk/about/

Finding 24

Low carbon gases will need some type of support to reach commercial maturity. There is a range of potential mechanisms that could be used to provide this. Regardless of which mechanism is chosen, launching demonstration projects and developing an enabling framework that both incentivises low carbon gas use and rewards its production will be important in growing a market for low carbon gas.

Set up robust standards for low carbon gases

Low carbon gases can only be sustainable if the feedstocks and production methods are sustainable, so a way to certify the origins of low carbon gases is important. This requires that robust methodologies to measure the carbon intensity of these gases are established early on and harmonised across all sectors. Biogases already have a certification scheme in the UK,[242] while an EU wide project, CertifHy,[243] has recently launched the first green hydrogen guarantee of origins scheme for use across Europe.

This raises a wider point. If further policies are enacted to encourage the production of low carbon gases, a decision will need to be made on how low carbon these gases are required to be from the outset. There may be reasons for providing initial policy support to forms of gas produced in a way that has minimal carbon benefit, such as in expectation of carbon capture and storage being added at a later date. However, this then runs the risk of providing support for supposedly 'green' technologies which make minimal or no contributions to the UK's climate change objectives.

Finding 25

If the government seeks to further develop low carbon gas as a decarbonisation route, a decision must be made on whether to only support low carbon methods of production from the outset, or whether for pragmatic reasons, the government might initially support higher carbon production routes for early projects.

[242] Green Gas Certification Scheme (2018), The Green Gas Certification Scheme. Available at: https://www.greengas.org.uk/
[243] Certifhy (2018), The 1st Green Hydrogen Guarantee of Origins are on the market soon. Available at: http://www.certifhy.eu/news-events/162-the-1st-green-hydrogen-guarantee-of-origins-are-on-the-market.html

Methodology and Steering Group

Carbon Connect carried out this inquiry between November 2017 and June 2018. Evidence was gathered by a series of evidence gathering sessions held between December 2017 and April 2018, interviews, written submissions, desk-based research and input from our Steering Group of experts. The views in this report are those of the authors. Whilst they were informed by the Steering Group and listed contributors, they do not necessarily reflect the opinions of these individuals and organisations.

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With many thanks to **Keith MacLean** who acted as special advisor to this inquiry.

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About Carbon Connect

Carbon Connect is the independent, cross-party forum that seeks to inform and guide a low carbon transformation underpinned by sustainable energy.

In 2009 the Rt Hon Ed Miliband MP, then Secretary of State for Energy and Climate Change, delivered a keynote address at the Westminster launch of Carbon Connect. Since then Carbon Connect has been at the forefront of policy debate, parliamentary engagement and research related to sustainable energy.

Over a number of years, Carbon Connect has built up an unrivalled portfolio of parliamentary roundtables and conferences, detailed policy briefings and highly respected reports. This has been achieved by drawing on the expertise of Carbon Connect members and working with a wide range of parliamentarians, civil servants, business leaders and experts who give their time and expertise to support our work.

Carbon Connect's main activities comprise facilitating discussion between industry, academia and policymakers on low carbon energy and producing its own research and briefings in this area. We do this by:

- Holding regular events and seminars in Parliament
- Producing concise briefing papers on energy and climate change policy
- Publishing research reports with evidence-based recommendations for policymakers
- Disseminating updates to parliamentarians and our members, with summaries of relevant stories, industry news, and other political developments

About Policy Connect

Policy Connect is a cross-party think tank improving people's lives by influencing policy. We collaborate with Government and Parliament, through our APPGs, and across the public, private and third sectors to develop our policy ideas. We work in health; education & skills; industry, technology & innovation, and sustainability policy.

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