IChemE ADVANCING CHEMICAL ENGINEERING WORLDWIDE

Hydrogen: The future fuel today

A collection of articles on generation, storage, transport and utilisation


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HYDROGEN
ZERO EMISSION

Introduction

Fossil fuels have been extracted and used as an energy resource for over 2,000 years. In the last 250 years, industrialisation has led to exponential growth of fossil energy consumption so that CO_2 produced by its combustion cannot be absorbed by the natural systems of our planet.

The consequence is about 3,190 Gt of CO_2 in the atmosphere[1]. The majority of this is the result of burning carboniferous materials for heat, directly or indirectly (eg transportation, electricity production, industrial process heating, and domestic and commercial space heating).

The 2015 Paris Agreement clearly states the need to replace carboniferous fuels with alternative, low-carbon sources. There must be a paradigm shift in energy utilisation to achieve the 1.5 °C target. Without rehearsing the associated facts again, it is sufficient to conclude here that time is not on our side.

Hydrogen is one potential low-carbon energy source. There are many engineers who believe this is a promising energy vector, which can avoid adding to the atmospheric CO_2 inventory. Hydrogen was discovered in 1766; however, understanding of it and its use is limited primarily because it is unfairly considered as less safe and more expensive than alternatives.

Hydrogen can be used safely. The series of articles captured in this book has been published in *The Chemical Engineer* magazine, between March 2019 and June 2020. The idea was birthed out of a desire to inform, educate and stimulate a wide readership about the important role that hydrogen can play.

I would like to thank those who have contributed to this popular series, whose names appear as authors. These people outline the case for hydrogen, the opportunities and the challenges associated with it. There are examples from around the world. These articles are the opinion of the authors and do not necessarily represent the views of IChemE. It is acknowledged that there will inevitably be differences of opinion between individual authors on some matters.

I would like to acknowledge the assistance of the editorial team at *The Chemical Engineer* in honing the articles, and IChemE for putting this book together. I have enjoyed contributing to this project, and have learned a great deal in the meantime. I have become a passionate advocate for promoting hydrogen as an energy vector, and am proud to think that I may have played some small part in the dawning of a new carbon-free era for the world.

Andy Brown, AFIChemE

1 As of 2018, CO_2 constitutes about 0.041% by volume of the atmosphere, (equal to 410 ppm) which corresponds to approximately 3,210 Gt CO_2 containing approximately 875 Gt of carbon. Ref. https://bit.ly/2BzJsLP [accessed 04/06/2020]

Contents

Why hydrogen?

Tommy Isaac MIChemE

The cheap, abundant and seemingly limitless energy supply of the 20th Century driven by fossil fuel consumption led to unprecedented economic growth and improvements in quality of life. But much like financial debt, the long-term cost will ultimately be higher than the short-term gain. Society has reaped the short-term benefits of fossil fuel consumption and the environmental bailiffs are now at the door.

Hydrogen offers a unique cross-system opportunity for fundamental change in the energy landscape. This series of articles will provide an overview of the opportunities and challenges facing hydrogen development and deployment. The potential benefits that adoption of hydrogen would accrue to the climate cause and energy customers will be discussed, as well as the barriers which must be overcome to achieve such deployment. All technical assessments will be framed within the context of the UK energy markets (power, heating and transport) given the maturity of the UK energy markets as well as the legally-binding carbon emissions targets set by the UK Government.

The challenge

Decarbonising the global economy is the largest challenge humanity currently faces, as the existential crisis of climate change becomes ever more present and violent. The cultural revolution taking place which is redefining the relationship between humanity and our environment will come to shape the trajectory of social development over the course of the 21st Century. As societal attitudes adapt and change, the transition from fossil fuel driven economies to environmentally sustainable economic models will provide new opportunities and economic benefits for those who have the courage to act now and grasp the first-mover advantage.

Like every great challenge facing humanity, environmental sustainability seems insurmountable when viewed from the perspective of the status quo. However, there is no alternative – maintaining the status quo is to knowingly continue to build the structure of society out of materials borrowed from its own foundations whilst wishing for calm winds.

Decarbonisation options

There are three options by which the world can decarbonise the global economy and meet the Paris targets of maintaining average temperature rises below 1.5 °C relative to pre-industrial times, or to push beyond that reduction to the recent IPCC assessment of net zero emissions by 2050. The three options are: reduce energy demand; capture carbon dioxide following fossil fuel combustion; and reduce the carbon intensity of energy.

Within each of these options lies a spectrum of technological avenues to policy makers and the exact balance of vectors will be country specific, determined ultimately by ease of use and minimum cost to customers. Taking each of these options in turn will allow a pragmatic conclusion to be drawn on the relative significance of each option.

Option 1 involves technological development in the form of efficiency gains and cultural change in the form of reducing absolute demand. Both of these strategies are, and will remain, important contributors in reducing carbon emissions; however, scale is the issue here. Carbon reductions on the scale required to achieve an 80% reduction by 2050 relative to 1990 simply cannot be achieved using this option without previously unseen technological advances and currently unacceptable disruptive changes to consumer lifestyles.

If option 2 is to be the dominant technology vector, this world view would be contingent on connecting every household's gas boiler flue, industrial flue stack, gas turbine and moving vehicle in the UK to CCS infrastructure. This is self-evidently not practical nor politically acceptable. Post-combustion CCS will likely

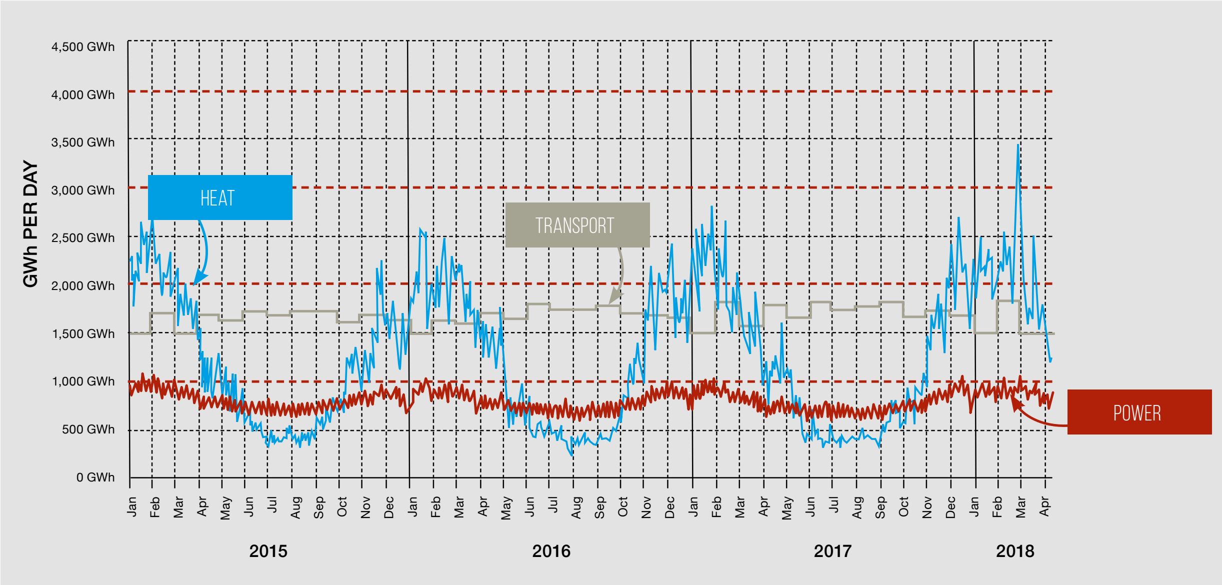


Figure 1: *UK Energy Demands (source: Grant Wilson, University of Birmingham)*

play a role, especially where easily isolatable streams of significant carbon dioxide volumes are ready for capture, such as during the production of fertilisers. However, post-combustion CCS is unlikely to be a universal solution.

This leaves us with option 3 – reducing the carbon intensity of energy by replacing fossil fuel usage with low carbon sources. This strategy is the least disruptive option from the perspective of the consumer and is achievable with current technologies given the maturity of the necessary technologies in other industries other than energy supply. The primary barrier to fully realising the opportunity of this strategy has been a clear and cohesive national plan with the necessary regulatory mechanisms to allow private investment and market-driven solutions.

Option 3 has been the dominant strategy to date via the electricity market by replacing coal fire stations with gas, biomass, wind and solar. This strategy has achieved a 50% reduction in the carbon intensity of electricity from 2013 to 2017[1].

Why hydrogen

Extending the current decarbonisation approach of electrification across all energy sectors would be, at a minimum, myopic and certainly unfeasible. Although wind and solar power have been transformative to date in decarbonising electricity, extending that logic to the other energy vectors of gas and oil (heating and transport) does not stack up when taking a system approach. As is shown in Figures 1 and 2, the UK's electricity demand is the smallest of the three, annual transport demand is 1.4 times electricity, and heat is 2.7 times electricity. Therefore, to electrify these demands with intermittent electrical supply would be predicated on building generation, transmission and distribution assets equating to four more grids along with industrial levels of battery deployment to transfer summer power to winter heat.

All considerations are then exacerbated when viewing the problem from the perspective of the current level of resilience required within the gas network which must cater for the six minute 1-in-20-year heating demand, and then factoring daily travel patterns regarding electric vehicle charging peaks.

Clearly, low carbon electricity has a natural economic ceiling to its deployment. The question therefore turns to alternative energy vectors to lower the carbon intensity of heating and transport in an economically and politically acceptable way. The two options for reducing the carbon intensity of energy supplies alongside electrification are: renewable hydrocarbon sources such as biomethane and liquid biofuels; and hydrogen.

Biomethane and liquid biofuels are important vectors within the energy landscape as they offer sources of fuel which promote a closed system of carbon. They are limited, however, to the availability of sustainable feedstocks. For example, biomethane based on domestic feedstocks could contribute 100 TWh/y, which represents around a third of domestic gas demand[2]. This is significant. However, other complementary sources will be required, given that total UK natural gas demand is up to around 1,000 TWh/y[3]. Hydrogen is not feedstock limited as it can be produced from a variety of sources and can potentially unlock negative emissions. Therefore, it has the potential to play a very significant role as a vector to reduce the carbon intensity of energy.

Heat

Displacement of natural gas for the purposes of heating is the principal opportunity that hydrogen represents. Heating accounts for almost half of all emissions in the UK[4], therefore tackling this source of carbon dioxide will be paramount in achieving the legally-binding reductions set by the UK government. Hydrogen deployment within the context of heat could take a variety of forms, from blending in the network, to full conversion of industrial users or even the wider network. The opportunity of hydrogen has been recognised by all gas distribution networks (GDNs) as demonstrated by the number of projects underway. The gas industry has a history of hydrogen, given that it was the single most abundant component in towns gas – the UK's gas supply prior to the discovery of natural gas beneath the North Sea. It is through demonstration projects such as the HyDeploy

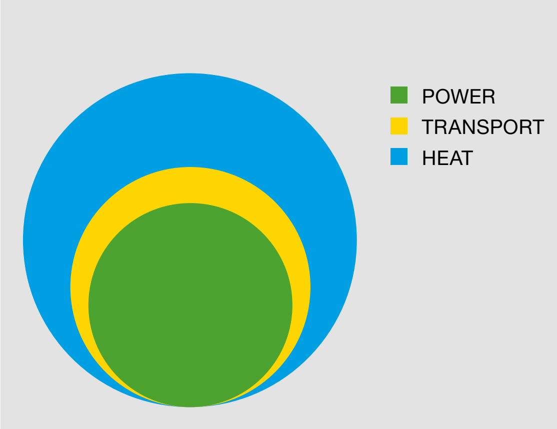


Figure 2: *To scale energy system comparison*

project that the hydrogen-for-heat landscape is being carved, setting the technical and regulatory scene for wider adoption and deployment.

Power

Within the electricity market, hydrogen is a symbiotic vector alongside intermediate renewables supplies. Electricity production from hydrogen is a dispatchable generation source which provides mechanical inertia to the grid. The reduction in mechanical inertia of the electricity grid, due to replacement of thermal generation (alternating current) with renewable generation (direct current followed by an inverter), has resulted in increased challenges in maintaining grid frequency, as recognised by National Grid's enhanced frequency control capability (EFCC) project. A low-carbon thermal generation source has a valuable role in stabilising the electricity grid if intermittent sources are to play the role they are expected to play within the future generation mix. Hydrogen-powered gas turbines or industrial fuel cells would provide the necessary mechanical inertia needed to maintain a stable electricity grid, whilst further reducing electrical energy carbon intensity.

Transport

Transport is a second-order decarbonisation problem – the technical solutions for electricity and gas will provide the infrastructural framework for transport decarbonisation. If electricity is to be the sole form of energy for transport then major investment in dispatchable generation, alongside smart technologies would be required to allow charging of vehicles when required. Hydrogen peaking plants are likely to provide a lower cost and more stabilising vector relative to the counterfactual of industrial batteries. Hydrogen can also be used directly for transport using fuel cells, delivering zero emissions at the point of use.

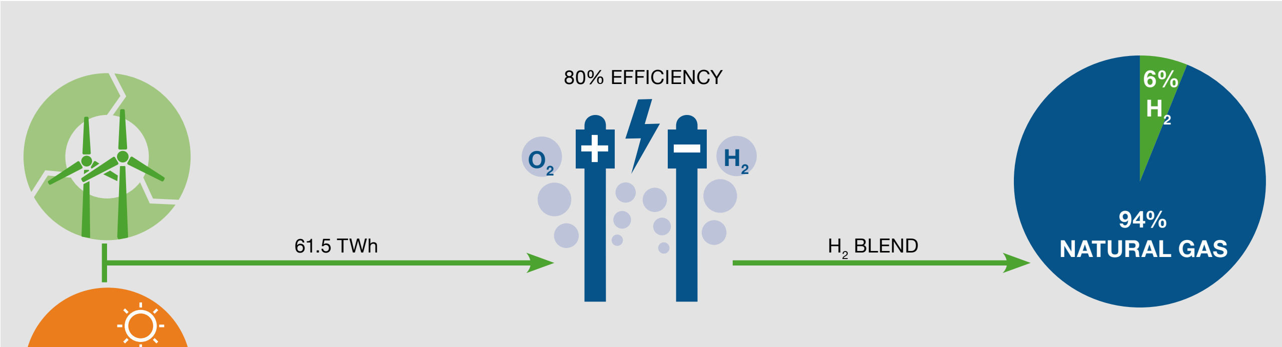
Building on the adoption of electric drive trains, a hydrogen fuel cell is functionally equivalent to a battery, with associated benefits of range and fill rate following development and deployment. The notion therefore holds that whichever decarbonisation strategy prevails within the transport market, hydrogen is expected to play a key role.

Production

If hydrogen is to play a central role in the decarbonisation of our energy systems, major investment in production will be required. The importance of hydrogen production technologies has been recognised by the UK Government and has resulted in the £20m Hydrogen Supply Competition.

Production technologies will be covered in more detail within this series, however the most established and suitable processes for bulk production require converting methane to hydrogen and carbon dioxide via steam methane reformation (SMR), or autothermal reformation (ATR). Therefore, deployment of bulk production at the scale required would be contingent on the establishment of CCS infrastructure. Electrolysis with renewable electricity has a role but cannot economically supply bulk hydrogen at the scale required, as demonstrated by Figure 3. In the long run, hydrogen produced via solar-thermal hydrolysis and transported in shipping tankers could provide the ultimate environmentally sustainable model.

Figure 3: *2017 Total electrolysis potential*



[4,5] *TOTAL ELECTRICITY GENERATION FROM WIND AND SOLAR IN 2017 WAS 62 TWh.*
IF ALL PRODUCTION WAS CONVERTED TO HYDROGEN VIA ELECTROLYSIS AT A TYPICAL EFFICIENCY OF 80%, HYDROGEN PRODUCTION WOULD HAVE BEEN 49 TWh. TOTAL NATURAL GAS USAGE IN 2017 WAS 875 TWh, THEREFORE ELECTROLYSIS WOULD HAVE DISPLACED 6% OF NATURAL GAS SUPPLY

Methane conversion coupled with CCS provides a necessary foundational production process which would allow the required regulatory and commercial frameworks to be developed to enable wider deployment.

Deployment strategy

The challenges of hydrogen deployment extend across technological development, commercial models, regulatory support mechanisms and customer perceptions. None of these challenges are insurmountable when considered in isolation, however when aggregated and put within the context of the scale of decarbonisation required, the sum total could seem daunting. It is therefore incumbent to tread the path of least regrets. Projects which de-risk the route map of deployment, for example by removing the need to modify existing appliances and equipment, whilst still representing material carbon savings, should be favoured for early deployment. Adopting this rollout strategy would allow the necessary commercial frameworks and regulatory mechanisms to be established to facilitate deeper deployment whilst minimising the cost of early adoption to consumers.

Cost

Finally, with regards to cost, it would be intellectually dishonest to set expectations that decarbonisation of the economy will not come at a cost compared to the status quo. This is because at present, our energy systems do not properly internalise the cost of the damage caused by carbon emissions. The known reserves of the major oil and gas companies are more than enough to exceed the carbon dioxide requirements to breach the Paris limits. Therefore, decarbonisation is fundamentally a moral decision, not an economic inevitability.

It is the duty of policy makers and informed entities to promote the least-cost pathway, as this will ensure the economic burden does not prohibit the success of the cause. Hydrogen is a key element of that pathway. The deployment of hydrogen can be achieved with known technologies in a way that maximises the utilisation of existing assets, principally the gas network, whilst enabling deeper deployment of other low-carbon technologies.

Through the course of this article series the opportunity that hydrogen presents, as well as the challenges facing its deployment, will be presented, to inform debate and drive evidence-based conversations.

Footnotes

1. *Future Energy Scenarios Workbook*, National Grid, UK, July 2018, https://ngrid.com/2YDqzjW
2. Barrow Green Gas, *Biogas comes of age*, [online], May 2016, accessed June 2020, https://bit.ly/2TZb1CI
3. *Supply and consumption of natural gas and colliery methane* (DUKES 4.2), BEIS, UK, July 2018, https://bit.ly/31E0rYh
4. *Final UK greenhouse gas emissions national statistics: 1990-2016*, BEIS, UK, March 2018, https://bit.ly/3eWsRRd
5. *Electricity fuel uses, generation and supply* (DUKES 5.6), BEIS, UK, July 2018 https://bit.ly/38pozix

Clean hydrogen part 1: hydrogen from natural gas through cost effective CO_2 capture

Bill Cotton FIChemE

Today, hydrogen is predominantly made by steam reforming of natural gas, which produces carbon dioxide as a byproduct. The reforming reaction for methane is:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \qquad \Delta H = +206 \text{ kJ/kmol}$$

In addition, the water gas shift reaction can be favoured by process conditions to generate further hydrogen:

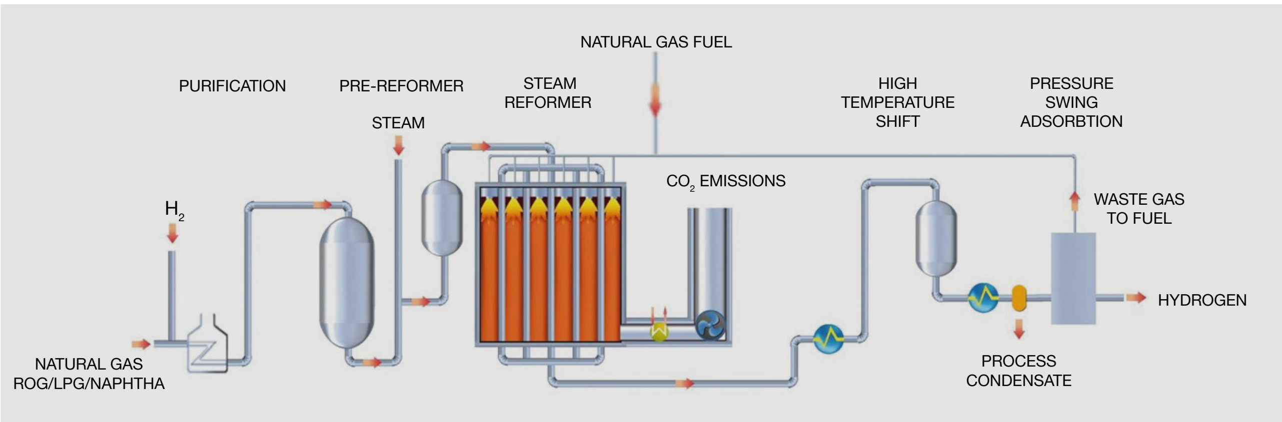
$$CO + H_2O \rightarrow CO_2 + H_2 \qquad \Delta H = -41 \text{ kJ/kmol}$$

The Hydrogen Council initiative quotes the global production of hydrogen to be 8 EJ/y (71,600 kNm^3/h) with a majority of users in refineries ammonia and methanol production. Growth is forecast in these markets and there is a growing body of evidence that to reduce carbon dioxide emissions to acceptable levels, deeper cuts across all sectors will be required. A low carbon gas solution for hydrogen production will be important to achieve the aims of the Paris Protocol and impact on climate change.

Compared to conventional Steam methane reforming (SMR), the low carbon hydrogen (LCH) flowsheet developed by Johnson Matthey offers a better solution for hydrogen generation with carbon capture by:

- recovering high-grade heat at the maximum exergy;
- using high reformer temperatures to minimise methane in the syngas and hence carbon dioxide emissions; and
- increasing energy efficiency and CAPEX benefits by recovering all the carbon dioxide at process pressure; and
- minimising the amount of difficult-to-capture CO_2 in combustion products

Figure 1: *Hydrogen production using SMR technology.*



Steam methane reforming

Critical to the process is the SMR which generates the majority of the world's hydrogen[1] as shown in the flowsheet in Figure 1. The SMR is a large refractory-lined box containing hundreds of pressurised tubes to convert hydrocarbon as per the reaction above.

To achieve long catalyst lives, the first stage in the process purifies the natural gas by a hydrodesulfurisation step in which the organo-sulfur compounds are reacted over a catalyst with recycled hydrogen to form hydrogen sulfide followed by absorption of that hydrogen sulfide in a zinc oxide bed through its conversion to zinc sulfide.

In an SMR, hydrocarbons present in the feed natural gas are reacted with steam at pressures of between 1m–4m Pa in the presence of a nickel catalyst in tubes, which are generally 12–14 m in length with a 125 mm inside diameter.

The reaction produces a gas mixture comprising hydrogen, carbon monoxide and carbon dioxide, which is often termed 'syngas'. The steam reforming reaction is endothermic, so heat is added to the process by burning additional natural gas and waste gas streams to heat the catalyst-containing tubes. Typically, the reformer exit temperatures are between 700–930 °C depending on the flowsheet and final product.

The syngas from the steam reformer is further processed over a third and, in some cases, a fourth catalyst stage when the water gas shift reaction takes place as detailed above to maximise hydrogen production. This reaction is exothermic and cooling the gas allows heat recovery back into the process which generally involves steam generation and boiler feed water pre-heating.

SMR flowsheets have been optimised over a number of years and have become the technology of choice to produce hydrogen, with production capacity ranging from MWs to GWs (1–330 kNm³/h). The designs are now deemed to be a mature technology that provides high purity hydrogen on a reliable basis required for downstream users. However, there are very few hydrogen plants that capture the carbon dioxide as there is no economic or legislative incentive to do so.

Therefore, if hydrogen is to play a role in reducing the impact of climate change2, then it will need to be produced with concomitantly low carbon dioxide emissions, which, when using natural gas as a feedstock implies coupling it with carbon capture and storage (CCS). The combustion process in an SMR produces carbon dioxide at low concentration and atmospheric pressure and hence inevitably leads to high capital cost estimates (CAPEX) solutions for CCS. These include post-combustion capture of the carbon dioxide or using process-produced hydrogen as the fuel in the reformer. Both of these introduce significant efficiency losses.

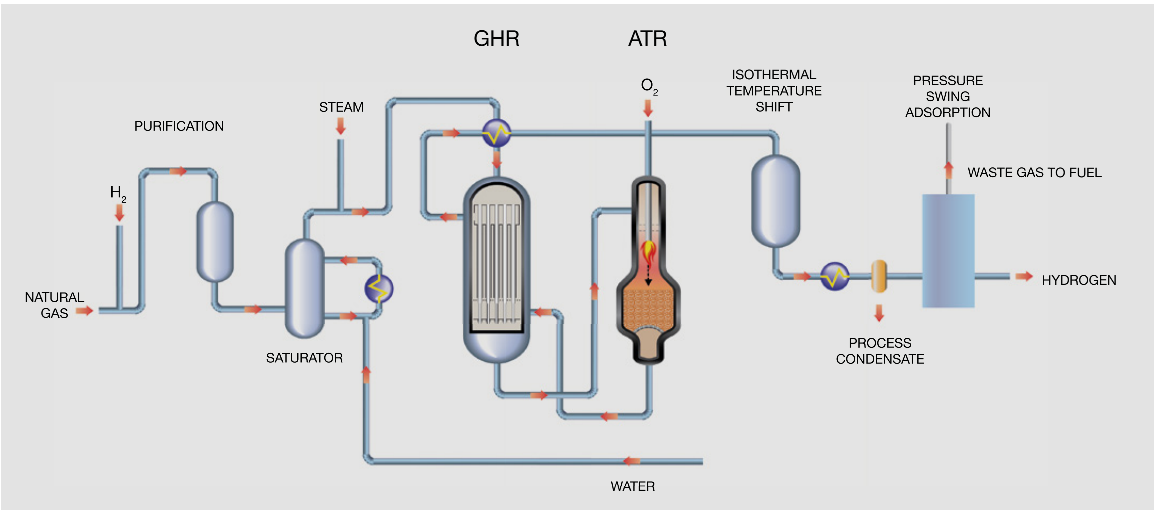
Accordingly, to produce low carbon hydrogen cost effectively, the products are ideally both high purity hydrogen and also now high pressure and high purity carbon dioxide for CCS. Additionally, consumers of this hydrogen would not want this with an unaffordable cost penalty.

Introducing low carbon hydrogen (LCH) technology

The LCH flowsheet recovers heat at maximum exergy (ie the highest possible quality) which offers efficiency benefits by coupling a gas heated reformer (GHR) with an autothermal reformer (ATR). The main difference between the LCH and SMR flowsheets is that the energy to drive the reaction is provided by introducing oxygen to the ATR as opposed to burning natural gas in the SMR. At the scales envisaged, this oxygen would come from an air separation unit. ATRs are already used in the production of syngas and are part of most modern schemes for production of methanol and liquid fuels from Fischer-Tropsch processes. These plants are very large and demonstrate that the technology is capable of producing hydrogen at large scale and therefore the scale-up risk is minimised.

At a basic level, a flowsheet showing hydrogen production using LCH technology is shown in Figure 2.

Figure 2: *Basic LCH process.*



Purified natural gas is pre-heated and reformed in the GHR before entering the ATR reactor. In the first reaction step in the GHR, 30% of the total hydrocarbon is reformed by reaction with steam to form syngas. In the second stage, the ATR, oxygen is added and combusts some of the partially-reformed gas to raise the process gas temperature to around 1,500 °C. The resultant gas then passes through a bed of steam reforming catalyst inside the same reactor for further reforming. Since the reaction is limited by equilibrium, operation at high temperature and steam flows minimises the methane content of the product gas which in turn minimises overall carbon dioxide emissions. The hot gas exiting the ATR passes back to the GHR providing the heat necessary to drive the reforming reaction in the GHR tubeside.

For the LCH flowsheet, all of the carbon dioxide is within the product stream and therefore is at high pressure and relatively high purity and can be easily removed using standard industry removal technologies. This has implications in terms of the overall CAPEX of the flowsheet because the size of the carbon dioxide removal system is significantly reduced.

The advantages of a LCH flowsheet are that:

- **heat is recycled at a higher quality than in an SMR flowsheet which uses medium pressure steam as a heat transfer medium; and**
- **the reforming reaction is conducted at a higher temperature, which means more methane is converted to hydrogen**

Comparison of the technologies

Whilst steam reforming using an SMR requires a large energy input from combustion of natural gas, energy integration means the flowsheet is relatively efficient. In an SMR, the waste heat generated primarily as steam is exported, whilst for an SMR with CCS, the steam is used to provide heat for carbon dioxide recovery and energy for carbon dioxide compression. In the LCH flowsheet, the waste heat is instead recycled to supplement the necessary reaction heat through the GHR, meaning natural gas fuel is not needed, resulting in reduced atmospheric emissions as illustrated in Table 1.

So, the benefits of the LCH flowsheet are:

- **it recycles exergy at the high possible level;**
- **it uses high reformer temperatures to minimise methane in the syngas and hence CO_2 emissions; and**
- **all of the CO_2 is recovered at process pressure, which offers energy efficiency and CAPEX.**

A further advantage of using the LCH technology is that compression energy required for the air separation unit and carbon dioxide compression need not be by steam raising. The LCH flowsheet can power compressors using electrical grid energy sourced from renewable energy sources. The LCH technology therefore can integrate renewable energy and provide a flowsheet with dramatically reduced greenhouse gas emissions, lower capital cost and lower natural gas consumption.

GHRs have run continuously on a commercial basis for over 100 cumulative years proving the concepts on a long term with best in class reliability. The technology has been scaled and in 2016 to facilitate a 5,000 mtpd methanol project in the US. In 2016, JM's technological breakthrough was awarded the top prize at the IChemE Global Awards (Outstanding Achievement in Chemical and Process Engineering).

Footnotes

1. Appl, M, *Modern Production Technologies*, CRU Publishing, 1997
2. UNFCC, Paris Agreement, 2015, https://bit.ly/31hR40h

Table 1: *Comparison of flowsheets.*

PARAMETER	UNITS	SMR FLOWSHEET	ATR FLOWSHEET	LCH FLOWSHEET
Natural Gas as Feed	kNm^3/h	39.74	41.22	38.31
Natural Gas as Fuel	kNm^3/h	5.36	0.19	0
Total Natural Gas	kNm^3/h	45.10	41.41	38.31
Natural Gas Energy#	MW	439	432	400
Hydrogen Production	kNm^3/h	107.4	107.4	107.4
Hydrogen Energy#	MW	322	322	322
Natural Gas Efficiency	%	73.3	74.5	80.6
CO_2 Captured	mt/h	83.7	83.6	76.3
CO_2 Emitted	mt/h	4.4	3.1	3.7
CO_2 Captured	%	95.0	96.4	95.4
ISBL + OSBL CAPEX	mGBP	261	195	159

 # Energy is stated on a lower calorific value basis

Clean hydrogen: part 2

Andy Brown AFIChemE

Atomic and molecular hydrogen are most common beyond the Earth. Hydrogen is the primary constituent of the Sun, as well as most other stars, and it can be observed in vast quantities throughout the universe. Hydrogen is also the main component of the atmospheres of gas giant planets, Jupiter, Saturn, Uranus and Neptune. Because Earth's atmosphere contains oxygen, any atomic hydrogen that might have been present has reacted to form water.

As a result, unlike natural gas, if a source of hydrogen is required, it has to be extracted from the compounds that it has formed. In the majority of cases this is water. This extraction process requires energy, and the application of technology to prevent the hydrogen from re-combining with oxygen to form water again. There are four principal methods to manufacture hydrogen, as shown in Table 1, dependent upon what feedstock is being used as the starting point.

METHOD	FEEDSTOCK
Steam/AutoThermal Reformation	Natural Gas, refinery off-gas, LPG, Naptha, Kerosene, Gas Oil
Cracking	Methanol, DME
Gasification	Coal, biomass, refinery bottoms
Electrolysis	Brine, water

Table 1: *Methods generally used to manufacture hydrogen.*

Hydrogen as a by-product of other industrial processes

A small number of industrial processes produce hydrogen as a by-product of the extraction of other chemicals. An example of this is in the production of chlorine, which is achieved by the electrolysis of brine (salty water/sodium chloride solution), known as the chlor-alkali process. The production of chlorine also results in caustic soda (sodium hydroxide, NaOH) as a by-product. These two products, as well as chlorine itself, are highly reactive. Chlorine can also be produced by the electrolysis of a solution of potassium chloride, in which case the co-products are hydrogen and caustic potash (potassium hydroxide). There are three industrial methods for the extraction of chlorine by electrolysis of chloride solutions, all proceeding according to the overall process equation, note all release hydrogen:

Production of chlorine is extremely energy intensive: energy consumption per unit weight of product is similar to that for iron and steel manufacture and greater than for the production of glass or cement. Since electricity is an indispensable resource for the production of chlorine, the energy consumption corresponding to the electrochemical reaction cannot be reduced. Energy savings arise primarily through applying more efficient technologies and reducing ancillary energy use, and process economics can be enhanced by marketing the by-products. For the hydrogen and the hydroxide to be marketable, they need to be of a high purity, and therefore the preferred production method is usually membrane cell electrolysis, as shown in Figure 1.

$$2NaCl\ (or\ KCl) + H_2O \rightarrow Cl_3 + H_2 + 2NaOH\ (or\ KOH)$$

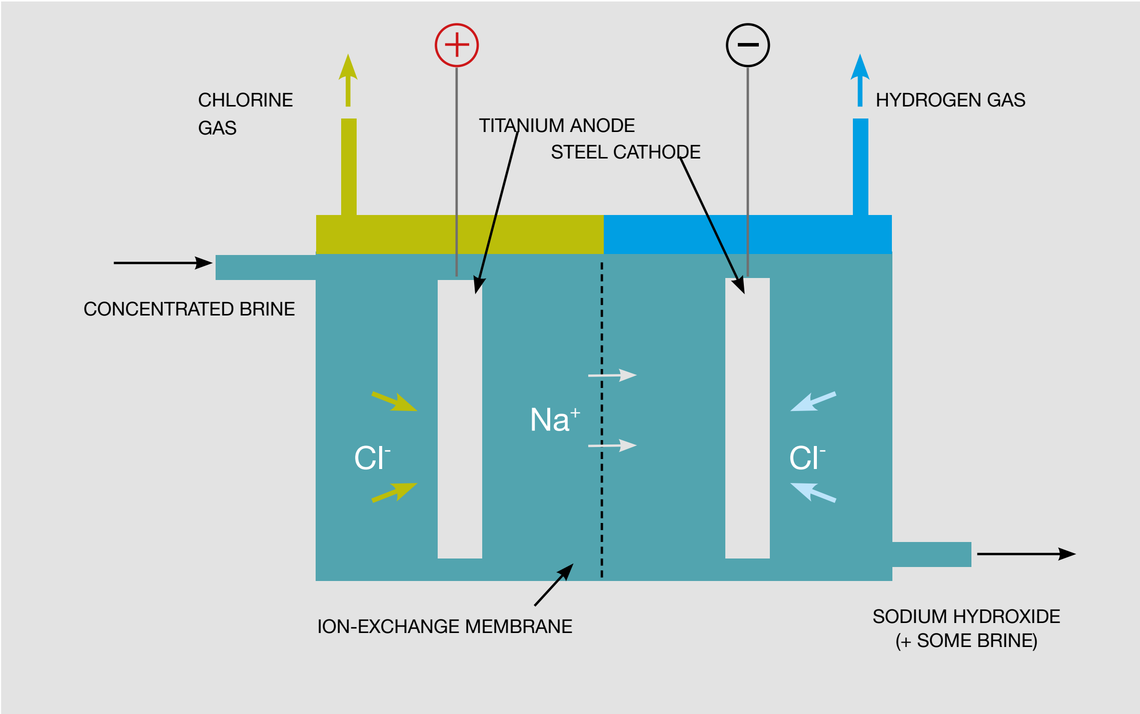


Figure 1: *Membrane cell electrolysis arrangement for producing chorine*

Hydrogen from the electrolysis of water

The principle of the cell shown in Figure 1 can be used with water instead of brine, in which case hydrogen emerges at the cathode and oxygen at the anode. In this context, the cell is known as an electrolyser, and single cells up to about 2 MWe are available commercially with efficiencies of around 80%. The levels of purity can be very high and the water pumped in at pressure, which means that the hydrogen is also at pressure. Electrolysers have a number of advantages over some other methods of hydrogen production, which include:

- individual cells can be clustered, making it a scalable technology;
- with no moving parts, maintenance is low;
- cells are agnostic with regards to the electricity source, and can use 'spill power' from wind generators or unsold 'base load' from nuclear power stations; and
- used in conjunction with wind or solar generation, they are 'zero CO_2 emissions' at source (ignoring any CO_2 emitted in the water supply).

Hydrogen produced on refineries

Specifications for transportation fuels are continuously changing to accommodate environmental objectives. For example, petrol now contains less aromatics and olefins than they did ten years ago, and constraints have been imposed on light hydrocarbons and sulphur contents. New legislation for diesel requires deep desulfurisation down to 10–50 ppm sulfur. This is achieved by reacting the sulfur compounds with hydrogen to produce hydrogen sulfide (H_2S), which can be removed from the hydrocarbon stream by one of a number of processes. The requirement to reduce the sulfur may be achieved

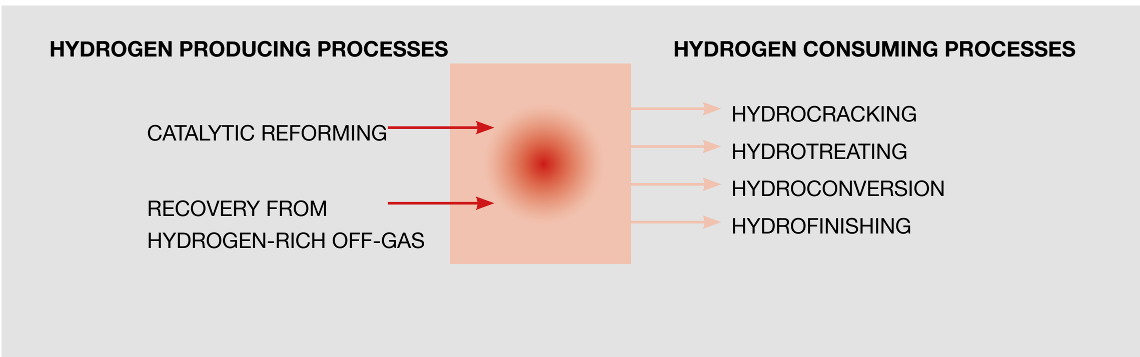


Figure 2: *Refinery hydrogen balance' from 'Large-scale Hydrogen Production', JR Rostrup-Nielsen, T Rostrup-Nielsen, Haldor Topsoe, presented at the 6th World Congress of Chemical Engineering, Melbourne, Australia, 2001.*

coincident with the removal of aromatic compounds, which are considered as carcinogenic. In general, these trends result in an increasing hydrogen content in the fuels (the H:C ratio is approaching 2). This has been achieved simultaneous with the crude slate becoming heavier, with higher contents of sulfur and metals in the crude. This has created a large requirement for more hydrotreating (HDS, HDN, HDM) and hydrocracking as a part of the refining processes. The hydrogen balance in a refinery is illustrated in Figure 2.

Traditionally, a major a part of the hydrogen consumption in refineries was covered by hydrogen produced as a by-product from other refinery processes, mainly catalytic reforming, described as 'platforming'. A main reaction in catalytic reforming (not to be confused with catalytic steam reforming, which was described in Part 1 of this series) is the conversion of paraffins into aromatics and hydrogen. As specifications require that the aromatic content of fuels is further reduced, less hydrogen will become available from platforming.

Dependent on the slate and the product mix, some refineries will be 'short' on hydrogen and others will be 'long'. Those refineries that are 'hydrogen short' have a number of options to make up the deficit, which include importing it from an adjacent SMR facility (as at the Lindsay refinery). Another option is to gasify the residual oils at the end of the process ('refinery bottoms'), as described below.

Those refineries that are 'hydrogen long', if there are no export opportunities, may use it to fuel fired process heaters. These have the potential to realise more value from the hydrogen by exporting it to industrial users.

Gasification as a route to produce hydrogen

The principal reactions described for SMR in Part 1 of this series represent partial oxidation of the methane. The same reaction can be applied to almost any carbon-containing feedstock, including coal, refinery bottoms, domestic waste, industrial plastic waste and biomass. Instead of the partial oxidation reaction being promoted by a catalyst(s), gasification involves reacting the feedstock sub-stoichiometrically with oxygen (ie with insufficient oxygen available to allow the reaction to proceed to completion). Of these feedstocks, the focus for bulk production of hydrogen has been on coal and refinery bottoms.

There are a number of different gasifier designs, but for hydrogen production a sub-set of these is favoured. For instance, gasification processes using air (instead of oxygen) tend to deliver a hydrogen/nitrogen mix at the end of the process, rather than pure hydrogen. A generic flowscheme to produce hydrogen using gasification is shown as Figure 3. The process is carried out under pressure, typically over 25 bar.

Plasma gasification is a variant of gasification which converts organic matter (such as sorted domestic waste) into syngas using a plasma torch powered by an electric arc. Anything else in the feedstock is left as a slag. Small plasma torches typically use an inert gas such as argon where larger torches require nitrogen. A high voltage passes between the two electrodes as an electric arc. Pressurised inert gas passes through the plasma created by the arc and is ionised. The temperature of the plasma can be anything from 2,200–13,500 °C depending on the process, the temperature largely determining the structure and shape of the plasma. The feedstock beneath

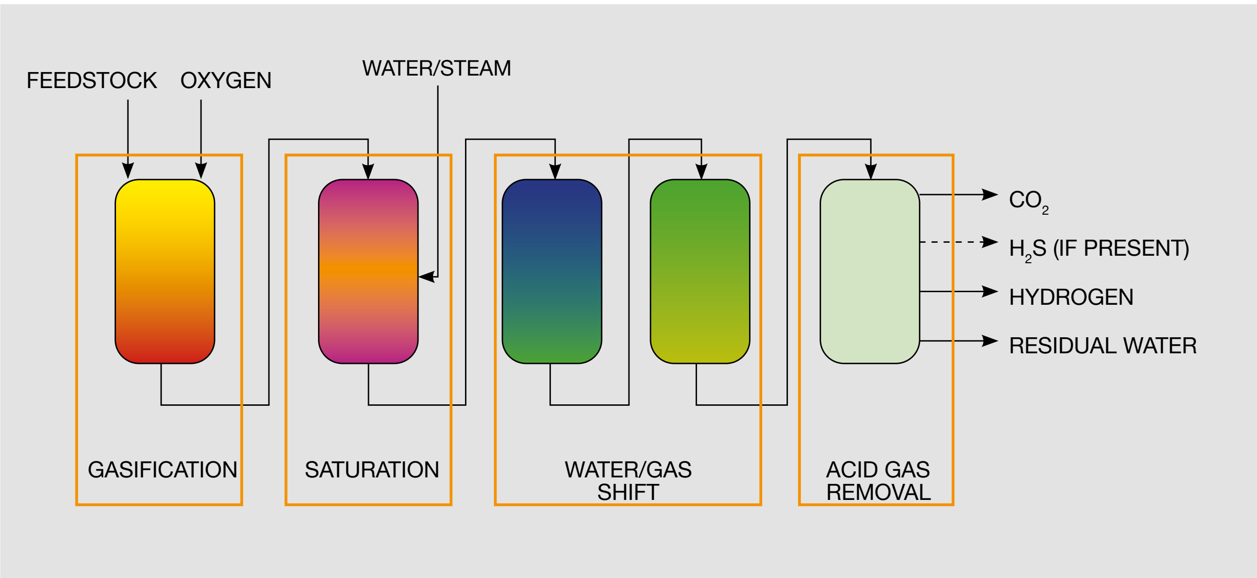


Figure 3: *Generic flowscheme to produce hydrogen using gasification.*

LOCATION	COUNTRY	HYDROGEN PRODUCTION (KG/H)	ELECTRICITY PRODUCTION (MW)	GAS TURBINES
Jazan	Saudi Arabia	8,200	2,400	10x Siemens SGT6-5000F
Sarlux	Sardinia, Italy	3,658	187.1	3 x GE9E
Shell, Pernis	Netherlands	11,875	120	2xGE MS 6541B

Table 2: *Some gasification plants producing hydrogen for refineries.*

the plasma is vapourised at these temperatures, and molecular dissociation takes place: the complex molecules are split into simple molecules (such as CO or H_2), or even individual atoms. The syngas thus formed can be used as a source of hydrogen or methanated to produce 'synthetic natural gas'.

It is relatively easy to link gasification with carbon capture and storage (CCS): where biomass is used as a feedstock, this can result in 'negative CO emissions'.

Hydrogen from residual oil

A refinery has a high electricity demand, and burning the syngas in a gas turbine to offset the import of electricity is a possibility to manage changes in the hydrogen demand of the refinery. Examples of where this has been or will be employed are provided in Table 2.

A feedstock of residual oil ('refinery bottoms'), asphaltines or bitumen is heated and pumped into a gasifier, as described above. The operating mode is usually that the process produces hydrogen for the refinery (eg for upgrading heavier elements of the slate), with electricity generation being used to utilise 'spill hydrogen' beneficially.

Hydrogen from micro-organisms

Hydrogen can be produced by a number of different micro-organisms: which ones and the associated science is beyond the scope of this series. Perhaps the most successful example of this has been attributed to researchers from Germany, who have an experimental facility in the Sahara producing hydrogen using a bacterium called *Thiorhodaceae*. This is carried out in a heliomite, a cone-shaped wooden construction with a transparent plastic pipe for the movement of the bacteria[2].

Results show that the rate of hydrogen production almost doubles when the heliomite receives sunlight from a side (as opposed to the top) as *Thiorhodaceae* favours the long-wave light reflected by the Sahara sand. The researchers combined bacteria and plant photosynthesis to provide nutrients for the bacteria. In this experiment, green algae and *Thiorhodaceae* are positioned adjacent to each other. The green algae react with the bacterial carbon dioxide and water to form oxygen and carbohydrates. The oxygen escapes and the carbohydrates feed the *Thiorhodaceae* solution, which produce a mixture of CO_2 and hydrogen. Each heliomite can produce up to 0.285 Nm^3/h of hydrogen.

Clearly this technology has a way to go before microbial hydrogen can make a significant impact on the current carbon-based economy, but it has the potential to make a contribution.

Dark fermentation

Hydrogen production by dark fermentation could be a very promising concept. Dark fermentation is described as the fermentative conversion of organic substrate to produce bio-hydrogen. It is a complex process manifested by diverse groups of bacteria, involving a series of biochemical reactions using three steps, similar to anaerobic conversion. Dark fermentation differs from photo-fermentation in that it proceeds without the presence of light.

However, this process has only been studied on the laboratory scale, and there is limited experience at the pilot scale. There remain a number of challenges with hydrogen purity, process stability and low conversion yields, all of which seem not to improve with increasing scale.

Thermochemical hydrogen production

Thermochemical water splitting uses high temperatures and chemical reactions to produce hydrogen and oxygen directly from water. Possible heat sources include concentrated solar power or, potentially, nuclear power. This is thought to be a long-term technology pathway, with

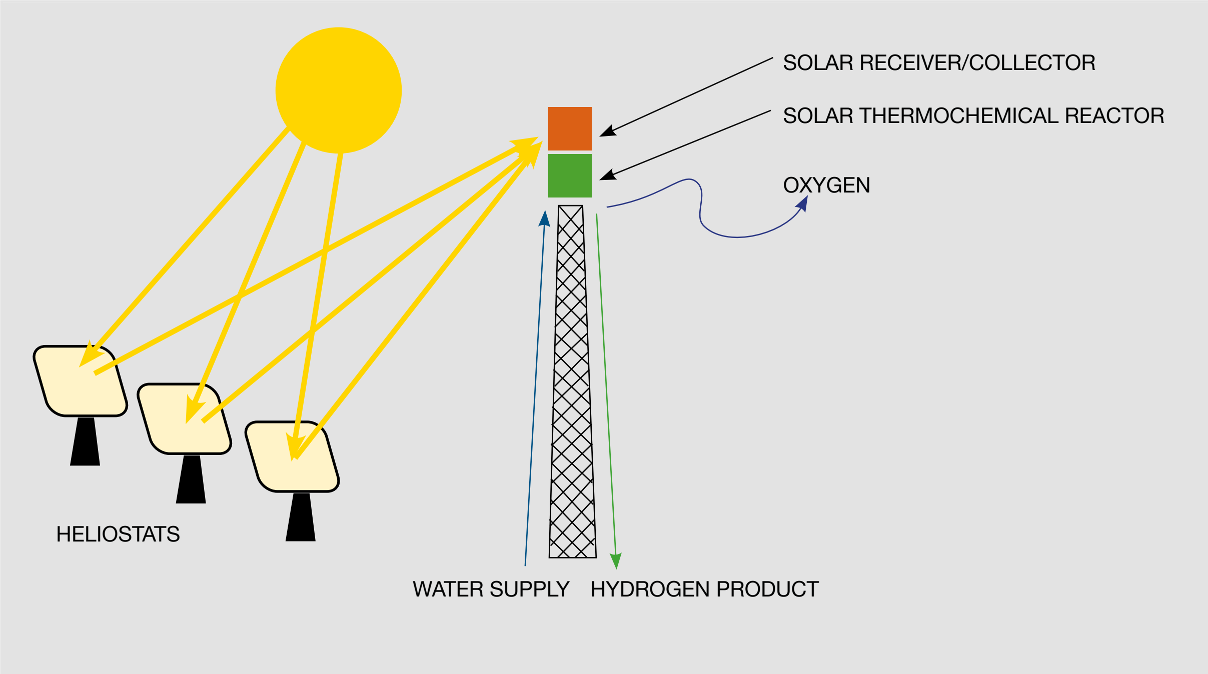


Figure 4 : *Thermochemical water splitting using solar radiation.*

potentially low or no direct greenhouse gas emissions. Figure 4 shows the principle using solar rays as the heat source.

Thermochemical water splitting processes use high-temperature heat (500–2,000 °C) to drive a series of chemical reactions that 'split water' into its component parts of hydrogen and oxygen. The chemicals used in the process are reused within each cycle, creating a closed loop that only consumes the water and produces hydrogen and oxygen gasses.

Hydrogen production by nuclear fission

Purely nuclear based production of hydrogen was observed in the 1940s in experimental nuclear reactors based on the Aqueous Homogeneous Reactor (AHR) concept, where the nuclear fuel is dissolved in the water coolant and circulates between the reactor core and a heat sink. These reactors were originally given the name 'water boiler' due to the observed bubbling of the liquid fuel. The bubbles are hydrogen and oxygen gas formed by radiolytic dissociation of the water from the ionising radiation of energetic neutrons and fission fragments. Radiolysis is actually considered a serious problem for water reactors, since it can lead — and has led — to explosions in the reactor system.

Due to the low energy efficiency of hydrogen production, this method was not considered promising as a commercial dedicated hydrogen production method[1].

Hydrogen as a low carbon energy vector

Hydrogen production by any method only makes sense if it does not also emit CO_2. In many instances, for example, gasification of refinery residues, the process lends itself to carbon capture and storage (CCS). CCS is necessary to make the technology acceptable environmentally. Were biomass to be used as a feedstock, then a case can be made for the hydrogen to have 'negative emissions'. Avoiding payments to emit CO_2 will assist Industry in offsetting some of the additional costs associated with fuel switching from natural gas to hydrogen (in whole or in part).

It is outside of the scope of this article to describe how CCS can complement hydrogen production, but an obvious synergy is that CCS infrastructure developed to support hydrogen as a low carbon energy vector could, under appropriate commercial and other conditions, then be available for use by other industries such as fertiliser and cement production, and steel making.

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1. International Atomic Energy Agency, *Hydrogen Production Using Nuclear Energy*, IAEA Nuclear Energy Series No. NP-T-4.2, IAEA, Vienna (2012). https://bit.ly/2ZclAGj Used with permission.
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Making fuel from water

Andrew Procter MIChemE, Fan Zhang, Stephen Carr and Jon Maddy

Reducing greenhouse gas (GHG) emissions to avoid the catastrophic consequences of global warming is the most significant problem of our time. Hydrogen can play a key role in helping the UK achieve its GHG emission reduction targets. Major reductions of emissions have been achieved in the electricity sector by increasing renewable electricity penetration as well as phasing out coal-fired power plants, but as well as continuing to reduce emissions from electricity production, progress in the heating and transport sectors needs to be drastically improved. Hydrogen can play a major part in reducing emissions in these sectors, and if produced electrolytically, provides a link between them.

The majority of hydrogen produced currently is through steam methane reforming, and is then used in the chemical industry, for example for ammonia production. This method is not low carbon unless used in conjunction with carbon capture and storage (CCS). With CCS, a 60–85% reduction in GHG emissions is possible over methane[1]. An alternative method to produce green hydrogen is via electrolysis. An electrolyser is a type of device that commonly used to decompose water using direct electric current. Hydrogen and oxygen will be produced from water through redox reactions. The overall reaction is:

$$H_2O \rightarrow H_2 + \tfrac{1}{2}O_2$$

If the electricity used in the process is from low carbon sources, then the hydrogen is a low carbon fuel. The exact chemistry of the reaction depends on the particular technology used, with some technologies more suitable for certain applications.

Electrolyser technologies

The discovery of water electrolysis is disputed. One view argues that it was discovered by Anthony Carlisle and William Nicholson in 1800. The other view gives the credit to Johann Ritter. It is estimated that in 2017, the global sales of electrolysers reached 100 MW/y. This indicates a daily hydrogen production of 50,000 kg[2].

There are three different types of electrolyte that can be used in a typical electrolysis process: a liquid electrolyte; a solid polymer electrolyte in the form of proton exchange membrane; or an oxygen ion conduction membrane. As a result, there are three main types of electrolysers, according to the adopted electrolyte technology, namely alkaline, proton exchange membrane (PEM), and solid oxide (SO) electrolysers.

Alkaline electrolysers were the first commercialised electrolysis system and remain the most mature and widely used system for hydrogen production. Two electrodes, an anode and a cathode, often manufactured from nickel are immersed in a conductive electrolyte. A 30% aqueous solution of potassium hydroxide (KOH) is commonly used as the electrolyte to enhance ionic conductivity. However, sodium hydroxide (NaOH) can also be used. The separator is used to allow the migration of hydroxide anions (OH^-) and avoid the mixing of hydrogen and oxygen gas generated. Despite the fact that it is an established technology, there are a number of technical disadvantages associated with alkaline electrolysers. This includes the use of corrosive electrolyte, low current density, limited turndown ratio and inability to operate at high pressures. A schematic is illustrated in Figure 1.

PEM electrolysers utilise a proton exchange membrane. The most commonly used membrane is *Nafion*, manufactured by DuPont with thicknesses ranging from 25–250 µm. Thicker membrane can be used to enable the electrolyser to cope with low load operation or frequent start-stops. This technology is at an early commercial stage. There is considerable ongoing research into the development of this technology.

Solid oxide electrolysers differ from both alkaline and PEM electrolysers in that instead of operating at about 80 °C, they operate at a high temperature range of 800–1,000 °C. At such high operation temperature, steam instead of water is fed into the electrolyser. The increased thermal demand is compensated by the decrease of electrical demand. When the thermal energy is provided as a waste stream from other high-temperature industrial processes, the cost for hydrogen production can be further reduced. However, it is identified that operating at such high temperature may cause a number of drawbacks, which includes poor long-term cell stability, interlayer diffusion, fabrication, and materials problems. There are research efforts in developing electrolysis cells working at intermediate temperatures (500–700 °C). At the present time, SOE is still in the research, development and demonstration stage.

It is likely that the different technologies will be suitable for different applications. PEM based electrolysers are more able to quickly adjust their output and have an operating range of 0–100%, so are suited to applications such as demand-side management and renewables integration where flexibility of operation is a key demand. Alkaline electrolysers as a more established technology are likely to continue being used where rapidly variable input is not a key demand. Solid oxide electrolysers have the potential to offer highly efficient production of hydrogen if some of the heat used is provided by waste streams.

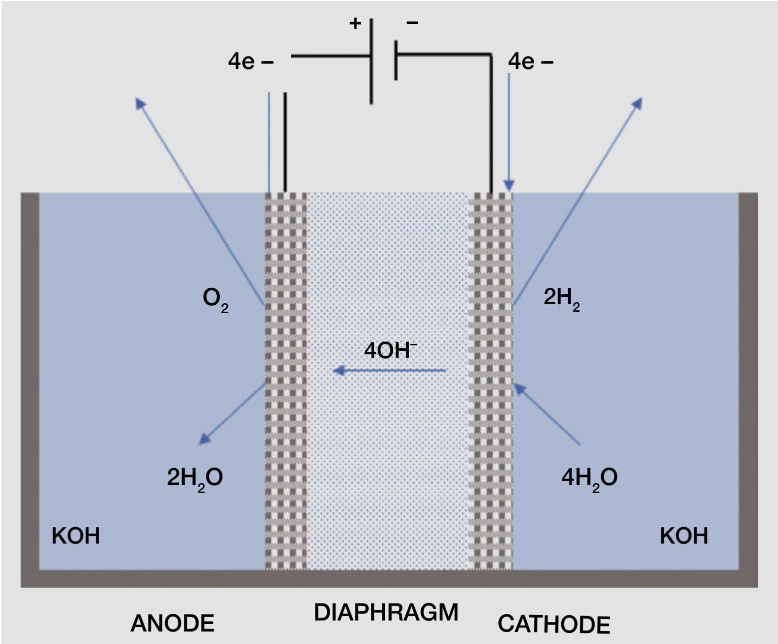

Figure 1: *Operating principle of an alkaline electrolysis cell.*

Applications

Hydrogen can be produced from a variety of sources such as fossil fuels, biomass, as well as electrolytically from water. It can be stored as a compressed gas, as a liquid, in solid state structures, or used to create synthetic fuels such as ammonia. Hydrogen can be used in fuel cells to generate electricity and heat, combusted, or used as a chemical feedstock amongst other methods. A large component of hydrogen produced in the future is likely to continue to come from fossil fuel sources if combined with CCS, due to the predicted hydrogen production costs from the different methods. However, due to its ability to support the operation of renewable electricity sources whilst providing a zero carbon fuel, electrolytically-produced hydrogen can play a key role across a number of different sectors. Hydrogen produced electrolytically is free from hydrocarbon contaminants, reducing the amount of cleanup required. This can increase the cost competitiveness of electrolytically-produced hydrogen, especially in applications requiring high purity hydrogen such as fuel cells. Figure 2 shows a schematic demonstrating how hydrogen can provide a link between the electricity, transport and gas sectors.

Renewables integration

Increasing amounts of renewable electricity production will necessitate the use of energy storage and demand-side management to alleviate constraints on the electricity network as well as allowing system wide balancing over different time scales. Hydrogen is particularly suitable to longer term energy storage, such as seasonal storage, due to its low energy storage related costs and can complement shorter term storage such as batteries. Hydrogen produced electrolytically can be compressed and stored, either in gas cylinders, or potentially in geological structures such as salt caverns. The stored hydrogen can later be used to produce electricity through a fuel cell as round trip storage.

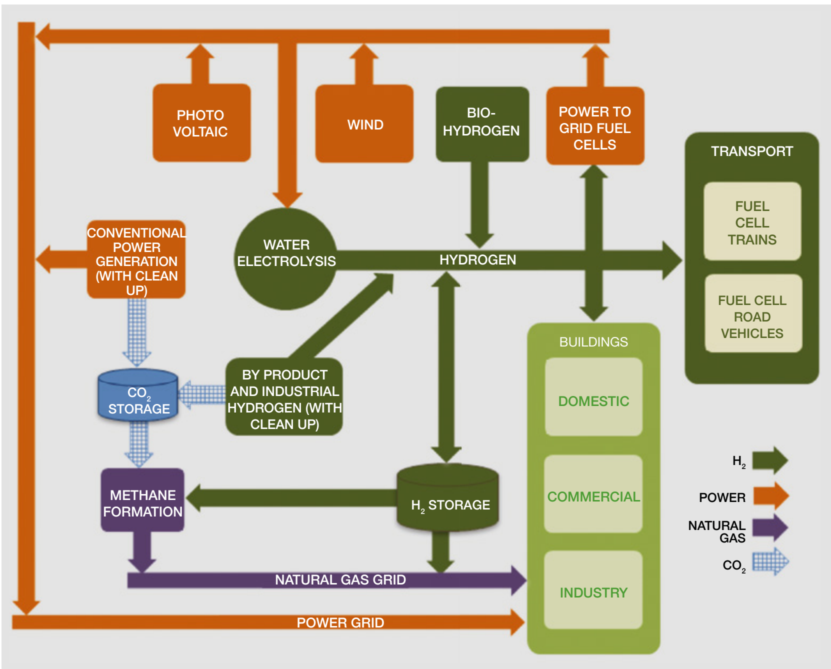

Figure 2: *Hydrogen systems integration with power, gas and transport networks.*

Power to gas

As well as round trip energy storage, hydrogen can provide a link between the electricity and heating sectors by injecting electrolytically-produced hydrogen into the gas network. Current regulations severely restrict the percentage of hydrogen in the network, but investigations have shown that up to 8% hydrogen by energy is technically feasible without causing problems to consumers[1]. If the hydrogen is produced from low carbon or renewable electricity, this has the ability to help decarbonise heating. Some schemes in the UK propose converting entire sections of the gas network to run on pure hydrogen. This hydrogen can then be used in converted gas boilers and other appliances, or be used in fuel cells to provide combined heat and power.

Vehicle fuelling (forecourt electrolysis)

Hydrogen fuel cell electric vehicles (HFCEVs) can play a key role in decarbonising transport emissions, particularly in heavier duty applications such as buses and goods vehicles in addition to large passenger cars and fleet vehicles. Hydrogen-related technologies can also contribute in decarbonising rail and shipping. The hydrogen can be produced electrolytically, either in large centralised facilities, or using forecourt electrolysers, providing a link between the electricity and transport sectors.

Industry

Industrial GHG emissions are difficult to reduce due to the need for high temperature heat in industrial processes, which is often provided by burning fossil fuels. As well as this, hydrogen used for chemical process reactions is currently mainly provided through steam methane reforming, with consequent GHG emissions. Production of hydrogen from steam methane reforming with CCS provides a route to partial decarbonisation of industry, which can be complemented and extended by using renewably-produced electrolytic hydrogen.

Figure 3: *HFCEV at the USW Baglan Hydrogen Centre.*

Case study – enabling hydrogen fuel cell electric vehicles

One of the issues with developing and introducing new technologies is the provision of infrastructure to enable early adopters of technology. A case in point is the use of hydrogen fuel cell electric vehicles (HFCEVs) which require development of a hydrogen fuelling infrastructure to precede the uptake of the vehicles.

Early adoption can be facilitated by commercial, public, and academic collaboration. An example is refuelling of HFCEVs operated by local organisations, such as the Wales and West Fire Service, which use the University of South Wales' hydrogen refuelling facility located at the Baglan Hydrogen Centre, which was supported through such a collaboration. Figure 3 shows a HFCEV at the University of South Wales Baglan Hydrogen Centre.

The hydrogen generated at the Baglan site is partially produced through 20 kW of roof-top solar PV connected to an onsite alkaline electrolyser, with the balance supplied from the electricity network. The electrolyser can produce 10 Nm^3/h of hydrogen, which is compressed and stored onsite. The hydrogen can then be used to produce power to the building or back to the electricity grid through an on-site fuel cell or be used to refuel vehicles. The vehicles can be refuelled in less than 5 minutes from the onsite storage, giving a potential maximum range of 594 km[3]. With the size of electrolyser currently installed at the Baglan Hydrogen Centre, it takes about 5 hours to replenish the storage from a single vehicle fill.

Summary

Electrolytically-produced hydrogen has the capability to provide a GHG free fuel which can be used across multiple sectors and applications. It is likely that this will play a key role alongside other low GHG technologies in providing a route to decarbonisation of our future energy systems.

Footnotes

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The unbearable lightness of hydrogen

Nuno Bimbo AMIChemE

Hydrogen has long been considered a transformative technology for the energy sector, as it fulfils the main requirements of a clean and sustainable energy vector. It is abundant in the Universe and on Earth, has the highest energy density on a mass basis of any chemical fuel, and can be easily converted between different forms of energy. For all of these reasons, hydrogen is considered one of the best options for decarbonising the transport sector, which is still almost completely reliant on fossil fuels.

A number of technical issues still preclude the widespread use of hydrogen as an energy vector, at the top of which is how to store hydrogen in an affordable, sustainable and safe manner. This difficulty comes from the physical properties of hydrogen – hydrogen is the first element in the periodic table and it is the lightest. Free hydrogen exists as a diatomic molecule (H_2) and has a density at standard temperature and pressure (0 °C and 0.1 MPa) of around 0.09 kg/m^3, [1] which is significantly less than air (1.3 kg/m^3). Its normal boiling and melting points are around -253 °C and -259 °C, respectively, and even as a liquid or a solid, it has extremely low densities. Liquid hydrogen at -253 °C and 0.1 MPa has a density of 71 kg/m^3 [2] and solid hydrogen at -259 °C and 0.1 MPa has a density of 88 kg/m^3.[3] Hydrogen has some peculiar properties, including the fact that it can be compressed as a liquid and as a solid. Figure 1 shows the density of hydrogen in the gaseous, liquid and solid state at increasing pressures.

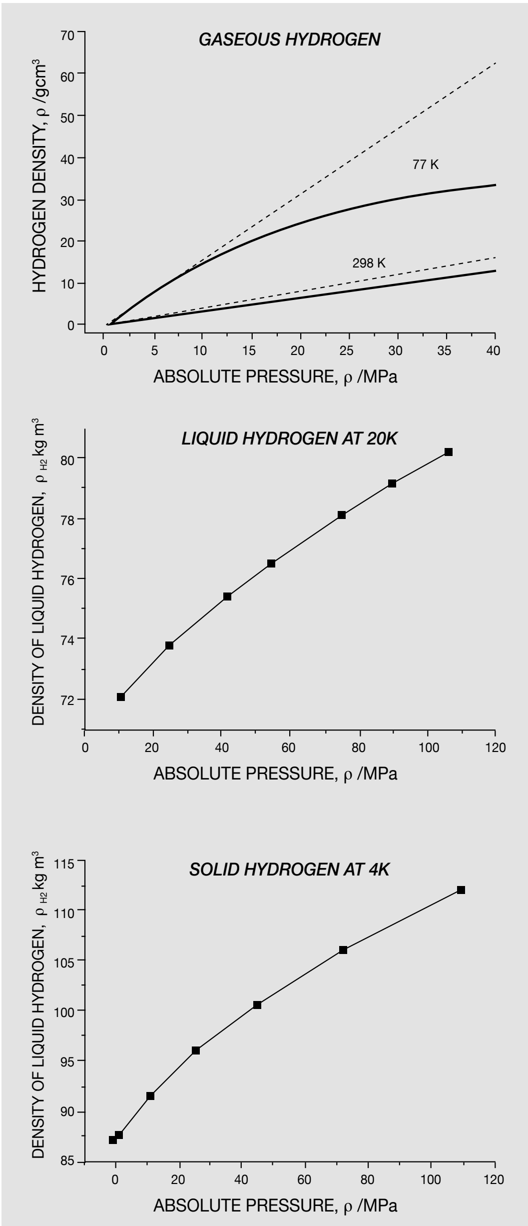

Figure 1: *Density of gaseous, liquid and solid hydrogen at -196.15 °C (77 K), 24.85 °C (298 K), 253.15 °C (20 K) and -269.15 °C (4 K), respectively. Dashed lines In gaseous hydrogen represent Ideal gas densities while solid lines are real gas densities*[1-3].

Hydrogen has a very large energy density on a mass basis, but the challenge is to improve on its volumetric energy density. To achieve this, a number of different technologies have been proposed, with the main goal being to design a hydrogen storage system that is affordable, sustainable, safe, and one in which hydrogen can be easily and quickly charged and discharged. Research in this area has been driven by targets created by the US Department of Energy for hydrogen storage systems in automotive applications[4]. These targets look at a number of practical requirements, including gravimetric and volumetric densities, delivery temperatures and pressures, number of cycles, efficiencies, cost, charging and discharging rates, safety, and others. To date, no material or system unequivocally addresses the majority of the different requirements.

Under pressure

The most conventional way of storing hydrogen and the current state-of-the-art in the chemical industry is to store hydrogen as a gas following compression. In vehicular storage systems, hydrogen is usually stored in compressed hydrogen cylinders at 35 or 70 MPa. For comparison, a typical tyre in a car has a pressure of 0.23 MPa! The hydrogen storage cylinders are classified in four different types: stainless steel or aluminium (type I), fibre-resin composites with thick metallic lining (type II), fibre-resin composites with fully wrapped metallic liners (type III) and polymeric liners fully wrapped in fibre resin composites (type IV), with volumes usually ranging from 0.050–0.200 m^3.[5] Type IV cylinders are the most common option, with a polymeric liner such as high-density polyethylene (HDPE) used as the gas permeation barrier. It is important to remember that hydrogen can easily permeate most materials, which is why properly lining the cylinders is so important. One of the main issues with compression of hydrogen is that it carries a large energy penalty – the energy used in compressing hydrogen to 35 MPa is 14.5 MJ per kg of hydrogen, and if compressed to 70 MPa, then it is 18 MJ per kg of hydrogen[6]. This would mean that, if stored at 70 MPa, about 15% of the energy contained in the hydrogen is spent compressing it! Still, compressed hydrogen is the technology of choice for the chemical industry and for most of the current commercial hydrogen fuel cell vehicles. Compressed hydrogen storage has good volumetric and gravimetric energy densities in comparison with other energy storage methods, as seen in Figure 2.

Cool down

Another conventional storage method to achieve higher volumetric densities is to liquefy hydrogen. The issues associated with liquefaction are that hydrogen's normal boiling point is –252.9 °C (20.2 K), which is a very difficult temperature to achieve and maintain. As a liquid, hydrogen is typically stored at 20.0 K and with pressures ranging from 0.1–1 MPa. In this state, hydrogen has a volumetric density of 70.3 kg/m^3,[6] which compares to volumetric densities of 23.2 kg/m^3 and 39.0 kg/m^3 for compression at room temperature at 35 and 70 MPa, respectively[1]. Despite the good hydrogen volumetric densities, liquid hydrogen has some issues, at the top of which is boil-off. It is very difficult to completely insulate the storage system, so some hydrogen will heat up and boil off, creating high pressures in the tank, which has to be depressurised by venting the hydrogen. This is an even bigger issue if the tank is left dormant for long periods of time. In addition to boil-off, there is also a large energy penalty with liquefaction of hydrogen, which can be as much as 36 to 47 MJ per kg of hydrogen, which is around 30 to 40% of its lower heating value, making liquefaction of hydrogen a very energy intensive method[6].

How about a mixture of the two?

Due to shortcomings in both liquid and compressed storage, other alternative physical storage methods are being investigated. One of these is cryogenic compression of hydrogen, which is a combination of compression and liquid storage, and tries to mitigate the issues that plague both methods by avoiding high pressures and very low temperatures. The main advantage of cryogenic compression is its flexibility, as it can operate at temperatures as low as 20 K (-253 °C) and at pressures

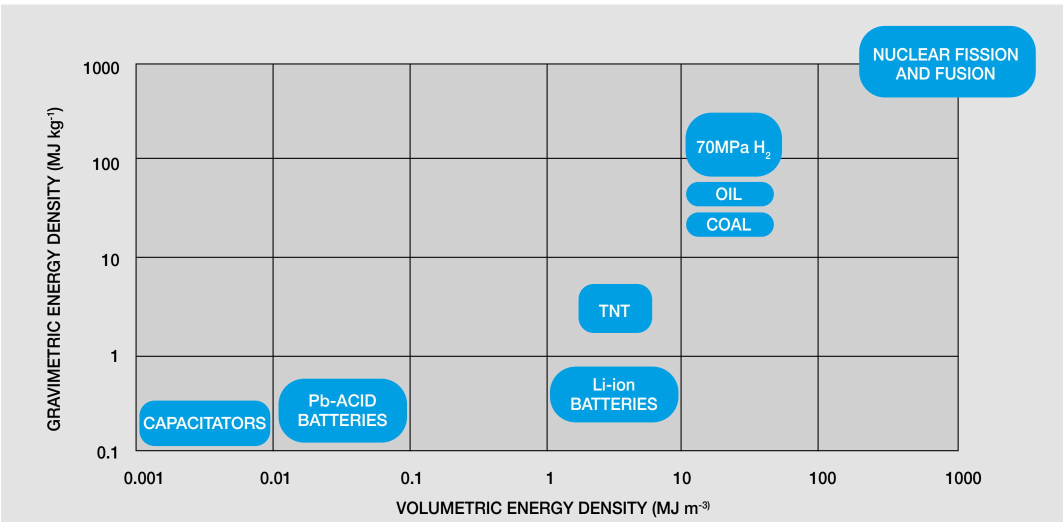

Figure 2: *Volumetric and gravimetric energy densities of different energy storage methods or sources. Adapted from Zuttel et al*[7].

up to 25 MPa, with typical operating conditions between 20 and 60 K (-253 °C and -213 °C, respectively). Having hydrogen both compressed and at cryogenic temperatures creates a bigger balance of-plant, but hydrogen gravimetric capacities for whole systems can be as high as 45.0 kg/m^3.[8] Much of the work done on cryogenic compression has originated from research in the US Department of Energy laboratories, and some car manufacturers such as BMW are looking into the technology.[9]

What about reacting hydrogen with something?

The issues surrounding compressed and liquid storage, especially the ones associated with costs and safety, have led to the development of other storage alternatives. One area that has seen considerable research is chemical storage of hydrogen. In chemical storage, the hydrogen molecule dissociates and reacts with a material, forming a hydride. Most of the issues associated with storing hydrogen as a hydride are related to dehydrogenation, which is difficult as it requires high temperatures, and reversibility, which can be problematic if the storage material is used over many cycles[6-10]. Hydride materials that have been suggested as hydrogen storage materials include palladium hydride (PdH), magnesium hydride (MgH_2) and magnesium borohydride $Mg(BH_4)_2$. Hydrogen can also be stored through other routes, including hydrogenation of organic molecules.

The ammonia economy

Another possibility is to take advantage of the current infrastructure available for liquid fuels and use ammonia as a hydrogen carrier. Ammonia has high volumetric and gravimetric hydrogen densities, can be stored as a liquid at moderate pressures and can be decomposed to release hydrogen in a catalytic reaction[11]. The main disadvantages of using ammonia as a hydrogen carrier are related to its toxicity and reversibility, as trace amounts of ammonia are found in the hydrogen after it decomposes[11]. The ammonia needs to be decomposed to release the hydrogen, which is usually done at high temperatures in the presence of a catalyst, with much recent research focussed on low temperature (<300 °C) catalytic decomposition of ammonia. In addition to its high densities, ammonia has the advantage of only releasing water and nitrogen when decomposed to release the hydrogen.

Storing hydrogen in nanomaterials

Hydrogen can also be stored through adsorption in a porous material. Adsorption will be very familiar to chemical engineers, as it is widely used in the chemical industry for gaseous separations in adsorption columns. Adsorption of hydrogen is considered an attractive option, as it can offer good densities at moderate pressures and temperatures[6]. In adsorption, the hydrogen molecule does not dissociate and does not react with the substrate material. Hence, hydrogen adsorption typically has fast kinetics and is completely reversible. The operating conditions are milder than other forms, as it is usually done at 77 K and in the 1 to 5 MPa range. Storage of hydrogen through adsorption is highly dependent on the type of material. Ideally, the material has a very high surface areas, as gravimetric hydrogen storage correlates with available surface area, and pores below 1 nm, as these have the highest energy of interaction with the gas[6]. In addition to this, it needs to be low density, low cost, and should possess good mechanical and thermal properties.

Many interesting developments in synthetic chemistry have occurred in the last five years, particularly in the synthesis of highly porous materials with tuneable properties. One excellent example are metal-organic frameworks (MOFs), crystalline materials made from metal centres and organic linkers. Examples of high surface-area metal organic frameworks that have been proposed as hydrogen storage materials include NU-100[16] and MOF-210[13], both of which have surface areas in excess of 6,000 m^2/g which is almost the area of the Wembley pitch in one gramme of material! Other recently discovered high-surface area materials include porous polymers and novel activated carbons, which can have surface areas in excess of 3,000 m^2/g[17-18]. The different hydrogen storage technologies are presented in Table 1, with gravimetric and volumetric densities, and operating conditions.

With a pinch of salt

In addition to applications in mobile vehicles, hydrogen has also been considered for grid-scale energy storage. In this context, as the storage is usually stationary, gravimetric and volumetric energy densities are less important, and hydrogen is stored underground in salt caverns or depleted oil and gas fields. Underground hydrogen storage is currently being used in the UK. Examples include the

STORAGE METHOD	LIQUID HYDROGEN	COMPRESSED HYDROGEN	CRYOGENIC COMPRESSION	ADSORPTION IN A POROUS MATERIAL	METAL HYDRIDE	COMPLEX HYDRIDES
Representative material	-	-	-	MOF-210	$LaNi_5H_6$	$Mg(BH_4)_2$
Gravimetric % of H_2	100.0	100.0	100.0	9.0	1.5	14.9
Operating temperature (in °C)	-253	25	-253 to -196	-196	0 – 30	25 – 320
Pressure (in MPa)	0.1 – 1	35 or 70	10 - 70	1 – 5	0.1	0.1
Volumetric density (in kg of H_2 per m^{-3})	70.3	23.2 (35 MPa) 39.0 (70 MPa)	45.0	44.0	108.0	146.0

Table 1: *Different hydrogen storage technologies, with operating conditions and gravimetric and volumetric hydrogen densities.*[1,12-15].

Teesside region, where three salt caverns are licensed for operation, each with 70,000 m³. The storage occurs at 4.5 MPa at a depth of 400 m, and the caverns are operated by SABIC, which used it to distribute hydrogen to chemical plants in the area[19].

The storage conundrum

In the transport sector, rather than a competing technology, hydrogen has been considered an excellent complement to battery electric vehicles, since it can be used as a range extender, as batteries start to become uneconomic with large sizes[20]. A hybrid solution that integrates fuel cells with battery systems seems to be the safest bet at the moment for decarbonising the transport sector, except for very small cars in urban areas that have low-cost batteries[20]. In order for hydrogen to be viable as a fuel in mobile applications, appropriate storage systems need to be designed and developed, focussing on affordability, safety and sustainability. While recent studies have shown potential in some technologies, there is still no clear cut answer to the hydrogen storage problem, with industry opting at the moment to use compressed hydrogen cylinders in commercial vehicles, which have safety issues and incur in large energy penalties. There is plenty of room for improvements and innovations in this fascinating topic, and many aspects where chemical engineers can add value. The transport sector is one of the sectors most dependent on fossil fuels, so it is imperative that we find clean and sustainable solutions that can be implemented at a global scale in this sector. Despite all the technical issues still present with hydrogen, there are many advantages of using it as an energy vector, and it is very likely that hydrogen will be part of a global future energy mix.

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Hydrogen: informing a safe decision to achieve net zero

Stuart Hawksworth

It was approximately two years ago when I last wrote about hydrogen as part of our cleaner, greener, more sustainable and safe energy future[1]. Then the UK had a target of reducing greenhouse gas emissions by 80% by 2050, compared to 1990 levels, as set by the Climate Change Act 2008.

Since then, global warming has risen still further on the international agenda and in the public psyche, following weather extremes observed in Australia, the US and other countries and with consequences described in the Intergovernmental Panel for Climate Change (IPCC) Global Warming 1.5 degrees special report[2].

In June 2019 the UK then became the first major economy in the world to pass laws to end its contribution to global warming by 2050[3]. This was a significant milestone. We will have to utilise every trick in the book to help us achieve it – which means getting to grips with a huge range of new and novel energy innovation and technologies, safely and very quickly.

Specifically, for hydrogen, the UK's Climate Change Committee recommends the development of a hydrogen economy to service demands for some industrial processes, for energy-dense applications in long-distance HGVs and ships, and for electricity and heating in peak periods. By 2050, a new low carbon industry is needed with UK hydrogen production capacity comparable in size to the UK's current fleet of gas-fired power stations.

With the emphasis on targets and timescales, it is very important to maintain our focus on safety. In 2019 there were three significant incidents involving hydrogen (US, Norway and South Korea), relating to refuelling of a pressurised hydrogen tube trailer, a hydrogen vehicle refuelling station, and a renewable energy recovery demonstration plant employing electrolysis.

The last of these was the most significant and sadly resulted in two deaths and several injuries.

It is clearly essential at an early stage to understand the underpinning safety assumptions and risk profiles for new technology, retrofitted infrastructure and combined systems planned to deliver the low carbon economy. There is potential for risks, both new and old, to emerge as the energy systems become more complex, but there are also opportunities, with smart systems, to utilise operational data to optimise safety and to introduce safety in design concepts early. It is therefore vital to be proactive when considering safety during the innovation and demonstration phases.

Role of HSE

As an enabling regulator, HSE is playing an active role in the safe development of hydrogen as an energy vector across the energy system. In addition to its role as the regulator, it is also using its ability to provide scientific research and consultancy services to other government departments and industry to enable the safe deployment of a number of key hydrogen projects. Helping operators to understand the risks associated with hydrogen use by combining evidence-based theory with real-world experimentation provides a pathway to safe innovation and has resulted in HSE partnering with industry in high profile projects relating to the use of hydrogen as an alternative energy solution.

HSE first started working in hydrogen technology participating in various EU projects investigating fuel cell applications, especially the storage and associated infrastructure. These were not typical of the well-established industrial environments, where hydrogen had been used safely for over 100 years. The drivers for the work at the outset were, and still are, around understanding the unique properties of hydrogen, including its: low ignition energy; wide flammable range; high flame speed and increased tendency for deflagration events to transition to detonation; high diffusivity; and high buoyancy.

Specialising in the safety considerations, HSE's role was to undertake exploratory research on the behaviour of hydrogen on its 223 ha Science and Research Centre in Buxton, Derbyshire, often working in collaboration with partners in Europe, the US and the Far East. Through these activities a good knowledge base has been established within HSE which is now being developed, and applied to a wider range of sectors, such as heating and power.

A key principle of our current work is understanding how hydrogen differs from incumbent technologies and when those differences really matter. When behaviour differences are understood, engineering or procedural solutions can be applied to maintain safety. We are increasingly involved in advising on safety for a range of hydrogen technologies, including production at scale, and demonstration of potential applications in power, heat and transport. Areas where the HSE has been particularly involved are listed in Table 1.

These projects and demonstrations are providing critical evidence to inform strategic decisions which need to take place soon if we are to meet Net Zero by 2050.

https://www.hy4heat.info	Addressing the challenges associated with hydrogen and its use in buildings, and the need to develop domestic appliances to burn hydrogen rather than natural gas
https://hydeploy.co.uk	Demonstrating that blending up to 20 vol% hydrogen into natural gas is a safe and greener alternative to the gas currently used
https://sgn.co.uk/about-us/future-of-gas/hydrogen/hydrogen-100	H100 project: construction and demonstration of the UK's first network to carry 100% hydrogen
https://www.h21.green	H21 suite of projects: repurposing the UK gas grid (distribution and transmission) to operate with 100% hydrogen
HyNTS	Conversion of the NTS to carry hydrogen

Table 1: *Areas in which HSE has played a key role*

Hydrogen in transport

In the UK, the sale of new internal combustion engine vehicles will now end in 2035, if not before.

'Decarbonised transport' therefore needs to see a rapid shift. Vehicles using battery and hydrogen energy storage both currently exist and are operating in the UK. For hydrogen, the sparse refuelling infrastructure, as well as the limited supply of vehicles, has slowed takeup. Nevertheless, hydrogen-powered cars, vans and buses have been operating safely on the UK roads for a number of years. The main safety challenges involve the high pressure (up to 700 bar) on-board storage, and the infrastructure to support them.

For light duty vehicles this safety challenge has been overcome through the use of incredibly strong, highly engineered composite tanks. In Japan and California, thousands of vehicles have been operating safely for several years employing this technology, which is proving itself very effective. In addition, hydrogen buses have been operating safely in many cities around the world, including London (operating since 2011) and more recently Aberdeen.

The challenge moving forward is for the use of hydrogen vehicles to expand, which will bring its own challenges including:

- **The increased uptake (quantitative growth) of the types of vehicles currently on the road and the growing infrastructure needed to support them. This will lead to larger refuelling station inventories, with larger stations possibly reaching lower-tier COMAH.**
- **The need for hydrogen vehicles to be used in the full scope of built infrastructure, including tunnels, car parks and other enclosed structures. This is being addressed by the EC-funded collaborative HyTunnel-CS4 project to produce pre-normative data that will form the basis for the vehicle-infrastructure system to operate safely.**
- **The third (and in some ways most interesting) challenge, is the accelerating adoption of hydrogen as a means to fuel different transport modes, driven by the need for large and compact energy storage for trucks, trains, boats and ships etc. Although not on the roads today, these are seeing strong interest including trucks (Nikola & Hyundai), rail (with a number of UK projects), and maritime (passenger ferry projects in UK and other larger projects internationally such as the Kawasaki LH2 carrier).**

Whilst stored at similar high pressures as for passenger vehicles, the additional safety challenge of hydrogen storage on trucks and vans arise from the larger inventories required to enable greater ranges, or a switch to liquid hydrogen (LH2). LH_2 has been used in industry for many years (including most space programmes), but its use for more novel transport application is being addressed by the PRESLHY project[5]. In its cryogenic liquid state (LH_2) hydrogen provides largest densities and some intrinsic safety advantages. Therefore, LH2 is attractive for scaling up supply infrastructures, eg for fuel cell driven trains, ships or car or truck fleets.

Moving forward: hydrogen-powered cars, vans and buses have been operating safely on the UK roads for a number of years.

Testing: Still of controlled liquid hydrogen spill from a tanker, performed on HSE's site In Buxton. Images captured from drone video recordings.

Industry knows how to handle LH2 safely. However, the new applications imply new conditions and untrained users. PRESLHY, an EU co-funded research and innovation activity, investigates respective knowledge gaps and will close these gaps with a large experimental programme providing new validated models and engineering correlations for efficiently safe design and operation of innovative hydrogen solutions.

So, hydrogen offers many opportunities for transport, by overcoming the remaining infrastructure and safety challenges to enable uptake at scale. A route to decarbonisation can be realised, coupled with the benefits of improved air quality and public health.

Hydrogen clusters and industry

In many ways industry is the obvious place to start with hydrogen, as many of these environments are already used to it. Other applications foreseen are power generation using gas turbines (and fuel cells) powered by hydrogen[6]. To do this CCS will be essential, and include multiple industrial clusters, integrated with domestic and transport. Such opportunities with the hydrogen would bring together domestic, industrial and potentially transport use in hubs, with examples such as HyNet[7] and Tees Valley[8].

HyNet is based on the production of hydrogen from natural gas. It includes the development of a new hydrogen pipeline and the creation of the UK's first CCUS infrastructure. Accelerating the development and deployment of hydrogen technologies and CCUS through HyNet positions the UK strongly for skills export in a global low carbon economy. On a practical level, the concentration of industry, existing technical skill base and geology means the region offers an opportunity for a project of this kind.

The Tees Valley Hydrogen Innovation Project (TVHIP) aims to support SMEs in the Tees Valley to stimulate the development of a hydrogen low-carbon economy, providing knowledge transfer services to SMEs. The project supports industry in a number of ways; collaboration through hydrogen network for knowledge and technical exchange, access to hydrogen productions which will all support the development of new products, and processes utilising hydrogen.

In terms of safety, these clusters offer great opportunity to bring together industrial expertise and practices interfacing with more novel applications utilising much of the safety knowledge developed from the projects, and as such are a very sensible way to scale hydrogen technologies.

Summary

Clearly this is an important time for hydrogen, which will have a key role in achieving Net Zero by 2050 in the UK, and international decarbonising targets more widely. It is clear that achieving this will need real pace in the development and implementation of technologies. It is essential that safety is fully considered as part of this rapidly developing pathway, building into all projects from the outset. It is essential that underpinning evidence base is robust and scientifically-based to ensure that all decisions are informed, and then effectively incorporated into standards and best practice.

This approach enables safety to be built into designs, using the best engineering, but also taking opportunities to use smart systems, data to optimise systems, and safety management.

Another important part of this picture is the growing critical national capability that will deliver scaleup and roll out this change. There is real concern in the community internationally that failure to enable developers to have the right knowledge and availability of expertise is a great risk, and could lead to inevitable loss of life and confidence in hydrogen as a solution.

Footnotes

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Hydrogen: making the case through life cycle analysis

Mike Keast MIChemE

The UK's pledge to reach Net Zero Carbon before 2050 has been primarily planned around decarbonising the electricity supply, leading on to the electrification of heat and transport, eg through domestic heat pumps and electric cars, trucks and trains.

A big challenge for the latter part of this approach is the fact that the additional energy demands for heating and transport are together more than four times the current electricity supply.

To deliver such an increase of electricity, whilst bringing emission to Net Zero Carbon, will require bringing more renewable energy from increasingly remote sites; a proportionately large expansion in transmission lines; a massive roll-out of new electrical technology on streets and in homes; and large capacity energy storage to buffer between renewable supply and demand cycles.

The large investment needed will not only be in terms of money but also in the amount of the Government's carbon emissions budget and other mineral resources (some rare) that will be used up just to *build all* these new facilities. It is important that the ecological suitability of what we build is part of the decisions we make about our future energy systems.

It is in this light that many stakeholders, including the Institution of Chemical Engineers' Clean Energy Special Interest Group, have identified hydrogen's potential as an alternative energy vector that can be competitive and complementary to electricity. They are suggesting that utilising hydrogen as a fuel for heating, transport and industry and as a means of energy storage and long distance transmission may provide ways to ease the transition to Net Zero Carbon.

One particular feature of hydrogen that may make it attractive is its potential to reuse existing fossil fuel infrastructure that would otherwise be abandoned were we to go all electric. Repurposing rather than scrapping these long-established systems will help hydrogen options be less disruptive and resource hungry, and potentially more cost effective to install.

The optimum energy system arrangement could be one where hydrogen and electricity vectors compete and interchange via commercially-available electrolysers and fuel cells, each playing its most effective role.

Such a two-vector approach, able to adapt existing infrastructure and draw engineering resource from our existing fossil fuels industry, might enable a more resilient quicker transition to net-zero carbon than might be the case if we rely on electricity alone.

Handling hydrogen safely is nothing new to engineers in the chemical and oil refining industries. There is vast experience of transmitting gas safely by pipelines – both onshore and offshore – that reside with utilities and oil and gas industries. Indeed, new infrastructure projects to transport hydrogen to domestic and industrial users (and associated carbon capture and storage) could herald a new era and a boost in activity for workers currently employed in oil and gas, chemical and other industries, as fossil fuel-based systems are gradually phased out.

Government support and at-scale demonstration

In its 2018 report on hydrogen[1], the UK's Committee on Climate Change (CCC) identified that hydrogen can be a strong complement to electrification and wants to see whether its technical and economic worth can be proven by operation at scale.

Demonstration projects that reflect this aim – to justify a real foothold for hydrogen, support its links with CCS and test its safe use in existing infrastructure – are now under way[2] in several potential hydrogen cluster regions as a result of support by Government grants[3].

How do we decide on hydrogen?

Given the country-wide nature of the task and the need to schedule the planning permissions, wayleaves and works whilst maintaining supply, the opportunity window to extend or convert the energy network to deliver the UK's target of net zero carbon emissions by 2050 is, in fact, relatively small.

If hydrogen is to play a part then we need to know as quickly as possible that it can be delivered safely and in which functional roles and circumstances it might perform better – technically, ecologically and economically compared with electricity. A possible set of criteria for assessing this is shown in Box 1.

Box 1: Techno-economic and life cycle criteria to compare hydrogen systems with their electrical counterparts

1. Safety.
2. Technical readiness (and development activities still required).
3. Technical life of components within the system.
4. Commercial availability and speed of deployment.
5. Whole-of-life environmental impact.
6. Capital and operating costs – cashflow needs.
7. Resource availability – the technology must be deliverable within the limits of the main materials (including critical materials) that it would need.
8. Location of the skillsets, training, and manufacturing facilities that could be capable of delivering the solutions plus business opportunities and export potential created.
9. Impact on natural capital and biodiversity.
10. Planning permission and regulation approaches.

There is now considerable activity from which evidence for such assessment can be drawn:

- **UK hydrogen demonstration projects – which are all striving to get to the point where investors engage (FID).**
- **Utility companies and safety consultants – who are studying transport of hydrogen by reusing existing networks.**
- **Trade and academic institutions – which are setting out their position regarding hydrogen.**

Now would be an excellent time for these stakeholders to agree to collaborate and use their outputs to form a consensus view on how hydrogen might best be used, alongside electricity, in future energy systems.

Whilst there is not yet all of the technical, cost and operation data to form the full assessment, there should now be sufficient mass and energy balance, and equipment supplier information from the front end engineering of hydrogen demonstration projects for life cycle or ecological comparison of hydrogen versus electricity-based systems to commence.

The idea would be not to compare project vs project or region vs region but, with the agreement of the companies involved, to draw data that would enable *generic* study of electricity vs hydrogen on *individual* functions within an energy system.

A generic consensus view on the *ecological* case might provide the first 'stake-in-the-ground' signal to stimulate manufacturers and investors to engage with hydrogen's role in future energy systems.

Energy system functions where hydrogen can contribute

Suggested generic functions that could be assessed include:

1. The different ways that hydrogen can be generated in bulk for introduction into such an energy system, comparing: the various 'grey' hydrogen processes making H_2 from natural gas but without capturing carbon emissions; 'blue' hydrogen – using these processes but with carbon dioxide captured then stored or reused; and 'green' hydrogen – generated by renewable energy sources without producing carbon dioxide in the first place, eg using renewable electricity to electrolyse water. The outputs from these assessments would play a part in the assessment of any of the cases below where hydrogen is raised as part of the function.
2. Transmitting energy across land by invisible buried pipelines rather than overhead transmission lines – potential for faster planning approval and lower capital cost.
3. Bringing 'green hydrogen' onshore by electrolysing water offshore then in a hydrogen pipeline (possibly repurposed redundant existing line) as a possible alternative to undersea HVDC cables.
4. Considering the chemical industry's ~40 years' experience of balancing hydrogen production and

Box 2: What is life cycle analysis?

Life cycle analysis (LCA) is a technique that assesses the environmental impacts associated with all the stages of the life of a product from mining of the raw material (eg iron ore), extraction through industrial processing (eg crushing, reducing, alloying, forming), manufacture, distribution, use in service, repair and maintenance, and, at the end of life, disposal or recycling. This technique, first applied in the 1960s, has become increasingly robust through ISO 14040/44 standards and the internationally-validated impact assessment data and methods that have emerged from ever improving science of emission pathways, toxicology and the effects of pollution on receptors.

LCA is increasingly used to determine government policies and legislation and is also in widespread use by companies. Firms are applying LCA to critique and compare the impact of both products and overall organisation, versus that of their competitors, and to identify 'hot spots' in their operations where their ecological credentials can be improved.

The EU is very much taking a lead on LCA. It published the International Reference Life Cycle Data System (ILCD) Handbook in 2010 and recommends common methods for Product and Organisation Environmental Footprints (PEF & OEF) with the aim to build a level playing field and single market for green products.

Using the EU's internationally-recognised guidance on data and methods allows the user to determine the most credible and widely-accepted view of the relative ecological impacts of using hydrogen versus other technologies over the 30/80-year 'system lifetime' that is described above.

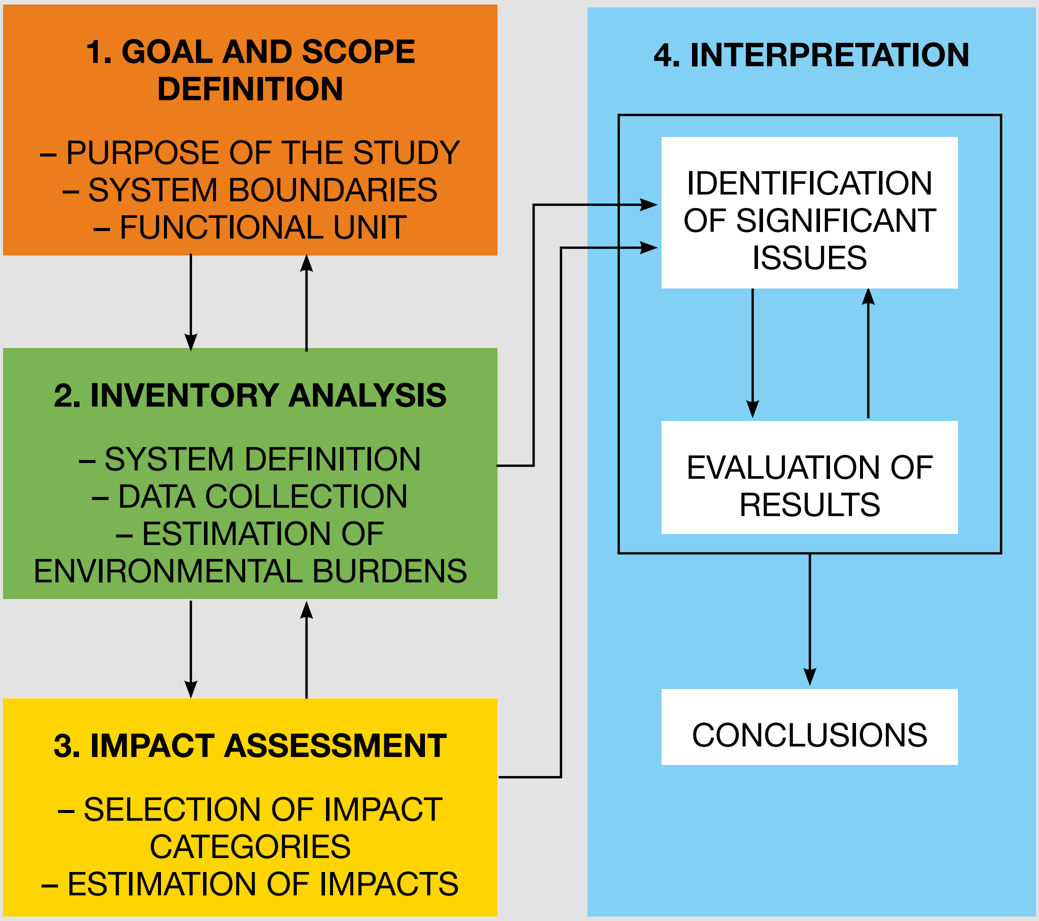

Figure 1: *Life cycle assessment stages, as defined by ISO 14040/14044*

use via storage in salt cavities, combined with fuel cells to provide both frequency response and short-term operating reserve (STOR), and maximising efficient delivery of renewable energy against other techniques proposed to buffer the national grid.

5. Raising hydrogen then blending it (~20%) into the existing natural gas network with the aim of achieving a small (~3%) but rapid reduction in emissions from heating systems at low capital cost and with minimum disruption to existing assets.
6. Using H_2 as a long-distance transport fuel – particularly for trains and trucks and in low population areas – an aspect of transport that can be a challenge to electrified vehicles.
7. Using hydrogen as a more ecologically sound alternative energy source for energy intensive industrial processes – eg through direct reduction of iron ore.

Proposed goal and methodology

As our goal is to establish the most viable, lowest carbon route to a net zero carbon energy system which, like its current counterpart has, will need to provide a stable long-term backbone service to the country's economy in 2050 and beyond, our choice needs to be focussed on long-term economic and ecological impact rather than short-term payback.

Our assessment needs to be based on at least the 30 years from 2020–2050, if not longer – perhaps 2020–2100, an 80-year time horizon.

With such a long time horizon, components involved will need to be replaced – some several times, and these studies will need to account for all cradle-to-grave ecological impacts, costs and resources, ie taking account of manufacture, installation, operation and maintenance to decommissioning and disposal for each time a component is replaced.

To be able to source the very best data for the ecological impacts of this, the ever-improving technique of life cycle analysis (LCA) may be applied, see Box 2.

Could we adapt existing fossil fuel pipelines and chemical industry systems?

As mentioned earlier in this article, substantial savings in cost, delivery time and embedded carbon emissions could be made if it were possible to migrate some existing systems over to renewable use rather than scrapping and writing-off the value of existing assets to build new.

Studies already looking at injecting H_2 to existing pipe networks, including HyDeploy and HyNet in the UK, start to bring into focus questions as to whether it would be possible to repurpose other existing systems to hydrogen:

- **If hydrogen were to be generated at offshore wind, wave or tidal farms, could use of redundant undersea oil and gas lines be a competitive alternative to laying new electric cables?**
- **Could adapting pipeline systems, routes and depots that currently deliver energy as fossil fuels over to hydrogen be the fastest or least intrusive way to deliver low carbon energy? As the geographical location of our energy needs will probably remain similar, hydrogen pipelines may be able to use existing easements and adopt the same routes that currently deliver energy as fossil fuels to countrywide depots, even if the material or burial depth of the existing pipe is found not suitable for the new service. The depots might then be repurposed with fuel cells to convert the hydrogen to the electricity that their local populated areas need.**
- **Could energy storage could be introduced to the energy grid through salt cavities being converted to store hydrogen instead of natural gas?**
- **If repurposing existing pipelines and salt cavities are found to be feasible, the cost and ecological impact of such refurbishment can be fed into the assessments of the energy systems functions 3, 4 and 5 listed earlier.**

By setting out a programme of pipeline assessment and repurposing or reusing previous fossil fuel routes or depots it might then be possible to undertake stepwise, system-by-system, and region-by-region switchovers from fossil fuel to low carbon energy source via hydrogen networks that complement and back up the electricity grid.

A vision for the future

Presently the world is locked into fossil fuels for its primary energy needs. The penalty for this, as has been said in countless contexts, has been rising levels of atmospheric CO_2 and associated weather and other degenerative changes. In order to wean the world off fossil and towards hydrogen as a better energy carrier, a cross-linked partnership of hydrogen and electricity is needed for the optimum pathway towards achieving both the security-affordability-sustainability 'energy trilemma' and net zero carbon emissions.

Developing such knowledge and expertise has the potential to cultivate a new UK and export workstream for engineers, for instance, in the oil and gas industry, to migrate to 'blue' or 'green' hydrogen and create an exemplar of how engineers of all disciplines can work in partnership with their industry counterparts and life cycle analysis experts to point the way to achieving and sustaining net-zero carbon emissions in the UK.

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Uses of hydrogen, part 1: industry

Andy Brown AFIChemE

There is significant, and understandable, focus today on the potential use of hydrogen as a substitute for natural gas for heating and electricity generation. Its principal advantages are seen as its high calorific value and the 'carbon-free' nature of its combustion products (simplistically, water). To access these two assets, significant efforts are being made to produce hydrogen cost effectively in bulk, and to manage, or engineer a way out of, some of the downsides of simply burning it. These would include:

- high flame temperature (leading to increased NOx production);
- high flame speed (increasing the potential for unstable flames);
- difficulties in compressing it (centrifugal compressors do not work well because of its low molecular mass and the ease with which it leaks back through the stages);
- storage at large scale (its low calorific value compared to natural gas means more has to be stored for the same energy content); and
- its low ignition energy (increased tendency to ignite in an unplanned manner).

And yet hydrogen has been produced since 1650, when Théodore de Mayerne first poured dilute sulfuric acid on iron to produce a gas of 'inflammable air'. It was not until 1783 when Jaques Charles made a hydrogen balloon large enough to carry him and a colleague over a distance of 36 km at a height of up to 550 m that it was appreciated that hydrogen had other uses. However, three subsequent discoveries really opened up the possibilities to realise its chemical potential. These were hydrogenation (1897), the Haber process to make ammonia (1910), and hydrocracking (1920).

Today, hydrogen is recognised as a premium product, and is produced with purities in the order of 99.999%. It has a role, often far beyond the obvious; and this short article describes some of them.

Oil refineries

Hydrogen is consumed in refineries in a variety of hydro-desulfurisation (HDS) and hydrocracking operations. HDS is a catalytic chemical process widely used to remove sulfur from natural gas and from refined petroleum products, such as gasoline or petrol, jet fuel, kerosene, diesel fuel, and fuel oils. Hydrocracking is a process which takes heavier refinery products and cracks the large molecules into smaller ones (distillate such as diesel or petrol) in the presence of hydrogen and a catalyst.

UK refineries together produce 156,563 Nm^3/h of hydrogen[1], which equates to over 100,000 t/y. This is likely to increase as recent legislation to ban the use of high-sulfur residual oil in ships ('Bunker C')[2] affects the market into which these heavy residues have traditionally been sold, and as the balance between diesel and petrol for transport use readjusts.

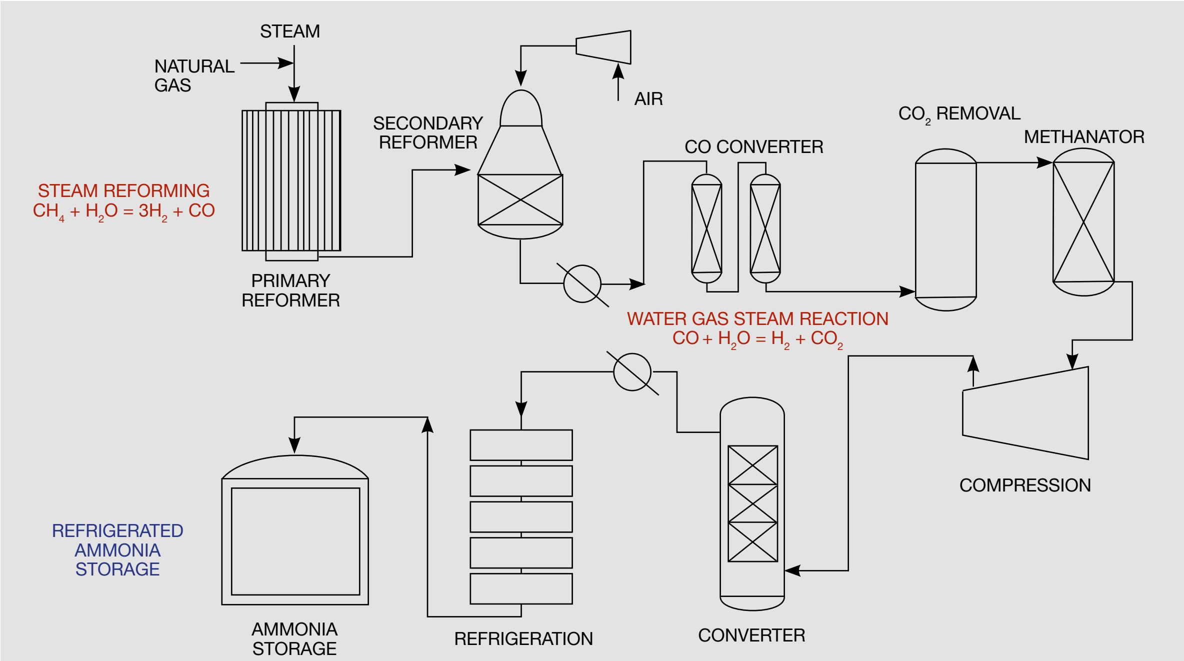

Figure 1: *Ammonia production overview*

Ammonia production

The Haber-Bosch process is the main industrial procedure for the production of ammonia today, and involves the direct combination of hydrogen and nitrogen under pressure and temperature in the presence of a metal catalyst. Ammonia (NH_3) is used to produce ammonium nitrate, a fertiliser, and is part of many household cleaning products. Next to oil refineries, ammonia is currently the largest application of hydrogen.

The process, in simple terms, requires nitrogen and hydrogen, mixed in a 1:3 ratio, to be placed under pressure and temperature in a vessel containing a catalyst. The most popular catalysts are based on iron promoted with K_2O, CaO, SiO_2, and Al_2O_3. The reactions typically take place at 15–25 MPa (150–250 bar) and between 400–500 °C. The mixed gases are usually passed over four catalyst beds, with cooling between each pass so as to maintain a reasonable equilibrium constant for the reactions. On each pass only about 15% of the gas is converted to ammonia: the liquid ammonia is stripped out and the unreacted gases recycled via a compressor. In modern plants, overall conversion rates in excess of 97% can be achieved.

Hydrogen for ammonia plants is normally produced using steam methane reforming (SMR) technology (Figure 1), and the projects get bigger and bigger as advantage of scale is taken. The largest single-train ammonia plant in the world is thought to be that located at Al-Jubail, Saudi Arabia. It produces 1,300 t/d and is owned by the Al-Jubail Fertilizer Company.

Metallic ore reduction

Hydrogen is used commercially to extract tungsten from its ore (wolframite, scheelite, and ferberite). The same concept can be used to produce copper from tenorite and paramelaconite (copper oxide, CuO).

Direct reduction of iron (DRI) using hydrogen is an idea that has yet to reach large-scale application, the advantage being that the blast furnace gas (BFG) is comprised mostly of water vapour and nitrogen with only a small amount of CO_2. The Luleå steel plant in Sweden, which is operated by SSAB, intends to build a DRI pilot plant using a process called Hybrit. If the pilot is successful, it is hoped that work to scale up to a demonstration capacity of 500,000 t/y would begin in 2025 with completion planned for 2035[3].

Hydrogen can theoretically be used as a reducing agent to produce silver, gold and platinum, but is not employed commercially.

Hydrochloric acid production

The large-scale production of hydrochloric acid (HCl) is almost always integrated with the industrial scale production of other chemicals as a pseudo byproduct. However, pure chlorine gas can be directly combined with hydrogen to produce hydrogen chloride directly in the presence of UV light. This is a highly exothermic reaction and rarely used commercially to produce HCl.

Hydrogenating agent

Hydrogen is used to turn unsaturated fats to saturated oils and fats. Food industries, for instance, use hydrogen to make hydrogenated vegetable oils such as margarine and butter.

Hydrogenation of saturated oils and fats is a batch process which takes place in a heated tank (see Figure 2). The oil feed (eg sunflower seed or olive oil) is pumped into a heated pressure vessel and a vacuum is applied to inhibit oxidation as the heating is applied. The temperature is raised to 140–250 °C and the mixture is stirred to ensure an even temperature. Nickel catalyst solids, mixed with a small amount of oil, are then pumped in, followed by hydrogen gas, which brings the pressure to 2.7–4 barg.

The hydrogenation reaction is exothermic, so the external heating is removed and cooling applied, vigorous stirring ensuring the temperature remains in the70–80 °C range. After 40–60 minutes the hydrogenated oil mixture is pumped out as a slurry and the catalyst solids removed in filters. Cooling to room temperature allows the hydrogenated oil to solidify.

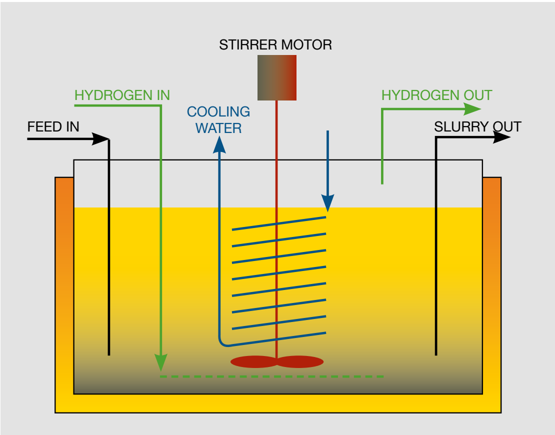

Figure 2: Hydrogenation vat

Atomic hydrogen welding

Atomic hydrogen welding (AHW) is an arc welding process that uses an arc between two metal tungsten electrodes in a shielding atmosphere of hydrogen, and can be used to weld refractory metals and tungsten.

Hydrogen as a coolant

Many modern large electrical generators use hydrogen gas as a rotor coolant at a pressure of around 4 bar. The advantages are:

- low density (leading to lower windage loss (about 10%) than for air);
- high thermal conductivity (reduced cooler sizes);
- high specific heat capacity; and
- it's cleaner than air, so has a lower potential to reduce the electrical resistance of bushings.

As a searching gas

Hydrogen is used in many manufacturing plants to check for leaks, since its environmental impact is less than that of the $CClF_3$-based gases that were used in the past. Hydrogen can be used on its own or with other elements.

Methanol production

Methanol can be produced from synthesis gas (carbon monoxide and hydrogen) in a fixed bed reactor using a catalyst of alumina pellets coated with copper and zinc oxides. Methanol can also be made by the direct combination of hydrogen and carbon dioxide: this reaction has been the subject of much attention over recent years because it offers the possibility of turning atmospheric CO_2 into a fossil-fuel substitute. The challenge is to make this thermodynamically efficient (ie to end up with more useful energy in the methanol than the total process energy that it takes to produce it). The majority of the work has been focussed on finding a good catalyst so that methanol can be produced in high selectivity at an efficient rate. Researchers in the US[4] have discovered that a combination of palladium and copper yields the most efficient conversion using nanoparticles of the catalyst dispersed on a porous support material, used to increase the surface area of the catalyst. With a catalyst pellet the size of a walnut, the internal surface area is similar to that of a football field.

In this process, hydrogen and carbon dioxide are pumped into the sealed chamber of a reactor vessel packed with the catalyst, and the contents heated to 180–250 °C. The maximum CO_2-to-methanol conversion is about 24%. The unconverted carbon dioxide and hydrogen is recycled and returned to the vessel. The overall thermodynamic efficiency of the process is not stated.

Manufacture of hydrogen peroxide (H_2O_2)

Hydrogen peroxide is a routine sterilising agent used in clinics and hospitals. It is a strong oxidising agent and is particularly effective for the cleaning of wounds, cuts and other damaged tissue portions. It is also used for bleaching hair, whitening teeth and removing stains from clothing. In research, H_2O_2 is also used for testing anti-oxidant potential of enzymes like catalase.

Hydrogen peroxide is typically made in a multi-step, energy-intensive process that requires it to be produced in large quantities and shipped and stored in a highly concentrated form. The manufacturing process involves the catalysis of the reaction of H_2 with atmospheric O_2 using anthraquinone (Q) as a hydrogen carrier. The first step is hydrogenation, where palladium catalyses the reaction between hydrogen and anthraquinone to create anthrahydroquinone (H_2Q). In the second step the palladium catalyst is filtered out of the solution. Next, the solution is oxidised by blowing air through the solution, forming the H_2O_2, and releasing the anthraquinone. Finally, the hydrogen peroxide is removed in a liquid-liquid extraction column and concentrated by vacuum distillation.

More recently, researchers from the UK and the US have developed a method of producing H_2O_2 on demand through a simple, one-step process, allowing dilute H_2O_2 to be made directly from hydrogen and oxygen in small quantities on site. This could make it more accessible to underdeveloped regions of the world, where it could be used to purify water[5]. Bimetallic compounds consisting of palladium and any of six other elements can effectively catalyse the hydrogenation of oxygen to form hydrogen peroxide.

As a reducing agent

Hydrogen is the key element involved in redox reactions. It is used in the manufacture of plate glass, for instance, to prevent the formation of stannous oxide (SnO) in the float bath.

In chemical analysis

Hydrogen is used in various methods of chemical analysis. These methods include atomic absorption spectroscopy. Here the hydrogen is used as fuel to generate heat, at the same time producing the neutral atoms.

Gas chromatography

Hydrogen is one of the gases which can be used as carrier phase in gas chromatography, used to separate volatile substances

Weather balloons

Because hydrogen is light compared to other gases, it is still used by meteorologists for high-altitude weather balloons.

As an energy carrier

Hydrogen gas is not an energy source, rather it stores and delivers energy in a usable form. Outside of combustion for heat and CHP it has an application as fuel for hydrogen fuel cells (which will be described in *Uses of Hydrogen: Part 2*) which may be used, for example, in trains, cars, buses, submarines, bikes and laptops.

Hydrogen use elsewhere

Human progress can be mapped in terms of revolutions brought about by more efficient energy use – from the early discovery of fire, to higher intensities made possible by coal (eg steam). More recent step changes have been made possible by nuclear power and natural gas. It is very possible that the next revolution will be the hydrogen era, opening the possibility of sustainable energy into the future, with applications in the home and transport (as described in the HyDeploy programme, see page 50).

Footnotes

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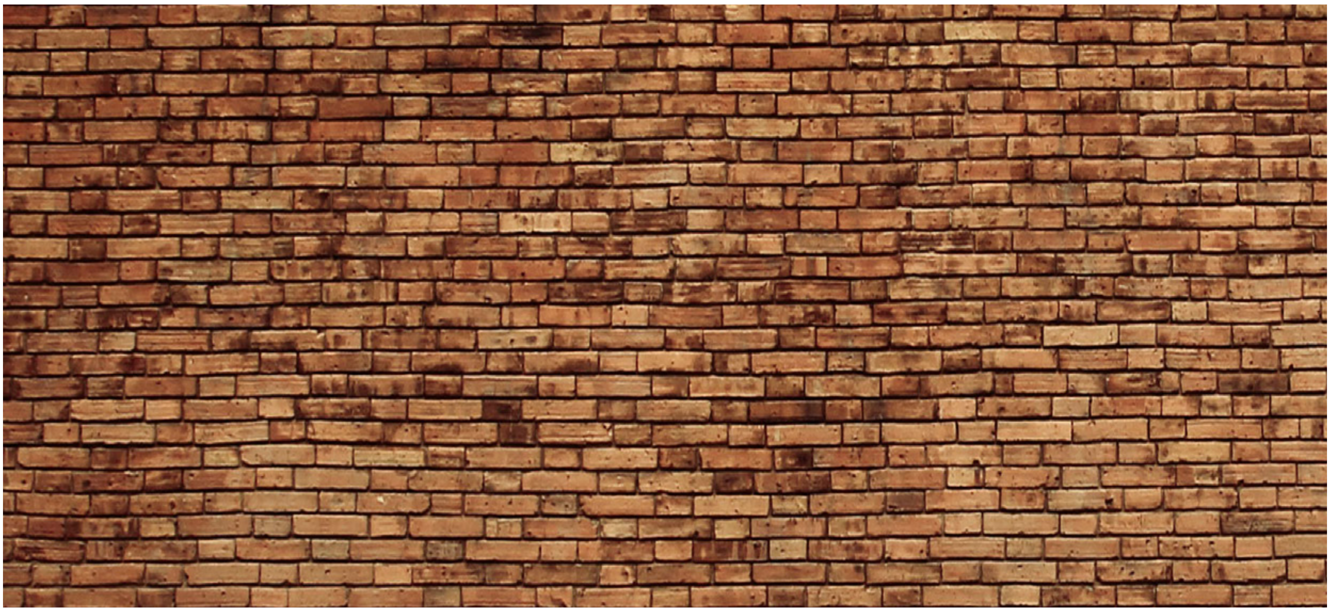


Hydrogen deployment barriers

Tommy Isaac MIChemE

Introduction

As history has made clear, electric vehicles have leap-frogged over fuel cells to become the flagship low-carbon alternative to fossil-fuelled personal transport. The primary reason for this has been the lower barriers to deployment, principally the inherent interdependency of production and use of hydrogen within hydrogen fuel cells, whilst electric vehicles could benefit from the already-established electricity generation market. The revival of the hydrogen economy has been due to the evolution of thought surrounding sustainability and a realisation that a low-carbon economy requires a more diverse field of energy carriers than simply low-carbon electricity. Hydrogen provides that much-needed diversity due to its physical properties, breadth of application and complementary nature to low-carbon electricity.

Other articles in this hydrogen series have focussed on the potential benefits a hydrogen economy could accrue to society. This article will focus on the barriers and challenges required to be overcome to enable those benefits to materialise. By reductively identifying, quantifying and overcoming challenges and barriers to deployment, the hydrogen economy will have the greatest chance of transitioning from rhetoric to reality. This article will attempt to summarise the current technical, commercial, regulatory and societal barriers to hydrogen deployment and highlight where barriers have been overcome to enable development.

Technical: production and distribution

Technical barriers to deployment largely concern unanswered questions rather than identified fundamental barriers. The necessary production technologies for both distributed power-to-gas production and bulk supply through methane conditioning and CCUS are all technically proven and available technologies. Therefore, there is no fundamental technical barrier related to the production of hydrogen.

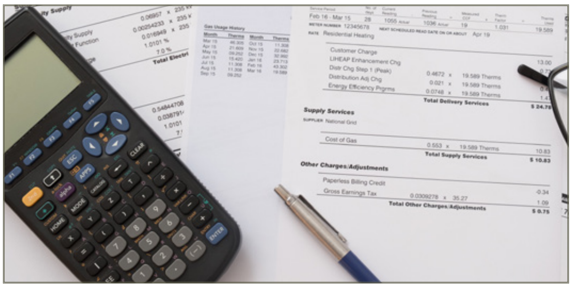
The distribution of hydrogen is currently being investigated by two active projects, H21[1] and H100. The H21 distribution philosophy is to understand if the current gas network is capable of safely distributing pure hydrogen, and the H100 distribution philosophy is to understand what the requirements are of new-build hydrogen distribution assets. Therefore, between these two programmes the lowest cost pathway for safe distribution will be identified and understood.

Technical: users

The acceptability of hydrogen to the current users of natural gas is where the most technical work is required. This is due to the magnitude and diversity of users connected to the gas network, from domestic appliances to commercial and industrial users, combined heat and power to gas turbines, as well as compressed natural gas (CNG) filling stations. There are many programmes underway to understand technical limits of current appliances for initial introduction of hydrogen, as well as the design for pure hydrogen use.

Programmes such as HyDeploy[2] are providing the evidence to understand any technical limitations of current users to accept a hydrogen blend of 20 mol% and the Department for Business, Energy and Industrial Strategy's

(BEIS) Hy4Heat programme is funding the development of hydrogen-ready domestic boilers for future use. Within a domestic setting, active programmes are identifying and addressing challenges to hydrogen. Within an industrial setting, work such as the BEIS Fuel Switching[3] programme is identifying potential challenges and route maps to overcome technical issues for industrial users. Within the power generation market, turbine manufacturers such as GE[4] and Siemens[5] are already developing gas turbine equipment that can operate on 100% hydrogen. The users where the most questions remain are with commercial applications, including CNG filling stations. Further work is needed to identify and address any potential technical challenges associated with this market in the UK. Overall though, the technical barriers to hydrogen deployment are being demonstrated to be limited and manageable – further work is required but the collective results of the current technical programmes is very promising!



Commercial

The commercial challenges of hydrogen deployment primarily relate to ensuring the billing process for gas supplies is robust to the introduction of hydrogen. As hydrogen has a lower calorific value (CV) than natural gas, gas meters will register a higher volume of use for the same energy supplied. Ensuring consumers are not disadvantaged by a potentially variable CV, along with ensuring robust energy settlement processes for gas shippers, is required to allow hydrogen to be rolled out commercially.

The Cadent-led Future Billing Methodology (FBM)[6] project has been developed to investigate technical solutions to allow a fit-for-purpose billing regime to be developed in time for gases such as unpropanated biomethane and hydrogen to be introduced into the network without disadvantaging consumers. Although FBM is seeking to understand the technical pathways which would enable lower-CV gases to be embodied within consumers' bills, to translate these findings to governance it is likely that a modification to the uniform network codes (UNC) will be required. The UNC defines the commercial relationships between gas shippers, transporters and suppliers and therefore underpins a consistent and fair billing process for all consumers.

Regulatory: policy requirements

The largest barriers to hydrogen deployment are regulatory, as it is the regulatory framework that defines commercial deployment models. Without clear regulatory frameworks to allow commercial projects to understand their cost and revenue basis, commercial projects will not be able to reach financial investment decision (FID). CCUS and heat policy are the two largest barriers to bulk hydrogen deployment.

Following publication of the UK Carbon Capture Usage and Storage Deployment Action Plan in November 2018 the CCUS Advisory Group was established by BEIS to develop policy options for consideration. The group has recently published three policy framework options for consultation, which will be reviewed by BEIS. The expectation is that BEIS will publish its preferred policy support framework by the end of the year, which will then be developed into regulation. A clear CCUS policy is required to allow commercial projects to reach FID.

Heat policy is less defined; without clear heat policy the support mechanism for hydrogen to act as a low-carbon heat vector will remain unknown, which in turn will stifle progress of commercial deployment. The current low-carbon heat policy of the UK Government, the Renewable Heat Incentive (RHI)[7], is drawing to a close in March 2021. Therefore, to minimise any development hiatus resulting from regulatory uncertainty, appropriate heat policy to enable support for low-carbon gas deployment will need to be developed with haste.

Regulatory: existing regulation

The 1996 Gas Safety (Management) Regulations (GS(M)R)[8], which define the specifications of gas that can be transported within the gas network, limits hydrogen to 0.1 mol%. GS(M)R falls under the 1974 Health and Safety at Work Act[9] and is primarily designed to ensure gas networks can only transport gas that domestic appliances are certified to safely operate on. The reason for the very low hydrogen limit is principally due to historical regulatory expedience and simplification, given that North Sea gas does not naturally contain hydrogen.

Although technical programmes are underway to demonstrate that greater levels of hydrogen can be safely transported, there will need to be a regulatory process to embody this evidence within the regulatory framework to allow gas distribution networks to transport hydrogen at greater concentrations than 0.1 mol%. The problem could be solved by applying a class-exemption precedent process, which is the current framework that allows biomethane with higher levels of oxygen to be injected into the gas grid. However, a more enduring solution for hydrogen networks connected to domestic consumers would be an official update to GS(M)R. The Institute of Gas Engineers and Managers (IGEM) is actively seeking to move GS(M)R into a technical standard governed by IGEM, which would allow such modification to be rigorously undertaken without being reliant upon parliamentary processes.

An enabling piece of legislation for the development to hydrogen infrastructure is the 1986 Gas Act[10], which establishes the legislative framework of the gas industry and underpins a gas network operator's licence to operate. The Gas Act defines gas as "wholly or mainly, methane, ethane, propane, butane, hydrogen or carbon monoxide"[11]; therefore a hydrogen network would fall under the same regulatory regime as a methane network. This legal definition should allow gas transporters to own network assets that transport hydrogen alongside the preexisting transportation assets used for natural gas.

Regulatory: asset ownership

The means of ownership of hydrogen production facilities is a challenge that spans regulatory and commercial. The available options for asset ownership will have a material implication on the cost of capital, and therefore will have a direct effect on the quantity of support necessary to incentivise investment. The lowest capital cost basis would be through a regulated asset base (RAB) model – essentially to treat hydrogen production as a national utility, such as the gas, electricity and water networks. By an appropriate allocation of risk, a RAB model would reduce the cost of capital, which in turn would reduce the level of support necessary to deliver a commercial project. The potential models for hydrogen production ownership is a live debate taking place between government, regulators and industry, the conclusion of which will help inform the commercial and support frameworks necessary for bulk hydrogen production.

Social acceptance

Outside of the quantifiable technical, commercial and regulatory barriers to hydrogen deployment are challenges concerning public knowledge and understanding. The community uptake of hydrogen as a 'green' solution to energy delivery will need to be promoted through targeted engagement activities to proactively socialise the benefit of hydrogen to the public. Misconceptions surrounding the safety and use of hydrogen will need to be addressed as well as promoting the environmental credentials of the gas as a means to decarbonise the UK energy system.

De-risking deployment

The number of barriers to deployment of hydrogen can be reduced by strategically designing an appropriate development pathway. By initially deploying hydrogen at a level that is acceptable to the current network and users (which is understood to be 20 mol%), the need to modify the gas network and appliances is eliminated. An example of such a project is the HyNet[12] project, which seeks to supply 2m homes in the North West with a blend of 20 mol% hydrogen. By de-risking the deployment pathway, the sum of deployment challenges can be broken up to allow material quantities of hydrogen to be delivered without the need to solve every challenge at once. This strategy will de-risk the ultimate deployment pathway of hydrogen development and allow society to enjoy the known benefits whilst other challenges relating to greater adoption are being addressed.

The Government's independent advisor for energy, the Committee on Climate Change, published its Net-Zero Report in May 2019 which outlined the need to develop 270 TWh/y of hydrogen[13] to allow the UK to meet its recently-updated carbon target of net-neutrality by 2050. Although the barriers to hydrogen deployment may seem high, the vast majority of them could be overcome with political will. The locus of challenges resides with ensuring an appropriate regulatory and policy framework to allow commercial projects to be developed, with many technical barriers either overcome or with funded programmes to address them.

If hydrogen is to play its part in the UK energy system, and society is to reap all of the environmental benefits available, increased political focus and regulatory clarity will be required.

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Hydrogen: the burning question

Mike Menzies MIChemE

The world is rising to the exciting challenge of controlling CO_2 emissions. Replacing natural gas with hydrogen is progressing up the list of potential remedies for the domestic market.

The general public is increasingly aware of global warming, and remedies such as Reduce, Reuse, Recycle. But 'Replace' is being investigated with respect to the carbon in the National Grid gas supply. We had hydrogen in towns gas throughout the middle of the last century and the researchers are investigating replacing methane in the gas main with hydrogen, at least in part to begin with.

Hydrogen is well known in many large industries, but for production of other materials. The hydrogen is usually made from natural gas, by steam methane reforming (SMR) without capturing the CO_2, and in sufficient quantity for the process. Choosing one of the iron and nickel family of catalysts, together with heat, steam, methane and oxygen, a large proportion of hydrogen is made, together with CO_2. Depending on production stability, the quantity of hydrogen may be in excess, in which case the plant looks to use the excess hydrogen elsewhere – usually by injecting it into the plant gas main. Hence this gas main composition changes from that of natural gas to include hydrogen, typically up to 30%.

What effect does the hydrogen composition have on the furnace, the flame, and the exhaust?

The good

The benefits of hydrogen include:

- it, like methane is not poisonous, (just asphyxiating and explosive)
- it has quite a high spontaneous ignition temperature (SIT) of 650 °C – it needs a spark to ignite
- it has very wide flammability limits (3–70% H_2 in air mixture) – it is easier to maintain a flame
- it burns to water vapour, thus eliminating CO_2 emissions
- it burns with a much higher flame speed (300 cm/s) than methane (30 cm/s), thus stabilising the flame.

The bad

Disadvantages include:

- the higher flame speed increases the flame temperature locally, which can generate high levels of NOx
- the wide flammability limits require consideration in the safety assessments

- hydrogen has a different Wobbe Index from methane, to be taken into account in design (the Wobbe Index is a measure of the ability of a gas to deliver heat through a jet hole at constant conditions. It is calculated by the calorific value divided by the square root of the specific gravity of the gas)
- hydrogen has a different combustion air requirement index, CARI (a measurement of the combustion air required for a gas), compared with methane.

Flames and NOx

This plant fuel gas is what the furnaces receive. So how does the hydrogen content affect the NOx emissions? The higher flame speed increases the flame temperature locally, which generates NOx. So the burner manufacturer has to design a burner to give a flame which will minimise the production of NOx. There are many ways of accommodating high hydrogen fuel gases whilst still keeping the flame cool enough to minimise NOx formation. The key is to slow down the rate at which the fuel and air mix. This gives rise to a diffusion flame. A diffusion flame is where the incoming gas is surrounded by the products of combustion where the gas and oxygen in the air have reacted. This sleeve or cloud of exhaust products slows the combustion because the gas has now got to diffuse out through the cloud, and the oxygen has to diffuse inward. Hence the name 'diffusion flame'. This flame is usually slow enough such that the heat of combustion is radiated to the surroundings without reaching the critical NOx temperature of 1,350 °C. The diffusion flame may well obtain sufficient temperature to crack the fuel before it is combusted. There will then be free carbon which will burn with a yellow flame. This does not look as well controlled as a sharp blue flame, so low-NOx burners, involving diffusion flames rather than deflagration, are only slowly being recognised by the operators. Many operators will remember bright yellow flames from heavy fuel oil or vacuum residue oil which had less acceptable exhaust composition.

The converse of a diffusion flame is a deflagration flame. In this case the gas and air are premixed and admitted into the combustion chamber, where they find a source of ignition. The flame propagates at the flame speed so the gases have to be injected at a velocity greater than the flame speed, otherwise the flame could 'flash back' and burn in the burner mixing chamber. Premix burners therefore have a limited turn-down range and are designed for a particular flame speed. Adding hydrogen increases that flame speed and makes existing premix burners unsuitable for conversion to high hydrogen gases. The combustion rate can be reduced by diluting combustion air with exhaust gases as a method of slowing down the flame to reduce the temperature, but many installations have natural draft or induced draft premix burners where chamber negative pressure and gas aspirators entrain fresh ambient air into the premixer and thence to the burner quarl (prefired refractory burner block). So, we cannot reduce the oxygen partial pressure in these burners without modification to the air and associated control systems.

Figure 1: *Diffusion flame (left) and deflagration flame*

The flame which one hopes never to see in a furnace is a detonation flame. The heat of combustion from a flame at the centre of a pre-mixed cloud of gas and air produces a pressure wave which is sufficient to provide the source of ignition to the adjacent mixture (like a diesel engine) and so the combustion front proceeds at the speed of sound, or greater.

There is a further flame to consider - flameless combustion. This is used in high temperature furnaces where the burner design is not important. The gas and air are injected into the chamber separately and are heated by the radiation within the chamber to well above the SIT before mixing occurs. So wherever the gas and oxygen meet they will react and give off more heat. The exhaust gases will, of course, take heat out of the high temperature furnace and so heat recovery devices such as regenerators or recuperators become a necessity. The radiation from the flame appears less because the flame is dissipated throughout the combustion chamber where the light intensity is high – white hot. In these cases the furnace can be designed for the gases to wipe the crown of the furnace transferring heat by convection to refractory. The refractory has an emissivity near 1, so radiation to the product is achieved. Radiated heat energy incident on a surface is either absorbed or reflected. The amount that is absorbed is also re-radiated or emitted. The type and surface of all materials has a different proportion of reflection and absorption (emission). The two proportions always add up to 1 and the particular material can be simply described by the emissivity value which will be between 0 (shiny gold surface) and 1 (matt black surface). Regenerators or recuperators are used to recover heat from high temperature furnace exhaust gases.

Natural draft premix burner

Returning to the natural draft premix burners, like the high temperature furnaces referred to above, they may well include design which promotes flame impingement onto the refractory to promote even radiative heat transfer from the heater wall to the product tubes. These small, wall-hugging burners use convection to transfer heat of the flame to the refractory using the Coanda effect or by nozzle design. (The Coanda effect results in a flow of gases, where these gases follow a curved surface because that curved surface has no gaseous molecules adhering to collide with – and therefore modify the direction of – the flow stream.)

Burner manufacturers have designs for both premix and nozzle mix flat flame burners, and for both induced draft and forced draft.

They may be suitable both for high hydrogen as well as low NOx. Adapting these burners for low NOx will often involve separating the flame into a rich and lean section where both parts of the flame have a lower flame temperature because of being away from the stoichiometric region. The rich zone may be as simple as a neat gas poker firing onto the edge of the lean gas flame. High hydrogen is ideal for these burners because of the wide flammable range of hydrogen in the lean zone and the high flame speed for stability of the rich jet.

The processes they are used on tend only to require a very limited turn-down range which allows a significant proportion of hydrogen in the fuel without incurring flashback on a premix burner. There are usually many burners, often several hundred, arranged in rows. During heatup after a shutdown, rather than trying to modulate the burners, gentle heat input is often achieved by lighting rows or individual burners on/off. Nozzle mix flat flame burners should not have any significant problem as the hydrogen content of the gas is increased, save for the choice of nozzle material. But the problem for premix flat flame burners is more significant with high hydrogen. A flashback might extinguish but will probably reoccur and if the flame stabilises at the premixer (a burnback) then the burner is likely to be destroyed in a short time, almost certainly before it can be observed by an operator. Fitting flame detection on all, say 500 burners, is likely to be blocked by financial considerations.

Process stability would suggest that modulation, even if it is only 2:1, would be beneficial. However, the percentage of hydrogen would be the limit to the range of modulation. Modulation of 2, 3, or 4:1 may be suitable with a methane gas but not for pure hydrogen. Phasing over from pure methane to high hydrogen could be achieved with new jets/nozzles, but this procedure would be suited to a specific change of fuel and not just to gradual changes in fuel composition.

Unlike the flat flame wall burners above, many boiler/heater/furnace/kiln low-NOx burner designs separate the combustion air into two parts – the primary air and the secondary air. The gas will be delivered in the centre with the primary air, and pilot flame or igniter (and often flame detection equipment). The secondary air is delivered outside the diffusion flame package, with low turbulence to minimise mixing. Power station burners tend also to be suited to low NOx and high hydrogen. It is these power station burners there can be several other fuels. It's not unknown for a boiler burner to have five different fuels, though one or two of these fuels may merely be a method of disposing waste or vent gas from another process. Coke oven and blast furnace gases are common, but they do have a significant influence on the original design of the burner. It is likely that one of the fuels may be 'plant gas' shared by energy consumers throughout the plant.

These boiler burners are generally well suited to utilising high hydrogen gases in a nozzle mix arrangement. Furthermore, the control system fitted on a boiler is often sufficiently well instrumented that air:fuel ratios can be continuously controlled allowing gas composition changes without notice. To achieve low NOx, one of the favourite procedures is to reduce the combustion air to all burners (making the flames sub-stoichiometric) and removing all the fuel lance internals from the last row of burners, thus supplying the 'secondary' air at the end of the combustion chamber. This design will need a further chamber for the final combustion (probably flameless combustion) before the exhaust gases pass into the convection section.

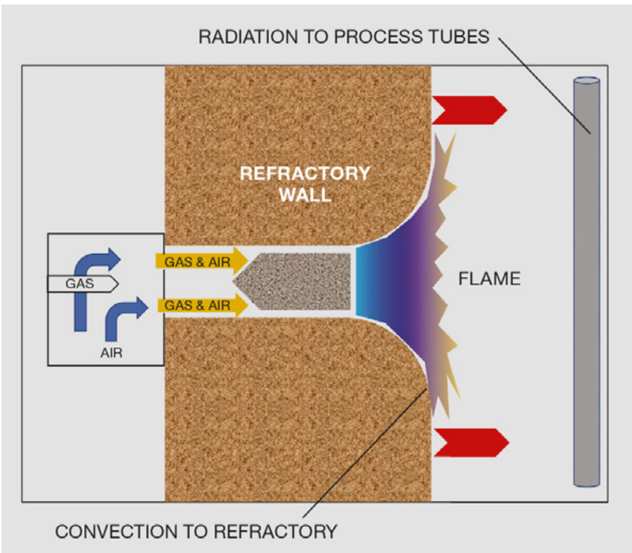

Figure 2: *Small wall hugging burners use convection to transfer heat of the flame to the refractory using the Coanda effect, then radiation to the process tubes*

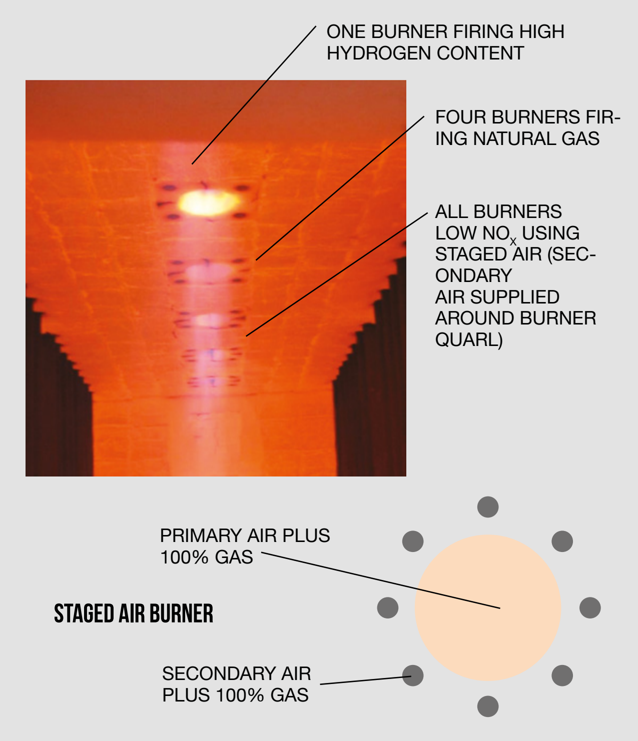

Figure 3: *Roof-mounted burners with different fuels*

Calculation or measurement of the Wobbe index can be undertaken and is both a simple and effective way of trouble-free inclusion of higher levels of hydrogen gases. The Wobbe Index is a measurement of the ability of a gas to deliver heat through a certain size jet, but this may require a different amount of air to achieve it. So even if you can get the same heat out of a burner, you may need to put in more combustion air. This calculation is very similar. The combustion air requirement index, CARI, is the amount of air required to combust the gas so that the air stays in ratio with the gas. It is common for such a gas to be continuously monitored in a Wobbe index analyser.

There are many other matters to consider. For instance, when we put high levels of hydrogen in the fuel, the exhaust could turn white with condensing steam droplets as it cools. So, the public may see a change in the stack plume.

Summary

This review has looked at the development of burner design to take account of emission regulations, specifically NOx. In the main, this requires separating the combustion air into primary and secondary streams so as to achieve a diffusion flame. This diffusion flame is larger, slower, and cooler than its predecessor, the deflagration flame. So, because changing to low NOx will probably require new burners, it would make sound economic sense to choose a burner design which is also suitable for high hydrogen.

Your plant is likely to be legally obliged to control the NOx emissions. It is in your neighbourhood and your nation you should be morally obliged to prepare for hydrogen. It's not difficult. Burners can be designed for any gas composition with hydrogen. It is just a little bit more difficult if the composition changes excessively.

But undoubtedly, hydrogen is our friend in the furnace. We just have to control it.

Hydrogen in vehicular transport

Andy Brown AFIChemE and Jack Walden

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Google the subject of this article, and you'll get hundreds of thousands of results. It is therefore a challenge to cover everything in less than 2,500 words!

So, in this article a number of vehicular transport types will be considered, albeit not at an exhaustive level; some of the challenges facing each will be described, and a number of potential opportunities will be noted.

In 1794 Robert Street patented what is arguably the internal combustion engine concept, which used a liquid fuel (petroleum), and then followed it by building a working engine. And for the last 225 years his invention has been the backbone of vehicular transport – to the point at which around 16% of the entire world population now owns a car[1].

The big decision is, are we going to replace (carbon-emitting) petrol in an internal combustion (IC) engine with (carbon-free tailpipe emissions) hydrogen, or are we going to use the hydrogen differently, such as in a fuel cell? Or is the answer somewhere in between as a hybrid? This is probably a good place to start.

Hydrogen internal combustion engines

The advantage of using IC engines such as Wankel and piston engines burning hydrogen instead of petrol, is that the cost of retooling for production and fitting the prime mover into existing body shell and floor pan designs is much lower.

The optimum fuel-to-air ratio for petrol is 14.7 (14.5 for diesel): for hydrogen it is 29. However, to minimise the formation of NOx, typically hydrogen engines are designed to use about twice as much air as this. Unfortunately, this also reduces the power output to about half that of a petrol engine of the same physical size, so to make up for this, hydrogen IC engines are usually much larger than petrol engines.

Other issues also need addressing, such as the increased potential for pre-ignition (knock or pinging) because hydrogen flame speeds are higher than those for petrol or diesel fuel.

A number of cars have been produced with hydrogen-fuelled IC engines: BMW produced the Hydrogen 7 in 2005–2007, and Mazda produced a hydrogen version of its rotary-engine RX-8, for instance. Neither of these are in current production.

There is, however, a niche market for hydrogen IC vehicles operating where there could otherwise be an accumulation of CO-rich fumes, such as fork-lift trucks in warehouses.

Hydrogen fuel cell cars

Earlier articles in this series present a case study, '*Enabling Hydrogen Fuel Cell Electric Vehicles*'[2], and look at the Toyota Mirai[3]. Fuel cells represent a better utilisation of hydrogen energy in cars than a hydrogen-fuelled IC engine, which is only about 40% compared to the possible 56% shown in Table 1[4] (blue rows show hydrogen fuel cell, and grey and green show petrol and biodeisel IC). However, because of the high energy requirement to pressurise the hydrogen, the overall well-to-wheel efficiency is not impressive. And neither is the price, around twice that of the equivalent IC-engined vehicle. What is impressive, is the emissions performance, with only water vapour appearing at the tailpipe.

Honda, Hyundai, Mercedes-Benz and Toyota have production models of fuel cell cars, with scores of other manufacturers offering concept cars.

When designing a hydrogen vehicle, there is a balance to be struck between making the fuel cell tolerant to impurities in the hydrogen and requiring it to be '4 9s' grade (ie >99.99% pure)[5]. The current market is to place the onus on the supplier, avoiding additional fuel cell costs, but this, in turn has its own suite of problems (*see Hydrogen supply infrastructure on next page*).

PRIMARY ENERGY SOURCE	EFFICIENCY (%)				
	H_2 PRODUCTION	H_2 DISTRIBUTION	RETAIL	VEHICLE	OVERALL
Oil	34	89	90	56	15
Gas	39	89	90	56	18
Coal	34	89	90	56	15
Biomass	24	89	90	56	11
Renewable power	68	89	90	56	30
Nuclear power	19	89	90	56	8
Oil	86	98	99	30	25
Biomass	35	98	99	35	12

Table 1: *Well-to wheel efficiency for cars*

Hydrogen fuel cell buses

In 1998 in Chicago, US and Vancouver, Canada, there was an early demonstration of fuel cell buses, but it was 2006 when they began operating in Beijing on an experimental basis. In 2004, London experimented with single-deck hydrogen-powered buses and by the end of 2011 there were eight. They are now a regular feature of London traffic.

Later this year, 20 new Wrightbus double-deck buses will be introduced into service in London. The StreetDeck FCEV uses a Ballard fuel cell, a Siemens drivetrain and a 48 kW traction battery pack. The system delivers a 322 km operating range, and a 426 km extended storage option is also available. Refuelling the bus takes approximately seven minutes[6]. With regenerative braking, frequent stop/start operation, a city centre route base, and its ability to accelerate rapidly into moving traffic, this promises to be an important contribution to mass transport in the approaching low-carbon era.

Martin Hoscik, Shutterstock

Other hydrogen road vehicles

Finding room for hydrogen storage tanks may be difficult in a compact vehicle like a car (see below), but vans, and trucks have a great deal more potential. Their stop/start duty – especially if a significant amount of time is spent queueing in heavy traffic – lends itself particularly well to fuel cell operation, coupled with battery storage to allow the fuel cells to generate at a fixed rate (ie base load).

Like buses, vans and trucks may also have the advantage that, parked overnight in a depot, they could be filled with hydrogen from a bulk supply, where all of the necessary safety precautions can be put in place and secured.

Hydrogen trains

In September 2018 that the first Coradia iLint hydrogen fuel cell train entered into commercial service in Germany. Now, two of the trains built by the French train maker Alstom are now operating on a 100 km stretch of line in northern Germany. Electrical energy is generated on-board in a fuel cell and intermediately stored in batteries, as described above. The battery stores energy from the fuel cell when it is not needed for traction, or from regenerated energy of the train during (electrical) braking. The batteries also allow additional support to boost energy delivery to the motors during acceleration phases.

Both the fuel cells and the hydrogen tanks are mounted on the roof, with cooler air providing additional cooling as the train moves along the tracks at up to 80 km/h.

Hydrogen trains are expected to come into service in the UK in 2022[7]. These are not the same as the iLint models because there is insufficient clearance in some UK tunnels to permit the roof installation of tanks and fuel cells, thus the designs tend to look more 'conventional'.

Hydrogen supply infrastructure

Storing hydrogen on-board light vehicles for use in fuel cells is one of the current limiting factors to their widespread introduction to the marketplace. This is because, as the least dense element in the universe, the chemical energy it contains per unit volume is several orders of magnitude lower than conventional hydrocarbon fuels. For example, at 0 °C and 100 kPa, hydrogen has a lower heating value (LHV) of 10.8 kJ/L, whereas petrol at 15 °C and 100 kPa boasts an LHV of 32,000 kJ/L. On a mass basis, this result is reversed, with hydrogen demonstrating its promise as a future energy carrier with an LHV of 120,000 kJ/kg vs petrol at 43,400 kJ/kg. Therefore, while significantly less mass of hydrogen fuel would be required to power a vehicle for the desired range, the problem arises with the volumetric storage of such a quantity.

Experience with existing prototypes reveals that a hydrogen fuel-cell car has a fuel economy of 199 km/kg. To have a typical range of 600 km, the tank of a hydrogen car needs to hold about 3 kg of hydrogen. The problems of storing hydrogen have been described elsewhere[6] in this series, and 3 kg of hydrogen would occupy 0.076 m³ were it compressed to 70MPa, which, although an engineering challenge in its own right, is typical. But how does one get the hydrogen to the filling point?

This has long been the 'chicken-and-egg' conundrum facing hydrogen for vehicular transport. There are three main options:

1. bulk delivery (by road in a tube trailer);
2. bulk delivery (by pipeline); and
3. on-site manufacture (eg by electrolysis).

All three have obvious downsides. A large hydrogen tube trailer can carry about 900 kg at 30 MPa[9], or about 300 tank-fulls (neglecting additional compression loads) which is enough for 120,000 vehicle-miles. A 44 t petrol tanker holds 38,000 L. At an average consumption of 5.5 L/100 km, this equates to 161,680 vehicle miles, 35% more and faster unloading times.

Bulk delivery by pipeline would require on-site purification (eg removal of oderant and any other impurities necessary to restore it to 4 9s), and compression from street-level pressures (less than 7barg) to tank pressure, which could be 70 MPa.

On-site electrolysis and compression represents a huge energy penalty, and also has the possibility that the electrical supply infrastructure may require reinforcement, not just at the local (400 V) level but beyond into the 11 kV system.

On-board storage of hydrogen – the problem

Optimising the compromise between gravimetric (per unit mass, often expressed as kg_{H2}/kg or wt%) and volumetric (per unit volume, often expressed as kg_{H2}/L) storage capacities is therefore key. This naturally leads to the question: Which is more important to a vehicle, mass or volume?

To tackle this, first consider what we mean by gravimetric storage capacity: the mass of hydrogen stored divided by the total mass of the storage system and hydrogen together. The inclusion of the entirety of the storage system mass is what largely contributes to the unfeasibility of many solutions, since tanks, pipework and instrumentation equipment is heavy, compared to the mass of gas stored. The volumetric storage capacity divides by the volume of storage space required to contain the desired mass of hydrogen. Working with a set volume (once an acceptable mass of stored hydrogen has been established) allows for some unconventional and often innovative solutions, such as hydrogen buses whose storage tanks are externally located on the roof, or in some cars where tanks can be incorporated into the floor and in otherwise dead space beneath seats etc[10]. An obvious (but important) principle to note is that volume can be distributed around a vehicle whereas mass is mass wherever you put it. Heavier vehicles require more fuel to travel the same distance as lighter vehicles, requiring more fuel, which leads to heaver vehicles… and the cycle continues. Since the vehicle mass is likely to be the limiting factor in hydrogen vehicle design, it is often concluded that prioritising a high gravimetric capacity is the more sensible option for cars.

On-board storage of hydrogen – some solutions

Conventionally, as stated above, the solution to this problem has been to utilise extreme high pressures (up to 70 MPa) to compress hydrogen gas to such densities that enough fuel can be stored to facilitate driving ranges comparable to existing hydrocarbon fuelled vehicles. However, there are some drawbacks to this approach. For instance, the composite tanks required to safely operate at such elevated pressures are expensive to fabricate and can deteriorate structurally with repeated pressurisation unless mitigation procedures are implemented. This concern has led to the tight regulation of pressure vessel specification, manufacture and transport, resulting in a well-established, safe storage method for hydrogen[11].

Although storing hydrogen as a compressed gas is a well-established technology, the development of alternative storage systems is ongoing, with a plethora of adsorptive solutions undergoing research. Adsorption is the process by which molecules adhere to the surface of a solid phase adsorbent via van der Waals intermolecular forces. This can facilitate higher storage capacities at reduced pressures but, in this application, is limited by small size and neutrality of the hydrogen molecule, resulting in very weak interactions with any solid framework. Novel materials such as covalent-organic frameworks show some promise in this area when doped with metal ions to enhance the interaction energy of the two phases[9], potentially paving the way for a future where hydrogen cars are the dominant means of personal transport.

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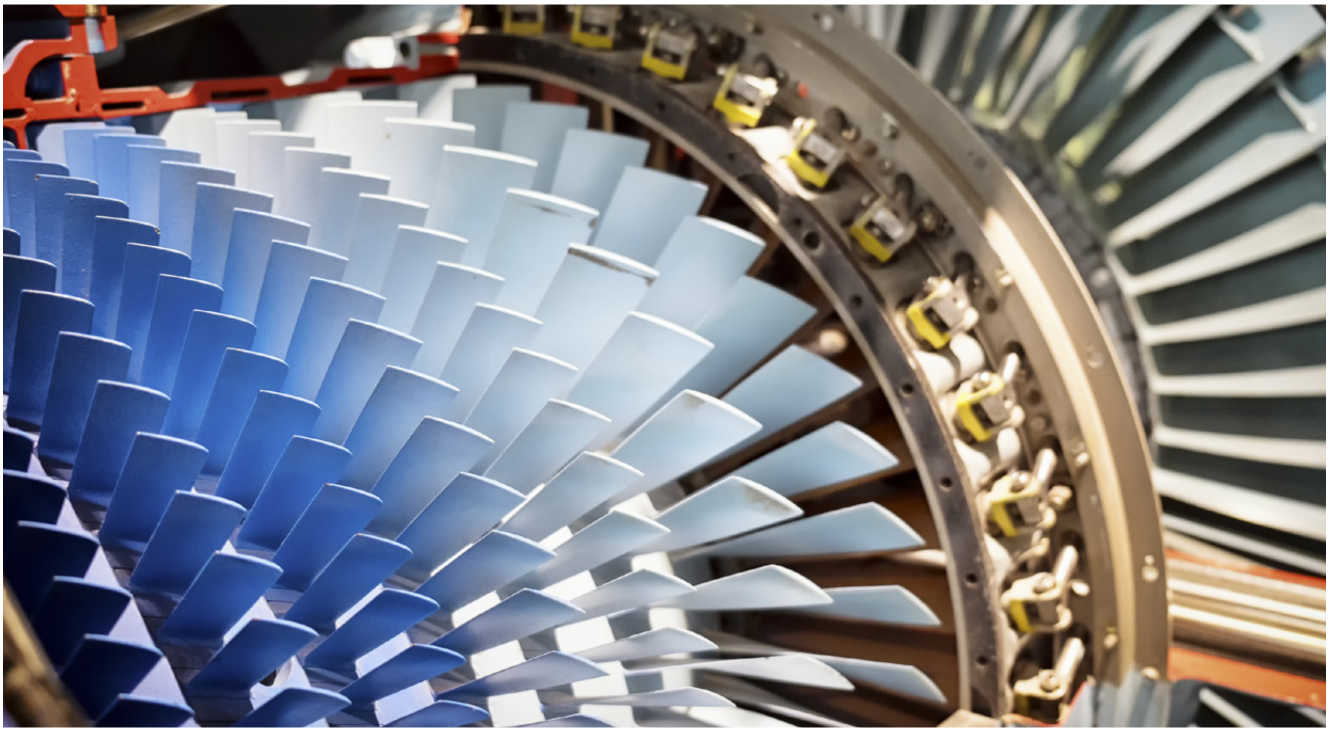

Hydrogen as a fuel for gas turbines

Andy Brown AFIChemE and Mike Welch

There are 39 Combined Cycle Gas Turbine power stations operational in the UK, with a nameplate capacity of almost 30 GW, as well as more than 350 industrial Combined Heat and Power (CHP) sites in the UK, producing around 5 GW of electricity.

There are many suppliers of gas turbines with offerings ranging from units with outputs of just a few MW to the latest utility-scale models of almost 600 MW in simple cycle.

Not all gas turbine manufacturers currently offer options for natural gas/hydrogen fuel mixtures but most of the major ones have developed combustion systems to handle off-spec gases to service markets such as steelworks off-gases (BFG, COG), IGCC applications, and bio- and waste-derived syngases. These off-spec gases include those with a high hydrogen content, and this article reviews the development status towards 100% hydrogen for one gas turbine manufacturer, Siemens.

Introduction

The gas turbine industry has evolved a great deal over the past century. The drivers for this in the power generation market have been improved efficiency, lower emissions, and increased output, whereas particularly for the aerospace market, reduced weight and smaller size have been the key criteria. These have often proved to be mutually exclusive, but so intense has been the competition between manufacturers that all the above have been achieved, often as a result of the introduction of new materials with improved properties.

The manufacture of larger gas turbines (>about 50 MW in simple cycle) particularly for power and CHP applications, has been dominated by a relatively small number of companies: General Electric (GE), Siemens, Mitsubishi Heavy Industries (MHI) and Ansaldo.

Medium-sized gas turbines (5–50 MW equivalent) are often developed for aerospace applications as the main market, though also find use in land-based applications including in, and in smaller-scale electricity production such as CHP or distributed power generation. There are other gas turbines serving the sub-5 MW market but these are not considered here.

Not all gas turbines will prove suitable for retrofit modifications to enable hydrogen combustion, in part or in whole. Redesign work with associated testing on older models, for instance, may not be justified compared to the cost of replacing the machine with a more up-to-date model for which the work has already been done.

Hydrogen combustion evolution

For many years, the heat from burning coal was used to boil water, superheat the steam and produce electricity by expanding it through a turbine/alternator. This is conventional power generation, the Rankine Cycle.

Another way to produce electricity was by burning natural

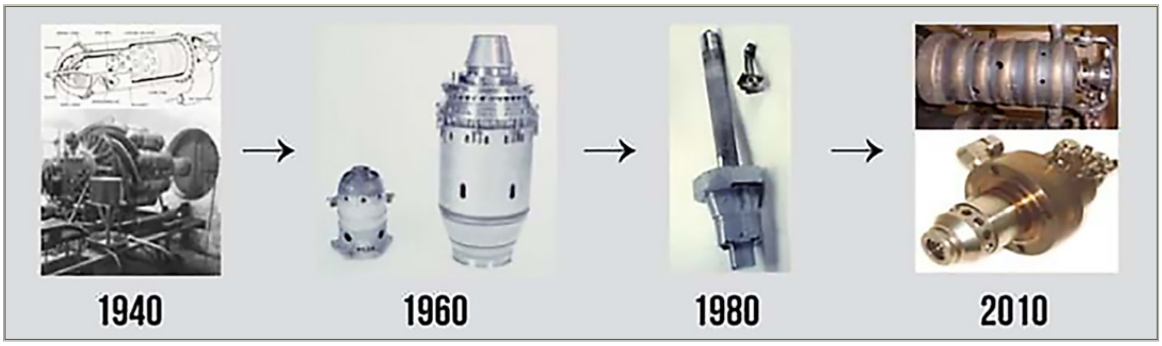

Figure 1: *Gas Turbine combustor design evolution.*

gas in compressed air, expanding the hot combustion products through a power turbine and using the shaft power to drive both the compressor and a generator, known as gas turbine arrangement (Brayton Cycle).

Additional energy can be usefully extracted by using the hot exhaust gases to raise steam and produce further electricity conventionally in a turbine/alternator. This combination is described as a Combined Cycle Gas Turbine (CCGT).

When environmental damage to trees and land was linked to sulfur dioxide (SO_2) emissions from the coal flue gas of power stations, two technological routes were developed. One was to scrub the SO_2 from the flue gas, the other was to produce a synthetic gas ('Syngas', a mixture of carbon monoxide and hydrogen) from the coal using a process called gasification. The Syngas is fed that into a gas turbine, to burn in a similar manner as natural gas. Chemical processes developed for the petrochemical industries, would wash the sulfur species from the syngas. This process was called Integrated Gasification Combined Cycle (IGCC). Because of the characteristics of the fuel gas were different, this necessitated developing different combustion arrangements for the gas turbines.

In the meantime, health and environmental concerns were raised over NOx production. Coal-fired power stations adopted low NOx burners and selective catalytic reduction. Gas Turbine manufacturers developed low NOx burners, using water- or steam-injection (so-called 'wet' systems) for older models (in diffusion-type burners) and eventually 'dry' variants for new machines, using staged or lean premix combustion techniques (so-called 'Dry Low Emission', or DLE burners).

Because the DLE route avoids the use of water or steam, it is attractive because:

- water purity requirements are very high in order to avoid impurities depositing on the expansion turbine blades and reducing cooling, leading to hot spots;
- water is emitted as steam with the exhaust gases, which is a costly loss to the plant;
- water is recognised as a resource and industrial freshwater use needs to be minimised to conserve it;
- under some climactic conditions a visible plume can appear, which should be avoided if possible;
- water injection in particular, but steam as well, reduces the lifespan of turbine blades; and
- the water volumes required are considerable, and often cannot achieve the same levels of emission reduction as the 'dry' techniques.

On the positive side there was some power enhancement as a consequence of increased mass flow through the expansion turbine, and as the water flashed off. For some fuels, wet combustors are currently the only choice, especially if very low levels of NOx emission are required.

Figure 2: *DLE (Lean pre-mix) combustion cans and fuel Injectors (1990s) to present.*

Next, when global warming became linked to rising levels of atmospheric CO_2, emissions from the coal flue gas of power stations were identified as one of the main sources. Again, two technological routes were developed. One was post combustion capture, which involved scrubbing the CO_2 from the flue gas produced by conventional power stations.

The other is pre-combustion capture and involves processing the syngas from IGCC plants to produce just hydrogen, and to feed that into a gas turbine, to burn in the same way as natural gas. The CO_2 could be washed out together with the sulfur species. Because of the very different characteristics of hydrogen as a fuel gas, compared to natural gas, even more combustion system changes would be required, along with changes to the auxiliary systems as well.

Again, two routes were followed for the gas turbines. One was to develop further the water- or steam-injected diffusion burners to use hydrogen, the other was to redesign the DLE burners to burn hydrogen. Both approaches are being developed by manufacturers, with DLE being the ultimate goal because they avoid all of the disadvantages described above.

Today, examples of each stage of development in the combustion process (see Figures 1 and 2) are still in use, even as the improved designs continue to become mainstream.

Siemens

Siemens offers a wide gas turbine portfolio from the KG2 Gas Turbine (2 MW in Simple Cycle) to the SGT5-9000HL (593 MW as a Simple Cycle, more commonly found in its combined cycle configuration, 870 MW in a 1x1 configuration). The smaller models are produced in Lincoln (UK), Finspång (Sweden) and Montreal (Canada), while the larger models are manufactured at its works in Berlin.

As well as natural gas, the company has considerable experience with both its small and large gas turbines operating on high hydrogen fuels, predominantly process off-gas, including large 'frame' machines operating on syngas in IGCC plants.

Siemens has experience in excess of 2m operating hours of burning fuels containing hydrogen derived from refineries, steelworks and coking works. While predominantly this experience has been gained on diffusion combustors, a recent order in South America will see a process off-gas with approximately 60 vol% (space between 60 and vol%) used in a DLE combustor.

Large gas turbines

For natural gas/hydrogen mixtures, the larger machines have different capabilities depending on which type of combustor has been fitted. Siemens has tested its F-class machines with a hydrogen content ranging from 30% to 73% in fuel gas[1]. The test results showed the emissions and operation targets could be achieved.

Light industrial gas turbines

Considerable effort has been made in developing some of Siemens' smaller industrial gas turbines to operate on natural gas/hydrogen mixes, both for diffusion and DLE combustors. Work in this area is continuing, particularly with the DLE burners, and increased hydrogen capabilities are under investigation.

For these smaller gas turbines fitted with DLE combustors, introducing up to 30 vol% of hydrogen into the natural gas system would apparently not present a technical problem for most models, but above that some modifications from the arrangement optimised for natural gas would be necessary. However, the DLE combustor design used on the turbines in the 25 MW–57 MW range (Simple Cycle, natural gas fuel) has been demonstrated to burn up to 60 vol% hydrogen (40% natural gas). Development work is in hand to deliver the low NOx performance at 100% hydrogen, expected to complete in the mid-2020s.

Aeroderivative gas turbines

The SGT-A35 (27.2–32.1 MWe) aero-derivative with a DLE combustor can handle 15 vol% of hydrogen in the Natural Gas fuel, but with diffusion combustors, and water injection for NOx control, for both the SGT-A35 and SGT-A65 (53.1–66 MW) up to 100 vol% hydrogen is possible. (both gas turbine output figures are in Simple Cycle and dependent on configuration and model, with Natural Gas fuel at ISO conditions.)

Into the future

In common with other manufacturers, Siemens has set a target of being able to offer gas turbines capable of burning 100% hydrogen across the range, and is developing DLE combustors to service the expected demand. The challenge is to do this without compromising efficiency, startup times, and emissions of NOx. This is being achieved by developing combustor designs with an increasing proportion of hydrogen in natural gas. The DLE burner design used on the SGT-700 (33 MW) has demonstrated up to 40 vol% H_2 capability. Recent testing has shown that 50 vol% is possible on the SGT-800 (50 MW), which translates to 60 vol% on the SGT-600 (25 MW) as this operates at a lower temperature.

As the hydrogen economy unfolds over the next decade, there is a clear intention that gas turbines will be ready to meet the upcoming market without compromising today's high performance expectations, in terms of emissions, response and efficiency.

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Heating with hydrogen

Tommy Isaac MIChemE

Hydeploy is the UK's first hydrogen demonstration project to inject hydrogen into a live gas network, up to 20 vol%, with the aim of providing a launch pad for the hydrogen blending market within the UK. A UK wide 20 vol% blend for domestic gas use would be the equivalent of removing 2.5m cars from the road[1].

The HyDeploy project is a collaboration between Cadent, Northern Gas Networks (NGN), Progressive Energy, HSE Bespoke Research and Consultancy, ITM Power and Keele University. Key subcontractors are Otto Simon Ltd (OSL), Dave Lander Consulting, and Kiwa Gastec. The programme is funded by Ofgem through the Network Innovation Competition and is the largest gas innovation project ever funded by Ofgem.

HyDeploy is a 6-year programme which started in 2017 and is due for completion in 2023. The programme involves three separate trials of blending hydrogen at 20 vol% into the gas distribution network – one on Keele University's private network, one on NGN's network, and one on Cadent's network.

The overarching aim of the project is to provide the safety case for hydrogen blending and facilitate the clearance of regulatory barriers necessary to kick start the hydrogen blending market. By the end of the programme, the objective is to enable a hydrogen producer to inject hydrogen into the gas network – just as a biomethane supplier can today.

Why 20 vol%?

Hydrogen and low carbon electricity, are likely to be the two key pillars for a decarbonised energy system. The no-regrets, low-risk, deployment of hydrogen is paramount to establish the lowest cost pathways for the UK to achieve its legally binding carbon reduction targets.

Previous work undertaken by the HSE[2] indicated that a 20 vol% blend of hydrogen would be unlikely to require significant gas network interventions. Additionally, all domestic gas appliances post the 1996 Gas Appliance Directive (GAD) have been tested with 23 vol% hydrogen as part of EU certification. The objective of HyDeploy is therefore to build the necessary evidence base to demonstrate that a 20 vol% hydrogen blend is as safe as natural gas.

By demonstrating that current appliances and gas networks are capable of adopting a 20 vol% hydrogen blend without modification, the commercial deployment of hydrogen becomes decoupled from the adoption of bespoke appliances, removing the need for mandated appliance change. This solves the 'chicken and egg' problem of supply waiting for demand and vice versa. It allows early hydrogen deployment to focus investment on the necessary supply infrastructure needed to deliver bulk production – most notably natural gas conditioning and CCUS infrastructure, whilst laying the groundwork for deeper carbon savings through transport fuel cells; low carbon flexible electricity generation; and potentially full gas grid hydrogen conversion.

Carbon savings

Heating demand in the UK accounts for just over half of total emissions[3], therefore small changes make a large impact. Blending hydrogen at 20 vol% into the natural gas network would unlock 29 TWh/y of low carbon heating within domestic gas demand[3].

To put this figure into perspective, in 2018 the Renewable Heat Incentive (RHI) delivered a total of 11 TWh of low carbon heat, and is forecast to deliver an additional 10 TWh/y by its end in 2021[4] (21 TWh/y in total). The RHI is

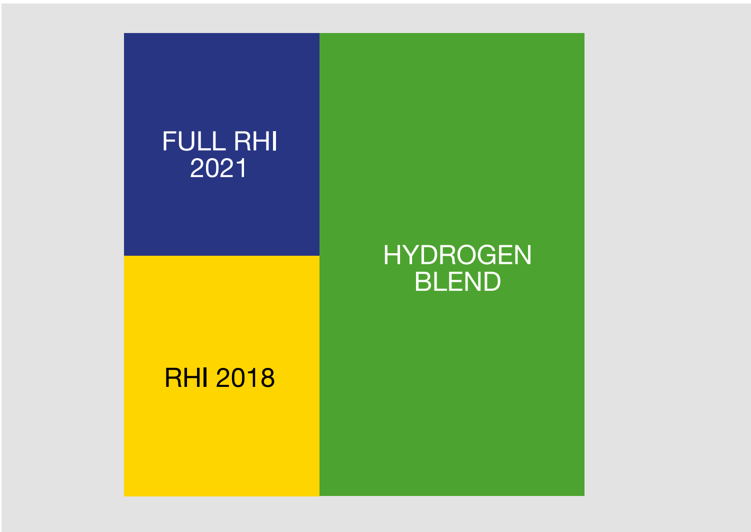

Figure 1: *Low carbon heat comparison.*

the UK Government's support mechanism for low carbon heat and covers both non-domestic (biomethane, waste, etc) and domestic (biomass boilers, air source heat pumps, etc) low carbon heat. The comparison with a hydrogen blend is illustrated shown in Figure 1.

It is therefore clear that blending hydrogen at 20 vol% would create material carbon savings, whilst de-risking the early deployment pathway of hydrogen adoption.

Building the safety case

All gas distribution networks are licensed by Ofgem to transport natural gas to consumers within the Gas Safety (Management) Regulations (GS(M)R). The current hydrogen limit within GS(M)R is 0.1 mol%[5], therefore HSE approval is required to transport gas with a greater hydrogen content. HSE approval is granted via bespoke Exemptions based on the presentation of scientific evidence to demonstrate that any proposed change is 'as safe as' the current operation.

HyDeploy was granted the UK's first ever hydrogen Exemption by the HSE in November 2018, for the first trial at Keele University.

A separate approval process will be required for each trial, therefore in total three Exemptions will be sought from the HSE to enable all three trials to be delivered.

Why three trials?

The three-trial structure of HyDeploy has been deliberately designed to appropriately manage the delivery risk of a 20 vol% hydrogen blend. Each trial is due to last for 10 months.

The first trial is due to commence in September 2019 and will blend hydrogen into the one of the live gas networks operated by Keele University. This first trial will deliver a hydrogen blend to 100 homes and 30 faculty buildings.

As part of the evidence gathering to support the first Exemption application, the gas appliances on the network were:

- Gas Safe checked;
- leak tested with up to 28 vol% hydrogen; and,
- safety tested with up to 28 vol% hydrogen.

All appliances that were safe and leak tight on natural gas were found to be safe and leak tight on blended natural gas – with no exceptions.

The ultimate rollout of a 20 vol% hydrogen blend cannot be contingent on visiting every home in the UK to Gas Safe and test all gas appliances. Therefore, a pathway exists between the appropriately-controlled trial at Keele, and ensuring the evidence base is sufficiently compelling to allow hydrogen to be blended without intervention.

By conducting two further trials, the necessary reduction in pre-trial intervention can be incrementally delivered as the evidence base allows. The two further trials will commence in 2020 and 2021, each supplying a 20 vol% blend to around 700 homes. The second trial will take place on NGN's network in the North East and the third will take place in Cadent's network in the North West.

Trial approval process

The successful approval process for each trial is dependent on identifying, understanding and mitigating the risk profile of the proposed undertaking. HSE Bespoke Research and Consultancy is leading the generation of the scientific evidence base. To support the first Exemption application, 18 months of laboratory, desk and field work was undertaken, with the key focus areas being:

- appliances;
- materials;
- gas detection;
- gas characteristics; and,
- operational procedures.

A comprehensive evidence base was generated in each of these areas, with a quantitative risk assessment (QRA) developed to allow all of the evidence to be aggregated into a single comparative analysis. The QRA was focused on understanding the trial risk profile and concluded that a blended natural gas containing 20 vol% hydrogen was as safe as natural gas[6].

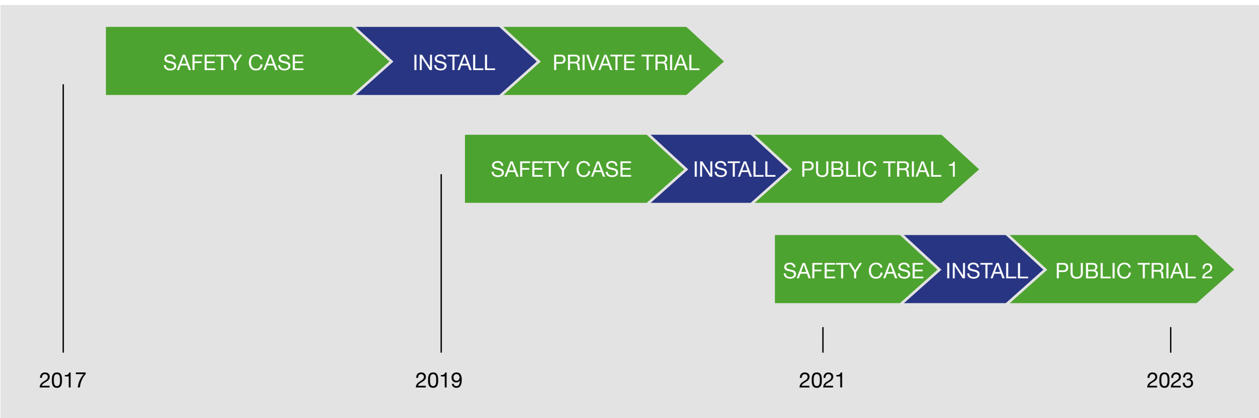

Figure 2: *Overall programme timeline.*

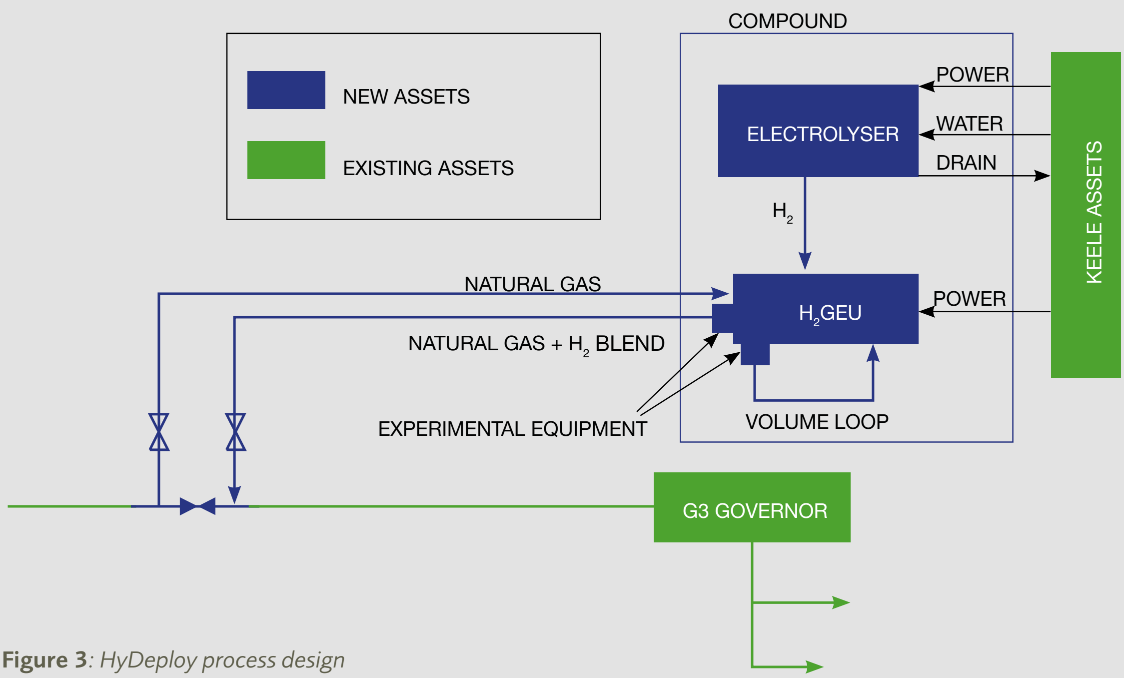

Figure 3: *HyDeploy process design*

Process design

The operational equipment used to deliver each trial will be a 0.5 MWe electrolyser, supplied by ITM power, and a hydrogen grid entry unit (H_2GEU), supplied by Thyson. The electrolyser will be supplied with renewable electricity to ensure the hydrogen generated is low-carbon. For each trial, a medium pressure natural gas supply line will be diverted into a secure compound. Within the compound, hydrogen will be generated by the electrolyser and blended with the natural gas within the H_2GEU (see Figure 3).

The blended gas will be returned to the medium pressure supply line, which will then be let down via the existing governor station into an isolated low-pressure network supplying homes. The control scheme will maximise the blend level, within process limits, whilst remaining within the Wobbe Index limits as specified by GS(M)R. The Wobbe Index is a measure of the energy delivery capacity of a gas, measured in MJ/m³.

A rigorous safety assessment has been undertaken throughout the design, including a Layers of Protection Analysis (LOPA) and HAZOP. The electrolyser and H_2GEU have been designed to operate automatically, with manual intervention only required to restart operation following a shutdown.

Each trial will locate the electrolyser and H_2GEU to minimise risk according to ALARP principles. Following the delivery of each trial, the electrolyser and H_2GEU will be decommissioned and transported to the next trial location for installation and operation.

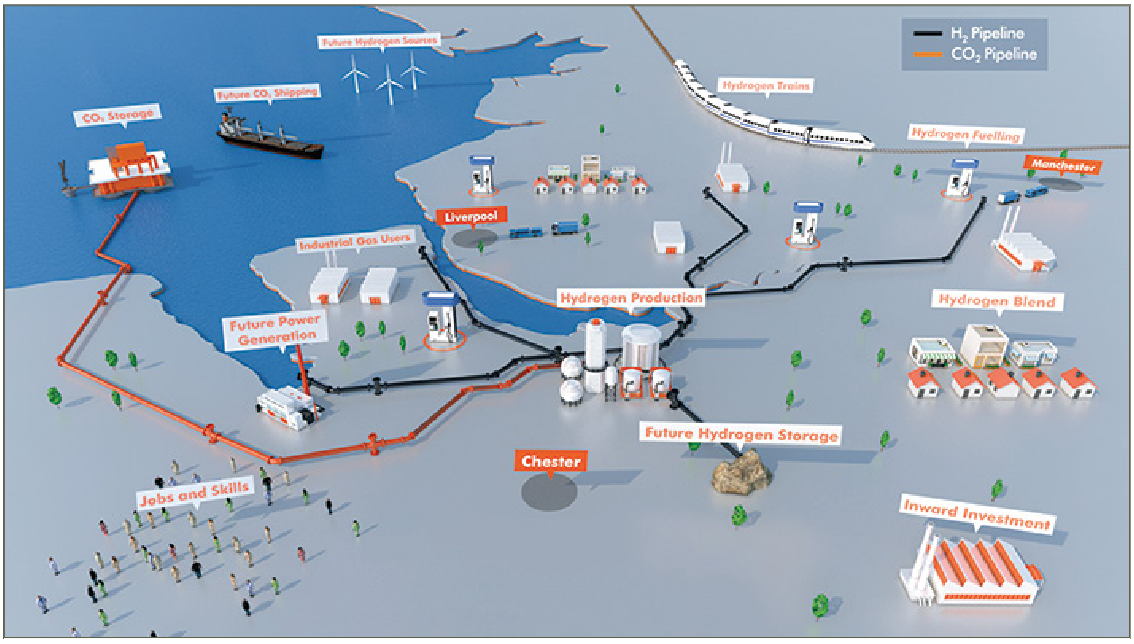

Figure 4: *HyNet project.*

Blending pathways

The purpose of HyDeploy is to provide a platform for hydrogen blending deployment. Following the successful delivery of the programme, a hydrogen supplier should be capable of applying for an Exemption without the need to generate any further evidence. This will kick start the hydrogen blending market to bring hydrogen blending on a par with biomethane as a low-carbon gas vector.

There are a number of deployment pathways that hydrogen blending could take, two examples are bulk supply, and power-to-gas projects.

Bulk supply of hydrogen blended gas, such as the HyNet project (see Figure 4), enables widespread application of blended natural gas. HyNet is designed to deliver a hydrogen blend to over 2m consumers across the UK's North West, along with decarbonising the North West industrial cluster. The production approach will be natural gas conditioning via auto-thermal reforming (ATR) in combination with CCUS infrastructure to decarbonise the gas and sequester the carbon dioxide.

Another blending deployment pathway is to utilise low-carbon electricity, where available and economic to do so, and generate hydrogen via electrolysis. This pathway would be unlikely to provide bulk supply in the near term[7] but could prove instrumental in early production, especially for distributed demand and high purity usage such as fuel cells.

Deeper carbon savings

By decoupling hydrogen supply investment from use, the investment requirements and deployment risk profile of hydrogen adoption is substantially reduced. This lays the foundations for hydrogen-based deeper carbon savings via fuel cells, low carbon dispatchable electricity generation – enabling use of more intermittent renewables – as well as potentially full gas network conversion.

HyDeploy is delivering practical deployment today, providing a launch pad for hydrogen adoption within the UK and beyond.

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Hydrogen transport

Andy Brown AFIChemE

Hydrogen is gathering support as a potential replacement for fossil-based fuels such as coal, oil, and natural gas. In theory, and for most applications, this is an attractive option: a relatively plenteous material whose use causes only a small environmental disturbance compared to, for instance, airborne emissions of carbon dioxide or particulate materials (PM2.5 and PM10). Unlike fossil-based fuels, hydrogen needs to be processed out of something else and delivered to the point of use. This article describes some of the delivery options, the factors that can influence the choice, and some of the associated challenges.

Transporting almost any fluid requires for a number of questions to be asked, perhaps the most relevant of which are: How much? How pure? What pressure? Clearly the answers to these will depend on the end use.

How much?

For most applications, hydrogen will be used as a gas, but that does not mean that it is always transported as a gas. The majority of the hydrogen moved around has been in steel cylinders or in specially-designed and refrigerated tube trailers. Single cylinders typically contain typically 5-8 Nm^3 of hydrogen at pressures ranging between 150–300 bar. BOC has the *Hydrogen Genie*, which is a lightweight, 20 L cylinder, which holds 7 kWh of energy and around 450 g of hydrogen.

With the increasing possibility of there being more hydrogen cars, there is the need for methods to store hydrogen that are both lightweight and safe. Compressed hydrogen can be stored on board in tanks based on type IV carbon-composite technology, an all-composite construction featuring a polymer, liner (typically a high-density polyethylene (HDPE) with carbon fibre or hybrid carbon/glass fibre composite. The composite materials carry all of the structural loads. The pressures used are usually either 350 bar or 700 bar. Capacities vary between manufacturers, but 5 kg is typical. The design and engineering of these tanks has delivered dramatic improvements over the past 10 years, as shown in Table 1[1].

PARAMETER	2005	2010	2015
Gravimetric capacity (kWh/kg)	1.5	2.0	3.0
Specific energy (kg H_2/kg)	0.045	0.060	0.090
System weight (kg)	111	83	55.6
Volumetric capacity (kWh/L)	1.2	1.5	2.7
Energy density (kg H_2/L)	0.081	0.036	0.045
System volume (L)	139	111	62
Storage system cost (US$/kWh)	6	4	2
System cost (US$)	1,000	666	333
Refuelling rate (kg H_2/min)	0.5	1.5	2.0
Refuelling time (min)	10	3.3	2.5

Table 1: *Improvement In vehicle hydrogen storage systems*

Hydrogen is also stored in cryogenic conditions in insulated tanks (typically cooled to -253 °C and at pressures of between 6 and 350 bar), or using advanced materials, (ie within the structure or on the surface of certain materials).

The next increment up, as it were, is hydrogen trucks. In the US, for longer distances, hydrogen is transported as a liquid in insulated, cryogenic tanker trucks. Over long distances, transporting liquid hydrogen by road is more economical than as gaseous hydrogen because a liquid tanker truck can hold a much larger mass of hydrogen than a gaseous tube trailer. Challenges with liquid hydrogen transportation include the potential for boil-off during delivery.

Typically, hydrogen is transported in tube trailers in the UK. A typical trailer (see Figure 1) would be filled to 228 bar, and would carry around 300 kg of hydrogen. There are now available on the market, high capacity 300 bar trailers, which could carry 600 kg at 228 bar and 900 kg at 300 bar. There are also 500 bar trailers in development[2].

In the US, liquid hydrogen is also moved in bulk by rail in tanks which have double walls (like a vacuum flask), multi-layer insulation and sunlight reflectors.

A liquid hydrogen truck is shown in Figure 2.

LH2-sized tank cars have a capacity of 7,711 kg. The pressure within the tank is typically 1.7 bara or lower and the temperature is usually below –252.87 °C. The boil-off rate is around 0.3–0.6% per day[3].

Hydrogen has been transported by pipeline since 1938. Between the Rhine and Ruhr areas of Germany a 250–300 mm diameter, 240 km long line constructed of a standard grade of pipe steel, has been carrying hydrogen at a pressure of 20–210 bar[4]. Since then, hydrogen pipelines are to be found in many different countries (*see Table 2*) and new ones are being constructed.

More is understood about the potential metallurgical impacts when hydrogen is transported in carbon steel pipelines, particularly hydrogen embrittlement, than was in 1938. Hydrogen embrittlement is caused by the interaction of hydrogen atoms with the crystal lattices within the steel. The presence of hydrogen enhances the generation of stress corrosion cracks. Steels with body-centred cubic lattice atomic structures (ferritic steels) are susceptible under certain conditions (high tensile stresses in the material). Metals with face-centred cubic lattice atomic structures (eg austenitic steels, Al, Ni) are less

Figure 1: *Liquid hydrogen tube trailer.*

Figure 2: *Liquid hydrogen truck – Air Products & Chemicals.*

susceptible. The likelihood of hydrogen embrittlement taking place can therefore be reduced by a combination of:

- lower partial pressure of hydrogen;
- lower temperatures;
- pipeline material selection; and
- conservative design (lower hoop stress).

In principle, bulk transport of hydrogen is little different from that of natural gas, and current design codes (eg BS PD 8010-1) apply. It is generally recommended[5] that only lower-strength API 5 5L grades (X52 or lower) should be specified, which keeps the hoop stresses low, and allows 'standard' pipeline sizes, materials and welding procedures developed for natural gas to be used.

IGEM is producing guidelines for more local distribution of hydrogen by pipe. For low-pressure pipelines, the same low grades of steel, as for high and medium pressure pipelines are used, but for pressures of 7 bar and lower, non-metallic pipelines become more cost-effective, especially over long distances. There are two polyethylene materials used for low pressure water and gas infrastructure in the UK, known as PE80 and PE100.

PE80 has been widely used for gas, water and industrial applications for many years. This material was earlier known as MDPE (medium density polyethylene) and HDPE (high density polyethylene).

PE100 is a higher performance polyethylene than PE80, and demonstrates improved resistance to rapid crack propagation as well as to long-term stress cracking. PE100 also has advantages over PE80 at low temperatures, since it is extremely crack resistant down to -20 °C. The higher

COUNTRY	LENGTH (KM)
Australia	8
Belgium	613
Brazil	8
Canada	147
China	65
France	303
Germany	390
Italy	8
Japan	1
Korea	87
Netherlands	237
Pakistan	5
Sweden	18
Switzerland	2
Thailand	13
United Kingdom	40
United States of America	2,608
TOTAL	***4,553***

Table 2: *Hydrogen pipeline lengths worldwide.*

strength of PE100 permits thinner pipe walls than PE80 for the same operating pressure: it uses less polymer material and provides for a larger bore and increased flow capacity for a given nominal pipe size. This can result in significant cost savings at certain sizes and pressure ratings.

PE80 and PE100 are not recommended globally for continuous pressure operation at temperatures above 40°C for any gases. In the UK, PE pipeline components are rated up to 7 bar pressure (10 bar elsewhere) at up to 20°C when carrying natural gas. There is currently no equivalent rating for carrying natural gas/hydrogen mixtures nor for 100% hydrogen.

Research work has been carried out, however[6], to compare the permeability of PE80 for natural gas with that for hydrogen at 5 and 20 bar with a range of compositions and temperatures. Permeability was not influenced by the applied pressure, and there appeared to be no mixture effect, in other words, for a given temperature, each gas (hydrogen or methane) keeps its intrinsic permeability coefficient whatever the composition of the feed mixture. The phenomenon was consistent with Arrhenius' Law, thus predictions could be made for pressures outside of those applied in the laboratory. Other work[7] has stated that the diffusion of hydrogen through PE pipelines is five times higher than the diffusion of natural gas, but is still negligible, with an annual loss of 0.0005-0.001% of the total transported volume.

How pure?

The two purity grades most commonly produced are 'high purity' (99.98% H_2) and 'ultra high purity' (99.999% H_2, so-called '5 9's purity'). Rarely will one find hydrogen of a lower purity being transported because there has been little market demand for it, as applications have demanded high purity. These would include fuel cells (especially proton exchange membrane (PEM) and alkaline fuel cells, and use as a coolant in large alternators). However, some types of fuel cells (eg molten carbonate) can use natural gas and bio-gas, so could also use lower purity hydrogen.

Other applications use hydrogen as a reducing agent (eg in glassworks to minimise oxidation potential) which again, would not need to be of a high purity.

Delivering high purity and very high purity hydrogen in cylinders has been commonplace for decades, and this is likely to remain a market for some time into the future.

Current proposals to replace some or all of the natural gas with hydrogen open up new opportunities for hydrogen, and if 'slightly impure' hydrogen can be delivered, for instance, to heat or domestic customers at a lower cost than the high purity grades, without affecting the quality of the product, it will improve the chances of a more widespread uptake.

The possibility of distributing 'slightly impure' hydrogen also opens up the possibility of a wider variety of hydrogen production technologies, some of which might result in small amounts of CH_4, CO or N_2 being present. This would avoid the costly and unnecessary removal of these species at low partial pressures from the bulk gas, and could bring closer the move toward a hydrogen-based economy.

But what about fuel cell applications requiring a higher purity grade? Take, for instance, fuel cell vehicles, won't this disincentivise hydrogen filling stations? Not necessarily, it means that the filling stations can draw their 'slightly impure' hydrogen from a wider pipeline infrastructure and process it locally using pressure swing absorption (PSA) or molecular sieve technologies in conjunction with the high pressure compressors that would be needed anyway.

It is very probable that pure hydrogen, introduced into pipes previously used for natural gas (repurposing), will, at the required levels in the ppmv (parts per million by volume) range, pick up sufficient impurities to require pre-treatment before use in a fuel cell anyway. Hence pipeline transportation of bulk hydrogen becomes a distinct possibility, even using existing infrastructure. Still more so if hydrogen is present together with natural gas at low (eg 20 vol%) levels.

Hydrogen filling stations: can use 'slightly Impure' hydrogen - Alexander Kirch, Shutterstock.

Garyville, Louisiana, US. Image courtesy of Air Products and Chemicals

Figure 3: *Ariel model JGU/6 hydrogen compressor – Air Products & Chemicals*.

What pressure?

Hydrogen is a compressible gas, but because of the small molecular mass, centrifugal designs are not ideal, as they need to operate at tip speeds three times faster than that of natural gas compressors to achieve the same compression ratio. Because of hydrogen's small molecule size, axial compressors are not very efficient either, as there is significant inter-stage leakage.

Hence positive displacement (reciprocating) compressors are often preferred, particularly where higher pressures are required. Positive displacement compressors can be reciprocating or rotary. Rotary compressors compress through the rotation of gears, lobes, screws, vanes, or rollers. Hydrogen compression is a challenging application for rotary compressors due to the tight tolerances needed to prevent leakage/hydrogen leakage back through the mechanism.

Reciprocating (or piston) compressors use a motor, sometimes with a linear drive, to move a piston or a diaphragm back and forth. This motion compresses the hydrogen by reducing the volume it occupies. These compressors can be large, heavy pieces of equipment. Figure 3 shows a 145 mm stroke 720 RPM compressor, taking hydrogen at 30 barg and delivering it at 50 barg. The motor power is 3.36 MW.

Ionic compressors are available today at the capacities and pressures required at hydrogen fuelling stations (>700 bar).

Ionic compressors are similar to reciprocating compressors but use ionic liquids in place of the piston. These compressors do not require bearings and seals, two of the common sources of failure in reciprocating compressors.

As a rule of thumb, hydrogen compression will require over 4% of the energy content of the gas itself to power the compressor. Higher compression without energy recovery will mean that even more energy will be lost during the compression step.

The answer, where possible, is to compress the source chemicals upstream (water in electrolysers, natural gas in autothermal reformers etc).

Summary

High purity hydrogen has been transported for a long time. Developing applications, like fuel cell vehicles have served to stimulate innovation to overcome perceived obstacles. The transition to a hydrogen-based economy will require bulk transport: this is not without its difficulties, but none of these seem insurmountable, and can draw significantly on the custom and practice of the natural gas industries.

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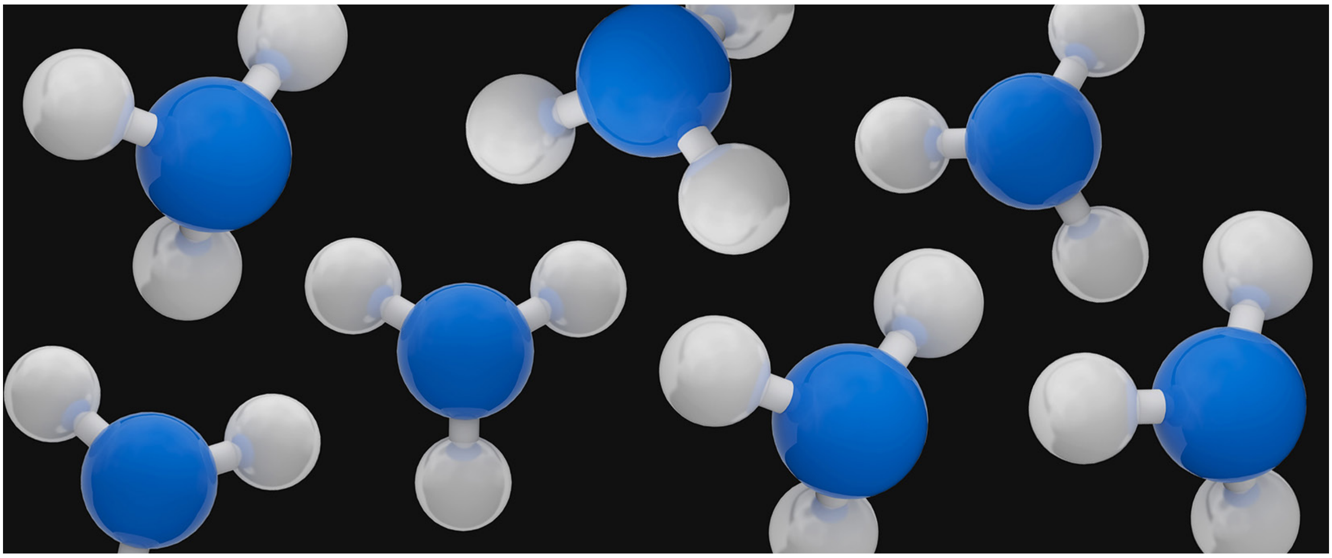


H_2 and NH_3 – the perfect marriage in a carbon-free society

Joseph El Kadi, Collin Smith and Laura Torrente-Murciano

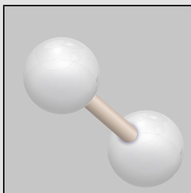
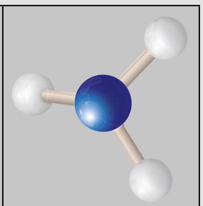
Transitioning our energy economy away from fossil fuel dependence towards one based on renewable and alternative forms of energy requires novel solutions for energy storage, in which the role of hydrogen has promising potential. The intermittency and seasonal variation of solar and wind power leads to a mismatch between energy supply and demand, which will intensify as we decrease our dependence on traditional gas and coal-powered generators. This challenge has driven extensive research into battery, capacitor and chemical energy storage as buffer systems to balance the variation of renewable energy supply on the grid.

As detailed in a previous article of this series[1], a significant obstacle to the wider implementation of hydrogen in energy trade is its costly and energy-intensive storage coupled with safety concerns associated with its high flammability. In this article, we focus on the chemical storage of hydrogen in the form of ammonia to alleviate hydrogen's storage and safety issues. Ammonia is explored as a complementary future energy vector with applications in specific cases.

Hydrogen carriers

Hydrogen-enriched compounds which are liquid at mild conditions, such as ammonia, methane and methanol, have recently gained attention as a distribution medium or for storage of hydrogen. Gaseous hydrogen storage requires high pressure vessels of up to 70 MPa while liquid storage needs cryogenic tanks maintained at -253 °C. Compared to conventional fuels, hydrogen has a low volumetric energy density in both gas and liquid form.

In contrast to other forms of chemical storage, ammonia is the only carbon-free hydrogen carrier and can be synthesised from renewable sources as demonstrated by the opening of a pilot plant by Siemens in Oxfordshire, UK in June 2018 and a 'green ammonia' plant by Nel Hydrogen and Yara starting up in Western Australia this year. In these projects, ammonia is produced by combining hydrogen from water splitting with nitrogen from the air. The ubiquitous abundance of nitrogen in the air – as opposed to carbon - supports the use of a carbon-free hydrogen carrier for a future, large-scale and sustainable energy storage cycle[2].

	 HYDROGEN, H_2	 AMMONIA, NH_3
Volumetric energy density (MJ/L)	$10_{(l)}$, $6_{(g,\ 700\ bar)}$	$14_{(l)}$
Gravimetric energy density (MJ/kg)	142	23
Flammability limit (Equivalence ratio)	0.10–7.1	0.63–1.40
*Flammability hazard**	4	1
*Health hazard**	0	3

** National Fire Protection Association (NFPA) 704 classification*

Table 1: *Energy density, flammability and hazard properties of hydrogen and ammonia*

Ammonia is a promising hydrogen carrier owing to its high hydrogen content (17.65 wt%), established distribution network and ability to be liquefied at 10 bar or -33 °C. Key properties are provided in Table 1. Hydrogen can be released on demand from ammonia through catalytic decomposition and consumed in a proton exchange membrane (PEM) fuel cell[3]. Alternatively, ammonia can be combusted directly or used in an ammonia-fed fuel cell. However, each of these conversions carries an energy penalty.

While ammonia has a narrow flammability range and its toxicity is a concern, its strong smell is, however, useful for identifying leaks. To overcome the issue of toxicity, ammonia can be stored in metal salts and released reversibly at around 250 °C[4].

Practical assessment of H_2 and NH_3 as energy carriers

The potential energy applications of hydrogen and ammonia can be broken down into the following timescales and sizes: short-term energy storage; long-term energy storage; long distance transport/trade of energy; and fuelling the transport sector. While each category is likely to involve a combined solution, there are aspects where hydrogen or ammonia are inherently more suitable, as depicted in Figure 1.

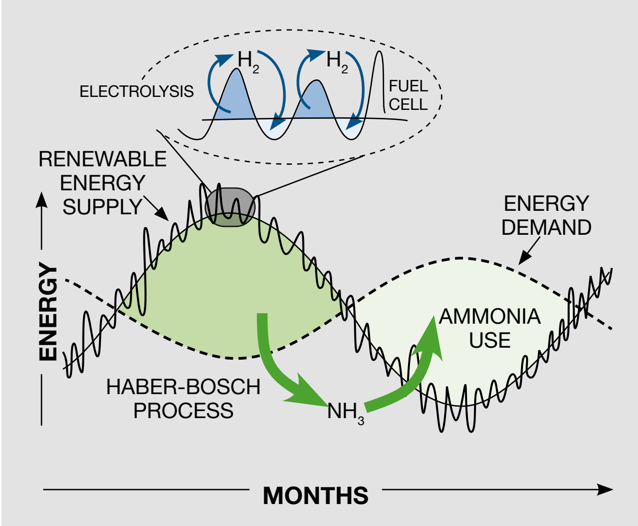


Figure 1: *Schematic representation of renewable energy intermittency and mismatch with seasonal energy demand. Hydrogen can be used to accommodate short-term fluctuations, while ammonia can be used to accommodate long-term fluctuations.*

Short-term (hours) energy storage

To match daily or hourly fluctuations in both supply and demand, hydrogen is a more promising option because the cycle of storing and harnessing energy in ammonia is unable to cope with rapid changes. The modern Haber-Bosch process which synthesises ammonia takes hours to days to reach steady-state, making it completely unsuitable for short-term storage.

Alternative ammonia synthesis technologies, such as electrochemical or non-thermal plasma-assisted ones, while more promising for rapid supply changes, are currently hampered by poor energy efficiencies and very low reaction rates due to simultaneous hydrogen evolution. Therefore, hydrogen is more competitive than ammonia for short-term energy storage.

Long-term (weeks–months) energy storage

An even larger scale of energy intermittency occurs on longer timescales – particularly between warm and cold seasons. For indoor heating to be powered by renewable energy, fluctuations in both weather and seasonal renewable energy supply need to be accommodated. Currently, reserves of natural gas are stored in the UK for heating during the winter months in the event of particularly cold periods.

Ammonia has a significant role to play in long-term energy storage due to its most advantageous feature – high volumetric energy density. When a large amount of energy needs to be stored for a long period of time, liquid ammonia becomes much more competitive due to the comparable volumes required for hydrogen gas storage and the energy losses (>30%) when storing liquid hydrogen[5].

Liquid hydrogen is estimated to be at least ten times more expensive to produce and store than liquid ammonia due to the requirement to reach very low temperatures. However, salt caverns, although geographically limited, provide the possibility of storing a large amount of gaseous hydrogen at a cost 10% less than liquid ammonia[6]. Alternatively, various solid hydrides and hydrogen adsorbents are being explored to increase the volumetric storage density, but ammonia is still very cost competitive.

Long distance transport/trade of energy

As renewable energy begins to be adopted worldwide, it has become clear that some countries benefit from more renewable energy potential than others. A similar situation developed in the era of fossil fuels, when countries with natural stores developed major export industries. Unfortunately, it is generally much easier to transport fossil fuels than renewable energy (electricity) over large distances, but converting renewable energy into a dense vector such as liquid ammonia may be a feasible – and carbon-free – solution.

Recently, Australia has been exporting energy to Japan in the form of liquid hydrogen due to the politically-driven large campaign for hydrogen fuel in Japan, however Australia has recognised liquid ammonia as perhaps a more promising alternative in the long-term[5].

When it comes to transporting either liquid ammonia or liquid hydrogen, ammonia has an additional advantage due to its already ubiquitous presence in world trade.

Synthetic ammonia has been used for over 100 years as a fertiliser and in order to feed approximately 50% of the world population, its current production exceeds 170mt annually. Its distribution from centralised plants fed by natural gas or coal is enabled by barges, rail cars, and pipelines to create a worldwide market exceeding US$5bn in 2017[7].

A particularly interesting aspect of ammonia transport is long-distance pipelines. The Magellan and NuStar pipelines in the US transport liquid ammonia from the coast and natural gas resources to fertiliser intensive regions over thousands of kilometres. When applied to energy transport, ammonia pipelines, rails, and trucks lose less energy than electricity transmission lines when transported over large distances[8], making ammonia a promising medium for an international trade of renewable energy.

Fuelling the transport sector

The powering of automobiles, trucks and buses constitutes a major segment of energy consumption that needs to be displaced by renewable energy. Due to space, weight and cost constraints involved in transport, the high volumetric energy density of liquid ammonia makes it particularly attractive. However, the technological issues associated with harnessing ammonia's energy, discussed in the next section, currently impede its use to fuel transportation. Therefore, hydrogen is currently a more feasible route to fuelling the transport sector, particularly with regards to large commercial vehicles where space and cost are less of a constraint, while small consumer vehicles may be more easily powered, at least in the time being, with batteries.

Ammonia – challenges and options

Synthesis of sustainable hydrogen

To store renewable energy in ammonia, as depicted in Figure 2, nitrogen can be obtained from air and hydrogen from electrolysis rather than methane. The Haber-Bosch loop compressors can be powered directly by electricity rather than steam, increasing their efficiency from ~45% to ~95%[2]. However, the hydrogen production efficiency from renewable energy via water splitting is significantly lower than from fossil fuels (ie reformation of methane), highlighting the key importance for the future development of efficient electrolysers to produce green hydrogen and hence green ammonia.

Redefining the Haber-Bosch process

Aligning ammonia production with renewable energy also requires re-defining the currently energy intensive Haber-Bosch process into one that is more agile and of low capital to match intermittent and isolated renewable energy. The high pressures (>100 bar), high temperatures (>400 °C), heat integration and a large recycle loop of the process make it only operational at steady-state in large-scale plants. Redefining the Haber-Bosch process could be made possible through the discovery of new catalysts – which has been an active area of research for over 50 years – or through the use of a new ammonia separation technique (ie absorption) to replace condensation and overcome the equilibrium limitations[2].

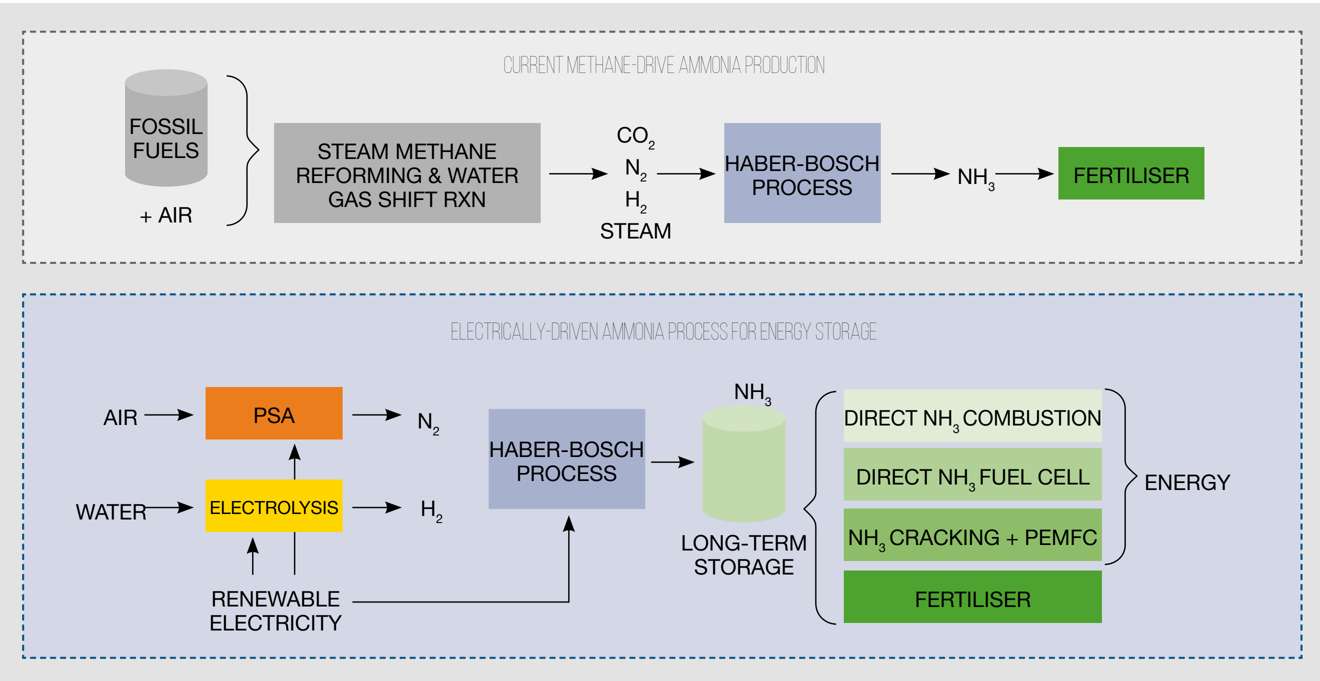


Figure 2: *Simplified flow diagram of the current methane-driven process for ammonia synthesis and an electrically-driven process for ammonia synthesis and energy storage.*

Harnessing energy from ammonia

Of the several ways to harness ammonia's energy, combining the catalytic decomposition of ammonia with commercial hydrogen PEM fuel cells is an attractive option given the technological maturity of hydrogen fuel cells compared to ammonia ones. A key challenge, however, is the need to selectively remove hydrogen to prevent unreacted ammonia from poisoning the fuel cell catalysts. In addition, this process relies on developing catalysts which crack ammonia at conditions aligned with those of PEM fuel cells, as identified by the US Department of Energy, leading to recent extensive research in the field[3].

Direct use of ammonia as transport fuel rather than hydrogen would be significantly cheaper when using a direct ammonia fuel cell, but this technology is in an early development stage. Alternatively, ammonia's energy can be harnessed directly by combustion. This approach suffers from high nitrogen oxide (NOx) emissions, which has initiated research into low-NOx ammonia combustion. Humidified blends of ammonia and hydrogen have demonstrated low polluting flames and efficiencies competitive with natural gas gas turbines. However, further work is required regarding the reactivity of unburned ammonia and water as well as scaleup to industrial conditions[9].

Round-trip efficiency

In the future implementation of ammonia in energy trade and storage, a key aspect is the round-trip energy efficiency - taking into consideration the energy required to synthesise ammonia from excess renewable energy and its delivery on demand. Currently, the round-trip efficiency of liquid ammonia is 11–19%, which is similar to the values of liquid hydrogen of 9–22%[10]. Technological advancements in electrolysis and hydrogen fuel cells will have an impact on both the viability of hydrogen and ammonia as renewable energy storage mediums and vectors, whereas improvements to ammonia synthesis and decomposition, combustion and/or fuel cells will make the use of ammonia more competitive.

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HyNet: demonstrating an integrated hydrogen economy

Andy Brown AFIChemE and Dave Parkin

Hynet North West is a combined hydrogen energy and carbon capture, usage and storage (CCUS) project, the immediate goal of which is to reduce carbon emissions from industry, homes and transport and support economic growth in the North West of England. However, HyNet North West has a more strategic series of objectives, which are to demonstrate the individual elements and provide and prove both hydrogen and CO_2 infrastructures to act as a stimulus for other low carbon development into the future.

Why the North West of England?

The North West of England is ideally placed for a futuristic project like HyNet. The region has a proud history of bold innovation, and today, clean energy initiatives are thriving (eg road and rail transport). On a practical level, the concentration of industry, existing technical skill base and geology (including a depleting oil and gas field close to shore) means the region offers an opportunity for a project of this kind. It has ample infrastructure and a massive potential for growth and innovation. It also benefits from forward-looking local government with a genuine appetite to be leaders in reducing their carbon footprint.

Home to Stanlow, the second-largest refinery in the UK, CF Fertilisers, Ineos, and Solvay, the region has much experience in production and utilisation of hydrogen.

Hydrogen production

Analysis, carried out in mid-2016 for National Grid Gas distribution (now Cadent Gas) identified natural gas as the only practicable source of primary energy from which hydrogen could be derived in sufficient quantities able to meet the expected demand in a short timescale (within ten years), and have the potential to meet the requirements of being classified as 'low carbon'. The role of electrolysis from renewable sources is acknowledged, but it was appreciated that there was still some way to go to decarbonise the electricity industry, and decarbonising heat as well would require an unrealistic expansion, for instance, of offshore wind or nuclear power.

Potential technologies were assessed by Progressive Energy, and autothermal reformation was identified as being the best, given the requirement for CO_2 capture, high product purity, and high overall efficiency.

Natural gas is first mixed with recycled H_2, preheated and passed over catalysts and absorbents that convert different sulfur species into H_2S and then take them out of the gas mixture. The gas is then saturated, mixed with more steam, and preheated further before being converted into syngas (a mixture of H_2, CO, and CO_2) via steam reforming within a gas-heated reformer (GHR) and autothermal reforming with an oxygen-rich gas inside an autothermal reformer (ATR). The GHR and ATR are highly-integrated, with the ATR effluent providing the heat of reaction for GHR whilst it is being cooled down. The resulting syngas is cooled further down before being shifted, resulting in a product comprising almost entirely of CO_2, H_2 and unused water. Once the water is knocked out, a proprietary acid gas removal separates out the CO_2 which can be then sent for storage. The H_2-rich gas is further purified using pressure-swing adsorption (PSA) with the offgas being used for heating purposes within the process. The pure hydrogen is exported. Heat integration within the process maximises efficiency.

This process, which was featured in more detail in '*Clean Hydrogen. Part 1: Hydrogen from Natural Gas Through Cost Effective CO_2 Capture*'[1] in the online edition of The Chemical Engineer, is fully scalable, placing the UK in the forefront of large-scale hydrogen production with associated CCS.

CO2 disposal

Previous CCS projects have all focussed on disposal in the North Sea. This implies long pipelines, deep waters and some of the harshest weather conditions in the world. HyNet North West is different: the Liverpool Bay fields are close to shore, in shallow waters and sheltered by the surrounding landmasses. Although the fields are some 30 km offshore, there is an existing pipeline infrastructure, currently bringing in natural gas, and a further 30 km on-shore pipeline (see Figure 1). Another ~30 km will be required to link this to where the hydrogen would be produced. The CO_2 would be transported in the gas-phase on land and initially offshore, eventually transitioning to dense phase as additional CO_2 sources are brought on line.

Disposal would be in the geological structures associated with the Liverpool Bay oil and gas fields, which are expected to be depleted within the timescales of the HyNet North West project. The CCS infrastructure would initially operate by receiving CO_2 which is currently being emitted to atmosphere by some of the local industries, bringing an early win to the producers.

CCUS is a vital technology to achieve the widespread emissions savings needed to meet the 2050 carbon reduction targets. The HyNet North West project will demonstrate simultaneously:

- **multi-source collection of CO_2 from diverse industrial sources (eg fertiliser production, cement manufacture, petrochemical refining);**
- **new-build CO_2 pipeline design, construction and gas-phase operation;**
- **repurposing of an existing on-shore natural gas pipeline to take CO_2;**
- **repurposing of an existing off-shore pipeline to take CO_2 in dense phase;**
- **dense phase CO_2 operation and lower pressure injection into subsea strata; and**
- **re-use of offshore natural gas production infrastructure for CO_2 disposal.**

Hydrogen market development

A significant proportion (53%, excluding transport) of the UK's heat is derived from the combustion of natural gas[3]. Of this, over 96% is used for high and low temperature processes and space and water heating[4]. Were this to be replaced with hydrogen, there would be a significant reduction in the associated emissions of CO_2. HyNet North West proposes to develop this market in a number of different ways:

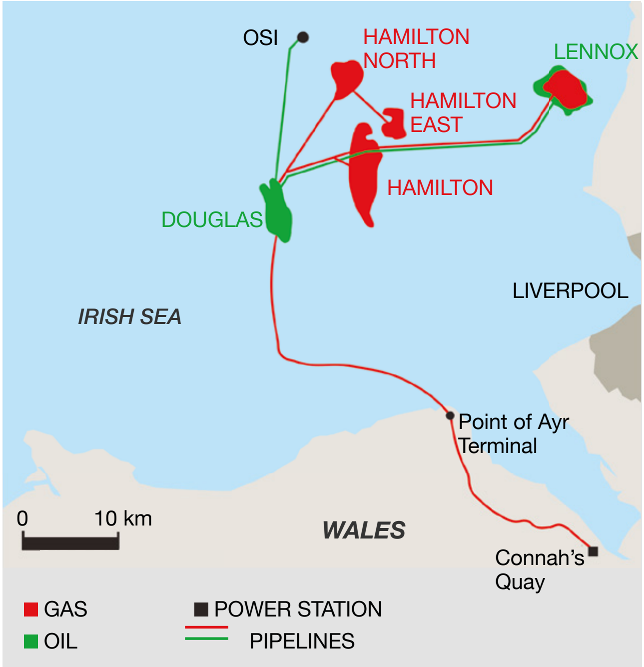

Figure 1: *The Liverpool Bay complex, oil and gas fields*[2]

1. Substituting, in whole or in part, for natural gas in large industrial processes. The North West is home to some heavy users of natural gas, for instance in glassmaking furnaces, brick kilns, and large industrial steam and hot water boilers. HyNet North West is working with such industries to find out how much hydrogen can be substituted for natural gas without adversely affecting the product, the process or the environmental performance. A modest investment can deliver significant reductions in CO_2 emissions for high hydrogen operation, making an important contribution to 'greening' a company's production facilities, and establishing world-class environmental performance.

2. The success of the UK's HyDeploy programme has shown that introducing up to 20% hydrogen into the natural gas supplies has a negligible impact on its combustion properties, and is no less safe. A second market for hydrogen can therefore be realised by introducing it into the low pressure natural gas system, enabling every home and every commercial premises to make a contribution to the national CO_2 reduction programme. Because of the negligible impact on the combustion properties, this would not require the replacement of any equipment, and would be at zero cost to the vast majority of customers. And if, for some reason, the scheme were not to work, there would be no re-conversion cost to revert to natural gas once again (ie a 'no regrets' approach).

3. Hydrogen-burning gas turbines have long been a dreamof the manufacturers, opening the door to a reliable, predictable, carbon-free electricity supply. With the arrival of low carbon hydrogen in bulk quantities, this potential can be realised. More details on this can be found in a recent article on their development[5], and this application is expected to open up another significant market in the North West (and elsewhere in the UK and internationally growing from it).

4. Transport applications, particularly for trains and larger vehicles (vans, trucks, buses), are being trialled in the North West, and the availability of a dispersed hydrogen distribution infrastructure will facilitate this. HyNet has the potential to offer this, by offering trunk hydrogen pipelines from which branches to 'filling stations' can be attached.

Hydrogen transportation

In June 2019 *The Chemical Engineer* published a report on the options and challenges of transporting hydrogen[6]. It concluded that pipelines represented the best option for bulk transport, and that applications requiring very high purity hydrogen (eg fuel cells) could benefit from local purification. HyNet envisages a hydrogen transportation system based on an arrangement shown as Figure 2.

The overall HyNet North West vision

The HyNet North West vision consists of three phases:

Phase 1: Building the evidence (2018–2023)

- Technical, cost and practical evidence to inform government heat and carbon capture policy.
- CCUS infrastructure created for industrial CO_2.
- Customer experience of blended hydrogen through the related HyDeploy project.

Phase 2: Project Delivery (2023–2026)

- Hydrogen infrastructure in place.
- Supply high hydrogen to industry.
- Supply blended hydrogen and natural gas to homes.
- CCUS infrastructure operational.
- Over 1m t CO_2 captured and stored every year.

Phase 3: Extension (2027–2035)

- Hydrogen supply extended to wider geography and for flexible power and transport.
- Realise opportunities for lower-cost H_2 and 'negative emissions' via bioenergy with CCUS.
- Hydrogen transport fuelling network in place.

2050 vision (2035 – 2050)

- Hydrogen supply extended to a wider geography and for flexible power and transport.
- Realise opportunities for lower cost H_2 and 'negative emissions' via bio-energy with CCUS.
- Hydrogen transport fuelling network in place.
- Up to 10 million tonnes CO_2 captured and stored every year.

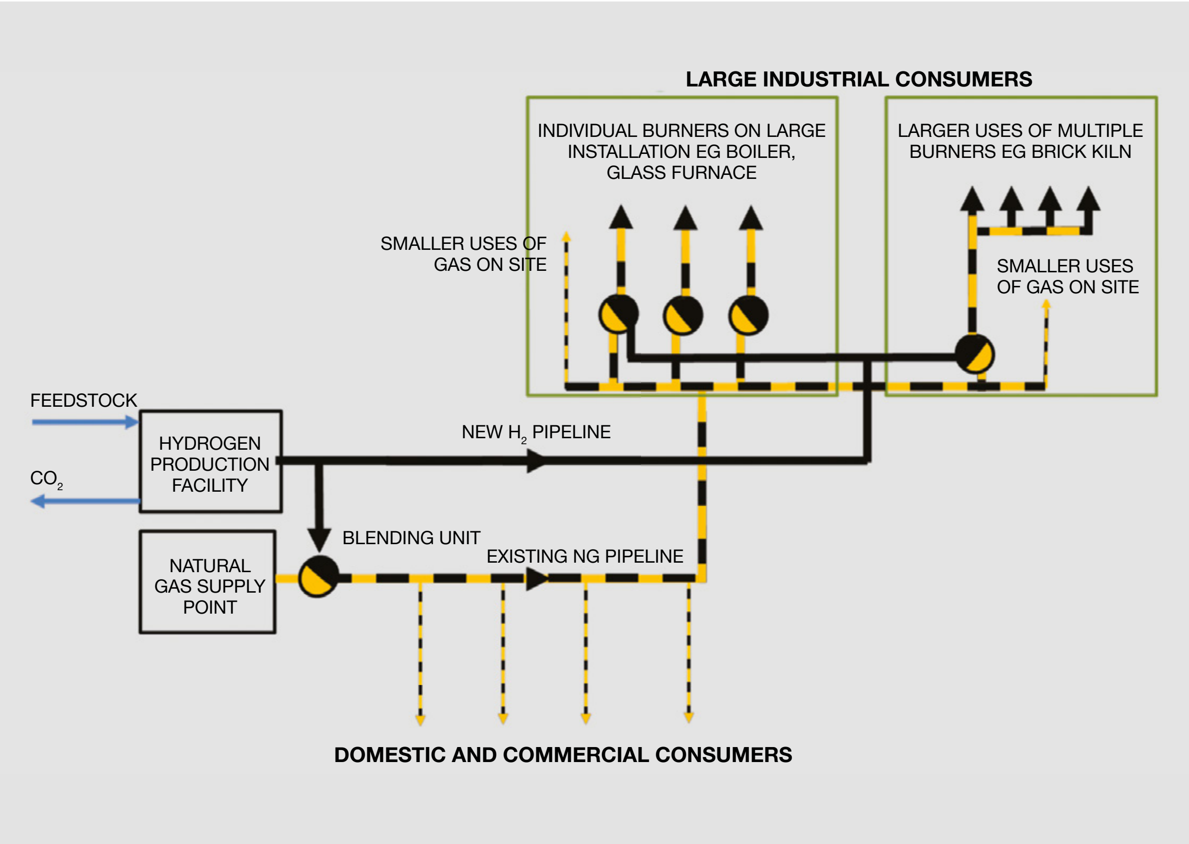

Figure 2: *Hydrogen distribution concept*

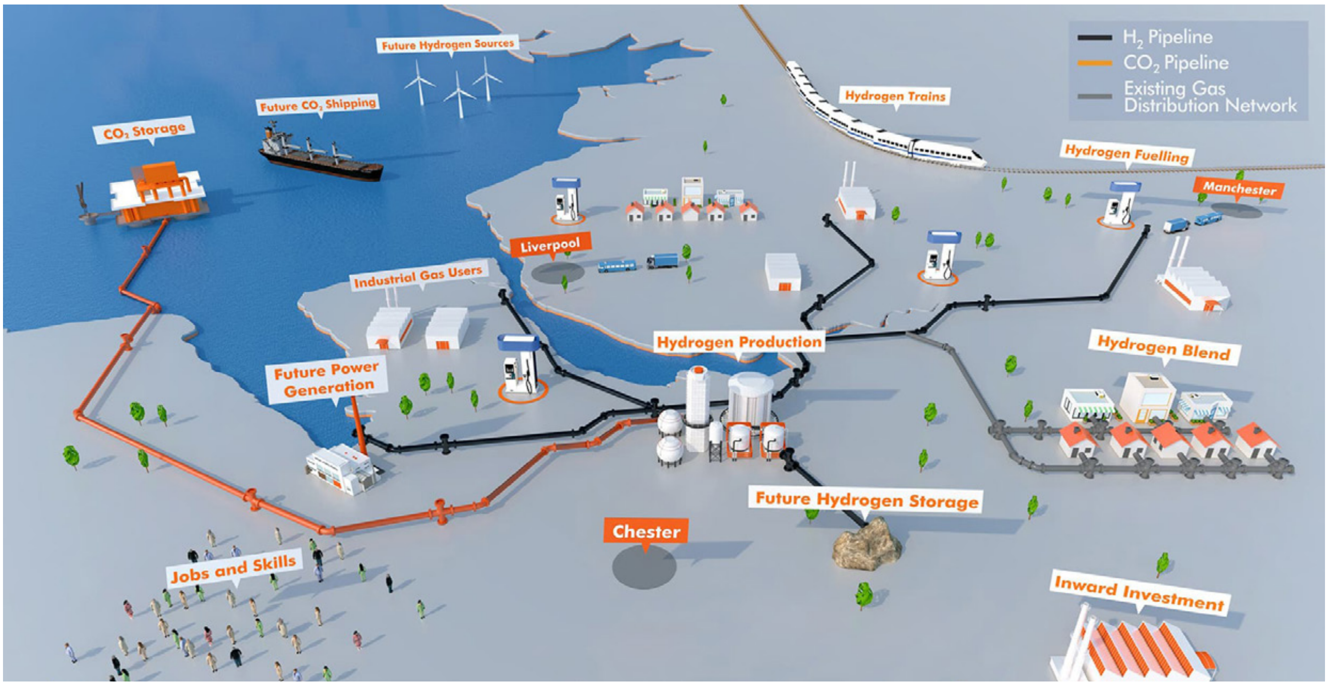

Figure 3: *Overview of the HyNet project*[7]

HyNet – gathering serious momentum

The engineering of the HyNet project is making significant progress. Pre-FEED work is complete on the hydrogen production plant design and combustion testing (up to 100% hydrogen on a glass furnace burner, and on a package boiler, typical of over 80% of the industrial designs in the UK). This work is currently in FEED.

Pre-FEED work is complete on the CO_2 export pipeline and storage (including flow assurance) and on a number of industrial capture sources. In parallel, the pre-FEED study on the hydrogen distribution system is well advanced with clear identification of demand profiles, network topography and storage requirements to manage variability in supply and demand.

In many respects, engineering HyNet is the simplest hurdle to be crossed – there is nothing in the HyNet vision that cannot be delivered with existing technologies and competent engineers. The biggest challenge is ensuring that a market framework is developed by government which makes HyNet an investable proposition.

We are at the stage of HyNet where we are transitioning from desktop studies to large-scale infrastructure delivery, and this requires serious investment to undertake surveys, consultations and secure consents.

The UK Government's level of focus in this arena has changed out of all recognition in the last 18 months, driven in large part by the Net Zero commitment and the recognition at all levels of government that hydrogen and CCUS is a necessity, and not an option. This has led to a political commitment to deliver investable business models for hydrogen and CCUS by the end of 2020, alongside with material levels of grant funding, and this will catapult HyNet into the execution phase.

HyNet stands ready to be the first, lowest-cost and lowest-risk integrated hydrogen/CCUS project in the UK, delivering a low carbon industrial cluster in the North West by the mid 2020s and building the infrastructure for whole-scale low carbon transformation of the hard-to-reach sectors of the economy.

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H21: the story so far

Tim Harwood

Climate Change, and how we tackle it, has become a defining issue for the global community in the last 12 months.

Greta Thunberg united a generation by calling out world leaders on their inaction. And although the Paris Agreement clock was already ticking, when Teresa May in June 2019 committed the UK to reaching Net Zero emissions by 2050, the deadline became even more ambitious.

While the UK power sector has made great strides in decarbonising, a credible solution for heat is yet to be settled upon.

The UK currently relies on 1,500 terawatt hours (TWh) of energy to heat buildings, fuel transport and power electric generation. Currently, less than 10% of this energy comes from renewable sources.

Almost half of the energy consumed in the UK is used for heat (760 TWh), with around 57% of this (434 TWh) heating our homes and hot water. Natural Gas currently heats 83% of our homes.

As a nation, we benefit from a world-class gas grid designed to ensure the continued safe, resilient and reliable supply of energy, whatever the weather.

At its peak, the network transports up to five times more energy than the electricity networks, and by its nature, acts as a giant storage facility.

In early 2018, when the so-called 'Beast from the East' left the country under a thick blanket of snow for a week, the Northern Gas Networks gas distribution grid alone delivered 470 GWh of energy in one single day, and provided 70 GWh of storage.

The scale of the challenge to replace it with a cleaner, greener alternative pathway is huge. If it cannot be repurposed, an asset worth £22 bn (US$26 bn), currently being reinvested in for another 100 years via the Iron Mains Replacement Programme (IMRP), risks eventually becoming stranded.

Hydrogen represents a credible pathway towards decarbonisation of heat. Zero carbon at the point of use, hydrogen could be deployed in our existing gas network, meeting the vast energy demand that natural gas currently supports today.

Repurposing the gas network to transport this clean gas would not only generate huge carbon savings, but also prevent disruptive and expensive change for consumers in our homes and highways.

Leading the work to present Government with the evidence on which to base policy is H21, a collaborative UK gas industry programme led by Northern Gas Networks, and focussed on conversion of the network to carry 100% hydrogen.

H21 received £9m of Ofgem Network Innovation Competition (NIC) funding in 2017, and a further contribution of £1.3m from the other distribution networks to deliver the first phase of critical safety evidence required. This will aim to show that a hydrogen network is of no greater risk than the methane network heating our homes today. A full report is due in Q3 2020.

The NIC was followed with 2018's H21 *North of England* report, a detailed engineering scenario written in partnership with Equinor and Cadent.

This set out how 3.7m homes in the North's major urban centres could be converted, and the associated production and storage infrastructure, as well as CCS, that would be required to deliver clean heat across the North.

At the end of 2019, H21 received £6.8m of further NIC funding to develop Phase 2 of the safety case, which will begin in Q2 2020

Background to H21

The H21 project began in Leeds as a feasibility study, examining whether converting the gas distribution network of a city (one of the same size and energy demand as Leeds) was both technically possible and economically viable.

In 2016, the Leeds City Gate study proved it was, and the carbon savings, if the UK converted wholesale, were calculated to be as much as 70% of total heat.

But without a robust and immoveable safety case to underpin it, no Government policy decision around hydrogen's use for domestic heat will materialise.

While the Government undertook the 'downstream of the meter' work through Hy4Heat – a £25m project looking at hydrogen's use in buildings and appliances – H21 shifted from desktop study into heavyweight research and demonstration project to provide the Government with this essential data on the network.

H21 NIC

The H21 NIC focussed on delivering the essential critical safety evidence. This was aimed at proving that a 100% hydrogen network was of no greater risk than the natural gas network currently heating homes and fuelling industry today.

Backed by all of the UK GDNs – Northern Gas Networks, Cadent, SGN and Wales & West Utilities in collaboration with the Health & Safety Executive and DNV-GL – Phase 1 has centred around two main workstreams since the start of 2018.

Phase 1A

Phase 1A comprises asset collection and background testing on a bespoke facility at the Health and Safety Executive's Science Division in Buxton.

This set of tests covers the huge range of metallic and PE assets, valves, joints, fittings and pipes across the UK, ranging in different pressure tiers and diameter. As part of the UK IMRP, a cross section of these assets has been removed from across the network, and transported to the HSE site in Derbyshire.

Here, on a specially-built leakage test rig, controlled testing with natural gas and 100% hydrogen is providing the essential evidence for changes to background leakage levels in a 100% hydrogen network.

Phase 1B

Phase 1B involves consequence testing at DNV-GL's rig at RAF Spadeadam, in Cumbria.

This phase is measuring the risk associated with background leakage from Phase 1a, such as failure leakage, mains fracture, third-party damage and operational repairs. Testing will establish the consequences of leaking hydrogen, such as tracking and dispersion, in scenarios with different potential sources of ignition, and comparing them to those of natural gas.

In addition to the two key phases, the H21 NIC is also delivering a quantitative risk assessment (QRA) and master testing plan (MTP). The QRA will be used to update the computer-based modelling systems for natural gas to 100% hydrogen applications, while the MTP was finalised for both sites' testing regimes, to ensure credibility, and that tests were undertaken in accordance with agreed methodology.

Interest in H21 has steadily grown since the Leeds City Gate report, and around 100 stakeholders – including Ofgem CEO Jonathan Brearley – visited the Buxton site last July, to see this pioneering facility in action.

Results from Phase One will be shared in a full report in Q3 2020.

Phase 1 - Various configurations of gas network assets assembled for testing at the bespoke facility based at the Health and Safety Executive's Science Division, in Buxton, Derbyshire.

evidence base. National Grid and Leeds Beckett University are also joining the H21 consortium for Phase 2.

The main focus of the work will involve simulating network operations on a specially-constructed mini network in Spadeadam, continuing to use the site deployed for Phase 1.

Network research trials on an unoccupied test site will also be undertaken, to demonstrate operational and maintenance procedures – an essential prerequisite to live trials – and will take place on a decommissioned part of the gas network.

A combined QRA will bring together findings from the network testing and that of the Hy4Heat programme, currently exploring hydrogen's use in buildings and appliances.

Customer research

Phase 2 will also build upon customer research carried out as part of Phase 1, working with social sciences teams from Leeds Beckett University to understand further public perceptions of hydrogen.

With no established evidence for how customers would respond to the prospect of a hydrogen conversion, and its effects on heating and cooking, the initial research was carried out to delve into the detail of public awareness of hydrogen as an energy source, and unpack any perceived associations or barriers to its use.

The full results of this research will be shared later in Q2 2020, at a special launch in Leeds, with outline findings showing customers are broadly supportive of hydrogen for heat, providing it comes at the right cost and without major disruption.

The social sciences workstream for Phase 2 will focus on developing resources to enable consumers to make informed choices on their future energy.

H21 North of England

While the NIC work got under way, back in November 2018, the H21 team published a second major report: *H21 North of England*.

This was delivered in partnership with global energy giant Equinor, a leader in the field of carbon capture and storage (CCS) technology, and Cadent, the UK's biggest gas network.

H21 North of England underpins the safety case, presenting a conceptual design for converting the existing networks of the North's major cities, and the precise requirements of the production, storage, transmission and CCS needed to deliver clean heat, at scale, across 3.7m homes, between 2028 and 2035.

The blueprint includes a 12.15 GW hydrogen production facility and 8 TWh of inter-seasonal storage, to generate carbon savings of 20m t/y by 2035.

What's next

Clean energy demonstrator projects are likely to take on increasing significance in the UK this year.

As the country prepares to host COP26 in November, expectation for us to take the lead on decarbonisation strategy will be high. Until Government policy on hydrogen is set, industry will continue to develop the evidence base to support it through projects like H21.

The H21 Phase 1 results report will be launched to key stakeholders in Q3 2020.

As Phase 2 gets under way, plans are now in development for Phase 3, involving a live demonstration in an occupied area from 2022. Phase 4 – part conversion of the network – could begin as early as 2024–25.

In the meantime, hydrogen's potential as a decarbonisation solution is gathering strong support overseas, and public awareness is growing.

Learn more about H21 by watching our NIC update film at www.h21.green.

Spadeadam – Views of the H21 test houses, locaeted at the specialist rig at DNV GL, in Spadeadam Cumbria. The houses are surrounded by a ring main that is fulled with hydrogen and released in a controllable manner.

Japan: taking a lead in hydrogen

Sanjoy Sen FIChemE

If you think the energy situation in the UK looks challenging, just consider that of Japan. With double the population (126m vs 65m)[1] crammed into brightly-lit, air-conditioned mega-cities, plus a vast manufacturing base to feed, total energy consumption is the world's fifth largest[2]. But Japan's domestic natural resources (coal, oil, gas) are practically non-existent.

From the 1960s onwards, Japan bet large on nuclear, constructing over 50 reactors. Its first plant at Tokai was, in fact, supplied by Britain's GEC. Then, in 2011, disaster struck as a massive tsunami overwhelmed the Fukushima Daiichi facility. With public confidence shattered, the entire atomic fleet was shut down. Whilst some plants are slowly returning to service following work to bolster their safety cases, energy-hungry Japan remains the world's largest LNG importer and the third largest coal importer[3].

With a change of direction essential, Japan has identified hydrogen as the answer, both for transportation and in power generation. Via the 3E+S (Energy Security, Economic Efficiency, Environment + Safety) principles enshrined in its 2014 Strategic Energy Plan, Japan intends to showcase hydrogen at the 2020 Tokyo Olympics[4]. Some 40,000 hydrogen fuel cell vehicles (FCVs) and 160 filling stations are to be ready for the Games, leading to 800,000 by 2030. As we're about to see, Japan's plans are certainly ambitious – and not without challenges.

Japan's massive car industry is getting on-board with its 'big three' (Toyota, Nissan, Honda) teaming up with Air Liquide to boost the national re-fuelling network[5]. And, having pioneered the Prius petrol-hybrid in the 90s, Toyota recently launched the Mirai (see Figures 1 and 2), the world's first purpose-built hydrogen fuel cell vehicle. Its hydrogen-fed fuel cell can even power homes[6], potentially a life-saver in an earthquake-prone nation.

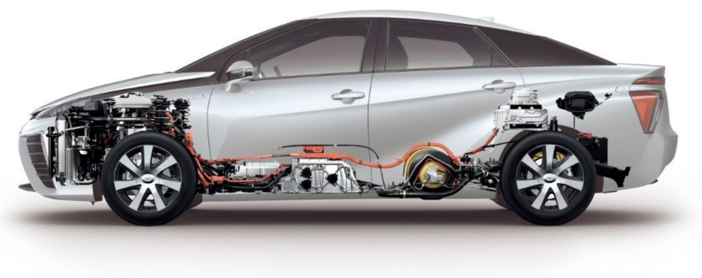

Figure 1: *Part-section of the Mirai - Toyota UK.*

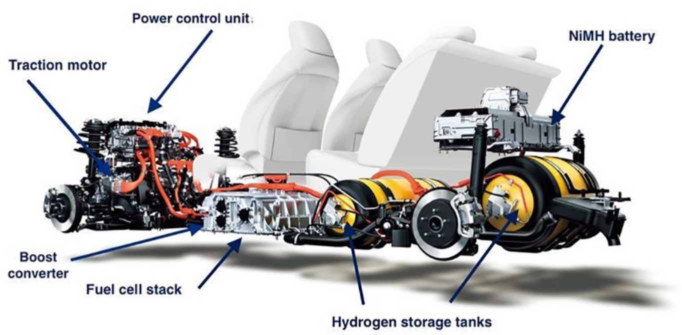

Figure 2: *Cutaway of the Mirai fuel cell-vehicle showing the hydrogen tanks and fuel cell stack - Toyota UK*

Fuel cell vs electric

But whilst economies-of-scale might address the Mirai's £60,000 price-tag[7], some warn of Japan creating unique 'Galapagos' solutions which cannot readily be marketed globally[8]. By constrast, North America is pursuing more of an 'electrify everything' philosophy[8] as exemplified by Elon Musk. Tesla's billionaire founder has slammed fuel cell vehicles as 'really dumb'[9], betting instead on an electric vehicle (EV) and domestic battery storage combination. And with limited take-up of 'hydrogen highways' to date, Europe also broadly favours the electrical route for transportation.

The fuel cell vs electric argument is not clear-cut, however. Electric vehicle proponents note that using renewables-sourced electricity to directly charge up a battery-electric vehicle is much more efficient (73%) than using the same power to generate hydrogen to feed a fuel cell vehicle (22%). Others counter that this may not provide the full picture: hydrogen could be produced from surplus 'green' power generated at effectively zero marginal cost. And that electricity distribution infrastructure (designed around relatively low mean demand) may struggle as electric vehicle charging demand ramps up. According to a German study, the overall cost of switching 20m vehicles to fuel cells would be cheaper than for electric vehicles. The study goes on to show, as we'll see below, that these two so-called rivals might instead complement each other with fuel cell vehicles used by larger, centralised users, and electric vehicles preferred by private motorists.

Storage and transport

Storing and transporting hydrogen is not without its challenges.

To prevent leakage and to ensure crash safety, automotive engineers have equipped the *Mirai* with a sophisticated 90 kg carbon-fibre fuel tank[10] to contain the 5 kg of hydrogen needed to provide a 482 km driving range. Meanwhile, chemical engineers have been busily addressing hydrogen challenges on a larger scale.

Building on its 30-year track record in LNG, Kawasaki is promoting liquefied hydrogen solutions for bulk shipping[11]. And it's using its experience gained in storing the liquid hydrogen used in Japan's space programme to develop the national storage network. To maintain the required temperature of -253 ºC, highly effective insulation is key: the tank is double-hulled with perlite (a thermal insulation material) between the inner and outer walls[12].

Elsewhere, Chiyoda's SPERA concept proposes organic chemical hydride (OCH) technology. By combining hydrogen with toluene to form methylcyclohexane (MCH), it can be transported long-distance by ship as a liquid at ambient conditions. Upon arrival, the process is reversed, releasing the hydrogen with the toluene recycled[13].

Such liquid organic hydrogen carriers (LOHCs) require complex synthesis and regeneration processes, however: Germany's Siemens instead proposes to convert hydrogen into ammonia[14] for ease of storage and transportation before using it directly as a fuel for power generation and transport.

Sourcing hydrogen

Returning to Japan, the issue of where to source hydrogen is also proving contentious. Last year, *The Chemical Engineer* reported that Kawasaki Heavy Industries and the Australian Government entered into a pilot-plant partnership[15] to begin converting Australia's Latrobe Valley's vast lignite reserves. Whilst a scaled-up development would include carbon capture and storage (CCS), environmentalists have lambasted it as yet another coal-based development. Furthermore, they note that upon arrival in Japan, the hydrogen could be bled into the supply to existing thermal power stations[3], thus prolonging the nation's dependence on imported fossil fuels.

That said, with storage and distribution infrastructure established, alternative hydrogen sources, including local renewables, could follow. Plans are already underway in the Fukushima prefecture[16] to construct an 11.3 MWe solar-powered plant to generate hydrogen via electrolysis. But just to prove there are no perfect solutions, elsewhere in densely-packed Japan, concerns have been raised[17] about the destruction of forests to make room for solar farms. Meanwhile, developments in floating offshore wind and tidal energy could prove key in the deep and stormy waters surrounding Japan.

What lessons can be learned?

So, what might the UK learn from Japan's early lead in hydrogen? Whilst technology learnings are always there to be shared, the deployment may be very different. In the UK, the renewables sector is well-established and growing further; some of this green electricity could be converted into green hydrogen. This could then be used in power generation to smooth out the intermittent output from offshore wind.

Or it might be used a substitute for (or a diluent to) natural gas for our heating needs as per the H21 concept[18]. By contrast, the typical Japanese home lacks central heating (at least as we understand it). And with parts of the UK North Sea oil and gas sector approaching decommissioning, redundant offshore infrastructure could be re-purposed for hydrogen production and storage.

And in transportation, we might see hydrogen best deployed as a substitute for large-scale diesel users: imagine the improvement in urban air quality of switching commuter trains, buses, delivery vans and taxis over to hydrogen. And as those major users can be re-fuelled from centralised hubs, the need for widespread new infrastructure can be much reduced, especially if the UK public plumps for EVs for its personal transport.

There's no doubting the scale of Japan's hydrogen vision and its determination to deliver on it. And whilst much of this makes sense in the context of the nation's unique energy challenges, the hydrogen roll-out won't be quick or cheap. Few other places may choose to embrace hydrogen as widely but there are sure to be valuable lessons to be learned from the Japanese.

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Hydrogen down under

Jacob Brown AFIChemE and Michael Kuhni

With the rise of electric vehicles, and increasing climate awareness amongst the world's population, hydrogen has returned to the global agenda. Climate advocates seek a zero-emissions fuel, and oil majors are looking to hydrogen as they seek to leverage their reservoir assets and fuel processing expertise in a climate-friendly energy economy.

This is nowhere more true than in Australia, a nation which finds itself suddenly in possession of the basis for a powerful hydrogen economy. Australia is an export nation, and mega-projects run in its blood. Now that Japan, a key export partner of Australian gas producers, has announced its commitment to a hydrogen future, Australia makes a natural choice as a supply partner. The Australians, always sensitive to movements in commodity prices, are keenly aware of this, and hydrogen development is a rare point on which both sides of politics largely agree. Whilst the promise of a A$1bn hydrogen stimulus package died with the re-election of Australia's Conservative Party at the federal level, the state governments have been co-ordinated and effective in their efforts to push for hydrogen development.

Japan published its 'Basic Hydrogen Strategy' in 2017, and the following strategic relationship development with Australia has catalysed considerable interest in the future fuel. Due to false starts in the 70s and 80s, hydrogen is still the subject of considerable scepticism within the energy community. However, by all accounts, Japan is serious about developing the technology and Alan Finkel, Australia's Chief Scientist, has at least been convinced. Over the past few years Finkel has been a strong advocate of the hydrogen opportunity. In October 2018, he presented to the Council of Australian Governments (COAG), estimating hydrogen exports of 137,000 t/y by 2025. Whilst insignificant in comparison to Australian LNG exports (soon to be the world's largest at around 70m t/y), the opportunity has triggered a large amount of policy, project, and research support for hydrogen activities across the country (see Figure 1).

In this hydrogen-friendly climate, the past two years have seen a number of world-leading projects announced. This is good news for the development of a hydrogen economy, but it should be noted that the climate credentials of some of these projects are questionable. Significant sums have been invested in renewable-powered electrolysis projects, but they have also been invested in strongly CO_2-emitting brown coal gasification. It is clear that Australia is interested in hydrogen, but it is still an each-way bet as to whether the industry and the government will choose the polluting path or the 'clean' one.

One of the most well-known projects, and probably the most controversial, is the coal seam gas project in the Latrobe valley of Victoria. The Latrobe valley is one of Australia's largest coal regions, and a flare point for much of the country's politics. Receiving A$100m in government support, the Latrobe hydrogen project could easily be seen as a political move, attempting to bridge the ever-widening gap between supporters of

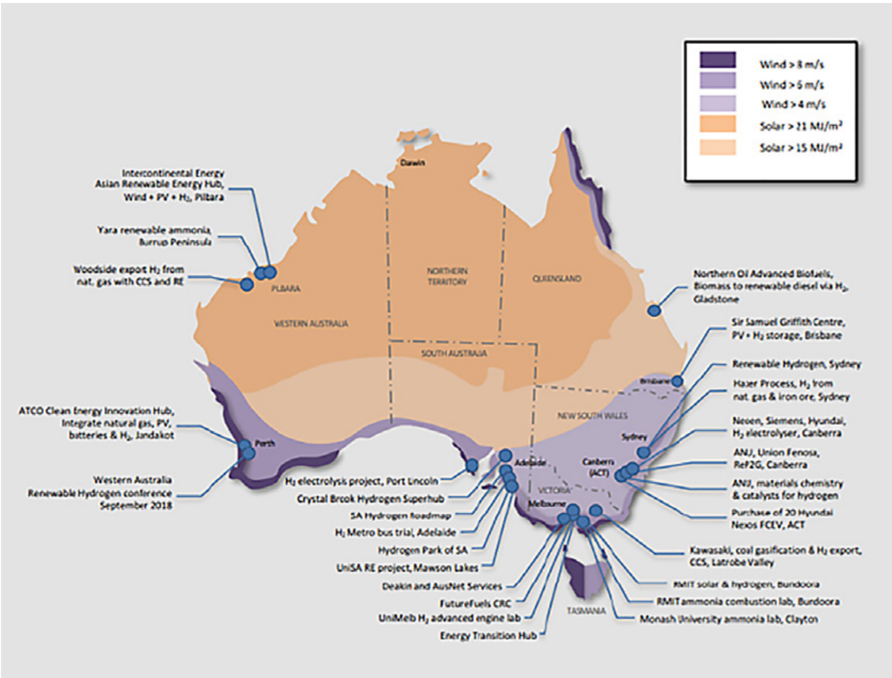

Figure 1: *Australia current hydrogen projects and recent activities, November 2018.*

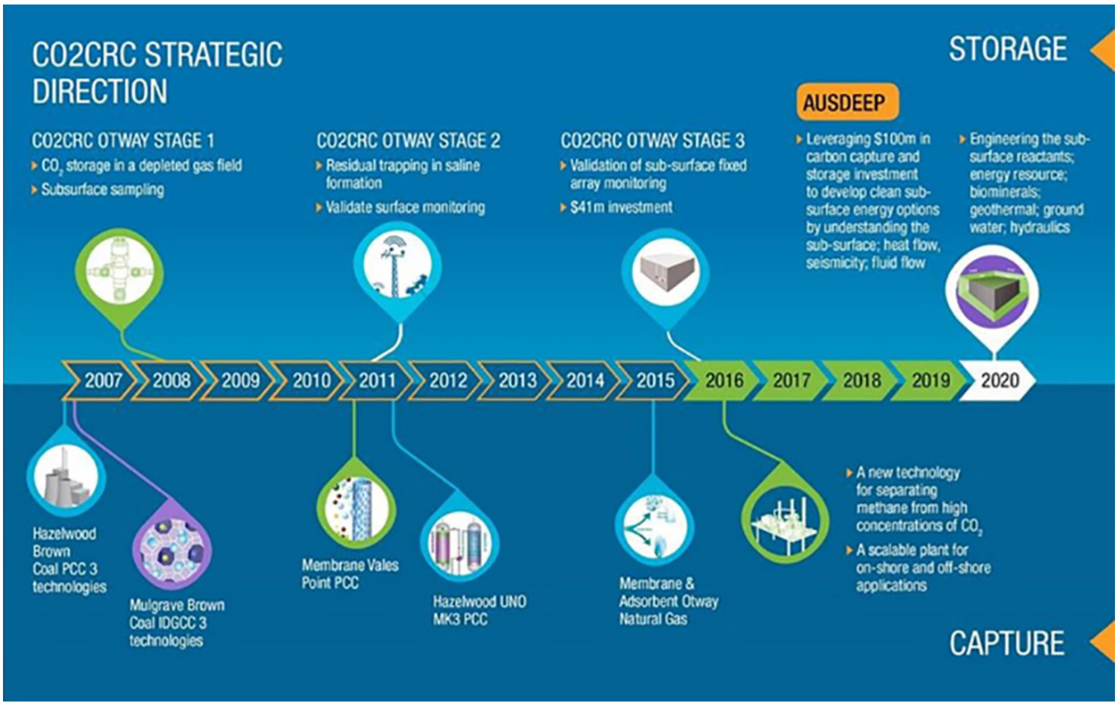

Figure 2: *CO2CRC strategic direction.*

the coal industry and those calling for climate action. The hydrogen will be extracted from coal gasification in the region, but it is as yet unclear what will be done with the resultant CO_2, and whether it will be captured and injected back underground. The industrially interesting test lies in the port facility, for which Kawasaki has recently announced its intent to construct a A$500m hydrogen liquefaction and export terminal. The incredibly cold temperatures required for hydrogen liquefaction (around -254 °C) will require extensive engineering consideration and design; and success depends upon handling these factors appropriately. At this stage, the project is just a pilot, consuming 160 t of coal, generating 100 t of CO_2 and producing only 3 t of hydrogen over its 12-month duration. It is unclear what steps will be taken after the completion of this phase but, as the maxim goes: 'From little things, big things grow'; proving the concept in Latrobe may be the first step to much more extensive investments in future years.

Whilst 'brown' (CO_2 released) and 'blue' (CO_2 captured) hydrogen from steam reforming have certainly been of interest in the country, Australia's renewable hydrogen proposals have so far dwarfed those of fossil-based projects. With the precipitous drop in the cost of solar and wind power (around 70% for wind, and 90% for solar) in the past decade, many believe that the cost of hydrogen will begin to follow the same downwards trajectory. Such a movement could cause fundamental changes in energy market economics and Australia's abundance of land, sun, and wind has lured many large organisations to pursue this opportunity.

Both the Yara ammonia plant in Western Australia, and Neoen's Hydrogen Super Hub in South Australia have announced the upcoming construction of 50 MW solar/wind-powered electrolysers for the production of 'green' hydrogen. This is significant, and if deployed today, either of these projects would be the largest of their kind in the world. In addition to these specifically hydrogen-focused deployments, an increasing number of renewables projects are also incorporating hydrogen development for grid balancing activities. The Asian Renewable Hub, an enormous 15 GW renewable park proposal aiming to deploy solar and wind energy in Australia's North-West, has also made clear its intention to deploy hydrogen electrolysis to make use of electricity in off-peak periods.

Whilst the industry is developing, some clear challenges remain. Particularly, shipping of hydrogen fuel is not a trivial task. Australian innovation, in the form of start-ups and government-funded research, is attempting to work around some of these barriers. One of the most interesting developments is that from CSIRO, the country's national science institution, announcing key advancements in the reversible conversion of hydrogen to ammonia. This is a key innovation for hydrogen, as ammonia carries much more energy per unit volume and liquefies much more readily. If CSIRO continues to achieve progress in this direction, it is hoped that the easy inter-conversion between hydrogen and ammonia will drastically reduce the cost of shipping the fuel.

Another key piece of technology lies in the abatement of CO_2 from fossil-based hydrogen projects (recall the earlier figure of 70m t/y in LNG exports). If carbon capture and storage becomes commercially viable, steam-reforming of methane to produce blue hydrogen from Australia's abundant natural gas reservoirs could become a mainstream practice. This opportunity, coupled with the fear of climate-related political action, means that Australia is keenly looking for a solution to this problem. So much so, that the Australian CO2CRC research council maintains the world's largest carbon capture research and storage demonstration project. Since 2007, the council has allocated over A$100m of government funds to end-to-end CO_2 production and sequestration research (see Figure 2).

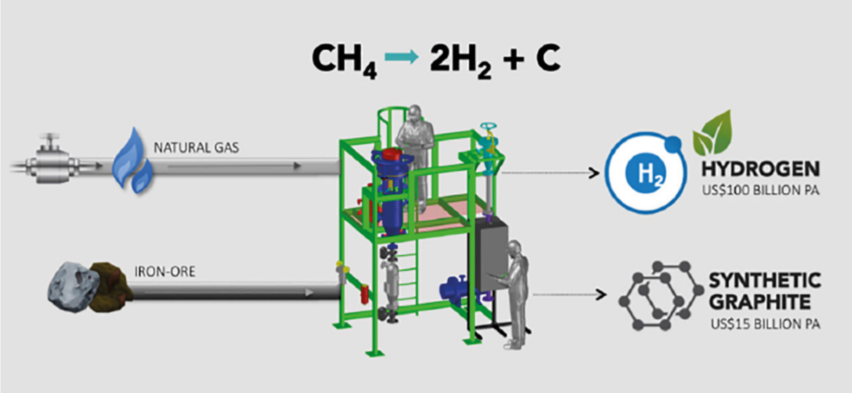

Figure 3: *The Hazer Process.*

One particularly interesting solution to the carbon capture problem is found in the Australian startup Hazer Group. Hazer is currently in the pilot stages of commercialising an innovative carbon-capture technology in which CO_2 production is completely avoided (see Figure 3). Based on methane cracking technology out of the University of Western Australia, the group aims to transform methane directly into graphite and hydrogen using a cheap iron ore catalyst. Such a process would eliminate the need for expensive CO_2 capture and has the potential to be disruptive if proven at larger scales. Successful development of these carbon abatement technologies could be a game-changer for fossil fuel companies seeking to adapt to our changing energy system. If this sleeping giant of the hydrogen economy is woken, it could lead to rapid and large-scale deployment of hydrogen energy globally.

Whilst the export opportunity is large, the attention being paid to the area has also led to interest in domestic applications. Much of the Australian housing system still has gas connections, and several projects are looking at distributing hydrogen throughout the network. The gas network operator in Western Australia, ATCO Gas, built and unveiled a 'green' hydrogen facility in July 2019, and is injecting a low concentration of hydrogen into the local network for use in homes. Virtually the same activity is also being carried out in Sydney by the gas retailer Jemena, arguing that customers are increasingly looking for sustainable solutions. The existence of these projects signals an unserved need in the Australian market; namely that households want their gas connections, but that they also want to lower their carbon footprint. As these projects develop, it will be interesting to see exactly how widespread the demand is for carbon-neutral fuel.

Energy is a vital part of Australia's economy; it has been, and will continue to be, a vital source of jobs, prosperity and political power in the country over the coming years. Unlike other green energy technologies, hydrogen can be a fuel, and stands to provide an important component of the energy mix as the world decarbonises. Exports can be sent to nations without renewable resources, and it is reasonable to assume that the geopolitics of energy supply chains will shift significantly if hydrogen exports are proven viable in the next decade. Whether or not hydrogen will become a dominant player is an open question, but observers would do well to pay attention to Australia's movements in the coming years.

Hydrogen in South Australia

Owen Sharpe

In 1972, academic professor John Bockris of South Australia's Flinders University coined the term 'hydrogen economy' in *Science Magazine*[1]. As the decades and technological advancements progressed, hydrogen's role as a potential solution to Australia's 'energy trilemma' – balancing energy affordability, security, and sustainability – has gathered momentum.

Global demand for hydrogen is increasing as a carbon-free fuel for transport, power and heating. Energy-hungry nations such as Japan and the Republic of Korea are seeking to utilise hydrogen to reduce their reliance on imported fossil fuels.

As an energy export superpower to the Asia-Pacific region, the International Energy Agency (IEA) and the World Energy Council have declared that Australia has the potential to be the world's largest hydrogen producer[2].

Australia is leading a considerable amount of work – both globally and domestically – seeking to quantify the economic opportunities associated with hydrogen[3]. The IEA suggests Australia could produce the equivalent of 100mt of oil in hydrogen per year[4], and the Economic Research Institute for ASEAN and East Asia forecasts Australia to export 42% of regional supply to East Asia by 2040.

As one of the world's leading jurisdictions in renewable energy development, with over 51% renewable electricity generation in 2018[5], South Australia has a fundamental competitive advantage in renewable hydrogen production arising from coincidental, complementary and high quality wind and solar resources. This advantage is shared domestically only with the south-west of Western Australia and small pockets of Queensland.

South Australia was the first Australian jurisdiction to showcase its land and infrastructure, abundance of renewable energy resources and experience in developing cutting-edge energy projects – such as the world's largest lithium-ion battery[6] – through the release of the *Hydrogen Roadmap for South Australia* in September 2017.

Why so much interest now?

In December 2018, Australia's Chief Scientist Alan Finkel achieved the endorsement of the Council of Australian Government's Energy Council to develop an ambitious *National Hydrogen Strategy* for consideration by the Council at the end of 2019.

The Strategy has the aim of building a clean, innovative and competitive hydrogen industry that benefits all Australians and is a major global player by 2030[7].

As Finkel explains in the COAG White Paper *Hydrogen for Australia's Future* [8], the impetus to decarbonise many countries' economies has combined with the price of solar and wind electricity dropping a hundredfold in the decades since the concept of the hydrogen economy was coined. Australia's near-neighbours are looming as major and enduring customers.

Through its *Basic Hydrogen Strategy*, Japan has established measurable objectives to showcase hydrogen's production and use to the world at the Tokyo Olympic Games in mid-2020 and beyond. Similarly, the Republic of Korea released its *Hydrogen Economy Roadmap* in early 2019, outlining its vision to become the world's leading hydrogen economy, including its evolution from a country of fossil resources to a major, eco-friendly producer of hydrogen fuel[9].

The South Australian Government has invested more than A$15m (US$10.4m) in grants and A$27.5m in loans to scaling up its renewable hydrogen production industry.

These projects include:

- Australian Gas Network's Hydrogen Park of South Australia (HyP SA) in metropolitan Adelaide;
- the University of SA's Mawson Lakes Renewable Energy System in metropolitan Adelaide;
- Neoen Australia's Hydrogen Superhub at the Crystal Book Energy Park in the State's regional mid-north; and
- the Port Lincoln Hydrogen and Ammonia Pilot Project in the State's regional Eyre Peninsula.

The projects target a range of end uses such as gas injection, transport, ammonia, and grid security services, and one project is to construct a testing facility with hydrogen consumed on-site.

Hydrogen Park of South Australia

Australian Gas Networks (AGN), part of the Australian Gas Infrastructure Group (AGIG), received A$4.9m from the South Australian Government for a A$11.4m hydrogen electrolyser demonstration project at the Tonsley Innovation District in Adelaide.

AGN owns gas distribution and transmission networks across Australia, including in South Australia. In the short term, AGN plans to blend 5% renewable hydrogen with natural gas for supply to customers using its existing gas distribution networks. This is a milestone first step towards decarbonising the gas networks.

The project will involve Australia's largest 1.25 MW Siemens proton exchange membrane (PEM) electrolyser that will use 100% renewable energy electricity contracted through a Power Purchase Agreement to produce renewable hydrogen.

The demonstration facility will inform the technical and economic feasibility of injecting hydrogen into a gas network more broadly in South Australia. It is also expected to show how electrolysers can be integrated into electricity networks to support energy stability, as more renewable energy generation capacity comes onto the grid.

Having completed the front-end engineering and design study and ordered the Siemens electrolyser, AGN is now working towards securing regulatory and development approvals, procuring land, and undertaking community and stakeholder consultation.

AGN aims to have the project operating in mid-2020. The installation of tube and trailer filling facilities is being considered as an expansion opportunity to Hydrogen Park SA, which will enable hydrogen to be transported and injected into other points in the network, as well as industry refuelling and export.

AGN is also investigating working with Australian and South Australian Governments and industry to establish the Australian Hydrogen Centre, to maximise its investment in and findings from the project.

Mawson Lakes renewable energy system

The University of South Australia is building a A$8.7m facility incorporating a solar installation, flow batteries, a hydrogen fuel cell stack and thermal energy storage at its Mawson Lakes campus.

The project – which attracted A$3.6m from the South Australian Government – aims to produce data to support multi-disciplinary research projects (such as optimising performance, economics, and energy and emissions) in hydrogen, battery storage and solar technologies. Produced energy will supplement campus needs especially at periods of peak demand.

UniSA announced the project in 2017, as building one of the largest flow battery and hydrogen fuel cells in any Australian university. It will feature solar panels on 18 buildings at Mawson Lakes, one hectare of ground-mounted solar panels, and 1.8m L of thermal energy storage.

The facility, to be completed during 2019, aims to increase the availability of zero-carbon renewable energy, and reduce pressure on the local electricity network and the likelihood of power cuts on the campus.

Partnering with Australian renewable energy companies, UniSA expects the facility to provide more than 250 MWh of electrical storage annually, reducing the campus's peak electrical load by 43%, cutting its emissions by 35% and making renewable energy available on demand. Annual energy savings are expected to be around A$470,000.

Neoen's Crystal Brook energy park

The Crystal Brook Energy Park development is a renewable energy project that combines storage, solar and wind, located approximately 3 km north of Crystal Brook in South Australia. The park is a 275 MW renewable energy facility with up to 125 MW of wind generation comprising 26 turbines, 150 MW of solar PV and 130 MW/400 MWh of battery storage with a purpose built sub-station to deliver the power back into the South Australian grid.

Neoen has completed an initial feasibility study for an A$600m renewable hydrogen production facility that would be located at the energy park. The proposed 50 MW Hydrogen Superhub would be the largest co-located wind, solar, battery and hydrogen production facility in the world, with the potential to produce around 25 t/d of hydrogen using 100% renewable energy.

Port Lincoln hydrogen power plant (H2U)

Hydrogen infrastructure company Hydrogen Utility (H2U) is developing a 30 MW electrolysis plant to generate hydrogen and ammonia using 100% renewable energy at Port Lincoln on the tip of Eyre Peninsula in regional South Australia. The project is anticipated to provide balancing services to the national electricity system and fast frequency response support to new solar plants on the Eyre Peninsula.

H2U's proposed A$117.5m green hydrogen and ammonia demonstration plant – to be situated near local wind farms and planned solar plants – will include a 30 MW electrolyser plant, a 50 t/d ammonia production facility, and a 16 MW hydrogen-fired gas turbine which will supply power to the grid. The ammonia will be used for the local industrial and agriculture markets and to support development of a new export industry.

2019 International conference on hydrogen safety

South Australia has attracted the 8th International Conference on Hydrogen Safety to be held in Adelaide, Australia on 24–26 September 2019. The conference will be jointly delivered with HySafe – the International Association for Hydrogen Safety, which is the focal point for all hydrogen safety related issues – and facilitate networking for the further development and dissemination of knowledge, and coordination of research activities in the field of hydrogen safety.

The conference is the premier hydrogen risk management event globally and the first seven conferences, held between 2005 to 2017, succeeded in attracting the most relevant experts from all over the world. The experts provide an open platform for the presentation and discussion of new findings, information and data on hydrogen safety – from basic research to applied development and from good practice to standardisation and regulatory issues.

Themes for the Adelaide conference include the physical properties and behaviours of hydrogen, and how they must be considered in energy-related innovation, including the benefits and risks related to hydrogen development; regulation codes and standards for transporting and exporting hydrogen; and how to educate and engage stakeholder groups and communities about hydrogen's applications and potential in sectors ranging from defence to residential electricity provision.

In South Australia, hydrogen has been a topic of conversation for almost 40 years. This year, it's expected to dominate discussions across government, industry and the state's world-recognised tertiary institutions – so perhaps the solution to that "energy trilemma" may soon be within reach.

Footnotes

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Where next?

Although these articles demonstrate a wide range of examples where work on hydrogen is active, there is still work to be done. Chemical engineers have a role to play in sharing knowledge with others in the profession and wider technical landscape as well as informing policy- and decision-makers. There is a need and opportunity to raise awareness about the importance of hydrogen as an energy vector for the future.

IChemE continues to promote the role of chemical engineering in a sustainable future. This collection of articles forms part of the wider activity to promote knowledge and understanding on the topic of climate change and the transition to net zero. So, where does hydrogen fit into this?

This series of articles provides evidence that hydrogen can:

- **be produced in large quantities using established technologies;**
- **be transported in a number of ways over long distances;**
- **be utilised in many ways, usually as a substitute for the burning of CO_2-producing fossil fuels;**
- **be a safe substitute for natural gas; and**
- **if used responsibly, contribute towards the 'zero carbon' target and a fully sustainable energy system.**

This series has also shown that no fundamental technological breakthroughs are necessary for the wide-scale adoption of hydrogen as an energy vector. What it lacks is implementation and a business model to incentivise commercial investment.

Enter the chemical engineer!

Working with a wide range of engineering and other disciplines, chemical engineers have the knowledge, skills and experience to help to bring about what amounts to a revolution in global energy. A revolution that marks the end of the carbon era that has had such a devastating impact on our planet, and the dawn of a new era for the world – the hydrogen era and a significant step towards net zero.

IChemE's purpose is to advance the contribution of chemical engineering worldwide for the benefit of society. We have the vision that we are led by members, supporting members and serving society. This work has been delivered by members to inform other members with the aim to support a low-carbon future. As a learned society we are committed to continuing to share knowledge on hydrogen, how to deliver a low-carbon future, and many other topics.

If you are a chemical engineer and would like to contribute to work that supports IChemE's vision then contact us at **chemengmatters@icheme.org.**

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Contact us for further information

UK
t: +44 (0)1788 578214
e: membersupport@icheme.org

Australia
t: +61 (0)3 9642 4494
e: austmembers@icheme.org

Malaysia
t: +603 2283 1381
e: malaysianmembers@icheme.org

New Zealand
t: +64 (4)473 4398
e: nzmembers@icheme.org

Singapore
t: +65 6250 0385
e: singaporemembers@icheme.org

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