

De-risking the hydrogen economy

Bridging the protection gap



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Executive summary

Hydrogen is a core component of the global drive to net zero emissions.

Global demand for hydrogen energy will grow by around of 3.5% annually to 2050. That won't be enough to meet net zero.

Current investments are focussed on production facilities, less on transmission, storage and distribution.

Governments, regulators and producers need to work together on safe adoption of hydrogen as a source of clean energy.

De-risking hydrogen energy is complex, and more knowledge is needed to make the sector more broadly insurable.

Traditional engineering and property covers should suffice for exposures in production. New liability risk pools will likely emerge as hydrogen use expands.

Carbon emissions need to reduce dramatically over the next 30 years to achieve the Paris Agreement goal of keeping global average temperature increases to less than 2°C above pre-industrial levels. Hydrogen is an attractive alternative to fossil fuels as it does not emit carbon dioxide and can be produced using renewable energy. However, it also has unique features making it complex to de-risk. Further, it has not yet been used as a fuel at scale. As such, the use of repurposed existing infrastructure to transmit, store and distribute hydrogen is still being tested, giving rise to potential unknowns.

The International Energy Agency (IEA) expects global demand for hydrogen, based on existing government pledges (also called the Announced Pledges Scenario (APS)) to reach around 250 million tonnes (Mt) per annum by 2050, up from 90Mt today. We estimate that this could make hydrogen a USD 600–800 billion industry in terms of annual revenues by 2050, if governments meet their pledges. However, the potential could be even greater given that the current APS outcome is well short of the ~530Mt per annum needed to achieve the net zero emissions (NZE) targets under the IEA's NZE scenario by 2050.

Current investment plans are focused on production facilities, and less on transmission, storage and distribution needed to transport hydrogen. More attention on risk factors that may hinder large-scale use of hydrogen is needed. Specifically, hydrogen has unique properties that cause permeation and embrittlement, resulting in leakages that can trigger fires and explosions. The severity of damage caused by accidents largely depends on the type of materials used to store and transport hydrogen, and the extent to which the fuel is blended with other substances. These exposures need to be stress-tested to ensure that the surge in demand required to fulfil the APS and NZE scenarios can be enabled.

Governments, regulators and producers need to work together to make safe adoption of hydrogen as a source of clean energy a reality. Over 70 countries accounting for 86% of global emissions have already taken an official position on expanding the use of hydrogen in the move to net zero. Coming from a low base, we anticipate the scale of production, transmission and storage of hydrogen will be very large.

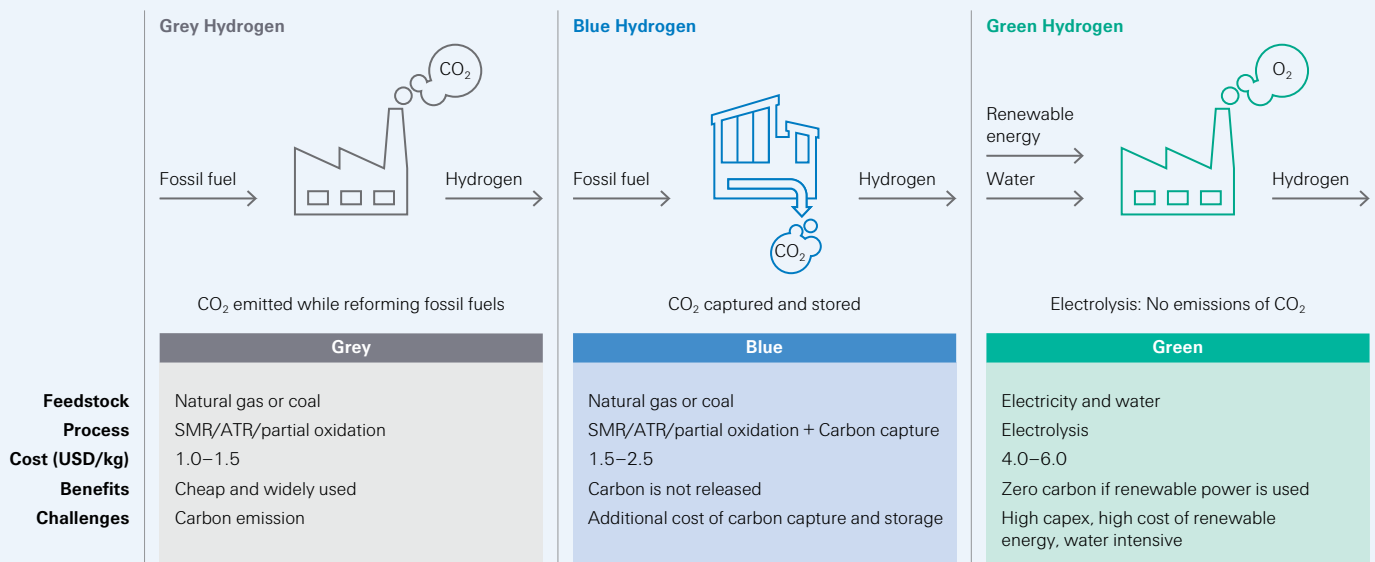
Better understanding is needed to make a fully-fledged hydrogen economy insurable, and the risk services industry needs to address several issues. The proposed blending of natural gas and hydrogen to ease transport is not well regulated. Required safety standards for the use of gas pipelines for large scale hydrogen transport are a "work-in-progress". Data will need to be generated in feasibility projects that will be crucial to successful scale-up. Maintaining the purity of hydrogen in underground storage facilities is also a concern given its propensity to react with microbes in the rock.

In the short-term, insurance covers for the hydrogen economy will mainly relate to the production and supply sides. Standard engineering policies should cover the risks inherent in the construction phase of hydrogen production facilities. In the medium- to long-term, business interruption covers may gain importance as hydrogen becomes more embedded in the global economy, and the need to guarantee uninterrupted supply of renewable energy to fuel hydrogen production becomes ever-more pressing. More generally, the expansion of the hydrogen economy will give rise to new risk pools in liability and associated demand for, among others, general third-party and product liability, employer's liability, professional liability and environmental liability covers.

Key takeaways

The pathway to clean hydrogen: blue and green to coexist

Industry consensus suggests that during the transition, green hydrogen becomes cost-effective across multiple applications and industries when the cost falls below USD 2/kg. Renewable green hydrogen parity is expected later this decade as the costs of both electrolyzers, and solar and wind power continue to fall.



Note: SMR – Steam Methane Reforming; ATR – Autothermal Reforming

Source: Swiss Re Institute

In the medium term, risk exposures will come from supply-side projects

New players entering the industry may lack relevant experience. All stakeholders, including users, producers, regulators and re/insurers need to work together for the safe adoption of hydrogen as a source of clean energy..



Source: Swiss Re Institute

The hydrogen economy: an overview

Why hydrogen?

Hydrogen is potentially a key alternative to fossil fuels in the transition to clean energy.

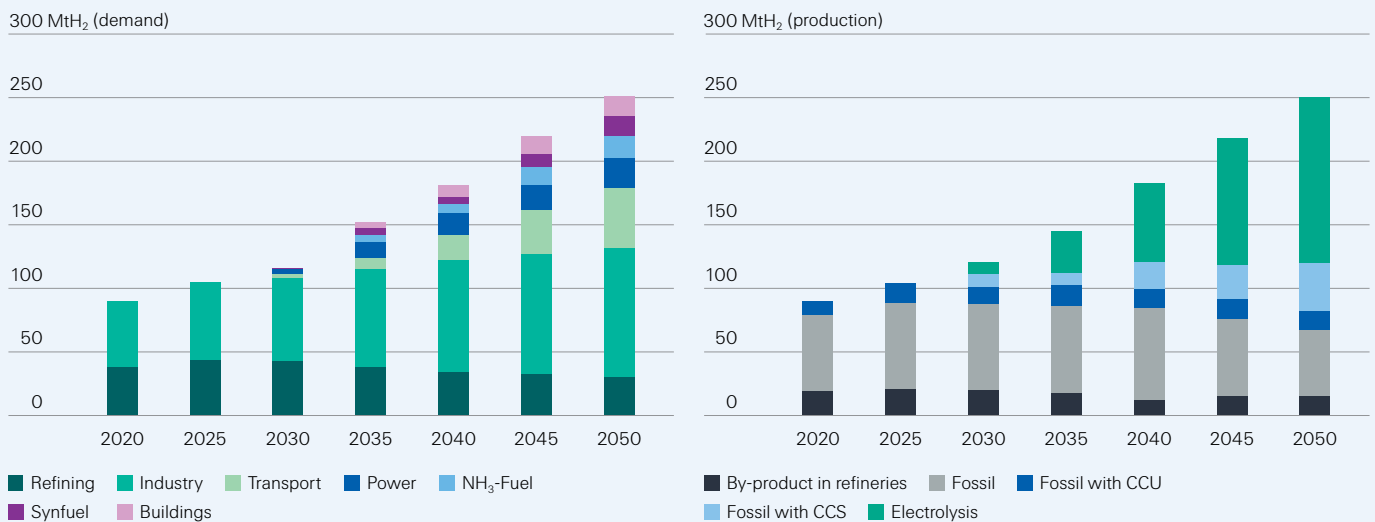
Hydrogen (H₂) is a potentially significant building block in the transition to clean energy and the phasing out of fossil fuels. A number of industrial companies have expressed interest in setting up hydrogen projects globally. Among other applications, hydrogen can be used as a medium for large-scale and long-term energy storage; it can be blended with natural gas to reduce carbon dioxide (CO₂) emissions which are given off when natural gas is used to generate power and heat; it can be used to power fuel cells and internal combustion engines; and finally, it can be combined with CO₂ (and other molecules) to produce a range of synthetic fuels, such as methane (CH₄).

Global demand for hydrogen is expected to reach around 250Mt per annum by 2050.

Based on commitments already in the Announced Pledges Scenario (APS), global demand for hydrogen is expected to increase by a compound annual growth rate (CAGR) of 3.5% between 2020–2050, to around 250 million tonnes (Mt) annually by 2050 (see Figure 1).¹ The IEA estimates that hydrogen demand could exceed 500 Mt by 2050 if net zero emissions (NZE) targets are achieved. In the current decade, demand will be driven by traditional sectors, mainly refining and chemicals. However, demand is expected to pick up strongly after 2035 as more industrial applications come onstream and the transport sector embraces enabling infrastructure to support decarbonisation at scale.

Figure 1

Current and potential use of hydrogen by different sectors, under Announced Pledges Scenario, (2020–2050)



Note: CCU – Carbon Capture and Utilisation; CCS – Carbon Capture and Storage
Source: *Global Hydrogen Review*, IEA, 2021

Greater investment in transmission and distribution infrastructure is needed.

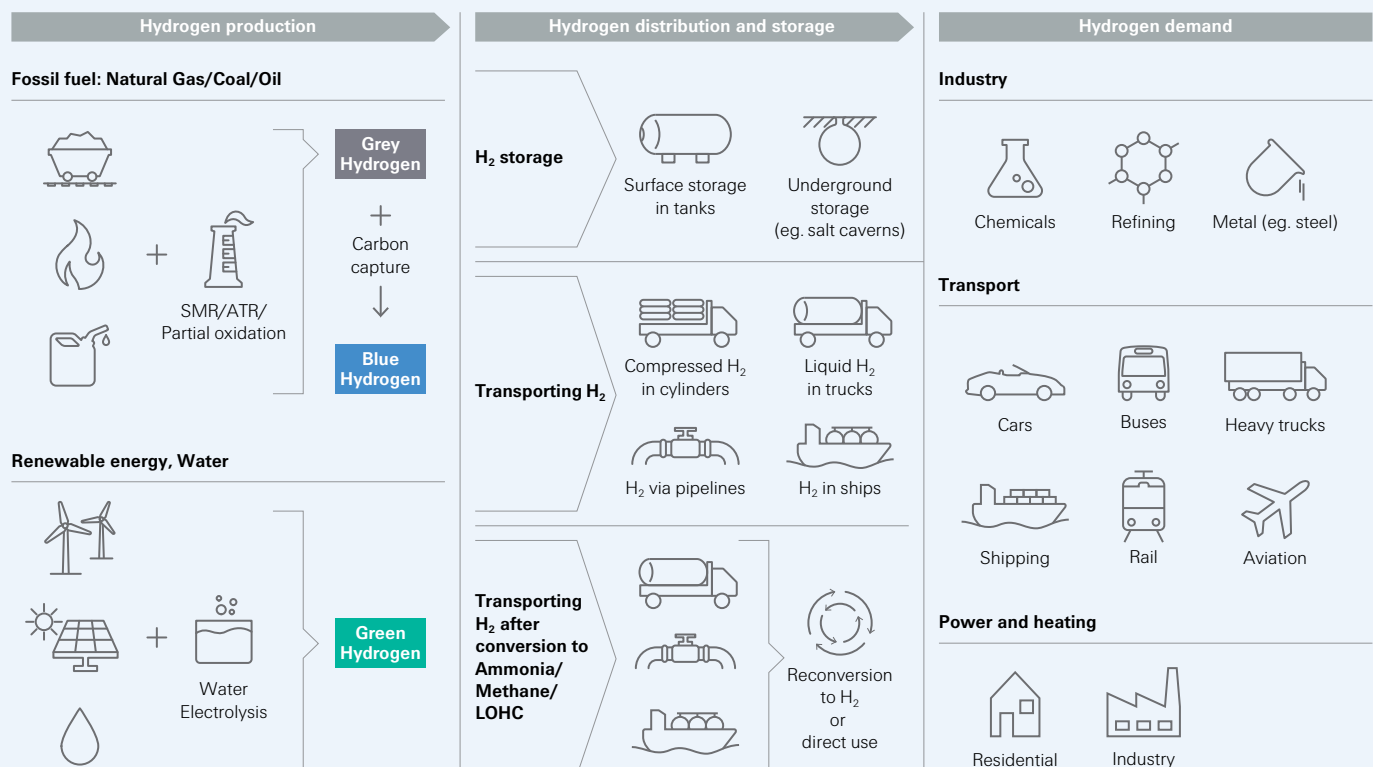
Demand estimates for hydrogen relating to the APS assume that all government pledges will be completed on time. The low-carbon hydrogen projects currently in the pipeline have capacity to deliver two-thirds of the emissions reductions pledged under the APS.² The current focus is concentrated around production (~90% of total investment). However, once production scales, distribution and storage infrastructure will be equally critical (see Figure 2). In order to meet the requirement for hydrogen dictated by the APS,

¹ The Announced Pledges Scenario (APS) considers national net zero emissions pledges and assumes they are realised in full and on time. See *Announced Pledges Scenario* webpage, IEA.

² About 400 green hydrogen projects are planned that could take hydrogen production to 8Mt by 2030 (against a target of 12Mt by 2030 in the APS) while around 50 blue hydrogen projects could reach 9 Mt (2030 target of 9 Mt). See *Global Hydrogen Review 2021*, International Energy Agency, October 2021.

the IEA estimates that the length of hydrogen-compatible pipelines globally will need to double from 5 000 currently to 10 000 km by 2030. And to fulfil demand arising from a scenario where NZE targets are met, 20 000 km of pipelines will be required.³

Figure 2
Scope of the hydrogen economy



Source: Swiss Re Institute

The supply-side pathway to clean hydrogen: blue and green to coexist during the transition

Hydrogen can be grey, blue or green depending on the type of feedstock and carbon emitted during production.

In the short- to medium-term, the majority of risk exposures emerging from hydrogen come from supply-side projects. Hydrogen can be produced in a number of ways depending on the type of feedstock used and the carbon emitted during the production process (See Table 1 for the benefits and challenges of various production methods).

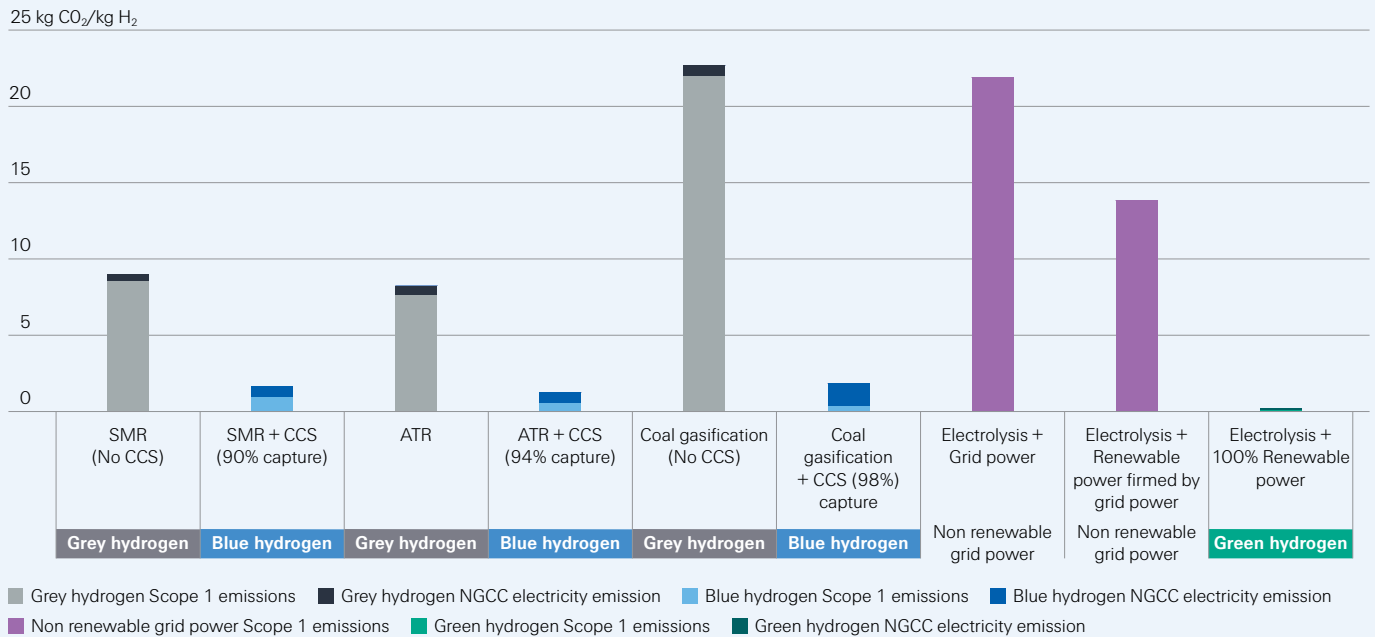
Table 1
Hydrogen production pathways

	Grey	Blue	Green
Feedstock	Natural gas/coal/oil	Natural gas/coal/oil	Electricity and water
Process	SMR/ATR/Partial Oxidation	SMR/ATR/Partial Oxidation + Carbon Capture	Electrolysis
Cost (USD/kg)	1.0–1.5	1.5–2.5	4.0–6.0
Benefits	Cheap and widely used	Does not emit carbon	Zero carbon when electricity is from renewables
Challenges	Carbon emission	Additional cost of carbon capture and storage	High capex, high cost of renewable energy, water intensive

Note: SMR – Steam Methane Reforming; ATR – Autothermal Reforming
Source: Swiss Re Institute

³ Global Hydrogen Review 2021, International Energy Agency, October 2021.

- **Grey/brown hydrogen:** The majority of hydrogen produced (90Mt globally in 2020) uses fossil fuels as feedstock, predominantly natural gas (grey), but also coal (brown) and oil. Natural gas is fed through steam methane (hydrocarbons react with water or steam in the presence of a catalyst) producing grey hydrogen. This is the cheapest way to produce hydrogen (USD1.0–1.5/kg) but the process is not environmentally friendly as it emits CO₂.

Figure 3Emissions intensity of hydrogen production (kg CO₂/kg H₂)

Note: SMR= Steam Methane Reforming; ATR = Autothermal Reforming; CCS= Carbon Capture and Storage; NGCC = Natural Gas Combined Cycle electricity generation. Source: Blue Hydrogen, *Global CCS Institute*, 2021

- **Blue hydrogen – bridging the transition:** Blue hydrogen is produced in the same way as the grey variant. However, carbon emitted during production is captured and either used or stored, this representing the main additional expenditure. Blue hydrogen could play a key interim role in the transition to large-scale adoption of green hydrogen (see Figure 3 for emission intensity of various methods of producing hydrogen). Further, existing production facilities only partly through their life cycle can be adapted to produce cleaner hydrogen without being shuttered altogether.
- **Green hydrogen – a long-term solution:** Green hydrogen is produced by electrolysis using renewable electricity and water.⁴ At present the cost of green hydrogen is around two to four times that of grey hydrogen, due to the high capital expenditure (capex) associated with setting up electrolysis plants and also the high cost of renewable energy. Cost advantages are regional and correlated with energy prices, capex and capacity factors. Several estimates suggest that the cost of green hydrogen will fall significantly by the end of the decade as electrolyzers become more efficient and the price of wind and solar power falls.⁵

As the size and operating hours of the electrolyser plants increase, the cost of green hydrogen production will decline.

Significant investment in electrolysing capacity is also under way. The most ambitious is a European Commission (EC) initiative to transform heavy industry and other areas that are difficult to decarbonise. The “EU Hydrogen Strategy” involves setting up electrolyser capacity of 40GW by 2030, a big jump from under 100MW in 2020.⁶ As electrolyser

⁴ Green hydrogen can be produced using fresh water, cleaned wastewater and desalinated sea water. However, irrespective of the source it must be deionised before using in electrolyzers. See M. Newborough, G. Cooley, “Green hydrogen: water use implications and opportunities”, *Fuel Cells Bulletin*, vol 12, 2021.

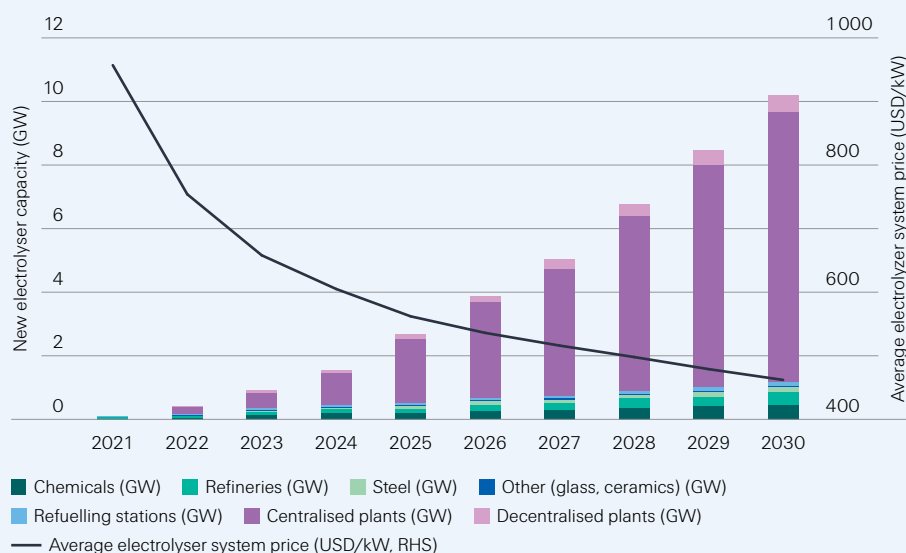
⁵ *Hydrogen Insights: A perspective on hydrogen investment, market development and cost competitiveness*, Hydrogen Council and McKinsey & Company, February 2021.

⁶ *A hydrogen strategy for a climate-neutral Europe*, European Commission, 2020.

operating hours increase, the impact of capex on the levelised cost of hydrogen falls. According to estimates by the International Renewable Energy Agency (IRENA), increasing plant capacity from 1MW (typical today) to 20MW could reduce costs by over a third.⁷ The IEA indicates capital intensity for electrolyser ranges between USD 500–1 400/kWe currently, but that it will fall over the medium-term.⁸

Figure 4

A roadmap to 40GW electrolyser capacity in the EU



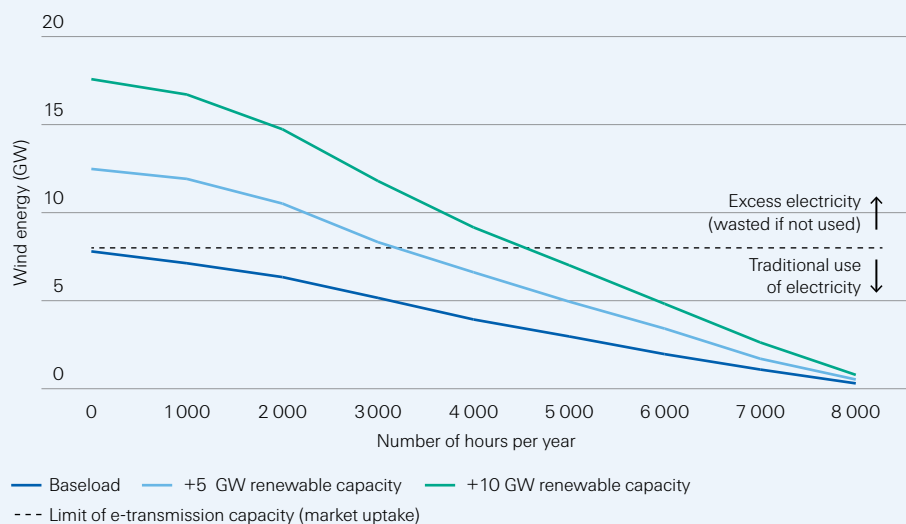
Excess renewable energy generated at peak loads, usually wasted, can be used to generate low-cost green hydrogen.

Turning excess renewable energy into hydrogen

As supplies of renewable energy increase, there will be more frequent periods when power production surpasses consumption. Surplus energy that is not fed into the grid is available for conversion into competitively priced hydrogen. See Figure 5 for illustrative movements in renewable energy supplies. The lowest slope (baseload) has fewer hours where renewable sources meet 100% of electricity demand (transmission capacity). With the build-up of renewable capacity (in this case wind power), the slope moves higher, allowing for periods of excess supply. Converting this excess power into other fuels such as hydrogen helps recoup investment by avoiding curtailment (eg, wind mills standing idle for long periods on windy days), and can also have grid stabilising effects.

Figure 5

Renewable energy generation slope (illustrative)



⁷ *Green Hydrogen Cost Reduction: Scaling up electrolyzers to meet the 1.5°C climate goal*, IRENA, 2020.

⁸ *The Future of Hydrogen: Seizing today's opportunities*, International Energy Agency, June 2019.

Large-scale adoption will depend on a combination of low-cost renewable energy, electrolyser capex and optimising production load factors.

Large-scale adoption of green hydrogen will depend on whether the cost of production is close to that for grey hydrogen produced using fossil fuels. This in turn is dependent on three key parameters: 1) the cost of renewable energy (levelised cost of electricity, or LCOE); 2) the capex of electrolysers; and 3) their load factor (operating hours). One study estimates that green hydrogen will achieve cost parity with grey when the cost of electricity is less than half of today's wholesale power prices, electrolyser capex is less than USD 500/KW and the load factor is more than 30%.⁹

⁹ *Path to hydrogen competitiveness: A cost perspective*, Hydrogen Council and McKinsey, January 2020.

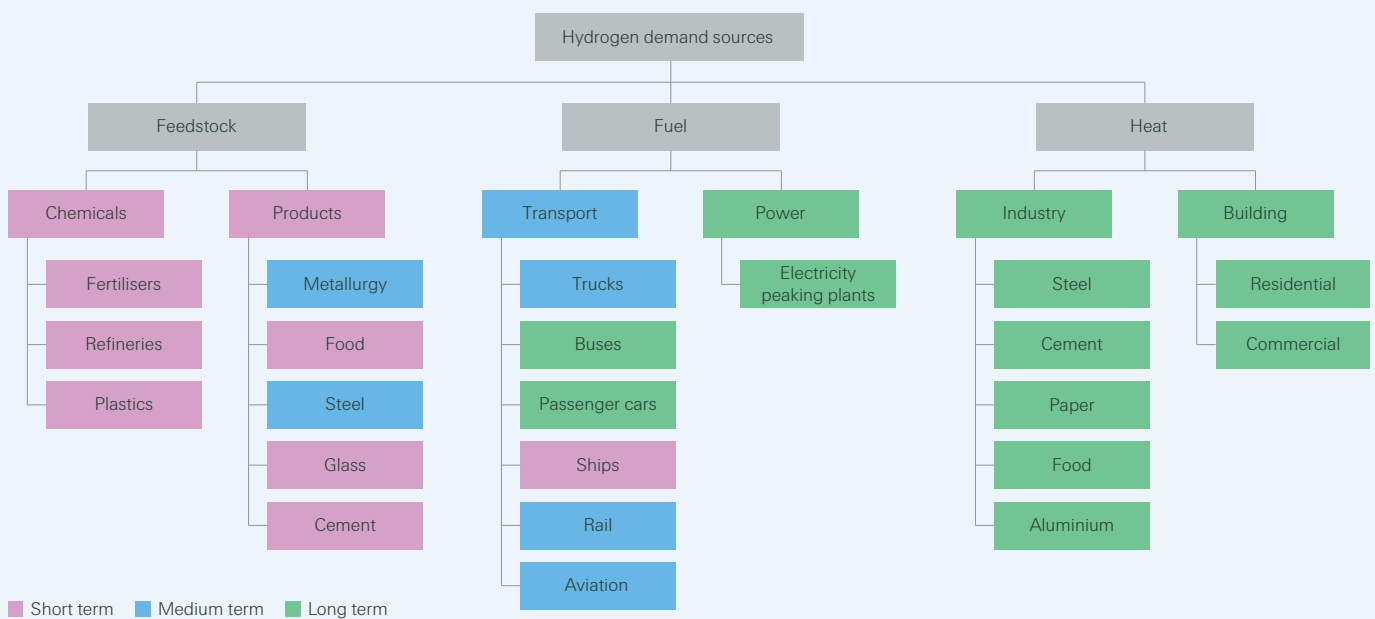
Mapping hydrogen demand

New sources of demand

Using information from different sources, we anticipate that demand for hydrogen from various sectors will come in phases

- In the short-term (2025–2030), demand will mainly come from industries that use hydrogen as feedstock, such as chemicals, fertilizer, oil refining and steel.
- In the medium- to long-term (2030–2040), increased interest in hydrogen as an energy carrier will broaden into use cases such as hydrogen power stations and transport, as the switch to sustainable energy gains traction. Development of hydrogen-based fuels such as green ammonia and other synthetic fuels is also likely to gather pace.
- In the very long term (2040 onward), hydrogen production will likely grow as medium-term use cases gain scale and a surge in demand prompts a significant increase in global trade of hydrogen.

Figure 6
Hydrogen demand landscape



Source: IEA, Swiss Re Institute

Short-term demand

Chemicals

Production of chemicals accounted for around half of global hydrogen demand in 2020.

Hydrogen is a key feedstock for the production of chemicals such as ammonia and methanol. Production of chemicals accounted for around 45Mt of hydrogen demand in 2020, this representing 50% of global demand.¹⁰ Most of the hydrogen (34 Mt, and 38% of global demand) was used in the production of ammonia, followed by methanol (11Mt, 13%). Given the challenges of transporting hydrogen, ammonia could eventually become an established alternative fuel source in its own right.

¹⁰ Ibid. p4.

Given the move to reduce dependency on fossil fuels, future demand for refining is expected to decline.

Refining

Refining is a large end market for hydrogen today, representing close to 40Mt of demand in 2020 (around 45% of the current global market).¹¹ Specifically, hydrogen is used to remove impurities like sulphur and nitrogen from oil products, and also to convert heavy oils into fuels such as gasoline and diesel. This is another reason why oil majors are developing clean hydrogen facilities (see *Case study: energy major Shell investing in hydrogen*). In the long run, however, demand for hydrogen from refining is likely to contract with the transition to net zero.

Case study: energy major Shell investing in hydrogen

Major energy companies are investing in hydrogen. Shell has a target to cut absolute emissions by 50% by 2030 from 2016 levels, and to become net-zero by 2050.¹² In 2021, it opened a 10 megawatt (MW) proton exchange membrane (PEM) electrolyser plant near Cologne, Germany, with plans to increase production to 100MW.¹³ The facility will produce up to 1 300 tonnes of green hydrogen a year. Shell intends to use green hydrogen initially to produce fuels with lower carbon-intensity, but also to help decarbonise other sectors such as road transport.

Together with partners, Shell aims to build the largest European green hydrogen project in the Netherlands by 2040. This will produce over 800 000 tonnes of green hydrogen using electricity from a 10GW offshore wind farm in the North Sea. It is also building a 12MW solar park in Emmen, Netherlands. In 2020, Shell also unveiled its first commercial hydrogen project in China, which includes a 20MW hydrogen electrolyser to produce green hydrogen from wind and solar resources in Hebei province.¹⁴

The move to decarbonise steel production will likely increase sector demand for hydrogen.

Metals

The steel industry is one of the biggest producers of CO₂, accounting for around 8–10% of global emissions. Around 70% of steel is made using energy-intensive blast furnaces (BF-BOF).¹⁵ A path to carbon-free steel is to switch to syngas, a mixture of hydrogen and carbon monoxide, also called the Direct Reduction of Iron-Electric Arc Furnace (DRI-EAF) method.¹⁶ Currently ~5% of production uses the DRI-EAF process, but leading steel makers are ramping up investment in greener technologies.¹⁷ The Hydrogen Council estimates that steel could account for about 4% of hydrogen demand in 2030 and around 20% of emissions reductions in the same year.¹⁸ Other metals processors will face pressure to substitute carbon emitting processes for clean hydrogen, boosting demand as the NZE deadlines draw nearer.

Case study: use of hydrogen in steel making – ArcelorMittal

ArcelorMittal has a target to reduce CO₂ emissions by 25% across the group and by 35% in Europe by 2030.¹⁹ Its Sestao steel plant in Spain will be a zero carbon-emissions by 2025. Around EUR 1 billion will be invested in a green hydrogen direct reduced iron (DRI) plant, as well as a new hybrid electric arc furnace (EAF). This will enable the plant to produce 1.6Mt of zero carbon-emissions steel by 2025.²⁰ In 2021, the group signed a MoU with Air Liquide to produce low-carbon steel in Dunkirk in

¹¹ *Global Hydrogen Review 2021*, International Energy Agency, October 2021.

¹² *Shell sets new target to halve scope 1 and 2 absolute emissions, complementing existing climate goals*, Shell, 2021.

¹³ *Shell starts up Europe's largest PEM green hydrogen electrolyser*, Shell, 2021.

¹⁴ *Shell sets new target to halve scope 1 and 2 absolute emissions*, op. cit.

¹⁵ See "Blast Furnace Ironmaking - an overview", *ScienceDirect*, 2015.

¹⁶ DRI with hydrogen and CO can reduce CO₂ emissions by 61%, and DRI with only hydrogen by 97%. See P. Fennell, J. Driver et al., "Cement and steel – ninesteps to net zero", *nature.com*, 23 March 2022.

¹⁷ T. Buckley, "World's biggest Steel manufacturers are committing to Hydrogen and CCS", *energypost.eu*, 11 January 2021.

¹⁸ *Hydrogen for Net-Zero: A critical cost-competitive energy vector*, Hydrogen Council, November 2021.

¹⁹ *Climate Action Report 2*, ArcelorMittal, 2021.

²⁰ *Sestao to become the world's first full-scale zero carbon-emissions steel plant*, ArcelorMittal, 2021.

France. The project is intended to reduce yearly CO₂ emissions from steel making by 2.85Mt by 2030.²¹

Further, its DRI-EAF plant in Hamburg is testing ability to switch to hydrogen instead of natural gas in the iron ore reduction process.²² The aim is to produce 100 000 tonnes of steel per annum using hydrogen by 2025. At first the steel maker will test the process using grey hydrogen and shift to green hydrogen when it becomes available in sufficient quantity. ArcelorMittal plans major investments in other sites in Germany also. These include a large-scale industrial plant for DRI- and EAF-based steelmaking in Bremen, and a DRI pilot plant and EAF facility in Eisenhüttenstadt. Up to 3.5Mt of steel could be produced by these plants by 2030 using green hydrogen.²³

Medium-term demand

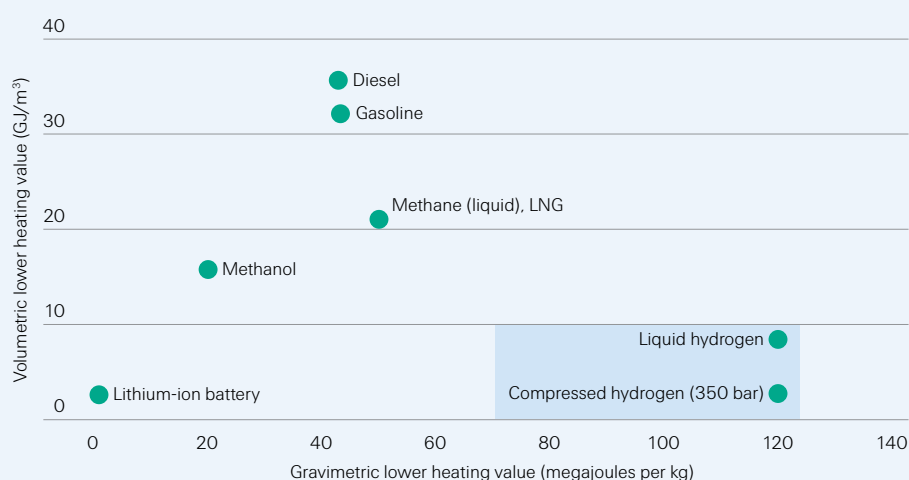
Transport

Long-haul trucks and buses

There is strong interest among automakers, governments and consumers in the commercialisation of fuel-cell electric vehicles (FCEVs). The transport sector accounts for around 23% of global carbon emissions, with fossil fuels the main source of energy.²⁴ Fuel cells are suited where alternative methods of decarbonisation (eg, batteries) are less viable (see Figure 7 for energy density of hydrogen alternatives). Studies suggest that long-haul trucks and buses have greater potential for shifting to fuel cells compared to other modes of transport.²⁵ Major auto manufacturers are currently deploying FCEVs in target markets such as the US (California), Europe (Germany, UK, Scandinavia) and Japan.

Hydrogen can be used to generate electricity through fuel cells.

Figure 7
Energy density of hydrogen relative to other fuels



Source: Swiss Re Institute, based on data from J. L. Breuer, J. Scholten et al, "An Overview of Promising Alternative Fuels for Road, Rail, Air, and Inland Waterway Transport in Germany" *energies*, 16 February 2022

Ammonia produced using hydrogen is being tested as a carbon neutral fuel for shipping.

Shipping

As well as testing pure hydrogen in fuel cells, the shipping industry is testing new fuels such as ammonia and methanol for which hydrogen is the primary feedstock. This is driven by the International Maritime Organisation's target to cut carbon emissions by 50% before 2050 compared to 2008.²⁶ Despite its lower energy density, ammonia

²¹ "Air Liquide and ArcelorMittal Join Forces to Accelerate the Decarbonization of Steel Production in the Basin of Dunkirk", *businesswire.com*, 17 March 2021.

²² *Hydrogen-based steelmaking to begin in Hamburg*, ArcelorMittal, 2019.

²³ *Climate Action Report 2*, ArcelorMittal, 2021.

²⁴ *Global energy-related CO₂ emissions by sector*, International Energy Agency, 2021.

²⁵ K. Julin, "Hydrogen Offers Promising Future for Long-Haul Trucking Industry", *newscenter.lbl.gov*, 8 April 2021.

²⁶ *Initial IMO GHG Strategy*, International Maritime Organisation, 2018.

(NH₃), a hydrogen derivative, might emerge as the go-to fuel of choice, partly because of existing supply chains but also because, unlike hydrogen, it does not have to be stored in high-pressure tanks. However, demand is expected to pick up only after 2030 as the technology has yet to be fully determined. The first ammonia-powered ship is expected to be ready by 2024.²⁷

Rail

Hydrogen can be an effective alternative for rail transport.

Hydrogen-based fuel technologies can become attractive in sections of rail networks that are not electrified. In western Europe just over 50% of train lines are electrified.²⁸ According to IEA estimates, hydrogen-fuelled trains will account for around 10% of non-electrified units by 2030 and for around 50% of non-electrified units by 2050 in Europe.²⁹ A study by Shift2Rail on fuel cells and hydrogen, found that the total cost of ownership (TCO) of hydrogen-run trains is already competitive with trains run on diesel and electricity.³⁰ Although there is scope for expansion, the main barrier remains the investment required in order to roll out refuelling infrastructure.

Long-term demand

Power and heating

In addition to industry and transportation, hydrogen can also be used for heating.

Hydrogen can be used to generate power when other renewable energy sources are not viable. However, the fuel is challenging, both to store and to transport. Currently there are pilots in progress to use both green and blue hydrogen to generate power. For example, Verbund is collaborating with Sunfire and TU Graz to use excess renewables to produce green hydrogen.³¹ Hydrogen also has the potential to generate heat for a wide range of manufacturing industries, including production of iron and steel, cement, chemicals, paper and aluminium, as well as to provide power for residential buildings (although in the case of the latter, full-fledged implementation has yet to be seen).

Case study: Unilever is piloting the use of hydrogen in boilers³²

Unilever has a target to reduce absolute emissions by 70% by 2025 and achieve zero emissions by 2030. The group says it has reduced its manufacturing carbon footprint by two-thirds since 2008. To progress further, it is piloting the use of hydrogen instead of natural gas in its plant at Port Sunlight, the first meaningful use of hydrogen in a commercial-scale boiler. The pilot aims to have a hydrogen-enabled burner ready for operation when hydrogen becomes economically viable. This project is funded by the UK government as part of a wider regional project called HyNet, which will use blue hydrogen to begin with, and later green hydrogen when it is available at scale.³³

International trade in hydrogen

Some countries are already signing hydrogen trade agreements.

Globally IRENA predicts that at least 30% of hydrogen production could be traded across borders by 2050, a higher share than natural gas today.³⁴ For example in 2021, the UAE and Japan agreed to build an international hydrogen supply chain. Renewable electricity typically comprises around two-thirds of the levelised cost of green hydrogen, making it the single biggest cost factor. Green hydrogen production could be more economical in regions with both sun and wind, allowing for long periods of continuous power. Hydrogen can be transported in ships as ammonia (NH₃), but can also be blended with natural gas and transported via retrofitted pipelines. As hydrogen trade between Asia, the Middle East and Europe builds, additional exposures to property and liability risk will arise.

²⁷ B. Foldager, "Why ammonia may be part of the future fuel mix", *globalmaritimeforum.org*, 8 September 2020.

²⁸ See "Percentage of the railway lines in use in Europe in 2019 which were electrified, by country", *statista.com*

²⁹ *The Hydrogen Handbook: Valuing the Supply Chain*, Morgan Stanley, September 2021.

³⁰ R. Berger, "Study on the use of fuel cells and hydrogen in the railway environment", *shift2rail.org*, 7 May 2019.

³¹ "Green hydrogen for gas turbines in Mellach", *sunfire.de*, 29 March 2019.

³² *Could hydrogen fuel replace natural gas on an industrial scale?*, Unilever, 2020.

³³ T. McDonough, "Essar, Unilever and Pilkington secure £13m for hydrogen projects", *lbndaily.co.uk*, 18 February 2020.

³⁴ *Geopolitics of the Energy Transformation: The Hydrogen Factor*, IRENA, January 2022.

When natural gas prices go up, green hydrogen can be less expensive to produce than the blue or grey variants.

One effect of the conflict in Ukraine has been to make green hydrogen relatively cheap to produce.

Another is to highlight the dangers of over-dependence on third-country sources for fossil fuels.

Ukraine crisis: impact on natural gas prices and the cost of producing hydrogen

Fluctuations in feedstock prices have a significant impact on the cost of hydrogen. Energy prices, in particular natural gas, have been volatile in recent months. As a result, some estimates have put the cost of producing green hydrogen at less than that for producing blue and grey variants. For example, according to one calculation, on 8 November 2021, in the UK grey hydrogen was 20% more expensive than green.³⁵

Natural gas prices have surged since the start of the conflict in Ukraine on 24 February 2022. This too reflects in lower prices for green than grey hydrogen. According to news reports citing a BloombergNEF study, in March 2022, green hydrogen produced in EMEA using Western electrolyzers was averaging at a levelised cost of USD 4.84-6.68/kg, compared with USD 6.71/kg for grey. Similarly, the cost of green hydrogen in China was USD 3.22/kg (using Chinese electrolyzers), compared to USD 5.28/kg.³⁶

Natural gas prices could normalise should there be an end to the conflict in Ukraine. Nevertheless, current circumstances are a stark reminder of the challenges of energy security and the risks inherent in over-reliance on third-country sources for fossil fuels. The conflict is set to accelerate expansion of the renewables sector, especially in parts of Europe where sources of renewable energy are still largely untapped. In March 2022, the European Commission (EC) proposed an outline of a plan to make Europe non-dependent on fossil fuels from Russia. In the short term, it plans to diversify gas supplies from non-Russian suppliers, but it also recognises that a shift to renewable energy is essential for long-term energy security. As such, the EC has emphasized the need to accelerate the switch to renewables and hydrogen energy, saying it is targeting a 15-Mt increase in green hydrogen production by 2030. This in addition to the 5.6 Mt already earmarked under the “Fit for 55” plan.³⁷

³⁵ “Green hydrogen now cheaper to produce than grey H2 across Europe due to high fossil gas prices” *rechargenews.com*, 12 November 2021.

³⁶ “Ukraine war: Green hydrogen ‘now cheaper than grey in Europe, Middle East and China’: BNEF”, *rechargenews.com*, 7 March 2022.

³⁷ *REPowerEU: Joint European Action for more affordable, secure and sustainable energy*, European Commission, 8 March 2022.

Mitigating risks in the hydrogen value chain

Properties of hydrogen pose several risks, depending on operating parameters and the type of material used to store and transport the gas.

Exposures caused by hydrogen's unique properties

Hydrogen has unique features that make it complex to de-risk (see Table 2). Although it is widely recognised as a valuable energy carrier, it has not yet been used as a fuel at scale. The severity and frequency of damage arising from failures in delivery infrastructure depend, among other things, on the type of materials involved and the extent to which the gas has been blended with other materials.

Significant exposures include:³⁸

- *Permeation*: Leakage rates through pipes and joints may be greater than for other fuels because hydrogen molecules are smaller.
- *Embrittlement*: Reactions between hydrogen and steel can make metal brittle, resulting in cracked pipelines. This can affect steel components across the entire hydrogen value chain.
- *Hydrogen-assisted fatigue*: Frequent fluctuations in pressure in transmission or distribution pipes can reduce the threshold cyclic stress intensity factor, and expose pipes to accelerated fatigue cracking, especially in carbon and low-alloy steel applications.
- *Enhanced crack growth*: Crack growth from existing defects can be exacerbated by introducing hydrogen due to the reduced ductility of steel.
- *Blistering and damage of carbon fibres*: Some valves used to release pressure in the event of high temperature use carbon fibres. Some of these fibres develop blisters that can be damaged when exposed to hydrogen.

Table 2
Properties of hydrogen

Properties	Hydrogen	Comparison
Density (gaseous)	0.089 kg/m ³ (0°C, 1 bar)	1/10 of natural gas
Density (liquid)	70.79 kg/m ³ (-253°C, 1 bar)	1/6 of natural gas
Boiling point	-252.76°C (1 bar)	90°C below LNG
Energy per unit of mass (LHV)	120.1 MJ/kg	3x that of gasoline
Energy density (ambient cond., LHV)	0.01 MJ/L	1/3 of natural gas
Specific energy (liquefied, LHV)	8.5 MJ/L	1/3 of LNG
Flame velocity	346 cm/s	8x methane
Ignition range	4–77% in air by volume	6x wider than methane
Autoignition temperature	585°C	220°C for gasoline
Ignition energy	0.02 MJ	1/10 of methane

Notes: cm/s = centimetre per second; kg/m³ = kilograms per cubic metre; LHV = lower heating value; MJ = megajoule; MJ/kg = megajoules per kilogram; MJ/L = megajoules per litre. Source: *The Future of Hydrogen: Seizing today's opportunities*, IEA, June 2019.

As a consequence of the above-mentioned failure modes, hydrogen usage can amplify associated loss-scenarios. These scenarios are mainly represented by:

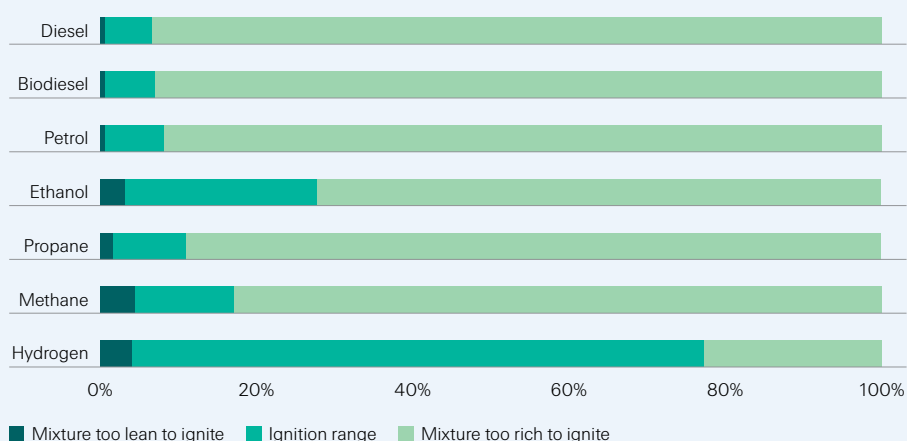
- **Leakage**: As materials can turn brittle when exposed to hydrogen, they can develop cracks if unchecked. Because it is a small molecule, hydrogen can escape through the smallest of cracks. Leaks can also happen due to loose-fitting, defective valves in the system. It is difficult to identify leaks without proper detectors, as hydrogen is colourless and odourless.

³⁸ E. Abohamzeh et al. "Review of hydrogen safety during storage, transmission, and applications processes", *Journal of Loss Prevention in the Process Industries*, vol 72, June 2021.

- **Fires and explosions:** Given its wide flammable range (see Figure 8), hydrogen can catch fire with low ignition when mixed with small amounts of air. If escaping hydrogen catches fire immediately, it results in a jet fire, with a high velocity flame. Jet-fires can cause thermal radiation and related risks. If the leaked gas is ignited with a delay after accumulating in an enclosed storage facility, the result can be a large explosion. In a closed environment, a hydrogen leak can cause asphyxiation.³⁹

Figure 8

Ignition range of various fuels
(% in air by volume)



Source: C. J. Coronado, J.A. Carvalho et al. "Flammability limits: A review with emphasis on ethanol for aeronautical applications and description of the experimental procedure", *Journal of Hazardous Materials*, vol 241–242, 2012; J. M. Kuchta, "Investigation of Fire and Explosion Accidents in the Chemical, Mining, and Fuel-Related Industries: A Manual," *US Bureau of Mines, Bulletin 680*, 1985; and I. A. Zlochower, G.M. Green, "The limiting oxygen concentration and flammability limits of gases and gas mixtures", *Journal of Loss Prevention in the Process Industries*, vol 22, Issue 4, 2009.

Risks during hydrogen production

The main risk in blue hydrogen production is storage reversal.

Blue hydrogen

Blue hydrogen production is similar to that of the grey variant, with the additional step of capturing and storing carbon. The main exposure is potential for storage reversal. For example, carbon can leak from storage reservoirs through insufficiently plugged wells. The reservoirs are meant to store carbon for a long time and as such, leakages may pose long-term liability risks.⁴⁰

Exposures in green hydrogen production mainly emanate from electrolyser plants.

Green hydrogen

Production of green hydrogen involves use of electrolysers. Three key technologies include: Alkaline (mature and commonly used); Proton Exchange Membranes (PEM); and Solid Oxide Electrolysis Cells (SOECs). There is still uncertainty regarding which process, if any, will emerge as the prevailing technology.

- Errors in managing flow of gases in electrolysers can result in accidents. For example, in alkaline electrolysers, the accidental mix of different gases can cause fires.⁴¹
- Electrolysers are also affected by high voltage and short circuits (due to corrosion of electrodes), which can result in explosions.
- The hydrogen industry still needs to undertake further research to ascertain how electrolysers perform at partial or low loads.⁴²
- Other exposures include freezing water in the stack, fracture of pressurised pipes or compartments, and breakages in membranes.⁴³

³⁹ *Report on hydrogen hazards and risks in tunnels and similar confined spaces*, Fuel Cells and Hydrogen Joint Undertaking, August 2019.

⁴⁰ *The insurance rationale for carbon removal solutions*, Swiss Re Institute, July 2021.

⁴¹ Excessive oxygen production and leaking into the hydrogen stream was the cause of an accident on a high-pressure electrolyser in Japan in 2005. See: *Minutes of the FCH 2 JU Workshop on Safety of Electrolysis on 18 November 2020*, Fuel Cells and Hydrogen Joint Undertaking, January 2021.

⁴² Ibid.

⁴³ Ibid.

Supply chain risks are high due to a limited number of third-party suppliers for key production components.

Supply chain failures can cause business interruptions given that there are only a few niche third-party suppliers of electrolyser components and hydrogen-fuelling products. These vendors make bespoke components to meet specific requirements and few suppliers are capable of delivering such specialised parts in a short time frame.⁴⁴ Moreover, as with all manufacturers, those of electrolysers face risk of product liability claims if malfunction, defects or improper installation result in injuries. An incident at a hydrogen fuelling station, for example, may force closure and a temporary halt in sales of fuel-cell vehicles. Electrolyser manufacturers may also be liable where workplace accidents cause personal injury to employees.

Risks during transmission, storage and distribution

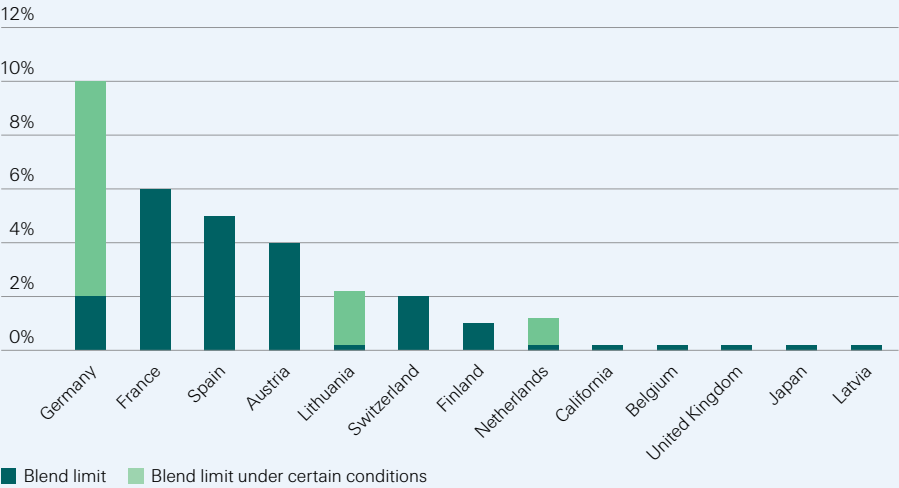
Risks are augmented on account of different agents/companies having responsibility for different steps in the value chain.

Beyond production, exposures during transmission, storage and distribution need to be better understood. At times these steps in the value chain are managed by different agents with different risk standards. Designs can vary because of different regulations and practices adopted during design engineering. For example, in our view distribution is usually less rigorously regulated by statutory requirements than transmission. Natural catastrophe exposure too can be very different between transmission and distribution depending on the location where these activities are carried out.

New exposures arise when natural gas pipelines are retrofitted to transport hydrogen.

Risks during transmission, in particular of hydrogen blends
To date there are around 5 000 km of purpose-built hydrogen pipelines globally, and these are concentrated mainly near consumer centres. To build capacity, an alternative is to repurpose existing natural gas pipelines for the transport of hydrogen blended with natural gas. Most hydrogen and natural gas pipelines are constructed from the same types of material, typically carbon-manganese steel. However, transporting hydrogen blends raises new risks (see Figure 9, for limits on hydrogen blending in natural gas networks). Hydrogen pipelines are manufactured in accordance with specific codes that are more restrictive than those for natural gas, particularly regarding chemical composition and allowable strength levels.⁴⁵

Figure 9
Limits on hydrogen blending in natural gas networks, 2020 (% of hydrogen by volume).



Source: IEA analysis based on Dolci et al. (2019); HyLaw (2019); Staffell et al. (2019).
*Dolci et al. "Incentives and legal barriers for Power-to-Hydrogen pathways: An international snapshot". *International Journal of Hydrogen*, 2019; HyLaw (n.d.), Online Database; Staffell et al. "The role of hydrogen and fuel cells in the global energy system", *Energy and Environmental Science*, 2019.

⁴⁴ Risk related to third parties, Nel Hydrogen, 2020.
⁴⁵ Pre-feasibility Study for a Danish-German hydrogen network, Energinet, April 2021.

Natural gas pipelines are widespread, with over 2 million kilometres of pipeline currently in commission worldwide.⁴⁶ The consensus is that it should be possible to ship hydrogen at 5–10% blends through existing natural gas networks with little to no modification, although this depends on pipeline metallurgy, age and other operating parameters (see Figure 10 for knowledge gaps).⁴⁷ A key concern is flammability: the ignition range for hydrogen is about seven times wider than for gas (methane), making blends of hydrogen and natural gas more prone to fire-risk.

Figure 10

Current knowledge of key challenges at different levels of injection

Knowledge areas/% of blend	1%	2%	5%	10%	15%	20%	30%	50%	>50%
Gas measurement and quality	High	High	High	High	Low	Low	Low	Low	Low
Network management and compression	High	High	High	Low	Low	Low	Low	Low	Low
Inspection and maintenance	High	High	Low	Low	Low	Low	Low	Low	Low
Transmission system integrity	High	High	High	High	Low	Low	Low	Low	Low
Distribution system integrity	High	High	High	High	High	High	Low	Low	Low
Safety parameters and mitigation	High	High	High	High	High	High	Low	Low	Low
End use equipment and appliances	High	High	High	High	High	High	Low	Low	Low
H ₂ /NG separation	Low	Low	Low	Low	Low	Low	Low	Low	Low
Underground gas storage	High	High	Low	Low	Low	Low	Low	Low	Low

■ High knowledge coverage ■ Low knowledge coverage

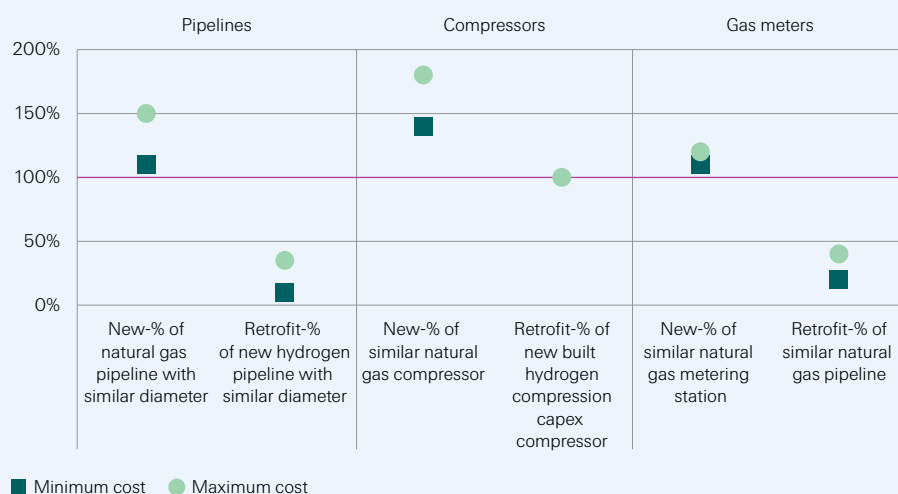
Source: Swiss Re Institute, adapted from *Pipeline Research Council International Inc. Presentation on Hydrogen Blending*

Retrofitting natural gas infrastructure: is it worth the cost?

In addition to material compatibility, the decision to use existing infrastructure depends on the cost of retrofitting natural gas pipelines. Two main parameters influence the extent of retrofitting: the volume of gas transported and distance to be covered. For mid- to large-volumes of hydrogen and for distances ranging from 100–2 000 km, pipelines remain the best option. As Figure 11 shows, the capex cost of retrofitting natural gas pipelines is much less than that of building new hydrogen-specific infrastructure.

Figure 11

Comparison of capital expenditure for construction of new versus retrofitting of existing infrastructure



Source: Swiss Re Institute, based on data from *European Hydrogen Backbone* report

⁴⁶ N. Gallon, R. Elteren, "Existing Pipeline Materials and the Transition to Hydrogen" *Pipeline technology conference 2021 Berlin*, April 2021.

⁴⁷ 2021 Investor Day, Kinder Morgan, January 2021.

The cost of retrofitting a natural gas pipeline amounts to 10–35% of the capex for a new hydrogen pipeline with similar diameters. On the other hand, the cost of a new hydrogen pipeline would amount to 110–150% of a new natural gas pipeline/retrofitted with similar parameters. For metering too, new stations would be notably more expensive than retrofitting. For compressors, the case is not so clear. Retrofitting a natural gas compression plant is almost as expensive as constructing a new hydrogen compression unit from scratch.⁴⁸

Table 3

Current examples of use of natural gas pipelines to transport hydrogen

Entity	Distance	Year	Conversion of a natural gas pipeline for full hydrogen service
 Gasunie (Netherlands)	12 km	In service from 2018	Throughput capacity of 1.25 kt H ₂ per year. It took seven months to repurpose.
 GRTgaz and Creos Deutschland (Germany)	70 km	Investment decision expected in 2022	Converting an existing gas pipeline into a pure hydrogen infrastructure (MosaHYc project).
 APA (Australia)	43 km	Testing to be done by 2022	Repurposing of Parmelia pipeline in Western Australia – demonstration project.

Source: Swiss Re Institute, *Global Hydrogen Review 2021*, IEA

A generally agreed upon and efficient approach for repurposing is needed.

Required standards and associated safety margins for conversion are still work in progress. A recent update to the American Society of Mechanical Engineers (ASME) B31.12 code (considered the main industry standard on hydrogen piping) now includes rules for the repurposing of natural gas pipelines to hydrogen service.⁴⁹ The European Industrial Gas Association (EIGA) has also set out a series of standards for pipeline conversion and guidelines for tests.⁵⁰ Given the different mechanical properties and chemical composition requirements of hydrogen pipelines, it is very likely that some test results on gas pipelines may not meet the requirements for hydrogen service. So far, guidance on what to do in these cases is lacking, in both the ASME and EIGA publications.⁵¹

Once scale of storage at a site exceeds tens of tonnes, underground storage is preferred for cost and safety.

New facility storage risks: less understood

Hydrogen can be stored in many ways. It can be pressurised into various forms of gas, hyper-cooled into liquid or combined with chemical compounds. And it can be housed above or below ground. Large-scale surface storage capacity is limited. Subterranean storage is the main alternative.⁵² Hydrogen, however, is more mobile than other gases such as methane, nitrogen or CO₂, and it can penetrate most rocks and filters. Hence, dispersion and diffusion research tests are critical to ascertain the viability of underground storage. Several parameters need to be analysed, including the geological formation of potential reservoirs, corrosion rates and diffusion phenomena, and the potential for permeability. Currently salt caverns – artificial cavities created in geological salt deposits – are deemed the most suitable underground storage option, along with lined-rock caverns, although these tend to be much smaller. Aquifers and depleted fields are other alternatives (see Table 4).

⁴⁸ *European Hydrogen Backbone*, Gas for Climate, July 2020.

⁴⁹ *Hydrogen Piping and Pipeline: B31.12*, The American Society for Mechanical Engineering, 2020.

⁵⁰ *Hydrogen Pipeline Systems: IGC Doc 121/14*, European Industrial Gas Association, 2014.

⁵¹ N. Gallon and R. Elteren, "Existing Pipeline Materials and the Transition to Hydrogen" *Pipeline technology conference*, April 2021.

⁵² R. Groenenberg, et al., "Large-Scale Energy Storage in Salt Caverns and Depleted Fields (LSES) – Project Findings", *TNO Report*, October 2020.

Table 4

Hydrogen underground storage options

Storage type criteria	Depleted field	Aquifer	Salt cavern	Lined-rock cavern
General suitability	Site-specific	Site-specific	High	High
Typical operation	Seasonal	Seasonal	Peaking	Peaking
Typical working gas capacity (TWh H ₂)	0.03–14	0.05–3.5	0.01–4	0.03–0.05
Depth (meters)	300–2 700	400–2 300	300–1 800	1 000
Operating pressure	20–285 bar	30–315 bar	30–210 bar	20–200 bar
Technical readiness for hydrogen storage*	4–6	3	8	5–6
Suitability	Hydrogen/Methane blend proven	Under study	100% Hydrogen proven	100% Hydrogen proven
Suitability factors	Operational conditions, rock composition, bacteriological activity	Operational conditions, bacteriological activity, tightness	Salt domes are superior to bedded salt structures	Metamorphic or igneous rock, low steel price
Research & Development	Effects of residual hydrocarbons, In-situ bacteria reactions	In-situ bacteria reactions, tightness of rocks	Injection and withdrawals timing	Lining materials compatibility with hydrogen

Note: * 1 is least suitable and 10 most suitable.

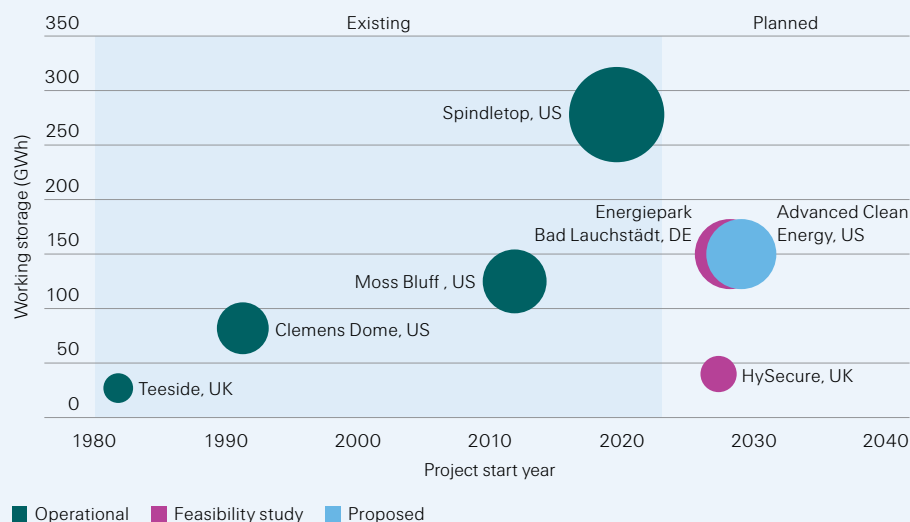
Source: Swiss Re, based on GIE database and SSO interviews

Storing large quantities of hydrogen underground for a long time can lead to unforeseen reactions.

Currently, there are only four mature hydrogen storage salt caverns in use by the petrochemical industry: three in Texas – Clemens Dome, Moss Bluff, and Spindletop, and one in the UK – Teeside (see Figure 12). These four facilities were developed specifically for hydrogen storage use.⁵³ Repurposing existing reservoirs or caverns originally designed for fuels such as natural gas or diesel is far more complex than creating structures for hydrogen from scratch. Among many challenges, one is maintaining the purity of the stored hydrogen in re-purposed caverns in the face of potential microbial activity. For example, if hydrogen sulfide creation were an outcome, this would pose significant contamination threats.⁵⁴

Figure 12

Existing and planned hydrogen storage facilities



Note: The bubbles represent working storage in gigawatt hours (GWh). The chart only includes facilities with storage capacity of more than 5 GWh. Source: Swiss Re Institute, IEA

⁵³ H. Hajibeygi, "Subsurface H₂ Storage: A Multiscale Experimental-Numerical Study", *MIT Fish Webinar*, 14 May 2021.

⁵⁴ M. Portarapillo, A.D. Benedetto, "Risk Assessment of the Large-Scale Hydrogen Storage in Salt Caverns", *Energies*, 2021.

Extensive studies on various risk aspects of caverns are needed before their commission.

Further, those caverns already in operation have not been stress-tested for periods of continuous high use, that is being filled and emptied every few weeks. There is little data on cyclic loading experiments for salt caverns at the rate that the future large-scale use of hydrogen would require. As a network of storage facilities evolves, operators will need to better understand the mechanics of multi-cavern systems, not least the extent to which cyclical loading in one cavern affects the larger ecosystem. The hydrogen industry needs to de-risk these interactions, and also the risks of subsidence and induced seismic activity through targeted research and development.

Typical distribution service lines are located in highly populated areas, and often not subject to inspection standards.

Risks during distribution

Like transmission line failures, corrosion, material defects and excavation can also lead to distribution failures. However, the characteristics are different as typical distribution service lines are smaller than transmission lines and operate under lower pressures. More pertinent from a risk perspective, distribution lines are less rigorously regulated than transmission lines and can be built using a broad range of materials from low alloy steel to polyethylene or other plastics. Facilities are typically located in highly-populated areas. Distribution pipeline incidents typically arise as a result of leaks: the higher the concentration of hydrogen at the point of release, the greater the hazard. Population densities across the hazard distance are thus an important consideration in assessing potential exposures.

The additional risk of hydrogen blending is better understood up to a mix of 20%.

In terms of risk exposure arising from the blending of hydrogen with natural gas (against a baseline of 100% natural gas), this is better understood up to a mix of 20% hydrogen (see Figure 10). If the hydrogen component of the mix increases beyond 20%, service lines can be impacted due to confinement, spacing and layout issues. In many cases, distribution facilities will require more thorough audits and risk mitigation measures (eg, special detection systems) than transmission lines. In order to evaluate and mitigate the impact of hydrogen blending on the integrity of re-purposed infrastructure, management of assets should be a key area of studies.

Distribution risks also include embrittlement and leakages.

Companies will have to look at leakage detection equipment, including personal protection. There is also the risk of embrittlement of steel pipes and equipment (welds are critical). New maintenance procedures will need to be developed, as well as new integrity management systems and inspection processes for hydrogen pipelines (pigging etc.). Changes of Atmospheres Explosive (ATEX) zones and explosion group classifications will also be needed.⁵⁵ As hazard levels increase, the infrastructure may have to be regulated by new (domestic) rules and it is also likely that the responsibility for regulatory oversight may change, as different regulators may have to step in depending on the changes in hazards.

Compression is required to transport hydrogen through pipelines.

Risks related to compression

Compression is required to transport hydrogen from one location to another. As hydrogen has a low density, major modifications to compressor stations may be needed depending on the capacity at which pipelines are operated. There are two main types of compressor for this kind of service: reciprocating and centrifugal.⁵⁶ The distinguishing factor is transport capacity. Reciprocating (piston) compressors are most economical for situations where less than 750 000 cubic metres of hydrogen is transported per hour. For higher volumes, centrifugal compressors are more suitable.

Existing natural gas compressors requires retrofitting for blends of 10–40% hydrogen, and complete replacement for above 40%.

Consideration must also be given to the materials which the compressors are made of. As the energy density of hydrogen is three times lower than that of natural gas, the process of compression can cause very high stress concentrations in the rotating part of the centrifugal compressor. This is not so much of a problem for blended fuels where the hydrogen content is below 10%, but for blends of between 10–40%, retrofitting may be required, particularly to the compressor's gears and impellers. For blends with hydrogen content in excess of 40%, the total compressor station will require replacing.⁵⁷

⁵⁵ As per EU directive 2014/34, when electronic or electrical equipment of any kind is intended for use in a potentially hazardous area, equipment must be ATEX (ATmospheres EXplosives) certified. According to ATEX 114 directive, Zone 1 denotes an area in which an explosive mixture is likely to occur in normal operation, while Zone 2 is an area in which an explosive mixture is not likely to occur in normal operation.

⁵⁶ *European Hydrogen Backbone*, Gas for Climate, July 2020.

⁵⁷ *Hydrogen infrastructure: the pillar of energy transition*, Siemens, 2021.

Compressing hydrogen needs three times more electricity than compressing natural gas.

A recent report from Siemens said that the pace of R&D is such that by 2030, compressor drive turbines will either be capable of handling pure hydrogen, or will be easily convertible.⁵⁸ However, the amount of electricity needed to compress each unit of hydrogen is about three times that for natural gas, which will lead to higher costs.⁵⁹

⁵⁸ Ibid.

⁵⁹ *Pre-feasibility Study for a Danish-German hydrogen network*, Energinet, April 2021.

Key stakeholders

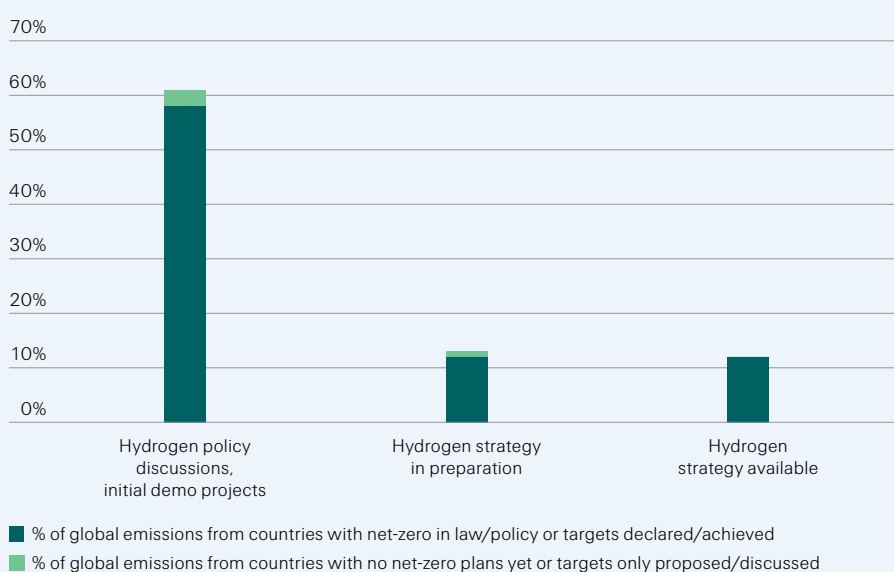
Given the move to cut carbon emissions, several countries are adopting hydrogen.

Role of policy makers/regulators

Participants at the 2021 UN Climate Change Conference (COP26) agreed to “phase down” the use of fossil fuels, with the result that countries accounting for 90% of the world’s CO₂ emissions are now committed to NZE. Countries accounting for 25% of emissions have already announced or are preparing formal hydrogen strategies (See Figure 13). Countries accounting for 61% of emissions have begun policy discussions or initiated demonstration projects around the use of hydrogen as a sustainable fuel.

Figure 13

Maturity of formal hydrogen strategies across countries in comparison to carbon emission (as of September 2021); share of global emissions



Source: Swiss Re Institute, World Energy, IRENA, IMF, Net Zero Tracker

Carbon pricing could more accurately account for the cost of hydrogen produced from fossil fuels.

Policy signals can act as market incentives

Industry participants will look for clear signals of demand and clarity in regulation before they raise capital and invest in hydrogen energy infrastructure. Before investing, participants could expect state subsidies. Estimates suggest this could call for ~USD 150 billion of government subsidies over the next ten years. This is less than half the annual outlay on fossil fuel consumption subsidies by governments.⁶⁰ Carbon pricing could be used to incorporate the cost of emissions into the price of grey hydrogen, thus disincentivising grey hydrogen. For example, the IEA noted that a carbon price of USD 100 per tonne can cause an increase of USD 0.90 per kilogram of grey H₂ (ie, natural gas based production without CCUS), or USD 2.00 per kilogram of brown H₂ (coal gasification without CCUS).⁶¹

There is a need to have common standards around safety measures. Work in this direction has been started.

Common approaches to safety standards are needed:

There is a need to establish common standards around safety measures. Work in this direction has already started. The European Commission has identified several safety issues for hydrogen (blend, conversion, dedicated pipes) and work is progressing through various standards with regards to safety and pipeline integrity. There is also an EC-CEN Pre-normative Hydrogen Project on safety to eliminate barriers for the use of hydrogen in gas systems.⁶²

⁶⁰ “Hydrogen Economy’ Offers Promising Path to Decarbonization”, *Bloomberg NEF*, 30 March 2020.

⁶¹ *Global Hydrogen Review 2021*, International Energy Agency, October 2021.

⁶² “GERG begins major project on Hydrogen pre-normative research requirements for CEN”, *The European Gas Research Group*, 18 February 2021.

Re/insurers in the hydrogen economy

While risks around hydrogen are familiar to re/insurers, the scale is changing with the move to net-zero.

The risks involved around handling hydrogen are not new. The insurance market has long been underwriting a suite of associated risks. However, the size and scale of exposures will be larger. Moreover, new players are entering the hydrogen economy and there is a risk that some may lack experience in handling hydrogen. Re/insurers can play a key role in the development of the hydrogen economy by providing risk management knowledge and risk transfer options at select points of the value chain (see Figure 14).

Figure 14

Stylised representation of risks across the value chain



Source: Swiss Re Institute

In the short term, risk exposure will be mainly related to the supply side. These are covered by standard policies.

Standard property insurance can cover risks in the operational phase.

In the medium- to long-term, when the hydrogen industry expands, the insurance industry can also cover risks around business interruptions.

Risk solutions for the immediate future

In the short term, risk exposure will be mainly related to the production/supply side. Increased investment in new plants, both using traditional (grey) hydrogen and blue/green hydrogen, will increase overall risk exposure. Engineering policies cover the risks associated with construction. For example, contractors all risk (CAR) insurance generally covers risks related to physical loss or damage to works during construction; delay in start-up (DSU) cover provides broad protection against delays arising from physical damage caused by peril types stated in the policy; construction liability insurance offers compensation for injury, damage and product-related claims, and marine insurance will protect against cargo, hull, production and liability exposures.

In the operational phase, main covers are for fire, explosion, malicious damage and natural peril (eg, flood, windstorm, hail and earthquakes) risks. In the event of physical loss, the industry can also be exposed to business interruption risks.

Risk solutions for the medium- to long-term

In the medium- to long-term, business interruption cover will gain importance as hydrogen technologies become more embedded in the global economy. Further, adoption of green hydrogen will require uninterrupted supply of renewable energy, often exposed to interruptions due to changing weather conditions. Moreover, large-scale electrolyser plants come with their own specific risk exposures that could disrupt hydrogen production. The expansion of the hydrogen economy will come with additional

exposures to liability risk, requiring a raft of insurance covers such as general third-party and product liability, employer's liability, professional liability and environmental liability.

For now, insurers can cover various risks through existing products.

Overall, the adoption of hydrogen at large scale and especially in the alternative/new uses is still at an early stage of development. For now, insurers can cover various risks through existing products. But as the industry expands and alternative use cases mature, insurers may need to create tailored products. Several questions need to be addressed to make the hydrogen economy insurable. Hydrogen producers and regulators need to work together for the safe adoption of hydrogen as a source of clean energy.

Conclusion

Large scale adoption of hydrogen would depend on factors such as technology development, and risk mitigation strategies.

More experiments are needed to understand suitability of existing infrastructure such as gas pipelines.

Policies such as carbon pricing, and better clarity around globally agreed safety standards could encourage more investment in hydrogen projects.

In the long term, hydrogen can be produced predominantly using renewable energy and thus play a significant role in the drive to net zero. However, the successful switch to a hydrogen economy can only succeed if developers and policy makers join forces to realise hydrogen's potential. Feasibility studies encompassing the full value chain must contribute significantly to overcoming operational challenges and give valuable input to regulation and standardisation processes, while safety regulation and standards must be addressed in a global context.

Further, system integration and efficient transmission, storage and distribution are needed to make full use of all hydrogen outputs. The gas grid can play an important role in transmitting and distributing hydrogen although its suitability as a transport medium for pure or blended hydrogen (with natural gas) is yet to be fully understood. Further studies are required to better understand the technical aspects of transporting hydrogen, such as which pipelines and associated assets are the most suitable for repurposing and how to modify them.

Policy makers have a key role to play in encouraging the shift to hydrogen. Carbon pricing could make fossil fuels more expensive, thereby encouraging a shift to carbon neutral fuels such as hydrogen. In addition, better clarity around globally agreed safety standards could encourage more investment in hydrogen projects. The re/insurance industry can play its part by providing risk management knowledge for evolving risk pools at various stages of the value chain.

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