ICSC/313 AUGUST 2021

HYDROGEN PRODUCTION FROM COAL

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Technology Collaboration Programme
by IEA

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ICSC REPORT NUMBER **ICSC/313**

ISBN **978–92–9029–636-2**

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PUBLICATION DATE **AUGUST 2021**

PREFACE

This report has been produced by the International Centre for Sustainable Carbon (ICSC) and is based on a survey and analysis of published literature and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own and are not necessarily shared by those who supplied the information, nor by our member organisations.

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The overall objective of the International Centre for Sustainable Carbon is to continue to provide our members, the International Energy Agency (IEA) Working Party on Fossil Energy and other interested parties with definitive and policy relevant independent information on how various carbon-based energy sources can continue to be part of a sustainable energy mix worldwide. The energy sources include, but are not limited to coal, biomass and organic waste materials. Our work is aligned with the UN Sustainable Development Goals (SDGs), which includes the need to address the climate targets as set out by the United Nations Framework Convention on Climate Change. We consider all aspects of solid carbon production, transport, processing and utilisation, within the rationale for balancing security of supply, affordability and environmental issues. These include efficiency improvements, lowering greenhouse and non-greenhouse gas emissions, reducing water stress, financial resourcing, market issues, technology development and deployment, ensuring poverty alleviation through universal access to electricity, sustainability, and social licence to operate. Our operating framework is designed to identify and publicise the best practice in every aspect of the carbon production and utilisation chain, so helping to significantly reduce any unwanted impacts on health, the environment and climate, to ensure the wellbeing of societies worldwide.

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ABSTRACT

The total global hydrogen demand in 2018 was around 115 MtH_2/y, which was produced local to the point of use, almost entirely from fossil fuels. This was used primarily as feedstock in the refinery and chemicals industries, with coal accounting for around 27% of the hydrogen supply. The global demand for hydrogen is forecast to increase to perhaps as high as 650 MtH_2/y, representing around 14% of the expected world total energy demand in 2050.

Low-carbon hydrogen production from coal gasification with carbon capture, utilisation and storage (CCUS) and natural gas steam methane reforming (SMR) with CCUS are lower cost than low-carbon hydrogen based on water electrolysis, typically by a factor of approaching three. Coal gasification with CCUS costs typically 1.6–2.4 $\$/kgH_2$ with the lowest cost being that in China. Learning by doing through large-scale commercial roll-out together with cost reduction through technology innovations could reduce the cost by perhaps 10–15% by 2050. In terms of emissions, the addition of CCUS at an assumed, conservative 90% capture rate can reduce the carbon intensity of this process to below 3 $kgCO_2/kgH_2$. Whilst this is good, it is not consistent with net-zero emissions, so capture technology with increased capture rates approaching 100%, or technologies such as the Allam Cycle based on supercritical CO_2 working fluid, should be explored in the medium-long term in the transition to 2050. Cofiring a portion of biomass or waste with the coal feedstock, coupled with CCUS could lead to net-zero or even negative CO_2/kgH_2 which would help to 'future proof' the gasification plant.

Near-term actions are required to overcome barriers and reduce costs to increase the uptake of low-carbon hydrogen from any source, including fossil fuel with CCUS, nuclear, geothermal and renewables. This includes policy actions to send positive long-term signals to potential investors, stimulate demand for clean hydrogen in existing and new markets, reduce investor risk and develop business models, set the agenda for technology research and development (R&D), demonstration, large-scale first of a kind deployment and finally to support the establishment of a regulatory framework.

ACRONYMS AND ABBREVIATIONS

AE	alkaline electrolysers
ASU	air separation unit
ATR	autothermal reformers
BECCS	biomass energy carbon capture and storage
BEIS	Department for Business, Energy and Industrial Strategy, UK
BEVs	battery electric vehicles
CAGR	compound annual growth rate
CCC	Committee on Climate Change, UK
CCGT	combined cycle gas turbine
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CHP	combined heat and power
CNG	compressed natural gas
DOE	Department of Energy, USA
DRI	direct reduced iron
ENTSOG	European Network of Transmission System Operators for Gas
EOR	enhanced oil recovery
ESA	electric swing adsorption
ETI	Energy Technologies Institute, UK
EU	European Union
FCCC	Framework Convention on Climate Change, UN
FCEVs	fuel cell electric vehicles
FCH JU	Fuel Cell and Hydrogen Joint Undertaking
FYP	Five-Year Plan
GCCSI	Global Carbon Capture and Storage Institute
GHG	greenhouse gases
GHR	gas heated reformer
H2CN	China Hydrogen Alliance
HESC	Hydrogen Energy Supply Chain
HRS	hydrogen refuelling stations
ICSC	International Centre for Sustainable Carbon (formerly IEA Clean Coal Centre, IEACCC)
IEA	International Energy Agency
IEAGHG	IEA Greenhouse Gas R&D Programme
IGCC	integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
LCOH	levelised cost of hydrogen
LHV	lower heating value
LNG	liquefied natural gas
METI	Ministry of Economy, Trade and Industry, Japan
MHI	Mitsubishi Heavy Industries

NECP	national energy and climate plans
OECD	Organisation for Economic Co-operation and Development
P2G	power-to-gas
P2P	power-to-hydrogen-to-power
PEM	proton exchange membrane
POX	partial oxidation
PSA	pressure swing adsorption
PV	photovoltaic
RAB	Regulated Asset Base (project funding model)
R&D	research and development
SDGs	Sustainable Development Goals, UN
SDS	Sustainable Development Scenario
SMR	steam methane reforming
SNG	substitute natural gas
UN	United Nations
UNGC	United Nations Global Compact
WGS	water gas shift

Note: all monetary values are in United States dollars ($) unless otherwise stated.

UNITS

CO	carbon monoxide
CO_2	carbon dioxide
EJ	exa-joule (1×10^{18} joule)
Gt	gigatonnes
GW	gigawatts
H_2	hydrogen
kg	kilogramme
MJ	megajoules
MJ/m^3	megajoules per cubic metre
m/s	metres per second
Mt	million tonnes
Mt/y	million tonnes per year
MPa	megapascals
TW	terawatt
TWh	terawatt-hour

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EXECUTIVE SUMMARY

Current demand – Total global hydrogen demand in 2018 was around 115 MtH_2/y. It was produced local to the point of use, almost entirely from fossil fuels and was used primarily as feedstock in the refinery and chemicals industries. Based on the energy input required to produce the hydrogen, coal accounted for 27% of this hydrogen demand, and natural gas for over 70%. Electricity as an energy input for electrolysis, accounted for less than 1% of the hydrogen demand and was mostly generated from fossil fuels.

Future demand – Hydrogen global demand is forecast to increase to possibly 650 MtH_2/y by 2050, representing around 14% of expected world total energy demand. More conservative forecasts estimate future demand at 180–275 MtH_2/y in 2050. This corresponds to a potential 160–570% increase from current hydrogen demand.

Uses for hydrogen – Hydrogen is likely to be adopted in applications where it is the only viable decarbonisation alternative, or where it has a proven advantage over competing solutions. This includes the continued use as feedstock in the chemical industry, feedstock use in iron and primary steelmaking industries, fuel for long-distance shipping and storage uses in 'island' power systems. Additional applications could include aviation, long-distance haulage, use in buildings to complement electrification and storage/buffering in interconnected power systems.

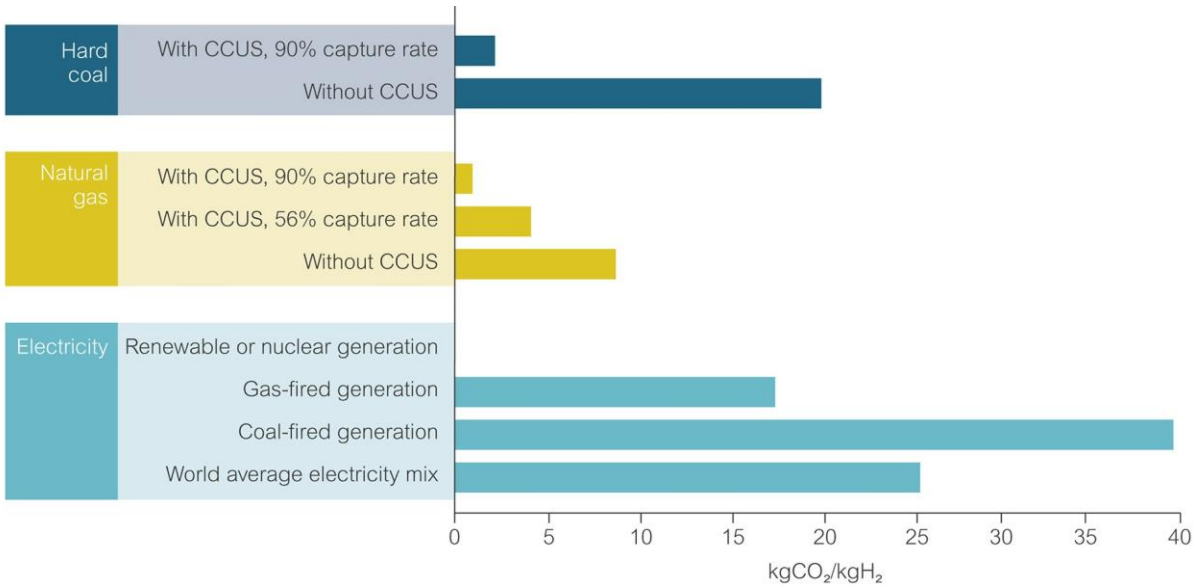
There will be regional variations in this future demand depending on local factors including resource availability, political support, existing gas infrastructure and greenhouse gas emission reduction targets. Heating of buildings for example is likely in countries with good gas infrastructure, whereas locations with existing industrial ports could become hubs for lower cost, lower-carbon hydrogen. A key advantage of hydrogen as an energy carrier is that as a chemical fuel, it can be transported globally so it could be produced in regions with the best resources and used in others where there is high demand.

Hydrogen production technology – The three main routes available for the production of hydrogen, depending on the fuel feedstock, are reforming of natural gas, gasification of coal and electrolysis of water. Hydrogen production from coal using gasification is a well-established technology, used for decades by the chemical and fertiliser industries, particularly in China. There are three key examples of the technology including carbon capture utilisation and storage (CCUS) in operation, producing hydrogen from coal, coke or asphaltene with a combined capacity of around 0.6 MtH_2/y. They are the Great Plains Synfuel and Coffeyville plants in the USA and Sinopec Qilu in China. These facilities demonstrate that large-scale production of low emissions hydrogen using carbon capture can already be technically and commercially feasible.

Cost of hydrogen – Low-carbon hydrogen production from coal gasification with CCUS is lower cost than low-carbon hydrogen based on water electrolysis, typically by a factor of approaching three. Coal gasification with CCUS costs typically 1.6–2.4 $/kg$H_2$, the lowest cost is in China. Learning by doing through large-scale commercial roll-out together with cost reduction through technology innovations could reduce the cost by perhaps 10–15%, with Capex reductions of 45–50% reduction possible by 2050.

In regions with access to low-cost renewable electricity, low-carbon hydrogen produced using water electrolysis could in time become a competitor with low-carbon hydrogen from coal or natural gas, possibly from 2025-35. However, hydrogen production from water electrolysis will typically operate 'mid-merit' at around 35–70% capacity factor. With a large existing unabated fleet of gas- and coal-based hydrogen production, much of which is in China, the cost of hydrogen assessment would indicate that the transition to large-scale, low-carbon hydrogen will require significant deployment of CCUS plant on existing coal-fired gasification plant.

Emissions from hydrogen – For coal gasification plant, the addition of CCUS at an assumed 90% capture rate can reduce the carbon intensity of this process to below 3 kgCO_2/kgH_2. This is good, but not consistent with net-zero emissions, so capture technology with increased capture rates approaching 100%, or technologies such as supercritical CO_2 working fluid cycles, should be explored in the medium-long term. Cofiring biomass or waste with the coal feedstock, coupled with CCUS, could lead to net-zero or even negative CO_2/kgH_2, which would help to 'future proof' the gasification plant.



CO_2 intensity of hydrogen production (IEA, 2019c)

Natural gas-based production will generally be lower emission than coal gasification due to the inherent fuel properties where natural gas has a hydrogen/carbon molecular ratio of 4:1 compared with typically 0.1:1 for coal. For water electrolysis, the CO_2 intensity depends on that of the electricity

used to produce it. Where this is entirely from renewable electricity sources, the carbon intensity is close to zero. However, to reduce the cost of hydrogen, or to match demand-side hydrogen requirements, the electrolyser may be operated at higher load factors where the impact of using water electrolysis could actually be detrimental. Thus the water electrolysis process should be used at a capacity factor that allows it to use mainly renewable electricity.

Hydrogen strategies and next steps – The number of countries with hydrogen strategies and roadmaps is growing. Funding to support these strategies is increasingly significant, particularly related to low-carbon hydrogen based on water electrolysis and its support to increasing renewables penetration. However, to move towards the increased uptake of hydrogen, near-term actions are required to overcome barriers and reduce costs. This includes policy actions to support sending positive long-term signals to potential investors, stimulate demand for clean hydrogen in existing and new markets, reduce investor risk and develop business models, set the agenda for technology R&D and finally to support the establishment of a regulatory framework. Deployment of hydrogen from fossil fuels with CCUS at scale is required, where the 'Hub and Cluster' model to improve the economics of clean hydrogen production should be pursued.

Compliance with SDGs – Finally, in terms of the wider SDG goals, hydrogen, including low-carbon hydrogen from coal, is a key technology contributing in particular to SDG 7- affordable clean energy for all, SDG 9- industry innovation & infrastructure and SDG 13- climate action.

1 INTRODUCTION

Hydrogen is used currently as a feedstock in industrial manufacturing processes including the production of ammonia, fertilisers and in oil refinery applications, and is produced almost entirely from fossil fuel sources. These fossil fuel-based processes which typically use steam methane reforming of natural gas or gasification of coal, generally do not capture carbon dioxide (CO_2). There is therefore the opportunity to reduce CO_2 emissions by adding carbon capture utilisation and storage (CCUS), or by switching to other cleaner production methods. The leading cleaner production process is water electrolysis using electricity derived from renewable energy sources such as wind and solar photovoltaic (PV). Electricity produced from nuclear energy could also be used as part of a cleaner hydrogen production process.

In addition, as part of the transition to a low emissions future, there is growing interest in utilising low-carbon hydrogen in a range of applications, such as fuel cells for long-distance land and air transportation, energy storage and power buffering to support the increased penetration of renewables in electricity grids, chemicals, iron and steel production, as well as direct utilisation in combustion engines or gas turbines. Hydrogen can also be blended with natural gas and added to pipelines to provide cleaner fuels for industrial and domestic heating applications as a complementary approach to electrification. There will be regional variations in this future demand for hydrogen depending on local factors such as fossil fuel, water and storage resource availability, government financial support and regulations, existing and proposed infrastructure, together with greenhouse gas emission reduction targets.

Scope of report

The report opens with an introduction to hydrogen as a fuel and explains why there is growing interest in it and explores some of the benefits and difficulties associated with the fuel. A global analysis of current hydrogen use together with potential future hydrogen markets is assessed, from both a global perspective as well as key geographic regions. Methods to produce hydrogen are then assessed, focusing on coal as the feedstock, but also including natural gas and water electrolysis-based systems.

The different production methods are then compared, particularly in terms of the cost of production and emissions, both in terms of the present-day case and looking forwards to the potential position in 2030 to 2050. Since the main driver to increase the use of hydrogen is to reduce greenhouse gas (GHG) emissions, the method of hydrogen production should be capable of delivering low, or even zero-emissions. In terms of cost, the production methods should be capable of delivering hydrogen at a cost that can compete with conventional fuels such as natural gas in the medium term, where the expectation is that CO_2 emissions will entail a cost through carbon taxes or emissions trading schemes. The cost of hydrogen will also be a key driver in determining which particular low-carbon hydrogen production method is adopted, for example how coal gasification with CCUS competes with water electrolysis-based production using electricity in the timeframe to 2050. Another driver will be the

rate of growth in demand for hydrogen as the highest marginal cost supplier will help determine the overall price in a mature market. A third driver will be the cost of scaling-up hydrogen infrastructure, where for example the cost of hydrogen in transport will depend on the number of refuelling stations, consumer demand growth and final delivery costs. These drivers will vary in importance in different geographic regions.

Examples of hydrogen production plant based on coal gasification with CCUS, either in operation or in the construction/planning phase are presented, together with an overview of the research and development (R&D) landscape for hydrogen production from coal.

The number of national strategies and roadmaps that are being put in place to promote the increased use of hydrogen, both from demand-side creation as well as targets for hydrogen, have increased significantly in recent years. They are reviewed together with the policies to support these plans, before finally making a wider assessment of hydrogen use in terms of the United Nations Sustainable Development Goals (SDGs).

2 HYDROGEN AS A FUEL

This chapter describes the characteristics of hydrogen as a fuel and highlights the potential safety issues relating to its use.

2.1 HYDROGEN FUEL CHARACTERISTICS AND SAFETY CONSIDERATIONS

Hydrogen contains more energy on a mass basis than either natural gas or gasoline, making it potentially attractive as a transport fuel. However, hydrogen is the lightest element and so has a low energy density per unit of volume. This means that larger volumes of hydrogen must be used to meet the same energy demand as can be achieved with gasoline and natural gas. The properties of hydrogen are shown in Table 1, with a brief overview of the properties of hydrogen in gaseous and liquid forms presented below.

TABLE 1 PHYSICAL PROPERTIES OF HYDROGEN AND METHANE (BASED ON DATA FROM IEA, 2019C; HANKINSON AND OTHERS 2009)

Property	Hydrogen	Methane
Gas density at 0°C, 0.1 MPa (kg/m^3)	0.090	0.716
Liquid density at boiling point, 0.1 MPa (kg/m^3)	70.85	423
Boiling point, °C	-252.9	-161.5
Fuel energy content – lower heating value (LHV), MJ/kg	120.1	50.0
Fuel energy content – lower heating value (LHV), MJ/m^3	10.8	35.6
Laminar flame speed – 100% H_2 (m/s)	3.46	0.37
Flammability limits, volume % in air	4–77	4.4–16.4
Auto-ignition temperature, °C	585	537
Minimum ignition energy, MJ	0.02	0.3

2.1.1 Gaseous hydrogen

Hydrogen is gaseous at atmospheric pressure and temperature and is typically found as part of chemical compounds, most commonly in the form of water, but also in hydrocarbons such as methane, gasoline and coal. It is colourless, odourless, tasteless, non-toxic, and non-poisonous (H_2 Tools, 2016; HySafe, 2007). It is also non-corrosive although it can cause embrittlement of some metals and alloys, including steel, particularly at temperatures above 200°C (Dwivedi and Vishwakarma, 2018). This has potential implications for material choice in pipelines and system components exposed to gaseous hydrogen.

Natural gas is also odourless, requiring the addition of sulphur-based odorants so that leaks can be detected. However, odorants are not readily available for hydrogen because they are not light enough to disperse with hydrogen at the same rate.

Gaseous hydrogen is close to being 60 times lighter than gasoline vapour and around 14 times lighter than air. This means that if released in an open environment, hydrogen will typically rise and disperse rapidly, representing a safety advantage, particularly in open spaces.

If released in a confined space however, any hydrogen leakage can accumulate and reach a flammable concentration due to its very small molecular size and low viscosity. The flammability limits for hydrogen at 4–77% (volume concentration in air) are significantly higher than those for methane (4–6% volume concentration in air), as shown in Table 1.

At the optimal combustion condition (29% hydrogen to air volume ratio), the energy required to initiate hydrogen combustion is 0.02 MJ, which is less than a tenth of the minimum ignition energy required for methane (*see* Table 1). This means that a relatively small spark would be required to ignite hydrogen compared with other common fuels. In addition, hydrogen leaks of any size in a confined space are a concern since hydrogen is impossible for human senses to detect. Adequate ventilation is therefore required with the use of detection sensors recommended to mitigate these hazards.

In terms of combustion, the auto-ignition temperature (the lowest temperature at which a gas will spontaneously ignite without the presence of a flame or spark) of hydrogen and methane are broadly similar as shown in Table 1, being 585ºC and 537ºC respectively. Hydrogen burns with a pale blue flame that is almost invisible under normal light conditions. Sensors are typically installed with hydrogen systems to identify quickly any leak and minimise the potential for undetected flames.

If a large hydrogen cloud comes into contact with an ignition source, ignition will result in the flame flashing back to the source of the hydrogen, due to the relatively high flame speed of hydrogen as shown in Table 1. In open spaces with no confinement, flames will propagate through a flammable hydrogen-air cloud at several metres per second, and even more rapidly if the cloud is above ambient temperature. It should be noted that hydrogen combustion is more rapid than that of other fuels.

Hydrogen has a high energy content of 120 MJ/kg on a mass basis, whereas on a volumetric basis, the energy content at 10.8 MJ/m^3 is relatively low when compared with methane for example (*see* Table 1). This is a particular challenge for storage, where to store sufficient quantities of hydrogen gas, it is typically compressed and stored at high pressures (H_2 Tools, 2016).

2.1.2 Liquid hydrogen

As liquid hydrogen has different characteristics compared to gaseous hydrogen, the potential hazards and control measures used to ensure safety are also different. The volume ratio of liquid to gas is approximately 1:850, so that one litre of liquid hydrogen can produce 850 litres of gaseous hydrogen

at atmospheric pressure and temperature. It undergoes a rapid phase change from liquid to gas, so ventilation and pressure relief devices are built into hydrogen systems to ensure safety. Liquid hydrogen is also colourless and can only be maintained in liquid form if stored in a cryogenic storage vessel at below -253ºC and typically at pressures of up to 1 MPa (H_2 Tools, 2016).

2.1.3 Hydrogen energy carriers

Hydrogen containing compounds which are liquid at temperatures and pressures relatively close to ambient conditions include ammonia (NH_3) and methanol (CH_3OH). These have attracted significant attention as a means of transporting and storing hydrogen, as fuels in their own right and as chemical reagents in industrial manufacturing processes.

Ammonia

Ammonia is the only carbon-free hydrogen carrier and has a hydrogen content of 17.7% by mass with an energy density of 18.6 MJ/kg LHV basis. Whilst ammonia has a narrow flammability range and its toxicity is a concern, its strong smell can actually be advantageous in terms of leak detection. It can be liquefied at pressures of 1 MPa or temperatures of -33°C, which makes it particularly attractive from a storage and distribution viewpoint (El-Kadi and others 2018; RSC, 2020).

Methanol

In a similar way to ammonia, methanol provides a potential medium as an energy carrier for hydrogen. Methanol is a liquid at ambient conditions and has an energy density of 791 kg/m^3 or 19.9 MJ/kg LHV basis. It is also relatively easy to convert to hydrogen through a catalytic fuel reformer, at relatively low temperatures of 200–300°C (Danish Technology Institute, 2009).

2.2 COMMONLY USED NOMENCLATURE FOR HYDROGEN PRODUCTION

As noted in Section 2.1, hydrogen is not typically found in its pure form and must therefore be manufactured. The routes for producing hydrogen are discussed in Chapter 4, where the technique used depends on the feedstock. In the case of coal, for example, this is typically gasification based (*see* Section 4.3 for further details).

A classification of hydrogen used commonly, based on the production method and the extent of decarbonisation methods used is as follows (Cătuţi and others, 2019; WEC, 2019):

- **'grey' hydrogen** – produced typically by steam methane reforming (SMR) of natural gas or by gasification of coal. Carbon abatement is not used, so CO_2 emissions for this type of hydrogen are relatively high;
- **'blue' hydrogen** – produced by SMR of natural gas or coal gasification as described for grey hydrogen, but includes carbon abatement, typically in the form of CCUS. CCUS has been

studied extensively by the International Centre for Sustainable Carbon, as covered most recently by (Kelsall, 2020; Lockwood, 2016, 2017, 2018a,b; Zhu, 2018); and

- **'green' hydrogen** – produced through the electrolysis of water using electricity generated from renewable sources. Green hydrogen has the lowest lifecycle GHG emissions, due primarily to those arising from the production of the materials used.

In general, there is no established colour classification for hydrogen from biomass, nuclear or different sources of grid electricity (IEA, 2019c). As the environmental impacts of each of these production routes can vary considerably by energy source, region and type of CCUS applied, colour-based classification for hydrogen production is not used in this report. Instead, the approach is based on a technology agnostic approach where the production method is described as either:

- low-carbon hydrogen, including coal or gas with CCUS, nuclear or renewable, or biomass; and
- unabated hydrogen, including coal and gas without CCUS.

2.3 SUMMARY

Hydrogen has an energy content on a mass basis of 120 MJ/kg which is higher than either natural gas or gasoline, making it potentially attractive as a transport fuel. However, on a volumetric basis, the energy content at 10.8 MJ/m^3 is relatively low, meaning that hydrogen gas is typically compressed and stored at high pressures.

Hydrogen is typically referred to as either unabated hydrogen, where the hydrogen is produced from fossil fuel sources without carbon capture; or low-carbon hydrogen, where the hydrogen is produced from fossil fuels including carbon capture, from the electrolysis of water using renewable electricity, or from biomass sources.

3 THE GROWING INTEREST IN HYDROGEN

Around 3% of global energy consumption is currently used to produce hydrogen, with less than 0.01% of this hydrogen, about 1000 t/y, used as an energy carrier. However, there is growing interest in the potential of hydrogen to become a clean energy carrier in the move towards limiting global temperature rise (Aarnes and other, 2018).

The primary reason for the increasing interest in hydrogen is its ability to support the reduction of GHG emissions. Analysis by the Intergovernmental Panel on Climate Change (IPCC, 2019) for example, shows that pathways to limit global warming to 1.5°C with no, or limited, overshoot require combinations of new and existing technologies and practices. This includes hydrogen use together with electrification, sustainable bio-based feedstocks, product substitution and CCUS. This increasing role for hydrogen is due to its features as noted in Section 2.1, namely that:

- it can be used without direct local emissions of air pollutants or GHGs; and
- it can be made from a diverse range of low-carbon energy sources, with its potential supply including production from renewable electricity, biomass and nuclear, together with low-carbon production from fossil fuels, primarily by combining with CCUS.

As noted already, hydrogen is an energy carrier rather than an energy source, which means that its potential role has some similarities with electricity. A key difference however between hydrogen and electricity is that hydrogen is a chemical energy carrier, which means that it can be transported and stored in ways similar to more conventional fuels such as natural gas and coal. It can be burnt to produce high-temperature exhaust gases for power production and heating and can be used in existing transportation and utilisation infrastructure, allowing the adoption of business models developed previously for conventional fossil fuels. This difference is the reason why hydrogen could be the energy carrier of choice relative to electricity in certain applications (*see* Section 3.2.3 for further details).

In addition, due to the molecular nature of hydrogen, it can also be combined with other elements to make hydrogen-based fuels that are easier to handle, such as ammonia and methanol. These hydrogen-based fuels could then be used as energy carriers, chemical feedstocks in industry, or directly as fuels in combustion systems or fuel cells.

This growing interest in hydrogen is explored further in Section 3.2, where the potential future demand through to 2050 is discussed. The current demand for hydrogen is outlined first below.

3.1 CURRENT HYDROGEN DEMAND

The demand for hydrogen increased by around 400% from 1975 to 2018 as shown in Figure 1 (IEA, 2019c). It is supplied almost entirely from fossil fuels (Muradov, 2017), with 6% of global natural gas and 2% of global coal being used for this hydrogen production.

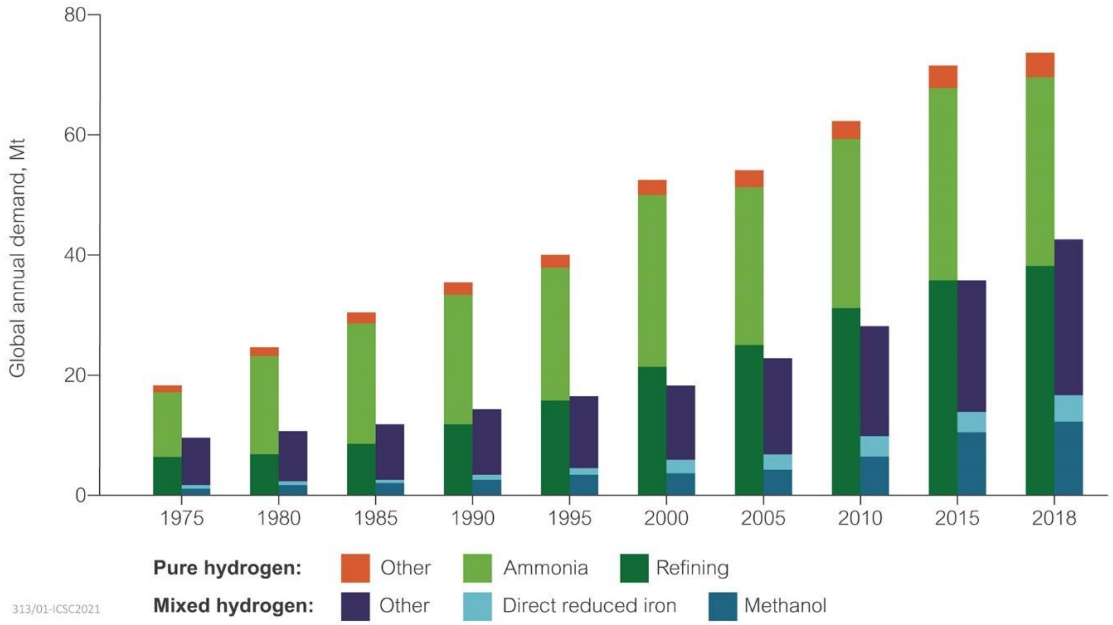


Figure 1 Global annual demand for hydrogen from 1975 to 2018 (IEA 2019a)

Coal accounts for around 27% of the hydrogen demand based on the energy input required to produce the hydrogen, as shown in Figure 2, with natural gas being the largest source accounting for over 70% of the hydrogen demand. Electricity as an energy input for electrolysis, accounts for less than 1% of the hydrogen demand, with fossil fuels still indirectly accounting for the majority of this, due to the electricity for electrolysis being largely produced from fossil fuels in the countries where the hydrogen is produced. This is illustrated in Figure 3, which shows the key manufacturing regions, highlighting the importance of China, including industrial processes that utilise hydrogen such as ammonia manufacture.

In energy terms, the total annual hydrogen demand worldwide is around 330 million tonnes of oil equivalent (Mtoe), equating to 70–73 million tonnes of hydrogen per year (MtH_2/y). The hydrogen is produced in dedicated facilities, primarily local to the point of use, and as shown in Figure 1 and Figure 2 its main uses are:

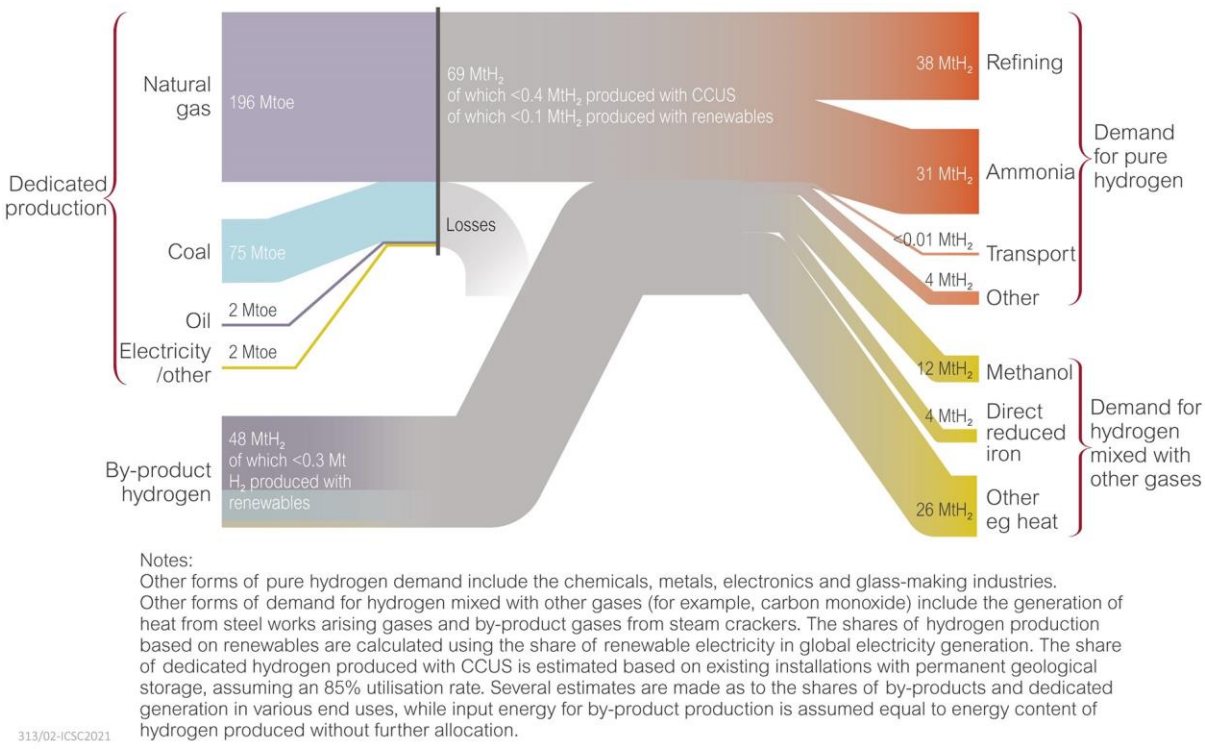
- 38 MtH_2/y, representing 52% of hydrogen demand for upgrading petroleum products in refinery applications; and
- 31 MtH_2/y, or 42% of hydrogen demand as a feedstock for ammonia production in the Haber-Bosch process.

Other important uses of pure hydrogen include food and drug production, crystal growth, glass manufacturing, chemical tracing, metal fabrication, polysilicon and semiconductor manufacturing, metal production, and thermal processing (USDOE, 2020).

In addition to this dedicated hydrogen demand, there is a further 45–48 MtH_2/y produced as a by-product from other processes, which as shown in Figure 1 and Figure 2 was used in 2018 for:

- 12 MtH_2/y for the manufacture of methanol;
- 4 MtH_2/y in the manufacture of steel using the direct reduced iron (DRI) process (IIMA, 2018). An example of this is the Hydrogen Breakthrough Ironmaking Technology (HYBRIT) using hydrogen as the reducing gas, producing water as a by-product instead of CO_2 (Åhman and others, 2018). Reduction occurs in a solid state at a lower temperature than in the blast furnace process and produces an intermediate product, sponge iron or direct reduced iron, with water vapour emitted from the top of the furnace. The resulting DRI can then be made into steel using electric arc furnaces, in the same way as traditional DRI is used. DRI is currently used for about 5% of global primary steel production, with the remaining 95% using blast furnaces; and
- 26 MtH_2/y for other applications such as synthesis gas for fuel or feedstock and process heating.

These existing markets for hydrogen reflect its key characteristics as defined earlier in Table 1; that it is light, storable, reactive, has high energy content per unit mass and can be readily produced at industrial scale.



Notes:
Other forms of pure hydrogen demand include the chemicals, metals, electronics and glass-making industries. Other forms of demand for hydrogen mixed with other gases (for example, carbon monoxide) include the generation of heat from steel works arising gases and by-product gases from steam crackers. The shares of hydrogen production based on renewables are calculated using the share of renewable electricity in global electricity generation. The share of dedicated hydrogen produced with CCUS is estimated based on existing installations with permanent geological storage, assuming an 85% utilisation rate. Several estimates are made as to the shares of by-products and dedicated generation in various end uses, while input energy for by-product production is assumed equal to energy content of hydrogen produced without further allocation.

Figure 2 Sankey diagram showing hydrogen value chains in 2018 (IEA, 2019c)

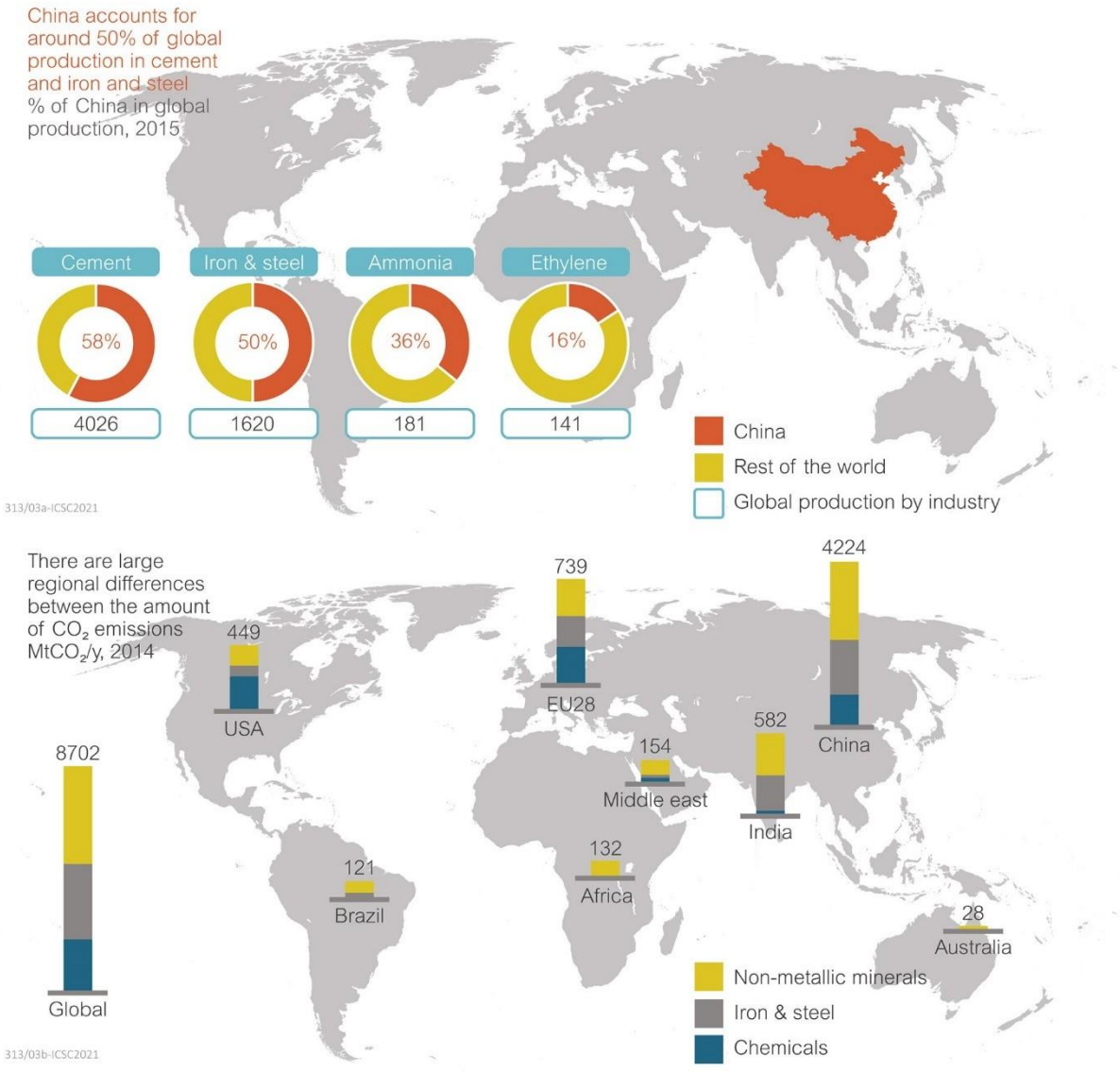


Figure 3 Regional variation in industrial manufacturing (McKinsey, 2018)

3.2 FUTURE HYDROGEN DEMAND

Several forecasts have been made of potential future hydrogen demand (Hydrogen Council, 2017b; IEA, 2019c; IRENA, 2019; DNV GL, 2018; FCH JU, 2019). These forecasts vary significantly between the scenarios as noted by De Blasio and Pflugmann (2020), with a selection of the forecasts presented in Table 2. The Hydrogen Council study estimates global demand at approximately 650 MtH_2/y in 2050, representing around 14% of the expected world total energy demand at that time. Studies by DNV GL are more conservative, with estimates of between 180–275 MtH_2/y in 2050, or 28–42% of the Hydrogen Council estimate. These compare with the current demand for hydrogen of 115 MtH_2/y, corresponding to a potential five- to six-fold increase based on the highest forecast of future demand.

TABLE 2 FUTURE DEMAND FOR HYDROGEN IN 2050 RELATIVE TO 2018 LEVELS (BASED ON DATA FROM IEA, 2019C; IRENA, 2019B; DNV GL 2018; HYDROGEN COUNCIL 2017B)

Forecast hydrogen demand	Base case				
	2018*	2050†	2050‡	2050§	2050¶
MtH_2/y	115	158	179	275	650
Mtoe	330	454	513	788	1863
TWh	3833	5278	5967	9167	21667
EJ	13.8	19	21.5	33	78

Note: EJ to MtH_2/y conversion based on hydrogen LHV of 120 MJ/kg

* IEA, 2019c; † IRENA, 2019b; ‡ DNV GL, 2018 (reference uptake); § DNV GL, 2018 (high uptake)
¶ Hydrogen Council, 2017b

The analysis by IRENA shows that hydrogen demand could be 158 MtH_2/y in 2050. It should be noted that for this case, the hydrogen is classed as low-carbon hydrogen, produced by electrolysis of water using renewable electricity, representing around 8% of the electrification share of final energy consumption in 2050. Whilst the IRENA study focuses on the potential of low-carbon hydrogen based on the electrolysis of water, it does acknowledge that fossil fuel-based low-carbon hydrogen will play a transitional role (IRENA 2019a), specifically hydrogen produced from fossil fuels with CCUS. This low-carbon hydrogen is recognised as providing a bridging solution as the cost of producing hydrogen from renewable power decreases, offering the prospect of continuity to fossil fuel producers, whilst supporting the achievement of GHG emissions reduction objectives at acceptable cost (*see* Sections 4.2 and 4.3 for discussion of cost reduction potential and emissions).

In terms of financial value, the hydrogen market is expected to grow to around $200 billion by 2030 from the current $136 billion in 2019, at a 4.3% compound annual growth rate (CAGR) between 2020 and 2030. The industry growth would be aided by the rising per capita income of people, which is driving the demand for food,

In all these assessments, hydrogen is seen as a necessary feature of the energy transformation required to limit global warming to 2°C or below. It could play an important role as part of a broader strategy, with applications which fall within two main categories (Philibert, 2020):

Firstly, applications where clean hydrogen is the only viable decarbonisation alternative, or where it has a proven advantage over all competing solutions:

- current feedstock uses in the chemical industry, primarily ammonia and methanol;
- feedstock use in iron and primary steelmaking industries;
- fuel for long-distance shipping; and
- storage uses in 'island' power systems.

Secondly, applications where hydrogen could become the preferred decarbonisation solution in the future:

- fuel use in aviation, where the main competitor is likely to be carbon offsetting;
- fuel use for long-distance, road-based haulage applications where the main competitor would be direct electrification with batteries and electric road systems;
- use in buildings to complement electrification, where the main competitor is likely to be electrification and efficiency improvements; and
- storage use in interconnected power systems.

The breakdown of the forecast use of the hydrogen demand in 2050 is shown in Figure 4. Hydrogen would be used primarily for industrial feedstock and energy, together with transportation, heating and power in buildings, and power generation usage of hydrogen including hydrogen buffering (Staffell and others, 2019). The spread of hydrogen usage across these sectors is reasonably uniform, with significant quantities of hydrogen used in each.

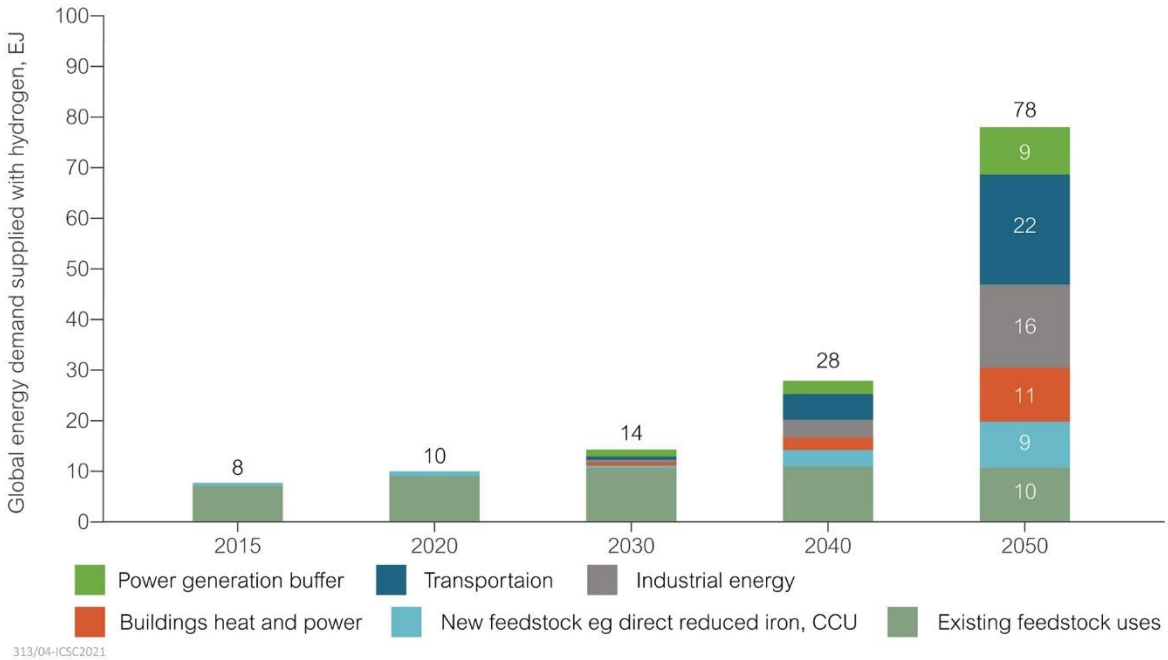


Figure 4 Forecast increase in global hydrogen demand (EJ) up to 2050 (Hydrogen Council, 2017b)

Analysis by the US Department of Energy (DOE) (2020) has shown similar strong potential of hydrogen use across a range of sectors (*see* Figure 5). It shows that in terms of market share, hydrogen use for industrial feedstocks will continue to be a key sector, providing almost 100% of the feedstock for ammonia and methanol and 80% of refinery feedstock.

There will be regional variations in this future demand for hydrogen, depending on local factors including resource availability, political support, existing gas infrastructure and GHG emission reduction targets. In terms of locations, the IEA recommends making the most of existing industrial

ports to turn them into hubs for lower cost, lower-carbon hydrogen, with areas around the North Sea coastline of Europe, the Gulf Coast of North America and, the southeastern coast of China set to become important centres (IEA, 2019c).

As an example of the regional variation and approach, the Fuel Cells and Hydrogen Joint Undertaking (FCH JU) has made a very good assessment of the potential future market for hydrogen in Europe. This is analysed in more depth in the following section, together with a review of the USA and Asia, primarily China and Japan.

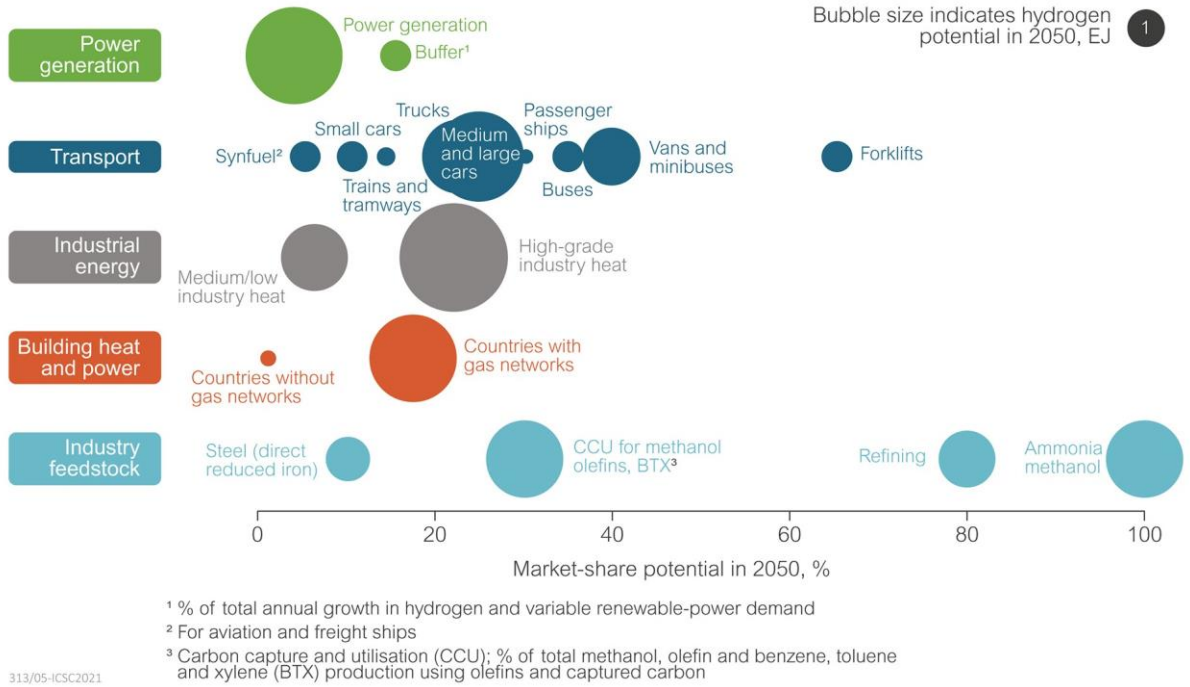


Figure 5 Hydrogen potential market share in 2050 (USDOE, 2020)

3.2.1 Hydrogen use in Europe

The FCH JU has analysed the role that hydrogen could play in Europe, based on the European ambition to achieve the 2°C temperature rise scenario. This 'ambitious scenario' is based on the worldwide perspective of the global Hydrogen Council and input from seventeen companies active in hydrogen technologies (FCH JU, 2019). The analysis concludes that hydrogen is an essential element in the energy transition and could account for 24% of the final European Union (EU) energy demand by 2050 as shown in Table 3. This would see hydrogen demand increasing from 325 TWh (10 MtH_2/y) in 2015 to around 2250 TWh (around 68 MtH_2/y) in 2050. The large-scale decarbonisation of key segments, including the gas grid, transport, and industrial processes that use high-grade heat and hydrogen as chemical feedstock, requires the use of large quantities of hydrogen. In addition, the electrification of the economy and the large-scale integration of intermittent renewable energy sources require large-scale energy storage, seasonal storage and the efficient transport of clean energy across Europe

at low cost. Hydrogen is seen as the primary energy carrier to address these challenges at the scale required.

A lower ambition for hydrogen in Europe is also analysed. Defined as the 'business-as-usual' scenario, the potential growth in hydrogen demand is much lower, *see* Table 3 (FCH JU, 2019). This assumes that current policies and other measures stay in place with modest development through to 2050. Here, the demand for hydrogen would increase to 780 TWh (approaching 25 MtH_2/y), representing 8–9% of the final EU energy demand by 2050.

TABLE 3 FORECAST HYDROGEN DEMAND IN THE EU BY SECTOR (FCH JU, 2019)

Sector	2015	2030	2050		
	Base, TWh	Business as usual, TWh	Ambitious, TWh	Business as usual, TWh	Ambitious, TWh
Existing industry feedstock	325	427	427	391	391
New industry feedstock	0	0	62	1	257
Industrial energy	0	54	8	53	237
Heating and power for buildings	0		33	207	579
Transportation	0		70	85	675
Power generation buffering	0		65	43	112
Total hydrogen demand	325	481	665	780	2251
Total final demand, TWh	14,100	11,500	11,500	9300	9300
Contribution of hydrogen, %	2.3	4.2	5.8	8.4	24.2

In terms of the sectors in which hydrogen could play a role, these are quantified in Table 3, with the 2°C temperature rise compliant scenario shown in Figure 6.

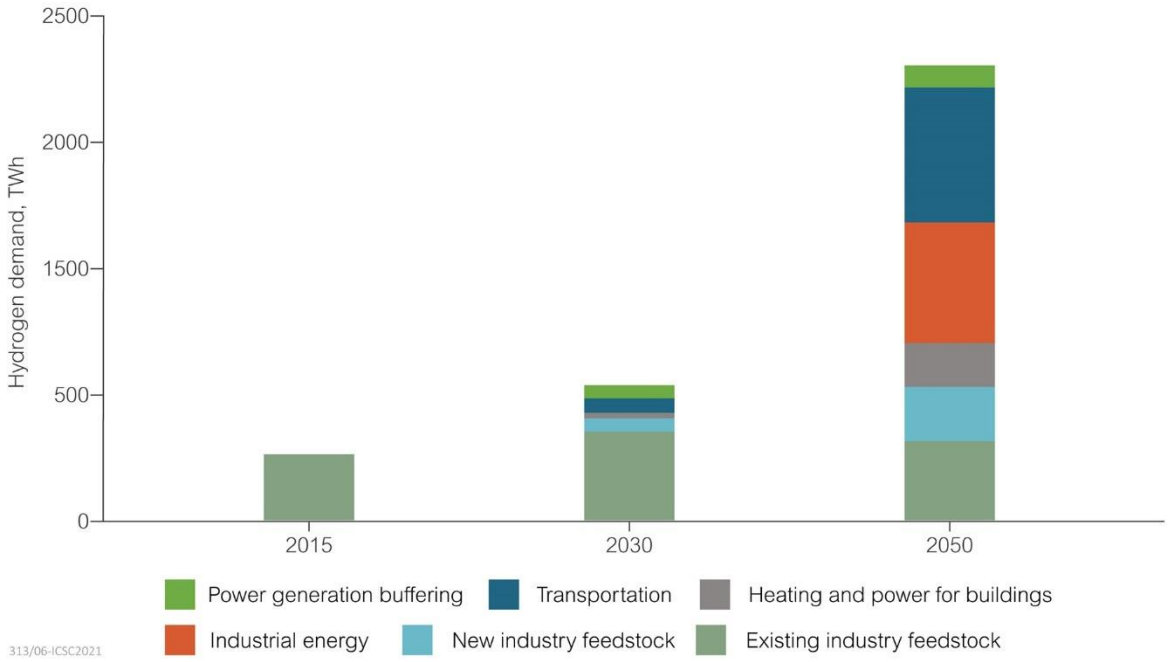


Figure 6 Forecast hydrogen demand in the EU to achieve 2°C temperature rise scenario (FCH JU, 2019)

3.2.2 Hydrogen use in Asia

Asia represents the fastest growing market for hydrogen use and it is expected to witness the fastest industry growth in the near future. Hydrogen consumption is rising in the region as a result of economic growth and expansion of the chemical, refining, metal processing, petrochemical and electronics sectors.

Japan

Japan was the first country to adopt a hydrogen strategy in 2017, which is summarised by Chaube and others (2020)(*see* Table 4). The strategy primarily aims to achieve cost parity with competing fuels such as gasoline in the transportation sector or liquefied natural gas (LNG) in power generation and covers the entire supply chain from production to downstream market applications (METI, 2020). In support of this, the Japanese government began investing in R&D from around 2014 including for low cost, zero-emissions hydrogen production, an expansion of the hydrogen infrastructure for import and transport abroad within Japan and an increase of hydrogen use in various areas such as mobility, cogeneration of power and heat, as well as power generation.

TABLE 4 TARGETS DEFINED IN JAPAN'S BASIC HYDROGEN STRATEGY (CHAUBE AND OTHERS, 2020)		
Benchmark factor	**Mid-term target, 2030**	**Long-term target, 2050**
Source of supply	Developing international H_2 supply chains and domestic power-to-gas	CO_2 free hydrogen, including fossil fuels with CCUS and power-to-gas
Hydrogen volume, MtH_2/y	0.3	5–10
Cost of H_2,$/t	3	2
Power generation cost, JP¥/kWh	17	12
Mobility • Hydrogen refuelling stations (HRS) • Fuel cell electric vehicles (FCEVs) • Fuel cell buses • Forklifts	900 800,000 1,200 10,000	Replace gasoline stations Replace gasoline vehicles Introduce large FCEVs
Fuel cells (stationary power), where Ene-Farm is a fuel cell-based domestic combined heat and power (CHP) system	5,300,000	Replace traditional energy systems

The approach proposed for Japan is to pioneer a global supply network for hydrogen production, shipping and applications in various economic sectors (Nagashima, 2020). For Japan, the majority of hydrogen and other derivative fuels are therefore expected to be imported. Examples include the AHEAD project which has commenced operation of the world's first international hydrogen supply chain. This involves producing hydrogen from natural gas and converting it into methylcyclohexane (MCH). The MCH is then shipped to Japan where it undergoes dehydrogenation to release the hydrogen (AHEAD, 2020). Hydrogen regenerated from the MCH was supplied to a gas turbine in Mizue Thermal Power Plant for power generation (Chiyoda Corp 2020). A further example is the Hydrogen Energy Supply Chain (HESC) involving coal gasification and gas refining in Latrobe Valley, Australia and shipping as liquid hydrogen to the Kobe liquid hydrogen storage and unloading terminal in Japan (HESC, 2018). This project is discussed further in Section 3.3.4 and Section 5.5. There is also the potential to cofire hydrogen or ammonia in power generation plant as noted in Section 3.3.4.

Areas of focus include hydrogen production, carrier technologies and international supply chains, hydrogen use in fuel cells, mobility and power generation. The industrial sector, whilst recognised as a potential area for hydrogen use, is not a priority in the near term.

Japan's strategy, which has a strong element of international co-operation, could have a positive global impact and in particular contribute to the creation of new synergies regarding international energy trading and business cooperation. These will be crucial to drive development and make technologies more affordable.

Overall, the hydrogen market growth in Japan is expected to grow more than 50 fold by 2030 to reach over JP¥400 billion (around $4 billion), with a particular focus being hydrogen refuelling stations (HRS) for transport applications (Chaube and others, 2020). This market is expected to increase by

around seven-fold to JP¥37 billion (around $350 million) by 2030. The number of HRS will increase from 111 in 2020 to 580 by 2025, and then to over 1300 throughout Japan by 2030.

China

The China Hydrogen Alliance (H2CN) released a landmark White Paper on China's hydrogen and fuel cell industry in June 2019, which is regarded as a key publication in support of Chinese governmental decision-making regarding hydrogen (Tu, 2020). Key targets recommended by H2CN are provided in Table 5 and summarised below:

TABLE 5 OVERALL TARGETS FOR HYDROGEN AND FUEL CELL DEVELOPMENT IN CHINA (TU, 2020)

Development target	Status in 2019	Target: 2020-25 Near term	Target: 2025-35 Medium term	Target: 2035-50 Long term
Hydrogen as proportion of primary energy, %	2.7	4.0	5.9	10.0
Sector revenue, yuan billions	300	1000	5000	12,000
Number of refuelling stations	23	200	1500	10,000
Number of FCEVs	2000	50,000	1,300,000	5,000,000
Number of stationary power projects	200	1000	5000	20,000
Number of fuel cell systems	10,000	60,000	1,500,000	5,500,000

- Hydrogen as a proportion of China's primary energy consumption should increase steadily from 2.7% in 2019 to 10% in 2050. This target is regarded as ambitious given the expected expansion of the Chinese energy economy over the same time period;
- Hydrogen economy-related revenue is expected to increase from 300 billion yuan (around $45 billion) in 2019 to 12,000 billion yuan (about $1860 billion) in 2050, the equivalent of close to 13% CAGR during the period;
- The number of HRS should increase to 10,000 by 2050, the equivalent of 22% CAGR in the next three decades. By comparison, the number of battery electric vehicles (BEVs) charging points in China reached over 1.4 million in 2020. In addition, the number of fuel cell electric vehicles (FCEVs) should increase to 5 million by 2050. As China's civil vehicle stock reached 262 million by the end of 2019, with sales of new vehicles at 25.8 million per year, the deployment target of FCEVs in 2050 is expected to account for a small fraction of the total Chinese vehicle stock; and
- The number of stationary power projects and fuel cell systems should grow from 200 and 10,000 in 2019 to 20,000 and 5.5 million in 2050, the equivalent of 16% and 23% CAGR respectively.

3.2.3 Hydrogen use in the USA

Based on analysis by the US Fuel Cell and Hydrogen Energy Association, with technical input from the Electric Power Research Institute (EPRI), hydrogen could support 14% of US final energy demand by 2050, equivalent to over 2468 TWh/y per year or around 63 MtH_2/y, with a further potential for 11 MtH_2/y in additional uses such as synthetic aviation fuels and ammonia fuels for shipping (FCHEA, 2020), as shown in Figure 7. Hydrogen in transportation applications is predicted to be the largest sector at around 27 MtH_2/y, followed by existing industrial feedstock applications at 16 MtH_2/y. By 2030, the hydrogen economy in the USA could generate an estimated $140 billion per year in revenue, growing to potentially $750 billion per year by 2050. This is based on an ambitious scenario where hydrogen is described as being championed as an economic growth driver, a leadership opportunity for US businesses and as a tool for significant decarbonisation in the USA. It assumes federal regulations and policies to require emissions reduction across industries and across the country. It also assumes state and regional support for low carbon initiatives and collaborative partnerships with key stakeholders to resolve the challenges in scaling up hydrogen.

For the base scenario, hydrogen demand would be lower, growing to around 20 MtH_2/y by 2050. This scenario assumes the USA does not take strong measures to support the growth of hydrogen. At the federal level, it assumes negligible or non-existent policies on climate change, as well as negligible policy support for hydrogen.

In terms of the roadmap to achieve the ambitious scenario, the key milestones are shown in Table 6, primarily in support of the transportation sector. This would see the number of FCEVs for road transportation increase to 1.2 million vehicles by 2030, with a further 300,000 FCEVs used in material handling applications such as forklift usage.

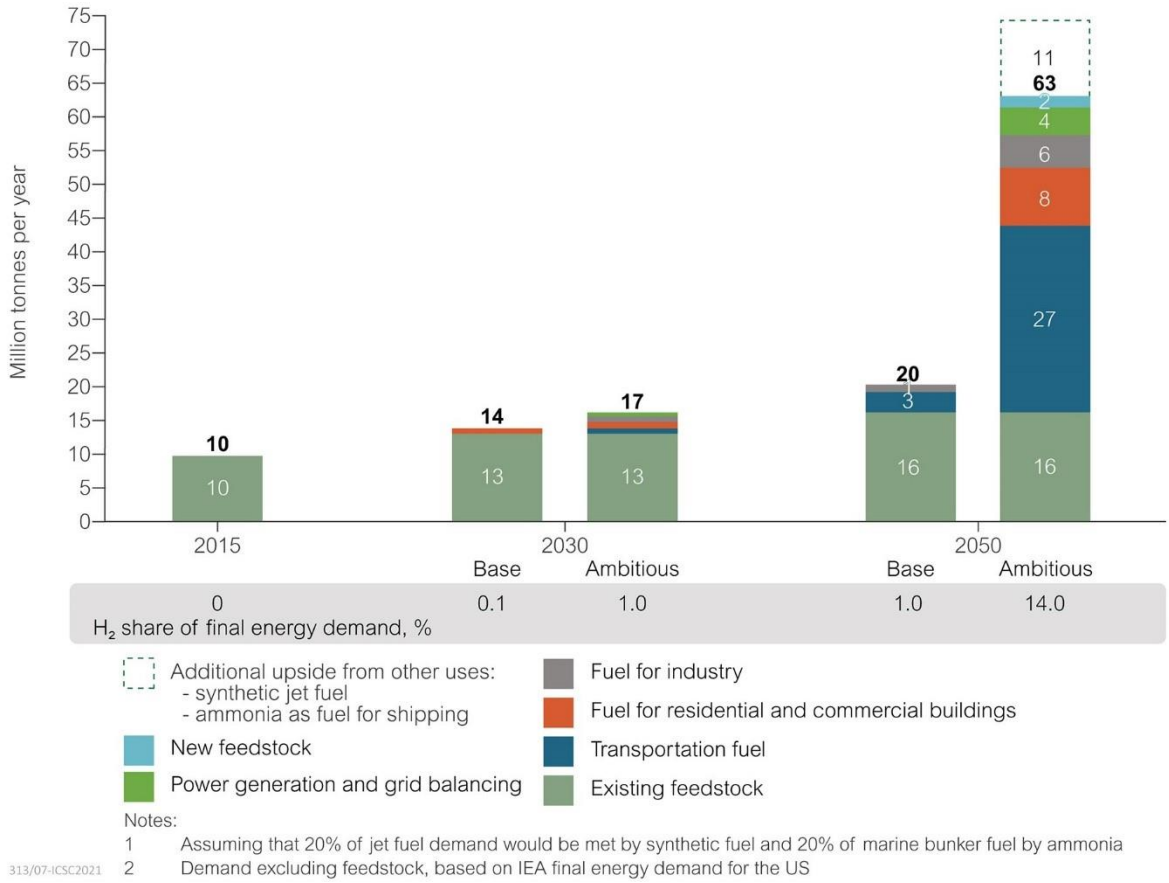


Figure 7 Forecast hydrogen demand in the USA (FCHEA, 2020)

TABLE 6 AMBITIOUS ROADMAP FOR HYDROGEN AND FUEL CELL ROLL-OUT IN THE USA (FCHEA, 2020)

	Status in 2020	2022 Early scale-up	2025 Diversification	2030 Roll-out
Hydrogen demand (MtH_2/y)	11	12	13	17
Annual investment ($ billion)		1	2	8
Number of refuelling stations	63	165	1000	4300
Number of FCEVs	2500	30,000	150,000	1,200,000
Number of material handling FCEVs (eg forklift trucks)	25,000	50,000	125,000	300,000
Number of material handling refuelling stations	120	300	600	1500

3.3 SPECIFIC USES OF HYDROGEN

Having looked at the potential future demand for hydrogen, this section provides more details on the specific opportunities for hydrogen already identified and provides some granularity to this in terms of the key geographic areas.

3.3.1 Transportation

Transportation represents the single largest potential market for hydrogen, at around 22 EJ or 185 MtH_2/y by 2050, representing nearly 30% of the total hydrogen (Hydrogen Council, 2017b), as shown in Figure 4. The primary use of hydrogen in transport is expected to be in FCEVs, where the main competition will be BEVs. Both BEVs and FCEVs have no point of use emissions and thus offer the potential to significantly reduce local air pollution, especially in cities. They can also significantly reduce GHG emissions when hydrogen produced from low carbon sources is used. Although the drivers for the deployment of FCEVs and BEVs are therefore generally the same, they have different characteristics which may provide a preference for one or the other in different transport sectors and regions (Aarnes and others 2018). In terms of:

- **Fuel cost –** BEVs tend to have the lower cost due to the relative prices of electricity and hydrogen;
- **Fuelling/recharging time –** FCEVs take less time;
- **Volume** – the space for the hydrogen storage tank and fuel cell drive train is less than that for the BEV batteries for an equivalent output;
- **Weight –** the FCEVs fuel cells and hydrogen tanks weigh less than BEV batteries;
- **Range –** FCEVs have longer ranges compared with the current generation of battery technologies, typically with a driving range more similar to internal combustion engine vehicles; and
- **Charging/fuelling infrastructure availability –** this is being rolled out both for FCEVs and BEVs and is dependent on the geographic region.

These differences indicate that there should be an advantage for FCEV-based transportation options for the large vehicle segments which require long range and typically heavy loads, with the highest uptake likely to be in the large cars, trucks and buses segments of road transportation. According to analysis by DNV GL, more than 80% of hydrogen demand for mobility will be for these applications (Aarnes and others, 2018).

In terms of technology readiness, FCEVs are commercially available now or will become available in the next five years in the transport sectors of large cars, buses, trucks, vans, trains, and forklifts. According to the Hydrogen Council, as FCEVs costs reduce through volume production and technology development, FCEVs will become increasingly competitive in the medium and smaller cars and minibus sectors. By 2030, 5–10% of cars sold in leading regions such as California, parts of Europe, Japan and South Korea could be powered by hydrogen, together with more than 350,000 FCEV trucks, and thousands of trains and passenger ships. There is also the issue of increasing car ownership in countries such as China and India which will further increase the demand for transport vehicles, of

which FCEVs will take a share (IEA, 2019c). Car ownership in these countries is well below that of the EU and the USA, where US per-capita car ownership is 25 times higher than in India for example.

There is a need to further reduce costs and build up refuelling station networks concurrently with vehicle uptake if more automakers are to be attracted to the FCEV market.

Looking specifically at the number of HRS worldwide, it has more than doubled in the last five years, marking the path towards more widespread commercial deployment. While early deployment until 2013 was mainly associated with demonstration projects where certain refuelling stations have been decommissioned after project completion, the number of stations since then has been continuously increasing.

The expansion of the HRS infrastructure has primarily been in Asia and Europe (*see* Figure 8) (H_2 stations, 2020). In North America, HRS infrastructure provision has been concentrated in California, USA and more recently, in British Columbia, Canada. Outside Asia, Europe and North America, HRS infrastructure is limited.

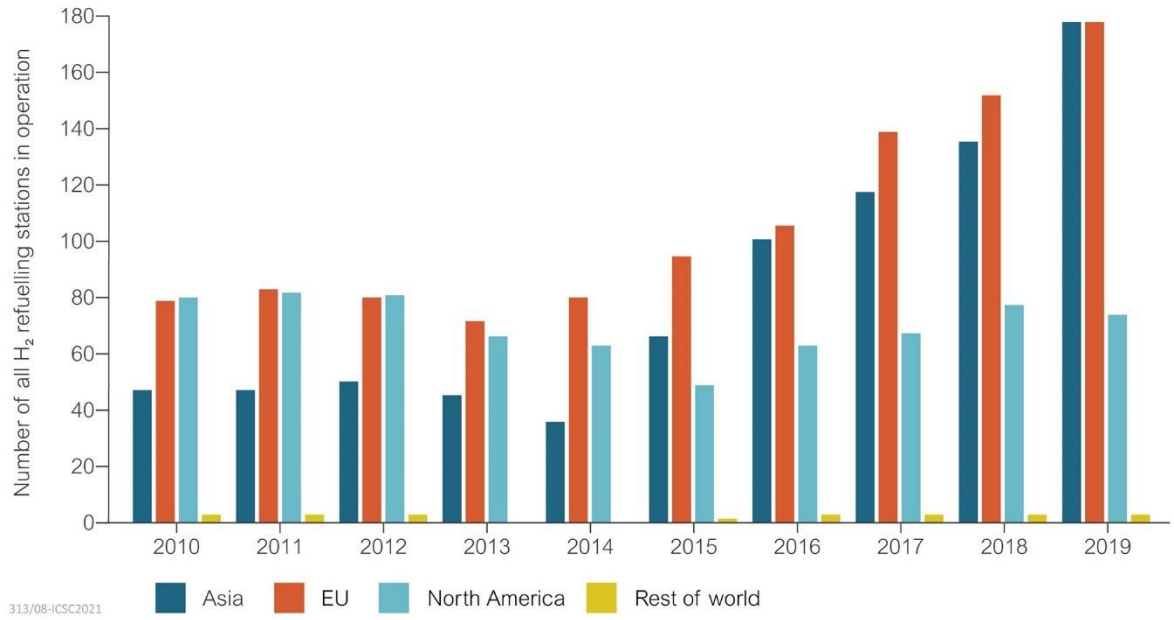


Figure 8 Hydrogen refuelling stations by region (H_2 stations, 2020)

Looking at the position in the leading markets of Europe and Asia:

Europe

The transportation sector could have a hydrogen demand in 2050 of 675 TWh (20 MtH_2/y), representing 30% of total hydrogen. This would involve hydrogen powering a European fleet of approximately 45 million automobiles, 6.5 million light commercial vehicles, 250,000 buses, and 1.7 million trucks, resulting in FCEVs making up 20–25% of the European fleet for these segments (FCH JU, 2019). For larger vehicles with long-range requirements, adoption rates could be higher since hydrogen has range advantages over BEV technology. Adoption rates could reach 30% for large

automobiles and vans and 55% for taxis, while small FCEVs might comprise 15% of the 2050 small automobile fleet. The infrastructure to fuel this fleet will need to increase in line with the number of vehicles on the road. Some 3700 large refuelling stations would be needed in 2030, increasing to 15,000 by 2050 (Figure 9). This is equivalent to an investment of roughly €8 billion by 2030, increasing to €27.5 billion by 2050. In 2020, there were 139 HRS in operation with the intention to increase this to around 1500 by 2025. However, this level of deployment will require a significant increase in activities and support measures to ensure this initial infrastructure is put in place.

In addition, hydrogen could play an essential role in the sector beyond road transport. From 2030 onwards, hydrogen and synthetic fuels derived from hydrogen could be increasingly used to fuel freight ships and aviation. As synthetic fuel, hydrogen could replace about 4% of the EU's fuel supply for aeroplanes and freighters. For non-electrified trains, 50% of sales in 2050 could involve fuel cell generated power, replacing almost 20% of EU-wide diesel trains in the fleet. The fleet could thereby reach about 5500 hydrogen powered trains in 2050.

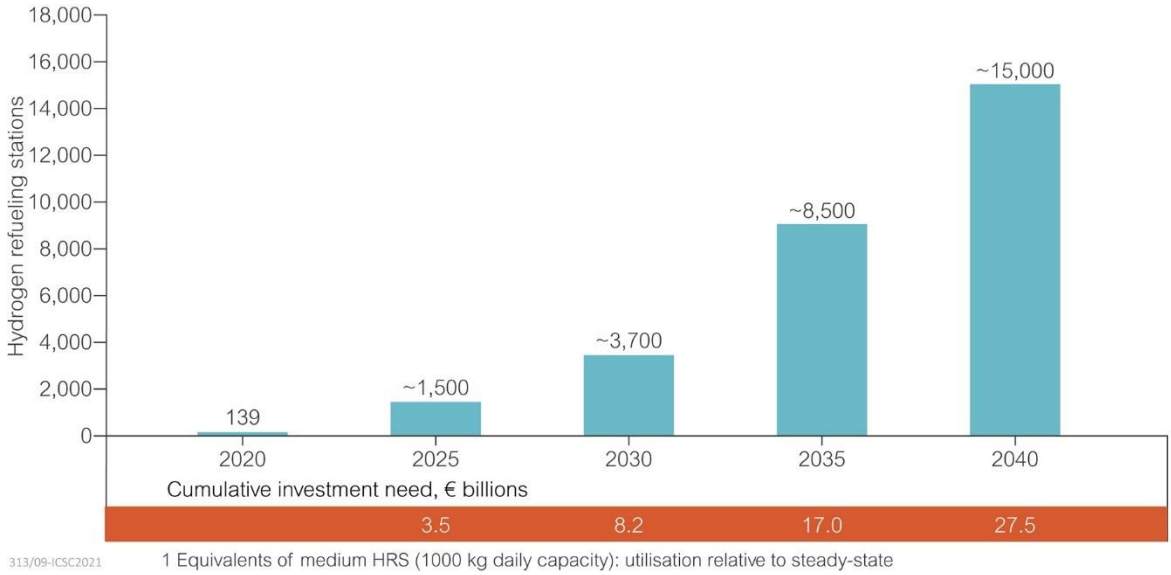


Figure 9 Cumulative investment and increased number of hydrogen refuelling stations to meet 2°C temperature rise scenario (FCH JU, 2019)

Asia – Japan

Japanese car manufacturers, including Toyota and Honda, are global leaders in FCEV development, although to date, the domestic deployment of FCEVs has been relatively low with around 3700 passenger vehicles sold in Japan since the first FCEV launch in 2014 (Nagashima, 2020). The official targets set for Japan are 200,000 FCEVs by 2025, and 800,000 FCEVs by 2030. In addition, Japan's Hydrogen Strategy has set out the ambitious aim to reduce the cost of FCEVs by JP¥1.1 million (around $10,500) in five years. It includes reducing the cost of fuel cell stacks and hydrogen tanks to around one quarter by 2025, with a further reduction to one fifth by 2030 (Chaube and others, 2020).

Around 20 fuel cell buses have been introduced in Japan through to 2018, with the target to achieve 1200 fuel cell buses by 2030. Regarding fuel cell-powered forklifts, 160 units have been sold, with the target of 10,000 forklifts by 2030.

The shipping industry is also looking to hydrogen and ammonia as a way to meet GHG emissions reduction. The Ministry of Land, Infrastructure, Transport and Tourism (MLIT) published the Roadmap to Zero Emissions in International Shipping in March 2020, in which hydrogen and ammonia are considered among the four potential options for the complete decarbonisation of the shipping industry. The initial commercial launch of each prototype is expected between 2028 and 2030 (Nagashima, 2020).

In terms of HRS, there are 116 refuelling stations operational in Japan (May 2020), focused on the four largest cities and key transit areas. Around 320 stations are expected to be operational in 2025 and 900 by 2030. Financial support for the development and operation of hydrogen stations is available through Japan Hydrogen Mobility (JHyM), a consortium of private companies and financial institutions created to support the refuelling business until 2027 (METI, 2018).

Asia – China

Key Chinese stakeholders consider FCEVs to be the most promising novel application of hydrogen in China. With an ambitious target of achieving 5 million FCEVs by 2050 (*see* Table 5), the country has been increasing the level of R&D and deployment of FCEVs. However, by the end of June 2020, cumulative sales of FCEVs in China were still less than 7000. To put this in context, the cumulative stock of China's 'new energy vehicles' (vehicles eligible for public subsidies, comprising BEVs, plug-in hybrids and FCEVs) was 4.2 million, meaning that over 99.8% of them were either BEVs or plug-in hybrid.

The number of hydrogen refuelling stations in China has increased rapidly. In 2019, Shanghai Chemical Industry Hydrogen refuelling station, at the time the largest HRS globally, opened in Shanghai. With an area of 8000 m^2, this station has a capacity of two tonnes of hydrogen per day, including 35 MPa and 70 MPa refuelling systems. By the end of June 2020, 72 hydrogen refuelling stations were operational in China, with many more under construction or in planning.

USA

In the ambitious scenario described in Section 3.2.3, up to 8 million FCEVs could be sold in the USA by 2050. This would translate into approximately 7 million light-duty passenger vehicles, half a million trucks, and 100,000 material-handling vehicles. This would reduce US transport carbon emissions by 30% and constitute 8% of total energy demand. In particular, hydrogen could play a role in the following areas (FCHEA, 2020):

- ***Heavy machinery/fleet trucking*** – FCEVs could make up about 10% of independently powered heavy machinery or captive vehicle sales by 2030 and 35% by 2050. This translates into fleet adoption rates of 2% in 2030 and 30% in 2050;
- ***Commercial fleets of small delivery trucks, buses, and medium/heavy duty trucks*** – FCEVs are estimated to make up 10% of commercial fleets and truck sales in 2030 and 35% by 2050;
- ***Light-duty passenger vehicles*** – FCEVs could account for over 5% of passenger vehicle sales by 2030 and potentially 40% by 2050. Passenger vehicles are likely to find high adoption rates with consumers seeking the capability to refuel quickly, drive long distances, carry heavy loads, or have more room. FCEVs may also figure prominently in higher utilisation use cases that require filling up more than once a day, such as taxis, autonomous vehicles, or delivery fleets;
- ***Material-handling equipment, including forklifts and handling vehicles in ports and airports, and automatically guided vehicles and robots*** – With more than 25,000 fuel cell forklifts in operation, representing 0.4% of all forklifts in the USA, material handling is the biggest market for hydrogen vehicles today. Hydrogen powered forklifts can be refuelled quickly, provide constant power output, and have low operating costs compared to alternatives. By 2030, hydrogen powered forklifts could make up 20% of forklift sales, with this number growing to 60% by 2050.

3.3.2 Industry feedstocks and process heat

The industrial sector comprising existing and emerging feedstock applications, and industrial energy is the largest overall sector for potential hydrogen use, comprising 35 EJ or around 190 MtH_2/y by 2050 (Hydrogen Council, 2017b), as shown in Figure 4. The potential breakdown of this hydrogen use is shown in Figure 10, where ammonia manufacture at 44%, followed by methanol manufacture at 20% and refinery applications at 14% are projected to be the largest users (Aarnes and others, 2018). As noted earlier in Section 3.1, the absolute levels of hydrogen use vary between forecasts, with the Hydrogen Council's forecast representing the likely upper limit of the industrial hydrogen market size. Looking at each of these potential uses:

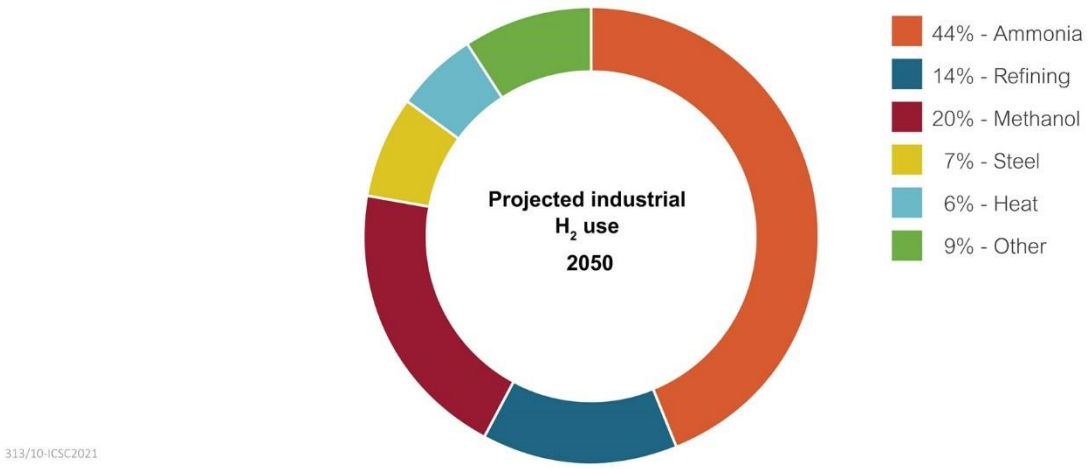


Figure 10 Projected industrial uses of hydrogen in 2050 (Aarnes and others, 2018)

Ammonia production – The annual growth rate in ammonia production has been around 2% over the last 20 years. If this growth rate were to continue, the hydrogen demand for ammonia could be around 54 MtH_2/y in 2050. As the primary use of ammonia is for fertiliser, its demand tends to correspond with global agricultural production. The United Nation's Food and Agriculture Organisation projects that cereals production will increase by 38% between 2005 and 2030 at a growth rate of 1.1% per year, then at 0.5% per year from 2030 to 2050 (Alexandratos and Bruinsma, 2012). Based on these growth rates for ammonia production, hydrogen demand for this purpose would be lower at 35 MtH_2/y in 2050. The IEA has estimated that ammonia production will grow by about 50% to 2050 (IEA, 2019b), which would correspond to a hydrogen demand of over 40 MtH_2/y.

Petroleum refining – The USA, China and Europe are the largest consumers of hydrogen in refineries. The three regions represent around half of total refinery hydrogen consumption, reflecting the volume of crude oil processed. Hydrogen has several applications in the refining industry, such as the removal of sulphur compounds from crude oil and the cracking of long chain hydrocarbons to shorter chains, for the production of gasoline. Heavier and sour crude oil requires extensive processing, and the production of the former is rising at a rapid rate. In addition, the strict environmental regulations to reduce sulphur in oil are leading to substantial consumption of hydrogen at refineries. For instance, the International Maritime Organisation (IMO, 2020) enforced a new 0.5% global cap on the sulphur content in fuel in January 2020, a significant reduction from the previous maximum of 3.5%.

Overall, the demand for hydrogen in the refinery industry is estimated to grow by around 3% per year to reach 26 Mt H_2/y in 2030. Since crude oil production is expected to remain relatively flat at current levels to 2030, this mainly reflects growth in hydrogen consumption per refined unit. Hydrogen demand for petroleum refining could actually decrease to 13 MtH_2/y by 2050 on a projected 50% decline in crude oil production from 2018 levels (DNV GL, 2018).

Methanol production – Demand for methanol for existing applications is set to grow at 3.6% per year between 2018 and 2030. The methanol to olefins and methanol to aromatics demand segments are set to grow more quickly than the total, at 4.1% per year over the same period, with nearly all this growth coming from China. This rate of growth would require 19 MtH_2/y for methanol production for these existing applications by 2030, increasing towards 25 MtH_2/y by 2050 (IEA, 2019b).

Steelmaking – Global steel production is projected to grow to 2100 Mt/y by 2050, with virgin steel production remaining near 1200 Mt/y while recycled steel production more than doubles. The Hydrogen Council estimates that about 10% of virgin steel could be produced through DRI by 2050. If all DRI processes use hydrogen as a reducing agent, this would lead to hydrogen demand of about 11 MtH_2/y, although a more realistic scenario could be that around half the DRI processes will use hydrogen as a reducing agent in 2050 (Aarnes and others 2018).

China's crude steel output was close to 1000 Mt in 2019, accounting for over half of the global total. Since the steel industry is one of the highest carbon-emitting industries in the world, representing

about 7% of global carbon emissions, a successful decarbonisation strategy is key for the sustainable development of the Chinese steel manufacturing industry. The leading options in China for the steel industry are the continued use of fossil fuels with CCUS, or the use of a hydrogen-fuelled DRI process (Tu, 2020).

It should be noted that using hydrogen as a fuel in steelmaking would require a near-complete overhaul of the steel production process. Hence, hydrogen-based steel production processes will generally be more economic for regions where new facilities are to be built (McKinsey, 2018).

Heating – As noted earlier in this section, 12% of global industry energy demand at around 16 EJ or 133 MtH_2/y could be met with hydrogen (Figure 4). This could comprise 23% of high-grade heat, 8% of medium grade and 4% of low-grade heat and power (Hydrogen Council, 2017b). Certain processes require combustion-based heaters, in which solids, liquids, or gases are burnt as the heat is transferred to the material. Blast furnaces for iron making are a good example, where the coke used in the furnaces not only creates heat needed to melt iron but, also enables the chemical reaction between the carbon electrodes in the coke and the oxygen in the iron ore that is necessary to reduce the ore to iron. While it is possible to enhance the heat of the blast furnace with other combustible fuels (such as natural gas or hydrogen), it is therefore not possible to substitute the blast furnace with an electric furnace. Clean hydrogen can create high temperatures while producing little or no CO_2 and equipment can be retrofitted to run on hydrogen or a combination of hydrogen and other combustible fuels. In the steel industry, as in the chemicals industry, hydrogen is already used to produce heat and power, as in the heat treatment of steel billets. Research shows that much larger shares of hydrogen-rich off-gases could be captured and used to generate power or enhance production elsewhere in the plant, either as fuel for the blast furnace or as a reducing agent in direct reduction iron making as described in Section 3.1. A similar intensification of hydrogen use could also support decarbonisation in other industries:

- **chemicals and petrochemicals**, whereby the hydrogen product could be used to retrofit equipment such as ethene crackers;
- **aluminium recycling**, where natural gas-fired furnaces could be retrofitted to run on hydrogen;
- **cement production**, where hydrogen could be combined with waste-derived fuels; and
- **pulp and paper industry**, where hydrogen could provide the high purity flame needed to flash dry paper.

For medium- and low-grade heat, from typically 100–400°C, hydrogen could complement electrification and heat pumps, potentially with hybrid boilers switching between electricity and hydrogen, which could allow factories to exploit price or supply differences. Here, the use of hydrogen is lower than for high temperature heat applications due to increasing competition from electrification. Analysis by DNV GL indicates that hydrogen demand for industrial heating may remain marginal

through to 2050, although there will be regional variations with higher deployment of hydrogen in areas which pursue the development of hydrogen infrastructure. Since there are some synergies with hydrogen supply for heating in industry and heating in buildings, the analysis projects a similar level of penetration for both. As the energy demand for heat in buildings is about two-thirds of that for heat in industry, this translates to a demand of around 6 MtH_2/y in 2050 (Aarnes and others, 2018).

The next sub-section looks at Europe as an example of the general global position in terms of hydrogen use for industrial feedstocks and processes:

Europe

The industrial use of hydrogen would be the largest sector in Europe in 2050, accounting for 885 TWh of hydrogen (27 MtH_2/y), representing close to 40% of the total hydrogen demand in Europe (FCH JU, 2019). Hydrogen is already used as a feedstock for refining and chemicals production, principally ammonia and methanol, and metal processing, with a current demand of around 325 TWh (10 MtH_2/y). The majority of this feedstock is unabated hydrogen produced from natural gas through SMR. Whilst decarbonising the hydrogen would require minimal or no change to these industrial processes themselves, new CCUS infrastructure would be needed. On this basis, by 2030, 10% of the process hydrogen could be low-carbon hydrogen, based on SMR in conjunction with CCUS, with perhaps another 20% of hydrogen in the form of by-products.

By 2050, hydrogen for existing feedstock uses could be close to fully decarbonised, with more than 75% of hydrogen from SMR with CCUS for these applications. New uses of hydrogen for feedstocks will contribute significantly to additional demand. Steel would be the leading sector for new feedstock applications of hydrogen, with more than 1% of European steel produced from DRI by 2025 growing to 20% in 2050, which would require 140 TWh of hydrogen (4 MtH_2/y). A recent study by McKinsey, (2020) notes that switching the DRI process to an entirely hydrogen-powered process is technically feasible, although the overall cost is still high and the technology has yet to be proven at large scale.

Additionally, 30% of methanol, olefins, and benzene toluene xylene (BTX) from captured carbon could be produced by hydrogen instead of methane by 2050. This would create additional demand for up to 120 TWh (approaching 4 MtH_2/y) of hydrogen as shown in Figure 6.

USA

The USA is responsible currently for 9% of global ammonia production, as well as about 15% of global petrochemical production, corresponding to about 11 MtH_2/y consumed as industrial feedstock. Almost all this hydrogen comes from unabated natural gas through SMR. Hydrogen usage in this sector could grow to around 16 MtH_2/y by 2050 with significant potential to switch to low-carbon hydrogen (FCHEA, 2020). As noted above, key growth areas include steel manufacture, chemical production and refining, or as a heating source to replace fossil fuels.

3.3.3 Heating and power for buildings

Heating and power for buildings could account for 11 EJ or around 92 MtH_2/y by 2050 (Hydrogen Council, 2017b), as shown in Figure 4. Countries that are likely to lead in this market are shown in Figure 11, where Australia, Canada, the Netherlands, South Korea, the UK and the USA could all adopt hydrogen space heating of buildings at a significant scale (Aarnes and others, 2018). These countries predominantly use gas for heating buildings and have infrastructure that can be adapted to hydrogen distribution and storage, which is discussed in more detail below.

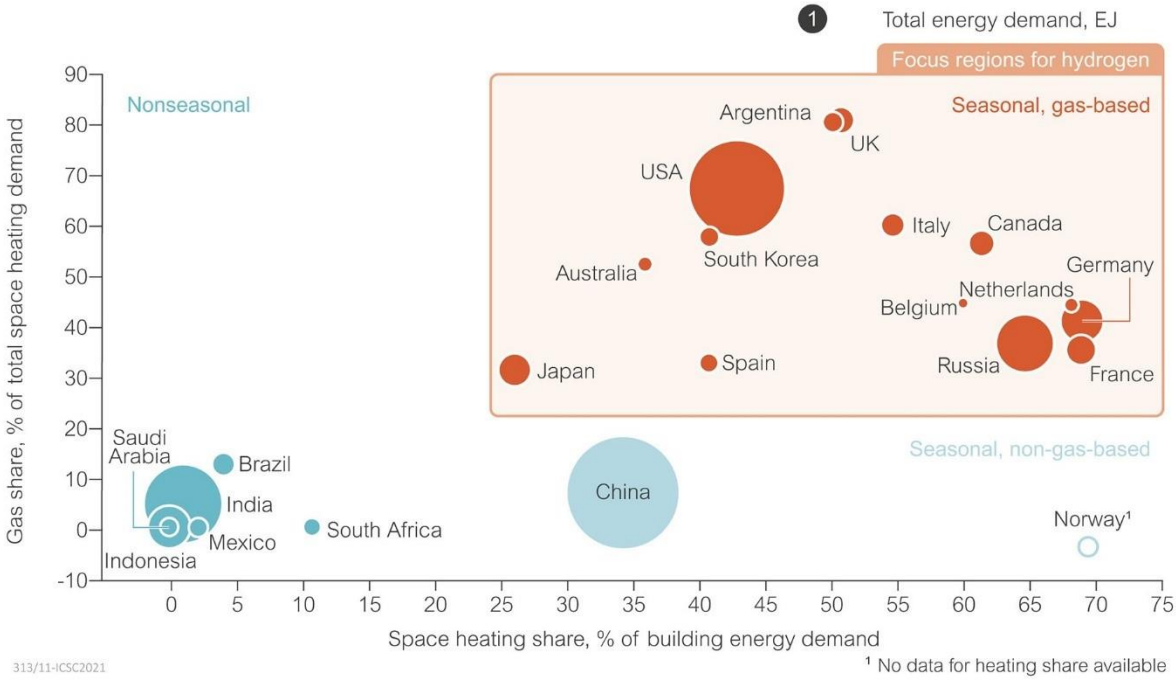


Figure 11 Potential leading countries for hydrogen-based space heating of buildings (Hydrogen Council, 2017b)

Hydrogen has the advantage compared with electricity in that it can be stored for long periods, which is relevant as heating demand is highly seasonal as noted earlier in Section 3. Electrification of heating using heat pumps would create a strong seasonal variation in the demand for electrical power, which would require considerable additional renewable capacity to cope with this winter demand. With hydrogen, a lower amount of renewable capacity could produce and store hydrogen throughout the year. For example, peak heating demand in the UK is about six times higher than peak electricity demand.

In addition, converting to hydrogen heating may be more convenient than full electrification, as no additional space or rewiring is needed to install new heating equipment and no adjustments to heating patterns need to be made. This could be an advantage for the use of hydrogen for space heating in terms of customer acceptance (Hydrogen Council, 2017b).

Gas infrastructure – Gas infrastructure plays a key role in many global energy systems, connecting gas production sites, import points and LNG terminal entry points together with demand points. Gas

transported through gas infrastructure provides a flexible, storable form of energy. As current transport grids often consist of parallel pipelines, part of existing pipelines could be used for hydrogen transmission in future systems. Whether existing natural gas transmission infrastructure can be repurposed to carry 100% hydrogen depends on the type of steel and pipeline pressure. Research in the Netherlands by the transmission system operator (TSO) Gasunie shows that long-distance networks could be repurposed to create the basis of a hydrogen transmission system (Gasunie, 2018). Most of the refurbishment costs for this would include the replacement of compressor stations, valves, and metering stations. These costs vary with location depending on the current gas grid characteristics.

Typically, carbon steel pipelines could carry hydrogen without suffering from hydrogen embrittlement or hydrogen stress cracking, provided current pressure levels are not significantly increased. For the different pressure levels, each steel grade would need to be tested thoroughly before a definitive statement of its suitability could be made. Alternatively, fibre-reinforced polymer pipelines are applicable for hydrogen transport, although these are currently only available in smaller diameters of around 15 cm (6”), compared to much bigger steel pipelines used currently for natural gas of typically 140 cm (56”).

A study carried out in the UK by Northern Gas Networks as part of the Leeds City Gate H21 study showed that it is technically feasible to reuse existing natural gas distribution networks for hydrogen (H21, 2016). In Japan, a similar study to H21 is being carried out where Toyota plan to build a prototype city of the future on a 71 hectares site called the Woven City, which will be a fully connected ecosystem powered by hydrogen fuel cells. The Woven City will serve as a home to full-time residents and researchers who will be able to test and develop technologies such as autonomy, robotics, personal mobility, smart homes and artificial intelligence in a real-world environment (Woven City, 2020).

A further study by the European Network of Transmission System Operators for Gas (ENTSOG, 2019) has proposed a hybrid energy system based on sector coupling, aimed at integrating renewable energy sources in both electricity and gas systems (*see* Figure 12). This would include a gas grid with inputs from natural gas including LNG, biogas/biomethane, together with using a portion of the natural gas to produce hydrogen via SMR. The gas grid would be effectively connected to the electricity grid via power-to-gas (P2G) with the production of low-carbon hydrogen based on water electrolysis, potentially with some methanation of the hydrogen utilising CO_2 from carbon capture plant linked to fossil fuel power generation and industrial applications. Although not considered in the ENSTOG study, hydrogen from coal gasification with CCUS could also be fed into the gas grid. There would also be the more conventional interconnection with gas, including hydrogen, used to produce electricity in gas turbines, CHP plant and fuel cells. The legislative framework for this should be considered from sector coupling perspectives on aspects which have not been integrated into the legislation so far. In particular, the P2G concept alleviates local/regional electricity infrastructure congestion issues and can contribute to avoiding curtailment of non-dispatchable electricity generated from renewable energy sources, and thereby reduce the occurrence of negative/very low electricity wholesale prices.

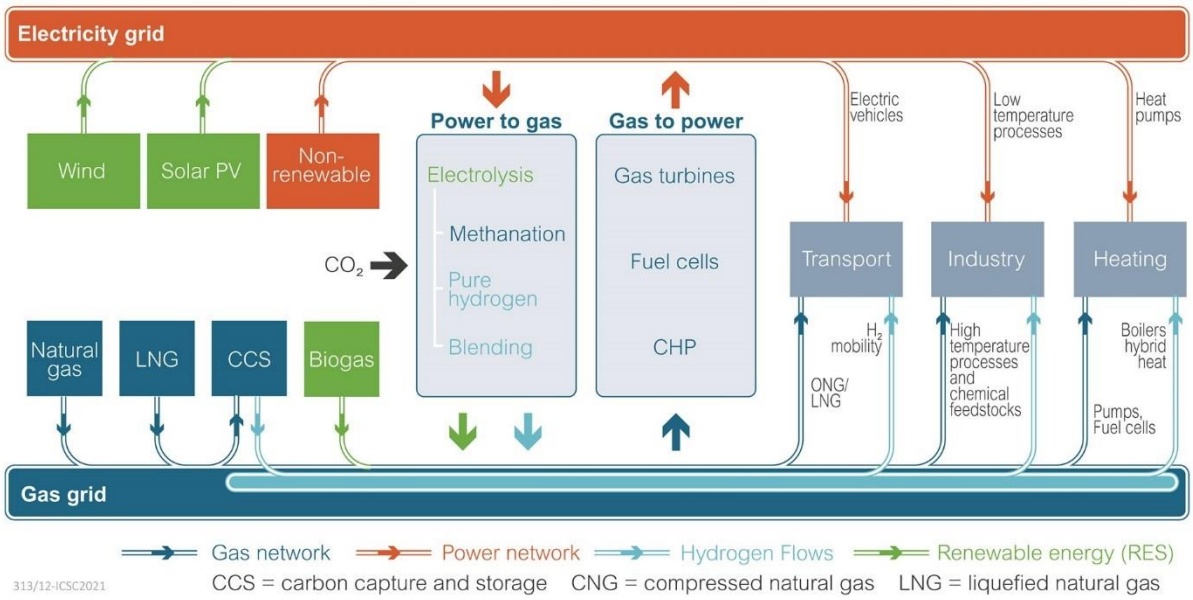


Figure 12 Potential hybrid gas/electricity energy system (ENTSOG, 2019)

Europe

Blending hydrogen into the current natural gas grid represents an immediate opportunity for decarbonisation. Blending is set to account for the first ramp-up of hydrogen in building heat, with a blending ratio increasing to 7% by volume by 2030. An estimated 25 TWh of hydrogen (less than 1 MtH_2/y) could be blended into the natural gas network by 2030, representing about 1% of the energy demand for heating in commercial and residential buildings. This development could be driven by Germany, the UK, the Netherlands, France and Denmark as early adopters in blending hydrogen into the grid.

Between 2030 and 2040, solely hydrogen (that is near 100% hydrogen) grids could emerge with whole cities and regions switching to these zero-emissions networks. This would require effective planning and the creation of new infrastructure, leading to market acceptability in 2040. By 2050, hydrogen could provide about 18% of the energy required by European households for heating, with the potential to replace up to 44% of natural gas, representing 465 TWh (around 14 MtH_2/y) of hydrogen. In such a scenario, the leading countries would have transformed 80% of their natural gas grid to hydrogen, while other countries could blend perhaps 10% hydrogen energy content into their natural gas grids.

In parallel, households could switch to micro-CHPs instead of natural gas boilers. Their market share could grow from the current 1% to more than 10% by 2030 and to 50% by 2050 (FCH JU, 2019).

USA

The natural gas pipeline network within the USA is highly integrated and moves natural gas across about 3 million miles (4.8 million km) of mainline to end-user markets and other pipelines between natural gas producing areas and storage facilities with consumers. Within this network, over

1600 miles (2500 km) of pipeline are dedicated to the transmission of hydrogen, representing some 57% of worldwide systems (USDOE, 2020).

Overall hydrogen usage for heating buildings could reach an estimated 2% of overall US final energy demand by 2050, corresponding to a hydrogen demand of 8 MtH_2/y (FCHEA, 2020). To achieve this, some 10% of hydrogen by volume would need to be blended into the grid by 2030 in the three regions of high natural gas consumption, namely the East North Central, Middle Atlantic, and Pacific regions. These are also the regions likely to follow the most progressive building and grid energy transition policies. Grids in these regions would need to contain 50% hydrogen by energy in 2050, meaning some states in these regions will have pure hydrogen networks and others will have high-volume blends. Other regions in the USA are likely to blend hydrogen at 20% by volume.

Japan

The approach of micro-CHP for residential applications is being pursued in Japan using the ENE-FARM residential fuel cell system that generates electricity and heat using hydrogen extracted from natural gas or propane gas. While the gas reforming process emits CO_2 emissions at the household level, the systemic level ENE-FARM is promoted for a lower environmental footprint compared to traditional utility-powered homes as a result of higher output efficiency and avoidance of transmission. Since entering the market in 2009, over 300,000 units were installed in Japan by November 2019. The roadmap for Japan targets 5.3 million units by 2030, equivalent to 25% of Japanese households (Nagashima, 2020).

It should be noted however that the ENE-FARM type approach using household-level gas reforming would lead to distributed, small-scale CO_2 emission sources. In the transition to net-zero emissions, these may be difficult to abate.

3.3.4 Power generation

According to the Hydrogen Council (2017b), the key targets for hydrogen by 2050 could be:

- 500 TWh of excess solar and wind electricity converted to 1.5 EJ hydrogen, representing 13 MtH_2/y;
- 1500 TWh of dispatchable power produced from 9 EJ hydrogen, representing 75 MtH_2/y, as shown in Figure 4;
- 55 MtH_2/y, or 8 EJ, transported globally; and
- 3,000 TWh of hydrogen, or 18 EJ (equivalent to 55 days of wind, solar, and hydrogen demand) stored in strategic hydrogen reserves.

As noted previously, these Hydrogen Council projections are at the upper end of potential hydrogen use for power generation, with other analyses showing lower levels of uptake. DNV GL for example show that by 2030, around 250 to 300 TWh of surplus renewable electricity could be stored in the form of hydrogen, together with more than 200 TWh of electricity which could be generated from hydrogen in

large power plants (Aarnes and others, 2018). Electrical energy stored in this way is often referred to as P2G.

According to the IEA sustainable development scenario (SDS), limiting global warming to 2°C or below requires more than half of global power generation to be based on wind and solar power by 2050 (IEA, 2019a,b). A key challenge to achieve this will be matching supply and demand as more power is generated from intermittent sources, transporting energy across sectors and regions and buffering supplies with strategic reserves. Hydrogen can contribute to this transition as an enabler in renewable power storage, distribution and buffering, as well as a complementary source of clean power generation.

Storage – The lack of economically viable options to store large quantities of electricity could limit the increased generation of electricity from solar and wind. This situation typically arises for shorter periods when renewable energy penetration increases to around 25–30% of the annual electricity mix. The duration and frequency of these periods increases as this percentage rises. The amount of long-term storage required therefore increases with the share of variable renewable energy; several studies of energy systems show the increase becoming significant as the penetration level exceeds around 60% (*see* Figure 13).

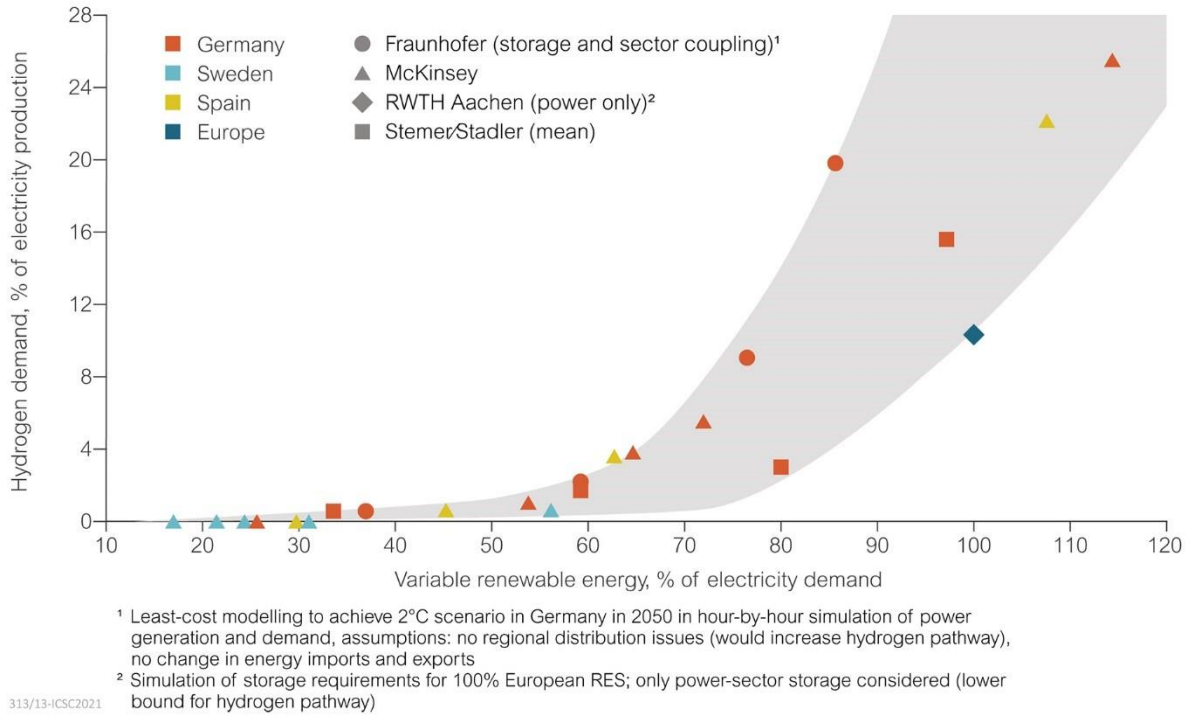


Figure 13 Increasing demand for hydrogen with renewable electricity penetration (Hydrogen Council 2017b)

Hydrogen could therefore be a medium for storing electricity using the P2G approach, with hydrogen produced from electricity later converted back. While this is possible, the roundtrip electrical efficiency is low, typically about 40%. This implies that the final electricity output from this value chain

has a relatively high cost per MWh. Electricity generation from hydrogen will, in general, be applied only when the electricity price exceeds this cost (Aarnes and others, 2018).

It should be noted that the use of hydrogen for peak shaving requires power generation technologies with adequate capacity for short-term production. If these systems are used for peak shaving only, the low capacity factor implies a relatively high contribution to the cost of electricity from the capital expenditure (Capex) of the generating technology. The business case therefore depends on expensive capacity in hydrogen power generation systems that can be deployed on demand. Figure 14 compares the cost of electricity from hydrogen relative to the cost of electricity produced from pumped hydro storage as the main alternative for large-scale, long duration energy storage. Despite the much lower energy loss from pumped hydro than for the two power-to-hydrogen-to-power (P2P) value chains, electricity storage by pumped hydro has a higher cost. This is due to the higher Capex of pumped hydro than the P2P options.

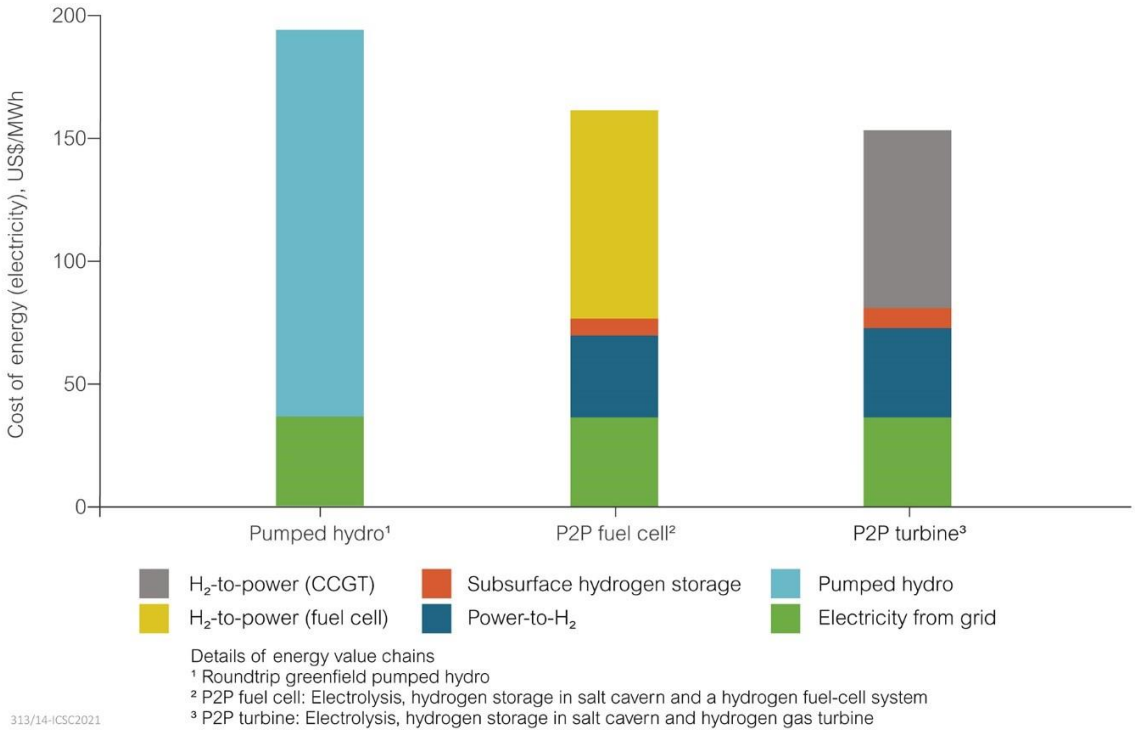


Figure 14 Cost of electricity from storage for three energy value chains (Aarnes and others, 2018)

Assumptions: Hydrogen storage in salt caverns, electricity storage corresponding to 10 days of production, 80 year lifetime of pumped hydro system, 20 year lifetime of the electrolyser and hydrogen fuel cell/ and turbine and input electricity cost is 36 $/MWh.

This shows that the hydrogen P2P systems adds about 120–130 $/MWh to the input electricity cost. This delta costs indicates that hydrogen can potentially be used for peak shaving if the electricity price is significantly above the electricity price used to produce the hydrogen. Lower estimates of hydrogen storage costs in salt caverns of 50–150 $/MWh have been provided by other sources (Hydrogen Council, 2017b).

Hydrogen based dispatchable power – Hydrogen could also provide clean dispatchable power where there are insufficient renewable capacities or during times of peak demand. In the Asian countries of Japan, South Korea, and Taiwan, for example, imported hydrogen could be used to generate clean power. Hydrogen could also play a role in decarbonising current power generation. Existing natural gas power plants can be retrofitted to burn hydrogen, which could be derived from natural gas, biogas or coal. This type of application is being deployed at large scale in power projects including the Magnum power plant in the Netherlands (IRENA, 2019a), Kobe power plant in Japan which is also developing the required hydrogen supply chain from Australia (KHI, 2019), the Intermountain Power Plant in the USA (Kakaras, 2021) and Keadby power plant in the UK (Keadby, 2020). Looking at these four power plants in a little more detail:

- Magnum is a 1.32 GW natural gas-fired CCGT power plant in Eemshaven, the Netherlands, which is operated by Swedish power company Vattenfall (IRENA, 2019a). The H2M project t is a collaboration between Nuon, Equinor and Gasunie to convert one of the three 440 MW units of the Magnum power plant, to hydrogen. Equinor will provide an ATR plant where hydrogen will be produced from natural gas that is imported from Norway with the CO_2 captured. The goal is to integrate a salt cavern to enable system flexibility, with the captured CO_2 shipped back to Norway and stored offshore. The project will use Mitsubishi Power's M701F gas turbine converted to 100% hydrogen combustion utilising diffusion flame technology with diluent injection, by 2025 (MHI, 2019).
- Kobe is a pilot-scale CHP power plant in Japan that utilises hydrogen produced in the Hydrogen Energy Supply Chain (HESC) project in Victoria State, Australia. Producing around 1.1 MW of electricity and 2.8 MW of heat, it utilises a Kawasaki Heavy Industries (KHI) gas turbine (KHI, 2019). If the tests are successful by 2022 or 2023, the project will be extended and will enter a commercial phase after 2030, with a new terminus being built for larger ships to transport the liquid hydrogen. Further details of the HESC project in terms of the lignite gasification plant in Australia are provided in Section 5.5.
- Intermountain Power Plant involves the conversion of a 1040 MW coal power plant to hydrogen in Salt Lake City, Utah, USA. The plant is being converted to an 840 MW CCGT firing hydrogen blends, based on Mitsubishi Power's M501JAC gas turbine. The power plant is scheduled to start using a mixture of 30% hydrogen and 70% natural gas by volume in 2025, which will be increased in incremental steps to 100% low-carbon hydrogen firing between 2025 and 2045, enabling carbon-free utility-scale power generation. The power plant is connected to the Los Angeles power grid by an existing high voltage direct-current (HVDC) transmission line. The plant has a purchased power agreement with Los Angeles Department of Water and Power and will dispatch to the California Independent System Operator. The project is also associated with the planned storage of low-carbon hydrogen and/or compressed air in underground salt caverns in Utah, as part of the Advanced Clean Energy Storage (ACES) project, which is adjacent to the Intermountain Power Plant.

- Keadby 2 is a new 840 MW gas-fired combined cycle gas turbine (CCGT) power station in North Lincolnshire, UK (Keadby, 2020). At an estimated cost of £350 million (around $455 million), it is being constructed by Siemens Energy and is due to be operational by 2022. The project secured a 15-year capacity agreement at a de-rated capacity of 804 MW in March 2020, through the UK's Capacity Auction process. Once completed, the station will be the most efficient CCGT in Europe, with a targeted combined cycle efficiency of 63%. The station will help to provide flexible energy generation capacity to the UK grid, with the turbine able to reach full combined cycle power in 30 minutes. The power plant will use the 50 Hz Siemens SGT-9000HL gas turbine with associated boilers and a single exhaust stack, one condensing steam turbine unit, and a heat recovery steam generator (HRSG). This will be the lead reference plant for the Siemens HL-class gas turbine in the global 50 Hz market. The station will be capable of being upgraded to further decarbonise its generation through carbon capture or hydrogen technology, as markets develop. This would be as part of the 'Zero Carbon Humber' initiative which aims to provide a zero-emissions industrial cluster in the UK (Net Zero Carbon Industrial Cluster, 2019). Funded in part by the Industrial Strategy Challenge Fund (ISCF) Industrial Decarbonisation Competition (Lochhead, 2020), this would see the Saltend chemical plant complex fitted with 600 MW of natural gas autothermal reformers (ATRs) to make hydrogen fuel for the chemical plants at Saltend and in the medium term (2027-28) to provide hydrogen for Keadby-2 and/or the proposed Keadby-3 CCGT power plant.

In terms of hydrogen powered fuel cells for stationary power applications, Japan is taking a leading role, with the aim of achieving a system cost of 300,000–500,000 JP¥/kW (2700–4600 $/kW) and power generation cost 17–25 JP¥/kWh (0.16–0.23 $/kWh) by 2025, depending on the operating pressure of the system. There is also a target for improving power generation efficiency and extending the life cycle. In March 2020, Tokyo Gas and Miura Kogyo began the demonstration of a jointly developed industrial Solid Oxide Fuel Cell (SOFC) system at a scale of 5 kW, with 65% generation efficiency (Nagashima, 2020). Mitsubishi Power has developed a 250 kW distributed hybrid system with SOFC and a micro gas turbine under the brand name MEGAMIE. The second commercial MEGAMIE unit has now been installed at the Hazama Ando Technical Research Institute in Tsukuba (Mitsubishi Power, 2020). It is worth noting that the fuel for these systems is natural gas, which is internally reformed in the SOFC to hydrogen, although they can be readily switched to hydrogen operation in the future.

There is also the option to cofire hydrogen, or hydrogen containing mediums such as ammonia with other fuels. As noted in Section 2.1.3, ammonia and methanol can be fuels in their own right. In March 2020, three Japanese companies JERA, IHI Corporation, and Marubeni in partnership with Australian group Woodside, signed an agreement with NEDO to participate in a feasibility study on the cofiring of ammonia in commercial thermal power plants (NEDO, 2019). Japan's Basic Hydrogen Strategy

states that Japan aims to mix ammonia with coal at coal power plants by around 2020 and to use ammonia for gas turbines by around 2030.

3.4 SUMMARY

The total global hydrogen demand in 2018 was around 115 MtH_2/y. This hydrogen was produced local to the point of use, almost entirely from fossil fuels and was used primarily as feedstock in the refinery and chemicals industries.

Hydrogen global demand is forecast to increase to perhaps as high as 78 EJ, or 650 MtH_2/y, representing around 14% of the expected world total energy demand in 2050. It would be used primarily for industrial feedstock and energy, together with transportation, heating and power in buildings, and power generation usage of hydrogen including hydrogen buffering.

Hydrogen is seen as a necessary feature of the energy transformation required to limit global warming to 2°C, where it could play an important role as part of a broader strategy. There will be regional variations in this future demand for hydrogen, depending on local factors including resource availability, political support, existing gas infrastructure and GHG emission reduction targets.

4 HYDROGEN PRODUCTION

There are three main routes available for the production of hydrogen depending on the fuel feedstock, which are summarised in Figure 15:

- reforming of natural gas, primarily SMR;
- gasification of coal; and
- electrolysis of water.

These primary hydrogen production methods can be expanded to include the following (Muradov, 2017):

- partial oxidation and autothermal reforming;
- refinery and chemical plant off-gases (including chlor-alkali process); and
- other minor sources such as plasma pyrolysis, residual oil and biomass gasification.

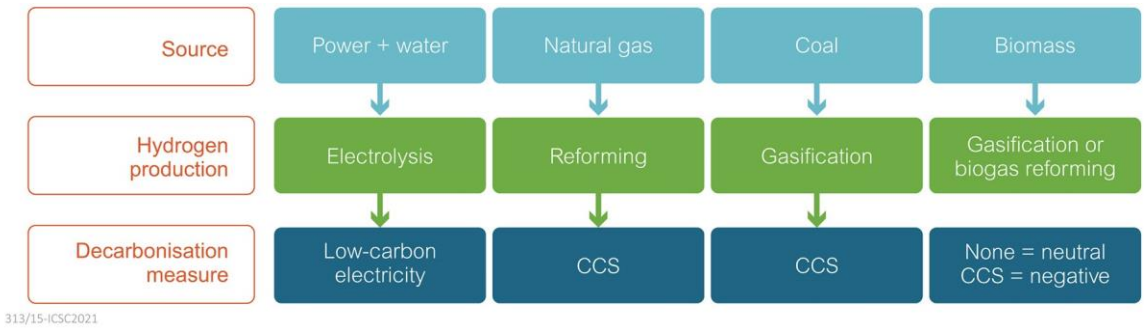


Figure 15 Options for hydrogen production (Aarnes and others, 2018)

Electrolysis is inherently low in GHG emissions as noted in Figure 15, provided that the source of electricity is renewable, whereas fossil fuel sourced hydrogen requires the addition of CCUS to reduce GHG emissions. The USDOE has identified additional fuel feedstocks which can be used instead of, or in combination with, fossil fuels to reduce GHG emissions, potentially producing negative GHG emissions when CCUS technology is utilised (USDOE 2020):

- producing hydrogen from diverse resources, including coal, biomass, natural gas, petroleum, petroleum products, waste plastics and other recyclable materials with CCUS; and
- co-gasification of blends of coal, biomass, waste plastics, and other recyclable materials with CCUS which can result in hydrogen produced with net negative GHG emissions and other environmental benefits when CCUS is integrated with the gasifier.

This section of the report explores the various hydrogen production methods, the relative costs of these techniques, together with the relative impact on GHG emissions.

4.1 OVERVIEW OF HYDROGEN PRODUCTION METHODS

An overview of the main hydrogen production processes is shown below to compare with the technology of coal gasification (Zapantis and Zhang, 2020; Olabi and others, 2020; Muradov, 2017).

4.1.1 Coal gasification

A number of coal gasification commercial concepts have been described previously by the ICSC (Minchener, 2019). In gasification, a hydrocarbon-rich feedstock, such as coal is heated at high temperatures to produce a syngas rich in hydrogen, which also contains carbon monoxide (CO) and CO_2. The syngas can then be upgraded by converting the CO to CO_2 and more hydrogen using the water gas shift (WGS) reaction and then separating the hydrogen (Committee on Climate Change, CCC, 2018). This allows the carbon to be separated and sequestered, which means that coal gasification can be a low-carbon, hydrogen production technology. The process can produce a stream of hydrogen of around 99.8 % purity, similar to that from SMR.

Hydrogen production from coal using gasification is a well-established technology, used for many decades by the chemical and fertiliser industries for the production of ammonia, particularly in China. Globally around 130 coal gasification plants are in operation with more than 80% of them in China (IEA, 2019c). In terms of gasification with carbon capture, there are currently three facilities producing hydrogen from coal, coke or asphaltene with a combined capacity of around 0.6 MtH_2/y (GCCSI, 2020) which are shown in Chapter 5. These facilities demonstrate that large-scale production of low emissions hydrogen using carbon capture can already be technically and commercially feasible.

There are of course some challenges to using coal gasification combined with CCUS. This is primarily because coal produces hydrogen with a relatively low hydrogen/carbon ratio of around 0.1:1 from coal compared with 4:1 for SMR using natural gas as fuel, together with the higher level of impurities in the feedstock such as sulphur and nitrogen containing compounds and minerals (Muradov, 2017). As noted above, the existing commercial applications of coal gasification, both with and without CCUS, mean that there are technical solutions to alleviate this.

An example of the coal gasification process including carbon capture is presented in Figure 16, with CO_2 capture achieved using acid gas removal. This can be an integral part of the coal gasification process using relatively mature physical absorption technologies such as Selexol™ and Rectisol™ (Zapantis and Zhang, 2020). CO_2 capture option C1 requires an additional process of CO_2 compression and dehydration. Since a large proportion of CO_2 is separated via acid gas removal, the amount of CO_2 entering the additional CO_2 capture (option C2) is relatively small. The same process would be applicable to petroleum coke and biomass gasification.

Further examples of coal gasification concepts are available in the literature, for example, the ash agglomerating fluidised bed gasification cycle (Li and others, 2019) and coal direct chemical looping (Li and others, 2020).

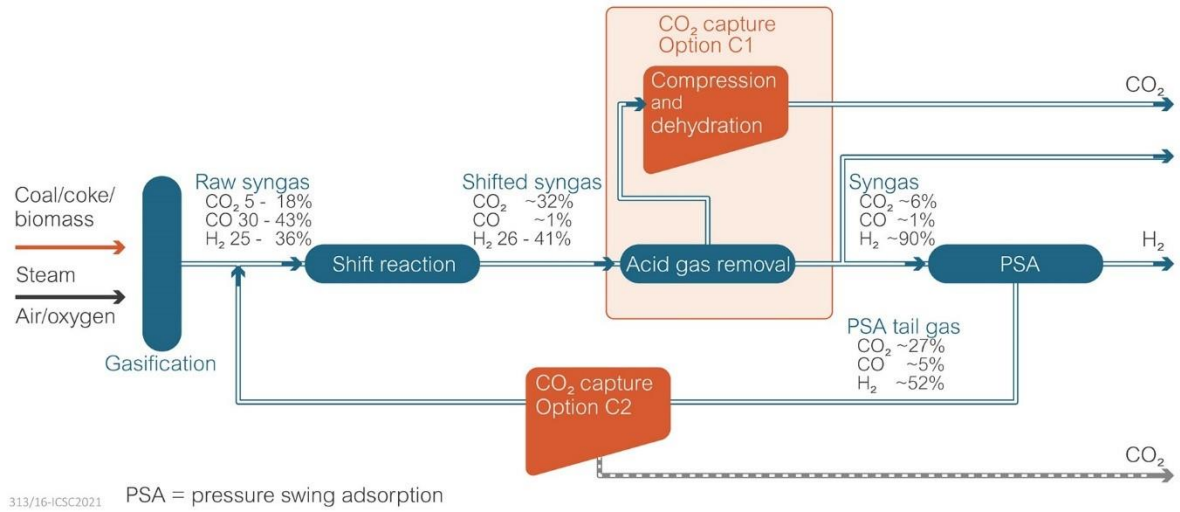


Figure 16 Hydrogen/syngas production using coal gasification with CCUS (Zapantis and Zhang, 2020)

The primary CO_2 capture options for coal gasification plants with CCUS to produce hydrogen rich syngas or hydrogen can be summarised as:

- **Base Case** – coal gasification plant without CCUS;
- **Option C1** – coal gasification plant with CO_2 capture from shifted syngas; and
- **Option C2** – coal gasification plant with dedicated CO_2 capture after acid gas removal (in addition to capture from shifted syngas).

The CO_2 capture and emissions information during coal gasification with CO_2 capture options C1/C2 are compared with coal gasification without CO_2 capture in Table 7.

TABLE 7 COMPARISON OF COAL GASIFICATION CCUS OPTIONS (ZAPANTIS AND ZHANG, 2020)

	Base case	CO_2 capture, option C1	CO_2 capture option C2
Case	**Gasification without CO_2 capture**	**Gasification with CO_2 capture on syngas stream**	**Gasification with additional CO_2 capture after acid gas removal**
CO_2 concentration at capture inlet, %	n/a	25–42	5-6
Pressure at capture inlet, MPa	n/a	3.5–5.7	5.3
CO_2 capture efficiency, %	n/a	90–95	90
Proportion of CO_2 captured, %	0	90	98
CO_2 emissions during syngas/ hydrogen production, kg/kg	19–25	2.1–2.7	0.4–0.6
CO_2 emissions including life cycle emissions from electricity, %	20–26	4.7–5.3	3–3.2
n/a = not applicable			

The performance of individual CO_2 capture technologies and methods for integrating them differ in terms of CO_2 removal rate as well as hydrogen and CO_2 purity levels. Hydrogen purity requirements vary strongly with end-use application. While most fuel cells require high purity levels, lower levels are sufficient for gas turbines, refinery processes and industrial boilers. Few technologies exist that produce both high purity hydrogen and CO_2 that is pure enough for other uses or storage, since gas separation technologies focus on either hydrogen removal or CO_2 removal. The optimal combination of hydrogen production route and capture technology therefore depends on what the hydrogen is going to be used for, as well as on the production costs (IEA, 2019c).

4.1.2 Steam methane reforming

Syngas production for industrial processes

A typical syngas production process using SMR for industrial processes is shown in Figure 17. Examples of industrial processes include direct reduced iron, methanol production and ammonia production. In ammonia production, CO_2 removal is typically integrated into the process for downstream urea fertiliser production, resulting in a high concentration of CO_2, ready for transport and storage.

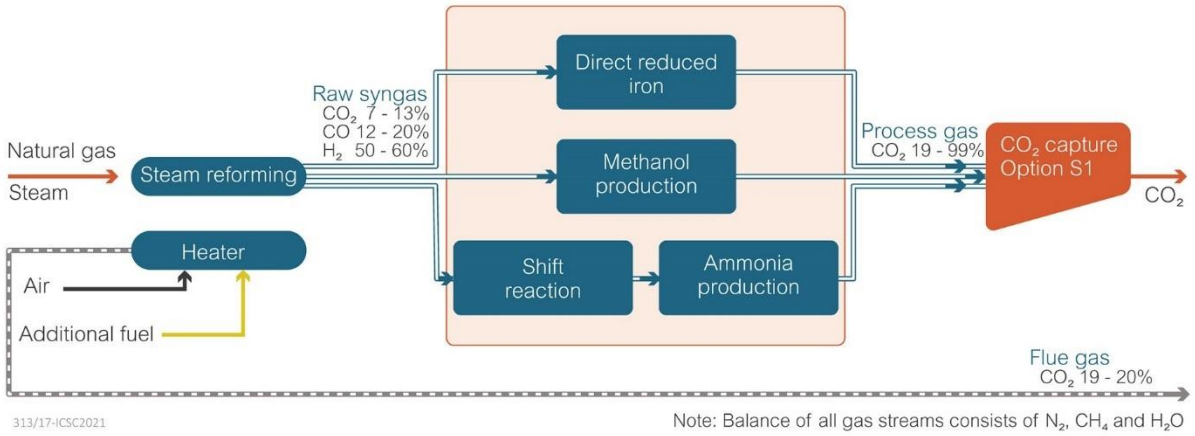


Figure 17 Syngas production using SMR with CCUS option S1 (Zapantis and Zhang, 2020)

Pure hydrogen production

A typical pure hydrogen production process using SMR is shown in Figure 18. Pure hydrogen production from natural gas requires the syngas to be fed to an additional WGS reactor to produce additional hydrogen and CO_2, with the CO_2 captured subsequently using a pressure swing adsorption (PSA) system. The gas exiting the WGS reactor contains around 60% of the total CO_2 produced in a typical SMR plant, with the balance of CO_2 produced primarily due to the combustion of additional fuel to heat the steam reformer to over 700°C. The tail gas from the PSA unit contains residual hydrogen and methane and is used as fuel to heat the steam reformer. This heat is required because the overall SMR reaction is endothermic as shown below:

SMR: $CH_4 + H_2O \leftrightarrows CO + 3H_2$ ($\Delta H^o_{298} = 206\ kJ/mol$)

WGS: $CO + H_2O \leftrightarrows CO_2 + H_2$ ($\Delta H^o_{298} = -41\ kJ/mol$)

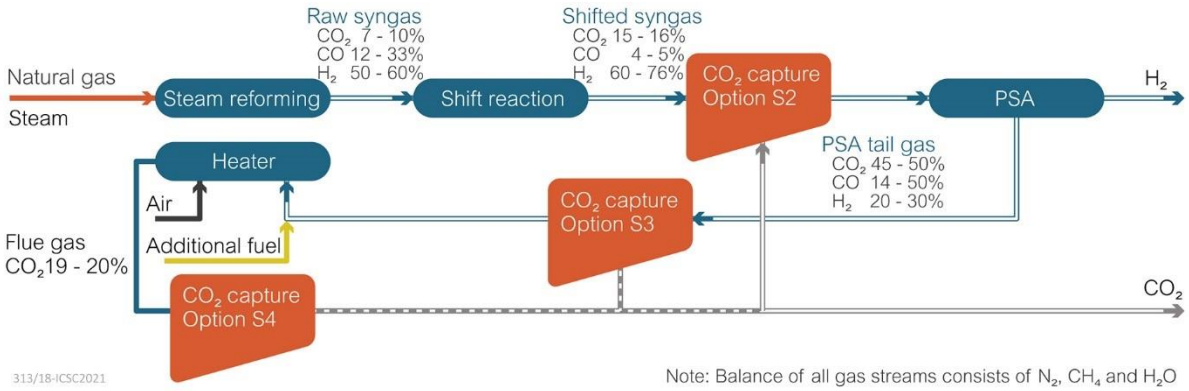


Figure 18 Hydrogen production using SMR with CCUS options S1/S2/S3 (Zapantis and Zhang, 2020)

The primary CO_2 capture options for SMR plants with CCUS to produce hydrogen rich syngas or hydrogen can be summarised as:

- **Option S1** – SMR with integrated industrial process and CO_2 capture;
- **Option S2** – SMR plant with CO_2 capture from shifted syngas for hydrogen production;
- **Option S3** – SMR plant with CO_2 capture from PSA tail gas for hydrogen production; and
- **Option S4** – SMR plant with CO_2 capture from SMR flue gas for hydrogen production.

4.1.3 Autothermal methane reforming

Autothermal reforming (ATR) combines the two processes of partial oxidation (POX) of natural gas with oxygen and catalytically reforming natural gas with steam (*see* Figure 19). It is a mature technology used for the commercial manufacture of hydrogen. One of the benefits of using the ATR process is that CO_2 can be recovered at a pressure of 0.3 MPa, which reduces the cost of further compression to pipeline pressure for subsequent transport (Muradov, 2017).

Due to the combustion of some of the methane in the reaction vessel, the total reaction of autothermal reforming is exothermic, that is, the heat released from the methane combustion shown below exceeds the heat input required for the endothermic SMR reaction. This means that an ATR does not need additional energy or fuel to sustain the ATR process and therefore does not produce additional CO_2 in a flue gas stream as is the case with SMR shown above in Section 4.1.2.

Methane combustion: $CH_4 + O_2 \leftrightarrow CO + 2H_2O$ ($\Delta H^o_{298} = -802\ kJ/mol$)

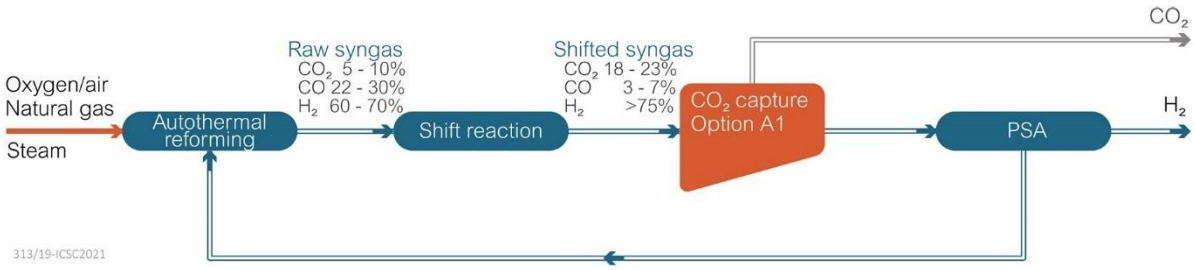


Figure 19 Hydrogen production using ATR with CCUS with CCUS option S1 (Zapantis and Zhang, 2020)

The ATR reactor operates at temperatures of typically 950–1100°C and pressures of up to 10 MPa, allowing a high rate of methane conversion. The high-pressure condition of the syngas also allows CO_2 capture to be achieved using relatively mature physical absorbent technologies such as Selexol™ and Rectisol™.

The primary CO_2 capture option for ATR with CCUS to produce hydrogen-rich syngas or hydrogen is therefore **Option A1** – ATR plant with CO_2 capture from shifted syngas for hydrogen production.

4.1.4 Hydrogen as a by-product of chlor-alkali production

Hydrogen is produced as a by-product of chlorine and sodium hydroxide (caustic soda) production through the electrolysis of brine. The process uses an electrolysis cell with an ion exchange membrane separating a bath of brine (NaCl) from a bath of sodium hydroxide (NaOH), as shown in Figure 20. Concentrated brine is fed to the anode side of the cell where chlorine ions release an electron to the anode to form chlorine gas (Cl_2). The sodium ions pass through the membrane to the cathode side of the cell. At the cathode, water is reduced to hydrogen gas, leaving hydroxide ions which then combine with sodium ions to produce sodium hydroxide (NaOH).

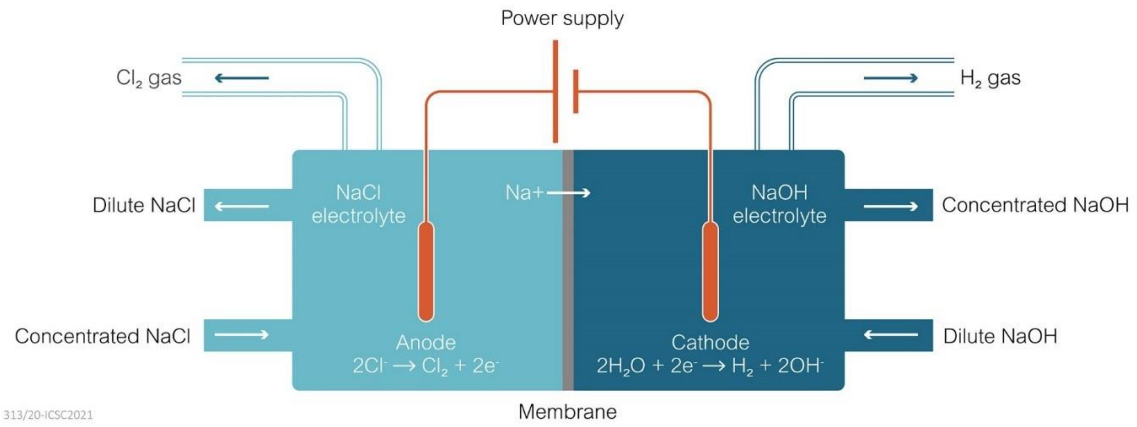


Figure 20 Chlor-alkali electrolyser cell (Zapantis and Zhang, 2020)

Each tonne of hydrogen produced using this process requires approximately 0.8 tonnes of salt and 1100 kWh of electricity (Zapantis and Zhang, 2020). This is clearly not a feasible process for the

production of hydrogen, other than in the context of being a by-product in the chlor-alkali production process.

4.1.5 Hydrogen production by electrolysis of water

There are two general classes of electrolysers that are commercially available, namely alkaline electrolysers (AE) and proton exchange membrane (PEM) electrolysers. Electrolysers based on solid oxide technology (SOE) are also being developed but are not fully commercial. The electrolysis process consumes high purity water and electricity to produce hydrogen and oxygen based on the overall chemical reaction:

$$2H_2O \rightarrow 2H_2 + O_2 \ (\Delta H^o_{298} = 286\ kJ/mol)$$

This equation determines a minimum theoretical requirement of 9 kg of pure water for every kg of hydrogen produced, although the actual water requirement will be higher due to system inefficiencies.

The power requirements for these electrolysers to produce 1 kg of hydrogen are as follows:

- Alkaline electrolysis 48–52 kWh;
- Proton exchange membrane electrolysis 56–60 kWh; and
- Solid oxide electrolysis 41–45 kWh.

Where desalination of seawater is required to produce the pure water, in regions of water scarcity for example, then an additional 3–4 kWh of energy consumption is required per kg of hydrogen produced.

Alkaline electrolysis

Alkaline electrolysis is a commercially available technology that uses an electrolysis cell with a membrane separating two baths of a caustic electrolyte such as potassium hydroxide (KOH) solution as shown in Figure 21. At the cathode side, water molecules pick up extra electrons and dissociate into hydrogen gas and hydroxide ions (OH^-). The hydroxide ions travel across the membrane to the anode side where they release electrons to form water and oxygen gas.

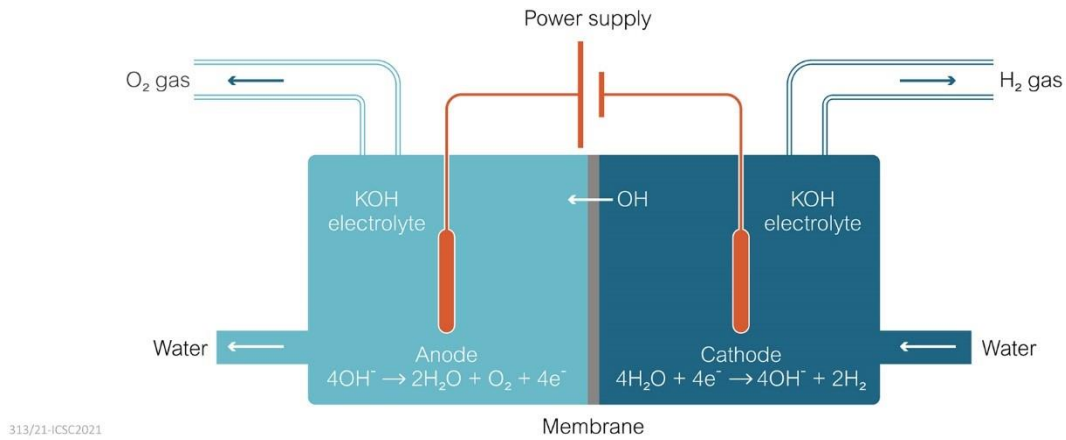


Figure 21 Alkaline electrolyser cell (Zapantis and Zhang, 2020)

Proton exchange membrane electrolysis

Proton exchange membrane electrolysers are also a mature, commercially available technology, using pure water as electrolyte with the two sides of the cell separated by a proton exchange membrane as shown in Figure 22. In brief, water molecules dissociate at the anode side to oxygen gas and hydrogen ions, releasing electrons. The hydrogen ions transport through the proton exchange membrane to the cathode side where they accept electrons to form hydrogen gas.

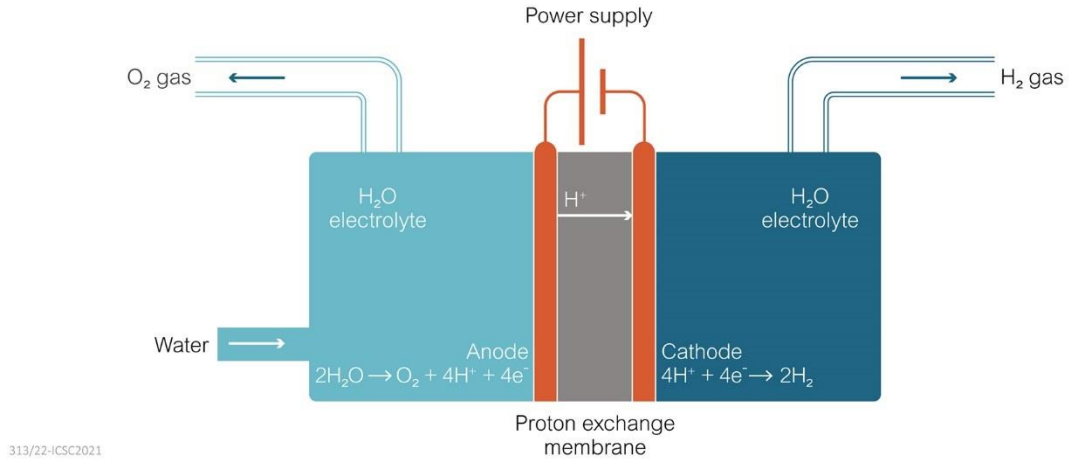


Figure 22 Proton exchange membrane electrolyser cell (Zapantis and Zhang, 2020)

Solid oxide electrolysis

Solid oxide electrolysis cells have not been fully commercialised, being at around the technology readiness level (TRL) 6-7. Operating at relatively high temperatures above 800°C, they utilise steam rather than liquid water and have a solid ceramic oxide electrolyte. High temperature operation enables higher electrical efficiency of the cell but requires an additional heat source to supply the steam. At the cathode side, steam dissociates into hydrogen gas and oxygen ions, accepting electrons in the process. The oxygen ions transport through the solid electrolyte to the anode side where they release electrons to form oxygen gas.

4.1.6 Hydrogen production from other methods

Two other potential routes for the production of hydrogen are:

- biological methods via either thermochemical or biochemical conversion to intermediate products that can then be separated or reformed to hydrogen or fermentation techniques that could produce hydrogen directly; and
- solar conversion, by either thermolysis using solar-generated heat for high-temperature chemical cycle hydrogen production or photolysis, in which solar photons are used in biological or electrochemical systems to produce hydrogen.

These are the subject of ongoing basic research and are outside the scope of this study based on their relatively low technology readiness levels.

4.2 COSTS OF HYDROGEN PRODUCTION

Many analyses have been carried out to assess the costs of hydrogen production using the different processes described in Section 4.1. Notable among these are IEA, 2019c; IRENA, 2019a; CCC, 2018; Hydrogen Council, 2017a, 2020; Bruce and others, 2018; and USDOE, 2020. Hydrogen costs vary significantly as a function of the production technology used together with the additional factors shown below (De Blasio and Pflugmann, 2020):

- local factors due to the geographic region considered;
- fuel prices;
- renewable electricity price, either wind or solar PV;
- capacity/load factors;
- learning rates for CCUS and water electrolysis systems; and
- carbon tax for residual CO_2 emissions.

This means that direct comparisons of the above studies are difficult to make due to the varying assumptions. However, a high-level comparison is made in Table 8 with a further comparison provided in Table 8. In general, this shows that low-carbon hydrogen based production routes of coal gasification with CCUS and natural gas SMR or ATR with CCUS are lower cost than low-carbon hydrogen based on water electrolysis, typically by a factor of around 3. This would indicate that with a large existing unabated fleet of gas- and coal-based hydrogen production, the transition to large-scale low-carbon hydrogen will require significant deployment of CCUS plant.

TABLE 8 COMPARISON OF HYDROGEN PRODUCTION COSTS (ZAPANTIS AND ZHANG, 2020; GCCSI, 2020)

Source of costs	Hydrogen cost from renewable electricity, $	Natural gas SMR/ATR with CCUS, $	Coal gasification with CCUS, $
CSIRO (Bruce and others, 2018)	7.7	1.7–2.1 (85% capacity factor)	1.9–2.4 (85% capacity factor)
IEA, 2019c	2–4 (renewable electricity cost of 40 $/MWh, 4000 h/y operation, best location)	1.5–2.4	1.5-2.0
IRENA, 2019a	2.7–6.8 (lower cost is wind at 48% capacity factor. Higher cost is solar PV at 26% capacity factor)	1.6–2.3	2.0
Hydrogen Council, 2020	6	1-2	2.1
USDOE, 2020	6.0	1.5–2.3	1.6
Averaged cost from the above five sources	5.6 with range of 2.0–8.3	1.8	1.9, with range of 1.6–2.4

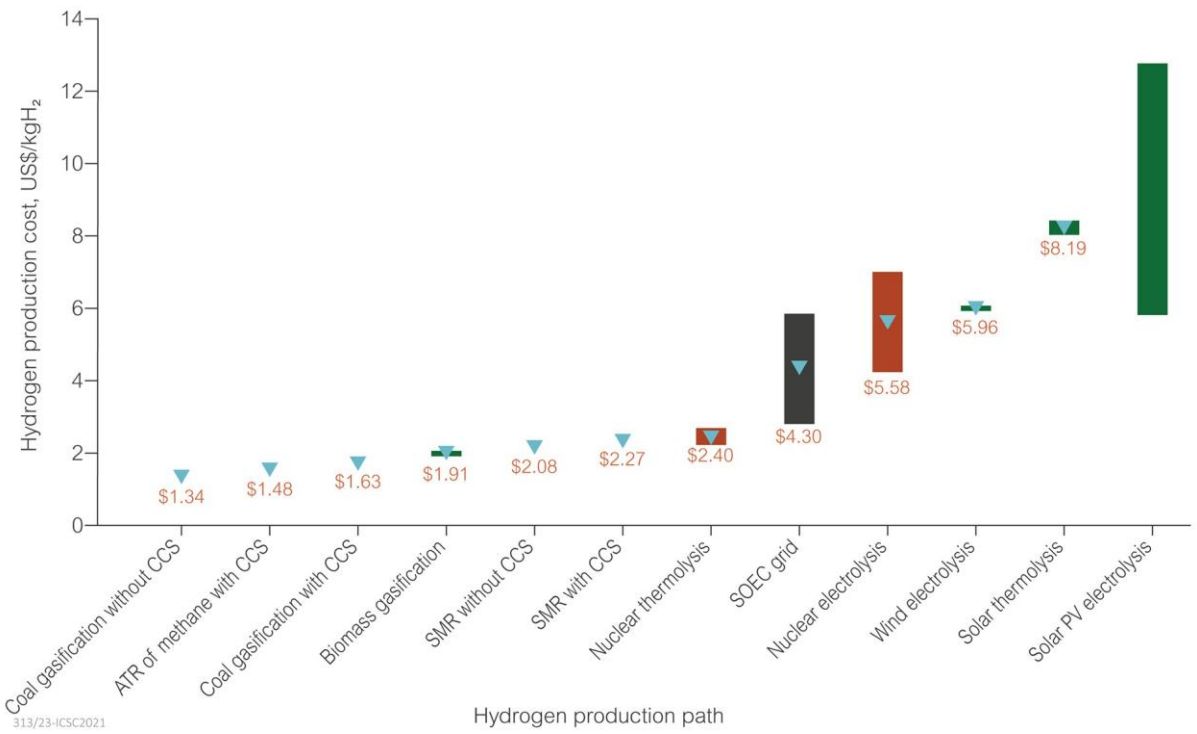


Figure 23 Comparison of hydrogen production costs (USDOE, 2020)

Given the economic advantage of coal gasification and natural gas reforming with CCUS, it is likely that these will continue to be the lowest cost source of large-scale hydrogen in the near- and medium-term. As shown in Figure 23, reforming of natural gas for hydrogen production costs vary from 1.5 $/kg$H_2$ to 2.3 $/kg$H_2$, including CCUS and are very sensitive to the natural gas price. The studies that this analysis is based on show the cost of hydrogen from coal gasification with CCUS at around 1.6 $/kg$H_2$ for coal and around 2.1 $/kg$H_2$ for coal/biomass/waste plastic with CCUS. These processes are of course highly dependent on the delivered feedstock price.

Coal gasification costs with CCUS in China are around 1.6 $/kg$H_2$ (IEA, 2019c), consistent with the figure shown in Figure 23. Indeed, since the IEA was a key source of data for the USDOE analysis, it is likely that the coal gasification cost presented is based on the case in China. Further information on hydrogen production in China is shown in Section 4.4.

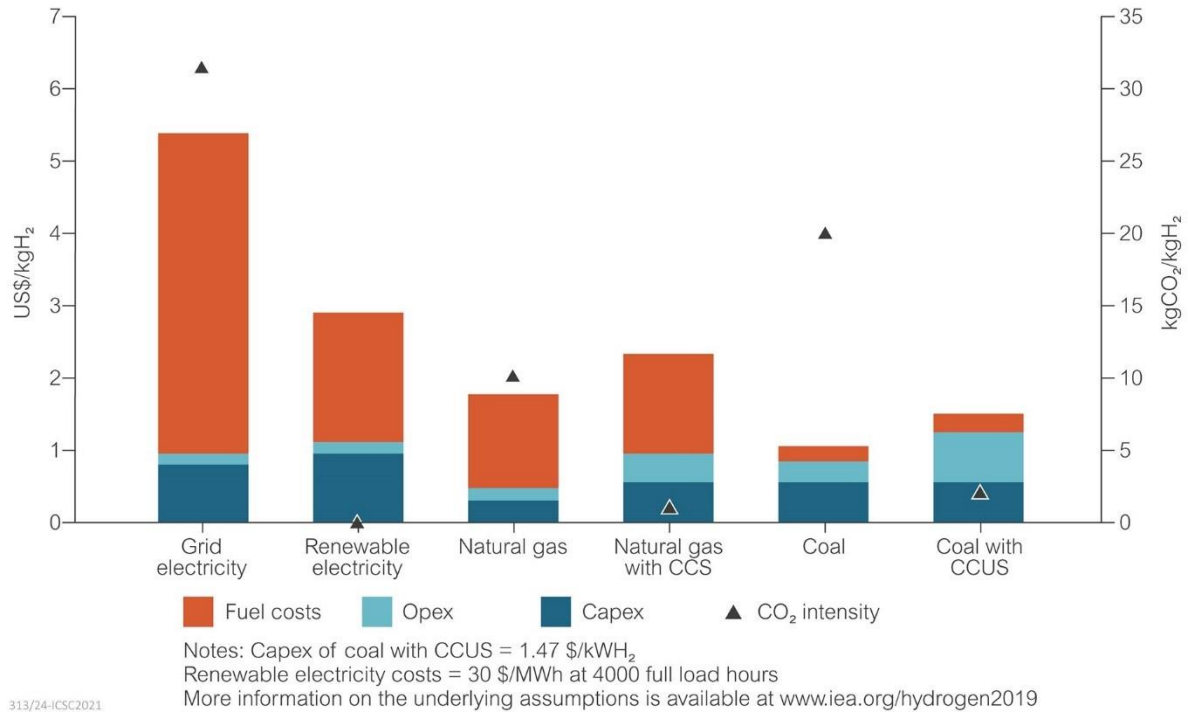


Figure 24 Hydrogen production costs in China in 2019 (IEA, 2019c)

Regional variations due to specific local factors are identified above as a key variable in the relative costs of hydrogen production, which is illustrated in Figure 24 for the case of China. The next sub-sections look at the costs of coal-based gasification and electrolysis in more detail and how the relative cost positions between the two could vary moving towards 2050.

4.2.1 Hydrogen costs from coal

In terms of the breakdown of the cost of hydrogen production from coal, in the case of China, capital expenditure (Capex) and operating costs (Opex) requirements account for around 80–85% of the cost, with fuel accounting for a further 15–20% (Figure 24). This reflects the relative complexity of the coal gasification-based approach compared with SMR and electrolysis, as shown earlier in Section 4.1.1. However, the availability and cost of coal as fuel still plays an important role in determining the viability of coal-based hydrogen projects.

The addition of the CCUS system contributes to around a 5% increase in Capex, with the largest cost addition being a 130% increase in Opex (that is, the difference between the 'coal' and 'coal with CCUS' bars in Figure 24).

Analysis by the Committee for Climate Change shows that for a new build case in the UK, gasification plant would cost around 70 £/MWh, including the costs of CCUS (CCC, 2018). Future savings from economies of scale could reduce this, lowering the cost of future coal gasification with CCUS by around 10–15% to closer to 60 £/MWh by 2050. This cost assumes a 95% carbon capture rate and a carbon tax by 2050 of 227 £/tCO_2, such that carbon costs account for 25% of the cost of hydrogen production. The value of future carbon taxes is therefore a significant variable in the analysis of future hydrogen

production costs and a potential risk to any investment decision. The potential for very high capture rates to approach 100% (Feron and others, 2019), as well as cofiring coal with a portion of biomass or other carbon-based waste materials, was identified as a potential direction of development for coal-based CCUS plant (Kelsall, 2020). This would both reduce the carbon cost associated with the uncaptured CO_2, as well as help to maintain the role of coal as fuel in the transition to a net-zero emissions future. After fluctuating in price since the second half of 2018 at between 20–30 €/tCO_2, the price of carbon in the European Emissions Trading System, broke through the 50 €/tCO_2 barrier in 2021, reaching over 57 €/tCO_2 in July 2021 (Carbon Viewer, 2021). This could provide a positive market signal in the direction of low carbon-based hydrogen technologies. The role of carbon pricing to support cleaner technologies has been discussed recently by the ICSC (Metzger, 2020).

In terms of Capex and Opex costs, the Committee for Climate Change analysis shows that these are again the most significant part of the overall cost, contributing around 55–60% of the total cost of hydrogen production. Since coal gasification is a relatively mature technology, the opportunity for further cost reduction through technology development was assumed to be relatively limited. Analysis for the UK Government by Element Energy however, points to there being good technology development opportunities on the major flowsheet sections that have the potential to reduce Capex and Opex of gasification-based hydrogen (Element Energy, 2018). Although not covered in any detail in this report, the opportunity for technology development in the area of hydrogen production based on coal gasification is highlighted in Section 6.

Based on the Element Energy study, it is predicted that the capital cost of coal gasification will decrease as shown in Figure 25, with perhaps a 45–50% reduction in Capex being possible by 2050 relative to the 2018 value.

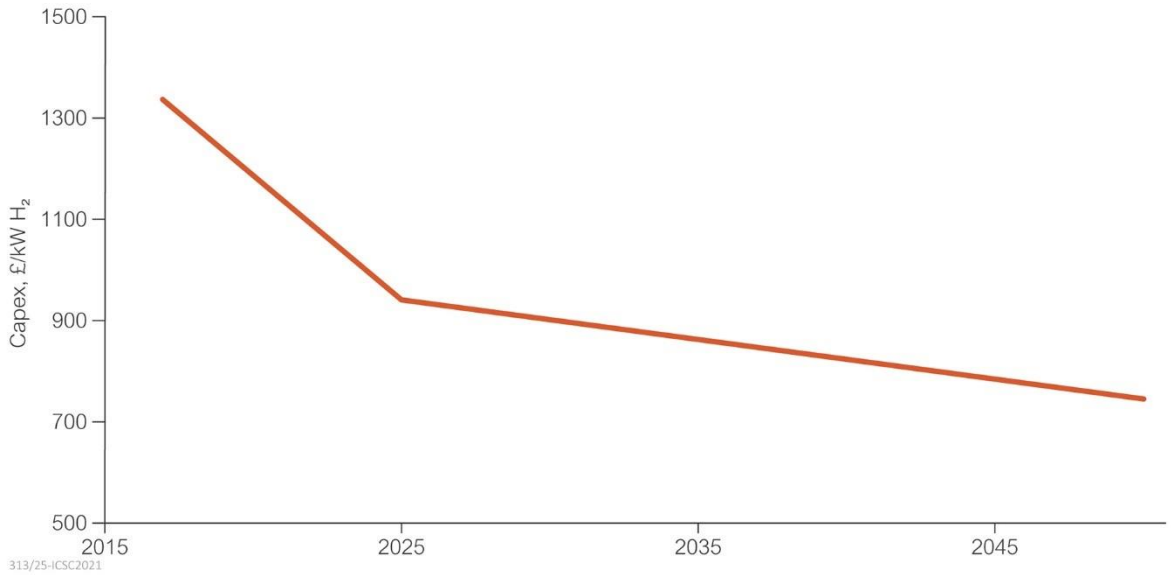


Figure 25 Coal gasification Capex reduction potential (Element Energy, 2018)

4.2.2 Water electrolysis

In regions of the world with access to relatively low-cost renewable electricity, based on high wind or solar incidence, low-carbon hydrogen produced using water electrolysis could in time become a competitor with low-carbon hydrogen from coal or natural gas. Potentially promising areas are Patagonia, New Zealand, Northern Africa, the Middle East, Mongolia, most of Australia, and parts of China and the USA (IEA, 2019c). This would suggest that China and Australia in particular could be regions where water electrolysis-based hydrogen production using renewable electricity could impinge on hydrogen production using coal gasification.

The potential cost reduction for water electrolysis is shown in Figure 26, in comparison with hydrogen from fossil fuels with CCUS. It should be noted however that in this analysis by IRENA, the cost of hydrogen production from fossil fuels was assumed to be constant over the period through to 2050, resulting in an increase in the levelised cost of hydrogen (LCOH), due to the assumed increase in carbon tax over the period (IRENA, 2019a). As a result, the cost of hydrogen from fossil fuels increases over time due to the assumed increase in CO_2 cost from 50 \$/tCO_2 in 2030 through to 200 \$/tCO_2 in 2050, which is not offset by any reduction through technology development or learning by doing. This is unlikely to be the case, however. As noted in Section 4.2.1, coal gasification costs are expected to decrease by around 10–15% and options to increase the carbon capture level or even generate negative CO_2 through cofiring with biomass or waste, could change significantly the LCOH profile for coal gasification with CCUS relative to the IRENA assumption.

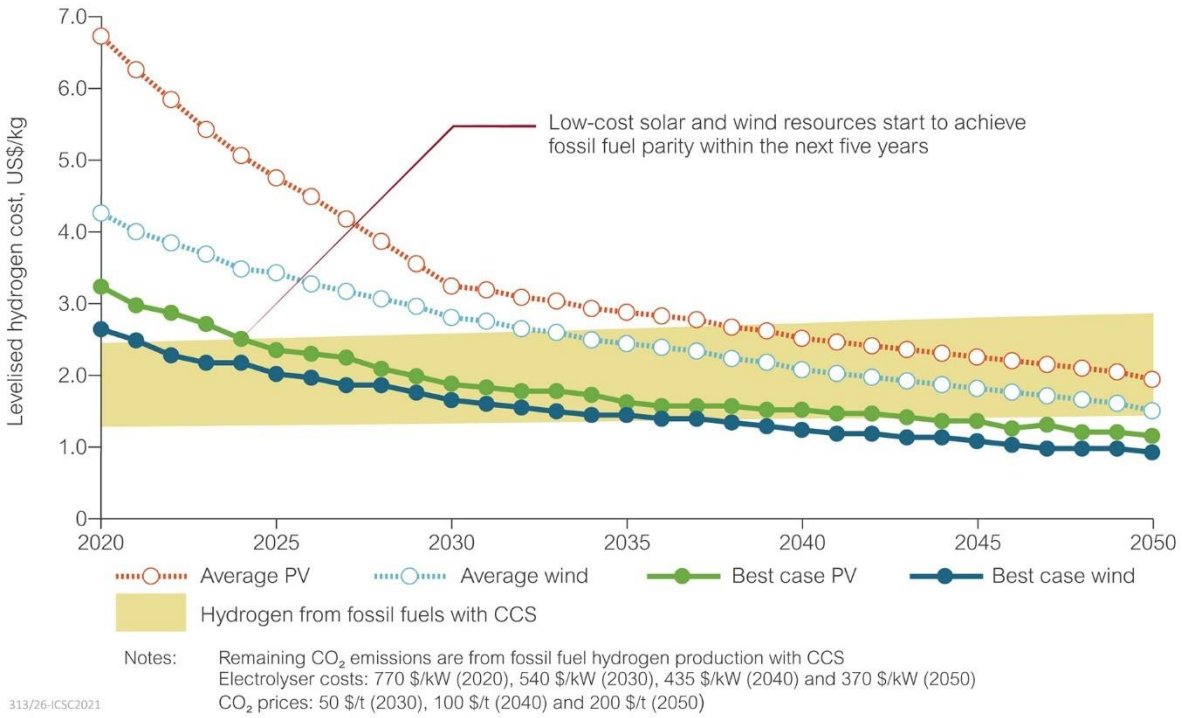


Figure 26 Cost comparison of low-carbon hydrogen (IRENA, 2019a)

Focusing however on the water electrolysis aspect of the study, the forecast is for hydrogen from low-cost wind to start to be competitive with the upper range of fossil fuel-based hydrogen prices in less than five years, perhaps competing with the lowest cost fossil fuel-based technologies by 2035. Low-cost solar PV shows a similar cost reduction profile to wind, although this would be achieved slightly later in time than for low-cost wind. For regions where wind and solar PV resources are closer to the global average, water electrolysis-based technologies may not become competitive with the upper range of fossil fuel-based technologies until after 2030-35.

Looking at this in more depth, the production costs of hydrogen from water electrolysis are influenced by various technical and economic factors, with Capex requirements, conversion efficiency, electricity costs and annual operating hours being the most important. In terms of Capex requirements, these are in the range of 500–1400 $/kWe for alkaline electrolysers and 1100–1800 $/kWe for PEM electrolysers. The electrolyser stack is responsible for typically 50% and 60% of the Capex costs of AE and PEM electrolysers respectively, with power electronics, gas conditioning and balance of plant accounting for the majority of the remaining cost. Future cost reductions will be in the areas of technology innovation, including the development of lower-cost materials for electrodes/ membranes, in addition to economies of scale in the manufacturing process. An example of the potential cost reduction projected by ITM Power as one of the leading global suppliers of PEM electrolysers, is shown in Figure 27.

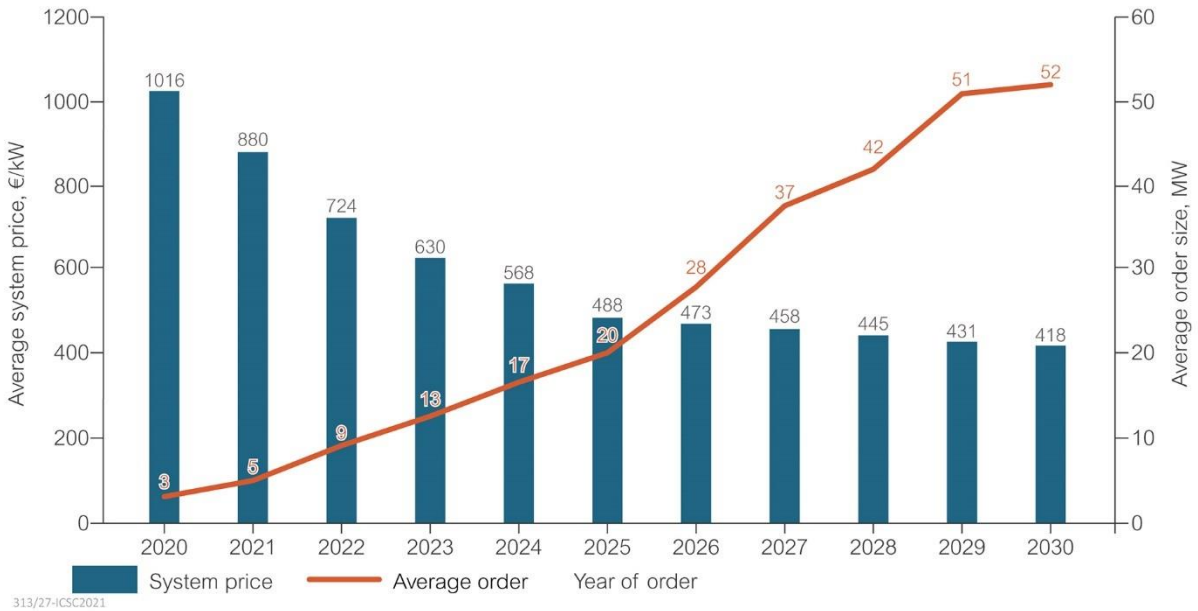


Figure 27 Cost reduction potential of PEM electrolysers (ITM Power, 2019)

However, as electrolyser operating hours increase, the impact of Capex costs on the LCOH reduces and the impact of electricity costs increases. Hence, the availability of low-cost electricity is needed to ensure that electrolysers can operate at relatively high full load hours. As the penetration of variable renewables in electricity systems increases, surplus electricity may be available at low cost. Producing hydrogen through electrolysis and storing the hydrogen for later use could be one way to take

advantage of this surplus electricity. But if surplus electricity is only available on an occasional basis it is unlikely to be commercially viable to rely on this for hydrogen production (IEA, 2019c). Instead, operating the electrolyser at higher full load hours and paying a higher price for the additional electricity could be preferable to using surplus electricity only, with lower full load hours. The relationship between electricity costs and operating hours is shown in Figure 28. Very low-cost electricity, typically due to curtailed variable renewables such as wind power, is available for a limited number of hours per year, which implies low utilisation of the electrolyser and hence high impact of Capex costs on the LCOH. As the operating hours of the electrolyser increases, electricity costs also increase. As shown in Figure 28, there is an optimum level of operation at around 3000-6000 equivalent full load hours per year (IEA, 2019c; Philibert, 2017, 2020). This means that hydrogen production from water electrolysis should operate 'mid-merit' at around 35–70% capacity factor. This may not be compatible with some applications of hydrogen such as industrial processes where a continuous supply of hydrogen may be required. Additional electrolyser capacity and hydrogen storage could be a solution, but this would impact the Capex of the system and therefore change the optimum capacity factor further downwards.

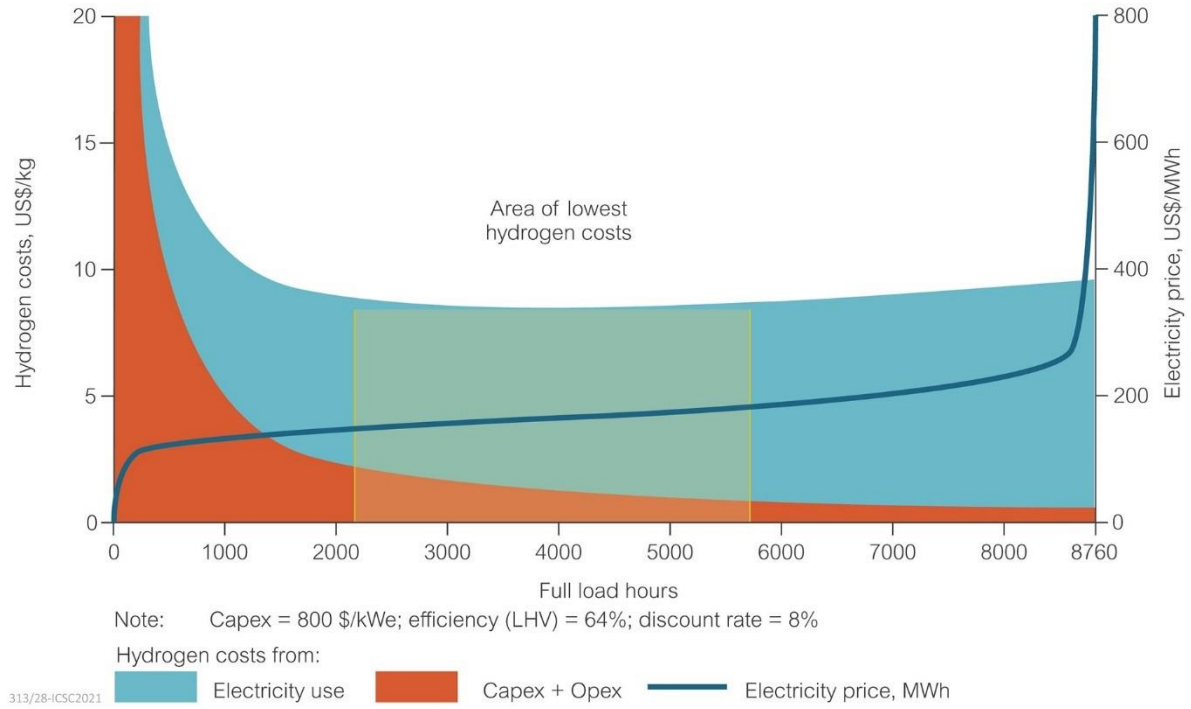


Figure 28 Hydrogen costs for water electrolysis using grid electricity (IEA 2019c)

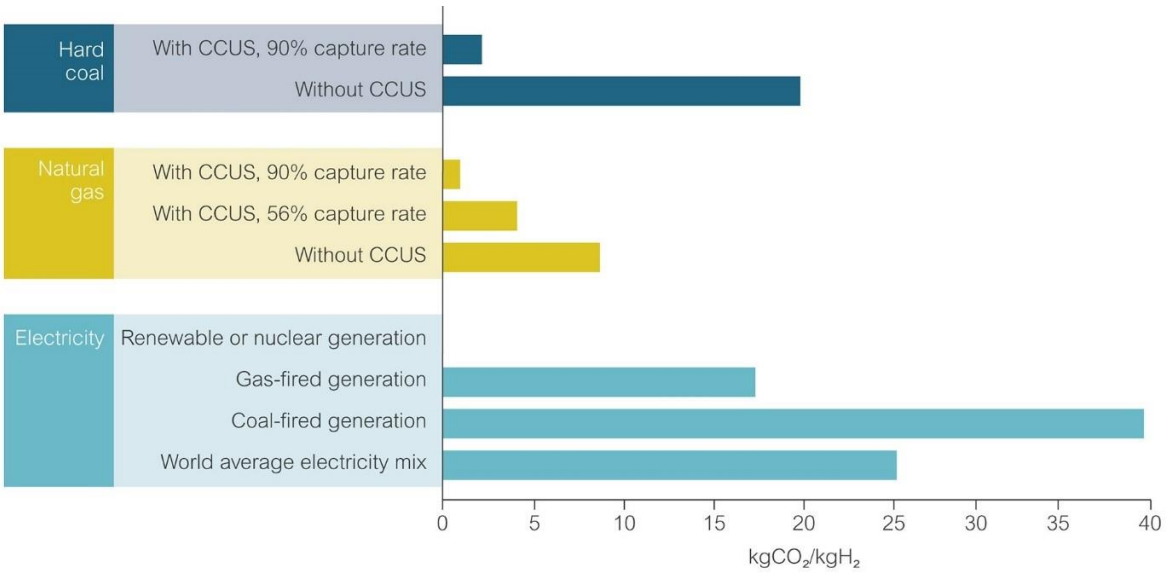
4.3 EMISSIONS FROM HYDROGEN PRODUCTION

In general terms, increasing the proportion of hydrogen use in the energy mix can have a positive impact on CO_2 emissions reduction. Based on the future forecast demand of hydrogen (*see* Section 3.2), hydrogen could deliver a CO_2 reduction potential of around 6 $MtCO_2/y$ by 2050 globally, with a breakdown by sector as shown in Table 9 (Hydrogen Council, 2017b).

Looking at the impact of the different hydrogen production methods, the estimated CO_2 emissions per kilogramme of hydrogen produced are shown in Figure 29, where the CO_2 impact of different hydrogen production technologies varies widely. The carbon intensity of hydrogen from unabated coal gasification is 19 $kgCO_2/kgH_2$, which is around double the value of the carbon intensity from SMR of natural gas. This is of course an inherent feature of coal due to its higher carbon/hydrogen ratio relative to natural gas (typically 0.1:1 compared with 4:1 for natural gas). However, when CCUS is added, this carbon intensity can be reduced to below 3 $kgCO_2/kgH_2$ as shown in Figure 29, based on 90% CO_2 capture. As noted earlier in Table 7, the hydrogen production process using coal gasification can be configured to capture 98% of the CO_2 emissions, which would reduce the carbon intensity of hydrogen from coal to even lower levels (Zapantis and Zhang, 2020) and there is the option to cofire coal with biomass and/or waste materials which can again reduce the carbon intensity.

TABLE 9 CO_2 REDUCTION POTENTIAL OF SWITCHING TO HYDROGEN BY 2050 (HYDROGEN COUNCIL, 2017B)

Sector	$MtCO_2/y$
Power generation buffering	0.4
Transportation (total)	3.2
• cars	1.7
• trucks	0.8
• buses	0.2
• other	0.4
Industrial energy	1.2
Building heating and power	0.6
Industrial feedstock	0.7
Total	**6.0**



1. Capture rate of 56% for natural gas with CCUS refers to capturing the feedstock-related CO_2, whereas for 90% capture rate CCUS is also applied to the fuel-related CO_2 emissions. Note that capture rates approaching 100% have been shown to be technically feasible (Feron and others, 2019)
2. CO_2 intensities of electricity taking into account only direct CO_2 emissions at the electricity generation plant: world average 2017 = 491 gCO_2/kWh; gas-fired power generation = 336 gCO_2/kWh; coal fired power generation = 760 gCO_2/kWh.
3. The CO_2 intensities for hydrogen also do not include CO_2 emissions linked to the transmission and distribution of hydrogen to the end users

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Figure 29 CO_2 intensity of hydrogen production (IEA, 2019c)

The CO_2 intensity of electrolysis depends on the CO_2 intensity of the electricity used to produce it. Where this is entirely from renewable electricity sources such as and wind and solar, the carbon intensity is close to zero. However, as noted in Section 4.2.2, for cost of electricity reasons, or to match demand-side hydrogen requirements, the electrolyser may be operated at higher load factors by using grid-supplied electricity at the prevailing carbon intensity level of the local grid. As there is often a high proportion of fossil fuel, the conversion losses during electricity generation mean that using electricity from natural gas or coal power plants results in higher CO_2 intensities than directly using natural gas or coal for hydrogen production. This means that for electrolysis to have the same or lower CO_2 intensity as hydrogen production from natural gas without CCUS, the CO_2 intensity of electricity has to be below 185 grammes of carbon dioxide per kilowatt-hour (gCO_2/kWh), which is around 55% of the CO_2 intensity from a state-of-the-art CCGT and less than 40% of the global average. Consequently, for the world average energy fuel mix, the carbon intensity of water electrolysis-based hydrogen production could be as high as 26 $kgCO_2/kgH_2$ (IEA, 2019c).

In the case of Australia, the impact of using water electrolysis for hydrogen production compared with coal gasification with CCUS is more pronounced as shown in Figure 30. Here, assuming a grid emissions intensity of 738 CO_2/kWh (Zapantis and Zhang, 2020), hydrogen produced using renewable electricity firmed by grid power could be over 25 $kgCO_2/kgH_2$. This assumes a total electrolyser capacity factor of 95% with 35% from wind and the remaining 60% from grid power. By comparison, 'scope one' emissions from SMR, ATR or coal gasification are process emissions from the reformer or gasifier plus emissions from the combustion of fossil fuels to provide heat, where required.

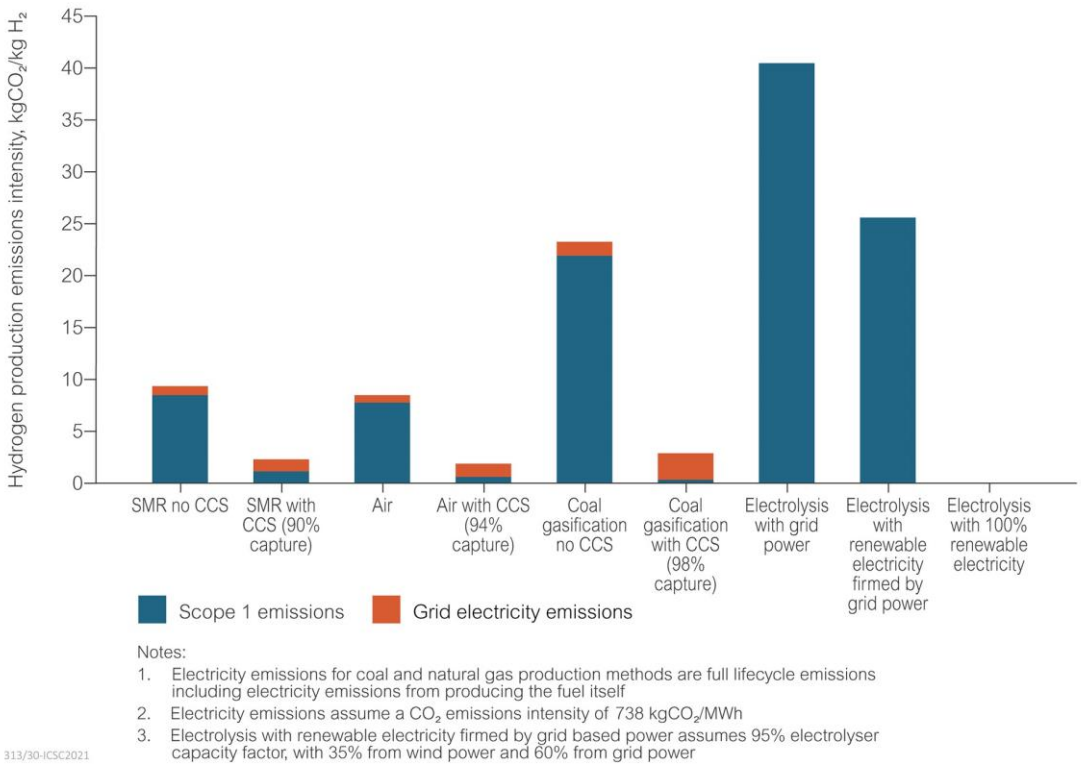

Figure 30 Estimated emissions based on hydrogen production method in Australia (Zapantis and Zhang, 2020)

In comparison, coal or natural gas production pathways with CCUS produce around 2–3 $kgCO_2/kgH_2$ including electricity emissions from the production of the coal or gas, consistent with the IEA analysis shown above.

The outcome of this is that in terms of moving towards net-zero emissions, the impact of using water electrolysis could be detrimental unless the water electrolysis process is used at a low capacity factor to use mainly renewable electricity, or until the penetration of renewables in a region's energy mix is such that the carbon intensity of grid electricity is reduced to a very low level. The approach could be for the hydrogen producer to secure a 'green' electricity mix through real-time power purchase agreements or perhaps real-time green certificates. The producer would then use the higher proportion of renewable-based electricity as a basis for calculating the carbon intensity of the hydrogen produced (Aarnes and others, 2018). However, analysis by Aarnes and others (2018) shows that for water electrolysis-based hydrogen production to deliver lower CO_2 emissions than fossil fuels with CCUS, the carbon intensity of the energy mix would need to be lower than 75 gCO_2/kWh. Similar results have been presented by Gardarsdottir and others (2019) where at least 95% of the electricity used in the electrolyser should come from renewable sources to be able to deliver lower emissions than fossil fuel-based hydrogen production with CCUS. From a systems level consideration, it is difficult to envisage how such high levels of renewables could be achieved without entailing significant cost or impacting on grid stability.

A further consideration is that electricity from wind- or solar-based hydrogen production may displace the use of green electricity in the rest of the electricity system. This would indicate that reductions in carbon emissions from production and use of low-carbon hydrogen from fully renewable electricity, at mid-merit capacity factor, could potentially be offset by an increase in overall power sector emissions. As noted by the GCCSI, using renewable energy to replace fossil fuel-based generation, provides three to eight times as much abatement benefit as can be achieved by using renewable energy to make low-carbon hydrogen. They conclude that the most effective support of moving towards a net-zero future is to produce hydrogen from natural gas or coal with CCUS, whilst using renewables predominantly for electricity generation (GCCSI, 2020).

4.3.1 CO_2 emissions reduction in coal-fired plant

CCUS is the key process in decarbonising coal gasification-based hydrogen production and CO_2 capture is the most energy-intensive and costly stage of the CCUS process. Significant research, development and demonstration effort into CCUS is underway (Lockwood, 2016; Mission Innovation, 2017; USDOE, 2020; CSLF, 2019; Kelsall, 2020).

In general, the selection of a particular CO_2 capture system is determined by various parameters, including CO_2 content of the gaseous stream, operational pressure and temperature and presence of sulphur contaminants. Modern hydrogen plants incorporate a variety of process streams including streams with relatively high CO_2 content, together with more dilute ones. In general, CO_2 capture from dilute CO_2 streams such as flue gas, presents a greater challenge compared to the capture from streams with a relatively high CO_2 concentration. This is mainly due to low CO_2 concentration in flue gas, typically less than 10% vol and its low pressure, resulting in larger equipment and higher energy penalties than CO_2 capture from more concentrated streams (Muradov 2017).

Whilst in principle, a number of CO_2 capture technologies could be applied to both low and high CO_2 concentration streams, in most cases, economic feasibility will be a major limiting factor. The majority of commercial CO_2 capture processes are based on the absorption technologies utilising selective solvents that can achieve more than 90% CO_2 capture from the process streams. A brief overview of the alternatives is given below:

Chemical absorption – Most chemical absorption systems utilise aqueous solutions of alkanolamines such as monoethanolamine, diethanolamine and methyl-diethanolamine, together with some application of chilled ammonia (NH_4OH) and hot potassium carbonate (K_2CO_3). The traditionally used alkanolamine based solvents incur a relatively high energy penalty due to the energy-intensive regeneration stage of steam stripping. Therefore, intensive research, development and demonstration efforts are focused on reducing the energy penalties during the regeneration step (Kamijo, 2019).

Physical absorption – Physical absorption methods are governed by Henry's law, with low temperature and high pressure favouring CO_2 capture. Therefore, the physical absorption method is

preferred for CO_2 capture from the gaseous mixtures with relatively high CO_2 partial pressure of typically greater than 5 MPa. The regeneration of physical solvents typically requires less energy input than chemical solvents; commercial physical absorption-based solvents include Selexol™ and Rectisol™, together with methanol and propene carbonate (Siefert and Hopkinson, 2018). On the downside, physical solvents exhibit a relatively low carrying capacity, which necessitates their circulation in relatively high volumes, with around 20 kg of the glycol solution required to capture 1 kg of CO_2.

Adsorption – Physical CO_2 adsorption processes work on the principle of the selective adsorption of CO_2 on high surface area solids such as zeolites, activated carbons and nanostructured sorbents. In this category PSA is the most widely used commercial technology. The PSA cyclic operation is based on adsorption of gases at high pressure, and their desorption at lower pressure by several adsorbent beds containing zeolites or activated carbons. PSA is the process of choice where high purity hydrogen is required. Technological variations of the PSA process include vacuum swing adsorption (VSA), temperature swing adsorption (TSA) and electric swing adsorption (ESA) processes (Bolland and Riboldi, 2017).

Gas separation membranes –These are membranes that allow the selective permeation of a gas to flow through them. Polymeric and inorganic membranes are two main types of membranes widely used for gas separation. The polymeric membranes are based on such polymers as cellulose acetate, polyimides, polyamides and polysulfone (Han and others, 2020).

Due to their large surface/volume ratio, polymeric membranes are effective in CO_2 separation and are relatively inexpensive, although they are subject to degradation, especially at elevated temperatures. In contrast, inorganic membranes are stable at high temperatures and corrosive environments, but they are more expensive than polymeric membranes. Inorganic membranes most widely used for the separation of hydrogen and CO_2 from shifted syngas include palladium alloys, perovskites, silica, activated carbon, zeolite and special glasses (Muradov, 2017). The key drawback of membranes is that their separation performance tends to be limited by a trade-off between permeability and selectivity.

Cryogenic separation – Cryogenic gas separation technology has been widely used commercially by the gas industry in the processes involving liquefaction and purification of CO_2. The method is based on the difference in boiling point between CO_2 or hydrogen and other components of the gaseous mixture. Air Liquide is demonstrating its Cryocap™ process that enables the cryogenic CO_2 capture from hydrogen plants (Pichot and others, 2017). Connected to Air Liquide's largest SMR hydrogen production plant in Normandy, France, the Cryocap™ unit has an annual CO_2 capture capacity of 100 $ktCO_2$. The cryogenic technology is reported to have good potential for economy of scale improvements and offers the advantage of direct production of liquid CO_2 that can be transported and/or stored in a liquid form at high pressure. However, the relatively high energy intensity and the

necessity to remove components with relatively high freezing points such as water prior to cooling could be an issue (Muradov, 2017).

4.3.2 Other considerations in the choice of hydrogen production technology

Other considerations which impact on the choice of coal gasification-based hydrogen production relative to natural gas reforming and water electrolysis technologies are listed below (CCC, 2018):

Land footprint – Coal gasification technologies typically require more land than gas reforming technologies or for water electrolysis, due to the higher number of process steps/unit operations and the need for onsite fuel storage of coal. The area required is typically 0.8–2.5 m^2/kW hydrogen produced from coal gasification, compared to 0.05–0.16 m^2/kW hydrogen production from natural gas reforming and 0.07–0.14 m^2/kW hydrogen production for water electrolysis. It should be noted that this land footprint for water electrolysis does not include the potentially significant land area for renewable electricity production to power the water electrolysis-based hydrogen production systems. A study in Australia carried out by GCCSI, estimated the land area for water electrolysis to be almost fifty times larger than for coal gasification to produce the same hydrogen output, where the area for renewable electricity production is also included (Zapantis and Zhang, 2020).

Water footprint – Coal gasification and natural gas reforming technologies require around 0.1–0.3 litres of non-potable water per kWh of hydrogen produced as a direct part of the gasification/reforming process. In addition, both require around 0.1–30 litres of water for cooling, although this could be reduced by using air or hybrid cooling technologies (Carpenter, 2018; Barnes, 2019; Kelsall, 2020; Int CCS KC, 2018). Water electrolysis, on the other hand, requires around 0.5 litre of potable water per kWh of hydrogen. This could be a constraint for water electrolysis, particularly in areas where potable water is scarce, although desalination of seawater could be used in coastal locations for an additional cost. This has a minor impact on the total costs of water electrolysis, increasing total hydrogen production costs by around 0.01–0.02 $/kg$H_2$. Research is also being carried out on the direct use of seawater in electrolysis in the future (IEA, 2019c).

Air quality – Coal gasification produces air pollutants nitrogen oxides (NOx) and particulate matter. However, these can be mitigated by fitting conventional filtration technology, such as selective catalytic reduction technologies and electrostatic precipitators to the plants.

Hydrogen production from coal or coal with CCUS – A further consideration where hydrogen is being produced for industrial applications for example, is whether the greatest benefit in terms of CO_2 emissions reduction at lowest cost could be achieved by adding CO_2 capture as a post-process capture technology to the industrial process itself, or as a pre-capture technology as part of a hydrogen production process. In steelmaking, for example, coke could continue to be used with downstream CO_2 capture, or there could be a switch from coke to hydrogen as the reducing agent. In general, CO_2 capture equipment and transportation infrastructure have significant economies of scale, so

post-process capture CCUS would be advantageous for large-scale operations (CSLF, 2019), whereas hydrogen appears to be well suited to the decarbonisation of more distributed sources of CO_2 emissions, for example from the food and drinks sector, where the alternative to capture the CO_2 may be impractical and costly (CCC, 2018). This suggests that post-capture CCUS would be a less expensive method for reducing emissions from most power generation and industrial heat applications (Bartlett and Krupnick, 2021).

4.4 HYDROGEN PRODUCTION FROM COAL IN CHINA

As China dominates the global production of hydrogen from coal using gasification technology, the situation in China is discussed further.

Most hydrogen production from coal takes place in China using gasification technology, mainly to produce ammonia (IEA 2019c). China is exploring the role of hydrogen in its economy, and using coal is currently the cheapest way to produce it, with costs without CO_2 capture of around 0.6-0.7 RMB/m^3 (around 1 \$/kgH_2). CHN Energy, China's largest power company, is also the world's largest hydrogen production company. Its 80 coal gasifiers can produce around 8 MtH_2/y, which is equivalent to 12% of global dedicated hydrogen production. The continued use of coal with CCUS therefore appears to be the lowest cost method of producing low-carbon hydrogen in China, being some 30% cheaper than hydrogen production from natural gas (De Blasio and Pflugmann, 2020). This is because there is an established coal mining infrastructure with significant resources of indigenous coal. According to Yang and others, (2019), assuming that 1% of China's coal resources could be used for hydrogen production by coal gasification, the potential of hydrogen production from coal could be around 2400 MtH_2. The potential of hydrogen production based on coal reserves differs among different provinces. Domestic coals are distributed primarily in Shanxi, Shaanxi, Inner Mongolia, Ningxia, Xinjiang, Huanghuaihai district and southwest China, with only a small amount located in Southeast China.

In addition, studies on the use of coal compared with coke oven gas as feedstock for gasification-based hydrogen production show that coke oven gas-derived hydrogen could be advantageous (Li and Cheng, 2020). Relative, to coal, the energy consumption is lower by 35%, life cycle carbon emissions by 37%, capital expenditure by 27% and operating expenditure by 9% for the coke oven gas case.

The interest in hydrogen to date has been primarily for the industrial manufacture of ammonia and methanol, as noted in Section 3.2.2, with the use of hydrogen to achieve decarbonisation being a lower priority. However, the announcement by President Xi Jinping in September 2020 that China aims to achieve carbon neutrality before 2060, with emissions peaking before 2030, marks a significant change to this position (Tu, 2020). Given the scale of CO_2 emissions reduction that this implies, hydrogen will need to play an increasingly important role. A particular strength of China will be its ability to reduce the unit manufacturing cost of hydrogen economy technologies and components through industrial network clustering and economies of scale. This could see a move towards the use of low-carbon hydrogen from electrolysis in addition to hydrogen from fossil fuels. In this respect, it should be noted

that in 2019, China had more than one-third of global wind and solar energy, which could start to provide the level of renewable energy necessary to support the increased use of water electrolysis based hydrogen production.

4.5 SUMMARY

The three main routes available for the production of hydrogen depending on the fuel feedstock, are reforming of natural gas primarily using SMR, gasification of coal and electrolysis of water. Hydrogen production from coal using gasification is a well-established technology, used for many decades by the chemical and fertiliser industries for the production of ammonia, particularly in China.

In general, low-carbon hydrogen production from coal gasification with CCUS and natural gas SMR with CCUS are lower cost than low-carbon hydrogen based on water electrolysis, typically by a factor of approaching 3. This indicates that with a large existing unabated fleet of gas- and coal-based hydrogen production, the transition to large scale, low-carbon hydrogen, will require significant deployment of CCUS plant.

In regions of the world with access to relatively low-cost renewable electricity, based on high wind or solar incidence, low-carbon hydrogen produced using water electrolysis could in time become a competitor with low-carbon hydrogen from coal or natural gas. Hydrogen from low-cost wind could start to be competitive with the upper range of fossil fuel-based hydrogen prices in less than five years, perhaps competing with the lowest cost fossil fuel-based technologies by 2035.

In terms of moving towards net-zero emissions, the impact of using water electrolysis could be detrimental. This is unless the water electrolysis process is used at mid-merit capacity factors of 35–70% to use mainly renewable electricity, or until renewables penetration of a region's energy mix increases significantly. This would mean the carbon intensity of grid electricity was reduced to a very low level. The continued use of coal gasification and natural gas reforming with CCUS will need to play a key role to deliver low-cost, low-carbon hydrogen at the scales required.

5 EXAMPLES OF HYDROGEN PRODUCTION FROM COAL/PETROLEUM COKE USING CCUS

Key global projects relating to the production of low-carbon hydrogen focusing on coal/coke as feedstock are shown in Table 10. These are generally covered in the GCCSI CO_2RE projects database (GCCSI, 2021) and are described briefly below. The Pouakai project in New Zealand based on the Allam Cycle is natural gas fired, but as noted in earlier Net Power project development studies in the USA, the cycle could also be fired with petroleum coke or coal (Lu and others, 2020; Zhu, 2017).

TABLE 10 HYDROGEN PRODUCTION FROM COAL/COKE INCLUDING CCUS (ON (ZAPANTIS AND ZHANG, 2020)

Facility	H_2 production capacity	Process	H_2 use	Operation date (with CCUS)
Great Plains Synfuel, USA	1300 t/d in syngas	Lignite gasification	SNG and fertiliser production	2000
Coffeyville, USA	200 t/d	Petroleum coke gasification	Fertiliser production	2013
Sinopec Qilu, China	100 t/d	Coal/coke gasification	Fertiliser production	2021 (planned)
Latrobe Valley, Australia (CCUS not included in pilot phase)	3 t/y (<0.1 t/d)	Lignite gasification	Export to Japan for power generation	2021
Pouakai, New Zealand	600 t/d (proposed)	Natural gas fired Oxyfuel/Supercritical CO_2	Fertiliser production	2024

5.1 GREAT PLAINS SYNFUEL

The largest clean hydrogen plant globally is the Great Plains Synfuel plant in North Dakota, USA, producing 1300 tonnes per day of hydrogen from the gasification of lignite. This facility has been producing hydrogen since 1988 and capturing CO_2 for storage since 2000, with around 3 $MtCO_2/y$ transported to Saskatchewan, Canada for enhanced oil recovery (EOR) (GCCSI, 2020).

The plant produces synthetic natural gas (SNG) and anhydrous ammonia using 14 Lurgi Mark IV gasifiers (NETLa, nd). Oxygen produced by an air separation unit (ASU) together with steam are fed into the gasifiers at the bottom of the reactor below the coal reaction bed, resulting in combustion temperatures reaching about 1200°C (2200°F). The syngas produced is cooled after exiting the gasifier, which removes tar, oils, phenols, ammonia and water from the syngas stream via condensation. After cooling, the gas is further treated to remove impurities, before entering the methanation unit where carbon monoxide and most of the remaining carbon dioxide is reacted over a nickel catalyst with hydrogen to form methane.

The product gas, now referred to as SNG, is then further cooled, dried and compressed. The compressed gas with a heating value of 975 Btu/ft^3 (36 MJ/m^3) leaves the facility to join the Northern Border Pipeline which supplies natural gas to the eastern United States.

The total cost for the design and construction of the plant was around $2 billion, which was designed with two product trains to improve plant availability, thus the plant could still operate at 50% capacity if one of the product trains was out of operation. The plant began operation in 1984, using 5–6 Mt of coal to produce 54 billion standard cubic feet (1.5 billion m^3) of SNG annually.

During the plant's life, it has been modified to improve productivity, efficiency and reduce environmental impacts. Some examples of modified components include:

- primary coal crushers;
- boiler fuel mix and configuration;
- gasifier grates;
- ash handling;
- flare and liquid waste incinerator systems;
- Rectisol™ tower trays; and
- product compression turbines.

In addition to plant upgrades to improve efficiency, the plant was also diversified to produce a wide range of secondary products. Ammonia scrubbers were added to the boilers to reduce sulphur emissions and enable the production of ammonium sulphate. In the 1990s, an anhydrous ammonia synthesis unit was added to the process train to use hydrogen-rich syngas to produce anhydrous ammonia for fertiliser manufacture.

CCUS was added to the plant in 2000, capturing about 3 MtCO_2/y, representing around 50% of the CO_2 produced at the plant when running at full capacity. This is transported through a 205 mile (around 330 km) pipeline to Saskatchewan, Canada, to be used for EOR.

5.2 COFFEYVILLE

Coffeyville Gasification Plant in Kansas, USA, commenced operation in 2013 producing approximately 200 tonnes per day of hydrogen from petroleum coke (NETLb, nd). The plant utilises dual GE quench gasifiers operating at 4.3 MPa pressure to produce hydrogen which is used to manufacture ammonia and urea ammonium nitrate (UAN) fertilisers. It produces about 5% of the total UAN demand in the USA. An ASU provides oxygen for the gasifier complex which has a capacity of 84 million standard cubic feet per day (around 6 m^3/h) of hydrogen. Nitrogen from the ASU is used downstream for reaction with the hydrogen to produce ammonia. The syngas is cleaned in a dual-stage acid gas removal process, separating hydrogen sulphide (H_2S) and CO_2 into separate streams. Cleaned syngas is supplied to a PSA unit, separating pure hydrogen which is then reacted with nitrogen in an ammonia plant. The

facility has the capability to process substantial amounts of the ammonia further into urea/ammonium nitrate fertiliser. Although the plant gasifies petroleum coke, the process would be essentially the same for a coal feedstock.

As a by-product of the process, the plant produces about 0.8 $MtCO_2/y$. Some of this is used in the urea synthesis process and around 0.6 $MtCO_2/y$ is used for EOR. The CO_2 is compressed and transported via a 70 mile (about 110 km) pipeline to deliver the CO_2 for injection into the North Burbank Unit in Oklahoma (GCCSI, 2020).

5.3 POUAKAI PROJECT

The Pouakai project owned by 8 Rivers Capital is a hydrogen, fertiliser and power generation industrial complex proposed for the Taranaki region of New Zealand. It will use natural gas as feedstock to produce hydrogen with CCUS to capture around 1 $MtCO_2/y$, resulting in near-zero emissions. The project will use one natural gas processing facility with three integrated processes as follows:

- NET Power's Allam Cycle electricity generation system;
- 8 Rivers' 8RH2 hydrogen production technology; and
- Commercial ammonia synthesis and synthetic nitrogen fertiliser production process technologies.

The project is at the front end engineering design (FEED) study stage, with the ambition of being operational by around 2024 (GCCSI, 2020; H_2 Taranaki Roadmap, 2020).

It is based on the Allam Cycle technology, developed through the partially owned subsidiary, NET Power. The proprietary system is based on a semi-closed loop, high-pressure/low-pressure ratio recuperated Brayton cycle that uses supercritical CO_2 as the working fluid (Allam and others, 2017). The captured CO_2 has the potential for use in EOR through targeted injection into Taranaki's depleting oil fields.

In the proposed Pouakai project, the Allam Cycle process is integrated with an 8 Rivers proprietary natural gas-fed reforming process, called 8RH2 which can use either partial oxidation (POX), gas heated reforming (GHR) or autothermal reforming (ATR) processes. Both high- and low-grade heat is exchanged between the Allam Cycle and the 8RH2 systems which generates hydrogen with close to 100% carbon capture, as shown in Figure 31. Oxygen and electricity for the reforming process are also provided from the power generation unit. The Allam Cycle plus the 8RH2 process could achieve hydrogen generation with higher thermal conversion efficiencies than competing SMR processes, with approximately 87% efficiency, with carbon capture, as opposed to around 65% for the SMR process without carbon capture according to the system developers (H_2 Taranaki Roadmap, 2020).

When completed, the proposed Pouakai facility will generate approximately 600 tonnes per day of hydrogen. In this proposed facility, the hydrogen feedstock is then used in other processes,

particularly the production of ammonia and urea, or when a domestic hydrogen market is developed, hydrogen could be sold directly into this. The Pouakai facility will also produce electricity with the potential to export 160 MWe at normal operating conditions, with a peak output of up to 360 MWe.

Although the Allam cycle is not strictly a hydrogen production technology, it is a technology that enables large-scale production of low-carbon hydrogen.

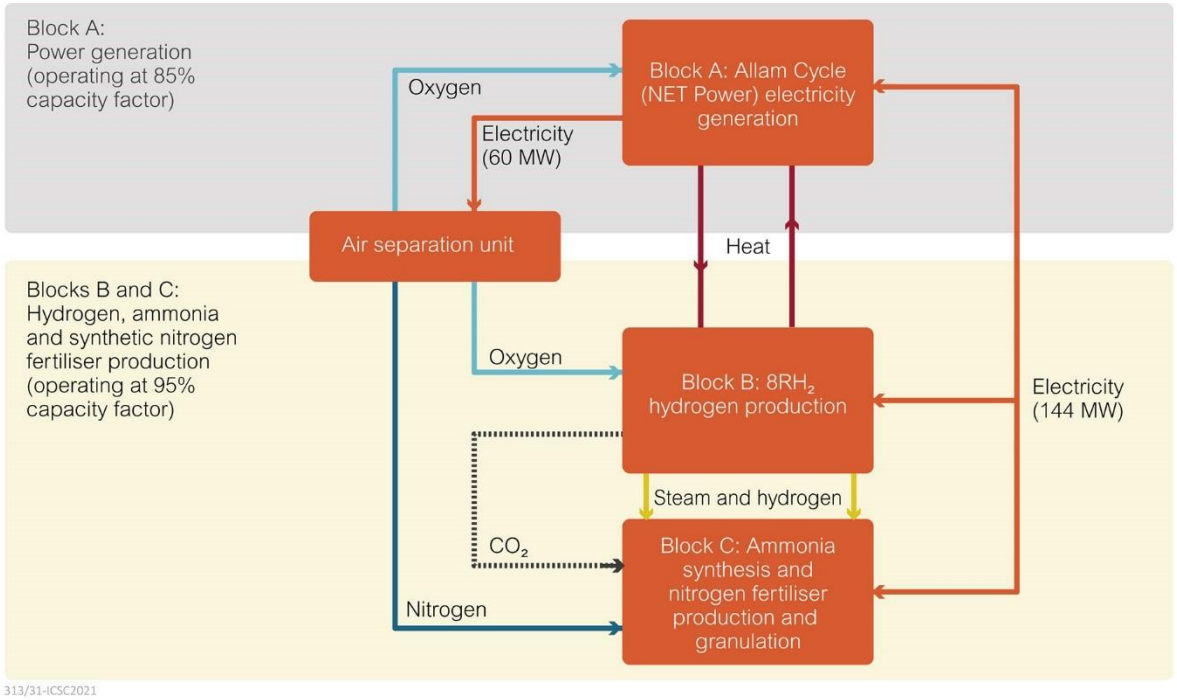

Figure 31 Allam Cycle integrated with 8RH2 hydrogen production fertiliser production (Lee, 2020)

In addition, the design of a commercial-scale 300 MW Allam cycle natural gas plant is underway for potential deployment at multiple locations in the UK with support from the UK Department of Business, Environment and Industrial Strategy (McDermott, 2020).

5.4 SINOPEC QILU

Sinopec Qilu petrochemical plant is in the process of retrofitting a CCUS system to an existing coal/coke water slurry gasification unit at a fertiliser plant in Zibo City, Shangdong Province, China. The initial phase of the facility under construction is capable of capturing almost 0.4 $MtCO_2/y$. The longer-term target is to capture 0.5 $MtCO_2/y$ by around 2021, with the captured CO_2 transported by pipeline to the Shengli oilfield for EOR. EOR is seen as a potential way of utilising the significant quantities of CO_2 from China's power and chemical manufacturing industries to enhance oil production from indigenous oil fields (Hill and others, 2020). The opportunity for revenue from EOR to support the roll-out of CCUS has been discussed previously by the ICSC (Kelsall, 2020). However, there are technical challenges in producing both high-quality hydrogen and CO_2 of sufficient quality for EOR due to the difficulties of gas separation (Voldsund and others, 2016).

Sinopec Qilu was licensed initially in 2006 and uses three GE gasifiers, allowing two to run while one is on standby for planned maintenance. Operation of the plant began in October 2008 to produce a synthesis gas consisting of hydrogen and carbon monoxide, used as feedstock to produce butyl alcohol and methanol.

5.5 HYDROGEN ENERGY SUPPLY CHAIN (HESC)

The Hydrogen Energy Supply Chain (HESC) is a project being developed in Victoria State, Australia with the support of Japan (HESC, 2018; IRENA, 2019a). The project aims to develop and demonstrate technologies for the production, storage and transportation of clean hydrogen from lignite fuel in the Latrobe Valley and to establish a supply chain through to utilisation in Japan (*see* Section 3.3.4 for further details of hydrogen utilisation in the Kobe CHP plant in Japan). The pilot phase encompasses a gasification plant in the Latrobe Valley and a liquefaction facility at the Port of Hastings. The AU$500 million ($390 million) project is supported by the Japanese government and Japanese industry, together with the Australian and Victorian governments which have each contributed AU$50 million (around $39 million) in funding. The project is being carried out by CO_2-free Hydrogen Energy Supply-chain Technology Research Association and an Australian consortium consisting of Iwatani, Marubeni, Kawasaki Heavy Industries, J-Power, Sumitomo and AGL Energy Ltd.

Motivation for the project from the Australian side of the consortium is the declining domestic use of lignite, leaving these deposits, which represent some of the world's largest recoverable reserves, as potential stranded resources, together with interest in low-cost generation of hydrogen (Reid, 2018). CCUS is not included in the initial pilot phase of the project due to the relatively small amount of CO_2 produced during the pilot phase. Carbon offsets have therefore been purchased for the CO_2 emitted in this phase, although it is recognised that for the subsequent commercial phase, CCUS will be needed with the captured CO_2 stored in a geological storage offshore site in the nearby Gippsland Basin, in cooperation with the CarbonNet storage project (HESC, 2021).

J-Power is leading the coal gasification and hydrogen refining facility which started construction in November 2019 and began producing hydrogen in January 2021 (HESC, 2021) following the Australian government's removal of legal obstacles to the development of the Latrobe Valley hydrogen production facility and associated CarbonNet CCS scheme (Moore, 2020). In particular, the amended legislation clarifies the regulatory environment for the geological storage site, which straddles both federal and state territorial waters.

The HESC project involves coal mining and processing, brown coal gasification, shift catalysis, hydrogen/carbon dioxide separation, hydrogen pressurisation and liquefaction, international ocean transport, and new ground transport vehicles and energy infrastructure (Reid, 2021).

In terms of project challenges, the key technical issue would appear to be the demonstration of the supply chain to ship hydrogen to Japan, where cryogenic hydrogen transport is proposed, based on KHI technology (KHI, 2019).

5.6 SUMMARY

The number of reference plants for low-carbon hydrogen produced from coal gasification with CCUS is relatively limited. However, there is a long track record of successful operation in fertiliser plant in the USA provided by the Great Plains and Coffeyville plants. These plants demonstrate that large-scale production of low-carbon hydrogen using CCUS is economically and technically feasible already.

The Sinopec Qilu CCUS retrofit to the existing coal gasification plant in China could lead the way to a wider roll-out of low-carbon hydrogen technology in Asia.

6 R&D PRIORITIES FOR HYDROGEN FROM COAL

The cost of hydrogen production from coal, with CCUS discussed in Section 4.2, is already at around 2–3 $/kgH$_2$ in a number of locations, and below 2 $/kgH$_2$ in China, where it is the cheapest method of hydrogen production. Coal gasification is a relatively mature technology, so cost reduction opportunities would be expected to be relatively limited. However, analysis has shown that even with coal gasification with CCUS, there is scope to reduce Capex by perhaps 45–50% by 2050 relative to the 2018 value (Element Energy, 2018). The areas proposed for development in this study were identified at a high level as:

Potential improvements through to 2025

- Replacement of current gas clean-up and sulphur removal technologies with next-generation technologies; and
- Improvement in Capex, Opex and efficiency through reduced parasitic power loads.

Potential improvements through to 2050

- Second generation gasifier to reduce Capex;
- More active CO_2 removal solvent; and
- More efficient and lower Capex CO_2 compression.

More specific research priority topic areas for hydrogen production from coal with CCUS have been defined (Muradov, 2017) and are presented below, together with promising research underway in 2021. Continued technical innovation to drive down costs of hydrogen production from coal with CCUS should be pursued to ensure that this technology remains a competitive option against the cost reduction planned for water electrolysis-based hydrogen production. This topic however, is too wide to cover in this report. Advanced WGS technologies to include higher activity and impurity tolerant CO-shift catalysts:

- Advanced hydrogen separation technologies, to include advanced membranes, sorbents, solvents, and reverse selective systems (Ruan and others, 2020; Xiang and others, 2020; Yu and others, 2021);
- Process intensification and integration of several processes such as syngas clean-up, WGS and hydrogen separation to move towards one integrated process step (Al-Zareer and others, 2017); and
- Demonstrations of advanced technologies integrated with CCUS (CSLF, 2019).

There are several national programmes to support such development. One example is the USA which has a number of research priorities to promote the use of hydrogen. The first of these priorities relates to the production of hydrogen from fossil fuels, including coal (USDOE, 2020):

Carbon-neutral hydrogen production using gasification and reforming technologies

- Develop advanced gasification materials, components (gasifier, clean-up systems, membranes, catalysts), and systems (small- and large-scale plasma, thermal, and microwave) with CCUS that can accept multiple fuels including coal, biomass and waste plastics to produce low-cost, carbon-neutral hydrogen (Baykara, 2018; Habibi and Mehrpooya, 2021; Liu and others 2020; Xia and others, 2020);
- Support advanced steam methane and auto-thermal reforming technologies with CCUS to provide near-zero hydrogen to the economy, and convert waste gaseous hydrocarbons to hydrogen using similar modular technologies;
- Develop pre-combustion CO_2 capture technologies (advanced solvents, solid sorbents, and membrane systems) for hydrogen production processes to demonstrate zero-carbon or negative-carbon emissions from fossil fuel, biomass, and waste plastics hydrogen production; and
- Develop CCUS technologies, including pre- and post-capture technologies for power and the industrial sector, as well as direct air capture technologies, that can remove CO_2 from the atmosphere.

Additional promising areas of research include the integration of coal gasification hydrogen production with natural gas SMR and/or water electrolysis based hydrogen production (Hamid and others, 2021; Huang and Liu, 2020; Zeng and others, 2017; Becker and others, 2019) together with the approach of polygeneration (Seyitoğlu and others, 2016).

6.1 SUMMARY

Further R&D into the technology components of coal gasification with CCUS would be beneficial to drive down the cost of low-carbon hydrogen from coal. A detailed assessment of the ongoing and future work in this area is beyond the scope of this report, but could be assessed in a follow-up report from the ICSC.

7 HYDROGEN STRATEGIES AND POLICIES

A selection of countries with strategies that aim to directly support investment in hydrogen technologies is shown in Table 11. The number of countries producing hydrogen strategies and the scale of ambition contained in them is increasing (IEA, 2019c).

TABLE 11 SELECTED HYDROGEN-RELATED STRATEGIES AND ROADMAPS SINCE 2018 (BASED ON IEA, 2019C AND COUNTRY UPDATES)

Country	Announcements and developments since 2018
Australia	Published a national hydrogen strategy in November 2019, with the Australian government committing AU$370 million to advancing Australia's hydrogen industry since the release of the strategy. The Council of Australian Government's Energy Council established the Hydrogen Project Team in March 2020 to implement the strategy. Also published a technical roadmap for hydrogen in Australia produced by the Commonwealth Scientific and Industrial Research Organisation (CSIRO).
Austria	Hydrogen strategy has been developed and is out for public consultation. The country's NECP emphasises the contribution of hydrogen to increase the share of renewable energy in final energy consumption to 45–50% by 2030.
Belgium	Published a government-approved hydrogen roadmap in 2018, with specific targets set for 2030 and 2050 and an associated €50 million regional investment plan for P2G. The country's NECP announced new federal and regional regulatory and financial measures to stimulate the deployment of renewable hydrogen in the industrial, building and transport sectors. Flanders also supports the deployment of CCUS installations that could be combined with fossil fuel-based hydrogen produced by SMR.
Brazil	Included hydrogen in the Science, Technology and Innovation Plan for Renewables and Biofuels. Hosted and supported the 22nd World Hydrogen Energy Conference in 2018. Brazil has potential to become a low-carbon hydrogen exporter, as well as decarbonising chemical industry and refining.
China	Announced that the Ten Cities programme that launched BEVs in the People's Republic of China would be replicated for hydrogen transport in Beijing, Shanghai and Chengdu, among others. Announced that Wuhan will become the first Chinese Hydrogen City, with up to 100 fuel cell automakers and related enterprises and up to 300 filling stations by 2025. Announced targets of 5000 FCEVs by 2020 and recommitted to the 2015 target of 1 million FCEVs by 2030, plus 1000 refuelling stations. Exempted FCEVs and BEVs from vehicle and vessel tax.
EU	The European Commission published its hydrogen strategy in July 2020, with the priority to develop renewable hydrogen, produced using mainly wind and solar energy, supported in the short/medium term by other forms of low-carbon hydrogen. To achieve this, a phased approach is proposed as follows: • 2020-24, the EU will support the installation of at least 6 GW of renewable hydrogen electrolysers; • 2025-30, hydrogen needs to become an intrinsic part of the integrated energy system, with at least 40 GW of renewable hydrogen; and • 2030-50, renewable hydrogen technologies should reach maturity and be deployed at large scale across all hard to decarbonise sectors. Set up a 'Hydrogen Energy Network' as a platform for discussion of hydrogen among EU member states. Twenty-eight European countries signed the Linz Declaration 'Hydrogen Initiative' promoting co-operation on sustainable hydrogen technology, alongside around 100 businesses, organisations and institutions.
France	Government presented a national hydrogen strategy in September 2020. It provides for an investment of €7.2 billion by 2030 and a hydrogen production capacity of 6.5 GW by 2030. At the same time, a national hydrogen committee has been established.
Germany	National hydrogen strategy published in June 2020. The strategy aims to build up industrial hydrogen generation facilities with a capacity of 5 GW by 2030, including the necessary onshore and offshore renewable energy supply, which is to be increased by another 5 GW by 2035 or 2040. Germany will provide €7 billion for the ramp-up of hydrogen technologies, in addition to existing support programmes.

India	A National Hydrogen Mission (NHM) is to be launched in 2021/22. The NHM should aim to establish appropriate physical infrastructure and legal framework for the use of hydrogen in India.
Italy	Launched a national hydrogen strategy in 2020, targeting investments in the sector of around €10 billion to 2030, with half of the amount coming from European funds and private investments. The Government plans to help boost production of low-carbon hydrogen from water, by introducing around 5 GW of electrolyser capacity by 2030.
Japan	Updated its Strategic Roadmap to implement the Basic Hydrogen Strategy, including new targets for hydrogen and fuel cell costs and deployment, and firing hydrogen carriers in power plants. METI allocated a budget of 80 billion yen (about $748 million) to R&D and consumer subsidies for hydrogen technologies and clean mobility in 2020. Japan aims to reduce the cost of clean hydrogen fuel as well as related technologies along the supply chain by scaling up their production and dissemination. Areas of focus include hydrogen production (including electrolysers), carrier technologies and international supply chains, the application in fuel cells, mobility and power generation. The industry sector does not appear to be a priority.
Korea	Announced its Hydrogen Economy Roadmap in January 2019. The roadmap outlines a goal of producing around 6 million FCEVs and rolling out at least 1200 refilling stations by 2040. Additionally, the plan aims to roll out up to 2000 hydrogen buses by 2022 and 41,000 by 2040. In terms of the energy sector, the roadmap outlines the objective to supply 15 GW of fuel cells for power generation by 2040.
The Netherlands	National hydrogen strategy published in April 2020. Published a hydrogen roadmap and included a chapter on hydrogen in the Dutch Climate Agreement. International trade of hydrogen is foreseen with potential imports of low-carbon hydrogen using water electrolysis from the Middle East, North Africa, Portugal or Spain. Demand is expected to be primarily in NW Europe such as Germany, so infrastructure connections should be considered. Harbours, notably the Port of Rotterdam, are seen as a strategic asset for the Netherlands to fulfil a 'hub function'. To boost demand for low-carbon hydrogen, the Netherlands suggests mandating an obligatory mix of hydrogen in gas networks of 2%, which could gradually be increased to 10–20%.
New Zealand	Signed a memorandum of co-operation with Japan to work on joint hydrogen projects and began preparing a New Zealand Green Hydrogen Paper and Hydrogen Strategy. Set up a Green Investment Fund to invest in businesses, including those commercialising hydrogen.
Norway	National hydrogen strategy published in June 2020, primarily encompassing research, development, commercialisation and use of hydrogen from a national perspective. Norway's position as a major supplier of natural gas to the EU, makes low-carbon hydrogen produced from natural gas with CCUS particularly interesting from a gas export perspective.
Saudi Arabia	Building a $5 billion plant powered by solar PV and wind that will be among the world's biggest low-carbon hydrogen production sites when it opens in the planned megacity of Neom in 2025.
South Africa	Included fuel cell vehicles as part of Green Transport Strategy to promote the use of fuel cell public buses in metropolitan and peri-urban areas of the country. Progress is being made in the South African hydrogen space, with the first government-led hydrogen roadmap under development and the Green Hydrogen Atlas-Africa initiative highlighting South Africa's potential to the global community.
UK	Hydrogen Strategy to be published in 2021, together with consultation on the Government's preferred business models for hydrogen. Published a review of evidence on options for achieving long-term heat decarbonisation, including hydrogen for buildings and is testing blending of up to 20% hydrogen in part of the UK natural gas network. Announced decarbonising Industrial Clusters Mission supported by £170 million of public investment from the Industrial Strategy Challenge Fund (Lochhead, 2020).
USA	Hydrogen roadmaps launched in 2020 for the USA (USDOE, 2020; FCHEA, 2020) with targets for FCEVs and hydrogen fuelling stations. Extended and enhanced the 45Q tax credit that rewards the storage of CO_2 in geological storage sites, and added provisions to reward the conversion of CO_2 to other products, including through combination with hydrogen. California amended the Low Carbon Fuel Standard to require a more stringent reduction in carbon intensity by 2030, incentivise development of refuelling stations and enable CCUS operators to participate in generating credits from low-carbon hydrogen (Beck, 2019). New Green Deal aims to cut greenhouse gas emissions by at least half from 2005 levels by 2030, which would put the nation on a path to reach a net-zero energy grid by 2035 and a net-zero economy by 2050.

The strategies and roadmaps generally identify five broad areas where hydrogen can be used to facilitate decarbonisation:

- in existing gas networks where hydrogen can be mixed with natural gas;
- in industry as an industrial feedstock and a source of heat;
- in transport, particularly in the medium to longer term;
- in homes and buildings as an energy source for space heating, water heating and cooking; and
- in energy production as an effective way to store surplus renewable energy.

These reflect the potential future markets for hydrogen identified in Section 3.2, with the variation in end uses summarised in Table 12.

TABLE 12 KEY END-USES FOR HYDROGEN IDENTIFIED IN STRATEGIES (KOSTURJAK AND OTHERS, 2019)

Region	<20% H_2 in existing gas pipelines [a]	100% H_2 in existing gas pipelines [a]	Long-term energy storage	Industrial heat	Industrial feedstock	Electricity generation	Household heating	Combined heat and power generators	Manufacture of fuel cell vehicles	H_2 for heavy vehicle transport	H_2 for small passenger vehicles	H_2 production for export
China										✓✓	✓✓	✓✓
EU (H_2 Roadmap Europe)	✓[b]	✓✓[b]	✓	✓✓	✓✓	✓	✓✓	✓✓		✓		
EU (Decarbonisation strategy)	✓[c]	✓✓[c]	✓	✓✓	✓✓	✓	✓✓[c]			✓✓	✓	
France	✓				✓✓					✓✓	✓✓	
Germany (power-to-gas)		✓✓[d]					✓✓	✓✓				
Hydrogen Council	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
IEA	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Japan	✓	✓	✓			✓	✓	✓✓	✓✓	✓✓	✓✓	
Netherlands	✓✓	✓✓				✓	✓			✓	✓	
Northern Netherlands	✓✓	✓✓	✓	✓	✓✓	✓	✓✓			✓	✓	
Norway										✓✓	✓✓	✓✓
Republic of Korea		✓✓		✓	✓			✓✓	✓✓	✓✓	✓✓	
United Kingdom	✓	✓✓		✓✓	✓		✓✓			✓✓	✓	
USA						✓✓				✓✓	✓✓	

✓✓ = primary use case assumed in strategy; ✓ = secondary use case assumed in strategy. These assessments of relative focus are necessarily subjective and reflect the focus of policy as outlined in the strategy document(s).

(a) Hydrogen concentration by volume rather than by energy

(b) The targeted approach is to blend to 5% to 15% by volume up to 2030, with transmission to a full H_2 gas network between 2030 and 2050.

(c) Hydrogen (or 'e-fuels' derived from low-carbon hydrogen and 0 net GHG emission sources of carbon) only has a substantial role in 'high h hydrogen' and 'e-fuel' scenarios. In other scenarios hydrogen would not be used in the gas distribution network, with the gas distribution network shut down and energy transmission (and localised uses derived from it such as industrial heat and household heating) fully electrified. In these other scenarios, the role for hydrogen would be focused on industrial feedstock and transportation (particularly heavy transport).

(d) As synthetic methane or other 'e-fuels' derived from low-carbon hydrogen and net-zero GHG sources of carbon.

Many of the national strategies are being supported by significant levels of government funding, in order to enable private companies to undertake research, development, and demonstration hydrogen technologies. Typically, governments are involved in providing financial support for infrastructure and access to end-use technologies (Kosturjak and others, 2019).

In addition to the financial support provided, other major roles covered in the strategies and proposed in roadmaps typically include:

- providing clear decarbonisation pathways for industry and sectors;
- supporting R&D to overcome existing technological barriers and reduce costs;
- providing a supportive regulatory environment and in particular, removing barriers from regulatory frameworks and guidelines so that issues in relation to the technical, safety and risks of hydrogen are recognised;
- helping to promote public awareness regarding the role and safety of hydrogen in order to gain community acceptance and improve safety practices;
- incorporating hydrogen into existing education and training programmes and curriculums; and
- providing coordination services for project proponents.

A more detailed review of the strategies and policies being implemented in the EU and China as key regions for the developing hydrogen market, follows.

7.1 EUROPEAN UNION

The EU has laid out its long-term vision to achieve net-zero greenhouse gas emissions by 2050, through a socially fair transition in a cost-effective manner, which includes seven strategic building blocks (EU, 2018). This was augmented in the more recent Green Deal (EU, 2019).

In terms of hydrogen, the most relevant building blocks are:

(1) Maximise the benefits from energy efficiency including zero-emissions buildings – This notes that for residential and industrial buildings, fuel switching to renewable heating (electricity, district heating, renewable gas, or solar thermal) will be required. Sustainable renewable heating will continue to play a major role, and hydrogen or renewable methane will play a key role.

(2) ***Maximise the deployment of renewables and the use of electricity to fully decarbonise Europe's energy supply*** – This notes that the competitive deployment of renewable electricity provides a major opportunity for the decarbonisation of other sectors such as heating, transport, and industry, either through direct use of electricity or indirectly through the production of power-to-x-fuels, when direct use of electricity or sustainable bio-energy is not possible.

(3) ***Embrace clean, safe and connected mobility*** **–** This notes that electrification using renewables alone will not be suitable for all transport modes. Alternative fuels will be important, with hydrogen-based technologies, such as hybrid electric vehicles and vessels based on fuel cells, potentially becoming competitive in the medium to long term. In long-distance shipping and heavy-duty vehicles, not only biofuels and biogas but also power-to-x fuels and ammonia could have a role.

(7) Tackle remaining CO_2 emissions with CCUS **–** this notes that while the potential for CCUS is lower than previously foreseen in Europe, CCUS deployment is however still necessary, especially in energy-intensive industries and in the transition to producing carbon-free hydrogen.

The EU launched its latest strategies for energy system integration (EU, 2020a) and hydrogen (EU, 2020b) in July 2020, aimed at moving Europe towards a more efficient and interconnected energy sector (*see* Table 11). The strategies build on the preceding EU long-term vision (EU, 2018).

7.1.1 Energy system integration strategy

This strategy aims to create new links between transport, industry, gas, and buildings sectors and exploit technological progress created in each. Energy system integration means that the system is planned and operated as a whole, linking different energy carriers, infrastructures and consumption sectors. The three main pillars to this strategy are:

- 'circular' energy system, with energy efficiency at its core. There is significant potential in the reuse of waste heat from industrial sites, data centres, or other sources, and energy produced from bio-waste or in wastewater treatment plants;
- greater direct electrification of end-use sectors. As the power sector has the highest share of renewables, electricity use should increase where possible. Examples include heat pumps in buildings, electric vehicles in transport or electric furnaces in certain industries; and
- for those sectors where electrification is difficult, the strategy promotes clean fuels, including clean hydrogen and sustainable biofuels and biogas.

7.1.2 Hydrogen strategy

The Hydrogen Strategy recognises that hydrogen can support the decarbonisation of industry, transport, power generation, and buildings across Europe. It addresses how to transform this potential into reality, through investments, regulation, market creation and R&D. The priority is to develop renewable hydrogen, produced using mainly wind and solar energy, supported in the short- to medium-term by other forms of low-carbon hydrogen. To achieve this, a phased approach is proposed as follows:

- 2020-24, the EU will support the installation of at least 6 GW of renewable hydrogen electrolysers in the EU and the production of up to one million tonnes of renewable hydrogen;

- 2025-30, hydrogen needs to become an intrinsic part of the integrated energy system, with at least 40 GW of renewable hydrogen electrolysers and the production of up to 10 million tonnes of renewable hydrogen in the EU; and
- 2030-50, renewable hydrogen technologies should reach maturity and be deployed at large scale across all hard-to-decarbonise sectors.

Together, these strategies place hydrogen as a central feature of European energy policy and are likely to result in a progressive move away from natural gas to low-carbon hydrogen and increasingly to low-carbon hydrogen based on water electrolysis.

Another element added during the 2018 revision of the Emissions Trading Scheme is the establishment of the €10 billion ($12 billion) Innovation Fund for the commercial-scale demonstration of breakthrough technologies to deliver low carbon solutions (EU, 2018).

7.1.3 Covid-19

Europe has been affected significantly by the Covid-19 pandemic, with a high proportion of European countries enforcing a spectrum of 'lock-down' measures. In Europe, in the first quarter of 2020, milder weather reduced natural gas demand by an estimated 2.6% during Q1 2020 relative to Q1 2019 (IEA, 2020).

In response to this, the EU has proposed a €750 billion recovery plan called 'Next Generation EU' which aims to ensure a sustainable and inclusive recovery from the Covid-19 crisis in the EU (EU, 2020c). The aspects of the plan relevant to hydrogen are:

- a proposal to strengthen the Just Transition Fund, the first pillar of the Just Transition Mechanism (EU, 2020d) by up to €40 billion, to assist EU member states in accelerating the transition towards climate neutrality; and
- a new Strategic Investment Facility built into Invest EU (second pillar of the Just Transition Mechanism) to generate investments of up to €150 billion ($176 billion) to boost the resilience of strategic sectors, notably those linked to the green and digital transition and key value chains in the internal market.

7.2 CHINA

The roadmap being introduced by China for hydrogen was covered earlier in the report in Section 3.2.2. To support the roadmap and China's hydrogen economy generally, a policy framework is in place which can be classified into three areas as described below (Tu, 2020).

7.2.1 R&D programmes

The first category is R&D programmes, which can be dated back to as early as the 1950s and includes:

Space programmes

When hydrogen and fuel cells research in China began in the 1950s by the Dalian Institute of Chemical Physics (DICP), it had an emphasis on applications for space programmes. Similarly, in the early 1950s, the liquid hydrogen-oxygen propellant rocket engine was foreseen by Chinese scientists as a key component of the country's infant space programmes, with breakthrough finally achieved in 1975.

863 programme or State High-Tech Development Plan

The 863 programme was started in 1986 to stimulate development of advanced technologies in a wide range of fields for the purpose of making China independent of financial obligations for foreign technologies. Before its conclusion in 2016, it accelerated research-based commercialisation of advanced hydrogen technologies.

973 programme or National Basic Research Programme

This programme was initiated in 1997 to develop basic research, innovations and technologies aligned with national priorities in economic and social development. With the first hydrogen project started in 2001, the 973 programme funded various hydrogen-related basic research before its conclusion in 2016.

National key R&D programme

In 2016, China consolidated different government R&D programmes including 863 and 973 under the National Key R&D Programme. Since this date, increasing levels of resource have been spent on hydrogen-related R&D through the programme, managed by the Ministry of Science and Technology (MOST).

7.2.2 Five-year plans

The second category is the Five-Year Plan (FYP). While planning is a key characteristic of centralised socialist economies, a plan established for the entire country normally contains detailed economic development guidelines for all regions, and China's FYPs are a series of such economic development initiatives.

13th Five-year plan

China's 13th FYP, issued in March 2016, set out the objectives and principles of the country's continued economic and social development between 2016 and 2020. Under the overarching guidelines, detailed plans for each sector were prepared by relevant government departments. The 13th FYP for energy issued by the National Development and Reform Commission (NDRC) and National Energy Administration (NEA) in December 2016 encourages R&D on advanced energy storage technologies especially fuel cells, coupled with pilot projects of hydrogen production. The 13th FYP for Transport Technology Innovation issued by MOST and Ministry of Transport (MOT) in June

2017 aimed to promote R&D on fuel cell technologies and encourage development of pilot hydrogen infrastructure.

14th Five-year plan

China's 14th FYP for economic and social development between 2021 and 2025 should be finalised and approved in early 2021, followed by more detailed sectoral plans over the next year, with the 14th FYP for energy and other energy subsectors most likely to be released during Q4 2021-2022 (Tu, 2020). Given the rising interest in the hydrogen economy, this topic is expected to be more extensively covered by sub-sector plans issued by MOST, NDRC, NEA, and Ministry of Industry and Information Technology (MIIT) among other central government agencies.

7.2.3 Laws, regulations, guidelines and administrative orders

The third category is major laws, regulations, guidelines and administrative orders issued by various government authorities, with several most notable ones being:

- Made in China (MIC) 2025 – launched in 2015, China plans to provide continuous support for fuel cell-related R&D, which is a strong indication of China's intention to commercialise advanced hydrogen technologies to further upgrade their manufacturing value chain;
- State Council's Work Report in 2019 – development of hydrogen infrastructure was mentioned for the first time in this document, one of the most important reports presented by the Chinese premier;
- Energy Statistical Reporting Mechanism 2019 – National Bureau of Statistics (NBS) plans to include hydrogen-related statistics starting from 2020, which is a clear signal that hydrogen has gained a more prominent role in China; and
- Draft Energy Law in 2020 – NEA released China's draft Energy Law for public consultation in April 2020. Compared with the first version of the draft Energy Law published in December 2007, hydrogen is classified as an energy carrier for the first time. As a result, energy-related utilisation of hydrogen is expected to gain traction in China.

7.3 USA

The broad roadmap for the USA to move towards increased hydrogen usage is defined by HEFCA, 2020 and USDOE 2020 and is outlined in Section 3.2.3.

The US roadmap is supported by a number of federal incentives directed at hydrogen, which include various tax credits and exemptions, loan programme support, and zero emissions incentives. Certain states also have incentives that make hydrogen more attractive. For example, California's Low Carbon Fuel Standard provides a significant boost to hydrogen, so much so that it is often raised as a potential policy prescription in other regions, although the reception to it varies by state.

One hydrogen-specific example is the Hydrogen and Fuel Cell Technologies Office (HFTO) which is the premier applied R&D programme at the USDOE. The office traditionally provides funding in the form of competitive grants to conduct R&D in hydrogen production, delivery, infrastructure, storage, fuel cells and multiple end uses across transportation, industrial and stationary power applications. The programme also provides support for technology validation, manufacturing, analysis, systems development and integration, safety, codes and standards, education and workforce development. The Consolidated Appropriations Act for Fiscal Year (FY) 2021 provided $150 million to the HFTO.

The largest area of focus for HFTO today is the H2@Scale initiative (H2@Scale, 2020). A consortium of stakeholders have come together through this programme to support and facilitate progress for the industry through seven R&D pillars:

- Grid simulation and testing R&D;
- Development and use of co-products R&D;
- Techno-economic modelling and analysis;
- Hydrogen materials compatibility R&D;
- Safety R&D (cross-cutting);
- Performance verification to guide R&D; and
- Materials and component manufacturing R&D.

As the initiative matures, new priorities such as H2@Aviation are beginning to emerge that build on existing efforts that have a more specific focus, such as on medium- and heavy-duty vehicles.

More recently, the US administration has pledged that the USA will cut greenhouse gas emissions by at least half from 2005 levels by 2030, which would put the nation on a path to reach a net-zero energy grid by 2035 and a net-zero economy by 2050. This is to be achieved through the Green New Deal, which also calls for global reductions of 40% to 60% in greenhouse gas emissions from 2010 levels by 2030, and net-zero global emissions by 2050 (Green New Deal 2019, 2021).

7.4 SUMMARY

The number of countries with hydrogen-specific or hydrogen-related national strategies and roadmaps is growing. The funding identified to support these strategies is increasingly significant, particularly related to low-carbon hydrogen based on water electrolysis and the support of increasing renewables penetration.

8 NEXT STEPS

The primary driver to expand the use of hydrogen is to reduce GHG emissions as part of the transition to a net-zero emissions future. Clean hydrogen is likely to be adopted in applications where it is the only viable decarbonisation alternative, or where it has a proven advantage over all competing solutions, as noted in Section 3.2. This includes feedstock uses in the chemical industry, feedstock use in iron and primary steelmaking industries, fuel for long-distance shipping and storage uses in 'island' power systems. Additional application where hydrogen could become the preferred decarbonisation solution include fuel use in aviation, fuel use for long-distance road-based haulage applications, use in buildings to complement electrification and storage/buffering use in interconnected power systems.

However, in order to move towards this increased uptake of hydrogen, near-term actions are required to overcome barriers and reduce costs. There is much similarity with the barriers and opportunities identified already for CCUS in a recent report by the ICSC (Kelsall, 2020), particularly for clean hydrogen produced from coal where the primary production method is coal gasification with CCUS. Whilst this is a very important area, it is therefore covered at a high level only in the current report. A subsequent report from the ICSC considering R&D topics for hydrogen from coal could include a deeper review of barriers and opportunities for clean hydrogen from coal, particularly when proposed hydrogen business models are published, such as the one under development in the UK (Frontier Economics, 2019).

8.1 PROPOSED POLICY SUPPORT ACTIONS

The IEA has identified five policy actions through to 2030 which should be pursued to increase the uptake of hydrogen in the energy transition (IEA 2019c). In general, these policy signals are needed to provide key stakeholders with certainty that there will be a future marketplace for hydrogen. Climate policies in particular, will be important, with potential actions including the establishment of high-level instruments such as emissions reduction targets, or commitments to deploy certain energy resources or carbon pricing systems.

- ***Establish longer term signals to promote investor confidence*** – provide key stakeholders with the confidence that there will be a future marketplace for low-carbon hydrogen and related technologies, supporting investment and co-operation between companies and countries. This should build on the existing progress with national hydrogen strategies and roadmaps as presented in Table 11. In particular, it should provide targets for hydrogen use, provide economy-wide emissions targets, establish national industrial strategies and develop international agreements and move towards establishing national commitments.
- ***Stimulate commercial demand for hydrogen in multiple applications*** – policies that create sustainable markets for clean hydrogen, especially to reduce emissions from fossil fuel-based hydrogen, are needed to underpin investments by suppliers, distributors and users. By

scaling up supply chains, these investments can drive cost reductions, whether from low-carbon electricity or fossil fuels with CCUS.

- ***Mitigate first mover risks, such as value chain complexity*** – new applications for hydrogen, as well as clean hydrogen supply and infrastructure projects, are typically at the highest risk point of the deployment curve. Targeted and time-limited loans, guarantees and other tools can help the private sector to invest, learn and share risks and rewards. As with CCUS, the development of business models along the line of that proposed by the CCUS Cost Challenge Task Force (2018) are needed. In the UK for example, a hydrogen business model is due to be published for consultation during 2021 (Frontier Economics, 2019).
- ***Promote R&D and knowledge sharing*** – together with cost reductions from economies of scale, R&D is crucial to lower costs and improve performance, including fossil fuels, where coal-related research, development and deployment priorities are outlined in Section 6. Government actions, particular access to public funds, are important to set the research agenda and to attract industrial and other key stakeholders' private capital for innovation.
- ***Harmonise standards and remove barriers*** – project developers face hurdles where regulations and permit requirements are unclear, unfit for new purposes, or inconsistent across sectors and countries. Knowledge sharing and the harmonisation of standards are important, including equipment, safety and certifying emissions from different sources. The relatively complex supply chains for hydrogen mean that governments, companies and other key stakeholders should consult on a regular basis. As noted by Kosterjak (2019), this should provide a supportive regulatory environment, which would include relaxing any existing regulatory barriers that currently restrict the introduction of hydrogen, such as restrictions on hydrogen blending in gas networks and on hydrogen storage in urban environments. It should also allow for the modification of existing regulations and guidelines so that issues in relation to the technical, safety and risks of hydrogen are recognised through the whole hydrogen industry chain from production, transport, storage and use.

8.2 DEPLOYMENT AT SCALE IN CLUSTERS

A priority for 2020-30 should be the deployment of hydrogen technologies at scale. This is to reduce the cost of fossil fuel-based hydrogen production with CCUS by learning by doing and to build confidence in the technology.

A good approach to achieve this would be to deploy clean hydrogen production at scale as part of CCUS clusters (CCC, 2018). This is consistent with the 'Hub and Cluster' model identified previously to move CCUS projects through to commercial roll-out, where shared transport and storage networks can improve the economics of CCUS due to economies of scale and overall de-risking of storage liability and cross-chain risk (Zapantis and others, 2019; CCUS Cost Challenge Task Force, 2018). Heavy industries often exist in clusters close to local resources, power generation supply and port or rail infrastructure. These industrial clusters can be supported by providing CO_2 transport and storage

network infrastructure which multiple CO_2 sources can access. The same clusters can also be supported by providing hydrogen infrastructure, reducing the unit cost of hydrogen/CCUS as the network capital cost is spread out across an increased quantity of hydrogen and/or CO_2. It also reduces cross-chain risk by creating multiple customers for the operators of the CO_2 transport and injection business and multiple CO_2 storage service providers for industrial CO_2 sources. This provides greater levels of operational flexibility than single source and sink facilities and reduces the operational risk. This Hub and Cluster approach is being used for example in the Net Zero Carbon Industrial Cluster (H2H, 2020), Porthos project in Rotterdam (Porthos, 2019) and the Northern Lights project in Norway (Northern Lights, 2019), with a further example being the HyNet project around Liverpool Bay in the UK (HyNet, 2019).

This approach is also consistent with the IEA's recommendation to promote hydrogen based on coastal industrial clusters as gateways to building clean hydrogen hubs (IEA 2019c).

8.3 SUMMARY

To move towards the increased uptake of hydrogen, near-term actions are required to overcome barriers and reduce costs. This includes policy actions to support sending positive long-term signals to potential investors, stimulate demand for clean hydrogen in existing and new markets, reduce investor risk and develop business models, set the agenda for technology R&D and finally to support the establishment of a regulatory framework.

Deployment of hydrogen from fossil fuels with CCUS at scale is required, where the 'Hub and Cluster' model to improve the economics of clean hydrogen production should be pursued, particularly in close proximity to coastal port locations.

9 SUSTAINABLE DEVELOPMENT GOALS

The United Nations (UN) has set 17 Sustainable Development Goals (SDGs) with the number of targets contained within them totalling 169. The SDGs cover a broad range of social and economic development issues and whilst they are broadly interrelated, each has its own targets to achieve (*see* Figure 32). Guides on how to set SDG goals and targets which have the greatest business impact on the SDGs are defined by the United Nations Global Compact (UNGC, 2020).

Figure 32 United Nations Sustainable Development Goals (https://sustainabledevelopment.un.org/)

This report has assessed the role of hydrogen to support the transition to a net-zero emissions future, but this transition should also be seen in the wider context of the UN SDGs. Indeed, the global climate policy and the SDGs are interconnected, as the way the climate problem is addressed strongly affects the prospects of meeting a number of the SDGs (Stechow and others, 2016). The Sustainable Development Scenario of the IEA's World Energy Outlook, for example, lays out a pathway to reach the SDGs most closely related to energy (IEA, 2019a), focusing on achieving universal energy access (SDG 7), reducing the impacts of air pollution (SDG 3.9) and tackling climate change (SDG 13).

There are still around 800 million people globally, primarily in the continents of Africa and Asia, who do not have access to electricity. As the living standards of these regions increase, they will seek to use indigenous energy sources such as solar, wind and biomass renewables, as well as coal. Therefore, the combined approach of limiting global temperature rise (SDG13), whilst providing access to reliable and affordable energy (SDG7) to support economic development and improved living standards is important. This forms part of an 'inclusive transition' where OECD countries need to work with developing nations to move towards a lower emissions future that does not disadvantage any section of the global population.

Looking at hydrogen specifically, the SDGs where hydrogen could play an important part are listed below:

- SDG 3 Disease and mortality;
- SDG 7 Affordable clean energy for all;
- SDG 8 Decent work & economic growth;
- SDG 9 Industry innovation & infrastructure;
- SDG 1 Sustainable cities & communities; and
- SDG 13 Climate Action.

There are also synergies with trans-national partnerships (SDGs 16 and 17) and sustainable production (SDG 12).

A brief review of the SDGs most heavily affected by the introduction of hydrogen is provided in Table 13.

TABLE 13 IMPACT OF COAL HYDROGEN ROLL-OUT ON SDGS (AUTHOR PREPARED)

SDG3: Disease and mortality	In end-use applications such as transportation and heating, hydrogen eliminates point of source emissions of sulphur oxides, nitrogen oxides, and particulates, which are linked to smog formation and cause an estimated 3 million premature deaths annually. It would also reduce nuisance issues including noise pollution in cities and water pollution in lakes, rivers, and ports which are linked to human health and well-being. The reduction in efficiency of coal gasification plant fitted with CCUS relative to unabated coal gasification plant, on the other hand, could mean that local air pollution is potentially exacerbated. There is also a low risk of CO_2 leakage from geological storage or the CO_2 transport infrastructure from source to sequestration location. However, offset against this is the significant risk of increased mortality through not achieving net-zero GHG emissions by 2050 if hydrogen/CCUS is not pursued (*see* SDG 13 below).
SDG6: Water efficiency and pollution prevention	Hydrogen production, both from fossil fuels and water electrolysis using renewable electricity, requires access to water as a reagent for the hydrogen production process as well as for cooling, which could contribute to localised water stress. For low-carbon hydrogen processes however, the CCUS component can potentially be configured for increased water efficiency compared to a system without carbon capture via process integration and use of air or hybrid cooling (Kelsall, 2020).
SDG7: Affordable and clean energy	Advanced and cleaner fossil fuel technologies are in line with the targets of SDG7. The United Nations Economic Commission for Europe (UNECE) for example is working with countries and industry to reduce the ecological footprint of fossil fuels. This includes disseminating best practices for deploying high efficiency, low emissions fossil technology with CCUS and hydrogen production, to help ensure energy access and promote investment in new technologies. A key challenge of achieving clean energy objectives is matching supply and demand as more power is generated from intermittent sources, transporting energy across sectors and regions and buffering supplies with strategic reserves (*see* Section 3.3.4). Hydrogen can contribute to this transition as an enabler in renewable power storage, distribution and buffering, as well as a direct source of clean power generation.

SDG8: Decent work and economic growth	The adoption of low-carbon hydrogen, including CCUS, allows countries with indigenous coal reserves to use those reserves along with renewables, to achieve economic growth whilst also meeting climate action in line with SDG13. On the downside, the IPCC noted a risk that the continued use of fossil fuel, enabled in part through low-carbon hydrogen production from coal, could lock in human and physical capital in the fossil resources industry (IPCC, 2019).
SDG9: Industry innovation and infrastructure	Approximately one-third of global energy consumption and 32% of global emissions of greenhouse gases are related to industry (UNIDO, 2018). Innovation is therefore needed to develop and promote the use of low-carbon hydrogen in industry, for example in fertiliser and chemicals production, petrochemical refineries and DRI for steel manufacture. Infrastructure provision is also needed in terms of hydrogen pipelines and high-pressure gaseous hydrogen or liquid hydrogen shipping. The IEA has recommended adapting existing industrial ports to turn them into hubs for lower cost, lower-carbon hydrogen, with areas around the North Sea coastline of Europe, the Gulf Coast of North America and the southeastern coast of China set to become important centres (IEA, 2019c).
SDG13: Climate action	The growth in hydrogen use proposed by 2050 could reduce annual CO_2 emissions by around 6 $GtCO_2$/y, contributing about 20% of the abatement required to reach the IEA's two-degree scenario (Hydrogen Council 2017b). Most climate models indicate that to achieve the 2°C temperature target of global temperature rise without CCUS, a key component of low-carbon hydrogen production, may not be achievable and would increase risk by limiting the potential for large-scale CO_2 removal using BECCS (Stechow and others, 2016), which could be used for net negative hydrogen production.

Thus, hydrogen, including low-carbon hydrogen from coal, is a key technology contributing in particular to SDGs 7, 9 and 13.

10 CONCLUSIONS

This report has examined the potential uses of hydrogen on a global basis to support the transition to a net-zero emissions future and how they will develop through to 2050. The technologies to produce hydrogen have been reviewed, focusing on clean hydrogen production from coal and how this competes with emerging water electrolysis-based hydrogen production, particularly in respect of the cost of hydrogen and the emissions generated. The key conclusions that can be drawn are outlined below.

In terms of hydrogen as a fuel:

Hydrogen has an energy content on a mass basis of 120 MJ/kg which is higher than either natural gas or gasoline, making it potentially attractive as a transport fuel. However, on a volumetric basis, the energy content at 10.8 MJ/m^3 is relatively low, meaning that hydrogen gas is typically compressed and stored at high pressures.

In terms of hydrogen demand:

Current – The total global hydrogen demand in 2018 was around 115 MtH_2/y, which was produced local to the point of use, almost entirely from fossil fuels and was used primarily as feedstock in the refinery and chemicals industries. Coal accounted for around 27% of this hydrogen demand based on the energy input required to produce the hydrogen, with natural gas being the largest source accounting for over 70% of the hydrogen demand. Electricity as an energy input for electrolysis, accounts for less than 1% of the hydrogen demand, with fossil fuels still indirectly accounting for the majority of this, due to the electricity for electrolysis being largely produced from fossil fuels in the countries where the hydrogen is produced.

- For the pure hydrogen market, 38 MtH_2/y, representing 52% of hydrogen demand is used for upgrading of petroleum products in refinery applications and 31 MtH_2/y, or 42% of hydrogen demand is used as a feedstock for ammonia production; and
- In addition to this dedicated hydrogen demand, there is a further 45–48 MtH_2/y produced as a by-product from other processes, which is used for the manufacture of methanol, for the manufacture of steel using the Direct Reduced Iron (DRI) process and for other applications such as synthesis gas for fuel or feedstock and process heating.

Future – Hydrogen global demand is forecast to increase to perhaps as high as 650 MtH_2/y, representing around 14% of the expected world total energy demand in 2050. Other forecasts are more conservative, estimating the future demand at between 180–275 MtH_2/y in 2050. Compared with the current hydrogen demand, this corresponds to a potential 160–570% increase.

In terms of the uses of this hydrogen, it is likely to be adopted in applications where it is the only viable decarbonisation alternative, or where it has a proven advantage over competing solutions. This includes the continued use as feedstock in the chemical industry, feedstock use in iron and primary

steelmaking industries, fuel for long-distance shipping and storage uses in 'island' power systems. Additional applications where hydrogen could become the preferred decarbonisation solution include fuel use in aviation, fuel use for long-distance road-based haulage applications, use in buildings to complement electrification and storage/buffering use in interconnected power systems.

There will be regional variations in this future demand for hydrogen, depending on local factors including resource availability, political support, existing gas infrastructure and GHG emission reduction targets. Heating of buildings for example is likely in countries with good gas infrastructure such as Australia, Canada, the Netherlands, South Korea, UK and the USA which are likely to be early adopters. In addition, existing industrial ports could be used where feasible to turn them into hubs for lower cost, lower-carbon hydrogen, with areas around the North Sea coastline of Europe, the Gulf Coast of North America and the southeastern coast of China set to become important centres. A key advantage of hydrogen as an energy carrier is that as a chemical fuel, it can be transported globally so that it could be produced in regions with the best resources and used in regions where there is high demand, with the HESC project being a good example of this.

In terms of hydrogen production:

Hydrogen production technology – The three main routes available for the production of hydrogen depending on the fuel feedstock are reforming of natural gas primarily using SMR, gasification of coal and electrolysis of water. Hydrogen production from coal using gasification is a well-established technology, used for many decades by the chemical and fertiliser industries for the production of ammonia, particularly in China. There are three key examples of the technology including CCUS in operation currently, producing hydrogen from coal, coke or asphaltene with a combined capacity of around 0.6 MtH_2/y. These are the Great Plains Synfuel and Coffeyville plants in the USA and Sinopec Qilu in China. These facilities demonstrate that large-scale production of low emissions hydrogen using carbon capture can already be technically and commercially feasible, with the Sinopec Qilu CCUS retrofit in particular, potentially acting as a catalyst for a wider roll-out of low-carbon hydrogen technology in the wider Asia and India. A further key example includes the HESC project, which will deliver hydrogen produced from lignite gasification in Latrobe Valley, Australia to the Kobe CHP plant in Japan, although this excludes the CCUS step for the initial pilot phase due to the small amounts of CO_2 generated.

Cost of hydrogen – low-carbon hydrogen production from coal gasification with CCUS and natural gas SMR/ATR with CCUS are lower cost than low-carbon hydrogen based on water electrolysis, typically by a factor of approaching three. Coal gasification with CCUS costs typically 1.6–2.4 $\$/kgH_2$ with the lowest cost being that in China. Learning by doing through large-scale commercial roll-out together with cost reduction through technology innovations could reduce the cost by perhaps 10–15%, with Capex reductions of 45–50% reduction being possible by 2050.

In regions of the world with access to relatively low-cost renewable electricity, low-carbon hydrogen produced using water electrolysis could in time become a competitor with low-carbon hydrogen from coal or natural gas. Hydrogen from low-cost wind starts to be competitive with the upper range of fossil fuel-based hydrogen prices in less than five years, perhaps competing with the lowest cost fossil fuel-based technologies by 2035. However, hydrogen production from water electrolysis will typically operate 'mid-merit' at around 35–70% capacity factor. This may not be compatible with some applications of hydrogen such as industrial processes where a continuous supply of hydrogen may be required.

With a large existing unabated fleet of gas- and coal-based hydrogen production, a significant portion of which is located in China, the cost of hydrogen assessment would indicate that:

- the transition to large-scale, low-carbon hydrogen will require significant deployment of CCUS plant on existing coal-fired gasification plant; and
- production of hydrogen from coal on cost grounds is set to continue in the near- to medium-term.

Emissions from hydrogen – Looking at coal gasification plant specifically, the addition of CCUS at 90% capture rate can reduce the carbon intensity of this process to below 3 $kgCO_2/kgH_2$. Whilst this is good, it is not consistent with net-zero emissions, so capture technology with increased capture rates approaching 100%, or technologies such as the Allam Cycle based on supercritical CO_2 working fluid, should be explored in the medium-long term in the transition to 2050. Cofiring a portion of biomass or waste with the coal feedstock, coupled with CCUS could lead to net-zero or even negative value of CO_2/kgH_2, which would help to 'future proof' the gasification plant.

In terms of competing production technologies, natural gas-based production using SMR or ATR will generally be lower emission than coal gasification due to the inherent fuel properties where natural gas has a hydrogen carbon molecular ratio of 4:1 compared with typically 0.1:1 for coal. For water electrolysis, the CO_2 intensity depends on the CO_2 intensity of the electricity used to produce it. Where this is entirely from renewable electricity sources such and wind and solar, the carbon intensity is close to zero. However, for reasons of reducing the cost of hydrogen, or to match demand-side hydrogen requirements, the electrolyser may be operated at higher load factors where the impact of using water electrolysis could actually be detrimental. The water electrolysis process should therefore be used at a capacity factor that allows it to use mainly renewable electricity, or until renewables penetration of a region's energy mix significantly increases such that the carbon intensity of grid electricity is reduced to a very low level. This again points to the continued use of coal gasification and natural gas reforming with CCUS to play a key role to deliver low-cost, low-carbon hydrogen at the scale required.

Further research and development into the technology components of coal gasification with CCUS would be beneficial to drive down the cost of low-carbon hydrogen from coal. A detailed assessment

of the ongoing and future work in this area is beyond the scope of this report, but it is recommended that this should be assessed in a follow-up report by the ICSC.

In terms of strategies and policy:

The number of countries with hydrogen specific or hydrogen-related national strategies and roadmaps is growing. The funding identified to support these strategies is increasingly significant, particularly related to low-carbon hydrogen based on water electrolysis and its support to increasing renewables penetration. However, to move towards the increased uptake of hydrogen, near-term actions are required to overcome barriers and reduce costs. This includes policy actions to support sending positive long-term signals to potential investors, stimulate demand for clean hydrogen in existing and new markets, reduce investor risk and develop business models, set the agenda for technology R&D and finally to support the establishment of a regulatory framework. Deployment of hydrogen from fossil fuels with CCUS at scale is required, where the 'Hub and Cluster' model to improve the economics of clean hydrogen production should be pursued, particularly in close proximity to coastal port locations.

Finally, in terms of the wider SDG goals, hydrogen, including low-carbon hydrogen from coal, is a key technology contributing in particular to SDGs 7, 9 and 13.

In summary, the transition to large-scale, low-carbon hydrogen will require the production of hydrogen from fossil fuels with CCUS, both on cost and on reduced emissions grounds.

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