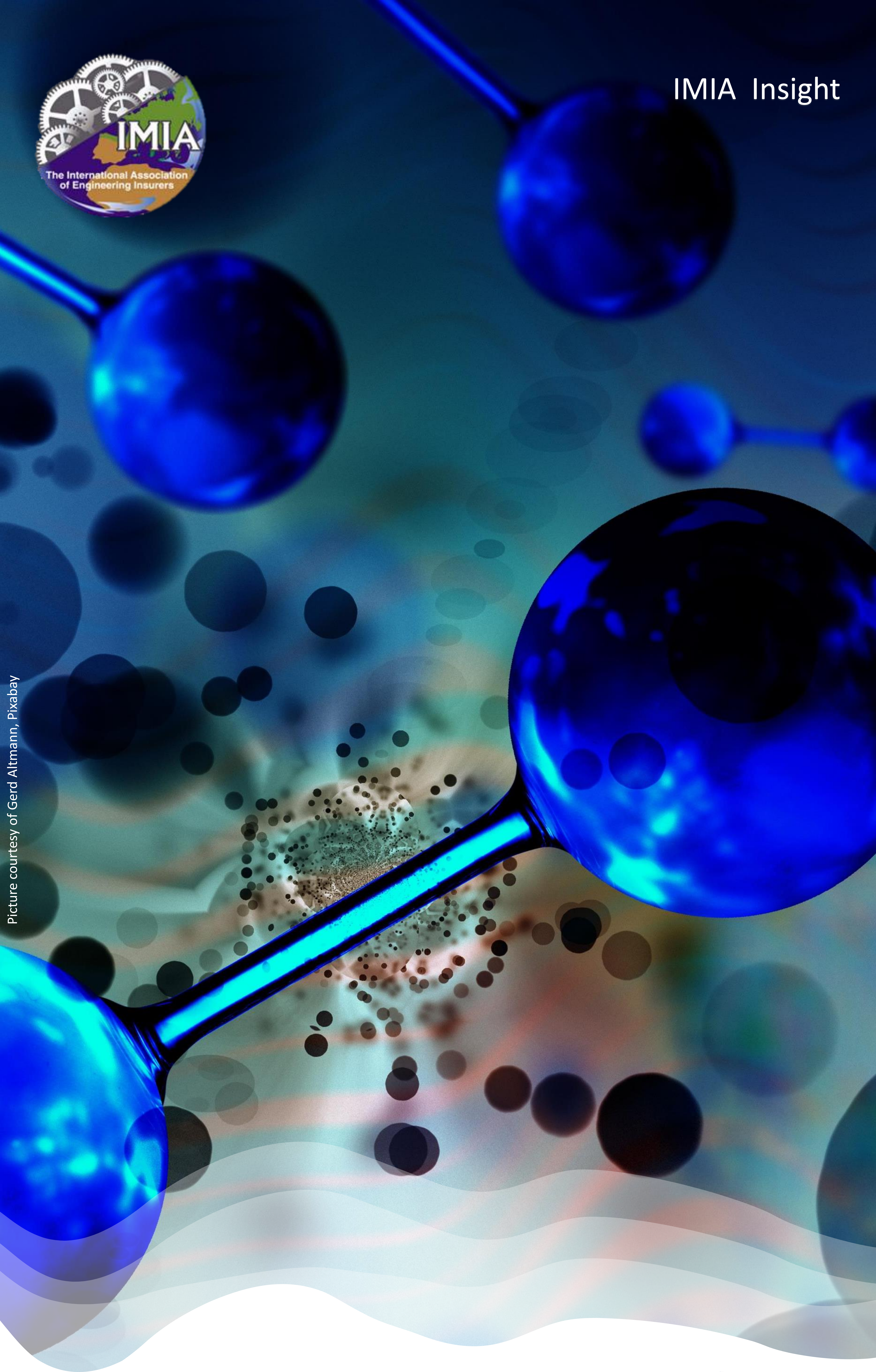
IMIA Insight



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Construction and Operation

Insuring Hydrogen Infrastructure

Outlook - Technology - Risk Mitigation - Underwriting - Claims

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How to read this document

The intention of this document is to provide Underwriters, Risk Engineers and interested members of the insurance community with relevant insights about hydrogen technology, associated risk drivers, mitigation measures, considerations while analyzing risk and structuring cover as well as assessing claims and relevant wordings.

In the race for decarbonizing energy production and heavy industries, hydrogen will play a key role as energy carrier and feedstock. New developments, projects, ideas are announced daily.

In knowledge that many statements may become obsolete in a near future our team focused on risk and implications for the insurance industry.

This paper is not intended to be digested at once, but rather to serve as reference while assessing new risks and technologies. Technical assessments, checklists and tools are provided in the Annex.

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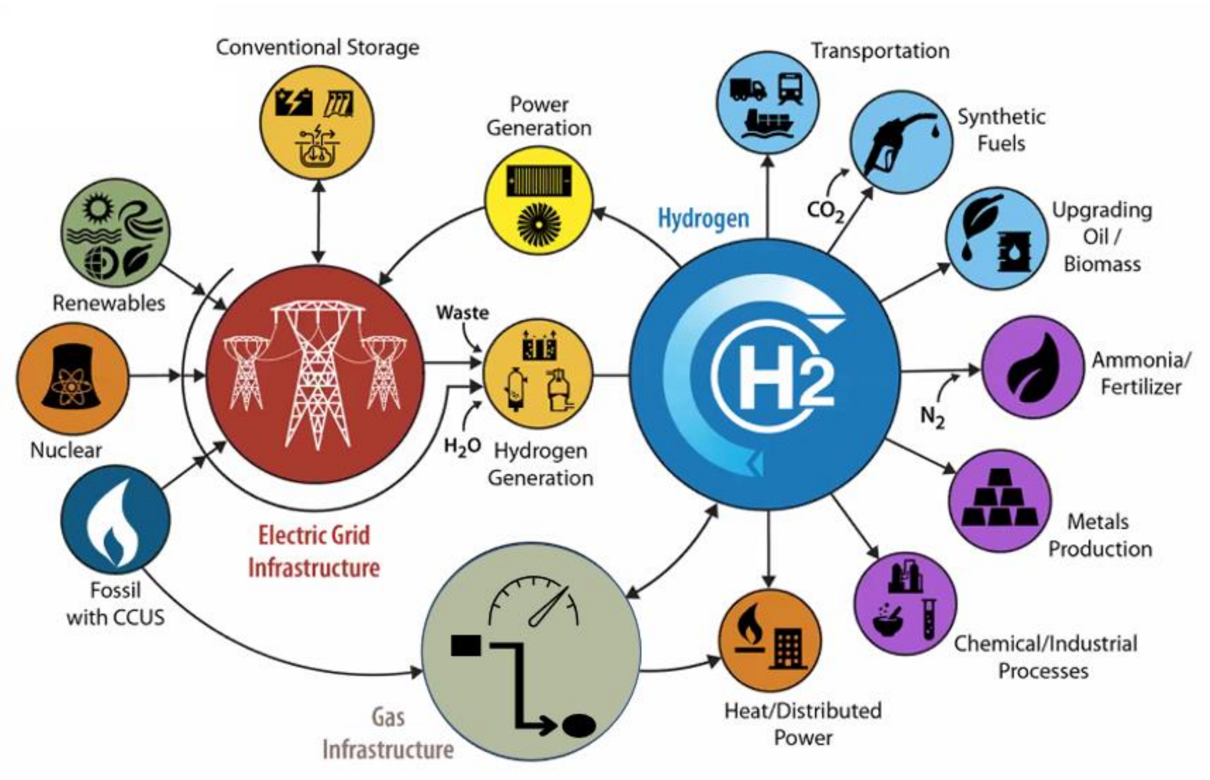
Why Hydrogen?

Decarbonization is the key element for a sustainable economy. More than ever before there is not only a political consensus and legislative pressure worldwide but also technological developments that will boost infrastructural transformation already within the next decade. Within this global move, hydrogen is well placed to aid the transition to decarbonization as an alternative, clean and potentially low-to-zero carbon fuel source and has already begun to gain momentum in the markets and governmental roadmaps to net-zero.

As a fuel, hydrogen has the highest energy content by weight of all known fuels —3 times higher than gasoline[1]— and is a critical feedstock for the entire chemicals industry, including for liquid fuels. Hydrogen (H_2) is also a clean-burning molecule, meaning when expended as fuel no carbon dioxide (CO_2) is produced, the only emission / by-product is water (H_2O). Hence, it could become a zero-carbon substitute for fossil fuels in hard-to-abate sectors of the economy and used to store, move, and deliver low- or zero-carbon energy to where it is needed.

An advantage of hydrogen as a low carbon energy source/store is that it is a chemical fuel, meaning there is no seepage or loss of energy over time, unlike current battery technologies. This could also help enable grid stability by being used as a responsive load or store, increasing the utilization of power generators, including nuclear, coal, natural gas, and renewables[2]. Hydrogen can be stored as a liquid, gas, or bound in a chemical compound and thus be transported to point of use or storage facilities via truck, pipeline, tanker, or other means. It then can be converted to energy via traditional combustion methods (in engines, furnaces, or gas turbines), through electrochemical processes (in fuel cells), or hybrid approaches such as integrated combined cycle gasification and fuel cell systems. Additionally, hydrogen is widely used as a feedstock or fuel in several industries, including petroleum refining, ammonia production, food and pharmaceutical production, and metals manufacturing.



Value chain of Hydrogen. Source: US Department of Energy, Hydrogen Energy Earthshot 2021

As a matter of fact the International Energy Agency (IEA) recognizes that hydrogen "is one of the leading options for storing energy from renewables and looks promising to be a lowest-cost option for storing electricity over days, weeks or even months"[3]. Apart from its key function as long term storage solution for renewable energy, hydrogen could also help decarbonize hard-to-abate sectors such as long-haul transport, chemicals as well as the steel industry.

However, not all hydrogen can be called climate neutral. The level of carbon emissions attached depends on the source and production method of hydrogen fuel. A multitude of methods are currently known, including:

• Thermochemical routes such as steam reformation or gasification of natural gas, coal, or biomass.

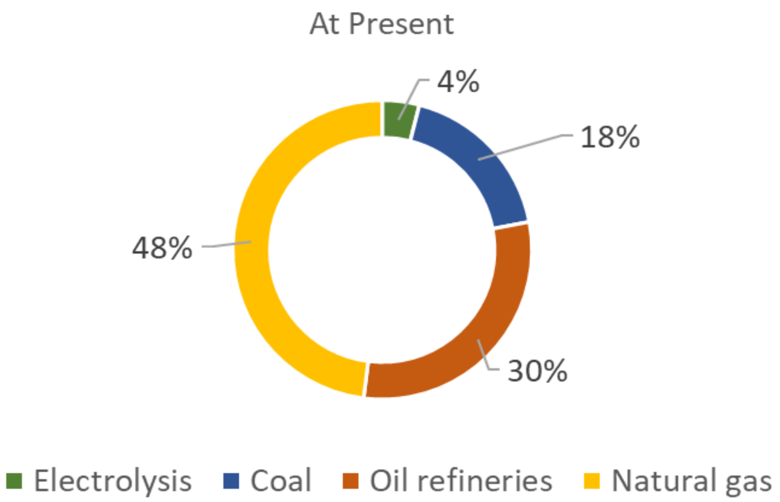
• Electrochemical methods using alkaline, solid oxide or polymer electrolyte membrane (PEM) electrolysers to split water.

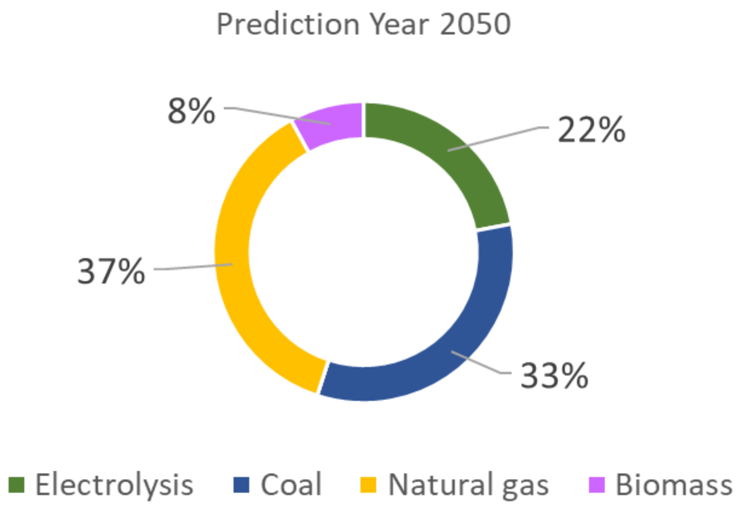
• Biological routes such as anaerobic digestion, photo-fermentation of biomass.

• Alternative thermochemical routes include microwave plasma technologies, auto thermal reforming, and partial oxidation of fossil fuels.

• Solar to fuel routes using photochemical catalysis for the splitting of water.

Below chart shows a breakdown of hydrogen production by source today and prediction for 2050.





Breakdown of hydrogen production by energy source. Data from IRENA, International Energy Agency

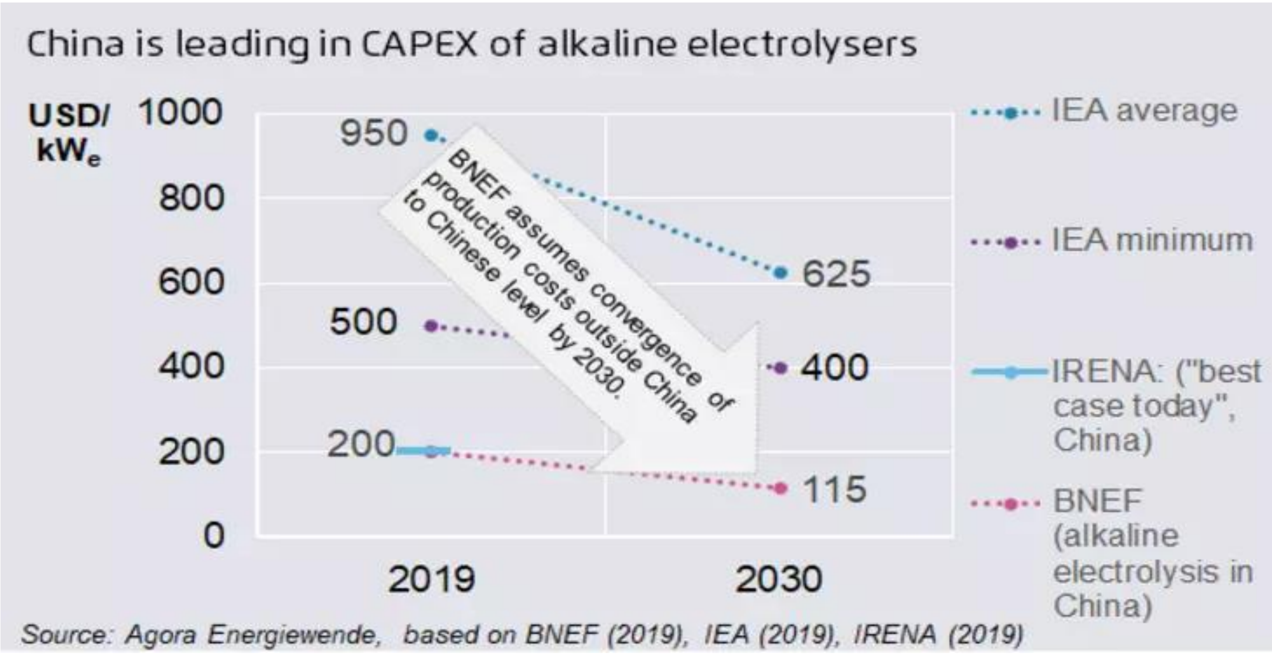
Today, industry extensively generates hydrogen from natural gas via the steam methane reforming method. During this process, CO_2 is released into the atmosphere hence it is labelled "grey hydrogen" due to its carbon emissions. Currently, fervid efforts are being made to deliver production technologies that reduce CO_2 emissions by either carbon capture storage (CCS) or complete removal of carbon from the production method. One such method is the production of H_2 by electrolysis of water using electricity generated from renewable energy sources, this is known as "green hydrogen" and has received a lot of attention in the media.

The cost of producing hydrogen from renewables is primed to fall, but demand needs to be created to drive down costs, and a wide range of delivery infrastructure needs to be built. That won't happen without new government targets and subsidies of around USD 150 bn.

Renewable electricity can help reduce emissions in road transport, low-temperature industrial processes and heating buildings. However, fossil fuels have a significant advantage in applications that require high energy density, industrial processes that rely on carbon as a reactant, or where demand is seasonal. To fully decarbonize the world economy, it's likely a clean molecule will be needed, and hydrogen is well placed to play this role.

Green hydrogen will be a game-changer for decarbonization across many industries and its utilization will vary from small, decentralized solutions to world-scale projects with high complexity

In this regard are cost reductions by scaling up a decisive factor. In 2018, over 99% of hydrogen was made using fossil fuels. With the cost of wind and solar continuing to fall, the question is whether the cost for electrolysers and renewable hydrogen can follow. While they are still expensive in Western markets, there are encouraging signs. The cost of alkaline electrolysers made in North America and Europe fell 40% between 2014 and 2019, and Chinese made systems are already up to 80% cheaper than those made in the west. On the other hand, Chinese electrolysers feature higher levelized cost of hydrogen, says China Hydrogen Energy & Fuel Cells Industry Innovation Strategic Alliance[4].



In April 2022, NEL has officially opened its 500MW fully automated alkaline electrolyser factory in Herøya, southern Norway, which the manufacturer says will help reduce the cost of green hydrogen by up to 75%. The Norwegian company has a goal to enable a levelized cost of green hydrogen production of \$1.50/kg (when the electricity used costs \$20/MWh, which is already being achieved by some solar projects around the world[5].

If electrolysers manufacturing can scale up, and costs continue to fall, then calculations suggest renewable hydrogen could be produced for $0.7 to $1.6/kg in most parts of the world before 2050, making it competitive with current natural gas prices in Brazil, China, India, Germany, and Scandinavia on an energy-equivalent basis, and cheaper than producing hydrogen from natural gas or coal with carbon capture and storage[1]. This certainly accentuated by the latest geopolitical developments.

Today, in the absence of sufficiently high carbon pricing, green hydrogen is not competitive with hydrogen from unabated fossil fuels, yet

Without a clear business case, private actors are unlikely to produce green hydrogen in meaningful volumes (beyond the scope of smaller pilot projects). This is why it has been discussed establishing technology-specific policy support for renewable hydrogen in the form of a green hydrogen quota. This quota would require suppliers of natural gas to provide an increasing share of green hydrogen to the market, either through injection into the natural gas network or through certified offtake in separate hydrogen grids or supply chains. Such a quota would create a stable demand for green hydrogen and ensure the financing of the technology learning cost of electrolysis[6].

What are the ambitions and drivers?

With a focus on energy-intensive industries, heavy transportation, energy production as well as storage, hydrogen was the matter of several carbon-free pledges during UN Climate Conference COP26 in Glasgow end of 2021[7].

The UN Climate Change Conference (COP26) celebrated in Glasgow during October 2021 brought together 120 world leaders with the aim of accelerating climate action for compliance with the Paris agreement. The urgency and opportunities to move towards a carbon-neutral economy and called for transparency and rigor in climate action plans was emphasized, both from governments and companies. Thus, it gave rise to the Glasgow Climate Pact, a document that contains the guidelines for political action agreed upon by all countries.

The pact includes the following agreements:

• Countries reaffirmed the Paris Agreement goal of limiting the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit it to 1.5°C.

• Reduce emissions by 45% - compared to 2010 levels - by 2030 and achieve zero net emissions by 2050. In this context, countries are urged to accelerate their climate action and are urged to review and increase their targets to 2030, in line with the Paris Agreement, before the end of 2022.

• The reduction of carbon and the elimination of inefficient fossil subsidies must be accelerated, providing support for a transition.

• Developed countries came to Glasgow falling short on their promise to deliver US$100 billion a year for developing countries. Developed countries, in a report, expressed confidence that the target would be met in 2023. A two-year plan is established to set a global climate change adaptation target and developed countries are asked to double financial support for adaptation by 2025 for developing countries.

There were many other deals and announcements – outside of the Glasgow Climate Pact –this includes:

• Significant commitments from big emitters like China and the USA.

• The Glasgow Financial Alliance for Net Zero is an international coalition of 450 leading financial institutions from 45 countries, which commits to accelerating and incorporating the decarbonization of the world economy and achieving net-zero emissions by 2050. $ 130 trillion of private capital has been committed.

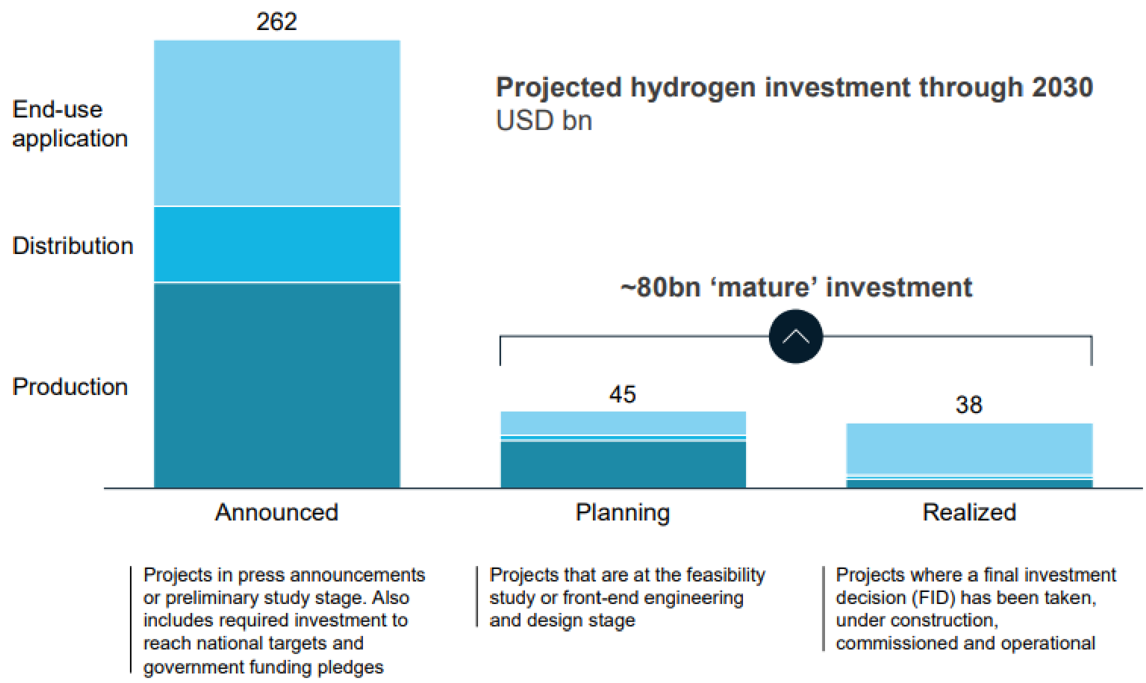
- The partnership of leaders from different countries with South Africa – the world's most carbon-intensive electricity producer– with $8.5 billion over the next 3-5 years to make a just transition away from coal to a low-carbon economy.

- Over 30 countries, six major vehicle manufacturers and other actors, like cities, set out their determination for all new car sales to be zero-emission vehicles by 2040 globally and 2035 in leading markets, accelerating the decarbonization of road transport.

- Race to Zero Energy members have committed to reaching 750 GW of capacity installed renewable energy by 2030[8].

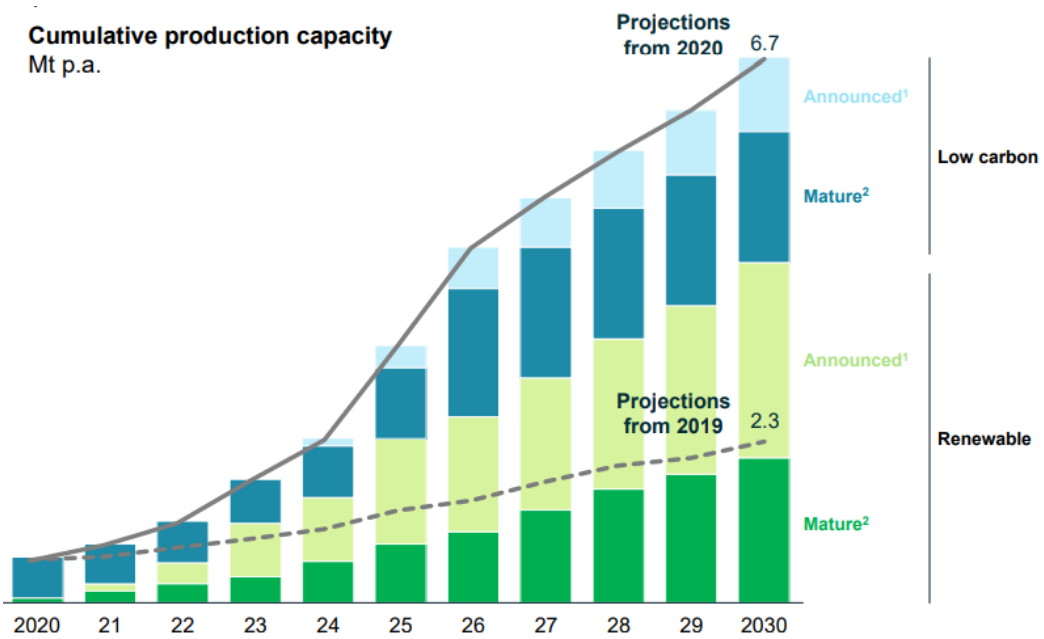
The US Industry has projected a potential $2.5 trillion global market for hydrogen technologies by 2050[9]

and a coalition of major industries teamed together to develop an industry-led roadmap on the potential for hydrogen in the United States. The roadmap report concludes that by 2050, the U.S. hydrogen economy could lead to an estimated $750 billion per year in revenue, representing a demand of 17 million metric tons by 2030 and 63 million metric tons by 2050[10].



Mature and projected investments in hydrogen. Source: Hydrogen Insights Report 2021, McKinsey&Co

Europe leads globally in the number of announced hydrogen projects, with Australia, Japan, Korea, China, and the USA following as additional hubs. Of all announced projects, 55% are located in Europe. While Europe is home to 105 production projects, the announced projects cover the entire hydrogen value chain including midstream and downstream. In expected major demand centers like Korea, Japan and Europe, the focus is on industrial usage and transport application projects. While Japan and Korea are strong in road transport applications, green ammonia, liquid H_2 (LH_2), and liquid organic hydrogen carriers (LOHC) projects, Europe champions multiple integrated hydrogen economy projects. These latter initiatives often feature close cross-industry and policy cooperation (e.g., the Hydrogen Valley in the Northern Netherlands)[11].



Projected hydrogen production capacity. Source: Hydrogen Insights Report 2021, McKinsey&Co

In the IEA's Net Zero, hydrogen use extends to several parts of the energy sector and grows sixfold from today's levels to meet 10% of total final energy consumption by 2050. This shall be supplied from low-carbon sources

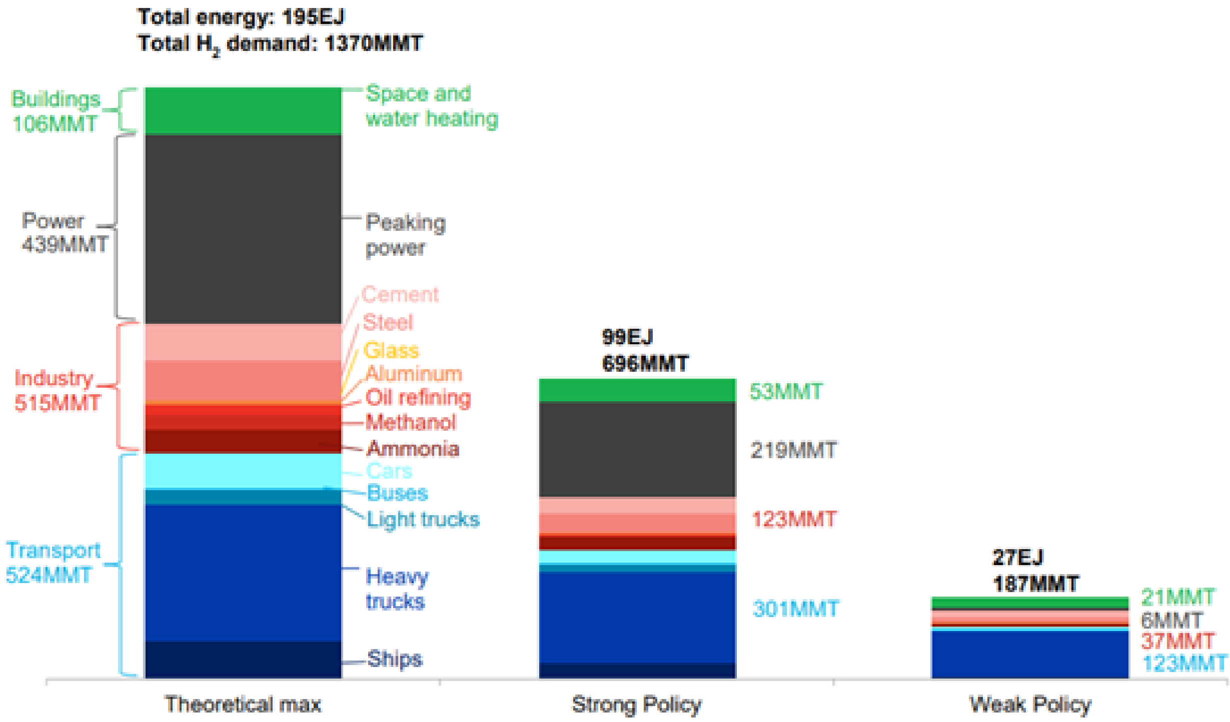
Hydrogen demand stood at 90 Mt in 2020, practically all for refining and industrial applications and produced almost exclusively from fossil fuels, resulting in close to 900 Mt of CO_2 emissions. But there are encouraging signs of progress. Global capacity of electrolysers, which are needed to produce hydrogen from electricity, doubled over the last five years to reach just over 300 MW by mid-2021. Around 350 projects currently under development could bring global capacity up to 54 GW by 2030. Another 40 projects accounting for more than 35 GW of capacity are in early stages of development. If all those projects are realized, global hydrogen supply from electrolysers could reach more than 8 Mt by 2030. While significant, this is still well below the 80 Mt required by that year in the pathway to net zero CO_2 emissions by 2050 set out in the IEA Roadmap for the global energy sector.

Europe is leading electrolyser capacity deployment, with 40% of global installed capacity, and is set to remain the largest market in the near term on the back of the ambitious hydrogen strategies of the European Union and the United Kingdom

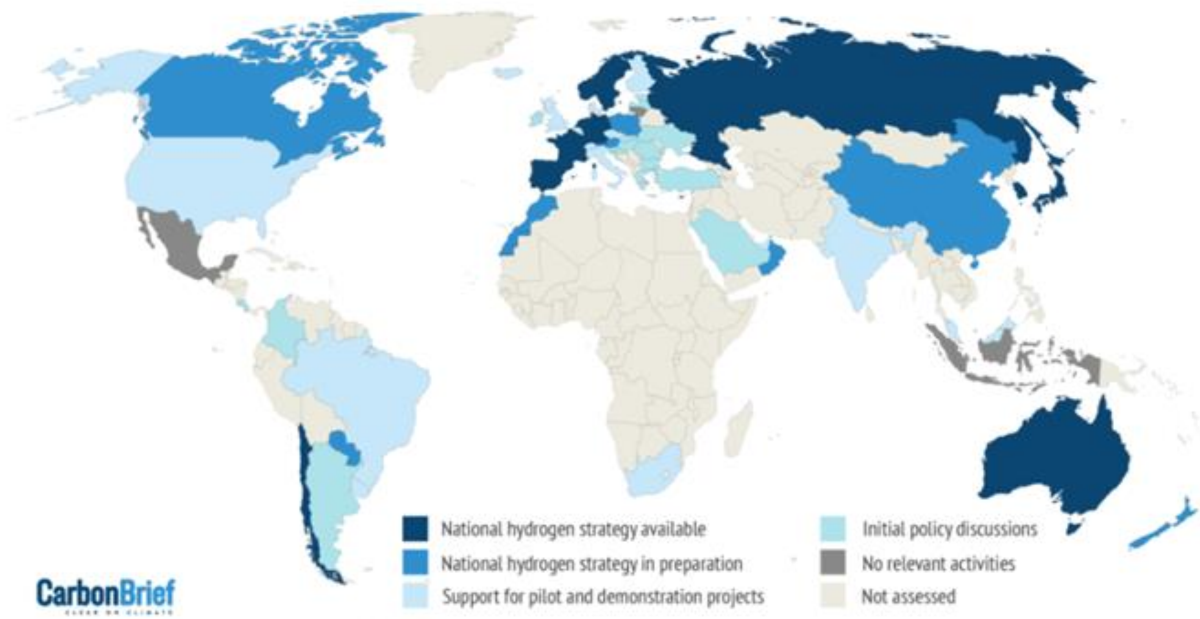
Australia's plans suggest it could catch up with Europe in a few years; Latin America and the Middle East are expected to deploy large amounts of capacity as well, in particular for export. The People's Republic of China made a slow start, but its number of project announcements is growing fast, and the United States is stepping up ambitions with its recently announced Hydrogen Earthshot.

Sixteen projects for producing hydrogen from fossil fuels with carbon capture, utilization, and storage (CCUS) are operational today, producing 0.7 Mt of hydrogen annually. Another 50 projects are under development and, if realized, could increase the annual hydrogen production to more than 9 Mt by 2030. Canada and the United States lead in the production of hydrogen from fossil fuels with CCUS, with more than 80% of global capacity production, although the United Kingdom and the Netherlands are pushing to become leaders in the field and account for a major part of the projects under development[12].

Projections depending on policymaking, estimate that 187 million metric tons (MMT) of hydrogen could be in use by 2050, enough to meet 7% of projected final energy needs in a scenario where global warming is limited to 1.5 degrees. If a strong and comprehensive policy is in force, 696MMT of hydrogen could be used, enough to meet 24% of final energy in a 1.5-degree scenario. This would require over $11 trillion of investment in production, storage, and transport infrastructure. Annual sales of hydrogen would be $700 billion, with billions more also spent on end-use equipment. If all the unlikely-to-electrify sectors in the economy used hydrogen, demand could be as high as 1,370MMT by 2050[1].



Hydrogen demand expectations depending on policy making. Source: Bloomberg "Hydrogen Economy Outlook"



World map of national hydrogen development strategies. Source: www.carbonbrief.org

The table below shows an overview of key initiatives by policy makers supporting H_2 development.

Country	Initiave	Description	Investment
Germany	National Hydrogen Strategy, 2020	Electrolyzers with a total capacity of 5 GW are to be built by 2030	EUR 9 bln by 2030 (~USD 10.3 bln)
France	Hydrogen Development Plan, 2018 National Startegy for Decarbonised Hydrogen Development, 2020	A new hydrogen goal to reach between 680 and 1000 kT in 2030. 6,5 GW of equivalent electrolyzers. 20%-40% industrial H_2 decarbonized.	EUR 7.2 bln by 2030 (~USD 8.2 bln)
Japan	Srategic Roadmap for Hydrogen and Fuel Cells, 2019 Green Growth Strategy, 2020,2021	Expand the japanese H_2 market from 2Mt to 3Mt per year. Target of 800,000 Fuel Cells and 320 fuel stations.	JPY 699.6 bln by 2030 (~USD 6.5 bln)
European Union	EU Hydrogen Strategy, 2020	Focus on green hydrogen. Objective to install at least 40 GW of renewable hydrogen electrolysers by 2030 and the production of up to 10m tonnes of renewable hydrogen in the EU	EUR 3.77 bln by 2030 (~USD 4.3 bln)
South Korea	Hydrogen Economy Roadmap, 2019	Producing 6.2 million fuel cell electric vehicles and rolling out at least 1200 refilling stations and supply 15 GW of fuel cell for power generatio by 2040.	KRW 2.6 tln in 2020 (~USD 2.2 bln)
Spain	National Hydrogen Roadmap, 2020	Installation of 4 GW of electrolysis power; 25% of industrial H_2 decarbonized; 100-150 HRS with public access; 150-200 FCEV buses; 5.000-7.500 light and heavy freight FCEV vehicles.	EUR 1.6 bln (~USD 1.8 bln)
United Kingdom	UK Hydrogen Strategy, 2021	5GW of low carbon hydrogen production capacity by 2030.	GBP 1 bln (~USD 1.3 bln)
Portugal	National Hydrogen strategy, 2021	Between 2-2,5 GW of installed capacity in Electrolyzers; 2 % to 5 % of green H_2 in the industrial sector's energy consumption;1 % to 5 % of green H_2 in the road transport sector's energy consumption.	EUR 900 mln by 2030 (~USD 1.0 bln)
Australia	National Hydrogen strategy, 2019	Focused on technology investment to bring the cost of clean hydrogen below $2 per kilogram. The government has provided funding to 72 hydrogen projects.	AUD 1.3 bln (~USD 0.9 bln)
Netherlands	National Climate Agreement, 2019 Government Strategy on Hydrogen, 2020	Realise 0.5 GW electrolyser capacity by 2025, and 3 to 4 GW by 2030.	EUR 70 mln/yr (~USD 80 mln/yr)
Chile	National Green Hydrogen Strategy, 2020	The goal is to have 5 GW of electrolysis capacity under development by 2025 and to create the cheapest green hydrogen on the planet by 2030.	USD 50 mln for 2021
Norway	Government Hydrogen Strategy, 2020 Hydrogen Roadmap, 2021	The government will contribute to developing technology for the capture, transport and storage of CO2 by CCS plants. The Government will facilitate the establishment of hydrogen hubs for maritime transport.	NOK 200 mln for 2021 (~USD 21 mln)
Canada	Hydrogen strategy for Canada, 2020	The Canada Strategy relies and builds on existing policy measures, including Canada's recently announced Climate Plan,carbon pricing, the Clean Fuel Regulations, the $1.5 Billion Low-carbon and Zero-emissions Fuels Fund, and the Incentives for Zero-Emission Vehicles program.	CAD 25 mln by 2026 (~USD 19 mln)
Russia	Hydrogen roadmap 2020	Export 0.2 million metric tons of hydrogen by 2024 and 2 million by 2035.	n.a.
NSEC memebers	North Seas Energy Cooperation	Ambitious offshore wind targets for 2030-2050: 60GW of offshore wind energy and 1GW of ocean energy by 2030. Including investment on hybrid projetcs for H2 production	

The European Commission declared in July 2021 its ambition to increase the production capacity of electrolysers from 250MW today to 40GW in 2030. Germany will switch off by law all coal plants (36 GW in 2020) by 2038[13] as well as existing nuclear plants by 2022[14].

This development leads to the question: Where is the green energy for hydrogen production on such a scale coming from? While this Paper shall not focus in detail on political constraints,

It is expected that a) different sources of hydrogen will be needed during the transformation process, even fossil-based such as natural gas or nuclear and b) this fact will, in turn, influence political decisions, infrastructural investments and ultimately on climate

The European Commission unveiled in January 2022 plans to label some gas and nuclear power as "green", stating that it is necessary to recognize that the fossil gas and nuclear energy sectors can contribute to the decarbonization of the Union's economy.

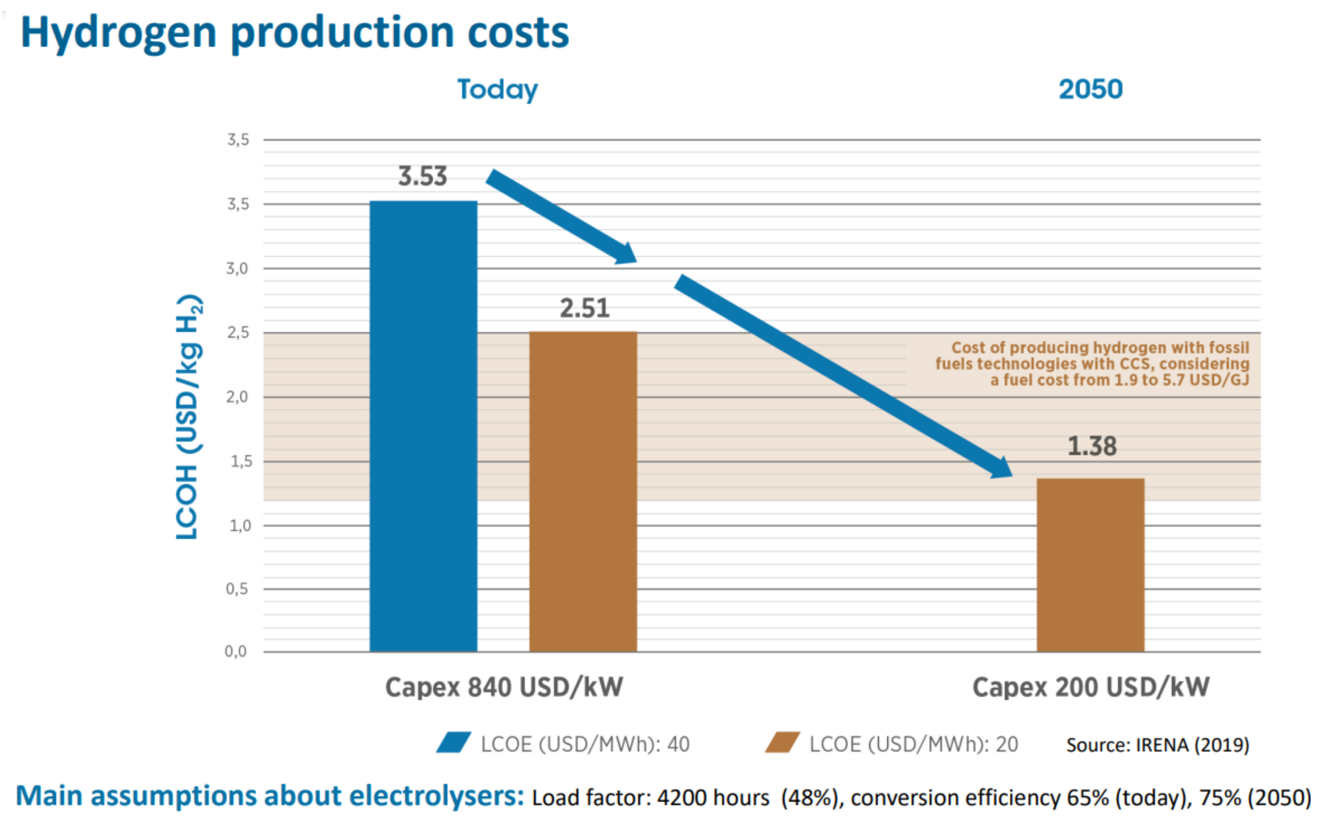
In 2017, Japan issued the Basic Hydrogen Strategy, becoming the first country to adopt a national hydrogen framework. The national government has also issued several strategic documents covering technological and economic aspects, such as the Strategic Roadmap for Hydrogen and Fuel Cells (2014, 2016, 2019), and the green growth strategy. Japan is focused on expanding its hydrogen market from two million tons per year today to three million tons per year by 2030 and 20 million tons per year by 2050; through scale while driving down the cost of hydrogen to about one-third of the current level by 2030[15].

Attention on hydrogen in China has surged after a slew of announcements by companies promising investment in emerging technology. The China Hydrogen Alliance was jointly launched in 2018 by large companies in such as energy production, equipment manufacturing, transportation, metallurgical materials, universities, and research institutes. this week the fuel could account for 20% of the nation's energy mix by 2060, the deadline that the Government has set for China to become a carbon-neutral country. Delivered low-carbon hydrogen costs are expected to drop sharply over the next decade and will account for up to 90 per cent of the total drop in TCOs from 2020 to 2030 across applications with shorter supply chains. Lower production and distribution costs will both contribute to lowered delivered hydrogen costs.

The cost of low-carbon and/or renewable hydrogen production will fall drastically by up to 60 per cent over the coming decade. This can be attributed to the falling costs of renewable electricity generation, scaling up of electrolysers manufacturing, and the development of lower-cost carbon storage facilities[16]

Many countries in the APAC region have ambitious plans to develop a hydrogen-based economy. Japan is co-financing decarbonization initiatives in the region of at least USD 10 Billion. Similar strategies have been released by the UK, Australia, and even emerging countries. These are just some of the most recent announcements, but they show a clear trend towards massive public investments in the sector.

Green H_2 will expectedly develop as LCOEs of renewables continue to drop and economies of scale in electrolyser technology are leveraged. The cost of H_2 production is a function of electricity price and CAPEX for electrolysers. Dropping LCOEs for renewable energy, technology evolution and economy of scale will expectedly make Electrolysis cheaper over time. Also, the price for grey hydrogen (via steam reforming) will expectedly increase with higher penalization of CO_2. Hence, green hydrogen has a real chance to beat grey hydrogen in the near future, this mainly driven by policy making.



Expected development of hydrogen production costs. Source: IRENA.org

Hydrogen: An industry in its infancy

At the time of issuing this report, the hydrogen industry is still in its infancy and has only recently been developed at larger scale globally. Even though electrolysis and H_2 processing are known technologies, their application at a larger scale and in the context of green H_2 is genuinely new.

It is important to point out that not only prototypes and unproven technologies are critical; scaling up of components, balance of plant, design, and operational procedures as well as standards addressing the human factor represent key risk elements to consider

As a result, there has been a lack of trusted industry standards and certification procedures. In spite of the favorable investment climate, large classification societies such as DNV have initiated joint industry projects to establish such important safety standards and ultimately increase confidence in the electrolyser market. Accordingly, certification standards have been developed by the European Union (EU) as well as by private service providers such as TÜV.

Collaboration on technologies and development as well as harmonization of regulations, codes and industry standards is seen as key to reduce uncertainties and risks in developing large H_2 projects at scale. It is worth noting that such standards ultimately should aim at entire H_2-projects and all equipment used along the often complex and highly integrated H_2 value chain, rather than just the electrolyser equipment itself.

New developments, ideas, projects are announced on a daily basis. This paper will address technological implications of new and traditional hydrogen applications from a risk perspective, including references, analyzes mitigation measures and provides design and safety standards as well as underwriting considerations.

1. Hydrogen Production

Multiple production pathways exist for the production of hydrogen; however, they all follow the same generalized route outlined below

Chemical feedstock + Energy source → **Conversion Method** → **H_2 + Byproduct(s)**

Methods of production can be divided into thermochemical, electrochemical, photochemical, or biological processes to Hydrogen[17], an extract of methods / technologies is shown below.

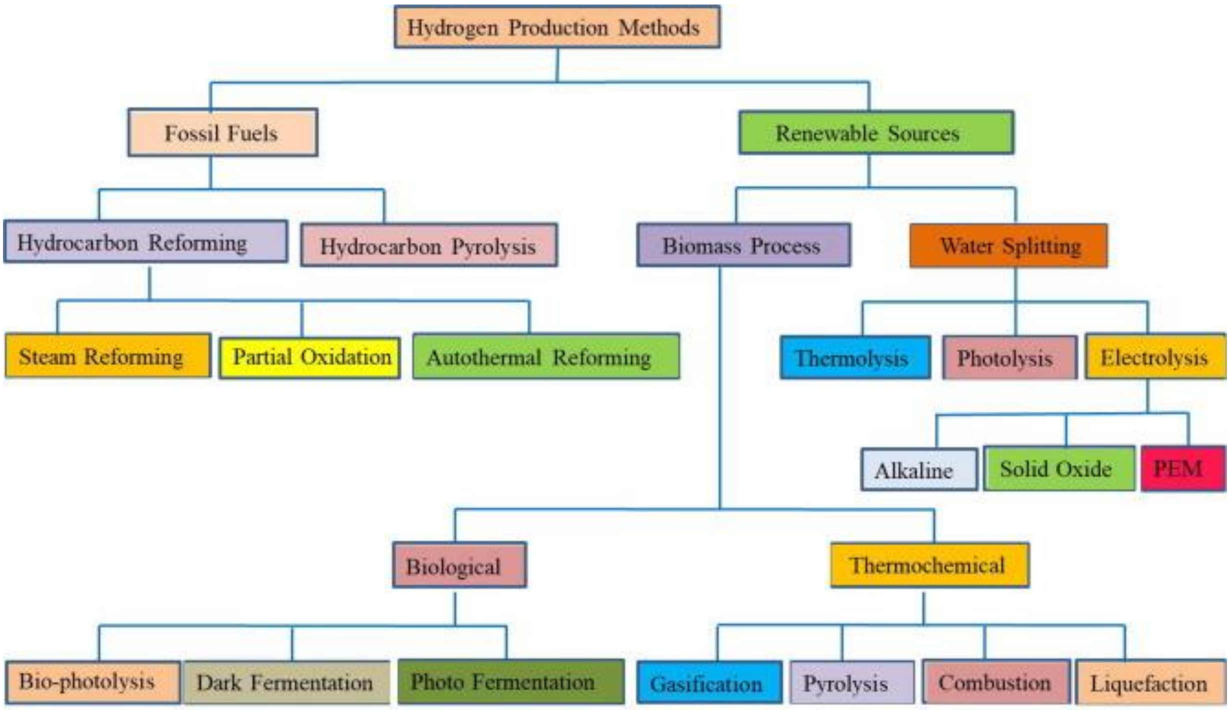
Process Category	Energy source	Chemical feedstock	Conversion Technology	Efficiency (%)	Cleanliness (C/N/CCS)	Technology maturity level (1-10)
Thermochemical	Heat	Fossil Fuels	Steam reformation	60-85	N/CCS	10
		Fossil Fuels and biomass	Partial oxidation	55-75	N/CCS	7-9
		methane	Autothermal	60-75	N/CCS	6-8
		coal	Coal gasification	74-85	N/CCS	10
		biomass	Biomass gasification	35-50	N	10
		methane	Methane pyrolysis	40-45		
Electrochemical	Electricity	water	Alkaline electrolysis	62-82	C	9-10
		water	Proton exchange membrane electrolysis	67-84	C	7-9
		water	Solid oxide electrolysis	75-90	C	3-5
		water	Anion exchange membrane	-	C	-
		water	Membrane-less electrolysis	-	C	-
Photoelectrochemical	Light	water	PEC Electrodes	0.5-28	C	1-2
		water	Photocatalytic slurry	-	-	1-2
Biological	Bioenergy	Microorganism	Dark-Fermentation	60-80	N	3-5
		biomass	Microbial Electrolysis	70-80	N	1-3

Comparison of hydrogen production methods[18]

However, for H_2 production, not just the method of production is important, the source of chemical feedstock, the source of energy to convert said chemical into H_2, the cleanness of the process (C – Clean with no emissions, N – Non-clean with emissions and CCS – Quasi clean using carbon capture and storage) and TML – Technological Maturity Level are also important considerations[18].

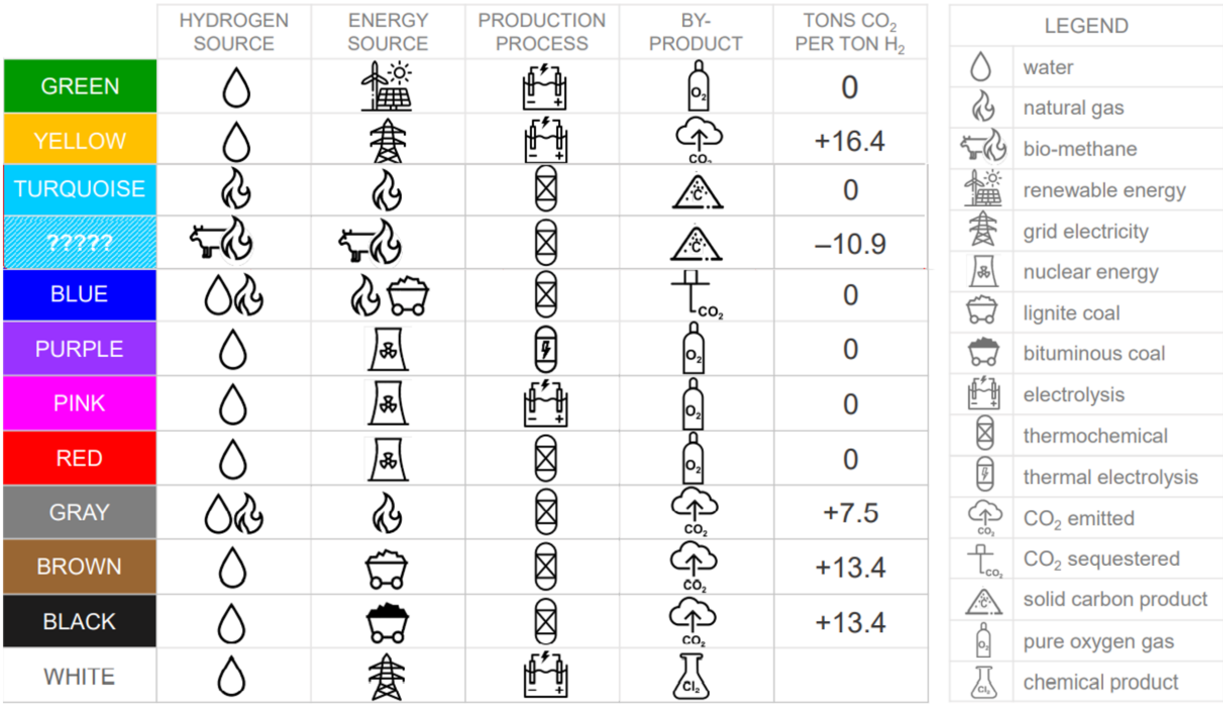
Hydrogen has been produced from various renewable and non-renewable energy resources such as fossil fuels, especially steam reforming of methane, oil/naphtha reforming, coal gasification, biomass, biological sources, and water electrolysis. The various comprehensive hydrogen production methods by source of energy are shown below. Currently ~96% of the global hydrogen production from non-renewable fossil fuels, in particular steam reforming of methane.

However, the usage of fossil fuels generates lower purity of hydrogen with high concentration of harmful greenhouse gasses. Further, the unremittingly growing the global energy needs and the limited reserves of fossil fuels together with sustainability and environmental impact need to be develop new energy approaches without any carbon emissions. Nowadays, the focus is on environmental-friendly production methods, to replace the current fossil-based energy production[19].



Hydrogen production by energy source[19]

Combinations of feedstock, energy source, production method and the handling of by-products have led to a color-coding system for H_2 production processes, which originally consisted of only "green hydrogen" (clean/renewable), blue (CCS) and grey (CO_2 emissions)[20] but has expanded and changed over time to what is shown in the below table. The color scheme shown below is currently used widely to define where and how hydrogen has been generated.



Color coding scheme for hydrogen production methods[21]

The color-coding scheme is aimed to give a perceived indication of level of CO_2 emission

It is important to note, that the present popular color-coding system is subjective of current perceptions and may not consider other sustainability or pollution factors[22] and what could be termed "green" in 2022 could be considered less "green" in 2032. A unified method of color coding is still debated[20].

In 2020, global hydrogen demand was 90 Mt and was met almost exclusively from fossil fuel sources. Where 79% of the total H_2 production came from dedicated H_2 production plants and remaining 21% as a by-product in other industrial processes[23]. The current largest share of dedicated H_2 production is gray hydrogen (~59%) whereas blue hydrogen accounted for just 0.7%. Likewise, all H_2 formed by electrolysis methods combined currently accounts for ~4% of global production[23]. However, over the coming decade this is expected to change.

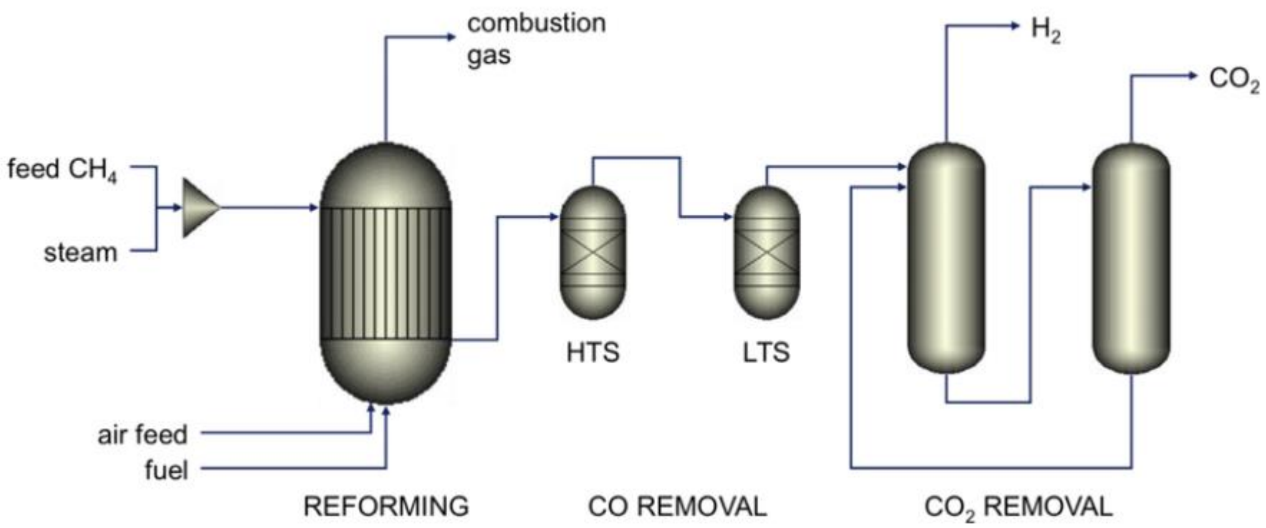
With net zero initiatives led by governments (see previous chapter) and moves by petrochemical companies towards decarbonization a shift from grey to blue H_2 is likely to be observed. Same applies for heavy industries, where efforts towards decarbonization are sensibly increased.

Additionally, with the building of multiple electrolysers capacity, economy of scale and reduction of investment and operational costs across Europe / USA / Australia, a scale up of green H_2 could reach up to 8 Mt over the coming decade[23].

1.1 Thermochemical methods

Steam Methane Reforming

In this technically mature production process, high-temperature steam (700°C–1,000°C) is used to produce hydrogen from a methane (CH_4) source, such as natural gas. In steam-methane reforming, methane reacts with steam under 3–25 bar pressure (1 bar = 14.5 psi) in the presence of a catalyst to produce hydrogen, carbon monoxide (CO), and a relatively small amount of carbon dioxide. Subsequently, in what is called the "water-gas shift reaction," the carbon monoxide and steam are reacted using a catalyst to produce carbon dioxide and more hydrogen. Despite the methane fuel source, ~50% of the H_2 produce comes from the superheated water, increasing water demand for hydrogen production (18kg H_2O/kg H_2).



Conventional steam reforming with multiple stages for H_2 production[24].

The steam-methane reforming reaction is shown below:

Steam-methane reforming reaction

$CH_4 + H_2O$ (+heat) > $CO + 3H_2$

Water-gas shift reaction

$CO + H_2O > CO_2 + H_2$ (+ small amount of heat)

In a final process step called "pressure-swing adsorption," carbon dioxide and other impurities are removed from the gas stream, leaving essentially pure hydrogen. Currently, the efficiency of steam-methane reformation plants is in the range 70-85%[25,26].

Steam methane reforming is a well-established technology that currently dominates the supply market, mainly because the capital cost is relatively low, and the chemical reaction is easy to control

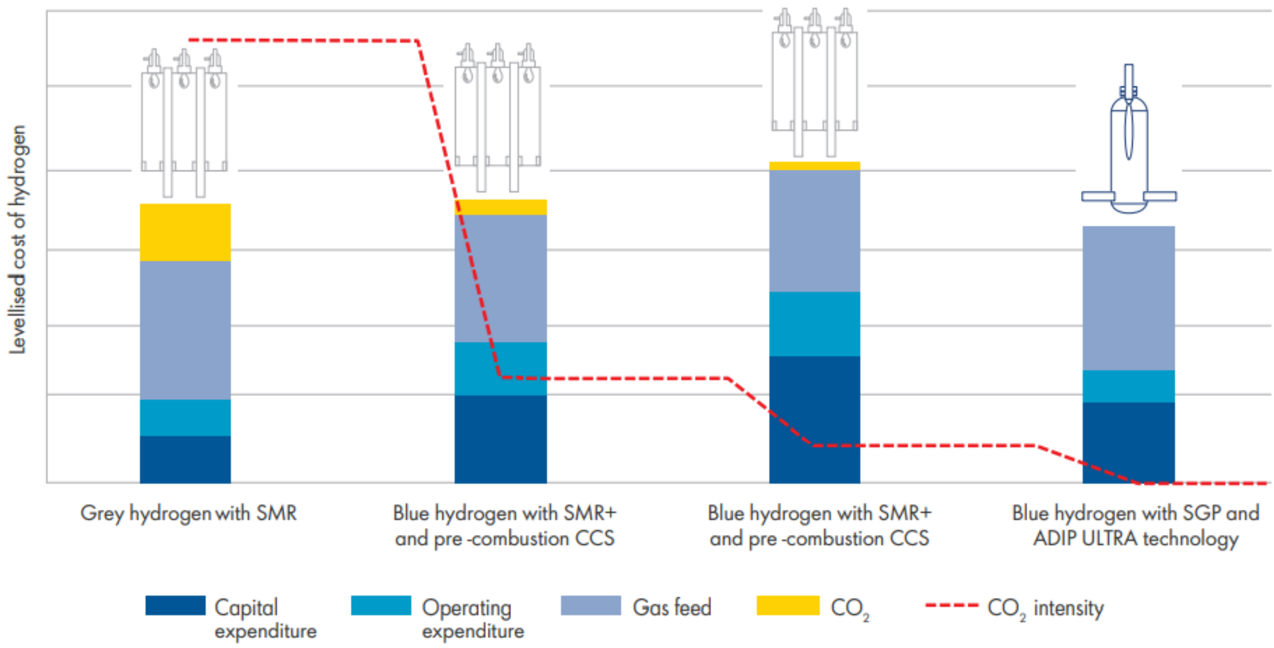
with reformer plant capacities ranging between 50-1000 MW[27].

Along with the CO_2 by product produced, the CO_2 emissions generated from creating the high temperature steam constitute a substantial proportion of the greenhouse gases emitted from the production process. Currently, this CO_2 is released into the atmosphere and constitutes H_2 productions' major contribution to global warming[28] at around 9.2 kg CO_2 / kg H_2.

However, a full lifecycle assessment of the H_2 production methods puts SMR's global warming potential (GWP) at ~11.2 kg CO_2-*eq* / kg H_2[29].

Movement towards carbon capture storage (CCS) systems in the effluent gas aims to drastically reduce this and decarbonize the sector. Steam reforming can also be used to produce hydrogen from other fuels, such as ethanol, propane, or even gasoline[30].

Future development: As SMR is the most technologically mature method of H_2 production, future developments are likely to be aligned with abatement potential of greenhouse gases, through (retro)fitting carbon capture storage (CCS) technologies to production streams, shifting the H_2 from 'grey' to 'blue'. SMR with CCS is estimated to reduce the lifecycle GWP footprint to levels around ~5 kg CO_2-*eq* / kg H_2[29].



Levelized cost of hydrogen with Carbon Capture options.
Source: http://media.hydrocarbonengineering.com/whitepapers/files/The-Shell-Blue-Hydrogen-Process.pdf

Post-combustion carbon capture can be retrofitted to conventional SMR in order to convert grey hydrogen production to blue

However, addition of CCS to obtain high purity H_2 and reduce CO_2 is estimated to reduce SMRs energy efficiency to ~60% and could increase the cost of production[31].

Reference plants:

Reference and planned CCUS projects.
Source: http://media.hydrocarbonengineering.com/whitepapers/files/The-Shell-Blue-Hydrogen-Process.pdf

Some additional processes have been developed for CO_2 capturing linked to SMR technologies. This is the case of the Shell's Cansolv CO_2 Capture System for capturing CO_2 from low pressure streams, including flue gas; and the Shell's ADIP Ultra technology for capturing CO_2 from high pressure process streams.

No major development in the area of steam methane reforming for greenfield projects is expected in the future

However, for greenfield blue hydrogen applications, oxygen-based systems such as autothermal reformation (ATR) and partial oxidation (POX) technologies are more cost-effective than SMR. An example based on a Shell economical study of different technologies is shown in the figure below. Here the levelized costs for grey and blue hydrogen production are compared for SMR and the Shell Gas Partial Oxidation process (SGP).

Partial oxidation

The partial oxidation method can also be used with a fossil fuel source such as natural gas or heavy hydrocarbons to produce H_2. Here the fuel is partially reacted with oxygen to produce carbon monoxide and hydrogen.

Partial oxidation reactions of methane and heavy hydrocarbons are shown below, respectively.

$CH_4 + 0.5O_2 > CO + 2H_2$ OR $C_nH_m + 0.5nO_2 > nCO + 0.5mH_2$

This can then be followed with the water gas-shift reaction as seen previously in for steam-methane reformation.

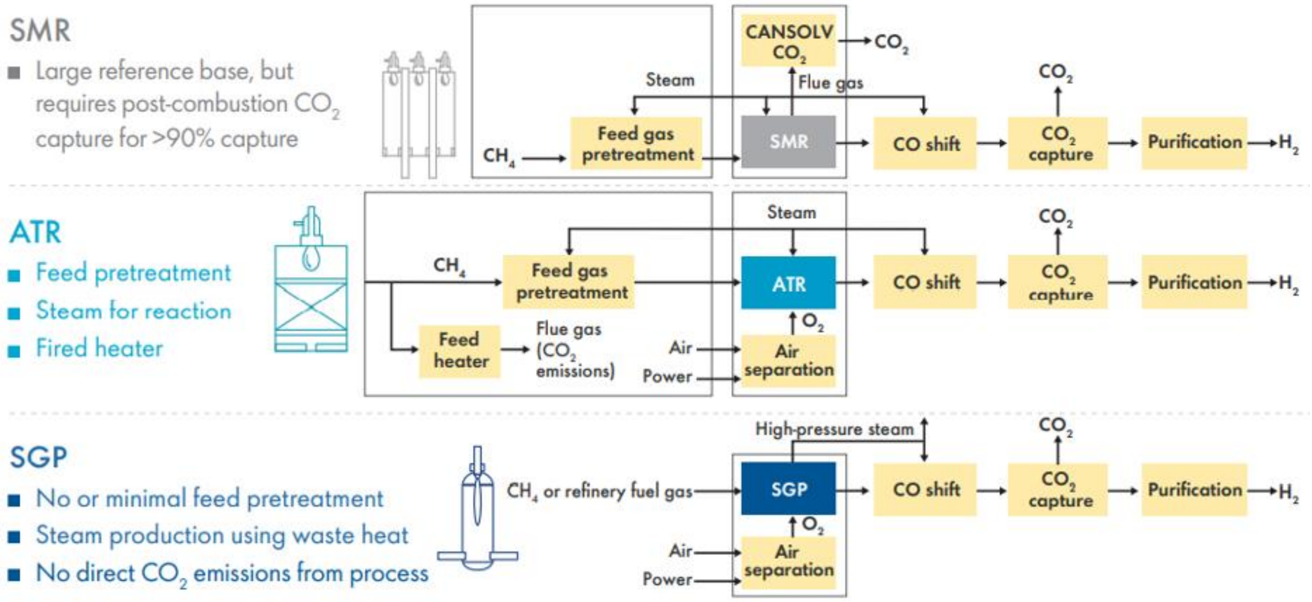
Although the reaction temperatures are high (950-1500°C) the reactions themselves are exothermic and the partial oxidation (or combustion) provides heat for the system to continue.

Compared to steam-methane reforming, this method reduces the level of external heat input in the production process, and the POX reactor is typically more compact than a steam reformer as the heat exchanger is no longer needed.

Partial oxidation can be performed without a catalyst and thus has better tolerances for sulfur impurities from the fossil fuel source

However, pure oxygen is needed for method to be efficient, if performed in air, downstream separation costs will be higher due to the high nitrogen content of air.

Although POX is a technologically mature method of H_2 production the current yield of H_2 from POX is not comparable to steam-methane reformation, and the efficiency ranges from 55-75%[25,26]. However, overall production costs can be reduced. For example, some commercially available POX processes like the Shell Gas Partial Oxidation Process (SGP) are sold as having economic advantages over other technologies, like auto-thermal reforming (ATR). Here, the Shell POX technology provides about 22 % lower levelized costs of hydrogen compared with ATR. These savings come from a 17% lower CAPEX owing to the potential for a higher operating pressure leading to a smaller H_2 compressor (single-stage compression), CO_2 capture and CO_2 compressor units, and a 34% lower OPEX (excluding the natural gas feedstock price) from reduced compression duties and more steam generation for internal power. Gas POX technology consumes 6% more natural gas, but this is offset by power generation from the excess steam[32]. A schematic comparison of future applications for MSR, POX (SPG) and ATR for blue hydrogen production is shown below.



Source: http://media.hydrocarbonengineering.com/whitepapers/files/The-Shell-Blue-Hydrogen-Process.pdf

As POX is a technologically mature technology, future developments of POX H_2 production are expected to be aligned with generation of blue hydrogen through addition CCS technologies into the production stream.

Partial oxidation plants are used to form hydrogen, carbon monoxide, carbon dioxide and water from the residues (liquids, highly viscous hydrocarbons) of the refining process[33].

Reference plant: To date Linde's La Porte POX Facility (USA) is the largest single-train based POX worldwide (200,000 Nm^3 / h H_2+CO), with natural gas charge.

La Porte Site (USA). Source: Chron

Autothermal reforming (ATR)

The autothermal reforming method combines steam-methane reforming with the partial oxidation method. It allows the production for hydrogen via connecting the devices of two processes in series. The heat required for ATR comes from the partial oxidation of natural gas and the exotherm energy of the oxidation process is used to achieve steam reforming[25].

ATR is more efficient because heat from the exothermic oxidation step can be utilized by the reformation reaction, but ATR also requires an oxygen input[27].

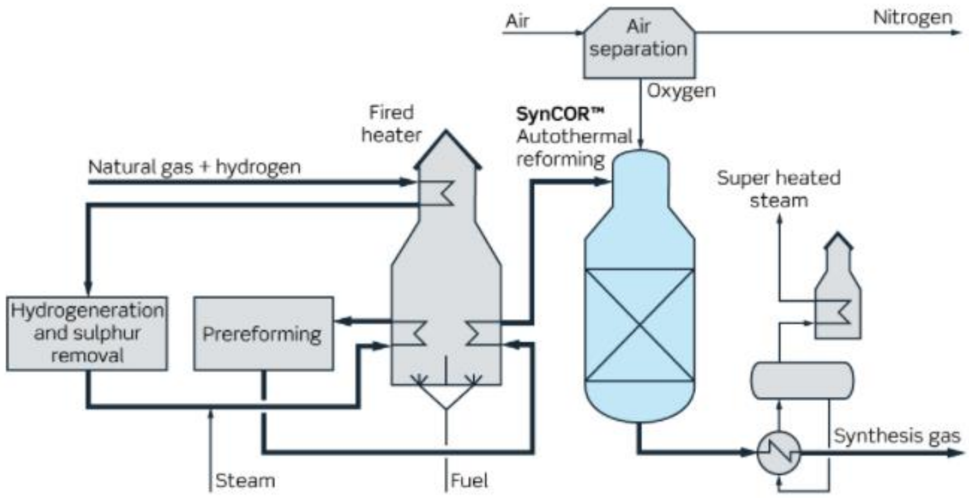
$4CH_4 + O_2 + 2H_2O \rightarrow 10H_2 + 4CO$ ATRs efficiency currently runs at around 60-75%[25,26].

The shifted gas is sent to the syngas purification (amine unit), where carbon monoxide is separated from the hydrogen-rich gas. The separated carbon monoxide is compressed and stored while the hydrogen-rich gas, containing unconverted carbon oxide, argon, and some trace gases, is sent to the pressure swing adsorption unit (PSA). In the PSA, 90% of the hydrogen is assumed to be recovered at a purity of 99.9%, while the remaining gases (fuel gases) are used as fuel in the boiler/ furnace. The CO_2 produced is released directly into the atmosphere[34].

Future Developments: Even though the technology behind autothermal reforming is not new, there is an increasing interest on ATR applications beyond the conventional methanol and ammonia production. A simplified diagram of ATR is shown in the figure below.

Future development mainly focuses on the combination of ATR and carbon capture and sequestration (CCS) for blue hydrogen generation

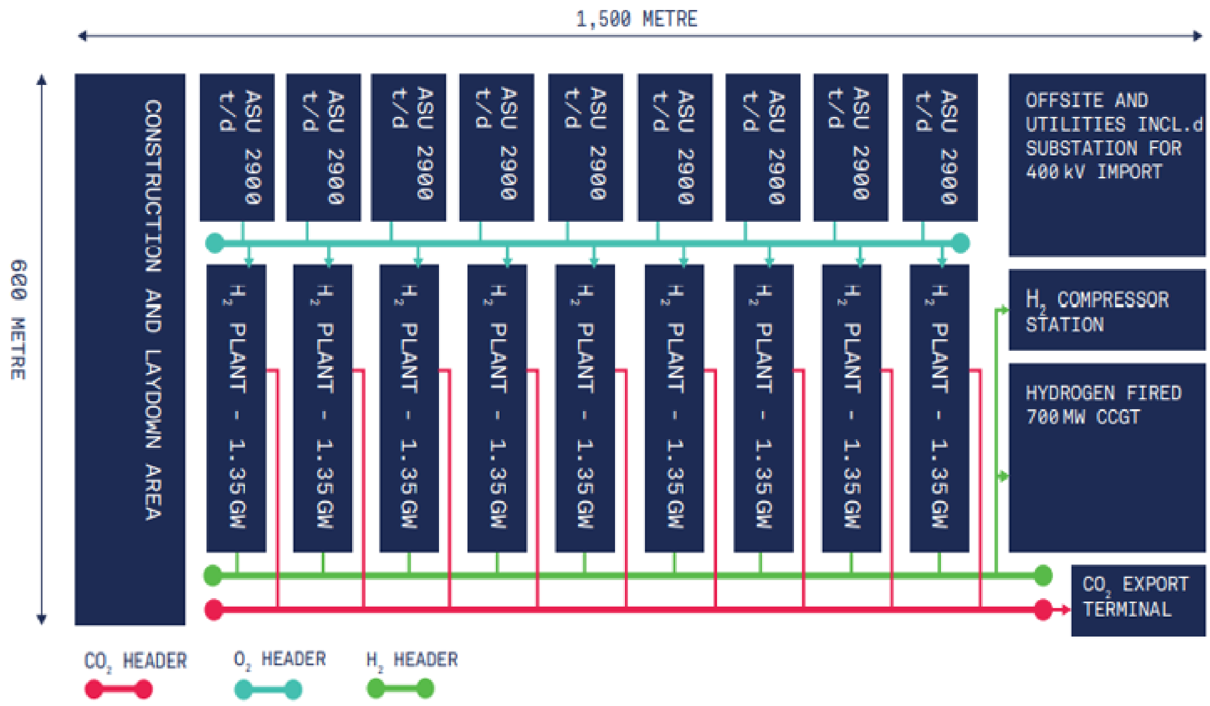
There are already some CCS applications in the world, mostly for power plants, petrochemical industry, as well as upcoming projects for the cement industry.



Source: Topsoe[35]

Today there is still no experience of ATR combined with CCS for blue hydrogen production on industrial scale

Reference plant: The H21 North of England project proposes a 12.15 GW hydrogen production facility based on nine auto thermal reactors (ATRs) to convert North-Sea natural gas to hydrogen. For this concept, an air separation unit (ASU) capable of 2,900 tons per day (tpd) of oxygen is required[36]. Design plant efficiency is 74.4 % HHV, CO_2 design capture rate is 94.2 %. An assessment of the technical and economic opportunities for hydrogen production utilizing Auto Thermal Reformation, ammonia storage and CCS deployment rates was done in 2019 for the first stage of this project[37]. Inter-seasonal hydrogen storage will be established using the deep salt strata in the Yorkshire area at Aldbrough. H21 NoE would represent the world's largest CCS scheme. It is a factor of 10 larger than existing configurations. Schematical representation of the plant is shown in the figure below.

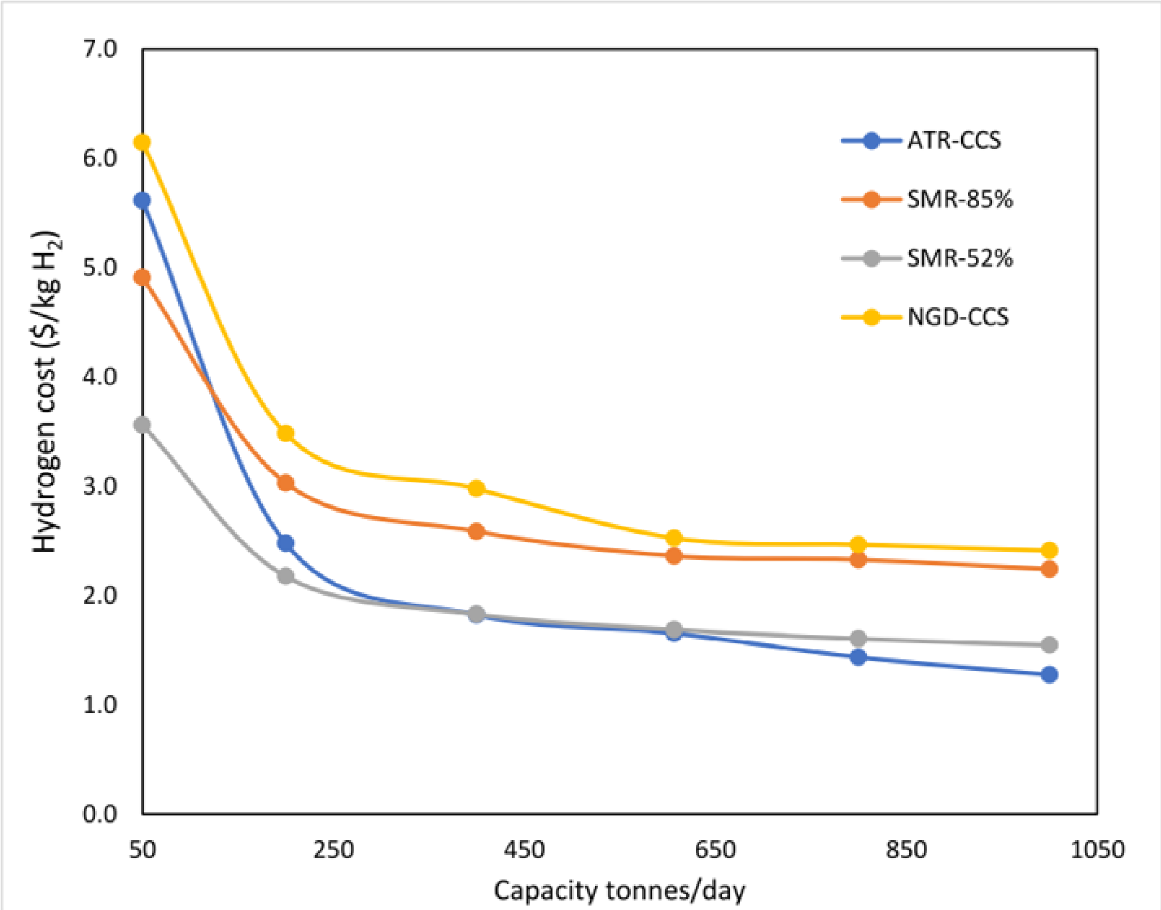


Schematic representation of the H21 NoE project[37]

Evaluation of CCS Technologies

A.O. Oni and other colleges from the University of Alberta performed in 2022 an economical study for the evaluation of hydrogen costs with different technologies including ATR with CCS, Natural Gas Decomposition with CCS (NGD-CCS) and conventional steam methane reforming with (SMR).

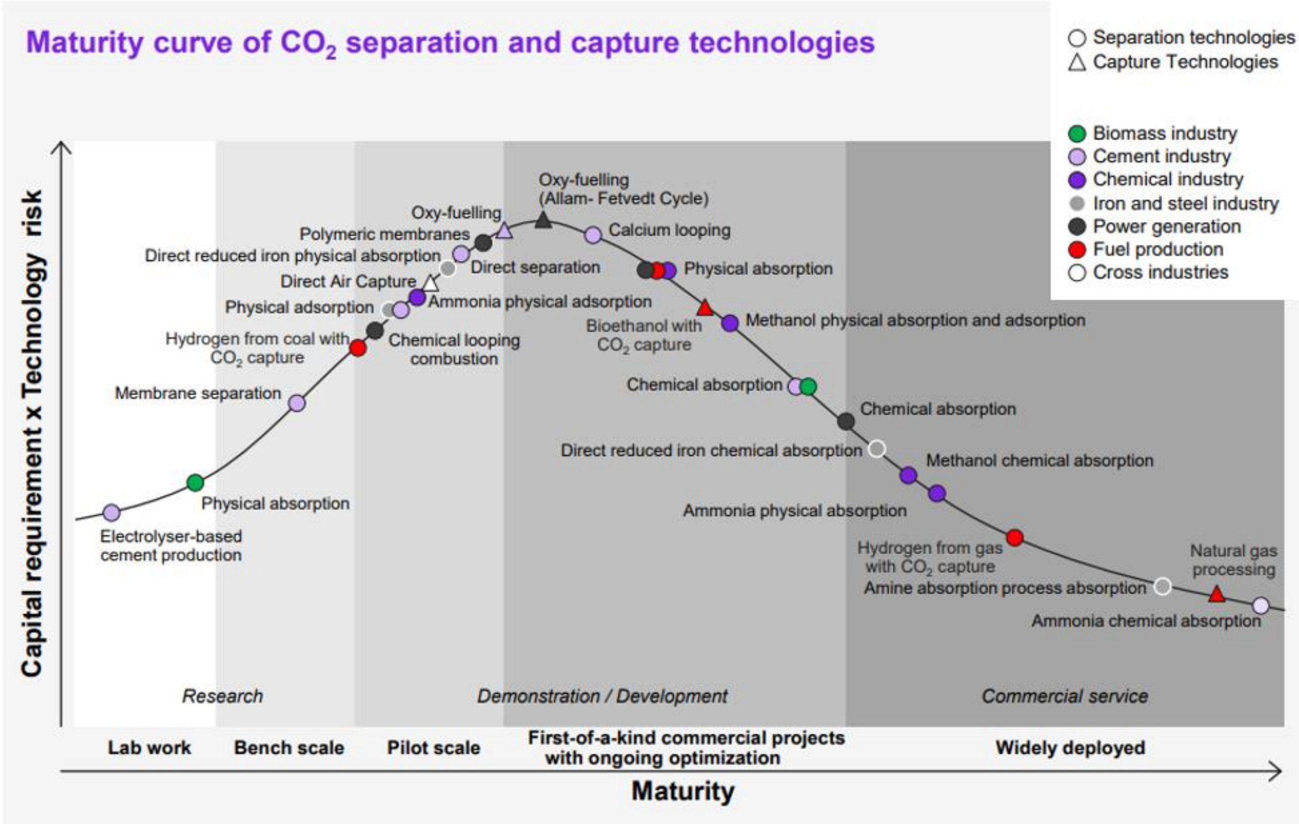
For SMR, capturing the CO2 emissions through the amine unit leads to a 52% capture rate. This case is referred in the graph below as SMR-52%. When the CO2 emissions from the reformer's flue gas are included, the overall capture rate increases to 85%. This case is referred in the graph below as SMR-85% The results of Oni's analysis is shown in the figure below, for different plant capacities.



Source: Energy Conversion and Management 254 (2022) 115245; Oni A.O., et al.

Most of CO_2 separation technologies are still in the demonstration phase.

Pre- and post-combustion are the two main capture technologies used in large scale CCUS facilities. Oxy combustion technologies are less mature, but being implemented in new projects already. The oil and gas industry uses pre-combustion technologies, especially for projects related to gas processing[38].



Maturity of CCS technologies. Source: Kearny Energy Transition Institute.

Coal Gasification

In this thermochemical method, coal is dried, ground and then fed into a gasifier, where it successively reacts with oxygen and steam under high temperature conditions to produce gas mixture containing H_2, CO and CO_2. The reaction equation is shown below.

$C + O_2 > CO_2$

$C + H_2O > CO + H_2$

This production process is intermittent.

Coal gasification method is already available for commercial production and provides 18% of the world's hydrogen production

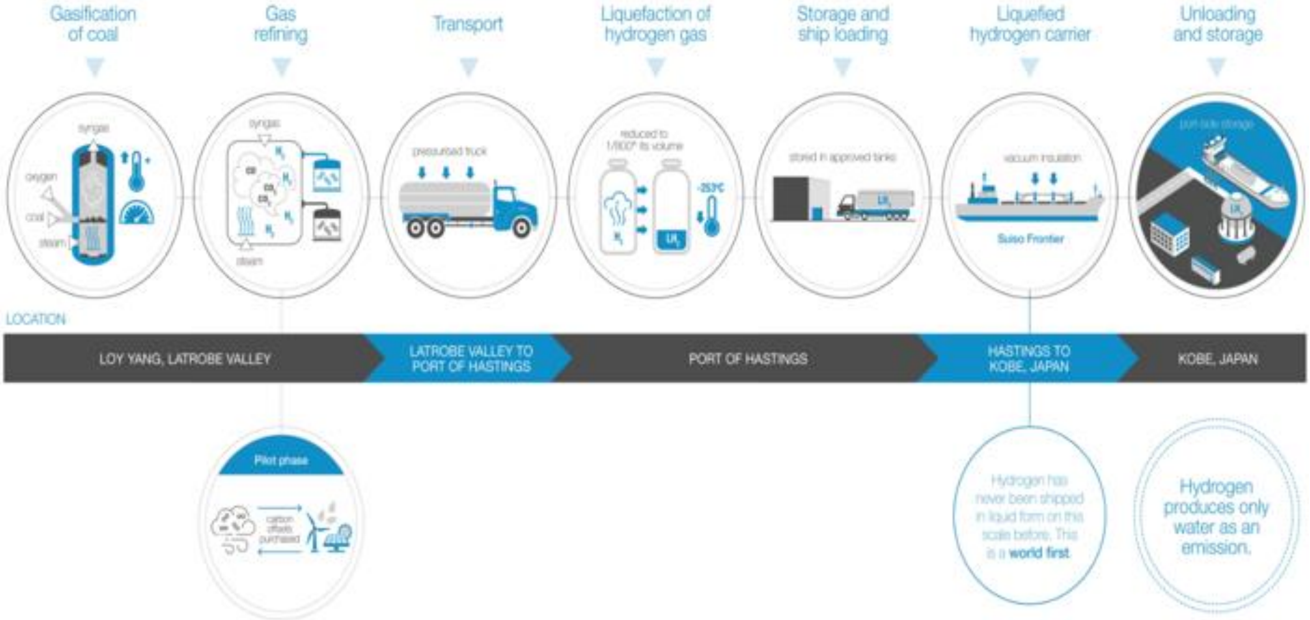
Since its lower efficiency (60-75%) than the SMR method, it is not as widely used as the latter. However, in countries and regions where coal reserves are relatively abundant or natural gas prices are not friendly, such as China, CG is also the mainstream hydrogen production process. With the shortage of natural gas reserves and rising natural gas prices, the economic advantages of CG in large-scale production are expected to make it a better choice in more regions in the foreseeable future"[25]. Coal gasification constitutes the largest lifecycle GWP footprint of all hydrogen production methods at ~25 kg CO_2-*eq* / kg H_2[29].

Globally, around 130 coal gasification plants are in operation with more than 80% of them in China

In terms of gasification with carbon capture, there are currently three facilities producing syngas from coal, coke, and petroleum coke at scale, with a combined capacity of around 0.6 MtH_2/y, namely Great Plains and Coffeyville in the USA and Sinopec Qila in China. These plants demonstrate that large-scale production of low emissions hydrogen using carbon capture can already be technically and commercially feasible. Hydrogen production from fossil fuels with CCUS are lower cost than green hydrogen based on water electrolysis, typically by a factor of around three. Coal gasification with CCUS costs typically 1.6-2.1 \$/kgH_2 with lowest cost being that in China[39].

Lifecycle GWP footprint of coal gasification with additional CCS is currently estimated at around ~ 10 kg CO_2-eq / kg H_2[29]. Therefore, further development of this technology is expected in the future

Reference plant: The Latrobe Valley gasification pilot plant in Australia is being developed by HESC, based on coal gasification technology with CCS. The project is being developed in two phases, beginning with a pilot, which aims to demonstrate that hydrogen can be produced using Latrobe Valley coal and transported to Japan. Key elements of the pilot supply chain are shown below[41].



Hydrogen is produced from coal at a newly constructed plant located at AGL's Loy Yang Complex in the Latrobe Valley through a coal gasification and gas-refining Carbon offsets have been purchased to mitigate emissions from the pilot. In the commercial phase, carbon dioxide would be captured during this process and stored deep underground in a process known as carbon capture and storage (CCS).

Hydrogen gas is transported by truck to a liquefaction and loading terminal at the Port of Hastings, the first of its kind in Australia.

Hydrogen gas is liquefied and then loaded on to a specially designed marine carrier for shipment to Japan.

Construction of the pilot facilities began in 2019, following planning approvals. Pilot operations started in 2021 and are expected to run for approximately one year through to 2022. Commercial operation is targeted for the 2030s, depending on the successful completion of the pilot phase, regulatory approvals, social license to operate and hydrogen demand[40]. Potential for 225,000 tons of liquid hydrogen production per annum[41].

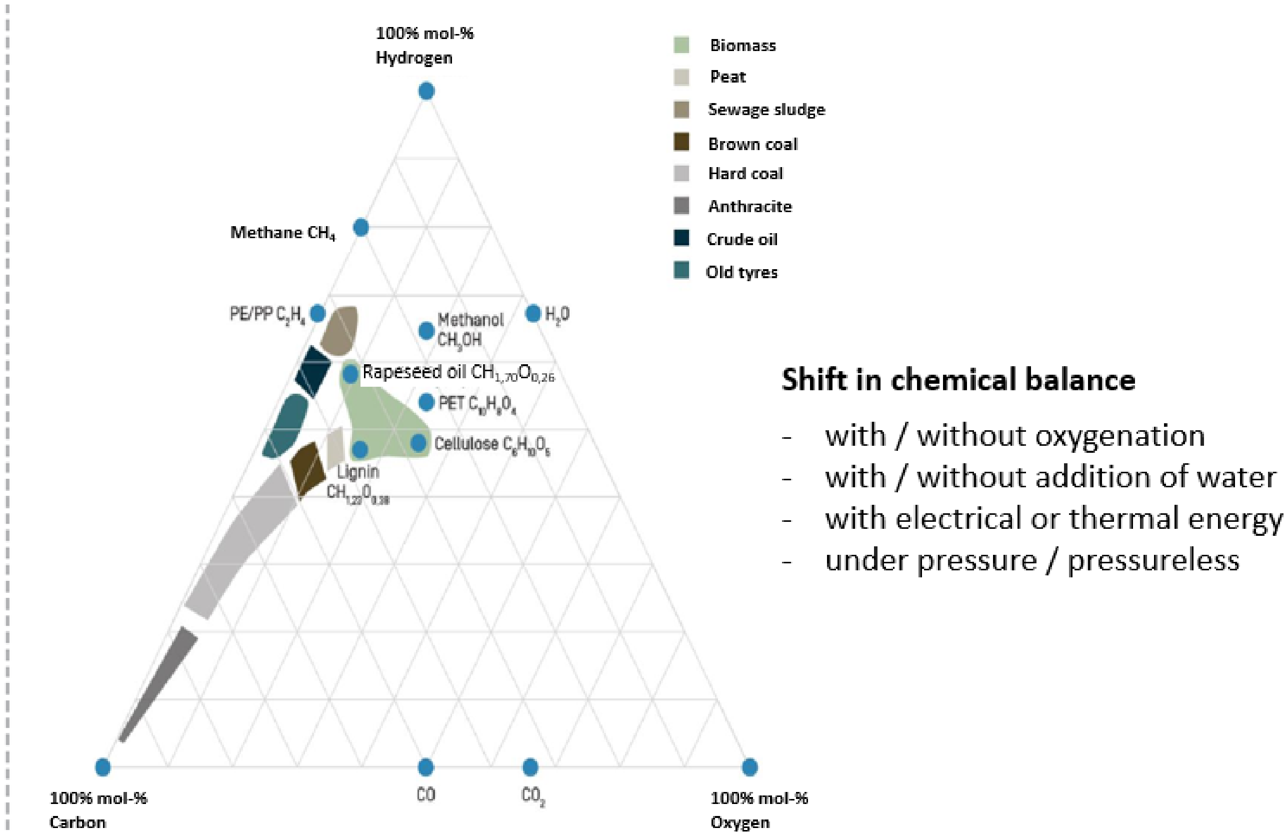
Biomass Gasification

Biomass gasification is a process used worldwide for syngas generation, here the chemical feedstock can be from sustainable biomass sources, such as wood, straw, sugarcane, rice husk etc. Similar to coal gasification, high temperature steam and oxygen are used to produce H_2. However, the reactions occurring in the gasifier are much more complex due to the chemical variety of the feedstock.

In order to obtain hydrogen, gasification must be coupled with water-gas shift reaction. In the first reaction, pyrolysis, the dissociated and volatile components of the fuel are vaporized at temperatures as low as 600°C. In the second step, the char is gasified through reactions with oxygen, steam, and hydrogen.

Various chemicals can be characterized by their carbon content (lower left 100%), the hydrogen content (top, 100%) and the oxygen content (lower right) of (diagram above). The chemical balance can be shifted with various processes e.g. to produce Hydrogen. Be aware that the byproducts CO and CO_2 are products to be avoided and if Carbon stems from a non-fossil source the process is a CO_2 sink. The lifecycle GWP footprint from biomass gasification is highly variable depended on the feedstock type and how much CO_2 it sequesters when it is alive, its land use impacts, water consumption and use of fertilizer, however it is estimated to be considerably lower than previous thermochemical methods mentioned (~0.7 kg CO_2-*eq* / kg H_2[29]).

Below graph shows different technological approaches and just some potential feedstocks.



Hydrogen production from organic waste[42]

Future developments: Because of the source of chemical feedstock, biomass gasification has the potential to be "carbon negative" if coupled with CCS technologies (-13 kg CO_2-*eq* / kg H_2 [29], however, this is yet to be demonstrated and relies on effective energy balancing. It is expected over the coming decade, that biomass gasification will achieve zero carbon emissions.

Mixing different categories of biomass in certain ratios has been found to cause increase the yield of H_2 produced – for example a hydrogen rich gas stream was generated by mixing banana peel, rice husk and Japanese cedar, here the alkaline earth metals found in banana peel helped catalyze the reaction[43].

However, the technology still needs to be improved on a larger scale in order to increase efficiency and reduce investment and production costs[44]. Presently, the efficiency of H_2 production via biomass is at ~50% but may increase with developments in pretreatment and alternative mixing ratios.

Contributing to production costs include pretreatment steps required for the biomass, and increased wear and tear of equipment from by-product formation of tar and char which can cause clogging or failure of catalysts

Reference Plants: Some technology examples that have been tested in pilot scale are: Sylvagas (BCL/FERCO), Enerkem bubbling fluid reactor (BIOSYN process), supercritical-gasification in water (Antal), supercritical partial oxidation (General Atomics), high-pressure high-temperature slurry-fed (Texaco).

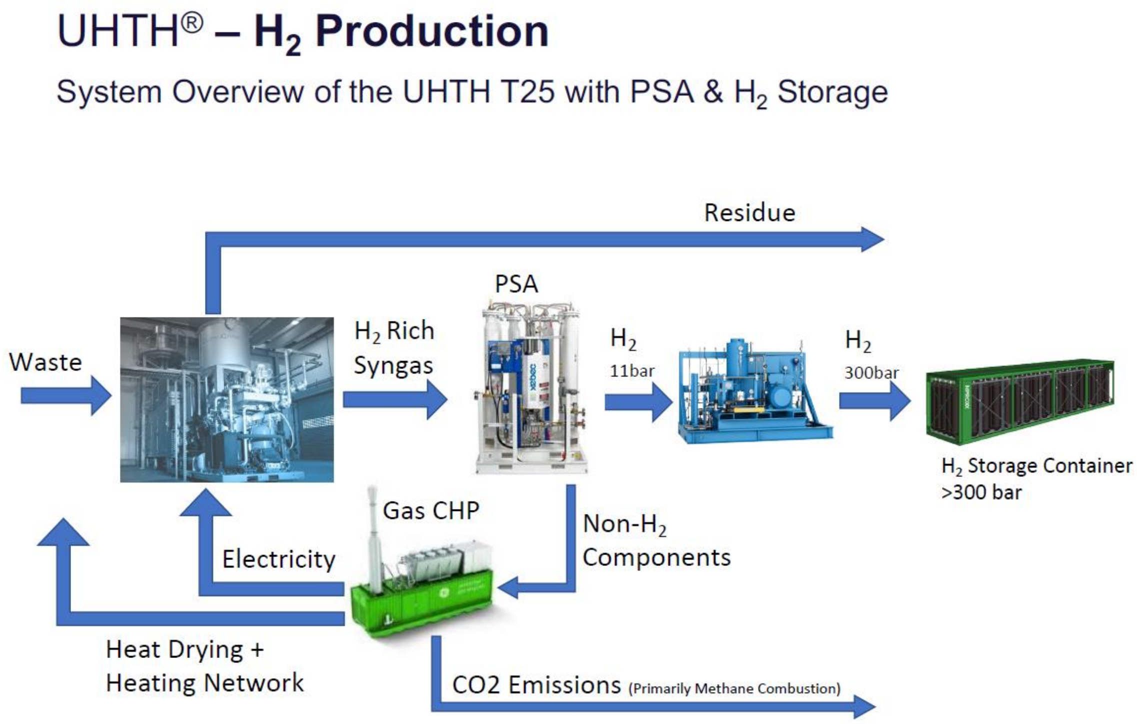
Choren was the first plant worldwide, where a semi-industrial hydrogen production plant was tested using the multi-stage Carbo-V gasification process.

Construction work of beta plant was completed by mid-2009. In January 2010, hot commissioning of the gasification island started. First commercial production was scheduled by 3rd quarter 2010.

In July 2011 the company announced bankruptcy due to financial problems for the commissioning of the Syngas plant. Reportedly, several technical issues as well as a too low yield were some of the reasons for the bankruptcy.

In July 2012 the Carbo-V technology was sold to Linde Engineering Dresden GmbH. This technology planned to be used in the Ajos project. One of the main investors, the Finnish company Vapo Oy, stepped out of the project. The Chinese company Sunshine Kaidi New Energy Group undertook the project. Commissioning was planned for Q4 2019. The project was frozen in 2014.

Below process description of a planned UHTH Plant by Clean Carbon Conversion AG in Germany.



Source: Clean Carbon Conversion AG

Biomass derived liquid reforming

Biomass resources can also be converted to cellulosic ethanol, bio-oils, or other liquid biofuels. The process for reforming biomass-derived liquids to hydrogen is very similar to natural gas reforming and includes the following steps[45]:

1. The liquid fuel is reacted with steam at high temperatures in the presence of a catalyst to produce a reformate gas composed mostly of hydrogen, carbon monoxide, and some carbon dioxide.
2. Additional hydrogen and carbon dioxide are produced by reacting the carbon monoxide (created in the first step) with high-temperature steam in the "water-gas shift reaction".
3. Finally, the hydrogen is separated out and purified (EERE)

Biomass derived liquid reforming has been tested so far only at pilot scale

Methane pyrolysis (Turquoise hydrogen)

Methane pyrolysis (also known as methane splitting, cracking or decomposition) is the process of converting methane into gaseous hydrogen and solid carbon (e.g. carbon black, graphite), without creating any direct CO_2 emissions[46]. This allows for potential CO_2-neutral use of fossil natural gas, as the solid carbon can be safely stored or be used as a valuable material for various industry branches and the energy source could come from renewable sources.

In the absence of a catalyst, the reaction proceeds by heating methane at temperatures above 1000-1200°C. Lower temperatures of ~ 700-800 °C can be achieved by using a metal catalyst or 800 – 1000 °C with a carbon catalyst. Reaching these high temperatures are generally achieved through conventional electrical heaters or can be plasma driven[31].

Per unit of hydrogen produced, methane pyrolysis uses three to five times less electricity than electrolysis; however, it requires more natural gas than steam methane reforming. The overall energy conversion efficiency of methane and electricity combined into hydrogen is 40-45%.

Notably, the process could create additional revenue streams from the sale of carbon black for use in rubber, tyres, printers, and plastics, though the market potential is likely limited, with global demand for carbon in 2020 being 16 Mt of carbon black, which corresponds to hydrogen production from pyrolysis of 5 Mt H_2. Carbon from pyrolysis could be used in other applications such as construction materials or to replace coke in steelmaking.[47]

Despite the reaction mechanism preventing the formation of direct CO_2 emissions, lifecycle emissions are made from the required electricity and those generated during the extraction and transportation of natural gas. Methane pyrolysis's lifecycle GWP is estimated at ~ 6 kg CO_2-*eq* / kg H_2[31,29], the lowest for unabated fossil fuel thermochemical production processes.

Researchers of Karlsruhe Institute of Technology (KIT) have developed a highly efficient methane pyrolysis process. Together with the industry partner Wintershall Dea, this process will now be further developed for use on the industrial scale[48]. Several methane pyrolysis technology designs under development show TRLs of 3 to 6. Monolith Materials (in the United States) uses thermal plasma to create the high temperatures required. After operating a pilot plant for four years, the company launched an industrial plant in 2020 (in Nebraska) and is planning a commercial-scale plant for ammonia production. To convert biogas into hydrogen and graphite, Hazer Group (Australia) is building a demonstration plant for its catalytic-assisted fluidized bed reactor technology[49], and BASF (Germany) is developing an electrically heated moving-bed reactor process. Together with RWE, in 2021 the company announced a project to use electricity from offshore wind to produce hydrogen from electrolysis and for a methane pyrolysis plant[50]. Gazprom (Russia) is developing a plasma-based process for methane pyrolysis[51]. The start-up C-Zero (United States) is working on an electrically heated molten-metal reactor for methane pyrolysis[52].

Reference plant: The Olive Creek project is a facility in Nebraska USA, developed by the company Monolith. The first phase has been commissioned 2020. The commercial scale facility produces about 5 ktpa Hydrogen an sequestrates about 15 ktpa of carbon per year. The next phase started 2022 with an expansion by a factor of 10 to 15 and shall be completed 2025.[53]

Olive Creek I Facility in Nebraska (USA). Source: www.energy.gov

Olive Creek is today the world´s largest CO_2 free hydrogen production plant and the first commercial scale methane pyrolysis facility

1.2 Electrochemical methods

The dominating electrochemical hydrogen production method is the electrolysis, using electric current for the splitting of water into hydrogen and oxygen.

When assuming an ideal conversion, 39 kWh of electricity and 9 kg of water are required to produce 1 kg of hydrogen by electrolysis. Assuming this electricity comes directly from the grid from fossil fuel-based sources, its GWP is estimated at ~29 kg CO_2-eq / kg H_2[25]

Electrolysis is a surprisingly old technology, with the first units in operation already more than 100 years ago

The largest electrolysis plant ever was the Rjukan plant in Norway, having a power consumption of 167 MW and producing 37,000 Nm^3/h. This plant was in operation from 1929-1988.[54]. This is calculated to be drastically reduced if the electricity is supplied via renewable energy sources such as solar or wind estimating ~ 1-2 kg CO_2-*eq* / kg H_2. The technology used in Rjukan, the alkaline electrolysis, still exists and is the prevailing electrolysis technology up to now. Further technologies have been added; four basic electrolysis technologies are commercially available today for hydrogen production, with decreasing maturity:

- Alkaline
- Proton Exchange Membrane (PEM)
- Anion Exchange Membrane (AEM)
- Solid oxide

	Alkaline	PEM	AEM	Solid Oxide
Operating temperature	70-90 °C	50-80 °C	40-60 °C	700-850 °C
Operating pressure	1-30 bar	< 70 bar	< 35 bar	1 bar
Electrolyte	Potassium hydroxide (KOH) 5-7 $molL^{-1}$	PFSA membranes	DVB polymer support with KOH or NaHCO3 $1molL^{-1}$	Yttria-stabilized Zirconia (YSZ)
Separator	ZrO_2 stabilized with PPS mesh	Solid electrolyte (above)	Solid electrolyte (above)	Solid electrolyte (above)
Electrode / catalyst (oxygen side)	Nickel coated perforated stainless steel	Iridium oxide	High surface area Nickel or NiFeCo alloys	Perovskite-type (*e.g.* LSCF, LSM)
Electrode / catalyst (hydrogen side)	Nickel coated perforated stainless steel	Platinum nanoparticles on carbon black	High surface area nickel	Ni/YSZ
Porous transport layer anode	Nickel mesh (not always present)	Platinum coated sintered porous titanium	Nickel foam	Coarse Nickel-mesh or foam
Porous transport layer cathode	Nickel mesh	Sintered porous titanium or carbon cloth	Nickel foam or carbon Cloth	None
Bipolar plate anode	Nickel-coated stainless steel	Platinum-coated titanium	Nickel-coated stainless steel	None
Bipolar plate cathode	Nickel-coated stainless steel	Gold-coated titanium	Nickel-coated Stainless steel	Cobalt-coated stainless steel
Frames and sealing	PSU, PTFE, EPDM	PTFE, PSU, ETFE	PTFE, Silicon	Ceramic glass

Note: Coloured cells represent conditions or components with significant variation among different companies.
PFSA = Perfluoroacidsulfonic; PTFE = Polytetrafluoroethylene; ETFE = Ethylene Tetrafluorethylene; PSF = poly (bisphenol-A sulfone); PSU = Polysulfone; YSZ = yttriastabilized zirconia; DVB = divinylbenzene; PPS = Polyphenylene sulphide; LSCF = $La_{0.58}Sr_{0.4}Co_{0.2}Fe_{0.8}O_3$-δ; LSM = $(La_{1-x}Sr_x)_{1-y}MnO_3$; § = Crofer22APU with co-containing protective coating.

Based on IRENA analysis.

Source: IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal

Further electrolyser technologies are under development, e.g. the membrane less electrolyser, microbial electrolysis or electrolyser operating with salt water.

Alkaline and PEM electrolysers are the most advanced and already commercial technologies for green hydrogen production. Alkaline electrolysers have the lowest installed cost, while PEM electrolysers have a much smaller footprint, combined with higher current density and output pressure. Meanwhile, solid oxide has the highest electrical efficiency (IRENA 2020), but require high operating temperatures. Gaps in cost and performance are expected to narrow over time as innovation and mass deployment of different electrolysis technologies drive convergence towards similar costs. A KPI analysis done by IRENA in 2020 for the four conventional electrolysers is shown below[55].

Over the past two decades, more than 200 projects have started operation to convert electricity and water into hydrogen via electrolysis, but most have been pilots or demonstration projects under 10 MW. Much larger and more ambitious projects are in planning, including those powered by renewable electricity.

In the following sections we cover the basics of electrolysis, information on how each technology works and design complexities, safety implications and considerations for specific offshore applications.

Electrolysis basics

Electrolysis is an endothermic chemical reaction driven by electrical energy that breaks down a chemical compound, in this case, water, into hydrogen and oxygen. The reaction type is known as Redox reaction with the important feature that the oxidation reaction part (creating the hydrogen) and the reduction reaction part (creating the oxygen) are physically separated.

The smallest physical unit for this reaction is called "cell", several cells can be connected in a series connection. Such connected cells are known as "stacks" or "modules"

The basic electrolysis cell consists of four main parts:

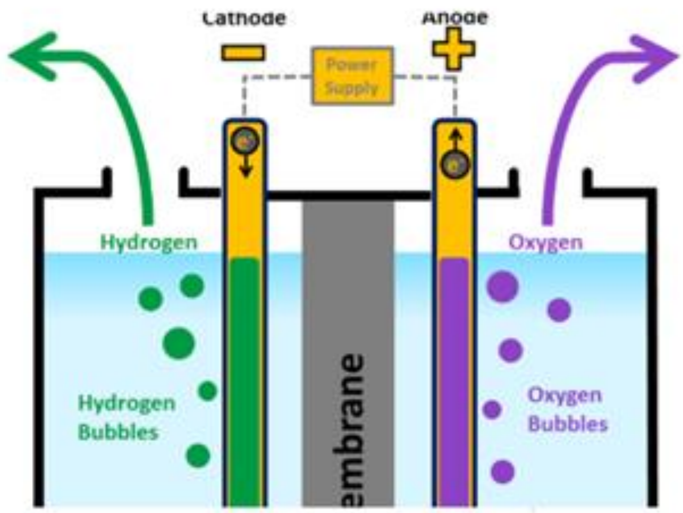
• A direct current power source

• A positive electrode, the anode where hydrogen is created

• A negative electrode, the cathode, where oxygen is created

• An electrolyte containing water allowing the flow electrically charged ions between the electrodes

• A diaphragm or membrane separating the two electrodes



Source: https://www.power-eng.com/emissions/siemens-energy-moving-forward-with-china-electrolysis-hydrogen-project/#gref

The details of the chemical reaction taking place at the electrodes and the type of ions depend on the electrolyte used, see further details below.

Real electrolyser cells and stacks are more complex. To reduce the chemical activation energy for the reactions taking place or even allowing them, catalytic materials are used at the electrodes. As the electrolysis does take place with liquid water only, the gas bubbles must be removed from the electrodes. This is done by gas diffusion layers. Bipolar blades connect various cells electrically. Furthermore, water supply systems, monitoring systems, gas collectors and gas treatment installations are required.

One of the major risks for electrolyser in general, besides leakages is the diffusion of product gases.

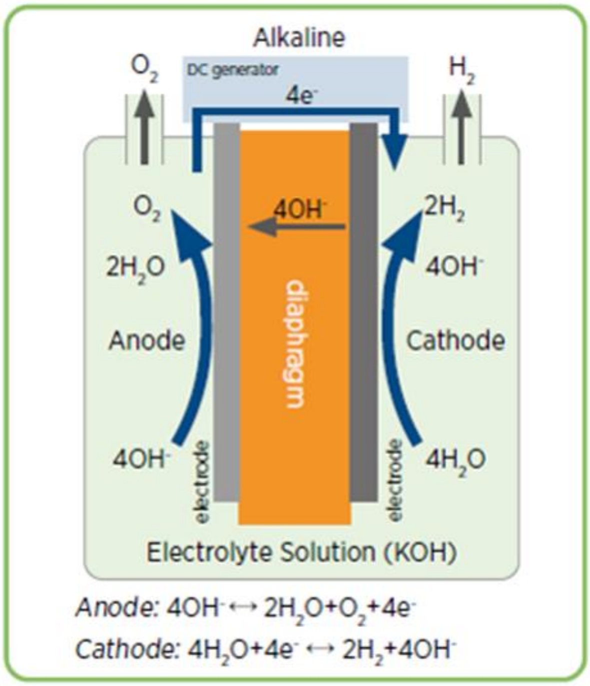
Alkaline electrolysis

Alkaline Electrolysis: from the above listed technologies AE is the clear market leader, accounting for most of the installed capacity worldwide. This technology is well established up to the megawatt range for commercial applications. Investment costs are very high when compared to conventional hydrogen production. Currently, novel membranes and AEM processes are being developed in order to reduce the costs. For example, Evonik introduced in September 2020 a new AEM process using a resistant polymer membrane with very high conductivity. The project will run for three years and receive funding of around €2 million from the European Union's Horizon 2020 research program[56].

Module sizes from 1 MW to 4 MW are considered proven technology,

larger modules will be developed in the future. Thyssen Krupp and Uhde Chlorine propose a 20 MW module. The module can be put in containers 40" to 46" with a weight of 36 t to 40t. Several modules will be stacked and operated in parallel.

Actual costs from existing projects are 1 MEUR per MW with a cost split of 15% for power electronics and power distribution, 45% hydrogen production and electrolyte cycle, 25% for hydrogen purification and compression and 15% infrastructure and control systems.



Source: IRENA Study: Scaling up electrolysers to meet the 1,5°C Climate Goal

"In the alkaline electrolysis a conductive fluid is utilized, normally a caustic potash/water solution. The OH- are then transported through the diaphragm. This diaphragm is fully permeable for the solution. When there is a load change required e.g. due to renewable electricity as energy source, oxygen and hydrogen start fluctuating on both sides since the diaphragm is rather like a mesh, this increases the risk of process runoff. The explosion protection limit is 4% hydrogen in oxygen, this means that alkaline electrolysers should be operated with a safety margin below this limit.

There are some national norms stating 2% as operational limit e.g. in Austria. In conclusion, for transient operation alkaline systems are far more critical regarding runoff than PEM systems, Alkaline systems can handle load changes in the range of percentage per minute"[57].

Another aspect is the idle operation, when the system is shutdown, the electrodes are in a very aggressive environment, which require protection of the electrodes which is realized by applying a current to the electrodes. This translates into a higher electricity consumption at idle than PEM systems.

The rather low current density of alkaline systems leads to more voluminous systems. If a higher current density is desired, more expensive materials for the electrodes (e.g. platinum) is required.

Most of the alkaline systems are operated pressure less yet, but scaling up and increasing efficiency may require pressurized systems in the future. Especially regarding transient operation, alkaline systems are far more critical regarding runoff than PEM systems

Reference plant: Chinese chemical manufacturer Ningxia Baofend Energy Group has commissioned the world's largest green hydrogen project in central China 2021 at the cost of ca. 200 MEUR. The 150 MW alkaline electrolyser is powered by a 200 MW solar array. Sinopec has begun construction of a 260 MW alkali electrolyser facility in Xinjang, northwest China also powered by solar energy (300MW). Air Liquide held the past record with 20 MW Becancour project.[58] The projected size for projects within ten years is 1 GW.

Source: https://fuelcellsworks.com/news/the-worlds-largest-green-hydrogen-project-with-a-150mw-electrolyser-comes-online-in-china-el-periodico-de-la-energia/

Alkaline electrolyser technology is under operation in the industry for many decades.

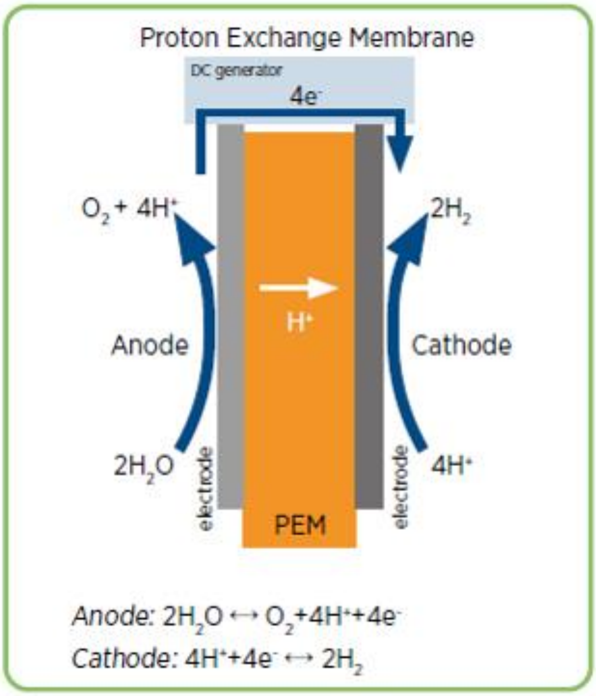
The risks are in the stability of the diaphragm (durability, subject to operational parameters, operating out of design parameters) and are rather general risks for plant design and scaling up, not related to the technology.

Up-scaling issues are related to control systems, larger components, compressors, new materials, and changes in manufacturing process.

Proton exchange membrane electrolysis (PEM)

PEM electrolysis has been commercially available since the beginning of the 21st century. PEM water electrolysis technology is similar to the PEM fuel cell technology, where solid polysulfonated membranes (Nafion®, fumapem®) was used as electrolyte[59].

The electrolysis process is an endothermic process and electricity is applied as the energy source. The water electrolysis reaction is thermodynamically possible at potentials higher than 1.23 V vs. RHE (reversible hydrogen electrode). The thermoneutral potential at which the cell can operate adiabatically is 1.48 V vs. RHE. Typical PEM water electrolysis devices operate at potential well over 1.48 V vs. RHE and heat is generated by the reaction[60]. Anode and cathode are separated by a solid polymer electrolyte (Nafion) of thickness below 0.2 mm. At the anode, water is oxidized to produce oxygen, electrons, and protons. The protons are transported across the electrolyte membrane to be reduced to hydrogen. The catalyst for water oxidation or oxygen evolution is typically iridium, which can withstand the corrosive environment due to high overpotential on the anode. Water is channeled to the anode by a titanium flow field, and a piece of porous titanium mesh is placed between the anode catalyst layer and the water channel serving as the diffusion layer. The cathode configuration is realized with Pt-based catalyst and a graphite flow field to transport hydrogen. A piece of carbon paper is used as the gas diffusion layer (GDL) placed between the cathode catalyst and the flow field[61].



Source: IRENA Study: Scaling up electrolysers to meet the 1,5°C Climate Goal

This technology offers high current density (above 2 A·cm^{-2}), compactness, small footprint, high efficiency, very thin membrane (i.e., 25–300 μm), high-pressure operation, fast response, and dynamic operation, making it suitable when coupling with renewable energy sources. However, the main drawback is its cost being relatively high since expensive catalyst materials (e.g., iridium, platinum) are used both at the anode and the cathode; at the moment, it hinders its development at large scale and market penetration. For this reason, one of the most important challenges is to decrease its production cost while maintaining high efficiency[61]. "In this process (compared to alkaline electrolysis) we have a less permeable membrane, which allows only the hydrogen protons to pass through. The main advantage of PEM compared to alkaline electrolysis is the very low permeability between the gases on both sides of the reaction, this means a much higher intrinsic operational safety.

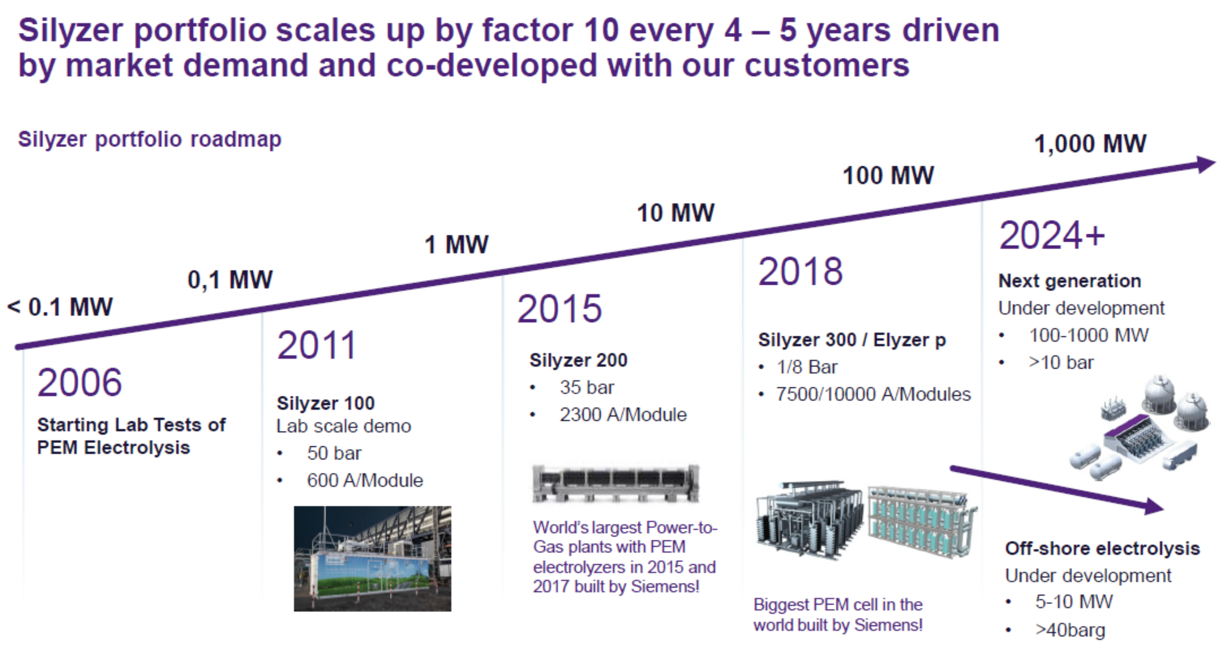
Compared to alkaline electrolysers, PEM offer a much higher intrinsic operational safety and can handle better transient and part load operation

Fresh water enters the electrolyser cell (which can be designed vertical or horizontal) and the hydrogens separates along the membrane, thus the gas concentration increases along the membrane. The product gases are then transported away from the membrane, in the so-called gas diffusion layer (GDL, materials used are titanium on the oxygen side and high-grade steel on the hydrogen side). With higher mass flows, the fractions of hydrogen in water reduces along the membrane. This is an intrinsic safety features of many systems in case of leakages. A safety advantage of vertical arrangements is provided by a reduced catalytic area in case of emergency shutdowns.

"PEM systems can handle load changes and transient operations in a much safer way than alkaline electrolysers (10%/sec load change)"[57].

One disadvantage of PEM systems is the fact that they are an electrochemical unit, which means it is subject to aging when at idle operation (similar to batteries), aging process with PEM technologies is less predictable than with alkaline systems. This is why most industrial system have adopted the EOH (equivalent operating hours) approach to manage electrolysers aging and lifetime of components depending on operating regime, this to be understood as a risk mitigation measure. Many PEM systems operate with pressure, which reduces costs due to the reduced compression costs. The problem hereby is that the diffusion of hydrogen in oxygen increments with higher pressure. These systems require special measures to reduce diffusion and/or to abreact hydrogen in the oxygen stream. Most of the electrolysers OEMs procure the coated membranes, some others coat themselves with proprietary systems, and are able to recycle (up to 90%) the used membranes at the end of the determine EOH cycle. Coating is mostly based on platin (hydrogen side, used as recombinator) and iridium (oxygen side).

Empirical tests are performed to reduce the required quantities of precious materials while maintaining acceptable lifetime, this fact may represent a risk for operational safety and reliability of future systems



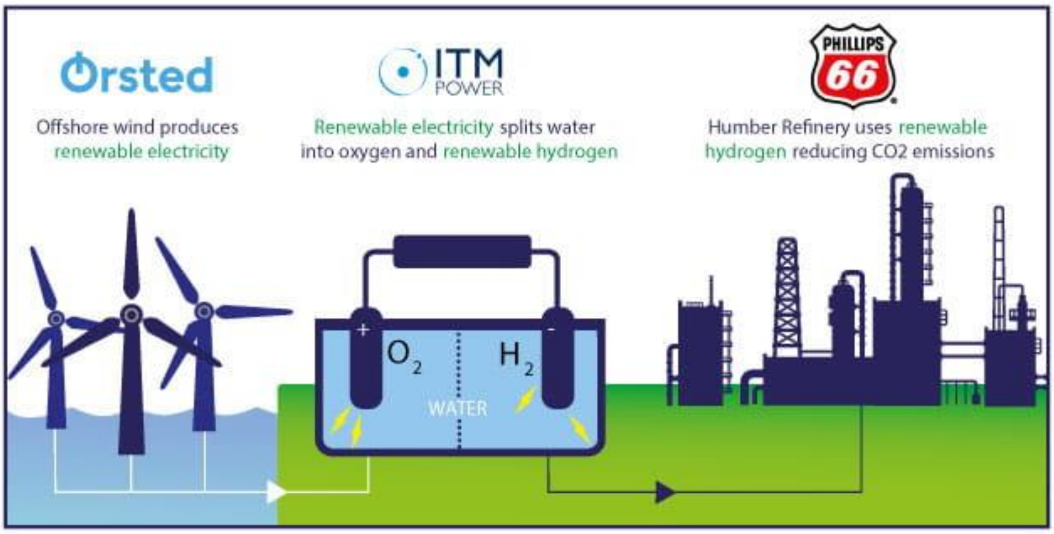
Planned scale up of electrolysers. Source: Siemens

"The thickness of the membrane is on the focus of further developments since this determines the ohmic resistance and thus the overall efficiency of the system. This optimization increases the risks of hot spots, which may cause a faster degradation of the membranes. With higher temperature and/or due to hot spots, fluor is faster degraded from the membrane. Fluor free membranes are thus a further focus of design optimization.

The quality of the surface of the GDL is decisive in regards of hot spots formation. With increasingly reduced membrane thickness, the risk of perforation increases. Well designed and thoughtfully tested compensation layers are recommended to reduce this risk

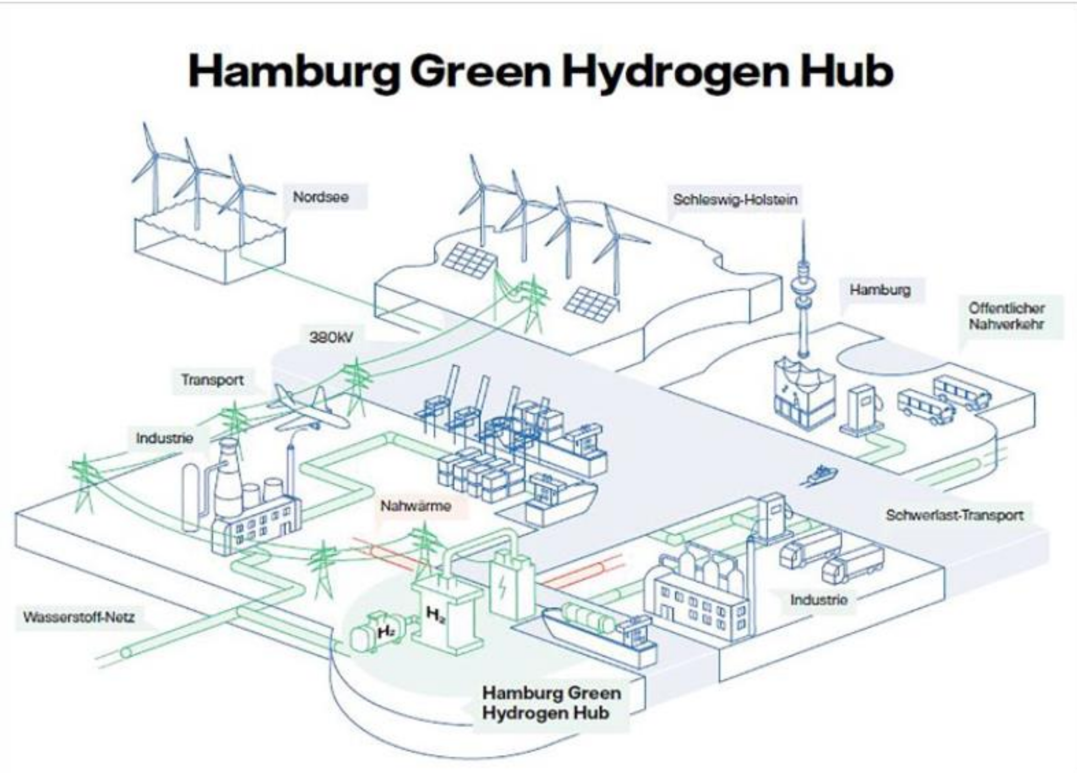
Cooling of the membrane (via increased mass flow of water) is a further factor for intrinsic operational safety, ideally both sides of the membrane should be cooled. Hot spots formation can be reduced by reducing the setpoint of systems temperature (most membranes start melting at 90°C)"[57].

Reference projects: Orsted Gigastack, the windfarm (1 GW nominal power) will produce renewable energy, feeding a 100MW electrolyser, the hydrogen will be led directly to the Humber refinery (Phillips 66 Ltd), reducing CO_2-emissions from the production. After the first phase of the project (feasibility study in 2019), Phase 2 started to demonstrate low-cost, zero-carbon hydrogen to industrial scale, the electrolyser stacks are further developed, a semi-automated manufacturing equipment will be installed. In Phase 3 a large-scale electrolyser will be installed in the Humber region.



Source: https://orsted.co.uk/media/newsroom/news/2020/02/gigastack-phase-2

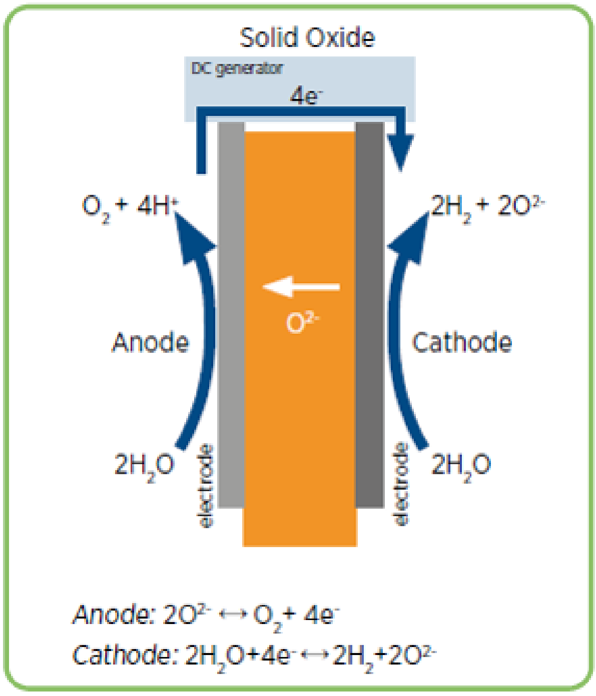
A further reference project is the Hamburg-Moorburg in Germany. A consortium of Shell, Mitsubishi, Vattenfall and Hamburg Wärme plans to use the grid connection from a decommissioned power plant in Hamburg-Moorburg (Germany) to produce green hydrogen from photovoltaic and wind farms and distribute hydrogen around the Hamburg harbor and an industrial site called "Green Energy Hub". A 100 MW electrolyser, which should be scaled up in the future is the basic component, planned to be operational in 2025.



Source: https://group.vattenfall.com/de/newsroom/pressemitteilungen/2021/wasserstoffprojekt-am-standort-hamburg-moorburg

Solid oxide electrolysis (SOE)

Solid oxide electrolysis has attracted an abundant deal of attention due to the electrical energy converts into the chemical energy along with producing the ultra-pure hydrogen with greater efficiency, by operating at high pressure and high temperatures 500–850 °C[59].



Source: IRENA Study: Scaling up electrolysers to meet the 1,5°C Climate Goal

SOE cell electrodes and electrolyte are exposed to permanent high temperatures at high flows of electrical charges (currents) in an electrical field coupled with high gas flows and local moisture saturation. Ceramic materials and special steels appear to be the only substances capable of withstanding this demanding environment. Fuel electrode is typically made of porous Ni doped YSZ (yttria stabilized zirconia). The air electrode is a porous layer typically made of LSM (lanthanum strontium manganite). The most common electrolyte is a dense ionic conductor consisting of YSZ.

SOEs required temperatures around 500-600°C. This results in longer start-up times, mechanical compatibility issues such as thermal expansion mismatch, and chemical stability issues such as diffusion between layers of material in the cell.

Even ceramic materials are not inert under these conditions and show[62]:

• Changes in morphology with consequences for gas transport, electrical conductivity, mechanical strength, and active surface area.

• Changes in phase composition with consequences for electrical conductivity and mechanical strength.

• Interdiffusion of substances with consequences for corrosion resistance, and electrochemical activity.

• Transport of species resulting in de-mixing and de-activation.

SOEs have been observed to degrade primarily due to air electrode (anode) delamination from the electrolyte

The delamination is a result of high oxygen partial pressure build up at the electrolyte-anode interface. Pores in the electrolyte-anode material act to confine high oxygen partial pressures inducing stress concentration in the surrounding material. The maximum stress induced can be expressed in terms of the internal oxygen pressure[63].

SOE technology shares many aspects of design, materials, and system integration with Solid oxide fuel cell (SOFC) technology[64].

Compared with alkaline and PEM electrolysis, this system has the advantage that it can work on both directions (as Electrolyser and as Fuel Cell)

"In theory PEM systems can also be adapted to operate as fuel cell, but it requires some component adaptations to ensure a homogeneous flow of hydrogen through the membrane"[57].

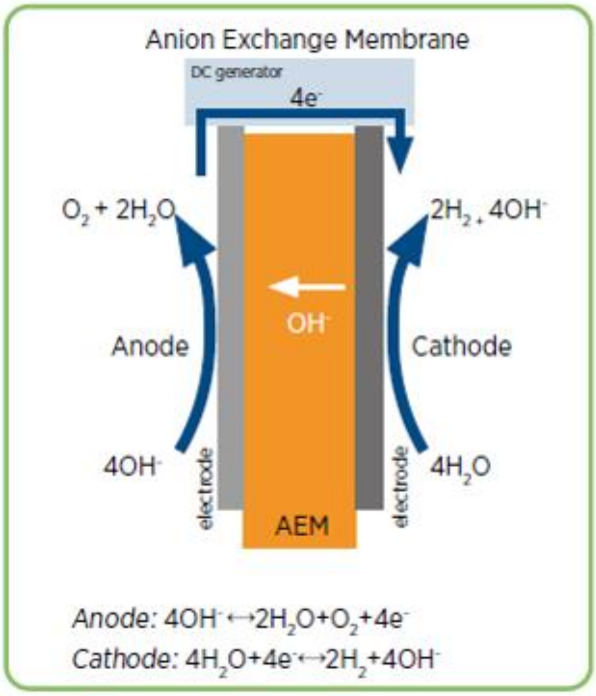
Reference project: To date SOE have only been deployed in pilot projects. For example, the GrInHy (Green Industrial Hydrogen Via Reversible High-Temperature Electrolysis) up-scaling project of the German manufacturer Sunfire, which was active between 2016 and 2019.

The main goal of this project was the operation for at least 7,000 h of a reversable generator based on high temperature electrolysis (HTE), meeting the hydrogen quality standards of the steel industry. After this pilot project, the GrInHy2.0 project was started, which is the first implementation of a high-temperature electrolyser with an electrical power input of 720 kilowatt in an industrial environment[65].

GrInHy test site. Source: https://www.green-industrial-hydrogen.com/project/grinhy-project

Anion exchange membrane electrolysis (AEM)

The single cell is separated into two half-cells by the anion exchange membrane. Each half-cell consists of an electrode, a gas diffusion layer (GDL), and a bipolar plate (BPP). The half-cell arrangement in an AEM electrolyser, allows the hydrogen and oxygen to be produced under pressure of 35 bar and 1 bar, respectively. The pressure difference between the half-cells can prevent the produced oxygen from crossing over to the high-pressure half-cell, thus ensuring that the hydrogen has very high purity (99.9 %).



Source: IRENA Study: Scaling up electrolysers to meet the 1,5°C Climate Goal

The water electrolyte, containing just 1% potassium hydroxide (KOH), only circulates in the anode half-cell and wets the membrane, while the cathode side remains dry. Therefore, the hydrogen produced from the cathode half-cell has a low moisture content, and it is important to note that no KOH can be found in the cathode half-cell. The water molecules travel through the membrane and are reduced at the cathode to produce hydrogen. The power supply from the external circuit is used to create an electrical potential difference at the interface of the electrolyte and electrode. The potential difference then drives the hydrogen evolution reaction (HER) by means of electron (e–) transfer: 4H2O + 4e– → 4OH– + $2H_2$. The produced hydrogen is then released through the GDL to the output pipeline. Appropriate HER catalysts at the cathode facilitate the process by lowering the energy barrier of the reaction.

In the mild alkaline environment of the AEM electrolyser, the remaining hydroxide ion (OH–) from the HER will return to the anode half-cell via the membrane. The exchanged OH– is an anion, which gives the AEM its name. In a proton exchange membrane (PEM) electrolyser, the proton (H+) is transported through the PEM in a highly acidic environment. Therefore, the PEM electrolyser requires platinum group metals (PGM) as catalysts and expensive titanium bipolar plates to survive the highly corrosive acidic environment, while non-PGM catalysts and steel bipolar plates are sufficient for effective hydrogen production in the AEM electrolyser. the diluted KOH solution in an AEM electrolyser is much safer to handle than the electrolyte with a pH of 14 in a TA (traditional alkaline) electrolyser.

After the OH– is transported back to the anode side of an AEM electrolyser, it is consumed by the oxygen evolution reaction (OER): 4OH– → $2H_2O$ + O_2 + 4e–. For every two units of hydrogen, one unit of oxygen is generated by transferring four units of electrons. Hence, the OH– concentration in the electrolyte can remain constant through constantly supplying water without adding more KOH. The OER is driven by the potential difference at the catalytic sites on the anode and the produced oxygen is removed from the anode half-cell via GDL along with the electrolyte circulation.

Using AEM water electrolysis, modular electrolysers can produce 500 NL of green hydrogen per hour, with a purity of 99.9 % (99.999 % after drying) at 35 bar pressure from 0.4 L of water and 2.4 kWh of renewable energy[66].

This technology combines the advantages of PEM and alkaline electrolysis and is at present in the development phase for commercial implementation

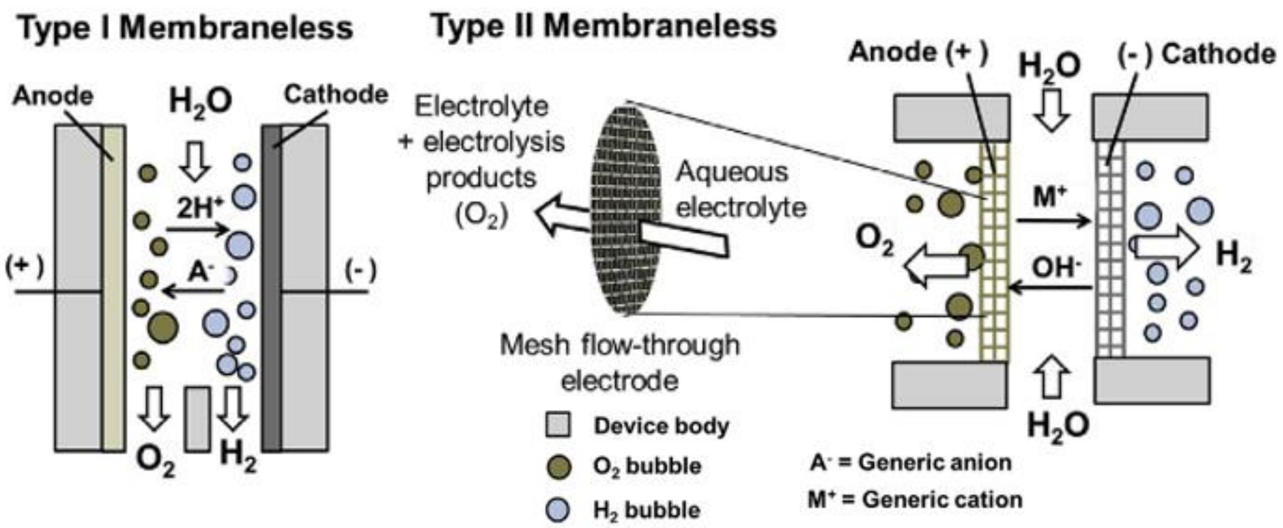
"The goal is to reduce the use of precious metals while achieving the operational efficiency and flexibility of PEM. As by now this technology has been tested in small scale pilot plants, we expect this technology to become commercial in 5-10 years[57]".

Membraneless/-free electrolysers

Although the economics of producing hydrogen from water electrolysis are currently dominated by the cost of electricity, electrolyser capital costs will become much more relevant with decreasing electricity cost for solar PV and wind.

In both alkaline and PEM electrolysers, the membrane and diaphragm permit the transport of ions between the electrodes while simultaneously performing the important task of physically separating the H_2 and O_2 products that could otherwise form an explosive mixture.

Despite its vital roles in PEM electrolyser operation, the membrane brings with it disadvantages, including the need for a complex MEA architecture and the risk of device failure due to membrane fouling or degradation in the presence of impurities. Besides directly affecting device lifetime and/or maintenance costs, the issue of membrane durability also affects the capital costs of electrolyser systems by placing stringent requirements on water purity and materials used within the system. Also, the high ohmic resistance associated with these dividers and the bubble-filled liquid gaps between electrodes typically limits operating current densities below 0.4 A cm^{-2}.[67]



Type I and II membraneless electrolysers[67]

These so-called membraneless electrolysers generally rely on flow- or buoyancy-induced separation of products whereby forced fluid flow (advection) and/or buoyancy forces are used to separate the O_2 and H_2 products before they can cross over to the opposing electrode. Membraneless electrolysers can be classified based on the type of electrodes employed. Type I devices are based on flow-by electrodes for which the aqueous electrolyte flows parallel to the electrode surfaces and carries H_2 and O_2 products into separate downstream effluent channels.

Although the fluid dynamics that underlie their operation can be different due to the presence of gas bubbles. Specifically, type I devices operating under supersaturation conditions can leverage the Segré-Silberberg effect, whereby the fluid velocity gradient helps to pin bubbles close to the electrode surface from which they evolve. Instead of flow-by electrodes, type II electrolysers utilize flow-through electrodes for which the flowing electrolyte passes through porous electrodes.

The above figure illustrates a type II configuration in which two circular metallic mesh electrodes are positioned in a face-to-face configuration while fresh electrolyte flows into the electrode gap from a pressurized outer chamber. As the fresh electrolyte is forced into the electrode gap, the flow diverges, carrying the H_2 and O_2 products away into separate effluent channels. H_2 product purity of 99.83% and current densities approaching 4Acm^{-2} were achieved.

More recently, a type II design was demonstrated that was based on angled mesh flow-through electrodes separated by an insulating baffle that was part of the device body. This modification enabled the use of an extremely simple device body that was 3D printed as a single, monolithic component. Furthermore, membraneless electrolysers allow for the possibility of an impurity-tolerant device that can operate on tap water, thereby eliminating the cost of a water purification unit while enabling lower-cost materials to be used in balance of system components.

Despite their advantages, membraneless electrolysers also present several challenges. One shortcoming of membraneless electrolysers compared with PEM electrolysers is lower voltage efficiency at high operating current densities (~0.5 A cm^{-2} or greater). For most membraneless electrolysers, there is a longer distance for ion transport, which results in a larger total ohmic resistance of the electrolytic solution (Rs), and subsequently a larger ohmic voltage loss.

Two current challenges for membraneless electrolysers are product purity and safety. Lower product purity is a concern in regards of explosion and/or system runoff

Thanks to the ability of solid electrolyte membranes to serve as a physical barrier to O_2 and H_2 product gases, commercial PEM electrolysers can generate H_2 with high purity, typically 99.99%, while simultaneously compressing H_2 to pressures up to150 bar. Membraneless electrolysers cannot electrochemically compress H_2 because they are not able to maintain a significant pressure difference between electrodes, although it should be possible to generate high pressure H_2 by performing electrolysis in a pressurized liquid electrolyte, which may increase the requirements in regards of safety, materials, and quality of assembly.

Another safety concern is electrical arcing between electrodes, which could result in sparks if a large voltage is applied across a very small electrode gap. It is paramount that such operating conditions be avoided

For these reasons, process safety principles utilizing sensors, interlocks, and fail-safe design features should be used in designing membraneless electrolysers to ensure that (1) the electrolyser is not allowed to run outside safe operating conditions and (2) O_2 and H_2 products remain separated in the event of electrolyser malfunction (e.g., pump failure).

Scale-up of membraneless electrolyser prototypes is another potential barrier to the success of this technology. In general, type I membraneless electrolysers demonstrated to date have been microfluidic in nature, although it may be possible to scaleup these devices through parallelization or (in a limited manner) through areal scaling. Yet some empirical studies will be needed to guide the design of membraneless electrolysers with maximum safety and product purity[67].

Electrolysers: Special considerations for integration with offshore wind

Motivation for producing hydrogen offshore is the cost for electrical transmission to shore. Electrical transmission per km cable is expensive compared to gas-pipelines.

200 MW to 300 MW are transmitted in AC. For longer distances above 50 to 100 km electrical losses become more significant and DC transmission including converter stations is utilized (e.g. German North Sea) 800 MW up to 1.2 GW DC. Costs for transformer and 100 km cable is approximately 1 bn EUR. Hydrogen gas pipeline costs are significantly lower (about 10%). In comparison gas pipelines can transport more than 10 GW per pipeline.

Electrolyser per wind turbine concept: Each WTG location can be equipped with container sized electrolyser. Transport of Hydrogen can then be performed via vessel or pipeline. This concept may be the best option for floating far offshore sites. Green hydrogen can be produced using an electrolyser array located at the base of the offshore wind turbine tower.

Electrolysers mounted on wind turbine platform should reduce electric losses to a minimum, while a modular approach attempts for a reliable, efficient, and scalable operational set-up. On the other hand, cost of repairs and maintenance will be sensible increased.

Reference project: In order to test electrolysers operations under harsh offshore conditions while achieving minimal maintenance and still meet performance targets, the EU-funded OYSTER project financed a pilot trial with a MW-scale electrolyser. The project is run by ITM Power (PEM technology), Siemens/Gamesa and Orsted. Location Port of Grimsby, UK[68]. Oyster aims to develop a "fully marinized" electrolysis system capable of direct integration with offshore wind.

Grimsby offshore site. Source: Siemens Gamesa

Electrolyser mounted on dedicated platform and/or integrated with offshore substation:

This approach foresees a centralized location for the electrolyser, hence on interface for handling of hydrogen and on location for maintenance. Currently, platform concepts are offering a basis for offshore hydrogen production in the range of 100 MW to 800 MW, this includes the electrolysis units and transformers for the transformation of the electricity supplied by the offshore wind turbines, along with desalination modules for producing the high-purity water required for electrolysis.

Centralization of electrolyser on a single platform leads to an overall cost reduction and competitive levelized cost of hydrogen, but increases the hydrogen inventory and the size of critical equipment. DSU/BI exposure is increased due to the built-in bottlenecks

Reference project: The Tractabel-Overdick concept is yet in the design phase and offers significant improvements compared to the single electrolyser per wind turbine concept. The add-on modules comprise a high-voltage export module, allowing to export electricity in parallel to hydrogen, an interconnection module to operate the hydrogen platform in a cluster of offshore high voltage substations and an offshore hydrogen bunkering module.

Tractabel-Overdick concept. Source: https://overdick-offshore.com/news/2020/large-scale-offshore-hydrogen-production

Electrolyser on energy island: This approach integrates the electricity generation from several offshore windfarms on an island with harbor, service, and storage facilities. The idea is to share assets between different grids, so it is like a more advanced way of having an interconnector. This concept offers more flexibility in the distribution between hydrogen production and electricity transmission. Maybe with a reduced electrical connection to the onshore grid.

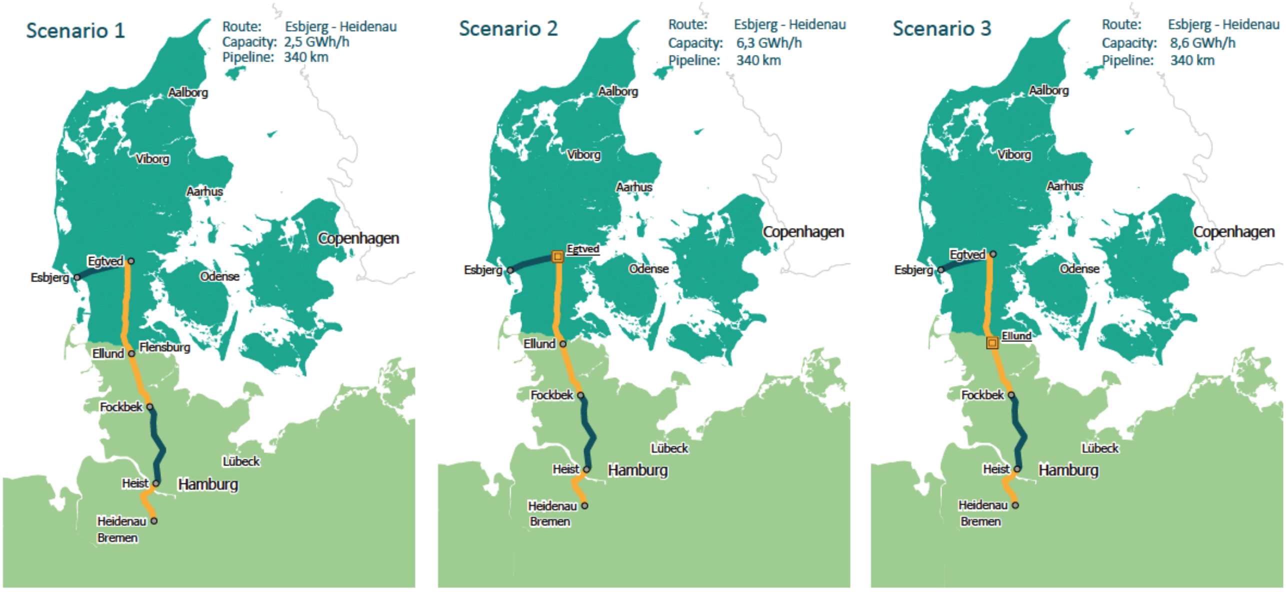
Reference project: In the North Sea, an artificial island is under construction with a minimum of 2 GW offshore wind connected by 2030, to Denmark and the Netherlands, with a long-term capacity reaching 10 GW offshore wind. In the Baltic Sea, Bornholm will be made an energy island to establish and connect up to 2 GW of offshore wind by 2030 with connections to Poland.[69]

Concept by VindØ includes energy storage, 'power-to-x' facilities such as hydrogen, as well as accommodation, O&M facilities, and HVDC converters for transmission and interconnectors. Source: VindØ

Electrolyser next to grid connection point onshore: Electrolyser and storage for hydrogen combined with electricity production based on hydrogen installed onshore in close proximity to grid connection. This provides the best option to manage electricity demand with volatile renewables supply. Additionally, the location has better environmental conditions and easier access compared to offshore. The downside is the expensive electrical connection to the offshore site.

Onshore close to connection point is probably the preferred option from a risk perspective since offshore wind claims are dominated by logistic costs

Reference project: Esbjerg project foresees an export potential of 2-15 TWh, 3-22 TWh and 5-28 TWh in the years 2030, 2035 and 2040 (corresponding to 0-3 GW, 1-4 GW and 1-6 GW assuming 5000 full load hours). The lower estimates are considered conservative, particularly considering the market's growing appetite for production of large-scale PtX. According to publicly available information a total of 4,5 GW electrolyser capacity could be developed in Denmark already by 2030.



Source: https://en.energinet.dk/-/media/5E43188402D54575B20D13A876FE221A.pdf

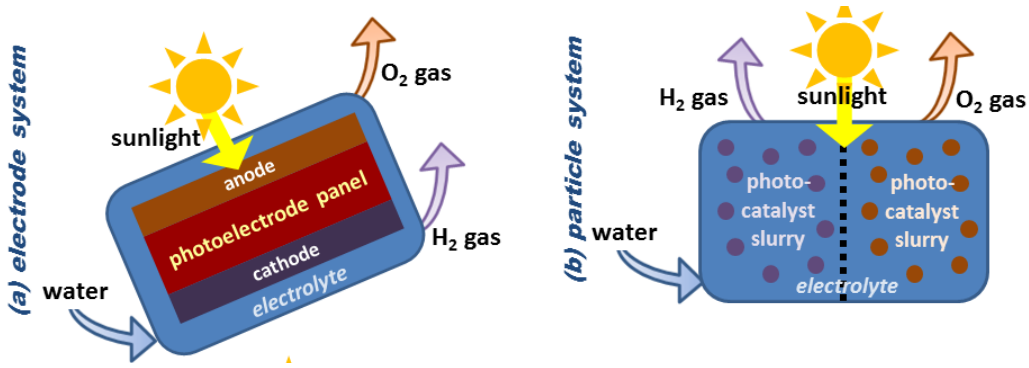
1.3 Photochemical methods

Photoelectrochemical (PEC) methods for hydrogen production are chiefly focused on splitting water into hydrogen and oxygen using sunlight and a photocatalyst. Because of the energy source, PEC has the potential for very low or zero greenhouse gas emissions.

This technology comes under the umbrella term of 'Solar to Hydrogen'. However, unlike "green hydrogen" produced via an electrolyser as described in the previous section, PEC technology is contained in one single device. This removes the need for added power + network infrastructure as well as the need to convert solar power from DC to AC and back again via a power management unit as would be needed for green (electrolyser based) H_2. Furthermore, power transmission losses are avoided improving the overall efficiency of the total process.

However, at the point of writing, this technology is still in its nascency, contained to laboratory-scale demonstrators with only a handful of pilot systems exhibiting H_2 production efficiencies ranging from 1-20%. However, with the rate of study, this is expected to change over the coming decade. Thus, in this section, we will share only the basics of PEC methods for hydrogen production from the current state-of-the-art demonstrators.

"Solar to hydrogen" reactors can have different design approaches with some examples shown below.



Source: Energy.gov

In the first method, the PEC reactor design is very similar to a photovoltaic solar panel, with an integrated semiconductive photoelectrode, however, the excited energy from adsorbed sunlight is directly used to split water *in situ*. Perovksite materials have been identified as high effective materials as semiconductive photoelectrodes. Alternatively, the reactor cell can contain a slurry of water and photocatalyst particles.

The US Department of Energy's ultimate solar to hydrogen energy conversion ratio target for PEC is set at 25%. Recently lab scale demonstrators at the Australian National University and University of New South Wales with a perovskite based photoelectrode achieved 17.6% and 20%, respectively[70,71]. Efficiencies can be increased by concentrating solar rays, at KAUST efficiency of 28% has been reached using a solar concentrator (41 suns), carrying out techno-economic analysis, the LCOH is rated at $5.9 kg-1 close to the current cost of c-Si solar farms[72].

Reference project: Repsol and gas grid operator Enagas SA have secured funding from the EU and begun building a demonstration plant in Puertollano using its proprietary PEC technology. The solar to hydrogen plant is projected to be capable of producing 100 kg H_2 per day from sunlight, with an annual capacity of 200 tons. The facility is expected to start operation in 2024[73].

Hydrogen production by photo-electrocatalysis. Source: Repsol

2. Hydrogen applications in heavy industries

For decades, hydrogen has been used as a raw material by the chemical industry, mostly in the production of ammonia (NH_3) and hence fertilizers, and in refineries, where hydrogen is used for the processing of intermediate oil products.

About 55% of the hydrogen produced around the world is used for ammonia synthesis, 25% in refineries and about 10% for methanol production. The other applications worldwide account for only about 10% of global hydrogen production[74].

Hydrogen also has a long history of use in several other industries. These include:

- Food: Hydrogen is used to turn unsaturated fats into saturated oils and fats, including hydrogenated vegetable oils like margarine and butter spreads.
- Metalworking: Hydrogen is used in multiple applications including metal alloying and iron flash making.
- Welding: Atomic hydrogen welding (AHW) is a type of arc welding which utilizes a hydrogen environment.
- Flat Glass Production: A mixture of hydrogen and nitrogen is used to prevent oxidation and therefore defects during manufacturing.
- Electronics Manufacturing: As an efficient reducing and etching agent, hydrogen is used to create semiconductors, LEDs, displays, photovoltaic segments, and other electronics.
- Medical: Hydrogen is used to create hydrogen peroxide (H2O2). Recently, hydrogen gas has also been studied as a therapeutic gas for a number of different diseases[74].

Hydrogen demand in 2020 was ~90 Mt, with more than 70 Mt used as pure hydrogen and less than 20 Mt mixed with carbon-containing gases in methanol production and steel manufacturing

Almost all this demand was for refining and industrial uses.

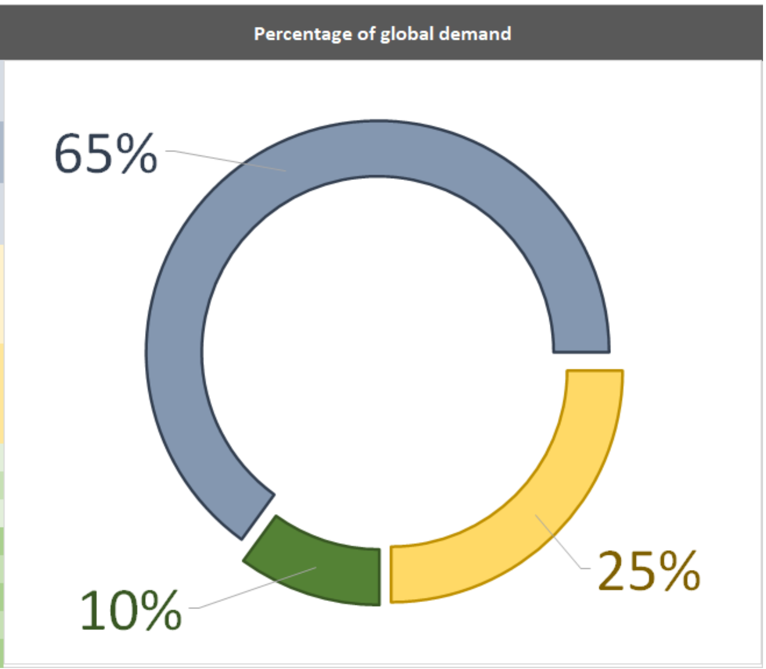
Oil refining is the largest consumer of hydrogen today (close to 40 Mt in 2020) and will remain so in the short to medium term

Hydrogen used in this sector is normally produced onsite by steam methane reforming, separated from by-product gases from petrochemical processes or sourced externally as merchant hydrogen (typically produced in dedicated plants for hydrogen production using steam methane reforming).

The use of low-carbon hydrogen in refining faces an economic barrier due to its higher cost compared with unabated fossil-based hydrogen. However, replacing this hydrogen production capacity with low-carbon technologies would not be as technically challenging as adopting hydrogen for new applications. Therefore, this is an ideal opportunity to easily ramp up low-carbon hydrogen demand while decreasing the CO_2 emissions from refining processes.

Industry sector demand for hydrogen was 51 Mt in 2020, with chemical production consuming ~46 Mt. Roughly three-quarters was used for ammonia production and one-quarter for methanol. The remaining 5 Mt was consumed in the direct reduced iron process for steelmaking. Only 0.3 Mt of 2020 demand was met with low-carbon hydrogen (close to 20% more than in 2019), mostly from a handful of large-scale CCUS plants, small electrolysis units in the chemical subsector, and one CCUS project in the iron and steel subsector[75].

Industrial Sector	Application
CHEMICAL	Ammonia
	Polymers
	Resins
REFINING	Hydrocracking
	Hydrotreating
IRON & STEEL	Annealing
	Blanketing gas
	Forming gas
GENERAL INDUSTRY	Semicon
	Propellant fuel
	Glass production
	Food industry (hydrogenation)
	Cooling of generators

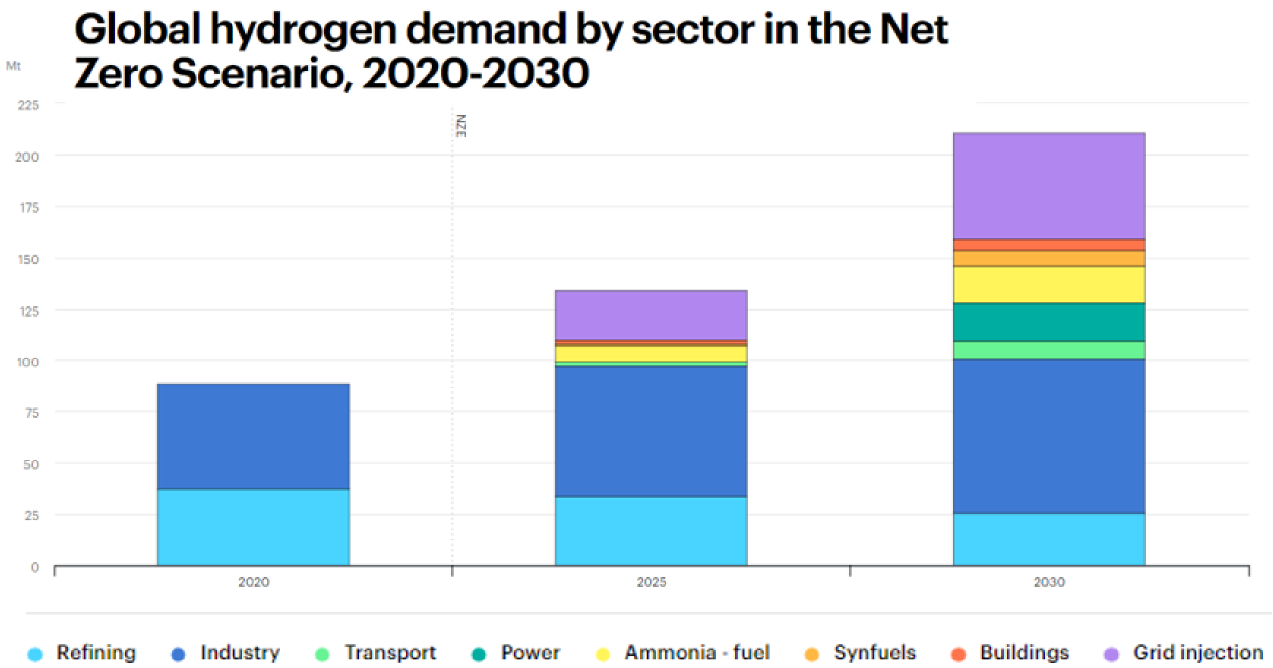


Data source: IRENA, Hydrogen from renewable power. Technology outlook for the energy transport.

For ammonia synthesis and hydrogen used in refining, the main cost driver today is the natural gas feedstock, which accounts for about 60% to 70% of the total cost of ammonia. Carbon costs between USD 50 to 100 a ton are sufficient to sequestrate a large share of emissions in most locations.

Methanol synthesis will likely take longer to decarbonize due to the complexity of the current integrated syngas-based process and the need for a clean source of CO_2. Annual global methanol production is expected to grow from its current 100 Mt to more than 120 Mt by 2025 and 500 Mt by 2050. Most of the growth to 2028 is expected to occur in China, and more specifically the demand to be for MTO and a smaller share for gasoline blending, formaldehyde, acetic acid, and MTBE. The chemical sector will thus continue to play an important role in methanol demand growth.

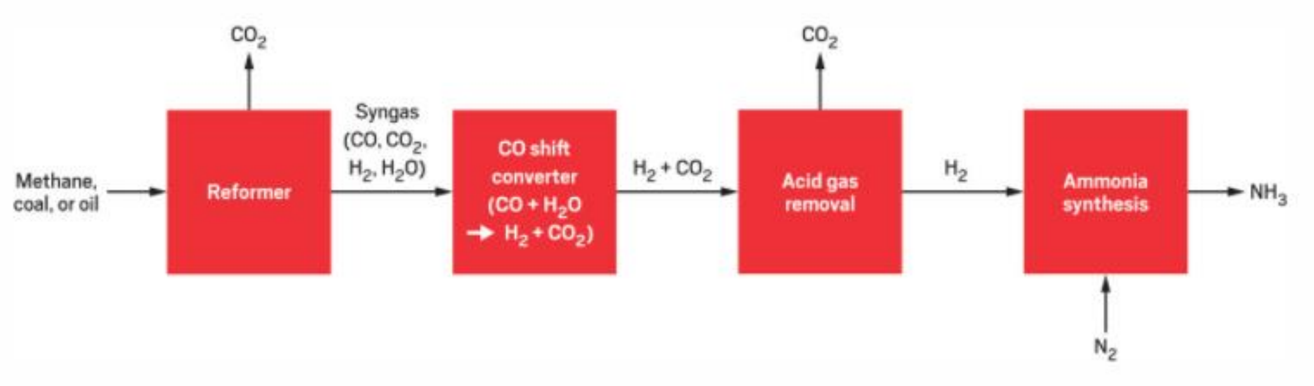
Looking ahead, however, the increase in methanol production is expected to see a progressive shift to renewable methanol, with an estimated annual production of 250 Mt of e-methanol and 135 Mt of bio-methanol by 2050[76].



Source: IEA, Global hydrogen demand by sector in the Net Zero Scenario, 2020-2030. IEA, Paris

2.1 Ammonia production

Ammonia is obtained on a large scale by the Haber-Bosch process. This process combines hydrogen and nitrogen together directly by synthesis. Nitrogen is obtained by low-temperature separation of atmospheric air, while hydrogen is typically produced on-site from hydrocarbons. Natural gas and coal are the two main hydrocarbon sources used today in ammonia production.



Source: https://cen.acs.org/

Between 75 and 90% of this ammonia goes toward making fertilizer, and about 50% of the world's food production relies on ammonia fertilizer[77]. For this purpose, a large part of the ammonia is converted into solid fertilizer salts or, after catalytic oxidation, into nitric acid (HNO_3) and its salts (nitrates).

The rest of the ammonia helps make pharmaceuticals, plastics, textiles, explosives, and other chemicals. Every NH_3 molecule generated in the process releases one molecule of CO_2 as a product. In the most efficient ammonia production process 1.6 tons of CO_2 is produced per ton of ammonia.

Ammonia is divided into 3 categories according to its CO_2 emissions:

- Grey ammonia: higher carbon ammonia produced using fossil fuels
- Blue ammonia: low-carbon ammonia. same process as grey ammonia but with carbon capture and storage technology
- Green ammonia: zero-carbon ammonia made using renewable energy sources to produce green hydrogen

There are different technologies for the carbon dioxide capture in the blue ammonia production process, amine absorption is the most common commercially available. Another technique is the cryogenic separation with the use of polymeric membranes or adsorption on solid.

The carbon dioxide captured can be used in different sector such as urea production. In order to completely eliminate carbon dioxide emissions and produce green ammonia both the hydrogen and the energy needed for the operation must be obtained from renewable sources, but this is limited in term of resources and the operation could not be continuous.

The using of electrolytic H_2 for ammonia production is at an early stage of development.

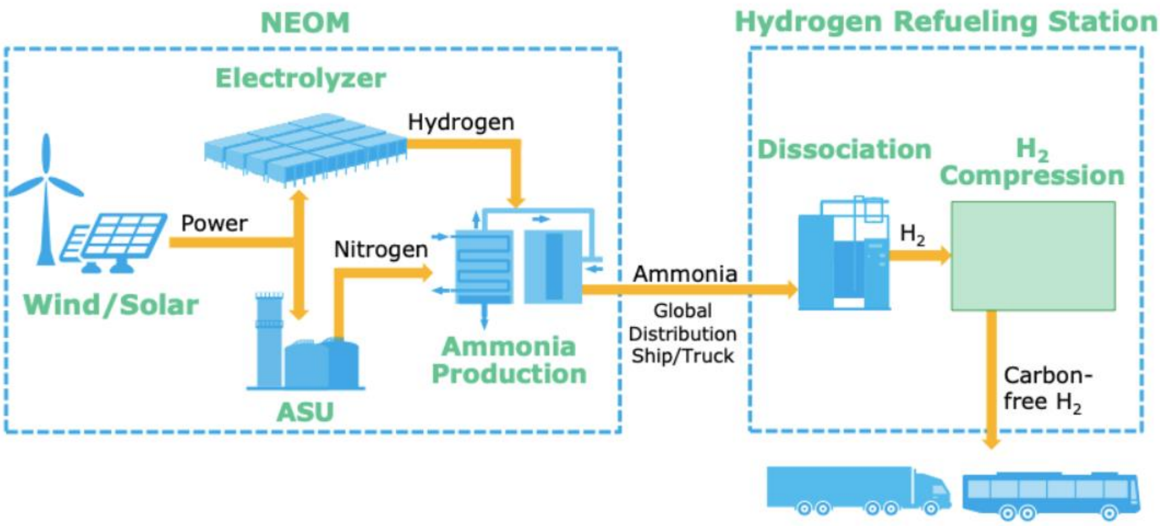
Reference projects: The largest green hydrogen complex for industrial use in Europe is underway in Spain and it is a partnership between Iberdrola and Fertiberia.

Iberdrola will construct a 100 MW photovoltaic plant, a battery installation, and a system for producing green hydrogen by electrolysis from 100% renewable resources. The green hydrogen produced will be used at the Fertiberia fertilizer plant in Puertollano, making it the first European company in its sector to develop large-scale expertise in the generation of green ammonia.

Fertiberia plans to reduce natural gas requirement of the plant by over 10%, which shall avoid 39.000 tons of CO_2/year emissions.

Planned layout of Fertiberia plant. Source: ammoniaenergy.org

Air Products, ACWA Power, and NEOM announced a $5 billion, 4-Gigawatt green ammonia plant in Saudi Arabia, to be operational by 2025. Air Products, the exclusive off-taker, intends to distribute the green ammonia globally and crack it back to "carbon-free hydrogen" at the point of use, supplying hydrogen refueling stations. It includes the integration of renewable power from solar, wind and storage; production of 650 tons per day of hydrogen by electrolysis using thyssenkrupp technology; production of nitrogen by air separation using Air Products technology; and production of 1.2 million tons per year of green ammonia using Haldor Topsoe technology[78].



Source: ammoniaenergy.org

2.2 Steel production

Steel is one of the world's highest CO_2-emitting industries, accounting for about 8% of global annual emissions due to the use of coking coal in the blast furnace process. Each ton of steel produced today still results in 1.4 t CO_2 of direct emissions on average.

To meet global energy and climate goals emissions from steel industry must fall by at least 50% by 2050

Recent studies estimate that the global steel industry may find approximately 14 percent of steel companies' potential value is at risk if they are unable to decrease their environmental impact[79].

Steel can be produced via two main processes depending on the type of raw materials used:

- Blast Furnace-Basic Oxygen Furnace (BF/BOF) route: produce iron from iron ore and in a second step a basic oxygen converter turns iron into steel. This is the predominant method in Europe.
- Electric Arc Furnace (EAF) route: use steel scrap or direct reduced iron (DRI) as the main raw material.

A total of 70.7% of steel is produced using BF/BOF route and 28.9% is produced via the EAF route[80]. Another steelmaking technology, the open-hearth furnace (OHF), makes up about 0.4% of global steel production. The OHF process is very energy-intensive and is in decline owing to its environmental and economic disadvantages.

The use of hydrogen in steel production represents a cost-effective decarbonization and could be competitive with a carbon cost less than USD 50 to 100 a ton. However, converting a steel plant to hydrogen requires significant investments.

Steel could account for about 4% of hydrogen demand (6 MT) by 2030 while driving nearly 20% of emissions reductions that year. It is estimated that by 2050 steel carbonization will require 35 MT of hydrogen, resulting in 12 GT of emissions avoided through 2050.

Steel decarbonization requires 35 MT of demand for hydrogen in 2050, resulting in 12 GT of emissions avoided through 2050.

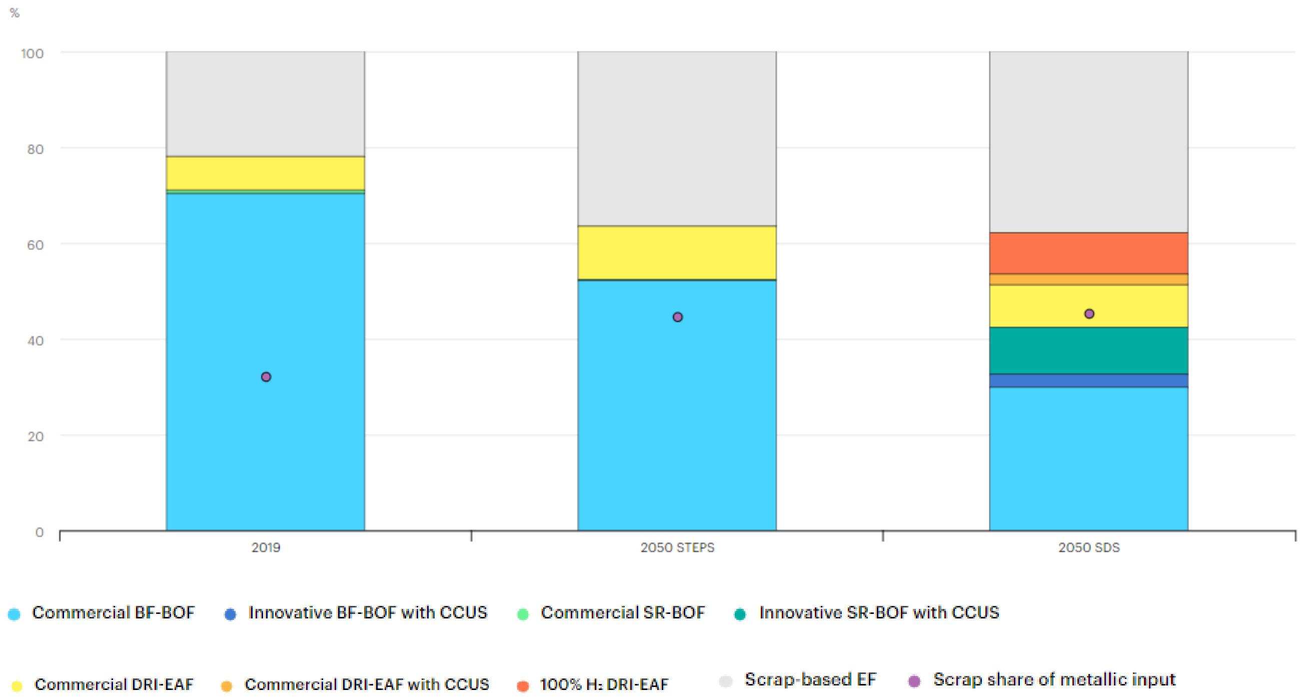
Europe is the center of early growth in hydrogen-based steelmaking, with significant activity ongoing in the industry. The region has announced more than 25 MT of clean steel capacity through 2030[81]

Projects currently in the pipeline amount to 0.5-0.8 Mt of low-carbon hydrogen through 2030, representing only ~7% of the Net Zero Emissions by 2050 Scenario 12-Mt target. Today, only a handful of plants use low-carbon hydrogen in iron- and steelmaking. These include a DRI plant equipped with CCUS in the United Arab Emirates, which captures CO_2 for enhanced oil recovery nearby and for some demonstration projects that use electrolytic hydrogen in steel-related projects[75].

There are two ways to use (green) hydrogen in steel production. First, it can be used as an alternative injection material to improve the performance of conventional blast furnaces. This way can reduce carbon emissions by up to 20% but does not offer carbon-neutral steel production because regular coking coal is still a necessary reductant agent in the blast furnace.

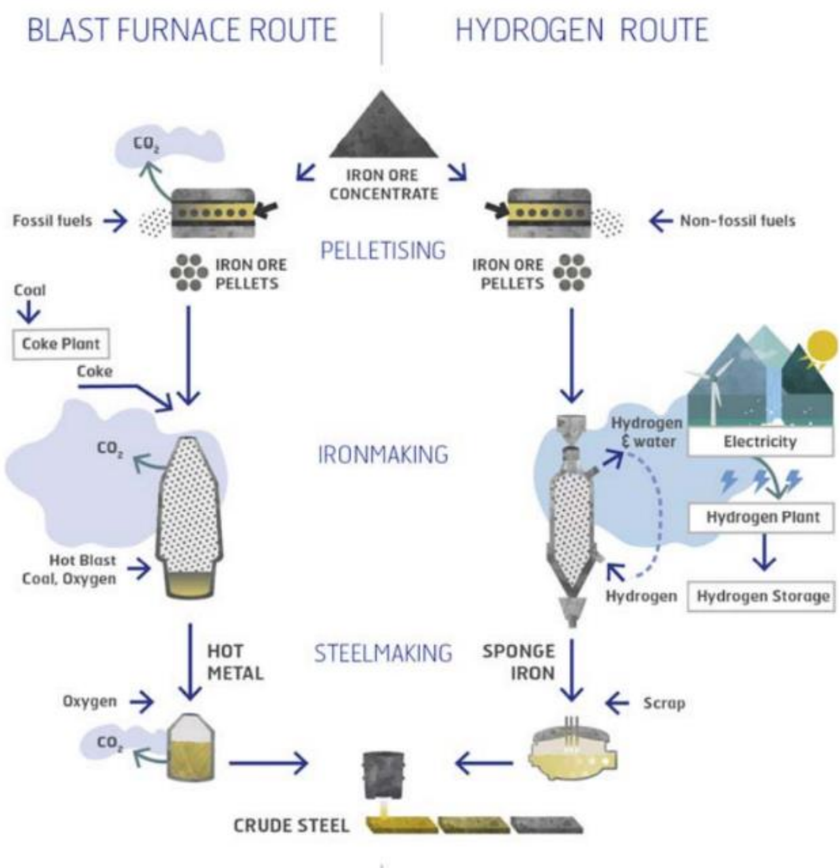
Second, hydrogen can be used as an alternative reductant to produce DRI that can be further processed into steel using an EAF. This DRI/EAF route is a proven production process that is currently applied using natural gas as a reductant, for example by players in the Middle East with access to a cheap natural gas supply. However, the direct reduction process can also be performed with hydrogen. Based on the use of green hydrogen as well as renewable electricity from wind, solar, or water, a DRI/EAF setup enables nearly carbon-neutral steel production[81].

Below figures show the expected crude steel production by process route and scenario 2019-2050, according to the IEA.



Source: https://www.iea.org/reports/iron-and-steel-technology-roadmap

Renewable energy can be also chosen as the energy source to produce hydrogen by water electrolysis to displace the use of an ancient industrial apparatus that is the blast furnace for metallic iron production from iron ore.

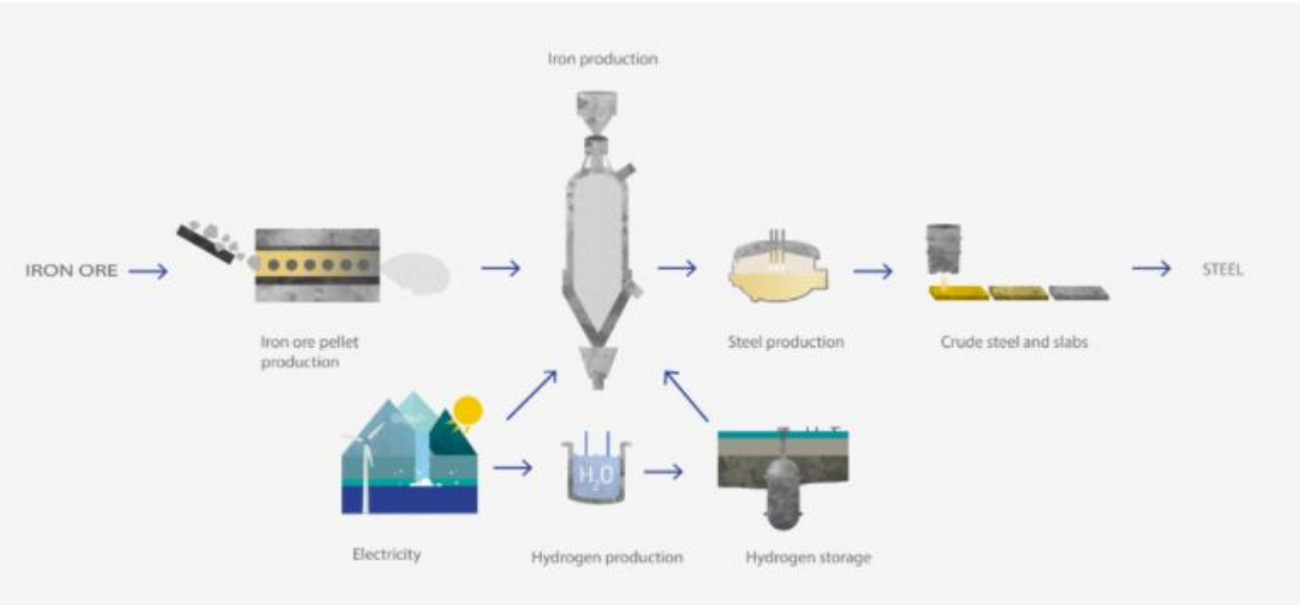


Source: Science and Engineering of Hydrogen-Based Energy Technologies. Hydrogen Production and Practical Applications in Energy Generation. 2021[82].

The left-hand side shows that iron ore concentrate is pelletized using fossil fuels, so that the mineral pellets and coke are fed into a blast furnace, which produces hot metal that is, subsequently, used to be transformed into crude steel. Coke and fossil fuels are used, and greenhouse effect gases and particulates and ashes are emitted with this conventional procedure. Alternatively, the right-hand side presents a "hydrogen route" in which iron ore concentrate is also used to produce pellets, but no fossil fuel is used for that.

Hydrogen is produced from water electrolysis on site or nearby using renewable electricity and is stored in large amounts to be used for two purposes: one is for the production of high-grade industrial heat and the other one is for the procedure of direct reduction of iron ore into metallic iron, which gives origin to sponge iron without using coke as a reducing agent, without using fossil fuels for heating, without deleterious environmental emissions, and also without having to convert the iron ore, the raw material, into liquid form as it has to be done in the blast furnace. The sponge iron is then used for crude steel production. Such a hydrogen route for the production of direct reduced iron from pelletized iron ore is very innovative and encompasses a future vision of using hydrogen energy to clean the ancient and pollutant steel industry into an environmentally friendly one[82].

Reference projects: The HYBRIT project, developed by SSAB, LKAB and Vattenfall – will produce sponge iron using 100% hydrogen in combination with biomass – is working towards transitioning from a pilot to largescale (~1 Mt of DRI) operation by 2025 in Sweden. In June 2021, Volvo Cars signed a collaboration agreement with SSAB to be an off-taker of the fossil-free steel produced in this project.



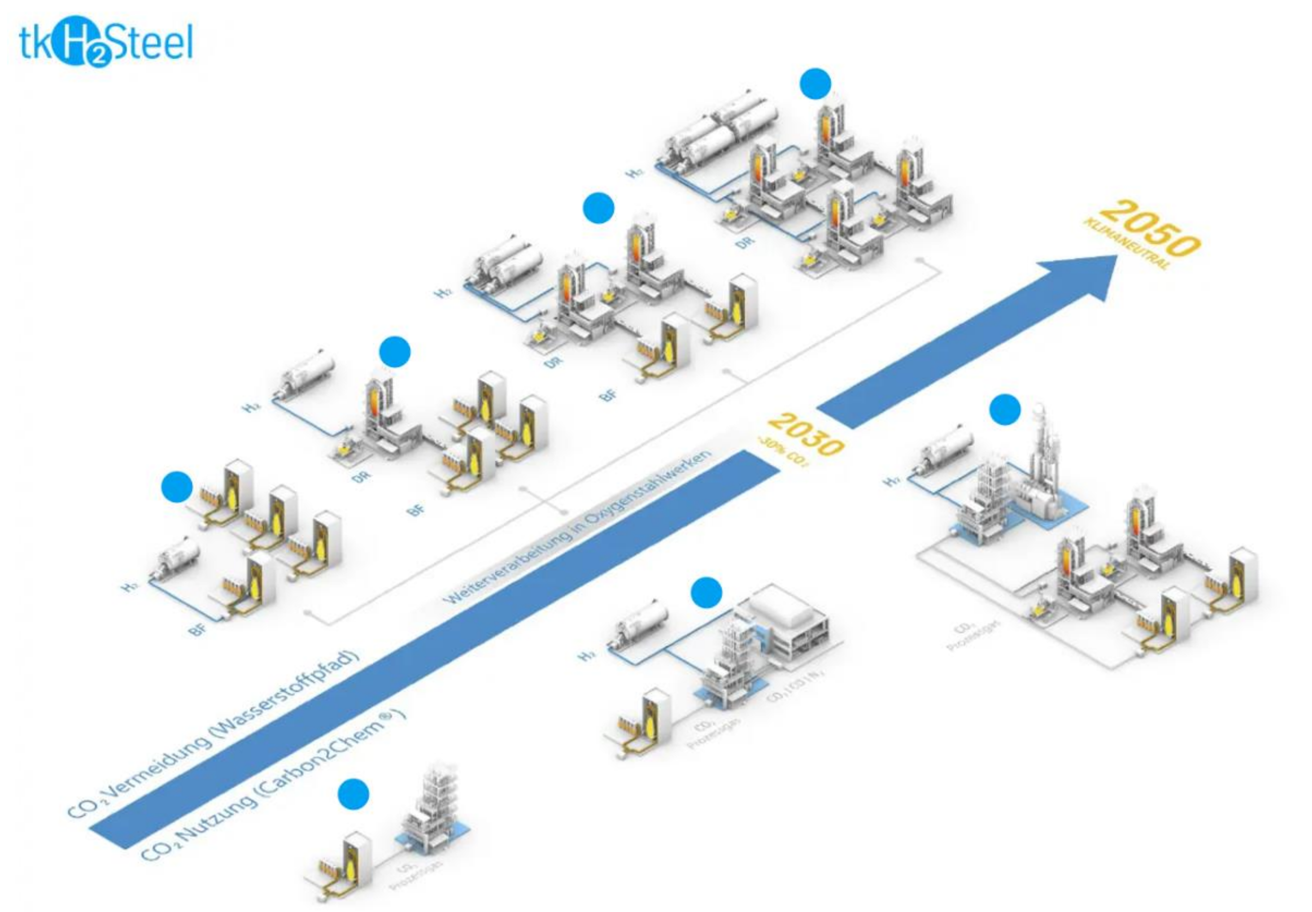
Source: https://www.hybritdevelopment.se/en/

ArecelorMittal has signed a memorandum of understanding (MoU) with the Spanish Government that will see a €1 billion investment in decarbonization technologies at ArcelorMittal Asturias' plant in Gijón.

At the heart of the plan is a 2.3 million-tons green hydrogen direct reduced iron (DRI) unit, complemented by a 1.1 million-tons hybrid electric arc furnace (EAF). The investments will reduce CO_2 emissions at ArcelorMittal's Spanish operations by up to 4.8 million tons, which represents approximately 50% of emissions, within the next five years[81].

Thyssenkrupp Steel announced its decarbonization project tkH2Steel, which aims to implement direct reduction in combination with an electric melter. The first step is the erection of an industrial scale plant for direct reduction of iron ore using natural gas, which will be later operated with 100% hydrogen.

According to the German Ministerium for Environment, already the first step of reduction using natural gas saves two thirds of direct greenhouse emissions compared to the current process which is based on coal as energy source.



TKH2Steel decarbonization pathway. Source: ThyssenKrupp

Direct reduction involves the production of a solid sponge iron, which is then melted to raw iron in a further process step using an electric melter, which would operate on green electricity to further decarbonize the process. With this combination, 90% of the emissions compared to the current process could be saved, this means for Thyssenkrupp around 6 Mio. Tons CO_2 per year savings.

This plant is expected to be operational by 2025.

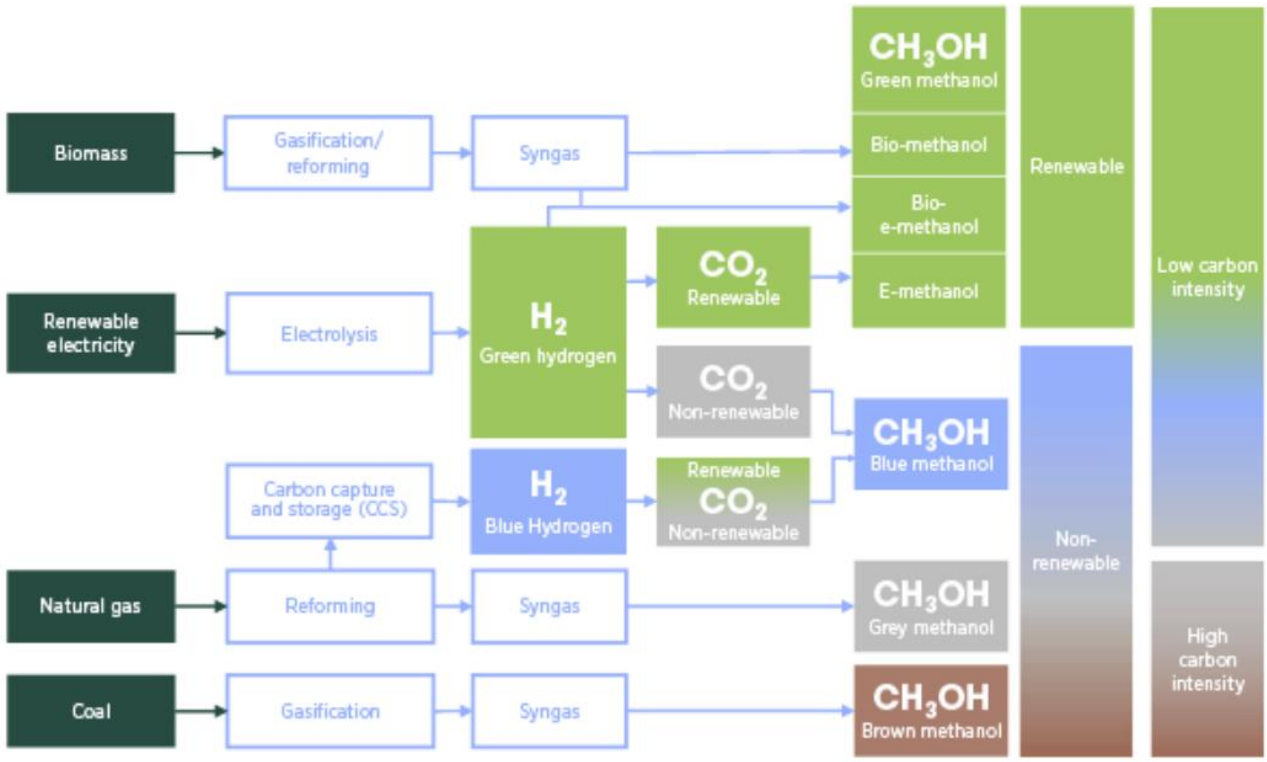
Most projects in the steel sector in the years to come refer to retrofitting, respectively modernization of existing plants to operate with hydrogen, thus representing challenges from a risk perspective not only linked to proper process design such as selection of materials, operational parameters, and safety systems, but also and especially to the use of existing components, and organizational/operational procedures.

2.3 Methanol production

Global methanol production could increase five-fold by 2050, but only if half the total comes from a decarbonized "e-methanol" sector currently in its infancy, according to International Renewable Energy Agency (IRENA) estimates.

In addition, such a jump would require unprecedented amounts of "green hydrogen" and a monumental scaling up of a sector that until now has lagged the other leg of the green methanol revolution—bio-methanol, which uses biomass as a feedstock rather than hydrogen produced via electrolysis as e-methanol does. Only one e-methanol plant is currently operational.

The possibility of such a transformation was unveiled in a study commissioned jointly by IRENA and The Methanol Institute, a global trade association. That scenario would see annual output soar to 500 million metric tons (Mt) in 2050 from the current 100 Mt, a figure that itself more than doubled over the past decade as the Chinese methanol-to-olefins sector boomed and natural gas supplies in the US soared on the back of the shale revolution.



Principal methanol production routes. Source: IRENA

Carbon Recycling International's George Olah plant in Reykanes, Iceland, is the only commercially operational e-methanol plant. It uses geothermal energy for electricity, carbon dioxide (CO_2) from the geothermal assets and hydrogen produced via water electrolysis. The output is used to produce biodiesel and for waste-water denitrification. It has an annual methanol production capacity of 4,000 mt.

To produce such a vast amount of e-methanol would require about 350 Mt of CO_2 and 48 Mt of hydrogen annually, according to the study. To produce this quantity of hydrogen through water electrolysis and assuming consumption of 50 MWh/mt of hydrogen produced, about 2.4 million gigawatt hours (GWh) of electricity would be needed. This would require about 275 GW of continuous electricity production, as well as 280 GW of electrolyser capacity, according to the study.

If the power was sourced from solar facilities, installed capacity of about 920 GW at a capacity factor of 30% would be required, or in terms of wind power, about 500 GW of installed capacity, at a capacity factor of 55% encountered by some offshore wind farms, would be called for[83]. Bio-methanol is produced from biomass. Key potential sustainable biomass feedstocks include forestry and agricultural waste and by-products, biogas from landfill, sewage, municipal solid waste (MSW) and black liquor from the pulp and paper industry. Green e-methanol is obtained by using CO_2 captured from renewable sources (bioenergy with carbon capture and storage [BECCS] and direct air capture [DAC]) and green hydrogen, i.e. hydrogen produced with renewable electricity.

Risk specific to the development of bio-methanol and green e-methanol would be similar to existing risks and exposures in the production industry

Methanol is highly flammable and can lead to explosion if handled improperly like gasoline, ethanol, or hydrogen. Currently production of renewable methanol remains more expensive than fossil methanol[84].

2.4 Refineries

CCUS processes are outlined in Chapter 1. Shell was the first mover with its 2005 project at Pernis refinery (in the Netherlands) to capture CO_2 from heavy-residue gasification units. Others have followed since, and there are already six facilities producing hydrogen from fossil fuels coupled with CCUS, the last one entering into operation in 2020 at the North West Sturgeon refinery (Canada). These facilities have a production capacity of 320 kt of low-carbon hydrogen (25% higher than in 2019), but production could rise to 380 t in 2021 if two projects currently under development in China become operational. In addition, two projects (both in Germany) currently use electrolytic hydrogen in refining operations: a 5-MW (~0.7 kt of production capacity) polymer electrolyte membrane (PEM) electrolyser at H&R Ölwerke Schindler refinery in Hamburg (since 2018) and the Refhyne project at the Shell Rhineland Refinery, a 10-MW (~1.5 kt of production capacity) PEM electrolyser that became operational in July 2021. Furthermore, the first phase of the HySynergy project at the Shell Fredericia refinery (20 MW, ~3 kt of production capacity) is expected to become operative in 2022, and construction recently began on the Multiphly project in the Netherlands to demonstrate a 2.4 -MW (~0.5 kt of production capacity) solid oxide electrolyser cell electrolyser in refinery operations[75].

Codes and standards such as NFPA, ASME, API would need to be adopted and tailored for electrolysers to meet industry specific hazards.

Reference project: The REFHYNE project - Clean Refinery Hydrogen for Europe., is funded by the European Commission's Fuel Cells and Hydrogen Joint Undertaking (FCH JU), the project will install and operate the world's largest hydrogen electrolyser in Shell's Rhineland Refinery in Wesseling, Germany. The first phase comprises a 10MW electrolyser, while phase II will target the construction of a 100 MW electrolyser.

Hydrogen production building at the Shell refinery in Wesseling, Germany. Source: Shell Deutschland Oil

2.5 Industrial heating

Industrial heating accounts for significant emissions today due to the extensive use of coal and natural gas, particularly for high-grade heat supply. Multiple decarbonization pathways exist, including biomass, direct electrification, post-combustion carbon capture and storage, and hydrogen combustion.

Hydrogen has a key role to play in decarbonizing industry heat, in particular for high-grade heat (temperatures above 400 degrees Celsius) applications such as cement plants, glassmaking, and aluminum remelting.

In 2050, demand for hydrogen in industrial heat could account for about 70 MT, mainly in high-grade heating applications.

Hydrogen is expected to play an increasingly important role in the storage and conversion of energy, as well as production of electricity. As hydrogen production capacity is being ramped-up worldwide, it is realistic that natural gas fired combined cycle power plants, which are currently being built or projected, will also be operated with hydrogen as a fuel in their lifetime, which is typically longer than 25 years. General infrastructure surrounding hydrogen as a fuel is a limitation. Transition of high-pressure fuel gas and natural gas systems to hydrogen.

Hydrogen suppling the plant does bring with it risk and exposures, piping systems, equipment parts without safety function, equipment parts with safety functions, and subsystems all have to be designed and or modified to handle hydrogen.

Hydrogen readiness concept comes with challenges that affect the plant systems and components.

Readiness can be broken down in 4 groups to determine if a unit is ready for hydrogen operation.

- H_2-Capable: The component or system is already fully capable to be operated under the expected boundary conditions after transition to hydrogen
- Retrofitting: The component or system is partly capable to be operated under the expected boundary conditions after transition. Several parts have to be replaced, but the system in total remains the same.
- Replacement: The component or system is not capable to be operated under the expected boundary conditions after transition. The component or system needs to be completely replaced.
- Obsolescence: The component or system is no longer required for the operation of the plant.

Reference projects: Below some examples of decarbonization of industrial processes

- Pilkington glass, St Hellens – 100% H_2 gas used in furnaces to produce Sheet glass. Pre-trial video: https://vimeo.com/637490821
- Kellogs, Manchester – Food production (cereals)
- Jaguar Landrover, Liverpool – car manufacture
- PepsiCo, Skelmersdale – Food production (potato crisps)
- Encirc, Ellesmere port – Glass bottle production
- Kraft Heinz, Wigan – Food production (tinned food)
- Essity, Northwales – Hygiene and health industry (including paper manufacture)

3. Power generation

Gas turbine combustion

In the power generation sector, gas turbines will very likely need to burn H_2 or blended mixtures of H_2 and natural gas to reduce CO_2 emissions in the near future, while balancing other emissions (NOx), operational safety and efficiency.

The combustion characteristics of H_2 differ from natural gas and other hydrocarbon fuels which poses challenges for the design of hot gas path (HGP) components, especially gas turbine combustors

The peripheric components and materials selection need special attention as well due to embrittlement and operational safety, this applies especially to retrofits and/or upgrades of existing equipment.

There have been some field tests in the last years, such as the Fusina hydrogen power station in Italy (100% hydrogen based on GE technology, decommissioned due to economics in 2018) and the promising Kawasaki's pilot plant in Kobe, Japan in 2020 with a scale up project in Lingen, Germany.

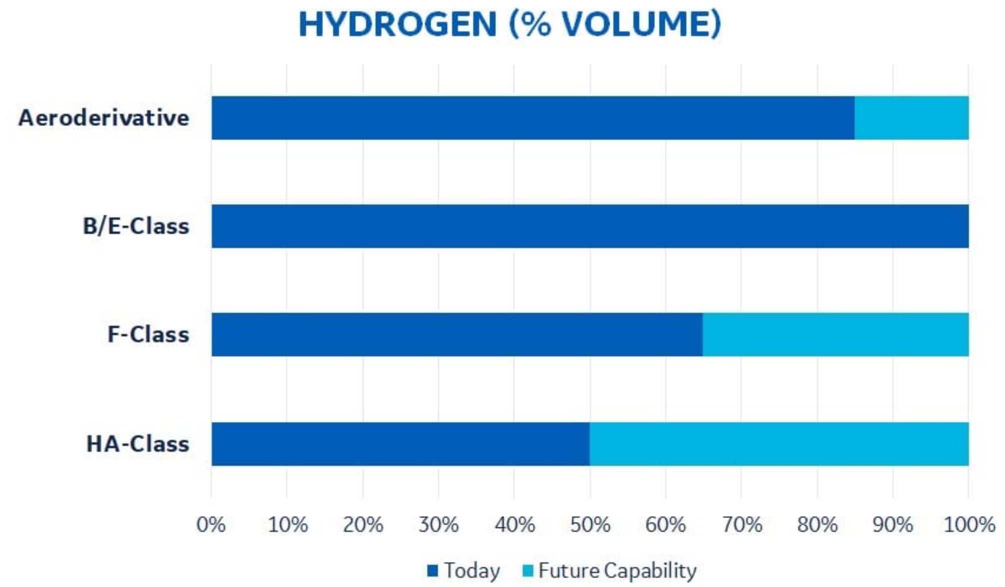
Also, aero turbines have been more or less successfully tested in specially designed aircraft by Martin, Tupelov, Boeing, and Skyleader, and airframers have pledged future hydrogen aircraft such as the Airbus ZEROe.[85]

In January 2019, the gas turbine industry strongly committed to develop gas turbines operating with 100% hydrogen by 2030. By extending the fuel capabilities of gas turbines to hydrogen, the role of gas turbines can become predominant in the energy transition period and beyond, mainly due to their versatility and operational flexibility but also in long-term energy strategies.

This will be a development process in phases, as Dr. Jeffrey Goldmeer, Emergent Technologies Director, Decarbonization at GE Gas Power stated:

It is not going from zero hydrogen to 100% hydrogen, but the discussion in many places is with incremental shifts

So maybe it's 5% or 10% or 20%. And so in that scenario, where we're going to walk our way up to 100% hydrogen" [86], See below GE Hydrogen path for H_2 turbines development.[86]



Source: https://www.powermag.com/the-power-interview-ge-unleashing-a-hydrogen-gas-power-future/

Aligning with a target set by European industry association, Siemens Gas and Power in January 2019 rolled out an ambitious roadmap to ramp up the hydrogen capability in its gas turbine models to at least 20% by 2020, and 100% by 2030. The push has been echoed to varying degrees by all the major gas turbine manufacturers, which posit that hydrogen capability may give gas power generators worldwide more options in low-carbon energy markets and prevent stranded assets owing to regulations and emissions restrictions.[87]

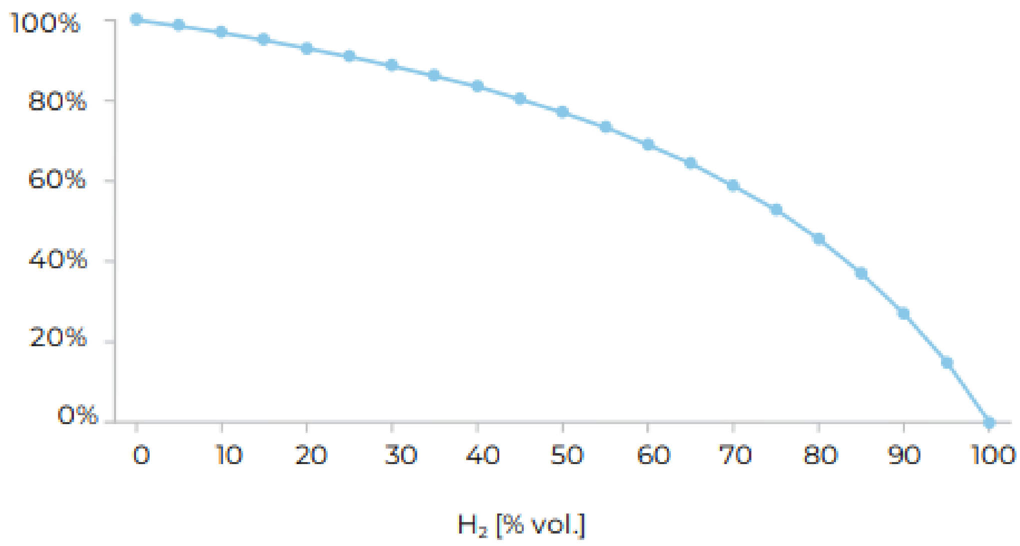
- In combined cycle configuration (CCGT), gas turbines are already the cleanest form of thermal power generation, offering high efficiency ratios. Indeed, for the same amount of electricity generated, gas turbines running on natural gas emit 50% less CO_2 emissions than coal-fired power plants.
- Mixing renewable gas (e.g., green hydrogen, biogas, syngas) with natural gas enables further reduction in net CO_2 emissions. This can be achieved by direct injection in gas grids or at plant level.
- Industry is committed to enable gas turbines to run entirely on renewable gas fuels by 2030 and therefore achieve capabilities for 100% carbon neutral power generation.
- Gas turbines are flexible, well-suited for frequent starts, and able to provide a fast response to grid demands, making them complementary to weather dependent renewable power generation.
- Hydrogen gas turbines can be an enabler for long term energy storage with power to gas (or power to liquids) technologies.

The development of retrofit solutions for existing gas turbines will be a key enabler for the implementation of the hydrogen gas turbine technology. The first steps can theoretically be achieved with relatively small modifications to existing combustors, allowing co-firing of hydrogen to significant fractions (>30 % vol., achieving approximately 11% of carbon reduction).

New types of combustors allowing up to 100% of hydrogen firing without the need for diluents for emission control are required and in development by all major manufacturers

Due to the non-linear dependency of carbon content in the fuel versus the volumetric hydrogen content, it is of importance to enable the use of higher hydrogen content as soon as possible to sensibly minimize CO_2 emissions.[88]

Carbon intensity of CH_4/H_2 mixtures

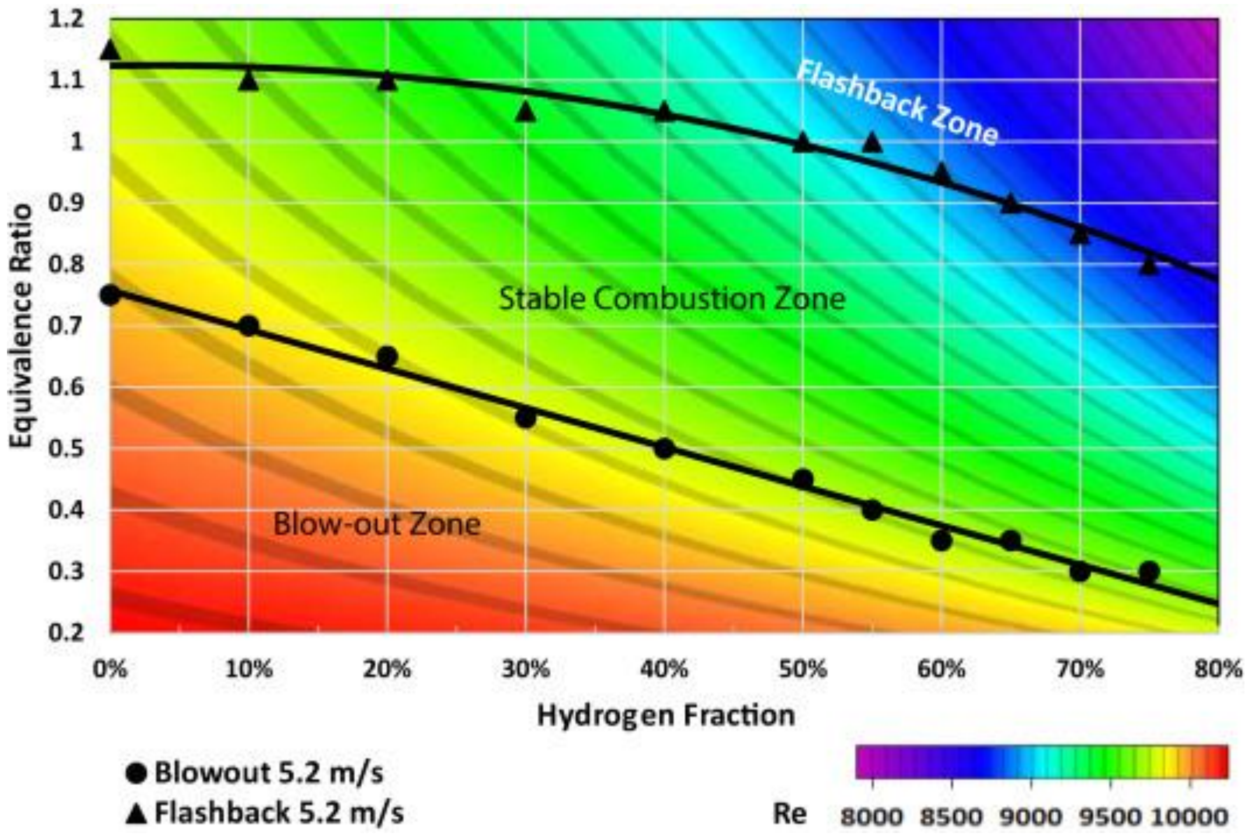


Source: ETN Hydrogen Gas Turbine Report[88]

Not all gas turbine manufacturers currently offer options for Natural Gas/hydrogen fuel mixtures but most of the major ones have developed combustion systems to handle off-spec gases to service markets such as steelworks off-gases (BFG, COG), IGCC applications, and bio- and waste-derived syngases. These off-spec gases include those with a high hydrogen content but also natural gas with higher fractions of H_2 and Methane.[89]

For traditional combustors technology, the higher concentration of hydrogen makes the combustion less stable, increasing the danger of flashbacks and (lean) blow off as well as thermal pulsations, while also generating higher levels of nitrogen oxide (NOx) emissions and significantly altering the heat distribution in the combustion chamber.

This means for existing combustor that a very narrow path between these constraints needs to be achieved as exemplary shown in the below diagram.[90]

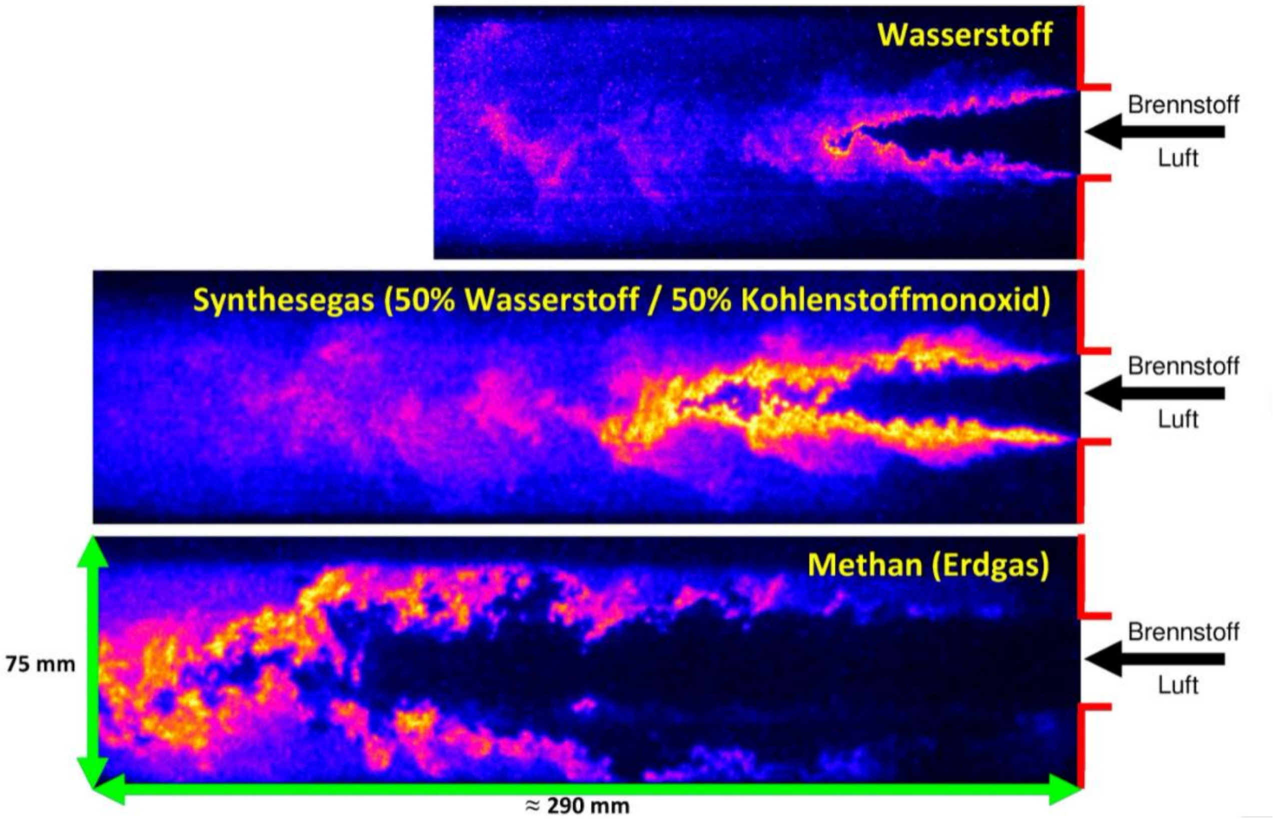


Source: Binash A. Imteyaz et al "Combustion behavior and stability map of hydrogen-enriched oxy-methane premixed flames in a model gas turbine combustor"[90]

Characteristics of hydrogen combustion

The reasons are the higher reactivity of hydrogen (which increases the risk of autoignition) and a lower density. Higher flow rates are required since the calorific value of the mixture reduces with increasing hydrogen content and the fact that the adiabatic flame temperature increases while the volumetric calorific value reduces.

Below picture (laser spectrometry) from Paul Scherer Institute illustrates the differences in flame reactivity between Hydrogen, Syngas (50% H_2, 50% CO) and Methane.[91]

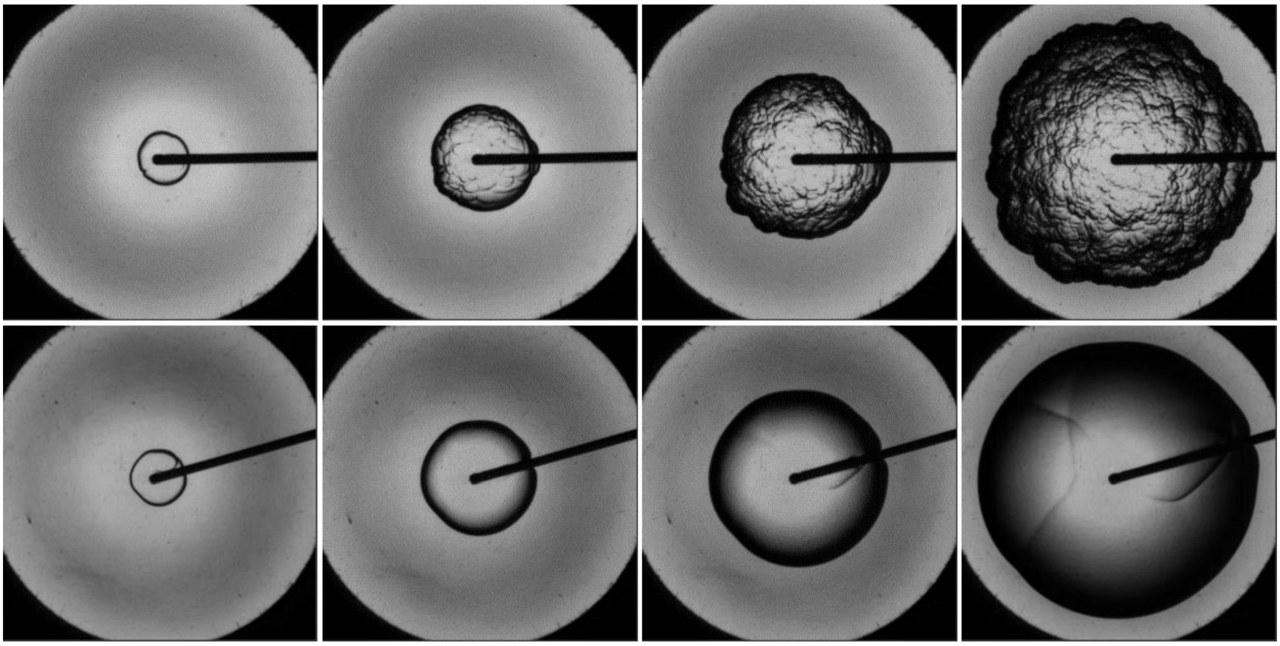


Source: Paul Scherer Institute

Flame reactivity, instability: "Hydrogen combustion leads to instabilities known as thermo-diffusive combustion instabilities. These instabilities do not occur for conventional fuels, but significantly affect the combustion process of hydrogen at lean conditions under which gas turbines are typically operated.

Thermo-diffusive combustion instabilities lead to a strong wrinkling of planar flames such that a significant flame speed acceleration and enhanced heat release of such flames is observed. Thus, to enable safe operation and optimize hydrogen combustion in actual engines, a deeper understanding of its combustion behavior is required."

"Below figure (top row) shows the expansion of a spherical lean hydrogen/air flame. The onset of thermo-diffusive instabilities is marked by the formation of cellular structures on the flame front. In contrast, bottom row shows the spherical expansion of a stable lean methane/air flame, which possesses a smooth flame front without cellular structures and represents the combustion mode of conventional fuels. The cell formation during hydrogen combustion enhances the overall flame speed and needs to be considered for the design of gas turbines."[92]



Source: Courtesy of Joachim Beeckmann, ITV RWTH Aachen University
https://www.jara.org/en/research/energy/news/detail/Challenges-of-Hydrogen-Combustion

The solution lies in allowing hydrogen and air to mix efficiently and ensure stable combustion.

"In order to mix hydrogen and air in a short period of time, it has to be done in a space as confined as possible,"

explains Satoshi Tanimura, Chief Engineer, General Manager at Mitsubishi Power's Gas Turbine Technology & Products Integration Division.

Engineers accomplished this by dispersing the turbine's firing flame and reducing the particle size of the fuel spray that the flame ignites to power the turbine.

"The key technology to this method is the fuel delivery nozzle," adds Tanimura. "We upgraded the design, which normally features eight nozzles, and created the distributed lean burning, or multi-cluster combustor, which incorporates many nozzles."

"By reducing the size of the nozzle opening, injecting air, and then spraying hydrogen, the air and gas mix can be achieved on a smaller scale, reducing the likelihood of flashbacks, and keeping NOx emissions low." These are generated in so called hot spots, which means that heat homogeneity and flame stability are key.

Overheating, monitoring & control: "To protect burners and fuel injectors from being overheated or damaged, burners are typically instrumented with thermocouples if more reactive fuels are used. In advanced, highly efficient gas turbines more and more complex burner design (e.g. multi-nozzle arrangements) are needed and therefore this method of protecting burners will become challenging and expensive. Other methods of detecting and preventing autoignition events leading to a flame stabilization in undesired locations are needed especially when increasing the hydrogen fraction in the fuel blend".[88]

Other methods such as fast characterization of the fuel (e.g. chromatography) and adjustment of the combustion parameters may complement safety systems.

Thermoacoustic: Compared to natural gas flames, hydrogen flames exhibit significantly different thermoacoustic behavior. This is due to higher flame speed, shorter ignition delay time and distinct flame stabilization mechanisms resulting in different flame shapes, positions, and different reactivity[89].

Risks derived from combustion dynamics (self-sustained combustion oscillations at or near the acoustic frequency of the combustion chamber) in modern gas turbines operated on hydrogen-rich fuels is expected to increase compared to natural gas operation

This implies that undesired and dangerous phenomena, such as combustion instabilities, flashback, and lean blow out, are likely to occur not only at steady conditions, but also more dangerously during transient operation, e.g. when rapid power changes are required and/or fuel composition changes.

In order to develop stable combustion systems for hydrogen-rich flames, various measures are required to avoid high pressure pulsations.

Hence, besides a deeper understanding of the physical mechanisms contributing to combustion dynamics, real-time, reliable monitoring and control systems are required to make combustors more efficient and flexible, and guarantee gas turbine availability.[93]

Damage due to high frequency (2350 Hz) thermoacoustic instabilities following inappropriate tuning of the machine. Source: ETN[94]

NOx Reduction: The higher adiabatic flame temperature of H2 will result in higher NOx emissions if no additional measures are undertaken. It will be particularly a challenge to achieve even stricter NOx-limits foreseen in the future. Lowering the flame temperature by engine derating would result in efficiency and power decreases.

Applying post-combustion De-NOx technology (i.e., Selective Catalytic Reduction) is very difficult and costly. Therefore, reducing the combustor NOx emissions is the preferred path.

Moisture Content: Burning hydrogen instead of natural gas will increase the moisture content in the exhaust gas causing higher heat transfer to the gas turbine hot gas path components. This will require an adaptation of the cooling in order to avoid overheating of components. In addition, due to the higher moisture content hot corrosion is more likely to occur. Therefore, measures need to be undertaken to avoid these effects."[88]

Flashback: Flame speed of hydrogen is an order of magnitude higher than that of natural gas. Therefore, flashback is the dominant issue for modern lean premixed combustors on hydrogen fuel.

Flashback is the most severe concern around high H_2 levels in systems designed for natural gas, as the flame can propagate upstream and catastrophically damage hardware

The higher flame speed of H_2 increases the risk of flame propagation upstream closer to the injection points and into premixing passages, and "autoignition" when fuel spontaneously ignites upstream of the combustion chamber, in both cases burning in areas that are not designed for the highest combustion temperature. For dry low emission (DLE) combustors - the current industry standard - flashback and autoignition can cause failures of hardware in the combustor (as seen in the left picture below)[95].

Flashback damage to a fuel nozzle.[96]

Blow off: "Blowoff – Combustors have flow velocities that can exceed 100 MPH and so preventing the flame from flying downstream and out of the system is a major challenge. Because hydrogen propagates so fast, blowoff challenges are alleviated with hydrogen. However, this issue is compounded for fuel flexible combustors, which must avoid blow out with slower burning natural gas fuel and simultaneously avoid flashback with high hydrogen fuel. For these reasons, the highest hydrogen capability marketed for any frame engine with lean premixed combustion is 50% hydrogen by volume, and much lower for most systems."[97]

Heat transfer: "Heat transfer coefficients of combustion products fueled with hydrogen are higher than natural gas. Because the peak temperature in a gas turbine is controlled by heat transfer to the rotating turbine, this could necessitate a reduction in turbine inlet temperature as hydrogen levels increase"[97] which would mean lower efficiency or it may result in higher requirements for materials and potential (long-term) damage to the hot gas paths components and/or reduction of lifetime.

Flame detection: Furthermore, it must be considered that hydrogen flames are hard to detect with standard UV systems. Therefore, flame detection systems specifically configured for hydrogen must be developed.[97]

Technological implications

Combustor: Diffusion flame combustors have been historically used for the co-firing of hydrogen due to the high speed of turbulent combustion, low ignition energy and its tendency to deflagration-to-detonation transitions, which makes it difficult to use premix combustors.

Diffusion flame combustors can handle up to 100% vol. hydrogen. However, these systems have several disadvantages

including an efficiency penalty compared to systems without dilution, higher NOx levels compared to lean-premixed technology, higher plant complexity and thereby higher capital and operational costs.[98]

Other combustor types that have been successfully implemented for hydrogen blends are single annular combustors for aeroderivatives, single nozzle combustors for B and E class turbines and multi-nozzle quiet combustors for heavy duty turbines up to F class.[99]

In situations where NOx emissions are not a concern, many options are available to use hydrogen and hydrogen blends, including the ability to use legacy combustor hardware for a range of hydrogen and natural gas blending levels. In other words, the key challenges associated with using hydrogen are in low NOx combustion systems. So called "diffusion combustors" are an older technology that leads to high levels of NOx pollutants. These systems require water or steam injection to comply with the NOx regulations in modern air permits, which may be unattractive due to the cost and complexity of the water management systems. These systems need large volumes of clean, de-mineralized water, which introduces additional environmental considerations. In many places, such as the desert, water injection systems are not practical. Nevertheless, diffusion combustors have good fuel flexibility. Many of these systems operate today on fuels with very high hydrogen content, fuels that are naturally produced as biproducts of industrial processes in steel mills and petrochemical plants. Many of these diffusion combustors are 100% hydrogen capable but their deployment is limited to locations and economies where water/steam injection is viable for NOx control.

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

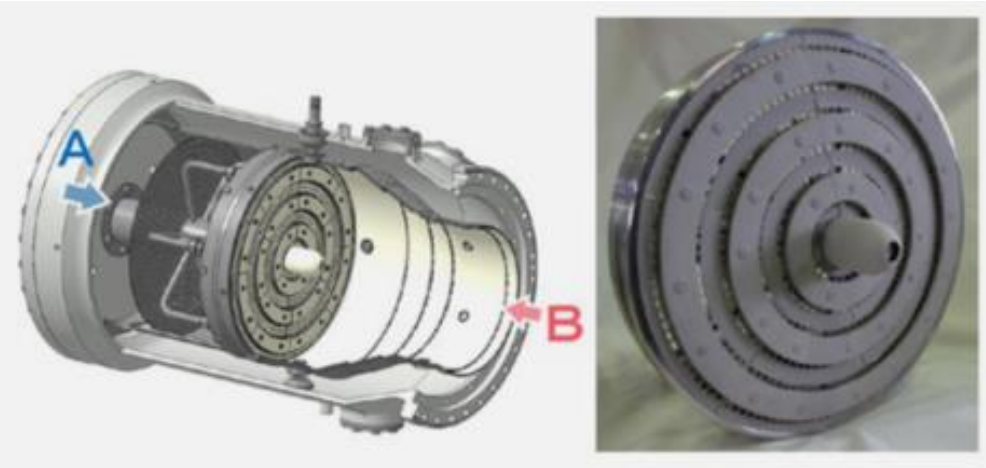
So called "lean, premixed combustors" are inherently low NOx systems, and can produce compliant emissions without any water or steam injection because they avoid the high temperature regions that produce NOx. Therefore, lean-premixed systems dominate new electric power plant installations and are the predominant technology in the power generating fleet. However, legacy DLE systems do not have the operational flexibility or fuel flexibility of diffusion combustors[100].

Lean-premix combustor technology has not been sufficiently developed yet with respect to operation on fuels with very high hydrogen content

or even pure hydrogen, together with high fuel flexibility[101]. These systems have a higher flashback risk. Consequently, the air to fuel mixing must be performed in a short time and in a confined space. For this reason, the applicability of lean premix systems has to be assessed case by case considering the peculiarities of each specific project. Again, two routes were traditionally followed. One was to develop further the water- or steam-injected diffusion burners to use hydrogen, the other was to redesign the DLE burners to burn hydrogen. Both approaches are being developed by manufacturers, with DLE being the ultimate goal[100].

The Micro-Mix DLE combustion chamber (MMX combustor) has been developed by Kawasaki using an interactive optimization cycle including experimental and numerical studies on test burners and full-scale combustion chamber investigations. The application of gaseous hydrogen as fuel in gas turbines is being investigated at Aachen University of Applied Sciences (AcUAS) where the low NOx Micro-Mix hydrogen combustion principle was invented. In 2011 Kawasaki Heavy Industries decided to cooperate with AcUAS and B&B-AGEMA to investigate the ability of the low NOx Micro-Mix combustion principle.

Below figure shows the prototype combustion chamber and Micro-Mix burner. The Micro-Mix burner with its three ring segments is implemented in a conventional can type combustion chamber. The rings are supplied with H_2 from the center which is connected via pipes to each ring segment. Each ring segment can be controlled individually depending on the power load.[102]

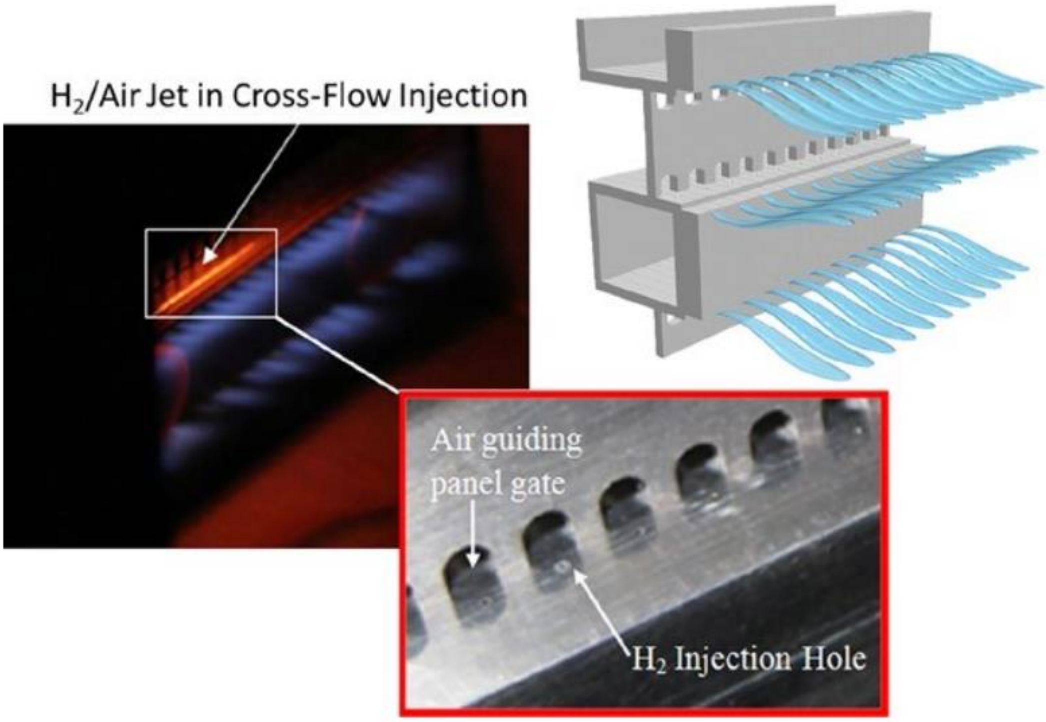


Source: Enhancement of fuel flexibility of industrial gas turbines by development of innovative hydrogen combustion systems. Nurettin Tekin, Mitsugu Ashikaga, Atsushi Horikawa, Harald Funke

"It is not advisable to handle hydrogen same way as natural gas, it is not enough to adapt existing technologies" states Dr.-Ing. Nurettin Tekin, Hydrogen Product Management at Kawasaki.

"Flame velocity, combustion stability, density, required ignition energy, just to mention some key differences between traditional fuels for gas turbines and hydrogen, which make the combustion chamber the most important element to rethink when burning hydrogen"[103].

"The Micromix combustor is a dry-low-NO_x combustor designed for 100% hydrogen. Since we realized that a high fuel flexibility cannot be (easily) achieved with traditional premix burners, we followed a totally different approach. First, we designed a combustor able to burn 100% hydrogen, then we are in the path (at present down to 50% natural gas / 50% hydrogen mixture) of making this combustor more flexible and able to operate with full fuel flexibility".



Source: Dr. Ing. Funke, Nurettin Tekin, Mitsugu Ashikaga, Atsushi Horikawa. Enhancement of fuel flexibility of industrial gas turbines by development of innovative hydrogen combustion systems. April 2019.

“The main challenge of burning hydrogen is the danger of flashbacks, the reason is that hydrogens flame velocity and reactivity is 9-10 times higher than natural gas. This is why it is so difficult to optimize a combustor for 100% hydrogen and for 100% natural gas”

When increasing the natural gas content in the fuel mixture, the risk of lean blowoff increases. Flame velocity is predefined by the diameter of the combustor holes, with higher content of natural gas the flame velocity is sensibly reduced. Although this is no major risk for the components, operational stability is endangered. Thus the challenge of full fuel flexibility is to optimize the combustor to operate with flame velocities between 30 cm/s and with 300 cm/s and find an operational path between flashback and blowoff, while keeping emissions and pulsations at acceptable levels.

The principle of micromix is to have not one but many (1000-1600) micro-flames (of 5-10 mm length). This miniaturization leads to a reduction of NOx emissions, due to a better temperature management and a reduced length of stay of the reactants in the flame. There is no premix, but a perpendicular feed of hydrogen and air (refer to above illustration), creating a transverse flow which ensures an improved air-fuel mix. In a nutshell, the advantages of the diffusion and of the premix combustor are combined.

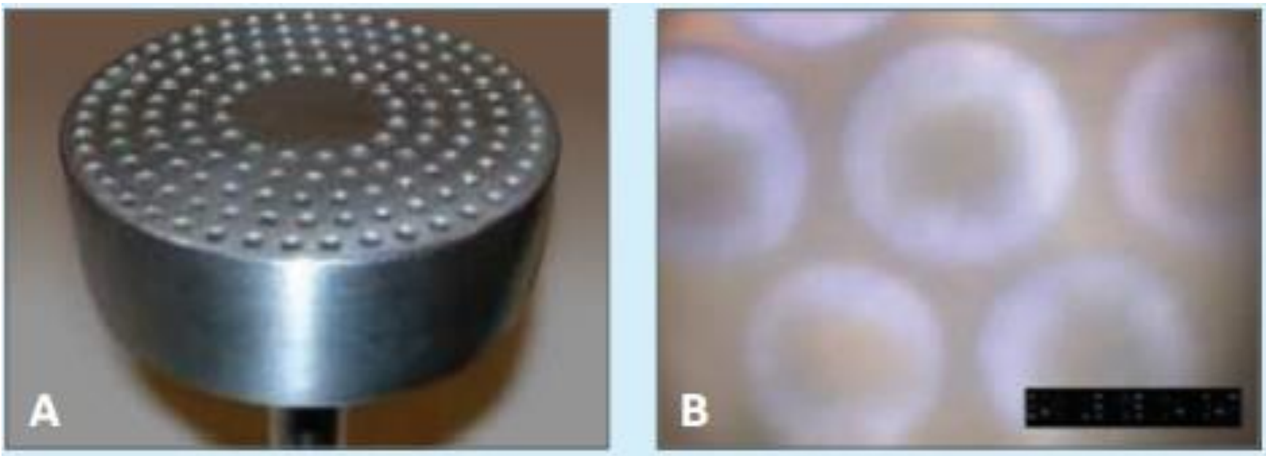
For the rest of the components, of course we need to adapt materials, valves, seals, detection systems, and firefighting to face increased risks of leaks through diffusion, but we believe that these risks are manageable. Also the risk of embrittlement is given and known, but with the right material selection and overhaul philosophy (full overhaul after 5 years or 40.000 EOH) this can be addressed. As an additional safety measure, our turbines start always with 100% natural gas, even if operating on 100% hydrogen to avoid risk of defective components or unproper purging”[103].

The next step is to build a hydrogen-powered gas turbine in cooperation with RWE in Lingen, Germany. The plant, which has a capacity of 34 megawatts (MW), could be operational by mid-2024.

“The first question when optimizing gas turbines to operate on hydrogen is: in which ratio of natural gas and hydrogen blending your client is focusing”

states Armin Städtler, SGT5-8000H Service Frame Owner at Siemens Energy. ”With existing and probably next generation burners you will have to focus on a determined bandwidth of hydrogen blending, you may have a burner system being able to operate from 0-30% hydrogen, next system may be able to handle 50% +/- 20% and next system will be perfect for 80-100% hydrogen“, when the client has defined this, you can start validating the rest of the hardware around the burner system”[104]

Current development of high hydrogen combustion systems includes as well multi-tube mixing concept (GE), which is based on the operating principle of small jet-in-crossflow mixing of the fuel and air streams.[99]



(A) multi-tube mixer concept hardware, (B) combustor test of multi-tube mixers on a H_2/N_2 fuel blend.[99]

Siemens has now set out to demonstrate that small industrial gas turbines using DLE are 100% hydrogen capable by 2023, and that all industrial and heavy-duty gas turbine with DLE technology are 100% hydrogen capable by 2030. The first test will come at the HYFLEXPOWER project. The installation of the gas turbine (an SGT-400) for natural gas/hydrogen mixtures and initial demonstration of advanced pilot plant concept is planned for 2022.[105]

Compressor-Turbine matching: Gas turbines are originally designed to run on natural gas or liquid fuels. Due to the higher volume flow rate in hydrogen combustion and the additional diluent for NOx control (steam, water, or nitrogen), using hydrogen alters the original design settings between the compressor and turbine. Therefore, a different running point has to be set by means of variation of the VGV angle, turbine inlet temperature (TIT) and pressure ratio.[106]

Nevertheless, most of the redesign efforts for hardware will be besides combustor, on the turbine side.

Depending on hydrogen content and combustors capabilities, a derating may be a preferred solution. When operating with diffusion burner systems and increased water or steam injection, components may reach some design limits due to the increased mass flow and derived hydraulic load. In any case and with all burner systems adapted to operate on hydrogen, the blade cooling needs special attention.

The temperature profile into the turbine changes sensibly, especially vane and blade stage 1 may require redesign, coating or even rework at the combustion system[104]

Blade cooling: Hydrogen combustion and additional dilution affect the cooling system. On one hand, the convective heat-transfer coefficient of the outer surface of the blade increases the thermal flux. On the other hand, higher pressure ratio increases the convective heat-transfer coefficient on the inner and outer blade surfaces well as the temperature of cooling air causing performance degradation.[107]

DeNOx: Hydrogen flames have a higher adiabatic flame temperature producing higher NOx levels. Therefore, a wet deNOx strategy, achieved by injecting water or steam, will remain necessary for diffusion burners. There is also an approach that includes the use of Nitrogen.

Auxiliaries: This includes additional systems such as gas blending systems, different gas sub-systems with dedicated control valves and piping, gas preheating system with adequate materials and temperature control in order to avoid damage due to H_2 embrittlement, purge system, ventilation, gas detection, fire protection, electrical cabinets, turbine control, diluent injection for diffusion combustion systems, gas blending / mix system, etc.[99]

HRSG: Modifications of the HRSG may include the installation of a supplementary duct burner in order to compensate for the lower GT exhaust temperatures, installation of SCR systems for NOx control, installation of necessary hydrogen gas detection etc., among others. Limitation of the lifetime of specific HRSG parts has to be carefully assessed.

Retrofitting of existing devices

There is no necessity to design and manufacture entirely new gas turbines for hydrogen combustion. Special attention is required on modifying the combustor and auxiliary parts, but most of existing gas turbines can theoretically be retrofitted to either partially or fully burn hydrogen. This conversion would not only avoid large capital spending but also save time in switching large fleets of current gas turbines to hydrogen.

"Most of the equipment may be mostly or is already amortized, thus the delta in investments will make retrofitting interesting, also it needs to be considered that a power plant is not only related to the gas turbine, nut HSRG, steam turbine, switch yard, cooling systems and permits"[104].

Not all gas turbines will prove suitable for retrofit modifications to enable hydrogen combustion, in part or in whole. Redesign work with associated testing on older models, for instance, may not be justified compared to the cost of replacing the machine with a more up-to-date model for which the work has already been done.[88]

While hydrogen combustion offers a promising energy storage and conversion pathway, it is not a "drop-in" fuel for much of today's natural gas fired energy conversion devices. In other words, alterations are needed in the fuel handling systems, valves and piping, and combustor hardware. These alterations are needed to address several issues of concern to stakeholders, including pollutant emissions, operability, and cost. These issues are highly interdependent.[108]

When using hydrogen as fuel, it is of utmost importance to take into consideration the delivery pressure and temperature in order to avoid embrittlement in the pipelines and other auxiliaries.

Existing piping and gas turbine valves shall be subject to retrofit when a gas turbine manifold running with natural gas is forecasted to run with H_2. Changes may include new valves design with a different sealing arrangement, and potentially new piping material.

While hydrogen embrittlement does not occur in stainless steel equipment at 50 barg and 100°C, increasing the temperature to around 200°C may cause H_2 migration through the material. Indeed H_2 embrittlement is a concern at temperatures above 200°C, although 316L grade stainless steel is considered quite suitable in reducing this effect. It is worth noting that, hydrogen embrittlement is not only related to temperature, but also to the stress endured by the material which affects the permeation of H_2.

Another point to consider is the incorrect purge of H_2 within the system. Indeed, the more components involved, the higher the likelihood for some H_2 to remain trapped within them, leading to explosion risks when doing maintenance or repair. On that basis, proper measurement apparatus for H_2 traces should be considered as part of any H_2 use with GTs. In addition, purge systems using CO_2 or nitrogen must be taken into consideration.[88]

A main issue is the installation of dedicated gas detection systems,

hydrogen is flammable and explosive over very wide ranges of concentrations in air at standard atmospheric temperature (4 - 75% vol. and 15 - 59% vol. respectively), its handling becomes a major safety concern in comparison to natural gas.

Same applies for operational procedures and behavioral issues of the operating and maintenance crews

Current development status of major gas turbines OEMs with hydrogen

Currently, typical hydrogen content values in gas turbine operation vary between 30-50% vol. for heavy duty engines and 50-80% vol. for industrial turbines and aeroderivatives. Currently, there isn't a commercially available fuel flexible gas turbine that can handle pure (100%) hydrogen. The experience gained by the main OEMs is outline in this section.

Mitsubishi-Hitachi: MHPS aims to have 100% hydrogen-fueled turbines certified in 2025, a groundbreaking engineering feat that will allow power plant operators with dual-fuel turbines to quickly migrate from today's natural gas and 30% hydrogen mix. The technology transitions to emission-free hydrogen without major infrastructure modifications or expensive plant downtime.

Today, the company has multiple types of combustors catering to individual project requirements and hydrogen densities. And its multi-cluster combustor can be installed in any size of project to power large, medium, or small gas turbines. A flexible gas turbine is also in the planning, designed to burn fuels with any mix ratio.

MHPS has extensive hydrogen firing experience in refineries, syngas and COG locations operating with hydrogen concentrations up to 90 % vol. This fleet is comprised of 31 machines that are equipped with diffusion burners. Combustion tests on DLN multi-nozzle combustor, which were newly developed for hydrogen co-firing, were performed successfully with a 30% vol. hydrogen mix in natural gas. The next stage is to reach up to 100% hydrogen.

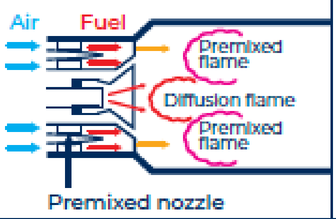
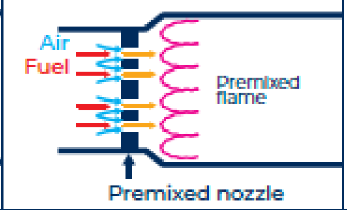
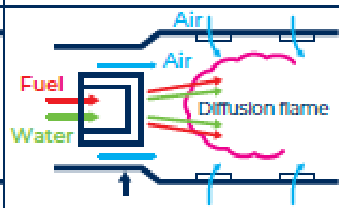
MHPS is also developing a multi-cluster combustor. This system has high flashback resistance and low NOx combustion. A rig test of this combustor has been accomplished for 80% vol. hydrogen co-firing. There are currently plans for operating the first M501 JAC using a mix of 30% hydrogen and 70% natural gas fuel by 2025. [109]

MHPS is also piloting a project converting one of three GT units (440 MW M701F) at Vattenfall's 1.3-GW Magnum CC plant in Groningen Netherlands to run 100% on hydrogen by 2023.

The Dry Low NOx (DLN) multi-nozzle combustor is a newly developed combustor for hydrogen co-firing. It is based on conventional DLN combustor technology, with the aim of preventing flashback. The air supplied from the compressor to the inside of the combustor passes through a swirler and forms a swirling flow. Fuel is supplied from a small hole on the swirler's wing surface and is mixed rapidly with the surrounding air thanks to the swirling flow effect.

Combustion tests were performed successfully with a 30% vol. hydrogen mix in natural gas and achieved a 10% reduction in carbon dioxide emissions compared to a natural-gas-fired power plant.

With such solution, it is possible to mix air and hydrogen at a smaller scale without using swirling flow, which may allow compatibility to both high flashback resistance and low NOx combustion. Combustion characteristics with 80% vol. hydrogen co-firing have been confirmed at rig test (see below MHPS combustor type overview).[88]

	Multi-nozzle combustor	Multi-cluster combustor	Duffusion combustor
Combustor type	**Premix**	**Premix**	**Diffusion**
Structure			
Dilution for low NOx	Not applicable (Dry)	Not applicable (Dry)	Water, steam and N_2
Cycle efficiency	No efficiency drop because of no steam or water injection	No efficiency drop because of no steam or water injection	Efficiency drop occurs because steam or water are injected to reduce NOx
Hydrogen co-firing ratio	**Up to 30% vol.**	**Up to 100% vol.** (under development)	**Up to 100% vol.**

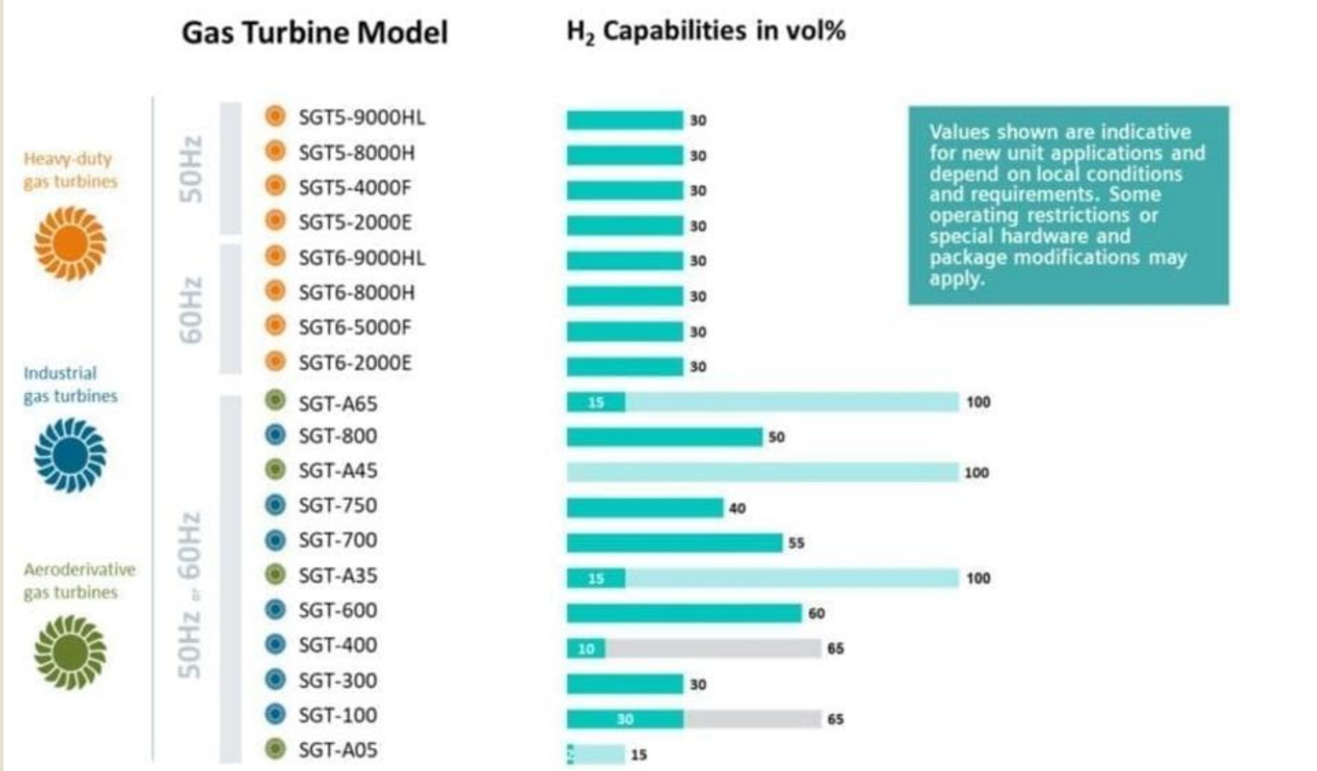
Source: ETN, Mitsubishi-Hitachi[88]

Siemens: Aeroderivative gas turbines can tolerate up to 100% vol. H_2 in diffusion combustion mode with NOx reduction using water. The industrial gas turbines series can achieve up to 65 % vol. hydrogen co-firing. Today's industrial gas turbines with the 3rd generation DLE system (SGT-700, SGT-800, and option for SGT-600) have capabilities to co-fire hydrogen up to 50 - 60% vol. H_2.

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

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

Siemens announced that all its aeroderivative units outfitted with WLE systems based on diffusion burner technology already fulfills the 2030 target of 100% hydrogen capability. WLE systems essentially use water, injected into the combustor, to reduce the combustion flame temperature, thereby reducing nitrogen oxide (NOx) emissions as well as boosting the gas turbine power output.



Source: Siemens Energy

But the company has said the next crucial step will entail enabling high-temperature combustion for its DLE systems to extend the fleet's 100% hydrogen combustion capabilities.

DLE technology essentially works by mixing fuel and air prior to combustion in order to precisely control flame temperature, which allows the control of the rates of chemical process that produce NOx emissions. However, "Hydrogen's higher reactivity poses specific challenges for the mixing technology in DLE systems," Siemens explained. "The acceptable fuel fraction of hydrogen depends on the specific combustion system design and engine operating conditions." Although Siemens' DLE combustion systems generally use swirl stabilized flames combined with lean premixing to achieve low NOx without dilution of the fuel, pushing hydrogen volumes beyond 50% and up to 100% requires hardware and control system changes—such as a new burner design.[87]

General Electric: GE's newest combustion system, the DLN 2.6e, includes an advanced premixer developed as part of the US Department of Energy's High Hydrogen Turbine program. The advanced premixer, unlike the DLN 2.6+, utilizes miniaturized tubes functioning as "fast" mixers. This miniaturization enables premixed combustion for gaseous fuels with higher reactivity (i.e. hydrogen).

The DLN 2.6e combustor with the advanced premixer has demonstrated the capability to operate on a 50% (by volume) blend of hydrogen and natural gas. As this technology was developed from a program intended for high hydrogen fuels, it has capability beyond 50% hydrogen; an internal roadmap has been developed, mapping out the steps to reach 100% hydrogen.

The experience with the DLN 2.6e combustion system is not limited to the lab. It has operated on 100% natural gas at full speed, full load on both 7HA and 9HA gas turbines. The first unit with this combustion system was shipped in 2018.[88]

In April 2022, GE announced the successful commissioning of its first advanced class hydrogen-burning power plant using at Long Ridge, USA. The plant is powered by a GE 7HA.02 gas turbine, which can burn between 15-20% hydrogen by volume in the gas stream initially and is expected to have the capability to utilize up to 100% hydrogen over time. For the demonstration, GE provided an integrated system – GE's H_2 Integrated fuel blending system - to allow an initial blending of 5%

hydrogen by volume and natural gas to demonstrate the capability. The blended fuel was injected to the combustion system of the gas turbine, and further upgrades will allow the power plant to utilize higher percentages of hydrogen subject to fuel availability and economics.

Ansaldo: There are two AE94.3A units operating commercially on various hydrogen / natural gas blends, achieving hydrogen concentrations up to 25% vol. Additionally, full scale, single burner high pressure tests were performed for the existing Ansaldo GT26 standard premix and reheat burners with blends of 15 to 60% vol. H_2 in natural gas. Further validation is ongoing, including full-scale, high-pressure tests.

The GT36 is offered for commercial operation with hydrogen fuel content up to 50% vol. Ansaldo also offers a "Flame Sheet Combustor", as a retrofit solution for hydrogen operation for existing GE, Siemens and MHI, E and F-class machines. Currently, seven F-class GE machines were retrofitted with these burners. Current studies are being done in order to demonstrate 0-100% hydrogen capability with less than 9ppm NOx emissions.

Kawasaki: The DLE Micro-Mix combustion principle for hydrogen fuel has been in development for many years to significantly reduce NOx emissions. This combustion principle is based on crossflow mixing of air and gaseous hydrogen which reacts in multiple miniaturized "diffusion-type" flames.

The second development is based on a conventional DLE combustor with hydrogen injection over the supplemental burner up to 60 Vol% hydrogen, which correspond to 30 % of the total thermal input. Basically the DLE combustor of KHI has pilot, main and supplemental burners.

Usually natural gas is supplied from the supplemental burners. Within this combustor, it can be switched from natural gas to hydrogen or natural gas and hydrogen mixing gas fuel via the supplemental burner.

Solar: Solar Turbines has gathered experience in China with 40 Titan 130 and Taurus 60 generator sets operating on Coke Oven Gas (COG) with a hydrogen concentration of about 25 %. These machines have diffusion combustors installed. Solar also introduced the SoLoNOx combustion system. Direct experience on the SoLoNOx platform is currently limited to a refinery generator set application where a Titan 130S has operated with natural gas mixed with up to 9% vol. hydrogen.

Industrial turbines: Theoretical and experimental studies are also being currently carried out by MAN for the THM and MGT industrial gas turbine families and by Baker Hughes for the NovaLT industrial gas turbine family.

The ultimate research & development target is thus the achievement of state-of-the-art low NOx emissions (< 25ppm) with fuel gas mixtures containing increasing amounts of (green) hydrogen (from electrolysis) up to 100% H_2. So far new/modified combustion technologies based on current dry low emission (DLE) combustion techniques (lean premixed combustion without dilution and/or water injection) is the main line of research & development activities. With such adapted DLE combustion systems OEMs (Ansaldo, Baker Hughes, General Electric, MAN Energy Solutions, Mitsubishi Hitachi Power Systems, Siemens, Solar Turbines) report of successful testing of frontrunner gas turbine products operated with fuel gas mixtures with up to 20% vol. H_2 (or even 30% vol. H_2). In some of these cases a de-rating of the gas turbine engine is still required (de-rating accomplished by reduced flame temperature). Combustor developments with novel combustion concepts (e.g. micro mixing concepts and constant pressure sequential combustion) are also being pursued and have shown promising results on gas turbine test bench installations.[88]

Fuel cells power plants

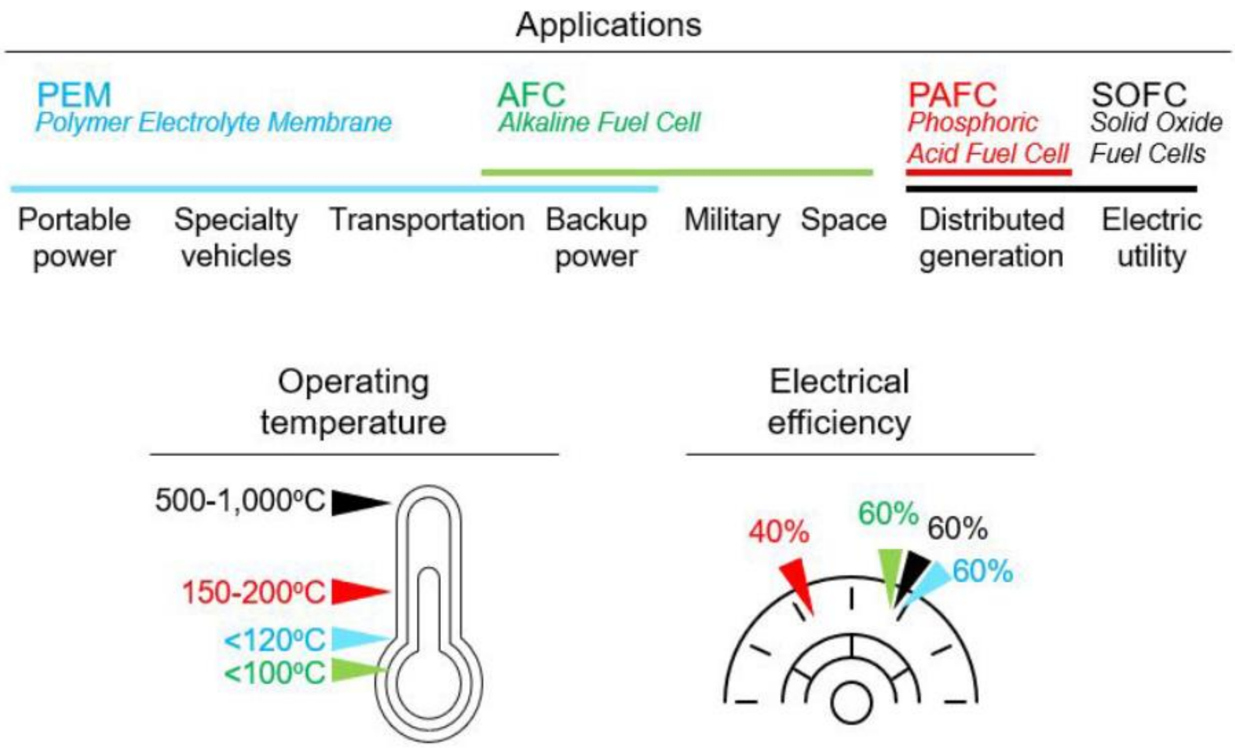
Fuel cells are a very interesting alternative for conventional power generation technologies because of their high efficiency and very low environmental effects. In conventional power generation systems, fuel is to be combusted to generate heat and then heat is converted to mechanical energy before it can be used to produce electrical energy. The maximum efficiency that a thermal engine can achieve is when it operates at the Carnot cycle.

On the other hand, fuel cell operation is based on electrochemical reactions and not fuel combustion. Bypassing this conversion of chemical energy to thermal and then mechanical energy enables fuel cells to achieve efficiency potentially much higher than that of conventional power generation technologies. A fuel cell can be considered as a “cross-over” of a battery and a thermal engine. It resembles an engine because theoretically it can operate as long as fuel is fed to it. However, similar to a battery, its operation is based on electrochemical reactions. This combination provides significant advantages for fuel cells[110].

Improved cell performance is required to ensure lower cost and enhanced durability for the range of fuel cell technologies. But also stack water and system thermal management require some further development, system air management meaning compressors and/or expanders need dedicated design for low/high temperature applications and startup/shutdown/transient operations requires optimization[111].

It is expected that different fuel cells systems will serve a certain market depending on efficiency, operational parameters, and economics.

Below an overview of expected use by technologies.



Source: U.S. Department of Energy. www.energy.gov

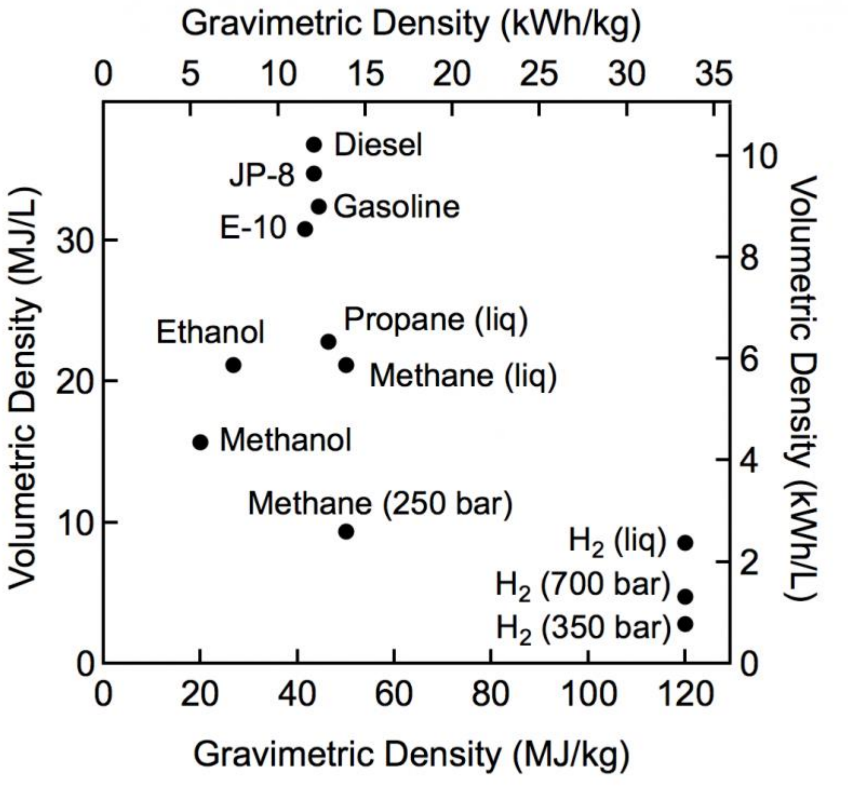
Annex 1: Technical assessment of fuel cells provides an overview of relevant technologies, describes technological challenges and associated risks

4. Industrial and large-scale storage of hydrogen

Similar to natural gas or oil, hydrogen is exceptionally suited to store large quantities of energy for long durations due to the potential energy being locked up in its chemical bonds. Thus, it can be stored for months as well as be transported without losing its power, unlike electrical storage systems which depreciate in power over time. This makes hydrogen a great way to store surplus energy produced from electrical power plants and intermittent renewable energy sources - known to cause oversupply when the sun shines or the wind blows, for example.

As such, stored hydrogen can be used to stabilize energy distribution in national grids or as a backup power to handle disruptions in the production/supply of energy for telecommunications, emergency services or basic infrastructure. Because hydrogen allows the storage and transport of renewable electricity efficiently over long periods it is considered a key enabler of the transition to renewable energy and by 2030, 250 to 300 TWh of surplus renewable electricity could be stored in the form of hydrogen for use in other segments.[112]

With the coming of hydrogen infrastructure, it will be necessary to store hydrogen in several links of the chain from production to end consumers and in connection to centralized locations for hydrogen production and distribution. Thus, for large scale hydrogen storage, multiple static and mobile storage options must be considered as well as safe dispensing technology.



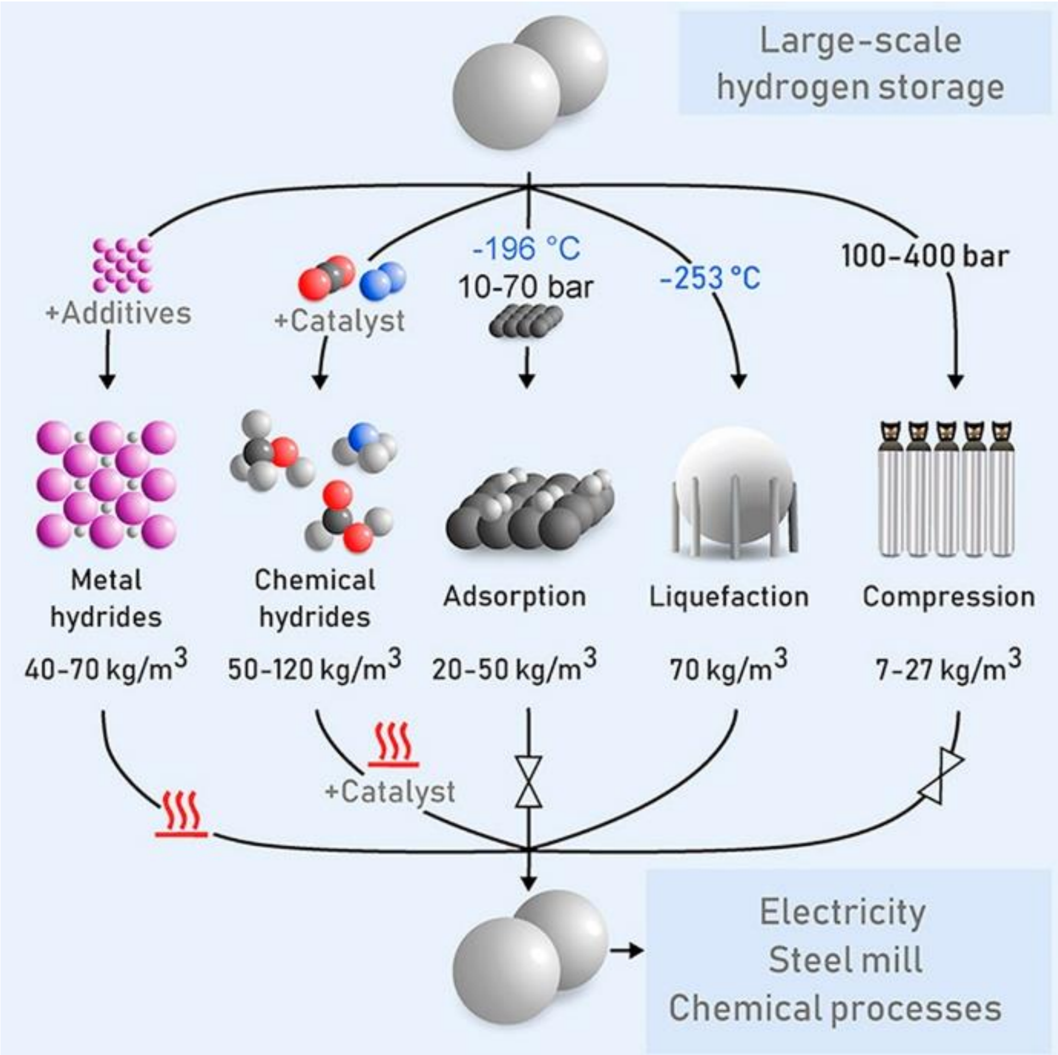
Source: DoE Hydrogen storage: Energy density of various fuels[113]

One of the main challenges with the global adoption of hydrogen fuel is related to its storage. Although H_2 has the highest gravimetric energy density of all fuels (~33.3 kWh/kg – 3 times higher than gasoline), the volumetric energy density is considerably lower (0.0028 kWh / L) due to hydrogen existing as a gas across most accessible temperatures and pressures (H_2 gas density 0.009 kg H_2/m^3). Comparing hydrogen to gasoline at standard temperature and pressures[114], the volumetric energy density is 0.0028 vs 9.5 kWh / L meaning much larger vessels are required to store equivalent energy. Likewise, batteries of today can store between 0.25-0.67kWh/L, much more than hydrogen gas[115]. Thus, the technologies around hydrogen storage are primarily aimed to increase the volumetric density of the fuel to make it a more compact energy source (i.e. increase kgH_2 / m^3). However, for stationary applications, vessel size limitations may be less of a concern than for portable applications.

Several methods currently adopted for hydrogen storage are:

- As a compressed gas
- As a cryogenic liquid
- Stored on the surface or in the pores of a material (adsorption)
- Chemically stored, bonded to other atoms/molecules (metal or chemical hydrides)

These are displayed in the image below and their approximate densities of stored hydrogen.



Source: Joakim Andersson, Stefan Grönkvist.[116]

Each storage method has its positives and drawbacks. Key considerations other than cost for use and adoption are the system's volumetric and gravimetric energy density, its operating temperatures and pressures, scalability, charging/discharging rate, temperature and/or pressure management systems required that could increase costs and weight as well as packaging and durability.

Key considerations for safety and risk management revolve around operating pressures and temperatures, material compatibility and fire rating, surrounding storage environment, leak detection.

Under pressure

Gaseous hydrogen storage systems typically require compressed gas vessels like tanks which can withstand pressures up to 700 bar. Liquid hydrogen storage on the other hand requires extremely low temperatures because its boiling point at atmospheric pressure is 253°C.

Hydrogen from the electrolyser is in gaseous form, normally from atmospheric pressure to 30 bar. With increased pressure the volume will decrease and will save a lot of space. Increasing the pressure from atmospheric to 70 bar will reduce the gas volume by a factor 65. Compression costs are normally low compared to production costs.

At 700 bar, which is 700 times normal atmospheric pressure, hydrogen has a density of 42 kg/m^3, compared with 0,009 kg/m^3 under normal pressure and temperature. At this pressure, 5 kg of hydrogen can be stored in a 125-liter tank.

The most mature and industrially utilized hydrogen storage method to date is compressed hydrogen gas in tanks/cylinders. Key differences are found between the composition and storage pressures. Below an evaluation of state-of-the-art industrial under pressure storage performed by Clean Carbon Conversion AG as reference.

	Type 1	Type 2	Type 3	Type 4
	Steel	Metal steel/aluminium tank and composite fiber (hoop wound)	Composite with thick metal liners fully wrapped.	Carbon Fiber Composite HDPE lining
Normal Economic Pressure Range	175 Aluminum and 200 Bar Steel (350 bar special applications)	300 Bar	700bar Normal (1000 bar Special)	380 or 500 Bar (normal applications higher 700 bar in special applications)
Storage Mass	Unlimited	Unlimited		Up to 1164 kg transportable
Transportability	Generally, too heavy. Some are transportable but inefficient	Better Than Type 1 but still heavy	Improved capacity versus weight but still limited standard road transport	ADR Approved as Standard and below street legal weight limits

Typ I

Typ II

Typ III und IV

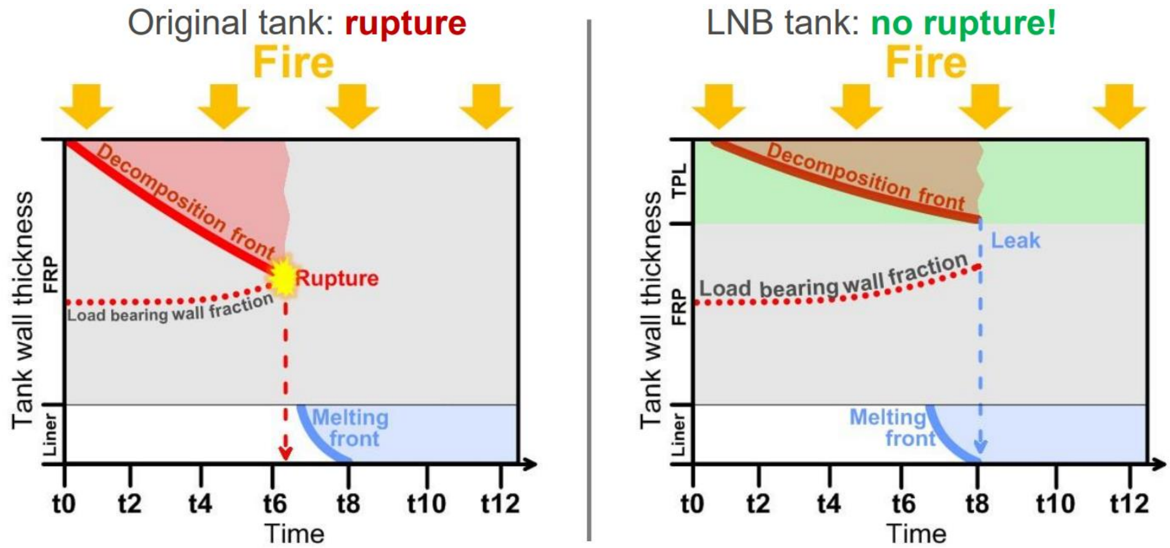
Type 1 represents the heaviest type of tank composed of all metal (typically steel) storing ~ 1 wt.% of hydrogen at 200-300 bar, the density of H_2 in these tanks reaches ~20 kgH_2/m^3. Type 2 tanks combine hoop wrapping a metal liner tank in composite fibers, reducing overall mass. Because of their metal composition, over time hydrogen embrittlement issues are to be considered for Types 1 and 2.[117]

Type 3 tanks are fully wrapped fiber-resin composite cylinders with a metal liner made of aluminum, contributing to >5% mechanical resistance. These materials are less affected by hydrogen embrittlement problems. Type 3 tanks reduce mass from type 1 and 2 by 25-75% and are rated to 700 bar, significantly increasing the H_2 wt.% of the vessel. At 700 bar, (700 times normal atmospheric pressure) hydrogen has a density of 42 kg H_2/m^3, compared with 0.009 kgH_2/m^3 under atmospheric pressure and temperature. At 700 bar, ~5 kg of hydrogen can be stored in a 125-litre tank[113]. Type 4 tanks are fully wrapped composite cylinders with a thermoplastic liner, acting as the hydrogen permeation barrier and reducing the cylinder weight further[117], Type 4 tanks have been shown to provide 5.5 & 5.2 wt.% and 18.5 & 24.6 kg H_2/m^3 of hydrogen at 350 and 700 bar, respectively.

The composite wrap in type 2-4 is typically made up of carbon fiber or carbon/glass fiber in an epoxy matrix and provides the structural integrity that allows the high pressures reached. However, due to the composite fiber wrapping process, these types of tanks are costly, and sizing is limited by composite wrapping technology. Whereas type 1 vessels can potentially reach any size, useful for static operations. However, stacking multiple small storage cylinders reduces the load on compressors and vacuum equipment used. Compression costs are normally low compared to production costs.

Future developments:

An interesting area of development is in the area of fuel tank safety. Recent experimental evidence of 'leak no burst' technology has been developed for type 4 composite tanks at the University of Ulster[118,119,120]. Whereby the heat transfer from a fire through the composite wrapping (FRP) to the thermoplastic liner can be managed by a thermal protection layer (TPL) before the cylinder loses its load-bearing ability and ruptures (see image below). Here, the TPL layer and composite wall thickness allow the thermoplastic liner to melt in a suitable timeframe to allow microleaks of H_2 through the semi-porous composite wall and to the cylinder surface before cylinder decomposition. Rather than long hydrogen jet fires that can be emitted from a TPRD, the entire cylinder slowly leaks H_2 causing either: micro-sized flames across the surface or decay below the lower flammability limit until the internal tank pressure is reduced to atmospheric pressure, all before the composite wall loses its load-bearing ability and catastrophic pressurized rupture occurs.



Source: H2FC Supergen HySAFER research talk 2019[121]

This technology was chiefly developed with hydrogen-powered vehicles in mind, as such, the level of risk for 'leak-no-burst' technology is assessed to be lower than fuel tanks in fossil fuel-powered vehicles. The technology also addresses the concerns of firefighters and rescue services, especially in confined spaces like tunnels where the blast wave practically does not decay, and the fireball propagates with unacceptable high velocity.

The managed heat transfer, regulated release, and micro flames of 'leak-no-burst' technology present a superbly safe storage option if the technology can be brought to an industrial, commercial scale and will likely be widely adopted across the hydrogen spectrum in the coming decades if so. Ultimately, this type of advancement in the level of safety could help sway public opinion on hydrogen away from the image of the 1937 Hindenburg disaster, classically associated with hydrogen vessels.

Potential hazards for gaseous storage

- Difficulty in identification of hydrogen release as the gas is odorless, and colorless. The odorants cannot be added to hydrogen.
- Hydrogen can cause embrittlement of metals. This may result in the decrease of material strength and consequently in container's fracture, leading to a hydrogen leak.
- Accumulation of hydrogen, over a long period of time, in enclosures.
- An explosion driven by chemical reaction (combustion deflagration of detonation) or physical explosion (vessel overpressure)
- Formation of hydrogen-oxygen or hydrogen-air flammable mixtures. The intake of flammable mixture into a building ventilation system may lead to a deflagration or even to a detonation.

- High pressure hydrogen jets may cut bare skin.
- Hydrogen can be ignited easily as its MIE is 0.017 mJ (which is 10 times lower compared to other fuels). A static spark can ignite hydrogen released.
- When pure hydrogen is burning its flames are invisible in the daylight.
- Hydrogen burns rapidly and does not produce smoke.
- Puncture of the storage vessel wall
- An external fire, heat or thermal radiation can cause a mechanical rupture of a tank due to the thermal decomposition of the polymeric and composite materials. The current value of fire resistance (publicly available) is up to 12 minutes before the catastrophic failure may occur.
- In case of a TPRD malfunction, a worst-case scenario is possible: a rupture (i.e. a catastrophic failure) of the hydrogen storage tank, producing a fireball, blast waves and burning projectiles.

"The major concerns related to compressed gaseous hydrogen include: the large amount of energy needed for the compression; the stress on the containers' materials caused by repeated cycling from low to high pressures; the inherent safety issues for the use of such high pressures in pressurized vessels (projectiles); as well as fire safety rating of the tanks and pressure relief mechanisms. The design and manufacture, transportation and use of vessels suitable for pressurized hydrogen storage are regulated by government agencies. The designed hydrogen storage vessels (as well as the materials they are made of) should comply with the requirements of RCS developed by ISO, CGA, ASME".[122]

"The main safety feature employed for hydrogen storage systems is the pressure relief device, to protect against failure of the vessel by releasing some or all of the tank in the event of high temperatures or pressures. In the event of a fire, a Thermally Activated Pressure Relief Device (TPRD) provides controlled release of the gaseous hydrogen from a high-pressure storage container before its walls are weakened by high temperatures, leading to a catastrophic rupture. PRDs are designed according to codes and standards. PRDs should be manufactured, installed, operated, maintained, inspected, and repaired according to the laws and rules of local jurisdictions. According to the European Commission Regulation (EU) No 406/2010, the onboard hydrogen storage must be fitted with PRDs/TPRDs."[122]

For large-scale compressed gas storage, cylinders should be located outside, away from ventilation intakes, at a safe distance from structures and shielded from vehicle impact. Cylinders should also be protected against extreme temperatures (from -20 ˚C to 50 ˚C) and securely anchored to non-combustible foundations. To prevent interaction between cylinders during unintended hydrogen release, distances between cylinders should be considered.

For more detailed guidance on the provision of fundamental safeguards for generation, installation piping, storing, use and handling of compressed hydrogen gas or cryogenic liquid hydrogen, see example standards set by NFPA 2 Hydrogen technologies documentation.[123]

Furthermore, further education and information on dealing with safety and risk associated with the storage of hydrogen and hydrogen fires can be found in the HyResponder programme from the European Union's train the trainer programme for responders.[124]

Liquid form

A state-of-the-art form of storing hydrogen at large quantities in a restricted volume is to convert gas to liquid by cooling it down to very low temperatures. Hydrogen turns to liquid when it is cooled down to a temperature of 252,87 ˚C, at atmospheric pressure. At liquid form and atmospheric pressure, hydrogen has a density of 71 kg/m^3. At this pressure, 5 kg of hydrogen can be stored in a 75-liter tank, this increases the volumetric energy density to ~2.3 kWh/L[114].

To maintain liquid hydrogen at this low temperature, the storage tanks need to be perfectly isolated. Storage tanks design is based around a dewar, with a vacuum insulated double-walled vessel and provisions for cooling, heating, venting and to achieve even higher volumetric densities, as in the case of cryo-compression storage devices, a high-pressure compressor. Disadvantage with storing liquid hydrogen is the energy needed to bring it down to liquid (-253°C) and to maintain it in liquid form. Between 30% and 40% of the hydrogen energy content is consumed. The advantage is the smaller storage volume. Currently there are only a few examples of liquid hydrogen tanks being placed in a room underground or being buried underground.

LH_2 storage is subject to boil-off which can occur from several factors including residual thermal leaks, sloshing of H_2 inside the vessel, flashing from high pressure to low pressure, and conversion of ortho-to-para hydrogen inside the vessel. Boil-off requires the prevision of pressure relief devices and a boil-off system on LH_2 storage vessels and is a major safety consideration in design.

All of the major industrial gas suppliers have cryogenic delivery tankers. LH_2 is used at hydrogen refueling stations and in airspace applications. In the US, there are over 450 large-scale LH_2 storage sites, with the largest located at the space center in Cape Canaveral with a capacity of 3800 m^3 shown in the image below.

Source: Nasa | Cape Canaveral LH2 storage[125]

Kawasaki Heavy Industries has launched the first liquefied hydrogen carrier worldwide. The vessel was developed to provide a means of transporting liquefied hydrogen at 1/800 of its original gas-state volume, cooled to –253°C, safely and in large quantities over long distances by sea. Kawasaki was planning to install a 1,250 m^3 vacuum-insulated, double-shell-structure liquefied hydrogen storage tank, currently being manufactured at Harima Works, on the ship and complete the vessel's construction by late 2020[126].

On 25 February 2022, the Suiso Frontier returned to Kobe in Japan. Therefore, it delivered the world's first cargo of liquefied hydrogen to the country. The cargo was generated from Victorian coal.

Potential hazards for liquid storage

- A loss of LH_2 containment. A damage of the external tank walls can lead to the disruption of vacuum, causing heating and subsequent pressure rise inside the vessel. This should be avoided wherever possible.
- Formation of oxygen-enriched atmospheres. The condensed air may form oxygen enriched atmospheres in the vicinity of LH_2 storage. The solid deposits formed by condensed air and LH_2 could be enriched with oxygen. This poses a risk of explosion if the external wall tank is damaged. The mechanism is considered as a possible reason for a powerful secondary explosion occurred during large-scale LH_2 release experiments at HSL.
- The boil-off. Pressure build-up is possible until the boil-off valves open.

- Ice formation. Low temperatures may result in ice build-up on the storage elements (e.g. valves, dewars) leading to an excessive exterior pressure, and to a possible rupture of the vessel.

Solid form

Hydrogen can be stored in an alternative, solid storage format known as materials-based storage. This can be via adsorption of hydrogen onto surfaces of solids / inside porous materials or by being chemically bonded within solid materials (absorbed) to create chemical hydrides, this is sometimes referred to as chemical hydrogen storage.

Chemical hydrogen storage: The term "chemical hydrogen storage" is used to describe storage technologies in which (1) hydrogen is released from a material through a chemical reaction and (2) the hydrogen is restored through a chemical reaction when the material is being recharged. Typically these take the form of finely divided powders. Common reactions involve heating chemical hydrides to release hydrogen and/or reacting chemical hydrides with water or alcohol.[127]

An example is to form solid metallic hydrides (MH_x) through the reaction of hydrogen with certain metal alloys. This is the result of the reversible chemical combination of hydrogen with the metal atoms that comprise these materials. Hydrogen can be stored in this format with high volumetric densities (40-70 kg H_2/m^3) and then released via thermal decomposition of the material. One of the promising candidates for stationary applications is the alanates (aluminum hydride-based alloys), such as magnesium and sodium alanates. For example, sodium alanate exhibits a high theoretical volumetric density of ~47 kg H_2/m^3, releasing ~ 3.7 wt.% H_2 at around 190˚C.[128]

One of the benefits of working with metal and chemical hydrides is that high pressures are no longer required, reducing inherent risks associated with high-pressure cylinders. Furthermore, they are typically designed to be stored at room temperature, so no cryo-refrigeration system is required. However, the high decomposition temperatures (typically >300 ˚C), thermal management/cycling of storage systems and morphological degradation of these materials are current challenges for this storage format. This storage technology is still in the R&D phase and thus commercial delivery of these systems is in its nascency but will likely occur over the coming decade. Before considering large-scale applications, certain key parameters such as kinetics (cell performance), and the temperature and pressure of the charge and discharge cycles of hydrogen in these materials need to be mastered.[129]

Additional safety implications to be aware of are that metal hydrides are typically pyrophoric materials and will ignite spontaneously with air or water (the same as lithium-ion batteries). Thus storage vessels require to be airtight. Vessels should also be designed with a safety margin to withstand the pressure of fully dehydrogenated material samples and/or be equipped with appropriate pressure relief devices. Other chemical hydrides may be more stable and not pyrophoric, but chemical safety data such as toxicity and accidental release measures of the storage chemical should be considered.

Adsorption based storage: Another method to increase the volumetric density of hydrogen is to adsorb it onto the surface of sorbent material with small enough pores. These types of materials can be thought of as "molecular sponges" that can densify the hydrogen to approach the density of liquid or solid hydrogen at lower pressures. By packing pores of the solid sorbent with hydrogen like this, total volumetric densities of the porous material + hydrogen between 20-50 kg H_2/m^3 are achievable. This means only a fraction of the pressure (1-50 bar) is required compared to hydrogen under compression without an adsorbent.

In comparison to chemical hydrides, only small changes in temperature or pressure are needed for hydrogen to be released from the surface/pores. This is because the energy binding the hydrogen to the surface is much weaker than a chemical bond. Ultimately, this allows for much faster adsorption-desorption kinetics and comparably lower working temperatures for adsorption-based storage.

Ideally, these sorbent storage systems are designed to be packed inside a storage tank, operating at room temperature and between 1-70 bar, significantly reducing safety and design considerations associated with high pressure compressed gas storage. One of the advantages of storing hydrogen via adsorption is that in case of an accident, hydrogen is released not instantaneously but gradually over time, which significantly reduces the risk of explosion and is a huge plus for a safe operation. The reduced operating pressures can reduce the load-bearing requirement for storage tanks, but the added sorbent material increases the tank weight considerably.

Although gas sorbent materials do operate and store hydrogen at room temperature, much better hydrogen storage capacities are achieved at lower temperatures. For example, at liquid nitrogen temperatures (-196 ˚C), the porous activated carbon, AX21, has a hydrogen storage capacity of ~5.2 wt.% when pressurized to 30 bar. But at room temperature and a slightly increased pressure of 50 bar, it only has a hydrogen storage capacity of ~0.5 wt.%[130]. This is the same for all sorbent materials, with reduced storage capacities found at room temperatures. Because of this, cryogenic storage vessels similar to those for LH_2 storage options as well as cryocharging gas cylinders (loading with cold, low-pressure H_2 and allowing to warm up and pressurize)[131] are under consideration for this method of storage. However, this has added cost considerations to the tank design and results in increased cost per kWh of hydrogen.

Currently, known sorbent systems do exhibit a high enough hydrogen storage capacity at room temperature to compete with the cost of compressed gas hydrogen storage (without a sorbent), thus, the technology remains within the R&D stage, with limited commercial examples available.

A variety of parameters affect the hydrogen storage capacity of these sorbent/porous materials: surface area, pore size, pore volume and the strength of interaction with the surface. Materials with high surface areas (>1000m^2/g) are considered for this application such as nanostructured carbons, metal-organic frameworks, and porous organic polymers. Metal-organic frameworks exhibit the highest hydrogen storage capacities of all the materials but are the least stable and have high fabrication costs. Although nanostructured carbons and porous organic polymers currently exhibit lower hydrogen storage capacities, they offer considerably lower fabrication costs and increased stability making them more commercially viable sorbents. Widescale research is currently devoted to increasing the operating temperature of sorbents by optimizing pore size or increasing the H_2-surface interaction energy.

Additional risks to consider for this form of storage is the chemical safety data related to the sorbent material used, and accidental release measures required. Before considering large-scale applications, it is also important to master certain key parameters such as kinetics (cell performance), and the temperature and pressure of the charge and discharge cycles of hydrogen in these materials.[132]

LOHC (Liquid Organic Hydrogen Carriers)

In addition to the solid chemical hydrogen storage options mentioned in the previous section, research efforts to store hydrogen chemically in liquid carriers, such as liquid organic hydrogen carriers (LOHCs) or ammonia, have been conducted. Hydrogen can be safely stored in LOHCs at room temperature and atmospheric pressure before being extracted at locations for use. Studies has been done on Liquid Organic Hydrogen Carriers LOHCs where for example methylcyclohexane (MCH) and Monobenzyltoluene (MBT) are promising candidates.

In addition to ongoing research collaboration with Hyundai Motor Group and Korea Gas Corporation, international collaborative research projects with Germany and Japan are being planned to widely disseminate this generalized benchmarking LOHC study platform for accelerating LOHC deployment in the hydrogen economy.[133]

Large scale storage

For storing hydrogen in large quantities there are mainly two ways of storing hydrogen, either in above ground vessels/tanks where the volumes normally can be up to around 1000 m^3 with operating pressures up to 1000 bar or in underground caverns with large volumes and operating pressures up to 250 bar. Compared to storage options on the surface, underground gas storage facilities can store much larger quantities of gas. Due to reasons of material properties and operating costs, large amounts of gaseous hydrogen are usually not stored at pressures exceeding 100 bar in aboveground vessels and 200 bar in underground storages. Storing hydrogen at high pressures above ground in vessels are expensive and requires advances materials. Storing in caverns at lower pressure requires less compression work and therefore lower operating costs. However, by storing in above ground vessels, a high level of purity can be ensured, in underground geological storage, hydrogen purity can potentially be affected depending on the quality of cavern lining or the presence of microbial degradation. Rock- and salt caverns are potential options for storing large quantities of gas.

Below is a list of reference projects for large scale storage.

Existing hydrogen storage facilities and planned projects

Name	Country	Project start year	Operator/ developer	Working storage (GWh)	Type	Status
Teeside	United Kingdom	1972	Sabic	27	Salt cavern	Operational
Clemens Dome	United States	1983	Conoco Philips	82	Salt cavern	Operational
Moss Bluff	United States	2007	Praxair	125	Salt cavern	Operational
Spindletop	United States	2016	Air Liquide	278	Salt cavern	Operational
Underground Sun Storage	Austria	2016	RAG	10% H_2 blend	Depleted field	Demo
HyChico	Argentina	2016	HyChico, BRGM	10% H_2 blend	Depleted field	Demo
HyStock	The Netherlands	2021	EnergyStock	-	Salt cavern	Pilot
HYBRIT	Sweden	2022	Vattenfall SSAB, LKAB	-	Rock cavern	Pilot
Rüdersdorf	Germany	2022	EWE	0.2	Salt cavern	Under construction
HyPster	France	2023	Storengy	0.07-1.5	Salt cavern	Engineering study
HyGéo	France	2024	HDF, Teréga	1.5	Salt cavern	Feasibility study
HySecure	United Kingdom	mid-2020s	Storengy, Inovyn	40	Salt cavern	Phase 1 feasibility study
Energiepark Bad Lauchstädt Storage	Germany	-	Uniper, VNG ONTRAS, DBI Terrawatt	150	Salt cavern	Feasibility study
Advanced Clean Energy Storage	United States	mid-2020s	Mitsubishi Power Americas Magnum Development	150	Salt cavern	Proposed

Source: IEA

Rock caverns

Technologies for large-scale storage of gas in rock caverns are widely known, but for facilities for storing hydrogen, the technology has not been fully tried and tested. For example, in Halmstad, Sweden natural gas is stored in the mountain at 200 bar. The geometrical volume is 40 000 m^3 which is 10 million m^3 at atmospheric pressure. The concept is called LRC (Lined Rock Cavern). It is 115 meters from the upper part of the gas storage to the rock surface.

First the lower part of the vessel is installed. The approximate 700 mm space between the rock wall and the steel shell is filled with compact (vibration free) concrete. Before the concrete work is done the steel vessel is filled with water to create a back pressure. The space between the mountain wall and the steel vessel is filled with self-compacting concrete. Alone the 12 – 15 mm thick steel plates will not withstand the pressure of 200 bar. But in cooperation with the surrounding mountain the steel plates will withstand the pressure.

On the rock walls a grid of 90 mm drainpipes are used to keep water out during the construction phase. During the operation phase it is used as a leakage detection system.

The steel plates on the outside are cladded with a layer of bitumen. It operates as a sliding layer for the steel vessel to be able to move. The gas outlet is via a pipeline in a vertical shaft.

Reference project: The company Hybrit is now building a pilot plant for the purpose of storing hydrogen in large scale. Hybrit is a cooperation between LKAB, SSAB and Vattenfall.

The volume of the hydrogen storage will be approximately 100 cubic meters and the maximum pressure will be about 250 bar. The technic use is called LRC (Lined Rock Cavern) and is used in other types of gas storage applications, and the storage facility will be built and based on tried and tested technology that has been used for natural gas. The LRC technic means that the cavern will be lined/coated with a selected material as sealing.

The storage is built 30 meters under the ground using drill and blast method. The storage is done to stabilize the energy system by producing hydrogen when there is a lot of electricity available and the price is low, for example when it is windy outside.

Based on risk analysis several safety-improvement measures, such as various parallel monitoring systems, physical collision protection, and other safety and protective barriers to limit the effects in the event of possible leakage have been implemented.

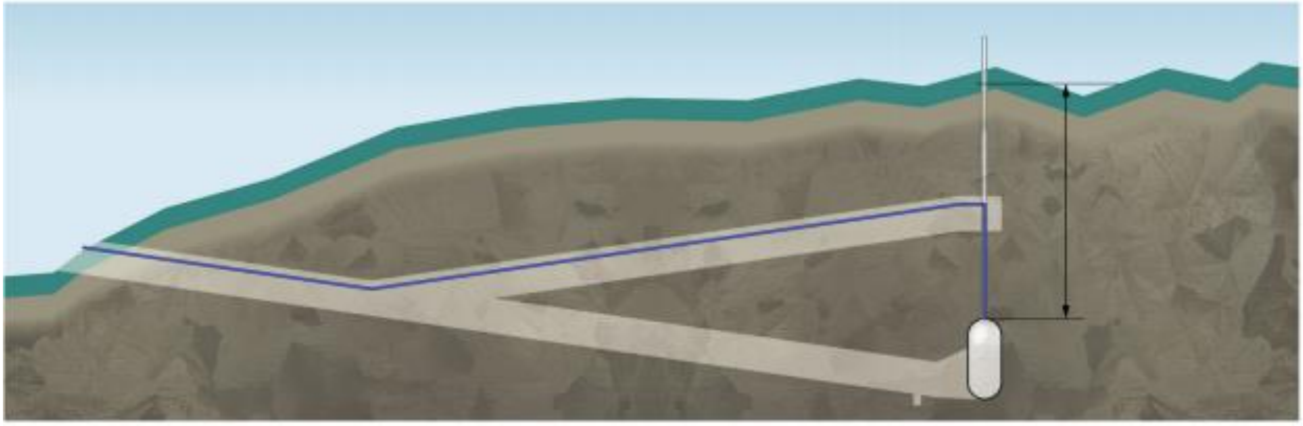


Illustration of the design of the pilot-hydrogen storage under the Svartö mountain. Source: Hybrit

Salt caverns

Salt caverns are artificial cavities which are created in geological salt deposits. Future caverns are generally located at a depth of 500 to 1500 meters. To create such a cavern, it is first necessary to drill into the salt. The second stage consists in injecting water into the salt to dissolve it. The resulting brine (water mixed with salt) is extracted and leaves room for a large, tight cavern where hydrogen can be stored under pressure.

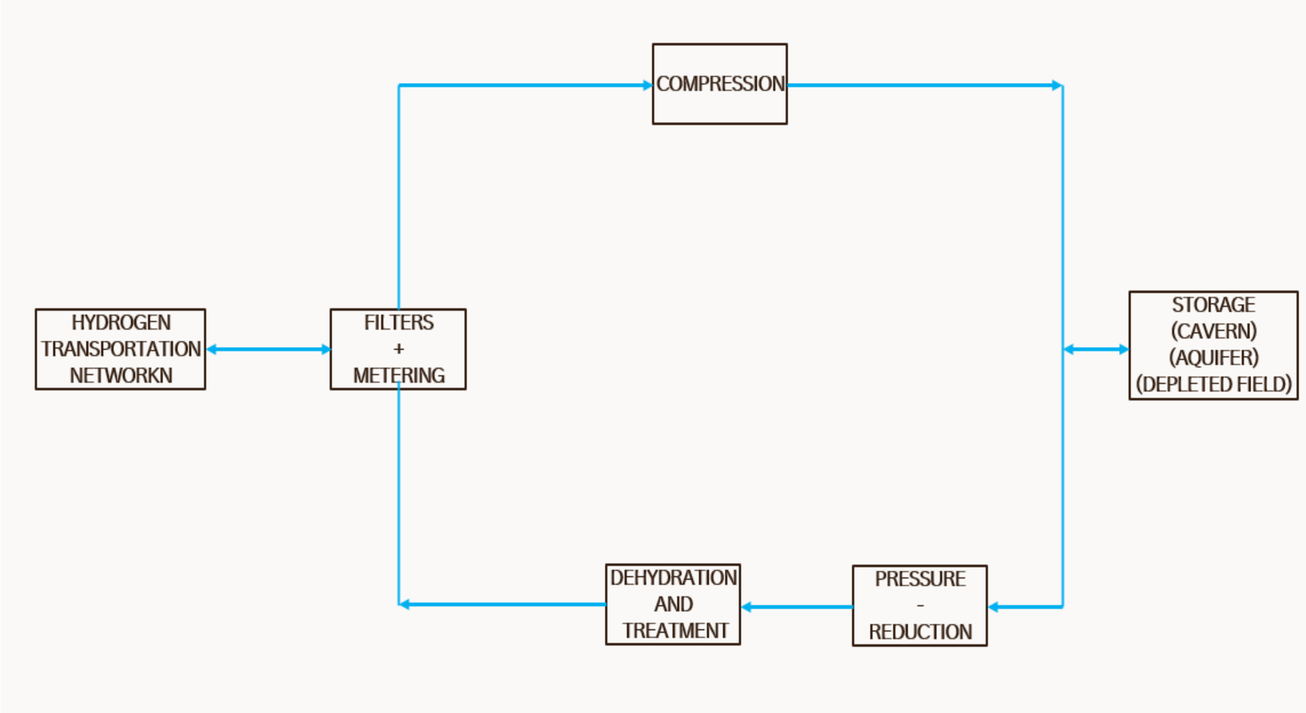
One of the aspects is the hydrogen leakage rate at high pressure. The effects of hydrogen leakage are the subject of many studies, and is widely considered its greatest safety hazard. Both leakage and diffusion of hydrogen should be considered when equipping the storage plant. But further research should also be done on the permeability of the rock salt cavern wall.

Town gas storage operations were realized in salt caverns in Europe until the 1970s e.g. in Germany, Kiel (32,000 m^3 of storage) and Bad Lauchstaedt[134].

Examples of salt caverns in operation storing hydrogen:

Location	Clemens Doem (US)	Moss Bluff (US)	Spindeltop (US)	Teeside (UK)
Operator	Conoco Philips	Praxair	Air Liquide	Sabic
Start	1983	2007	2014	1972
Volume [m3]	580 000	566 000	> 580 000	3 x 70 000
Pressure [bar]	70 - 135	55 - 152	Confidental	45

When consumption is high, for example during winter, gas is extracted from the caverns. The gas is dehydrated to remove any water it contains. The water is collected and treated.



Typical block flow diagram of storage in a saltwater rock cavern

Important aspects are preventing leaks, controlling the behavior of the salt, and understanding gas thermodynamics

Preventing leaks due to the small, very ignitable molecule which easily can diffuse through any small passages. Controlling the behavior of the salt is to prevent decreasing storage volume too quickly, especially for the deepest cavities. But it can also cause damage to the wall and/or salt-access shaft interface. Understanding gas thermodynamics is about brines that contains sulphates from the anhydrate (H_2S) which can be associated with underground salt. The gas is wet and loaded with various impurities including H_2S which is particularly harmful for downstream gas users. In these cases, purification may be needed.

Pros.

- Salt caverns are flexible regarding their injection and withdrawal cycles. Depending on their depth, salt caverns may be operated at pressures up to 200 bars and allowing for large volume hydrogen storage up to 6 000 tons.
- Due to their tightness, salt caverns allow for safe storge of large quantities of hydrogen under pressure. The first hydrogen storage cavern, which was built in the United Kingdom in 1972 is still in service.

Cons.

- There are today 4 hydrogen storage sites in salt caverns existing in the world. These storage facilities are strategic reserves for the use in hydrocarbon refineries. The frequencies and quantities used are low. For energy uses, injection and withdrawal cycles will have to be quicker and offer greater amplitude. Experimental evaluations of the consequences of such more intensive modes of operation will enable us to confirm the concept and viability of future salt cavern hydrogen storage projects.

- Another potential problem linked to the operation of a cavern with hydrogen is the development of the composition of hydrogen contained in the cavern. If the hydrogen is expected to absorb moisture (as it is the case for natural gas), it is also possible that bacteriological and chemical reactions take place, thus transforming some of the hydrogen and modifying the overall composition of the gas. Specific treatment to purify the hydrogen at the cavern outlet could thus be necessary (in addition to dehydration).[135]

Reference projects: The Advanced Clean Energy Storage project it's a joint venture between Mitsubishi Power and Magnum Development that will take excess power generated from renewable energy and electrolyze it into hydrogen for storage in the salt caverns, where it can later be used for power, industrial and transport applications.

This will become the world's largest storage facility and it is located in the U.S., some 200 kilometers south of Salt Lake City. Scheduled for operation by 2025, the first phase will provide 150,000 MWh of renewable power storage capacity — enough to power 150,000 households for one year. The project was recently invited to apply for up to $595 million in loans from the US Department of Energy's Loans Program Office.

Source: Mitsubishi

A government-funded German consortium of more than 100 companies plans to build a salt cavern in Saxony-Anhalt with about 150,000 MWh of energy from wind power-generated hydrogen.

If the project is approved, the Hydrogen Power Storage and Solutions East Germany (HYPOS) could be continental Europe's first hydrogen storage cavern. More broadly, the project aims to produce green hydrogen on an industrial scale, as well as to build an extensive network of distributor networks and storage stations across Germany to make hydrogen available to all regions[135].

Potential hazards for cavern storage

- Tunneling and subsidence risks during construction and operation require special consideration.
- Metal alloy selection is critical when considering interactions with hydrogen and the potential for embrittlement which is why metals used with hydrogen should be selected in accordance with ASME B31 criteria.
- Will the vessel be in contact with the ground or protected by a coating and is that coating impervious to ground water and soil interactions? Galvanic interactions with soil must be considered and mitigated to prevent vessel failure.
- Will the vessel material be in contact or encased in concrete? Thermal expansion and contraction must be considered and the extent to which it may occur based on concrete and various metals having different thermal expansion coefficients.
- Pressure relieving device discharges should be directed to the outside atmosphere with consideration for personnel safety as well as the ability of the discharge to migrate back into the access tunnels/passageways.
- Relief valve testing and inspection frequency must be considered to assure over-pressurization of the vessel does not occur.
- Maintenance practices, such as proper purge techniques and validation must be considered to assure hot work activities do not endanger personnel or equipment.
- Access to the interior of the vessel, should the exterior be incased in concrete, for inspection and testing of the pressure vessel walls, to assure the absence of corrosion and validating minimum wall thickness has not been exceeded, needs to be considered as part of the facility design and construction.
- Seismic activity of the area must be considered.
- Embrittlement is important to consider for materials selection, especially due to the required long lifetime of the components with limited possibilities to exchange.
- Cathodic protection, temperature influences for carbon steel, concrete
- Hydrogen reactivity (such as with sulfur deposits) could produce undesirable reaction products including toxic materials

Aquifer reservoirs

An aquifer is an underground body of rock, sand, or gravel that holds groundwater. In some areas natural aquifers have been converted to natural gas storage reservoirs. An aquifer is suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. Aquifers are only appropriate for gas storage use if the formation is not connected to an aquifer used for producing water.

Cushion gas is the amount of gas that is permanently stored in a natural gas storage. The main function is to maintain sufficient pressure in the storage to allow for adequate injection and withdrawal rates at all times. Another name for this type of gas is base gas. The amount of required cushion gas depends on the type of storage. For example, in depleted gas reservoirs around 50% of the total volume consists of cushion gas. In comparison, salt caverns require typically around 25% of the total volume. Aquifer reservoirs require more: up to 80% of the total volume. In short, the exact amount required depends on the exact characteristics of the storage and the required withdrawal rates.

As a result, cushion gas is an important cost element for a gas storage project. It can amount to 50%-80% of the total investment costs. You can only withdraw this gas at the end of the lifetime of a gas storage facility.

Most aquifer storage facilities were developed when the price of natural gas was low, meaning this cushion gas was not very expensive to give up. However, with higher prices, aquifer formations are increasingly expensive to develop.

5. Hydrogen transportation

Transportation of hydrogen from one location to another presents different levels of risks depending on the method of transport and the potential for failure of the transport methodology and subsequent release of hydrogen.

Initial investment in an underground pipeline may seem to be foreboding determining costs project cost when planning a production facility but the amortization costs of a pipeline over the life of the facility makes it practical when considering alternative transportation costs.

The volume of hydrogen that can be transported utilizing vehicle-based tanks is limited so if a production facility plans to continually generate and move large volumes of hydrogen, vehicle transport becomes restrictive. Vehicles designed for hydrogen transport present risks not only to the loss of product but also risks to the public. Transport vehicles that are involved in accidents that occur on public roadways expose the public to potential fire and or explosion. Accidental release and fire can also occur during hydrogen transfer operations at facilities that can result in a fire and or explosion such as the event that occurred at a transfer facility in Santa Clara, California on June 1, 2019.

Transporting gaseous hydrogen via existing pipelines is a low-cost option for delivering large volumes of hydrogen. The high initial capital costs of new pipeline construction constitute a major barrier to expanding hydrogen pipeline delivery infrastructure. Research today therefore focuses on overcoming technical concerns related to pipeline transmission, including:

- The potential for hydrogen to embrittle the steel and welds used to fabricate the pipelines
- The need to control hydrogen permeation and leaks
- The need for lower cost, more reliable, and more durable hydrogen compression technology.

Potential solutions include using fiber reinforced polymer (FRP) pipelines for hydrogen distribution. The installation costs for FRP pipelines are about 20% less than that of steel pipelines because the FRP can be obtained in sections that are much longer than steel, minimizing welding requirements.[136]

One possibility for rapidly expanding the hydrogen delivery infrastructure is to adapt part of the natural gas delivery infrastructure to accommodate hydrogen. Converting natural gas pipelines to carry a blend of natural gas and hydrogen (up to about 15% hydrogen) may require only modest modifications to the pipeline. Converting existing natural gas pipelines to deliver pure hydrogen may require more substantial modifications. Current research and analyses are examining both approaches.

Long range planning is required to develop and implement pipeline transportation of hydrogen from a production facility to an end user or storage facility. The distance and path of an underground pipeline will predicate the pre-planning and approval required to complete the project.

A natural gas liquification plant located on the western shore of the Cheasapeake Bay in Lusby, Maryland submitted their application in 2013 and the project completed in 2018. The pipeline was designed to transport natural gas from the source locations to the facility for liquification and eventual transport via specialized ships. Regards of the gas that is planned to be transported, project timelines can be many years in the planning, development, and completion of the project.

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Risk associated to the use of existing (natural gas) pipelines

Utilizing existing pipelines for the transport of Hydrogen presents risks that may not have been considered when the original pipeline was installed.

Hydrogen has a small atomic structure and can penetrate and leak from materials of the existing pipeline not originally designed for hydrogen

Erosion and corrosion of an existing pipeline would have to be determined to assure safe transport as well as life expectancy of the pipeline. Postulated accidents would have to be evaluated and their potential for harm to the public, depending upon the location and proximity of the pipeline to public causeways. While there may be short term savings in utilizing existing pipelines, the long-term costs related to maintenance, enterprise interruption, and product loss should also be considered in project development.

Blending hydrogen into the existing natural gas pipeline network has been proposed as a means of increasing the output of renewable energy systems such as large wind farms. If implemented with relatively low concentrations, less than 5%–15% hydrogen by volume, this strategy of storing and delivering renewable energy to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in end-use devices, overall public safety, or the durability and integrity of the existing natural gas pipeline networks. However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis.

Any introduction of a hydrogen blend concentration would require extensive study, testing, and modifications to existing pipeline monitoring and maintenance practices (e.g., integrity management systems)

Additional cost would be incurred as a result, and this cost must be weighed against the benefit of providing a more sustainable and low-carbon gas product to consumers.

Blending hydrogen into natural gas pipeline networks has also been proposed as a means of delivering pure hydrogen to markets, using separation and purification technologies downstream to extract hydrogen from the natural gas blend close to the point of end use. As a hydrogen delivery method, blending can defray the cost of building dedicated hydrogen pipelines or other costly delivery infrastructure during the early market development phase. This hydrogen delivery strategy also incurs additional costs, associated with blending and extraction, as well as modifications to existing pipeline integrity management systems, and these must be weighed against alternative means of bringing more sustainable and low-carbon energy to consumers.

Though the concept of blending hydrogen with natural gas is not new, the rapid growth in installed wind power capacity and interest in the near-term market readiness of fuel cell electric vehicles has made blending a more tangible consideration within several stakeholder activities, including recent agreements on "Power-to-Gas" initiatives. Delivering blends of hydrogen and methane (the primary component of natural gas) by pipeline also has a long history, dating back to the origins of today's natural gas system when manufactured gas produced from coal was first piped during the Gaslight era to streetlamps, commercial buildings, and households in the early and mid-1800s. The manufactured gas products of the time, also referred to as town gas or water gas, typically contained 30%–50% hydrogen, and could be produced from pitch, whale oil, coal, or petroleum products. The use of manufactured gas persisted in the United States into the early 1950s, when the last manufactured gas plant in New York was shut down and natural gas had displaced all major U.S. manufactured gas production facilities. In some urban areas, such as Honolulu, Hawaii, manufactured gas continues to be delivered with significant hydrogen blends and is used in heating and lighting applications as an economic alternative to natural gas.

Multiple factors must be taken into consideration to assess the safety concerns associated with blending hydrogen into existing natural gas pipeline system. It is difficult to make general claims about safety due to the large number of factors involved; detailed risk assessment results likely will vary from location to location. Because hydrogen has a broader range of conditions under which it will ignite, a main concern is the potential for increased probability of ignition and resulting damage compared to the risk posed by natural gas without a hydrogen blend component.

The durability of metal pipes degrades when exposed to hydrogen over long periods, particularly in high concentrations and at high pressures.

This effect may be of concern for cases where hydrogen is injected at high concentrations into existing high pressure natural gas transmission lines. The effect is highly dependent on the type of steel and must be assessed on a case-by-case basis. However, metallic pipes in distribution systems are primarily made of low-strength steel, which are generally not susceptible to hydrogen-induced embrittlement under normal operating conditions.

At the pressures and stress levels occurring in the natural gas distribution system, hydrogen induced failures are not major integrity concerns for steel pipes. For the other metallic pipes—including ductile iron, cast and wrought iron, and copper pipes—there is no concern of hydrogen damage under general operating conditions in natural gas distribution systems. There is also no major concern about the hydrogen aging effect on polyethylene (PE) or polyvinylchloride (PVC) pipe materials. Most of the elastomeric materials used in distribution systems are also compatible with hydrogen.

In most research programs, the focus of integrity management has been on transmission pipelines because of concerns at high operating pressures, up to 2,000 psi (139 bar), and the pipeline steels that are subject to hydrogen-induced cracking. Hydrogen can be carried by existing natural gas transmission pipelines with only minor adaptations to the current Integrity Management Program. The adaptations needed depend on hydrogen concentration and operating conditions of the individual pipelines. These are generally insignificant with concentrations up to 50% hydrogen, but a detailed investigation for every case is mandatory and could result in the upper limitation on hydrogen concentration being reduced.[138]

Leakage

The permeation coefficient of hydrogen is higher through most elastomeric sealing materials than through plastic pipe materials. However, pipes have much larger surface areas than seals, so leaks through plastic pipe walls would account for the majority of gas losses. Permeation rates for hydrogen are about 4 to 5 times faster than for methane in typical polymer pipes used in natural gas distribution systems.

Leakage in steel and ductile iron systems mainly occurs through threads or mechanical joints

Leakage measurements from GTI for steel and ductile iron gas distribution systems (including seals and joints) suggest that the volume leakage rate for hydrogen is about a factor of 3 higher than that for natural gas.

Hydrogen is more mobile than methane in many polymer materials, including the plastic pipes and elastomeric seals used in natural gas distribution systems

A calculation based on literature data for the permeation coefficient of hydrogen and methane in polyethylene (PE) pipes suggests that most gas loss would occur through the pipe wall, rather than through joints, in distribution mains smaller than 2 in. and operating at 60 psig (5 bar) or higher.[138]

Pipeline racks (underground and aboveground)

While some pipelines are located above ground, the main part of them are concealed underground which allows them to reach more places without interfering with buildings, homes, and areas of greenery.

Most common causes of pipeline incidents (35%) involve equipment failure.

For example, pipelines are subject to external and internal corrosion, broken valves, failed gaskets, or a poor weld. Another 24% of pipeline incidents are due to rupture caused by excavation activities, when heavy equipment accidentally strikes a pipeline. Overall, in the US, pipeline incidents are most common in Texas, California, Oklahoma, and Louisiana, all states with considerable oil and gas industry[139].

There are two types of pipeline incidents: leaks and ruptures. A leak is a slow release of a product whereas a rupture is a breach in the pipeline that may occur suddenly. In general, leaks are more common, but cause less damage as opposed to ruptures that are relatively rare but can have catastrophic consequences.

Pipelines are considered to be low frequency / high severity risks

meaning that incidents are relatively rare considering the total mileage of pipelines and the volume of product transported, but when incidents do occur, they often have catastrophic consequences. There are a number of causes of pipeline incidents including corrosion, excavation damage, incorrect operation, material/weld/equipment failure, and natural force damage (i.e., Hurricane Katrina)[140].

Risks associated with buried piping:

• Even after applying mitigating measures such as external coating and cathodic protection, buried steel pipes are subjected to external corrosion.

• Draining, cleaning buried pipes is difficult compared to an aboveground pipe.

• Leak detection and repair of buried pipes is a difficult and expensive exercise. Modern underground pipeline leak detection systems are available, but they are very expensive to install.

• Buried pipes are subjected to mechanical damage when soil excavation work is being carried out in close vicinity.

Risks associated with aboveground piping:

• Above ground pipes could be subjected to vehicle impact exposure both in terms of road crossing when impacting the rack but also the pipe rack support columns if not protected properly.

• More exposed to natural hazards like hurricanes.

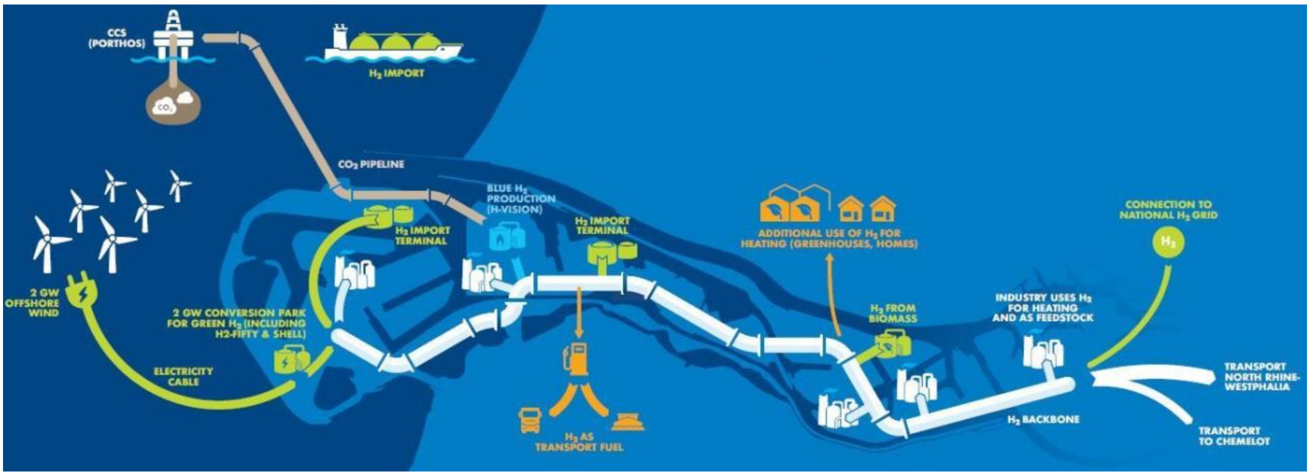
• More exposed to pipeline vandalism and sabotage.

• In terms of total cost, installing pipes above ground will be more expensive because you must consider the foundation, structural steel elements and support elements included in the project.

Reference projects: Rotterdam is today the main port for energy traffic in Northern Europe serving today 13% of the energy consumption in Europe. Current planning foresses to convert the port into the hydrogen hub in Europe with a yearly volume of 20 Mio. tons hydrogen traffic until 2050.

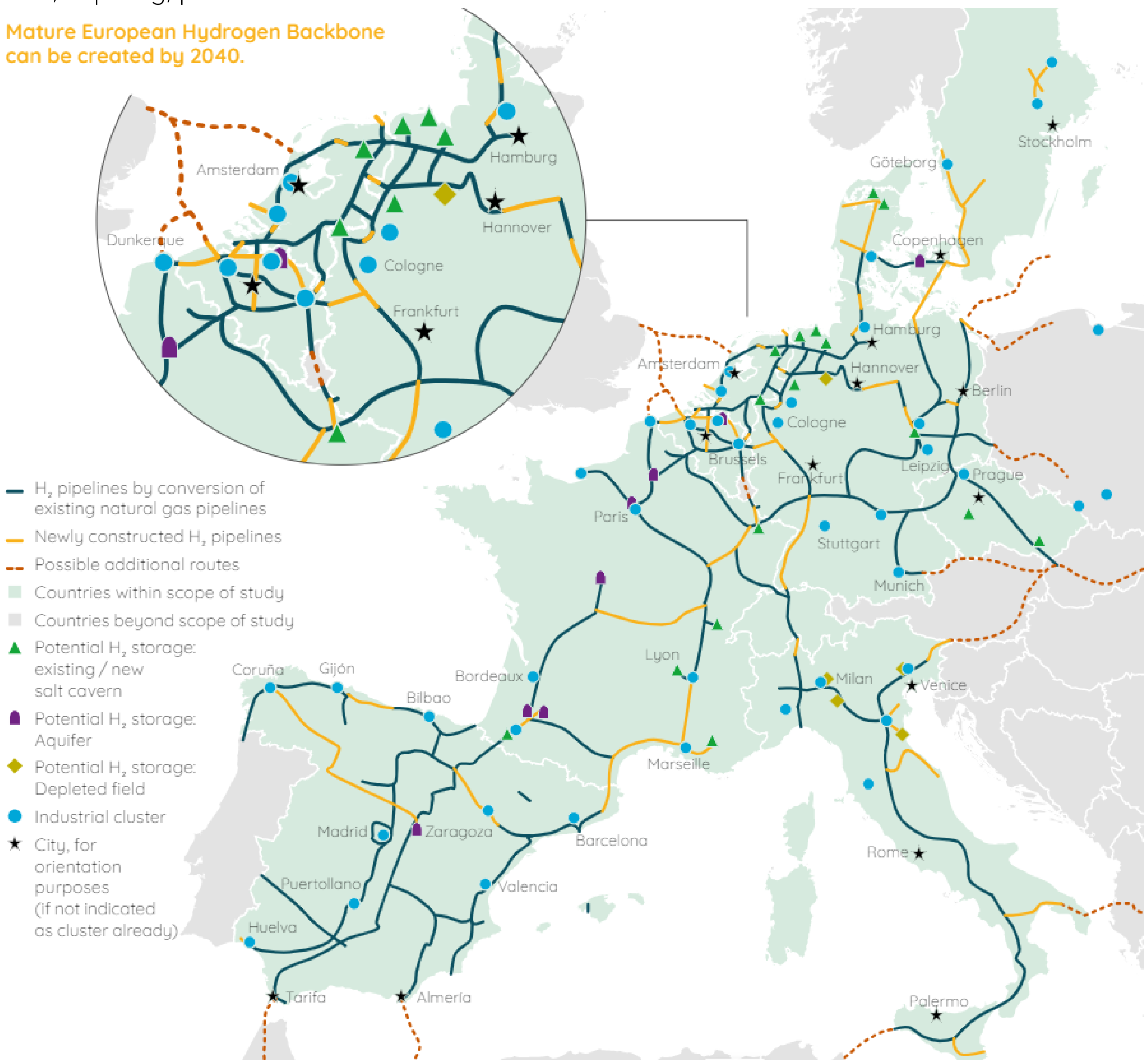
Most of the hydrogen will be imported from areas where (renewable) energy is cheaper in form of ammoniac, methanol, liquid hydrogen (LH2) liquid organic hydrogen carriers (LOHC) and systhetic methane, while locally up to 1,2 Mio. tons of climate-neutral (blue and green) hydrogen (2 GW electrolyser capacity) until 2030 is planned. Heavy industries shall serve as "launching customers" (refineries, chemicals, steel) and transport is planned via waterways and mainly pipelines through Europe.

Both Netherlands and Germany are planning a National hydrogen transport network primarily serving heavy industries. Several German companies including BP started the development of a 130 km pipeline between Lingen and Gelsenkirchen (Project GET H2 Nukleus), expected to be in operation, together with a 100 MW electrolyzer plant by end of 2022.



Furthermore, the project DELTA CORRIDOR foresees four pipelines between Rotterdam and Northrhine Westfalia for the transport of C4-LPG, propylen, hydrogen and CO_2. For several companies and regions along the route, there will be so-called linking options. For example, linked to the construction of hydrogen filling stations for freight traffic and inland shipping. Extending the pipelines to North Rhine-Westphalia (near Venlo and/or Sittard) and Antwerp (from Moerdijk) will allow many more large industries to be interconnected and more use to be made of the pipelines[141].

The project in Rotterdam can be seen as part of an even larger initiative, the European Hydrogen Backbone Initiative. This vision yet in a preliminary state foresees investments of EUR 43-81 billion until 2040 to repurpose existing natural gas infrastructure, combined with new hydrogen pipelines and compressor stations. The initiative stives for 116,000 km and 39,700 km of new and reconverted pipelines until 2030 and 2040 respectively, this would transfer into a cost of transport of around EUR 0,11-0,21 per kg, per 1'000 km.



Planned hydrogen transport network. Source: https://gasforclimate2050.eu/ehb/

Ultimately, two parallel gas transport networks will emerge: a dedicated hydrogen and a dedicated (bio)methane network. The hydrogen backbone will transport hydrogen produced from (offshore) wind and solar-PV within Europe and also allows for hydrogen imports from outside Europe.

6. Risk mitigation

Facility design and construction

There are multiple codes and standards that are required by governmental agencies when designing a hydrogen facility. Annex 2: Regulations, standards, and codes provides an overview of relevant regulations and design standards.

Codes and standards are the minimum requirements that must be followed, not always best practices

Additional factors should be considered while designing a facility and determining what types of process, materials and procedures are selected. The structure and safety equipment that comprise the facility should not be underestimated while designing in regards of long-term operation and safety, same applies for risk management measures and procedures.

Designing the facility with multiple trains of operation is not only a good way of maintaining production while maintenance is performed, but a great mitigation measure both for material damage and business interruption. Best practice is separating the trains in different fire areas.

Retrofits and decarbonization projects in existing facilities should consider that the site was not originally designed for hydrogen operations

this not only in regards of process and components but also relating to organizational and safety issues.

Geographical location must be considered when designing for seismic response of the facility. Not only in regards of process operability, but seismic design criteria should also apply for any other peripheral and safety equipment that has the potential to cause a major event. The ancillary equipment does not necessarily have to meet full seismic design criteria but at least it should remain in place during a seismic event. An example would be a sprinkler system that is installed over top of hydrogen process equipment. The design should be such that the suppression piping does not dislodge and drop onto the hydrogen equipment.

Material selection

Piping, tubing, valves, and fittings shall be designed and installed in accordance with applicable sections of ASME B31, Code for Pressure Piping, and Sections 704.1.2.3, 704.1.2.4, and 704.1.2.5 of the ICC International Fuel Gas Code (IFGC) and/or equivalent.

Cast, ductile, malleable, or high-silicon iron pipe, valves, and fittings shall not be used.

Material properties, such as stress and strain limits, must be understood when selecting metal alloys to be used within the hydrogen systems. Temperature and pressure effects that the systems will be subject to, must be considered when selecting the appropriate materials. If it is known that a specific process must be controlled at specific modes of operation to prevent damage, then detailed operating procedures as well as other safety measures, such as electromagnetic relieving devices (controlled by a program that monitors the system parameters) must be implemented.

A common issue for hydrogen storage, transportation and usage is deterioration, embrittlement, and cracking of materials due to the contact with hydrogen. -Hydrogen embrittlement involves the diffusion of atomic hydrogen through a materials microstructure where it may form brittle metal-hydride pockets or recombine to make small pressurized H_2 bubbles throughout the material. Both of which can result in increased internal pressure, propagation of cracks, and decohesion of internal material surfaces.

Hydrogen embrittlement is most commonly known and observed in steels, particularly steels that have a pearlitic phase

From Matin Connellys' (Technical director at Liberty Pipes) recent address to IOM3 A Material Challenge from Fossil Fuels to Net Zero 12/10/21 talk entitled "H_2 and CO_2 transmission from a pipe manufacturers perspective. Various materials are used in the equipment and pipelines of today's natural gas networks, for instance, stainless steel, carbon steel, cast iron, copper, plastics, and elastomers, and some are more tolerant to hydrogen than others. These materials and the components/equipment such as storage tanks, pipes, compressors, valves, and meters need to be tested to understand and mitigate the risk of component failure associated with hydrogen exposure.

In general, hydrogen damage occurs at a stress level below those typically experienced for a particular metal in an environment without hydrogen, which is affected by the pressure, purity, temperature, stress level, strain rate, and material microstructure and strength. Generally, high-strength steel (>100 ksi yield strength) used in high-pressure transmission pipelines is more susceptible to hydrogen induced brittle fracture or catastrophic rupture.

On the other hand, low-strength (carbon and low alloy) steel commonly used in low-pressure distribution system is subjected to loss in tensile ductility or blistering that assists ductile fracture in hydrogen containing environment. Carbon and low alloy steels also show accelerated fatigue crack growth and degradation in endurance limits when exposed to hydrogen. As a result, fatigue is also a concern for these materials when pipeline experiences pressure fluctuations even at relatively low pressures.

For both high- and low-strength steels, hydrogen concentration and operating pressure are the most critical factors[142]

In addition, fracture within steel can also lead to an increased rate of hydrogen reaction and subsequent corrosion[143].

Embrittlement induced crack[144].

Hydrogen has little or no interaction with plastics and elastomers used in low-pressure distribution pipelines or well sealing. Diffusion or permeation of hydrogen through these materials, however, is of higher rate that increases the leakage

Recommendation of using Sour Service Steel that complies with ASME B31.12 Appendix G for future 100% H_2 pipelines.

“Sour service” piping refers to pipes that have H_2S (hydrogen sulfide) and a wet acidic environment. These steel pipes tend to receive accelerated hydrogen embrittlement due to a chemical reaction of the H_2S and the acidic environment, and thus the microstructure of the steel is designed to have the higher level of resistance to hydrogen embrittlement. However, H_2 service steel is different to sour service steel or sour service conditions. The chemical reaction previously described that generates the H diffusion is not happening with just pure H_2 gas. Therefore, H_2 service steel should see a lower potential of H_2 in the steel.

Research suggests that the potential for H_2 in the steel from a H_2 service pipe range from 5-20% of equivalent severity to a NACE solution A sour service pipe. Thus, to err on the side of caution, in his opinion,

Steel that has the equivalent microstructure to sour service steel should be used for new H_2 pipelines

I.e. those compliant with ASME B31.12 Appendix G. Furthermore, when assessing existing pipelines compatibility with H_2, the mistake of assessing the pipeline by its age alone is incorrect, and it should be assessed by the steels Microstructure. Many recent lines will have been made with higher C ferritic pearlitic steel as well as the old ones and therefore would have a higher degree of susceptibility to hydrogen embrittlement.

Compression

The much lower molecular weight and heating value of hydrogen relative to natural gas have implications on the type and design of compressors used in H_2 compression. Reciprocating compressors are currently the most efficient solution, but they are not able to handle nearly as much gas volume as centrifugal compressors.

Because of the lighter weight of hydrogen, to achieve a pressure ratio comparable to an existing natural gas line, the rotating speed, and the number of stages of centrifugal compressors need to be higher

The higher speed may further demand impeller designs using high-strength titanium alloys, a type of design not yet commercially available. For 10% H_2 mixture, the existing compressors can be operated without any significant changes. When the H_2 volume is under 40%, the compressor housing can be maintained, but the impeller stages and gears may require adjustment.

For pipeline systems with greater than 40% H_2 content, the entire compressor must be redesigned[145]

Hydrogen embrittlement certainly attacks metal components in a compressor causing cracks and reducing service life, as seen on an impeller in the right figure[145]. For highly stressed rotating components like impellers, embrittlement is a particular concern. While titanium alloys offer excellent strength, they are subject to hydrogen embrittlement just like steel alloys. To avoid this failure mechanism, impellers may require reliable surface coatings and enhanced inter-stage cooling to achieve better component reliability.

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mechanism, impellers may require reliable surface coatings and enhanced inter-stage cooling to achieve better component reliability.

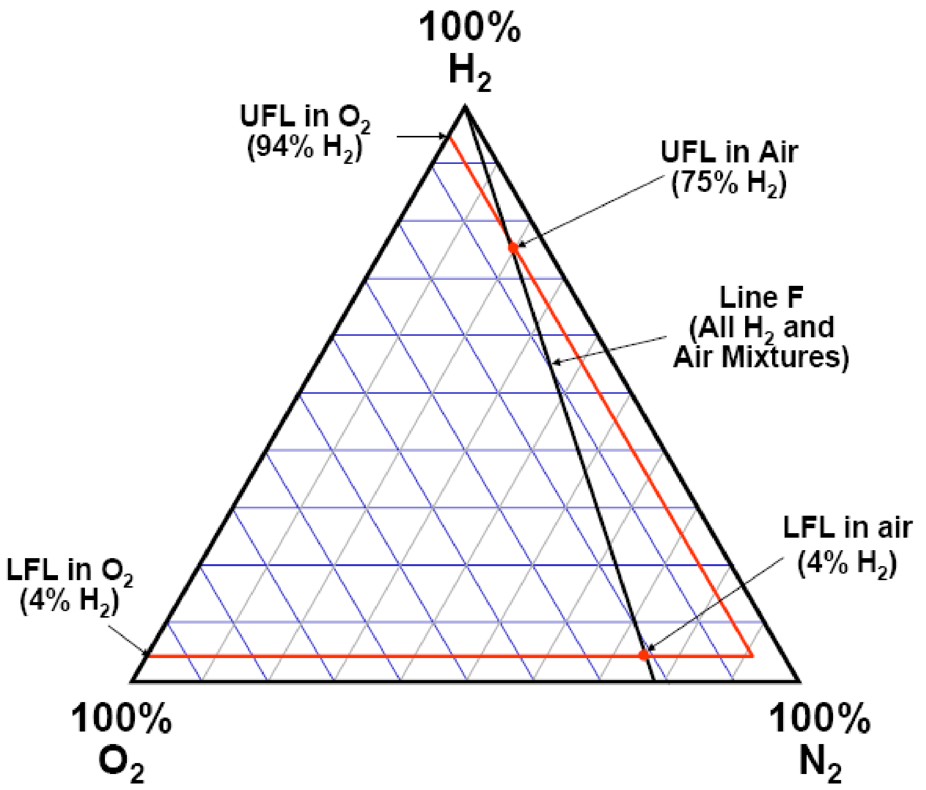
Embrittlement induced crack in rotating machine. Source: Turbomachinery International[145]

Leakage, fire, and explosion

Relative to natural gas, hydrogen has a greater tendency to leak through valves, gaskets, seals, and pipes, and risks associated with accumulation in confined spaces from those leaks could require additional monitoring/detection devices.

The leakage of hydrogen in steel and ductile iron systems mainly passes through the threads or the mechanical joints, at about a three times higher rate than natural gas. In addition, hydrogen is more mobile in plastic and elastomeric materials, with a permeation rate about 4-5 times that of natural gas through plastic pipes, and even a higher rate through elastomeric seals. The amount of gas loss may be negligible from an economic point of view, but gas leaking in a confined space may increase H_2 concentrations to levels that may become threats from the safety standpoint[142]. Besides newly developed materials that can be used as a replacement, lower pressure, and temperature in general will reduce the leakage.

Regarding fires from leaks, hydrogen covers a very wide flammability range as shown in the image below. In air at standard temperature and pressure, it ranges by 4-75% by volume. In addition, the detonability range in air is 18-59%. Thus, the potential for dangerous hydrogen mixture levels in air from a leak or accidental release is high. Hydrogen is odourless and colourless, which is why leaks are hard to detect. Scent compounds such as mercaptans used in natural gas cannot be added to hydrogen streams as this can poison fuel cells or other equipment. Autoignition temperature of hydrogen is observed above 510 ˚C (higher than most long-chain hydrocarbon fuels). Thus, one should be aware equipment or objects hotter than 500 ˚C in contact with hydrogen-air mixtures could cause ignition.



Flammability diagram of hydrogen in nitrogen at standard ambient temperature and pressure.[146]

The ignition probability is higher for hydrogen-natural gas mixtures due to the significant reduction in the minimum ignition energy, and a 20% lower low flammability limit (and a wider ignition range)

While in a vented explosion, only 50% or higher H_2 addition will increase the severity (With a lower density, a low leak rate of H_2 does get dispersed easier in a vented condition), the explosion severity due to gas buildup in a confined space increases moderately with 30% H_2, and significantly for 40% or more H_2[142].

Ignition can be caused by various sources:

- Hot surfaces
- Electrical arcs and sparks
- Electrostatic discharge
- Atmospheric discharge (lightning)
- Mechanical friction or impact sparks
- Electromagnetic radiation
- Ultrasonics
- Adiabatic compression (shock waves)
- Ionizing radiation
- Optical radiation
- Chemical reactions
- Open flames

In addition, low flame visibility and lack of odor of H_2 gas makes both ignited and unignited leaks hard to detect.

Fire protection

Hazard analysis is a key element for hydrogen plant construction, operation, and maintenance.

Investing in identifying and mitigating known hazards during the design phase, as well as those that may present in the future operation is probably the best fire protection measure

Knowing and understanding how a fire may arise and propagate is key.

Hydrogen represents a major risk regarding fire and explosion. Building construction materials and compartmentalization of areas can be evaluated for fire resistance and the ability to isolate the fire for a specific duration of time. Areas of potential hydrogen accumulation from system leakage should be evaluated for damage to the structure related to a hydrogen explosion. Are the structure walls able to withstand the shock wave, or is the structure able to relieve the pressure increase via blow out panels?

Does the facility have appropriate ventilation to prevent the accumulation of hydrogen? Are passive blowout vents in place? Where does the ventilation discharge? The location of the ventilation discharge is as important as having the discharge. Evaluate the location of the discharge to ensure enough distance from other intake and/or ignition sources.

Early detection is a further key element to preventing either an event from occurring or minimizing the effects of the event.

Best practice is to install systems that will detect hydrogen prior to the levels reaching the lower explosive limit, minimizing the risk to operations and personnel

Additionally, is there a dedicated fire brigade on site? What level of training do they have? If not, how long would it take for the local fire department to respond?

Suppression systems should be fit for purpose. When designing a gaseous suppression system, one must also consider its effects on humans in the event of discharge.

Regular inspection and testing of suppression systems is mandatory

Operation and maintenance

Procedure adherence is most relevant to safely operating and maintaining a facility. The procedures must address human factors as well and safety considerations. The facility must also consider ancillary processes, such as storage of materials, that could affect operations and must address those as well through procedures for the facility. How and where transient combustible materials can be stored should be addressed to minimize the risk of their involvement in a fire and potentially making the fire large then the installed system is designed to mitigate.

Operation and maintenance of hydrogen units with its connecting systems are critical since both technical- and human errors are potential large risk exposures

When large losses occur, it is not uncommon that it is a combination of technical and human errors. Minimizing the risk of human errors increases the probability to minimize the loss, or at least to decrease the effects of the loss.

Operation of hydrogen systems, being a very flammable and explosive gas, requires a high level of procedures which should be well documented and frequently updated.

Important areas of operation are:

- Startup- and shutdown procedures
- Emergency procedures
- Inertization
- Leakage control
- Flange management
- Drains
- Combustible control
- Labelling of piping and equipment
- Operator training program

Safety plan documentation and implementation, training of staff prior to accessing the site and regular inspections as well as internal/external audits are highly recommended.

Startup- and shutdown of process units which include hydrogen plants are not always routine since the turnaround frequency can be several years and for a shift operator it could be that he/she is not working during that period. This means that it can take several years before operators are involved in a certain startup- or shutdown specific step/task. It will also take several startups and shutdowns before the operators are familiar with the procedures and can feel confident.

Having clear startup- and shutdown procedures will minimize the risk of operators doing mistakes

The procedures/instructions should be written in local languages with step-by-step instructions preferable connected to valve tag numbers, pumps numbers etc. The instruction should be a part of the operator training and referring also to P&IDs and PFDs. Startup and shutdown instructions should be available in paper form in the control room and updated based on MOC or similar from changes in the process or surroundings.

In the event of an emergency the stress level will be high, it is easy to do mistakes and/or to miss something which can increase or delay the emergency event. Emergency instructions is an important tool for the operators to lean on during an exceptional event. The emergency instructions should cover events like fire event, power failure, loss of cooling water, loss of instrument air etc. The instruction should be based on PHA and risk analysis connected to the different events.

Emergency instructions should be available in paper form in the control room and reviewed and updated annually

A part of the startup and/or emergency event is Inertization of the process unit and connected systems. Inertization is done before startup and shutdown of all system that contains flammable gas. If hydrogen is introduced to an environment containing oxygen, there is a significant risk of fire/explosion, especially due to the wide explosion range of hydrogen. Hydrogen burns/explodes in 4 – 75% gas/air mixture. The purging should be done with an inert gas, for example nitrogen. Before startup after for example a maintenance shutdown, the system needs to be free from oxygen and purged to the atmosphere (not to the flare system since it can contain oxygen). The system is normally purged until the oxygen level is at least below 0,5%vol. This can be done by pressurizing the systems with the inert gas to 5 bar and releasing it down to 0,5 bar. This is done repeatedly until the oxygen level is low enough.

After shutdown the system is inertized in the same way, but the gas since the gas do not contain oxygen it can be released to the flare system (if there is one). Otherwise vented on at high elevation not exposing surrounding systems or persons.

Before any assembly is performed LEL-measurements should be done to verify that the system is free from flammable gas. Note that any human entry into the systems require additional measures

It is important to include all systems that will be exposed to flammable gas including dead ends and pipelines.

If the unit is connected to a flare system, it is normal procedure to purge nitrogen and flammable gas into the flare system. No air or oxygen should be purged into the flare system due to the risk of getting a flammable mix with explosion as potential consequence. If a flare system exists all safety valves containing flammable gas should be connected.

Another important management procedure before startup is to have control of flanges and other dismantling works. Installing the wrong gasket (size or pressure class) can lead to leakage and fire.

A flange management system where all flanges are checked in a structured way after assembly is required, controlling the right type of gasket in terms of size and pressure class, right length of bolts tightened correctly will minimize the risk of leaks during startup

After each flange has been correctly checked, it is recommended to have sealing on the flange to insure it has not been broken after the check. Leakage control should also be done as a part of the startup procedure by pressuring the system first with an inert gas. When the pressure is set for at example 7 bar a trend curve can be set in the DCS to follow any pressure decrease at a certain time.

At the same time leak spray should be used on flanges valves etc. Any noted leaks should be corrected, and the systems tested again.

Before unit start up the process areas should be free of combustible material. This should be checked as part of the startup procedure before any flammable gas or liquids are introduced into the unit. During operation, a part of the housekeeping routines, is to make sure that the process area is free of combustible material.

Drains and vents connected to flammable gas or flammable liquid should during operation be capped. This should be reviewed during the normal safety rounds in the plants.

Process systems should have a high level of labelling of piping and equipment with color codes for different media with flammable gas/liquid tags when applicable

Labelling of piping with media- and risk type helps identifying risks in the event of a leak or other type of events. Also, labeling of equipment with signs and valves with tags helps operators when used together with instructions and training connected to P&IDs and PFDs.

Training programs for operators is especially important when working with high-risk type of production. Specified classroom training for operators with mentor program and if possible, simulator training is key to reaching a high level of operator knowledge. Before operators starts to "work alone" some type of knowledge test can be an option to determine if the operator is ready for the task.

A hot work program must be implemented at the facility to minimize the probability of an event occurring. Hydrogen represents a risk to be mitigated even without the presence of an ignition source.

Introducing a maintenance process that purposefully applies heat to the process equipment requires specific controls and processes to reduce risk and prevent equipment and personnel injury that could result from either a hydrogen fire or explosion.

The type of tooling that is used at the facility should be considered. Non sparking tools should be used when working in areas where hydrogen could be present.

Equipment manufacturers generally specify a frequency at which either preventative maintenance should be performed, or parts should be replaced. Obtaining experience through performance and maintenance data could help to reduce maintenance costs by transitioning to a performance-based maintenance schedule. Replacing a part or calibrating an instrument well before it would present operational issues not only reduces out of service time and material costs, but also the overall man-hours required to maintain the facility.

Annex 3: Summary of best practices and risk mitigation for hydrogen facilities is a checklist for assessing hydrogen project, while the table is not exhaustive it may help identify and address known safety issues during design, operation, and maintenance.

7. Underwriting considerations

Risk evaluation

In general, underwriting technical risks is a difficult task for any seasoned insurance underwriter let alone the novice underwriter. Imperative for any underwriter embarking on such a task is possessing a degree of technical knowledge of how that risk operates (how hydrogen is processed). In part, engineering review and inspection provides the fundamentals and basics of any technical risks from which underwriters develop knowledge of potential material issues and exposures. Ultimately, the underwriter will need to determine the overall insurability of any potentially troublesome technical risk. Hydrogen production and storage certainly falls into that category demanding the technical best from both an Engineering and Underwriting standpoint.

Electrolyser technology is challenging regarding insurability with constant new developments and significant scaling up expected in the years to come. As such Underwriters and Engineering together need to keep up with the fluid technology evident in the fast progression of this renewable energy class.

While many of the innovations may represent improvements in operational stability, robustness, and safety, others are just plain difficult to assess to ultimately determine proven status definition.

Since most OEMs are planning scalation steps of factor 10-20, it is important to differentiate between the following factors: a parallelization of existing/proven equipment; major changes in the applied technology; increased process parameters; and exhausted operational limits. All these factors will demand strict underwriting attention with the expected wide-spread development of this multi-faceted renewable class.

Also, the significant peripheral and ancillary components common with Hydrogen production/storage will also demand special underwriting attention. Depending on the scale of electrolysis, the electrical equipment can be complex and expensive representing a potential high degree of exposure from both a Property Damage and Business Interruption perspectives. Hydrogen storage will certainly be PML relevant involving both systems integrations and process logic. Notice should be also directed to those downstream associated risks (receivers) which may rely on consistent supply for H_2 for operations.

One important factor to consider when underwriting a Hydrogen risk is overall OEM experience.

Traditional equipment manufacturers may be in a better position to both scale up proven and implement unproven technologies than disruptors (or those OEMs relatively new to the industry)

Another critical factor involves the actual General Contractor (or EPC) contracted for the specific project. Is the selected GC well-versed with this class? Do they have a 'Hydrogen' history under their belt? By and large, Insurance carrier Engineers will focus on ALL the players involved with these Hydrogen projects to determine experience in this developing space and overall acceptability - Owners, GCs, Subs, Engineers, Architects & Designer, etc.

The Owner of the project is also a critical underwriting factor. Again, does the owner have adequate experience in this space? Similar past projects under their belt? Have they worked with the selected GC before on similar projects? Financially viable? Experience is vital to the success of any project.

Other relevant issues when evaluating insurability are Catastrophic exposures; adjacent property risks; lifetime of critical components; warranties on critical components; expected refurbishment time;

recovery time after catastrophic events; Contingent interdependencies; spares for critical equipment; lead times for critical spares and availability of; and Geotech conformance.

Attending pipeline support (Existing or New) is also a critical feature of any hydrogen project requiring careful underwriting review. Any repurposing, common with hydrogen projects of scale, requires evaluation of the existing pipeline materials and condition of valves. Though technically challenging polymer linings may be a suitable option in the end.

Third party inspections, audits and certifications are a key element for validating escalation and improving operational safety

Subjective risk: Driven by operator and project owners

- Organigram: experienced management
- Contractors: experienced, track record
- Strong Risk (HSE) involvement and awareness
- Adherence to procedures and standards, continuous improvements, lessons learnt

Critical to all technical risks is the spare parts inventory for critical equipment and the lead times to replace such equipment. Delay in Start Up (DSU) is a critical cover in demand on most technical builders' risks offering Business Interruption restitution for losses triggered by a PD loss to key equipment. Owners will most likely be seeking loss of profits with Contractors seeking soft costs for additional expenses incurred as the result of a loss. Underwriters must be aware of these exposures and somehow mitigate the magnitude and material consequences of such a DSU loss.

Hydrogen electrolysers and their main components (including compressors and transformers) may take 12 to 24 months to replace

No doubt, an adequate waiting period for DSU should be applied from an underwriting standpoint to address this issue. DSU coverage is not an easy cover to underwrite on technical risks of this nature. DSU values may be determined in numerous ways. There is a slew of reporting methods based on a variety of factors - profit schemes, proforma showing monthly breakdown of revenue and cost streams, debt service, fixed costs and, of course, soft costs.

In any case the underwriter needs to carefully determine what exactly the insured is seeking from a restitution standpoint should the project suffer DSU loss. There are a variety of conditions influencing a DSU loss. As such it's imperative the underwriter (and Engineering) runs a variety of loss scenarios particular to a DSU loss event.

What are the key triggers/key equipment? Linear in nature, seasonally impacted, or front/back loaded? Long term agreements in place based on a fixed cost or will it be open market variable price? Can another existing plant pick up the lost capacity if there is a delay? Spares available? Supply chain situation?

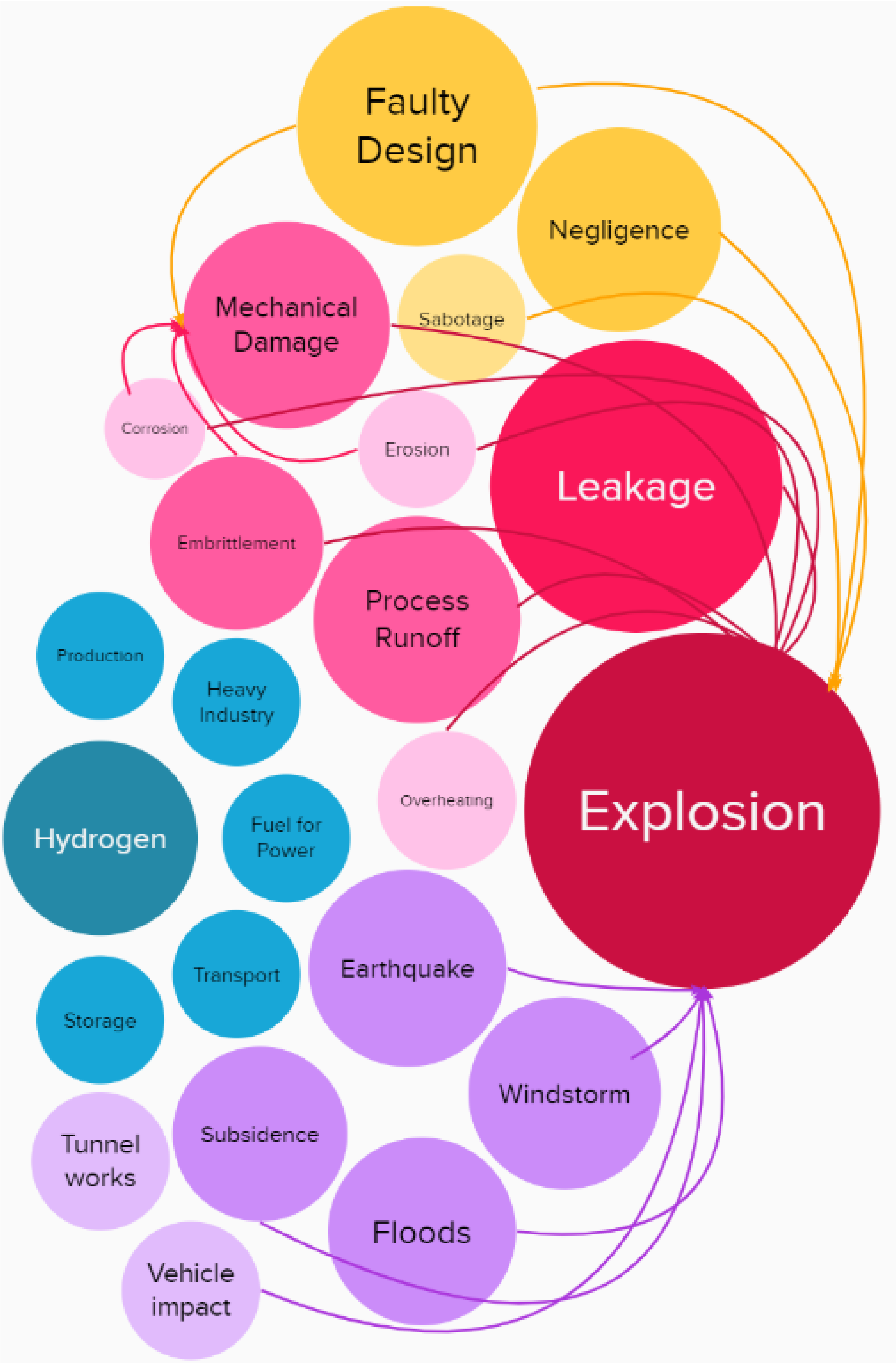
DSU is a critical cover for both the Insured and the carrier. As such, attention to detail is necessary from all parties to navigate this material cover.

The fluid and volatile nature of this class demands all stay on top of any future developments whether positive or negative. The proper underwriting of hydrogen with all its peculiarities will be a work in progress for many years to come

While mapping main risks associated with hydrogen applications, following conclusions were drawn:

- Risks associated to design, especially to material selection (and operating parameters) such as embrittlement, corrosion, erosion can be considered as risk clusters relevant to all hydrogen applications
- Same applies to the main exposure explosion, which increases sensibly the relevance of high design standards, detection systems, leakage control, and operational excellence
- Higher exposure and rather severe worst-case scenarios derived from natural catastrophes compared with fossil-based feedstock
- Same applies for the human factor, negligence, malicious damage as well as cyber exposure can rapidly aggregate to catastrophic explosion scenarios. Access control, work- and safety procedures, and cyber-security are more important than ever before

A growing number of applications are being investigated and developed, implemented, and scaled up. The prototype nature of most applications will remain for many years



Hydrogen risk mapping showing relevant risk cluster and interdependent causality

This aggregative nature should be considered not only in regards of risk selection, but also while structuring coverage, pricing risks, and performing risk engineering assessments. While the insurance industry will face some non-assessable risks in the years to come related to prototypes, scale-up, aging, lifetime of components, etc. Some others known risk elements such as safety standards, detection, and firefighting systems, etc. should be carefully and actively addressed to assure manageable and fair risk transfer in a hydrogen-based economy.

Undoubtedly there will be growing pains affecting all with the rapid development of this renewable class. To some degree the renewable industry itself is striving to determine how this hydrogen-based economy will transcend time in the age of sustainability. As such insurance carriers are being solicited to find risk-transfer solutions for the industry. Insurance Engineers are educating themselves priming for the renewable onslaught as well striving to provide underwriters with much needed technical knowledge to address pertinent class exposures. No doubt underwriters will rely heavily on Engineering for knowledge and direction to profitably underwrite a potentially difficult class of business.

Engineers and Underwriters will need a firm relationship to successfully navigate the underwriting world of hydrogen.

PML Considerations

Possible Maximum Loss (PML) considerations are key for adequate pricing and underwriting of H_2 risks. Obviously PML exposures vary across the different phases of a project. Large parts of the construction phase are characterized by lower build-up in values, but lack of protection and safety systems due to unfinished state of the project. Values typically peak with during testing and commissioning as well as during the operational phase which ultimately drives PML exposure. For the sake of this chapter we will look at PML scenarios assuming peak values:

Internal scenarios

Internal PML is driven by technology immanent factors and typically related to key components which have a high value and are bottlenecks for the business. These are:

- Electrolyser runoff, gasifiers, fire/explosion due to disintegration of product compressor incl. propagation. High pressure gas release with flash or jet fire in the compressor damaging adjacent equipment depending on the spacing. Lube oil system fire.
- Ammonia plant – Reformer explosion or vessel disintegration in the high-pressure ammonia synthesis reactor or the urea reactor. Lube oil system fire within the compressor.
- Methanol Reformer – fire or explosion in the reformer due to hydrogen embrittlement or disintegration of the methanol synthesis reactor. Lube oil system fire within the compressor.
- Pipelines - Incorrect backfill leading to excessive settlement which requires replacement of a certain length of backfill – Welding failure with improper alloy and lining damage or insulation failure while the pipeline is buried. Flood of an open trench section of the pipeline. Micro TBM or HDD could get stuck or collapse of the tunnel for the pipeline. External coating or paint failure leading to a corrosion issue. Damages at main compressor stations.
- Explosion at main product storage (identify and mitigate larger H_2 volume)
- Other risks: serial losses resulting from defects of key elements such as welding, coating, and membranes

The actual PML scenario is driven by the extent of the damage, which will, among other factors, depend on the layout of the project and the cost of repair (PD) respectively the indemnity period (DSU/BI). As many H_2 risks are built in modular forms, plant layout is crucial to determine a reliable PML scenario.

On the positive side it has to be noted that the modular layout of projects can ensure special distance as well as redundancy which mitigate PD as well as DSU/BI risks. Also, H_2 is lighter than air which means that, unlike other explosive gases, it will not accumulate at ground level potentially leading to vapor cloud explosion (VCE).

External scenarios

External PML scenarios to be considered:

- Loss resulting from existing property
- Vapor cloud explosion (VCE) cause by nearby refinery or petrochemical complex
- Explosion of ammonia/ fertilizer plant
- Nat Cat events: Fire, explosion due to natural catastrophes (earthquake, windstorm) but also major damage due to floods / ensuing floods. Electrolyser internals should be able to withstand (since pressurized) water intake if switched off timely but cleaning works and down time relevant. Consider also secondary natural perils.
- Earthquake: rupture of pipelines and tanks leading to fire and explosion, transformer damage
- Flood: flooding of electrical components such as electrolysers
- Secondary perils: damage cause by wildfire, tornado, torrential rain, lighting strike
- Terrorism & Cyber: H_2 projects can be part of critical infrastructure which can be subject to both Terrorism and Cyber-attacks both of which are capable to induce high PD and DSU/BI losses

Risk management outlook

The green H_2 industry is still in its infancy and not anticipated to scale before the early 2030s. However, there will be plenty of pilot projects (often involving unproven/ prototypical technology or setups) coming to market as new players enter the H_2 industry. In fact the H_2 economy will most likely blur traditional industry boundaries and attract players from the oil & gas, the chemicals as well as the power and utilities industries. This shift will unleash plenty of private capital and comes in line with increased political efforts to foster the use of green H_2 for decarbonization. Decreasing electricity costs for renewable energy and rising CO_2 costs of fossil fuels (incl. grey H_2) are likely to fuel the demand for green H_2. As a result, economies of scale will kick-in and together with technological evolution and smarter manufacturing lead to decreasing levelized costs of H_2 – LCOH[147].

Against this background there will be continued developments of electrolysers and other H_2 technology which will inevitably require a constant technological evaluation and a thorough application of best practices and lessons learnt. From a risk management perspective the following aspects deserve special attention:

- Industry standards and certification: plenty of effort is undertaken in this space and it is likely that the H_2 industry will follow the example of other developing industries such as renewable energy. As a result there will be joint industry standards which will allow for efficient and transparent certification of H_2 technology and projects and thereby help to reduce risks. The latter will most likely include type certification of electrolysers and overall certification of projects in terms of bankability and insurability which will improve risk management. This is especially relevant for interface risk which currently lacks transparent and aligned standards
- Regulatory framework: the key drivers of LCOH are electricity costs and electrolyser CAPEX. With electricity grids adopting higher shares of renewable energy and a multitude of subsidy schemes being rolled out across different countries, there is often a regulatory gap concerning the H_2 industry. It is likely that this gap is going to be closed and that efficient regulation will be introduced to create investment certainty, managing risk allocation, and allowing H_2 industry growth through sustainable business models. Some of this regulation is likely to span across countries (for instance when it comes to a European power grid). The introduction of regulatory frameworks will support risk allocation and management across the industry

- Original equipment manufacturer (OEM) market structure: currently the H_2 industry continues to see new entrants with leading degrees of experience, but as technology evolves and becomes more standardized there is likely going to be more concentration in the OEM space with a couple of vendors dominating the market for electrolysers and other key H_2 equipment. Like wind or gas turbines, H_2 technology will be part of an iterative cycle of upgrades, certification, and series maturity. Ultimately this will drive market wide definitions of prototype and proven status of equipment and increase overall transparency and trust in technology
- Formation of industry bodies: in order to balance economic growth, technology evolution and risk management, trusted industry bodies will emerge in the H_2 economy. The constant exchange of industry experts and other stakeholders is likely going to facilitate overall risk management efforts and thereby improve overall risk quality in the industry
- Continued H_2 integration: as the industry develops there is more and more integration of H_2 in industrial processes. Together with the creation of new business models, this will raise questions of risk allocation and responsibilities. Ultimately this could lead to broader forms of risk management solutions such as cross-LoB policies. Also, specific open cover or turnover solutions for OEMs and project developers are likely to emerge as well as warranty insurance.

The outlook of the hydrogen economy continues to bear a high level of known and emerging risks, with a high level of interdependencies between risk factors

Newly developing business models and standards, inexperienced market participants as well as prototypical/unproven technology require thorough analysis and constant monitoring.

Underwriting best practice

In reaction to the new challenges posed by the H_2 industry, solid Underwriting is required. The following underwriting considerations are by no means exhaustive and will require constant rethinking, but they should serve as best practice to address key risk areas:

Prototypes / Defects: Defect coverage should be carefully considered on the basis of the technology in scope. The power and renewables industry has set basic standards to align defects cover with technology risk. Covering damage resulting from defects may turn out to be costly and highly disputed, this dependent on the "maturity" of the corresponding legislation framework (wording definitions, assessment of loss and associated costs, responsibility, and subrogation rights).

It is vital to stick to modern, comprehensive, and proven wording avoiding manuscript and "home-grown" wording

For prototypical technology AND scaling up comprehensive wordings (such a Munich Re CPI) to adequately reflect special components, topped with adequate LEG clause (DE not recommended) or corresponding endorsements to achieve the same result. LEG 1 for prototypical elements, meaning technology which has no type certification. LEG 3 for proven technology. LEG 3 can be granted case by case following dedicated risk engineering assessment as long as the fleet leader has reached proven status (e.g. 8,000 hours for gas turbines).

Basis of indemnity: This is crucial in many aspects given that (1) membranes, catalysts, hot gas path components, refractories and other components have limited lifetime which depend on the operation regime and (2) there may be pre-used/refurbished equipment in overhaul/retrofitting projects which should be analysed in terms of depreciation.

Best practice is to assess an equivalent operating hours scheme for components with limited lifetime and/or expected high degradation and to have clear and adequate depreciation wording agreed

Corrosion / Erosion / Embrittlement: H_2 projects are subject to corrosion, erosion and embrittlement and thus adequate exclusions should be in place. Even if considered in design, these risks are inherent to hydrogen operations and the question of sudden/unforeseen is per natura to be affirmed.

Firefighting standards: Given the increased risk of fire and explosion, adequate fire protection measures and safety standards need to be ensured. Appropriate clauses need to be implemented. Especially live testing and protocol of readiness prior to critical operations needs to be addressed.

Manufacturer's warranty: With reference to the dynamic H_2 technology development, it should be ensured that manufacturer's warranty as well as any form of availability guarantees should remain primary to the insurance.

The risk of assuming entrepreneurial risks is very high, both in property damage and business interruption.

Series loss clause: With modular technology (e.g. containerized electrolysers) and scaling up via parallelization serial loss exposure resulting from defects in design, plan, specification, material, and/or workmanship becomes highly relevant. Insurers may seek to limit their PD and BI exposure by application of increasing deductible per loss and/or by reducing the indemnity via serial loss provisions.

The Serial loss clause should be aligned with the defect language and with the definition of occurrence to avoid an unintended broadening in cover

Testing: As soon as hydrogen production equipment is started for testing purposes, H_2 projects are subject to explosion risks. It is therefore recommended to develop a clear definition of testing and limit the testing period accordingly for phased testing and commissioning.

Handover: With many H_2 projects coming in modular forms, the takeover procedure needs to be clearly defined (takeover of the entire project vs. individual items). Likewise, contractual provisions for initial operation (incl. PD and BI) need to be set out in the policy. In this context it is worth noting that initial operation can sensibly impact the PML scenario of the project.

Maintenance: Given the often unproven/prototypical nature of H_2 projects, maintenance cover has to be considered carefully and no maintenance coverage should be wider than defined elsewhere in the policy. some hydrogen projects might be unproven/prototypical. In this case extended or guarantee maintenance may involve high risks. Therefore, each project must be carefully analyzed prior binding. Maintenance cover has to be considered carefully and no maintenance coverage should be wider than defined elsewhere in the policy.

Existing / Surrounding property: H_2 projects are often developed within or adjacent to exposed property and hazardous operations. Therefore the risk of damage to and from existing property needs to be examined and limited.

Physical loss: Electrolysers, reactors, reformers are subject to condensation, corrosion, impurities, and recombination of gases all of which do not by themselves necessarily constitute physical loss or damage. In fact a proper definition of the later prevents insurers from assuming liability for pure clean-up costs. Likewise pure electrical breakdown without physical loss or damage should not be part of the policy trigger.

DSU / BI: given the variety of H_2 related business models as well as the potential risk of fluctuating commodity market prices. Additionally, long lead times must be considered for hydrogen generation equipment.

It is important to structure the DSU/BI indemnity on the basis of "actual loss sustained"

Accordingly, there should be no indemnity for the amount of any sum saved or received (e.g. through contractual penalties) as a result of delay/interruption nor covering additional costs due to market risks related to speculation or demand/supply interruptions.

Pre-fabrication: Significant pre-fabrication issues have been reported in the oil & gas as well as the renewables industry with welding, coating, and painting works being a specific area of concern. That said, adequate underwriting measures such as defects exclusion, loss limits and robust deductibles have to be taken where pre-fabrication is included.

Hydrocarbon exclusion: From the moment in which hydrocarbons and critical media are processed,

Insurers may seek to enforce industry safety standards as precondition to any liability

and to limit and/or exclude losses affecting specific items (e.g. catalyst).

Sections: Exposure for pipelines and open trenches should be limited by section clauses, same applies for tunneling works.

Horizontal Directional Drilling (HDD): Downstream integration of H_2 projects may include complicated CAR/underground works incl. HDDs which carry high levels of risk. Adequate HDD exclusions are required to mitigate the exposure.

Tunnel boring machines (TBM): Careful assessment, adequate deductibles and insuring clauses are mandatory when TBMs are involved (e.g. cavern storage), same applies for Tunneling Code of Practice.

Cargo and transport risk: H_2 projects can involve both, expensive equipment with long lead times (e.g. transformers, gas compressors) and items being shipped in large quantities (e.g. containerized electrolysers). Where cargo risk is included, it is recommended evaluate this in more detail and implement appropriate contractual measures such as Marine 50/50 clause and relevant sub-limits.

Cyber exclusions: H_2 projects can be part of critical infrastructure and thus be subject to cyber-attacks. It is therefore recommended to use market standard cyber exclusions.

Malicious damage and social risks: Malicious damage by employees, subcontractors, external partners and SRCC related events are much more critical in regards of catastrophic exposure insuring hydrogen projects, compared to traditional engineering risks. Access control and emergency plans are mandatory, wording should consider and limit these risks elements. Needless to state this applies for war and terrorism provisions.

Third party liability: From damage to 3rd party property and bodily injury (e.g. through explosion) to pollution and contamination (e.g. through alkaline electrolytes),

Hydrogen projects bear plenty of TPL risks which need careful assessment

The TPL trigger needs to be clearly defined and pure financial losses (e.g. through contractual liability) should be avoided. Robust exclusions to TPL coverage (e.g. EIL) are required.

Annex 4: Required underwriting information is a list of relevant underwriting information to allow adequate assessement of hydrogen projects.

8. Coverage, Claims

Coverage and claims considerations are discussed in this section. At the time of writing, construction is yet to commence (or has only just commenced) for many of the announced industrial hydrogen projects. Accordingly, this section discusses some known industrial hydrogen incidents from the last 5 years but also considers hypothetical claim scenarios that may arise in future. The hypothetical claim scenarios focus predominantly on the electrolyser.

Given that some of the claims and coverage scenarios can only be speculated upon at this stage, the intention is to provide the key areas for underwriters to consider as new industrial hydrogen risks are presented to them. It is not intended to provide a complete overview of every type of claim scenario that might arise. Whether bespoke hydrogen wordings are produced will also have a bearing on the future handling of claims.

On existing hydrogen technologies (for example: pipelines, storage, transport, handling, production from natural gas, and existing electrolysis) the authors have researched existing hydrogen claims databases. Dominant root causes (such that they have been identified) for different industries and statistics are also be presented.

Exemplary claims

Electrolyser runoff leading to explosion

Our first scenario occurred in 2019. It relates to an explosion at an experimental fuel-cell power system in the South Korean city of Gangneung during a test operation. Three tanks of 40 m^3 capacity each were all destroyed in an explosion which sent debris across an area of well over 3,000 m^2.

The preliminary investigation indicated that the tanks exploded as a result of a static spark when oxygen concentration exceeded 6% in one of the buffer tanks. The investigation also identified several construction and workmanship issues, from which there are important lessons to be learnt:

- The oxygen removing component appeared to have been omitted during system implementation. Although the designer included oxygen remover in the initial design, it was removed when the contractor provided a notification that it could not provide an oxygen remover for construction completion.
- The static spark remover in the buffer tank was also omitted during construction. It should have been connected to earth but was not. This was because the contractor identified a concrete foundation underneath the tank's proposed location, which could have been damaged or difficult to reestablish.
- The operator ran the water electrolysis system below the as-designed power level, which induced the increase of oxygen concentration. The system had an asbestos separation membrane that had to be operated at a minimum of 98 kWh. However, the system obtained its power from solar power. Due to the inconsistencies associated with solar panel power production, the system often operated at a level below the necessary 98 kWh. It is believed that the power inconsistency caused the electrolyser membrane to degrade.
- The oxygen concentration was allegedly detected to be higher than 3% prior to the incident. This should have prompted the operator to install an oxygen remover. However, the operator apparently ignored this issue and continued the operation to reach the 1000 hours of required experiment validation time.
- Finally, the safety management team did not follow safety regulations that required it to monitor hydrogen quality daily[148,149].

The deteriorating "Membrane" in this scenario led to a H_2–O_2 explosive mix, which quite clearly caused damage to other components of the facility. Claims may therefore be presented to underwriters in future that involve consequential damage to insured and/or neighboring property.

There are two key take-aways from this claim scenario:

- The importance of proper process monitoring. For example, if membrane issues had been discovered earlier or if the contractor had properly followed the design, it is clear that the explosion would not have happened or could have been prevented. How the policy would respond in these circumstances depends on the combination of what obligations are placed on an operator by underwriters to review installation procedures and also what requirements are on the insured to conduct adequate maintenance and rectification. Once damage does occur, the consideration of faulty part wordings and / or LEG clauses for prototype technology will be significant, particularly when there are likely to be consequential losses to unrelated components.
- This scenario also highlights one of the key risks associated with the production of "green" hydrogen. Renewable energy sources are often intermittent (for example: windfarms can only produce power when the wind is blowing, and solar panels can only produce power when the light conditions allow) and this creates difficulties for elements that require consistent power to function correctly. How designers and operators seek to overcome these intermittent power issues with the electrolyser in truly "green" industrial hydrogen projects will be a matter for underwriters to keep under close review.

Failure in detection system leads to explosion

As discussed earlier in this report, suitable hydrogen gas detection is key. A failure to detect hydrogen leakage creates a clear explosion risk. For example, in the AB Speciality Silicones explosion in the USA in 2019, a failure to detect a hydrogen leak at a silicone plant was directly attributable to the explosion that subsequently occurred. The US regulator found:

"The building was not equipped with functioning detectors for hydrogen or other flammable gases. While the building filled with flammable vapours, the workers attempted to open the emulsion area to outside air and turn on fans. They were unable to complete these efforts before the building exploded"

In this scenario, the operator was fined $1.5 million by the US Department of Labour's Occupational Safety and Health Administration. Sadly, there were also four fatalities.

From a claim perspective, it is quite clear that leakage detection measures will be scrutinised when losses caused by leaks are presented. Although we consider that for most industrial hydrogen projects leakage detection should be manageable, the quality of leakage detection should form a key part of underwriters' risk analysis.

However, in this context it is important for underwriters to consider the law and jurisdiction of the policy they are proposing to write. For example, in some jurisdictions a failure to request specific information from an insured in a proposal form might mean that insurers remain on risk notwithstanding a failure on the part of the insured to disclose that it did not have hydrogen detection mechanisms in place. Underwriters should seek appropriate advice in the jurisdiction they are seeking to make the policy subject to and should not assume that the same proposal forms or policy wordings will have the same effect in all jurisdictions.

Hydrogen leak leads to explosion

One of the major construction losses in recent years was the explosion at Medupi power plant in South Africa on August 8, 2021. Unit 4 was in a short-term outage when the incident occurred.

Medupi reported as part of its preliminary findings that the explosion has resulted in extensive damage to the generator. Following the preliminary investigation, it appears that while performing this task air was introduced into the generator at a point where hydrogen was still present in the generator at sufficient quantities to create an explosive mixture, which ignited and resulted in the explosion. It also appears that there was a deviation from the procedure for carrying out this activity. Two operators and four managers have been suspended pending an investigation.

Loss estimate as of today is USD 150,000,000. The generator was opened instead of purging fully with carbon dioxide, this allowed air to get into the generator, which mixed with the hydrogen causing an explosive mixture that ignited and blew up the generator. Poor training and incompetence are among suspected root cause of the incident.

Damage at unit 4 due to wrong purging procedure.
Source: https://hydrogen-central.com/explosion-eskom-medupi-power-plant-newest-expensive-coal-plant-hydrogen-leak-photos/

Hypothetical claim scenarios

Serial losses – Electrolyser stacks

As discussed in earlier chapters of this report, the electrolyser is the fulcrum of most hydrogen projects. It is therefore critical to consider the electrolyser specifically in the context of claim scenarios.

Firstly, even before construction has commenced on many projects, electrolyser manufacturers are seeking to increase electrolyser output. For example, it is not uncommon for 10-20MW projects to announce that 100MW output of hydrogen is the eventual goal [reference is made to reference projects in this magnitude Refhyne in Germany and Gigastack in the UK]. Indeed, an increase in output with PEM electrolysers, is usually associated with an increase in the number of modules in an electrolyser "stack". For example, for a 10MW PEM electrolyser, it is common to see 5 x 2MW modules which together form the 10MW "stack" output. From a claim perspective, the following considerations are relevant:

- It remains to be seen whether the continued development of PEM electrolysers will see increased module capacity as an alternative to an increase in stack size. However, if module capacity is increased as an industry standard then how quickly will existing modules become obsolete? In a claim scenario where obsolete modules are damaged, repair and / or replacement costs for obsolete items are likely to be key adjustment considerations.
- Some industry experts have suggested that high-temperature membrane electrolysers will prove to be more efficient and more powerful than PEM membrane electrolysers. If that is the case and if PEM as a technology becomes obsolete, then the same issues will apply.
- As more electrolysers come to market, the extent to which modules are compatible with each other will also be significant. For example, if only one manufacturer is able to supply a particular replacement module, then supply times and availability could have ramifications under various claims scenarios, particularly those involving significant Business Interruption exposures.

- Linked to supplier availability is supplier viability. In circumstances where a sole manufacturer produces specific modules per electrolyser stack, the unavailability of replacements as a result of supplier insolvency, or a lack of availability (say due to excessive lead-times) could have a significant impact on the total costs that could be incurred. Additionally, the extent to which an Insured is able to claim for a repair or a replacement under a warranty is also significant and Insurers may want to consider up front where the risk of supplier insolvency should lie.
- It will also be important for underwriters to assess which components within modules are realistically replaceable. For example, depending on the issue, a claim concerning damage to a membrane might require the replacement of an entire module, or even the replacement of an entire stack. It is for this reason that Insurers should keep abreast of developments of electrolyser technology.
- A related point is that if it is assumed that membranes in industrial-scale electrolysers will be replaceable after they reach the end of their service lives (which is currently estimated to be around 2 years after the commencement of production) then that is likely to require underwriters to consider whether a reducing basis of indemnity should be included for those membranes. This is particularly significant given that approximately 45% of project CAPEX for industrial hydrogen project cost relates to the electrolyser.
- Finally, we note above that PEM electrolysers work by "stacking" modules. Therefore, a design type issue in one module may be replicated in other modules. As the number of modules increase, so does the risk of serial issues becoming ever more costly to underwriters. In these circumstances, underwriters may wish to include a series loss clause into their hydrogen wordings. This has the effect of covering the same defect on a sliding scale, usually starting at 100% for the first [x] number of losses and then decreasing for the next [x] number of losses until a set value of series losses has occurred after which no cover is provided. The key issues for underwriters to consider are what types of incidents or defects would underwriters propose the series loss clause to be applicable to and, depending on the scale of the project, how many of the same type of losses would underwriters propose to cover before the scale decreases or expires entirely.

NatCat: EQ, lightning, storm, wildfires, flood

Where, as noted above, something as seemingly inconsequential as a static spark might cause an explosion at a hydrogen facility, it is not difficult to foresee that most NatCat scenarios may lead to catastrophic explosion events, potentially affecting not only the insured property but also neighboring infrastructure. Business Interruption could also be significant.

As a result, explosion prevention and then explosion protection are likely to be relevant considerations for insureds as well as for underwriters. Design considerations as well as applied standards will be in focus and policy wordings relating to faulty design will be key in regards of coverage.

Consideration of blast dynamics: Explosion prevention is a significant consideration for insureds that operate with hydrogen. However, the blast dynamics of hydrogen in commercial use are not yet fully understood. Insurers may face liability claims as a result of hydrogen explosions, the question of what damage was caused by a hydrogen explosion as opposed to, say pre-existing damage or some other cause, may require some refinement. Accordingly, Underwriters must ensure that their knowledge of hydrogen blast dynamics, design standards and its interaction with NatCat scenarios is up to date.

Flood scenarios can cause serious damage to facilities even if not catastrophic, even if most electrolysers are pressurized and this may offer some kind of inherent protection for module internals, damage to electrical equipment, cost of clean-up and restarting operations should not be underestimated. BI and CBI damage can then be significant.

Control system failure

As with any industrial facility, the maintenance of adequate control systems will be fundamental to the risk profile. For a hydrogen facility it is likely that operators will have numerous units integrated into a single facility. Should a control system fail at a hydrogen facility, the authors consider unlikely that the cost of repair to that system will drive the costs of any claim. Instead, Business Interruption is likely to provide the greatest exposure, not least because current electrolyser designs are so sensitive to their environments (be that temperature, power supply or even water quality). Accordingly, even with a shut-down as a result of a control system failure, the knock-on effect to the electrolyser and other critical equipment is likely to create knock-on issues to the facility that may, at first be unforeseen. How underwriters settle an initial control system failure claim will therefore be significant for potential future claims at the same facility. The same can be said even if control system warranties are easily enforceable.

Depending on agreed wordings, liability for business interruption could be based on contractual schemes, e.g. availability guarantees, volatility of prices for replacing product and other variables which were not assessable and may represent entrepreneurial risk elements, thus Underwriters need to stick to "actual loss sustained" and a clear basis of indemnity.

Quality of energy supply

The quality and / or reliability of energy supply is critical for a PEM electrolyser, but it is also critical for all electrolyser types. Issues with the energy supply include voltage peaks, voltage drops, drops in supply or no supply. Any of these issues could cause production problems for electrolysers and even, possibly, electrical damage. Equally, energy supply issues can also affect other electrical distribution systems. Transformer design and electrical protection logic should consider and mitigate many issues, and UPS systems should be able to ensure safe shutdown. But at this stage of scaling up facilities and optimizing processes no system can be considered as fail-safe, disregard of the human factor.

How this energy supply issue can be managed by an operator will differ from project to project, however it is clear that green hydrogen (i.e., hydrogen produced from solely renewable sources) is likely to face unique challenges. For example, for a hydrogen plant connected to a windfarm, how will a consistent energy supply be maintained when the wind is not blowing? At present there appears to be two alternatives: (i) the use of battery power to store energy produced in abundant periods; and (ii) the connection of the facility to the grid. The problem with (i) is that battery storage on a large scale presents its own risks (particularly at sites with significant fire and explosion risks in any event); and (ii) connecting a "green" facility to the grid may call into question the extent to which the facility can truly be regarded as "green" (thus undermining the very purpose of the project in the first place).

It is also the case that, with varying energy supply, Contingent Business Interruption might be affected depending on the extent of the coverage provided and the interdependency of projects. In this context it is notable that some green hydrogen projects will produce hydrogen for a single local customer.

Premature membrane deterioration

From a claim perspective the deterioration or failure of components over time call into question issues such as gradual deterioration (which may be excluded in a policy wording) and might also call into question whether electrolyser membranes themselves can be considered a "part" in possible faulty or defective part wordings.

An additional issue here is that with membrane degradation being linked to the operational regime in most systems, if an insured fails to accommodate known power fluctuations and/or needs to contractually respond to extreme or untested operational cycles, this may bring due diligence considerations to the fore. Due diligence may also be a consideration in circumstances where warnings in relation to deterioration may have been missed or ignored.

Other considerations

From a claims perspective, the following considerations are also relevant

- As can be seen from the claim scenarios discussed in this section, requirements for service and maintenance intervals (for example, (equivalent) operational hours of membrane and water quality and/or operational parameters as a trigger for preventive maintenance) could provide significant protections for underwriters and an analysis of these requirements will need to be conducted carefully at the claims stage.
- We have discussed above the importance of underwriters considering where the risks of warranty viability should lie. In addition to that is the issue of the interconnectivity of warranties. For example, whether warranties are provided for a single turnkey project and if not whether there the inter-dependence of warranties are suitable in long term installation projects. It is also important to assess the expiry of warranties and whether underwriters are, in effect, being asked to provide guarantee maintenance. This issue may well differ from project to project, but upon the presentation of a claim the viability of existing warranties and the obligations on the insured to comply with warranty claim requirements will need to be explored thoroughly.
- Some hydrogen projects are considering placing electrolysers offshore. Under offshore conditions, electrolysers are likely to face much harsher and more corrosive environments. They are also likely to be more difficult (and more costly) to inspect and maintain. We suggest that underwriters consider their pricing carefully when considering risks associated with offshore hydrogen assets as it is also likely that investigation and adjustment costs will increase at the claim stage.
- As noted elsewhere in this report, the risk of metal embrittlement of from hydrogen is significant. One factor that will be key from a claims perspective is the potential effect of embrittlement on existing structures, for example: in existing pipelines and storage tanks. Understanding the process of embrittlement (not just for existing property that has been converted for hydrogen use) and when the embrittlement process can be said to cause damage is going to be a key consideration for claims handlers working on hydrogen claims. This is an issue that is also likely to differ from jurisdiction to jurisdiction.
- As to general claim exposure, green hydrogen projects linked to offshore wind farms are likely to be dominated by logistics costs (including vessel spreads). A typical offshore wind claim is usually split as follows: two thirds logistics costs and one third costs for parts and repair. Equally, claims for the offshore transport of hydrogen should be comparable to claims in other energy classes (for example, natural gas), with offshore explosion risks being broadly similar, although smaller quantities of hydrogen are expected initially.
- At a practical level, given that industrial hydrogen projects are going to expand significantly in the coming years, ensuring that there is adequate expertise available from service providers (particularly loss adjusters and experts) will be critical. A feature of some hydrogen incidents is the difficulty in underlying cause detection. For example, at a hydrogen fuel plant explosion in North Carolina, USA, in April 2020, it has been publicly reported that the cause of the explosion may never be known. This is of course of some concern for insureds that use hydrogen at their facilities, however it is also of concern for underwriters given the importance of cause analysis to claims handling. It is anticipated that cause investigation technology will improve as hydrogen claims become common, however it is also likely to be the case that claims handlers may need to consider specialist experts who operate outside of their usual networks. By way of example, property or energy insurers may need to consider specialist chemical engineering or blast dynamic experts when investigating hydrogen claims.

Claims databases

Following claims databases relating to hydrogen are publicly available:

- General infrastructure including storage and transport

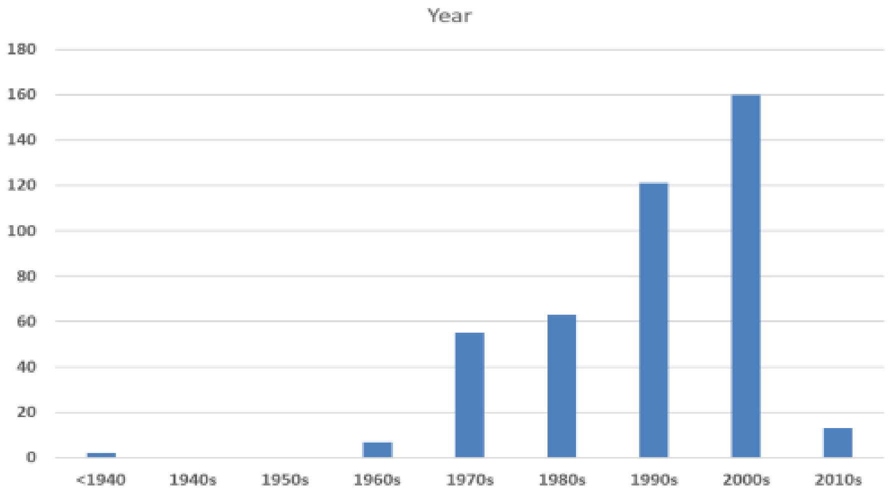
https://h2tools.org/lessons

- Chemical industry / refineries

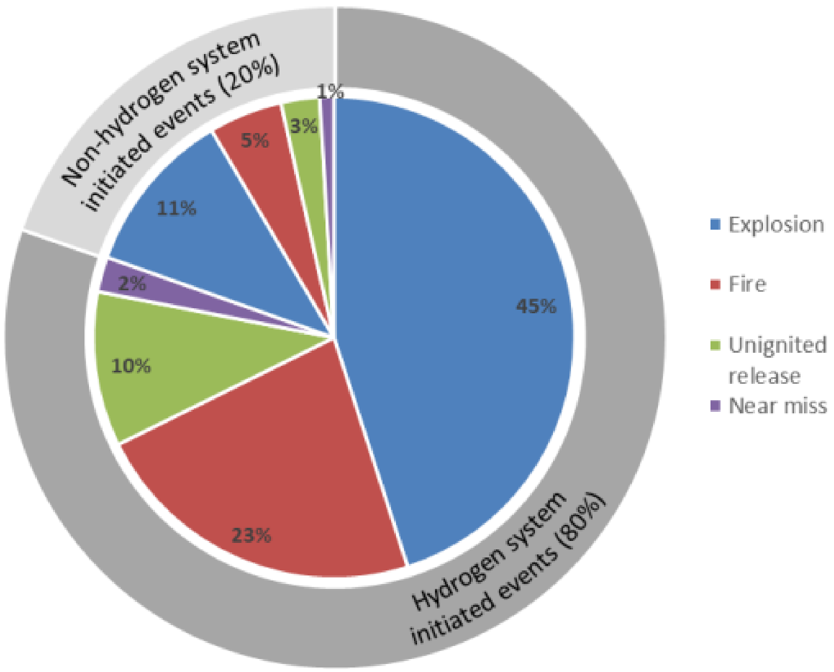
https://www.csb.gov/investigations/completed-investigations/?Type=2

https://hysafe.info/hiad-2-0-free-access-to-the-renewed-hydrogen-incident-and-accident-database/

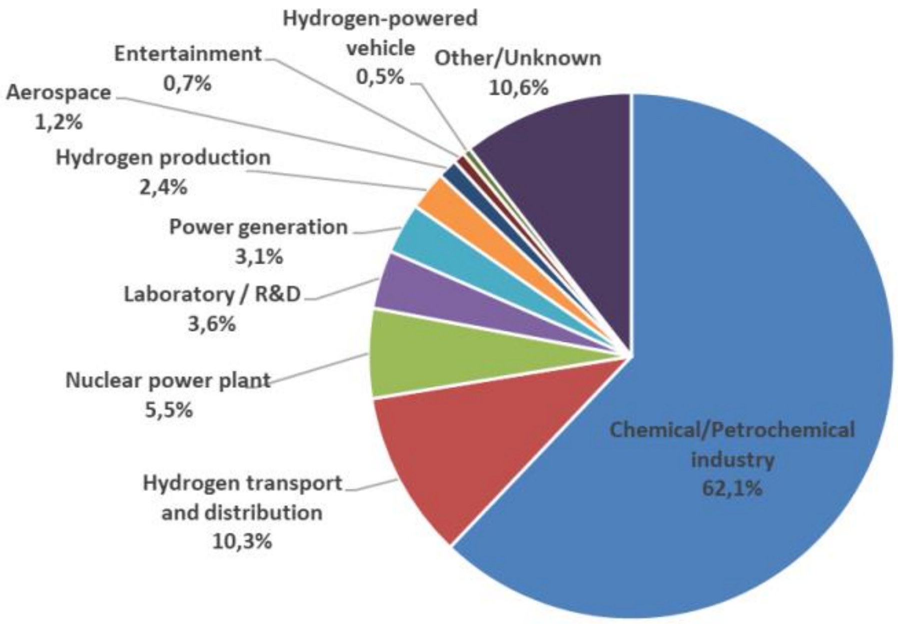
As shown below, accumulation of events is consistent over time:



Distribution over time of events registered in HIAD 2.0 Database[150]



Distribution by system of events registered in HIAD 2.0 Database[150]



Distribution of events by industry registered in HIAD 2.0 Database[150]

Fuel cells Large stationary: The applications will increase in number and size and larger stationary installation will show similarities with electrolyser scenario above (serial clause, consequential loss, technology level, supplier insolvency, run outside design parameters).

We could not find public incidents on stationary fuel cells.

Fuel cells mobility application: We could find only one documented event: explosion of a fuel cell powered forklift potentially caused by the fuel cell.

Hydrogen Steam reforming + Carbon capture and storage (CCS): Root causes for incidents and near misses were mainly

- Disconnected alarms
- Opening valve
- Pipe breaks (embrittlement, corrosion)
- Wrong handling / human error

Hydrogen Pyrolysis: No claims in databases: new process / scaling up risks

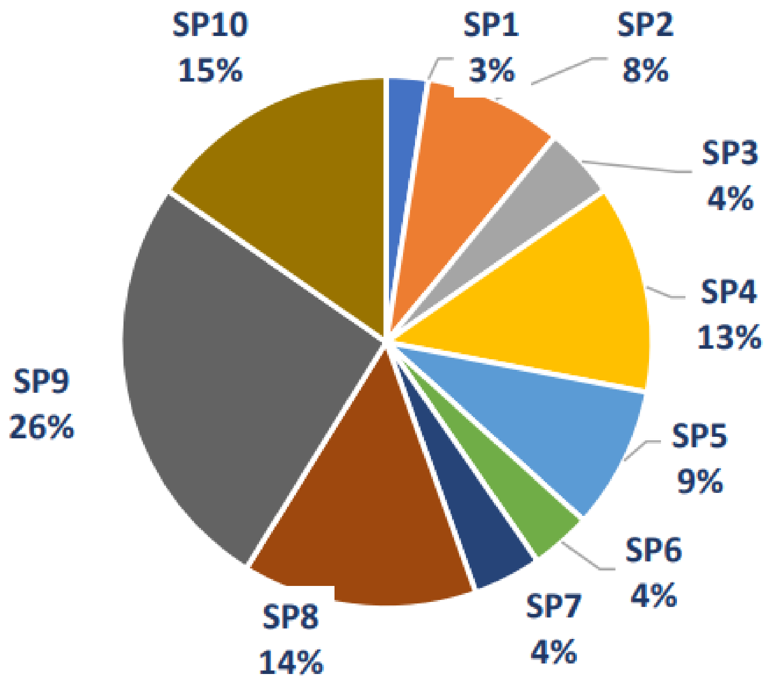
Storage of Hydrogen (Cavern): No incidents on caverns found

Transport and handling of Hydrogen (Pipeline, Truck, cylinders, pumps, valves): Several incidents are well documented. Prominent root causes:

- Valves e.g., failures in handling / design / installation
- Leaking pump
- External perils e.g. collision during transport
- Embrittlement
- Failure in detection
- Lack of safety / HSE rules / Human error

Claims in Gas turbines: Pure Hydrogen as energy source: no incidents found. Natural gas turbines few incidents on false manual handling of hydrogen as a coolant (generator) which leads to explosion were reported.

Most registered incidents could have been avoided by following basic safety principles as outlined below. The human factor, meaning organizational safety principles seems to be the key element (SP 9 + SP 10) out of the historical claims experience.



Incidents reported by safety principle HIAD 2.0 Database[150]

Number	Safety Principle	Explosion/ Protection Tier
1	Limit hydrogen inventories, especially indoors, to what is strictly necessary	1st Tier
2	Avoid or limit formation of flammable mixture by applying appropriate ventilation systems, for instance	
3	Carry out ATEX zoning analysis	
4	Combine hydrogen leak or fire detection and countermeasures	2nd Tier
5	Avoid ignition sources using proper materials or installations in the different ATEX zones, remove electrical systems or provide electrical grounding, etc.	
6	Avoid congestion, reduce turbulence promoting flow obstacles (volumetric blockage ratio) in respective ATEX zones	3rd Tier
7	Avoid confinement. Place storage in the free, or use large openings which are also supporting natural ventilation	
8	Provide efficient passive barriers in case of active barriers deactivation by whatever reason	
9	Train and educate staff in hydrogen safety	Organisational Safety Principles
10	Report near misses, incidents and accidents to suitable databases and include lessons learned in your safety plan	

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Annex 1: Technical assessment of fuel cells

3.1 Fuel cells power plants

The main advantages of fuel cells can be summarized as follows.

- Direct energy conversion (no combustion): Most fuel cell attributes stem from direct electrochemical power generation. In conventional power plants, most irreversibilities, more than 30%, take place in the combustion process.
- Potential for high efficiency: Stand-alone fuel cell electrical efficiency is in the range of 40% to 60%, based on the lower heating value (LHV). For hybrid and cogeneration fuel cell systems, efficiency of around 70% (LHV) and higher than 80% have been predicted, respectively.
- Lower pollution: Fuel cells can generate electricity with very low amounts of pollutants, such as GHG, NO_x, and SO_x. This is due primarily to their high efficiency. Also, since there is no combustion in the power generation process, the emissions associated with combustion are eliminated. Moreover, since most fuel cells should be operated on desulfurized fuels, they do not emit any SOx.
- Scalability: The unique characteristic of fuel cells is that their high efficiency and other attributes are nearly unaffected by the size of the plant. That means fuel cells are scalable to all sizes with, more or less, the same high efficiency, low emissions, and costs. In addition, modular installations of fuel cells can help them to match load and increase their reliability.
- No moving parts in the energy converter: A fuel cell generates electricity by the movement of mobile ions and electrons. Therefore, there are no moving parts in the fuel cell itself. However, some compressors and/or fans are required to supply oxidizer and fuel to the system.
- Quiet operation: Due to minimal moving parts, fuel cells can be operated with minimal noises and vibrations. This is very important for some applications such as residential distributed electricity generation.
- Fuel flexibility: The ideal fuel for a fuel cell is hydrogen. If fueled by hydrogen, there are no emissions by the fuel cell and the only emissions are for hydrogen generation. However, fuel cells can operate on a wide range of fuels, from conventional fuels, such as natural gas, petroleum, and coal, to renewable fuels, like biogas and ethanol, to landfill gas. This fuel flexibility can provide smoother transition to future power generation infrastructures. Fuel cells can operate, directly or indirectly, based on the fossil fuel, until renewable hydrogen is available commercially. In other words, fuel cells are power generators of today and tomorrow.
- Easier carbon capture: In the fuel cell operation, fuel and air streams are not mixed, making CO_2 capture easier and less energy intensive. Possibility for water production: If pure hydrogen and oxygen are used as a fuel and oxidizer, respectively, the only products of the fuel cell operation are electricity, heat, and potable water.
- Hybrid systems and cogeneration: Most fuel cells, especially high operating temperature ones, can be used in hybrid systems to produce further electricity and/or in cogeneration systems to produce heating and/or cooling as well as electricity.
- Operational flexibility: fast response to load changes, unattended operation, good off-design load operation, reliability, and high availability[1].
- Stationary fuel cell systems also take up much less space in proportion to other clean energy technologies. For instance, a 10 MW fuel cell installation can be sited in a about an acre of land. This is compared to about 10 acres required per MW of solar power and about 50 acres per MW of wind[2].

Similar to electrolysers, fuel cells are subject to a trade-off between efficiency and power output. Efficiency is highest at low loads and decreases with increasing power output. In comparison to conventional technologies, fuel cells can achieve their highest efficiencies under transient cycles.

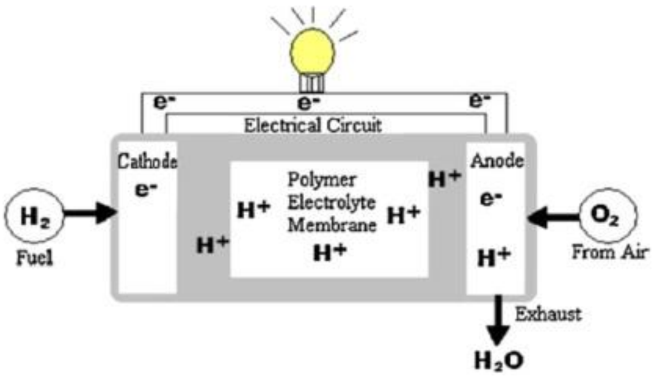
While PEMFCs and alkaline fuel cells have low operating temperatures of around 80°C, the others operate at higher temperatures of up to 600°C (SOFC), which makes them more suitable to combined heat and power applications. The higher the temperature, the better the efficiency at otherwise similar parameters[3].

As in the case of electrolysers, different fuel cell types exist, which can mainly be distinguished by their membrane type and operating temperature. Fuel cells can be categorized into:

PEM fuel cell (PEMFC)

The proton exchange membrane (PEM) fuel cell consists of a cathode, an anode, and an electrolyte membrane. Hydrogen is oxidized at the anode and the oxygen is reduced at the cathode. Protons are transported from the anode to the cathode through the electrolyte membrane and the electrons are carried over an external circuit load. On the cathode, oxygen reacts with protons and electrons producing heat and forming water as a by-product.

The process of a PEMFC is shown below.



Scheme of a PEMFC[4]

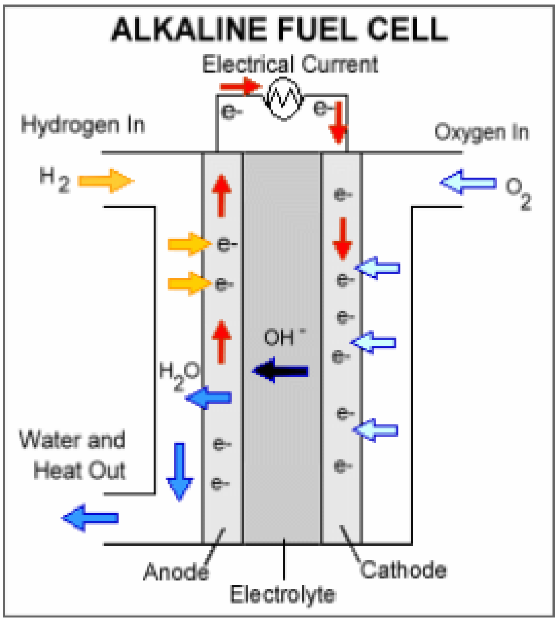
Depending on the operating temperature, we can distinguish two different types of PEMFCs. The first type, Low-Temperature Proton Exchange Membrane Fuel Cell, operates in a range of 60–80 °C. The second type operates in a range of 110–180 °C, therefore, it is called High-Temperature Proton Exchange Membrane Fuel Cell. The standard electrolyte material used in Low-Temperature PEM fuel cells is a fully fluorinated Teflon-based material produced by DuPont for space applications in the 1960s, which is generally called Nafion.

For High-Temperature PEM fuel cells, it is possible to use Nafion or Polybenzimidazole (PBI) doped in phosphoric acid. Platinum is classically used in the catalyst for Low-Temperature PEMFCs, while Platinum–Ruthenium is used for High-Temperature PEMFCs catalyst.

The electrical efficiency for Low-Temperature PEM fuel cells is about 40–60%, while for High-Temperature PEM fuel cells it is about 50–60%[4].

Alkaline fuel cell (AFC)

Alkaline fuel cells are a type of low-temperature fuel cells and works at 65–220 ◦C. Some features of the AFC include high efficiency, easy control, small-scale and/ or power plant implementation, suitable for dynamic operating procedures and cheaper than PEM fuel cells. However, it requires pure oxygen and hydrogen to operate. AFCs are the first fuel cells that can produce significant power for transportation purposes. AFC uses KOH solution as the electrolyte.



Scheme of AFC[5]

At the anode side, hydrogen reacts with hydroxyl ions to form water and releases electrons ($H_2 + 2OH^- \rightarrow 2H_2O + 2e^-$). At the cathode side, oxygen reacts with water to form hydroxyl ions ($H_2O + 1/2O_2 + 2e^- \rightarrow 2OH^-$)[6].

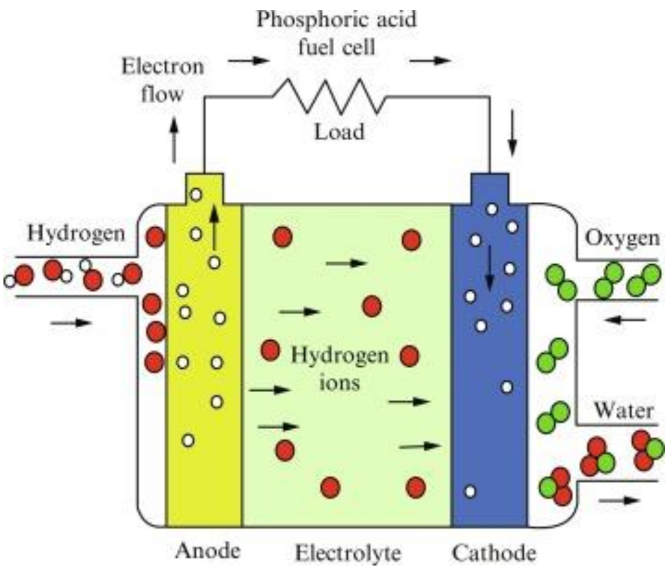
The advantage of AFCs to enable non-precious metal catalysis has been outweighed by the increased system complexity and difficulties of working with a liquid electrolyte, as well as issues with carbonate formation.

The world has moved on from AFCs, as the focus of R&D has shifted to the development of the polymer anionic exchange membrane fuel cell (AEMFC) and all underlying facets[7].

Phosphoric acid fuel cell (PAFC)

PAFCs were considered the first generation of modern fuel cells and were the first class of fuel cells to receive significant attention and R&D investment from national governments as well as public institutions (gas and electric utilities and related organizations). The enthusiasm that surrounded PAFCs was likely a direct result of the disappointing performance of AFCs and its intolerance for CO_2. Researchers undoubtedly felt that PAFCs finally had overcome all the shortcomings of previous fuel cell designs.

PAFCs are tolerant of CO_2 in fuel gas streams and in air and they are more tolerant of CO than PEMFCs. PAFCs can tolerate a CO concentration of about 1 percent at 200 °C, greatly simplifying the choice of fuels they can use, including natural gas, petroleum products, coal liquids, and coal gases. PAFCs are considered well suited for distributed generation (DG) because electricity can be generated very near where it is used, thereby reducing the amount of energy lost in transmitting electricity as well as reducing the construction of power grid infrastructure. Moreover, PAFCs generate high temperature waste heat that can be used for heating water, space heating, and low- pressure steam in a CHP cogeneration system. In comparison to lower temperature fuel cells, such as AFCs and PEMFCs, PAFCs have been regarded as ideally suited for installations in urban areas (near point of use) and as an on-site cogeneration power source[8].



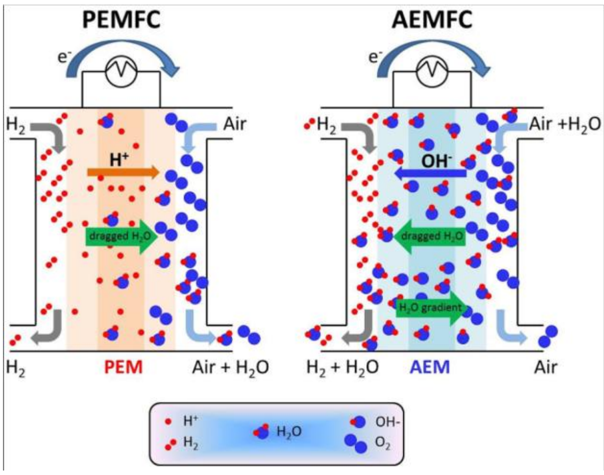
Scheme of a PAFC[9]

Efficiency of PAFC is ~ 35%–45%, which is higher than PEMFC, but lower than MCFC and SOFC. When it works with CHP, heat and power are applied simultaneously, so the efficiency grows dramatically and reaches to about 85%[9].

Polymer anionic exchange membrane fuel cell (PAEMFC) and Anion exchange membrane fuel cells (AEMFC)

Compared with that of proton exchange membrane fuel cells (PEMFCs), alkaline anion exchange membrane fuel cells (AEMFCs) with alkaline anion exchange membranes (AEMs) as electrolytes are attracting increased attention due to their potential use as non-precious catalysts. As one of the key components of AEMFCs, an ideal AEM must possess high hydroxide conductivity, good thermal stability, sufficient mechanical stability, and excellent long-term durability at elevated temperatures in an alkaline environment.

Compared with that of PEMFCs with Nafion® membranes (electrolyte), AEMFCs that operated under high pH conditions enable the use of non-precious metal catalysts (such as cobalt, nickel, or silver) instead of Pt-based catalysts. Furthermore, AEMFCs with solid anion exchange membranes (AEMs) solved the electrolyte leakage problem (KOH solution) of the traditional alkaline fuel cells. As a key component of AEMFCs, an ideal AEM should possess high hydroxide conductivity, excellent mechanical property, good thermal stability, and robust alkaline stability to play the important role in separating fuels and transporting OH− from anode to cathode of AEMFCs[10].

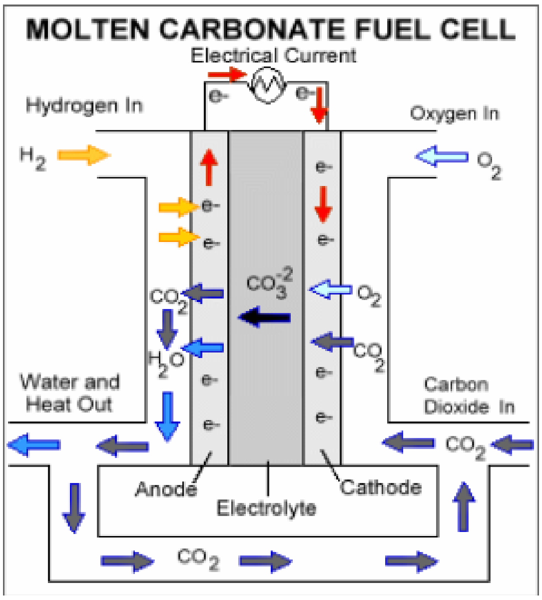


Schematic of an AEMFC as compared to a PEMFC[11]

Technically, AEMFCs are like PEMFCs, with the main difference being that the solid membrane is an alkaline AEM instead of an acidic PEM. With an AEM in an AEMFC, the OH− anion is transported from the cathode to the anode, opposite to the H+ conduction direction in a PEMFC. Although in principle both technologies are similar, the use of an AEM creates an alkaline pH cell environment, and therefore, the AEMFC offers several potential advantages over the mature PEMFC technology[11].

Molten carbonate fuel cell (MCFC)

The carbonate fuel cell power plant is an emerging high-efficiency, ultraclean electric power generation system utilizing a variety of gaseous, liquid, and gasified solid carbonaceous fuels such as coal for commercial and industrial applications. The power-producing component of this system is the carbonate fuel cell, which uses alkali metal carbonate mixtures as the electrolyte immobilized in a porous ceramic matrix. The fuel cell operates at 550–650 °C. The fundamental understanding and the state-of-the-art material and electrolyte choices are based on extensive research carried out in Japan, Europe, and the United States in the 1960s and the early 1970s. Present-day carbonate fuel cell construction employs commonly available stainless steels. The electrodes are based on nickel and fabricated using well-established manufacturing processes including sheet metal forming, tape casting, and low-temperature sintering[12].



Scheme of a MCFC[13]

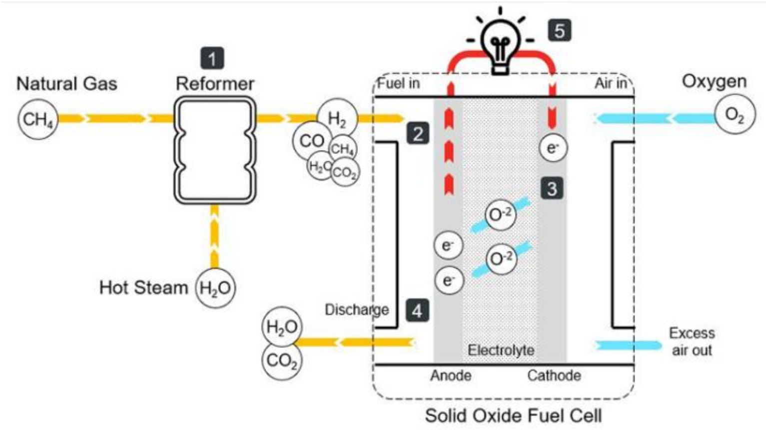
Solid oxide fuel cell (SOFC)

A solid oxide fuel cell utilizes the movement of electrons and generates electricity in few basic steps.

Natural gas goes through a steam-reforming process. This chemical reaction produces hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2) and steam (H_2O). There will be some unreformed natural gas left in the mix as well. The mix of elements from the reformer enter the fuel cell at the anode side. Meanwhile, air (including oxygen) enters the fuel cell at the cathode side. Oxygen in the air combines with free electrons to form oxide ions at the cathode. Oxide ions with free electrons travel from the cathode to the anode through the electrolyte.

At the anode, oxide ions react with hydrogen forming water (steam) and with carbon monoxide (CO) forming carbon dioxide (CO_2). These reactions release free electrons. These free electrons travel to cathode through the external electrical circuit, producing electricity.

Electrical efficiency of solid oxide fuel cells reaches up to 60%[14].



Source: Cummins

SOFC are being commercially developed for smaller decentralized applications, even for housing and office buildings.

Reference project

At present, the world's largest hydrogen fuel cell power plant is situated in South Korea. It can provide electricity to some 250,000 households per year and was put into operation in South Korea's western port city of Incheon.

Source: https://hydrogen-central.com/largest-hydrogen-fuel-cell-power-plant-korea-kospo/

The plant has a capacity of 78,96-Megawatt plant using fuel cell generators (SOFC) supplied by POSCO Energy and Doosan Fuel Cell. The project cost was about USD 292 Million. It would also produce hot water for heating that can be used by about 44,000 households and simultaneously removes microparticles from the air from a nearby LNG power plant[15].

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Annex 3: Summary of best practices and risk mitigation for hydrogen facilities

Below a summary of best practices and risk elements to be considered for hydrogen facilities, while the table is not exhaustive it may help identify and address known safety issues during design, operation, and maintenance.

Facility Design and Construction	
Element	Description
Design codes	- Define and implement state-of-the-art design codes - Tunneling code - Introduce unique equipment indentifier system from design phase
Ensure system integrity	- Leak tightness design and test - Avoid screwed connections - Ensure and test proper seal design for valves
Prototype	- Throughout validation of prototypes and scaled up components - Consider changes in operational modes (on/off vs.permanent) - Consider increment of units per stack for safety design - Consider changes in the control systems while scaling up - Combination of two known components is "new" philosophy
Lifetime of components	- Consider lifetime of components and define operating and maintenance cycles - Consider aging vs. Operating regime, including impact of changes in regime (EOH philosophy) - Define and monitor lifetime of critical components (HGP in turbines, membranes in electrolysers, materials exposed to embrittlement, corrosion, erosion) - Monitor parameters defining aging and integrate into EOH logic
Catalyst poisoning, regenaration	- Reformer catalysts are very sensitive to sulphur. Sulphur content can vary a lot between different natural gas streams, and it is important to have control of the desulphurization system in a SMR plant (hydrogenation reactor and zink oxide reactors). - In the hydrogenation reactor sulphur is converted to H2S and in the zink oxide reactors the H2S is absorbed. Normally there is teo reactors in series and any sulphur breakthrough would be between the two reactors. It is important to continually track the sulphur content at this point. - Steam reformer catalyst are normally activated with hydrogen/natural gas when fresh during initial startup. If this is not done in a proper way there is a risk that the catalyst do not work properly. This is especially important for SMR:s operating on naphtha instead of natural gas. - Operating steam reformers with the wrong steam/carbon ratio (steam/natural gas ratio) can damage the reformer catalyst (coke formation) giving an increased pressure drop with over heating of the reformer tubes as consequence. Over heating of the tubes can lead to tube rupture.
Vibrations and pulsations	- Consider vibrations and pulsations in design - Validate during commissioning and maintenance - Define and implement monitoring systems - Define and implement logic for alarm/trip
Operating limits	- Define and monitor operating limits (temperature, pressure, flow, concentration) - Define and implement in the systems logic alarm/trip thresholds - Check of transient operations during commissioning - Qualitative evaluation of safety effects resulting from failure of controls
Safety distance	- Consider enough distance between units for maintenance operations (e.g. between electrolyser to perform maintenance while other modules are operating)
Feed quality	- Define and monitor feed quality (e.g. water quality for electrolysers, fuel and air quality for turbines)
Safety design	- Preferred Fail-safe features and components - Best practice: Double block and bleed safety design - Interlock systems where applicable and according applying design standards - Relief and safety valves - Define and audit construction materials and procedures - Define and audit electrical classification, certification of electrical equipment - Pressure relief design and considerations - Ventilation systems design - Soild foundation design to avoid pipe and/or equipment rupture - State of the art flare design

Materials	- Consider corrosion and erosion (process flow, sea air, corrosive media) - Consider embrittlement and define lifetime, inspection and control plans - Consider thermal stability - Consider pressure resistance acc. standard including transient operations - Consider thermal expansion - Consider rupture limits, overheating of tubes and apparatus - Consider galvanic interaction - Consider aging - Consider creep behavior - Consider changes in operating parameters, transient operations and related impact - Validation of materials compatibility
NatCat	- Prevention and emergency plans in windstorm areas - Consider wildfires and floods and emergency plans - Earthquake design according state-of the-art standards for buildings, equipment and piping - Seismic response procedure, inspection and restart procedures following seismic events - Preferred vertical AND horizontal force compensators - Acceleration sensors and integration into logic (alarm/trip) - Consider and avoid freezing of safety valves and actuators
Audit	- External design audits (e.g. TüV) - Internal reviews during design, construction and operations - PHA, HAZOP Study

Fire Protection

Element	Description
Limit hydrogen inventories	- Preferred outdoor storage - Reduce size of storage units - Preferred on-demand onsite production - Define and audit maximum allowed storage of hazardous materials
Limit leak volume	- Preferred small pipe diameters, flow restrictors when possible - Design of excess flow valves and discharge nozzles
Ventilation	- Preferred natural ventilation - Use mechanical ventilation system or inerting system if natural ventilation not enough - Ventilation design and operatibility for indoor storage - Ventilation management in process logic and emergency procedures - Avoid confinement, avoid protective roofs etc., where hydrogen might accumulate - Increase distances - Use passive ventilation, explosion vents - Continuous control of mechanical ventilation, avoid cost saving measures
Suppression systems	- Use catalytic recombiners where relevant (for large release rates recombiners might be not suitable, in high hydrogen concentrations a recombiner could be an ignition source) - Use flame or detonation arrestors, periodic control - Define and audit firefighting systems, inert gas suppression (CO2/N2), isolation
ATEX Zones	- Definition and control of ATEX Zones - ATEX Materials and certified equipment - Avoid ignition sources in ATEX sources,both in design and operational procedures - Proper grounding and control - Avoid congestion, reduce turbulence promoting flow obstacles (volumetric blockage ratio) in the respective ATEX zone - Publish map of ATEX zones, safety marking
Leak detection	- Use of LEL Detection systems and dedicated analysis of required locations - Process monitoring considering leak detection, alarms and trip logic - Emergency shutdown of equipment where required - Emergency shutoff of valves and restrictors - Emergency signals and measures - Shutdown of electrical equipment - Define other countermeasures and document accordingly
Lightning protection	- Proper lightning protection, periodic tests
Inertization	- Inertization is done before startup and shutdown of all system that will contain flammable gas. This should be done with an inert gas like nitrogen. Before startup, after for example a maintenance shutdown, the system needs to be free from oxygen and purged to the atmosphere (not to the flare system since it can contain oxygen). The system is normally purged until the oxygen level is at least below 0,5% vol. This can be done by pressurizing to 5 bars and realizing it down to 0,5 bar. This is done repeatedly until the oxygen level is low enough. - After shutdown the system is inertized in the same way but the gas is released to the flare system (if there is one). Otherwise vented on at high elevation not exposing surrounding systems or persons. - Before any assemble LEL-measurements should be done to verify that the system is free from flammable gas. Any human entry into the systems require additional measures. - It is important to include all systems that will be exposed to flammable gas including dead ends and pipe lines
Flame visibility	- Consider visibility of hydrogen flames - Thermal imaging, linear heat detection
Combustible control	- Control combustible elements during maintenance shutdown

Human factor	
Element	**Description**
Startup/Shutdown procedures	- Clear startup and shutdown instructions in local languages with step by step instructions preferable connected to valve tag numbers, pumps numbers etc. - The instruction should be a part of the operator training and referring also to P&IDs and PFDs - Startup and shutdown instructions should be available in paper form in the control room
Emergency procedures	- Emergency instructions should cover events like fire event, power failure, loss of cooling water, loss of instrument air, etc. - The instruction should be based on PHA and risk analysis connected to the different events - Emergency instructions should be available in paper form in the control room, in local language
Safety plan	- Provide site specific annual and multi-annual safety plan - Define and monitor significant hazards and hazardous operations - Distribute within staff and integrate into safety training prior to site access - Organize periodic safety reviews - Mitigation planning - Emergency planning and management - Define safety champions and responsibilities - Review proposed changes to materials, technology, equipment, procedures and staff
Preventive Maintenance	- Define and implement preventive maintenance plan - Periodic calibration of safety related systems and instruments - Hose and pipes exchange requirements
Corrective Maintenance	- Continuos monitoring of leaks and malfunctioning - Correct deficiencies outside acceptable limits
Testing and inspection	- Perform periodic testing of components and safety systems - Dedicated testing and documentation of detection systems, calibration - Proper documentation of inspection and results
Training	- Initial training including process overview, operating procedures, safety and health hazards, work permits, ATEX zones, emergency operations, etc. - Access control to construction site subject to hydrogen specific training (incl. ATEX zones and emergency procedures) - Organize and control participation in hydrogen-specific safety courses for operational and maintenance personnel - Perform refresher courses on periodic basis
Audits	- Perform periodic internal and external audits - Develop self-audits and related templates, checklists - Develop and monitor pre-startup safety reviews - Develop and implement whistleblower policy for safety issues - Perform periodic simulated emergency operations
Reporting	- Report near misses, incidents and accidents - Introduce and follow up implementation of lessons learnt, update safety plan - Document and distribute changes in design and procedures
Information	- Inform staff about changes in saftey plan and procedures and lessons learnt - Issue and distribute safety data sheets for materials and components
Work permits	- Introduce work permits in ATEX zones, audit and control - Hot work permits and hazardous operations (welding, brazing, etc.) - Lock out, tagging and marking systems (unique equipment identifier) - Ensure all detection systems live and tested prior to start-up and/or restart operations - Equipment and line opening and clearing procedures - Work permits for confined spaces
Signaling and marking	- Clear marking of ATEX zones - Color code and nomenclature systems for equipment and piping - No smoke marking, dedicated smoke areas
Flange management, gasket size	- Having control of flanges after maintenance TA and other dismantling works is very important. - Installing the wrong gasket (size or pressure class) can lead to leakage and fire. - A flange management system where all flanges are checked in a structured way after assembly, controlling the right type of gasket in terms of size and pressure class, right length of bolts tightened correctly will minimize the risk of leaks during startup. - After each flange has been correctly checked it is recommended to have sealing on the flange to insure it has not been broken after the check
Leakage control	- Leakage control is done as a part of the startup procedure by pressuring the system first with nitrogen. - When the pressure is set for at example 7 bars a trend curve can be set in the DCS to follow any pressure decrease at a certain time. - At the same time leak spray should be used on flanges valves etc. Any noted leaks should be fixed.
Flare system	- If the unit is connected to a flare system, it is normal procedure to purge nitrogen and flammable gas into the flare system. - No air or oxygen should be purged into the flare system due to the risk of getting a flammable mix with explosion as a consequence. - If a flare system exists all safety valves containing flammable gas should be connected.
Drains	- Drains connected to flammable gas or flammable liquid should during operation be capped. This should be reviewed during the normal safety rounds in the plants.

Interdependencies and Business Interruption	
Element	Description
Redundancy	- Preferred multiple trains of operation - Consider redundant philosophy to allow further operation for bottleneck equipment (e.g. compressors)
Critical spares	- Preferred no single source equipment - Define critical spares and long lead items, consider BI losses vs. Sourcing and storage costs - Proper storage and control humidity and other factors which may affect equipment
Contingent business interruption	- Consider and mitigate loss of utilities (power, feed, etc.) - Consider and mititgate unability to take off product by clients (T&D lines, pipelines) - Consider and mititgate unability to deliver feed at site (electricity, water, hydrogen)

Annex 2: Regulations, standards, and codes

While codes and standards provide the roadmap and framework for construction, as well as guidelines for operation, a site or fleet specific procedure for operation and maintenance of the facility needs to be developed in an effort to safely operate and maintain the plant.

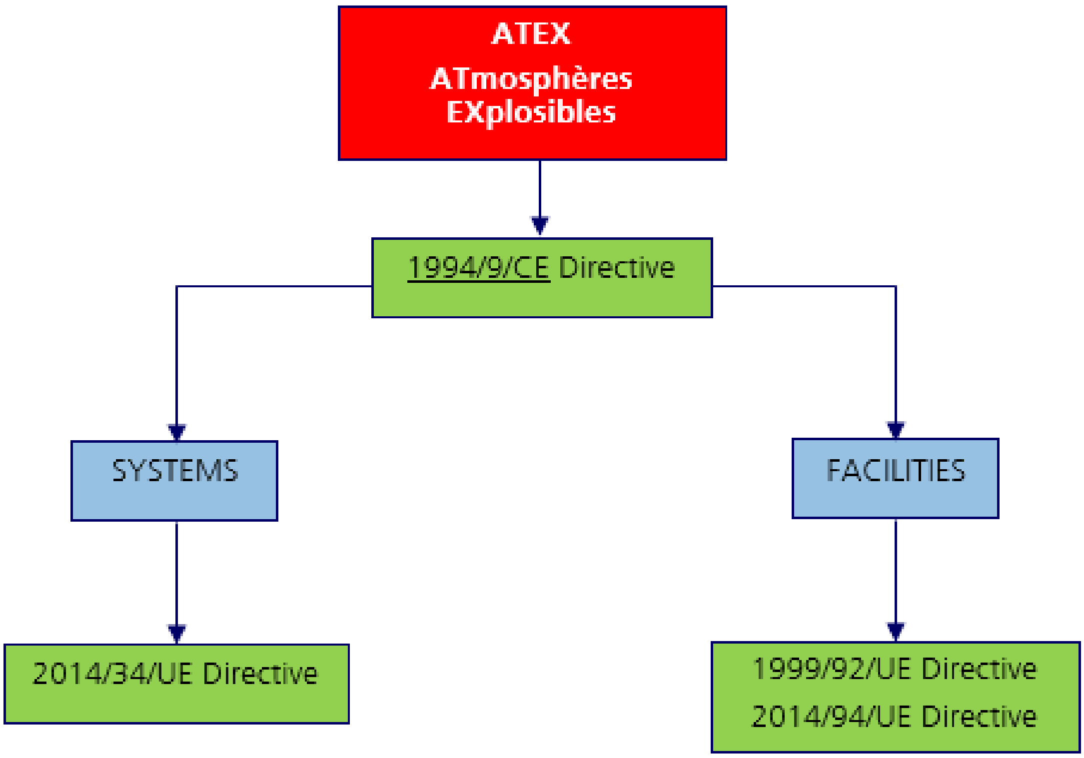
Most of the relevant safety aspects are regulated by EU directives and through statutory regulations, standards, and codes.

EC Directives

European laws, such as Directives or Regulations, prevail over national laws. In order to carry out their task and in accordance with the provisions of the Treaty establishing the European Community (the EC Treaty), the Parliament acting jointly with the Council, the Council and the Commission make regulations and issue directives according to Art. 249 of the EC Treaty.

A directive shall be binding, as to the result to be achieved, upon each Member State to which it is addressed, but shall leave to the national authorities the choice of form and methods (national transcription).

Requirements for products and operational requirements are strictly separated in EU legislation since they belong to different political objectives and are governed by different articles of the EU treaty[1].



Guidelines to application of the Directive 2014/34/EU:

https://ec.europa.eu/docsroom/documents/41403/attachments/1/translations/en/renditions/native

ATEX directive 99/92/EC relates to minimum requirements for improving the safety and health protection of workers potentially at risk from explosive atmospheres (ATEX).

Hydrogen is a flammable gas which can form an ATEX where mixed with air (such an ATEX is defined by the directive as a mixture in which, after ignition occurred, combustion spreads to the entire unburned mixture). Hazardous zones are defined as follows:

• Zone 0: a place in which an ATEX is present continuously or for long periods or frequently.

• Zone 1: a place in which an ATEX is likely to occur in normal operation occasionally.

• Zone 2: a place in which an ATEX is not likely to occur in normal operation but, if it does occur, will persist for a short period only.

ATEX directive 2014/34/EU applies to equipment and protective systems intended for use in potentially explosive atmospheres. It also applies to controlling devices and regulating devices intended for use outside potentially explosive atmospheres but required for or contributing to the safe functioning of equipment and protective systems with respect to the risks of explosion are also covered by the scope of this directive.

Both directives are interrelated. Equipment from certain categories according to 2014/34/EU can be used in certain zones defined according to 99/92/EC, but is forbidden in others.

The PED (Pressure Equipment Directive – 97/23/EC of the European Parliament and of the Council of 29 May 1997 on the approximation of the laws of the member States concerning pressure equipment) is applicable in Europe since December 1999 and mandatory since end of May 2002. It applies to all stationary vessels with service pressure of more than 0.5 bar and a volume of more than 50 liters.

Since this directive is mandatory in Europe, a number of "Notified Bodies" have been notified to Brussels by the authorities of each EU members states. These notified bodies can make the "evaluation of conformity" of the pressure equipment; this evaluation is confirmed by the "CE" mark applied onto the equipment. Any notified body (from every country) can approve a CE marked equipment to be used in every country of the EU.

This directive only defines the "essential requirements". Detailed requirements are given in the harmonized standards (e.g. prepared by CEN). These EN-Standards are not mandatory, other procedures or "state of the art" can be used by the manufacture in order to demonstrate to the notified body that the essential requirements are fulfilled.

This European directive doesn't cover the use of the equipment (operational requirement, periodic inspection, …) which are still under national regulations. This may create difficulties if such equipment is to be moved from one country to another.

The most important committee in Europe is CEN/CENELEC TC 6 "Hydrogen in Energy Systems". It has not yet published standards of its own. The committee cooperates closely with ISO TC 197.

Hydrogen relevant standards are not made only by one or a few committees, however. Since hydrogen energy has relationships to many other fields, standards for pressure vessels, pipelines, gas quality etc. must be taken into consideration as well[1].

Standards and codes

These are not legal requirements. However, they serve as guidelines for design and safe operation.

The directives offer the possibility of meeting safety requirements by designing and manufacturing the products of compliance with the essential health and safety requirements, through the harmonized standards that have been developed specifically by relevant government agencies, to allow a presumption of conformity with such requirements.

European National Standards

European Standard (EN) are developed by a recognized European Standards Organization such as CEN, CENELEC, or ETSI. These European Standards have been developed by the Technical Committee and adopted in the EU states as identical national standards:

- UNE: Spanish national Standard
- DIN: German national Standard
- BS: British national Standard
- NF/AFNOR: French national Standard
- UNI: Italian national Standard

The "European Standards" (EN), which were established by the CENELEC countries, are valid as national standards in all affiliated countries. The European Standards (EN) are identical in all countries with regard to their content. They are published as national standards as follows:

Country	Requirements General	Box Explosion-proof "d"	Safety increased "e	Security intrinsic "i"
International (CENELEC)	EN 50 014	EN 50 018	EN 50 019	EN 50 020
Belgium	NBN C23-001	NBN C23-103	NBN C23-102	NBN C23-101
Denmark	AFSNIT 50	AFSNIT 50-4	AFSNIT 50-4	AFSNIT 50-6
Germany	DIN EN 50 014 VDE 0170/0171 T.1	DIN EN 50 018 VDE 0170/0171 T.5	DIN EN 50 019 VDE 0170/0171 T.6	DIN EN 50 020 VDE 0170/0171 T.7
Finland	SFS 4094	SFS 4098	SFS 4099	SFS 4100
France	NF C23-514	NF C23-518	NF C23-519	NF C23-520
Britain	BS 5001: Parte 1	BS 5501: Parte 5	BS 5501: Parte 6	BS 5501: Parte 7
Italy	CEI 31-8	CEI 31-1	CEI 31-7	CEI 31-9
Netherlands	NEN-EN 50014	NEN-EN 500 018	NEN-EN 500 019	NEN-EN 500 020
Norway	NEN 110	NEN 114	NEN 115	NEN 116
Austria	EN 50 014	EN 50 018	EN 50 019	EN 50 020
Sweden	SS EN 50 014	SS EN 50 018	SS EN 50 019	SS EN 50 020
Switzerland	SEV 1068-EN 50 014	SEV 1072-EN 50 018	SEV 1073-EN 50 019	SEV 1074-EN 50 020
Spain	UNE 21 814	UNE 21 818	UNE 21 819	UNE 21 820

International Standards

ISO: International Organization for Standardization (ISO TC197 Hydrogen technologies)

IEEE: Institute of Electrical and Electronics Engineers

IEC: World standardization organization for electrical, electronic, and related technologies) is responsible for international standardization in the field of electrical technology.

The IEC has introduced a procedure – so called IEC-Ex Scheme – intended to become a globally recognized test and certification procedure in the field of explosion protected electrical apparatus. Hydrogen systems should be classified according to the IEC 60079-10-1 standard. It is very important to follow said standard to prepare the classification of areas and define the danger of the different areas of the installation based on acquired classification.

IEC Standards	EN	Description
IEC 60079-0	EN 50 014	General requirements
IEC 60079-1	EN 50 018	Construction and testing of explosion-proof boxes for electrical appliances
IEC 60079-1A	----------	Test method for determining the maximum experimental security gap
IEC 60079-2	EN 50 016	Electrical appliances – type of protection „p"
IEC 60079-3	EN 50 020	Spark Test Apparatus for Intrinsically Safe Circuits
IEC 60079-4	-----------	Test method for ignition temperature -4A
IEC 60079-5	EN 50 017	Sand Filled Apparatus
IEC 60079-6	EN 50 015	Oil immersed apparatus
IEC 60079-7	EN 50 019	Construction and testing of electrical apparatus, type of protection „e"
IEC 60079-10	EN 60079-10	Classification of high-risk areas
IEC 60079-11	EN 50 020	Construction and testing of intrinsically safe apparatus and other related equipment
IEC 60079-12	EN 50 014	Classification of gas or vapor mixtures with air according to their maximum experimental safety gap and minimum ignition currents
IEC 60079-13	---------	Construction and use of rooms or buildings protected by pressurization
IEC 60079-14	EN 60079-14	Electrical installation in explosive gas atmospheres (other than mines)
IEC 60079-15	pr EN 50 021	
IEC/TR 60079-16	----------	
IEC 60079-17	EN 60079-17	
IEC 60079-18	EN 50 028	
IEC 60079-19	prEN 60079-19	
IEC/TR 60079-20	----------	
IEC 60079-29		Gaseous hydrogen detectors are, many times, a safety requirement and must comply with the IEC 60079-29-1 standard

Regulatory regime around hydrogen supply chain:

H2 GENERATION

- ISO TC197 Working Group 9 (ISO 16110-2) Hydrogen Generators Using Fuel Processing Technologies
- ISO 22734:2019 - Hydrogen generators using water electrolysis — Industrial, commercial, and residential applications
- ISO 16110-1:2015 Hydrogen generators using fuel processing technologies
- ISO/TC 197 Hydrogen technologies
- ISO/TC 158 - Analysis of Gas
- AIAA G-095 - Guide to Safety of Hydrogen and Hydrogen Systems
- ISO TR 15916 Basic Considerations for the Safety of Hydrogen Systems
- IEC/TC 31 - Equipment for explosive atmospheres

STORAGE/TRANSPORT/ DISTRIBUTION

- CE 1272/2008 - Storage at the production site for later distribution.
- NFPA 55 Storage, Use and Handling of Compressed Gases and Cryogenic Fluids in Portable and Stationary Containers, Cylinders and Tanks

Land Transport:
- CEN/TC 268 - Storage and transport of liquid hydrogen
- CEN/TC 23 - Storage and transport of compressed hydrogen

Pipeline:
- CEN/TC 234 - The injection of hydrogen and the mixture of hydrogen with natural gas (H2NG) in the gas infrastructure

Maritime Transport:
IMO IMDG Code
IMO IGC Code

REFUELING / TRANSFER

- IEC 60079-29-2 Explosive atmospheres – Gas detectors - Selection, installation, use and maintenance of detectors for flammable gases and oxygen
- ISO/TS 20100:2008 - Gaseous hydrogen — Fuelling stations
- ISO 17268:2020 - Gaseous hydrogen land vehicle refueling connection device
- EN 17124:2018 - Hydrogen fuel - Product specification and quality assurance
- EN 17127:2020 – Outdoor hydrogen refueling points dispensing gaseous hydrogen and incorporating filling protocols
- CEN/TC 305 - Potentially explosive atmospheres - Explosion prevention and protection

COMERCIAL USE

- CEN/TC 268/WG 5 Specific applications of hydrogen technologies
- IEC TC 69 - electric vehicles
- IEC TC 35 - fuel cells
- ISO TC 58 - compressed gas cylinders
- ISO 14687-2 Hydrogen Fuel - PEM fuel cell applications for road vehicles
- CLC/SR 105 - Fuel cell technologies
- EN 62282-3-100:2012 - Part 3-100: Systems stationary fuel cells. Security. IEC 62282-3-100:2012
- EN 62282-3-300:2012 - Part 3-300: Systems stationary fuel cells. Installation. IEC62282-3-100:2012
- EN 62282-3-100:2012. - Part 5-1: Battery Systems portable fuel.

Design Codes

Codes are developed by interested industrial parties. Some relevant codes and organizations are listed below for reference:

- EIGA: IGC Docs (Hydrogen stations, Pipelines)
- SAE International: J2601 (Fueling protocols)
- EHA European Hydrogen and fuel cell Association
- FCH-JU Fuel Cells and Hydrogen Joint Undertaking
- Hydrogen Europe
- HySafe International Association for Hydrogen Safety http://www.hysafe.org/
- HyER Hydrogen Fuel Cells and Electro mobility in European Regions
- H2ME Hydrogen Mobility Europe
- IEA International Energy Agency
- IPHE International Platform for Hydrogen and fuel cells in the Economy
- SHHP Scandinavian Hydrogen Highway Partnership
- The New European Research Grouping on Fuel Cells and Hydrogen – N.ERGHY

Certifications

Some hydrogen technologies are fairly new and not standardized, certification and joint industry projects can help improve the reliability of technology and establish trusted electrolyser models and OEMs. Some recognized certification entities are DNVGL and TüV, which have developed industry standards teaming up with OEMs and established certification schemes.

References

[1] Safety planning for hydrogen and fuel cell projects. Fuel cells and hydrogen 2 joint undertaking (FCH 2 JU). July 2019

Annex 4: Required underwriting information

Required information

General
- Geology, Hydrology
- Plant layout
- Earthquake design standard, Restart procedures after EQ
- Technology and involved Main Contractors, References
- Scale-up operating references, scale up factor
- Lifetime of critical components vs. operating regime, equivalent operating hours calculation
- Cumulative hours, on-stream availability
- Design considerations for buildings (fire proofing, compartments, emergency exhaust systems)
- Design and installation considerations for piping, fittings, tubing, valves, gauges
- Separation from hazardous processes
- Distance of hydrogen piping and apparatus to overhead lines
- Fencing, access control
- Detection systems
- Fire Protection systems, firefighting concept
- Ignition source control standards, ATEX, Mechanical Ventilation (local and remote activation?)
- Interface to the electricity production, overhead lines/subsea cables included?
- Where is the interface to the hydrogen transport, pipeline included?
Storage & piping
- Construction standards for pressure vessels
- Safety valves design approach (main shut off, double bleed, interlock)
- Safety relief systems to avoid trapping of hydrogen and moisture/freezing of valves and safety systems
Process
- Design standards for main process equipment
- Design standard for electrical equipment
- Previous escalation steps (pilot plants, reference plants)
- Process parameters and escalation factors
- Process quality control at battery limits (e.g. water quality)
- Design measures to avoid embrittlement, erosion, and corrosion
- Monitoring of critical process parameters, safety philosophy during testing and operation
- Redundance design factor/features
Human element
- Site organization (especially in regards of safety, mgmt. of subcontractors)
- Access to site and safety training, including using of emergency equipment
- Inspection regime and operational safety (monitoring and control of leakages)
- ATEX Zones access controls
- Near-miss reporting and follow up
- Hot works procedures and administrative controls during erection and operation
- Startup / Shut down procedures
- Emergency shut down
- Emergency response plan
- Dedicated firefighting team? Cooperation with local firefighting? Distance and response plan?
Business interruption and interdependencies
- Redundancies
- Critical spares
- Interdependencies
- Fluctuating product/feedstock pricing
- Operating regime, fix vs. variable cost elements