Sector Research: Hydrogen

350PPM
Capitalist Solutions to Climate Change

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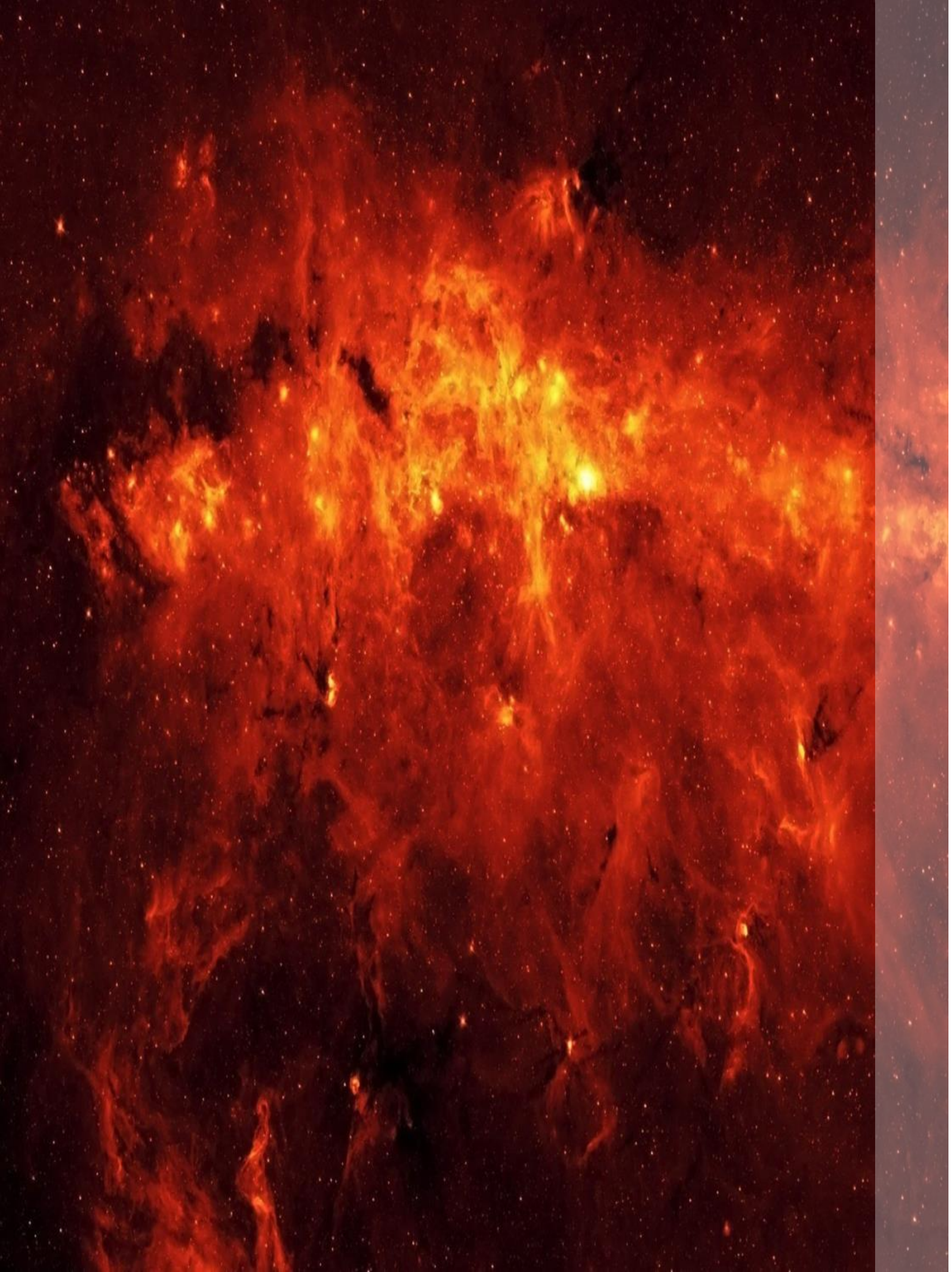

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Introduction

Given a clearer picture of the consequences, climate change ambitions – certainly in the UK - are shifting towards the goal of limiting global warming to 1.5 ºC above pre-industrial levels, rather than 2 ºC. This goal dictates a global transition to net-zero energy-related CO_2 emissions by 2050 at the latest.

Achieving this goal will be challenging. Current methods for the decarbonisation of energy – increased energy efficiency, switching to electricity from renewable energy sources rather than fossil fuels, and increased electrification – can, by wide agreement, only take us so far. In addition, these methods present significant challenges in their wider adoption.

In this report, we introduce how hydrogen – a clean, versatile and abundant element, currently used mostly in the production of chemicals - could help obviate or overcome some of these challenges. Hydrogen could do this by expanding into a role as a complementary energy carrier alongside zero-carbon electricity.

In this role, hydrogen produced from renewable and carbon-abated fossil fuel sources could help decarbonise certain end-use sectors, particularly those less suited to full decarbonisation with electricity, such as transport, heavy industry and heat for buildings. It could also help with the decarbonisation of the electricity supply, in part by enabling the integration of high levels of renewable energy.

Much of the technology needed to make this vision a reality exists today, but can it be scaled economically from today’s demonstration and early commercial ventures to mass market acceptance, or are there fundamental issues that will limit its uptake? Frankly, no one knows if hydrogen will become a ‘central pillar’ of our decarbonisation efforts, providing 18% of final energy demand globally by 2050, with associated revenue potential of $2.5 trillion a year, as suggested by the Hydrogen Council, a prominent hydrogen advocacy group. Regardless, given this potential, investors need to be aware of hydrogen. This report provides a high-level overview of the topic.

Note on References

References used more than once are listed below and are denoted in the main text with a superscript letter of the alphabet. References used once are listed as a footnote on the page and are denoted with a superscript number.

Repeated references:

A. 'Hydrogen in a Low Carbon Economy', Committee on Climate Change, 2018.

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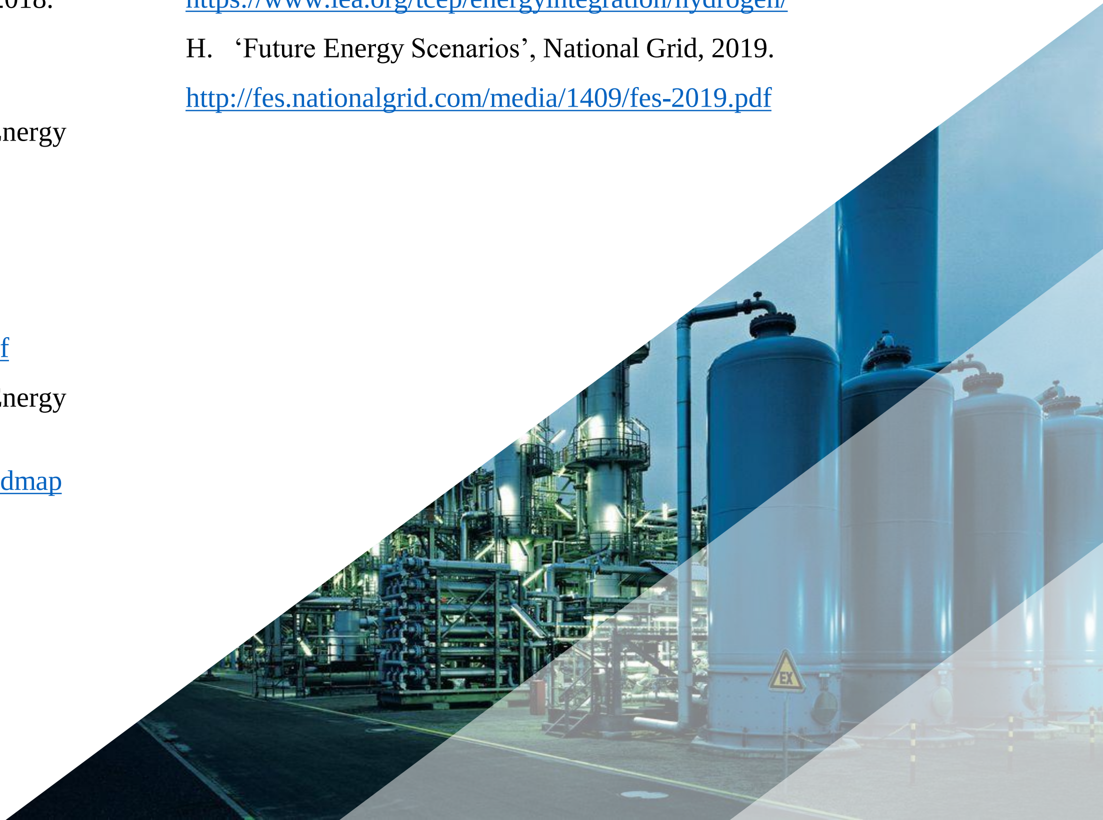


Why Hydrogen?

Why Hydrogen?

The Need

To limit global warming to 1.5 ºC above pre-industrial levels, or at least to have a good chance of achieving this, requires net-zero energy-related CO2 emissions by 2050, globally.

This requirement dictates the complete replacement of fossil fuels with zero-carbon alternatives, or, where not feasible, the use of carbon capture to achieve net-zero CO_2 emissions overall, with the CO_2 either being stored or reused (henceforth referred to as 'CCUS' - Carbon Capture, Usage and Storage). This transition must not only happen, but do so rapidly and economically, while retaining the reliability and convenience of fossil fuel-based energy provision. Otherwise people, given a choice, will not switch.

Current Decarbonisation Methods

There are several complementary methods for displacing or replacing fossil fuels, some more established, some less so, but with considerable potential for future application. Hydrogen fits into this latter category. Recent progress towards decarbonisation has largely been made by a combination of:

- Switching electricity generation from fossil fuels to low-carbon primary energy sources – nuclear and renewables (solar, wind, hydro, etc.).
- Electrification of end-uses previously relying on direct fossil fuel use, e.g. the use of electrical heat pumps instead of natural gas for heating buildings.
- Improved energy efficiency.

Limitations and Challenges

There appears to be a broad consensus that extended use of these methods can take us a large part of the way towards full decarbonisation of the energy system, though there is a wide range of opinions on exactly how far. Implicit in this view is a scepticism that these methods can take us all the way. Such scepticism seems justified as the extended use of these methods comes with serious challenges, likely to limit their use:

- Improving energy efficiency has technical limits. Sooner or later you run up against the fundamental laws of physics, preventing further progress. In some areas, the low-hanging fruit of efficiency have arguably already been developed, if not fully rolled out, e.g. LED lighting.
- Attempts to reduce energy demand through efficiency improvements are likely to be overwhelmed as the world population swells and becomes ever more power-hungry. Even factoring in forecast energy efficiency improvements, global primary energy demand is forecast to grow 10% by 2050 [1].
- Electrification has barely begun in several significant sectors, such as transport and heat for buildings. As these electrify, global electricity demand is forecast to increase 62 per cent by 2050 [2]. In the UK, a full electrification pathway could lead to an increase in peak electricity demand of up to four or five times by 2050 [A], along with significant seasonal peak demand variation due to the electrification of heating. This implies the need to increase electricity generation capacity multiple times over – much of which would only be used for part of the year - and to upgrade electricity transmission infrastructure to cope, both inefficient and hugely expensive prospects.
- As well as these electricity system considerations, electrification of certain end-use applications may be technically difficult, disruptive and/or expensive. We unpack this sentence throughout this report.
- Wind and solar are on track to provide nearly half of grid power globally by mid-century [2]. Without use in combination with suitable storage (or other flexibility), such variable renewables sometimes produce excess electricity, and at others, not enough. The higher the penetration of renewables, the larger this ‘intermittency problem’, and the greater the challenges of maintaining a stable electricity system. Note that there is a seasonal component to this problem, with renewable generation often highest across a year when demand is lowest and vice versa (compounding the difficulties of supplying enough electricity in the event of the widescale electrification of heating). Separately, renewables generate where the conditions are appropriate, and not necessarily where this electricity has most value.

[1] IEA (2017): Energy Technology Perspectives 2017
[2] https://www.businessgreen.com/bg/news/3077640/report-wind-and-solar-to-deliver-half-the-worlds-power-by-2050

Hydrogen to the Rescue?

Fortunately, there are additional methods we can turn to for deep decarbonisation of the energy system. These include the use of biofuels - fuels derived from organic material – CCUS, and the use of hydrogen.

Fundamentally, hydrogen provides an alternative way of transferring energy from primary energy sources to end-users in a convenient form. This is what electricity does. Hydrogen and electricity are often both labelled as ‘energy carriers’ (or ‘vectors’) to highlight their basic use and similarity. Neither are primary energy sources, but both are ‘produced’ from them and carry a fraction of their energy content. Both can be produced from either fossil or renewable energy sources, and both can be converted into the other, see **Figure 1**.

Before we describe how hydrogen might help with the issues identified in the previous section, we first review its basic properties, including the fundamental advantage it has over electricity as an energy carrier - it can be stored at scale and over long periods.

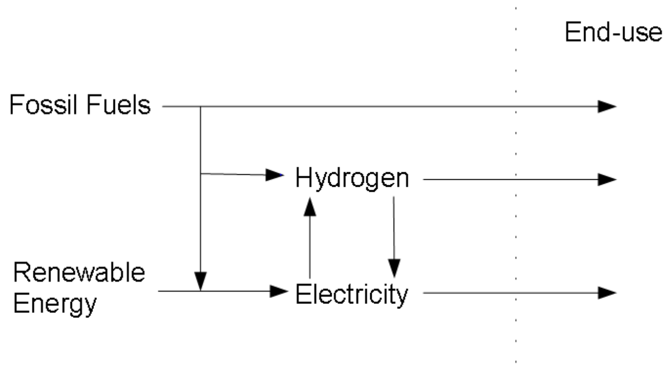


Figure 1 – Hydrogen and electricity as similar and interconvertible energy carriers

Hydrogen Basics

Hydrogen is the lightest element and the third most abundant element on the Earth's surface. Under ordinary conditions, it exists as the colourless and odourless gas H_2. Unfortunately, it does not exist in significant quantities in this form, so energy must be expended to extract it from abundant hydrogen-containing compounds such as water and fossil fuels. Currently, it is produced almost entirely from fossil fuels, and its main use is in the chemical and petrochemical industries, rather than the energy system.

Current Production [C]

Methods for producing hydrogen have been known for more than 200 years, though industrial large-scale production did not start till after World War I.

Today, global annual hydrogen production is ~60 Mt, roughly equivalent to 1.5% of world primary energy supply, with an estimated value of $115 billion [E]. 96% of this hydrogen originates from fossil fuel sources – from the reforming of natural gas and oil, or the gasification of coal, see **Figure 2.** The remainder originates from electrolysis, which involves using an electrical current to separate the elements in a compound. Electrolysis is explained in more detail in the later section 'Low-Carbon Hydrogen Production'.

Most of hydrogen is today generated and used on industrial sites as 'captive hydrogen'. In the EU, more than 60% of hydrogen is captive, one-third is supplied from by-product sources, and less than 10% of the market is met by merchant hydrogen [D]. UK production is from 15 sites, with half a by-product [A].

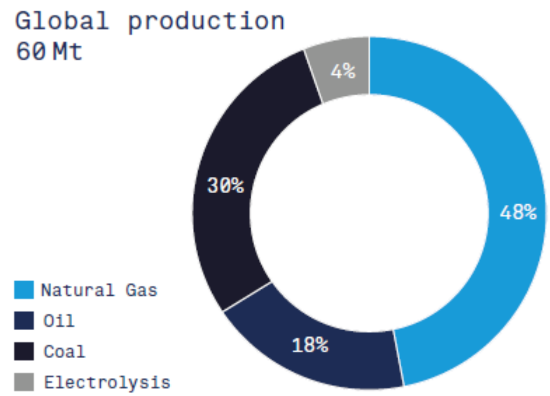


Figure 2 – Global hydrogen production [C].

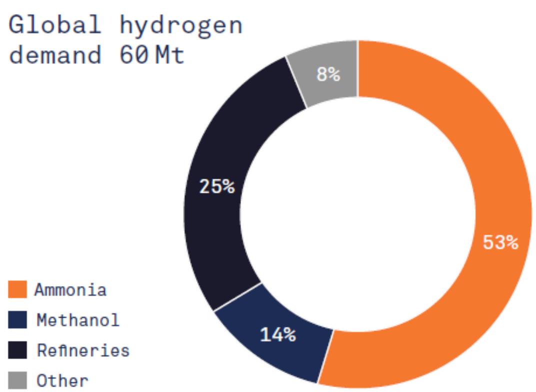


Figure 3 – Global hydrogen demand [C].

Current Use

Hydrogen's main use is in the chemicals industry, where it is used as a building block in the creation of important compounds, most commonly ammonia and methanol, see **Figure 3**. Ammonia is mostly used in the production of fertilisers, whilst methanol is largely used as a precursor to other commodity chemicals, such as formaldehyde.

Another significant use of hydrogen is in refineries, where it is used to crack longer chain hydrocarbons into shorter ones, and the desulphurisation of road transport fuels. Hydrogen is also used in a range of other industries such as iron and steel, glass, electronics and food production. Use as a rocket fuel is a minor use.

Fundamental Properties of Hydrogen for Decarbonisation

Hydrogen's potential use for deep decarbonisation of the energy system is built on the following key points:

Given the abundance of hydrogen-containing compounds, hydrogen is not resource-constrained in its production, unlike some other decarbonisation options – biofuels, for example.

Technologies exist, and others are in the process of development, for hydrogen to be produced in a range of low- and zero-carbon ways, most importantly:

- Electricity can be converted flexibly to hydrogen using water electrolysis, the splitting of water into hydrogen and oxygen using a direct current. If the electricity comes entirely from zero-carbon sources, then the hydrogen produced is likewise zero-carbon.
- Although not yet common, existing fossil fuel based production methods could be decarbonised to a large extent using CCUS.

We explore hydrogen production in more detail in the later section 'Low-Carbon Hydrogen Production'.

As well as being used as a building block in the creation of chemicals – its main current use - hydrogen can also be employed in two other ways, neither of which produce greenhouse gas emissions, or any other pollutants created by the combustion of fossil fuels (or only trace amounts):

- Hydrogen can be combusted, acting as a direct replacement for fossil fuels, most naturally natural gas, to which it is similar in many regards. Combustion may, however, lead to trace nitrous oxide (NO_x) emissions, which are a harmful pollutant.
- Hydrogen can be efficiently converted to electricity in a fuel cell. The only by-products of this process are water and heat. This is the reverse process to the electrolysis of water. For more detail, see the box 'An Introduction to Fuel Cells', two pages ahead.

Hydrogen, like natural gas, is a readily storable and transportable fuel:

- Hydrogen can be stored and transported as a gas – its natural state under ordinary conditions – or a cryogenic liquid. Alternatively, it can be stored and transported as part of a hydrogen-containing compound such as gaseous methane (CH_4), liquid ammonia (NH_3), or other more experimental compounds including Liquid Organic Hydrogen Carriers, solid metal hydrides and graphene.
- Hydrogen and related compounds can be flexibly transported by vehicle, or, in gaseous form, by pipeline, including potentially through existing natural gas pipelines.
- Unlike electricity, hydrogen can be practically stored in large volumes, for long periods of time (seasons). Storage options include in pipelines, tanks and manmade or natural underground spaces, such as salt caverns.
- In transport applications, hydrogen plus related equipment has a higher energy density than today's batteries (~2.3 MJ per kg versus ~0.6 MJ per kg [B]).

Hydrogen has similar, though not identical, safety characteristics to natural gas:

- Being a smaller molecule, hydrogen may leak more easily, and can ignite at higher concentrations and with the input of less energy than natural gas.
- Hydrogen produces a colourless and odourless flame, and burns with lower radiant heat than natural gas. For detection purposes, it may require the addition of a colourant and odourant.

According to the Committee on Climate Change (henceforth 'CCC'), none of these or other characteristics makes hydrogen inherently less safe than natural gas, if appropriate safety protocols are followed [A].

Economics of Hydrogen for Decarbonisation

Despite its promising characteristics, hydrogen's use in the energy system is yet to take-off to any meaningful extent, largely due to a lack of economic competitiveness, rather than a lack of technical capability. On a fundamental level the reasons for this include:

Hydrogen is generally a less efficient way of transferring energy to end-users than straight electrification. This is due to additional conversion steps, and the inefficiencies of those steps. This implies the need for significantly more energy to provide the identical end-use, impacting costs. In more detail:

- As **Figure 1** suggests, there are no established, efficient ways of going directly from zero-carbon energy to hydrogen. Therefore zero-carbon hydrogen must be produced indirectly via electrolysis. This leads to an energy loss in the region of 35% (dependent on the electrolyser).
- Minor energy losses may also occur in distributing the hydrogen from where it is produced to where it is consumed. If the hydrogen is converted into another form (e.g. ammonia), this energy loss is likely to be greater.
- Additional inefficiencies arise in the end-use – be it in a boiler, turbine, fuel cell, etc. Note that in certain end-uses it is possible to use electricity much more efficiently than hydrogen. For example, as we cover later, electric heat pumps are multiple times more efficient than hydrogen boilers.

Combined, it is often much more efficient to use zero-carbon electricity directly, rather than using hydrogen produced from zero-carbon electricity, or any other way. We expand on this in later sections.

As well as these efficiency considerations – impacting operational costs – there are also the capital costs of the hydrogen infrastructure and end-use appliances to consider. Although the costs of some end-use appliances may be significantly lower than low-carbon alternatives which use electricity, the costs of building the hydrogen production, storage and distribution infrastructure will be considerable. This is quantified in the later section 'Hydrogen Forecast'. To a limited extent, electrification can proceed simply using existing infrastructure.

On a more niche technical point, in transport applications, the energy density of hydrogen systems is lower than that of incumbent fossil fuel systems. This presents challenges in displacing the use of fossil fuels (though as we stated above, hydrogen systems have better energy density than current batteries).

An Introduction to Fuel Cells

A fuel cell is a device that converts chemical energy to electricity, much like a battery does. Unlike a battery, a fuel cell is supplied with an external supply of fuel and can therefore run indefinitely if the fuel supply remains - there is no need to 'recharge' a fuel cell. A variety of input fuels are used, including hydrogen, natural gas and liquid fuels such as methanol or diesel. A supply of oxygen, usually from the air, is also required. With hydrogen as the fuel, the only exhaust is water vapour and heat. Fuel cells are used because they are a fundamentally more efficient way (up to 70% HHV (Higher Heating Value) [D]) of converting hydrogen to electricity than combustion-based alternatives.

Figure 4 shows a typical fuel cell, which works as follows: at the anode, a catalyst oxidizes the fuel, turning it into a positively charged ion and a negatively charged electron. The electrolyte is a substance specifically designed so ions can pass through it, but the electrons cannot. The freed electrons travel through a wire creating the direct electric current. The ions travel through the electrolyte to the cathode. On reaching the cathode, the ions are reunited with the electrons and the two react with oxygen to create water and heat.

A single cell, such as that shown in **Figure 4**, does not produce much power. A more useful fuel cell 'unit' is built from a stack of individual cells. Fuel cell units can typically provide power from 1W to multiple MW, and can therefore be used in a wide range of applications.

In comparison to batteries, fuel cells can achieve their highest efficiencies under transient cycles, such as in transport applications, discussed in detail later. In non-transport applications, fuel cells are used to provide uninterruptible and backup power for locations such as datacentres and telecom towers, to supply off-grid power in isolated regions or islands, and for CHP (Combined Heat and Power) systems, which are very efficient.

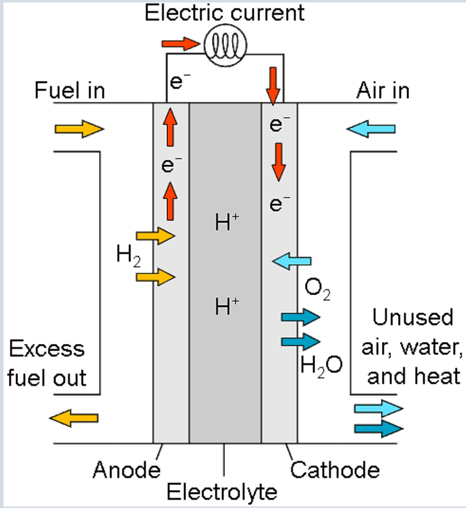


Figure 4 – A generic fuel cell. [3]

[3] https://commons.wikimedia.org/w/index.php?curid=42838482

Introduction to Fuel Cells cont.

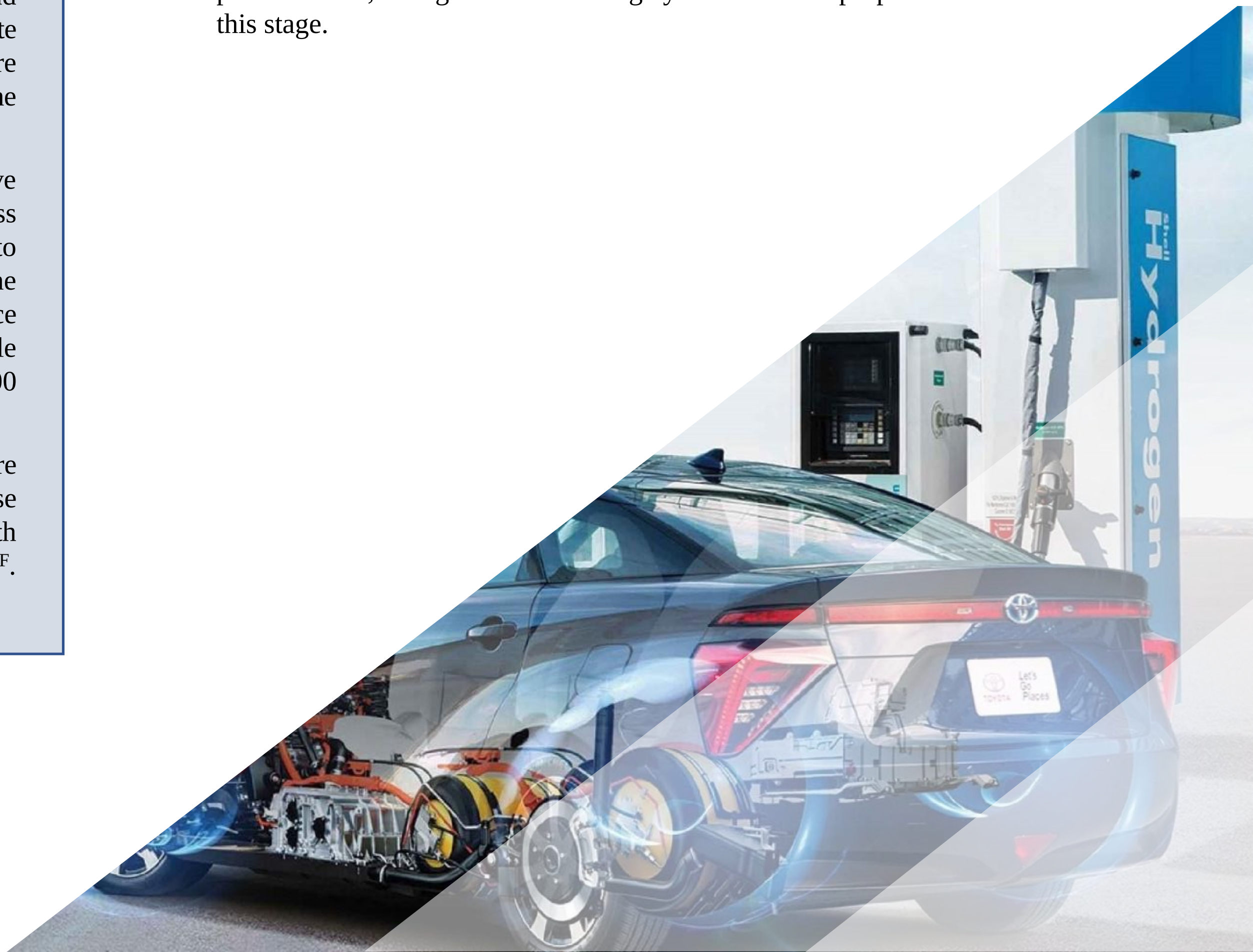
Fuel cells employ an assortment of electrolytes, catalysts and temperatures, and are usually categorised by their electrolyte, see here for more detail. While Proton Exchange Membrane (PEM) fuel cells – the most suitable option for FCEVs - and alkaline fuel cells operate at low temperatures, others operate at higher temperatures of up to 600°C, making them more suitable for CHP applications. The higher the temperature, the better the efficiency at otherwise similar parameters.

In almost all cases, fuel cell manufacture requires expensive electrolytes, precious metal catalysts and high process temperatures. There are ongoing efforts to reduce costs and to improve the reliability and lifetime of the fuel cell stack. The cost of transportation fuel cells has already fallen by 60% since 2006 (though they remain expensive versus batteries), while fuel cell durability has increased by a factor of 4, to 120,000 miles [4].

The fuel cell industry is small but growing. In 2018, there were ~ 75,000 shipments of fuel cell units – largely Japanese micro-CHP units - with a combined power of 800 MW, with most of this power being employed in transport applications [F]. Most fuel cell companies are yet to turn a profit.

Hydrogen's Energy Decarbonisation Role

Having outlined the fundamental characteristics of hydrogen in the previous section, we now sketch out hydrogen's broad potential role in the deep decarbonisation of the energy system. This role is promoted by organisations such as the Hydrogen Council, a 'global initiative of leading energy, transport and industry companies with a united vision and long-term ambition for hydrogen to foster the energy transition'. Much of what is described here is technically possible now, though it remains largely a theoretical proposition at this stage.



[4] https://www.energy.gov/eere/fuelcells/fact-month-april-2018-fuel-cell-cost-decreased-60-2006

Hydrogen for the Decarbonisation of End-Uses

The fundamental idea is that if hydrogen is produced via low-carbon methods, then using this hydrogen instead of fossil fuels in end-use applications will decarbonise these applications. As a reminder, most hydrogen created today is not low-carbon. We explain how low-carbon hydrogen can be produced later.

In most end-use sectors, hydrogen will compete with electrification as the main decarbonisation alternative. While use of hydrogen is generally less efficient than electrification – as we highlighted in the previous section, and explore in more detail later - hydrogen potentially has a role to play in applications where full electrification is technically difficult, disruptive and/or expensive:

- **Buildings**: hydrogen can be blended with natural gas, or replace it completely, to provide heat (and power) to buildings, potentially using existing pipelines for delivery. This provides a convenient alternative or complement to electrification with heat pumps, which although efficient, have drawbacks in their installation and operation.

- **Transport**: hydrogen-powered FCEVs (Fuel Cell Electric Vehicles) provide a convenient alternative to BEVs (Battery Electric Vehicles). FCEVs are more suited to heavier payloads and longer distances than BEVs, and, unlike BEVs, benefit from refuelling times similar to today's non-electric vehicles.

- **Industry:** hydrogen can provide heat (and power) to industry, particularly in high-temperature and direct-firing applications, where electrification is difficult. Hydrogen can also potentially replace fossil fuel feedstocks in certain industrial processes, e.g. ironmaking.

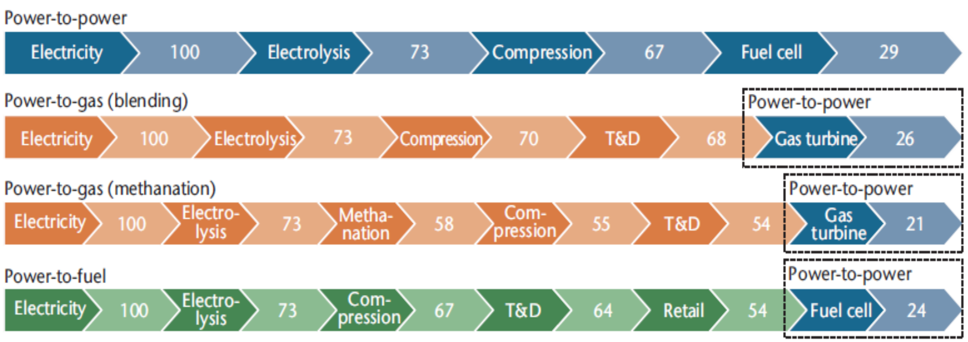
There are some areas where hydrogen may be the first-choice route for decarbonisation, due to its storability (e.g. for transport), or a continued need for high-temperature heat (e.g. some parts of industry). In other areas, hydrogen and electrification are alternatives and potentially complementary (e.g. in residential heating). Even where electrification is clearly the preferred solution, hydrogen can offer a back-up option should barriers to electrification prove too great. Although not universally true, other decarbonisation options - such as biofuels and CCUS - are generally limited in their applicability or scalability, even if current adoption barriers were to be overcome. We discuss decarbonisation on a sector by sector basis later.

Hydrogen as Energy System Enabler

If low-carbon hydrogen is used for decarbonisation of end-uses instead of electrification, this has significant knock-on effects for the electricity system. Most obviously, it eliminates the need and associated costs - highlighted earlier - to generate and transport extra electricity. To some extent you are simply replacing electricity system costs with costs related to your new hydrogen production and delivery system. However, with low-carbon hydrogen, you are also gaining new mechanisms for decarbonisation of the electricity system:

- Converting renewable electricity to hydrogen by electrolysis can aid in the integration of variable renewable energy, overcoming some of the inherent challenges highlighted earlier.
- Replacing fossil fuels with hydrogen in electricity generation plants will decarbonise them, while retaining the crucial services such dispatchable (on-demand) generation can provide.

We expand on these points in the following sections.



Note: The numbers denote useful energy; except for gas turbines, efficiencies are based on HHV; the conversion efficiency of gas turbines is based on LHV.

Figure 5 – Current conversion efficiencies of various hydrogen-based variable renewable integration pathways [D].

T&D – Transmission and Distribution, HHV – High Heating Value, LHV – Low Heating Value

Hydrogen for Variable Renewable Energy Integration

To overcome the associated intermittency problem, the integration of large shares of variable renewable energy into the electricity system requires increased operational flexibility. By converting excess renewable electricity into hydrogen, electrolysis provides a mechanism of supplying this flexibility. By excess, we mean that the electricity is not wanted at that time, place, in the form of electricity, or some combination of these things. Today this excess may be dealt with simply by not generating it in the first place – by curtailing renewable generation. In hydrogen form, this excess – which should be very cheap, or even negatively priced - can instead be shifted flexibly across time and/or place, and then funnelled to end-use applications most suited to decarbonisation with hydrogen.

Figure 5 highlights some of these ‘power-to-X’ routes, as they are known, such as power-to-power, which involves converting electricity to hydrogen using electrolysis, then back again to electricity in a fuel cell. Power-to-fuel is similar, but specific to transport applications, while the power-to-gas routes combust the hydrogen in a turbine (we explain the distinction between blending and methanation later). Although all the **Figure 5** pathways convert back to electricity, this need not be the case – the hydrogen could be combusted for heat rather than converted to electricity. **Figure 5** reemphasises the point made earlier that energy pathways involving hydrogen tend to have low efficiencies.

Energy Integration cont.

On the face of it, converting excess renewable electricity into hydrogen seems like a grand idea. After all – baring any other options - the electricity would have been wasted, and should be cheap, meaning that the low efficiencies of the pathways are less important. However, there are flaws in this reasoning.

One problem is the amount of the available excess. Currently, the amount of excess renewable generation requiring curtailment is only a few percent of generation in the UK [5]. Although it makes sense that as the renewable share goes up, then so might the amount of excess renewable electricity, it is not clear if the amount of hydrogen that could be produced as a result could remotely match that required in the case of widespread hydrogen use. Quoting the CCC:

'the infrequency and relatively small size of this opportunity [of excess renewable electricity] is such that the volumes of hydrogen that can be expected to be produced [in the UK] using very low cost electricity are small in the context of the overall energy system (e.g. up to 44 TWh a year in 2050, less than 10% of building gas consumption)' [A].

A lack of excess renewable electricity means that the hydrogen would have to be produced by some other route. If sticking with electrolysis – rather than other possible hydrogen production routes – we are forced into using non-excess renewable, or non-renewable electricity as our input. So, we are back to needing to generate and transport extra electricity, one of things we were trying to avoid in the first place.

Another problem is that there are indeed other things you could do with this excess, rather than convert to hydrogen. You could store the excess as electricity, for example (or heat). However, hydrogen potentially allow us to do things not possible or less practical than when using electricity as the storage medium, including the time- and place-shifting of renewable electricity.

Whilst the short-term time-shifting of renewable electricity is perfectly feasible and increasingly economic using electrical storage, hydrogen is the only practical at-scale technology for long-term – weeks and seasons - energy storage, see **Figure 6**.

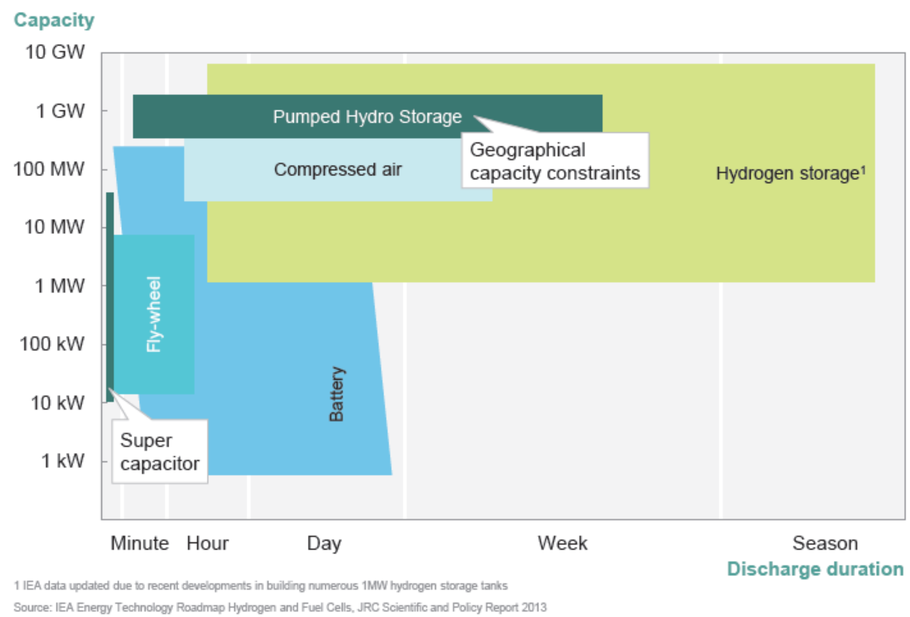


Figure 6 – Overview of carbon-free energy storage technologies [D].

[5] https://eciu.net/blog/2018/wind-constraint-payments-on-the-way-down

Energy Integration cont.

With hydrogen, it would potentially be possible to store renewable energy captured in the summer, and to use this to provide heating in the winter, when, as we highlighted earlier, renewable generation is often naturally lower.

At current renewable penetration levels, the variability of renewable generation on all time scales can be matched perfectly well, if not entirely cleanly, without hydrogen storage (current curtailment aside). Depending on location, this matching happens variously using nuclear and fossil-fuelled powered plants, as well as short-term electrical storage and other flexibility measures. However, according to multiple studies quoted by the Hydrogen Council, long-term storage becomes a necessity as the share of variable renewable energy increases, see **Figure 7a**. So the argument goes, without this long-term storage, additional renewable capacity above a certain threshold would not be efficient to build, and other non-clean technologies would be required.

As well as providing a route for long-term storage, electrolysis can (and does already in the UK on a small-scale [A]) provide a range of balancing and ancillary services to help maintain the minute-by-minute stability of the electricity system. Frequency response is an example. These services are likely to become increasingly important as the renewable share increases and electricity systems become increasingly difficult to control as a result. There are more conventional means of providing these services, and competition will be high, but provision would improve the economics of electrolysis, covered separately later.

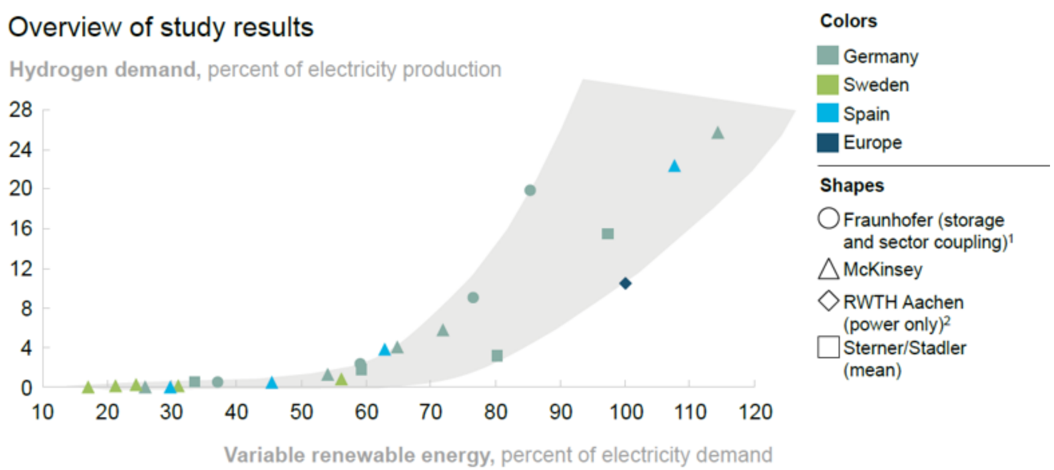


Figure 7a – Hydrogen demand increases exponentially with variable renewable energy share [B].

1 Least-cost modeling to achieve 2°C scenario in Germany in 2050 in hour-by-hour simulation of power generation and demand; assumptions: no regional distribution issues (would increase hydrogen pathway), no change in energy imports and exports
2 Simulation of storage requirements for 100% European RES; only power-sector storage considered (lower bound for hydrogen pathway)

As well as these time-shifting examples, in hydrogen form it would also be possible to place-shift renewable electricity from where it is generated most cheaply, to where demand is strongest. This could take place within a region, for example, using hydrogen as a way of manoeuvring around local electricity grid constraints. Or this could take place internationally, with countries abundant in renewables exporting to those lacking. For distances above 3,500 to 4,500 km – such as from Australia or Brunei to Japan, both being investigated as options – converting power to hydrogen and shipping it overseas could theoretically be less expensive than transmitting it through cables as electricity [B].

Hydrogen for Dispatchable Electricity Generation [A]

The other way hydrogen could help decarbonise the electricity system is by replacing fossil fuels in power plants. This would decarbonise these plants, whilst retaining the crucial services such dispatchable generation can provide (e.g. system balancing, inertia and voltage control). However, according to the CCC, carbon prices would need to rise significantly in the UK to encourage such a switch (to £70-100/tonne CO_2, not expected till after 2030).

Use of hydrogen is potentially feasible at all scales of power generation. With similar efficiency and limited additional cost, hydrogen could replace natural gas in today's large Combined-Cycle Gas Turbine (CCGT) plants. There are already turbines available that run on limited hydrogen blends and full conversions are being explored in projects in the Netherlands and Japan. Hydrogen could also replace natural gas or diesel in smaller peaking plants, either supplying engines or fuel cells. Despite their cost, fuel cells already have a distributed generation niche, see the earlier box, 'An Introduction to Fuel Cells'.

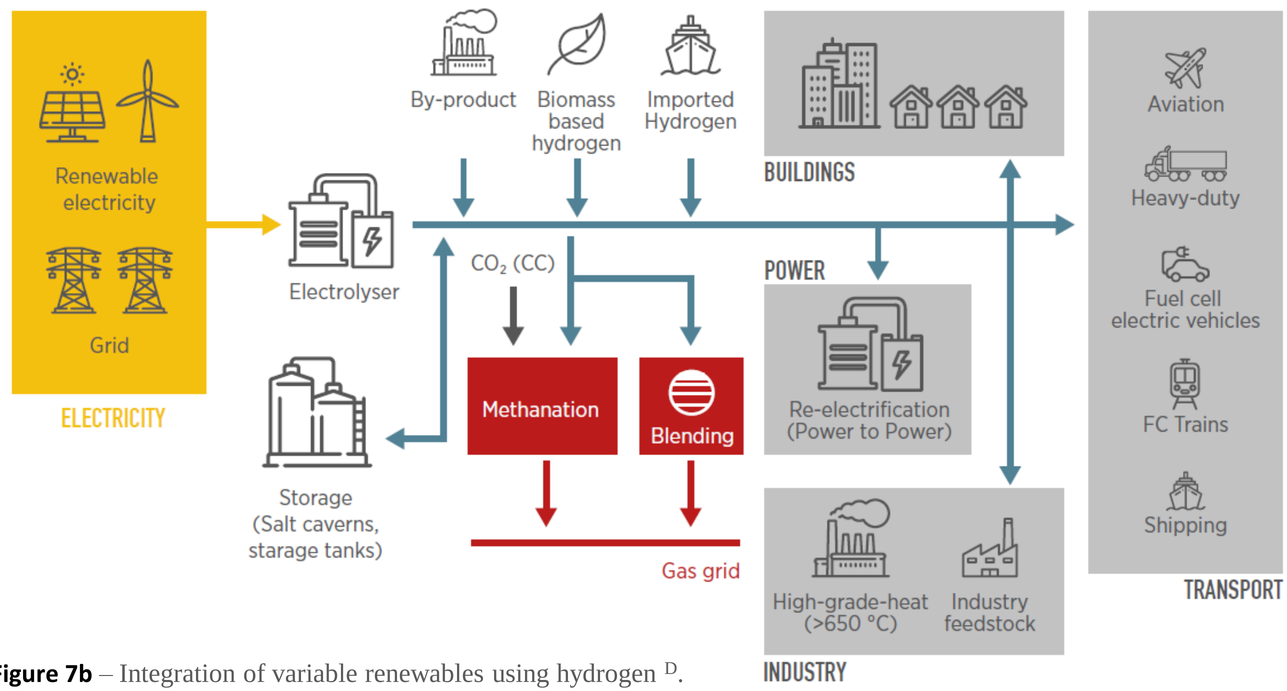


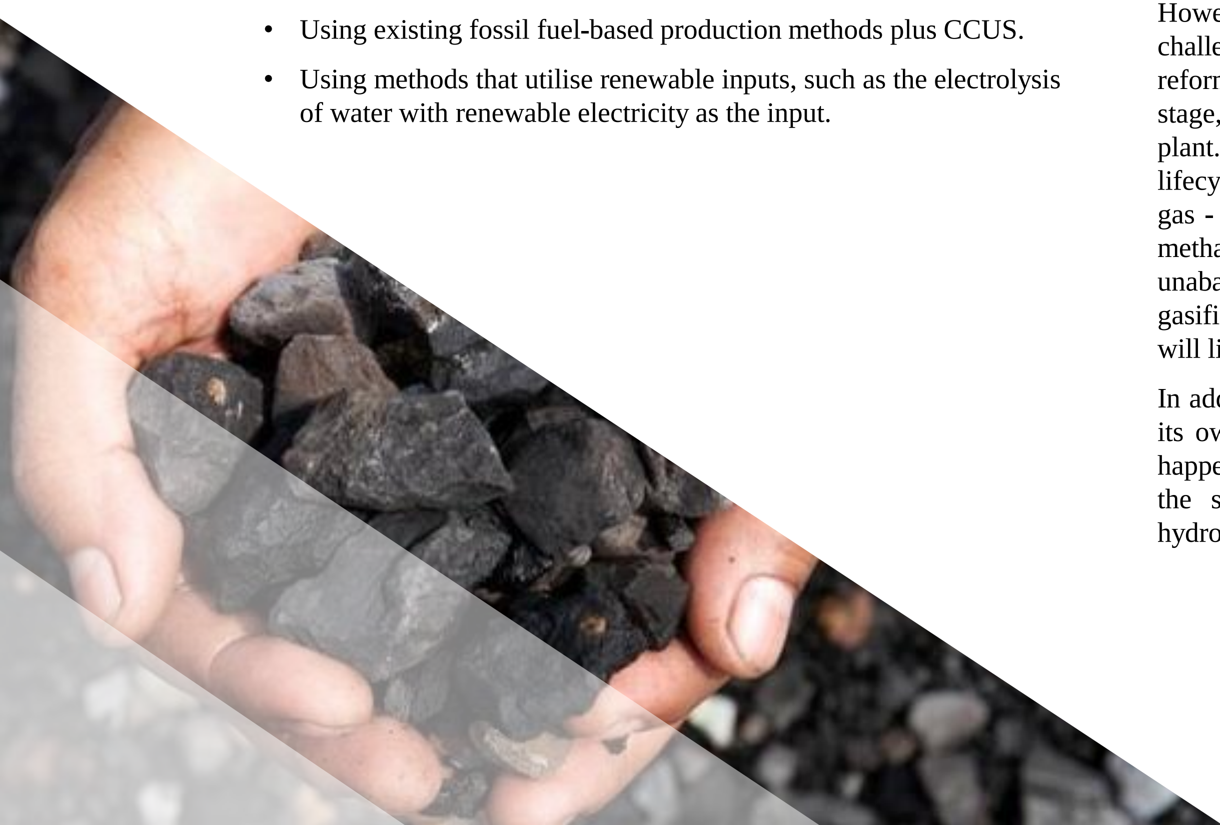
Figure 7b – Integration of variable renewables using hydrogen [D].

Low-Carbon Hydrogen Production

Low-Carbon Hydrogen Production

As noted earlier, hydrogen is currently produced almost entirely from fossil fuels, see **Figure 2**. However, for hydrogen to play the decarbonisation role covered in the previous section, it will need to be produced in greater quantities and in a low- or zero-carbon fashion. There are two main ways of doing this:

- Using existing fossil fuel-based production methods plus CCUS.
- Using methods that utilise renewable inputs, such as the electrolysis of water with renewable electricity as the input.



Existing Methods Plus CCUS

Existing fossil fuel-based hydrogen production methods, such as steam methane reforming of natural gas and the gasification of coal, have the significant advantage of technological maturity, having been used for decades. Scaling these methods should be technically feasible, and, in many countries – especially those with ample fossil fuel resources – offer the cheapest, if not the purest, source of large-scale hydrogen production.

However, the requirement to capture the emitted CO_2 presents challenges. CCUS is a novel technology. Steam methane reforming plants with CCUS do exist, but they are at an early stage, and currently only capture 60% of the CO_2 produced at the plant. This can be improved, though when considering the full lifecycle - including emissions from the production of the natural gas - it is expected that the CO_2 emission reduction from steam methane reforming is inherently limited to 60-85% compared to unabated gas use. The equivalent CO_2 reduction for coal gasification is 7-56%. In summary, hydrogen from fossil fuels will likely always have a carbon footprint, even if using CCUS. [A]

In addition, CCUS adds to costs, reduces process efficiency, has its own infrastructure requirements, and, depending on what is happening to the CO_2 – for example, if it is being stored under the sea - may put geographical restrictions on where the hydrogen can be produced, or necessitate CO_2 transport.

Renewable Inputs

Instead of using fossil fuels, it is possible to use renewable inputs for hydrogen production. The most straightforward examples use existing methods but swap out the fossil fuel for a bio-derived equivalent. For example, gasification not with coal, but with biomass, and steam methane reforming not with natural gas, but with biomethane. These methods are novel and resource limited, though biomass-based hydrogen production plus CCUS could provide negative CO_2 emissions (removing CO_2 from the environment).

Although other methods are being actively developed, electrolysis from renewable electricity is the only other currently viable hydrogen production method within the 'renewable inputs' category.

Electrolysis

In the inverse operation to that performed in fuel cells, electrolysis produces hydrogen and oxygen by splitting water with a direct current, see **Figure 8**. To echo back to the last section, electrolysis is a particularly important way of producing hydrogen as it provides the link between renewable electricity and hydrogen.

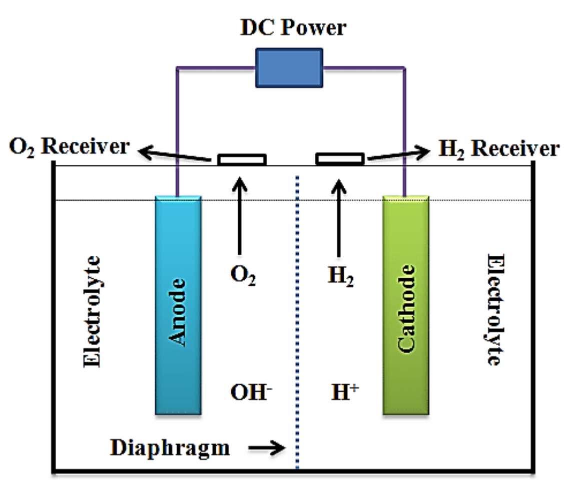


Figure 8 – Outline of a generic electrolyser.

Figure 8 shows a generic electrolyser, consisting of two electrodes emerged in an electrolyte (not in practice pure water, but a liquid or solid electrolyte). With a power source connected, hydrogen appears at the cathode, and oxygen at the anode.

Whilst no CO_2 emissions are produced directly from electrolysis, there are indirect emissions from the input electricity. Currently in the UK, a grid-connected electrolyser would see emissions of around 288-358 gCO_2/kWh. However, in a largely decarbonised electricity grid in 2050, the emissions are likely to be very low. [A]

Electrolysers are modular technologies, with unit sizes from kW up to ~10 MW, and are therefore well suited to small-scale on-site hydrogen production (larger plants can be built by stacking smaller electrolysers, though there is limited economy of scale). In addition, unlike fossil fuel-based hydrogen production methods, electrolysis naturally produces very pure hydrogen, making it suitable for use in fuel cells. Combined, these two properties make electrolysis suitable for transport refuelling applications (though not the only option).

Today, three main types of electrolyser exist, distinguished by the electrolyte, charge carrier and temperature of the system (similar to the differences between fuel cell types). Alkaline electrolysers are a mature technology and produce the vast majority of global electrolytic hydrogen. Proton Exchange Membrane (PEM) electrolysers are currently in the demonstration phase of their development. These electrolysers are more expensive, and have shorter lifetimes, but are more suitable for use in combination with intermittent renewable generation. In contrast to the other two, which operate at low temperatures, solid oxide electrolysers are an emerging technology which utilise heat from other sources to increase the efficiency of production significantly. [A]

The water electrolyser industry is currently even smaller than its fuel cell counterpart; deployment in 2018 was below 100 MW (compared to 800 MW for fuel cells). However, very large projects have been announced (e.g. a 5 x 100 MW project in Dunkirk), others are in the pipeline, and the industry is putting significant capacity upgrades in place. This suggests that the industry could respond reasonably fast to a dramatic increase in demand. [F]

Economics of Electrolytic Hydrogen [D]

For those wanting more detail, the levelized cost of electrolytic hydrogen – the cost spread out over the entire lifetime of the electrolyser - is determined by:

- The capex of the electrolyser.
- The efficiency of the electrolyser at converting electricity to hydrogen.
- The cost of the input electricity. If providing grid services, the revenue generated is effectively a discount on this cost. If the electrolyser is grid-connected, any applicable grid charges add to this cost.
- The load factor of the electrolyser (actual generation divided by potential generation over a given period of time).
- The price obtained for the by-product oxygen (if any).

These factors are not independent. For example, minimising the costs of input electricity is likely to be accompanied by a lower load factor, as very low-cost, surplus renewable electricity will only be available for a limited amount of time per year. However, operation at low load factors is less economical, with the capex of the electrolyser dominating a much higher levelized cost of hydrogen. Batteries or other energy storage can help increase the load factor, but their extra cost may nullify the benefit [A].

Low load factor also impinges on the viability of building dedicated off-grid renewables for the sole purpose of supplying low-carbon electricity for an electrolyser to produce low-carbon hydrogen. This is likely only to be economical in specific locations and with specific technologies, e.g. Chile, using a combination of wind and solar.

For electrolytic hydrogen to compete with, for example, hydrogen from natural gas reforming, this requires low-cost renewable electricity, and a combination of higher natural gas and carbon prices. If produced on-site, electrolytic hydrogen avoids the transport costs associated with larger-scale centralised production, but this does not necessarily give it a competitive advantage.

Which Production Method?

If low-carbon hydrogen is ever used at scale, it is likely that all these hydrogen production methods, and others, will play a part. The choice will be influenced by a host of factors, including the required scale of production, the type and cost of available inputs, and the cost of the technology itself. This choice is therefore likely to vary by region. The method with the cheapest local inputs may be the preferred solution.

Focussing on the UK now, **Figure 9** summarise the properties of the main hydrogen production techniques that the CCC considers as relevant in the near-term. Reforming of natural gas is the clear winner cost-wise, although producing large volumes of hydrogen in this way could result in significant residual CO_2 emissions. The CCC suggests that all the other technologies, including electrolysis, are only likely to play a niche role. Unfortunately, electrolysis is currently one of the most expensive options, and is likely to remain so. The cost of electricity would have to be less than £10/MWh for electrolysis to be competitive. In addition, the CCC worries about the impact of electrolysis on the electricity system. [A]

Although at a small scale, low-carbon hydrogen production for energy applications has already commenced in the UK. For example, there are a handful of operational electrolysis-based hydrogen refuelling stations for fuel cell vehicles, see **Figure 19**. Looking forward, there are plans for larger-scale hydrogen production as an integral part of proposed CCUS clusters; for example, the [HyNet North-West] project in Liverpool. If greenlit, projects such as the [H21 North of England] project – introduced later - would lead to a significant scale-up in UK low-carbon hydrogen production.

Long-term, an international market in hydrogen (or ammonia for conversion to hydrogen) may develop. The CCC states that this hydrogen could potentially be imported to the UK at similar cost to producing hydrogen directly in the UK, even when including the transportation costs. [A]

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

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

Figure 9 – Key characteristics of hydrogen production technologies (in the UK) [A]

Decarbonising End-Uses: Buildings

Decarbonising End-Uses: Buildings

Residential and commercial buildings require almost as much energy as the industrial sector and more than the transport sector [B], both covered separately later. Most of this energy (~75% in the UK [6]) comes not from electricity – which will naturally decarbonise in tandem with the electricity supply – but from the direct combustion of fossil fuels to provide heat for living spaces, water and food. The challenge of the full decarbonisation of buildings is therefore chiefly related to heat provision. This is our focus here, and our first example of how hydrogen could help decarbonise end-uses.

On a system level, decarbonisation of building heat is one of the bigger sectoral challenges, due to the scale and seasonality of the energy requirement. This is illustrated in **Figure 10**, which shows that in the UK heat demand is many times that of electricity demand in the colder months. Currently, most countries with cold winters rely on natural gas for heating (e.g. the UK, USA, Canada, Argentina, continental Europe and South Korea). In these countries, most households are connected to a natural gas network. In these and other countries, those not relying on natural gas for heating instead rely on oil, coal, biomass, electricity, etc.

Early progress towards the decarbonisation of building heat has largely been made using efficiency improvements, as well as limited installation of biomass boilers and stoves, solar thermal panels and heat pumps, all of which benefit from the Renewable Heat Incentive (RHI) subsidy in the UK.

Heat pumps use electricity to produce heat efficiently by extracting it from the air, ground or water, producing several units of heat for each unit of electricity input. Long-term, electrification with heat pumps is regarded as the main alternative to the use of hydrogen. Before we compare these pathways, we introduce how hydrogen could decarbonise heat. Note that its use remains largely a theoretical proposition at this stage.

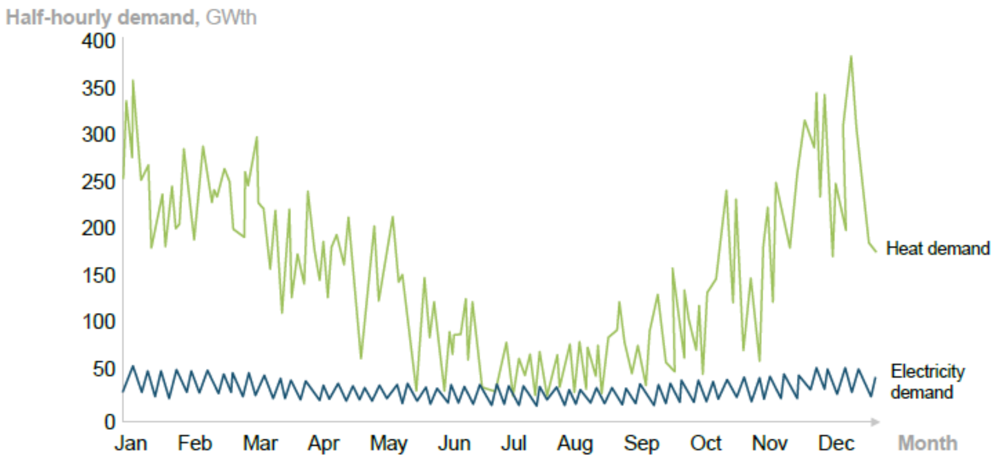


Figure 10 – Synthesised UK half-hourly heat and electricity demand, 2010 [B].

[6] https://ec.europa.eu/eurostat/statistics-explained/index.php/Energy_consumption_in_households

Hydrogen for Heat Decarbonisation

Hydrogen can be combusted instead of fossil fuels to provide heat for buildings. Given their similarity, this happens most naturally with hydrogen replacing natural gas. This switch is therefore most attractive in countries with an existing natural gas network, as this provides existing infrastructure upon which hydrogen delivery can piggyback. Hydrogen can be delivered in three forms for combustion purposes: blended with natural gas, used in its pure form, or converted to natural gas, a process known as methanation.

As an alternative to combustion, fuel cells can be supplied with hydrogen to provide combined heat and power (CHP), or just power, though this is not our focus in this section. CHP units can be deployed in family homes, in residential or commercial building blocks, or centrally in district heating networks. On a global scale, about 190,000 buildings are already heated with hydrogen-based fuel cell micro-CHPs, largely in Japan [B]. As covered earlier, fuel cell use may place strict demands on the purity of the hydrogen supply, whereas combustion does not.

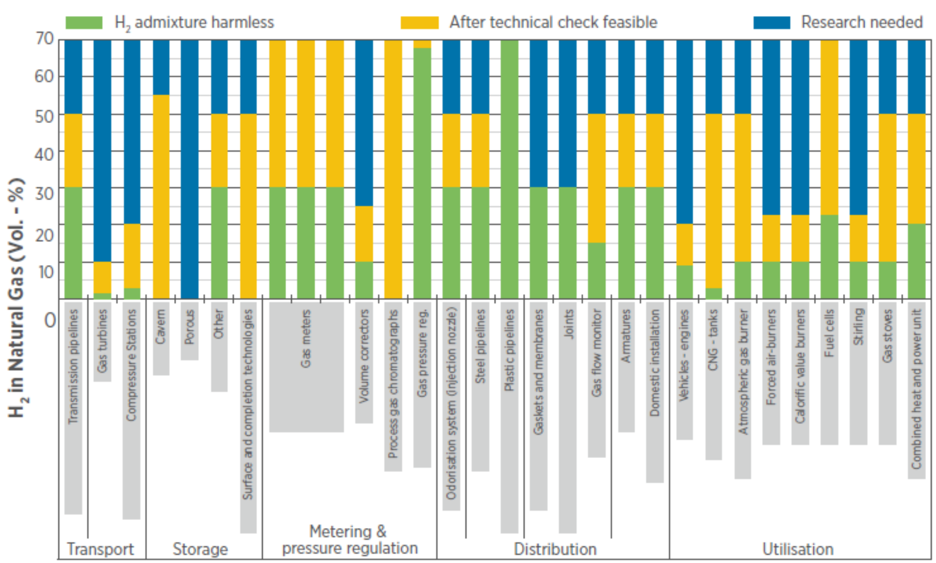


Figure 11 – Hydrogen tolerance of gas infrastructure components [E].

Blending Natural Gas with Hydrogen

Without major adaptations to infrastructure or appliances, low percentages of hydrogen – up to 10-20% by volume - can be safely blended into existing gas networks. This percentage is determined by the characteristics of the existing network, the natural gas composition and the appliances connected to the network, see **Figure 11**. Going above 20% by volume requires more significant changes, so it may be more economic to completely transform the network and end-uses to work with pure hydrogen, see the next section. [E]

Blending hydrogen into the gas supply is not a new concept – the US, UK and Australia have previously used hydrogen blends (30-60%) in the form of "town" gas. In fact, hydrogen blends are still used in Hawaii, Singapore and some other areas with limited natural gas resources. In the UK, the HyDeploy project is investigating hydrogen blending, with a live trial at 130 homes in Keele scheduled to commence this summer. Globally, installations that can blend roughly 1,700 tonnes of hydrogen per year into the gas network are already in place (this is a tiny amount of hydrogen) [G].

Replace Natural Gas with Pure Hydrogen

Unlike blending at low levels, which can be done invisibly to consumers, switching completely from natural gas to pure hydrogen is a major decision, requiring careful coordination between government, industry and the public. Such a switch requires upgrades both to the gas network and to connected appliances:

Connected appliances, including ovens and stoves, boilers and hot water tanks, need to be converted or replaced.

For the network, leakage control needs to be improved and pipelines need to be retrofitted or replaced with noncorrosive and nonpermeable materials, such as polyethylene. In some countries, this replacement is already happening independent of any potential switch to hydrogen. In the UK, the ongoing Iron Mains Replacement Programme means that by the early 2030s gas distribution networks - the low-pressure networks that connect to households - should be hydrogen-ready. It is expected that new hydrogen transmission pipelines – the higher-pressure backbone of the gas network - would be added as and when required. There remain uncertainties over the need to change gas pipework within buildings.

The UK is arguably leading the world in researching and planning for a switch to pure hydrogen. Most notably, the H21 North of England project presented a detailed and credible engineering solution for converting gas networks across the North of England to pure hydrogen between 2028 and 2034. It also presented a longer-range plan to replace all natural gas in the UK - for all applications, not just building heat - with hydrogen by 2050. See reference C for more details. Such a project has the potential – almost singlehandedly – to kick off a hydrogen economy in the UK. The H21's widest ambition is for a transition to a global hydrogen economy by 2100.

Methanation

As an intermediate step between hitting the upper blending concentration and going to 100% hydrogen (or otherwise), it is also technically possible to convert hydrogen into methane - the main ingredient in natural gas - through a process called methanation. This requires a carbon source – from biomass or CCUS - and energy for the conversion, leading to a lower efficiency of about 20% compared to direct blending, and creating additional costs [B]. The advantage is that the resulting substitute natural gas or SNG is pure methane and hence fully compatible with the existing natural gas infrastructure as well as all appliances. SNG from electrolysis is being piloted in Germany, Italy and Switzerland in the "STORE&GO" project.

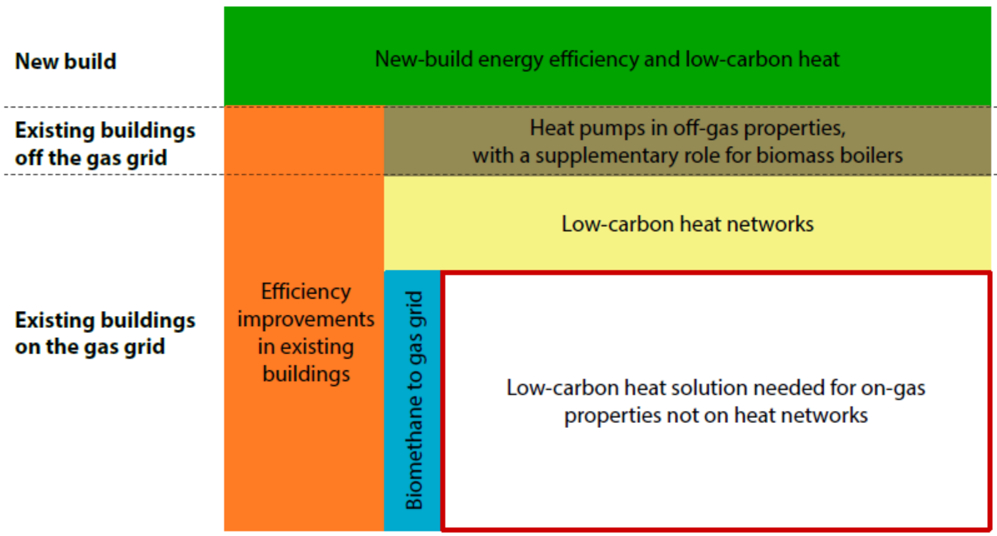


Figure 12 – Low regret measures and remaining challenges for heat decarbonisation [A]

Heat Decarbonisation Pathways

The CCC has identified five low-regret routes to heat decarbonisation that can be pursued immediately [A]. These are designed for the UK, though they should also apply more widely:

- Improve the energy efficiency of existing buildings (e.g. by installing insulation, smart heating controls).
- Add heat pumps to buildings not on the gas network.
- Roll-out low-carbon heat networks in population-dense areas. Possible heat sources include waste heat from industry, large-scale heat pumps, geothermal and potentially hydrogen.
- Design new buildings to be highly energy efficient and with low-carbon heating from the start.
- Inject biomethane into the gas network. This provides a use for methane emissions captured from biodegradable wastes. In the UK, biomethane's potential use is limited to 5% of gas consumption.

Combined, these measures can make a significant dent in heat-related emissions, see **Figure 12**. However, they do not address the largest group of buildings - those on the gas network and not on heat networks.

Hydrogen versus Electrification

To reduce emissions in the remaining group of buildings, there are two primary routes – electrify heat provision using heat pumps and/or the use of 100% hydrogen in the gas network. It is not a binary choice between these two routes. Indeed, going 100% down either route is arguably the least practical thing to do from a systems point of view. We have already discussed system problems associated with a 100% electric route, and there are equivalent concerns with the 100% hydrogen route – can you create and distribute enough low-carbon hydrogen to meet the considerable implied demand.

Although system considerations are important, the cost and convenience of a given heating system for end-users will ultimately determine its viability, so we cover this next.

For end-users, heat pumps have their advantages. Crucially, they are an established technology, ready for installation today. Hydrogen is not yet even an option for most. Heat pumps are also a much more efficient way of converting low-carbon electricity into heat, meaning you need far less electricity to get the same heat output, reducing operating costs significantly. This is demonstrated in **Figure 13**. Estimated comparative fuel costs are shown in **Figure 14**.

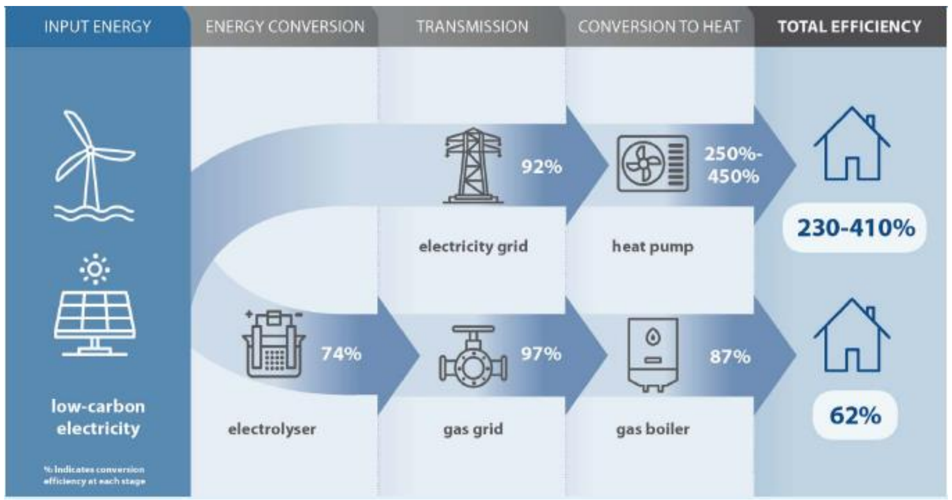


Figure 13 – Relative efficiency of heating using electricity in heat pumps vs electrolytic hydrogen in boilers [A].

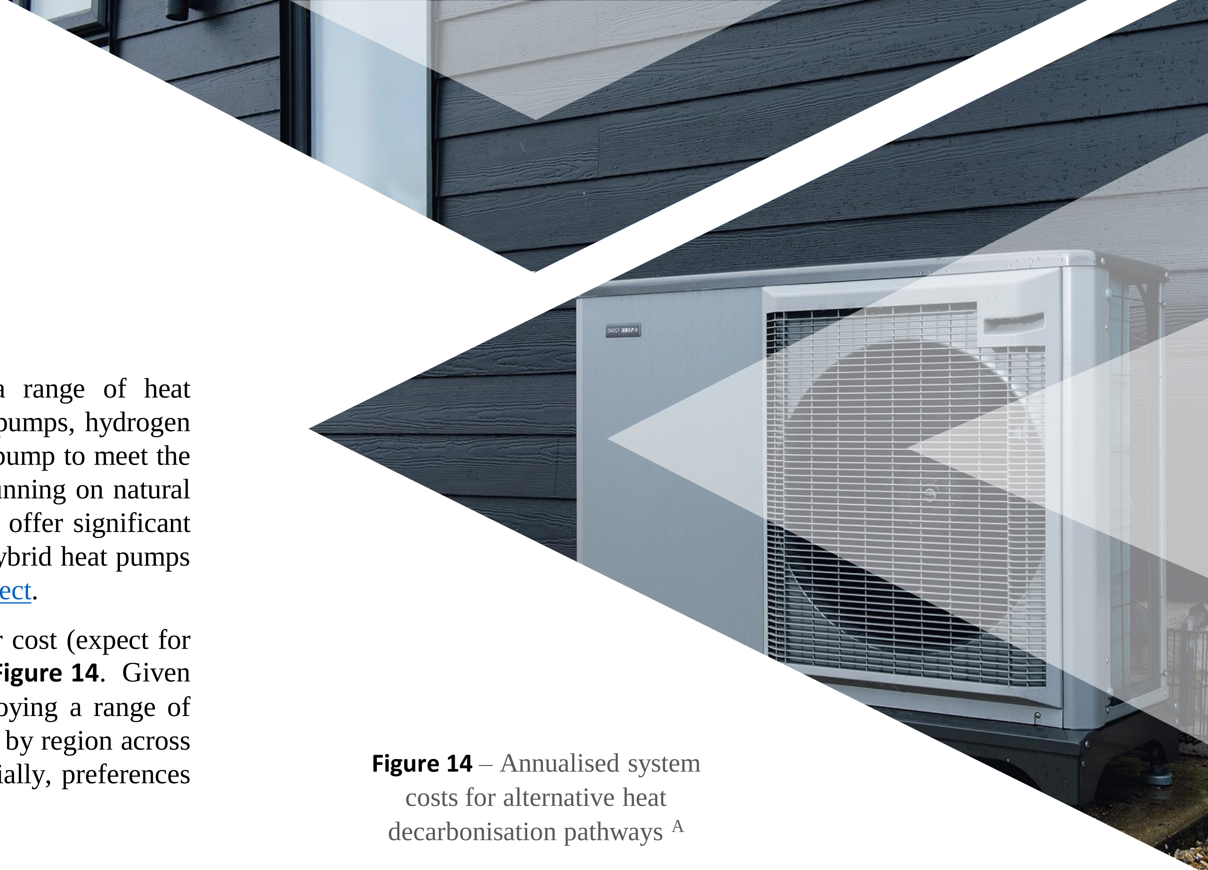
Although it does not alter the argument, the efficiency of hydrogen-based systems can be improved if micro-CHP units rather than burners are used, creating power alongside heat with a total efficiency of more than 90% and an electrical efficiency of about 40 to 45% [B].

Given the estimated operating costs of **Figure 14**, why would anyone want to use hydrogen rather than heat pumps? Well, hydrogen is arguably the more convenient solution, both when installing and operating the system:

The installation of a hydrogen system requires the conversion or replacement of gas-connected appliances. This should be a relatively non-disruptive process. In contrast, heat pumps produce heat at relatively low temperatures, which may require the installation of larger radiators, adding to the cost and disruption of installation. In addition, heat pumps require space for installation (depending on type), as well as an electrical connection. This may make heat pump installation impossible or costly for densely populated urban areas and for older buildings.

In terms of cost, KPMG estimated that in 2016 the household adaption costs of full electrification were £10,000 to 12,000 per property for air source heat pumps and related equipment. This compares to appliance change costs for hydrogen conversion at £4,500 to 5,500 per property. [B]

In operation, a hydrogen system should perform indistinguishably from one burning natural gas, providing heating flexibly on demand. Heat pumps are not sized to provide equivalent on-demand heating. Heating patterns must therefore be adjusted to achieve a similar outcome. In addition, on the coldest days, when heat demand is obviously greatest, heat pumps experience a drop-off in efficiency and must therefore greatly increase their electricity consumption to compensate. This has cost implications for the end-user, and, turning back to system considerations briefly, these spikes in electricity demand add to the challenges for the wider electricity system.



Hybrid Solutions

To figure out the optimal route, the CCC has modelled a range of heat decarbonisation pathways in the UK, including the use of heat pumps, hydrogen and the hybrid solution – hybrid heat pumps. These use a heat pump to meet the bulk of demand, while retaining the gas network and boilers (running on natural gas or hydrogen) to provide heat on colder winter days. These offer significant end-user and system advantages over the individual systems. Hybrid heat pumps are novel but have been trialled successfully in [The Freedom project](#).

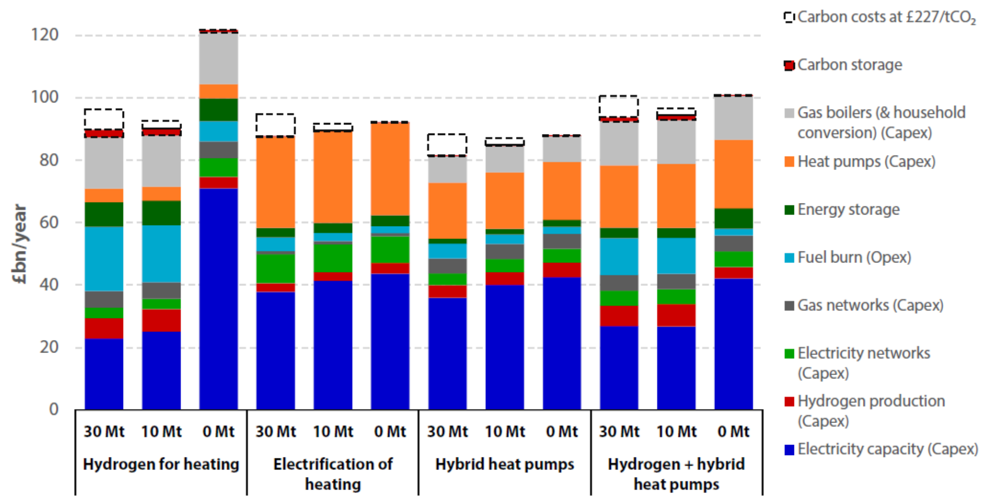
The CCC's modelling indicated that all pathways have a similar cost (expect for the case of complete decarbonisation with hydrogen alone), see **Figure 14**. Given similar costs, the CCC suggests there is an argument for deploying a range of solutions for heat decarbonisation, with these potentially varying by region across the UK depending on local resources, infrastructure and, potentially, preferences of the local population.

The CCC's recommendation is for the at-scale deployment of hybrid heat pumps, which – although not the only option - could lead to a long-term solution of hybrid heat pumps with hydrogen boilers.

Having looked at the use of hydrogen for the decarbonisation of building heat, we next move onto the use of hydrogen in the industrial and transport sectors. Note that these sectors are not isolated from one another, as they may share hydrogen production and delivery infrastructure. The availability of pure hydrogen in the gas network is likely to impact hydrogen uptake across all sectors.

A forecast for the timing and extent of hydrogen use in all sectors is given in the later section 'Hydrogen Forecast'.

Figure 14 – Annualised system costs for alternative heat decarbonisation pathways [A]



Decarbonising End-Uses: Industry

Decarbonising End-Uses: Industry

The industrial sector accounts for a third of final energy consumption and a quarter of CO_2 emissions. Two-thirds of all energy is consumed by only five industries: aluminium; chemicals, petrochemicals, and refining; cement; iron and steel; and pulp and paper, all of which require large quantities of energy to run equipment such as boilers, steam generators, and furnaces. See **Figure 15**. The chemical and petrochemical sectors also use 25 EJ worth of fossil fuels as feedstock each year, and about 8 EJ of hydrogen - as highlighted earlier the main current use of hydrogen. For comparison, 1 EJ (~278 TWh) is approximately one day of the world's total final energy demand. [B]

Low-carbon hydrogen could contribute to decarbonisation of industry in two main ways:

- Replacing fossil fuels to provide heat (and power), especially in high-temperature and direct-firing applications, where electrification is difficult.
- Replacing fossil fuel feedstocks in certain processes.

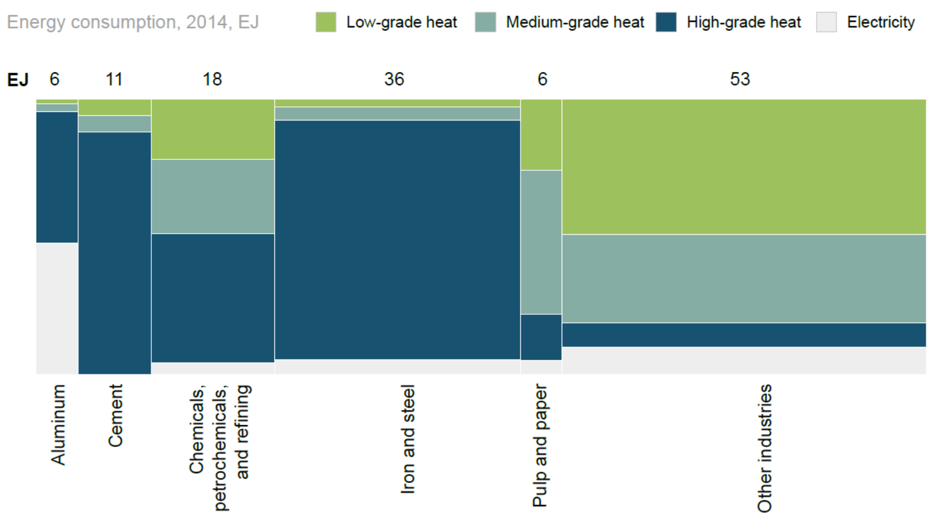


Figure 15 – High-grade heat constitutes a large share of energy use in heavy industry. [B]

Hydrogen for Industrial Feedstock Decarbonisation

Most obviously, low-carbon hydrogen could replace high-carbon hydrogen in its current uses in the chemical and petrochemical sectors. Selected plants are already pioneering this; for example, in the refining industry, Shell and ITM Power are looking to install a 10-MW electrolyser at a Shell site in the Rhineland Refinery Complex in Germany [7]. Low-carbon hydrogen could also replace fossil fuels used as a feedstock in certain other industrial processes:

A product specific example is steelmaking. While 95% of global primary steel is produced using a blast furnace method, the remainder uses direct reduction of iron (DRI). More energy efficient than the traditional blast furnace route, this process is growing much faster than overall steel production. DRI currently relies mainly on natural gas as the reducing agent, but this can potentially be replaced by hydrogen, as is currently being demonstrated in the Hydrogen Breakthrough Ironmaking Technology (HYBRIT) project.

A more widely applicable example is the use of a combination of low-carbon hydrogen and CCUS to replace fossil feedstock in the production of hydrocarbon-based chemicals, such as methanol and derived products. This is an example of the usage part of CCUS. Although thermodynamically unfavourable and currently costly, initiatives are being actively pursued in this area. For example, Carbon Recycling International's George Olah plant in Iceland produces hydrogen from electrolysis and captures CO_2 from a geothermal power plant to produce about 4,000 tons of methanol per year and recycle about 5,500 tons of CO_2 in the process [8].

[7] http://www.itm-power.com/project/refhyne
[8] https://www.carbonrecycling.is/george-olah

Hydrogen for Industrial Energy Decarbonisation

As with the decarbonisation of heat for buildings, there are several low-regrets measures that can be pursued immediately to kick-off the deep decarbonisation of industrial energy use. The most important of these is to increase efficiency by deploying best available technologies and production processes, as well as by recycling materials and waste heat. As one example, by boosting efficiency using existing tools, such as better furnace technology and heat and energy recovery, steel producers in India could reportedly reduce emissions by 40% [B].

To decarbonise the remaining emissions, we have an extended range of options over what was available for building heat. This is because many large-scale industrial processes produce significant point sources of CO_2. This means that as well as switching from fossil fuels - via electrification, biomass/fuels, or hydrogen – we must also consider the option of sticking with fossil fuels but capturing the emitted CO_2.

When looking at the fuel switching options alone, the CCC estimates that hydrogen will be the most cost-effective option for all the main industrial fuel consuming processes: steam production, high- and low-temperature heating (both direct and indirect heating), and reduction processes. It is worth pointing out that this view is not universal and, as the CCC point out, is sensitive to biomass usage and price assumptions. [A]

Low-Grade Heat

For low- and medium-grade heat – from under 100 to 400 ºC - hydrogen could complement electrification, heat pumps and biomass/fuels. This is particularly relevant where hydrogen is readily available because it is used as an input into an industrial process and wherever it is produced as a by-product. Hybrid boilers, which switch between electricity and hydrogen, could allow factories to exploit price or supply differences. Hydrogen-based cogeneration units could provide factories with heat and power.

High-Grade Heat

At higher temperatures, hydrogen comes into its own as a decarbonisation option, as other options become less feasible or efficient. For direct-firing applications, hydrogen is essentially the only fuel switching option, as biomass and electrification are rarely suited [A]. Direct firing refers to combustion-based heating processes, such as those occurring in furnaces and kilns, where the combustion gases come into direct contact with the product that is being heated.

Blast furnaces for steelmaking are a good example of direct firing. The coke used in these furnaces not only creates heat needed to melt iron, but also enables the chemical reaction between the carbon electrodes in the coke and the oxygen in the iron ore that is necessary to reduce the ore to iron. While it is possible to enhance the heat of the blast furnace with other combustible fuels (such as natural gas or hydrogen), it is therefore not possible to substitute the blast furnace with an electric furnace.

So, hydrogen could be used to help decarbonise both the blast furnace and direct reduction methods of steel production. A similar intensification of hydrogen use is possible in the other energy-intensive industries of **Figure 15**, according to the Hydrogen Council [B]:

- Chemicals and petrochemicals - by-product hydrogen is produced and could be used to retrofit equipment such as ethylene crackers.
- Aluminium recycling - gas-fired furnaces could be retrofitted to run on hydrogen.
- Cement production - hydrogen could be combined with waste-derived fuels.
- Pulp and paper industry - hydrogen could provide the high-purity flame needed to flash-dry paper.

Hydrogen versus CCUS

Although hydrogen may be the 'only' fuel switching option in an important subset of high-grade heat applications, the potential use of CCUS is likely to be a key competitor. Given the likely major role for CCUS in bulk hydrogen production – notably in the UK, see the earlier section 'Low-Carbon Hydrogen Production' - these options are effectively 'pre-process' and 'post-process' forms of CCUS, see **Figure 16**. There is considerable overlap between these two methods, though each is more suited to certain applications:

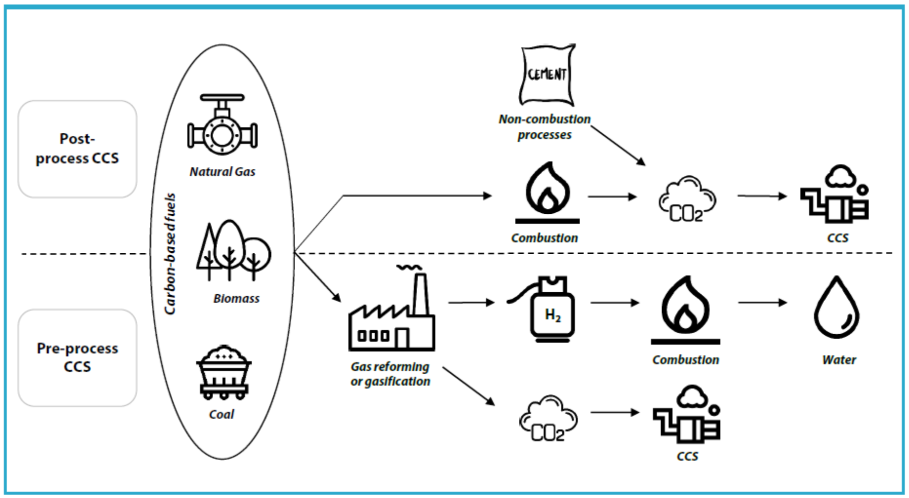


Figure 16 – 'Pre-process' and 'post-process' forms of CCS for industry [A]

Pre-process CCUS – the use of hydrogen produced in combination with CCUS, removing the carbon before use. This is applicable to a wide range of fuel-using industrial processes (combustion and reduction). It is well suited for smaller sources of emissions and those further from CO_2 networks, for which fitting CO_2 capture equipment and connecting to a CO_2 network are likely to be more difficult and expensive.

Post-process CCUS – the direct application of CCUS to industrial sites, removing the carbon after use. This is well suited to large point-sources of CO_2, especially those located close to CO_2 networks. An advantage of this approach over the use of hydrogen is that the CCUS can be used to reduce emissions from industrial processes that do not use fuel, such as calcination in the cement sector, in addition to fuel-using processes.

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

Overall, hydrogen is a competitive decarbonisation method for several important processes in the industrial sector. However, given the cost sensitivity and long equipment lifetimes in this sector, the uptake of hydrogen may be slower than in other sectors. Since retrofitting of existing equipment to burn hydrogen is inexpensive compared to new (electrical) equipment, the main barrier to the uptake of hydrogen is the comparatively high cost of hydrogen production itself [B].

As with all sectors, a forecast for the timing and extent of hydrogen use in industry is given in the later section 'Hydrogen Forecast'.

Decarbonising End-Uses: Transport

Decarbonising End-Uses: Transport

The global transportation sector depends almost entirely on fossil fuels and emits more than 20% of all CO_2 emissions, across all sectors [B].

As one option, full decarbonisation of transport requires the complete replacement of existing vehicles - there are over a billion of them - with fully electric versions, either Battery Electric Vehicles (BEVs), Fuel Cell Electric Vehicles (FCEVs), or some hybrid thereof. In some applications, these emerging electric vehicles will have to compete with existing internal combustion engine vehicles (ICEVs) – though cars of this type are being banned in some countries, including the UK - and hybrid electric/non-electric vehicles.

Alternatively, existing vehicles can be switched to using low-carbon fuels, rather than fossil fuels. These low-carbon fuels can either be biofuels, or, in the future potentially synthetic fuels, built from the ground up from low-carbon hydrogen and CO_2. The creation of such synthetic fuels may involve CCUS. This use of CCUS is similar to its use for feedstock decarbonisation in the industrial sector.

When looking at the suitability of these potential solutions, it is necessary to break the transport sector up into segments, as requirements differ greatly. What works for a scooter is unlikely to work for a jumbo jet. Each segment can be broadly characterised by:

- the weight of the vehicle (including payload), which determines the requisite performance of the engine (e.g. energy delivery per unit time).
- the required range, which determines fuel storage requirements (i.e. total amount of stored energy).

Figure 17 plots vehicle weight versus required range (in average kilometres per day per trip), and suggests which solutions are most suited. Fuel switching is currently the only option for the heaviest payloads and longest journeys – largely in aviation and shipping - as it is not feasible to design electric vehicle replacements, due to the low energy density of the fuel systems used in such vehicles. Synthetic (and bio-) fuels have the requisite energy density but suffer from low overall energy efficiency, and production limitations, meaning their use elsewhere is likely to be limited. In less energy-intensive transport segments, therefore, BEVs and FCEVs are the main alternatives. We discuss each segment separately below, but first we make some general points.

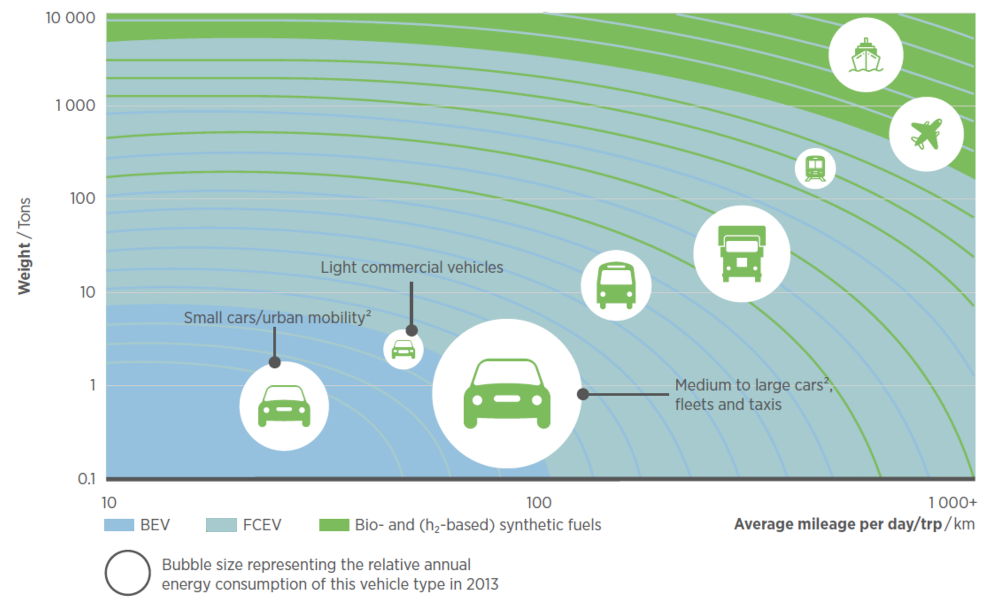


Figure 17 – Segmentation of the transport market and options for decarbonisation [E]

Broadly speaking, BEVs are currently only suited for lighter vehicles and shorter ranges, while FCEVs are more suited to heavier vehicles and longer ranges:

- To repeat, hydrogen plus related equipment has a considerably higher energy density than currently available BEV batteries (~2.3 MJ per kg versus ~0.6 MJ per kg [B]). BEVs are therefore limited in the amount of energy they can store, in turn reducing the achievable weight and range. New battery technology would be needed to address this flaw.
- BEVs are more efficient than FCEVs at converting input energy into energy providing motion to the vehicle, impacting operational costs. This is true both well-to-wheel (taking into account energy lost in creating the fuel) and fuel-to-wheel. See **Figure 18**, which also shows that both BEVs and FCEVs are more efficient than ICEVs. For this, and a whole host of other reasons, BEVs are more competitive than FCEVs where weight and range are less important.

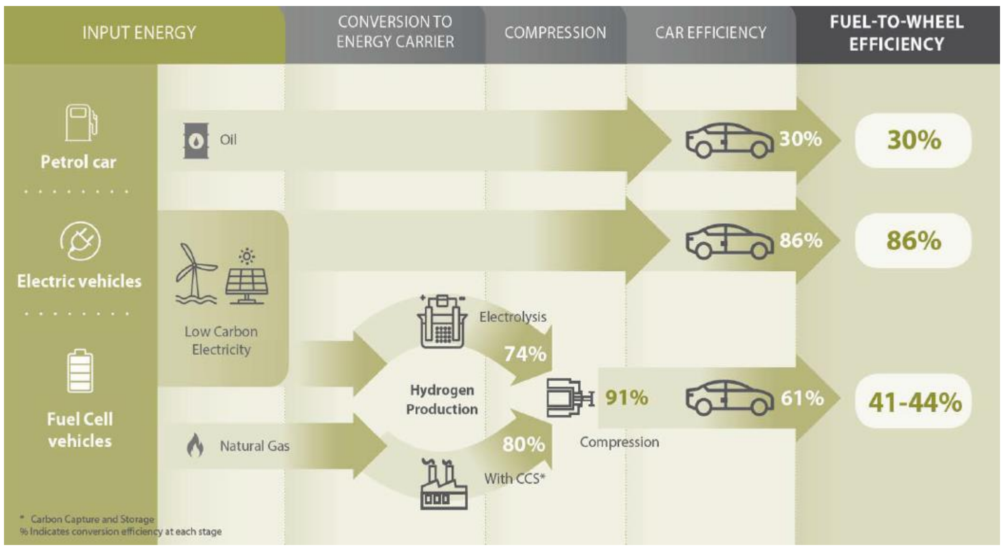


Figure 18 – Relative efficiency of hydrogen fuel cell, electric and petrol cars [A]. This diagram shows the indicative efficiency of using a given amount of zero-carbon electricity in powering a car.

In summary, FCEVs should be considered as complementary to, more than competitive with, BEVs in the broader context of the energy transition. Whilst they may compete in some market segments – where cost, convenience, available infrastructure and other factors will play a big role - for each segment there is a clear competitive advantage for one or the other. The decarbonisation potential per vehicle is greater in the segments for which FCEVs have an advantage, given that they are more polluting.

In the fight against ICEVs, BEVs and FCEVs have their advantages. Both use electric powertrains - so the development of one will help the other – which are quiet, high torque, and have zero tailpipe emissions, improving local air quality. Both should benefit from any government subsidies available for low emission vehicles (e.g. initial cost reduction, exemption from emission charging zones). On a lifecycle basis – including manufacture - CO_2 emissions from BEVs and FCEVs are considerably less than ICEVs and, assuming zero-carbon fuel, similar to one another [B]. FCEVs are, however, free from concerns about ethics and sustainability that affect the lithium-ion batteries commonly used in BEVs.

While FCEVs can achieve refuelling times similar to ICEVs, BEVs currently take significantly longer to charge – for cars, 30 minutes at best (available in only a few locations), up to many hours at a home charging point - though faster charge technologies are being developed and rolled out now. This makes FCEVs more suitable for applications that do not have long periods of downtime in their duty cycle which would allow for BEV charging (see the section below on material handling, for example). Trends that increase the utilization of transportation assets, such as autonomous driving and car sharing, increase the need for continuous operation without long recharging periods.

From a systems perspective, use of FCEVs could help offset the impact of large-scale BEV rollout on the electricity system. In the UK, such a rollout could add 100 TWh to yearly energy demand and up to 25 GW to peak demand [H]. However, it should be possible to reduce the peak demand significantly using smart charging and vehicle-to-grid technologies.

We now look at the transport segments in more detail. FCEVs are available now, or within the next five years, in medium-sized/large cars, vans, buses, HGVs, trains/trams and forklifts. There are also other experimental and emerging uses.

Material Handling [B]

Hydrogen applications for material handling have experienced the largest uptake so far. Fuel cell powered forklifts, in particular, outperform battery powered alternatives in a total cost of ownership comparison where high uptime is required. More than 15,000 fuel cell forklifts (such as those by Plug Power and Toyota) are operational in global warehouses today, with major projects in Amazon and Walmart warehouses in the US. Many other captive fleets that are otherwise challenging to decarbonize – such as airport ground operations, logistics, mining, and construction – could benefit from employing hydrogen.

Cars

Hydrogen cars are in the early stages of commercialisation. For cars regularly travelling long distances exceeding the range of electric cars, hydrogen cars provide the ability to travel further in a larger car on a single tank of fuel and to refuel more quickly. However, the electric car market is considerably more advanced both in availability and cost of both cars and refuelling infrastructure.

In the UK, there are only a few models of hydrogen car available (or at least priced) by major car manufacturers, including the Toyota Mirai and the Hyundai Nexo, see **Figure 19**. Globally, 10 models of FCEV are (optimistically) expected by 2020 [B]. In contrast, there are more than 50 models of electric car currently available in the UK [A].

As well as some of the major car companies, there are also a few start-ups involved in hydrogen cars. For example, Riversimple is a UK company aiming to commercialise hydrogen cars on a subscription basis.

Hydrogen cars currently cost considerably more than equivalent ICEVs - roughly double, largely due to the cost of the fuel cells - while electric cars cost more than equivalent ICEVs but considerably less than hydrogen cars, though this depends on range. As production scales, the cost of all types of light passenger vehicle are predicted to converge to within 10% of each other by 2030. On a total cost of ownership basis, electric cars are already cheaper than equivalent ICEVs, while hydrogen cars are more than double the cost, both due to fuel costs. [D]

The cost of fuel for FCEVs varies considerably by country, depending on how it is produced and taxed. In the UK the price is about £12/kg [9], similar to the price in California [10]. However, in Norway the price is reportedly less than £1/kg [9]. In the US, the National Renewable Energy Laboratory predicts that the fuelling costs per mile for FCEVs could fall below ICEVs during the period 2020-25 [10]. To shelter users from the initially high price, it is a common practice for manufacturers to include several years' of fuel as part of the purchase/lease.

Figure 19 – Hydrogen-powered cars advertised in the UK with prices. Above, the Toyota Mirai (£62,500). Below, Hyundai Nexo (£65,995).

[9] https://www.autotrader.co.uk/content/advice/hydrogen-fuel-cell-cars-overview
[10] https://cafcp.org/content/cost-refill

Cars cont.

As well as cost and availability, another major barrier to FCEV uptake is the lack of refuelling infrastructure. In the UK, there are only 13 existing hydrogen refuelling stations, mostly in the south-east of England, see **Figure 20**. As well as charging at home and at workplaces, electric cars can be charged at over 8,500 public EV charging locations across the UK according to [Zap-Map](Zap-Map) (this is similar to the number of petrol stations). Globally at the end of 2018, 376 hydrogen refuelling stations were in operation. Japan leads the way with 100 stations, followed by Germany (43) and the United States (38), mostly in California [G].

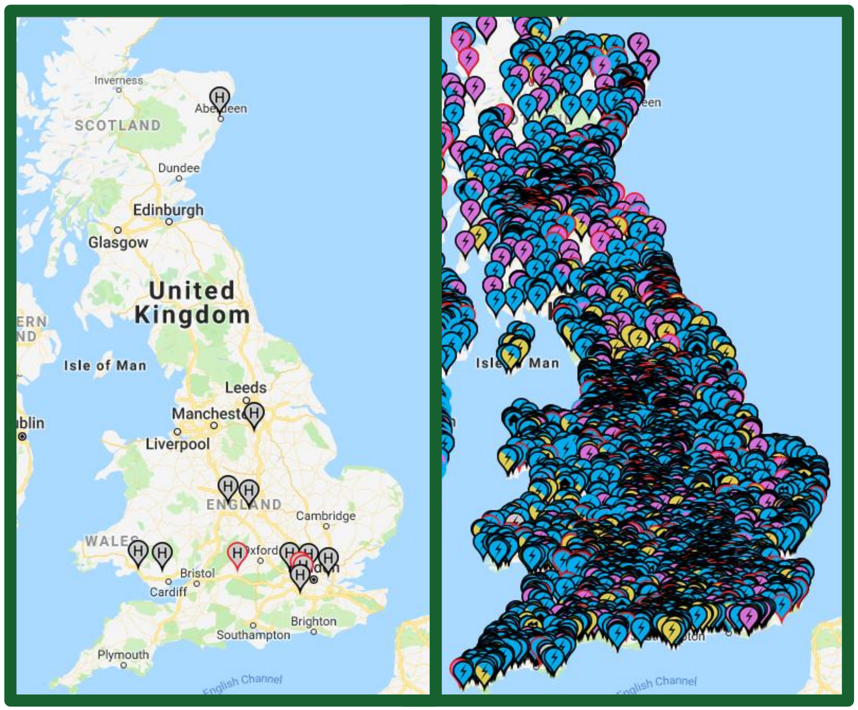


Figure 20 – Comparison of number of public charging stations for hydrogen and pure electric cars in the UK. Hydrogen on left, electric on right.

The proliferation of refuelling infrastructure is being held up by the lack of FCEVs of all types, and vice versa. Construction of refuelling infrastructure is currently financially risky due to high costs, and the early under-utilisation of the facilities, which can lead to a negative cumulative cash flow over 10 to 15 years [D]. Governments subsidies are one way of ensuring that sites can survive this 'valley of death', as it is known. Optimal siting and reducing costs are also important. The Hydrogen Council claim that refuelling capital costs per vehicle could be roughly similar for BEVs and FCEVs ($1500 to $2,000 per FCEV to 2030, falling to $1000 by 2030) [B]. They quote a study comparing infrastructure costs for 20 million FCEVs and 20 million BEVs in Germany, which found that, when required grid investments are considered, the total cost per FCEV may even be lower than for BEVs.

Given the barriers discussed above, hydrogen cars currently sell in the thousands per year, globally, while electric cars sell in the hundreds of thousands, and conventional cars in the tens of millions. The global FCEV stock reached just 11,200 units at the end of 2018, with sales of around 4,000 in that year (80% more than in 2017). Most of the sales are Toyota Mirai cars in California, supported by the Zero Emission Vehicle (ZEV) mandate and an expanding refuelling infrastructure. [G]

Given infrastructure limitations, hydrogen car deployment is likely to be led by return-to-base applications such as taxis and other commercial fleets. Early uptake is also likely to be highest in the sedan, luxury, and SUV segments, as these require the power and ranges of fuel cells, and their owners are somewhat less price sensitive. As costs decline through the scale-up of manufacturing and hydrogen, hydrogen cars could also compete for shares of smaller segments. [B]

While current deployment is low, several countries have announced ambitious FCEV targets towards 2030, currently amounting to 2.5 million vehicles [G].

Buses

Hydrogen buses are already getting significant traction, notably in Europe, Japan, South Korea, and China. They offer an important early market for FCEVs:

- Depot-based fuelling limits the hydrogen refuelling infrastructure required.
- Operation of buses occurs predominantly in cities, where air quality and noise pollution are a particular problem. Deployment of quiet, ultra-low-emission buses in place of polluting diesel buses is therefore attractive, especially where local authorities have the power to make this happen.

Coaches and intercity buses that travel long distances are also well suited for a hydrogen powertrain. Most intercity buses travel from bus depot to bus depot – hence a refuelling station in every depot suffices.

More than 450 hydrogen buses from different OEMs (including ADL, Daimler, Foton, Solaris, Solbus, Van Hool, VDL, Yutong, and Wrightbus) are on the road in the US, Europe, Japan, and China today. In the UK, there are fleets in London and Aberdeen and plans for Birmingham and Dundee. Countries have ambitious plans to deploy thousands more over the next few years. South Korea plans to replace 26,000 compressed natural gas buses with hydrogen buses until 2030. Shanghai alone is planning to operate 3,000 buses by 2020. [B]

As with cars, and indeed all transport segments, hydrogen buses are more expensive than electric versions. While smaller buses and buses with shorter-range requirements may run on batteries, fuel cells will allow larger buses to go longer distances and operate with fewer interruptions. As well as cost, local circumstances will dictate the choice (e.g. route lengths and practicalities over charging and hydrogen refuelling infrastructure).

Trains

For the same basic reasons as for buses, trains are emerging as another important market for FCEVs. Hydrogen trains are an attractive alternative to polluting diesel trains, in particular on non-electrified railways – where roughly 70% of the world's 200,000 locomotives operate today – and in the markets of Europe and the US (together operating about 55,000 diesel locomotives today) [B].

Whilst electrification of non-electrified lines is a valid decarbonisation alternative, the business case is strongest only on the busiest high-speed lines. These are exactly the types of line for which hydrogen is not suited - its energy density means that it is difficult to store sufficient hydrogen to service these routes. The two options therefore complement one another nicely. Battery-powered trains are not often discussed as a competing option.

Hydrogen trains are already being introduced for light-rail and regional railways. In 2018, the world's first hydrogen-powered passenger train, the Coradia ILint manufactured by Alstom, entered revenue service on a 100km regional line in Lower Saxony, Germany [F]. In the UK, hydrogen trains are currently being trialled, with the expectation that they could be in use on commuter lines across the country by 2022 [11]. As well as trains, hydrogen trams are viable. These are currently being deployed in several Chinese cities [B].

[11] https://www.independent.co.uk/environment/hydrogen-trains-replace-diesel-electric-alstrom-eversholtair-pollution-a8715861.html

Heavy Goods Vehicles (HGVs)

While small vans and light commercial vehicles are possible (and indeed already available) both in hydrogen and electric form, as the vehicle gets heavier and travels longer distances, the use of hydrogen becomes the only option (although fuel switching of existing vehicles remains an option).

Hydrogen trucks are currently being used on urban delivery and short distance routes in demonstration projects across the world, including several projects in California. In the heavy, long-haul segment, the first FCEV models are already commercially available in China, where Nation Synergy has signed contracts for the delivery of more than 3,000 trucks. Several additional models are expected to be commercially available within the next few years, e.g. from HV Systems (800-mile range, 10-minute refuel time), Toyota, Nikola Motor (500-1000-mile range, 15-minute refuel time) and VDL. [B]

Like their hydrogen rivals, light electric trucks are also being trialled on urban delivery and short distance routes. In addition, Tesla has released specifications for a fully electric truck with an estimated range of up to 500 miles, indicating there is potential for electric trucks to service longer routes, though for the longest and heaviest journeys, new battery technology will likely be required.

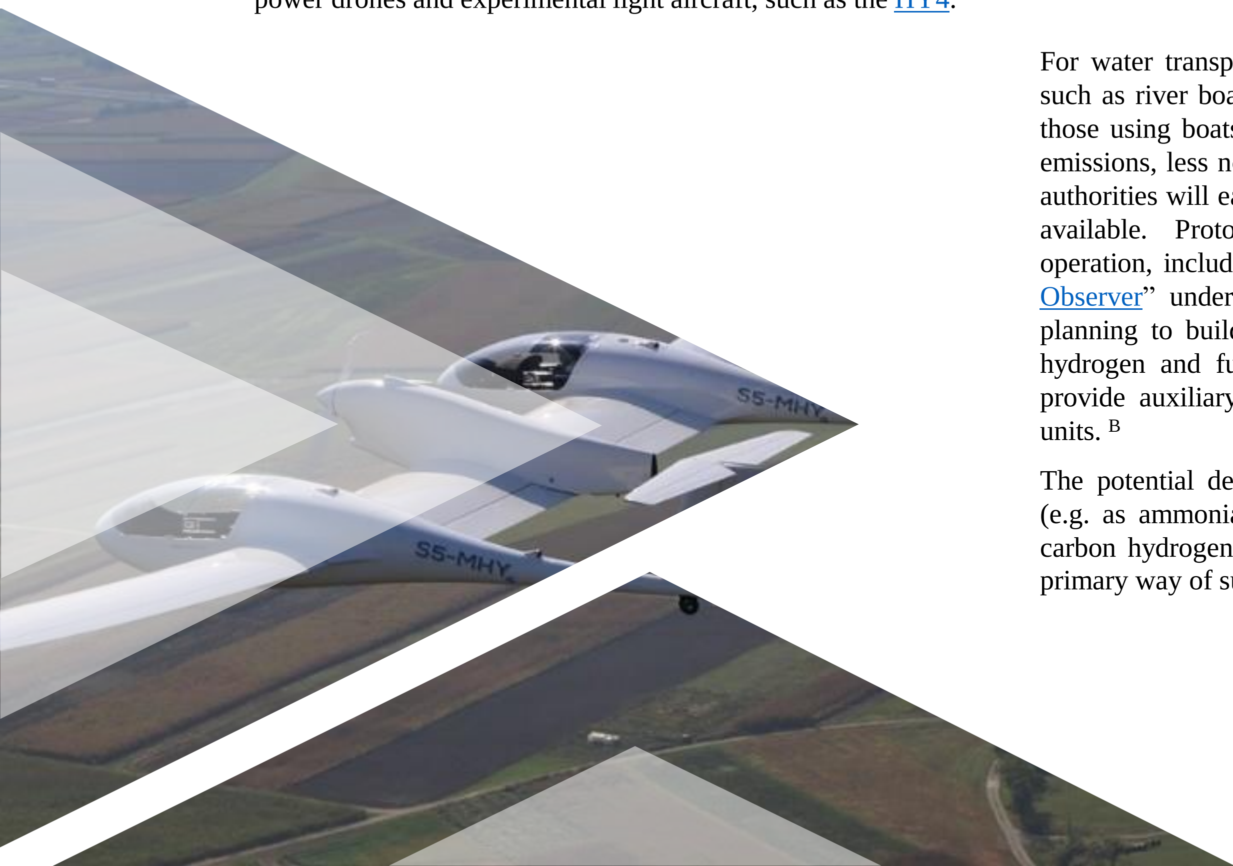
Alternatively, technologies can be deployed that charge electric trucks whilst they drive. Examples include overhead catenaries, dynamic inductive recharging embedded into the road, and conductive on-road strips. However, installing this infrastructure on major roads is likely to be expensive and disruptive to road users.

For either electric or hydrogen trucks, suitable infrastructure must be available in all countries that HGVs travel from, to and through. Any one country cannot therefore consider decarbonisation of long-distance haulage in isolation from other countries. The same applies to shipping and aviation, our final transport segment.

Shipping and Aviation

As stated earlier, fuel switching – including the use of synthetic fuels made from low-carbon hydrogen - is currently the only option for the heaviest payloads and longest journeys in shipping and aviation. However, for other journeys, FCEVs, and to a lesser extent BEVs, are a possibility (as are all sorts of hybrid).

For aviation, the CCC worries that using hydrogen in aviation would lead to increased emission of water vapour at altitude, where it enhances the greenhouse effect, compared to continued use of kerosene [A]. Therefore, they do not see a role for hydrogen in decarbonising aviation. Nevertheless, fuel cells are being tested in commercial airliners for powering aircrafts during taxiing. Although taxiing only accounts for a small amount of fuel use, if used on mass this would make a significant impact. Manufacturers have also applied fuel cells to power drones and experimental light aircraft, such as the HY4.



For water transport, hydrogen is most relevant for passenger ships such as river boats, ferries, and cruise ships. Passengers, especially those using boats for recreation and tourism, will value lower local emissions, less noise, and less water pollution. River, lake, and port authorities will easily ban such emissions once viable alternatives are available. Prototypes for fuel cell passenger ships are already in operation, including the “MS Innogy” in Germany and the “Energy Observer” under the French flag. In Norway, Viking Cruises is planning to build the world’s first cruise ships powered by liquid hydrogen and fuel cells. Besides propulsion, fuel cells can also provide auxiliary power on ships, replacing polluting diesel-based units. [B]

The potential development of an international market in hydrogen (e.g. as ammonia), shipped from countries with low costs of low-carbon hydrogen production, raises the possibility of this being the primary way of supplying low-carbon fuel for refuelling at ports.

Hydrogen Forecast

Hydrogen Forecast

Global Hydrogen Demand 2050

Current forecasts for global hydrogen demand vary widely, from 35-1,100 TWh per annum in 2030 (up to 1% of global primary energy demand), scaling up to 300-22,000 TWh per annum by 2050 (0.2 - 12% of primary demand). See **Figure 21**.

Hydrogen Council Forecast [B]

To give some idea of the blue-sky potential of hydrogen, we now look in more detail at the forecast generated by the Hydrogen Council. This is by far the most optimistic of those shown in **Figure 21**. Overall, this forecast - which assumes energy demand in 2050 consistent with a two-degree scenario - sees the annual demand for hydrogen increasing tenfold by 2050 – from 2200 TWh in 2015 to almost 22,000 TWh in 2050, the equivalent to 12% of global primary energy demand.

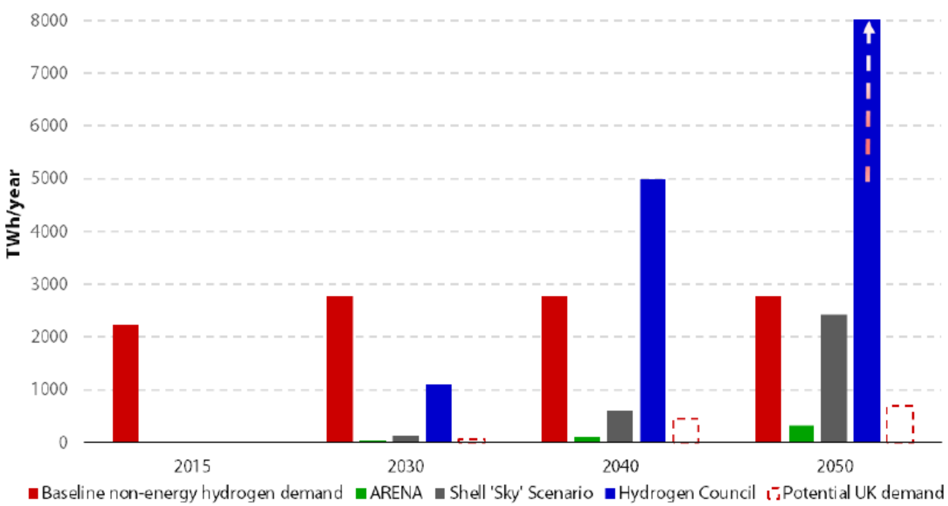


Figure 21 – Selection of global hydrogen demand forecasts. [A]

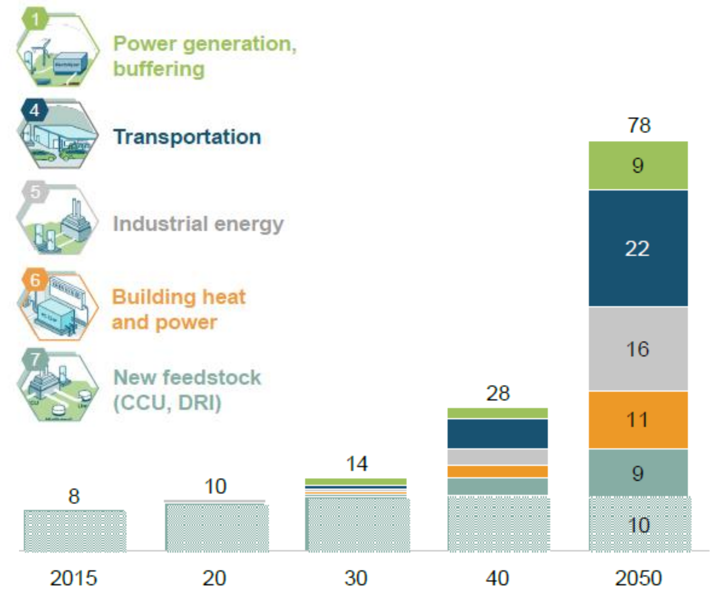


Figure 22 – Hydrogen Council forecast of global energy demand supplied with hydrogen, EJ (1 EJ = 278 TWh). [B]

Looking at the sector breakdown - see **Figure 22** – new uses of hydrogen are forecast to outpace current uses, with hydrogen playing ‘a central role of the energy transformation’. **Figure 22** suggests that transport is the sector with the largest potential, which is consistent in ordering, if not in scale, with some other forecasts, such as that by the International Renewable Energy Agency (IRENA) [E].

Hydrogen Council Forecast cont.

On a more granular level, the forecast suggests that by 2050 low-carbon hydrogen globally could:

- Power 20-25% of road-based transportation segments:
    - 400 million cars,
    - 15-20 million trucks and
    - 5 million buses.
- Power 20% of trains.
- Replace 5% of fuel supply to airplanes and freight ships.
- Generate 1500 TWh of electricity.
- Provide 10% of heat and power required for residential and industrial sectors:
    - The residential share is higher - 15-20 % - for heat and power in regions with existing natural gas infrastructure.
    - The industrial share is higher - 20-25% - for processes that use high-grade heat (>600C).
- Fully decarbonise current uses of hydrogen.
- Be used to produce 30% of methanol and derivatives from captured carbon instead of methane.
- Produce 10% of steel, using direct reduction processes.

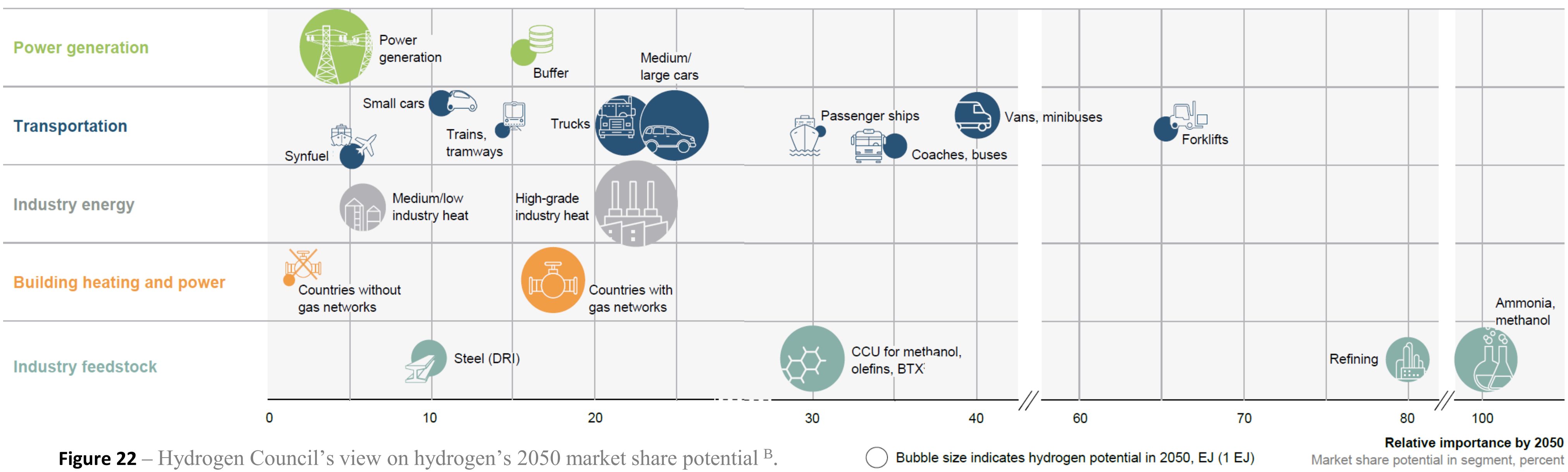


Figure 22 – Hydrogen Council's view on hydrogen's 2050 market share potential [B].

Hydrogen Council Forecast cont.

Figure 22 shows this same market share potential data in graphical form. Achieving this forecast could 'create significant benefits for the energy system, the environment, and businesses around the world'. Specifically, it could:

- Reduce annual CO_2 emissions by roughly 6 Gt compared to today, see **Figure 23**. This is roughly 20% of the abatement needed to meet a two-degree scenario.
- Create a revenue potential of more than $2.5 trillion a year, half from the sale of hydrogen, the other half from sales of vehicles, trains, heaters, machinery, industrial equipment and components.
- Directly and indirectly employ more than 30 million people. 15 million additional jobs would be associated with the value added around fuel cells, e.g. fuel cell vehicles.

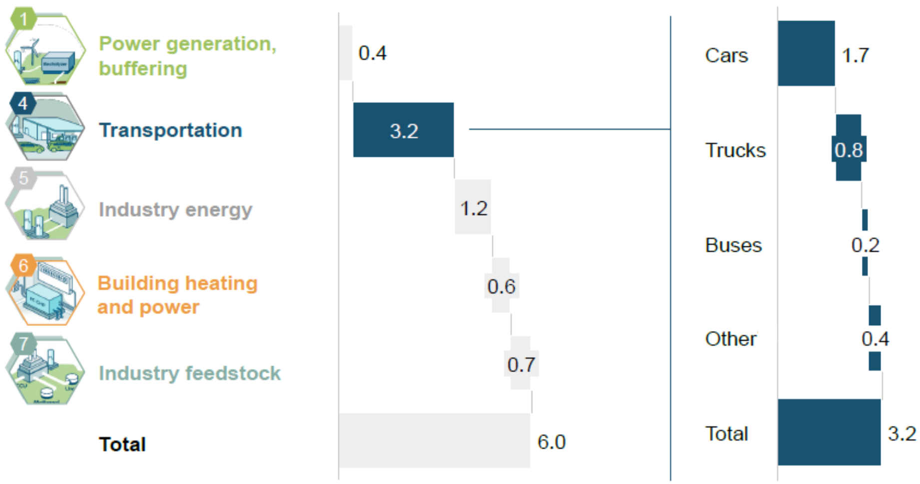


Figure 23 – Hydrogen Council's breakdown of hydrogen's 2050 CO_2 avoidance potential by sector (Gt) [B].

Timing

The Hydrogen Council's forecast also includes a timetable of when the commercialisation of each sector might start and when mass market acceptability might be achieved (defined as >1% market share). This is shown graphically in **Figure 24**.

Figure 24 highlights that some energy-related hydrogen applications have already started commercialisation, including certain transport segments, blending of hydrogen for use in building heat and power, and the decarbonisation of current hydrogen use.

Figure 24 also highlights that – even under optimistic assumptions – commercialisation of other applications is not expected to start until the middle, end, or even after the 2020s, with mass market acceptability following considerably later. These lagging applications include industrial energy, power generation and the use of pure hydrogen for buildings. This implies that a wide-scale hydrogen economy, and its associated benefits, are not expected any time soon, even by those trying to sell the idea.

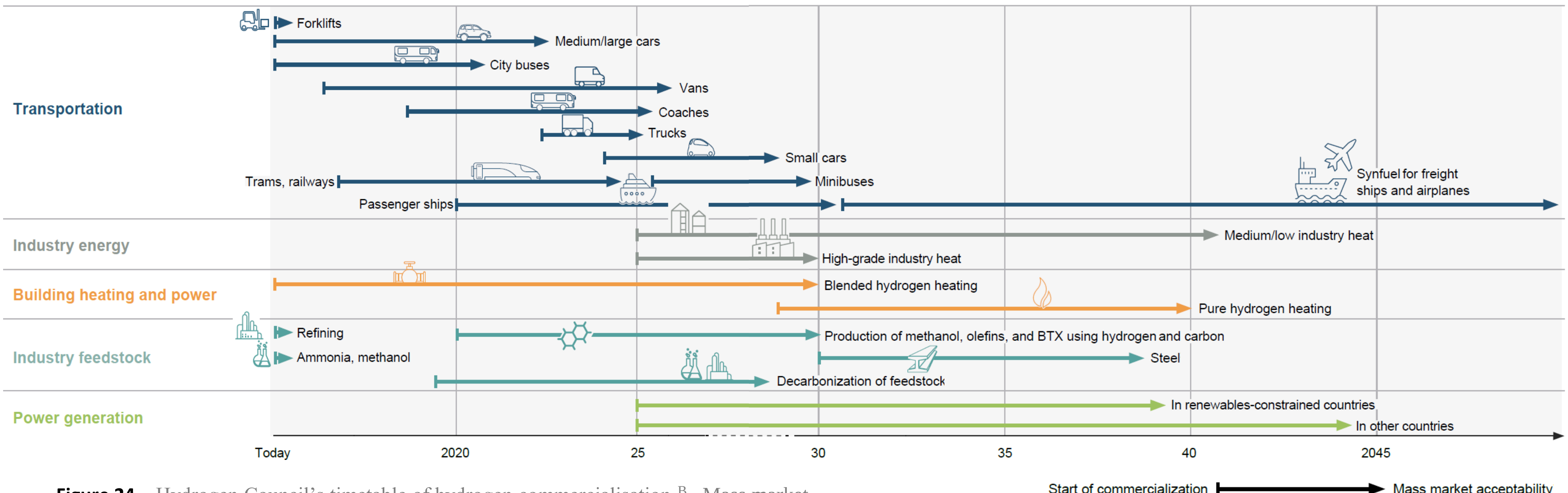


Figure 24 – Hydrogen Council's timetable of hydrogen commercialisation [B]. Mass market acceptability is defined as >1% of market share.

Getting There

Getting There

Given the blue-sky potential for hydrogen outlined in the preceding section, what will it take to get us there, or at least further along than we are now? Before we attempt to answer this question, it is helpful to quickly remind ourselves of our starting point.

Summary of Current Situation

Hydrogen is already used at scale and has been for decades. However, hydrogen produced today is largely not low-carbon and not used in the energy system.

Technologies for the production, storage and delivery of low-carbon hydrogen, and technologies that would provide a market for this in the energy system, are largely ready for deployment.

Being in the demonstration or early commercialisation phase of their development, neither supply or demand side technologies have scale, and for this (and other) reasons are expensive. Renewables integration pathways involving hydrogen are low efficiency.

Although hydrogen has great long-term potential for decarbonisation, today, near-term emissions reductions are easier to come by - cheaper and more readily available - using other methods, chiefly electrification.

Hydrogen does have a niche as the only, most convenient, or cheapest option for decarbonisation in some applications, but is still mostly uncompetitive cost-wise versus the incumbent high-carbon alternative.

Realising the Vision

Although the Hydrogen Council's vision for hydrogen is unquestionably ambitious, they consider it realistically achievable and have outlined how to make it a reality. In hard dollars, to scale up and achieve competitive costs across the hydrogen value chain, it is suggested that annual investments of $20 to $25 billion for a total of about $280 billion until 2030 would be required. This would be split as follows:

- 40% into the production of hydrogen.
- 33% into the storage, transport and distribution of hydrogen.
- 25% into product and series development and the scaleup of manufacturing.
- The remainder into new business models – FCEV taxi fleets, car sharing, on-demand transportation of goods and the contracting of combined heat and power units.

Given that the world already invests more than $1.7 trillion into energy each year, this is not an insurmountably huge sum of money, according to the Hydrogen Council. Within the right regulatory framework – including long-term, stable coordination and incentive policies – they see that attracting these investments is possible.

The Role of Government

Governments are in the privileged position of being able to take a high-level perspective and to put in place policies and finance to bring out the full benefits of a hydrogen-based energy system. Without this intervention, it may be hard for industry alone to crack the 'chicken and egg' problem, with hydrogen supply and demand waiting on each other to scale. With this problem in mind, various public-private organisations have been established, including the EU's Fuel Cells and Hydrogen Joint Undertaking (FCH JU), and for transport specifically, the H_2Mobility set of organisations, including UK H_2Mobility.

The Role of Government cont.

On a more granular level, there is a plethora of ways that governments and other regulatory and standards bodies can help hydrogen on its way to mass market acceptance.

For encouraging individuals and businesses to switch from high to low carbon alternatives, governments have a range of instruments at their disposal - carbon pricing, emissions restrictions, renewable energy content mandates etc. These tend to be technology neutral, as this allows markets to find the least cost solution, so will not help hydrogen alone. Even so, they remain crucial to its adoption. Examples of more targeted policies include:

- Introduction of subsidies to (partially) cover the initial cost difference with high-carbon technologies. These subsidies may apply both to the price of hydrogen technology - most immediately necessary for FCEVs and associated refuelling infrastructure - and to the price of hydrogen itself (covered in the next bullet point).
- Introduction of measures to improve the economic viability of renewable integration routes:
    - As we saw earlier, the price of electricity is crucial to the economics of electrolysers. Partial exemptions of relevant grid charges, taxes and levies for electrolysers would be beneficial.
    - As we saw earlier, provision of grid services improves the economics of electrolysers, so it is important that electrolysers can compete on a level playing field for such services.
    - A subsidy covering the cost difference between hydrogen and natural gas (as exists for biofuels in some countries) would encourage the blending of hydrogen into the gas network. This would help support electrolysers (and other hydrogen production), even if creation of hydrogen for blending was not their principal purpose.
- Continued investment in R&D to keep reducing costs and improve overall system efficiencies.
- Removal of regulatory obstacles and uncertain standards. Areas for close attention include [G]:
    - Hydrogen refuelling standards.
    - Refuelling station permitting processes.
    - Natural gas network blending limits.
    - Demonstration of safety measure effectiveness in new applications.
- Widescale deployment of hydrogen-ready technologies (e.g. boilers, turbines), supported by policy. This makes the subsequent switch to hydrogen – when available - far simpler.
- Certification of hydrogen from low-carbon sources, similar to existing guarantee of origin schemes for electricity.
- Education of the public about hydrogen as a decarbonisation option, including addressing historical concerns with safety.
- Early adoption of hydrogen technology by government bodies, with FCEVs an obvious target.

Several countries and sub-national governments already have comprehensive policies relating to hydrogen, including Japan, France, California, Australia and Korea. Whilst the UK has a range of government and industry supported hydrogen initiatives (some described in this report, see also p 106-107 of reference H), it has no specific hydrogen strategy or roadmap.

As well as national policies, coordination between countries will be vital to establish a global hydrogen market and to enable hydrogen's use in international transport.

Conclusion

Hydrogen has been recognised as an option to reduce emissions for a long time, but it has yet to justify its deployment at scale. To quote the CCC [A]:

‘*Continuing an incremental approach that relies on isolated, piecemeal demonstration projects may lead to hydrogen remaining forever an option 'for the future'. The longer it takes for hydrogen to become a proven option, the smaller the role it will be able to play by 2050. This is likely to continue unless and until costs can be driven down, including through deployment at scale, and incentives for its use become stronger*.’

This opinion is echoed by many. Almost universally, the view is that hydrogen should be rolled out:

- As soon as possible, especially in countries that are already early adopters, using current activities as platform, and supported by long-term policy.
- At scale. This is important to quickly reduce costs, and to raise awareness about the decarbonisation potential of hydrogen. In the UK, the CCC sees that it would make sense to start as part of a CCUS cluster, given CCUS’s role in hydrogen production from natural gas.
- In applications where hydrogen stands out as the best option to meet climate change targets and those with minimal infrastructure requirements (e.g. buses, power generation, industry or blending at small proportions into the natural gas network).

Early successes can then be rolled out nationally and internationally, as well as providing a springboard to applications with more complex infrastructure requirements, such as switching whole regions and countries to pure hydrogen.

In conclusion, although cost considerations may limit its use, 350 PPM is optimistic that at least a sizeable niche for hydrogen is realistically achievable. Even a niche could be very valuable for investors, given the size of the overall market. This optimism stems from hydrogen arguably being a ‘must-use’ tool if governments are serious about limiting global warming to 1.5 ºC above pre-industrial levels. It also stems from the existence of a concerted effort on the part of more (and more powerful) companies - such as the members of the Hydrogen Council - to get the hydrogen ball rolling. It is not a given that a sizeable niche will emerge, and timings remain uncertain, but the odds are improving all the time.

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