Fuelling the Future

Policy Exchange

Hydrogen's role in supporting the low-carbon economy

Joshua Burke and Matt Rooney

Foreword by Ben Houchen, Mayor of the Tees Valley

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Policy Exchange

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Foreword

by Ben Houchen

Hydrogen has been used industrially for generations, but a new era presents us with new opportunities.

We face the challenges of decarbonisation, energy security and availability of natural resources. At the same time governments must consider the impact of policy on prices and people's lives. Hydrogen offers part of the solution. It can play a leading role in heating and powering our lives and can reduce the environmental impact of doing so.

Tees Valley currently produces 50% of the UK's hydrogen. We have a strong base from which we can do more. As policy develops we need informed debate. It is important to understand the wide range of opportunities, from home heating to fuel cell vehicles, and to carefully consider how best to pursue them. Hydrogen must be considered in context. The context of industrial by-product, carbon capture and storage technology and developing future solutions to the challenges of today.

The UK is well placed to be a world leader. We have strong clusters of relevant industry and production. We have a significant domestic demand and the potential to meet it. We should grasp the opportunities that the hydrogen economy represents.

This report sets out some of the challenges, as well as the opportunities. I want the UK, and Tees Valley, to lead the way in developing the hydrogen economy, creating jobs and reducing environmental impact. Informed debate is needed as we set off down this path. It seems likely hydrogen will be an even larger part of our future than it has our past. It is right that we plan for it now.

Ben Houchen is Mayor of the Tees Valley

Glossary of Terms

Term	Definition
BEV	**Battery Electric Vehicle**
Biofuels	A range of fuels produced from various types of organic matter, including wood, crops, food waste and algae.
Biomass Gasification	A process that converts organic carbonaceous materials into carbon monoxide, hydrogen and carbon dioxide through reacting the materials at high temperatures (over 700oC) without combustion.
CCS	Carbon Capture and Storage: An emissions reduction process which involves capturing the CO2 produced by industry, and permanently storing it in a secure location underground.
Coal Gasification	A process in which coal is heated in absence of oxygen to produce a synthetic gas.
CO_2	Carbon Dioxide (CO_2) is the main greenhouse gas. The vast majority of CO_2 emissions come from the burning of greenhouse gasses and their relative effect on climate change compared to carbon dioxide.
CO_2e	Carbon Dioxide equivalent: A term used to account for the 'basket' of greenhouse gases and their relative effect on climate change compared to carbon dioxide.
DNO	Distribution Network Operator: Regulated Companies which own and operate the 14 regional distribution networks across Great Britain.
Electrolysis	The process of using electricity to split water into its chemical components; Hydrogen and Oxygen.
FCEV	Fuel Cell Electric Vehicle: An electric vehicle that is propelled by an electric motor using a hydrogen fuel cell as a source of electricity, rather than a battery.
Feedstock	The bulk raw material used to supply or power a machine or an industrial process.
Hydrogen	A clear, odourless gas which is highly flammable, the most common element in the universe which can be used as a low emission alternative fuel source.
Hydrogen Economy	A vision of using hydrogen as an alternative low carbon energy carrier that can be used as a replacement in transport, heating fuel and also storage.
GW	Gigawatt: A measure of electrical output. One GW equals 1,000,000 kW.
NOx	Nitrogen Oxides: A group of gaseous pollutants comprised of nitrogen and oxygen that are found in vehicle exhaust fumes as well as other sources. They can be harmful to human health if found in large enough concentrations in the air.
Ofgem	The Government regulator for gas and electricity markets in Great Britain.
PM	Particulate Matter: Small particles that come from a range of sources, including transport, and that can be harmful to human health when inhaled.
PtG	Power-to-Gas: The conversion of surplus energy into a grid combustible gas. This surplus energy can produce hydrogen which can be mixed with natural gas and injected into the gas grid or in higher value markets such as hydrogen refuelling stations.
RIIO	Revenue=Incentives+Innovation+Outputs: Ofgem's performance-based framework which is used to set network price controls.

Term	Definition
SMR	Steam Methane Reformation: A process in which methane (from natural gas) is heated, along with steam and a catalyst, to produce a mixture of carbon monoxide and hydrogen which can be used in organic synthesis and as a fuel.
TWh	Terawatt-hour: A measure of electrical energy equivalent to the power consumption of one terawatt for one hour. One TWh equals 1,000,000,000 kWh.
ULEV	Ultra-Low-Emission-Vehicle: A motorised vehicle that produces extremely low levels of emissions in comparison to other vehicles.

Executive Summary

The 'hydrogen economy'

The concept of a 'hydrogen economy' has been put forward by proponents for many decades. In theory, this abundant element is a perfect solution to our clean energy needs. It does not produce greenhouse gases when burned, it can be stored in large quantities for long periods, and it can be used as a fuel in virtually every sector of our economy, from transport to heavy industry to home heating. Yet the potential of hydrogen has yet to be realised. Electric cars have begun to gain a foothold in the market while those powered by hydrogen fuel cells have stalled. In heavy industry, the lack of a serious carbon tax disincentivises the move to cleaner alternatives than coal and gas. And although hydrogen does not produce carbon dioxide when burned, the primary method of producing it, steam methane reformation, does.

So before this is a reality in the UK and globally, two high-level issues need addressing. Firstly, cost effective, scalable and sustainable production methods need to reach mass market and so targeting investment towards reducing the high cost of producing large volumes of low carbon hydrogen is crucial. Secondly, a comprehensive and systemic approach is essential to determine the most appropriate application(s) of hydrogen within the economy. This is because the different uses for hydrogen are likely to be highly interconnected and this will have implications for the energy system.

Despite these challenges, hydrogen has the potential to be a fuel of the future, particularly for cleaning up certain hard-to-decarbonise sectors of our economy. Although we may never end up living in the true 'hydrogen economy' that some optimists predicted, it can still play a key role in our energy transition.

Context

The UK has set ambitious targets to reduce greenhouse gas emissions by at least 80% (from the 1990 baseline) by 2050. Great progress has been made in the power sector, where increased deployment of wind and solar power, combined with almost a complete phase out of coal, has seen a faster decarbonisation of electricity generation than almost any other country in recent years. Progress in other sectors has been more mixed, and if the Government is to meet future legally binding emissions reduction targets, certain barriers to the clean energy transition need to be overcome. These include:

- decarbonising hard to reach sectors such as heat, transport and industry;
- finding ways to store large quantities of energy to act a as system buffer, a role that is currently mostly fulfilled by natural gas;
- integrating increasing amounts of variable renewable energy into the system

Projections of decarbonisation pathways have typically involved reducing dependence on natural gas through greater electrification of heat and transport. However, the gas network holds value in relation to flexibility of operation and enabling less expensive storage at scale[1] compared to electric heaters or pumps. Retaining and repurposing gas infrastructure to accommodate hydrogen or other sustainable biogases may be worthwhile, particularly as barriers to electrification of heat persist. Set against this context, the debate has often been framed as *either* electrification *or* 'greener' gases to achieve decarbonisation targets. Yet this polarisation presents a false dichotomy which could lead to policy paralysis. Transport is perhaps an exception where the choice is perhaps more binary. Within this overarching premise, the following report takes a systemic view of the potential of hydrogen to help overcome the challenges the UK faces when transitioning to a low carbon economy, recognising the importance of specific local circumstances relating to the electricity or gas grid, which will determine what mix of decarbonisation options are deployed.

Decarbonising hard to reach sectors and feedstocks

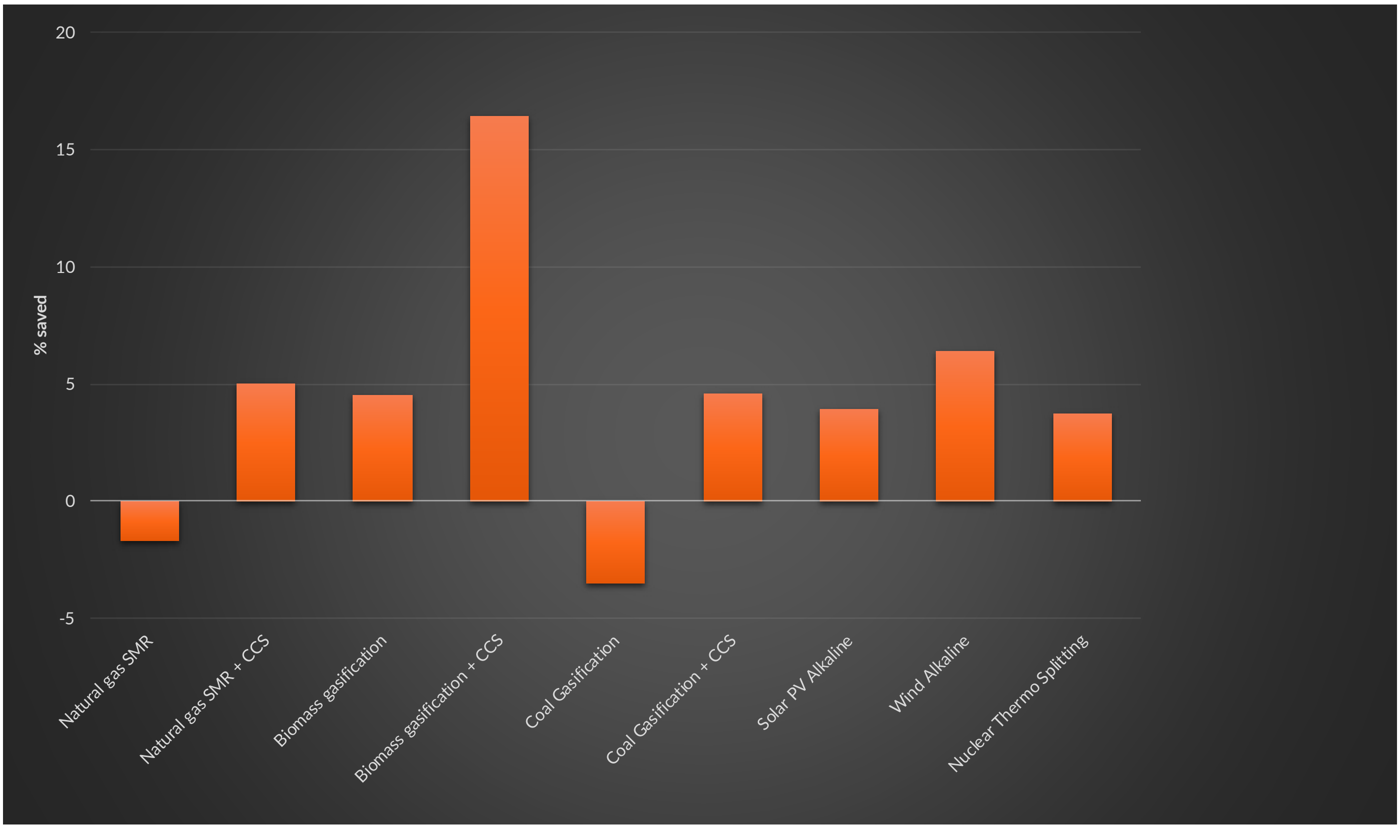
Domestic heating

A precautionary approach should be applied when assessing how hydrogen can be used to decarbonise domestic heating through replacing natural gas. Our analysis highlights three pressing questions that need addressing. **Firstly, will hydrogen blending deliver substantial carbon savings?** Different hydrogen models have emerged, ranging from 100% conversion to hydrogen to blending up to 20% (by volume) into the gas network. Our analysis illustrates that **blending up to 20% by volume still only delivers small carbon savings – ≈ 5%. This should therefore only serve as a starting point** as much higher blends are needed. It is also important to highlight that blending 20% of hydrogen in the gas networks using either steam methane (i.e. natural gas) reformation (SMR) or coal gasification without carbon capture and storage (CCS) will increase overall emissions by 1.7% and 3.4% respectively, as shown below in Figure ES1. **Production processes using fossil fuel feedstocks without CCS are therefore incompatible with domestic decarbonisation targets.** Clearly, the lack of CCS poses a significant barrier to clean hydrogen production.

Secondly, if higher blends are needed, is it possible to build the infrastructure in time? If hydrogen was to fully replace natural gas by 2050, with large scale production commencing in 2030, **this would require a minimum of 6GW of new hydrogen capacity to be built per**

1. Balcombe, P. et al. (2018). 'The Carbon Credentials of Hydrogen Gas Networks and Supply Chains'. Renewable and Sustainable Energy Reviews, Vol 91, Pages 1077-1088. https://www.sciencedirect.com/science/article/pii/S1364032118302983

Figure ES1: Gas network emissions savings from 20% hydrogen blend



year. To put this in to context, the installed capacity of wind (both offshore and onshore) grew at an average annual rate of 1.8GW from 2010-2017[2]. Installed hydrogen capacity would therefore have to grow **at a rate 3 times as fast as what has been witnessed in the wind sector,** and do so consistently for 20 years**. The third question is whether converting gas grids to run entirely on hydrogen is even possible in a liberalised market** since the previous conversion from town gas to natural gas – commensurate with the present-day challenge – occurred in a command and control economy**.** With the liberalisation reforms introduced by the Thatcher Government, the structure of the utility markets changed substantially and now includes different groups with disparate aims and objectives. Consequently, a coherent and unified vision sometimes struggles to emerge. **This represents a significant barrier to the future of gas decarbonisation unless roles and responsibilities are clearly co-ordinated**. Even If these questions can be sufficiently addressed, a system view may still suggest hydrogen may be better suited to applications other than decarbonising domestic heating. Until these questions are answered it is difficult to envision, or indeed advocate a widespread conversion of the gas grid to hydrogen. At this point the renewable heat incentive (RHI) and other inducements should not change to encourage hydrogen for heating until the best use of the resource is determined.

However, in the longer term, if hydrogen for heating is deemed an appropriate application and solutions to the scaling challenges are overcome, a support framework for hydrogen that is compatible with

2. DBEIS. (2018). 'Energy Trends'. https://www.gov.uk/government/collections/energy-trends

the overarching ambition of lowering the cost of decarbonising heat is potentially possible**.** This could be achieved if the Government broadens the scope of technologies that are eligible for support under the RHI to include hydrogen. In terms of abatement costs, renewable technologies eligible under the RHI (e.g. biomass, heat pumps) are more expensive than forms of hydrogen production such as steam methane reformation with carbon capture and storage (SMR + CCS). Hydrogen produced via SMR + CCS would deliver carbon savings at a quarter of the price of air source heat pumps and ground source heat pumps, whilst hydrogen produced from electrolysis would deliver carbon savings at approximately half the price. A support framework along these lines would ensure greater affordability to the taxpayer and make subsidies go further.

Industry

Despite industry reducing emissions by 49% from 1990-2017, there has been a recent stall in emissions reductions over the last five years, and in 2017 emissions rose by 1%. In the UK, final energy consumption in the industrial sector is dominated by electricity and natural gas. They account for 34% and 36% respectively. Switching these fuels to cleaner alternatives such as hydrogen could help to decarbonise industrial sectors. In 2016 emissions from natural gas used in industry amounted to just over 25 million tonnes. Our analysis illustrates that if natural gas was completely replaced by hydrogen, the emissions would drop by 71% if the hydrogen was produced by SMR with CCS or 91% if produced by wind power electrolysis. However, although fuel switching to hydrogen is a technically viable option and has the potential to decarbonise the iron and steel sectors in the long-term, at present production costs are currently 20 to 30% higher than normal steel production. Reducing these costs is therefore key and the Government should work with industry to understand how to produce steel using hydrogen from renewable electricity in a cost competitive way.

Analysis in this report suggests that Northern England and Scotland are advantageous for the development of decarbonised hydrogen production and CCS. In drawing this conclusion it is important to recognise that the UK is not homogenous in terms of its energy production or markets. Underpinning any decision to develop hydrogen production clusters should be an appreciation of the specific local economic or geographical circumstances. This should not just be based on a single factor such as prevailing industrial strength, but where a range of deployment opportunities exist. For example, wind curtailment clusters, grid constraints and the majority of onshore wind farms are almost exclusively located in Scotland. Moreover, the curtailment clusters have a broad correlation with areas that possess high-level strengths – such as advanced manufacturing and energy – and critical mass needed for innovation, as well as unique proximity to abundant geological storage under the Central North Sea and existing oil and gas infrastructure.[3] As such, **the UK Government should give consideration to developing regional support programmes**

3. Element Energy. (2014). *Scotland and the Central North Sea CCS Hub Study*. http://www.element-energy.co.uk/wordpress/wp-content/uploads/2014/06/Element-Energy-Scottish-CCS-Hub-Study-Revised-Final-Main-Report-310314c.pdf

capable of incentivising local investment based on their particular energy circumstances.[4] These factors point to a regional opportunity, not only for utilising curtailed and non-curtailed wind to establish electrolysis-based hydrogen production, but also for hydrogen production with CCS.

Transport

Transport is one of the sectors highlighted by the Committee on Climate Change that has made little progress in decarbonisation. In the last 20 years, emissions from road transport in the UK have remained virtually static as gains in energy efficiency have been offset by increasing road miles. There are, however, signs that this is set to change rapidly. The accelerating uptake of electric cars, kick-started by a suite of Government subsidies and tax-breaks, has allowed the electric car market to flourish. As shown in the 2017 Policy Exchange report *Driving Down Emissions*[5], economies of scale in the industry have brought down costs to the extent that light vehicles powered entirely by a battery are almost cost competitive with those power by an internal combustion engine on a total cost of ownership basis. Hydrogen vehicles in the light fleet market have been left behind and it is difficult to see how they will catch up any time soon. This does not mean that hydrogen cannot play a role in decarbonisation of the transport system. In fact, our analysis suggests that **hydrogen production is most scalable and cost effective when targeted towards the certain segments of the transport sector, such as heavy goods vehicles, buses, trains and potentially shipping.**

Hydrogen as a fuel has two distinct advantages over electricity – faster refuelling and higher energy density – that mean it should be able to find niche applications. Any business that values fast refuelling and/or must cover large distances may prefer hydrogen to electricity as a transport fuel. Hydrogen refuelling infrastructure could also be scaled up without the electricity grid upgrades that would be required if, for example, a large fleet operator wanted to go all electric.

In the short-to-medium term, hydrogen could fill the gaps less suited to battery electric vehicles. The greatest potential in the near future exists in replacing diesel HGVs, buses and trains with those powered by hydrogen fuel cells. To kick-start this process the Government should work with industry to develop the necessary refuelling infrastructure required to enable the road freight and trains to make the transition. This will enable an initial skeleton system of hydrogen refuelling stations to be rolled out, using taxpayer's money in an efficient way to develop a network that would be required to enable relevant sectors to switch to hydrogen. The Government should also continue to support local authorities in developing pilot programmes to support the roll-out of buses powered by hydrogen fuel cells.

4. Smith, M. J. et al. (2017) *The Economic Impact of Hydrogen and Fuel Cells in the UK: A Preliminary Assessment Based on Analysis of the Replacement of Refined Transport Fuels and Vehicles*. H2FCSUPERGEN. http://www.h2fcsupergen.com/download-economic-impact-hydrogen-fuel-cells-uk/
5. Howard, R. et al. (2017). *Driving Down Emissions: How to clean up road transport?* Policy Exchange. https://policyexchange.org.uk/wp-content/uploads/2017/06/Driving-down-emissions-How-to-clean-up-road-transport.pdf

Hydrogen's role in integrating renewable energy

As renewable generator penetration deepens, there is a need to explore how best to integrate that generation, which could include a role for hydrogen. The huge increase in renewable generation opens up potential for new business models that can provide services to address the system constraints that ensue. This includes services to balance supply and demand, store surplus energy and manage frequency and voltage levels. These are vital for the efficient integration of increasing amounts of intermittent generation.

Although these are relatively new challenges for the power system, they have profoundly altered the structure of electricity markets in Great Britain. Consequently, this has created a large market in 'ancillary services' – the name given to services and functions provided to, and procured by – the System Operator (SO) to manage system constraints created by intermittent generation. Power-to-gas (PtG) technology has potential to alleviate some of the problems associated with intermittent supply. PtG works by making use of surplus energy in order to produce a grid compatible gas, typically using wind power and electrolysers. It is important to note that electrolysis using surplus wind is often championed[6,7] because input costs for electrolysis (i.e. electricity) are high relative to gas used in methane reforming and so electrolysis could only work economically using 'spare' wind. While it is fashionable to posit electrolysis as the perfect way of using up surplus wind and solar power, this is probably wrong.[8]

Firstly, there is not that much surplus energy. Curtailed wind serves as a proxy for surplus wind energy. Curtailments can result when operators or utilities command wind and solar generators to reduce output to minimize transmission congestion.[9] In 2017 1.5TWh of wind was curtailed, representing 0.4% of total power demand. This amount of curtailment could **only produce enough hydrogen to replace <0.5% of natural gas used domestically. Curtailed wind cannot produce the volumes of hydrogen needed to make a substantial contribution to decarbonised gas production.** Even in the longer term if the curtailment levels reach a high level of 75TWh by 2050 and heat demand stays relatively constant, curtailed wind could only provide approximately 14% of the UK domestic heating load. Secondly, the problem with only using spare wind is that electrolysers can't run constantly. As this is a capital intensive industry with typically low margins, for electrolysers to be economical they need to have a high utilisation rate, so only using curtailed power – which is limited – is likely to be uneconomic**. Business models based solely on curtailed wind are therefore unlikely to be compatible with this type of capital intensive industry with low margins**. This is not to say that hydrogen production using wind power and electrolysis will not and should not expand, it's just unlikely this will be with curtailed wind alone. Indeed, operating a business model that combines revenues streams from both hydrogen sales and ancillary services could help to increase electrolyser utilisation – a key determinant of economic viability.

Although batteries dominate the flexibility markets, electrolysers have characteristics that could make them eligible to challenge in the

6. Troncoso, Enrique & Newborough, M. (2011). Electrolysers for mitigating wind curtailment and producing 'green' merchant hydrogen. *Fuel and Energy Abstracts*. 36. 120-134. 10.1016/j.ijhydene.2010.10.047.
7. M. Shujun, Z. You, Y. Ye, Z. Ding, L. Jin and S. Kai, "A curtailed wind power accommodation strategy based on wind-hydrogen-heat-storage integrated energy network," 2017 *Chinese Automation Congress (CAC)*, Jinan, 2017, pp. 6146-6150. doi: 10.1109/CAC.2017.8243884
8. Liebreich, M. (2018). 'Beyond Three Thirds, The Road to Deep Decarbonization', BloombergNEF. https://about.bnef.com/blog/liebreich-beyond-three-thirds-road-deep-decarbonization/
9. Bird, L., Cochran, J. and Wang, X. (2014). *Wind and Solar Energy Curtailment: Experience and Practices in the United States*. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy14osti/60983.pdf

future. For example, electrolysers have very fast response times which may enable them to provide frequency and voltage control**. Power-to-gas using electrolysers could also help facilitate higher penetrations of intermittent generation**. This is estimated to be 150MWh (Megawatt hours) per annum for every new MW of hydrogen production capacity. **Savings in the Levy Control Framework (LCF) and Contracts for Difference could also be made**. This is **estimated to be about £70,000 per year for every new MW of hydrogen production capacity**[10] – allowing more renewable generation to be supported through the LCF.

However, due to the falling costs of batteries and the high level of liquidity in the ancillary services market, ancillary service provision is extremely competitive. It is unlikely that electrolysers will be cost competitive in the short term, but the longer term potential remains. Consequently, given that production of hydrogen using electrolysis has the potential to achieve far greater cost reductions than other mature production technologies, the Government should consider targeted investment to reduce the cost of electrolysers, at the same time giving due regard to export opportunities for the technology as part of the industrial strategy.

Recommended policy approach

When examining the role hydrogen can play in facilitating the clean energy transition, Policy Exchange believe that a number of overarching principles should be followed:

1 Take a systems view.

The transition to a low carbon economy has significant technological and system challenges. It is important to fully understand that producing hydrogen as an alternative low carbon energy source – that can be used as a replacement in transport, heating fuel and also storage – has systems implications because these different uses for hydrogen are likely to be highly interconnected. **Assessing the role of hydrogen in isolation from the rest of the energy system may lead to biased inferences**. Although identifying the precise role of hydrogen is difficult, the regulatory model needs to be flexible enough to adapt to changes within the energy system, whilst still providing market and policy certainty. We recommend that Ofgem gives **long term policy visibility required for business planning**, **particularly for the next RIIO price control period (2021-2026).**

2 Support consumer preferences.

The Government needs to ensure that consumers remain at the heart of any strategy to integrate hydrogen intothe energy system. Some cities or regions will be better placed to initiate full conversion to hydrogen heating. Geographical conversions of this kind give rise to issues of governance pertaining to **consumer choice and rights.** For example, if a city decides to unilaterally switch the gas network from natural gas to hydrogen – and this results in higher bills (because hydrogen is 1.5-2x more expensive than natural gas) than neighbouring areas that haven't converted – to what

10. SSE. (2018). *RHyMES: Renewable Hydrogen Models for Energy Storage, Feasibility Study Final Report*

extent can households opt out of this? **The Government needs to develop a hydrogen strategy that takes in to account consumer preferences and does not unduly penalise households.** To this end, we reiterate our call for **Ofgem to provide clarity on the arrangements for the next RIIO (Revenue=Incentives+Innovation+Outputs) charging period, giving consideration as to how costs can be socialised in the most equitable way.**

3 Pursue cost effective solutions.

Given that energy costs are a key concern for households, the Government must focus on the lowest and most cost-effective technologies to decarbonise hard to reach sectors such as domestic heating. In the future, broadening the scope of technologies that are eligible for support under the RHI could minimise the burden on consumers and taxpayers compared to technologies currently supported. The Government needs to create a set of conditions which allows these technologies to compete on a level playing field, driving out the lowest cost routes to decarbonisation.

4 Combine quick wins with a long-term vision.

Quick wins that help to develop both supply and demand markets for hydrogen should be pursued. Examples include; removing regulatory barriers to hydrogen blending; setting 'standards' for green hydrogen and aligning them with Renewable Transport Fuel Obligation; continuing exemptions for hydrogen from fuel duty; and clarification on how investment in hydrogen funded under the RIIO price control mechanism is compatible with RIIO's objectives to deliver least cost solutions.

5 Provide cross departmental leadership.

Hydrogen cuts across multiple sectors – building, industry, transport and power. Consequently, industry groups and several different parts of Government have an interest. This could present a challenge when putting forward a coherent vision and policy framework and may manifest in a lack of joined up thinking. For example, recent modelling by the National Infrastructure Commission on decarbonised heat options concluded that a hydrogen grid would be the most cost-effective, costing £50 billion less than the next cheapest option and costing less than half that of the two electrification options.[11] By contrast, modelling by the CCC suggests that switching to hydrogen for heating would be more expensive that switching to electricity or hybrid heat pumps. Granted, the model assumptions used by each organisation are different. However, irrespective of the input assumptions, the overall lack of a coherent policy message is likely to obfuscate policy makers rather than enlighten them. **All organisations will need to coordinate and work towards a common and long term vision of how gas and gas networks should be utilised, articulating clearly how this is compatible with the UK carbon budgets and any move towards net zero.**

11. Element Energy (2018). Cost analysis of future heat infrastructure options, E4tech. https://www.nic.org.uk/wp-content/uploads/Element-Energsy-and-E4techCost-analysis-of-future-heat-infrastructure-Final.pdf

Specific policy recommendations

Our report also makes a number of detailed technology and policy-specific recommendations:

Hydrogen Production

- **Correct distortive incentives**
  - The price of heating fuels should reflect their relative carbon intensity. The Government could increase VAT to the standard rate of 20% for carbon intensive fuels such as natural gas.
- **Drive cost reductions and seek competitive advantage in production technologies as part of the Industrial Strategy Challenge Fund**
  - Given the clear cost reduction pathway, the low production carbon intensity and the opportunities to build and export intellectual property, it is recommended that a greater R&D effort should be put in to developing and lowering the cost of electrolysis and SMR + CCS.
  - The Government should prioritise demonstration projects to develop real cost evidence.

Integrating renewables

- **Quantity the system benefits of Power to Gas**
  - National Grid should make an assessment of how PtG deployment (Power-to-Gas) can reduce system costs, including an assessment of the cost of PtG relative to the costs of other options to mitigate intermittent renewables.
- **Create an upstream PtG market**
  - To validate the benefits of hydrogen electrolysers for flexibility service provision, a pilot study should be established for testing parameters and electrolyser performance.
  - The 'Green hydrogen standards' working group should resume, in conjunction with industry, to define appropriate emissions levels for low carbon hydrogen and determine whether this should be uniform across all sectors. This should be done by 2021 to align with the next RIIO charging period. The development of a quality mark for hydrogen should be underpinned by strong standards and enforcement.
  - Scaling hydrogen use will require an import market. Therefore, following Brexit, the UK Government needs to clarify how future domestic standards may diverge or align with standards set by the European Union.
- **Reduce informational barriers**
  - Ofgem must provide clarity on what constitutes allowable spend (on hydrogen) by gas networks during the period 2021-2026.

  - National Grid should set out the technical parameters of the grid services they require and examine how new and existing technologies can be encouraged to actively participate in the ancillary services market.

Decarbonising Domestic Heating

- **Encourage green gas**
  - To help stimulate the supply side market, the permissible levels of hydrogen should be increased from 0.1% in accordance with the conclusion of the HSE.
  - Blending up to 20% volume delivers carbon savings of ≈5%. As such this should be considered as a preliminary step in establishing the viability of cost effective and scalable steam reforming with CCS.
- **Improve and co-ordinate supply chains**
  - Warranties associated with plant machinery and equipment, and domestic appliances need to be developed that allow for a change in the permissible limit of hydrogen in the gas network.
- **Support appropriate governance**
  - Geographical conversions of gas to grid hydrogen give rise to issues of governance pertaining to consumer choice and rights (interacting with those of a developed local government). Consideration must be given to the distributional impacts.
  - For the next RIIO charging period, Ofgem must give consideration as to how costs can be socialised in the most equitable way.

Decarbonising Industry and feedstocks

- **Develop Industrial Hydrogen Hubs**
  - The UK Government should maximise the synergies that exist between industrial activity, gas infrastructure, grid constraints and opportunities for innovation and consider deliberate national investment in clustering.
  - The hub could examine: how to increase deployment of CCS in order to enable and establish cost effective hydrogen production from SMR; how to support opportunities to decarbonise industry; and the extent to which PtG can reduce system costs.
- **Promote fuel switching options**
  - Government should help to identify fuel switching options across industry and develop a strategy to promote lower carbon options.
  - A pilot study should be established to examine opportunities to drive cost reductions in the use of hydrogen as alternative feedstock.

Decarbonising Transport

- **Enable innovative hydrogen transport pilots**
  - Offer innovation grants for pilot programmes to develop innovative uses of hydrogen for transport systems in large industrial facilities and warehouses for applications that are less suitable for battery powered vehicles.
- **Develop a network of refuelling stations for haulage**
  - Work with the freight industry to examine the economic and environmental case for a strategic network of hydrogen refuelling stations that would enable the HGVs or trains to travel around the country's main transport networks using hydrogen fuel cell technology.
- **Incentivise the use of hydrogen fuel**
  - Exemptions for hydrogen from any fuel duty should continue during the early stages of market development.
  - The Government needs to give long term signal on how hydrogen will be taxed going forward, with any policy changes signalled clearly in advance.
  - The Renewable Transport Fuel Obligation should be expanded to allow companies to use hydrogen as part of their contribution. A similar system to the current sustainability checks on biofuels should be set up to ensure that the use of hydrogen reduces carbon emissions at a system level.

1 Introduction

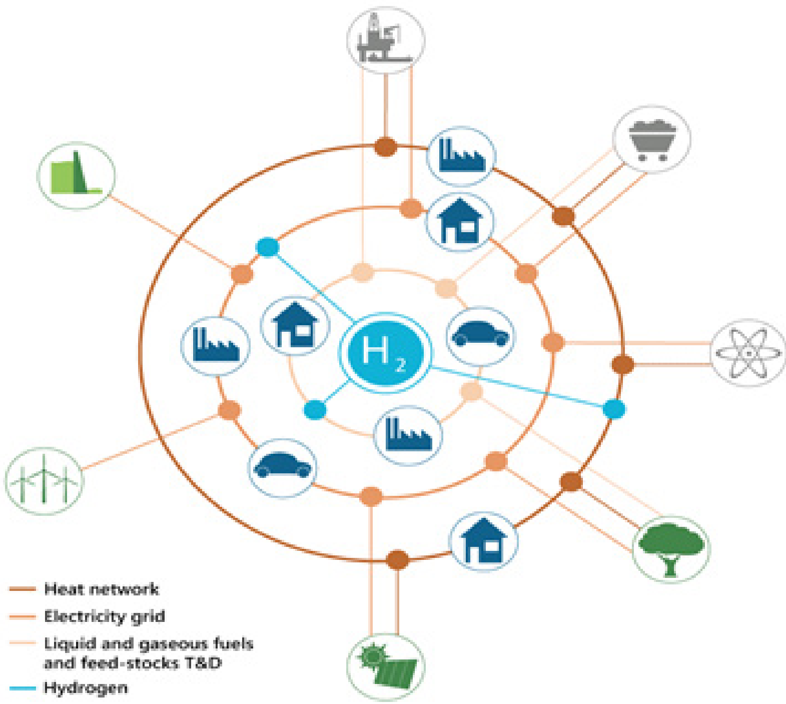
This chapter provides context to the report, explaining the concept of a 'hydrogen economy', its role in the UK to date and the challenges posed by the emerging energy transition.

Defining the 'Hydrogen Economy'

It is increasingly difficult for anyone working in the UK energy sector to be unaware of the way hydrogen has crept back in to the discourse for transitioning to a low carbon economy. Through the Clean Growth Strategy[12] – published in October 2017 – and the announcement of the Hydrogen Supply Programme in May 2018, the UK Government has committed political and financial support to accelerate the deployment of hydrogen infrastructure.

This has led some to declare we are on the verge of a new 'hydrogen economy' paradigm. The hydrogen economy refers to a vision of using hydrogen as an alternative low carbon energy carrier that can be used as a replacement in transport, heating fuel and also for storage. In a

Figure 1.1: Hydrogen Economy Schematic



International Atomic Energy Agency (2018) 'Hydrogen: Tracking Clean Energy Progress'

12. HM Government. (2017). *The Clean Growth Strategy: Leading the way to a low carbon future.* https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/700496/clean-growth-strategy-correction-april-2018.pdf

hydrogen economy, these different uses for hydrogen are likely to be highly interconnected with one service creating a supply for other uses.[14] It is precisely this interconnectedness and interdependency that creates a hydrogen economy.

Hydrogen has a number of characteristics that lend itself to this vision. First, it is the most abundant element in the universe[15]. Second, at the point of use, no harmful emissions are produced when it is burned – only water vapour. This gives hydrogen a fundamental advantage over conventional fossil fuels – from an environmental perspective at least. Third, hydrogen has the ability to act as an efficient energy vector, storing and transporting energy. But it is not just a battery play; it can also be used to power vehicles and used for power-to-gas which can be injected into the gas grid. These characteristics are a target of those in pursuit of a truly sustainable energy system and thus underpin the concept of a 'hydrogen economy,' facilitated by Government and organized markets that allow its commercialisation with competitive prices, quality, reliability and security of supply.[16]

Despite the notion of a hydrogen-based economy existing for some time, and recognition of the environmental benefits that this entails, it is yet to fully materialise. Renewed efforts in technological research and development for hydrogen have begun, but a number of technological and non-technical barriers still persist. The reality is that the state of the 'hydrogen economy' in the UK is more aptly described as 'hydrogen in the economy'[17], albeit relatively small amounts, with recent changes based on the incremental introduction of hydrogen rather than full system transformation.

History of 'Hydrogen in the Economy'

It is important to highlight that hydrogen in the energy system is not new, nor is the concept of a Hydrogen Economy. The latter was an expression introduced by General Motors Co. in 1970 to name a new economy based on the use of hydrogen as an energy source[18].

Up until the 1970's hydrogen made up 50% of the local gas supply.[19] Originally this was produced by coal gasification – a process in which coal is heated in absence of oxygen to produce a synthetic gas. Coal gas, or 'town' gas as it was colloquially known, became the dominant source of domestic gas. But as coal prices rose, industry began looking for alternative, cheaper feedstocks.

One alternative was mine gas. However, because it was almost pure methane, the gas needed to be reformed first in a process known as Steam Methane Reformation (SMR) which is still the most widely used method today. This process involves the injection of steam to split the methane into its constituent parts: hydrogen, carbon dioxide and carbon monoxide. Whilst useful, the quantity of mine gas available could only serve a fraction of Britain's requirements[20].

Oil was subsequently used as a feedstock for gas production. Naphtha, a distillate from crude oil, was treated with SMR to produce a gas cleaner than that produced using coal, again producing hydrogen, carbon

13. Energy Research Partnership. (2016). *Potential Role of Hydrogen in the UK Energy System.* http://erpuk.org/wp-content/uploads/2016/10/ERP-Hydrogen-report-Oct-2016.pdf

14. Roy, P. (2017). 'Hydrogen Is The Most Common Element: Here's The Reason Why'. *The Science Times.* http://www.sciencetimes.com/articles/11524/20170403/hydrogen-is-the-most-common-element-heres-the-reason-why.htm

15. Da Silva Veras, T. et al. (2017). 'Hydrogen: Trends, production and characterization of the main process worldwide'. *International Journal of Hydrogen Energy*, Vol. 42, No. 4, Pages 2018-2033. https://www.sciencedirect.com/science/article/pii/S036031991632715X?via%3Dihub

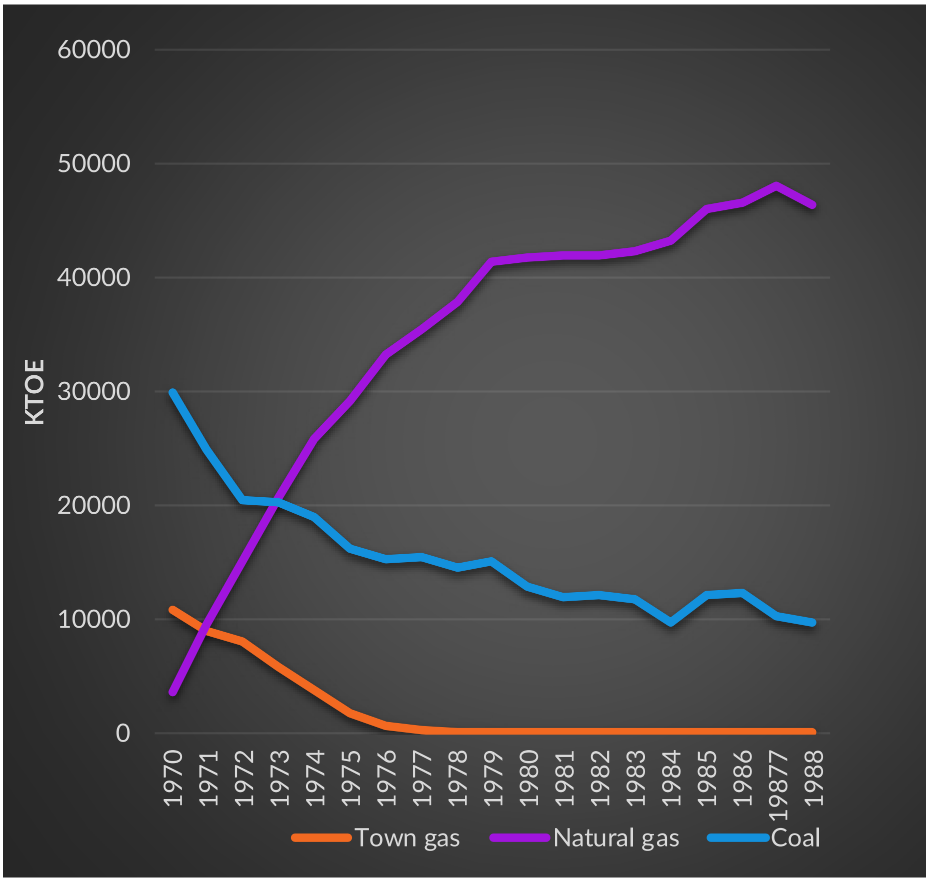
16. Brandon, N. (2012). 'What's the 'hydrogen economy'?', *The Guardian.* https://www.theguardian.com/environment/2012/oct/11/hydrogen-economy-climate-change

17. Nuttall, W.J., Glowacki, B. and Krishnamurthy, S. (2016). Next Steps for Hydrogen: Physics, technology and the future. Institute of Physics. http://www.iop.org/publications/iop/2016/file_67429.pdf

18. Energy Research Partnership. (2016). *Potential Role of Hydrogen in the UK Energy System.* http://erpuk.org/wp-content/uploads/2016/10/ERP-Hydrogen-report-Oct-2016.pdf

19. Thomas, R. (2014). 'The History and Operation of Gasworks (Manufactured Gas Plants) in Britain'. https://www.researchgate.net/publication/268447664_The_History_and_Operation_of_Gasworks_Manufactured_Gas_Plants_1_Written_by_Dr_Russell_Thomas_1422014

Figure 1.2: Decline of town gas



DBEIS (2018) *Energy consumption in the UK: 2018 update*

dioxide and carbon monoxide. Reforming of petroleum feedstocks to produce gas became far cheaper and thus began the demise of both coal and town gas feedstocks.

A combination of rising coal prices and the discovery of North Sea Gas in the UK Continental Shelf[21] ultimately lead the UK Government to adopt a new national policy for gas supply, which aimed to convert all UK supply and associated infrastructure from town gas to natural gas. The conversion began in 1966 and was completed in 1977. It changed over 40 million appliances in 13 million homes[22] and cost over £500m[23] using public funds – approximately £8.5billion in today's money.

Not only did this necessitate new organisational developments but also the conversion of almost all end use devices such as gas boilers and cookers. Because the Gas Council chose not to transform natural gas into a chemical combination closer to that of town gas[24] they were no longer compatible. Cost aside, the transition required significant institutional, regulatory and governance changes, all commensurate with the scale of the present-day challenge.

Switching to a hydrogen network today is comparable to the UK's conversion from coal/town gas to natural gas 50 years ago. Therefore, an understanding of this historically important process can provide insights into future network transitions and assist in the study and design of new

20. Webber, C. (2010). 'The Evolution of the Gas Industry in the UK. *Oslo: IGU.* http://members.igu.org/old/gas-knowhow/publications/igu publications/publications/mag/april10/pages%20 198-220.pdf
21. Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute. http://www.sustainablegasinstitute.org/wp-content/uploads/2017/12/SGI-A-greener-gas-grid-what-are-the-options-WP3.pdf?noredirect=1
22. British Gas. (2012). 'History of British Gas'. https://www.britishgas.co.uk/business/history
23. Araposthathis, S., Pearson, P.J.G. and Foxon, T. (2014). 'UK natural gas system integration in the making, 1960-2010: Complexity, transitional uncertainties and uncertain transitions'. *Environmental Innovation and Societal Transitions*, Pages 87-102.

policies. Hydrogen re-emerged in sustainability lexicon around the turn of the century, predominantly concerning its role in greenhouse gas reduction in transport. Whilst hydrogen powered fuel cell electric vehicles (FCEVs) gained much exposure, a lack of commercial models contributed to a switch of attention towards battery electric vehicles (BEVs)[25].

The debate over the role of hydrogen has since re-emerged and advanced. This can be attributed to a number of reasons: 1) greater commercial maturity of hydrogen and fuel cell vehicles; 2) changes in the energy policy and technology landscape, such as the rapid deployment of intermittent renewables that require grid scale storage; 3) the continuing difficulty in decarbonising heat; and 4) the response by gas incumbents to the threat of stranded assets in a decarbonised world.

To put the latter into context, one key question facing policymakers is the role of natural gas in a decarbonised world. The UK has set ambitious targets to reduce greenhouse gas emissions in order to mitigate the effects of climate change. Yet projections of decarbonisation pathways have typically involved reducing dependence on natural gas grids, through greater electrification of heat and transport. Without Carbon Capture and Storage (CCS), or decarbonised/low carbon gas, continued use of gas could result in stranded assets and compromise the UK's decarbonisation ambitions. In this scenario, gas use in 2050 could be as low as 10% of its 2010 level.[26] However, the gas network also holds value in relation to flexibility of operation and enabling vast and less expensive storage[26]. Retaining and repurposing gas infrastructure to accommodate hydrogen or other sustainable biogases may be worthwhile, particularly as barriers to electrification of heat persist. The continued difficulty in decarbonising heat should not be underestimated as a key driver. To understand why hydrogen has become central to ongoing discussions about 'Clean Growth' it is important to recognise that slow progress has been made in this area.

Set against this context, the debate has often been framed as *either* electrification *or* 'greener' gases to achieve decarbonisation targets. But this polarisation presents a false dichotomy, with the exception of transport where the choice is perhaps more binary. As this report will argue, neither approach is a silver bullet; rather the application of each should be context dependant.

Power, heating and transport are the three features of the UK energy landscape that form the constituents of total energy decarbonisation. These thematic areas are deeply interlinked, and set against a backdrop of the UKs greenhouse gas emissions targets, have combined to serve as the catalyst for a deeper examination of the possibilities and challenges of a hydrogen economy. Improving our understanding of the role that hydrogen could play in decarbonising the UK's energy system is critical in informing better targeted policies in support of the nascent sector. In doing so, it is important to realise that assessing the role of hydrogen in isolation from the rest of the energy system may lead to biased inferences, failing to capture interactions with other drivers of the energy system.[27] As such, its role should not be limited to one application but should be focused on the

24. Dodds, P. E. and Hawkes, A. (Eds.) (2014). *The role of hydrogen and fuel cells in providing affordable, secure low-carbon heat*. H2FC SUPERGEN, London, UK. http://www.h2fcsupergen.com/wp-content/uploads/2014/05/H2FC-SUPERGEN-White-Paper-on-Heat-May-2014.pdf

25. McGlade, C. et al. (2018). 'The future role of natural gas in the UK: A bridge to nowhere?'. *Energy Policy*, Vol. 113, Pages 454-465.

26. Balcombe, P. et al. (2018). 'The carbon credentials of hydrogen gas networks and supply chains'. *Renewable and Sustainable Energy Reviews*, Vol. 91, Pages 1077-88.

27. Sgobbi, A. et al. (2016). 'How far away is hydrogen? Its role in the medium and long-term decarbonisation of the European energy system'. *International Journal of Hydrogen Energy*, Volume 41, Issue 1, Pages 19-35.

challenges of this transition and examined through a systems lens.

Context: Challenges of the energy transition

A global and national energy transition is underway. The UK has set an ambitious set of targets to reduce greenhouse gas emissions in order to mitigate the effects of climate change. Under the Climate Change Act (2008), the UK has committed to reducing total greenhouse gas emissions by 80% by 2050 (compared to 1990 levels), as well as setting a number of five yearly 'carbon budgets', the latest of which covers the period 2028 to 2032. As part of the Paris Agreement on climate change in 2015, the UK also agreed to a longer term target to achieve 'net zero' global greenhouse gas emissions during the second half of the twenty-first century in order to limit warming to 2°C and pursue efforts to limit warming to 1.5°C.[29]

In April 2018 the UK Government's commitment to consider net zero was re-affirmed by Rt Hon Claire Perry, stating that the UK "will be seeking advice from the UK's independent advisers, the Committee on Climate Change, on the implications of the Paris Agreement for the UK's long-term emissions reduction targets".[30] Achieving this ambitious target will require deep decarbonisation of the energy system. Increasingly stringent domestic emissions targets will have significant implications for the role of natural gas during the transition towards, and achievement of, statutory targets.

As well as the many benefits decarbonisation brings, such as better air quality, and clean technology innovation, it also presents a number of challenges. These include; how to integrate increasing amounts of variable supply; how to decarbonise hard to reach sectors such as heat, transport and industry; and which low carbon solutions can perform the function of an energy system buffer – a role that is currently fulfilled by natural gas.

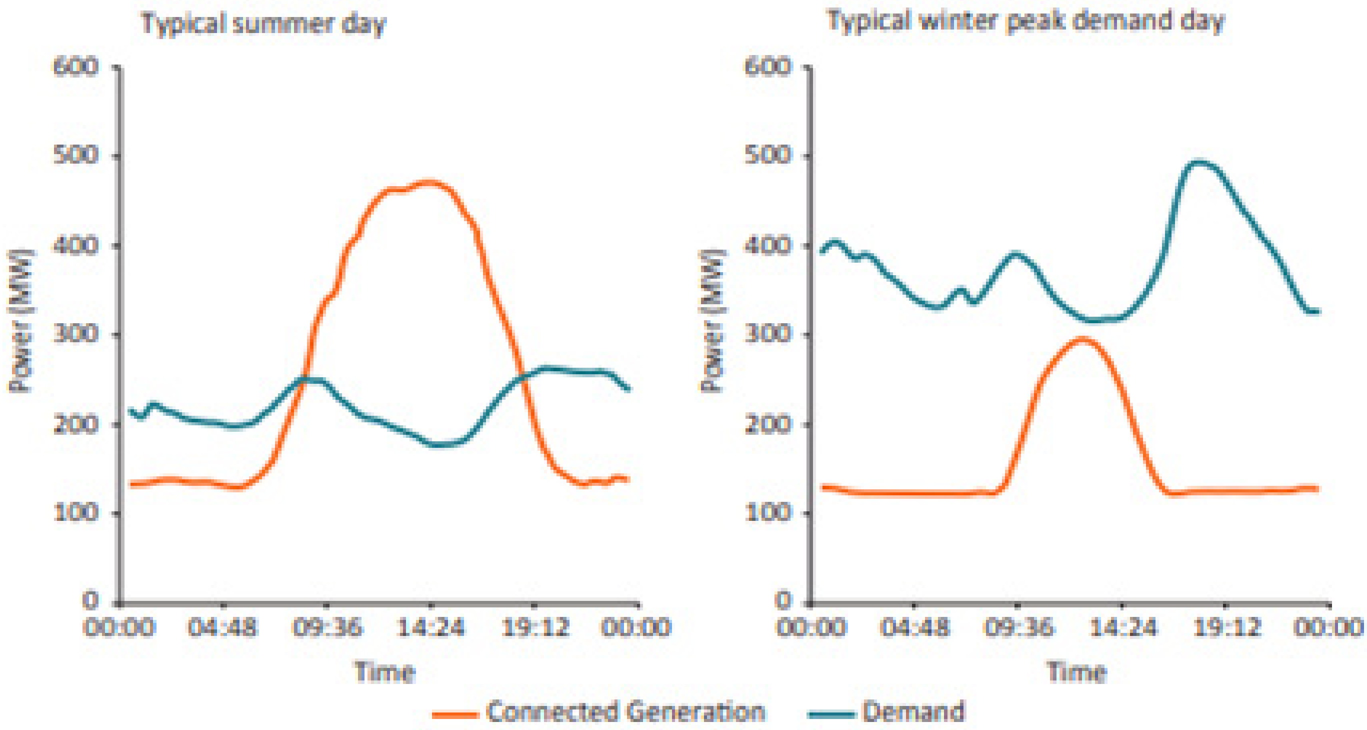
Integrating variable renewables

Variability in supply requires action to balance supply and demand within the system. Accommodating for supply side variability requires greater flexibility within the system. Although there are times that generation increases with demand, imbalances occur when generation falls and demand increases or vice versa. At present this flexibility is supplied by back up (gas, diesel, battery or pumped hydro) generation that can ramp up and down quickly to meet imbalances. There is yet to be a grid scale solution to store excess power when generation increases and demand falls, although battery storage is advancing across technological and economic dimensions. Figure 1.3 illustrates the electricity generation and demand profile for a typical winter and summer day in Cornwall. As illustrated, the connected generation capacity far exceeds demand during the day. The excess capacity can be exported to other parts of the country provided there is sufficient network capacity available.[31]

However, if there is not sufficient network capacity then generators may receive payments to curtail this power. Whilst policies exist to minimise curtailed power, such as demand turn up in which users are incentivised to consume additional power when the market is oversupplied, the

28. Committee on Climate Change (2015). 'UK climate action following the Paris agreement'. https://www.theccc.org.uk/wp-content/uploads/2016/10/UK-climate-action-following-the-Paris-Agreement-Committee-on-Climate-Change-October-2016.pdf
29. Twidale, S. and Chestney, N. (ed.). (2018). 'Britain to review its climate targets – government minister'. *Reuters*. https://uk.reuters.com/article/uk-britain-climatechange/britain-to-review-its-climate-targets-government-minister-idUKKBN1HO1DO
30. Howard, R. and Bengherbi, Z. (2016). *Power 2.0: Building a smarter, greener, cheaper electricity system*. Policy Exchange. https://policyexchange.org.uk/wp-content/uploads/2016/11/POWER-2.0.pdf

Figure 1.2: Supply and demand imbalance



Turvey, N. (2016) 'Challenges to the Electricty Network of a Low Carbon Cornwall'. *Western Power Distribution*

volume of constrained wind generation has increased by 2,500% from 2011-2017. Whilst this seems high, it was starting from a very low base and curtailed wind generation in 2017 was just 4%, of total wind output which is still relatively modest.

Nevertheless, given that the UK's penetration of renewable power is increasing, periods of excess generation will become more frequent and of larger magnitude[31]. The ability to store this surplus energy is vital for the efficient integration of increased amounts of intermittent generation. The ability of hydrogen as an energy vector to carry out this function and optimise the power system for renewables will enable increases in the penetration of renewables. The application of hydrogen in this context has the potential to enhance security of power supply, serve as a carbon-free seasonal storage and improve economic efficiency of renewable investments. [33]

The latter is possible because in areas with a large amount of distributed capacity of renewables, the shortage of network capacity is making it difficult to connect any new generation. New generators wishing to connect in such areas are usually required to contribute towards the reinforcement of the network, and this often renders such projects uneconomic. As an alternative, some Distribution Network Operators (DNOs) now offer "flexible connection agreements" under which new generators can avoid network reinforcement costs but are then constrained off the network when it reaches capacity with no compensation. Whilst this may result in a cost saving, it adds significant risk to new generation projects since

31. Qadrdan, M. et al. 'Role of power-to-gas in an integrated gas and electricity system in Great Britain', *International Journal of Hydrogen Energy*, Volume 40, Issue 17, Pages 5763-5775.
32. Hydrogen Council. (2017). *Hydrogen Scaling Up: A sustainable pathway for the global energy transition.* http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf

there is uncertainty about the extent to which they will be constrained, making financing such projects more difficult. Redirecting excess power towards hydrogen production instead of having generation constrained may reduce the uncertainty around revenue.

System buffer

Aligning storage and changing patterns of demand is a significant challenge presented by the energy transition. Ensuring there is enough capacity to meet sudden increases in demand, particularly in heating – as the heat peak is 6.5 times greater than peak electricity demand – is integral to a well-functioning system. Having enough capacity – or a buffer– within the system that is distributed across regions and seasons increases energy-system resilience.[34]

At present fossil fuels provide most of the storage capacity, maintaining a reserve of approximately 15% of the world total annual demand[35]. In the UK, there is a working storage of gas of about 4% or 14 days of demand.[36] However, the electrification of transport and heating may mean that this buffer could shrink, since it only serves fossil fuel end uses. Hydrogen may prove to be a viable and low carbon option for overcoming the buffer hurdle. Yet there still remains growing pressure from the gas industry for the Government to define a clear long-term strategy for the ongoing use of gas networks.

Decarbonising hard to reach sectors and feedstocks

In 2017 an estimated 34% of carbon dioxide emissions were from the transport sector, 29% from energy supply, 18% from business and 17% from the residential sector[37]. Whilst power sector emissions have been dramatically reduced, far less progress has been made in the transport sector. Emissions have virtually remained static, decreasing by just 0.7% from 1990-2017. Slightly more progress has been made in the residential sector with emissions reducing by 18% since 1990 levels. Table 1.1 and figure 4.1 illustrate how much progress has been in each sector.

Table 1.1: Sector emissions reduction (1990–2017)

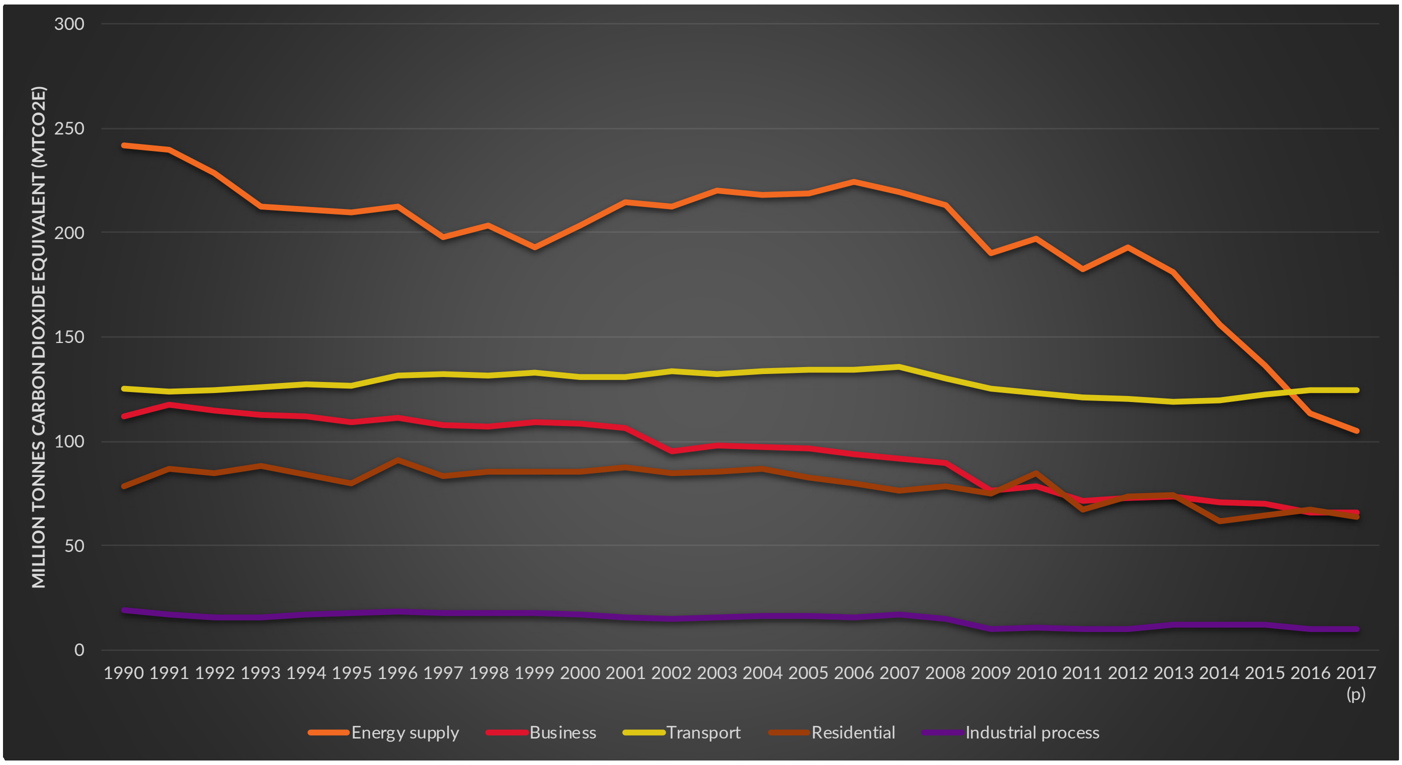
Sector	% Reduction (1990–2017)
Energy supply	-56.6%
Business	-41.2%
Transport	-0.7%
Residential	-18.2%
Industrial process	-49.5%

DBEIS. (2017). '2017 UK Greenhouse Gas Emissions, Provisional Figures'.

Emissions from industrial processes have reduced considerably. Partly, this reflects underlying structural changes in the UK economy – moving away from heavy industry to less energy intensive industrial activity

33. Heid, B. et al. (2017). 'Hydrogen: The next wave for electric vehicles?'. *McKinsey & Company.* https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/hydrogen-the-next-wave-for-electric-vehicles
34. Hydrogen Council. (2017). Hydrogen Scaling Up: A sustainable pathway for the global energy transition. http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf
35. https://fueloilnews.co.uk/2014/09/gas-grid-and-storage-facilities-in-the-uk/
36. DBEIS. (2017). '2017 UK Greenhouse Gas Emissions, Provisional Figures'. https://www.gov.uk/government/statistics/provisional-uk-greenhouse-gas-emissions-national-statistics-2017

Figure 1.4: Emissions by sector (1990–2017)



DBEIS. (2017). '2017 UK Greenhouse Gas Emissions, Provisional Figures'.

– but it is also a response to greater regulation, increasing volumes of embedded generation, fiscal policies; and the implementation of demand side response and energy efficiency solutions. Whilst early progress was made, more recently (2012-2016), there has been a stall as emissions have not been reduced at all over this period. The transformation of the power sector is well underway – illustrated by the steep decline of energy supply emissions since 2012. At the same time, as emissions from road transport have stayed static, it is now the most significant source of UK emissions.

In a number of these sectors, transitioning to full electrification will remain technologically and economically challenging even with a very high carbon tax. This is likely to apply to heavy freight, non-electrified trains, aviation and some energy intensive industries that require continuous, high grades of heat. If technological and economic barriers prevent full electrification, hydrogen is potentially a viable alternative to natural gas as a heat source.

Yet the inability to decarbonise is not just limited to the aforementioned sectors. It also applies to fossil fuel feedstock used within industry. Renewable energy may not be able to replace all fossil fuels used in petro-chemical production processes. Fossil fuels used in plastics production provides a good example, as over 99% of plastics are produced from chemicals sourced from fossil fuels[37], and this is unlikely to significantly change anytime soon. Continued use of fossil fuel feedstock within industry is only compatible with long term decarbonisation targets if this is pursued alongside carbon capture and storage (CCS). Indeed, analysis[38] suggests

37. Center for International Environmental Law (2017). 'Fueling Plastics: New Research Details Fossil Fuel Role in Plastics Proliferation'. https://www.ciel.org/news/fueling-plastics/

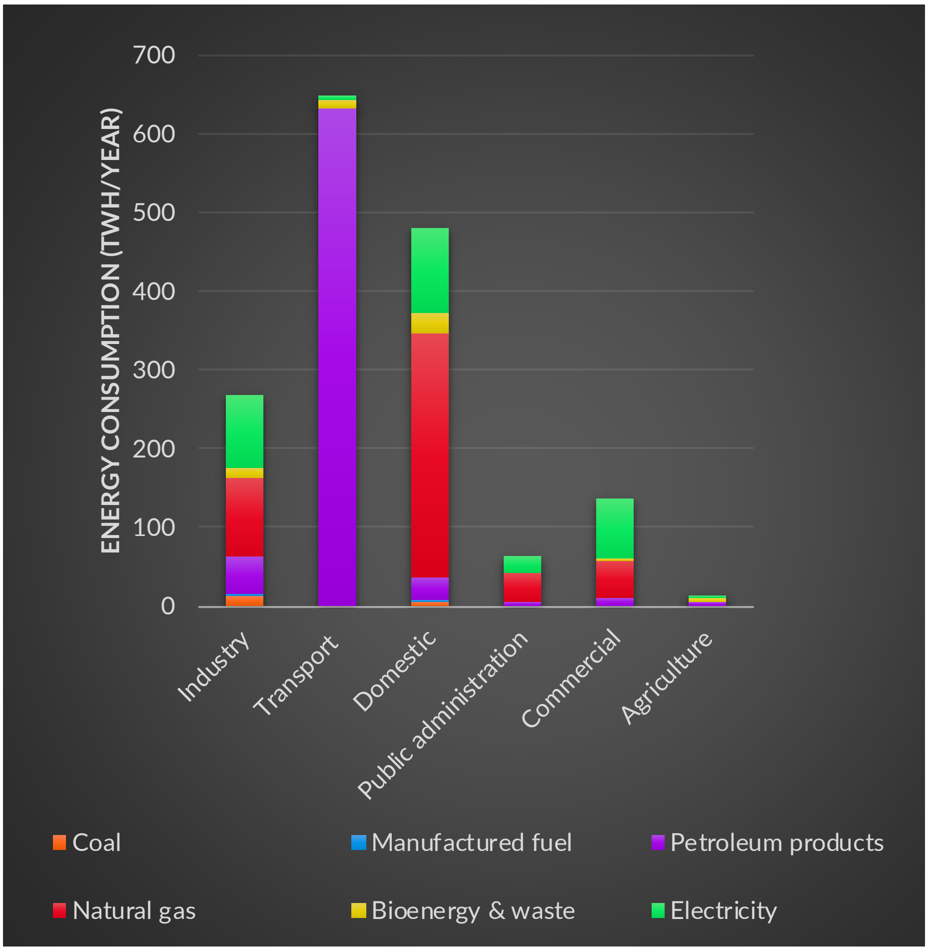
38. McGlade, C. et al. (2018). 'The future role of natural gas in the UK: A bridge to nowhere?'. Energy Policy, Vol. 113, Pages 454-465.

that if the UK is to meet its emission reduction targets there is limited scope for gas in power generation after 2030, in the absence of CCS. This has significant implications for the way in which hydrogen is produced.

Mutually beneficial synergies exist between hydrogen and CCS, in both the production of hydrogen itself and the creation of environmentally friendly feedstocks that can act as alternatives to gasoline. For example, combining hydrogen with captured CO_2 can produce methanol, demonstrating it may be possible to harness the power of CO_2 and integrate it into the utilisation cycle as a sustainable form of energy production[39].

The development of a hydrogen economy will be examined in the context of these challenges and the role it can play in addressing such issues. Of particular interest will be how a low carbon transition can be achieved in industry, transport and domestic sectors. As figure 1.5 below illustrates, these sectors account for the highest energy consumption (and in the case of transport also the highest emissions) and tend to be dominated by oil and natural gas fossil fuel feedstocks.

Figure 1.5: UK final energy consumption by sector and fuel 2016



DBEIS. (2018). 'Digest of UK Energy Statistics (DUKES): energy'.

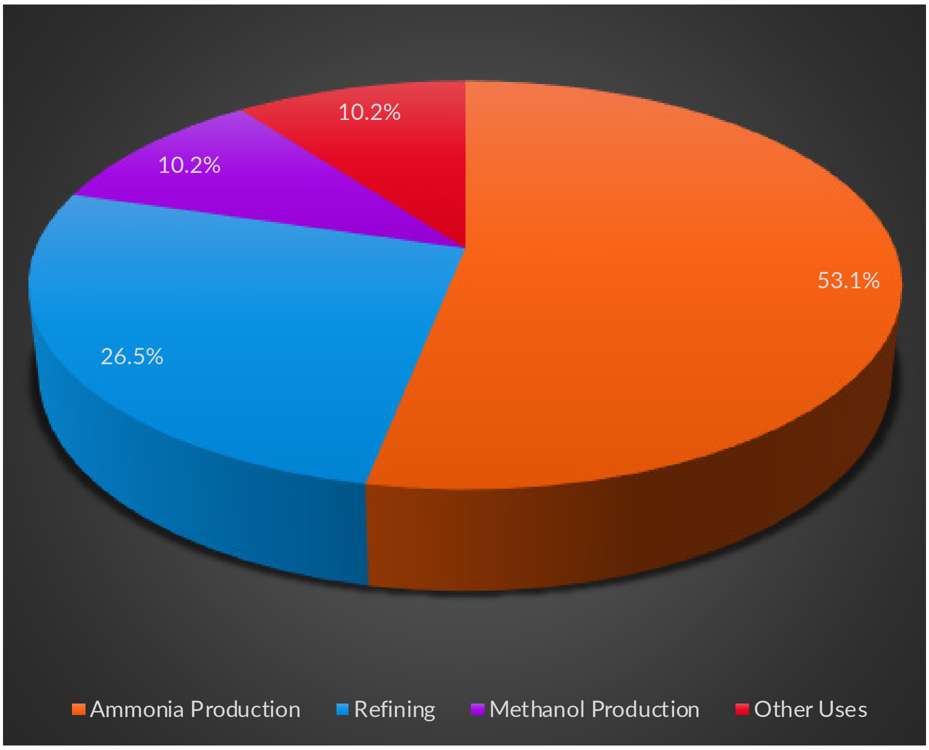
39. R&D Magazine. (2012). 'Green fuel from carbon dioxide and hydrogen?'. https://www.rdmag.com/news/2012/06/green-fuel-carbon-dioxide-and-hydrogen

2 Production, Transportation and Storage

Current uses of hydrogen and potential future demand

Global hydrogen production stands at around 60 million tonnes per year.[40] Although there is increasing interest in hydrogen as an energy carrier, only a tiny fraction of that is currently used in related sectors. It is predominantly used in the chemical industry for the production of ammonia and methanol.[41]

Figure 2.1: Hydrogen by end use 2010



Zakkour, P. and Cook, G. (2010). *CCS Roadmap for Industry: High-Purity CO_2 Sources*. Carbon Counts.

If current yearly global hydrogen production was entirely used in the energy sector, it would provide more than 1% of global energy supplies[42] and would be enough to cover the entire energy needs of the UK.[43] However, domestic production currently amounts to just 26.9 TWh, around 1% of our own energy requirements.

So in order for hydrogen to play a significant role in the UK's energy

40. Philibert, C. (2017). 'Commentary: Producing industrial hydrogen from renewable energy'. *International Energy Agency*. https://www.iea.org/newsroom/news/2017/april/producing-industrial-hydrogen-from-renewable-energy.html
41. Kalamaras, C. and Efstathiou, A. (2013). 'Hydrogen Production Technologies: Current State and Future Developments'. *Conference Papers in Energy*, Volume 2013. https://www.hindawi.com/journals/cpis/2013/690627/
42. International Energy Agency. (2017). *Key World Energy Statistics*. https://www.iea.org/publications/freepublications/publication/KeyWorld2017.pdf
43. DBEIS (2018). 'Energy Consumption in the UK: 2018 update'. https://www.gov.uk/government/statistics/energy-consumption-in-the-uk

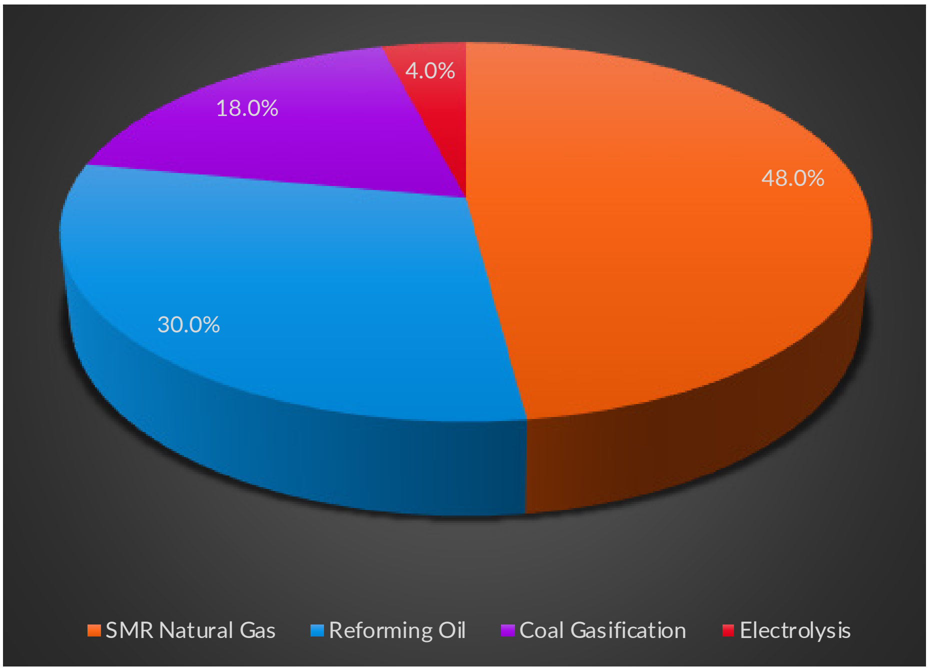
system, domestic production would need to be scaled up or import infrastructure developed – while also the challenge of producing it in a way that limits carbon emissions, and bring downs costs so that it can compete with conventional fossil fuels.

Hydrogen production

Hydrogen in the molecular form H_2 does not occur naturally in large quantities on earth, but there are many different ways in which this form of hydrogen can be produced, including:

- **Steam methane reformation:** The most common methods today all use fossil fuels as the feedstock, mostly the steam methane reformation of natural gas, but also oil reformation and coal gasification (with by-products if CO_2, CO)
- **Electrolysis of water:** A small percentage is currently produced through the process of splitting water (H_2O) into hydrogen and oxygen (with oxygen as a by-product)
- **Thermochemical water splitting:** A method that may offer potential in the near-future is the thermo-chemical splitting of water into hydrogen and oxygen using heat from, for example, a nuclear reactor or solar energy (with oxygen as a by-product)
- **Biomass and biological production:** Biomass gasification could contribute to hydrogen production in the short term, while more speculative methods include the biological production of hydrogen using algae. (with by-products if CO_2, CO)

Figure 2.2: Hydrogen production by method 2016



Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute.

The percentage contribution of each production method at a global level is shown in Figure 2.2.

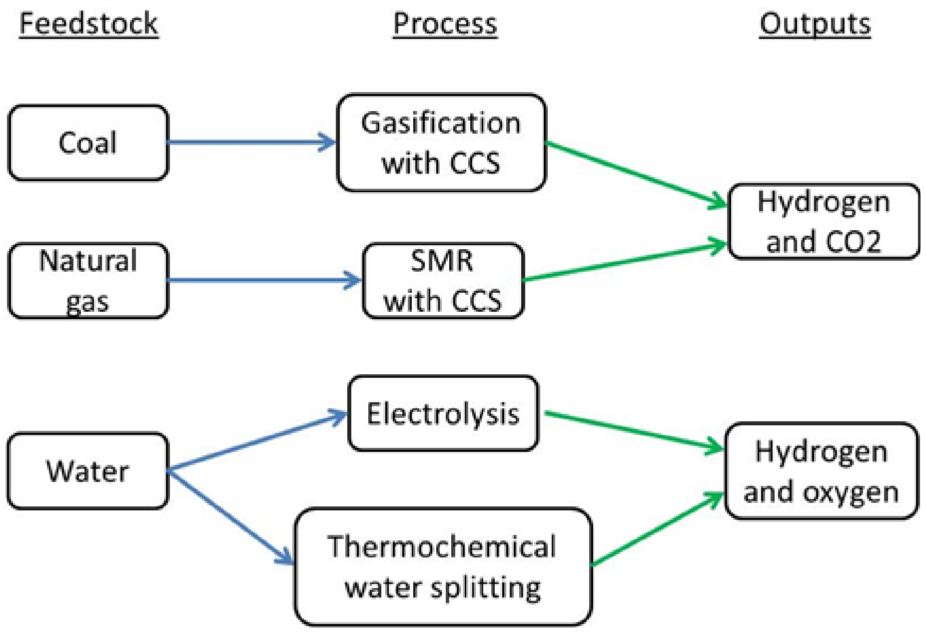
As the hydrogen economy is only a desirable concept if it reduces greenhouse gas emissions, in this report we mainly consider low carbon production methods. We have also restricted the options to those that are technically feasible and scalable in the short-to-medium term, i.e 2035. Having applied this filter, the main options are summarised in Figure 2.3.

Producing hydrogen from fossil fuels can only be considered low carbon if the process is combined with carbon capture and storage (CCS). Similarly, producing hydrogen from water is only low carbon if the source of electricity or heat is also emissions free (e.g. solar, nuclear, etc.).

If the feedstock is biomass or biogas and this is combined with carbon capture, then the hydrogen production can result in negative lifecycle emissions. This is commonly referred to as BECCS (bio-energy with carbon capture and storage). Both the Intergovernmental Panel on Climate Change[44] and the UK's Committee on Climate Change[46] have highlighted the importance of BECCS as a technology option if we are going to prevent dangerous levels of climate change in the second half of the century.

The carbon dioxide and oxygen that is produced as a by-product in these processes could also be considered a resource. Both have a number of uses, but given the scale of hydrogen that would need to be produced to have a significant impact in decarbonising our economy they will most likely be considered waste products, with the harmless oxygen being released into the atmosphere and the carbon dioxide being compressed and stored in underground or undersea geological repositories. The market for carbon dioxide is too small and unless currently unknown large-scale uses for the gas can be found, this will remain the case for the foreseeable future.[47]

Figure 2.3: Main options for low-carbon hydrogen production



44. Intergovernmental Panel on Climate Change. (2014). *Climate Change 2014 Synthesis Report Summary for Policymakers*. http://ipcc.ch/pdf/assessment-report/ar5/syr/AR5_SYR_FINAL_SPM.pdf
45. Committee on Climate Change. (2017). *Meeting Carbon Budgets: Closing the Policy Gap: 2017 Report to Parliament*. https://www.theccc.org.uk/wp-content/uploads/2017/06/2017-Report-to-Parliament-Meeting-Carbon-Budgets-Closing-the-policy-gap.pdf
46. Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute. http://www.sustainablegasinstitute.org/wp-content/uploads/2017/12/SGI-A-greener-gas-grid-what-are-the-options-WP3.pdf?noredirect=1

Process Comparisons

Each process takes a feedstock and energy to produce hydrogen. Clearly different feedstock and the sources of energy have different carbon intensities in themselves. Each process also has a different 'efficiency' inherent in its methodology, and depending on the relative maturity of each method there is a greater or lesser potential for innovation and cost savings, not all methods have the potential to show the massive cost improvements per unit of delivery that off shore wind has shown.

For reference here we illustrate the data on the respective processes to highlight the conversion rates and relative efficiencies of each process.

The table opposite illustrates a range of production efficiencies, with coal gasification the lowest at 64% and solid oxide electrolysis the highest at 80%. The table also shows the amount of electricity required in each process to produce a kg of hydrogen. As electricity is not the main input fuel for thermos-chemical, the quantity required is much lower than for electrolysis where electricity is the main input. This illustrates the importance of input costs, which is explained in more detail below.

Cost

Given the long history – relative to other processes and feedstocks – and market dominance of steam methane reformation it is not surprising that it has become one of the least costly production methods in terms of pence / kWh. Another factor is that SMR production costs are highly influenced by the prevailing cost of natural gas, which has been at historically low levels for some years now. Low (or completely absent) carbon taxation rates have also meant that there has been no major incentive for producers to equip their SMR plants with carbon capture and storage.

Input costs are also key for other production methods and they have a significant impact on the cost of production, whether that's the price of wind energy for electrolysis or biomass for gasification. In a recent report, the Sustainable Gas Institute aimed to compare the cost of different production methods. Using their data, Figure 2.4 below compares the average production and storage costs (where CCS is used), against the average 2017 UK gas and electricity wholesale prices to provide context. Production and storage costs can serve as a proxy for wholesale costs. As the wholesale prices of electricity and gas in Figure 2.4 already includes a profit margin, a discretionary 6% margin has been added to make the comparison more meaningful.

Figure 2.4 shows that while some technologies are cheaper than wholesale prices, these do not include CCS and so would not be compatible with the UK's decarbonisation targets. However, the total production costs for the most viable technologies – SMR + CCS and Electrolysis – are greater than the benchmark of the average wholesale price of gas.

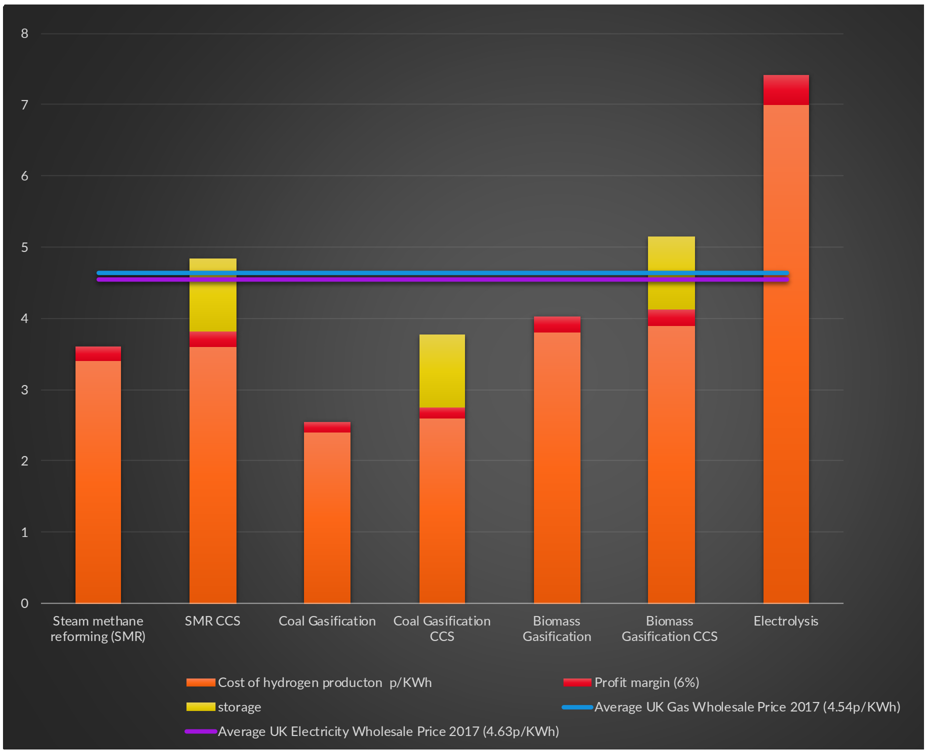
An approximated final cost to the consumer is illustrated below. In addition to the production and storage costs (which account for ≈ 65% of the total cost) a number of additional cost components have been added[48] which make up the remainder of consumer bills, such as: VAT (5%); profit margin (6%); environmental levies; billing; and transportation cost. Combined, these

47. Additional cost components have been added based on Northern Gas Networks H21 Leeds Citygate Project. (2018). https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf

Table: Process conversion rate and relative efficiencies[i, ii, iii, iv]

Type	Thermo-Chemical			Electrolysis	
Conversion Pathway	Steam methane reforming	Coal gasification	Biomass gasification	PEM electrolysis	Solid oxide electrolysis
Input	Natural gas	Coal	Biomass	Electricity	Electricity
Electricity (kWh/kg H_2)	1.11	1.72	0.98	54.6	36.14
Efficiency	74%	64%	68%	65%	80%

Figure 2.4: Cost of hydrogen production (p/kWh)



Production costs from Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute.

equate to the remaining 35% of the bill and offer an indication of the likely retail offering of each production process. Consumer costs, i.e. appliance conversion have also been added to make the full costs as reflective as possible.

This comparison shows that all technologies produce hydrogen at a cost greater than the 2017 average wholesale price of gas. **SMR with CCS, the most dominant form of hydrogen production, is 1.5x more expensive than the retail price of gas whilst the cleanest production technology – electrolysis – is double the current cost.[49]**

i. Energy Research Partnership. (2016). Potential Role of Hydrogen in the UK Energy System.

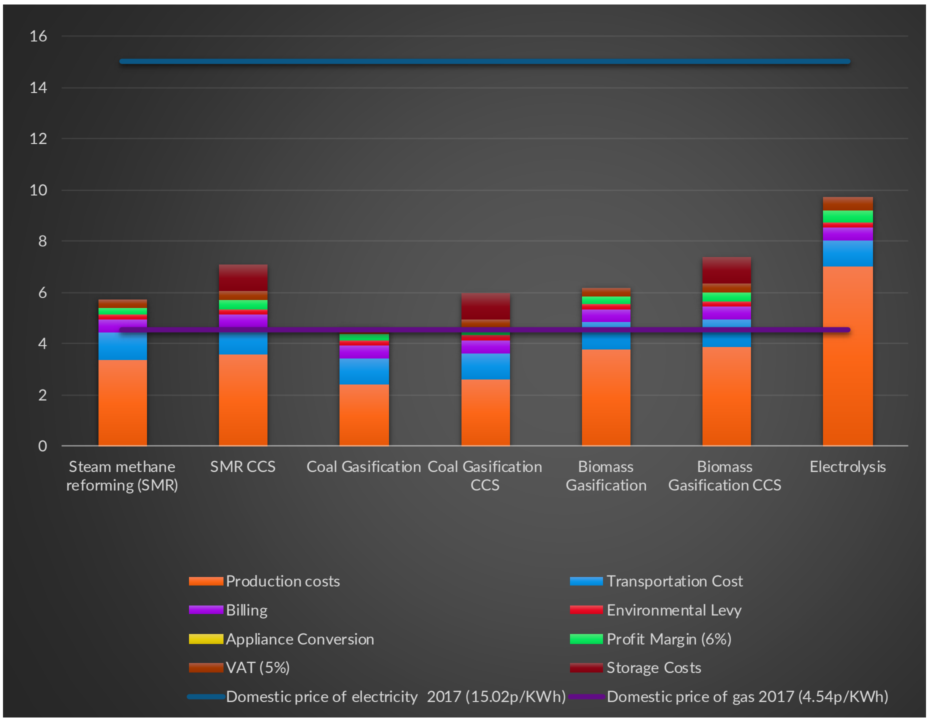
ii. Life Cycle Assessment and Water Footprint of Hydrogen Production Methods: From Conventional to Emerging Technologies Andi Mehmeti 1,* ID , Athanasios Angelis-Dimakis 2 ID , George Arampatzis 3 ID , Stephen J. McPhail 4 and Sergio Ulgiati 5

iii. Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute.

iv. Ciferno, J and Marano, J. (2002). *Benchmarking biomass gasficatiion tecjnologies for fuels, chemicals and hydrogen production.*

48. Wholesale prices of gas and electricity include a profit margin, one which Ofgem assumes to be 10% but the retail offering only assumes 6% margin. This may cause a small error of margin.

Figure 2.5: Estimated hydrogen retail price (p/kWh) based on different production methods



That said, while electrolysis is the most expensive production technology, it has the potential to achieve far greater cost reductions than other technologies. Although the extent of future cost reductions is always uncertain, the Sustainable Gas Institute projects that from 2014-2050 electrolysis costs will fall by 54%, with biomass gasification costs expected to fall by 45% and biomass gasification with CCS by 33%. Because the other technologies are already mature, there is less scope for ongoing reductions. **Given that ≈ 65% of the total price can be attributed to production and storage processes, opportunities to minimise decarbonised gas prices should therefore target these areas. Therefore, it is recommended that the Government prioritise demonstration projects to develop real cost evidence.**

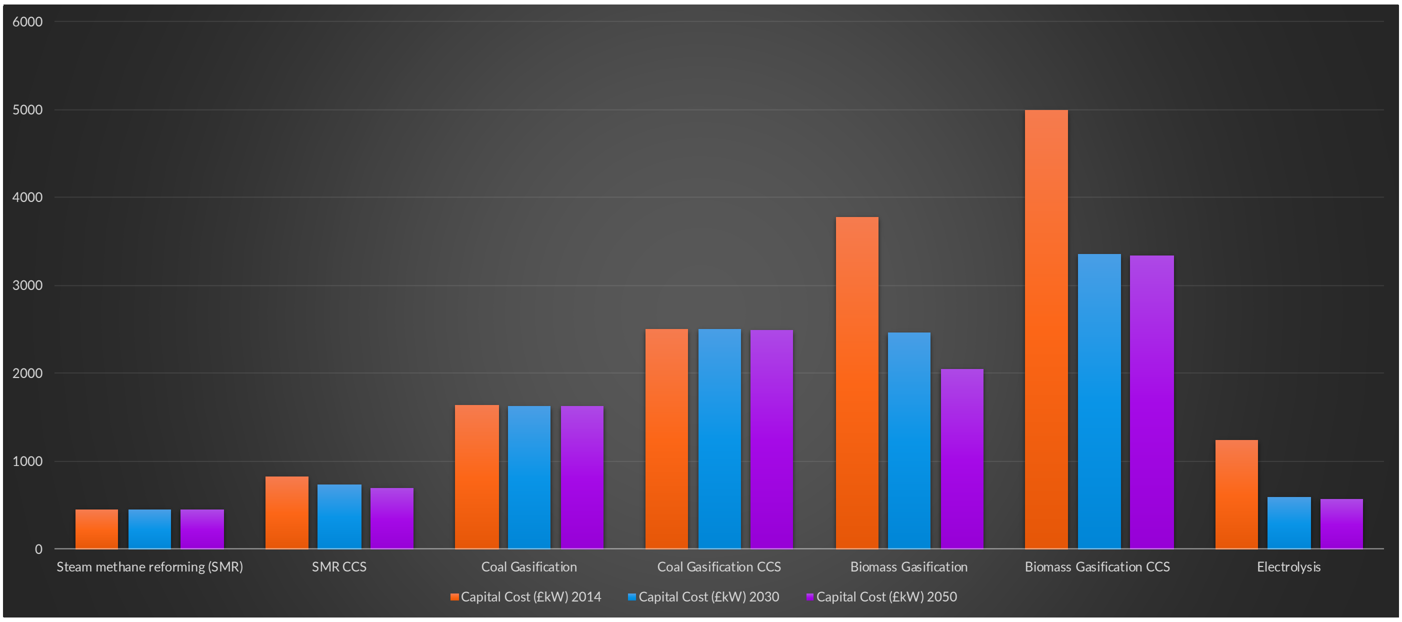
In addition to this, the Government needs to create a set of market conditions that allows technologies to compete on a level playing field. A logical place to start would be to ensure that the price of fuels for heating reflects their relative carbon intensity, allowing the market to deliver lower carbon solutions rather than higher carbon solutions. The power sector is a good example of what can be achieved through the use of carbon taxes. For example, the Carbon Price Floor alone has caused a 73% reduction in coal generation from 2012 to 2016.[50]

Yet despite this, the current taxes and levies placed on domestic fuels are creating a perverse and distortive set of incentives. VAT is levied at a reduced rate of 5% on gas, solid fuels and heating oil (rather than the prevailing rate of 20% on most other goods and services).

In order to address this, Government should consider adjusting taxes and levies on electricity, gas and other heating fuels to better reflect their

49. Aurora Energy Research. (2017). 'The carbon price thaw: Post-freeze future of the GB carbon price.' https://www.auroraer.com/wp-content/uploads/2017/10/GM-CPS-final_publication_Nonsubscribers.pdf

Figure 2.6: Projected potential capital cost reductions for hydrogen production processes (£/kW)



Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute.

carbon content. In this context, the Government could increase VAT to the standard rate of 20% for carbon intensive fuels (gas and coal) that are used to produce heat.

To avoid pushing up overall energy bills, the additional revenue raised could be used to reduce or remove the policy costs levied on energy sales, either by moving policy costs into public expenditure, or through bill rebates. These changes would have the effect of increasing the unit cost of more carbon intensive fuels, encouraging improvements in energy efficiency and switching to less carbon intensive fuels, whilst avoiding an increase in energy bills. Increasing taxes on more carbon intensive fuels would also send a strong signal to industry to invest in lower carbon fuels and heating technologies. [51]

Carbon

Figure 2.7 shows how carbon intensive each method of hydrogen production - including variants of electrolysis - currently assesses to be by Spiers et al is. A number of interesting results emerge:

1. All production processes contribute net emissions of carbon dioxide to the atmosphere, with the exception of biomass gasification with carbon capture and sequestration. Deploying bioenergy with carbon capture and sequestration (BECCS) results in a net reduction in atmospheric carbon. Without capture, biomass is deemed to be carbon neutral as there is a net transfer of CO_2 from the atmosphere into the growing biomass. When capture is added, the CO_2 from combustion is then captured and stored in geological formations, thus permanently removing CO_2 from the atmosphere and achieving an overall negative CO_2 balance. [52]

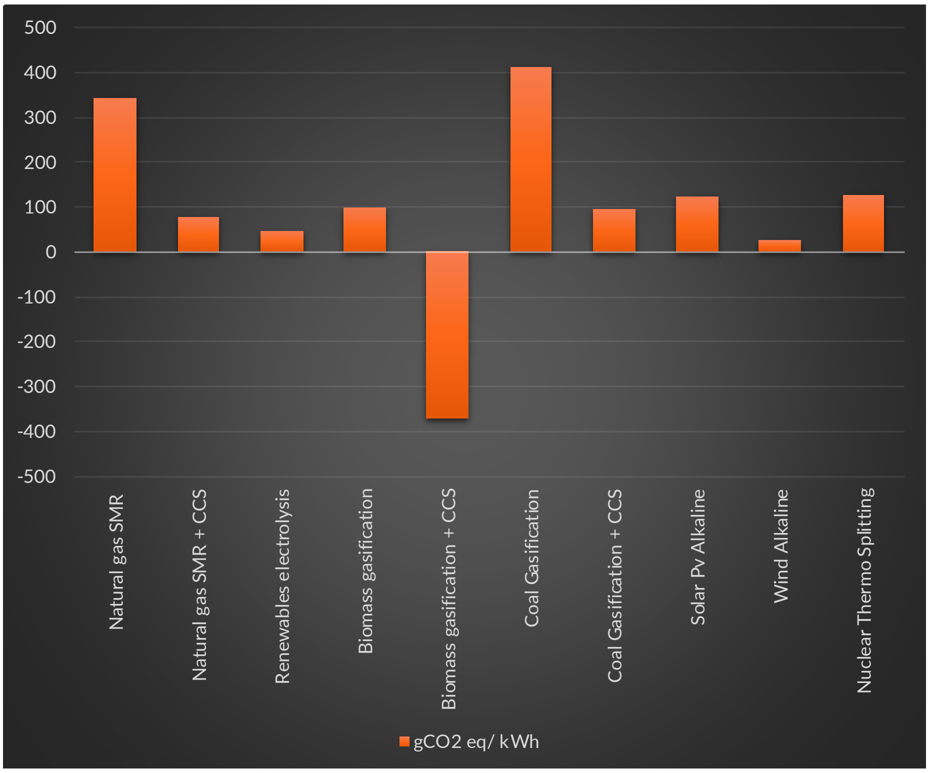
50. Howard, R. and Bengherbi, Z. (2016). *Too Hot to Handle? How to decarbonise domestic heating*, Policy Exchange. https://policyexchange.org.uk/wp-content/uploads/2016/11/PEXJ4810_Too_hot_to_handle_09_16-V2-WEB.pdf
51. Bui, M., Fajardy, M. and Mac Dowell, N. (2017). 'Thermodynamic Evaluation of Carbon Negative Power Generation: Bio-energy CCS (BECCS)'. *Energy Procedia*, Vol. 114, Pages 6010-6020.

2. Natural gas and coal gasification emit the most CO_2. When coupled with CCS this reduces the emissions during the process considerably. Given that steam methane reformation is the most widely adopted production method this means that without a credible CCS policy and infrastructure this method of production would not be compatible with the UK's long term climate targets.
3. Renewables electrolysis (including lifecycle emissions), in particular wind alkaline, has the lowest emissions. This reinforces the view that the process is even more sustainable if electricity used is derived from renewable sources e.g., wind, solar, hydro, etc.

The proliferation of BECCS as a production technique seems an obvious conclusion to draw. However, before this is the case caution over BECCS should be displayed until the implied trade-offs with other land-based policy goals- such as agriculture- are better known.

Given the clear cost reduction pathway, the low production carbon intensity and the opportunities to build and export IP, it is recommended that a greater R&D effort should be put in to developing and lowering the cost of electrolysis production, targeting the most efficient processes.

Figure 2.7: Carbon intensity of different production methods



Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute.

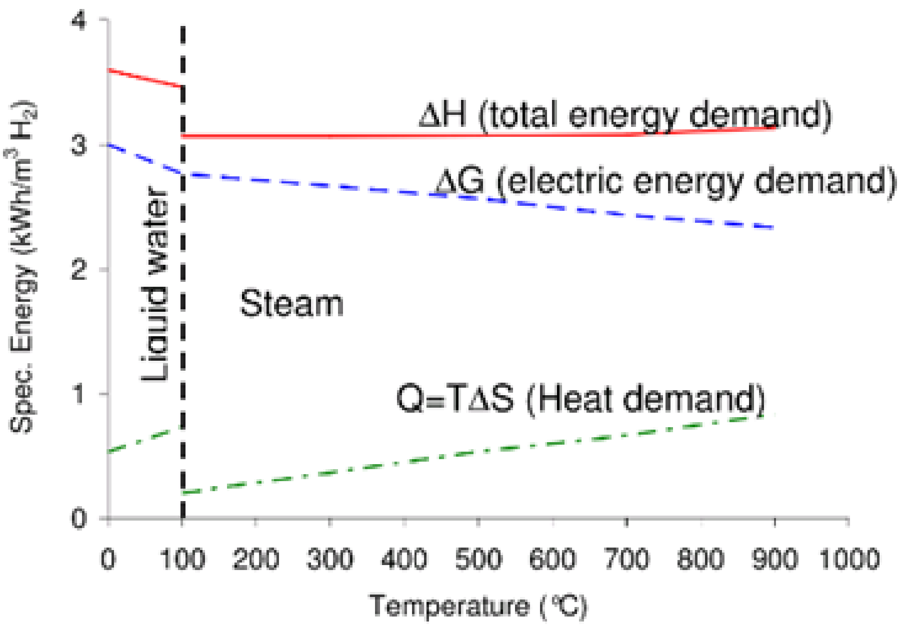
Waste Heat Hydrolysis

In addition to these (established) methods, there are alternative production methods that offer promising opportunities. Integrating processes that produce waste heat offers an opportunity to increase the efficiency and reduce the electrical power requirement needed to produce hydrogen. This is perhaps best exemplified by using high temperature heat sources, such as nuclear energy. Using high temperature heat to assist electrolysis with an alternative chemical process can improve efficiency from ≈ 50% to ≈ 70% as Moore states in his seminal paper.[53]

In terms of reducing the amount of electrical energy required for electrolysis, the transfer from water to steam electrolysis causes a significant drop in the electricity demand followed by a continuous decrease with increasing temperature,[54] as illustrated by Figure 2.8 below.

A number of processes in the UK generate waste/surplus heat that has no end market. Analysis by Ricardo Energy and Environment[54] suggests this could be as much as 46 TWh from power station heat, 3 TWh from waste incinerator heat and 3 TWh from industrial heat. Combined, this amounts to 52 TWh of heat. It is important to note that this will be relatively low-grade heat at temperatures towards the low end of the heat demand in Figure 2.8. That said it may be possible to make a contribution to efficiency gains and reductions in electricity inputs in the production of hydrogen. Combining waste heat with the production of hydrogen will help to decrease capital costs, but in order for steam electrolysis technologies to fully valorise waste heat into hydrogen there needs to be a route to market which there currently is not.

Figure 2.8: Waste Heat Electrolysis



52. Moore, J. (2017). 'Thermal Hydrogen: An emissions free hydrocarbon economy'. *International Journal of Hydrogen Energy*, Vol. 42, Issue 17, Pages 12047-12063.

53. Odukoya, A. and Naterer, G.F. (2014). 'Upgrading waste heat from a cement plant for thermochemical hydrogen production'. *International Journal of Hydrogen Energy*, Vol. 39, Issue 36, Pages 20898-20906.

54. Ricardo Energy & Environment. (2015). *National Comprehensive Assessment of the Potential for Combined Heat and Power and District Heating and Cooling in the UK*. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/499417/Final_NCA_Report_for_publication.pdf

Transportation and distribution

In theory there are no barriers to the transportation and storage of hydrogen that do not exist for natural gas (methane). There is a worldwide market for natural gas and it is transported from continent to continent via pipelines and tankers. However, due to the physical nature of hydrogen (H_2) compared with methane (CH_4), in reality it is significantly more challenging. Firstly, it is more difficult to contain due to the smaller molecules of hydrogen. Secondly, liquefying hydrogen for transport via road or sea requires more energy than for methane due to the fact that the temperature at which hydrogen becomes a liquid at atmospheric pressure is -253°C, whilst for methane it is -162°C. In practice, what this means is that it is more expensive to transport and store hydrogen than methane.

Hydrogen is mostly transported by road in the UK, but this is not going to be practical if it is to scale up to comprise a significant component of our energy system. For use in larger quantities it will either be produced where it is used or transported via pipeline or ship – local transportation of small amounts may still be practical via road. In the UK there are already emerging plans to use the existing natural gas networks to transport hydrogen and use it as a low carbon replacement for methane in home heating, industry and power.

Transport by ship has not yet happened to any major extent, but there are trials planned. Japan has high ambitions for developing a hydrogen economy and in April 2018 Kawasaki Heavy Industries confirmed they will collaborate with Australia's AGL Energy Ltd to produce hydrogen from coal gasification in Australia.[56] The resulting hydrogen will then be liquefied and exported to Japan via sea. As this has never happened before, Australia and Japan are working together to develop safety standards for the bulk transport of hydrogen via sea, which will be a major step towards creating a global hydrogen market.[57]

As the liquefying process results in significant energy losses, novel methods of transporting hydrogen in different forms are being researched, including to transport it in the form of ammonia (NH_3) which liquefies at higher temperatures and so could reduce energy losses.

Of course in certain cases it will be appropriate to produce hydrogen at the point of use. There is an advantage to this as it reduces the need for transport at all, thus saving energy and money, but this would need to be balanced with the economies of scale effects that can be achieved by large, centralised production facilities. Whether bulk production and long-distance transport or local small-scale production are more appropriate will depend on the specific location and application.

Large-scale hydrogen storage

A major advantage of hydrogen over electricity as an energy carrier is that it can more easily be stored in large quantities for large periods of time. This is especially useful in the UK, where energy demand is multiple times higher in winter than in summer due to home heating requirements. Storing enough hydrogen to provide a significant proportion of our winter

55. Kaye, B. (2018). 'Australia's AGL to host coal-to-liquid hydrogen export trial for Japan's Kawasaki Heavy'. *Reuters*. https://www.reuters.com/article/us-japan-hydrogen-australia/australias-agl-to-host-coal-to-liquid-hydrogen-export-trial-for-japans-kawasaki-heavy-idUSKBN1HJ0ET

56. Australian Maritime Safety Authority. (2017). 'Australia and Japan develop safety standards for shipping liquid hydrogen'. https://www.amsa.gov.au/news-community/news-and-media-releases/australia-and-japan-develop-safety-standards-shipping-liquid

needs would, however, require vast volume containment. Such volumes exist in the form of salt caverns. The UK already has 30 such caverns in use for storing natural gas and many of these could be repurposed for storing hydrogen.

In 2015 the ETI commissioned Atkins to assess the potential for salt cavern storage of hydrogen in the UK.[58] They found that a set of six such caverns could store 150 GWh of hydrogen for storage on a seasonal basis. For reference the entire domestic demand for natural gas for heating in the UK is over 300,000 GWh, equivalent to approximately 12,000 large salt caverns filled with hydrogen. Seasonal storage may be infeasible if referring to storing our entire winter demand for heating fuel from summer to winter. However, it is worth pointing out that natural gas storage is not intended to hold a whole winters worth of gas, rather it acts as more of a buffer to insulate against price shocks in the winter or for contingency against pipeline failure. With this in mind, large salt cavern storage facilities could still be useful in a hydrogen-based energy system to act as system buffers to smooth supply and demand over days and weeks, as is currently the case with our natural gas storage facilities.

Recommendations

- **Drive cost reductions and seek competitive advantage in production technologies as part of the Industrial Strategy Challenge Fund**
  - Given the clear cost reduction pathway, the low production carbon intensity and the opportunities to build and export intellectual property, it is recommended that a greater R&D effort should be put in to developing and lowering the cost of electrolysis and SMR + CCS.
  - The Government should prioritise demonstration projects to develop real cost evidence.

57. Energy Technologies Institute. (2015). *Hydrogen: The role of hydrogen storage in a clean responsive power system.* https://d2umxnkyjne36n.cloudfront.net/insightReports/3380-ETI-Hydrogen-Insights-paper.pdf?mtime=20160908165800

3 Decarbonising Hard to Reach Sectors

Decarbonising heat continues to be a perennial policy problem. Unlike like the power and the transport sector – which both have clear decarbonisation pathways – the future of heat is less clear, despite lots of work/research. Natural gas has been relatively untouched by the decarbonisation process so far but, as the focus turns to heat, this could change given that natural gas is the biggest single source of heat in the UK.

Domestic Heating

Policy

BEIS is undertaking a £25 million programme to explore the potential use of hydrogen gas for heating UK homes and businesses as well as the role of regulatory standards in delivering this. Following a competition, BEIS appointed Arup to run the project to test the possibility of domestic gas pipes for hydrogen and to develop a range of innovative hydrogen appliances such as boilers and cookers.

A further £10 million will sponsor the second phase of work by the Energy Systems Catapult on its Smart Systems and Heat Programme. The programme will help develop local energy plans alongside Local Authorities, and bring down the cost of energy bills, while supporting the development of the UK's low carbon heating projects. This project will run from 2017 to 2021 and will aim to define a hydrogen quality standard and will explore, develop and test domestic and commercial hydrogen appliances.

Gas Mains Replacement

Two key drivers exist for the continued utilisation of the gas networks: a) it currently supplies 87% of homes and 23 million households; and b) the 'Gas Mains Replacement Programme'. With some of the oldest iron gas pipes having been in the ground for almost 40 years, their replacement has become a priority for the Health and Safety Executive (HSE) in order to avoid damage to buildings and human life. Consequently, the HSE has advised the gas distribution networks (GDNs) to accelerate the rate of replacement for all cast iron mains within 30 metres of buildings.[59] This represents a significant investment in upgrading existing gas infrastructure.

Various programmes of iron mains replacement have existed for the last 35 years, with the focus since 2002 on the most 'at risk' pipes within a 30 year period[59]. Almost 100,000 old iron low pressure pipes will be

58. Vallely, L. (2015). 'Gas mains replacement programme: the story so far'. *Utility Week*. https://utilityweek.co.uk/gas-mains-replacement-programme-the-story-so-far/

59. Health and Safety Executive. (2013). 'Enforcement Policy for the iron mains risk reduction programme 2013-2021'. http://www.hse.gov.uk/gas/supply/mainsreplacement/enforcement-policy-2013-2021.htm

replaced with polyethylene mains by 2032. These improve the security and reliability of the network, limit repair work (lasting up to 100 years) and reduce the quantity of gas that can escape. More importantly perhaps, is that by 2032, the majority of the low-pressure distribution network – having been replaced by polyethylene – will now be compatible with hydrogen delivery.

Table 3.1: Network composition

	Km
National Transmission System	7,600
Distribution Networks	280,000
High Pressure	12,000
Intermediate/Medium Pressure	35,000
Low Pressure	233,000

Dodds, P. and McDowall, W. (2013). 'The future of the UK gas network'. Energy Policy, Vol. 60, Pages 305-316.

Concerns[61] have already been raised about whether the work has been undertaken in the most effective manner. If the distribution networks are subsequently underutilised or even abandoned then scrutiny will only intensify. Given the existing network upgrades, if cost effective and sustainable hydrogen production is forthcoming then the UK is well positioned to use hydrogen.

Domestic

The scale of the challenge should not be underestimated; a total of £32 billion a year is being spent in the UK heating homes and other buildings, accounting for nearly half of all energy consumed and one third of total greenhouse gas emissions. A UK market for low-carbon heating is beginning to emerge with three main sectors: domestic, industrial and services. Over the last three years, overall energy consumption in the heating sector has decreased by 3%, whilst transport has increased by 2% and non-heat by 1%. Within the heating sector, energy used domestically has fallen by 2% as has heat used in industry. In contrast, heat used in services has increased by 1% and is now the second largest heating sector.

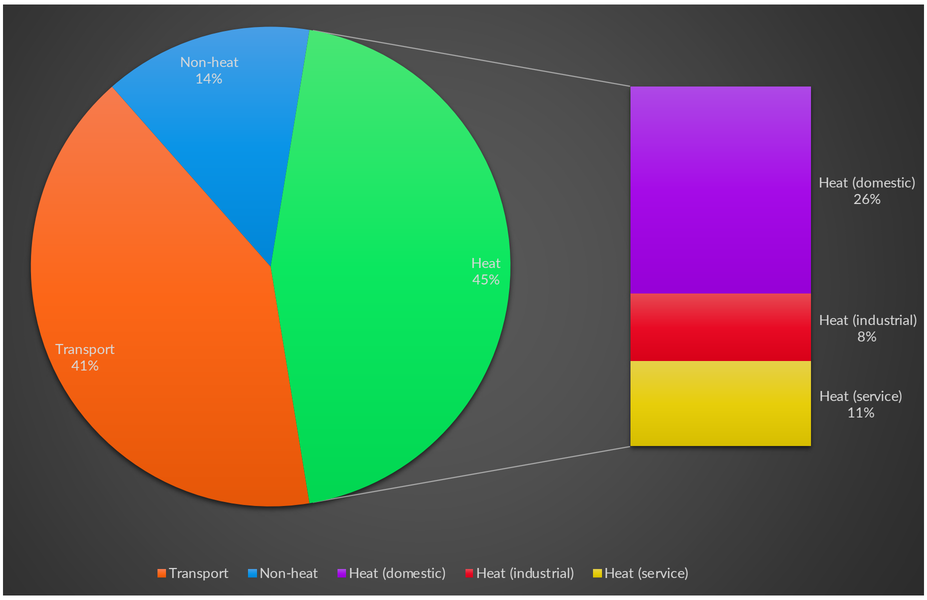
Within this market for heating, hydogen technolgies face competion from established and emerging technologies for water and space heating such as: condensing gas boilers, biomass boilers, heat pumps, solar water heating and district heating via heat networks.

Gas is by far the most dominant form of heating in UK homes. In 2016 gas met 76% of domestic needs when space heating, water heating and cooking are combined and the gas network supplied 87% of UK households (as of 2014).

The other main fuels used in domestic heating are electricity (8.7%), oil (7.2%), bioenergy and waste (5.9%) and solid fuel such as coal

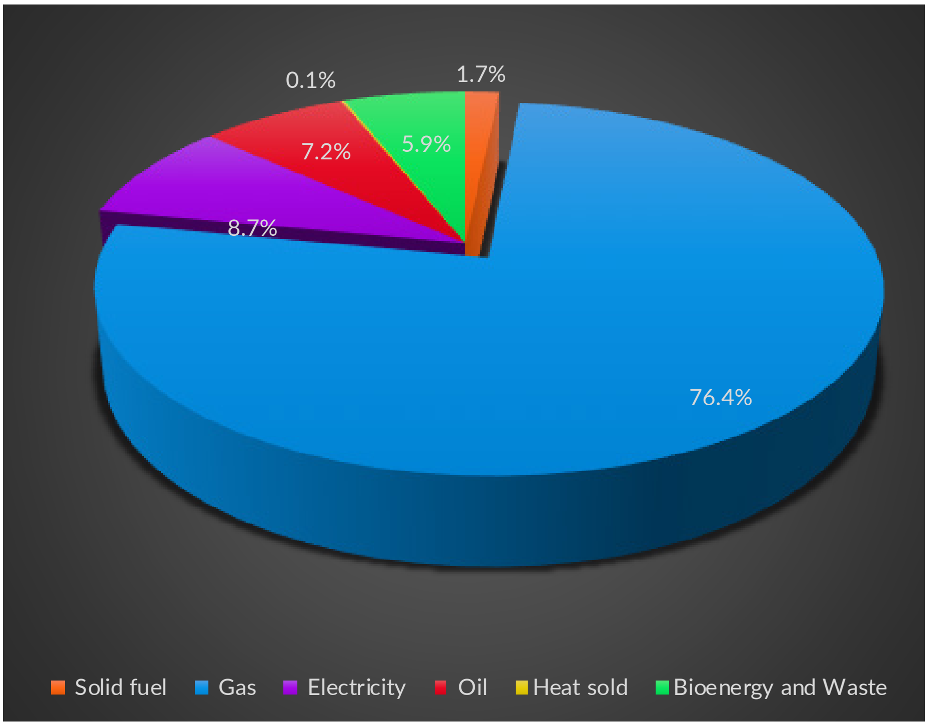
60. Health and Safety Executive. (2011). *10 year review of the Iron Mains Replacement Programme*. http://www.hse.gov.uk/research/rrpdf/rr888.pdf

Figure 3.1: Energy consumption by end use and sector, 2016



DBEIS (2017). Energy Trends.

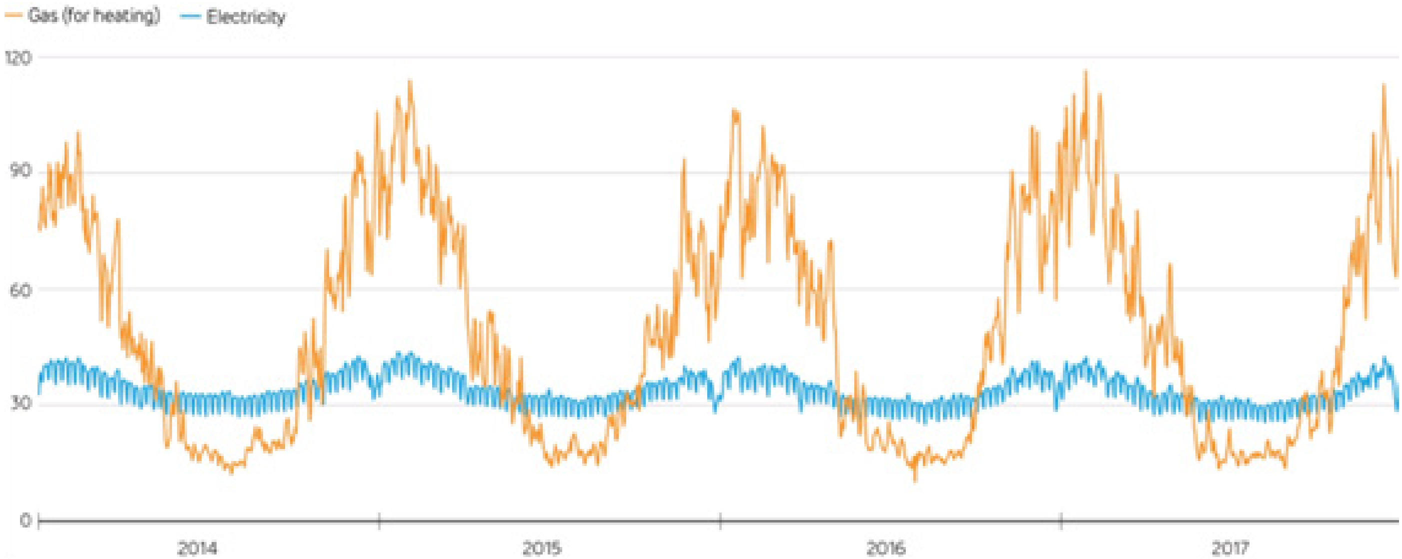
Figure 3.2: Fuels used in domestic heating, 2016



DBEIS (2017). Energy Trends.

(1.7%). It is striking that despite a concerted effort to electrify heat, there has only been an increase of 0.1% from 2013-2016. The slow pace of electric heating shows that there are problems scaling this approach. By contrast the penetration of condensing gas boilers, driven by the 2015 efficiency directive, reinforces the attachment to 'wet' central heating systems prevalent in today's domestic heating sector.

Figure 3.3: Daily average demand of heat and electricity (GW) 2014–2017



Drax Electric Insights. (2018). 'Quarterly Reports'.

Challenges of electrification

The relative success of power sector/electricity decarbonisation, led the UK Government to conclude that this new low carbon electricity could play a major role in decarbonising heat. Indeed, the 2013 Heat Strategy, produced by DECC (now BEIS) put forward a vision based on electrifying heat. Previous analysis by Policy Exchange in *Too hot to handle*[62] identified significant weaknesses with the Government's approach, in particular the challenge of meeting peak heat demand.

With the demand for heat reaching peaks of up to 120 GWs, or around 3 times the peak demand for electricity (40GWs), and the variable nature of the peaks, the impact of full electrification on peak demand would be significant. According to Baringa[63] this would necessitate around 105 GWe of additional electricity supply capacity. This represents an increase of 175% over and above current peak power demand levels and is equivalent to adding 130 large gas power stations to the grid. The capital cost of building this amount of gas generation capacity would be over £60 billion.[64] Clearly this would be an extremely costly way to decarbonise heating.

Figure 3.3 illustrates just how much greater heat demand is compared to electricity demand. Meeting variable and peak heat demand requires a large amount of storage. This is only possible at present due to the capability of the gas system to store energy and then quickly convert this into heat as required. The gas networks can store considerably more energy than the electricity system - 50,000 Gwh and 27 GWh respectively. The fundamental ability of the gas network to store more energy than the electricity system, and do so more cheaply (the cost of storing electricity is at least 2,000 times more expensive than gas on a £/MWh basis)[65] underpins the continued use of the gas network for decarbonising heat in the near term. That is not to say that improvements in electricity storage via batteries can't displace some of the gas for heating purposes, but it still remains relatively expensive and is

61. Howard, R. and Bengherbi, Z. (2016). *Too Hot to Handle? How to decarbonise domestic heating*, Policy Exchange.
62. Baringa-Redpoint (2013) Modelling to Support the Future of Heating: Meeting the Challenge. DECC; ETI (2014) Modelling Low-Carbon Energy System Designs with the ETI ESME Model
63. Ibid.
64. MacLean, K. et al (2016). *Managing Heat System Decarbonisation: Comparing the impacts and costs of transitions in heat infrastructure.* Imperial College London, Centre for Energy Policy and Technology. https://www.imperial.ac.uk/media/imperial-college/research-centres-and-groups/icept/Heat-infrastructure-paper.pdf

yet to scale to a size that can make a significant contribution.

Taking peak demand from figure 3.3 as 120GW of natural gas, if hydrogen was to fully replace it by 2050 – with large scale production commencing in 2030 – it would require 6GW of new hydrogen capacity to be built per each year, every year. To put this in to context, the installed capacity of wind (both offshore and onshore) grew at an average annual rate of 1.8GW between 2010-2017[66]. Installed hydrogen capacity would therefore have to grow at a rate three times as fast as what has been witnessed in the wind sector.

Models of hydrogen application

With regard to decarbonising heating, a number of different models have emerged, that range from full 100% conversion to hydrogen based heating to a blending approach with up to 20% hydrogen (by volume) used in to the gas network. The figure of 20% has been chosen because research has shown that this is the maximum quantity that can be blended whilst achieving the least disruption to consumers in terms of appliance compatibility. The Hydeploy project is examining how this would work in practice.

Meanwhile, increasing the quantity of hydrogen in the gas networks is inhibited by a number of barriers, explored below.

Box 3.1: Hydeploy Case Study

Hydeploy is a consortium that includes Cadent Gas Limited, Northern Gas Networks, Health and Safety Laboratory, ITM Power and Progressive Energy. In partnership with Keele University, the Hydeploy trials aim to establish the potential for blending up to 20% Hydrogen (by volume) into the gas network in an attempt to reduce CO2 emissions from heating. The project is funded by Ofgem's Gas Network Innovation Competition, Cadent and Northern Gas Networks and is split in to three phases:

1. Planning and safety tests to ensure homes and buildings involved in the trial are adequately prepared (April-September 2017)
2. Approval by the Health and Safety Executive and subsequent scheme design and building of equipment (July 2018- March 2019)
3. Live trial (April 2019- March 2020) commences with 100 houses and 30 faculty and multi-occupancy buildings

Barriers

Regulatory (Gas Standards)

Regulations, codes and standards have often not been designed with new sources of gas in mind, including bio-methane, synthetic natural gas and hydrogen. Whilst the Gas Act (1996) allows for the presence of these gases, secondary legislation, namely the Gas Safety (Management) Regulations (GS(M)R) presents a regulatory barrier that may restrict hydrogen deployment unnecessarily. The section below analyses this further.

65. DBEIS (2017). Energy Trends. https://www.gov.uk/government/collections/energy-trends

Gas standards present a significant barrier to hydrogen injection at present. The Gas Act and subsequent standards, although allowing for the presence of other gases, only really had natural gas in mind with no provision or flexibility to accommodate a wide range of gases that a future gas grid could transport.

Table 3.2 Gas Standards

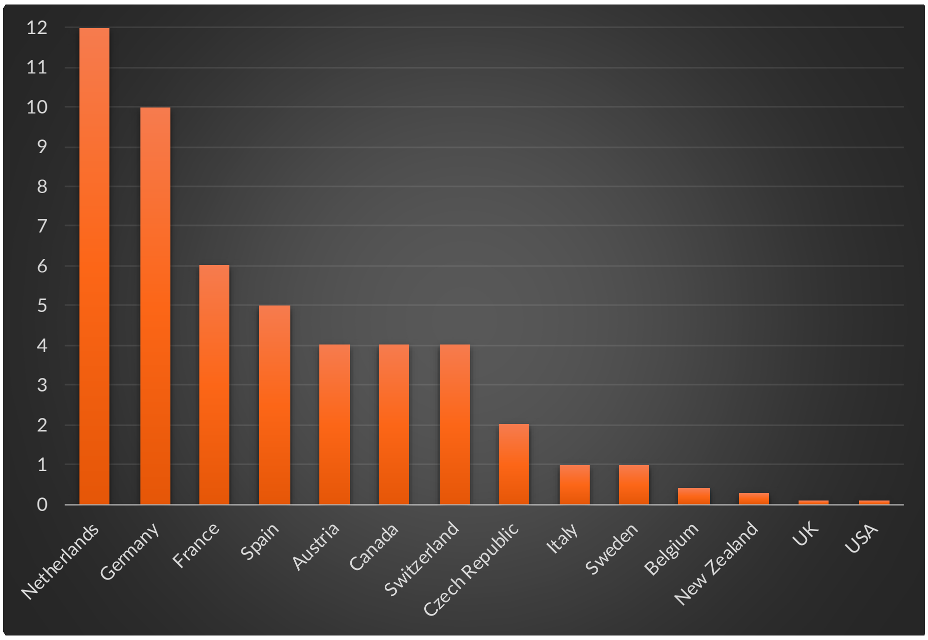
Content	Value
Hydrogen sulphide (H_2S) content	≤5 mg/m3
Total sulphur content (including H_2S)	≤50 mg/m3
Hydrogen content	≤0.1% (molar)
Oxygen content	≤0.2% (molar)

National Grid.

It is possible to gain exemptions from these standards, allowing Gas Networks to operate outside defined gas contents under the GS(M)R. However, consideration should be given to extending the range of gas standards in line with best practice and examples from other countries. At present, the UK has one of the lowest permitted levels of hydrogen blending in Europe (and further afield) as stipulated by the (GS(M)R). Under Schedule 3 'Content and other characteristics of gas', Regulation 8 Part I "Requirements under normal conditions" states that the hydrogen content and characteristics of gas shall be ≤0.1%.

The HSE is responsible for the rules that govern this as they are responsible for enforcing health and safety law for the onshore and offshore pipelines industry. A HSE report from 2015 concluded that "concentrations

Figure 3.4: Permitted levels of national hydrogen blending



Parkin, D. (2018). 'The UK Journey to Decarbonising Heat'. *ITM Power*.

of hydrogen in methane of up to 20% by volume are unlikely to increase risk from within the gas network for gas appliances to consumers or members of the public"[67] Blends below 20% require no modifications to end-user appliances which minimises consumer disruption. This builds on – and conclusions mirror – extensive experience in the Netherlands. A four year field trial from 2007 to 2011 found that when hydrogen was mixed in the natural gas supply, incrementally increasing from 5% to 20% (volume), (increasing the hydrogen content in steps of 5%) off-the-shelf gas appliances identified no serious problems in operation.[68]

Since the HSE concluded that far higher levels are safe as well as a growing body of literature and examples from other European countries, **this limit should be increased in accordance with the conclusion of the HSE** and could follow the Dutch example of increasing in 5% increments. This will allow higher quantities of hydrogen to be blended in to the network. Removing this regulatory barrier would be a quick win. Blend concentration may vary significantly due to natural gas composition within pipelines and the end-user typology, which is the reason it must be assessed on a case-by case basis.[69]

This is certainly true for power stations using gas such as Combined Cycle Gas Turbines (CCGT). It should also be noted that even at low blends gas turbines may require modifications and plant efficiency may be impacted at blends above 3-5%. Blends at this level could also increase NOx emissions. **These unintended consequences should be avoided where possible.**

Since CCGT's (Combined Cycle Gas Turbines) tend to connect to the gas transmission system, one solution may be to only permit the blending of hydrogen at the distribution level that could circumvent the problem. That said, there are over 5GW[70] of flexible gas reciprocating engines that are connected to the gas distribution network and they may still suffer. **Further work needs to be done to assess how the impacts of this can be mitigated.**

Billing

If hydrogen is to be blended in the gas network as envisioned in the Hydeploy scheme, Ofgem will also need to reconsider the regulations concerning how consumers are billed for the gas they consume. Gas is currently charged based on an assumed energy content which at the moment is uniform across the gas network. However, if hydrogen is injected into the grid in some areas but not others, then the energy content of mains gas would vary area by area. Billing systems would need to be changed to allow different households to be billed based on the energy-content (Calorific Value) of the gas they consume. This would also require the gas distribution network to be fitted with sensors to measure the energy-content of gas distributed to households.[71] National Grid are already alert to this and are currently investigating the possibility of assigning calorific value (CV) to smart meters to enable a specific energy calculation for the gas supplied to an individual property as well as how to

66. Hodges, JP. et al. (2015). *Injecting hydrogen into the gas network – a literature search*. Health and Safety Executive. http://www.hse.gov.uk/research/rrpdf/rr1047.pdf

67. Kippers, M.J., De Laat, J.C., Hermkens, R.J.M., Overdiep, J.J., van der Molen, A., van Erp, W.C., van der Meer, A., 2011. 'Pilot project on hydrogen injection in natural gas on Island of Ameland in the Netherlands'. In: *International Gas Union Research Conference 2011, Seoul, South Korea*. http://members.igu.org/old/IGU%20Events/igrc/igrc2011/igrc-2011-proceedings-and-presentations/poster%20paper-session%201/P1-34_Mathijs%20Kippers.pdf

68. de Santoli, L., Paiolo, R. and Lo Basso, G. (2017). 'An overview on safety issues related to hydrogen and methane blend applications in domestic and industrial use'. *Energy Procedia*, Vol. 126, Pages 297-304.

69. EMR Delivery Body

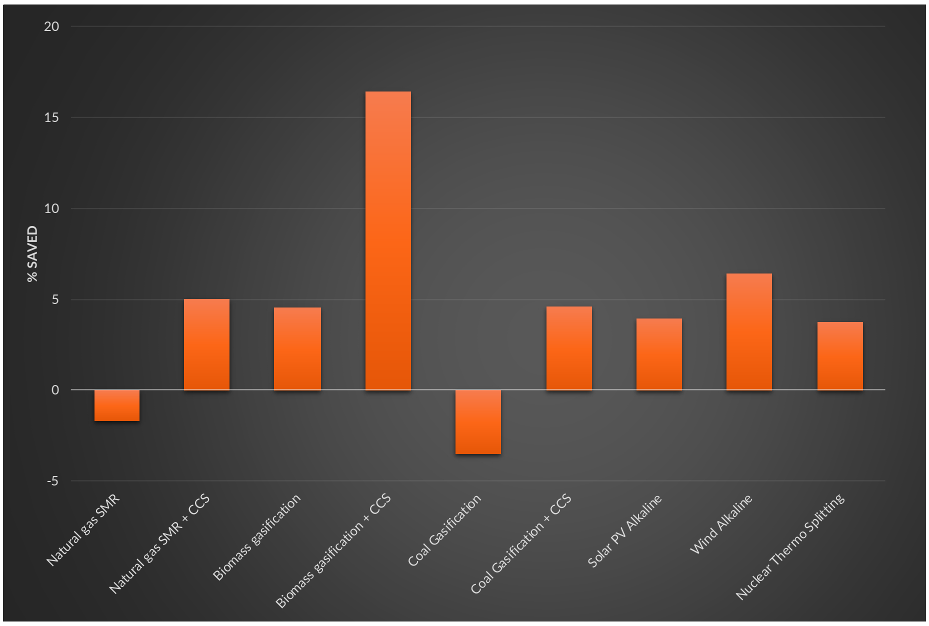
70. Howard, R. and Bengherbi, Z. (2016). *Too Hot to Handle? How to decarbonise domestic heating*, Policy Exchange.

calculate CV to gas flows within different parts of the network to calculate customers' actual energy usage[72]. There are two alternatives to this. Firstly, and linked to the issue of equity, would be to **continue to apply uniform pricing across the network and socialise the cost of price differentials** that occur as a result of hydrogen conversion in certain areas. Secondly, if Gas development Networks (GDN) know the hydrogen blend at a given time, then a price modification could be carried out as the GDN tier rather than wider UK socialisation.

Emissions reduction through hydrogen blending

Replicating the Hydeploy model of a 20% hydrogen blend by volume, our analysis below shows the impact of this scheme if it was replicated across the entire gas network. The analysis is presented in terms of how much carbon would be saved as a percentage reduction or increase against current lifecycle emissions of natural gas used in the gas network.

Figure 3.5: Emissions savings from 20% hydrogen blend by volume



The results show that blending 20% of hydrogen in the gas networks using either Natural gas SMR or Coal Gasification production techniques without CCS will increase overall emissions by 1.73% and 3.48% respectively. Biomass gasification with CCS delivers the biggest carbon savings, followed by wind alkaline and natural gas SMR with CCS. The latter two are considered the most scalable production techniques and could deliver savings of 4.9% and 6.3% respectively.

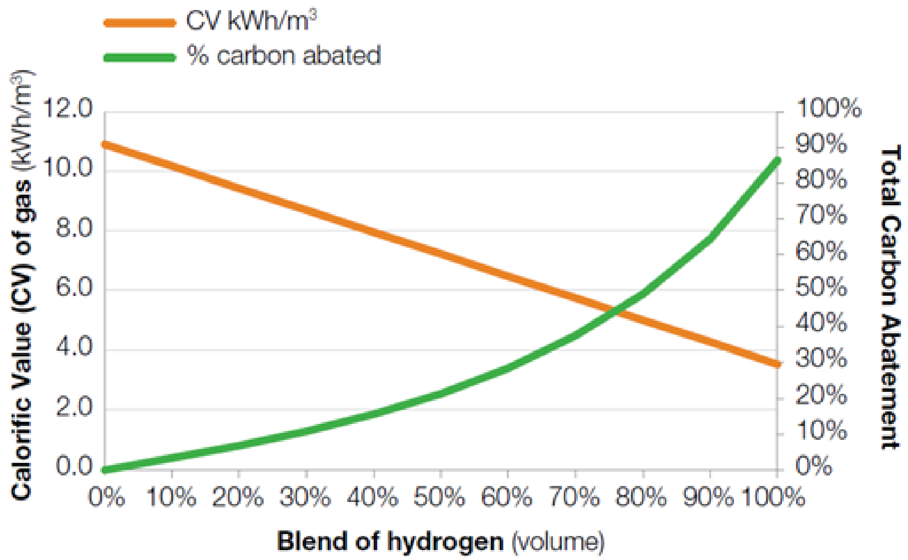
Production processes using fossil fuel feedstock without CCS are incompatible with global emissions targets and domestic decarbonisation targets under the Climate Change Act 2008. Clearly any benefits of using hydrogen are negated if production doesn't include CCS. This underpins the need for SMR with CCS and a wider CCS policy.

Part of the reason that a 20% blend only achieves a reduction of

71. National Grid Connecting. (2017). 'Hydrogen in the mix'. http://nationalgridconnecting.com/hydrogen-mix/

4.9% using SMR with CCS is because the calorific value of hydrogen is approximately 1/3 of natural gas, so larger quantities must be used to achieve the same output. This combined with relatively high lifecycle emissions in the production of the natural gas – which is the primary feedstock – mean that the overall carbon reduction is small. **As such this should be considered as a preliminary step in establishing the viability of cost effective and scalable steam reforming with CCS – but it would not in itself be anything like sufficient to achieve overall the emissions savings needed if the UK is meet its 4th and 5th Carbon Budget.** This points to the need for greater quantities of hydrogen in the gas network in order to achieve greater carbon reduction and this is supported by research conducted by the Energy Research Partnership.[73]

Figure 3.6: Hydrogen blend vs carbon abatement



Energy Research Partnership. (2016). *Potential Role of Hydrogen in the UK Energy System*.

However, to understand some of the challenges that exist with a 100% conversion to hydrogen, the Leeds H21 provides a good case study.

Leeds H21 scheme

The scheme aims to convert the gas grid to run on pure hydrogen. The first step was to examine the technical feasibility and economic viability of hydrogen, which has now been completed. The subsequent report[74] identified the main costs and challenges of hydrogen conversion as follows:

- **Hydrogen production:** the first challenge is how to produce the required volume of hydrogen. Whilst small amounts of hydrogen are already produced, mainly for industrial processes, a massive scale up is needed. To put this in to context, a recent report by SSE suggests that if 5% of the total consumption of gas – which was 900 TWh/annum in 2016 (DBEIS, 2017) – were to be substituted

72. Energy Research Partnership. (2016). *Potential Role of Hydrogen in the UK Energy System*. http://erpuk.org/wp-content/uploads/2016/10/ERP-Hydrogen-report-Oct-2016.pdf
73. Northern Gas Networks H21 Leeds Citygate Project. (2018). https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf

with hydrogen on a like-for-like calorific basis, this would require the production of 726,000 tonnes/year of hydrogen compared to a current UK annual production of electrolysed hydrogen of 100 – 200 tonnes/year.

- **CO_2 capture and storage:** hydrogen produced from an SMR process can only be considered low carbon if the CO_2 by-product is captured and permanently stored. As analysis in this report shows, net emissions will increase if CO_2 is not captured. However, there are currently no large scale CO_2 storage projects in the UK, and the future role out of CCS is uncertain given that the Government decided to cancel its £1 billion Carbon Capture and Storage Commercialisation programme in 2015.
- **Transmission Network and Storage**: once hydrogen is produced, a new hydrogen transportation system would be required to move hydrogen from where it is produced to the local gas distribution network. The study estimates that this would cost an estimated £230 million for a network serving the city of Leeds. Moreover, as the daily and seasonal peaks in heat demand vary so significantly (as fig 4.3 shows) large scale storage (intraday storage suitable for a 1 in 20 peak hour demand of 3,180 MW would be needed in order to meet peak demand). The report suggests a figure of £366 million to build two storage facilities to serve Leeds.
- **Distribution Network**: due to the gas mains replacement programme, which has converted old iron pipes to polyethylene, the gas distribution network and pipeline could transport hydrogen safely and this would not require substantial investment.
- **Appliance conversion**: lastly, additional costs will be incurred when gas appliances (i.e. boilers, and hobs where installed) are converted to be compatible with hydrogen. The cost of this is estimated to be just over £3,000 per home. There are already a few hydrogen appliances on the market, but appliance manufacturers would need to develop a wider range of products as well as warranties that allow for a change in the permissible limit of hydrogen in the gas network. It is estimated that this process in the Leeds case study would take three years to complete with individual consumers disconnected for no longer than a few days.

It is estimated that converting the gas system in Leeds will have a capital cost of £2.05 billion and an annual operational cost of £139 million. As mentioned earlier in the report, how the costs of such a scheme are shared is an important consideration when converting one area to hydrogen. In order to minimise the cost to consumers in Leeds, it is assumed that the costs will be shared across the entire UK population and so the increase to all consumer bills will be just 1%. If all the costs were borne by residents of the Leeds H21 scheme the increase in consumer bills would be inevitably higher. Putting cost aside for one moment, there are also a number of other complicating factors with 100% conversion to hydrogen.

Supply Chain Fragmentation

Up until the late 1980's, the UK monopoly utilities comprised of three relatively cohesive groups of organisations:

- National and international oil and gas companies.
- Gas transmission companies (National Grid now own and operate the UK's high pressure transmission network, supplying directly to industry or the local distribution network).
- Low pressure networks owned by local distribution companies.
- With the liberalisation reforms introduced by the Thatcher Government, the structure of the utility markets changed substantially. Whilst national and international oil and gas companies largely remained, transmission companies morphed intoa number of different groups[75]:
- Utilities holding generating assets – mainly gas-fired power stations;
- Mid-stream energy traders: trading gas, power and many other (energy and non-energy) products;
- Network companies: transmission system owners and operators (TSOs) and distribution system owners and operators (DSOs);
- Local distribution companies which serve smaller customers in competition with a range of other suppliers;
- Storage owners and operators, some of which are owned by TSOs and NOCs (National Oil and Gas Companies), and some in independent ownership.

What was previously a vertically integrated industry no longer exists today. The structure of the market now includes 4 main groups: 1) Producers and exporters of gas as a commodity; 2) Suppliers and traders of wholesale and retail gas; 3) Generation, regasification and storage asset owners; 4) Network owners (and operators).

Because the aims and objectives of these four groups are disparate, a coherent and unified vision sometimes struggles to emerge and represents a significant barrier to the future of gas decarbonisation, hydrogen production and operating machinery with hydrogen feedstock, all of which require co-ordination across supply and value chain groups. One example that illustrates the latter is the manufacturing warranties associated with commissioned CCGTs which do not allow for hydrogen blends above a couple of percent. **Without manufacturers underwriting for greater quantities of hydrogen, any existing warranties could become invalid.**

Given the fragmented nature of the value chain since market liberalisation, an important question to ask – assuming it is desirable – is **whether full scale conversion to hydrogen is even possible in a liberalised market**, since the previous conversion from town gas to natural gas – commensurate with the present day challenge – occurred in a command and control economy.

Furthermore, to facilitate hydrogen production clusters the fragmented

74. Stern, J. (2017). *The Future of Gas in Decarbonising European Energy Markets: the need for a new approach.* The Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/01/The-Future-of-Gas-in-Decarbonising-European-Energy-Markets-the-need-for-a-new-approach-NG-116.pdf

nature of research by and between leading universities, public sector organisations and professional institutions needs to coalesce around a coherent set of aims and objectives. Recognising that collaboration is key, researchers at Bath University organised an International Hydrogen Research Showcase spanning national and international research bodies, industries, governments and professional associations[76]. They concluded a coordinated programme was needed, one that will address the scientific, engineering, socioeconomic, policy and environmental aspects of hydrogen research.

Following this, the Hydrogen and Fuel Cells Supergen Hub (H2FC Supergen) was established to co-ordinate efforts and has since published a number of papers. Their recent publication 'The economic impact of hydrogen and fuel cells in the UK' concluded that the burgeoning UK hydrogen supply chain would require the reallocation of spending and related supply chain activity away from traditional fossil fuels.[77]

Governance
As outlined earlier, some cities or towns may be better placed to initiate full conversion to hydrogen heating. However, geographical conversions of this kind give rise to issues of governance pertaining to **consumer choice and rights.** For example, if a city decides to unilaterally switch the entire gas network from natural gas to hydrogen, to what extent can a household opt out of this? The inability to do so could give rise to a lack of equity between all network consumers that could be exacerbated if network conversions occur on a city by city basis. This could result in higher bills than they previously had or higher bills compared to neighbouring areas that haven't converted. **When Ofgem provide clarity on the scope and arrangements for the next RIIO charging period, this must give consideration as to how costs can be socialised in the most equitable way.**

Cost Effectiveness
Until some of these challenges are addressed, it is difficult to envision or indeed advocate a large conversion of the gas grid to hydrogen. At this point the RHI and other incentives should not change to encourage hydrogen for heating until the best use of hydrogen is determined.

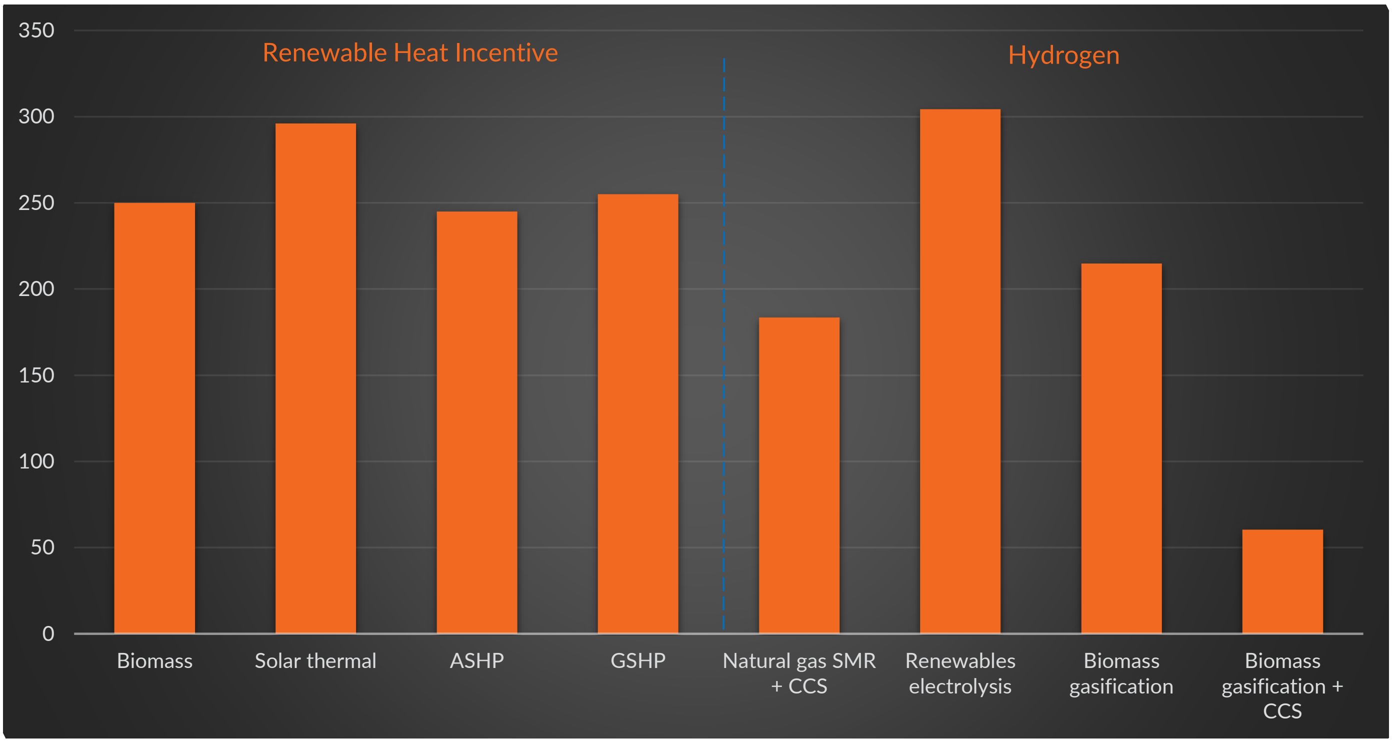
However, in the longer term if hydrogen for heating is deemed an appropriate application, the scaling challenges are overcome, and issues pertaining to consumer rights and choice are better understood, a support framework for hydrogen that is compatible with the overarching ambition of lowering the cost of decarbonising heat is potentially possible**.**

Examining the £/tonne abatement cost shown below illustrates that from an abatement cost perspective, hydrogen production is competitive with eligible RHI technologies. Indeed, renewable technologies eligible under the RHI (e.g. biomass, GSHP) are more expensive than other forms of hydrogen production such as steam methane reformation with carbon capture and storage (SMR + CCS). Hydrogen produced via SMR + CCS would deliver carbon savings at a quarter of the price of Air Source Heat Pump and Ground Source Heat Pumps, whilst hydrogen produced from

75. Mench, M. 'The case for a coordinated, less fragmented UK Hydrogen Energy programme'. *University of Bath.* http://www.bath.ac.uk/case-studies/the-case-for-a-coordinated-less-fragmented-uk-hydrogen-energy-programme/

76. Smith, M. J. et al. (2017) 'The Economic Impact of Hydrogen and Fuel Cells in the UK: A Preliminary Assessment Based on Analysis of the Replacement of Refined Transport Fuels and Vehicles'. H2FCSUPERGEN. http://www.h2fcsupergen.com/download-economic-impact-hydrogen-fuel-cells-uk/

Figure 3.7: £/tonne abatement versus existing subsidised technologies



RHI data from Chaudry, M. et al. (2015). 'Uncertainties in decarbonising heat in the UK'. *Energy Policy*, Vol. 87, Pages 623-640. and McManigal, B. (2016). 'Levelling the playing field: Unlocking heat infrastructure investment'. *The Association for Decentralised Energy*. Hydrogen figures from Policy Exchange analysis.

electrolysis would deliver carbon savings at approximately half the price. A support framework along these lines would ensure greater affordability to the taxpayer and make subsidies go further.

Against a backdrop of uncertainty regarding the continuation of the RHI beyond 2020/21, one alternative might be to **reform RHI in to a low carbon heat incentive focussed on the most cost-effective decarbonisation technologies including renewable and non-renewable technologies, at some stage incorporating those that can produce hydrogen**. Figure 3.7 illustrates that widening what is eligible to include hydrogen production technologies could lower the overall spend by Government whilst also reducing emissions. This is consistent with Governmental strategy that seeks to pursue a technology-neutral strategy to decarbonising heat focussing on the most cost-effective technologies available.

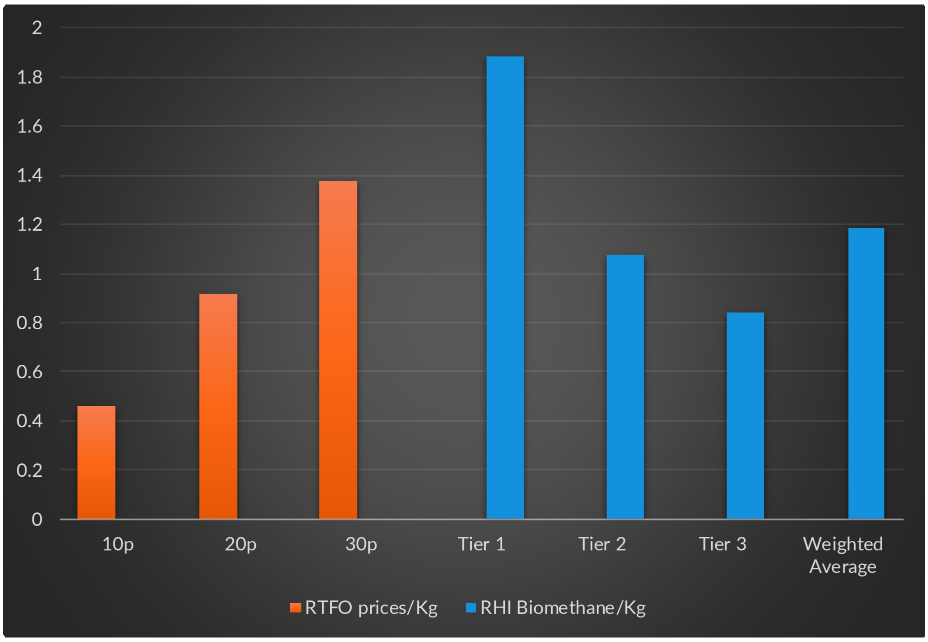
The difference in abatement costs between hydrogen production and those technologies eligible for RHI may appear modest – but this is the most conservative estimate, especially for ASHP and GSHP, as other studies[78,79] estimate these costs to be between £500-800/tonne CO_2 abated. Taking this upper band of abatement costs would mean hydrogen produced via SMRR + CCS would deliver carbon savings at a quarter of the price, whilst hydrogen produced from electrolysis would deliver carbon savings at approximately half the price. A support framework along these lines would ensure greater affordability to the taxpayer and make subsidies go further – a view also espoused by the CCC.[80]

77. Cadent (2017). *The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project*. Progressive Energy Ltd. https://cadentgas.com/getattachment/About-us/Innovation/Projects/Liverpool-Manchester-Hydrogen-Cluster/Promo-LMHC-downloads/Summary-report.pdf

78. The Association for Decentralised Energy (2016). *Levelling the playing field: Unlocking heat infrastructure investment*. https://www.theade.co.uk/assets/docs/resources/Levelling_the_playing_field_Unlocking_heat_infrastructure_investment.pdf

79. Committee on Climate Change. (2017). *Meeting Carbon Budgets: Closing the Policy Gap: 2017 Report to Parliament*. https://www.theccc.org.uk/wp-content/uploads/2017/06/2017-Report-to-Parliament-Meeting-Carbon-Budgets-Closing-the-policy-gap.pdf

Figure 3.8: Value of 1kg of hydrogen under RTFO and RHI biomethane tariff



In addition to demonstrating that hydrogen production technologies could lower the overall spend by Government whilst reducing emissions, it important to analyse what level of government support might bring forward hydrogen production. Research suggests that hydrogen production for transport is the most viable business model due to support under the RTFO. Assuming this is the case; figure 3.8 illustrates the value of 1kg of hydrogen receiving support from the RTFO under three price sensitivities (10p, 20p and 30p per RTFO certificate) and a scenario where 1kg of hydrogen receives support under current biomethane RHI tariffs.

Figure 3.8 shows that 1kg of hydrogen produced for transport - which received a RTFO certificate worth 10p - would return a value £0.46 per kg. If the RTFO certificate was worth 20p, the value of a kg of hydrogen would be £0.92. If the RTFO certificate was worth 30p, the value of a kg of hydrogen would be £1.37.

Now, if hydrogen produced for low carbon heat was to achieve similar values, it would also need support. Here the biomethane RHI tariff is used as a proxy for support. Hydrogen produced under tier 1 receiving a tariff of £0.05 would return a value of £1.88 per kg, under tier 2 with a tariff of £0.032 the value would be £1 per kg and under tier 3 with a tariff of £0.025 the value would be £0.84 per kg. The weighted average off all tiers is £1.18 per kg. To achieve the weighted average value of £1.18 per kg requires support of approximately £0.035 per kWh. This would enable hydrogen produced for low carbon heat to be competitive with hydrogen produced for low carbon transport.

Energy Efficiency

Ultimately there is no substitute for a coherent energy efficiency policy and this should underpin all efforts to decarbonise heating.

Improving energy efficiency is amongst the easiest and cheapest ways to decarbonise our energy system and can make a significant contribution to decarbonising heating, as well as reducing the quantum of non-fossil fuel gas required in the future. Whilst the UK has made some progress, greater ambition is needed.

New homes need to be built to the highest possible energy efficiency standards, in order to reduce heating demand and associated emissions. Although building regulations have been successively tightened in recent years, no significant changes in building regulations have been seen since 2014. Scrapping of the zero carbon policy in 2015 created significant uncertainty when supply chains and businesses were ready to comply, following nine years of preparation. Net zero carbon standards by 2030 are now back on the agenda, but this new target illustrates 15 years of missed efficiency opportunities.

Energy efficiency has previously been championed by Policy Exchange in a number of past reports such as 'Too hot to Handle', 'Warmer Homes', 'Efficient Energy policy' and 'How to boost business energy productivity'. Past policy recommendations include:

- Energy efficiency should be considered a Top 40 national infrastructure priority. This could now be put into practice by making energy efficiency an area of focus for the new National Infrastructure Commission;
- Government should strengthen requirements for landlords to improve efficiency by tightening the Private Rented Sector Energy Efficiency regulations;
- Linking the Stamp Duty system to the energy performance of a dwelling to create an incentive for homebuyers to purchase a more efficient dwelling;
- Reforming mortgage affordability tests to better reflect the energy performance of a dwelling and to encourage lenders to offer energy efficiency mortgages.

With reference to the last recommendation, the use of 'green mortgages' has gained traction, featuring in the Government's Clean Growth Strategy published in 2017. In April 2018 Barclays announced plans to launch a green mortgage where buyers of new-build energy efficient homes can access lower interest rates.[81] The National Infrastructure commission in its 2018 National infrastructure Assessment also took up the baton of energy efficiency concluding that "improving the energy efficiency of the UK's buildings will reduce demand for heat and mitigate some of the emissions".[82]

Policy Recommendations

As there is no silver bullet, decarbonising hard to reach sectors will need a nuanced approach, with an understanding that measures which are appropriate to certain areas might not be right elsewhere. For example,

80. Cuff, M. (2018). 'Barclays launches its first green mortgage'. *Business Green*. https://www.businessgreen.com/bg/news/3029690/barclays-launches-first-uk-green-mortgage
81. National Infrastructure Comissions, 2018. *CONGESTION, CAPACITY, CARBON: PRIORITIES FOR NATIONAL INFRASTRUCTURE*

this might include hydrogen in the North West, heat pumps in rural off grid areas and district heating networks in areas that are heat dense and where CHP plants are being developed.

- **Promote lowest cost options**
  - Reform RHI in to a low carbon heat incentive focussed on the most cost-effective decarbonisation technologies including renewable and non-renewable technologies, incorporating those that can produce hydrogen.
- **Encourage green gas**
  - Since the HSE concluded that blending up to 20% hydrogen by volume is safe, the limit should be increased from 0.1% in accordance with the conclusion of the HSE to create the conditions needed to help stimulate the supply side market. This could begin in 5% increments.
  - However, as blending up to 20% volume delivers carbon savings of only ≈ 5% – this should be considered as a preliminary step in establishing the viability of cost effective and scalable steam reforming with CCS.
- **Improve supply chains**
  - Warranties associated with plant machinery and equipment, and domestic appliances need to be developed that allow for a change in the permissible limit of hydrogen in the gas network.
- **Support appropriate governance**
  - Geographical conversions of this kind give rise to issues of governance pertaining to consumer choice and rights. Consideration must be given to the distributional impacts.
  - When Ofgem provide clarity on the scope and arrangements for the next RIIO charging period, this must give consideration as to how costs can be socialised in the most equitable way.
- **Drive energy efficiency**
  - Sitting alongside the use of hydrogen to decarbonise industry needs to be a coherent energy efficiency policy. Both strategies should be pursued in tandem.

Industry

Whilst industrial decarbonisation is valuable in its own right, it increasingly sits as part of a broader set of strategic actions and initiatives an organisation can take in order to create, maintain or improve a sustainable competitive advantage. These are enabled by improvements in technology and provide scope to drive cost reductions and access new markets.

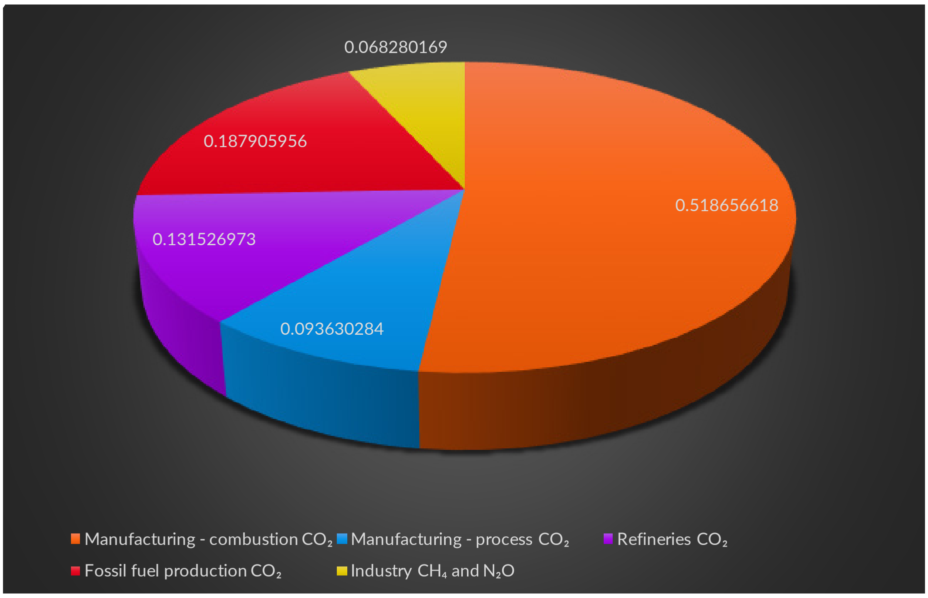
Despite industry reducing emissions by 49% from 1990-2017, there has been a recent stall in emissions reductions over the last five years. In 2017 both temperature adjusted and unadjusted emissions rose by 1% – the latter more than any other sector.

Within industry, using 2017 figures, 60% of greenhouse gas emissions

Figure 3.9: Change in UK CO2 emissions between 2016 and 2017

Committee on Climate Change. (2018). *Reducing UK Emissions: 2018 Progress Report to Parliament*

Figure 3.10: 2017 emissions from industry



Ibid

(GHG) came from manufacturing (combustion and process). The remaining 40% is made up from refining of petroleum products, fossil fuel production and usage of nitrogen and methane gases.

The GHG emissions from the UK industrial sector can be split by sub-sector. Table 3.3 shows that emissions are dominated by a small number of industries. Indeed, 73% of emissions are derived from 6 subsectors: Iron and steel; refineries; construction; chemicals; cement and lime; and food, drink and tobacco.

Given that a small number of sectors dominate, this suggests Pareto like priorities for decarbonisation. The UK Government has recognised the pressing need for industrial decarbonisation, producing the Clean Growth

Strategy alongside seven Industries Decarbonisation and Energy Efficiency Action Plans and the Industrial Strategy White paper.[83] Combined, these provide a framework for industrial energy efficiency and decarbonisation – with a number of technological options put forward.

These include energy efficiency, material efficiency, electrification of heat, carbon capture and storage (CCS) and fuel switching. In this context, the potential role of hydrogen lies with the latter as fuels can be switched to biomass or greener gases such as hydrogen, particularly as gas is the dominant feedstock used by industry, accounting for 50% of all fuel used for heating.

Table 3.3: Industrial emissions by subsector

Subsector	Emissions share
Iron and steel	17%
Refineries	14%
Construction	12%
Chemicals	12%
Cement and lime	10%
Food, drink and tobacco	8%
Wood	4%
Mechanical engineering	4%
Rubber and plastics	3%
Paper, pulp and printing	3%
Glass and ceramics	3%
Vehicles	2%
Water and waste management	2%
Textiles	2%
Other manufacturing	2%
Non-ferrous metals	1%
Electrical engineering	1%

Policy

The Government has recognised the need to incentivise industry to begin switching from fossil fuel use to low carbon alternatives. This was highlighted in the Clean Growth Strategy (2017), which accepted that beyond 2030, the switch to low carbon fuels for industry will need to substantially increase in scale. Consequently, the Government has launched the first phase of an innovation competition that has been allocated up to £20 million and focuses on market engagement and potential scope for fuel switching in industry. The competition aims to stimulate early investment in fuel switching processes and technologies, so that a range of technologies are available by 2030.[84]

Within the industrial sector, fuel switching to hydrogen is a technically viable option. It is considered to be an innovative technology with potential to decarbonise the iron and steel sector in the long-term. Box 3.2 looks at

82. Cooper, S. and Hammond, G. (2018). 'Decarbonising Industry: Towards a Cleaner Economy'. *University of Bath*. http://blogs.bath.ac.uk/iprblog/2018/02/13/decarbonising-industry-towards-a-cleaner-economy/

83. DBEIS. (2017). 'Funding for low carbon industry'. https://www.gov.uk/guidance/funding-for-low-carbon-industry

how hydrogen is already helping to produce fossil free steel.

Such large-scale projects will help to demonstrate the feasibility of clean hydrogen use in industry and will provide the basis for more widespread adoption of low-carbon hydrogen feedstock beyond 2030. However, whilst this shows that it is technically feasible to deliver such projects, it is also estimated that this will raise steel production costs by 20-30%.[85] Reducing these costs is therefore key, and the Government should work with industry to understand how to produce steel using hydrogen from renewable electricity in a cost competitive way.

Box 3.2: HYBRIT – Toward fossil-free steel[v]

In 2016, SSAB, LKAB and Vattenfall joined forces to create HYBRIT – a joint venture project seeking to develop low carbon steel. HYBRIT aims to replace coking coal, traditionally needed for ore-based steel making, with hydrogen. The result will be the world's first fossil-free steel-making technology, with virtually no carbon footprint.

A pre-feasibility study was conducted between 2016-2017 and this provided the basis for the next phase of HYBRIT. The Swedish Energy Agency contributed SEK 60 million (approximately £6.8million) to the pre-feasibility study and a four-year-long research project. This concluded that fossil-free steel produced today, given the price of electricity, coal and CO2 emissions, would be 20-30% more expensive than conventional steel. But with falling prices in electricity from fossil-free sources and increasing costs for CO2 emissions through the European Union Emissions Trading System (ETS), the pre-feasibility study considers that fossil-free steel will, in future, be able to compete in the market with traditional steel.

In spring 2018, a pilot plant for fossil-free steel production will be planned and designed in Luleå and the Norrbotten iron ore fields, 250 km North West of Luleå. Sweden has unique conditions for this kind of project, with good access to fossil-free electricity, Europe's highest-quality iron ore and a specialised, innovative steel industry. In spring 2018, HYBRIT will also begin looking at the possibilities of broadening the project to include Finland. If the HYBRIT scheme is successful it has the potential to reduce Sweden's CO2 emissions by 10% and Finland's by 7%.

The cost of planning and designing the pilot plant is estimated at SEK 20 million (approximately £1.7 million). Half of the finance will be provided by the Swedish Energy Agency and the other half will be covered by joint venture. The pilot phase is planned to last until 2024, after which it will move to the demonstration phase in 2025-2035 -with the overall aim of the scheme to have a solution for fossil-free steel by 2035.

To be able to carry out this project, however, a number of barriers need to be overcome. This includes access to fossil-free electricity, improved infrastructure and rapid expansion of high voltage networks, research initiatives, faster permit processes and the government's active support for the pilot.

v. SSAB. 'HYBRIT – Toward fossil-free steel'.

84. SSAB. 'HYBRIT – Toward fossil-free steel'.

Moreover, using hydrogen for the production of low carbon steel can also open up additional revenue streams. The H2FUTURE[86] project provides a good example of this. It is a European flagship project for the production of low carbon hydrogen using renewable energy and electrolysers. Under the coordination of the Austrian utility VERBUND, the steel manufacturer Voestalpine and Siemens, a large-scale 6 MW electrolysis system will be installed and operated at the Voestalpine Linz steel plant in Austria. The Austrian transmission system operator (TSO) Austrian Power Grid (APG) is supporting the prequalification of the electrolyser system for the provision of ancillary services. This illustrates how organisations and business can unlock additional revenue streams from on-site equipment – mirroring many of the opportunities that UK businesses currently have. For example, demand shifting and grid services offer additional means of increasing energy productivity. These form part of a Demand Side Response (DSR) continuum, ranging from price signals such as avoiding grid charges at peak times to procured services such as capacity or frequency regulation. As highlighted in Policy Exchange's report 'Clean Growth: How to boost business energy productivity',[87] Demand Turn Up (DTU) is one potential source of revenue within the Reserve Market. It has been developed to allow demand side providers to increase demand (either through shifting consumption or reducing embedded generation) as a solution to managing excess renewable generation when demand for electricity is low.

Feedstocks

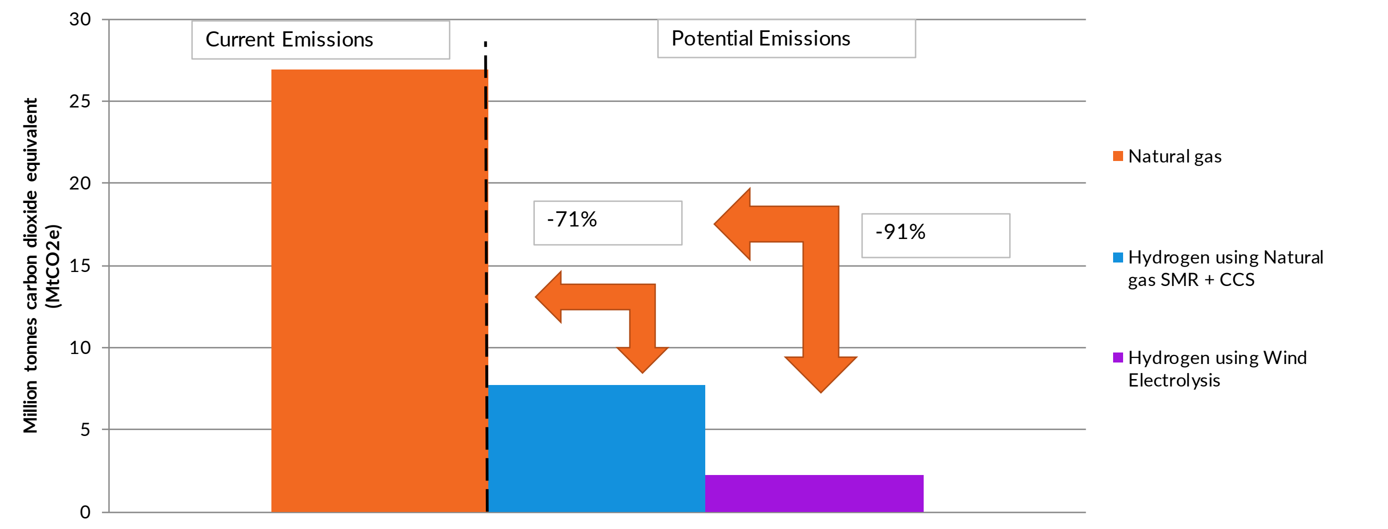
Almost all of globally produced hydrogen is used for refining ammonia and methanol, accounting for 31%, 50% and 10% respectively.[88] Against a backdrop of increasing demand for hydrogen feedstock – estimated to be by 3.5% per year[89] – the need to decarbonise its production is paramount. Hydrogen as a feedstock can be decarbonised by using renewable sources or CCS. Going further, green hydrogen could replace other fossil fuels as feedstock that certain industries rely on. For example, it could be used together with captured CO_2 to replace fossil feedstock in the production of hydrocarbon-based chemicals such as methanol or it could replace carbon (from natural gas or coal) as a reducing agent in the iron-making process.[90]

Industries that currently use hydrogen as a feedstock include the refining industry and the production of fertiliser (based on ammonia) and chemicals (based on methanol). If both of these industries continue to grow as expected, so will the demand for hydrogen. An increase in demand for hydrogen is driven, in part, by different factors, including; oil refineries seeking to reduce the sulphur content of fuels in accordance with stricter desulfurisation requirements; and the fertiliser and chemical industries, where the demand for hydrogen is likely to grow.

Yet, at present almost all hydrogen production for use as industry feedstock is not decarbonised and is currently produced on-site in dedicated plants or as a by-product from other processes. If the production of hydrogen feedstock is decarbonized (through carbon capture, electrolysis or through the increased use of by-product hydrogen), this could reduce

85. H2FUTURE. (2017). https://www.h2future-project.eu/
86. Burke, J. (2017). *Clean Growth: How to boost business energy productivity*. Policy Exchange.
87. Hydrogen Council (2017). Hydrogen Scaling Up: A sustainable pathway for the global energy transition. http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-Scaling-up_Hydrogen-Council_2017.compressed.pdf
88. Hydrogen Europe (2017). 'Decarbonise Industry'. https://hydrogeneurope.eu/index.php/decarbonise-industry
89. Hydrogen Council (2017). *Hydrogen Scaling Up: A sustainable pathway for the global energy transition.*

Figure 3.11: 2016 industrial emissions vs potential emissions



global annual CO_2 emissions by as much as 440 million tons in 2050.[91]

One example of new industry feedstocks is the George Olah Renewable Methanol Plant in Svartsengi, Iceland, which began production in late 2011 and was completed in 2012. All energy used in the plant comes from the Icelandic grid, which is generated from hydro and geothermal energy. The plant uses this electricity to make hydrogen, which is converted into methanol in a catalytic reaction with carbon dioxide (CO_2) and capturing the CO_2. In 2015 the plant expanded from a capacity of 1.3 million litres per year to more than 5 million litres a year (of methanol). The plant now recycles 5.5 thousand tonnes of carbon dioxide a year that would otherwise be released into the atmosphere.[92] Independent research by SGS GROUP – an inspection, verification, testing company – suggests that the use of renewable methanol from the plant releases 90% less CO_2 than the use of a comparable amount of energy from fossil fuels.

Looking specifically at the UK context, final energy consumption in the industrial sector is dominated – electricity and natural gas. They account for 34% and 36% respectively. Switching these fuels to cleaner alternatives such as hydrogen could help to decarbonise industrial sectors – but by how much?

Switching away from electricity provided by the grid towards cleaner on-site generation would be very challenging for certain industry groups. Where this is the case, replacing natural gas with hydrogen, either through conversion of the local gas grid or on-site storage may offer a more realistic route to decarbonisation. Figure 3.11 illustrates the 2016 emissions from natural gas used in industry amounted to just over 25 million tonnes. If natural gas were completely replaced by hydrogen – the emissions would drop by 71% if the hydrogen was produced by SMR with CCS or 91% if produced by wind power electrolysis. Despite the obvious decarbonisation benefits, this could increase manufacturing cost by 20-30% in the short term. Reducing these costs is clearly needed to maximise the benefits of fuel switching.

90. Ibid.

91. Carbon Recycling International. (Date Unknown). ' World's Largest CO_2 Methanol Plant'. http://carbonrecycling.is/george-olah/

A pilot project in the UK, seeking to convert large industrial users to hydrogen instead of natural gas is already underway.

Box 3.3: Liverpool–Manchester Cluster[vi]

The Liverpool-Manchester cluster project is a conceptual study to develop a practical and economic framework to introduce hydrogen into the gas network in the Liverpool-Manchester area.

The project proposes to produce hydrogen using Steam Methane Reformation with the removal, capture and storage of any CO2 produced during the process. Unlike other pilot schemes in the UK, the hydrogen will serve 10 –15 large industrial customers (with demand > 5.9 GWh/annum) and will be blended in to the gas network rather than converting the network to run completely on hydrogen.

This region was chosen as the location for the project because both are industrial areas with a cluster of process industries, both are close to potential offshore CO2 stores and both are close to extensive salt deposits already used for natural gas storage enabling the future extension of an initial project

CO2 emissions emitted whilst producing the hydrogen will be stored in Liverpool Bay Oil and Gas Fields, and it estimated that this could be approximately 1.5 million tonnes per annum.

The project will supply 1,620 GWh/annum of hydrogen, and this equates to blending 10% by volume in to the gas distribution network. Unlike in domestic gas supply where demand is highly seasonal, seasonal variation for industrial demand is minimal, with peaks of 482 GWh in winter and lows of 353GWh in winter. The smaller variation in demand means that the scale of hydrogen production and storage infrastructure is less than if this project was supplying hydrogen to domestic homes.

Industrial Hydrogen Hubs/ Hydrogen Production Hubs

Northern England and Scotland are advantageous for the development of hydrogen production hubs due to their concentration of industry but also because moving further North, population and market density reduces significantly. Consequently, cluster locations in Scotland but also Liverpool, Manchester and Teesside are interesting from a strategic UK Government investment perspective in terms of industrial strategy. Their relative distance from London's financial markets makes it more difficult for them to attract venture funding than is the case for the South East and Midlands. As such, deliberate national investment in clustering in the North makes sense.[93] Moreover, northern England and Scotland are advantageous for the development of hydrogen production hubs due to the location of wind turbines and grid constraints.

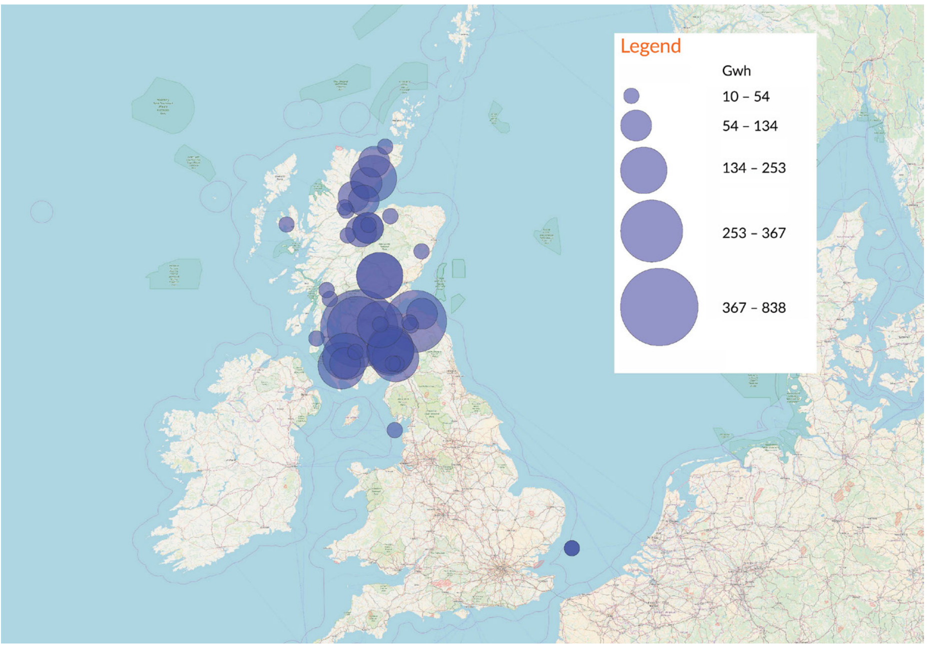
The latter is a particular problem in Scotland, where 7.7 GW of wind capacity feeds a demand that averages just 3 GW[94]. Until recently there were only three highly congested north-south transmission lines connecting Scotland to England and Northern Ireland, with a total capacity of 3.25 GW. This helps to explain why curtailment clusters arise in this area.

vi. Cadent (2017). The Liverpool-Manchester Hydrogen Cluster: A Low Cost, Deliverable Project. Progressive Energy Ltd. https://cadentgas.com/getattachment/About-us/Innovation/Projects/Liverpool-Manchester-Hydrogen-Cluster/Promo-LMHC-downloads/Summary-report.pdf

92. Smith, M. J. et al. (2017) *The Economic Impact of Hydrogen and Fuel Cells in the UK: A Preliminary Assessment Based on Analysis of the Replacement of Refined Transport Fuels and Vehicles*. H2FCSUPERGEN. http://www.h2fcsupergen.com/download-economic-impact-hydrogen-fuel-cells-uk/

93. Staffell, I. and Joos, M. (2018). 'Wind farm curtailment falls by two-thirds'. *Electric Insights*. http://electricinsights.co.uk/#/reports/report-2018-q1/detail/wind-farm-curtailment-falls-by-two-thirds?&_k=0zr7dr

Figure 3.12: Curtailment Clusters



Since December 2017, a new transmission line (Western HVDC Link) with a capacity of 2.2GW that connects Scotland and North Wales has been in partial operation. Now this is live, how curtailment rates change going forward will be interesting to observe. Initial analysis suggests wind farm curtailments have fallen by two thirds.[95]

It is important to recognise that the UK is not homogenous in terms of its energy production or markets. This is illustrated by figure 3.12 and shows where wind power and subsequent curtailment is located. As such, the UK Government should give serious consideration to **developing nuanced regional support programmes capable of incentivising local investment based on their particular energy circumstances.[96]** This echoes one of Policy Exchange's previous recommendations in *Too Hot To Handle?* which put forward the idea of a national strategy with a localist approach.

For example, decarbonised gas solutions will only be feasible for buildings connected to the gas grid. Beyond that, there will be heat-dense regions located near sources of low carbon heat, well-suited to heat networks, and rural off-gas regions well-suited to heating using biomass. New and well-insulated existing buildings may be better suited to heating with heat pumps. These specific local circumstances relating to the electricity or gas grid, and the presence of local renewable sources of energy, will provide both constraints and opportunities[96], resulting in a mix of heating options being deployed.

As the wind curtailment clusters and the majority of onshore wind farms are almost exclusively located in the Scotland, this highlights a regional opportunity, not just for the utilisation of curtailed and non-curtailed wind power, but wider hydrogen production and CCS development. Underpinning any decision to develop hydrogen production clusters should be an appreciation of the specific local economic or geographical circumstances.

94. Ibid.
95. Dodds, P. E. and Hawkes, A. (Eds.) (2014). *The role of hydrogen and fuel cells in providing affordable, secure low-carbon heat.* H2FC SUPERGEN, London, UK. http://www.h2fcsupergen.com/wp-content/uploads/2014/05/H2FC-SUPERGEN-White-Paper-on-Heat-May-2014.pdf
96. Element Energy (2018). 'Cost analysis of future heat infrastructure options', E4tech. https://www.nic.org.uk/wp-content/uploads/Element-Energy-and-E4techCost-analysis-of-future-heat-infrastructure-Final.pdf

Therefore in this context, the hubs main focus should be driven by:

a. the need to maximise the use of renewables generation (including curtailed power) with the primary objective of establishing electrolysis-based hydrogen production; and
b. the unique proximity to abundant geological storage under the Central North Sea and existing infrastructure from 40 years of oil and gas production.[97]

The dual aim being to examine how PtG may improve the ability to reduce system costs and be a cheaper alternative to infrastructure upgrades/ network reinforcement, deployment of CCS to enable and establish cost effective hydrogen production from SMR as well as opportunities to decarbonise industry.

The idea of developing a 'hydrogen economy' in specific geographical niches is something that the Netherlands has also been actively pursuing. They have focussed their attention on developing a hydrogen hub in the Northern Netherlands based on the same characteristics that make the North of England an optimal location. These include:[99]

- Capitalising on the location of the existing gas industry and gas fields that are situated in the Northern Netherlands. The required knowledge, infrastructure and industrial activities for both gasses are in close proximity and to a certain extent are comparable. This could enable industry to switch to hydrogen;
- A large future supply of renewable electricity from Norwegian hydropower, Danish wind and Dutch and German offshore wind, while the electricity grid has capacity constraints;
- Chemical and agricultural companies are present in the Northern Netherlands, which could profit from a green hydrogen supply.

Adopting a similar approach in the UK could be beneficial. Developing innovation and production clusters around an area (or areas) in Northern England and Scotland should not just be based on a single factor such as prevailing industrial strength, but should be located in an area where a range of deployment opportunities exist. For example, curtailment clusters have a broad correlation with areas that possess high-level strengths – such as advanced manufacturing and energy[100] – and the critical mass needed for innovation.

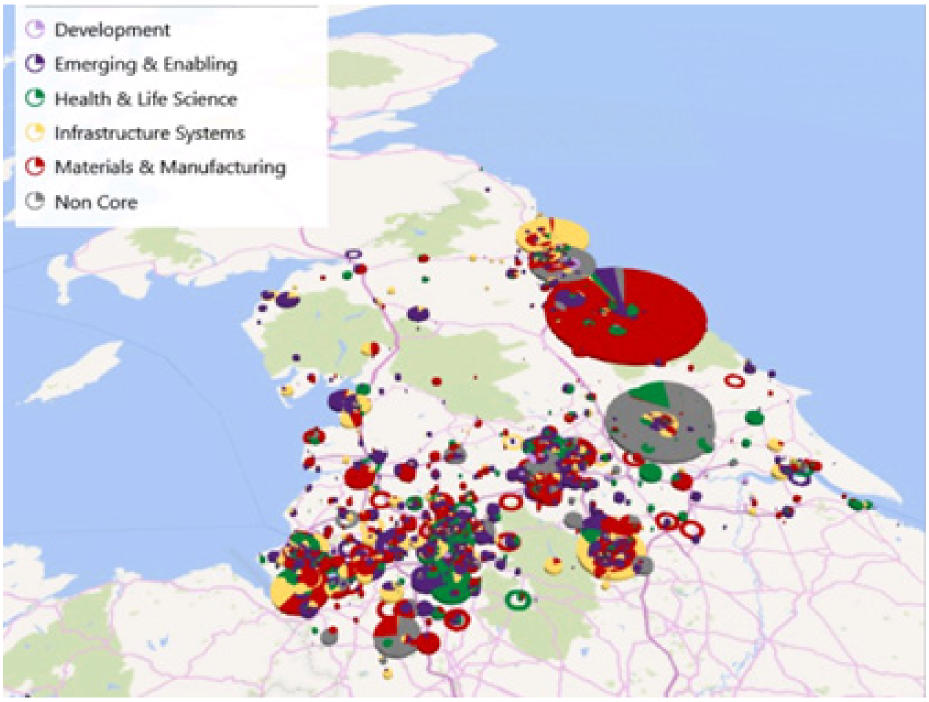
Therefore, like the Northern Netherlands, **the UK should maximise the synergies that exist between industrial activity, gas infrastructure, grid constraints and opportunities for innovation in northern England.** This should form the basis for the development of industrial hydrogen and CCS hubs. The development of clusters could also help overcome some of the issues surrounding supply chain fragmentation that were highlighted earlier in the report.

97. Element Energy. (2014). Scotland and the Central North Sea CCS Hub Study. http://www.element-energy.co.uk/wordpress/wp-content/uploads/2014/06/Element-Energy-Scottish-CCS-Hub-Study-Revised-Final-Main-Report-310314c.pdf

98. Van Wijk, A. (2016). 'Green Hydrogen Economy in the Northern Netherlands'. *Noordelijke Innovation Board*. https://www.deingenieur.nl/uploads/media/5880bffadd9af/Green%20Hydrogen%20Economy%20in%20Northern%20Netherlands.pdf

99. Energy sits within the 'Infrastructure Systems' classification.

Figure 3.13: Innovation clusters in Northern England



Energy productivity

It is also important to recognise the strong relationship between energy efficiency and productivity within industry and how energy efficiency investments can provide a significant boost to overall productivity. This presents a natural synergy between Clean Growth Strategy, energy efficiency, productivity and the wider Industrial Strategy.

Therefore, sitting alongside efforts to encourage the switch to low carbon fuels should be a coherent framework and policies to promote industrial energy productivity – which aims to produce more output (GDP) per unit of energy used. The Government's Industrial Energy Efficiency Accelerator will help to support innovation in energy efficient technologies and leverage private sector investment but more is needed. Policy Exchange's report 'Clean Growth: how to boost business energy productivity' put forward a number of suggestions such as:[101]

- Fiscal incentives to improve energy efficiency, directed towards landlords by linking – but not fully basing - business rates to EPC.
- Establishing an Energy Efficiency Delivery Unit (EEDU).

There is no silver bullet to decarbonise industry and different policies targeting different areas must be delivered concurrently. **It is recommended that in order to decarbonise industry, ways to improve energy productivity should be pursued alongside switching to cleaner fuels.**

Policy Recommendations

- **Develop Industrial Hydrogen Hubs**

100. Burke, J. (2017). *Clean Growth: How to boost business energy productivity*. Policy Exchange.

- The UK should maximise the synergies that exist between industrial activity, gas infrastructure, grid constraints and opportunities for innovation in northern England and consider deliberate national investment in clustering.
- The hub could examine: how to increase deployment of CCS in order to enable and establish cost effective hydrogen production from SMR, how to support opportunities to decarbonise industry and how PtG can reduce system costs.

- **Promote fuel switching options**
  - Government should help to identify fuel switching options across industry and develop a strategy to promote lower carbon options.
  - A pilot study should be established to examine opportunities to drive cost reductions in the use of hydrogen as alternative feedstock.
- **Pursue opportunities to increase energy productivity**
  - Use fiscal incentives to improve energy efficiency, directed towards landlords by linking – but not fully basing – business rates to EPC.

Transport

Around 10 years ago, cars powered by hydrogen fuel cells and by batteries seemed equally far from mass market deployment and were equally costly. However, the recent accelerated uptake of pure battery electric vehicles (BEV) has meant that this technology has taken off; while hydrogen powered vehicles still remain niche. Hydrogen vehicles and, to a lesser extent, infrastructure has been eligible for similar Government grants and subsidies to battery electric vehicles and charging infrastructure (see Box 4.4), but they have not taken off as many expected, primarily due to the lack of an adequate refuelling network.

In a 2017 report, *Driving Down Emissions: How to clean up road transport?*[102], Policy Exchange analysed the costs of cars powered by batteries, fuel cells and internal combustion engines. We concluded that the costs of producing batteries has tumbled to the extent that BEVs are already cost competitive with cars fuelled by internal combustion engines on a whole cost of ownership basis, and they will likely have a lower sale price at some point in the 2020s. In the short term, in the race to corner the low carbon transport market for light vehicles, batteries seem to have won and fuel cells have lost. Even if increased production brings down the purchase cost of fuel cell electric vehicles (FCEVs), we are still a long way from producing enough low carbon hydrogen to fuel them and building the associated production, transport, storage and refuelling infrastructure that would be required.

However, hydrogen retains certain advantages over electricity as an energy carrier that mean fuel cells can still play a role in the decarbonisation of our transport system. Firstly, hydrogen refuelling is much quicker than charging a battery. Secondly, the energy density of hydrogen is higher as

101. Ibid.

Box 3.4: Current incentives for hydrogen transport[vii, viii, ix]

- Plug-in car, van and motorcycle grants: These subsidies currently cover up to 35% of the upfront cost of an ultra-low emission car (up to a maximum of either £2,500 or £4,500 depending on the model), 20% of the cost of a van (up to a maximum of £8,000), or 20% of the cost of a motorcycle (up to a maximum of £1,500).
- Fuel Duty: Fuel duty is not applied to hydrogen as a fuel, only combustible fuels.
- Vehicle Excise Duty: Zero emission vehicles valued less than £40k are exempt from VED (car tax). Other than this, VED will be free for the first 12 months, then £130 per 12 months subsequently, a marginal saving on combustible engine vehicles.
- Capital Allowances: Businesses that purchase hydrogen cars, zero emission goods vehicles, or refuelling infrastructure are eligible for 100% first year allowance.
- Company Car Tax (CCT) Reductions: ULEVs are currently split into two emissions bands for CCT, with corresponding payments being more expensive accordingly. From 2020-21, these bands will diverge further based on zero-emission mileage distance.
- The Hydrogen for Transport Programme: Allocated £23million of new grant funding until 2020 to support the growth of refuelling infrastructure and the deployment of new vehicles.

A number of further benefits are available for drivers of Hydrogen powered vehicles in different parts of the country, including:

- London Congestion Charge exemption: Exemption from the £10 per day charge for hydrogen powered vehicles.
- Discounted parking: Local authorities are operating a range of schemes to provide discounted or even free parking for ULEVs. Parking for residents, visitors and businesses are included.
- Traffic restriction exemptions: A number of cities are reviewing options for future restrictions on traffic in key hotspots to reduce congestion and improve air quality.

a storage medium than lithium-ion batteries (though the gap is closing). Finally, the production of batteries is an energy intensive process and this currently means that there are high embedded carbon emissions associated with the production of battery electric vehicles, as well as the other pollution and waste effects associated with the mining and disposal of certain rare earth metals. In '*Driving Down Emissions*' we highlighted the fact that a large and growing proportion of the lifecycle emissions of BEVs are due to those emissions associated with the manufacture of the vehicle and we recommended that embedded emissions be increasingly taken into account when assessing how clean a new vehicle is. Hydrogen vehicles,

vii. Hydrogen for Transport Programme. (Date Unknown). Hydrogen Transport Programme. Ricardo. https://ee.ricardo.com/htpgrants

viii. Hayes, J. £23 million boost for hydrogen-powered vehicles and infrastructure. Department for Transport, Office for Low Emission Vehicles. https://www.gov.uk/government/news/23-million-boost-for-hydrogen-powered-vehicles-and-infrastructure

ix. Howard, R. et al. (2017). Driving Down Emissions. Policy Exchange.

potentially, are a more sustainable form of transport.

Aside from the current lack of large-scale production, the main barrier holding hydrogen vehicles back is the lack of refuelling infrastructure. The success of BEVs has largely been due to the fact that electric batteries can be charged at home overnight. It is not feasible for every home to have their own hydrogen refuelling station, and for the Government to roll out an extensive network of hydrogen refuelling stations before there is a market for them would be a large and risky investment. However, once in place, hydrogen refuelling facilities can be scaled up easily, whereas large-scale battery charging may require expensive network upgrades. This would especially be advantageous to companies operating large fleets.

Due to the advantages and disadvantages of hydrogen mentioned above, there are certain niche areas where hydrogen could play a role in the short-to-medium term. These will be transport systems in which refuelling time is important and where the vehicles always return to the same place allowing for one or two refuelling stations to service many vehicles. Examples include:

- Bus and taxi fleets
- HGVs
- Trains
- Ships
- Forklift trucks

Box 3.5: Hydrogen forklift trucks

Hydrogen vehicles have found an initial uptake in the market for warehouse forklifts. In America both Walmart and Amazon have begun trials, citing the much faster refuelling time of a fuel cell compared to a battery as the main advantage. A National Renewable Energy Lab (NREL) report suggests that hydrogen fuelled forklifts are already cheaper than conventional forklifts on a 10-year cost of ownership basis. In Japan, a consortium has gone a step further by producing hydrogen using electricity from wind turbines for use in 20 forklift trucks.[x]

Hydrogen powered trains could be an alternative to electrification for reducing carbon emissions from rail transport. They could be particularly useful on lines that, for infrastructure or geographic reasons, would be difficult to electrify, but electrification will remain a more cost-effective solution in most cases. Hydrogen may also be a long-term solution for decarbonising shipping, but, like for aviation, the turnover of ships is quite slow, so it is unlikely to make a short term impact on carbon emissions. The two best applications for hydrogen use in the transport sector are likely to be long distance road freight and coach/bus travel.

In 2017 heavy goods vehicles registered in Great Britain travelled a total of 18.6 billion kilometres delivering 1.4 billion tonnes of goods.[103] Although they make up only 5% of traffic flow they account for 18% of road transport emissions, totalling 19.6 billion tonnes in 2016.[104]

x https://www-sciencedirect-com.imeche.idm.oclc.org/science/article/pii/S1464285917302948

102. Department for Transport. (2018). 'Domestic Road Freight Statistics, United Kingdom 2017'. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/728937/domestic-road-freight-2017.pdf

103. Department for Transport. (2017). 'Domestic Road Freight Statistics, United Kingdom 2016'. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/627597/domestic-road-freight-statistics-2016.pdf

The Committee on Climate Change have highlighted road transport, and particularly the heavy goods sector, as an area in which the UK has failed to take sufficient action to incentivise cleaner vehicles.[105] There is still room to make conventional vehicles more efficient in the short term, but in the longer term HGVs powered by hydrogen fuel cells represent a good opportunity for full decarbonisation of the road freight sector.

Research published in 2018 considered HGVs to be one of the technologies most suitable to be an early adopter of hydrogen as a fuel for economic reasons.[106] This is because the fuel duty paid on diesel represents an effective carbon tax of over £200 per tonne. Given that hydrogen is currently exempt from any fuel duty, hydrogen HGVs could quickly become an attractive option for freight companies if the purchase price can be brought down through mass production.

Assuming the hydrogen is produced from a low carbon process, such as electrolysis from renewable electricity sources, it should be eligible as an alternative or compliment to biofuels in the Renewable Transport Obligation Scheme (see Box 4.6), which would further boost the economics of hydrogen as a road transport fuel from a producers point of view. This existing system of taxation and subsidies that favours hydrogen also makes it relatively easy from a political perspective. Although a lack of fuel duty on hydrogen could be seen as an implicit subsidy, it does not require any major legislation to be passed or for the Treasury to find funds in the short term. By contrast, in heating and industry the absence of a high carbon price means that hydrogen will find it difficult to compete without new large direct subsidies from the Government.

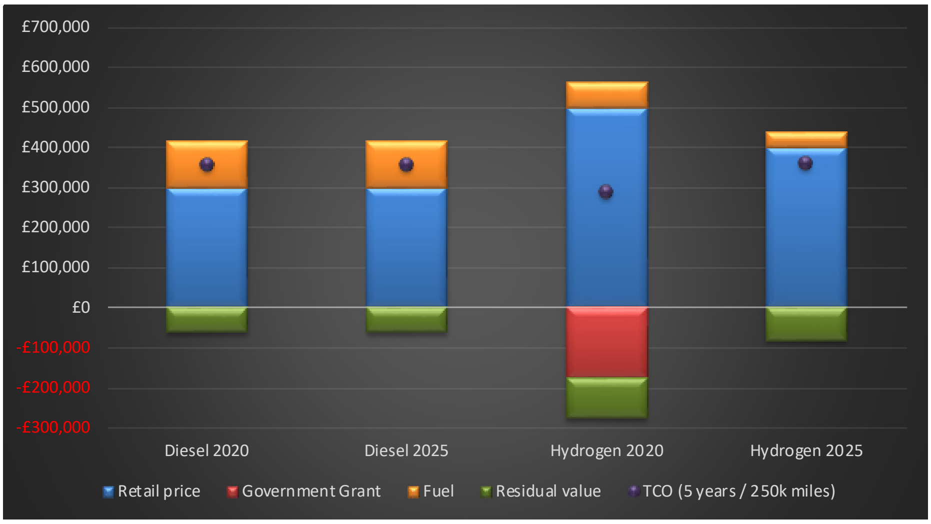
Simple calculations can illustrate the potential fuel savings from using hydrogen as an alternative to diesel for road transport. Assuming VAT exempt diesel and a yearly mileage of 75,000 miles, a fuel efficiency of 7.9 miles per gallon, the fuel cost for a single 4-axel articulated lorry will be over £35,000. A 2016 Road Haulage Association report found that fuel was the greatest cost for haulage companies (excluding labour) and comprised on average 27.4% of their total outgoings. Even small savings in fuel costs can therefore result in major long-term savings in the HGV sector. Given that fuel duty on diesel in the UK is currently 57.95 pence per litre (more than half the VAT-exempt total), simply exempting hydrogen from fuel duty during the initial scale-up of fuel cell powered HGVs can act as a massive financial incentive. Nikola, who are developing a semi-truck with a range of 800-1200 miles, claim they can achieve double the fuel efficiency of similar conventional diesel HGVs. If this is really the case, then total fuel savings of around 75% could be achieved by companies that switch to hydrogen HGVs.

Hydrogen may also be an attractive option for bus companies, especially if they travel long distances and always return to the same depot (thus making refuelling easier). To analyse what effect these fuel savings could have on the initial uptake of the economics of hydrogen powered coaches, the whole cost of ownership of a diesel powered versus a hydrogen powered bus can be compared. Although direct Government subsidies are

104. Pink, H. (2017). 'Toyota to put hydrogen fuel cell HGV into action at Californian port'. *Freight in the City*. http://freightinthecity.com/2017/04/toyota-put-hydrogen-fuel-cell-hgv-action-californian-port/

105. SSE. (2018). *RHyMES: Renewable Hydrogen Models for Energy Storage, Feasibility Study Final Report.*

Figure 3.14: 5-year cost of ownership for hydrogen- versus diesel-powered HGV



likely to be required for the initial deployment of hydrogen buses, as is the case in the recent decision by Birmingham City Council to trial 20 in their transport network,[106] potential capital cost reductions, combined with tax and RTFO fuel cost savings, could make hydrogen buses an attractive prospect compared with diesels in the next decade.

The graph uses a number of assumptions. This includes a fuel cell efficiency of hydrogen 1.4 times greater than diesel[108], 5000 miles driven per year for five years, a fuel price for hydrogen assumed to be the same cost as diesel, but minus duty of 57.95 p/l and an initial total capital expenditure of £500,000 for hydrogen buses,[109] falling to £400,000 with increased deployment.

Figure 3.14 illustrates that when taking in to account government grants the total cost of ownership (TCO) after five years (undiscounted) could be competitive with existing diesel buses. This can be attributed to the lack of fuel duty applied to hydrogen fuel and better hydrogen fuel cell efficiency. However, it also shows that the initial cost of purchasing a hydrogen bus is not competitive without some form of government grant because the up-front cost of a hydrogen bus is much higher. In this model we have assumed an extension of the current plug-in car, van and motorcycle grants which cover up to 35% of the upfront cost of an ultra-low emission vehicle. This equates to a grant of approximately £175,000. There are also a range of additional benefits for hydrogen buses as they would qualify as ULEVs, and if they are used in London they would be exempt from paying the congestion charge, which makes the economics even more favourable. Clearly there are also additional co-benefits of hydrogen HGV's and buses in helping address air quality, particularly in urban areas.

106. Birmingham City Council. (2017). *Cleaner hydrogen buses to be given green light*. https://www.birmingham.gov.uk/news/article/178/cleaner_hydrogen_buses_to_be_given_green_light

107. NREL (2016). Fuel Cell Buses in U.S. Transit Fleets: Current Status

108. *Birmingham Mail*. https://www.birminghammail.co.uk/news/midlands-news/new-fleet-500000-zero-emission-13800364

Box 3.6: Renewable Transport Fuel Obligation[xi, xii]

- The RTFO is one of the Government's main policies for reducing greenhouse gas emissions from road transport in the UK.
- The RTFO is a requirement on transport fuel suppliers to ensure that a proportion of their annual fuel supply originates from renewable and sustainable sources.
- RTFO applies to all suppliers of 450,000 litres (or equivalent) of transport and non-road mobile machinery fuel per year in the UK; smaller suppliers can freely register to become an obligated fuel supplier if they so choose.
- The total volume of fuel supplied in 2018 by an 'Obligated Fuel Supplier' must include no less than 7.25% of renewable and sustainable fuel. The percentage will rise yearly and is scheduled to reach 12.4% by 2032.
- Only 4% of the renewable fuel supply can come from crop-derived biofuels. This percentage is scheduled to decrease from 2020.
- The RTFO's scheduled rise in obligations is likely to increase demand for alternative fuel sources in the UK.

A final note on making the best use of limited hydrogen production capabilities

Hydrogen as a proportion of our energy production in the UK at the moment is still insignificant and scaling up production will take many years. In the meantime it is worth thinking about the best way to make use of the limited hydrogen we will have. As outlined elsewhere in this report, plans have been put forward to blend up to 20% (by volume, ≈7% by energy) hydrogen in our national gas network, which would require over 2 MTOE (Million Tonnes of Oil Equivalent).[109] Assuming improved efficiency of fuel cell powered HGVs compared with diesel, the same amount of hydrogen to decarbonise <7% of our natural gas network would be enough to decarbonise between 20-30% of road freight.

Of course, new markets for hydrogen will incentivise increased production facilities, but there will be time lags of years before the infrastructure catches up. Whilst we wait to scale up production, it is worth determining what the best uses of scarce hydrogen will be. Due to a lack of credible alternatives for decarbonisation, long distance road freight should be high on the list of priorities.

It is therefore important to determine which is the optimal use of hydrogen, in terms of the ability to scale up production and deliver cost effective carbon savings.

The chart is a function of production costs – which are the same in both sectors – and the different carbon intensities of the fuels used in each sector; diesel for freight transport (trains, boats and road) and natural gas used in heating. As the price is constant, but the carbon intensity of diesel is greater than natural gas, the abatement costs are less in transport (noting

xi. Department for Transport. (2016). Renewable Transport Fuel Obligation statistics: Notes and Definitions. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/519910/notes-and-definitions.pdf

xii. Gov.uk. (2018). The Renewable Transport Fuels and Greenhouse Gas Emissions Regulations 2018. https://www.legislation.gov.uk/uksi/2018/374/pdfs/uksi_20180374_en.pdf

109. BEIS (2018). *Energy Consumption in the UK: 2018 update*. https://www.gov.uk/government/statistics/energy-consumption-in-the-uk

this does not take in to account associated system costs or infrastructure upgrades).

Moreover, using the operating model where a proportion of the output from non-curtailed wind is used in conjunction with curtailed wind – it is possible to examine how scalable this approach would be in certain sectors. The analysis below takes this model and extrapolates this across all the UK's installed wind capacity. It shows how much hydrogen could be produced to replace the dominant feedstock in a number of different sectors using 10% of all wind generation.

Section 3 in this report looked into the potential for electricity from curtailed wind to be used to produce hydrogen and concluded that, realistically, this could contribute an almost insignificant proportion of our total energy requirements. However, due to their lower total energy requirements, relatively small quantities of hydrogen can make a big impact in certain hard-to-decarbonise transport sectors. Figure 3.16 shows the percentage of fossil fuels that could be displaced by hydrogen produced from 10% of curtailed wind for different sectors of the economy. Whilst almost insignificant when compared with the heat, transport or industry sectors as a whole, this hydrogen could be used to decarbonise a significant proportion of rail, shipping, road freight or bus travel.

This analysis suggests that hydrogen production is most scalable and cost effective when targeted towards the transport sector, and it also happens to have the strongest economic case. We recommend that the Government conduct a rigorous systems analysis of how to best use hydrogen in the system to deliver cost effective and substantial carbon savings.

Figure 3.15: Abatement costs in different sectors

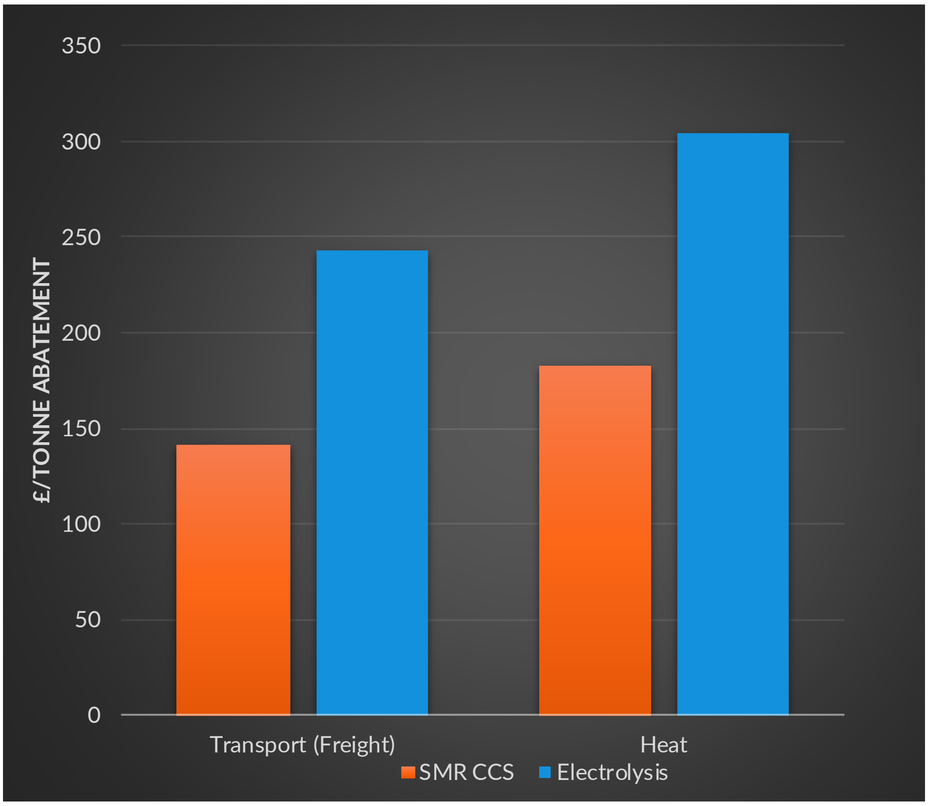
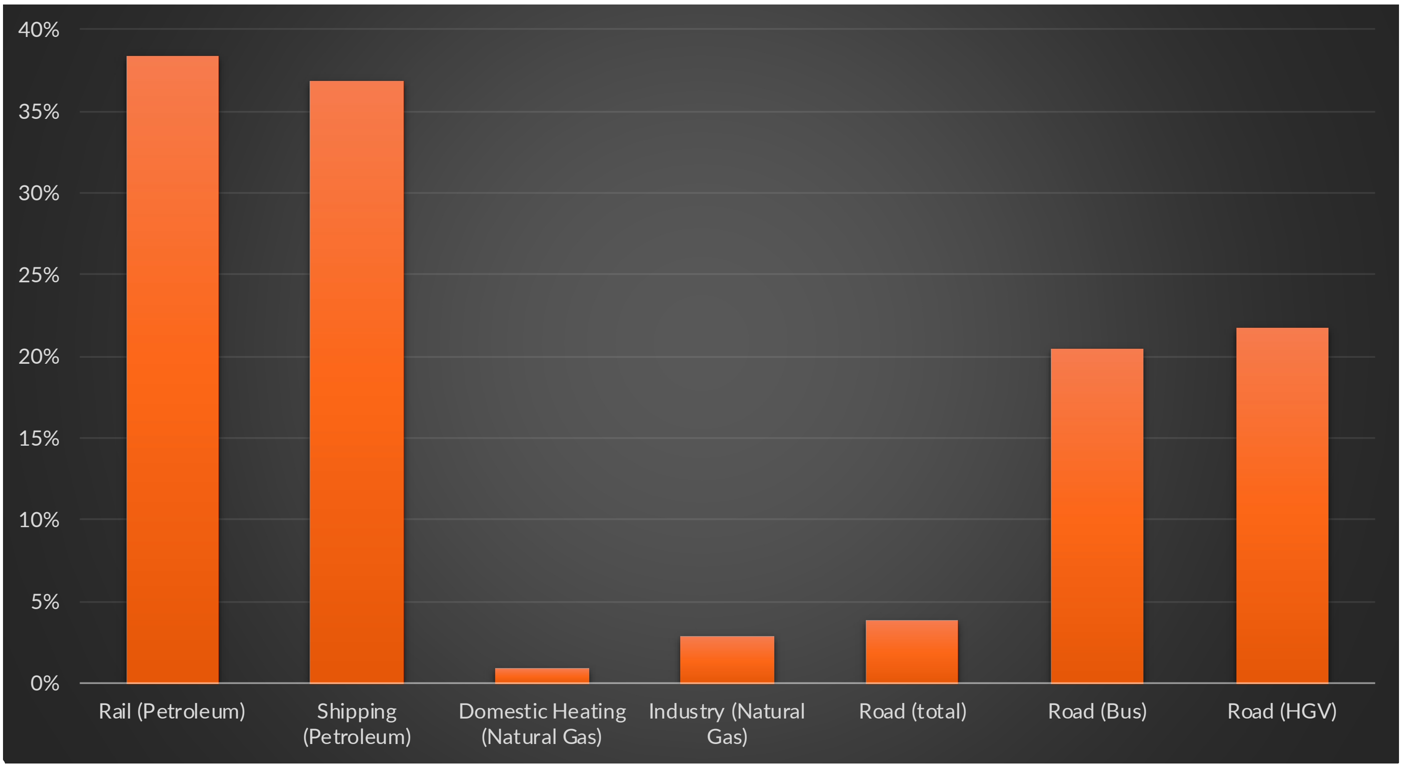


Figure 3.16: % feedstock replacement using 10% of all installed wind



Policy recommendations

- **Incentives for innovative hydrogen transport pilots**
  - Offer innovation grants for pilot programmes to develop innovative uses of hydrogen for transport systems in large industrial facilities and warehouses for applications that are less suitable for battery powered vehicles.
- **A network of refuelling stations for haulage**
  - Work with the freight industry to examine the economic and environmental case for a strategic network of hydrogen refuelling stations that would enable the HGVs or trains to travel around the country's main transport networks using hydrogen fuel cell technology.
- **Incentivise the use of hydrogen fuel**
  - Exemptions for hydrogen from any fuel duty should continue during the early stages of market development.
  - The Government needs to give long term signal on how hydrogen will be taxed going forward, with any policy changes signalled clearly in advance.
  - The Renewable Transport Fuel Obligation should be expanded to allow companies to use hydrogen as part of their contribution. A similar system to the current sustainability checks on biofuels should be set up to ensure that the use of hydrogen reduces carbon emissions at a system level.

4 Integrating Renewables

This section looks at hydrogen's role as an energy system buffer, in place of natural gas and the possibilities of renewable power to gas with a focus on the UK's wind sector. The practicalities of using both curtailed wind and non-curtailed wind to produce hydrogen are explored below.

Power-to-Gas

Through the Renewable Energy Directive, the European Commission has set rules for the EU to achieve its 20% renewables target by 2020. The deployment of more renewable electricity will inevitably be crucial in achieving these targets as well as the UK's mandated carbon budgets. In the UK, wind power already comprises the highest share of renewable electricity supply – in 2017 wind contributed 14.8%, up from 2.7% in 2010.

With an increasing share of renewable electricity generation, how this is best integrated remains an important issue. In particular, issues such as the ability to balance supply and demand, store surplus energy and manage frequency and voltage levels are vital for the efficient integration of increased amounts of intermittent generation. Looking at this in more detail:

- **Balancing Supply and Demand**: whilst this is not new, the advent of renewables and their intermittent nature has meant that the job of balancing has become more difficult as the output is far less predictable and controllable than conventional thermal generation.
- **Surplus Capacity:** The grid now experiences periods where supply exceeds demand. For example, during windy and sunny summer days where generation is high, demand can be simultaneously low. Constraints on the transmission system can prevent this power from being transported to areas of higher demand so this power is 'curtailed'.
- **Frequency + Voltage:** The power grid is designed to operate at a constant frequency and voltage in order to maintain stability. The frequency level is controlled within the limits of 49.5-50.5Hz. System frequency is constantly changing and is a function of the balance between supply and demand. If demand is greater than generation, the frequency falls while if generation is greater than demand, the frequency rises. This has traditionally been provided by the 'inertia' from conventional thermal generation. However, as this is in decline, alternative ways to stabilise the grid are now sought.

These are relatively new challenges for the power system yet they have profoundly altered the structure of electricity markets in Great Britain. Consequently, the need to mitigate this has created a large market in 'ancillary services' – the name given to services and functions provided to – and procured by – the System Operator (SO) that facilitate and support the continuous flow of electricity so that supply will continually meet demand.[110] The total cost of balancing services increased from £642 million in 2005-06 to £1.08 billion in 2015-16.[111]

Power-to-Gas (PtG) technology has the potential to alleviate some of the problems associated with intermittent supply. PtG works by converting surplus energy into a grid compatible gas.[112] The processes for this are outlined below.

Figure 4.1: Power to gas

Götz, M. et al. (2016). 'Renewable Power-to-Gas: A technological and economic review'. *Renewable Energy*, Vol. 85, Pages 1371-1390

What does this look like in practice? Using an electrolyser efficiency of 70-80%, 57kWh of electricity as an input to the electrolysis process is enough to produce approximately 1Kg of hydrogen[113] that can be used for gas grid.

Of interest is how surplus energy can produce hydrogen that can be mixed in small quantities with natural gas for injection into the gas grid or used in higher value markets such as hydrogen refuelling stations. Indeed, numerous reports suggest that "one of the most promising technologies for storing the excess energy, that would be otherwise lost, is the production and storage of hydrogen through water electrolysis"[114]. The UK Government also espoused this view in their 2013 paper 'The Future of Heating: Meeting the challenge' and identified this as a potential option, stating that the electrolysis of water, using electricity from low carbon sources had potential for hydrogen production and injection into the gas grid. More recently, National Grid, in their 'Future of Gas' 2018 report, made the case for utilising excess wind power by "making increasing use of excess renewable generation, when available, to produce hydrogen via electrolysis".[115] As input costs have often been too high to make electrolysis economical, the ability to take advantage of negative electricity wholesale prices associated with renewables curtailment is a key driver behind the concept of PtG.[116]

110. Energy UK. (2017). *Ancillary Services Report 2017*. https://www.energy-uk.org.uk/publication.html?task=file.download&id=6138
111. Howard, R. and Bengherbi, Z. (2016). *Power 2.0: Building a smarter, greener, cheaper electricity system*. Policy Exchange.
112. Götz, M. et al. (2016). 'Renewable Power-to-Gas: A technological and economic review'. *Renewable Energy*, Vol. 85, Pages 1371-1390. (http://www.sciencedirect.com/science/article/pii/S0960148115301610)
113. London Research International. (2015). 'Hydrogenics Power-to-Gas', Issue 25. http://londonresearchinternational.com/wp-content/uploads/2015/03/GTE-Newsletter-ENG-25-Hydrogenics.pdf
114. Kavadias, K.A., Apostolou, D. and Kaldellis, J.K. (2017). 'Modelling and optimisation of a hydrogen-based energy storage system in an autonomous electrical network'. *Applied Energy*.
115. National Grid. (2018). 'The Future of Gas: How gas can support a low carbon future'. http://futureofgas.uk/wp-content/uploads/2018/03/The-Future-of-Gas_Conclusion_web.pdf
116. Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute. http://www.sustainablegasinstitute.org/wp-content/uploads/2017/12/SGI-A-greener-gas-grid-what-are-the-options-WP3.pdf?noredirect=1

Box 4.1: ITM Case Study

ITM power has established a pilot scheme called the Hydrogen Mini Grid System (HMGS) based in Rotherham, UK. The site consists of a 225kW wind turbine coupled directly to an electrolyser, 200kg of hydrogen storage and a hydrogen dispensing unit. When there is excess energy, the electrolyser is used to generate hydrogen gas. The gas is then compressed and stored ready for dispensing into hydrogen fuel cell vehicles. This exemplifies Power-to-Gas and refuelling solutions but the gas could also be injected into the gas network to decarbonise heat.

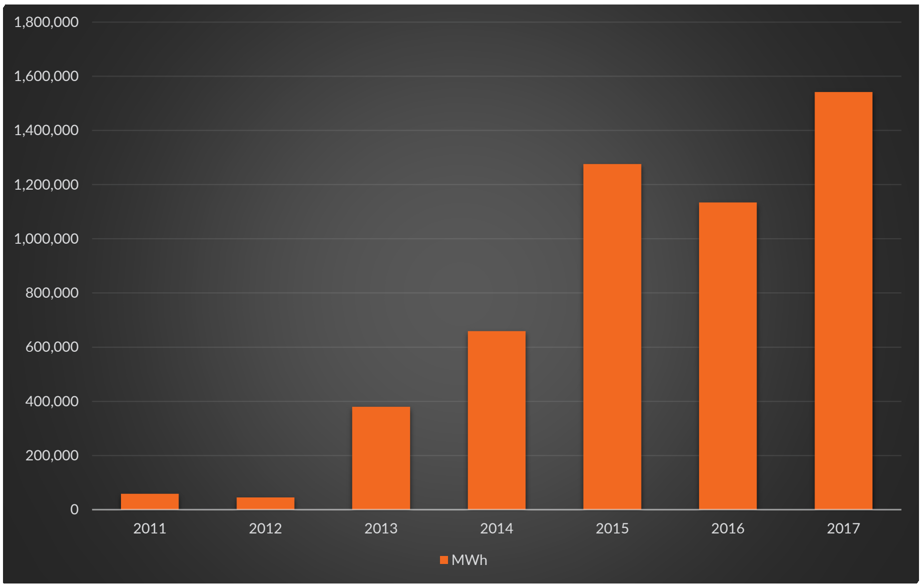
The case for hydrogen production and injection during periods of high wind and low demand is strong given the headlines over 'constraint payments' paid to generators and in particular to wind farms to reduce output when the transmission network is overly constrained. Theoretically at least this makes perfect sense. But how does the reality stack up?

Curtailment

Curtailed wind serves as a proxy for surplus wind energy. *Curtailments* can result when operators or utilities command *wind* and solar generators to reduce output to minimise transmission congestion or otherwise manage the system to achieve the optimal mix of resource[117]. *Wind curtailment* typically occurs when demand is low and *wind* production is high. In the UK, generators are paid to curtail their power through the Balancing Mechanism (BM). By studying the curtailment payments made through the BM it is possible to quantify how viable the current PtG proposition is.

Figure 4.2 illustrates an upward trend in the annual quantity of wind power that has been curtailed from 2011-2017. Fluctuations in curtailment of wind power, as seen in 2016, are because of sensitivities to insufficient transmission capacity, low consumer demand and installed 'must-run' generation units such as nuclear.[118] With this in mind, an interesting

Figure 4.2: Annual MWh curtailed



117. Bird, L., Cochran, J. and Wang, X. (2014). *Wind and Solar Energy Curtailment: Experience and Practices in the United States. National Renewable Energy laboratory.* https://www.nrel.gov/docs/fy14osti/60983.pdf
118. Qadrdan, M. et al. 'Role of power-to-gas in an integrated gas and electricity system in Great Britain', *International Journal of Hydrogen Energy*, Volume 40, Issue 17, Pages 5763-5775.

systems question that needs addressing is whether the expansion of the UK's nuclear programme could make this worse

Examining figure 4.2 in more detail, it shows that in 2011 just 58,000 MWh were curtailed. By 2017 this had increased to 1,500,000 MWh or 1.5TWh – an increase of 2500%. In total from 2010-2017 a little over 5 TWh of wind was curtailed. This was driven by a huge increase in the deployment of wind power in the UK, brought to market through Government support in the form of the Renewable Obligation Certificates and the superseding Contracts for Difference. For comparison, total wind generation in 2017 was 49.6 TWh[120]

Academic research[120] suggests that electricity curtailment could reach 2.8 TWh per annum by 2020 and as much as 50-100 TWh per annum by 2050 depending on the amount of installed renewables. Given the level of curtailment now, 2.8 TWh by 2020 is certainly plausible. In part the level of curtailment will depend on how much renewable energy is deployed. For example in Germany, in a scenario of 90% renewables it is estimated that that there could be as much as 170TWh/year by 2050. [121]

Box 4.2: Quantity of hydrogen that can be produced from curtailed wind

Using an electrolyser efficiency of 70-80%, 57kWh equates to 1kg of hydrogen.[xiii]

1.5TWh/57kWh = 26,315,789 kg of Hydrogen

The energy density of hydrogen is approximately 33.3kWh/kg [xiv]

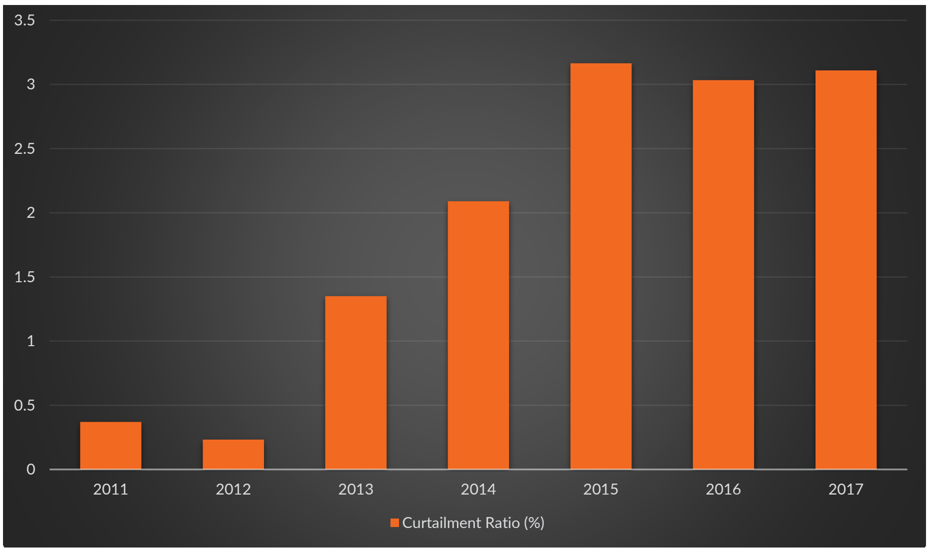
33.3 × 26,315,789 = 876,315,773.7 kWh

876315773.7 / 1000000 = 867 Gwh of hydrogen from curtailed wind

The quantity of gas used for domestic purposes is 311,375 GWh

So 867/311,375 = 0.3%.

Figure 4.3: Curtailment Ratio (%)



xiii. London Research International. (2015). 'Hydrogenics Power-to-Gas', Issue 25. http://londonresearchinternational.com/wp-content/uploads/2015/03/GTE-Newsletter-ENG-25-Hydrogenics.pdf

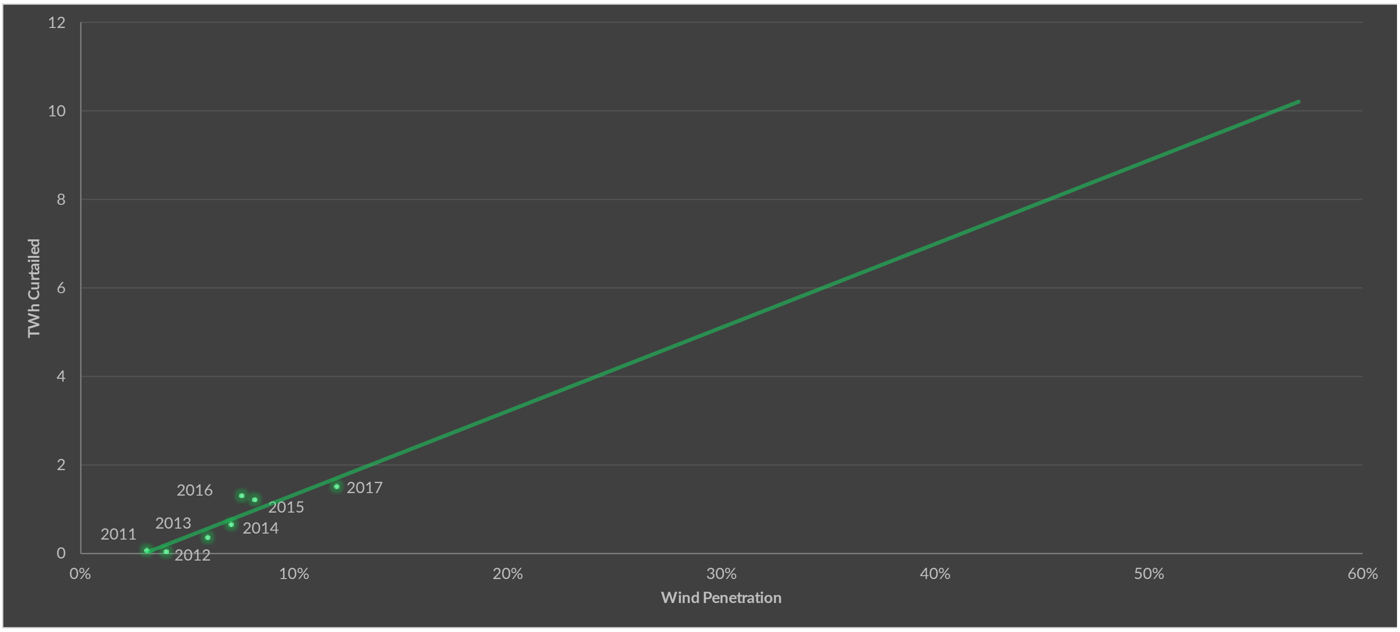
xiv. https://hypertextbook.com/facts/2005/MichelleFung.shtml

119. BEIS 2017: UK energy statistics (https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/695626/Press_Notice_March_2018.pdf)

120. Ibid.

121. Hydrogen Council. (2017). Hydrogen Scaling Up: A sustainable pathway for the global energy transition. http://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf

Figure 4.4: Wind Penetration vs TWh curtailed with linear projection



Using the amount of wind power curtailed in 2017 – 1.5TWh – it is possible to calculate how much hydrogen this 'spare' wind could produce. Box 4.2 demonstrates that the amount of curtailed wind in 2017 was enough to produce approximately 876 GWh of hydrogen. Given that the quantity of gas used for domestic purposes is 311,375 GWh per annum (2016 figures); hydrogen production from curtailed **wind could replace approximately 0.3% of gas used domestically.**

Although more curtailed wind is expected in the future, it has remained fairly constant. The curtailment ratio shows how much wind power is curtailed as a function of total generation. In 2017 the curtailment ratio was 3.1%. This has remained fairly constant over the last three years despite wind output increasing by 23%[122].

From this analysis it is logical to conclude that while it is fashionable to posit electrolysis as the perfect way of using up surplus wind and solar power, this is probably wrong[123]. Putting cost aside for one moment, **curtailed wind cannot produce the volumes of hydrogen needed to make a substantial contribution to overall hydrogen production.** Curtailed wind on its own – in the UK – has limited applications. It has a role to play and what little hydrogen that can be produced from curtailed wind should be integrated in to the energy system. But principally this should be for management of the electricity grid or specific industrial sectors rather than a viable production method for decarbonising the entire gas grid and domestic homes.

In the longer term if the curtailment levels reach a high level of 50-100 TWh by 2050 and heat demand stays relatively constant, curtailed wind could provide approximately 43,000 GWh[124] of hydrogen. Even this scenario would still only provide approximately 14% of the heating load. To reach the 75 TWh of curtailment needed to get anywhere close to this amount of hydrogen production, a linear extrapolation suggests it would take 200 years

122. DBEIS (2018). 'Energy Consumption in the UK: 2018 update'. https://www.gov.uk/government/statistics/energy-consumption-in-the-uk
123. Liebreich, M. (2018). 'Liebreich: Beyond Three Thirds, The Road to Deep Decarbonization'. *BloombergNEF.* https://about.bnef.com/blog/liebreich-beyond-three-thirds-road-deep-decarbonization/
124. Assuming 75TWh of curtailed power.

and wind penetration would need to extend far beyond 60%.

Reaching 75 TWh of curtailment also relies on some fairly bold assumptions, such as: no further network reinforcing; no mass market battery storage; and a very high curtailment ratio above 30%[126] which as shown in Figure 4.3 is hovering around 3%.

Non-Curtailed Wind

This is not to say that hydrogen production using wind power and electrolysis will not and should not expand, it's just unlikely this will be with curtailed wind alone. It is important to note that one of the reasons this form of production (electrolysis with curtailed wind) has been championed[128],[128] is because input costs for electrolysis (i.e. electricity) were high relative to the gas used in methane reforming, and so electrolysis could only work using 'spare, free' wind. That said, the problem with only using spare wind is that electrolysers can't run constantly. As this is a capital-intensive industry with typically low margins, for electrolysers to be economical they need to have a high utilisation rate, so only using curtailed power – which is limited – is likely to be uneconomic. Therefore, a more viable method – which could increase electrolyser utilisation – would be to combine curtailed and non-curtailed wind. For example, a proportion of the output from non-curtailed wind could be used in conjunction with curtailed wind for continuous hydrogen production. This type of model is currently being examined by industry.

If electrolysers can be scheduled to run using non-curtailed wind and then ramp up during periods of excess low carbon generation, increasing demand in these periods reduces the need to curtail this low-carbon generation. **Optimising curtailment in this way could save up to £100 million pounds per annum in the balancing market and increase low carbon generation**. If increased demand supports wholesale prices, spend under the Levy Control Framework (LCF) could be reduced as CfD (contracts for difference) payments are cut down. This could happen because the gap between strike price and wholesale price is reduced if wholesale prices rise. This in turn allows more renewable generation to be supported through the LCF and makes higher penetrations of intermittent generation technically feasible. It estimated that for every new MW of hydrogen production capacity, about £70,000 per year could be saved from the total cost of CfDs under the Levy Control Framework, as well as supporting about 150 MWh per annum of increased low carbon generation[129].

That said a number of caveats need to be applied. Firstly, the most significant cost savings occur in a scenario where there are high levels of nuclear and renewable generation in combination with a small rollout of new interconnectors. Secondly, every addition of a new hydrogen production plant would start to create wider feedback in the market such as price cannibalisation, but this is a longer-term problem.

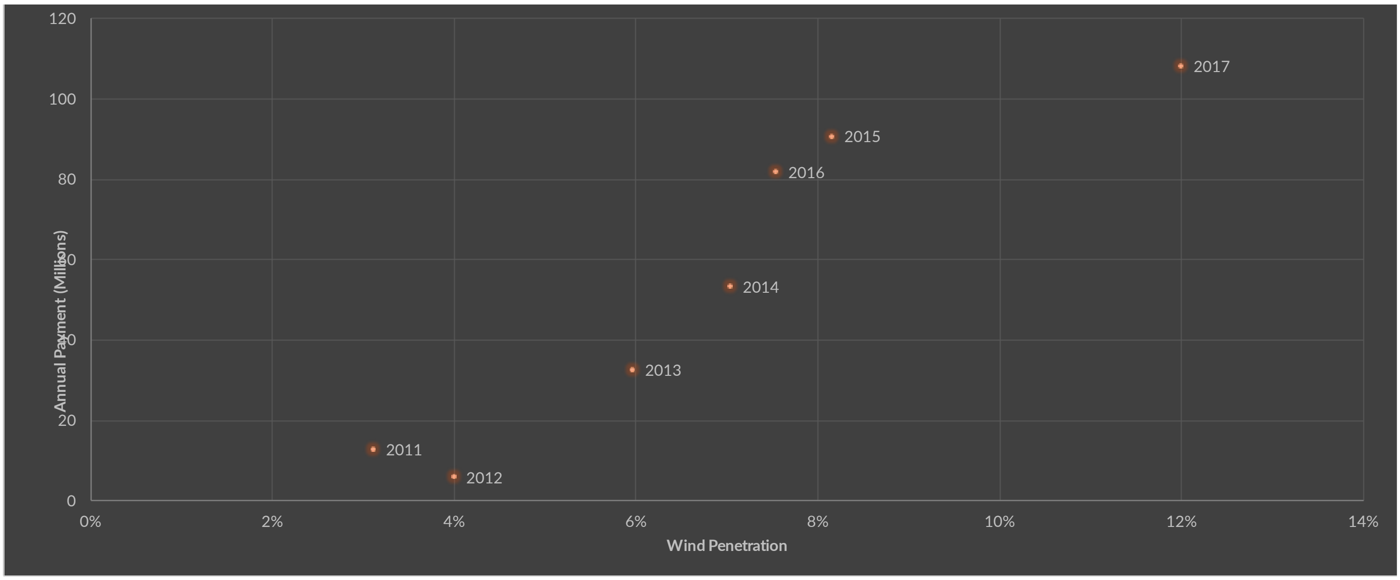
125. Strbac, G. (2012). 'Strategic Assessment of the Role and Value of Energy Storage Systems in the UK Low Carbon Energy Future'. Imperial College London, Carbon Trust. https://www.carbontrust.com/media/129310/energy-storage-systems-role-value-strategic-assessment.pdf

126. Troncoso, Enrique & Newborough, M. (2011). Electrolysers for mitigating wind curtailment and producing 'green' merchant hydrogen. *Fuel and Energy Abstracts*. 36. 120-134. 10.1016/j.ijhydene.2010.10.047.

127. M. Shujun, Z. You, Y. Ye, Z. Ding, L. Jin and S. Kai, "A curtailed wind power accommodation strategy based on wind-hydrogen-heat-storage integrated energy network," 2017 *Chinese Automation Congress (CAC)*, Jinan, 2017, pp. 6146-6150. doi: 10.1109/CAC.2017.8243884

128. SSE. (2018). *RHyMES: Renewable Hydrogen Models for Energy Storage, Feasibility Study Final Report.*

Figure 4.5: Annual balancing market constraint payments vs wind penetration



System Buffer

The low carbon transition is driven by a number of factors other than carbon reduction. The so called 'energy trilemma' of affordability, sustainability and security of supply has often framed policy decisions. Opportunities to export domestic renewable energy expertise and equipment now augment the scope of the original trilemma. As the Industrial Strategy and Clean Growth Strategy demonstrates, the UK Government is seeking the twin benefits of decarbonisation and economic growth.

But as the UK transitions to a low carbon economy, the extent of the role fossil fuels will play is widely debated. To date, the role of fossil fuels in the energy system has been characterised by availability and low cost versus low carbon and renewable sources, but the latter is fast approaching grid parity. This represents an important milestone, one that brings questions over fossil fuels to the fore. If they are no longer cheaper to use than cleaner sources, how, if at all, should they be deployed in a decarbonised system?

Principally, this should be looked at through the lens of security of supply and the ability of fuel/gas-based energy to act as a system buffer. As UK energy demand is highly seasonal – due to heating during the winter period – the buffer needed to accommodate this has come from fuel-based energy storage. Going forward this is likely to continue and given the size of storage required (TWhs) the use of fossil fuels may be more appropriate than other forms of storage such batteries. The size and seasonality of the storage required is key, as different forms of energy storage are better suited to storing energy over different timeframes. For example, lithium ion batteries are superior at discharging power over a short cycle, but this is incompatible with the characteristics required for season level storage which may need energy to be stored over a number of months.[130] Moreover, opportunities to expand pumped hydro are small because the main barrier to wide scale deployment is suitable geography and environmental constraints[131].

Therefore, the benefits to energy systems from the stores of fossil

129. Wilson, I. A. G. and Styring, P. (2017). 'Why Synthetic Fuels Are Necessary in Future Energy Systems'. *Frontiers in Energy Research.* https://www.frontiersin.org/articles/10.3389/fenrg.2017.00019/full

130. Edberg, O. and Naish, C. (2010). *Energy Storage and Management Study*. AEA Group. https://www.gov.scot/Resource/Doc/328702/0106252.pdf

fuel-based energy are unlikely to be replaced without some other form of fuel-based energy storage. Consequently, the question is not whether it is required, but what type of fuel-based storage is needed[132]. This is where hydrogen has potential. This is looked at further in the context of decarbonising heating.

Creating an upstream Power to Gas market

Key in determining the optimal end use of hydrogen produced is the need to address both sides of the supply and demand equation in the hydrogen economy. Knowing whether supply will create new markets, or whether creating initial markets for the product will kick-start supply is a commonly occurring problem within markets. At present, renewable hydrogen is not produced in large quantities because demand does not exist at scale in the market. Similarly, potential end users do not see large sources of renewable hydrogen available in the market and this is likely to discourage adoption of new hydrogen compatible transport technologies or appliances[133].

Attempts to address both sides of the supply and demand equation are hampered by: a **lack of market and policy certainty** needed to unlock the private sector investment in innovation and large-scale manufacturing capacity; **and long term visibility required for business planning**, **particularly for the next RIIO price control period (2021-2026).** The two are intrinsically linked – without the former, the latter is not possible. Given the length of the price control period and the timetable for network companies running the gas and electricity transmission and distribution networks to submit business plans (Q1 2019), market and policy certainty is urgently needed. At the earliest opportunity**, Ofgem must provide clarity on what constitutes allowable spend by gas networks during the period 2021-2026 and whether investment in hydrogen can be funded under the RIIO price control mechanism.**

Innovation and competition can help reduce network costs and network companies should facilitate the efficient integration of renewable energy with the electricity and gas grid. The RIIO 2 consultation proposes to extend competition across the sectors (electricity and gas, transmission and distribution) and continue to develop models of competition for building new assets and potential for earlier stage competitions for solutions to network problems[135]. This provides an emerging framework for the participation of PtG as a solution to network issues and it is important that the framework is flexible enough to allow new market entrants.

Business Models

Future deployment of electrolysis is highly dependent on electrolyser cost-competitiveness. Yet, currently, there is little or no commercial driver for the use of renewable hydrogen, meaning that it would compete directly with natural gas[135]. Therefore, it is crucial to examine new electrolyser business models as well as potential markets that are best suited for hydrogen applications. This should be done in conjunction with examining where technological advancements can be made.

131. Wilson, I. A. G. and Styring, P. (2017). 'Why Synthetic Fuels Are Necessary in Future Energy Systems'. Frontiers in Energy Research. https://www.frontiersin.org/articles/10.3389/fenrg.2017.00019/full
132. SSE. (2018). *RHyMES: Renewable Hydrogen Models for Energy Storage, Feasibility Study Final Report.*
133. Ofgem. (2018). 'RIIO-2 Framework Consultation: Our approach to setting price controls for GB gas and electricity networks'. https://www.ofgem.gov.uk/system/files/docs/2018/03/riio2_march_consultation_document_final_v1.pdf
134. SSE. (2018). *RHyMES: Renewable Hydrogen Models for Energy Storage, Feasibility Study Final Report.*

The business cases for hydrogen conversion are complex and rarely viable under existing regulatory frameworks. Current business models for grid integrated electrolysers tend to be based on retail spot market sales of hydrogen from either grid injection or transport. Therefore, the economic viability of this business model is contingent on the price customers are willing to pay for hydrogen. In the longer term, price signals may enable hydrogen to be produced from wind or solar power and electrolysis. Indeed, wholesale prices are falling and periods of negative pricing are now more frequent. However, this alone is not sufficient at the moment.

Traditional business models are currently orientated towards sales of hydrogen feedstock, mainly to industrial process. However, the huge increase in renewable generation opens up potential for new business models. Central to this is the ability to unlock additional revenue streams so hydrogen producers can 'stack' revenue from physical sales of hydrogen and other services that optimise the economic viability in the short term. To increase electrolyser utilisation – a key determinant of economic viability – potential business models could include: a) grid embedded electrolysers providing flexible services to system operators such as National Grid b) cross commodity arbitrage in addition or in conjunction with spot market sales and ancillary services.

Cross Commodity Arbitrage

Looking first at cross commodity arbitrage, this business model for electrolysers relies on trading between the electricity market and markets for hydrogen during times where the price is low for electricity[136]. Situations with low electricity prices often coincide with the need for grid service provision. This coupled with high spot price variability increases price arbitrage opportunities. As these electricity market characteristics are more prevalent with greater penetration of renewables, this enables business models directed towards electrolyser arbitrage trading.

The dispatch of electricity from an electrolyser should be optimized against the electricity price in case of cross commodity arbitrage trading because electricity prices are more volatile than hydrogen or natural gas prices.[137]If electrolysers are flexible enough to shut down and ramp up quickly, this will allow for dispatch models to be based on spot market prices. This will enable operators to benefit from low electricity prices and shut down when electricity prices are high. Figure 4.6 illustrates how this works in practice.

The electrolyser runs at full output when the spread between the electricity spot market and hydrogen sales price is large enough to cover electrolyser conversion losses, i.e. electrolyser operation generates greater profit margins in situations when the electricity price is lower than the required (to make a profit) electricity price. This is illustrated by the shaded blue areas in between the electricity spot price and the required electricity price.

Research[138] suggests that cross commodity arbitrage trading can achieve profitability in the transportation sector but the industrial sector and natural gas system applications such as fuel switching are less efficient.

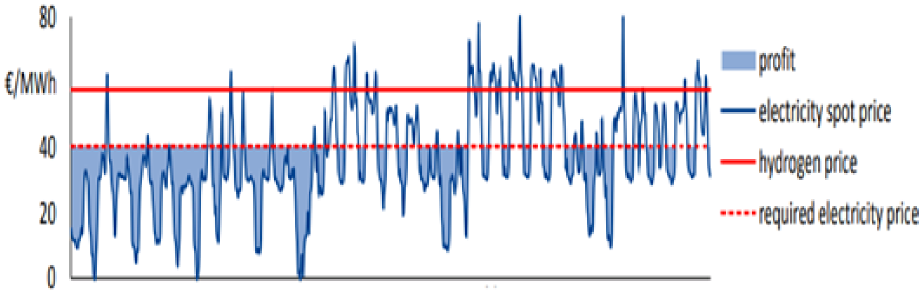
For these less efficient applications or when the hydrogen price is low,

135. Larscheid, P., Lück, L. and Moser, A. (2018). 'Potential of new business models for grid integrated water electrolysis'. *Renewable Energy*, Vol. 125, Pages 599-608.

136. Ibid.

137. Larscheid, P., Lück, L. and Moser, A. (2018). 'Potential of new business models for grid integrated water electrolysis'. *Renewable Energy*, Pages 599-608.

Figure 4.6: Electrolyser dispatch in cross-commodity arbitrage trading



Lück, L. (2017). 'Opportunities of water electrolysers in the European flexibility markets'. *Elyntegration*.

spare capacity in situations that are unprofitable for cross commodity arbitrage trading may, instead, be used for ancillary service provision. This can be an option of increasing the electrolyser utilisation ratio and profitability.

Ancillary Services

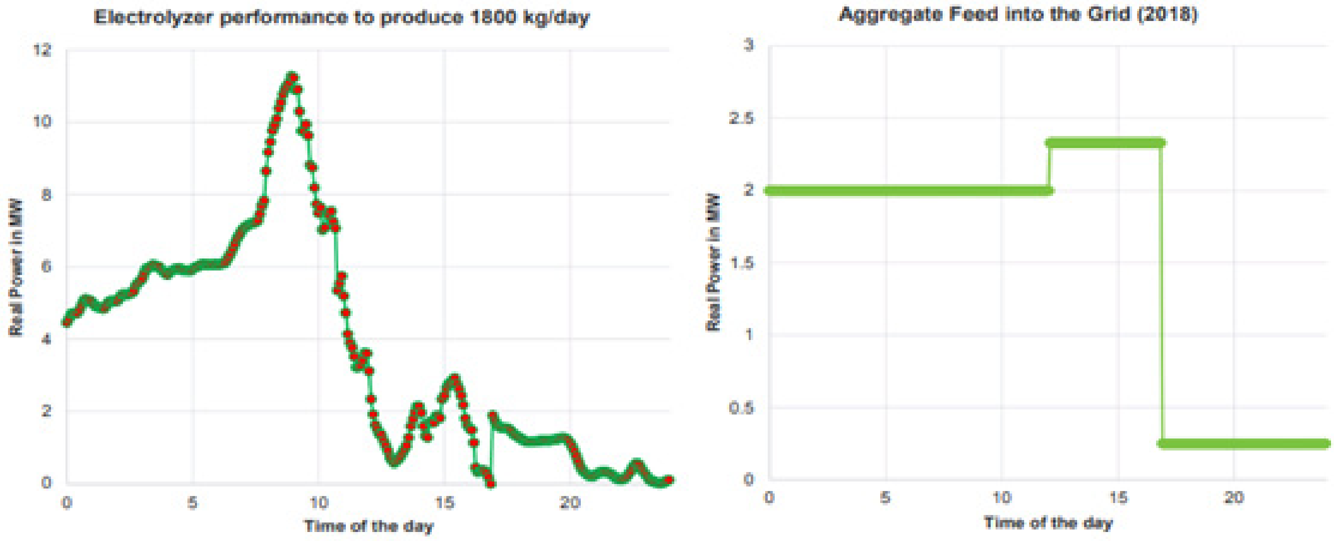
In the absence of adequate price signal, lessons can be learnt from the growth of the renewables sector. This was enabled by an initial 20-year government backed income stream (ROCs) and then superseded by a 15-year government-backed income stream in the form of CfDs. This price certainty and long term contracted revenue enabled project developers to leverage lower cost private capital in order to build a pipeline of projects. In the absence of this, the question is whether potential investment is willing to take merchant risk. The decarbonisation of the power system and growth of renewables has significantly altered the economics of power generation, dampening the wholesale market price, and the signal for new investment. As such the appetite for merchant financing has tended to be relatively constrained in the UK energy market[139] and virtually no investment in new generation capacity is taking place without some form of government contract. Carrington CCGT provides a good example, as do gas peaking plants. Without an ancillary services contract it is difficult for these types of new build projects to raise funding (although not impossible). The same could be said for offshore wind project developers who are still likely to require some form of price stabilising CfD even if they have reached grid parity.

At the same time as the dampening wholesale market price, the value of balancing and ancillary markets is growing rapidly. A number of services are available and in order to make projects viable, generators can 'stack' these revenue streams. For example, flexible generators can make money by selling power into the wholesale and balancing markets and by providing flexibility services directly to National Grid. As electrolysers have very fast response times and are flexible with respect to ramp-up and load range – cold start to full power is possible in less than 10 seconds and the dynamic range almost covers the entire scale from 0% to 100% load[140] –this may enable them provide frequency and voltage control. These characteristics

138. Deasley, S. and Thornhill, C. (2018). *Market and Regulatory Frameworks for a Low Carbon Gas System*. *Frontier Economics*. ttps://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/699678/Final_BEIS_low_carbon_gas_070318_clean-STC.pdf

139. International Energy Agency. (2015). *Technology Roadmap: Hydrogen and Fuel Cells*. http://ieahydrogen.org/pdfs/TechnologyRoadmapHydrogenandFuelCells-(1).aspx

Figure 4.7: Electrolysis supply smoothing



Hovsapian, R. (2017). 'Role of Electrolyzers in Grid Services'. *Hydrogen Technical Advisory Committee.*

could make electrolysers eligible to participate in the ancillary markets that batteries currently operate in.

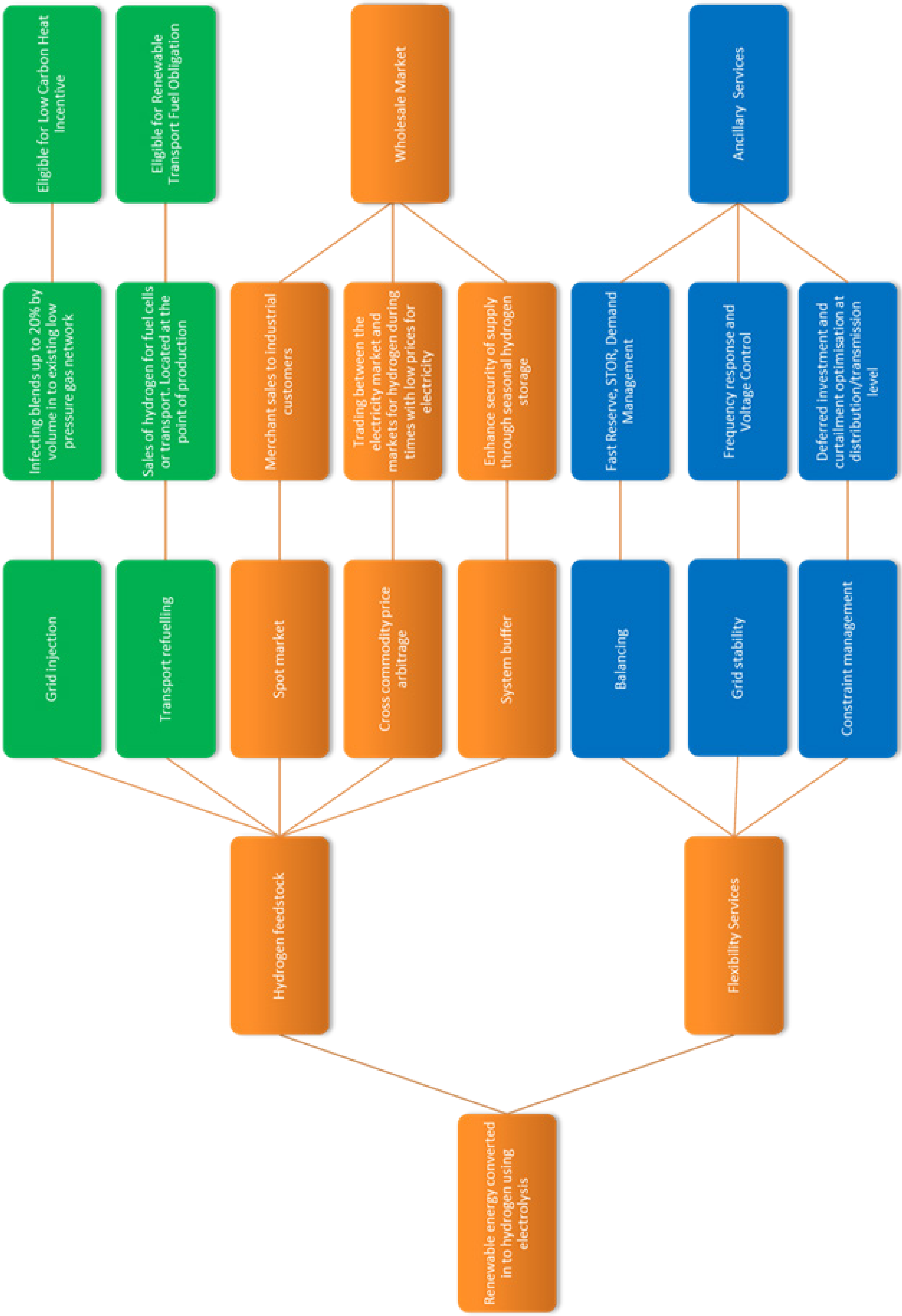
Electrolysers also have the potential to smooth out the variability of renewable sources by using advanced control of electrolysis plant and equipment. By co-ordinating the operation of a number of electrolysers, fixed and predictable power can be injected into the grid.

Operating a business model that combines revenue streams from both hydrogen sales and government backed electricity market contracts could be used to de-risk projects. However, these contracts should only be awarded on a competitive basis and due to the falling costs of batteries and the high level of liquidity in the ancillary services market, ancillary service provision is extremely competitive. It is unlikely that electrolysers will be cost competitive in the short term. But given that production of hydrogen using electrolysis has the potential to achieve far greater cost reductions than other mature production technologies, the Government should consider targeted investment to reduce the cost of electrolysers, at the same time giving due regard to export opportunities for the technology.

This could also be increasingly important in a world of subsidy free renewables and in the absence of a price stabilising CfD. For example, if a proportion of wind output is siphoned off for renewable electrolysis production this would be eligible for government support either in the form of RHI if it was for heat or RFTO if it was for transport. This additional support could act a hedge against volatile wholesale prices in the absence of a price stabilising CfD. This illustrates the importance of de-risking projects so that barriers to investment can be overcome.

However, at the moment there is limited experience with using electrolysers as ancillary service providers. Consequently, the regulatory framework for the participation of electrolysers in the ancillary service market is unclear. **While there appears to be no regulatory barriers to the participation of electrolysers in this market, informational barriers do**

Figure 4.8: Examples of different revenue streams from renewable energy electrolysis



Box 4.3: Hydrogen business models from California[xv,xvi]

As the Californian electricity sector evolves and increasing amounts of variable renewable generation are installed on the system, greater system flexibility is needed to balance supply and demand. The role of hydrogen to support the grid in this area has been examined, with emphasis on obtaining information about the economic competitiveness of hydrogen system configurations.

This was explored using 2012 data from the California wholesale electricity markets to quantify the value of hydrogen energy storage and demand response systems. The yearly revenues from feedstock sales, ancillary services and capacity markets were compared to the yearly cost to establish economic competitiveness for hydrogen systems and conventional storage systems (e.g., pumped hydro, batteries).

The results show that hydrogen systems can present a profitable business model using current markets. The main findings were:

1. For hydrogen systems participating in California electricity markets to be most profitable, producing and selling hydrogen was found to be much more valuable than producing and storing hydrogen to later produce electricity. Therefore, systems should focus on producing and selling hydrogen and seek additional revenues through the provision of ancillary services and arbitrage.
2. Greater integration of hydrogen applications with electricity markets generates greater revenues (i.e. systems that participate in multiple markets such as frequency regulation, capacity or reserve in the UK will receive the highest revenue).
3. More storage capacity, in excess of what is required to provide day to day shifting, does not increase competitiveness in current California wholesale energy markets.

At the moment the day to day price volatility is too low to provide sufficient arbitrage opportunities that can offset the cost of long term storage. The most important factor is the frequency of low prices rather than how low they can be. This may change as renewables take a greater share of electricity output and the importance of long term storage is reflected in price signals or through additional markets.

exist. These challenges are commensurate with those faced by the nascent battery storage market over the last few years. Where possible, lessons should be learnt from this, such as issues of transparency, understanding exactly what services National Grid (and in due course the distribution operators) require, and how to access them when this may not be the core business model. Reducing these barriers to entry and ensuring a level playing field needs to be encouraged.

Recognising this, the System Operator has recently published its System Need and Product Strategy (SNAPS), which responds to the inherent complexities of DSR and rightly seeks to rationalise, standardise and

xv. Eichman, J., Townsend, A. and Melaina, M. (2016). Economic Assessment of Hydrogen Technologies Participating in California Electricity Markets. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy16osti/65856.pdf

xvi. Decourt, B. et al. (2014). Hydrogen-Based Energy Conversion. SBC Energy Institute. http://www.4is-cnmi.com/presentations/SBC-Energy-Institute_Hydrogen-based-energy-conversion_FactBook-vf.pdf improve the number of products on offer. Industry feedback has often cited complexity and a lack of transparency as a barrier to entry and SNAPS aims to reduce the 20 plus products on offer down to just five clear areas.

By reducing the different technical requirements for each market and harmonising markets that are either over or under subscribed, this should make it easier for businesses to capitalise on and access the numerous flexibility markets.

The System Operator and businesses also need to collaborate to deliver stakeholder priorities such as optimal contract structures. Given the high level of liquidity in the ancillary services market, offering long term contracts when cheaper alternatives either exist or are likely to emerge may not provide the best value for money. Balancing the need for long term contracts in order to raise project finance with value for money remains a challenge.

This illustrates that the System Operator needs to continually examine how new technologies and existing technologies can be encouraged to actively participate in the ancillary services market. This should be woven in to the System Operator existing work that is exploring possible different hydrogen market models and what they would mean for the operation of the gas system[141].

But before electrolysers can enter the market, further work might include:[143]

- definition of test, measurement methods and load cycles in electrolyser performance standards to enable qualification for ancillary service provision (as well as conformity assessment by the System Operator
- definition of quality related parameters to determine/value the quality of supply of ancillary services

Following this, in order to validate the benefits of hydrogen electrolysers through flexibility service provision a pilot study should be established to assess how electrolysers and the definitions above respond to different demand profiles. These could include[143]:

1. Ramp Up, Ramp Down : variations in increasing or decreasing load steps
2. Load Steps : variations in the size of change
3. Utility Demand Response : expected performance of electrolyser in grid application
4. Random Variations : variations in the speed of change

Moreover, electrolyser business models that are based on transmission grid services will need to locate electrolysers in suitable locations in order to deliver attractive project returns. To date, hydrogen production projects have tended to site electrolysers at the point of demand, e.g. a refuelling station. However, a recent study[145] suggests that this could be the least

140. National Grid (2018). *The Future of Gas: How gas can support a low carbon future.* http://futureofgas.uk/wp-content/uploads/2018/03/The-Future-of-Gas_Conclusion_web.pdf

141. Steen, M. (2014). 'Putting Science into Standards: Power-to-Hydrogen and HCNG: Concluding Remarks'. *European Commission.* https://ec.europa.eu/jrc/sites/jrcsh/files/hcng-2014-conc1-steen.pdf

142. Hovsapian, R. (2017). 'Role of Electrolyzers in Grid Services'. Hydrogen Technical Advisory Committee. https://www.hydrogen.energy.gov/pdfs/htac_may17_08_hovsapian.pdf

143. SSE. (2018). *RHyMES: Renewable Hydrogen Models for Energy Storage, Feasibility Study Final Report.*

economically viable route to producing hydrogen at scale, largely due to the non-commodity charges included in the price of the input electricity.

Optimal locations for electrolyser placement are expected to be within close proximity to sources of production, curtailment and grid constraints. Indeed, a more viable model could be to produce hydrogen at the source of electricity generation as this could allow access to the wholesale market price of electricity and its full volatility – including periods of low or even negative prices as well as periods of curtailment. The main drawback of such an approach is that the hydrogen would need to be transported to demand centres and this will incur significant costs**. To mitigate this it is suggested that the hydrogen is produced and consumed at the point of electricity supply in order to achieve the most attractive project return, as this option avoids both non-commodity and transport costs**.

Although the costs of PtG are more expensive in comparison to other options, positive business cases are likely to exist in particular geographical and system niches.[145] For example, if there is an increase in commercial/industrial demand for hydrogen produced from low carbon sources – facilitated by organised/regulated markets – and applications occur in certain clusters or regions, the low carbon price premium for hydrogen produced from wind or SMR with CCS can be shared. Demand clusters might also enable arbitrage and efficient hydrogen production during periods of variable demand and acute grid constraints in specific geographies such as Scotland, where curtailed wind power is most prevalent and where 60%[147] of onshore wind output is produced.

Standards

Standards can play a central role in the creation of markets, providing a foundation to develop new technologies, enhance existing practices, open up market access and encourage innovation.[147] Yet there currently lacks a UK definition of 'green hydrogen', which presents an obstacle for policy support for hydrogen[149]. This is despite DECC's 'Green Hydrogen Standard' consultation and call for evidence in 2015. This sought views on what constitutes 'green' in the context of this standard and discussed thresholds and technologies the Standard should cover.[149] In addition, DECC also established a Green Hydrogen Working Group with industry to define a process for the Standard's development and as a first step is developing an agreed definition of 'low carbon'. The aim being to find a way of providing assurances to buyers of hydrogen that the product they are purchasing meets their environmental expectations. However, the working group was subsequently disbanded.

In Europe, a number of similar initiatives are underway. Examples include the TUV standard in Germany and the 'Garantie Origine' or 'Guarantee of Origin' approach being developed in France. In the case of the French standard, which requires hydrogen to be derived entirely from renewable fuels, this runs counter the UK's approach of technology neutrality Attempts to design the first EU-wide Green Hydrogen standard began in 2015 and in early 2018, the CertifHy project was launched.[150]

144. Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute. http://www.sustainablegasinstitute.org/wp-content/uploads/2017/12/SGI-A-greener-gas-grid-what-are-the-options-WP3.pdf?noredirect=1

145. Bassi, S. (2016). 'Where are onshore wind farms located in the UK and where are the proposed future sites?'. *The London School of Economics and Political Science.* http://www.lse.ac.uk/GranthamInstitute/faqs/where-are-onshore-wind-farms-located-in-the-uk-and-where-are-the-proposed-future-sites/

146. European Telecommunications Standards Institute. (Date Unknown). 'Why we need standards'. https://www.etsi.org/standards/why-we-need-standards

147. Dodds, P. and Abad, A.V. (2016). 'Definition of a UK green hydrogen standard'. *UCL Energy Institute.* http://www.h2fcsupergen.com/wp-content/uploads/2016/09/green_hydrogen_standard_h2fc_research_forum_st_andrews_sep2016.pdf

148. Department of Energy & Climate Change. (2015). 'Green Hydrogen Standard'. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/403774/Green_Hydrogen_Standard_Call_for_Evidence.pdf

149. http://www.certifhy.eu/

This will enable the first green Hydrogen Guarantee of Origins that will be available for sale EU-wide, providing information of the source of the product and allowing hydrogen users to track the origin of the product very soon. It is important to consider the impact of differing standards with neighbouring countries particularly for imported hydrogen if there is no regulatory harmonisation with other EU countries. This is even more pressing given that scaling hydrogen use will be contingent on a liquid import market and the UK is leaving the European Union. **Regulatory alignment or divergence could have significant implications for the development of this nascent market.**

Setting the emissions level of the standard is one of the most critical issues for the development of a wider hydrogen market. One of the difficulties is that whilst it is crucial to quantify the carbon content of the hydrogen produced, a new industry requires a market for its product, and setting the Standard at a too stringent level out from the offset may hamper and stifle innovation and development[151]. That said, if the hydrogen is to be eligible for support under either the RTFO or a reformed RHI, there must be tangible emissions reductions from using hydrogen feedstock. Therefore, the hydrogen standard must represent a serious emissions reduction against more carbon intensive fuels. The overarching principle should be technology neutrality so long as this delivers a reduction in emissions. This would allow renewable and non-renewable production methods to be eligible for Government support, so long as the latter was equipped with CCS. Parallels can be drawn with the sustainability criteria and the GHG thresholds used for bioliquids under the Renewables Obligation, which only enables Government support if it meets a 60% reduction against the EU fossil fuel average. This approach would be similar to the qualification criteria used by the TUV SUD green hydrogen initiative in Germany where the qualification level is set at 35-75% emissions reductions below baseline[152], depending on the production process.

A full lifecycle analysis (LCA) of production methods should be conducted to assess definitive carbon intensities for different production methods, with industry led agreement over the exact formulation of the LCA. One way of framing the standard could be to set it against the backdrop of the UK's carbon budgets, with increasingly stringent targets over time. This could help to find a balance between stifling innovation and having realistic thresholds.

It is recommended that the 'Green hydrogen standards' working group resumes work, in conjunction with industry, to define appropriate emissions levels for low carbon hydrogen and determine whether this should be uniform across all sectors. The development of a quality mark for hydrogen should be underpinned by strong standards coupled with an enforcement and compliance framework.

150. Ibid.

151. Dodds, P. and Velazquez, A. (2016). 'Development of a Green Hydrogen Standard for the UK'. *UCL Energy Institute*. https://www.all-energy.co.uk/RXUK/RXUK_All-Energy/2016/Presentations%202016/Hydrogen%20and%20Fuel%20Cells/Paul%20Dodds.pdf?v=635993507733221810

Recommendations

- **Quantity the system benefits of Power to Gas**
  - Curtailed wind cannot produce the volumes of hydrogen needed to make a substantial contribution to overall hydrogen production – just 0.3% of gas used domestically. Curtailed wind has a role to play and what little hydrogen can be produced from curtailed wind should be integrated into the energy system. Principally this should be for management of the electricity grid.
  - An assessment should be made of how PtG may reduce system costs, including, an assessment of the cost of PtG relative to the costs of other options to mitigate intermittent renewables, which include: temporary curtailment of intermittent generators; interconnection of electricity networks with other countries; demand side response to manage variable electricity demand; use of dispatchable gas fired power stations as back-up generators; and some form of electricity storage.[153]
- **Create an upstream PtG market**
  - In order to validate the benefits of hydrogen electrolysers for flexibility service provision a pilot study should be established by 2021. This should include defining testing parameters and measurement methods to assess electrolyser performance against qualification criteria to fully understand quality of supply of ancillary services.
  - It is recommended that the 'Green hydrogen standards' working group resumes, in conjunction with industry, to define appropriate emissions levels for low carbon hydrogen and determine whether this should be uniform across all sectors. This should be done by 2021 to align with the next RIIO charging period. The development of a quality mark for hydrogen should be underpinned by strong standards and enforcement.
  - Scaling hydrogen use will require a liquid import market. Therefore, following Brexit, the UK Government needs to clarify how these future standards may diverge or align with standards set by the European Union.
- **Reduce informational barriers**
  - To plan investment in hydrogen production, long term visibility is required for business planning, particularly for the next RIIO price control period (2021-2026). Ofgem must provide clarity on what constitutes allowable spend by gas networks during the period 2021-2026 and whether investment in hydrogen can be funded under the RIIO price control mechanism.
  - National Grid should continually examine how new and existing technologies can be encouraged to actively participate

152. Speirs, J. et al. (2017). *A Greener Gas Grid: What are the Options?*, Imperial College London and Sustainable Gas Institute. http://www.sustainablegasinstitute.org/wp-ontent/uploads/2017/12/SGI-A-greener-gas-grid-what-are-the-options-WP3.pdf?noredirect=1

in the ancillary services market. While there appears to be no regulatory barrier to the participation of electrolysers in this market, informational barriers do exist. National Grid should continue to promote transparency, so that developers can understand exactly what services National Grid require, and how to access them when this may not be the core business model.

5 Conclusions and Policy Recommendations

This chapter of the report provides a set of high level guiding principles that the Government should follow when determining the role hydrogen can play in facilitating the transition to a low carbon economy.

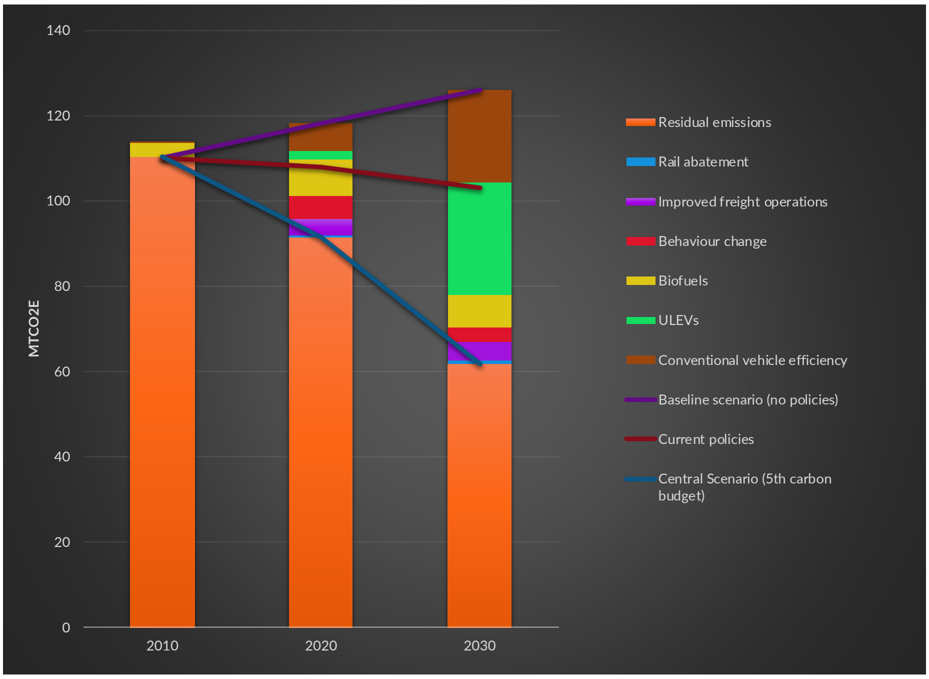
The need for new policies to decarbonise hard to reach sectors

The fifth carbon budget set by the Committee on Climate Change contains comprehensive analysis on how to decarbonise domestic homes, transport and industry. In addition to setting the decarbonisation trajectory needed to reduce emissions by 80% compared to 1990 levels (as set out in the Climate Change Act), the progress reports also contain detailed information on whether existing policies are sufficient to meet the statutory targets and the level of risk associated with these policies. The risk is split in to three categories – low risk, medium risk policies that may not deliver, and high risk policies that are only high-level intentions. Even taking into account all categories of existing policies this is still not sufficient to meet the 5th carbon budget in all the sectors that this report focusses on. The difference between emissions reductions from current policies and emissions reductions needed to achieve the carbon budgets is known as the 'policy gap'. As it stands there is a policy gap in buildings, industry and transport, and is largest in the transport sector. Under current policies, emissions will fall to 103 $MtCO_2e$ (metric tons of carbon dioxide equivalent) by 2030 rather than the 62 $MtCO_2e$ required to fulfil the fifth carbon budget. This leaves a policy gap of 41 $MtCO_2e$.

Analysis in this report and previous Policy Exchange work such as *Driving Down Emissions* suggests that emissions reductions in the transport sector will be achieved through the adoption of Ultra Low Emission Vehicles (a saving of 27 $MtCO_2e$ by 2030) and further improvement in conventional vehicles (22 $MtCO_2e$). The policy gap in the buildings sectors (figures 5.2) is slightly less than the transport sector. Under current policies, emissions will fall to 90 $MtCO_2e$ by 2030 rather than the 66 $MtCO_2e$ required to fulfil the fifth carbon budget. This leaves a policy gap of 26 $MtCO_2e$. The smallest policy gap is within the industrial sector, where the shortfall is 7 $MtCO_2e$.

Although the buildings policy gap is smaller in comparison to the transport sector, the path forward is less clear, particularly with regard to residential buildings. **Overall, it is clear that Government needs to**

Figure 5.1: Surface transport abatement in the Fifth Carbon Budget central Scenario



Howard, R. et al. (2017). *Driving Down Emissions*. Policy Exchange.

Figure 5.2: Building abatement in the Firth Carbon Budget central Scenario

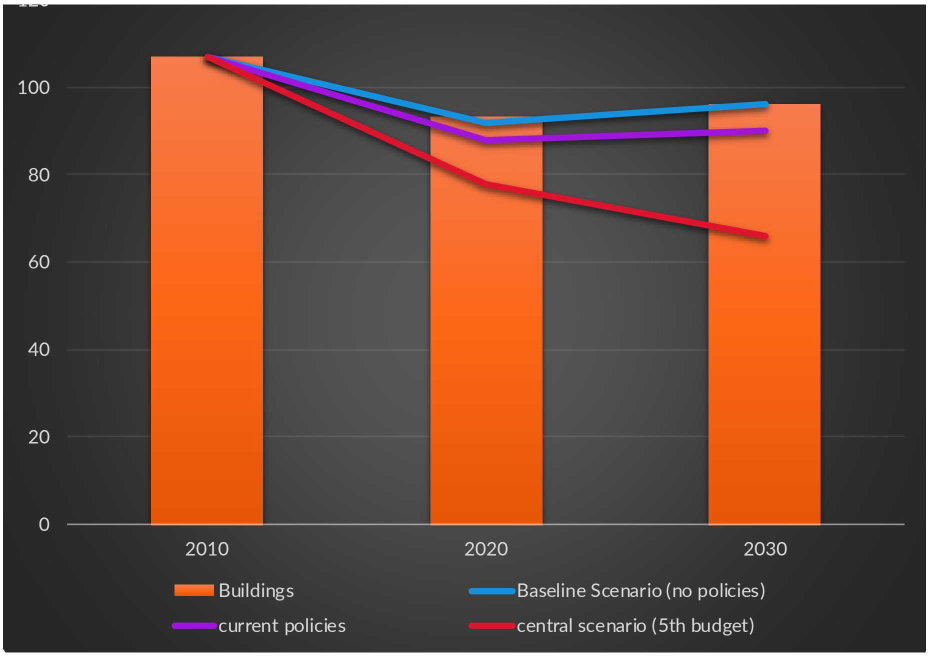
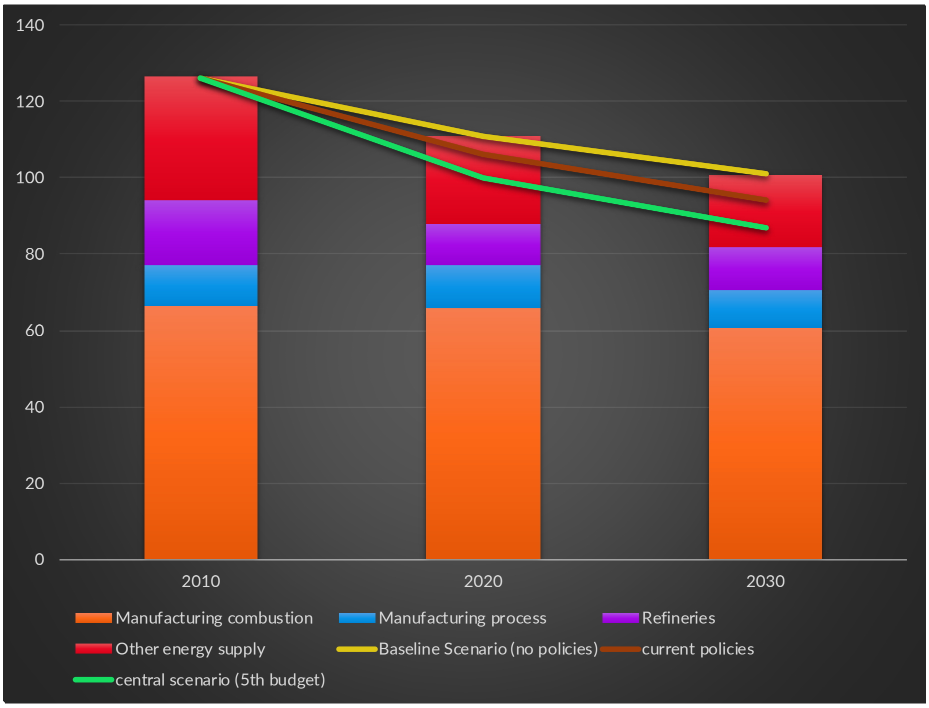


Figure 5.3: Industrial abatement in the Fifth Carbon Budget central Scenario



develop new policies to decarbonise these sectors in accordance with the statutory targets set out by the CCC. Without adequate new policies beyond 2020, meeting the fifth carbon budget becomes increasingly difficult. Echoing our own analysis, the CCC suggests effective policy on **reducing emissions from buildings must include reformed support for low-carbon heat through the 2020s,[154] including an effective long term market framework for hydrogen beyond 2021**. This should inform wider preparation for strategic decisions on the role of hydrogen in decarbonising hard to reach sectors.

In addition to the specific policy recommendations in the previous chapters, we suggest that when examining the role hydrogen can play in facilitating the clean energy transition, a number of overarching principles should be followed:

1 Take a systems view

Power, heating and transport are the three features of the UK energy landscape that form the constituents of total energy decarbonisation. These thematic areas are deeply interlinked, and set against the backdrop of the UKs greenhouse gas emissions targets, have combined to serve as the catalyst for a deeper examination of the possibilities and challenges of a hydrogen economy. As mentioned in chapter one, the transition to a low carbon economy has significant technological and system challenges, such as how to best integrate increasing amounts of intermittent renewable energy.

As such it is important to fully understand that producing hydrogen as an alternative low carbon energy source – that can be used as a replacement in transport, heating fuel and also storage – has systems

153. Committee on Climate Change. (2017). *Meeting Carbon Budgets: Closing the Policy Gap: 2017 Report to Parliament*. https://www.theccc.org.uk/wp-content/uploads/2017/06/2017-Report-to-Parliament-Meeting-Carbon-Budgets-Closing-the-policy-gap.pdf

implications because these different uses for hydrogen are likely to be highly interconnected with one service creating a supply for other uses. **Assessing the role of hydrogen in isolation from the rest of the energy system may lead to biased inferences and a failure to capture interactions with other drivers of the energy system**.[156] The role hydrogen can play in clean energy transition should not be limited to one application but should be focused on all the challenges of this transition and examined through a systems lens.

For example, whilst using hydrogen – through power to gas – may reduce system costs, it is important that this is looked at relative to the costs of other options to mitigate intermittent renewables, which include: temporary curtailment of intermittent generators; interconnection of electricity networks with other countries; demand side response to manage variable electricity demand; use of dispatchable gas fired power stations as back-up generators; and some form of electricity storage. Moreover, plans have been put forward to blend up to 20% (by volume, ≈7% by energy) hydrogen into our national gas network. Assuming improved efficiency of fuel cell powered HGVs compared with diesel, the same amount of hydrogen to decarbonise <7% of our natural gas network would be enough to decarbonise between 20-30% of road freight. Our research also shows that using hydrogen to decarbonise certain areas of transport such as trains and boats is more cost effective than using it to decarbonise domestic heating. Therefore, decisions about how to best deploy hydrogen should take a holistic approach.

Whilst it is possible to pinpoint high level inflexion points within the system – and where hydrogen could potentially help – identifying the precise role of hydrogen is difficult. The regulatory model therefore needs to be flexible enough to adapt to changes within the energy system. However, integrating hydrogen is currently hampered by the **long-term visibility required for business planning, particularly for the next RIIO price control period (2021-2026).** The two are intrinsically linked – without the former, the latter is not possible. Given the length of the price control period and the timetable for network companies running the gas and electricity transmission and distribution networks to submit business plans (Q1 2019), market and policy certainty is urgently needed.

2 Support consumer preferences

In our previous report, 'The Customer is Always Right', we argued that under the Coalition Government and previous Labour administrations, energy policy became increasingly detached from what consumers and voters want.

The Government needs to ensure that consumers remain at the heart of any strategy to integrate hydrogen in to the energy system. Energy bills are large components of annual household bills. In 2016 UK households were spending on average 4% of their total expenditure on energy, up from approximately 3% in the early 2000s. This is even more acute in lower income households. In 2016 households in the lowest

154. Sgobbi, A. et al. (2016). 'How far away is hydrogen? Its role in the medium and long-term decarbonisation of the European energy system'. *International Journal of Hydrogen Energy*, Vol. 41, Issue 1, Pages 19-35.

income decile spent nearly 8.5% of their total expenditure on energy.[157] As noted in the previous chapters although some cities or towns may be better placed to initiate full conversion to hydrogen heating, geographical conversions of this kind give rise to issues of governance pertaining to **consumer choice and rights**. For example, if a city decides to unilaterally switch the entire gas network from natural gas to hydrogen, to what extent can an individual household opt out of this? The inability to do so could give rise to a lack of equity between all network consumers which could be exacerbated if network conversions occur on a city by city basis. This could result in higher costs compared to the gas they previously had, or higher costs than in neighbouring areas that haven't converted. Therefore, policies that promote conversion to hydrogen in specific cities or localities could have an impact on household budgets and the cost of living.

Government needs to develop a hydrogen strategy that takes in to account consumer preferences and does not unduly penalise groups of households. A hydrogen strategy should focus on how to minimise consumer costs from conversion to hydrogen, including hardware costs such as replacement of traditional system boilers, cookers, heaters or other equipment. **When Ofgem provide clarity on the scope and arrangements for the next RIIO charging period, this must give consideration as to how costs can be socialised in the most equitable way.**

3 Pursue cost-effective solutions

Given that energy costs are a key concern for households, **the Government must focus on the most cost-effective technologies in order to minimise the burden on consumers.**

This is best achieved by adopting a technology neutral approach – pursuing the lowest cost technologies to achieve a given environmental outcome. Yet, the Government is a long way from adopting a technology neutral approach to decarbonise heat. For example, the Renewable Heat Incentive is only eligible for renewable forms of heating, rather than other low carbon options such as hydrogen. In our view the Government should pursue the lowest cost solutions to decarbonise heat, and broaden the scope of technologies that are eligible for support under the RHI. This could include measures such as energy efficiency. In the longer term, if hydrogen for heating is deemed an appropriate application and solutions to the scaling challenges are overcome, a support framework for hydrogen that is compatible with the overarching ambition of lowering the cost of decarbonising heat is potentially possible**.** Renewable technologies eligible under the RHI (e.g. biomass, GSHP) are more expensive in terms of abatement costs than other forms of hydrogen production such as SMR + CCS or electrolysis. For example, our analysis illustrates that compared to the most expensive technologies eligible for support under the RHI, **hydrogen produced via SMR + CCS would deliver carbon savings at a quarter of this price, whilst hydrogen produced from electrolysis would deliver carbon savings at approximately half the price**. The Government needs to create a set of conditions that allows these technologies to compete on

155. Ofgem. (2018). 'Energy spend as a percentage of total household expenditure (UK)'. https://www.ofgem.gov.uk/data-portal/energy-spend-percentage-total-household-expenditure-uk

a level playing field, flushing out the lowest cost routes to decarbonisation.

Against a backdrop of uncertainty regarding the continuation of the RHI beyond 20/21, one alternative might be to **reform RHI in to a low carbon heat incentive focussed on the most cost effective decarbonisation technologies including renewable and non-renewable technologies, incorporating those that can produce hydrogen**. Widening what is eligible to include hydrogen production technologies could lower the overall spend by Government whilst reducing emissions. A support framework along these lines would ensure greater affordability to the taxpayer and make subsidies go further. However, if the system view suggests hydrogen for transport is more favourable than hydrogen for decarbonising domestic homes, a reformed RHI and other incentives should not change to encourage hydrogen for heating in the short term.

4 Combine quick wins with a long-term vision

The Government's approach to developing a 'hydrogen economy' should combine 'quick wins' with longer term objectives. The challenge is to balance these competing priorities. Our analysis demonstrates there are a number of short term opportunities to advance the use of hydrogen to integrate renewables and decarbonise hard to reach sectors. The options to decarbonise heating using hydrogen will require significant investment and infrastructure upgrades across gas and electric networks. We are fast approaching the time that network companies running the gas and electricity networks will need to submit business plans under the next price control period. This enables them to plan future investment. Yet there is no decision on how network companies can recoup the cost of hydrogen investment. This reinforces the need for **Ofgem to provide clarity on what constitutes allowable spend by gas networks during the period 2021-2026 and whether investment in hydrogen can be funded under the RIIO price control mechanism.**

At the same time, quick wins that help to develop both supply and demand markets for hydrogen should be pursued. Standards can play a central role in the creation of markets, providing a foundation to develop new technologies, enhance existing practices, open up market access and encourage innovation.[158] Setting the emissions level of the standard is one of the most critical issues for the development of a wider hydrogen market. Yet there currently lacks a UK definition of 'green hydrogen', which presents an obstacle for policy support for hydrogen. **It is recommended that the 'Green hydrogen standards' working group resumes work, in conjunction with industry, to define appropriate emissions levels for low carbon hydrogen** and determine whether this should be uniform across all sectors**. The development of a quality mark for hydrogen should be underpinned by strong standards coupled with an enforcement and compliance framework.** In Europe, a number of similar initiatives are underway. Therefore, it is important to consider the level of r**egulatory alignment or divergence after Brexit, as this could have significant implications for the development of this nascent market.**

156. European Telecommunications Standards Institute. 'Why we need standards'. https://www.etsi.org/standards/why-we-need-standards

Moreover, regulations, codes and standards have often not been designed with new sources of gas in mind and current gas standards present a significant barrier to hydrogen injection. The Gas Act and subsequent standards, although allowing for the presence of other gas, has no provision or flexibility to accommodate a wide range of gases that a future gas grid could transport**. At present, the UK has one of the lowest permitted levels of hydrogen blending in Europe** (and further afield) as stipulated by the Gas Safety (Management) Regulations (GS(M) R) which states that hydrogen blending can not exceed ≤0.1%. However, A HSE report from 2015 concluded that "concentrations of hydrogen in methane of up to 20% by volume are unlikely to increase risk from within the gas network for from gas appliances to consumers or members of the public".[159] Since the HSE concluded that far higher levels are safe as well as a growing body of literature and examples from other European countries, **this limit should be increased in accordance with the conclusion of the HSE**. This will allow higher quantities of hydrogen to be blended in to the network. Removing this regulatory barrier would be a quick win.

5 Provide cross departmental leadership

One of the striking features about the use of hydrogen is how many different sectors it cuts across – domestic and commercial buildings, industry, transport and power. Governance of hydrogen should also take a systems approach, incorporating leadership across the different sectors. Whilst the Clean Growth Strategy and Industrial Strategy provide a framework that cuts across these sectors, one body is not responsible. For example, in transport alone there are several organisations pursuing policies to promote better air quality of low carbon alternatives. These include The Department for Transport (DfT), Office for Low Emission Vehicles (OLEV), Department for Food and Rural Affairs (DEFRA) and the Committee on Climate Change (CCC). Beyond this, Treasury have an interest in transport related taxation.

Similarly, when it comes to decarbonising buildings and integrating renewable energy, several organisations are involved. For the former this includes: Local Authorities and Local Enterprise Zones helping to facilitate regional conversions to hydrogen networks; Heat Networks Delivery Unit (HNDU) which provides support and guidance for local authorities developing heat networks; and The Department for Business, Energy and Industrial Strategy (BEIS) which sets support levels for renewable heat. For the latter, National Grid take a central role at the transmission level through their procurement of ancillary services, whilst at the distribution level, Distribution Network Operators (DNOs) will increasingly play a part as we transition away from this model towards Distribution System Operators (DSO).

This represents eleven different organisations/bodies that could have a role in the governance of hydrogen, or none if they assume responsibility lies elsewhere. Clearly, this could present a challenge when putting forward not just a coherent vision, but a coherent policy framework. This could manifest to a lack of joined up thinking. For example, recent modelling for the National Infrastructure Commission on four decarbonised heat

157. Hodges, JP. et al. (2015). *Injecting hydrogen into the gas network – a literature search*. Health and Safety Executive. http://www.hse.gov.uk/research/rrpdf/rr1047.pdf

options (electrification through heat pumps, electrification through direct electric, hybrid gas-electric, hydrogen grid) concluded that a hydrogen grid would be the most cost-effective, costing £50 billion less than the next cheapest option (hybrid gas-electric), and costing less than half that of the two electrification options.[160] By contrast, modelling by Imperial for the CCC suggests[161] that switching to hydrogen for heating would be marginally more expensive that switching to electricity for heating and hybrid heat pumps. The CCC modelling also suggests that the cost between the different decarbonised heat scenarios is very small, unlike the NIC report that has enormous differences in cost. Granted, the model assumptions used by each organisation are different and this explains the inconsistency. However, irrespective of the input assumptions, the overall lack of a coherent policy message is likely to obfuscate policy makers rather than enlighten them.

The RTFO's sustainability compliance policy which sets standards for renewable hydrogen should align with the wider development of green standards for hydrogen so that the market is not too complex as to stifle innovation and development. **All departments will need to coordinate and work towards a common and long-term vision of how gas and gas networks should be utilised, articulating clearly how this is compatible with the UK carbon budgets and any potential move towards net zero.**

158. Element Energy. (2018). *Cost analysis of future heat infrastructure options*. E4tech. https://www.nic.org.uk/wp-content/uploads/Element-Energy-and-E4techCost-analysis-of-future-heat-infrastructure-Final.pdf

159. Strbac, G. et al. (2018). 'Analysis of Alternative UK Heat Decarbonisation Pathways'. *Imperial College London.* https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways-Executive-Summary.pdf

The concept of a 'hydrogen economy' has been put forward by proponents for many decades. In theory, this abundant element is a perfect solution to our clean energy needs. It does not produce greenhouse gases when burned, it can be stored in large quantities for long periods, and it can be used as a fuel in virtually every sector of our economy, from transport to heavy industry to home heating. Despite the notion of a hydrogen based economy existing for sometime, and recognition of the environmental benefits that this entails, it is yet to fully materialise

This report considers the role of hydrogen in helping the UK achieve its ambitious targets to reduce greenhouse gas emissions by at least 80% (from the 1990 baseline) by 2050, focusing on barriers to the clean energy transition that need to be overcome.

These include:

- decarbonising hard to reach sectors such as heat, transport and industry;
- finding ways to store large quantities of energy to act a as system buffer, a role that is currently mostly fulfilled by natural gas;
- integrating increasing amounts of variable renewable energy into the system.

The report argues that two high level issues need addressing. Firstly, cost effective, scalable and sustainable production methods need to reach mass market and so targeting Government investment towards reducing the high cost of producing large volumes of low carbon hydrogen is crucial. Secondly, a comprehensive and systemic approach is essential to determine the most appropriate application(s) of hydrogen within the economy.

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