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Global Hydrogen Review 2022

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Executive Summary

Hydrogen demand is growing, with positive signals in key applications

Hydrogen demand reached 94 million tonnes (Mt) in 2021, recovering to above pre-pandemic levels (91 Mt in 2019), and containing energy equal to about 2.5% of global final energy consumption. Most of the increase came from traditional uses in refining and industry, though demand for new applications grew to about 40 thousand tonnes (up 60% from 2020, albeit from a low base).

Some key new applications for hydrogen are showing signs of progress. Announcements for new steel projects are growing fast just one year after the start-up of the first demonstration project for using pure hydrogen in direct reduction of iron. The first fleet of hydrogen fuel cell trains started operating in Germany. There are also more than 100 pilot and demonstration projects for using hydrogen and its derivatives in shipping, and major companies are already signing strategic partnerships to secure the supply of these fuels. In the power sector, the use of hydrogen and ammonia is attracting more attention; announced projects stack up to almost 3.5 GW of potential capacity by 2030.

Considering policies and measures that governments around the world have already put in place, we estimate that hydrogen demand could reach 115 Mt by 2030, although less than 2 Mt would come from new uses. This compares with the 130 Mt (25% from new uses) that would be needed to meet existing climate pledges put forward by governments around the world so far, and with nearly 200 Mt needed by 2030 to be on track for net zero emissions by 2050.

The pipeline of projects for low-emission hydrogen production keeps expanding, but few are reaching FID

Much of the increase in hydrogen demand in 2021 was met by hydrogen produced from unabated fossil fuels, meaning there was no benefit for mitigating climate change. The production of low-emission hydrogen was less than 1 Mt in 2021, practically all of it coming from plants using fossil fuels with carbon capture, utilisation and storage (CCUS). However, the pipeline of projects for the production of low-emission hydrogen is growing at an impressive speed.

If all projects currently in the pipeline were realised, by 2030 the production of low-emission hydrogen could reach 16-24 Mt per year, with 9-14 Mt based on electrolysis and 7-10 Mt on fossil fuels with CCUS. In the case of electrolysis, the realisation of all the projects in the pipeline could lead to an installed electrolyser capacity of 134-240 GW by 2030, with the lower end of the range similar to total installed renewable capacity in Germany and at the upper end in all of Latin America. Meeting governments' climate pledges would require 34 Mt of low-emission hydrogen production per year by 2030;

a path compatible with reaching net zero emissions by 2050 globally would require around 100 Mt by 2030.

A significant portion of projects are currently at advanced planning stages, but just a few (4%) are under construction or have reached final investment decision (FID). Among the key reasons are uncertainties about demand, lack of regulatory frameworks and of available infrastructure to deliver hydrogen to end users.

Expanding electrolyser manufacturing capacity is critical to rolling out of hydrogen supply chains

Electrolysers using low-emission electricity are needed to produce low-emission hydrogen. Today, electrolyser manufacturing capacity sits at nearly 8 GW/yr, and based on industry annuncements it could exceed 60 GW/yr by 2030. This would be enough to meet current government targets for electrolysis deployment, but the build-out depends on government targets being translated into real-world projects beyond the current project pipeline. Although it is expected that the project pipeline will continue to grow over the coming years, there is a need to provide early support for projects to ensure that they reach FID and scale up.

Our analysis suggests that with today's fossil energy prices, renewable hydrogen could already compete with hydrogen from fossil fuels in many regions, especially those with good renewable resources and that must import fossil fuels to meet demand for hydrogen production. There is of course uncertainty about how this plays out over the next few years. But if electrolyser projects in the pipeline are realised and the planned scale-up in manufacturing capacities takes place, costs for electrolysers could fall by around 70% by 2030 compared to today. Combined with the expected drop in the cost of renewable energy, this can bring the cost of renewable-based hydrogen down to a range fo USD 1.3-4.5/kg H_2 (equivalent to USD 39-135/MWh). The lower end of this range is in regions with good access to renewable energy where renewable hydrogen could already be structurally competitive with unabated fossil fuels.

Large volumes of hydrogen could be traded by the end of the decade if barriers are addressed soon

The world's first shipment of liquefied hydrogen from Australia to Japan took place in February 2022, a key milestone in the development of an international hydrogen market. Based on the export-oriented projects under development, an estimated 12 Mt of hydrogen could be exported annually by 2030, with 2.6 Mt/yr planned to come online by 2026. Nearly all of these export-oriented hydrogen project plans have been announced in the last two years, with most projects that have identified a hydrogen carrier chosing ammonia as the preferred option.

However, off-take and importing arrangements are lagging behind the scale of planned exports: only 2 Mt H_2/yr has secured a customer or potential customer. Project developers and investors are facing high uncertainty in a nascent market and many governments have yet to implement specific hydrogen trade policies, which are necessary for the successful development of projects. International cooperation is vital to facilitate alignment and identify barriers that could slow the development of a hydrogen market.

The global energy crisis: an additional impetus for hydrogen?

The global energy crisis underscores the need for policy to align energy security needs with climate goals. Hydrogen can contribute to energy security by decreasing dependency on fossil fuels, either by replacing fossil fuels in end-use applications or by shifting fossil-based hydrogen production to renewable hydrogen. The development of an international hydrogen market can additionally add to the diversity of potential energy suppliers, enhancing energy security for energy importing countries in particular.

If governments implement ambitious policies to meet their climate pledges, hydrogen could help avoid 14 bcm/yr of natural gas use, 20 Mtce/yr of coal and 360 kbd of oil use by 2030, equivalent to more than today's fossil fuel supply of Colombia. Heavy industry, heavy duty road transport and shipping offer the largest opportunities to deliver fossil fuel and emissions savings.

There are opportunities and challenges with repurposing infrastructure for the use of hydrogen

Repurposing natural gas pipelines for the transmission of hydrogen can cut investment costs 50-80%, relative to the development of new pipelines. There are projects under development to repurpose thousands of kilometres of natural gas pipes to 100% hydrogen. However, practical experience is limited and significant reconfiguration and adaptation will be necessary.

Governments, particularly in Europe, are considering repurposing liquified natural gas (LNG) terminals, though the opportunities depend on whether they will ultimately receive hydrogen or ammonia. Initial studies indicate that repurposing to accept ammonia can be possible at additional 11%-20% of the investment costs of a new LNG terminal. Repurposing LNG terminals for liquefied hydrogen faces greater technical challenges due to the much lower temperature needs, which limits the reuse of existing equipment. This has important cost implications. The LNG tank alone accounts for around half the cost of an LNG terminal investment and a newly built liquefied hydrogen storage tank to replace it can be 50% more expensive than a LNG tank. There is no experience yet converting existing LNG terminals to ammonia or hydrogen, rendering cost estimates uncertain. Uncertainty regarding the scale of future demand for hydrogen and its derivatives can limit the uptake of new terminals that can be hydrogen- or ammonia-ready.

As policy action intensifies, the focus must move to implementation

Governments continue to consider hydrogen a pillar of their energy sector strategies: nine new national strategies have been adopted since September 2021, bringing the total number to 26. Some countries are moving to the next step by implementing concrete policies, with a particular focus to support commercial scale projects for low-emission hydrogen production and infrastructure (e.g. the EU Important Projects of Common European Interest, the US Inflation Reduction Act and the German H2Global Initiative). However, there is still not enough policy activity for creating hydrogen demand, which is critical to secure off-take agreements. A lack of demand creation can hinder final investment decisions.

IEA policy recommendations to accelerate low-emission hydrogen production and use

Move from announcements to policy implementation: the focus of governments on defining the role of hydrogen in their energy strategies in recent years has helped industry understand the potential marketplace for hydrogen, and develop plans to incorporate hydrogen into technology and project portfolios. These technologies are ready to scale, but the hydrogen market is still nascent and its future evolution is uncertain, discouraging first movers from reaching FID. Governments need to implement policies to reduce risk and improve the economic feasibility of low-emission hydrogen projects.

Raise ambitions for demand creation in key applications: in existing hydrogen applications, the sharp increase in fossil fuel prices observed since the end of 2021 has significantly closed the cost gap between low-emission and unabated fossil-based hydrogen. However, investment decisions continue to be hindered by general uncertainty around the long-term development of energy prices. Policies to create demand for low-emission hydrogen are needed, using instruments such as auctions, mandates, quotas and requirements in public procurement. In new hydrogen applications, such policy action should be complemented by innovation and demonstration efforts, with a focus on sectors where hydrogen can both support decarbonisation and reduce dependency on fossil fuels, such as heavy industry, heavy duty road transport and shipping.

Identify opportunities for hydrogen infrastructure and ensure that short-term actions align with long-term plans: governments and the private sector need to look at opportunities to accelerate the development of hydrogen infrastructure, both in terms of new assets and repurposing existing natural gas infrastructure. For the latter, there are technical challenges, including for repurposing LNG terminals. As governments address immediate energy needs today, it is nonetheless important to carefully consider how new gas-related infrastructure may potentially support the future development of hydrogen in the context of climate ambitions.

Intensify international cooperation for hydrogen trade: the development of an international market for low-emission hydrogen will strongly depend on effective international cooperation. There are a number of areas where governments need to work together: developing a standard for emissions intensity of hydrogen production and transport, defining robust and workable regulations, and cooperation on certifications to ensure interoperability and avoid market fragmentation.

Remove regulatory barriers: the presence of a clear and stable regulatory framework must be balanced with a dynamic regulatory approach, calibrated to regular market monitoring. Actors involved in a hydrogen market need clear rules, but applying rigid regulatory principles in a nascent market could discourage investments.

Improving regulatory processes, such as licensing and permitting, can help shorten project lead times. Governments should work to increase the efficiency and co-ordination of these processes without compromising environmental standards and public consultation. This should apply also to enabling infrastructure projects, including renewable generation capacities and CO_2 transport and storage.

Introduction

Overview

The momentum behind hydrogen continues to be strong. It has been recognised as a key option to realise the net zero greenhouse gas emissions commitments that governments have announced in recent years. Industry is investing in large-scale projects to produce hydrogen from water electrolysis or fossil fuels with CCUS.[1] The global energy crisis sparked by the Russian Federation's (hereafter "Russia") invasion of Ukraine has accelarated the momentum. Many governments, particularly in Europe, are looking at low-emission hydrogen[2] as a way to reduce dependency on fossil fuels. It offers opportunities to simultaneously contribute to decarbonisation targets and to enhance energy security.

Yet, the adoption of low-emission hydrogen as a clean industrial feedstock and energy vector is at an early stage and, as with other clean energy technologies, there is a need to effectively track progress to assess if developments are happening fast enough and are on a trajectory for hydrogen to play its part in the clean energy transition and to enhance energy security.

In that regard, this report, the Global Hydrogen Review, provides an annual update of progress in the transformation of the hydrogen sector. It is an output of the Clean Energy Ministerial Hydrogen Initiative intended to inform energy sector stakeholders on the current status and future prospects of hydrogen technologies. This review aims to help decision makers fine tune their strategies to attract investment and facilitate deployment of low-emission hydrogen.

This 2022 edition takes stock and presents the analysis in seven chapters. First it comprehensively assesses the status of **global hydrogen demand** and **production,** provides in-depth analyses of recent advances and explores short- and medium-term trends.The **infrastructure** and **trade** chapters assess progress in these areas, the need for developing them faster and the short-term opportunities for deploying hydrogen infrastructure and kick-starting hydrogen trade. A chapter on **policy trends** describes progress made by governments in adopting hydrogen-related policies. A chapter on **investment and innovation** assesses how hydrogen companies are performing, the challenges and opportunities available to mobilise investment and progress in the development of key technologies across the hydrogen value chain. The **role of hydrogen in a changing energy landscape** chapter assesses how hydrogen technologies can help to tackle current and future energy crises, how governments are trying to tap hydrogen's potential to enhance energy security and the challenges to meet government ambitions in this area.

[1] See Explanatory notes annex for CCUS definition in this report.

[2] See Explanatory notes annex for low-emission hydrogen definition in this report.

The Hydrogen Initiative

Developed under the Clean Energy Ministerial framework, the Hydrogen Initiative (H2I) is a voluntary multi-governmental initiative that aims to advance policies, programmes and projects that accelerate the commercialisation and deployment of hydrogen and fuel cell technologies across all areas of the economy. Ultimately, it seeks to ensure hydrogen's place as a key enabler in the global clean energy transition.

The IEA serves as the H2I co-ordinator to support member governments as they develop activities aligned with the initiative. H2I currently comprises the following participating governments and intergovernmental entities: Australia, Austria, Brazil, Canada, Chile, the People's Republic of China (hereafter "China"), Costa Rica, European Commission, Finland, Germany, India, Italy, Japan, Netherlands, New Zealand, Norway, Portugal, Republic of Korea (hereafter "Korea"), Saudi Arabia, South Africa, United Arab Emirates, United Kingdom and United States. Canada, European Commission, Japan, Netherlands and United States co-lead the initiative, while China and Italy are observers.

H2I is also a platform to co-ordinate and facilitate co-operation among governments, other international initiatives and the industry sector. The H2I has active partnerships with the Hydrogen Council, the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE), the International Renewable Energy Agency (IRENA), Mission Innovation (MI), the World Economic Forum (WEF) and the IEA Advanced Fuel Cells and Hydrogen Technology Collaboration Programmes (TCPs), all of which are part of the H2I Advisory Group and participate in various activities of the H2I. In addition, several industrial partners actively participate in the H2I Advisory Group's bi-annual meetings, including Ballard, Enel, Engie, Nel Hydrogen, the Port of Rotterdam Authority and thyssenkrupp nucera.

HYDROGEN INITIATIVE

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Hydrogen is making inroads and accelerating as a consequence of the energy crisis

Hydrogen has a notable role to play in supporting annouced government climate committments and to enhance energy security. To fulfil this role in a timely manner, this decade needs to see massive deployment of available hydrogen technologies and accelerated innovation of those still under development.

Accelerated deployment of certain key hydrogen technologies was evident in 2021. It was a record year in electrolysis deployment, with more than 200 megawatts (MW) of additional installed capacity, three-times more than the previous record year (2020) and bringing total operational capacity above 500 MW. We track a portfolio of projects and note progress; if all these projetcts are realised, electrolysis capacity could be 134-240 gigawatts (GW) by 2030.[3] This compares to the outlook of 54-91 GW by 2030 in the 2021 edition of the Global Hydrogen Review. However, only a small fraction of the projects (around 9 GW) have reached the final investment decision stage. The favourable outlook for growth in electrolyser demand has stimulated a boost in electrolyser manufacturing capacities, which has reached around 8 GW/year worldwide. Announced expansions could push this to nearly 50 GW by 2025.

Global hydrogen demand was nearly 94 million tonnes (Mt) in 2021, a 5% increase from the previous year. Most of this demand growth was from traditional uses of hydrogen, particularly in refining and industry. But some new applications are also seeing accelerated deployment, such as fuel cell electric vehicles (FCEVs). By end-2021, the global FCEV stock was more than 51 000, up from about 33 000 in 2020, representing the largest annual deployment of FCEVs since they became commercially available in 2014. Most FCEVs are passenger cars, but several demonstration projects for fuel cell trucks and a strong push in China put nearly 800 hydrogen fuel cell heavy-duty trucks into operation in 2021.

In other areas, the pace was slower. For example, in carbon capture associated with hydrogen production. In 2021, 0.6 Mt of hydrogen were produced from fossil fuels with CCUS, capturing roughly 10 Mt. This was the same production and capture level as in 2020 as no new projects started operation.The outlook for 2022 is boosted by a project in China (with capacity to capture 0.7 Mt CO_2 annually) that was commissioned in January 2022 and should start operation during the year. The project portfolio is increasing and if realised, the

[3] The lower range of our tracking portfolio includes projects in operation, under construction, with a final investment decision, as well as those that are undergoing feasibility studies. The higher range includes projects at very early stages of development, e.g. only a co-operation agreement among stakeholders has been announced.

projects would represent 80 Mt CO_2 captured annually in association with hydrogen production by 2030.

Some key hydrogen technologies, such as direct reduced iron (DRI) for steel manufacturing, the use of ammonia in shipping vessels and the use of synthetic fuels in aviation, are not yet commercially available. However, the number of demonstration projects is increasing and some are expected to become commercially available earlier than previously thought. An example is the use of hydrogen in DRI. Just one year after the first demonstration started operation, plans for several commercial-scale DRI plants have been announced, mostly in Europe. Efforts to demonstrate hydrogen use in various sectors, in particular industry and transport, are expected to intensify, with clear intent to reduce Europe's dependence on imported oil and natural gas.

In addition to technology deployment, progress is noted over the last year in policy areas. For instance, nine governments presented new national hydrogen strategies and some existing strategies are being updated to raise ambitions. New policies have been announced to create demand for hydrogen and to support first movers, but few have been implemented. The development of an international carbon accounting standard is progressing, with the International Organization for Standardization aiming to develop a Draft Technical Specification by end-2023 based on the IPHE Guidelines. In addition, some governments have started to develop certification schemes and to implement regulatory tools for the adoption of low-emission hydrogen as an energy vector.

The first steps towards international trade for hydrogen have been taken. Early in 2022, international transportation of liquefied hydrogen – for the first time – was demonstrated in a shipment from Australia to Japan. In addition, several large projects have been announced to export low-emission hydrogen, most using ammonia as the carrier, either to be used directly (as feedstock for chemicals or as a fuel for power generation and maritime transportation) or to be reconverted to hydrogen. These are critical steps for hydrogen to be able to play its role in improving energy security since many countries will need to import significant amounts of hydrogen to support their decarbonisation objectives while decreasing their dependency on fossil fuels. Governments are making important efforts to facilitate the emergence of an international hydrogen market. In this respect in March 2022, the European Commission launched the strongest signal as part of its REPowerEU Plan to make Europe independent from Russian fossil fuel imports before 2030 with a target to import 10 Mt of renewable hydrogen by 2030.[4]

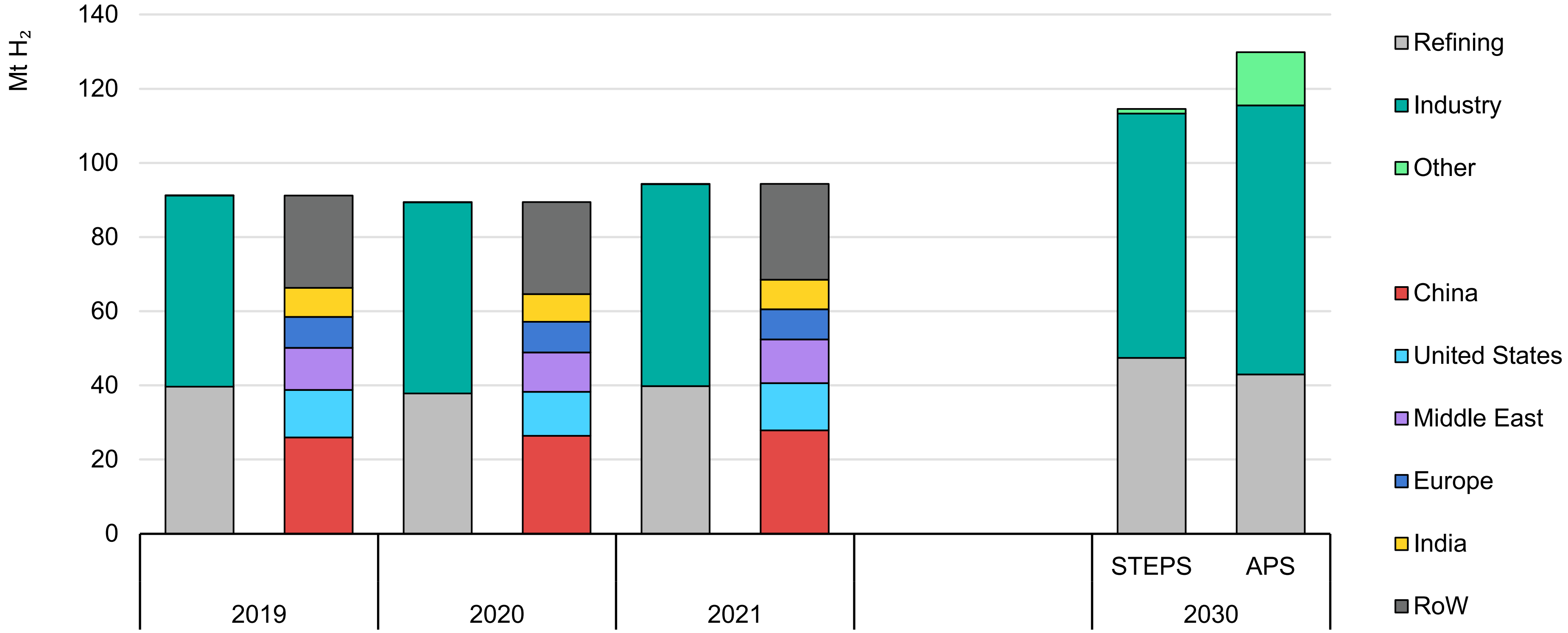
[4] See Explanatory notes annex for renewable hydrogen definition in this report.

Hydrogen demand

Overview and outlook

Global hydrogen demand increased 5% in 2021, reflecting recovery of economic activity in traditional applications from the pandemic-related curtailments

Hydrogen demand by sector and by region in the Stated Policies and Announced Pledges scenarios, 2019-2030



Notes: Mt H_2 = million tonnes of hydrogen; STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario. *Other* includes transport, buildings, power generation sectors and production of hydrogen-derived fuels and hydrogen blending.

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Global hydrogen demand reached more than 94 million tonnes (Mt) in 2021[5], a 5% increase from the previous year and compared to 91 Mt in 2019 (pre-pandemic level). Most of the increase was for the use of hydrogen in traditional applications, particularly in chemicals, with nearly 3 Mt increase, and in refining with about 2 Mt increase from 2020. These sub-sectors, particularly refining, were strongly affected by the Covid-19 pandemic. Activity that was restrained due to the lockdowns and the general economic slowdown started to recover in 2021, as reflected in increased hydrogen demand. Most of the hydrogen supplied was produced from fossil fuels with no benefit for climate change (see "Hydrogen production" chapter).

Demand for hydrogen in new applications, such as in heavy industry, transport, power generation and the buildings sectors or the production of hydrogen-derived fuels, was very low in 2021, at around 40 kilotonnes (kt) H_2 (about 0.04% of global hydrogen demand). This was for use mostly in road transport, which observed a significant increase (60%, albeit from a very low base) and reflects accelerated deployment of FCEVs, particularly in heavy-duty trucks in China.

China is the world's largest consumer with demand in 2021 of around 28 Mt H_2, up 5% from 2020. The United States is the second-largest and the Middle East the third-largest consumer at around 12 Mt H_2 each, with demand in 2021 increasing by 8% and 11% respectively relative to 2020. Europe is the fourth-largest consumer with demand of more than 8 Mt H_2 in 2021, practically the same level as 2020. India is next with demand of 8 Mt H_2, up 7% from the previous year as economic recovery increased in refining and, particularly in steel production, two areas that were hard hit by the pandemic in 2020.

The IEA Stated Policies Scenario (STEPS) reflects current policy settings based on a sector-by-sector assessment of the specific policies that are in place, as well as those that have been announced by governments around the world. The outlook in the STEPS suggests that hydrogen demand could reach 115 Mt by 2030. Most of this growth would be from traditional applications with small demand (less than 2 Mt) for new uses or the replacement of unabated fossil-based hydrogen in traditional uses. This would have limited benefit to achieving climate pledges. The IEA Announced Pledges Scenario (APS) assumes that all climate commitments made by governments around the world, including Nationally Determined Contributions and longer-term net zero targets, will be met in full and on time. The outlook for hydrogen demand in the APS is 130 Mt by 2030, of which about 25% would be for new applications and the use of low-emission hydrogen in traditional applications. This would require a step change to stimulate demand for hydrogen supported by ambitious and concrete policies actions.

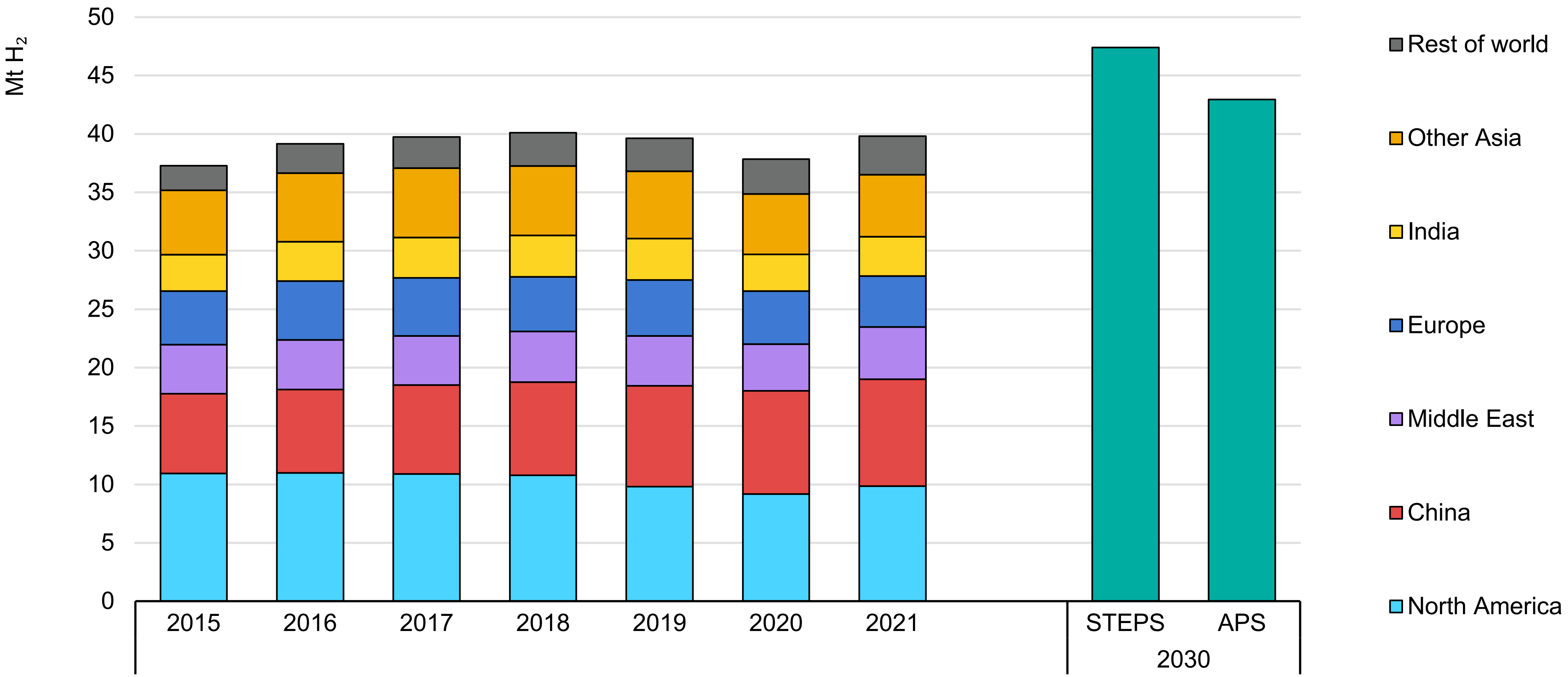
The rest of this chapter examines the state of play of hydrogen demand in the refining, industry, transport, buildings and power generation sectors and the outlook for hydrogen demand to 2030.

[5] This includes more than 70 Mt H_2 used as pure hydrogen and more than 20 Mt H_2 mixed with carbon-containing gases in methanol production and steel manufacturing. It excludes around 30 Mt H_2 present in residual gases from industrial processes used for heat and electricity generation, as this use is linked to the inherent presence of hydrogen in these residual streams, rather than to any hydrogen requirement, these gases are not considered here as hydrogen demand.

Refining

Hydrogen demand in refining recovered from the pandemic-related slowdown

Hydrogen demand in refining by region in the Stated Policies and Announced Pledges scenarios, 2015-2030



Notes: STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario. Demand includes the use of hydrogen produced in refineries as a by-product of catalytic reformers.

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Refineries use hydrogen to remove impurities, especially sulphur, and to upgrade heavy oil fractions into lighter products. Hydrogen demand in refining reached its historic maximum at 40 Mt in 2018 when refinery throughputs were at their all-time peak.[6] Hydrogen demand in refining maintained that level in 2019. It dropped sharply to around 38 Mt in 2020 as the pandemic put the brakes on refining activity as demand for mobility – the main consumer of oil products – fell sharply. With the situation easing in 2021, demand for refined petroleum products was sparked, particularly for diesel, which reached an all-time high in the last quarter of 2021. This underpinned a quick recovery of hydrogen demand in refining to reach nearly 40 Mt. Almost all hydrogen used in refineries is produced from unabated fossil fuels, resulting in more than 200 Mt CO_2 emitted in 2021.

We estimate that demand for hydrogen in refining in 2022 may reach a new record of more than 41 Mt. This is led by recovery in global crude processing and by the impact of regulations for lower sulphur emissions limits for marine bunkers that came into force in 2020. Yet, current high volatility in fossil fuel markets renders high uncertainty of the potential evolution of hydrogen demand in refining.

Nearly half of global hydrogen demand for refining in 2021 was in two regions: North America at almost 10 Mt and China at more than 9 Mt. Demand in both regions has completely recovered to pre-pandemic levels, although China may see a slight drop of around 250 kt for 2022 due to pandemic-related lockdowns early in the year. China recently surpassed the United States in installed refinery capacity. China accounts for nearly 70% of global net refinery additions in the 2019-2023 period. However, North America remains the largest user of hydrogen in refining since China now has the largest fleet of spare refinery capacity.

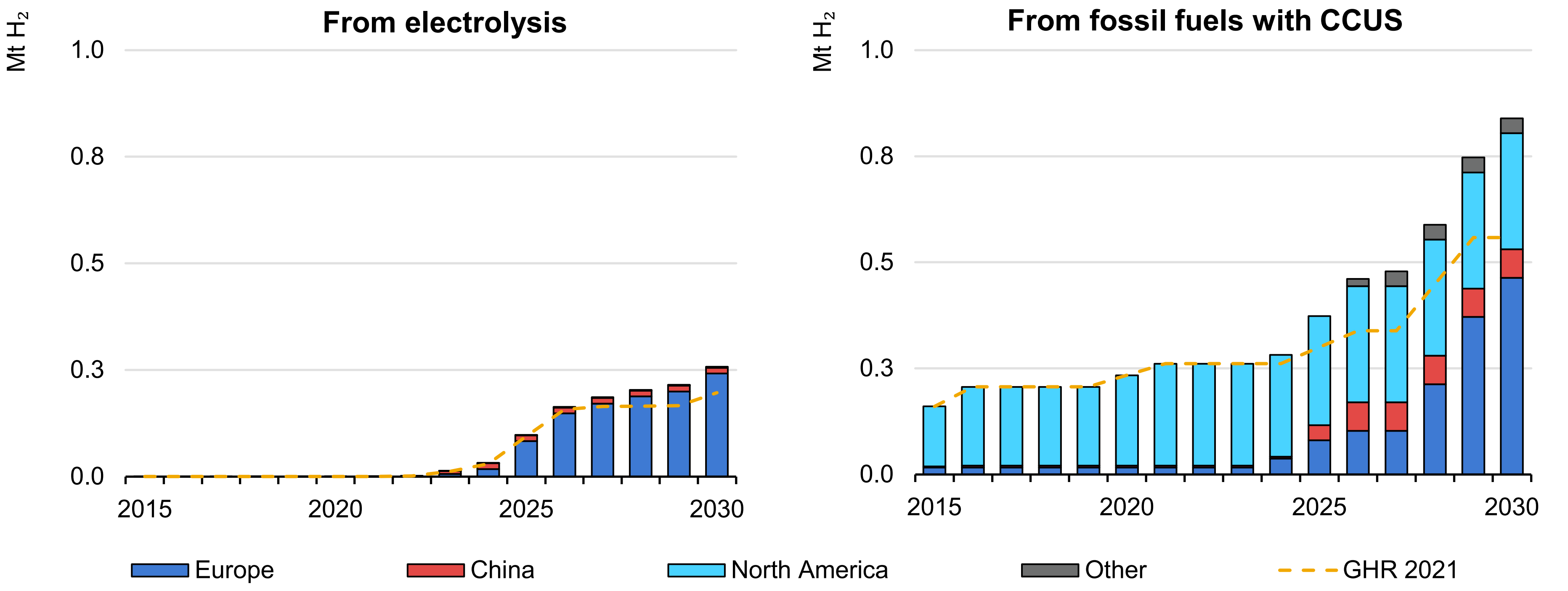
Only Europe, among the other major refining regions, has not recovered to pre-pandemic demand levels of hydrogen demand in refining and it is not expected to do so in 2022. Europe has observed a significant decrease in refining capacity in the last two years and no changes are expected in 2022 and 2023. In addition, sanctions imposed on Russia as a result of its invasion of Ukraine have generated uncertainty on Russian-operated refineries, which have not received exemptions.

The outlook in the STEPS suggests that global hydrogen demand in refining will rise strongly to reach around 47 Mt by 2030. In the APS outlook, the projected hydrogen demand in refining is more modest reaching about 43 Mt by 2030 reflecting increased penetration of clean technologies in the transport sector, e.g. direct electrification, hydrogen and hydrogen-derived fuels and biofuels.

[6] This demand includes the use of hydrogen produced in refineries as a by-product from catalytic reformers. We estimate refinery hydrogen demand using crude oil processing rates, crude sulphur content and final product output and sulphur specifications. We derive by-product hydrogen supply by estimating catalytic naphtha reformer activity rates and, where applicable, integrated naphtha cracking processes. The balance comes from onsite production and merchant supply. Typical refinery product yields and hydrogen demand and supply assumptions can be found at the IEA Oil Market Report.

Production of low-emission hydrogen for use in refining will mostly be from fossil fuels with CCUS in the near term …

Planned production of low-emission hydrogen for refining by technology and region, 2018-2030



Notes: CCUS = carbon capture, utilisation and storage. GHR 2021 = Global Hydrogen Review 2021. Only planned projects with a disclosed start year of operation are included. Projects at a very early stage of development, such as those in which only a co-operation agreement among stakeholders has been announced are not included. GHR 2021 shows the estimated production of low-emission hydrogen from projects that were included in IEA Hydrogen Projects Database as of August 2021.

Source: IEA Hydrogen Projects Database (2022).

… but the energy crisis and Russia's invasion of Ukraine may accelerate the use of renewable hydrogen in refining

Most hydrogen supply in refining today comes as a by-product from catalytic naphtha crackers and steam crackers for dedicated onsite generation using unabated fossil fuels (around 45% of supply each in 2021). The majority of the latter is based on steam methane reformers fed with natural gas, although refineries in China produced nearly 1 Mt of hydrogen from coal gasification in 2021. Onsite production is supplemented with purchased (merchant) hydrogen, mostly produced using steam methane reformers, to meet demand.

There are only eleven plants to produce low-emission hydrogen[7]: seven are facilities retrofitted with CO_2 capture and four use electrolysers. They produced around 260 kt of low-emission hydrogen in 2021 (around 0.7% of hydrogen demand in refining), a slight increase from the 230 kt used in refineries in 2020. This increase represents the 2021 start-up of the REFHYNE project (10 megawatts [MW]) in Germany. In 2022, Orlen, an oil refiner and petrol retailer, started operation of a small electrolyser at the Trzebinia refinery (2 MW) in Poland. In Colombia, a small pilot electrolyser (50 kilowatt) started operating at an Ecopetrol refinery in 2022. It is expected that by end-2022 a 20 MW project will start operation in at the HySynergy project in Denmark.

Replacing unabated fossil fuel-based hydrogen with low-emission hydrogen in refining presents relatively low technical challenges as it is a like-for-like substitution rather than a fuel switch. Projects under development, however, are limited in number and size, so they could only slightly increase the production and use of low-emission hydrogen in refining in the near term. If all projects under development that aim to be in operation by 2030 are realised, the annual supply of low-emission hydrogen to refineries could reach more than 1 Mt.

Some noteworthy projects that plan to produce hydrogen via electrolysis include: Shell's Holland Hydrogen I (200 MW), which took a final invesment decisions in July 2022; extension of the HySynergy project (300 MW by 2025 and 1 gigawatt [GW] by 2030); a project that Sinopec is developing at Kuqa (260 MW) in China; and the H2fifty project that BP and HyCC are developing in the Port of Rotterdam (250 MW) in the Netherlands. The REFHYNE 2 project in

[7] See Explanatory notes annex for low-emission hydrogen definition in this report.

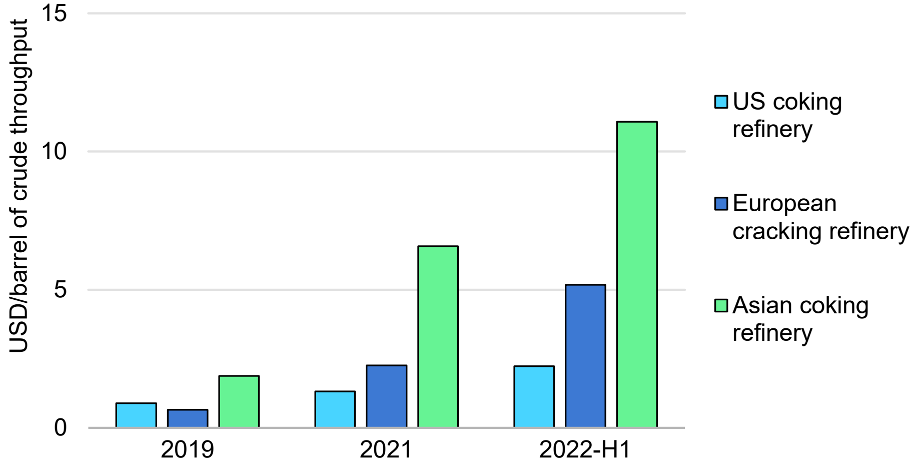
Germany secured funding to expand its installed capacity to 100 MW with a FID expected in late 2022 and project completion scheduled for 2024.

Some noteworthy projects that plan to produce hydrogen from fossil fuels with CCUS[8] include the CNPC China Northwest hub in Xinjiang, which aims to capture 1.5 Mt CO_2/year from coal gasification. Several projects with undisclosed capacities that involve Air Liquide, Air Products, ExxonMobil and Shell are under development at the Port of Rotterdam to use the Porthos carbon capture and storage (CCS) infrastructure and are expected to become operational in 2024.

Europe is home to most of the planned low-emission hydrogen for refining projects, accounting for around two-thirds of the total production capacity of such projects. The current energy crisis could offer an opportunity to accelerate the uptake of low-emission hydrogen, particularly of renewables-based hydrogen, in refineries in the region (see "Hydrogen in a changing energy landscape" chapter).

In 2019, when average natural gas prices in Europe were USD 4.5 per million British thermal units (MBtu), hydrogen production costs per barrel of crude refined in Europe averaged around USD 0.60-0.70/barrel (around 10% of the refinery margin net of hydrogen costs). At the end of 2021, with natural gas spot prices reaching historical highs, the indicative hydrogen production costs shot up to more than USD 5/barrel (nearly 50% of the refinery margin net of hydrogen costs). Since end-2021, natural gas prices have remained high and volatile, contributing to increased costs for refiners and feeding into higher product prices for consumers.

Cost of hydrogen for processing crude oil in different types of refineries



Note: 2022-H1 = first-half of 2022.

Emissions allowances in the EU Emissions Trading System represent another cost item for refiners that has soared recently due to the increase in CO_2 prices combined with a reduction in free allocations. We estimate that at USD 70-80/tonne CO_2 as observed in late 2021, refiners can face a cost penalty of USD 0.75-0.90/barrel compared with around USD 0.2/barrel over 2019-20.

[8] See Explanatory notes annex for CCUS definition in this report.

This situation has help close the cost gap between unabated natural gas-based and renewables-based hydrogen production. This increases the opportunity to boost the use of renewables-based hydrogen in European refineries with a view to help decrease demand for natural gas. Although it is quite uncertain how long the current situation will endure and whether it will be sufficient to push projects to reach FIDs.

The REPowerEU action plan working document projects the use of 2.3 Mt of renewable hydrogen[9] in refining by 2030, which could decrease annual natural gas demand in European refineries more than 10 billion cubic metres (bcm) (equivalent to nearly 3% of current natural gas demand and almost 7% of Russian gas imports in the EU countries). The action plan is under discussion among EU legislators and would subsequently need to be implemented through regulatory instruments that are not yet in place. (see the “Hydrogen policies” chapter).

Hydrogen use in other operations in refineries

In addition to refining, new sources of hydrogen demand in refineries may arise in the near term. These may include biofuels upgrade, production of low-emission synthetic hydrocarbon fuels (synfuels) or high-temperature heating for processes.

An example of hydrogen use for biofuels upgrade is the Varennes Carbon Recycling project in Canada which will produce 125 million litres of biofuel and includes deployment of an 88 MW electrolyser in 2022. Similar biofuel upgrade projects from TotalEnergies in France (125 MW electrolyser) and Repsol in Spain (250 kt biofuels) are expected to start construction soon and come into service over the next couple of years.

The production of synthetic fuels is still at the very early stages of development. In 2021, Atmosfair, a German non-profit organisation, inaugurated the first project for the production of synthetic fuels using hydrogen produced from renewable electricity, which included an off-take agreement for 25 000 litres of synthetic kerosene annually with the airline Lufthansa. Other synthetic fuel production projects have started construction in Spain (10 MW) and Chile (1 MW) and are expected to become operational in the next couple of years. Projects at larger scale but earlier stages of development have also been announced over the last year in Germany, Netherlands, Norway, Portugal, South Africa and Sweden. If all the projects currently under development are realised, by 2030 they could be producing more than 2 billion litres of synthetic kerosene annually, which could help to replace like-to-like oil-based kerosene consumption in aviation, thus reducing the equivalent of nearly 1% of 2021 global demand for oil-based products in aviation.

[9] See Explanatory notes annex for renewable hydrogen definition in this report.

In the United Kingdom, Essar is investing GBP 45 million (~USD 55 million) in its Stanlow refinery to install a first-of-a-kind furnace able to operate with pure hydrogen that will be online in 2023. Initially, the furnace will operate with natural gas. In 2026 it will switch to 100% hydrogen when the HyNet North West project for the production of hydrogen from natural gas with CCUS becomes operational and begins supplying hydrogen for the furnace.

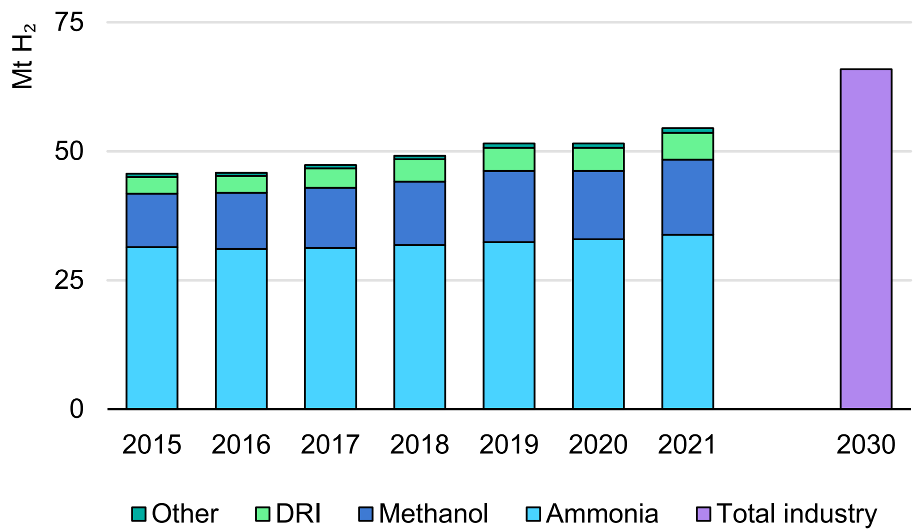
Industry

Hydrogen use in industry

Today the main uses of hydrogen in the industry sector are to produce ammonia (34 Mt of hydrogen demand), methanol (15 Mt) and DRI in the steel industry (5 Mt).[10] Other industrial applications, where comparatively small volumes of hydrogen are produced onsite, or imported from a merchant supplier, include various processes in electronics, glassmaking and downstream chemical industries. Large volumes of hydrogen are produced as a by-product of the chlor-alkali processes in industry and during the operation of steam crackers, blast furnaces and coke ovens, which are generally combusted or otherwise utilised onsite, e.g. for hydrogenation or electricity generation.

Hydrogen demand for the main industrial applications remained relatively robust during the pandemic. Ammonia production – the largest industrial hydrogen application – rose 2% in 2020 relative to 2019 levels. Global hydrogen production for methanol declined by 4% in 2020, owing in part to dramatic reductions in activity in the transport sector – around one-third of global methanol demand (including its derivatives) is for fuel applications. While steel is produced all over the world, DRI production is highly concentrated in the Middle East (around 40% of global production) and India (around 30%). India's crude steel output was hit hard in 2020 as the country suffered the consequences of the pandemic, with output falling by around 10% in 2020 – its first decline since the turn of the millennium.

Global hydrogen demand in industry, 2015-2030



Notes: DRI = direct reduced iron. Ammonia excludes fuel applications. *Other* includes small volumes in the downstream chemical industry and other dedicated industrial production, but excludes hydrogen generated as a by-product from industrial processes, such as chlor-alkali processes, blast furnaces, coke ovens and steam crackers. 2021 values include estimated quantities.
Sources: IEA analysis based on International Fertilizer Association, World Steel Association and Wood Mackenzie.

[10] The data for DRI includes all conventional production, where hydrogen is produced as a component of the synthesis gas input to the iron making furnace.

In 2021, hydrogen demand in industry recovered and slightly exceeded pre-pandemic levels. The highest rates of economic growth ever recorded in many countries, in part, are reflected by a surge in demand for hydrogen-derived products: global ammonia production rose by 3%, methanol by 12% and DRI production by 12%.

The outlook for 2022 is unclear. The full extent of the consequences of Russia's invasion of Ukraine is not yet known and the turmoil in global energy markets is severely dampening the rebound in industrial activity seen in 2021. Markets for key end-use products that drive industrial hydrogen demand have been severely disrupted in 2022. The interlinkages between the supply of food, fertiliser, hydrogen and natural gas mean that the global energy crisis is exacerbating the global food crisis.

Virtually all hydrogen used in the industry sector today is produced from unabated natural gas or coal, leading to 630 Mt of direct CO_2 emissions on a net basis, or 7% of industrial CO_2 emissions in 2021.[11] Demand for hydrogen is set to rise substantially in the medium term given current trends and announced policies, as demand for products derived from hydrogen will rise as the population and economic output grow. In that context, we project industrial hydrogen demand to increase by 11 Mt by 2030 relative to 2021 levels.

New hydrogen applications in industry have the potential to curb growth in greenhouse gas emissions to 2030. Many technologies currently under development form the foundation of a net zero emissions energy system. These include new low-emission production processes for conventional industrial outputs, such as electrolytic and CCUS-equipped ammonia, methanol and steel production, as well as hydrogen use for industrial heat demand, among other applications. If governments enact the policies required to achieve the goals set out in their climate pledges, these new technologies could account for more than 13 Mt of industrial hydrogen production by 2030. This more than offsets the downwards pressure on overall demand stemming from efforts to use hydrogen and its derived products more efficiently, including material and nutrient use efficiency strategies. This section reviews progress on key low-emission hydrogen applications in the industry sector: ammonia, methanol and steel production.

[11] This includes an estimated 290 Mt CO_2 emitted downstream of the energy sector during the use of urea and methanol.

Low-emission hydrogen projects for ammonia are expanding rapidly

Ammonia is the starting point for all mineral nitrogen fertilisers, which account for around 70% of global ammonia demand. The remaining 30% of ammonia demand is for a wide range of industrial applications, including explosives, synthetic fibres and specialty materials. Producing one tonne of ammonia requires around 180 kilogrammes (kg) of hydrogen: total production of ammonia was around 190 Mt in 2021, representing approximately 34 Mt of demand for hydrogen, or around two-thirds of hydrogen demand in the industry sector.

The nitrogen in ammonia (NH_3) is sourced from the air, whereas the hydrogen is sourced from fuels used as feedstock or raw material inputs. Today virtually all feedstock is supplied from fossil fuels. Worldwide, about 70% of ammonia is produced from natural gas, and most of the remaining 30% from coal, the latter mainly in China. Ammonia production accounts for 1.3% of global energy demand and around 1% of energy-related CO_2 emissions, including industrial process emissions.

One tonne of ammonia production results in around 2.2 tonnes of CO_2 emissions on average. This emissions footprint, if sustained, is incompatible with the climate ambitions of many governments. The IEA Ammonia Technology Roadmap uses scenario analysis to examine pathways toward more sustainable nitrogen fertiliser production. Two key technology families can achieve substantial emissions intensity reductions for ammonia, resulting in low-emission ammonia production[12] – electrolysis and the use of CCUS.

The project portfolio examined for this report suggests rapid growth in low-emission ammonia production over the remainder of this decade, if planned projects are realised. Compared to analysis conducted for the 2021 edition of the Global Hydrogen Review, the portfolio of electrolysis projects to 2030 has expanded by more than 200% in capacity terms, and the CCUS project portfolio by around 40%. Europe leads the way in planned electrolysis capacity, accounting for 60% of the capacity projected to be online by 2030, while North America and the Middle East lead in plans for CCUS capacity additions. Asia Pacific, where most of the growth in ammonia production is expected in the coming years, lags relative to the size of its market.

From negligible volumes today, electrolysis projects look set to add nearly 1.3 Mt of low-emission hydrogen production capacity for ammonia production by 2030.[13] Key electrolysis projects newly added to the IEA project database include: Green Wolverine (over 100 kt hydrogen capacity) project in Sweden: Catalina project in Spain (260 kt hydrogen capacity and a first phase of close to 90 kt in

[12] See Explanatory notes annex for low-emission ammonia definition in this report.

[13] This could increase to 2.9 Mt H_2 if projects at a very early stage of development are included, e.g. only a co-operation agreement among stakeholders has been announced.

advanced planning stages); EBIC Ammonia in Egypt (15 kt hydrogen capacity); and Unigel project in Brazil (over 30 kt hydrogen capacity, with a contract in place for suppling the electrolysers of the first phase, 10 kt hydrogen capacity).

Five CCS-equipped plants are operating today – three in the United States, one in Canada and one in China – with an estimated combined output of 0.2 Mt of low-emission hydrogen. Key CCUS projects newly added to the IEA hydrogen project database include: Maire Tecnimont (0.2 Mt hydrogen capacity) and Lapis Energy El Dorado (44 kt of hydrogen capacity) projects in the United States. If realised, all the CCUS projects in the portfolio would lead to 0.8 Mt of low-emission hydrogen capacity by 2030. The Olive Creek 2 project in Nebraska (United States), which will use natural gas as a feedstock, but produce carbon black rather than CO_2 as the main by-product due to the pyrolysis process, would add a further 45 kt of low-emission hydrogen production.

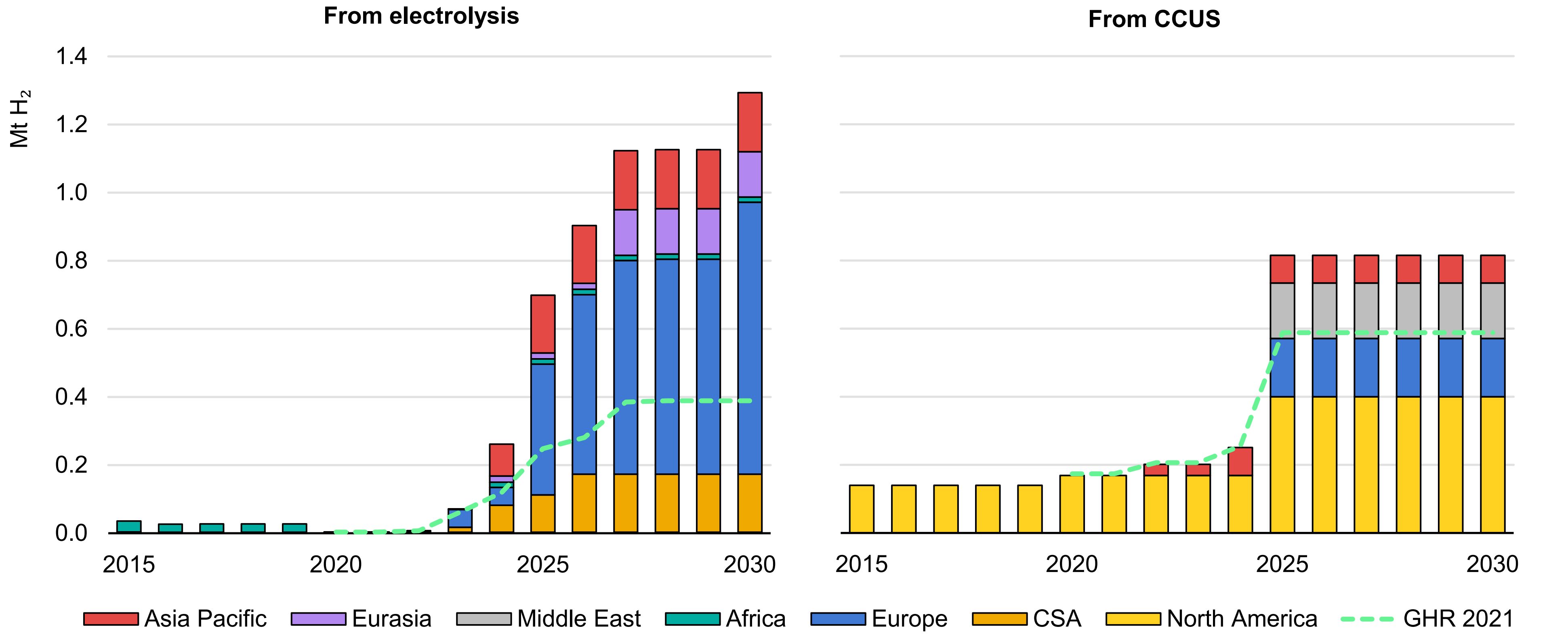
The difference between capacity and production is crucial: hence the difference between total production and true low-emission production. Projecting forward capacity factors specific to each technology leads to an estimated 1.3 Mt of low-emission hydrogen production from the project portfolio by 2030.[14] This is significantly lower than the total project portfolio capacity, and equivalent to about 4% of the hydrogen required for total global ammonia production today.

Unlike CCUS and pyrolysis technologies, switching to production via electrolysis can lead to reductions in fossil fuel demand – an important energy security goal under the current geopolitical circumstances for some countries, alongside the concomitant climate benefits. If realised, the estimated low-emission production from the electrolysis project portfolio for ammonia could displace 540 petajoules (PJ) of fossil fuel consumption by 2030, assuming best available technology energy performance and that all of the electricity required is sourced from new non-fossil fuel generation. This would be equivalent to nearly 15 bcm of natural gas, or around 10% of the quantity the European Union imported from Russia in 2021.

To achieve cost parity with natural gas-based production at current natural gas prices (as high as USD 40/MBtu in Europe in mid-2020), the electrolysis route would need electricity at the same capacity factor at around USD 100 per megwatt-hour (MWh). While this is very high compared to long-run prices for electricity, the prices seen in European countries in recent months have regularly surpassed this level. This is in part because natural gas is the price-setting fuel in the electricity markets of many European countries. Despite lower capacity factors than grid electricity, captive solar PV and wind electricity generation, with the necessary storage and flexibility requirements, could offer the potential for a cost-competitive move away from natural gas.

[14] This could increase to 2.4 Mt H_2 if projects at a very early stage of development are included, e.g. only a co-operation agreement among stakeholders has been announced.

Operational and planned low-emission hydrogen production capacity for ammonia by technology and region, 2015-2030



Notes: CCUS = carbon capture, utilisation and storage; CSA = Central and South America; GHR 2021 = Global Hydrogen Review 2021. Projects producing ammonia explicitly for use as an energy carrier are not included. Hydrogen produced from fossil fuels where the captured CO_2 is utilised for producing urea is not included. Only projects with a disclosed start year for operation are included. Projects at a very early stage of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included. GHR 2021 shows the estimated production of low-emission hydrogen from projects that were available in the IEA Hydrogen Projects Database as of August 2021.

Sources: IEA analysis based on data from the International Fertilizer Association and IEA Hydrogen Projects Database (2022).

Low-emission hydrogen projects for methanol are still at an early stage

Methanol – the second-largest industrial hydrogen application – is used mainly as an intermediate product to produce other chemicals. Formaldehyde is its largest-volume derivative, which is used to produce resins used by the construction, automotive and consumer goods industries. Several fuel applications, either using methanol directly or after conversion to another compound, are also important (e.g. methyl-tert-butyl ether). In China, methanol serves as an intermediate in the production of high-value chemicals (key chemical precursors for making plastics) from coal, an alternative to conventional oil-based routes.

Around 130 kg hydrogen is required as feedstock per tonne of methanol. The 113 Mt methanol produced in 2021 globally led to around 15 Mt of hydrogen demand, and virtually 100% of this production was from fossil fuels. One tonne of methanol production generates 2.2 tonnes CO_2 on average with coal-based production, which is dominant in China, accounting for around half the global total. This is significantly more emissions-intensive than the natural gas-based production, which is dominant in the rest of the world. Similarly as for ammonia production and the rest of the chemical industry, the emissions intensity of methanol production must decline substantially in the coming years, if countries are to fulfil their climate pledges.

Two key technology families can achieve low-emission methanol production: electrolysis and the use of CCUS.[15] These routes reduce emissions from the production of hydrogen as feedstock, which accounts for the vast majority of the CO_2 generated. Alongside hydrogen, the carbon in methanol is also sourced from the fossil fuel feedstock used to produce it. The utilisation of CO_2 (and carbon monoxide) in the process is inherent to the next step in the process of methanol production after the hydrogen is generated. If the methanol (or its derivative product) is combusted or otherwise oxidised during use or disposal, this results in fossil fuel-related CO_2 emissions. Given that it is not possible to track the precise fate of all methanol and its derivatives, the utilisation of CO_2 to produce methanol is not counted as low-emission methanol production unless the CO_2 is of biogenic or atmospheric origin.

The project portfolio for low-emission hydrogen production capacity for methanol has increased only modestly over the last year in absolute terms. Electrolysis capacity projected to be online by 2030 nearly tripled, but in absolute terms the total volume (0.23 Mt H_2) is

[15] See Explanatory notes Annex for low-emission methanol definition in this report.

still relatively small.[16] Virtually all of this electrolysis capacity is planned in Europe and the Asia Pacific region, with one very small project planned in the Central and South America region. Key projects using low-emission hydrogen to produce methanol that have been added to the 2022 project database include: European Energy project in the Port of Aabenraa (17 kt hydrogen capacity and with a with a contract in place for suppling the electrolysers); Vicat Montalieu-Vercieu cement plant in France (57 kt hydrogen capacity); Antofagasta Mining Energy Renewable in Chile (14 kt hydrogen capacity); Vordingborg Biofuels project in Denmark (19 kt hydrogen capacity); and China Coal Ordos Energy and Chemical project (19 kt hydrogen capacity).

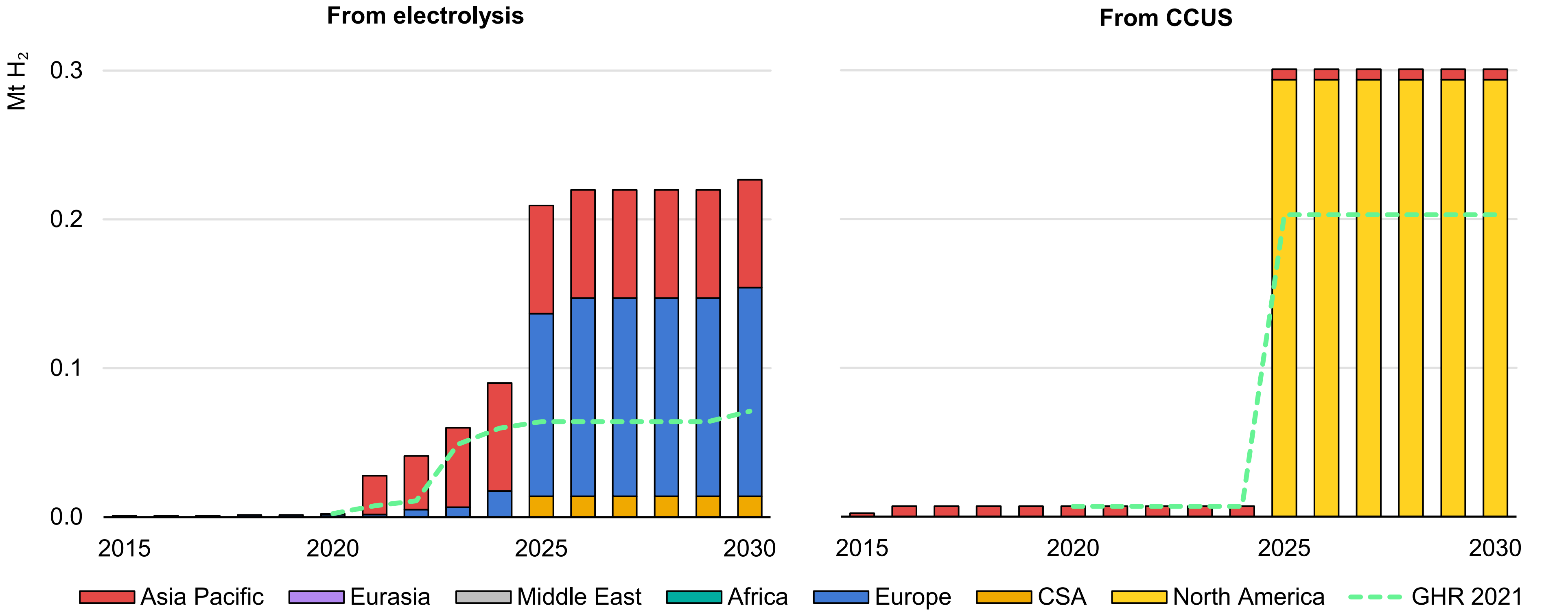
The CCUS project portfolio looks set to deliver nearly 0.3 Mt of low-emission hydrogen capacity for methanol production by 2030. However, the CCUS-equipped portion is highly dependent on the outcome of a couple of projects, the Lake Charles Methanol project in Louisiana (United States), 0.2 Mt H_2, and Nauticol Blue Methanol in Alberta (Canada), 0.1 Mt H_2. Several comparatively small volume projects are planned in Europe.

These projections account for capacity factors specific to both the electrolysis and CCUS-equipped projects and includes the share of low-emission electricity used in the electrolysers. While an encouraging start, the project portfolio for low-emission hydrogen for methanol production is still at an early stage, relative to the total volume of hydrogen used for methanol production globally (15 Mt in 2021).

The electrolysis pathway for methanol production can lead to reductions in fossil fuel demand, as in ammonia production. However, given the relatively small volumes of natural gas-based methanol capacity in Europe (around 2 Mt), there is relatively limited scope to displace natural gas consumption in the region. If realised, the estimated low-emission production from this project portfolio – only around half of which is planned in Europe – could displace 2.5 bcm of natural gas consumption by 2030, assuming the additional electricity demand is not supplied by natural gas. It is only captive generation supplied by non-fossil electricity sources, with the necessary storage and and/or other sources flexibility required, that can provide the de-coupling with fossil fuel prices necessary for the electrolysis pathway to achieve cost competitiveness with natural gas-based production.

[16] This could increase to 0.3 Mt H_2 if projects at a very early stage of development are included, e.g. only a co-operation agreement among stakeholders has been announced.

Operational and planned low-emission hydrogen production capacity for methanol by technology and region, 2015-2030

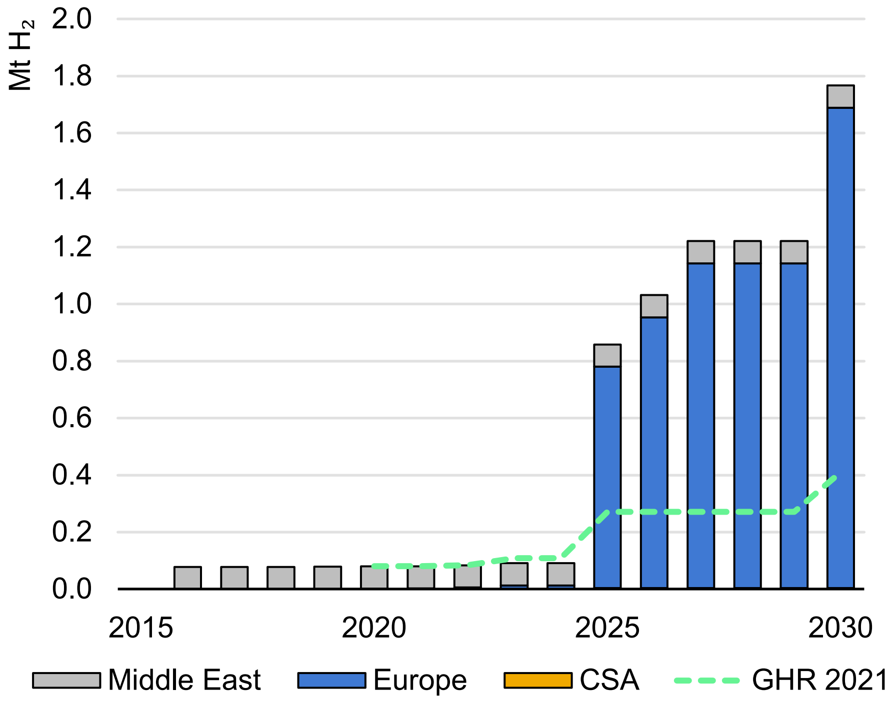


Notes: CCUS = carbon capture, utilisation and storage; CSA = Central and South America; GHR 2021 = Global Hydrogen Review 2021. Only projects with a disclosed start year of operation are included. Projects at a very early stage of development, such as those in which only a co-operation agreement among stakeholders has been announced are not included. GHR 2021 shows the estimated production of low-emission hydrogen from projects that were available in the IEA Hydrogen Projects Database as of August 2021.

Source: IEA Hydrogen Projects Database (2022).

Low-emission hydrogen for steel manufacturing

Operational and planned low-emission hydrogen production capacity for steel making by region, 2015-2030



Notes: CSA = Central and South America; GHR 2021 = Global Hydrogen Review 2021. All projects included produce hydrogen through water electrolysis. Only projects with a disclosed start year of operation are included. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders have been announced are not included. GHR 2021 shows the estimated production of low-emission hydrogen from projects that were available in the IEA Hydrogen Projects Database as of August 2021.

Source: IEA Hydrogen Projects Database (2022).

Ammonia and methanol production are two demand segments for which low-emission hydrogen offers the largest potential to substitute existing emissions-intensive industrial hydrogen production. But hydrogen also offers the potential to mitigate industrial CO_2 emissions with other industrial applications. For instance, hydrogen can be used to replace fossil fuels in steelmaking, along with a variety of heating applications across all sub-sectors that deliver emissions reduction. New industrial hydrogen applications should be considered selectively, given the availability of other potentially cheaper and more efficient emissions mitigation options, particularly in the case of low- or medium-temperature heating applications.

The production of DRI in the steel industry is an avenue for hydrogen applications using both existing and new process technology. Conventional DRI technology uses a mixture of carbon monoxide and hydrogen – all generated from fossil fuels – to chemically reduce iron ore for steel making. Accounting for around 5 Mt of industrial hydrogen demand today, DRI already constitutes a significant opportunity to reduce emissions associated with existing industrial applications. One DRI project with CCUS launched in 2016 – the Al Reyadah carbon capture project in the United Arab Emirates – produces an estimated 70 kt annually of low-emission hydrogen. It demonstrates promising potential and commercial scale operation;

however, it is the only project of its type in operation today. No similar projects of this scale are under development.

Hydrogen produced via electrolysis can also be used to reduce emissions from existing steel production processes. It can be blended into conventional DRI units, substituting natural gas and coal with only minor modifications to the equipment, depending on the furnace design and the desired blending rate. Hydrogen can also be blended for use in existing blast furnaces, although the maximum rate achievable of 30% is currently thought to be substantially lower than for existing DRI furnaces.

Full hydrogen-based DRI production, i.e. targeting no, or very little use of natural gas, even if a larger quantity is used in the interim, is at a comparatively early stage in its development relative to other technologies and projects described. HYBRIT, a leading project in this category, produced its first few tonnes of steel in 2021. The project portfolio suggests that 1.8 Mt of low-emission hydrogen capacity for DRI production will be online by 2030, if all planned projects achieve their announced targets on time.

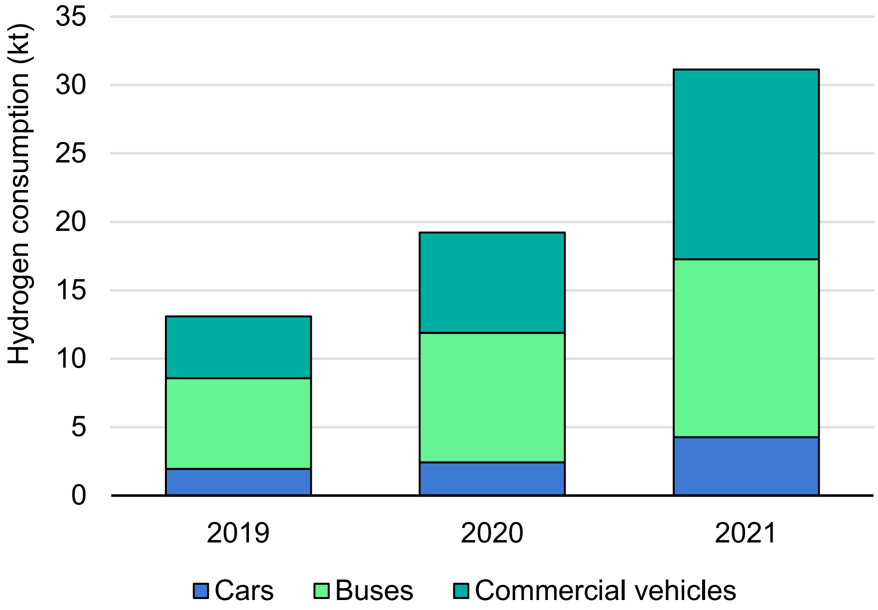
In addition to the continued development of HYBRIT, other project announcements over the last year include:

- Start of building works at the H2GS project at Boden (Sweden) (139 kt hydrogen capacity).
- FID reached for the SALCOS project (Germany) developed by Salzgitter (136 kt hydrogen capacity).
- GravitHy project in France (120 kt hydrogen capacity).
- Joint project of Air Liquide and Arcelor Mittal in Dunkirk (France) (69 kt hydrogen capacity).
- AM Gent H_2 consumption hub in Belgium (90 kt hydrogen capacity).
- HyDeal España (Spain) project to provide hydrogen to a number of industries (total 780 kt hydrogen capacity) including an ArcelorMittal steel manufacturing facility.

Transport

Hydrogen demand in road transport has increased 60% since 2020

Hydrogen consumption in road transport by vehicle segment, 2019-2021



Note: Commerical vehicles include light commercial vehicles, medium-duty trucks and heavy-duty trucks.

Hydrogen demand in transport totalled over 30 kt in 2021, more than 60% higher than the previous year. As a share of total hydrogen demand, however, transport represents only 0.03%, and as a share of total transport energy, hydrogen represents only 0.003%.

Road vehicles, by far, are the major source of hydrogen demand in transport. Most of this is consumed in trucks and buses due to their high annual mileage and heavy weight relative to the larger stock of fuel cell electric cars. The number of heavy-duty hydrogen trucks increased significantly in 2021 (up over 60-fold from 2020), as has the estimated hydrogen demand from commercial vehicles, i.e. vans and trucks. In 2021, hydrogen demand for commercial vehicles exceeded that from buses for the first time, reaching 45% of total hydrogen demand in the transport sector.

The successful trials of hydrogen-fuelled passenger trains in Germany led to the deployment of the first fuel cell train fleet (14 trains) in Lower Saxony in August 2022. Interest is growing around the world. Other countries are performing their own trials. Hydrogen offers a solution to decarbonising diesel rail lines where electrification is difficult and the distances are too far to be covered by battery electric trains.[17] Given the limited deployment of hydrogen trains, hydrogen consumption for rail was less than 0.1 kt in 2021.

[17] See Future of Rail (IEA, 2019) for more on the competitiveness of fuel cell technologies for rail.

However, based on industry announcements, hydrogen's role in rail transport is expected to rise in the near term.

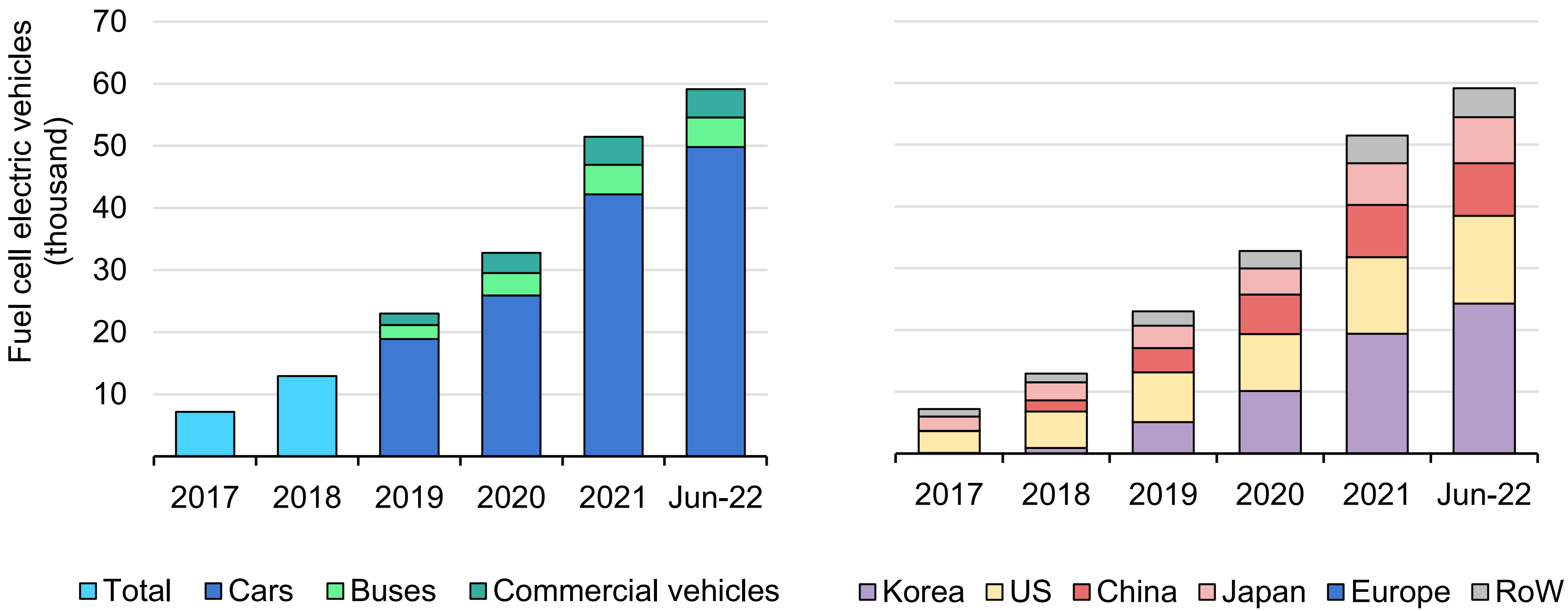
Interest is also increasing in the use of hydrogen and hydrogen-derived synthetic fuels in the maritime and aviation sectors, though the technologies are less mature than those for road and rail. There are a number of projects and orders for vessels that can operate on hydrogen, ammonia and methanol that will be realised in the coming decade. There are also a number of companies, including Airbus, that are developing hydrogen-fuelled aircraft, though commercialisation will likely take place after 2030. Similarly, the use of hydrogen-derived synthetic fuels for aviation is not expected to make inroads in the short term.

Hydrogen demand in transport in the Stated Policies Scenario reaches 0.7 Mt by 2030.[18] Most of this demand is for road transport, especially as hydrogen trucks are deployed. In the STEPS, there is only a small penetration of hydrogen in other transport modes, primarily shipping (as both hydrogen and hydrogen-derived fuels). Hydrogen demand in transport in the Announced Pledges Scenario reaches almost 8 Mt by 2030, of which over 60% is in shipping.

[18] This value includes demand for the direct use of hydrogen in transport and hydrogen demand to produce derived fuels, such as ammonia and synthetic hydrocarbons, that are used in transport.

Stock of fuel cell electric vehicles exceeded 50 000 in 2021

Fuel cell electric vehicle stock by segment and region, 2017-June 2022



Note: US = United States; RoW = rest of world.

Sources: Advanced Fuel Cells Technology Collaboration Programme; California Fuel Cell Partnership; International Partnership for Hydrogen and Fuel Cells in the Economy; US Department of Energy Hydrogen and Fuel Cell Technologies Office; Korea's Ministry of Trade, Industry and Energy monthly automobile updates; Clean Energy Ministerial Hydrogen Initiative country surveys.

Expansion of hydrogen and fuel cells for road vehicles

Recent developments

In 2021, the stock of FCEVs was over 51 000, a more than 55% increase from end-2020.[19] In 2021, there was impressive growth in Korea, which almost doubled the stock of fuel cell electric cars with the addition of more than 9 200 FCEVs over the year, representing more than 0.5% of car sales. While small, this is more than ten-times the fuel cell electric car sales share in Japan and almost 30-times the sales share in the United States, the only two other countries with more than 1 000 fuel cell electric cars sold in 2021.

By end-June 2022, the global stock of FCEVs was more than 59 000, a 15% increase from end-2021. In general, expansion in the FCEV stock is primarily for fuel cell electric cars. More than 1 800 fuel cell electric cars were registered in California in the first-half of 2022, roughly equal to the number registered in the first-half of 2021. In Korea, sales in the first-half of 2022 totalled almost 4 900, with 1 270 fuel cell electric cars sold in May alone.

China continues to dominate in hydrogen use in the heavy-duty vehicle transport segment. It accounts for over 85% of the world's fuel cell buses with more than 4 100 on the road[20] and over 95% of all fuel cell trucks with more than 4 300 at end-2021.[21] In particular, there was strong growth in heavy-duty fuel cell trucks in China, with about 800 deployed in 2021.[22] This expansion continues in 2022 as FAW Jiefang delivered 300 fuel cell trucks in June, including cargo, dump and tractor models.

The market for fuel cell trucks is expected to continue to expand outside of China. Policies such as the California's Advanced Clean Truck regulation and the Global Memorandum of Understanding on Zero Emission Medium- and Heavy-Duty Vehicles, signed by 16 countries and endorsed by a number of industry stakeholders, puts pressure on truck manufacturers to increase their offerings of zero emissions trucks. In Europe, H2Accelerate was launched in late 2020 as a collaboration between hydrogen producers, infrastructure operators and vehicle manufactures to enable the use of hydrogen in long-haul heavy-duty trucking across Europe.

[19] For comparison, at end-2021 there were almost 18 million electric vehicles (excluding two/three-wheelers) on the road. The percentage increase in electric vehicles from 2020 to 2021 was similar to that observed for FCEVs, slightly above 55%.
[20] There were over 4 700 fuel cell buses on the road worldwide at end-2021. The stock of electric buses is two orders of magnitude larger at more than 670 000 on the road at end-2021.
[21] At end-2021, there were about 4 500 fuel cell trucks worldwide and over 66 000 electric trucks. China dominates the electric truck market with about 70% of the global stock.
[22] Heavy-duty trucks are defined as commercial vehicles with a gross vehicle weight over 15 tonnes. Medium-duty trucks have a gross vehicle weight between 3.5-15 tonnes.

Industry announcements

Industry announcements indicate that the market for hydrogen-powered vehicles is poised to expand over the next decade in all road segments.

Cars

- In June 2021, Jaguar Land Rover announced testing of a prototype passenger fuel cell vehicle, as part of a project partially funded by the UK government.
- Changan launched a fuel cell version of their large sedan model in July 2022, the first mass-produced hydrogen fuel cell car in China.
- BMW aims to produce a small series of the iX5 Hydrogen fuel cell vehicle by end-2022, after successfully completing winter weather testing.
- Great Wall Motors is expected to launch a luxury brand focussing on hydrogen fuel cell passenger cars by end-2022.
- Riversimple unveiled a prototype hydrogen fuel cell car in February 2022.
- Renault announced an electric concept car with a hydrogen fuel cell range extender, which is expected to debut in 2024.

Vans and other light commercial vehicles

- Hyundai continue to increase its range of available FCEV models and plans to introduce a fuel cell multi-purpose vehicle.
- Several Stellantis brands including Citroën, Peugeot and Opel are introducing hydrogen light commercial vehicles, which are expected to be available in 2023.
- Hino Motors, Isuzu, Toyota and Commercial Japan Partnership Technologies Corportation have announced a plan to jointly develop light-duty commercial trucks.

Buses

- Kansai Airport (Japan) launched a hydrogen fuel cell shuttle bus service in 2022.
- In September 2022, Solaris announced plans to unveil an 18-metre fuel cell bus with the first deliveries scheduled for the second quarter of 2023. Since 2019, Solaris has delivered nearly 100 of their 12-metre fuel cell buses to European customers.
- Wrightbus will supply up to 60 fuel cell buses to the City of Cologne (Germany), and Solaris will provide up to a further 20 fuel cell buses with deliveries beginning in 2023.
- The United Kingdom's West Midlands will deploy 124 new fuel cell buses, adding to the existing fleet of 20 buses.

Trucks

- Nikola delivered two Tre heavy-duty hydrogen fuel cell trucks to Anheuser-Busch in the United States in February 2022 for daily service for a three-month pilot test.
- SINOTRUK and Weichai unveiled China's first heavy-duty truck powered by a hydrogen internal combustion engine in June 2022.

- Hyundai plans to deploy 30 heavy-duty fuel cell trucks at the Port of Oakland (United States) in 2023.
- Symbio, along with other partners, has been selected to produce a heavy-duty long-haul fuel cell truck for a California Energy Commission project expected to begin in 2023.
- Hyzon signed a memorandum of understanding with TotalEnergies, including the expectation to provide 80 fuel cell trucks to their customers in France by 2023.
- Hyundai Motor has deployed 47 XCIENT fuel cell heavy-duty trucks in Switzerland as of July 2022, which have accumulated over 4 million km in driving experience; total deployment of 1 600 trucks by 2025 is planned.
- Diamler Truck North America and Cummins are collaborating on a heavy-duty fuel cell truck, with initial units expected to be available in 2024 for select customers.
- R'HySE project to deploy 50 hydrogen trucks in the south of France in 2024-2025.
- Hyundai signed a memorandum of understanding with Shanghai Electric Power, Shanghai Sunwise New Energy System and Shanghai Ronghe Electric Technology Financial Leasing that aims to supply 4 000 fuel cell trucks to China by 2025.
- The HyTrucks initiative aims to develop 25 hydrogen refuelling stations and deploy 1 000 hydrogen trucks in Belgium, Germany and Netherlands by 2025.
- Hyzon Motors, in a partnership with Hiringa Energy, plan to deliver 1 500 heavy-duty fuel cell trucks in New Zealand by 2026.
- Daimler Truck/Mercedes-Benz GenH2 liquid hydrogen truck, said to offer a range of 1 000 km, is projected to begin series production in 2027.

Heavy-duty fuel cell electric truck models, 2022

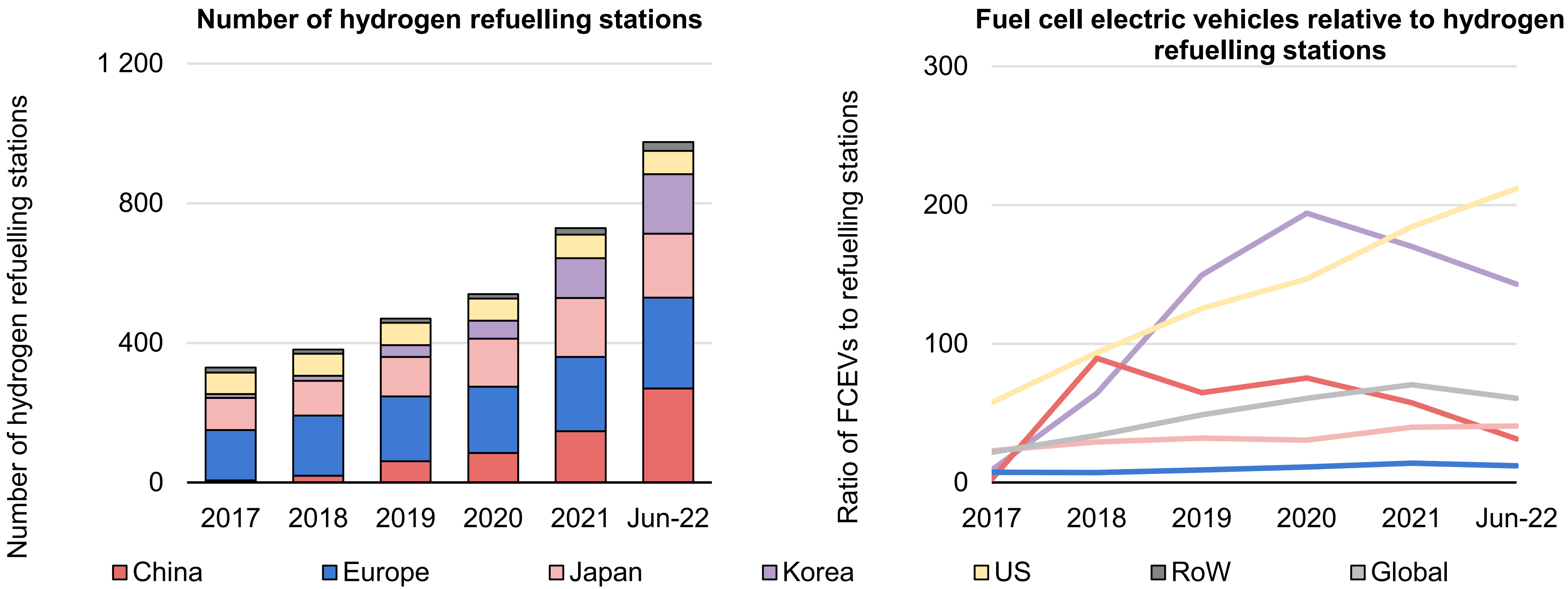
Make	Model	Range (km)	Year available
Hyundai	XCIENT	400	2019
Hyzon	Hymax	400-680*	2021
Hyzon	FCET 8	800	2021
Dayun	E8	310	2021
Dayun	E9	430	2021
Skywell	TP11	500	2021
FAW	J7	700	2022
Feichi	FSQ4250	500	2022
King Long	KLQ4250FCEV3	510	2022
SAIC	CQ1180FCEVEQ		2022
Shaanxi	X5000		2022
Dongfeng	LZ5180	460	2022
Hyundai	HDC-6	1 280	2023
Kenworth	T680	480	2023
Nikola	Tre	800	2023
Nikola	Two	1 450	2024

* Ranges given for the 24-, 46-, and 70-tonne configurations.

Source: CALSTART (2022), Drive to Zero's Zero-emission Technology Inventory (ZETI) Tool Version 7.0

Infrastructure for hydrogen use in transport is expanding – more than 700 hydrogen refuelling stations in operation at end-2021

Hydrogen refuelling stations by region and ratio of fuel cell electric vehicles to refuelling stations, 2017-June 2022



Note: FCEV = fuel cell electric vehicle; US = United States; RoW = rest of world.
Sources: Advanced Fuel Cells Technology Collaboration Programme, International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE), Clean Energy Ministerial (CEM) Hydrogen Initiative (H2I) country surveys.
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The number of hydrogen refuelling stations (HRS) around the world surpassed 700 at end-2021 and reached 975 by the end of June 2022.[23] The largest increase in HRS stock since 2020 has been in China (+185) and Korea (+118). In Korea, the ratio of FCEVs to HRS peaked in 2020 at almost 200, and has since declined to about 140 FCEVs per HRS. In China, the ratio of FCEVs per HRS has declined due to the rapid deployment of refuelling stations, reaching about 30 in June 2022. In the United States, the deployment of FCEVs has outpaced that of HRSs in recent years, making the US ratio the highest at over 200 FCEVs per HRS. Worldwide, there are about 60 FCEVs per HRS.

Given that over 80% of FCEVs at the end of 2021 were cars, the majority of refuelling stations outside of China, are configured to dispense hydrogen at 700 bar for passenger light-duty vehicles. Buses store hydrogen at lower pressures, so some stations are dual pressure, able to dispense at 700 (for cars) or 350 bar (for buses), while other stations only dispense at 350 bar (for buses and other commercial vehicles).

As hydrogen trucks are rolled out, there is a need to develop stations that can dispense hydrogen at 700 bar but at faster flow rates than the current light-duty vehicle refuelling stations. Hydrogen trucks have storage tanks with combined capacity around 8- to 12- times that of light-duty vehicle tanks. So, with current technology, the fill time is also that much longer for trucks. Both government and industry stakeholders are working to develop technologies and protocols for high-throughput heavy-duty hydrogen refuelling.

As part of the collaborative European H2Haul project, in September 2022 Air Liquide is slated to begin operation of a 1 tonne/day dual pressure hydrogen refuelling station that can serve both cars and trucks. While currently limited to flow rates of around 60 grammes per second (g/s), similar to refuelling stations for light-duty vehicles, once new nozzles are available in 2023-24, the station will be upgraded to achieve flow rates two- to three-times higher. As part of the R'HySE project, Air Liquide is planning to open three 2 tonne/day heavy-duty truck refuelling stations in the south of France in the 2024-25 timeframe.

In the United States, the National Renewable Energy Laboratory, as part of a project funded by the US Department of Energy (US DOE), Air Liquide, Honda, Shell and Toyota, built a heavy-duty truck hydrogen refuelling station. In a recent test, they surpassed the US

[23] For reference, there were over 1.7 million public electric vehicle chargers globally at the end of 2021. However, the number of public electric vehicle chargers is not directly comparable to the number of hydrogen stations.

DOE target flow rate for heavy-duty truck hydrogen refuelling, reaching an average mass flow rate of 14 kilogrammes per minute.

Some governments are starting to promote the development of hydrogen refuelling networks. In 2020, the Auvergne-Rhône-Alpes Regional Council (France) started the Zero Emission Valley (ZEV) project, with the objective of deploying 20 HRS to serve 1 200 vehicles by end-2023. In March 2022, the New South Wales, Victoria and Queensland regional governments (Australia) launched a hydrogen highways initiative, with the objective of developing a renewable hydrogen refuelling network for heavy transport and logistics along Australia's eastern seaboard by 2026.

Ports are particularly well suited to become hydrogen hubs and a number are beginning to integrate hydrogen infrastructure to support heavy-duty trucks, cargo handling and other port equipment, and maritime vessels. CMB.TECH opened the world's first multimodal hydrogen refuelling station at the Port of Antwerp (Belgium) in 2021. Air Products is building an HRS for trucks at the Port of Rotterdam (Netherlands), which is expected to be operational in 2023. Shell built two high-capacity HRSs with the Port of Los Angeles (United States) to supply to heavy-duty trucks developed by Toyota and Kenworth.

As interest in hydrogen for maritime vessels increases, bunkering technology to fuel the vessels will become more important. In November 2021, the first hydrogen fuelling of a commercial maritime vessel was completed in the United States, using technology that enables fuelling directly from a hydrogen truck. The same month, Unitrove unveiled what is said to be the first liquid hydrogen bunkering facility. In 2022, Yanmar Power Technology completed a high-pressure (700 bar) hydrogen refuelling of a ship based on Toyota's Mirai system in efforts to increase the cruising time and hence the viability of the technology application.

In March 2022, the European Commission released a call for proposals for a large-scale demonstration of hydrogen fuel cell propelled inland waterway vessels. The demonstration is to include hydrogen bunkering at two ports and "preferably" a hydrogen bunker barge to fuel the demonstration vessels while in transit, at anchorage or moored at a pier.

Hydrogen demand in non-road transport

Rail

Hydrogen use in passenger rail is beginning to take off, especially in Europe. Alstom's Coradia iLint is the world's first mass-produced passenger train powered by hydrogen fuel cells. Between 2018 and 2020, field trials of the first two pre-series trains covered over 180 000 km of regular passenger service in Germany. Trials have also taken place in Austria, France, Netherlands and Sweden. Trials by a different company in Spain and another in Japan have also taken place, plus China has developed and tested a locomotive powered by fuel cells.

The success of the hydrogen fuel cell train trials in Lower Saxony (Germany) underpinned the move by its public transport operator to proceed with plans to replace all diesel trains on that line with hydrogen. In August 2022, the first hydrogen fuel cell train fleet started operation with 14 Coradia iLint series trains delivered by Alstom as part of the 41 trains ordered in Germany. Italy ordered six Alstom hydrogen fuel cell trains, and France has placed an order for 12 dual-mode trains (electric/catenary and hydrogen/fuel cell traction). Polish PKN Orlen signed an agreement with Alstom in which it will be responsible for the supply and distribution of hydrogen and Alstrom will supply the trains. Their first hydrogen trains are expected to roll out on regional lines within two years.

In addition to Alstom, Siemens Mobility has developed a hydrogen-powered passenger train and mobile hydrogen storage trailer. Siemens stated they will begin testing their train in mid-2023 with full service in Germany scheduled for January 2024. Stadler has also unveiled their hydrogen-powered passenger train which is expected to enter service in California in 2024.

Alstom and Engie have partnered to bring hydrogen to European rail freight. Australia's largest rail freight operator, Aurizon, and mining company Anglo American have an agreement to conduct a feasibility study into using hydrogen-powered trains for bulk freight. Fortescue Future Industries, part of Fortescue Metals Group, has been testing zero emissions locomotives, including the successful combustion of blended ammonia fuel in a two-stroke locomotive. Further testing and demonstrations planned for 2022 will support Fortescue's aim to decarbonise their mining fleets.

Mining

Anglo American unveiled their prototype hydrogen-powered mine haul truck in South Africa in May 2022, capable of carrying a 290 tonne payload. The following month, Anglo American announced a deal with First Mode engineering company to retrofit Anglo American's fleet of 400 haul trucks to hybrid battery/hydrogen fuel cell power.

In Chile, the Hydra consortium is working to pilot a stationary mining truck prototype, which if successful as a proof of concept, will lead to the conversion of a 2 MW mining truck from diesel to hydrogen by around 2023. It has been estimated that such a truck would have daily hydrogen consumption of 800-1 000 kg.

Australia's Fortescue Metals Group has also begun testing a hydrogen-powered haul truck, with roll-out anticipated in the second-half of this decade. In December 2022, Hyzon Motors is expected to deliver five 140 tonne-rated fuel cell electric trucks for short-haul transport of zinc concentrate and ingots between a port and a zinc refinery in Australia.

Material handling equipment

In 2022, more than 50 000 fuel cell material handling equipment (MHE) units are in service in the United States, an increase of about 10 000 from the previous year. An estimated 25 tonnes/day (9 kt in 2021) of hydrogen are required to power this stock of fuel cell MHE units. Plug Power is the major player in the US market and has provided fuel cell MHEs to several companies, including Walmart with which Plug Power recently signed an agreement to provide renewable hydrogen to fuel their fleet of 9 500 fuel cell forklifts.

In other countries, the level of MHE unit deployment is much lower. In Japan, fuel cell forklifts total only about 400, though this is about a 20% increase over 2020. Both Canada and France have about the same volume stock as Japan.

In Korea, Hyundai entities are working together to develop hydrogen-powered forklifts and medium and large excavators, with mass production targeted for 2023. In April 2022, heavy equipment manufacturer Doosan Bobcat signed a memorandum of understanding for a joint venture between Korea's SK E&S and US Plug Power to develop and supply hydrogen forklift trucks.

British construction equipment manufacturer JCB has developed a prototype backhoe loader powered by a hydrogen combustion engine. They have also unveiled a hydrogen-powered loadall telescopic handler that can serve the construction industry and farms.

Agricultural equipment is another area where hydrogen or hydrogen-based fuels could play a role in decarbonisation. H2Trac is expected to deliver a hydrogen-fuelled tractor to a farm in the Netherlands in 2022. In 2019, the University of Minnesota (United States) successfully demonstrated a duel-fuelled (diesel and ammonia) tractor. In 2022, a John Deere tractor was modified to run on liquid ammonia using fuel cells.

Cargo handling equipment

In addition to maritime applications, ports are considering using hydrogen fuel cells to power port equipment to reduce emissions and air pollution. At the end of 2021, the world's first hydrogen fuel cell-powered mobile crane was deployed at the Port of Shanghai (China). In Japan, aligning with the government's Carbon Neutral Port Initiative, a fuel cell rubber tyre gantry crane is expected to be introduced at the Kobe International Container Terminal in 2022. In the United States, a fuel cell rubber tire gantry crane is expected to be delivered to the Port of Los Angeles for feasibility testing, aiming for operation from the second-half of 2024.

The Port of Valencia (Spain), as part of the H2PORTS project, will test a fuel cell reach stacker and a terminal tractor. After successful testing of a hydrogen forklift truck and terminal tractor in 2021, Antwerp Euroterminal (Belgium) is planning the commercial introduction of a hydrogen-powered terminal tractor in 2023. To contribute to the decarbonisation goals of the Port of Hamburg (Germany), the H2LOAD project is planning the operation of more than 100 fuel cell vehicles, including empty container stackers in addition to trucks and van carriers.

Hydrogen fuel cell technologies have also been developed for ground support equipment at airports. Plug Power developed fuel cell cargo tow tractors that have been tested at the Albany International Airport (United States) and Hamburg Airport (Germany)

Shipping

The Getting to Zero Coalition notes numerous ongoing pilot and demonstration projects, of which about 45 focus on hydrogen, 40 on ammonia and 25 on methanol use in shipping. The majority of hydrogen projects focus on small vessels, ammonia projects on large vessels, and methanol projects split between both. In terms of ship orders for new builds, 66 orders were placed for ammonia-ready vessels, three for hydrogen-ready vessels and five for methanol-fuelled vessels in the first-half of 2022.

In terms of vessel deployment, a 75-passenger hydrogen-fuelled fuel cell ferry, Sea Change, was expected to start carrying passengers across the San Francisco Bay (United States) in June 2022. However, the launch has been delayed by the lack of existing regulations and approval from the US Coast Guard. Similarly, the MF Hydra, a liquid hydrogen-powered ferry, delivered in July 2021, is still awaiting approval from the Norwegian authorities and DNV to begin operation. Once launched, the MF Hydra will carry up to 300 passengers and 80 cars. In France, the EU Flagships project has completed construction of the world's first hydrogen-powered fluvial cargo vessel, expected to begin operation in September 2022. The Hydrocat 48, a dual-fuelled hydrogen and marine gas-oil crew boat, is scheduled to operate from July 2022 to the end of the year as part of a pilot programme in the Belgian North Sea. The launch of a dual-fuelled (hydrogen and diesel) tugboat is expected at end-2022 and to be used by the Antwerp Port Authority (Belgium) for daily operations.

The Norwegian government's plan to reduce emissions from domestic shipping by 50% by 2030 has led to a commitment to build five hubs to produce hydrogen and provide the infrastructure to fuel 35-40 ships. A contract has been awarded to a Norwegian ferry builder and operator for the construction and operation of two hydrogen-powered ferries, expected to launch in late 2025 for a hydrogen-fuelled bulk carrier in the North Sea in 2024.

In Germany, testing has begun of a hydrogen-fuelled push boat, which is expected to enter operation in 2023. Canada is planning to launch its first hydrogen-fuelled recreational harbour cruise boat.

To enable hydrogen and for hydrogen-based fuels to be taken up in the international shipping sector, safety codes, standards and other regulations need to be further developed to specifically address the use of these fuels. In April 2022, the International Maritime Organisation's (IMO) Maritime Safety Committee approved interim guidelines for the safety of ships using fuel cell power installations. For fuel storage and fuel supply to the fuel cells, the International Code of Safety for Ships Using Gases or Other Low-Flashpoint Fuel (IGF Code), originally written considering liquified natural gas, can apply to hydrogen. However, specific guidelines could better facilitate wider adoption of hydrogen and hydrogen-based fuels in international shipping. For example, interim guidelines for the safety of ships using methanol were adopted in late 2020 and have allowed for its use.

Governments and industry are working towards ammonia-powered vessels, where ammonia appears better suited than hydrogen for large, deep sea, long-distance vessels. Enova has funded two deep sea ammonia-powered tankers and two car carriers. The NoGAPS project is producing a detailed design of an ammonia-powered carrier, while ITOCHU and several partners have launched a joint study into ammonia bunkering. In an EU-funded project, ShipFC is planning to install an ammonia fuel cell system in an offshore vessel in 2023 and will perform studies on the ability to use ammonia fuel cells in other vessel types.

As a near-term step to deploy ammonia-fuelled vessels, companies such as MAN Energy Solutions and Wärtsilä are working on dual-fuel engines capable of operating on diesel and ammonia fuel. Orders have been placed for these flexible fuel engines and are expected to be commercially available for large ocean-going vessels by 2024. Wärtsilä, by 2023, and Swiss-based engine developer, WinGD, by 2025, plan to develop engines to operate on pure ammonia. In addition, Japan is developing engines, fuel tanks and fuel supply systems for hydrogen- and ammonia-powered ships through its Green Innovation Fund.

In 2022 it was agreed that the IMO should add development of non-mandatory guidelines for safety of ships using ammonia as fuel to its work programme, with a target to submit for approval by 2023. A number of organisations have also announced a joint study framework for ammonia bunkering safety to promote the development of a safe fuel supply system and ammonia bunkering vessels.

Methanol has a higher technology readiness level than hydrogen or ammonia technologies for shipping. There are 56 methanol vessels in operation or on order (including dual-fuel). As a hydrocarbon fuel, it has a high energy density that makes it well suited for long-distance vessels. It is actively being pursued by companies including Maersk for large, long-distance container ships. Maersk has plans to introduce eight large ocean-going container vessels capable of being operated on carbon neutral methanol in 2024. Maersk is developing several strategic partnerships for methanol production for their vessels.

Different from hydrogen or ammonia, methanol is a liquid at room temperature and is much less toxic than ammonia. When made from renewable electrolytic hydrogen and sustainable sources of CO_2, referred to as synthetic methanol, it can constitute a pathway to decarbonise shipping in a similar way to hydrogen/ammonia. However, constraints on the availability of biogenic or direct air capture CO_2 feedstock at a reasonable cost make the competitive edge of synthetic methanol over low-emission ammonia uncertain. Similar constraints challenge the role of synthetic methane as a sustainable shipping fuel.

Aviation

Activity that will generate demand for hydrogen in aviation is concentrated in two sectors: the production of drop-in hydrogen-derived sustainable aviation fuel (SAF) and the development of hydrogen-powered aircraft for short- to medium-haul flights. Of the two, hydrogen-derived SAFs are much more mature with cost being the main barrier to deployment. Hydrogen-powered aviation is more challenging and the technologies are still at a relatively early stage of development.

In July 2022, the European Parliament markedly increased its ambition regarding aviation decarbonisation, amending the ReFuelEU Aviation proposal by the European Commission The amendments introduce a minimum share of 0.04% synthetic fuels by 2025 (compared with zero share in ReFuelEU) increasing to 2% by 2030 (0.7% in ReFuelEU), 13% by 2040 (8% in ReFuelEU) and 50% by 2050 (28% in ReFuelEU). If all the projects currently under development in the European Union are realised, by 2030 they could be producing more than 330 million litres of synthetic kerosene annually,[24] which would meet 0.5% of EU aviation fuel demand, lower than the 2% targeted by the most recent proposal of the European Parliament.

[24] This could increase to 390 million litres of synthetic kerosene if projects at a very early stage of development are included, e.g. only a co-operation agreement among stakeholders has been announced.

The first steps from the private sector have already been taken. Lufthansa and Atmosfair have signed an off-take agreement for 25 000 litres of synthetic kerosene per year. KLM has started using 0.5% SAF on flights departing from Amsterdam, although this also includes non-synthetic SAFs. The relatively high cost of SAFs means mandates like those in the European Union will likely still be needed to encourage widespread adoption.

TakeOff is an EU-funded project which aims to reduce the cost of CO_2 and renewable hydrogen-based SAF by 36% compared to other power-to-liquid processes. Demonstrations such as the Zenid project in the Netherlands aim to reduce the cost of SAF and produce them close to large existing kerosene trading areas.

For synthetic fuels to truly be sustainable, the CO_2 feedstock must also be sustainably sourced. In 2022, INERATEC commissioned a plant in Germany to produce 4.6 million litres of synthetic fuel including synthetic kerosene using biogenic CO_2 and renewable electricity. Sewage sludge in Germany is being explored as a source of CO_2 for the same reason.

A consortium that includes Uniper, Airbus, Siemens and Sasol – emerging experts in power-to-liquids – announced the Green Fuels

Hamburg project. It will use Fischer-Tropsch synthesis to produce 10 000 tonnes of synthetic kerosene from renewable hydrogen and biomass derived carbon.

Among the established airplane manufacturers, Airbus has the most ambitious programme for hydrogen-powered aircraft. The company aims to develop hydrogen-powered aircraft by 2035. Airbus launched the ZEROe demonstrator in 2022, which will receive support from the UK government and the European Union. Airbus is targeting not just the turboprop segment, but turbofan planes with a range of over 2 000 nautical miles, and novel blended wing aircraft better able to accommodate onboard hydrogen infrastructure.

Boeing remains more cautious than Airbus in terms of hydrogen, but in conjunction with the US National Aeronautics and Space Administration (NASA) conducted testing of a large cryogenic fuel tank in late 2021. Boeing has more focus on SAF than on hydrogen. Several smaller aviation companies are developing small- to medium-size hydrogen-fuelled aircraft that are expected to be tested in the mid-2020s. Building on the successful ground testing of their 600 kW hydrogen-electric powertrain, ZeroAvia will begin flight testing by converting one of two engines on a mid-sized aircraft to hydrogen-electric. They aim to continue testing and deploy a 100% hydrogen-fuelled aircraft by mid-2023, followed by full certification in 2024.

Universal Hydrogen has signed an agreement with regional air carrier Connect Airlines in Canada for 75 retrofitted aircraft to be operated on renewable hydrogen, with deliveries scheduled for 2025. A similar deal for three aircraft was made with Amelia in France.

Wright is also developing hydrogen-powered aircraft and is targeting the much larger the 100-passenger plane segment by 2026, specifically avoiding combustion technologies to maximise the environmental benefits.[25] Their focus is on air-aluminium batteries with much higher energy density that would allow the planes to serve a bigger share of the market, but which would need substantial recycling infrastructure.

Another company, Hypoint has a focus on developing fuel cells specifically for aviation applications with plans to deploy commercially by 2025. Their modular system integrates into existing aircraft from small fixed wing planes to large commercial airliners, though explicit progress towards this goal over the past year is unknown.

[25] Combustion also produces nitrogen oxides, water vapour and soot, each of which also has an impact on the climate, as explored in a study by McKinsey & Company for the Clean Sky 2 Joint Undertaking and Fuel Cells and Hydrogen JU.

Buildings

Hydrogen demand in buildings

Hydrogen accounts for a negligible share of energy demand in the buildings sector, with no significant increase from the previous year. Technologies that use natural gas for heating and cooking account for nearly one-fourth of worldwide energy demand in the buildings sector. In the context of the current energy crisis and national commitments to achieve net zero emissions, several countries are introducing bans on fossil fuel use in new buildings, e.g. France from 2022 and Austria from 2023. Some are making energy performance in building requirements more stringent, e.g. the revision of the Energy Performance of Buildings Directive in the European Union.

The general expectation is that to meet climate goals, current fossil fuel use in buildings will switch to low-carbon options such as electricity, district heat and distributed renewables, ahead of hydrogen technologies. A key reason is that when accounting for the energy losses associated with hydrogen conversion, transport and use, hydrogen technologies for use in buildings are much less efficient than other available options and also require new infrastructure and devices.

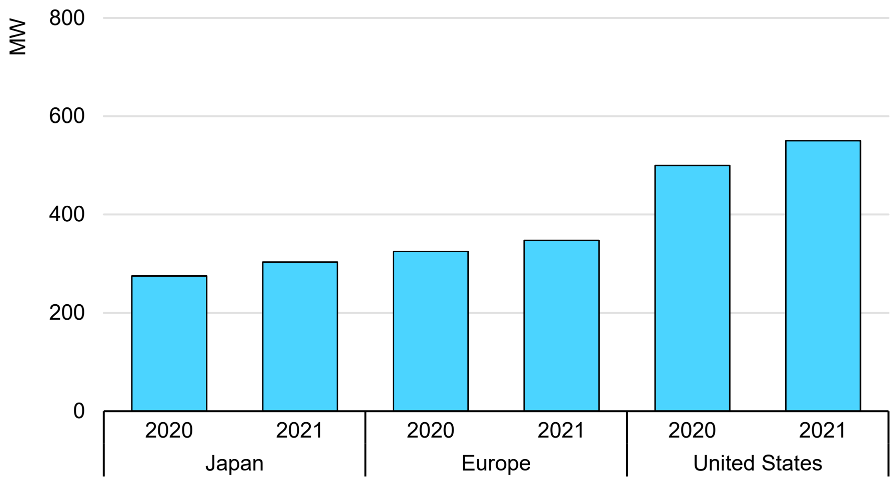
However, there may be opportunities for hydrogen applications in buildings where natural gas infrastructure is already in place and where energy use is hard to decarbonise, for instance due to cold climates, old city centres and poorly insulated buildings. Demonstration projects to use hydrogen (pure or with blending options) in buildings are ongoing and standards for hydrogen-ready technologies are being developed if/when such specific applications are needed.

Hydrogen use in the buildings sector will depend on many factors. Based on the Stated Policies Scenario with current policies and announcements, the outlook for global hydrogen demand in the buildings sector could reach 0.15 Mt H_2 by 2030, around 0.01% of the sector's total energy demand. In the Announced Pledges Scenario, hydrogen demand in the buildings sector could increase up to around 2 Mt H_2 by 2030, less than 0.2% of the sector's total energy demand. In the short term, demand would be primarily in the form of hydrogen blended in existing natural gas networks, with pure hydrogen applications most likely not deployed until after 2030.

Growth of the fuel cell market

Today, fuel cells in the buildings sector are installed predominantly in Europe, Japan, Korea and United States. Thanks to the ENE-FARM programme the cumulative sales of fuel cell micro combined heat and power (CHP) units exceeded 430 000 in Japan at end-2021. Japan is the global leader in micro-CHP fuel cell technology for buildings. Japan also leads in deployment of small fuel cells <5 kW whereas the United States dominate in total deployed capacity. Across various system sizes of stationary fuel cells, in 2021 the United States had installed capacity of around 550 MW (up 50 MW over 2020 capacity), Europe at about 190 MW installed (up 41 MW from 2020 capacity). Japan is estimated to have about 300 MW installed (up 25 MW from 2020) and Korea had about 18 MW installed (up from nearly 16 MW in 2020)

Fuel cell stock in selected regions, 2020-2021



Note: The average fuel cell in Japan is assumed to be around 700 Watts.
Sources: CEM H2I country surveys; Fuel cells and Hydrogen Observatory; Fuel Cell & Hydrogen Energy Association; Japan's Ministry of Economy, Trade and Industry; E4tech.

Both proton exchange membrane fuel cells (PEM) and solid oxide fuel cells (SOFC) have been tested and operated in residential and other building types, e.g. in the PACE project in ten European countries. PEM systems are more widespread in residential buildings due to their better flexibility to adapt to loads, despite having lower electric efficiencies than SOFC. SOFC systems are more common in non-residential buildings, such as sports centres, shopping malls, supermarkets, hospitals and data centres. In these applications baseload demand is relatively continuous over the year and waste heat can be easily exploited. The ComSos European project plans to demonstrate 25 installations of mid-sized power ranges (between 10 and 60 kW) SOFC fuel cells involving three primary suppliers of fuels cells. The ongoing tests and analysis are focussed on the technical (natural gas and blending feed, performance curve, fuel cell lifetime), economic (spark spread) and environmental (CO_2, nitrogen oxide [NOx] emissions) performance of such systems.

Most fuel cells use natural gas or liquified petroleum gas for conversion into hydrogen by reformers. A switch from 100% natural gas to a certain degree of hydrogen blending might be tolerated by the existing technology (up to 50% in some cases) and is viable for PEM fuel cells. But switching to 100% hydrogen fuel cell system is not that simple, particularly for SOFCs. The main limitation is related to the balance of plant components that act as cooling agents during the reforming reaction. An ongoing EU project, TULIPS, funded by the European Green Deal and started in January 2022, aims to contribute to enhancing sustainability at airport operations. TULIPS is testing a pilot system that consists of an electrolyser to produce hydrogen to feed a fuel cell stack for electricity and heat production. A pilot project at the Turin airport (Italy) will test the capability of SOFC systems to tolerate variable hydrogen blending rates and the switch from pure methane to pure hydrogen.

Currently the conversion of existing natural gas fuel cells to 100% hydrogen is not possible, but fuel cells operating on 100% hydrogen are already available on the market. For example, in October 2021, Panasonic launched a 5 kW pure hydrogen fuel cell generator to be used in commercial operations. In Japan, there are several 100% hydrogen fuel cell applications, such as Michinoeki-Namie and Prefectural Azuma Sports Park. In addition, 100% hydrogen fuel cells were used for the Olympic Village for the Tokyo 2020 Olympics.

Hydrogen fuel cells can also be used for power backup. For example, the NorthC data centre in Groningen (Netherlands) became the first data centre in Europe to use hydrogen for emergency backup generation. The project was planned to be operational in mid-June 2022. Plus, NorthC data centre is equipped with a 500 kW hydrogen-powered fuel cell generator manufactured by the Dutch company Nedstack.

Progress for hydrogen blend, hydrogen boilers and cookstoves

In several countries natural gas networks are being prepared for hydrogen blending. For instance, from 2023, part of the UK gas network will be ready to use up to 20% hydrogen blends. In Australia, the Hydrogen Park SA supply blended gas made of 5% hydrogen to 700 homes; the Dampier-Bunbury natural gas pipeline is capable of coping with up to 9% hydrogen blend; and the 43 km Parmelia gas pipeline is 100% hydrogen-ready.

Increasing hydrogen blending shares could potentially impact the use of existing and new boilers, and cookstoves. Key ongoing or planned demonstration projects (with blending up to 20% by volume) include:

- Successful test in 2022 under the HyDeploy programme in the United Kingdom intended to demonstrate that hydrogen can be blended in the natural gas network up to 20% by volume. This trial included 668 residential properties, a primary school, a church and several small businesses.
- Planned power-to-gas tests in Sardinia (Italy) for residential and industrial users from 2022.
- Successful 20% hydrogen blend experiment in closed-loop system in Southern California, (United States) in 2021. In a controlled field environment, it was demonstrated that blending up to 20% hydrogen does not present risks for the existing natural gas infrastructure and household equipment.
- HyBlend initiative under the US DOE to assess the main obstacles to hydrogen blends inexisting natural gas networks.
- Avacon, an E.ON subsidiary, started adding a 20% hydrogen blend to the natural gas sub-grid in the Saxony-Anhalt region (Germany) in December 2021.

While hydrogen blend-ready boilers are already available, equipment standards are evolving to safeguard the operation of all boilers with various hydrogen blending ratios. For example, European standards were published in February 2022: the UNI/TS 11854 standards cover boilers operating on methane mixtures with up to 20% hydrogen blend. This harmonised regulation will be the reference standard for all boiler manufacturers. The percentage of hydrogen within the natural gas grids will not be constant across the networks, it will depend on the location of injection points relative to the buildings. Accordingly, these standards are crucial to ensure that equipment can operate safely across a range of hydrogen blends.

A potential impact of such variability is not just on the equipment, but also on gas flow meters, which also should be able to operate within such tolerance ranges. The first meters that are able to switch from metering natural gas and 100% gas for residential applications have been developed. In Canada and United States, experimental data show that with mixtures of up to 30% hydrogen blend, the combustion stability of the burners is not affected. However, given the variations in existing equipment across regions, these ranges and upper bounds should not be generalised globally.

Standards are also evolving for equipment to operate with 100% hydrogen. It is expected that from 2023 to 2025, hydrogen-ready standards will become the norm for gas boilers in the United Kingdom. When those standards are imposed, all natural gas boilers for purchase will have to be easily modifiable to operate on 100% hydrogen. Hydrogen-fired boilers are ready to be used in households, but also in high-temperature applications.

Advances in the use of pure hydrogen in buildings are ongoing. European countries are leading these developments.

- Hoogeveen (Netherlands): construction of hydrogen district will start in third-quarter 2022.
- Stad Aan‘T Haringvliet (Netherlands) a demonstration house has been heated using hydrogen. A demonstration project to heat about 600 homes to start from 2025.
- Phase 2b of the H21 project in Middlesbrough (United Kingdom) where standard natural gas operations have been tested with pure hydrogen in an existing gas network.
- H100 Fife (United Kingdom) 100% hydrogen network is planned to start operation in 2023.
- Projects for individual buildings are ongoing, for example, in Murcia (Spain) a solar PV facility will be coupled with an electrolysis plant to produce hydrogen to operate a pure hydrogen boiler in a hospital (including production and storage of oxygen for hospital use).
- Green Hysland hydrogen project on Mallorca (Spain) is intended to produce hydrogen from electrolysers powered with solar PV generation and use it to supply energy to a hotel and to fuel cell buses.
- Hydrogen hybrid heat pumps were successfully tested in 2022 in the United Kingdom. This test combined hydrogen-fired boilers with electric air-source heat pumps and could be an interesting application, especially for existing buildings in cold climates.
- Conversion of the natural gas grid to 100% hydrogen (including odorisation) for use in a demonstration project for ten old residences in Lochem (Netherlands) with a planned start in third-quarter 2022.

For areas connected to a hydrogen network, hydrogen-fuelled stoves for cooking are being tested by the Swiss research institute Empa, which developed a catalytic diffusion burner powered by hydrogen. At the current stage, the technology is not market ready.

Progress on safety assessments

Fossil fuel and biomass combustion have been used in buildings for decades. Appropriate handling of hydrogen use in buildings requires effective attention to safety issues to ensure acceptability by consumers.

The Northern Gas Networks and the UK government are co-operating on the H21 and Hy4Heat programmes. In the experimental facility, DNV GL's HyStreet, terraced houses were built to assess reliability and safety concerns. Safety is being studied with respect to leakage and the relative risks of ignition as well as developing a model of what potential leaks in a system might look like.

Downstream risk, i.e. in household appliances, mainly occurred due to a lack of flame failure devices. Therefore, all market available hydrogen appliances should be equipped with this feature. In the safety assessment of the Hy4Heat project, it was shown that small leaks (<2 milimeters [mm]) do not create large enough flammable clouds that could induce injuries. Medium-size leaks (2-6.5 mm) might create large enough gas clouds to be flammable in a small room. Large holes (>6.5 mm) create large flammable clouds even in large household areas. The controlled trial recognised the high importance of a ventilated room (where the hydrogen appliance is located); however, the study considered only non-closable rooms for ventilation and mechanically ventilated buildings were excluded from the trial. High importance was also assigned to standards for hydrogen appliances (mainly to be equipped with appropriate leak sensors). Since hydrogen is new to end-users, the same odorant that is used for natural gas, i.e. mercaptan might be applied where possible to heighten consumer responsiveness to potential leaks. However, the use of mercaptan would make hydrogen unfit for fuel cells; there is a need to find other safety solutions. Gas safety engineers should be effectively trained for the use of hydrogen in buildings such as installations, testing, inspections and maintenance. The HyDelta-programme in the Netherlands has a dedicated work package on hydrogen safety.

Indirect use of hydrogen in buildings

Hydrogen can be used directly and indirectly to operate district heating networks. Today, more than 90% of district heat networks rely on the use of fossil fuels. Their decarbonisation will be fundamental to deliver low-emission heat in dense urban areas in particular. In 2023, a hydrogen-fuelled CHP system will provide power and heat to the district network in St.Paul, Minnesota (United States) and distribute both chilled and hot water to connected buildings. The pilot project aims to increase understanding of the use of hydrogen within existing equipment. Such a solution can support the district heating industry to increase flexibility and to decarbonise.

In 2017, a 1 MW gas turbine fuelled by hydrogen and natural gas demonstration plant was completed in Japan. The Hydrogen Cogeneration System started its trial run, followed by stand-alone testing. In 2018, the plant successfully supplied electricity and heat (steam and high-temperature water) to four nearby facilities using a cogeneration system fuelled by 100% hydrogen.

In Denmark, the company Everfuel in late 2021 signed an agreement with the TVIS district heating company to supply surplus heat from a 20 MW hydrogen electrolyser to its local network. The surplus heat will provide heating to 500-600 homes. The REPowerEU Plan targets 10 Mt of renewable hydrogen production in EU member states by 2030, which, according to the action plan working document, would require 65-80 GW electrolyser capacity to be available. Utilising 5-10% of the waste heat generated by such electrolysis capacity in district heating networks could provide heat to 115 000 - 525 000 households. This could reduce close to 3% of current fossil fuel demand for district heating in the European Union.[26]

[26] Assuming electrolyser efficiency in the range of 65-70%, annual load factors of 40-70% and buildings heat consumption per residence of 180 kWh/m^2/year.

Electricity generation

Hydrogen use in the power sector

Hydrogen plays only a negligible role as a fuel in the power sector today. It accounts for less than 0.2% of global electricity generation and mostly uses mixed gases with high hydrogen content from steel production, refineries and petrochemical plants as well as off-gases from the chlorine-alkali industry.

Electricity generation technologies that can use hydrogen are commercially available today. Some current designs of reciprocating gas engines, fuel cells and gas turbines are technically capable of operating on hydrogen-rich gases or even pure hydrogen.

Reciprocating gas engines can handle gases with a hydrogen content of up to 70% (on a volumetric basis).[27] Various manufacturers have demonstrated engines using 100% hydrogen that should be commercially available in the coming years.

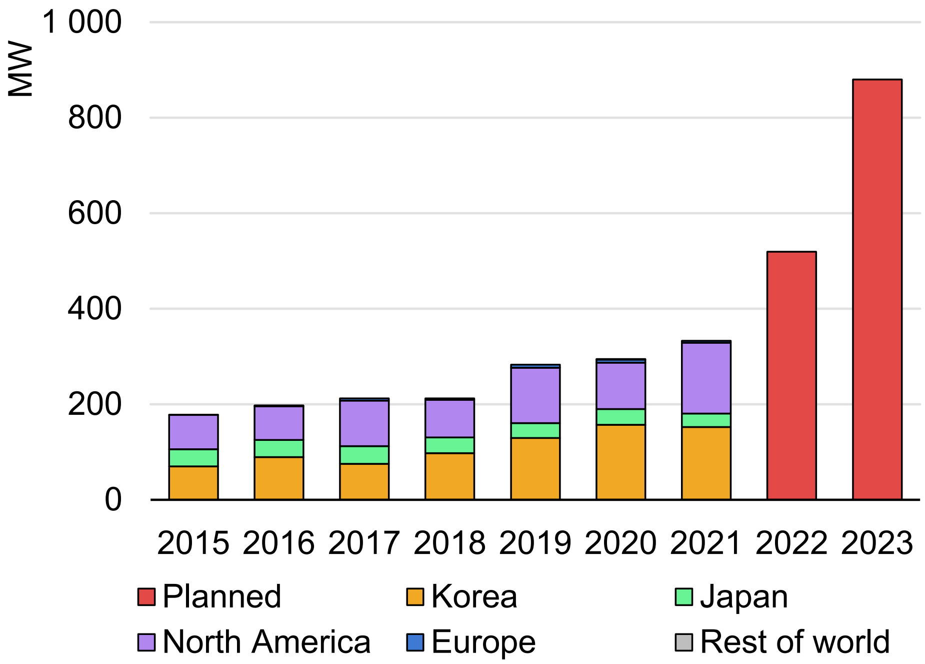
Gas turbines can also operate on hydrogen-rich gases. In Korea, a 45 MW gas turbine at a refinery has been operating on gases of up to 95% hydrogen for 25 years. This experience in almost 100% hydrogen firing has been realised largely with wet low-emission technologies (humidified gas turbines), which help to reduce the high NOx emissions of hydrogen combustion, but also require demineralised water and related water demineralisation equipment. State-of-the-art gas turbines avoid this efficiency drawback by using dry low NOx technologies to manage emissions. The maximum allowable co-firing share of hydrogen in dry low NOx (DLN) gas turbines can vary significantly across the fleet of different manufacturers, due to the different burner designs and combustion strategies implemented, with typical values ranging from 30-60% by volume. Research and development activities are underway to develop DLN gas turbines that are able to handle the full hydrogen blending range of up to 100%. Firing 100% hydrogen with DLN technology has been successfully demonstrated in Japan at a 1 MW scale. Manufacturers are confident of delivering standard gas turbines that can operate on pure hydrogen by 2030. In the United States, the development of combustors that can be retrofitted for existing gas turbines is underway, enabling fuel mixtures of up to 100% hydrogen. In Korea, gas turbine manufacturer Doosan is working on commercialising gas turbines using hydrogen extracted from ammonia. Several planned new natural gas-fired power projects already take into account the option to co-fire hydrogen or fully convert to hydrogen in the future, e.g. in Germany and United States.

Fuel cells can convert hydrogen into electricity and heat, achieving electrical efficiencies of over up to 50-60%. They maintain high

[27] If not stated otherwise, hydrogen shares are on a volumetric basis.

efficiencies also in part load operation, which makes them particularly attractive for providing flexibility to electricity systems. In 2021, 348 MW of stationary fuel cell capacity was added worldwide. Including cumulative deployment since 2007, global installed capacity of stationary fuel cell capacity was about 2.5 GW in 2021, though not all may be in operation and only around 90 MW use hydrogen as fuel, while most operate on natural gas.

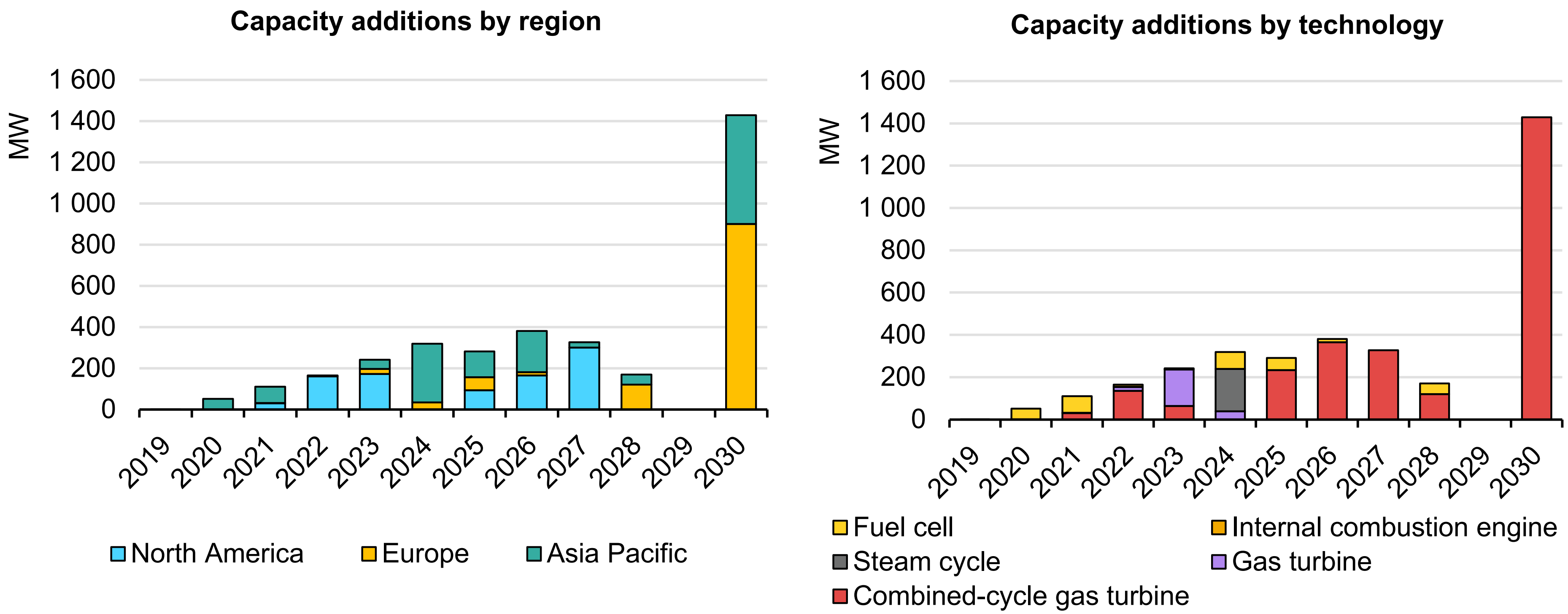
Stationary fuel cell capacity in selected regions, 2016-2023



Notes: Planned capacity (2022-2023) based on capacity increases and historic trends.
Source: E4tech.

Planned projects to use hydrogen and ammonia for electricity generation

Capacity additions for power generation using hydrogen and ammonia, 2019-2030



Notes: Capacity is derived using hydrogen and ammonia co-firing shares, i.e. equal co-firing share multiplied by total plant capacity. For projects without a specified co-firing proportion, a share of 10% (in energy terms) is assumed. Capacity additions include existing plants for which co-firing of hydrogen or ammonia is added. Analysis is based on about 60 projects; capacity deployment in 2030 of around 1 400 MW is linked to two large projects in Australia and the United Kingdom.

Hydrogen use in electricity generation attracts more attention

Despite the low deployment levels of hydrogen in the power sector so far, interest in the use of hydrogen and ammonia is increasing. Co-firing with hydrogen or ammonia can reduce emissions in existing gas- and coal-fired power plants in the near term. In the longer term, hydrogen- and ammonia-fired power plants can support the integration of variable renewables by providing flexibility or large-scale, seasonal storage to electricity systems.

Several projects have been announced or are under development that could represent around 3 500 MW of hydrogen- and ammonia-fired power plant capacity worldwide by 2030.[28] Around 85% of these projects focus on the use of hydrogen in combined-cycle or open-cycle gas turbines. The use of hydrogen in fuel cells and the co-firing of ammonia in coal-fired power plants each account for around 10% and 6%, respectively, of the capacity of the project pipeline by 2030. Most of the gas turbine projects initially start with a hydrogen co-firing share in the range of 5-10% in energy terms (15-30% volumetric), but plan to move to higher shares and in some cases even 100% hydrogen firing in the longer term.

These projects are mainly concentrated in the Asia Pacific region (40%), Europe (33%) and North America (26%). In the United States, 5% co-firing of hydrogen with natural gas (in volume terms) was successfully demonstrated in Ohio at the 485 MW Long-Ridge Enegy Terminal in March 2022.

In the United Kingdom, co-firing 30% of hydrogen (in volumetric terms) at the existing 1 200 MW Saltend CHP is planned by 2028. Another example in Europe is the 1.4 GW Magnum combined-cycle gas-fired power station in the Netherlands. In both cases, the power plants will be integrated in hydrogen hubs and include hydrogen storage to provide flexibility to balance seasonal variations in electricity demand or variable renewable electricity supply. With hydrogen-fired power plants likely being large hydrogen consumers, they can provide economies of scale for hydrogen production infrastructure from which small consumers can also benefit. For example, a 500 MW combined-cycle gas turbine plant, when fully operating on hydrogen at an annual average 15% capacity factor, consumes around 35 kt H_2 per year, which would require an electrolyser capacity of 400 MW (at a 50% capacity factor).

While the majority of the announced projects are linked to hydrogen use in gas turbines, several projects look to the direct use of ammonia for power generation. In Japan, co-firing a 1% share of ammonia in a

[28] In case of co-firing hydrogen or ammonia, the capacity corresponds to the total installed capacity times the co-firing share in energy terms.

commercial coal power plant was demonstrated in 2017. By 2024, the Japanese utility, JERA, plans to demonstrate 20% ammonia co-firing at a 1 GW coal power station. Early in 2022, research projects were announced to develop burners for existing coal power plants capable of at least 50% ammonia co-firing.

IHI, a Japanese turbine manufacturer, demonstrated 100% ammonia firing in a 2 MW gas turbine in June 2022, after having achieved a 70% share in co-firing in 2021. Mitsubishi Power plans to develop a 40-MW gas turbine operating on 100% ammonia by 2025. First small-scale combustion tests in August 2021 were promising according to the company.

Low-emission hydrogen and ammonia are likely to remain expensive energy carriers for power generation in the period to 2030. The cost gap between the generation cost and the value of the produced electricity can be moderated by wholesale electricity markets that allow higher prices during peak demand periods. IEA analysis shows, for example, that co-firing 60% of low-emission ammonia in a Japanese coal power plant in 2030 would lead to a generation cost that is 30% higher than the energy market value at base load, but just 15% higher during peak load conditions. Electricity markets designed to reward flexibility, capacity and other system services as well as support measures such as carbon pricing can help to close the cost gap with incumbent fossil fuel-fired electricity generation.

Given current trends, the demand for hydrogen in electricity generation is expected to remain quite low, around 0.3 Mt, in the period to 2030. The outlook in the Announced Pledges Scenario push demand for hydrogen in the power sector up to 5 Mt by 2030.

Yet, there have been no new announcements of targets for the adoption of hydrogen in power generation since the release of our Global Hydrogen Review 2021. To date, only Japan, Korea and Portugal have announced targets for the use of hydrogen and ammonia in power generation. Also, there has been limited progress in the adoption of relevant policies.[29] However, there was a noteworthy announcement in the Hydrogen Jobs Plan (Government of South Australia) of the construction of a 200 MW power generation plant by 2026 that will include 250 MW electrolysis capacity for the production of hydrogen and storage facilities.

[29] In 2017, Japan set a target to use 0.3 Mt H_2/year in electricity generation by 2030, corresponding to 1 GW of power capacity, rising to 5-10 Mt H_2/year (15-30 GW) in the longer term. Korea's hydrogen roadmap targets 1.5 GW of installed fuel cell capacity in the power sector by 2022 and 8 GW by 2040.

Hydrogen production

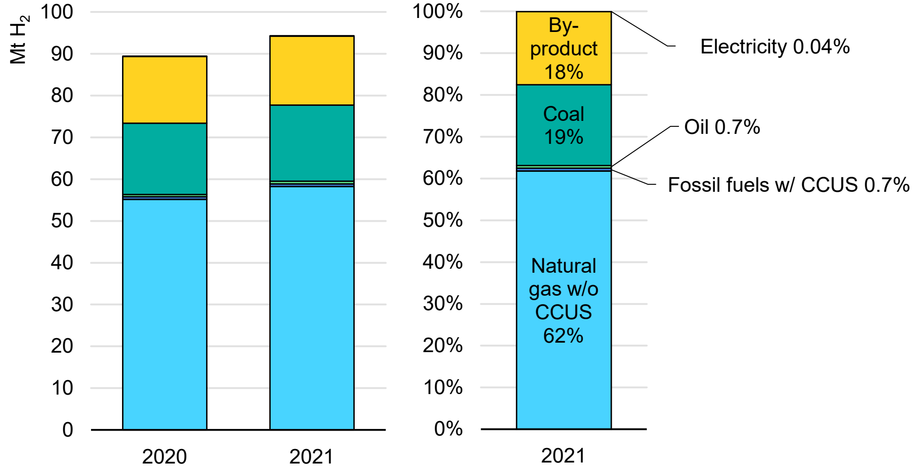
Overview and outlook

Current status of hydrogen production

Demand for hydrogen is met almost entirely by hydrogen production from unabated fossil fuels. In 2021, total global production was 94 million tonnes of hydrogen (Mt H_2) with associated emissions of more than 900 Mt CO_2.[30] Natural gas without CCUS[31] is the main route and accounted for 62% of hydrogen production in 2021. Hydrogen is also produced as a by-product of naphtha reforming at refineries (18%) and then used for other refinery processes (e.g. hydrocracking, desulphurisation). Hydrogen production from coal accounted for 19% of total production in 2021, mainly based in China. Limited amounts of oil (less than 1%) were also used to produce hydrogen.

Low-emission hydrogen production was less than 1 Mt (0.7%) in 2021, almost all from fossil fuels with CCUS, with only 35 kt H_2 from electricity via water electrolysis. The amount of hydrogen produced via water electrolysis, while very small, increased by almost 20% compared to 2020. This reflects increasing deployment of water electrolysers.

Hydrogen production mix, 2020 and 2021



Note: CCUS = carbon capture, utilisation and storage.

[30] This includes 74 Mt H_2 of pure hydrogen production and around 20 Mt H_2 mixed with carbon-containing gases in methanol production and steel manufacturing. It excludes around 30 Mt H_2 present in residual gases from industrial processes used for heat and electricity generation: as this use is linked to the inherent presence of hydrogen in these residual streams, rather than to any hydrogen requirement, these gases are not considered here in the demand and supply of hydrogen. By-product hydrogen from the chlor-alkali industry is not included here.

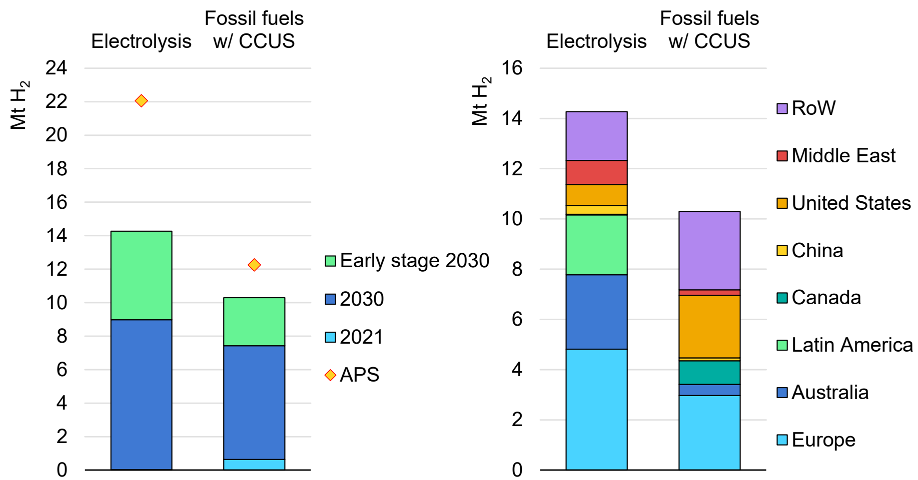
[31] See Explanatory notes annex for CCUS definition in this report.

Outlook for low-emission hydrogen production to 2030

According to the pipeline of hydrogen production projects that the IEA tracks, the number of announced projects that will produce low-emission hydrogen[32] is rising at an impressive pace. If all the announced projects for hydrogen from water electrolysis or fossil fuels with CCUS currently under development are realised, the annual production of low-emission hydrogen could reach more than 24 Mt H_2 by 2030.

The current status of these projects varies; some are at advanced planning stages (68% in terms of production level), including projects under construction or for which an FID has been taken (4%), and some at very early stages (32%).[33] For electrolyser projects, the share at very early stages is a bit higher at 37%. A large number of electrolyser projects were announced in 2021, but developing these projects will require time and some may never be realised. For example, in South Australia an electrolyser project with 6 gigawatts (GW) of renewable electricity supply was cancelled in 2022 due to water supply concerns. Nevertheless, the number of planned projects that reach the advanced planning stages should increase in the coming years. The expected production from the planned projects of more than 24 Mt H_2 in 2030 identifies a wide gap with the projected production of 34 Mt H_2 in the APS, largely for hydrogen production from electrolysis with a difference of almost 8 Mt H_2, while the pipeline of projects that use fossil fuels with CCUS is close to the outlook in the APS.

Low-emission hydrogen production, 2020 and 2030



Notes: RoW = rest of world; APS = Announced Pledges Scenario. In the left figure, the blue columns for 2020 and 2030 refer to projects at advanced planning stages. The right figure includes both projects at advanced planning and early planning stages. Only projects with a disclosed start year for operation are included.
Source: IEA, Hydrogen Projects Database (2022).

[32] See Explanatory notes annex for low-emission hydrogen definition in this report.

[33] Advanced planning stages refer to projects for which a feasibility study is in progress or for which a final investment decision has been taken.

With additional new projects being announced and developed over the coming years, the production gap between the project pipeline and the APS is expected to become smaller.

Europe and Australia are front runners in hydrogen production projects using water electrolysis. Based on the current project pipeline, low-emission hydrogen production from water electrolysers in Europe could reach close to 5 Mt H_2 by 2030 (projects at advanced and early planning stages), with Germany and Spain together accounting for 1.4 Mt H_2. Australia has become a hotspot for electrolysis projects, taking advantage of its good resource conditions for solar PV and wind electricity generation. It plans to export hydrogen to high demand centres in Asia, including Japan and Korea. The first shipment of liquefied hydrogen from Australia to Japan was in February 2022, though this hydrogen was produced from coal. Overall, Australia's hydrogen production from renewable electricity could reach 3 Mt H_2 by 2030 based on the project pipeline, corresponding to an electrolyser capacity of nearly 50 GW.

Large amounts of electrolytic hydrogen are also expected to be produced in Latin America, Middle East and Africa (more than 4 Mt H_2 in 2030), often for exports of hydrogen or ammonia to Europe and Asia. In China, several electrolyser projects have been announced in the last year. In 2022, new project announcements in China dropped after March, potentially an impact of lockdowns due to Covid-19 in some regions.

Hydrogen production from fossil fuels in combination with CCUS in Europe could account for 3 Mt H_2, based on announced projects, mostly in the Netherlands and United Kingdom. Planned projects in the United States and Canada combined would reach a similar production level by 2030, accounting for 33% of the hydrogen produced from fossil fuels with CCUS.

Electrolysis

A rapidly evolving electrolyser project pipeline

Water electrolysis uses electricity to split water into hydrogen and oxygen. In 2021, water electrolysis accounted for only around 0.1% of global hydrogen production. But the installed capacity of electrolysers is expanding quickly and reached 510 megawatts (MW) by end-2021, an increase of 210 MW, or 70% relative to 2020. The completion of the Ningxia Solar Hydrogen Project in China with an electrolyser capacity of 150 MW accounted for almost three-quarters of the increase. Today it is the world's largest electrolyser in operation.

The rapid scale-up in electrolyser capacity is expected to continue and accelerate in coming years. Globally, there are about 460 electrolyser projects currently under development or construction. The global electrolyser capacity could exceed the 1 GW level towards the end of 2022 and reach around 1.4 GW, almost tripling the 2021 level, with almost 40% of this capacity developed in China and around a third in Europe. Based on the current project pipeline, global electrolyser capacity could stand at 134 GW in 2030[34], a significant increase over the 54 GW expected for 2030 on the basis of the project pipeline in the 2021 edition of the Global Hydrogen Review. Though, among all the new projects in the pipeline, only about 175 are currently under construction or have reached FID status, accounting for about 9.5 GW, while the others are at a less advanced stage of development. There are many uncertainties of course, even for planned near-term projects. Some projects originally planned to become operational in 2022 and 2023 have been delayed due to problems of securing financing.

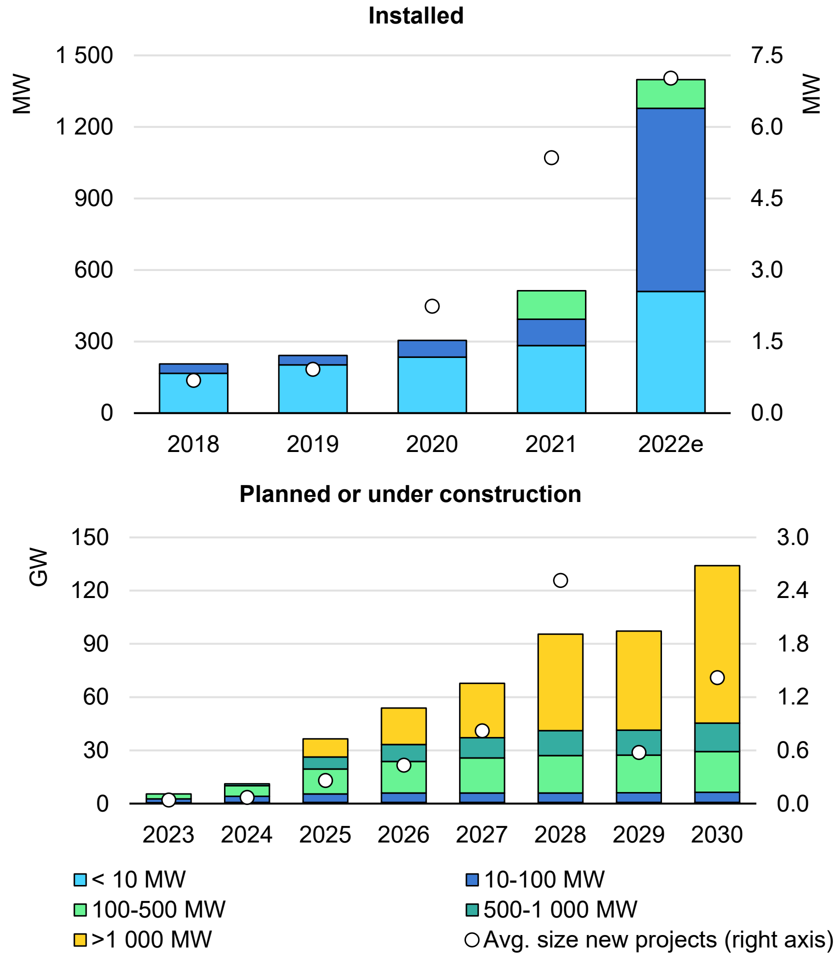
A critical factor in the expected uptake in electrolyser capacity is the advance to commercial-scale projects that would be expected following successful pilot and demonstration projects. While the average plant size of new electrolysers starting operation in 2021 was 5 MW, the average size of new plants could be around 260 MW in 2025 and in the GW-scale by 2030. Of the projects under construction or under development, 22 (or 5%) are above 1 GW.

Announced electrolyser capacity projects expected to be online by 2030 are mostly located in Europe (32%), Australia (28%) and Latin America (12%). With projected installed capacity of 39 GW in 2030 based on announced projects, the European Union is close to meeting the 44 GW target of the Fit for 55 package, but would fall short of the 80 GW stated in the REPowerEU Plan. Meeting the more ambitious level requires further progress on electrolyser capacity additions.

[34] This could increase to 240 GW if projects at very early stages of development are included, e.g. only a co-operation agreement among stakeholders has been announced.

In 2021, almost 70% of the installed capacity was alkaline electrolysis, followed by proton exchange membrane (PEM) electrolysers accounting for one-quarter. Other emerging technologies are solid oxide electrolysis cells and anion exchange membranes electrolysis, but they are less mature than alkaline and PEM electrolysers and represent only a minimum share of the installed capacity today. Looking at the project pipeline, in many cases developers have not yet announced the electrolyser type, especially for projects coming online after 2025. The share of alkaline electrolysis in the total installed capacity (for which technology information is available) remains at around 60% for the next five years, but decreases afterwards, so that by 2030 the total capacity could be equally split between alkaline and PEM electrolysers. But the final split of technologies will depend on the choice of projects with a combined capacity of 115 GW projects for which the electrolyser type has yet to be announced.

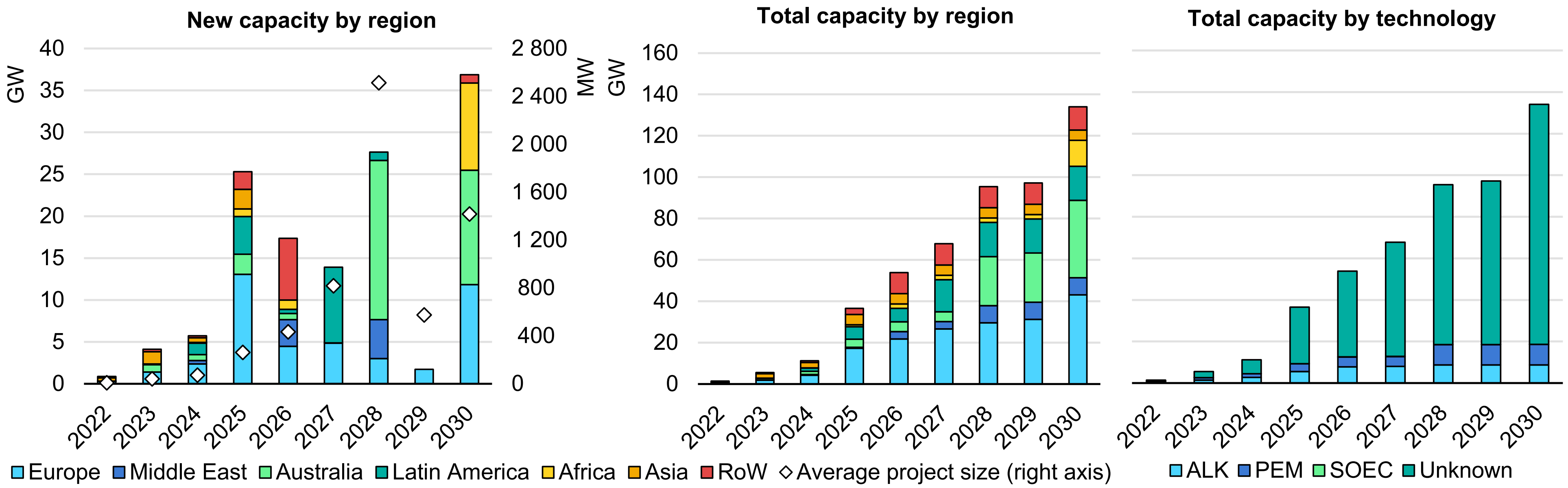
Global electrolyser capacity by size based on project pipeline, 2018-2030



Notes: e = estimated. Only projects with a disclosed start year for operation are included. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included.
Source: IEA, Hydrogen Projects Database (2022).

Global electrolyser capacity could exceed 35 GW by the mid-2020s and reach 134 GW by 2030 based on the current project pipeline

Electrolyser capacity by region and type based on project pipeline to 2030



Notes: RoW = rest of world; ALK = alkaline electrolyser; PEM = proton exchange membrane electrolyser; SOEC = solid oxide electrolyser. Only projects with a disclosed start year for operation are included. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included
Source: IEA Hydrogen Projects Database (2022).

Can manufacturing capacity keep pace with mid-term ambitions?

Developing industrial supply chains for electrolysers will be critical for low-emission hydrogen to play the role envisioned in roadmaps and strategies by governments and industry. Global manufacturing capacity for electrolysers stood at 8 GW per year in 2021, with two regions, Europe and China, accounting for 80% of global manufacturing capacity. With water electrolyser capacity additions of 210 MW in 2021, the global manufacturing capacity of 8 GW[35] is largely underutilised. Several factors explain this imbalance. The market for electrolysers is experiencing very significant growth, with an increasing number of large projects being planned. Manufacturers have started to expand their production capacities based on expectations of future demand growth. In addition, building or expanding manufacturing plants are long-term decisions. To avoid the need to expand capacities in incremental steps and repeatedly go through permitting processes and civil engineering site works, manufacturers may decide to incorporate expected future growth in new build plants and related infrastructure, and not necessarily use the full capacity from the start. Furthermore, new manufacturing plants are not only built for expanding capacities, but also for moving to new more automated production processes, in some cases also supported by national research programmes, e.g. United Kingdom and Germany.

Based on company announcements, global manufacturing capacities could reach 65 GW per year by 2030 (more than 105 GW per year by also considering projects with an unknown year of operation), with several manufacturers establishing plants in the 1 GW-scale. Manufacturing capacities in Europe and China are expected to continue to expand and dominate global manufacturing, but their combined market share may decline to less than 65% as other regions are building or expanding capacity, notably the United States, India and Australia.

Alkaline electrolysers dominate today with a share of 60% global manufacturing capacity, reflecting the maturity of the technology compared to PEM and SOEC electrolysers. By 2030, alkaline electrolysers are projected to account for 64% of manufacturing capacities, followed by PEM (22%) and SOEC (4%). Another technology, anion exchange membrane electrolysers, has so far been mainly deployed in demonstration projects, but the leading manufacturer Enapter has plans to build manufacturing capacities of 280 MW by 2023.

[35] It also includes manufacturing capacity for chlor-alkali electrolysers.

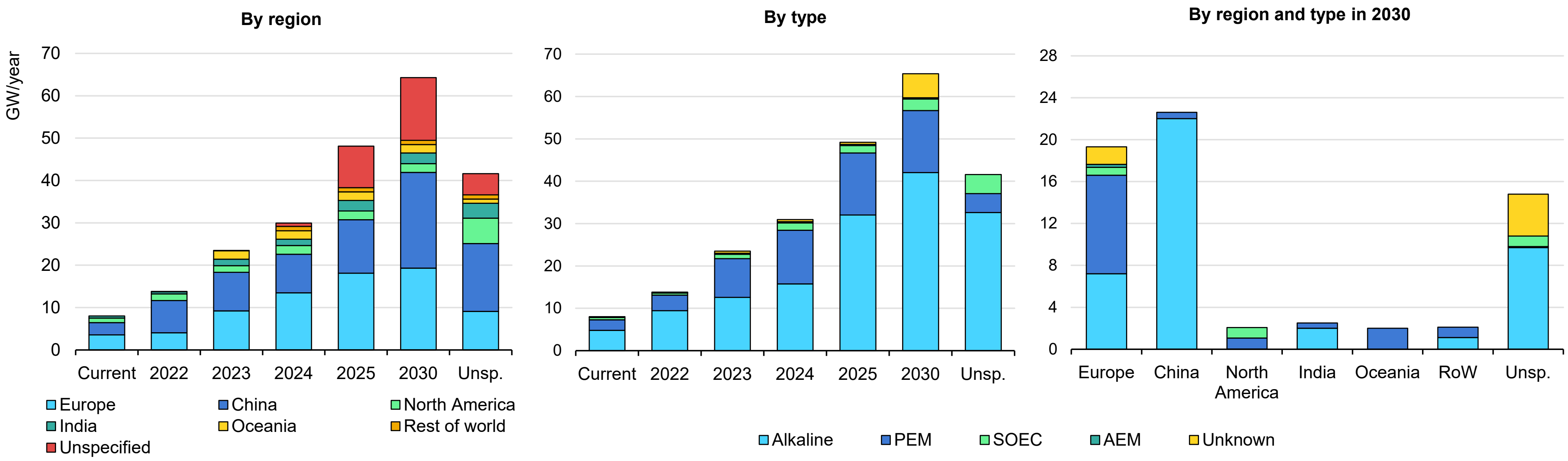
Assuming that all the planned manufacturing plants produced electrolysers at 90% utilisation rate, their cumulative output of electrolysers could reach around 270 GW by 2030. This is well above the pipeline of electrolyser projects of 134 GW and aligned with the combined policy targets for 2030, which are in the range of 145-190 GW, but would fall short to meet the deployment level of 850 GW by 2030 in the IEA Net Zero Emissions by 2050 Scenario. This target range excludes the capacity corresponding to the import of 10 Mt H_2 expressed in the REPowerEU Plan, since part of it may already be included in national targets of countries, aiming to export to the European Union. To realise this EU import target, both manufacturing capacities and the development of projects have to be scaled up even faster in the coming years.

In May 2022, European manufacturers committed to increase the total annual production electrolyser capacity to 25 GW by 2025 following the announcement of the REPowerEU Plan. The company strategies announced so far would result in a cumulative output of around 95 GW by 2030, which would be only slightly lower than that required to reach the target of 10 Mt of annual renewable hydrogen[36] production in the REPowerEU Plan. This, however, would only hold if European manufacturers were not exporting their electrolysers to customers outside of Europe.

[36] See Explanatory notes annex for renewable hydrogen definition in this report.

Electrolyser manufacturing capacity could exceed 60 GW per year by 2030, with Europe and China leading the way

Electrolyser manufacturing capacity by region and type to 2030

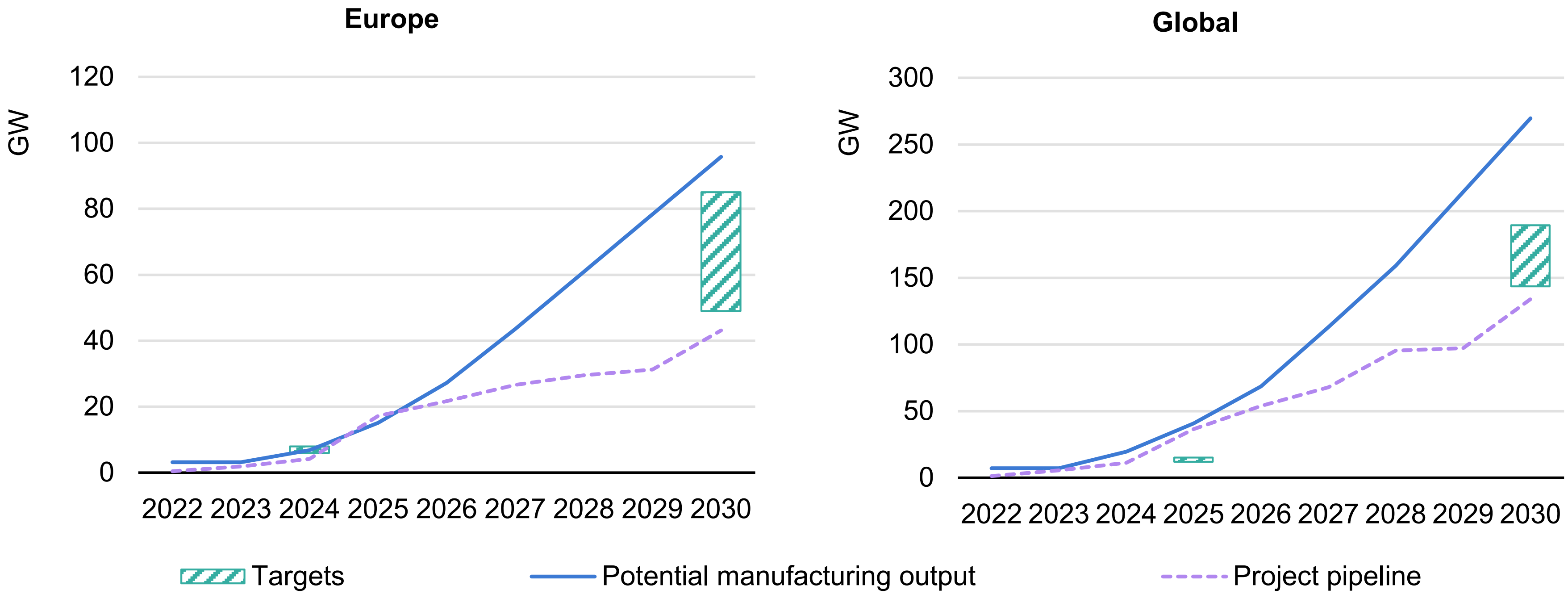


Notes: RoW = rest of world; ALK = alkaline electrolyser; PEM = proton exchange membrane electrolyser; SOEC = solid oxide electrolyser; AEM = anion exchange membrane electrolyser. Unsp = unspecified year and includes manufacturing facilities for which the start year is unknown. Unspecified region includes manufacturing facilities for which the geographical location is unknown.

Source: IEA analysis based on announcements by manufacturers and personal communications.

Electrolyser manufacturing capacity could support project developments to achieve targets set out in national strategies

Electrolyser project pipeline, manufacturing output and targets in Europe and globally, 2022-2030



Notes: Only projects with a disclosed start year for operation are included. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included. The potential manufacturing output is the cumulative production of factories considering 90% utilisation rate of planned projects with a disclosed start year of operation. For Europe, the targets includes the European Union and the United Kingdom electrolyser deployment targets; for the European Union, the lower range for the electrolysers deployment corresponds to the Fit for 55 package and the upper range to the RePowerEU plan. The global target is based on national hydrogen strategies.
Source: IEA analysis based on the Hydrogen Projects Database (2022) and announcements by manufacturers and personal communications.

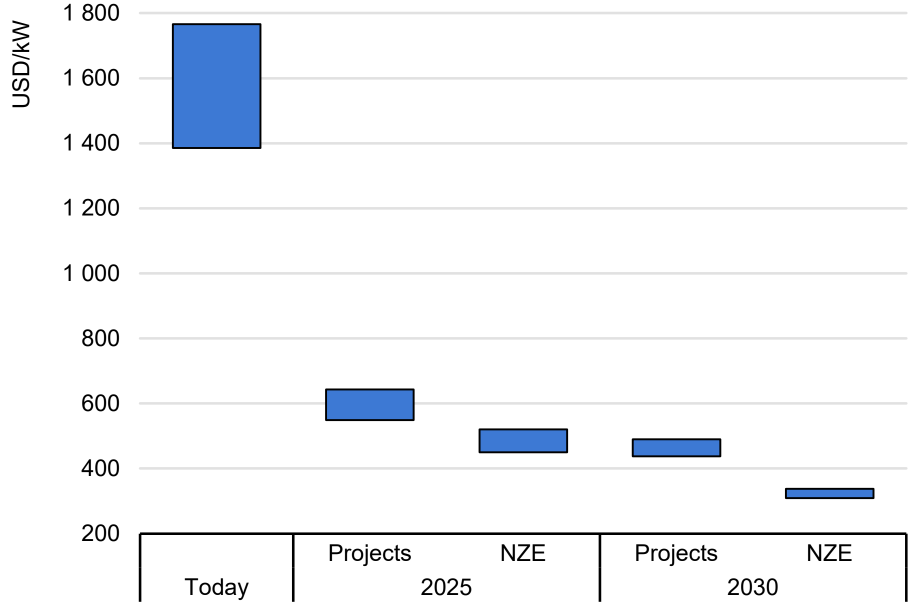
Cost reductions based on electrolyser capacity deployment

Today, the cost of an installed electrolyser (including the equipment, gas treatment, plant balancing, and engineering, procurement and construction cost) is in the range of USD 1 400-1 770 per kilowatt (kW), with the lower range corresponding to alkaline electrolysers and the upper one to PEM electrolysers, while solid oxide electrolyser costs are much higher and are not included in this range. Alkaline electrolysers produced in China can be much cheaper than the ones produced in Europe or North America, with costs around USD 750-1300/kW, and some sources pointing to cost as low as USD 300/kW.

Comparing only the initial investment costs can be misleading: the stack and control system design, as well as the material choices have an impact on the overall efficiency and on the degradation of the cell. Taking these aspects into account in the overall costs over the lifetime of an electrolyser, doubts have been raised that some Chinese electrolysers are not necessarily always more economic compared to ones produced in other parts of the world. In fact, with investment costs going down, the impact of efficiency on the hydrogen production costs will become more relevant.

Future electrolyser costs can be estimated using a component-wise learning curve approach, which describes costs as a function of cumulative capacity deployment. A learning rate of 18% is assumed for the electrolyser stack, which also takes account of learning rates for fuel cells that rely on the same electrochemical processes, while for the other components, representing almost half of the cost of an electrolyser, the assumed learning rate varies between 7-13%.

Evolution of electrolyser capital costs based on project pipeline and in the Net Zero Emissions by 2050 Scenario, 2025 and 2030



Note: NZE = Net Zero Emissions by 2050 Scenario.
Source: IEA analysis based on data from McKinsey & Company and the Hydrogen Council; STORE&GO (2018).

Based on this approach, the current pipeline of projects under construction and planned would reduce the capital cost of electrolysers by 60-64% by 2025, and 68-72% by 2030 (USD 440-500/kW). When looking at the Net Zero Emissions by 2050 Scenario, with an installed capacity of 725 GW globally by 2030, the cost reduction is 1.2-times the current projects deployment, reaching a reduction of 78-82% and resulting in electrolyser costs slightly above of USD 300/kW.

Since electrolysers require minerals for their production, in particular nickel and platinum group metals depending on the technology type, prices for these commodities can impact electrolyser costs. While limited data availability make it challenging to analyse how the recent surge in metal prices has affected the manufacturing costs of electrolysers, one can estimate the potential impacts of metal prices on overall electrolyser costs. Key metal inputs for alkaline electrolysers are nickel (800 kilogramme per megawatt [kg/MW]), steel (10 000 kg/MW) and aluminium (500 kg/MW). With current metal prices, this results in costs of around USD 25/kW, at around 3.5% representing only a small share of total alkaline electrolyser costs. For PEM electrolysers using platinum (0.3 kg/MW) and iridium (0.7 kg/MW), the situation is somewhat different. Also taking into account demand for steel, aluminium and titanium, the metal costs for PEM electrolysers, at USD 125/kW, currently account for around 12% of total electrolyser costs, largely linked to the costs for platinum and iridium. Production of iridium is largely concentrated in South Africa and Russia as a by-product of platinum and palladium mining. South Africa also dominates mining for platinum with a share of about 70%, followed by Russia with a market share of 10%. Prices for iridium and platinum can be quite volatile. Iridium prices for example reached an all-time peak in April 2021 of USD 200 000/kg, but declined by more than 20% by June 2022. While it is hard to predict how future prices for these metals will evolve, efforts are also being pursued to reduce the material needs of platinum group metals of PEM electrolysers. A reduction of specific iridium needs per MW by a factor of ten seems feasible in the next decade according to some experts.

Water access, besides electricity supply and the electrolyser itself, is an additional cost factor to be taken into account when planning hydrogen production projects. The use of seawater, where feasible, can be an option to overcome constraints in water-stressed regions. Desalination costs for reverse osmosis of seawater are estimated at around USD 1 per cubic metre (m^3) of water, adding up to less than 0.5% to the total cost of electrolytic hydrogen production. The energy requirements for desalination correspond to less than 0.1% of the electrolyser's energy consumption (reverse osmosis for desalination requires 3-6 kWh of electricity per m^3 of water). Water from desalination plants can also be transported to inland areas with limited freshwater resources. The water transport costs would increase the total costs for hydrogen only marginally by around USD 0.05-0.06/kg H_2 for 100 km distance. In areas without access to clean water, the local population could also benefit from the desalination plant, which on its own is too expensive for a local community, but represents only a small fraction of the renewable hydrogen project.

Direct seawater electrolysis would avoid the need for desalination plants, but this technology is not yet commercially available due to electrode corrosion from the high salinity of the seawater. Research projects are underway to develop electrolysers capable of using seawater. A start-up in the Netherlands supported by the German automotive supplier Schaeffler aims to develop PEM electrolysers which can directly use seawater by distilling the water with the heat from the electrolyser process. Direct seawater electrolysis could become an attractive option for the offshore production of hydrogen from wind energy, avoiding a separate desalination unit on a platform or in the bottom of a wind turbine. The Maryland based company sHYp B.V developed a pilot project that uses a membrane-less electrolyser and does not require seawater desalination; therefore it does not produce brine. Similarly, Stanford University researchers have demonstrated a new way of separating hydrogen and oxygen gases directly from seawater via electricity.

Hydrogen production with CCUS

State of play in hydrogen production from fossil fuels with CCUS

Gas reforming and coal gasification are the main technologies for hydrogen production today and generate significant CO_2 emissions. CCUS is a suite of technologies which involves the capture of CO_2 from point sources or from the air, and the subsequent utilisation of CO_2 as a feedstock in a range of products, or its permanent storage in deep underground geological formations. CCUS can contribute to low-emission hydrogen production by mitigating emissions from existing hydrogen plants in the refining and chemical sectors, and providing a potentially lower cost option to hydrogen produced by electrolysis in regions with abundant low-cost gas and/or coal resources and CO_2 storage capacity and/or regions with limited spare renewable energy capacity. The competitiveness of fossil fuel-based hydrogen hinges on the availability of relatively low-cost gas or coal resources, which is currently challenged by high natural gas prices particularly in gas-importing regions like Europe.

Production routes and deployment status

Close to 45 Mt CO_2 is captured today in around 35 CCUS facilities across a range of applications. Hydrogen production makes up a quarter of global capture capacity, with around 15 facilities, including retrofitted hydrogen production units in refining and fertiliser production in the United States that have been in operation since the early 1980s, and in steel manufacturing in Abu Dhabi since 2016. Most of the captured CO_2 from hydrogen plants today is injected in oil fields for enhanced oil recovery. Only one facility, the Quest plant in Canada commissioned in 2015, injects CO_2 in dedicated geologic storage formations.

Steam methane reforming (SMR) is the most widely used technology for natural gas-based hydrogen production, and is used in most of the gas-based operating facilities that are equipped with CO_2 capture. In a SMR process, natural gas is transformed into syngas in a reformer, which is then shifted into a hydrogen-rich mixture in a water-gas shift (WGS) reactor, from which high purity hydrogen can be obtained. Roughly 60% of the process CO_2 comes from natural gas oxidation in the reforming and shift reactors, and is available for capture in a high concentration stream, while the rest is emitted from the reformer furnace with a lower concentration. The energy required for CO_2 capture (steam for solvent regeneration and electricity for compression) can be partly recovered from the process, therefore only slightly increasing the amount of natural gas use. Overall, 90% capture can be achieved in an integrated SMR system with a relatively low energy penalty. A study by IEAGHG shows that achieving up to 99% CO_2 capture efficiency is possible at a marginal cost increase.

Autothermal reforming (ATR) is an alternative process in which gasification and WGS happen in the same reactor in the presence of pure oxygen. All the process CO_2 is available in a high concentration stream and over 95% of the CO_2 can be captured. CCUS-equipped ATR is not commercial but several new facilities plan to use the technology for dedicated hydrogen or ammonia production targeting capture rates of 95-99%, including the Stanlow refinery and H2H Saltend facilities in the United Kingdom, Barents Blue ammonia project *in Norway* and the Dakota H_2 Hub in the United States.

Partial oxidation (POx) is a route which converts a gaseous or liquid fuel (typically low value waste products in refineries) into hydrogen with no catalysts required. However, the hydrogen yield can be increased by the use of catalysts. POx could reach even higher energy and capture efficiencies than ATR and SMR. A POx hydrogen plant in the Pernis refinery in the Netherlands has been capturing 0.4 Mt CO_2 per year since 2005 for use in greenhouses, and plans to extend to biofuel production in 2024.

Hydrogen production from coal gasification has been used for many decades by the chemical and fertiliser industries for the production of ammonia and methanol, mostly in China. Coal gasification involves the conversion of coal into syngas, and the shift to a H_2/CO_2 rich stream from which 90-95% of the process CO_2 can be separated using chemical absorption or physical separation. Today two commercial coal-based hydrogen production units are capturing CO_2, the most recent completed in February 2022 at the Qilu fertiliser plant in China. In addition to several facilities planning to retrofit CCUS to existing coal-based production, some new plants are under development, for example as part of the Hydrogen Energy Supply Chain (HESC) project in Australia.

Hydrogen can also be produced via gasification using biomass feedstock instead of coal, which, in combination with permanent storage, can provide carbon dioxide removal (CDR). The first commercial biomass gasification plant to hydrogen could start capturing 0.15 Mt CO_2 per year in 2025 in California (United States).

It has also been suggested to use alternative sources of energy in SMR to run the reforming process. For example, electrification of SMR, if based on low-emission electricity, would reduce natural gas consumption and related CO_2 emissions by a third, leaving only the concentrated process flux of CO_2 to capture.

CCUS project pipeline

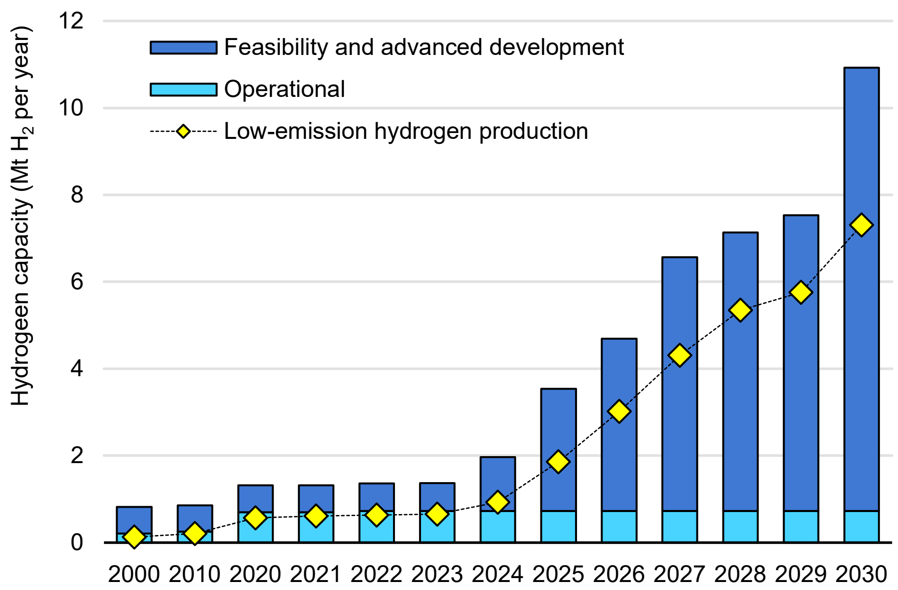
Low-emission hydrogen and ammonia[37] production has been a key driver of CCUS development in recent years, along with an improved investment environment and strengthened climate goals. Around a third of the global CCUS project pipeline plans to capture CO_2 from hydrogen production. Since January 2021, over 50 new hydrogen projects with CCUS were announced. If all projects under development go ahead, around 80 Mt CO_2 could be captured from hydrogen production by 2030, including around 50 Mt CO_2 in

[37] See Explanatory notes annex for low-emission ammonia definition in this report.

dedicated facilities for merchant hydrogen or ammonia production, around 5 Mt CO_2 in methanol and just over 15 Mt CO_2 in refineries[38]. Low-emissions H_2 production from CCUS-equipped facilities could reach around 7 Mt H_2 in 2030.[39] While promising in terms of the deployment pipeline, very few of these projects had reached final investment decisions as of August 2022. Further, it remains unclear whether current natural gas price hikes might delay FIDs planned for the coming year, especially in Europe.

Plants dedicated to hydrogen or ammonia production for off-site use dominate the project pipeline. At the regional level, the role for low-emission hydrogen production with CCUS is increasing in Europe, particularly in the United Kingdom and the Netherlands, boosted by industrial decarbonisation programmes. New hydrogen facilities are increasingly announced in close proximity to industrial clusters, which constitute both potential hydrogen demand centres, and cost sharing opportunities with other emitters in the construction of CO_2 transport and storage infrastructure. Around half of the announced capture capacity is being developed as part of CO_2 transport and storage hubs catering for multiple industrial sources, with around 80% located in Europe and 15% in Canada.

Past and planned capacity of CCUS-equipped hydrogen production facilities, 2000-2030



Note: Only includes hydrogen production capacity of projects with a disclosed start year for operation. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included.

Source: IEA tracking.

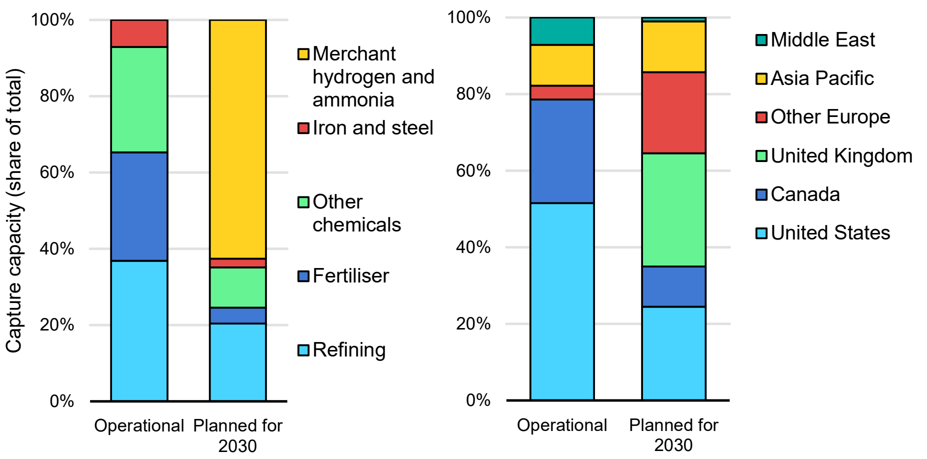
Biohydrogen with CCUS could also benefit from a boost in CDR investment. In the United Kingdom, the GBP 100 million DAC and other Greenhouse Gas Removal technologies competition was

[38] Only includes announced capture capacity of projects with a disclosed start year for operation. Projects for which CO_2 capture capacity is unknown are excluded.

[39] This could increase to around 10 Mt H_2 if projects at very early stages of development are included, e.g. only a co-operation agreement among stakeholders has been announced.

announced in June 2020 for new research and development of direct air capture (DAC) and CDR. In May 2022, three biohydrogen with CCUS projects were selected for RD&D funding out of 23 CDR projects. The GBP 5 million Hydrogen BECCS Innovation Programme, launched in January 2022, also specifically funds feasibility studies for bioenergy with carbon capture and storage (BECCS) hydrogen projects.

Hydrogen production with CCUS project pipeline by application and region

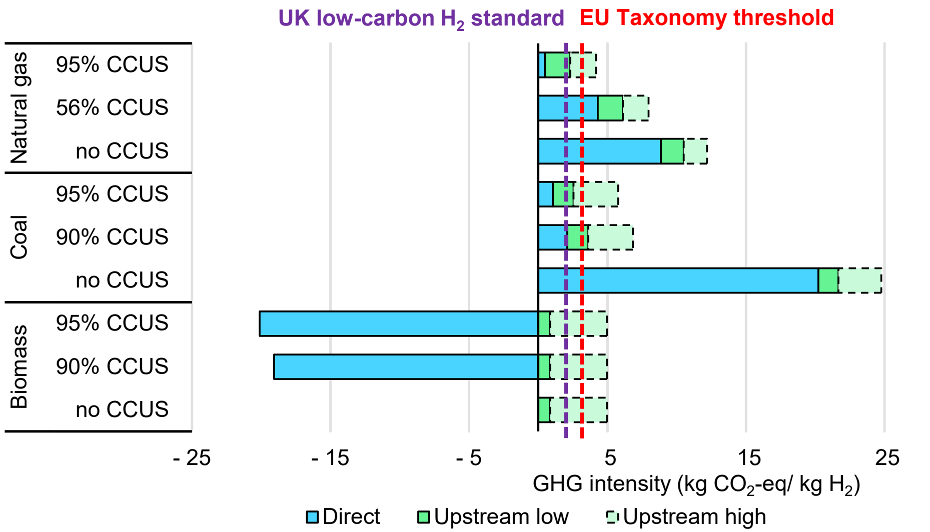


Note: Only includes announced capture capacity of projects with a disclosed start year for operation. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included.

Emissions from hydrogen production with CCUS

The life cycle greenhouse gas (GHG) impact of different hydrogen production routes varies widely. Direct process CO_2 emissions from hydrogen production from natural gas and coal can be considerably reduced by applying CCUS.

Direct and indirect GHG emissions from H_2 production



Notes: UK = United Kingdom; EU = European Union; CCUS = carbon capture, utilisation and storage; GHG = greenhouse gas.

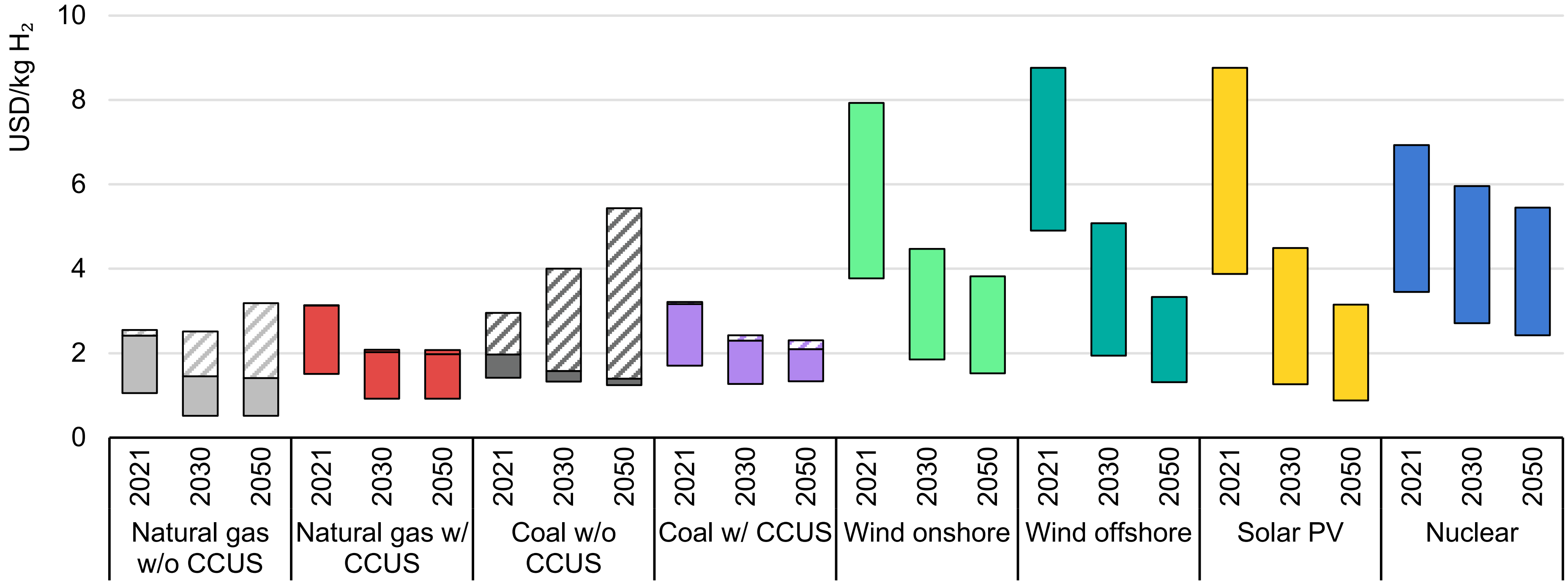
Sources: 10-90% range for upstream coal and gas GHG emissions from IEA (2019) and IEA (2022), respectively. Biomass supply chain emissions from the world range in IEA (2021) based on the GREET model.

High capture rates (>90-95%), however, are essential to minimise residual emissions from fossil fuel-based hydrogen-CCUS production routes, and to maximise CO_2 removal from biomass-CCUS routes. Depending on how fuels and materials are sourced, upstream natural gas, coal and biomass GHG emissions (CO_2, plus methane and nitrous oxide) can also significantly increase the GHG footprint of hydrogen production. Minimising and accounting for upstream emissions in certification frameworks is crucial to ensure hydrogen deployment delivers emissions reductions.

Comparison of hydrogen production routes

Opportunities for cost reductions to produce low-emission hydrogen

Levelised cost of hydrogen production by technology in 2021 and in the Net Zero Emissions by 2050 Scenario, 2030 and 2050



Notes: Ranges of production cost estimates reflect regional variations in costs and renewable resource conditions. The dashed areas reflect the CO_2 price impact, based on CO_2 prices ranging from USD 15/tonne CO_2 to USD 140/tonne CO_2 between regions in 2030 and USD 55/ tonne CO_2 to USD 250/ tonne CO_2 in 2050.

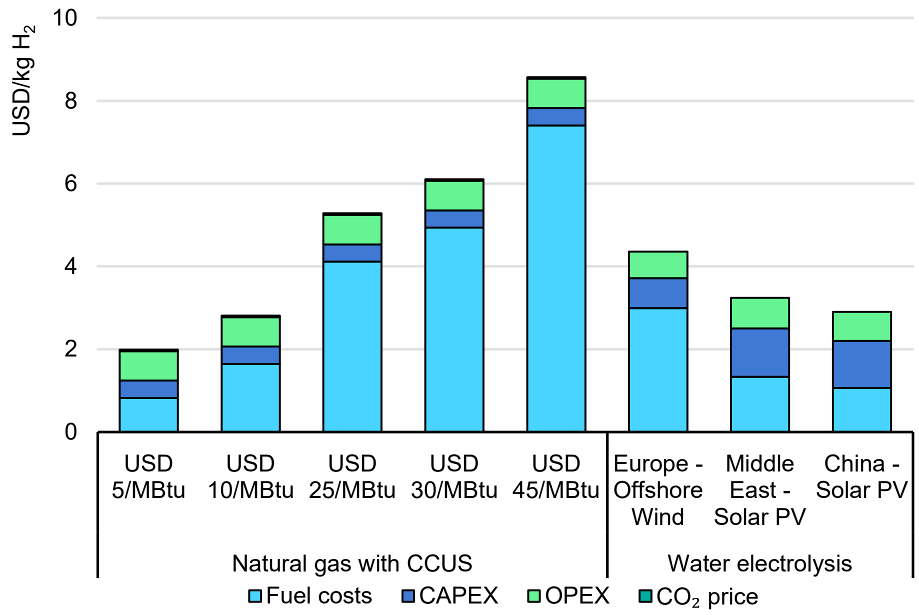
Sources: Based on data from McKinsey & Company and the Hydrogen Council; Council; IRENA (2020); IEA GHG (2014); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries; Element Energy (2018).

Bringing down production costs of low-emission hydrogen

In 2021, in most regions the cost of low-emission hydrogen production was more expensive than the fossil fuels without CCUS route. The average cost comparisons are: USD 1.0-2.5/kg H_2 from unabated natural gas; USD 1.5-3.0/kg H_2 from natural gas with CCUS; and USD 4.0-9.0/kg H_2 for production via electrolysis with renewable electricity.

Russia's invasion of Ukraine in early 2022 has amplified energy security concerns, with physical supply constraints for natural gas in Europe and a surge in natural gas prices over recent months, following a price surge in the second-half of 2021, as demand recovered from the Covid-19 pandemic. This has changed the economics of producing hydrogen from natural gas, for both with and without CCUS. At prices of USD 25-45 per million British thermal units (MBtu) observed in June 2022 in gas markets in Europe, hydrogen production costs from unabated natural gas at USD 4.8-7.8/kg H_2 are up to three-times the levels in 2021. Costs for hydrogen from natural gas with CCUS are in the range of USD 5.3-8.6/kg H_2, of which USD 4.1-7.4/kg H_2 alone is due to natural gas costs. With such prices, renewable hydrogen could become the cheapest option for producing hydrogen today in many regions if production capacity was available. It is, however, unclear how long this price situation will prevail. In the longer term, natural gas prices may decline again, improving the competitiveness of hydrogen production from natural gas.

Levelised hydrogen production costs from natural gas at various gas prices and from renewable electricity, 2022



Notes: CCUS = carbon capture, utilisation and storage; CAPEX = capital expenditure; OPEX = operational expenditure. Stack replacement cost included in OPEX for electrolysis. CO_2 price assumed at USD 80/tonne CO_2.

Sources: Based on data from McKinsey & Company and the Hydrogen Council; Council; IRENA (2020); IEA GHG (2014); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries; Element Energy (2018).

By 2030, hydrogen from solar PV could fall below USD 1.5/kg H_2 and by 2050 below USD 1/kg H_2 in regions with good solar conditions, (i.e. 2 600 full load hours), and thus low costs for electricity from solar PV, which account in these cases for around 55% of the total hydrogen production costs. Solar PV electricity costs have to fall to USD 14/MWh by 2030 and USD 11/MWh by 2050 to reach these hydrogen production cost levels. Alongside cost reductions and efficiency improvements for electrolysers, this would make hydrogen from solar PV by 2030 in regions with good resource conditions competitive with hydrogen production from natural gas with CCUS. The US Hydrogen Earthshot initiative aims to achieve hydrogen costs of USD 1/kg H_2 by 2030.

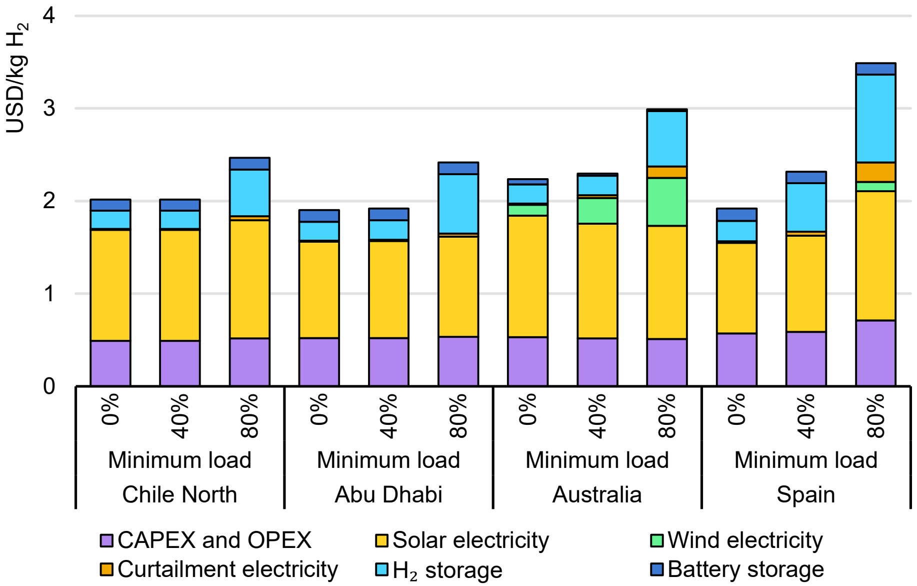
Addressing variability of solar and wind generation for hydrogen production

Considering only levelised costs when comparing low-emission hydrogen production routes ignores their operational differences. Hydrogen production from solar PV and wind is driven by the temporal availability of these variable renewable resources, while the production from dispatchable electricity or the production from fossil fuels with CCUS allows for a more stable production throughout the year. For a given electrolyser capacity, the production from variable renewables can result in lower full load hours over a year compared to the use of firm power supply from the grid, resulting in lower annual hydrogen production. In addition, costs may arise from needing to smooth renewable hydrogen supply fluctuations (daily or seasonal). While electrolysers can operate quite flexibly to accommodate the variability of renewable electricity supplies, downstream hydrogen users (whether consuming it directly or converting it into ammonia or synthetic hydrocarbon fuels) generally require supply stability.

Various options exist to increase the stability of hydrogen supply from variable renewables. Hybrid plants combining different renewable resources, such as solar PV and wind generation, can increase the annual full load hours, thus also lowering the overall production costs, despite the higher electricity costs from the combined solar PV and wind system. Overrating the renewable electricity capacity relative to the electrolyser capacity can increase the overall full load hours of the electrolyser and thus the hydrogen supply. During peak times of renewable electricity generation, this results in renewable electricity curtailment, if no other off-taker or use is available, but depending on renewable supply characteristics and the capital costs of the renewables and the electrolyser, the resulting cost disadvantages from curtailment can be more than offset by better utilisation of the electrolyser. Batteries can be used to balance the variability of renewable electricity generation. Storing hydrogen depending on the geologic availability in salt caverns or in tanks, though more expensive, can balance fluctuations in hydrogen production for downstream processes, such as ammonia production. If available, low-emission grid electricity can be used to compensate for hours with very low renewable generation, reducing the variability of the electrolyser operation.

Depending on the variability of the renewable electricity supply, ensuring more stable hydrogen production can increase the production costs compared to the case where stability aspects are ignored. The costs will depend on local conditions. To illustrate the impact of operational constraints on hydrogen production costs, the production of hydrogen from solar PV and wind for ammonia synthesis has been analysed for different locations by imposing minimum load factors for the ammonia synthetic process. To some extent the capital cost for the ammonia synthesis leads to an increase in the load factors to ensure a cost-effective operation (which accounts for the very similar cost levels at some locations for the case of no load factors and the case of a 40% minimum load factor in the figure). Hydrogen storage is a relevant option for all locations, while the choice of a hybrid design combining solar PV and wind, curtailment or the use of battery storage depends on the specific local conditions.

Levelised hydrogen production costs from solar PV and wind at different locations and minimum load factors, 2030



Notes: CAPEX = capital expenditure; OPEX = operational expenditure. The minimum load factors are applied to a downstream Haber-Bosch synthesis to produce ammonia, i.e. the synthesis process has to operate each hour of the year at or above this load factor. H_2 storage assumes storage tanks. Storage costs are allocated to hydrogen production. No access to grid electricity has been assumed.

Source: IEA analysis based on data from McKinsey & Company and the Hydrogen Council

These additional steps taken to increase the operating hours of subsequent synthesis processes generally increase the hydrogen production costs, as illustrated in the figure representing global hydrogen supply cost curves for different minimum load factors. Still, at locations with excellent renewable resources for electricity generation, hydrogen production costs, taking into account operational requirements to provide a more stable hydrogen supply, could fall below USD 1.5/kg H_2 by 2030.

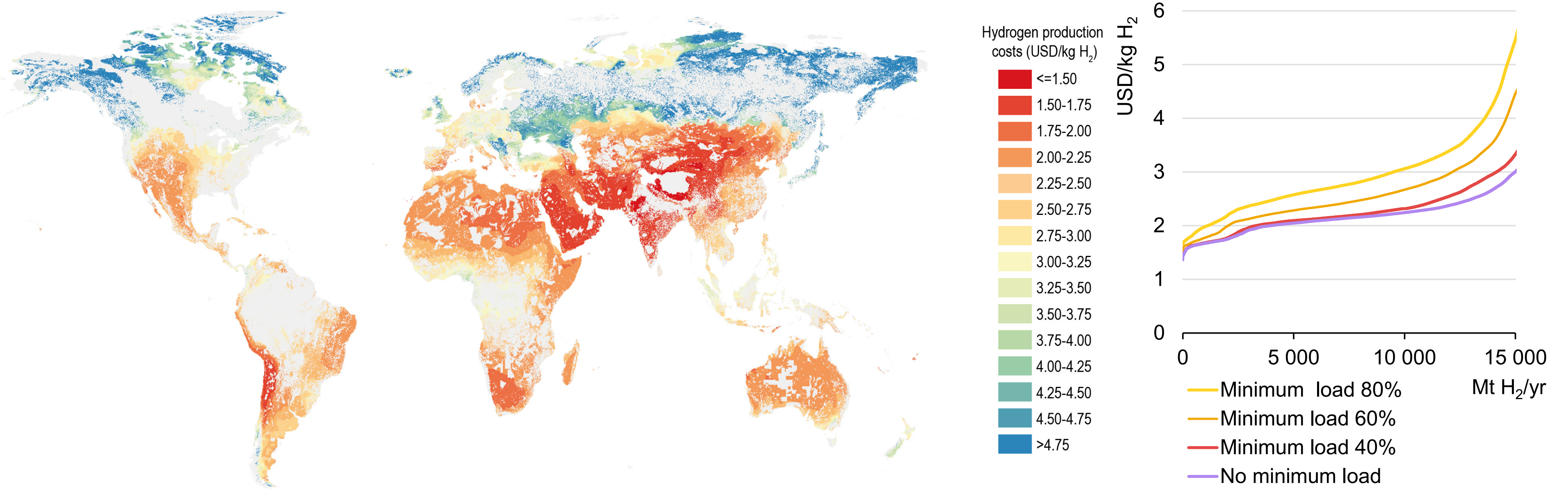
Using offshore wind generation for electrolysis is another option to provide hydrogen at relatively high full load hours and high utilisation rates for further synthesis steps in regions with good resource conditions, such as Argentina, Australia, China, Europe and New Zealand. By 2030, the global potential to provide hydrogen from offshore wind at costs below USD 3/kg H_2 and at capacity factors in the range of 50-75% stands at 250 Mt H_2. Higher capacity factors coincide in many cases with lower costs, but in some cases additional costs for moving to more distant locations from the coast or floating offshore wind turbines may outweigh the cost benefits of higher capacity factors.

Renewable resources such as geothermal and hydropower can provide a very stable electricity supply at high full load hours for hydrogen production. Large-scale electrolysers were built in the last century in countries with large hydropower resources (Canada, Chile, Egypt, Iceland, India, Norway, Peru and Zimbabwe) to produce hydrogen for ammonia production. The Southern Green Hydrogen project in New Zealand plans to use electricity from an existing hydropower plant to supply a 600 MW electrolyser.

Solar and wind can power hydrogen production at low costs and high load factors when combined or coupled with storage

Hydrogen production costs from hybrid solar PV and wind systems for a minimum load of 40%, 2030 (left map)

Global supply cost curves for different minimum load factors (right figure)



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

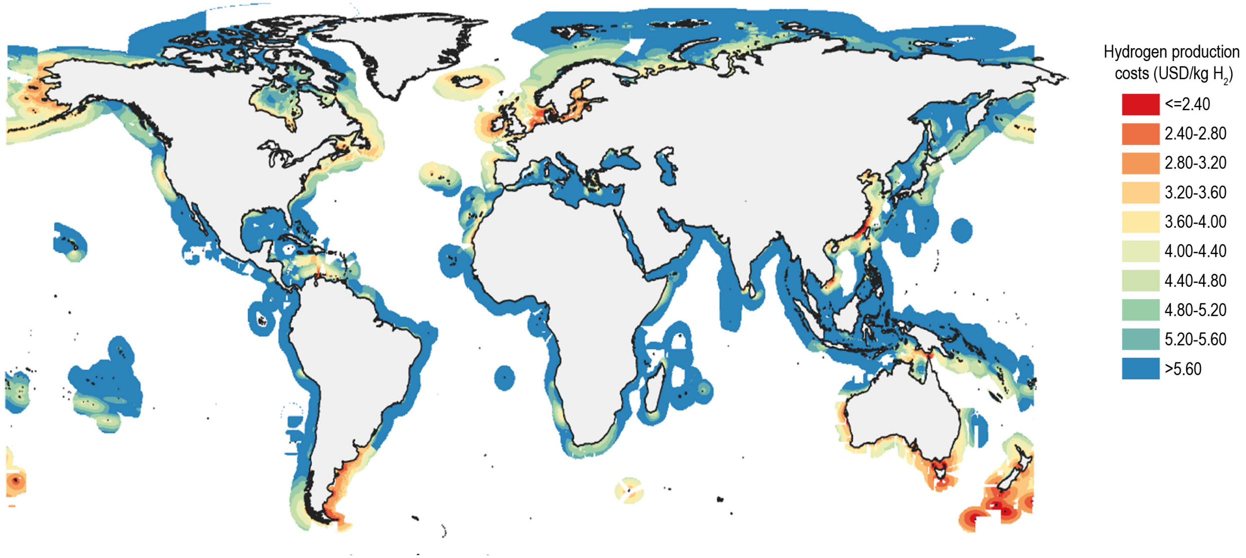
Notes: In the map, the grey colour represents areas that are excluded due to being protected areas or other land uses, though hydrogen projects may not be precluded in practice. The right figure shows hydrogen production costs. They are derived by determining the least-cost ammonia production costs for each location by optimising the mix of solar PV, onshore wind, electrolyser, ammonia synthesis, battery and hydrogen storage tank capacities, with an hourly minimum load of 40% for the ammonia synthesis process. The supply curves consider only locations less than 200 km from a coast.

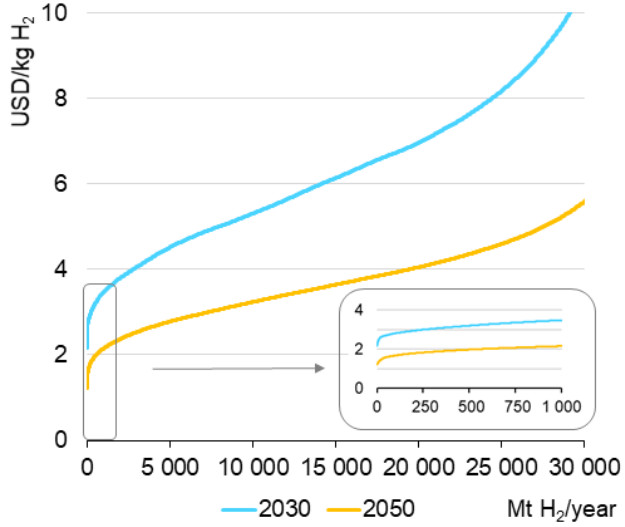
Sources: Based on hourly wind data from Copernicus Climate Change Service and hourly solar data from Renewables.ninja. Land-use data from GlobCover 2009, World Database on Protected Areas, Global Lakes and Wetlands Database and FAO Digital Soil Map of the World.

Offshore wind can become a cost-effective option for hydrogen production at high full load hours

Hydrogen production costs from offshore wind in the Net Zero Emissions Scenario, 2030 (left figure)

Supply cost curves for hydrogen production with offshore wind electricity generation, 2030 and 2050 (right figure)





This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Note: Only sites with an annual average capacity factor above 20% are considered in the supply cost curves in the right figure.

Source: Based on hourly wind data from Copernicus Climate Change Service, exclusive economic zones from Marine Regions and protected areas from the World Database on Protected Areas.

Hydrogen-derived fuels

Progress in hydrogen-derived fuel projects

Hydrogen has low volumetric energy density, which makes it more expensive to transport and store compared with fossil fuels. Converting hydrogen into ammonia and synthetic hydrocarbon fuels (synthetic methane, methanol, Fischer-Tropsch fuels) results in hydrogen-derived fuels and feedstocks with higher energy density that can often use existing infrastructure, for example, natural gas pipelines. The advantages of hydrogen-derived fuels being able to use existing infrastructure must be assessed against the additional conversion losses and costs to produce these fuels.

Worldwide, 78 projects for hydrogen-derived fuels were in operation in 2021, often pilot or demonstration projects consuming 0.03 Mt H_2. Synthetic methane dominates existing projects with a two-thirds share, while ammonia, methanol and Fischer-Tropsch fuels each account for around 10% of the number of projects. Interest in hydrogen-derived fuels is growing, with 154 projects announced for the period to 2030, almost twice the number of operating plants in 2021 and nearly double the 84 projects identified in the 2021 edition of the Global Hydrogen Review.

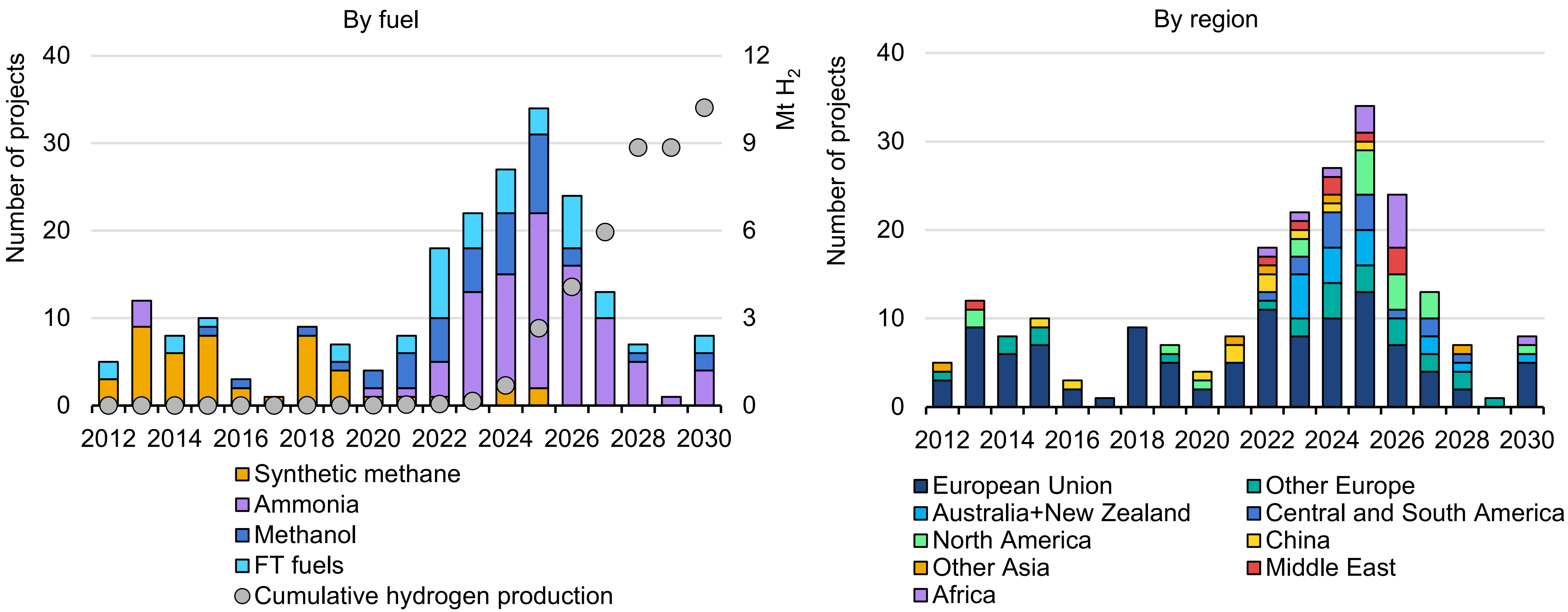
If all announced projects come to fruition, hydrogen demand would be more than 10 Mt H_2 by 2030.[40] The focus of the projects under construction or planned shifts from synthetic methane, accounting for 4% of the project pipeline, to ammonia, representing almost 60% of the planned projects.

The dominance of ammonia projects reflects that the fertiliser industry is a long-standing consumer and could be a ready market for low-emission ammonia. It requires no changes to processes or new technologies. In contrast to synthetic hydrocarbon fuels, ammonia does not require carbon as input for its production, resulting in a simpler supply chain. Ammonia can also be a near-term energy carrier option for long-distance transport of hydrogen, with existing experience in shipping and handling ammonia from the fertiliser industry. The Helios Green Fuels project in Saudi Arabia with 2 200 MW electrolyser capacity and 1.2 Mt NH_3 ammonia export volume is starting construction in 2022.

[40] This could increase to 11 Mt H_2 if projects at very early stages of development are included, e.g. only a co-operation agreement among stakeholders has been announced

Growing project pipeline for hydrogen-derived fuels

Projects to produce hydrogen-derived fuels and feedstocks from electrolytic hydrogen by start year and region



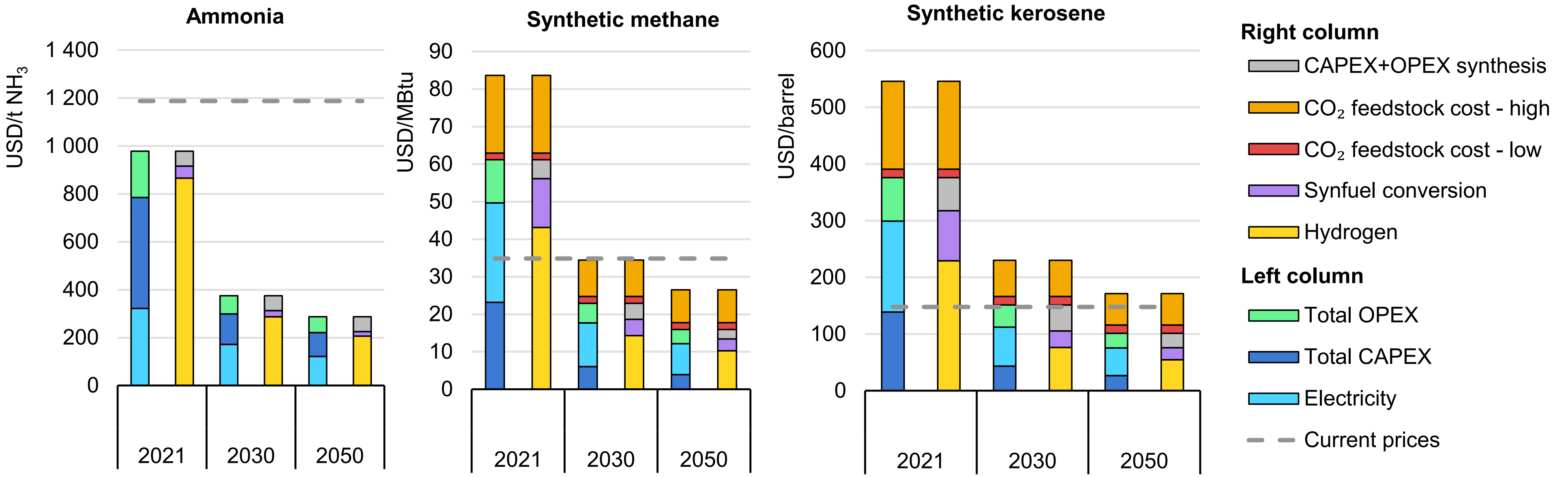
Notes: FT = Fischer-Tropsch. Circles in top figure represent cumulative number of hydrogen production facilities.
Source: IEA analysis based on the [Hydrogen Projects Database (2022)] and announcements by manufacturers and personal communications

Liquid hydrocarbon fuel projects are also attracting more attention, accounting for 40% of the project pipeline. Compared to ammonia, these fuels require CO_2 as an input, but can use existing infrastructure. Initially, the required CO_2 can be sourced from hard-to-abate emissions sources, such as cement plants, but in the longer term has to be captured at bioenergy conversion plants or directly from the atmosphere. By 2029, the Norsk e-fuel project (Norway) aims to produce 100 million litres of synthetic kerosene per year and using direct air capture to source the CO_2.

More than 80% of the existing projects are located in Europe. It accounts for about half of the planned pipeline projects, though more projects are being planned in other parts of the world. In particular, these are in Africa, Australia, Chile, Middle East, Australia and the United States, to take advantage of good renewable resources or access to cheap natural gas and CO_2 storage for the production of hydrogen-derived fuels.

Future cost reductions for hydrogen-derived fuels

Levelised costs of ammonia, synthetic methane and synthetic kerosene for electricity-based pathways in the Net Zero Emissions by 2050 Scenario, 2021, 2030 and 2050



Notes: NH_3 = ammonia; MBtu = million British thermal units; CAPEX = capital expenditure; OPEX = operational expenditure. Production costs refer to the Middle East region. Current prices refer to average European prices for ammonia, natural gas and kerosene in the first seven months of 2022. The left column for each year provides a breakdown of costs for electricity, CAPEX (electrolyser+synthesis plant), OPEX (electrolyser+synthesis plant) and CO_2 feedstock costs, whereas the right column for each year provides a breakdown of hydrogen costs, CAPEX and OPEX (synthesis plant), conversion cost and CO_2 feedstock costs.

Source: IEA analysis based on data from McKinsey & Company and the Hydrogen Council.

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Production costs and supply chains for hydrogen-derived fuels

Converting hydrogen into other fuels and feedstocks adds to its cost. For ammonia from electrolytic hydrogen, the additional costs of the Haber-Bosch synthesis account for around 15% of the total ammonia production costs, though electricity used for the production of hydrogen remains the biggest cost element with 30-40% of the total ammonia production costs. For ammonia produced from natural gas with CCUS, the fuel cost share can range from 40% for a gas price of USD 5/MBtu to 80% at a gas price of USD 30/Mbtu.

For the production of synthetic kerosene from electrolytic hydrogen, the conversion losses and CAPEX of the Fischer-Tropsch synthesis and the CO_2 feedstock costs are all relevant cost factors in addition to the electrolytic hydrogen costs. The CO_2 feedstock costs vary, largely depending on the available CO_2 sources. For example, biogenic CO_2 from ethanol production can have costs of USD 30/t CO_2, but its availability may be limited by the bioenergy availability and linked to the future deployment of BECCs (liquid biofuel production, biogas upgrading and power sector).

DAC is another CO_2 source option, which does not face supply constraints. DAC technology is still at an early development stage, with only a few plants worldwide in operation. Current DAC costs are USD 125-335/t CO_2, but with further deployment and technology improvements, costs could fall to USD 75-180/t CO_2 by 2030 and to USD 60-140/t CO_2 by 2050.[41] As a consequence, production costs of synthetic kerosene from renewable hydrogen which today are in the USD 390-550/barrel range are much higher than conventional kerosene (at almost USD 150/barrel in the first half of 2022), but could fall to USD 115-170/barrel by 2050.

[41] The cost projections refer to solid DAC, which requires low-temperature heat that can be provided from renewable sources, such as solar thermal energy or waste heat. Liquid DAC is another technology option, which requires high-temperature heat and therefore the use of natural gas, resulting in a CO_2 stream that also contains the CO_2 from natural gas, so that, if used for synthetic fuel production, part of the resulting fuel would be based on fossil CO_2 and could not be considered carbon neutral when combusted.

Hydrogen infrastructure

Unlocking infrastructure for hydrogen transmission and storage

Today hydrogen is mostly produced close to where it is used. As both production volumes and transport distances expand to meet increasing demand, significantly more hydrogen infrastructure will need to be developed to connect areas with good resources for low-emission hydrogen[42] production with markets. Developing the infrastructure for hydrogen transmission is not a minor undertaking: it is challenged by the low energy density of hydrogen (one cubic metre of hydrogen only contains a third of the energy of a cubic metre of natural gas at the same pressure and temperature) and its low boiling point, which is -253 degrees Celsius (°C) compared with -162 °C for natural gas.

Hydrogen is transported through pipelines much the same way natural gas is today. Currently about 2 600 kilometres (km) of hydrogen pipelines are operating in the United States and in Europe the estimate is around 2 000 km. Owned by merchant hydrogen producers such as Air Liquide, Air Products, Linde and others, these pipelines are located where large hydrogen users, such as petroleum refineries and chemical plants, are concentrated. Hydrogen gas can be transported to consumers with relatively low demands in multi-element gas container trailers, such as steel high-pressure tubes and in lighter composite pressure vessels, or in thermo-insulated cryogenic vessel trailers as liquid hydrogen for consumers with medium-size demand, where dedicated pipelines are not economically feasible due to relatively low volumetric flows.

In the short term, hydrogen is likely to be produced in clusters close to where it is used, mainly industrial facilities or refineries. More widespread use of hydrogen in this decade could require retrofitting[43] and repurposing[44] of existing natural gas networks, as well as building new dedicated hydrogen infrastructure. Over time, as demand for hydrogen rises, the cost advantages of producing large volumes of hydrogen in areas with high wind and solar resources for electricity generation or with the potential to store CO_2 could drive hydrogen infrastructure development, including by fostering international markets for hydrogen trade. In addition, importing countries will seek to diversify supplies geographically to reduce dependence on single markets and to strengthen security of supply. Long-distance transportation networks may need to be developed, using pipelines where possible, and ships for longer transport distances, which will require the conversion of hydrogen to a higher density form, i.e. liquefaction or conversion to ammonia, liquid

[42] See Explanatory notes annex for low-emission hydrogen definition in this report.
[43] Retrofitting is an upgrade of existing infrastructure that allows the injection of certain amounts of hydrogen into a natural gas stream up to a blending threshold.
[44] Repurposing implies converting an existing natural gas pipeline to a dedicated hydrogen pipeline.

organic hydrogen carriers (LOHC) or synthetic hydrocarbon fuels. Synfuels, will be used directly as feedstock and fuel, and ammonia may also be used directly without reconversion to hydrogen. In addition, hydrogen may also be used for the production and trade of hot briquetted iron[45] for steel manufacturers, especially in regions with iron ore mines.

The hydrogen infrastructure of the future has many elements and may include pipelines, compressors, trucks, ships, liquefaction and conversion plants, storage tanks and underground storage facilities. Some of these technologies are readily available today because hydrogen has long been used in industrial applications; however, the level of growth of low-emission hydrogen demand required to meet climate commitments and goals will require innovation to scale up the supply chain, including some technologies that are still at an early stage of development, particularly for long transportation distances.

[45] Hot briquetted iron refers to direct reduced iron (DRI) that has been compacted at a temperature above 650 °C into a pillow-shaped, high-density briquette to facilitate shipment of merchant DRI production.

Hydrogen transport by pipeline

Existing gas transmission networks can fast-track the development of hydrogen infrastructure

There are more than 1.2 million km of installed natural gas transmission pipelines worldwide. Projects for approximately another 200 000 km are under construction or in pre-construction development. The full implementation of net zero emissions pledges is set to considerably reduce natural gas consumption over time. This portends risks that part of the gas networks may become stranded assets. The existing natural gas infrastructure could be used to fast-track the deployment of low-emission gases. Some low-emission fuels[46], such as biomethane or synthetic natural gas, have almost identical physical and chemical characteristics as natural gas. This means that they can be used in the existing pipelines with some reconfiguration to accommodate their more decentralised production and the different gas quality.

Repurposing natural gas networks to hydrogen, however, will require more significant reconfiguration and adaptation. Depending on the type of pipeline and its operational characteristics, the technical challenges will differ; some will be manageable, while for others, such as offshore pipelines, further research is needed. If the technical challenges can be addressed, repurposing will be cheaper and faster than building new dedicated hydrogen networks and will reduce the risks of stranded assets. Two basic conditions will guide the opportunity to repurpose gas pipelines for hydrogen:

- The existence of unused or under-used pipelines and parallel pipelines, such that one line could be repurposed to pure hydrogen, while the other could satisfy the existing natural gas demand.
- A minimum hydrogen market uptake by relatively large consumers co-located with the repurposed pipeline, with expectations that more users will shift to hydrogen once the network is developed.

In cases where repurposing is technically not feasible and/or where natural gas demand remains, constructing new hydrogen pipelines alongside existing natural gas ones can benefit from established right-of-way and siting permits that can reduce costs and shorten lead times for pipeline development.

Repurposing gas networks will require an adjustment of the compression strategy, often including compressor replacements and a thorough inspection of the pipeline and the integrity of its components. Plus, there will be relatively simple measures, such as replacing valves and other leak-prone parts, and reconfiguring or replacing gas meters.

46 See Explanatory notes annex for low-emission hydrogen derived fuels and feedstocks definition in this report.

Pipeline integrity

Both hydrogen and natural gas transmission pipelines are constructed with carbon steel materials. Hydrogen specific codes, such as ASME B31.12 for inland hydrogen pipelines, however, tend to be more restrictive than their natural gas equivalents, as hydrogen may reduce ductility, fracture toughness and increase fatigue growth rate compared to natural gas. Due to differences in chemical properties, hydrogen can accelerate pipe degradation through a process known as hydrogen embrittlement, whereby hydrogen induces cracks in the steel.[47] There are solutions to combat some potential drawbacks, depending on the specific pipeline:

- Regularly monitor the pipeline integrity, e.g. through in-line inspections and pigging.
- Apply a hydrogen barrier coating to protect the pipelines.
- Lower pipeline pressure until the required threshold values for safe operation are met.
- Minimise pressure swings.

The HyReady industry partnership was established in 2014 and aims to formulate a set of practical guidelines to prepare natural gas transmission and distribution networks for blends and pure hydrogen. The consortium consists of more than 20 industrial partners, including gas transmission system operators (TSOs) and distribution system operators, from Asia, Canada, Europe and United States. Other activities include:

- In 2021, the ROSEN group opened its first hydrogen test lab at Lingen (Germany) to research repurposing gas infrastructure for hydrogen.
- In 2022, Ofgem's Strategic Innovation Fund granted GBP 1.1 million to National Grid Gas Transmission to evaluate the use of hydrogen in the UK gas grid, including to assess the potential of hydrogen barrier coatings to protect assets and to improve in-line inspection of pipelines prior to the first hydrogen injection (HyNTS pipeline data set project).
- In Germany, the HYPOS H2-PIMS project is developing a pipeline integrity management system (PIMS) with guidelines to operate pipelines with hydrogen blends and for repurposing them.

Some challenges remain to repurpose offshore gas pipelines as monitoring with current technology is difficult, there is often no detailed documentation on how the pipeline has been operated, and there are no standards for offshore hydrogen pipelines, unlike the ASME B31.12 for onshore ones. The H2PIPE project, launched by DNV in 2021, is assessing how the existing standard DNV ST-F101 for submarine pipeline systems should integrate hydrogen. The

[47] Hydrogen embrittlement is a metal's loss of ductility and reduction of load bearing capability due to the absorption of hydrogen atoms or molecules by the metal resulting in material separation (cracking) and ultimately embrittlement.

PosHYdon project in the Netherlands, among other activities, is analysing the repurposing of gas infrastructure assets in the North Sea, including pipelines, oil and gas wells and platforms for offshore hydrogen production. Research has shown that the 264 km NOGAT and 470 km Noordgastransport offshore pipelines connecting the North Sea to gas processing facilities in the Netherlands are conducive for the transport of pure hydrogen.

Repurposing pipelines for hydrogen use can cut investment costs 50-80% relative to new pipelines

Overview of capital costs for various design capacities of repurposed and new hydrogen pipelines

Pipeline diameter (mm/inch)	Type	Design capacity	Pipeline capacity (GW H_2, LHV)	Pipeline CAPEX (million USD/km)	Compression capacity (MW/1000 km)	Compression CAPEX (million USD/km)	Pipeline and compression CAPEX (million USD/km)
1 200/48	New	100%	16.9	3.3	434	1.7	5.0
	Repurposed			0.6			2.3
	New	75%	12.7	3.3	183	0.7	4.0
	Repurposed			0.6			1.3
	New	25%	4.2	3.3	6	0.02	3.3
	Repurposed			0.6			0.6
900/36	New	100%	4.7	2.6	93	0.4	3.0
	Repurposed			0.5			0.8
	New	75%	3.6	2.6	40	0.2	2.8
	Repurposed			0.5			0.6
	New	25%	1.2	2.6	2	0.01	2.6
	Repurposed			0.5			0.5
500/20	New	100%	1.2	1.8	26	0.1	1.9
	Repurposed			0.3			0.4
	New	75%	0.9	1.8	6	0.02	1.8
	Repurposed			0.3			0.3
	New	25%	0.3	1.8	0.6	0.002	1.8
	Repurposed			0.3			0.3

Notes: GW = gigawatt; LHV = lower heating value; km = kilometre; CAPEX = capital expenditure. It is assumed that the investment cost of a compressor station is USD 4 million per megawatt and that 48 inch pipelines would operate at 80 bar, while 36 and 20 inch pipelines would operate at 50 bar.

Source: IEA calculations based on data from Guidehouse (2021).

Compression needs

New compressors will be needed for repurposed transmission systems as well as more powerful turbines or motors, as the volumetric flow of hydrogen is up to three-times higher than for natural gas for the same pressure drop along the pipeline. As a result, for a hydrogen pipeline the maximum energy capacity could be up to 80-90% of that of a natural gas pipeline. Nevertheless, the dimensioning of the repurposed pipeline, i.e., for a given pipeline diameter of an existing or a new pipeline, the pressure and the throughput capacity compared to the theoretical maximum, can be optimised to minimise total costs. European gas TSOs have conducted hydraulic simulations to determine throughput capacity and compression power of common natural gas transmission pipelines with results that imply for a new 48-inch (80 bar) pipeline, compressor power is a significant expense. Operating the pipeline at 75% of its design capacity, the compression power and the subsequent electricity consumption would be around 45% lower, sufficient to lower the overall transmission costs. Repurposed 48-inch pipelines would be 15% cheaper to operate at 25% than at 75% of their design capacity, as the new compressor would be the major cost of repurposing when operating at high capacities, and decreasing the compressor size would also decrease electricity consumption. At the outset, when hydrogen flows are likely to be modest, investment in new compressors may be small. As hydrogen volumes increase, additional compression capacity may be added to raise the throughput capacity. Smaller diameter pipelines have higher pipeline costs for both repurposed[48] and new pipelines compared to compression, and the optimisation strategy would differ.

For offshore pipelines, the compression strategy is uncertain. Offshore natural gas pipelines operate at a higher pressure than onshore ones, avoiding intermediate stages of compression in route. However, hydrogen pipelines may not be able to operate at such high pressures to avoid fatigue cracking and potential embrittlement. This can be especially relevant for free-spanning offshore pipelines, i.e., suspended above the seabed and subject to more vibrations than buried onshore pipelines.

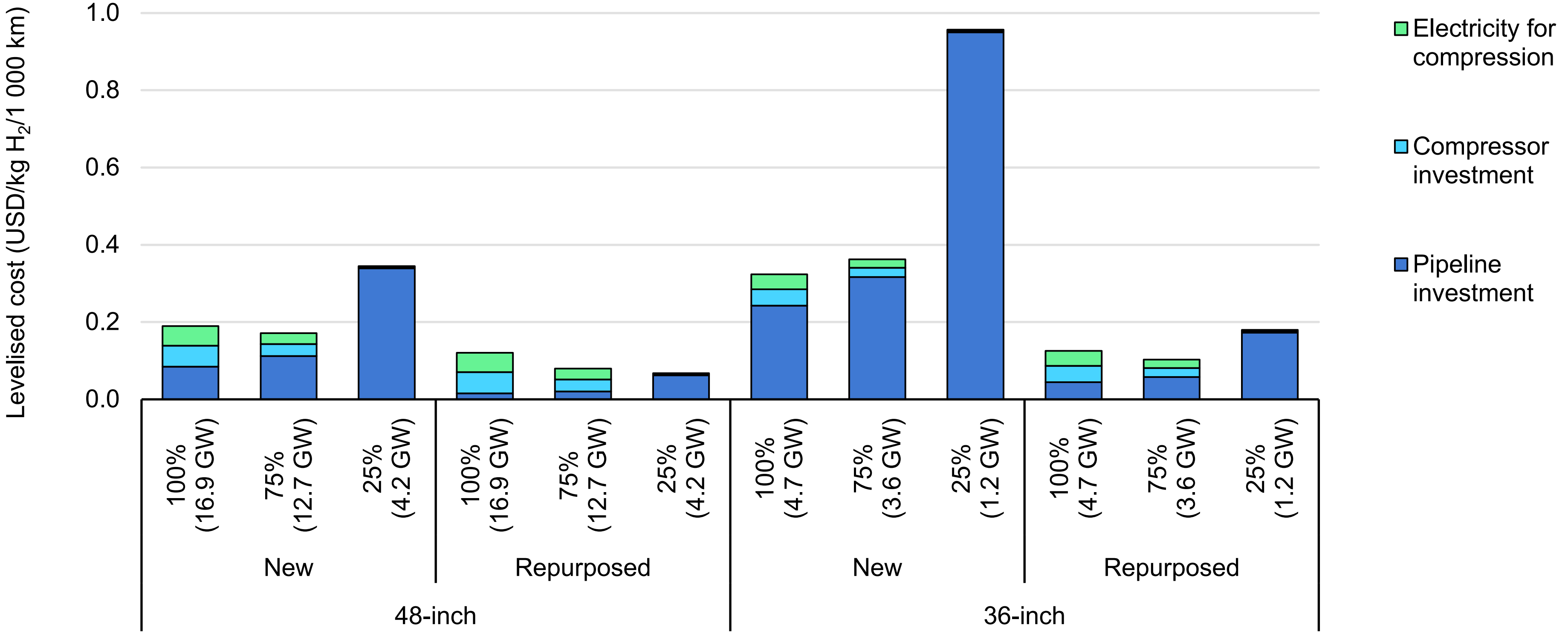
A natural gas network offers a few hours of storage through linepack.[49] Since hydrogen's volumetric density is one-third that of natural gas, the linepack potential would also be one-third smaller. Linepack introduces pressure variations, which particularly in offshore pipelines, might lead to fatigue cracking and embrittlement, but further research is needed. For onshore pipelines, it seems possible to define a safe operating range for linepack to avoid these issues. For example, Hynetwork has estimated an indicative operational pressure regime of 30-50 bar and a design pressure of 66.2 bar for the future hydrogen network in the Netherlands.

[48] Although the pipeline as an asset would remain, there may be some investment costs such as inspection of the integrity of the pipelines (in-line inspections, pigging) or coating, and replacement of some sections.

[49] Linepack refers to the storage of gas in a pipeline by compressing it, increasing the pressure of the pipeline. Since the pipeline can operate within a safe pressure range, the amount of gas injected into a pipeline may differ from the amount of gas withdrawn at a specific time, providing short-term operational flexibility to match supply and demand.

Optimise compression needs and throughput capacity of new and repurposed hydrogen pipelines to minimise transmission costs

Levelised cost of hydrogen transmission based on pipeline diameter and throughput capacity



Notes: A 100% throughput capacity means that the pipeline is designed to operate at 100% of the theoretical maximum throughput capacity, e.g. a 48-inch pipeline would have a theoretical maximum capacity of 16.9 GW of hydrogen. Analogously, a 75% throughput capacity means that the pipeline is designed to operate at 75% of the theoretical maximum throughput capacity, i.e. 75% of 16.9 GW, so the maximum throughput capacity would be 12.7 GW of hydrogen. Compressors use electricity from the grid (electricity price is assumed to be EUR 50 per megawatt-hour [MWh] [USD 59 /MWh]). Inland pipelines are modelled.

Source: IEA calculations based on data from Guidehouse (2021).

Blending can kick-start hydrogen production as demand increases to justify dedicated infrastructure

Blending is the injection of hydrogen into a natural gas stream using the existing infrastructure. Blending can be an interim strategy to trigger hydrogen production until the market grows sufficiently to justify the repurposing of existing gas assets or the construction of dedicated hydrogen pipelines.

Some research indicates that integrating blended hydrogen into natural gas transmission networks is feasible at levels of around 5-10% with relatively minor upgrading. In distribution networks, with polymer-based pipelines blending, shares of up to about 20% would not require significant changes in the infrastructure, although the gas chromatographs would need to be adapted.[50] While a 20% threshold in the distribution grids will require some upgrading, such as retrofitting the compressors, it seems to be the technical upper limit, above which significant investment may be needed, in particular for some downstream installations and end-use equipment. Research and development may extend the range to higher concentrations.

The threshold value must be established carefully, taking into account different consumers sensitivity to gas quality, such as natural gas refuelling stations and gas-fuelled vehicles. For example, gas cylinders are currently certified for a maximum hydrogen content of 2% (ISO 11439 standard). Differences in blending thresholds could affect cross-border interoperability of gas infrastructure, which may need harmonisation at exchange points. In the European Union, the REPowerEU Plan acknowledges that blending hydrogen into natural gas grids requires careful consideration, but suggests the possibility of blending up to 3%, equivalent to 1.3 million tonnes of hydrogen (Mt H_2) by 2030.

Hydrogen blending projects

Blending in the gas distribution grid. Several demonstration projects have investigated the feasibility of hydrogen blending in the distribution grid, initially in Europe and, in recent years, in other regions. Hydrogen blends of 20% in the distribution grid have been tested in Germany, France, Netherlands and the United States. Australia is already blending hydrogen at a distribution network level and there are several other projects around the world testing their networks with various blend ranges. Some countries are also

[50] If not stated otherwise, the hydrogen blending shares refer to volumetric blending shares. Since the volumetric energy density of hydrogen is one-third that of natural gas, a volumetric blending share of 30% corresponds to a 10% blending share in energy terms.

assessing the possibility of introducing wider hydrogen blending targets at the national level:

- In 2023, the United Kingdom government will take a decision on blending up to 20% of hydrogen into parts of the natural gas distribution grid.
- The Slovak gas transmission system operator, EUSTREAM, is planning adjustments to make their network ready for up to 5% hydrogen blending by end-2023.
- In Greece, the White Dragon project is planning to blend hydrogen until a dedicated hydrogen pipeline can be built.
- In Korea, Kogas plans to complete demonstration projects to verify the safety of the network to blend 20% hydrogen by 2026.

Some countries use town gas for cooking and heating by residential and commercial users. Town gas already has around 50% hydrogen content, so replacing conventional hydrogen supply with low-emission hydrogen would reduce greenhouse gas emissions from hydrogen production without entailing distribution challenges. For example, Singapore distributes town gas by pipeline and its town gas provider, City Energy, is exploring the feasibility of importing low-emission hydrogen to substitute hydrogen from natural gas reforming. In the United States, Hawaii has been blending up to 15% hydrogen since the 1970s and Hawaii Gas is looking into low-emission hydrogen to substitute the current hydrogen injection.

Blending in the gas transmission grid. In Italy in 2019, Snam introduced 5% and 10% hydrogen blends into a high-pressure gas transmission network as a trial. In Denmark, Energinet tested up to 15% in a closed-loop high pressure system (40-80 bar) and is now testing a share of up to 25%. Hydrogen blends of up to 30% were tested in an offline test loop to evaluate changes on an existing transmission pipeline in the HyNTS Hydrogen Flow Loop project in the United Kingdom. In the United States, the HyBlend project will test pipeline materials with different blend shares and pressures up to 100 bar.

Hydrogen deblending

Hydrogen deblending extracts pure hydrogen for dedicated uses as well as for hydrogen-free natural gas from blended hydrogen and natural gas streams. Although gas separation technologies, such as cryogenic separation, membrane separation or pressure swing adsorption, are mature and have been used in the industry for decades, the technology has not yet been used on a large scale, e.g. in a distribution network. Various situations may require or benefit from hydrogen deblending:

- Some consumers cannot use a blended gas with high levels of hydrogen, such as some old gas turbines or natural gas refuelling stations, which may require >98% natural gas.
- Some consumers will require a >99.97% hydrogen gas (ISO 14687:2019), such as fuel cell vehicles.
- It may be beneficial to extract the hydrogen in bulk at an industrial hub for further distribution to compatible and contracted users.

Deblending cost will depend on the hydrogen concentration in the blend, the pressure and the desired level of purity of hydrogen and natural gas. H2SITE estimates a cost range of USD 0.5-0.8/kg for hydrogen blends between 5% and 20% to obtain 99.97% hydrogen.

In the United Kingdom, HyNTS Deblending is exploring options for various hydrogen blends to provide modular solutions for refuelling automotive applications that require hydrogen with high purity levels and is planning to build an offline demonstration facility.

Selected operational and planned hydrogen blending projects in distribution networks

Project name	Country	City	Start year	End year	Blending volume	Project size as announced
HyP SA	Australia	Tonsley	2021	-	<5%	700 homes
Western Sydney Green Gas	Australia	Sydney	2021	2026	2%	23 500 residential, 100 commercial and 7 industrial customers
Clean Energy Innovation Park	Australia	Perth	2023	-	<10%	1 500 t H_2/year
HyP Murray Valley	Australia	Albury and Wodonga	2024	-	<10%	800 homes
HyP Gladstone	Australia	Gladstone	Mid-2020s	-	<10%	66 kg H_2/day, 770 homes
Enbridge Gas and Cummins Ontario	Canada	Markham	2022	-	2%	3 600 customers
ATCO - Alberta	Canada	Fort Saskatchewan	2022	-	5%	2 100 customers
Gasvalpo Energas-Coquimbo	Chile	La Serena	2022	-	5-20%	1 800 customers
Promigas, Surtigas - Heroica	Colombia	Cartagena	2022	-	NA	1.6 t H_2/year (15 t H_2/year in next pilot phase)
GRHYD	France	Dunkerque	2017	2019	0-20%	100 homes
Jupiter 1000	France	Fos-sur-Mer	2020	-	1-2%	430 kg H_2/day
ITM Power Thüga Plant	Germany	Frankfurt	2013	2017	NA	325 kW electrolyser
WindGas Haßfurt	Germany	Haßfurt	2016	-	4-5%	14 000 customers
Freiburg Municipal Energy Network	Germany	Freiburg	2017	-	2%	300 kW electrolyser
Wind2Gas Energy	Germany	Brunsbüttel	2019	-	2%	2.4 MW electrolyser
GAIL- Madhya Pradesh	India	Indore	2022	-	2%	NA
NTPC-Gujarat Gas Limited	India	Hazira	Mid-2020s	-	5%	200 homes
H_2 in natural gas in Ameland	Netherlands	Ameland	2007	2011	<20%	14 homes
Green Pipeline Project -Setubal	Portugal	Seixal	2022	-	2-20%	80 customers
HyDeploy	United Kingdom	Staffodshire	2019	2021	<20%	130 homes (Keele University campus)

Project name	Country	City	Start year	End year	Blending volume	Project size as announced
HyDeploy 2	United Kingdom	Winlaton	2021	2022	<20%	688 homes, a church, primary school and several small businesses
HyNet North West	United Kingdom	various	2025	-	<20%	2 million customers (Liverpool, Manchester, Warrington, Wigan and North Cheshire)
CenterPoint Energy - Minnesota	United States	Minneapolis	2021	-	<5%	432 kg H_2/day
ThermH2	United States	Salt Lake City	2021	2021	5%	various test homes
New Jersey Resources	United States	Howell	2021	-	<1%	65 kg H_2/day
Dominion Energy-Utah	United States	Delta	2023	2021	5%	NA
NW Natural- Oregon	United States	Eugene	2024	-	5-10%	2 300 residential, 160 commercial and 6 industrial customers
HyGrid – Long Island	United States	Hempstead	2022	-	5-20%	800 homes

Notes: t = tonnes; kg = kilogramme; kW = kilowatt; NA= not available. When the project does not have a distinct project name, the name of the main company developing the project is used. The start year represents the year in which a project became operational or the expected date when it will become operational.

Repurposing natural gas pipelines to accelerate hydrogen deployment

Practical experience with repurposing natural gas pipelines to 100% hydrogen is very limited. The only example is a 12 km repurposed pipeline in the Netherlands which transports more than 4 kilotonnes (kt) per year of hydrogen that is a by-product from Dow Chemical Benelux factory provided to Yara, a chemical manufacturer in Sluiskil, for use as a raw material.

There is a concept to develop a dedicated hydrogen pipeline network in Europe - the European Hydrogen Backbone (EHB). In 2022, the CEOs of 31 European gas infrastructure companies from 25 EU member states, Norway, Switzerland and United Kingdom presented a pledge to the European Commission to establish hydrogen supply corridors by 2030, initially to connect local supply and demand, and progressively to connect European and neighbouring regions with export potential. This is to be realised by converting pipelines that fall redundant due to declining natural gas demand to minimise stranded assets and by developing new infrastructure where needed. By 2030, the EHB could consist of an initial 28 000 km pipeline network to connect emerging hydrogen clusters, ports and regions that have high potential for low-emission hydrogen supply. By 2040, this network could expand to a pan-European network with a length of about 53 000 km, of which about 60% of repurposed natural gas pipelines and 40% new pipelines. Some European countries are starting to translate the ideas of the EHB into concrete actions and investments.

In the Netherlands in June 2022, the government announced the investment of EUR 750 million to develop a national hydrogen transmission network by 2031. The first stage, due to be completed by 2026, will connect northern Netherlands and include planned hydrogen salt caverns in Zuidwending. The hydrogen network will be 1 400 km, of which 85% will be repurposed natural gas pipelines. The announced investment, including co-financing from Gasunie, will not include compression, as the hydrogen transport network is intended to be operated at 30-50 bar, so that the output pressure provided by electrolysers will suffice. Beyond 2035, and once hydrogen flows increase, additional investment in compressors may be needed.

Gas TSOs in other countries, such Denmark, Germany, Italy, Spain and United Kingdom have indicated plans to repurpose relatively large parts of their natural gas transmission network to hydrogen, in particular to connect several industrial clusters to promising areas for low-emission hydrogen production. Mexico, in its 2022-2036 Electricity Programme, suggests the future possibility of repurposing of a large part of its natural gas pipelines to hydrogen in areas with good renewable energy resource potential and access to desalinated water.

Planned projects for repurposing natural gas transmission pipelines to hydrogen

Project name	Country	Start year	Companies	Length (km)	Description
Hydrogen network Netherlands	**Netherlands**	2026-2031	Gasunie	1 400	Gasunie will develop and operate the hydrogen network, which will consist of 85% repurposed natural gas pipelines. It will connect seaports with large industrial clusters in the Netherlands, storage facilities as well as neighbouring countries, Germany (Ruhr area and Hamburg) and Belgium.
Get H2 Nukleus	**Germany**	2024	OGE, RWE, BP, Evonik, Nowega	134	Repurposing 122 km of existing Evonik and OGE pipelines to transport 100% hydrogen and construction of 14 km of a new hydrogen pipeline to connect to the Get H_2 Nukleus project. It would supply hydrogen to BP refineries in Lingen and Ruhr Oel refinery in Gelsenkirchen, and to the Marl Chemical Park.
HyPerLink	**Germany**	2025-2030	Gasunie	610	HyPerLink envisions a hydrogen pipeline network to connect wind-powered hydrogen production to storage and consumers in industrial and urban centres in northern Germany. It will mostly repurpose existing gas infrastructure.
Green Octopus	**Belgium, Germany, Netherlands**	2022-2030	WaterstofNet, Gasunie, Fluxys, Ports of Rotterdam, Antwerp and Zeebrugge	-	Collaboration between Belgium, Germany and the Netherlands to establish a hydrogen network to integrate low-emission hydrogen produced from offshore wind and imports with storage facilities and demand.
H_2ercules	**Germany**	2026-2030	OGE, RWE	1 500	H_2ercules aims to link electrolysers, import terminals and storage facilities from the north with industrial consumers in the west and south of Germany, using mostly repurposed pipelines. The estimated cost is EUR 3.5 billion. Thyssenkrupp has signalled their interest. RWE intends to build at least 2 GW of H_2-ready gas-fired power stations close to the planned H_2ercules pathway. The Get H_2 Nukleus project is part of H_2ercules.
Project Union	**United Kingdom**	2030	National Grid	2 000	Project Union hydrogen network aims to link industrial clusters and repurpose around 25% of the existing gas transmission pipelines. National Grid will carry out a feasibility study in 2022-23 to assess which pipelines could be repurposed and additional infrastructure needs.
Danish-German Hydrogen network	**Denmark, Germany**	2030	Energinet, Gasunie	330-440	The planned hydrogen network from Esbjerg (340 km, 63% repurposed pipelines) or Holstebro (440 km, 48% repurposed) in Denmark to industrial demand centres in Hamburg, Germany. Energinet and Gasunie have signed a memorandum of understanding to continue analyses. Pipelines in Germany would also be part of the HyPerLink project.

Project name	Country	Start year	Companies	Length (km)	Description
Snam 2030 vision	**Italy**	-	Snam	2 700	Snam has verified the compatibility of its existing natural gas pipelines for hydrogen, identifying that 99% of its network is ready to transport 100% hydrogen, 70% of it with no or limited pressure reduction. The Snam 2030 vision aims to spend around EUR 3 billion to repurpose the gas network from Sicily to the north of Italy.
Catalina	**Spain**		Enagás, Naturgy, Fertiberia, Vestas	450	Catalina would link hydrogen production in the area of Aragón to demand centres on the Spain’s east cost (Valencia) for production of green ammonia, other industrial uses and blending.

Underground hydrogen storage

Hydrogen storage is needed to balance fluctuations and to ensure security of supply

Underground natural gas storage plays a key role in meeting gas supply flexibility requirements. Current global storage capacity is close to 430 billion cubic metres (bcm), about 10% of global natural gas demand. In addition to meeting seasonal demand swings, natural gas storage sites can meet short-term demand fluctuations. Seasonal spreads between winter and summer natural gas prices, together with short-term price volatility are the two key market value drivers of gas storage. Storage facilities can also provide benefits through optimised design of gas transport networks. Available storage capacity can facilitate the initial development of gas trading, by providing the physical volumes necessary for hedging. In addition, natural gas storage facilities support the system security in case of supply disruption. Similarly, as hydrogen is expected to have an important role in the energy system, storage will also be important to maintain its reliability:

- Balancing fluctuations in supply from electrolysers using variable renewable electricity and some seasonality in hydrogen demand.
- Providing energy security in case of supply disruptions, such as trade conflicts, unforeseen outages, natural disasters, and reducing related price volatility.

Characteristics of hydrogen underground storage types

	Salt cavern	Depleted gas field	Aquifer	Lined hard rock cavern
Specific investment	Medium	Low	Low	High
Levelised cost of storage	Low	Medium	Medium	Medium
Cushion gas*	25-35%	45-60%	50-70%	10-20%
Capacity	Medium	Large	Large	Small
Annual cycles	Multiple	Few	Few	Multiple
Geographic availability	Limited	Variable	Variable	Abundant**

*Cushion gas is the volume of gas required as a permanent inventory in a storage facility. Its goal is to maintain sufficient pressure in the storage to meet withdrawal demands at a high rate, even at low storage levels.

**Igneous or metamorphic rock.

Natural gas storage today is driven by strong seasonality in demand for heating. Hydrogen demand variability is expected to be less seasonal, though strong fluctuations in variable renewables-based electricity generation will require flexible hydrogen storage, not only to match demand but to minimise oversizing the associated infrastructure.

Four types of underground storage are in operation today for natural gas: salt caverns, depleted gas fields, aquifers and lined hard rock caverns. The project feasibility and progress to use these storage types for hydrogen are summarised here.

Salt caverns

Salt caverns are already in use today for hydrogen storage. Hydrogen has been stored in salt caverns at Teesside (United Kingdom) since 1972 for use in ammonia and methanol production. Total capacity of these salt caverns is 0.2 million cubic metres (m^3) and around 25 gigawatt-hour (GWh) of working storage at 45 bar.[51]

Hydrogen is also stored in salt caverns along the Gulf Coast in Texas (United States) to supply the chemical and petrochemical industries. They include Clemens Dome (81 GWh since 1983), Moss Bluff (123 GWh since 2007) and Spindletop (274 GWh since 2016). These examples demonstrate feasibility to store hydrogen in salt caverns. However, the geographical availability of suitable salt caverns is limited and they typically have smaller working storage capacity. They can be operated flexibly, with several cycles per year, referred to a fast-cycling operation. Further research is needed in a number of areas including to assess the integrity of the salt cavern when subject to fast cycling, as hydrogen from electrolysis will require higher flexibility. This aspect is the subject of current analysis in Task 42 on Underground Hydrogen Storage of the IEA Hydrogen Technology Collaboration Programme.

Projects. Many ongoing and planned demonstrations and first-of-a-kind commercial facilities aim to demonstrate hydrogen storage in salt caverns. For example, EWE, within the HyCAVmobil research project, started leaching a salt cavern in Rüdersdorf (Germany) in 2021 and expects to start testing how storage affects hydrogen purity by end-2022, with a budget of nearly EUR 10 million. The HyPSTER project (Storengy) in France aims to demonstrate large-scale storage of hydrogen from electrolysis, including fast cycling, with a budget of EUR 13 million and a capacity of 0.1 GWh, with tests planned to start in 2023.

In various projects, salt caverns for hydrogen storage are planned adjacent to existing natural gas storage caverns, or are planned for repurposing decommissioned natural gas storage caverns, as both alternatives are likely to offer expedited permitting processes, access to existing infrastructure and easier siting approvals than greenfield developments. During 2021 and 2022, the HyStock project is using a borehole in EnergyStock's natural gas salt cavern facility in Zuidwending (Netherlands) to investigate the effect of hydrogen on existing equipment, materials and the salt wall, and to understand the

[51] 1 gigawatt-hour (GWh) is equivalent to the energy content of 30 tonnes of hydrogen.

different procedures and equipment that hydrogen storage may require compared to natural gas.

Some salt caverns used for natural gas storage are being readied to be able to accommodate shares of hydrogen blends from the grid. Carriço, a salt cavern facility in Portugal, plans to store between 1-5% of hydrogen blended in natural gas by 2025 and around 10-15% by 2030, with an allocated investment of EUR 40 million up to 2024 for this adaptation. New natural gas salt cavern storages may also be built as hydrogen-ready. For example, UK Oil & Gas intends to build their new 1.2-bcm natural gas salt caverns in Portland Port in United Kingdom, as hydrogen-ready, which could provide some 4 000 GWh of hydrogen storage once repurposed.

Depleted natural gas fields

Depleted natural gas reservoirs account for 76% of the total natural gas storage capacity in the world and have been used for decades. Gas fields are larger in volume than salt caverns and are more geographically widespread; however, challenges remain for their use for hydrogen storage. This is because hydrogen may be more difficult to contain than natural gas due to its higher compressibility factor, diffusivity and lower viscosity, and because it is also more reactive. Due to their porous nature, depleted natural gas fields do not provide large short-term flexibility and operate only with a few cycles per year. They could therefore play an important role in managing seasonal fluctuations of supply and demand and enhancing security of supply.

Projects. There are no commercial facilities to store pure hydrogen in porous rock. Relevant information, however, can be drawn from experience with underground storage of town gas that is produced via coal gasification and may had more than 50- hydrogen content. Such experience includes town gas operations in the depleted gas field of Kirchheilingen (Germany) in the 1970s. In the late 2010s, the Underground Sun Storage project in Austria stored hydrogen from electrolysis and demonstrated the ability of the storage facility to tolerate up to 20% hydrogen concentration. The subsequent Underground Sun Storage 2030 project aims to provide insights into the storage of up to 100% hydrogen in depleted gas fields. The Hychico storage project in Argentina is also testing blends in a demonstration gas field since 2016. In Ireland, the Green Hydrogen @Kinsale project has conducted proprietary evaluations of the hydrogen storage potential in depleted gas fields. In Italy, Snam conducted a series of tests that confirmed the possibility of storing hydrogen in its depleted gas fields, with tests underway to assess the impact of 100% hydrogen.

Aquifers

Aquifers represent about 11% of existing underground natural gas storage capacity. The geology of aquifers is similar to depleted natural gas fields. They are both porous sedimentary rock structures but aquifers contain water instead of natural gas, and must be overlaid with an impermeable cap rock to keep the gas underground. The aquifer can be converted for gas storage by injecting gas at high pressures, with both water and the rock overlaying serving as containment. However, unlike depleted gas fields, which are known to be tight because they were originally filled with gas, aquifers may not be tight on all sides, and extensive geological surveys are required to determine whether there are ways for gas to escape. The operation of aquifers as natural gas storage usually requires more cushion gas and allows less flexibility in injecting and withdrawing gas.

Projects. No commercial aquifer storage for hydrogen is in operation, and pure hydrogen storage in aquifers has not yet been tested. However, in the 1970s, saline aquifers were used to store town gas in Lobodice (Czech Republic), Engelbostel and Ketzin (Germany) and Beynes (France). The RINGS (Research on the injection of new gases into storage facilities) project is analysing the impact of adding hydrogen and biomethane to the natural gas flow injected into Teréga's aquifers in France.

Lined hard rock caverns

Lined hard rock caverns have been used for storing natural gas liquids (propane, butane) and crude oil. Hard rock caverns could also be used to store hydrogen, either as compressed gas at 100-250 bar or liquefied. For compressed gas, a liner can help to improve the tightness of the rock cavern. The feasibility of lined hard rock cavern for natural gas storage was demonstrated in 2002 at the Skallen project (Sweden), including fast cycling of the storage, which makes hard rock cavern storage particularly interesting to meet short-term supply and demand swings.

Hydrogen could also be liquefied and then stored in a lined hard rock cavern, which would, however, require a containment and insulation system similar to above-ground hydrogen storage tanks. The use of hard rock caverns for LNG storage was demonstrated in Korea in 2004.

Projects. In Sweden in June 2022, SSAB, LKAC and Vattenfall inaugurated the HYBRIT demonstration facility (100 m^3, <250 bar) to store hydrogen in lined hard rock caverns at Luleå. It is the first of its kind and is expected to run until 2024, with total funding of SEK 331 million (USD 33 million). At a later stage, a full-scale facility of around 100 000 m^3 (60 GWh H_2) could be constructed.

Research and development needs for hydrogen storage

While there has been significant progress in recent years in the announcement of salt cavern storage projects for hydrogen, which will be key to provide a degree of flexibility to systems, the pace of progress, including required research development and demonstration for storage in porous reservoirs, i.e. depleted gas fields and aquifers, remains slow. More research is needed to evaluate the effects of residual natural gas in depleted fields, in-situ bacteria reactions in aquifers and depleted gas fields that may yield contaminants and hydrogen losses, and storage tightness that may be compromised by the characteristics of hydrogen.

Several ongoing European research projects are addressing these issues and their outcomes will be important to inform future demonstration projects and industrial deployment. For example, the Hystories research project in Europe is assessing the techno-economic feasibility of underground storage of pure hydrogen in aquifers or depleted fields in the 2021-22 timeframe. The current HyUSPRe research project in Europe is analysing the feasibility and potential of hydrogen storage in porous reservoirs in Europe, including the identification of suitable geological reservoirs.

In addition to the technological challenges, underground natural gas storage projects have considerable lead times, five to ten years for salt caverns and depleted reservoirs, and 10-12 years for aquifer storage. For hydrogen storage projects, even larger time lags can be expected at the beginning, as there is only limited practical experience and just with one technology, salt caverns. While the use of existing natural gas storage facilities could fast-track permitting, the flushing time of a salt cavern is of two to five years. The HyStock project in the Netherlands estimates that the entire process from granting of permits until commissioning could take about seven years, which does not include the planning phase.

Geology determines the potential for underground gas storage facilities. In areas where that potential is limited, hydrogen can be stored on a large scale as a liquid carrier through a chemical conversion process, such as ammonia, methanol and LOHCs. The variable costs for these high-density storage options are largely associated with a high heat demand for reconverting the liquid carrier back into hydrogen, which significantly reduces the efficiency of the process by around 30%.

In Dormagen, Germany in March 2021, the company Hydrogenious LOHC started construction of a LOHC benzyltoluene storage plant at CHEMPARK with capacity of around 1 800 tonnes per annum (tpa) H_2 and scheduled for completion in 2023. The project will analyse whether the heat released during the LOHC hydrogenation could be used as process heat in the industrial park. The LOHC will be transported to end-users by truck, where dehydrogenation will take place at a smaller scale.

Hydrogen storage projects in salt caverns are being developed, but progress is slow for depleted gas fields and aquifers as more research is needed

Planned underground hydrogen storage facilities

Type	Project name	Country	Project start year	Operator/developer	Working storage (GWh)	Status
Salt cavern	Green Hydrogen Hub	Denmark	2025	Gas Storage Denmark A/S, Corre Energy BV, Eurowind Energy A/S	250	Feasibility study
	HyGreen Provence	France	2028	Engie, Storengy	200	Feasibility study
	Stor'Hy Cerville	France	2026	Storengy	0.3	Concept (Demo)
	H2 Gronau-EPE	Germany	2027	RWE Gas Storage West	115	Feasibility study
	Energiepark Bad Lauchstädt	Germany	2027	VNG Gasspeicher, ONTRAS Gastransport, DBI, Terrawatt, Uniper	150	Feasibility study
	HyStock Zuidwending	Netherlands	2027	Gasunie	165 (per cavern, up to 4 caverns)	Feasibility study
	Damaslawek	Poland	2030	Gaz-System	-	Concept
	H2toES Cuenca Vasco-Cantábrica	Spain	-	Repsol	-	Concept
	Humber Hydrogen Storage	United Kingdom	2028	Equinor, SSE Thermal	320	Feasibility study
	HyNet/HyKeuper	United Kingdom	2030	INOVYN, Costain, Geostock	70 (per cavern, up to 19 caverns)	Feasibility study
	HySecure	United Kingdom	mid-2020s	Storengy, Inovvn, Element Energy	40	Concept
	Advanced Clean Energy Storage	United States	2025	Mitsubishi Power, Magnum Development	150 (per cavern, up to 100 caverns)	Feasibility study
	Hydrogen City – South Texas	United States	2026	Green Hydrogen International, Energy Estate	120 (per cavern, initially 2 caverns and possibly, up to 50)	Concept
Salt cavern (new or repurposed)	Windsor salt cavern	Canada	-	Altura Power, Plains All American	-	Concept

Type	Project name	Country	Project start year	Operator/developer	Working storage (GWh)	Status
Salt cavern (repurposed)	HyGéo	France	2027	Teréga, Hydrogène de France	1.5	Concept (Demo)
	H_2Cast Etzel	Germany	2022	Storag Etzel, KBB, DLR, Hartmann Valves, TU Clausthal, SOCON	230 (per cavern, possibly up to 99 caverns if fully deployed)	Under construction (Demo)
	Krummhörn NG Storage	Germany	2024	Uniper	0.7	FID (Demo)
	WestKüste 100	Germany	mid-2020s	Raffinerie Heide, Hynamics, Holcim, OGE, Ørsted, Stadtwerke Heide, Thüga, Thyssenkrupp	-	Feasibility study
	Jemgum Storage	Germany	-	Astora	250 (per cavern, 9 natural gas caverns)	Concept
	HyStock	Netherlands	2027	Gasunie	670	FID in 2024
Depleted natural gas field	CO_2CRC H2 Storage	Australia	mid-2020s	CO2CRC, CSIRO, Geoscience Australia	-	Concept (Demo)
	Dolni Dunajovice – European H_2 Backbone	Czech Republic	-	-	-	Concept
	Rehden	Germany	-	Astora	10 725	Concept
	Aquamarine	Hungary	2025	Hungarian Gas Storage	-	Under construction (Demo)
	Green Hydrogen @ Kinsale	Ireland	2030s	ESB, dCarbonX	3 000	Feasibility study
	Storage Hub Italy	Italy	-	Snam	-	Concept
Aquifer	Lacq Hydrogen	France	2030s	Teréga		Concept
Hard rock cavern	HYBRIT	Sweden	2030s	SSAB, LKAB, Vattenfall	60	Concept

Notes: FID = final investment decision. Projects at a concept stage are projects that have been publicly announced, e.g. through the signing of a memorandum of understanding, but for which a feasibility study has not yet started.

Hydrogen transport by ships

Ships and port infrastructure are essential for international hydrogen trade

Countries and companies are looking to significantly increase cross-border trade of hydrogen. Such trade requires upgrading of existing or construction of new infrastructure. It is likely that, where feasible, onshore or offshore pipelines will be the conveyance as it is the most efficient and least costly way to transport hydrogen up to a distance of 2 500-3 000 km, for capacities around 200 ktpa. For longer distances, seaborne transportation may be the least costly choice. Hydrogen can be transported as liquefied hydrogen (LH_2), as ammonia (NH_3), as a LOHC or converted into a synthetic hydrocarbon fuel.

If ammonia is used directly in the importing country, without reconversion to hydrogen, the technologies associated with conversion and trade are mature, although they may need to become larger and more flexible. The challenges associated with synthetic hydrocarbon fuels relate to the production technology but not to trade, which will use the same technologies as natural gas and oil today. However, the pathways of liquefied hydrogen and LOHC still face challenges, in particular due to high (re)conversion losses and/or low technology readiness levels at some stages, which require an accelerated innovation effort to bring the technologies to a commercial stage at the scale needed in the next decade.

Liquefied and compressed hydrogen

Liquefied hydrogen: The energy sector has vast experience in producing, transporting and storing LNG; however, the lower boiling point of hydrogen (-253 °C) compared to natural gas (-162 °C) requires different technologies. The transport of hydrogen in the form of LH_2 may be attractive for users requiring high purity hydrogen. Hydrogen liquefaction and storage are mature technologies that have been used for decades, mostly for space applications and petrochemicals; however, at relatively modest levels compared with the LNG industry. Ships for transporting LH_2, however, are not yet commercially available. RD&D projects are working on an efficient upscaling of the different steps of the supply chain.

Hydrogen liquefaction is a reasonably well-established process, with a global installed liquefaction capacity of around 500 tonnes per day (tpd). Most large hydrogen liquefaction plants were constructed for the US NASA during the 1950-1970 period, and the largest plant in the world with a capacity of 34 tpd is still in operation. During the last two decades only smaller plants of around 5-10 tpd were built, and a few plants of around 30 tpd have been built in United States since 2020 to satisfy rising demand in the transport sector. Korea is constructing the largest hydrogen liquefaction facility in the world with a capacity of 90 tpd to start operation in 2023, mainly to serve the transport sector.

Hydrogen liquefaction is an energy-intensive process. The most recent hydrogen liquefaction plants have average electricity consumption of approximately 10 kilowatts per kilogramme (kWh/kg), equivalent to around 30% of the energy content (lower heating value) of hydrogen. The minimum theoretical energy requirement[52] to liquefy hydrogen is 2.7 kWh/kg, much lower than actual consumption. The European IDEALHY project achieved 6.4 kWh/kg in a conceptual process design in 2013. The US Department of Energy (US DOE) has set the ultimate target for large-scale plants (300 tpd) at 6 kWh/kg, equivalent to 18% of the energy content of the hydrogen. For LNG, the total primary energy consumption of liquefaction facilities is much lower at about 5-10% of the LNG. Despite the relatively high energy needs, large hydrogen liquefaction terminals for export will likely be located in areas with access to low cost and low-emission electricity. Assuming electricity costs of USD 25 /MWh and the US DOE target of 6 kWh/kg, electricity expenditures for liquefaction would be USD 0.15 /kg. However, electricity costs would only be a fraction of the hydrogen liquefaction costs, as the capital cost for liquefaction remains a major cost component that influences overall economic feasibility. The US DOE has set a target for capital costs of large-scale hydrogen liquefaction plants (300 tpd) at USD 142 million (excluding storage). This compares with current cost estimates of USD 560 million.

Today, large-scale liquid hydrogen storage technology is relatively similar to that of the 1960s, with the largest facility at NASA's Kennedy Space Center (Florida, United States). It is a double-walled vacuum insulated sphere, used for space applications, with a capacity of 3 200 m^3 (230 tonnes). In addition, construction of a new spherical tank by CB&I, with a capacity of 4 700 m^3, is nearing completion also at NASA. Although similar to previous tanks, its design introduces innovative aspects to minimise boil-off-gas[53] (BOG) to less than 0.05%/day, an improvement of 25% compared to the 3 200 m^3 tank. Further design innovation is needed to increase tank size. In December 2021, CB&I announced the completion of a conceptual design for a 40 000 m^3 storage sphere – about eight-times larger than the one under construction for NASA. A consortium led by Shell of public, private and academic experts (including CB&I and NASA) will assess the feasibility and conduct a demonstration project of a large-scale liquid hydrogen storage tank for installation at import and export terminals, with a capacity of 20 000-100 000 m^3. The project is 50% co-financed by a USD 6 million grant from the US DOE under the H2@Scale initiative.

[52] 25 bar, 30 °C and *para*-hydrogen fraction of 25%.

[53] Despite tank insulation, small amounts of heat will cause gas evaporation, known as boil-off, which must be removed in order to avoid an increase in pressure.

The Hydrogen Energy Supply Chain (HESC) project in Australia is the first demonstration facility to test liquefied hydrogen shipping. It integrates a hydrogen liquefaction facility (0.25 tpd), a LH_2 storage container (41 m^3) and a loading facility in Victoria. LH_2 is transported to Japan in the world's first LH_2 carrier, Suiso Frontier, with a capacity of 1 250 m^3 (75 tonnes of LH_2 per trip) and double-shell vacuum insulation tanks. The first shipment of LH_2 arrived at the receiving terminal HyTouch Kobe in Japan in February 2022. HyTouch terminal is equipped with a 2 500 m^3 LH_2 tank, a double-shell vacuum insulation and a spherical design to reduce heat transfer. In a commercial phase, the HESC project aims to produce 225 kilotonnes per year (ktpa) of liquid hydrogen from a mix of Latrobe Valley (Victoria) coal and biomass, as well as to capture and store CO_2.

Also in Australia, the Central Queensland Hydrogen Project (CQ-H2) has completed a feasibility study for a liquefaction plant at the Port of Gladstone to export up to 1005 tpd of liquid hydrogen by 2026, with the potential to scale up to 800 tpd by 2031. The FID is expected in late-2023.

Also in Queensland, in the Port of Townsville, Origin Energy and KHI are assessing the potential of hydrogen trade, including the development of a liquefaction facility, new berth and related port infrastructure to export around 36.5 ktpa by the late 2020s. In western Australia, Woodside has proposed to build the H2Perth project in Kwinana, which aims to produce 300 tpd of hydrogen and expand up to 1 500 tpd for export as ammonia and LH_2 to Singapore and potentially Japan. Construction is expected to start in 2024 subject to the FID.

In Europe, RWE is looking at the possibility of importing liquefied hydrogen via their planned LNG terminal in Brunsbüttel (Germany). In July 2022, Shell New Energies, Engie, Vopak and Anthony Veder signed an agreement to study the feasibility of hydrogen liquefaction and transport of 100 tpd from Sines (Portugal) to Rotterdam (Netherlands), with the potential to scale up over time.

Hydrogen regasification could theoretically provide 1.7-times more cooling than LNG with interesting opportunities to develop cold value chains near regasification terminals, including cryogenic air separation, warehouse freezing and cooling, district cooling and industrial process cooling. Such process integration, which could improve the overall efficiency of LH_2 trade, should be considered in the planning for LH_2 import terminal projects.

Various companies are working on the design of the first commercial liquefied hydrogen tankers and assessing ways to minimise BOG as well as how to use the BOG as a low-emission shipping fuel and avoid venting it. KHI has received approval in principle (AIP)[54] from the classification society ClassNK for a large LH_2 tanker of up to 160 000 m^3 (approximately 10 kt of H_2 per trip), with a propulsion system that can use hydrogen, including BOG. C-Job Naval Architects in partnership with LH2 Europe are planning to build a 37 500 m^3 LH_2 tanker powered by hydrogen fuel cells, including BOG, expected to be available by 2027. Korea Shipbuilding & Offshore Engineering and its shipyard Hyundai Mipo Dokyard have received an AIP to build a LH_2 tanker of 20 000 m^3, which will use hydrogen BOG as fuel for fuel cells and is expected to be ready between 2025 and 2027. In July 2022, GTT, a technology firm for design of cryogenic containment systems used to store and transport liquefied gases, in the framework of its co-operation with Shell International Trading and Shipping Company, received two AIPs from the ship classification society DNV for the design of a membrane-based LH_2 containment system and for the preliminary concept design of a liquefied hydrogen tanker.

Compressed hydrogen: Companies are also considering shipping compressed hydrogen. Australian Provaris, (formerly Global Energy Ventures), received an AIP in 2021 from the American Bureau of Shipping for a compressed hydrogen pilot tanker with a 430 tonne cargo capacity at 250 bar (26 000 m^3) and for a full-scale 2 000 tonne tanker. Hydrogen would be stored in the hull in the cargo hold and used as fuel. Several projects in Australia are assessing the needs for compressed hydrogen storage and loading facilities at ports, specifically in the Gascoyne region (HyEnergy) and on the Tiwi Islands and targeting first exports in 2026. Singapore is involved in the conceptual design of a marine jetty facility to unload compressed hydrogen and decompress it for pipeline distribution. Norwegian companies, Gen2 Energy and Sirius Design & Integration, are working on the design of a tanker to transport containers with compressed hydrogen, using hydrogen as fuel (about 500 containers, resulting in around 30 000 m^3 assuming 40-foot standard shipping container dimensions).

Ammonia

There is a high level of technological maturity in many aspects of ammonia storage and transport, due to its widespread use as a feedstock for fertiliser. Indeed, an established worldwide ammonia infrastructure already exists with significant maritime trading of around 20 million tonnes per year (Mtpa), and 195 ammonia terminals at over 120 ports. International shipping routes are well established and there is a comprehensive network of ports worldwide that handle ammonia on a large scale. Ammonia is shipped in fully

[54] An approval in principle is an independent assessment of conceptual and innovative shipbuilding within an agreed framework, confirming that the ship design is feasible and no significant obstacles exist to prevent the concept from being realised.

refrigerated, non-pressurised tankers, often designed to carry liquefied petroleum gas (lower boiling point [-42 °C] compared to ammonia [-33 °C]) provided there are no parts containing copper or zinc or their alloys in contact with the cargo. Although ammonia is toxic, corrosive and has a pungent odor, there are established practices for its safe shipment and storage; however, international maritime standards will have to be adapted if ammonia, defined as a toxic product, is used as fuel by ships.

As international trade of ammonia is mature, there is an opportunity for importing countries to replace fossil fuel-based imports with low-emission alternatives. There are uncertainties though as to how much ammonia can be used additionally, such as through co-firing in coal power plants or as a shipping fuel. If the end-uses require hydrogen and not ammonia, it must be reconverted to hydrogen using ammonia crackers that decompose the ammonia into nitrogen and hydrogen. Ammonia cracking at small scales (1-2 tpd) and high temperature (600-900 °C) is already commercially available and used in metallurgy, but the energy consumption is around 30% of the energy content of the ammonia and rarely includes hydrogen purification. Ammonia cracking at lower temperatures (<450 °C), which would decrease energy consumption, and without the use of precious metals as catalysts is at low maturity levels. The Strategic Research and Innovation Agenda 2021-2027 of the Clean Hydrogen Joint Undertaking (European Union) aims to decrease the overall energy consumption associated with the use of hydrogen carriers, including the round-trip efficiency of ammonia production, shipping and conversion to hydrogen to 36% by 2030. In addition, the technology for separation and purification of hydrogen after ammonia cracking needs to become less costly and more efficient, e.g. comply with the composition requirements set out for fuel cells (ISO 14687). For fuel cell vehicles, the minimum hydrogen purity is 99.97%, and the maximum concentration of ammonia is 0.1 parts per million by volume (ppmv) and of inert gases (nitrogen and argon) is 100 ppmv. Therefore, innovation around ammonia cracking needs to address challenges related to efficiency, costs, purity and scale.

In the United Kingdom, the Tyseley Ammonia to Green Hydrogen Project was awarded GBR 6.7 million of public funding in May 2022 to build a demonstration ammonia cracking unit of 0.2 tpd to supply hydrogen to a refuelling station in Birmingham. It will use technology developed by H2SITE, a Spanish start-up company, with a palladium-based membrane reactor that produces hydrogen from ammonia, complying with purity requirements, with a cost range of USD 0.8-1.5 /kg at a small-medium scale.

In Germany, Thyssenkrupp Uhde, an engineering and construction company, reported in 2021 that its proprietary ammonia cracking technology would have an efficiency of 78% and hydrogen purity of ~99.96% at large scale. The TransHyDE project in Germany is looking at different hydrogen transport pathways, supported by several research networks, including AmmoRef, which aims to develop new catalysts and technologies for ammonia cracking at scale with lower costs and higher efficiency. Companies such as Clariant, for the development of improved catalysts, and Thyssenkrupp are part of the AmmoRef project, which in 2021 received funding of around EUR 14 million from the German government. Haldor Topsøe, a Danish company specialising in catalysts and process technology, offers different ammonia cracking catalysts, and is working on the design of a 5-500 tpd H_2 plant with fuel cell quality hydrogen.

The existing port and shipping infrastructure could enable the accelerated adoption of large-scale ammonia transport. Some ports are already planning to expand their capacity. OCI has made an FID to expand its capacity in the Port of Rotterdam (Netherlands) from 400 ktpa of ammonia to 1.2 Mtpa by 2023 at a cost of USD 20 million. Basic engineering has been completed to assess the potential to increase the capacity above 3 Mtpa, including the construction of a large ammonia storage tank and the scale-up of the jetty infrastructure.

The Green Wilhelmshaven project in Germany includes a large-scale ammonia cracker facility, where Uniper intends to commission a new terminal during the second-half of this decade to deliver up to 295 ktpa of hydrogen. Also in Germany, RWE wants to build a terminal for ammonia imports in Brunsbüttel to import around 300 ktpa of ammonia by 2026 with an estimated investment of around half a billion euros, and with the possibility to expand it to 2 Mtpa of ammonia and build a large-scale cracker to supply hydrogen to the grid at a later stage.

In the Netherlands, Gasunie, HES International and Vopak are planning an import terminal, ACE Terminal, in Rotterdam's Maasvlakte, to be operational by 2026 potentially using ammonia crackers. Air Products and Gunvor Petroleum Rotterdam have announced a joint development agreement for an ammonia import terminal in Rotterdam by 2026, and the subsequent supply of hydrogen. In July 2022, Proton Ventures was awarded the Smart Energy Systems grant from the City of Rotterdam to conduct a techno-economic feasibility study of a large ammonia cracker.

Liquid organic hydrogen carrier

Hydrogen can also be incorporated in an organic molecule, resulting in a LOHC with similar properties to oil products. LOHCs do not require cooling and can be transported and stored using the existing oil infrastructure. At the destination, the hydrogen is extracted from the LOHC. The hydrogenation and dehydrogenation processes require energy, which corresponds to around 35-40% of the energy content of the transported hydrogen. Although some degradation occurs, the carrier molecule can be reused, but it needs to be shipped back to the export terminal, resulting in additional shipping fuel consumption, which is only slightly higher than for an empty ship.

The HySTOC project in Finland commissioned a LOHC hydrogenation and storage facility in 2021, using Hydrogenious LOHC technology, to supply hydrogen to a refuelling station, where the dehydrogenation unit is located. At the refuelling station, hydrogen is released from the LOHC and goes to a pressure swing adsorption process (HyGear technology), supplying high purity hydrogen for fuel cell vehicles.

The Advanced Hydrogen Energy Chain Association for Technology Development (AHEAD) project in 2019 commissioned a hydrogenation demonstration facility in Brunei Darussalam to transport hydrogen as methylcyclohexane (MCH) to a gas turbine at the TOA Oil Co Keihin refinery in Japan (May 2020). MCH was dehydrogenated to separate hydrogen and toluene, the latter being shipped back to the exporting terminal, so that it could be used again as a hydrogen carrier. MCH was transported in 24-m^3 ISO tank containers mounted on container ships. The project demonstrated the LOHC technology. In 2022, the AHEAD project shipped MCH produced at the facility in Brunei Darussalam to an ENEOS oil refinery in Japan using, for the first time, a conventional chemical tanker with a size of around 12 500 deadweight tonnage.

ENEOS (Japan) and Origin Energy (Australia) signed a memorandum of understanding in 2021 to study the potential of producing hydrogen in Queensland, transporting it as MCH in tankers to Japan for use at ENEOS refineries. ENEOS partnered with PETRONAS Hydrogen in March 2022 to conduct a feasibility study for the production of low-emission hydrogen in Malaysia and its conversion into MCH for shipment to Japan. The project would have a capacity of up to 50 ktpa by 2027, and a FID is expected by the end of 2023. ENEOS, Mitsui and Abu Dhabi National Oil Company agreed in June 2022 to a joint study to evaluate the feasibility of exporting hydrogen from the United Arab Emirates to Japan as MCH. The initial planned capacity would be 50 ktpa, with the possibility of increasing it to 200 ktpa.

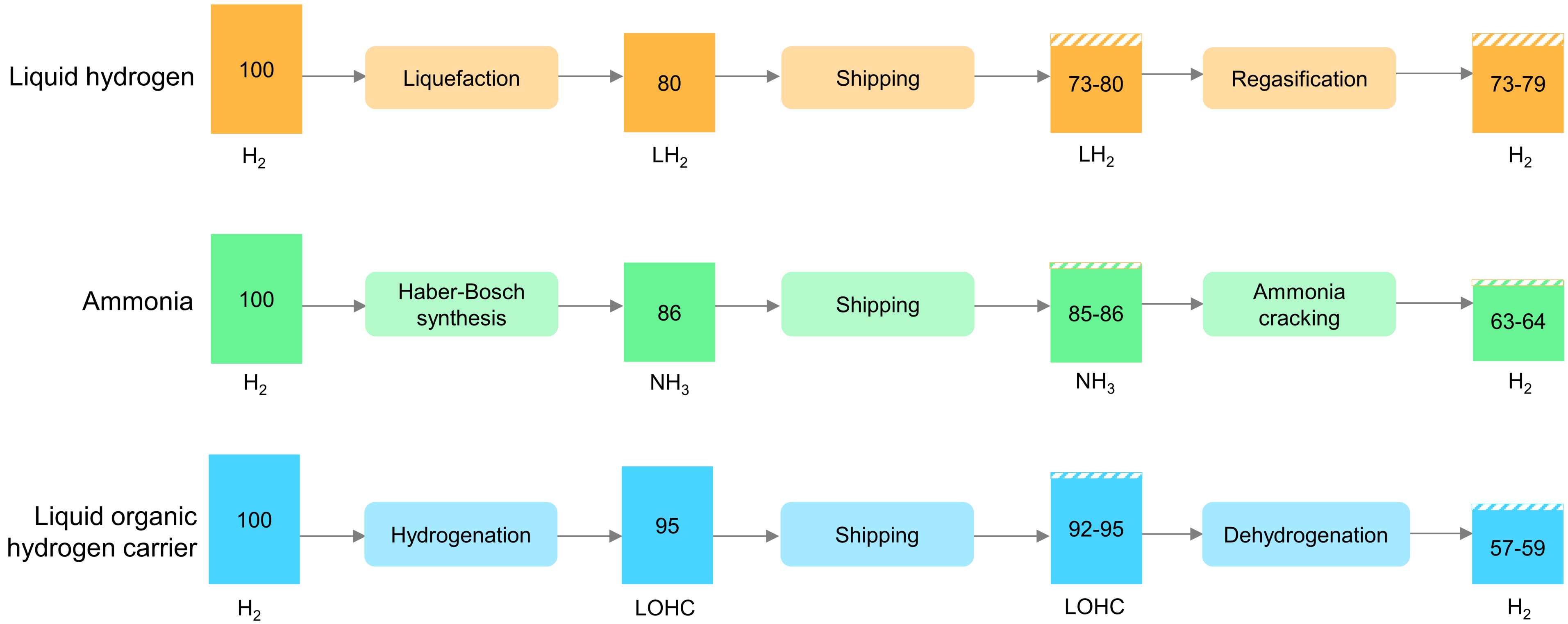
Five Singaporean companies (Sembcorp, City Energy, PSA, Jurong Port, Singapore LNG), Chiyoda and Mitsubishi signed a Memorandum of Understanding (MoU) in March 2020 to assess the technical and commercial feasibility of importing hydrogen as MCH, and in October 2021, some of the companies entered into a strategic partnership. In March 2022, the Singapore government awarded a grant to two universities and the above-mentioned consortium of companies for an RD&D project to decrease the cost of LOHC dehydrogenation. The consortium aims to semi-commercialise the technology by 2025 and to achieve full commercialisation by 2030.

The Port of Rotterdam, Koole Terminals, Chiyoda and Mitsubishi signed a MoU in 2021 to assess the potential of using Chiyoda's technology of MCH to import hydrogen to the northwest European hydrogen market.

The AquaVentus project on the island of Helgoland (Germany) plans to establish a demonstration LOHC hydrogenation and storage plant with Hydrogenious technology by 2024, linked to offshore hydrogen production. Helgoland will use the heat released during the hydrogenation process to cover its heat demand. The LOHC will be transported via the TransHyDE project from the island to a dehydrogenation plant to be built at the Port of Hamburg. The H2A project is a consortium of partners including the Port of Amsterdam, Evos Amsterdam and Electriq Global that aims to import up to 1 Mtpa H_2 to the Port of Amsterdam. The Port of Amsterdam is assessing the use of various carriers, including as a LOHC in co-operation with Hydrogenious or as a hydrogen liquid carrier (using a liquid silicon hydride derivative) in co-operation with HySiLabs. Hydrogenious has also established a partnership with Emirates Specialized Contracting & Oilfield Services from the United Arab Emirates to evaluate hydrogen storage and transport through LOHCs, including potential exports to Germany, Japan and Korea.

The final use will influence the choice of the shipping option, as energy losses vary between the different hydrogen carriers

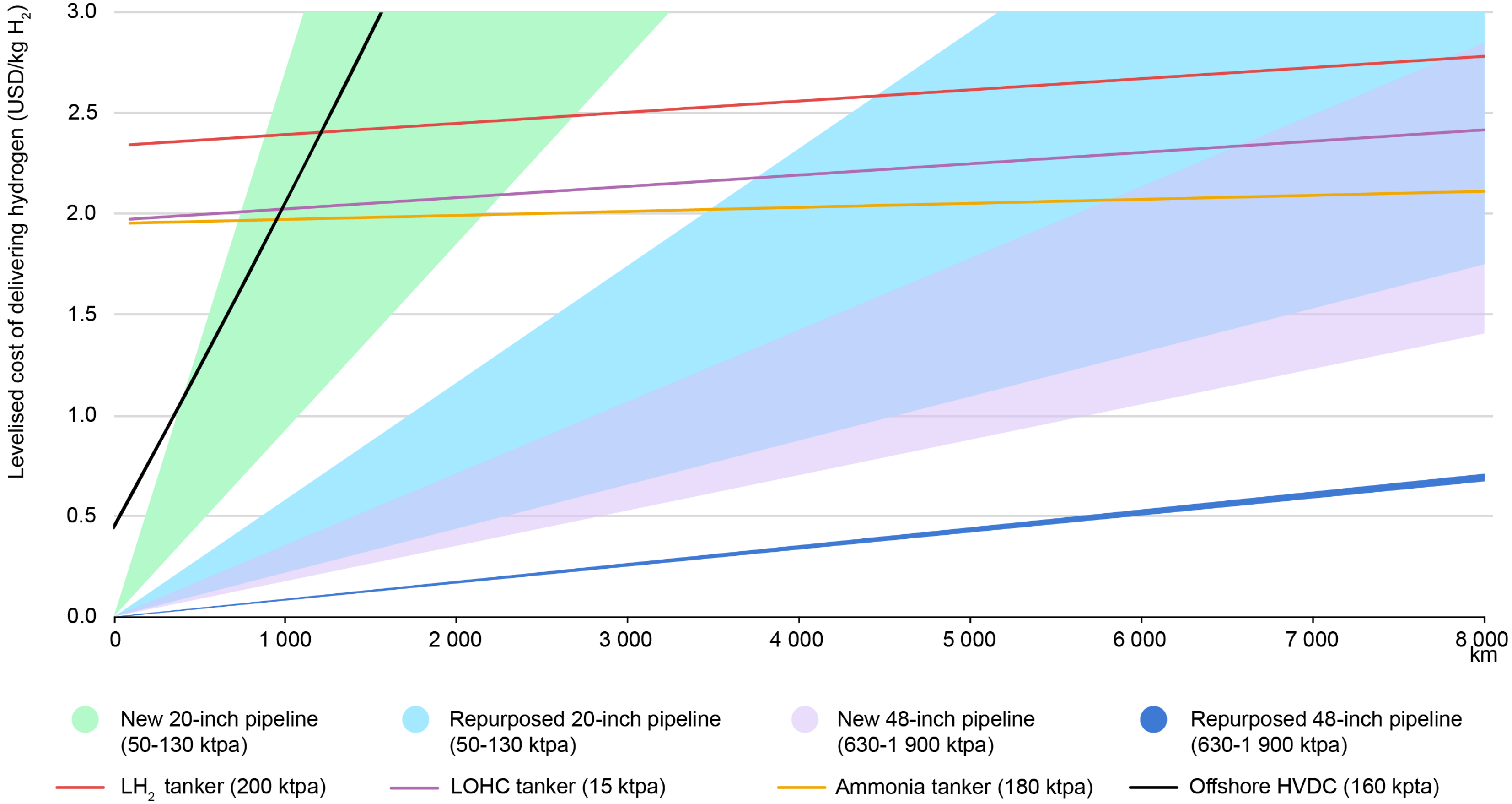
Energy available along the conversion and transport chain in hydrogen equivalent terms, 2030



Notes: LH_2 = liquefied hydrogen; NH_3 = ammonia; LOHC = liquid organic hydrogen carrier. Numbers show the remaining energy content of hydrogen along the supply chain relative to a starting value of 100, assuming that all energy needs of the steps would be covered by the hydrogen or hydrogen-derived fuel. The Haber-Bosch synthesis process includes energy consumption in the air separation unit. Boil-off losses from shipping are based on a distance of 8 000 km. For LH_2, dashed areas represent energy being recovered by using the boil-off gases as shipping fuel, corresponding to the upper range numbers. For NH_3 and LOHC, the dashed area represents the energy requirements for one-way shipping, which are included in the lower range numbers.

Cost of hydrogen delivery for various transport distances

Levelised costs of delivering hydrogen by pipeline and by ship as LH_2, LOHC and ammonia carriers, and electricity transmission, 2030



Notes: ktpa = kilotonnes per year; LH_2 = liquefied hydrogen; LOHC = liquid organic hydrogen carrier. Includes conversion, export terminal, shipping, import terminal and reconversion costs for each carrier system (LH_2, LOHC and ammonia). The import and export terminals include storage costs at the port. Pipelines refer to onshore transmission pipelines operating at ranges between 25% and 75% of their design capacity during 5 000 full load hours. Electricity transmission reflects the transmission of the electricity required to obtain 1 kg H_2 in an electrolyser with a 69% efficiency located at the distance represented by the x-axis.

Source: IEA analysis based on data from Guidehouse (2021) and IAE (2016).

Repurposing LNG infrastructure

Planning for purpose: the role of existing and new LNG terminals

Major events – including the Russian invasion of Ukraine and the impacts of the Covid pandemic – are straining the global energy and economic situation. This has put considerable pressure on an already tight natural gas market and raised energy security concerns. Europe has been at the epicentre of market tensions and lower Russian supplies have largely been compensated for by liquefied natural gas (LNG).

Some European countries, including Germany, Greece and Italy, are planning to construct new LNG import facilities to reduce their reliance on natural gas from Russia. Current project pipelines include 60 Mtpa capacity of regasification terminals (or expansion of existing ones) under construction[55] in the Asia Pacific region and are due to be operational in the next five years, and about 13 Mtpa capacity in Europe (of which 5 Mtpa from floating units). These will be in addition to the global level of about 860 Mtpa of receiving terminals today. Including the announced projects, regasification capacity in Europe could increase by 70 Mtpa by the end of this decade, with almost half of it at terminals in Germany.

More than 200 Mtpa capacity of liquefaction plants are under construction or have been announced. Of these, half are projects in North America, mainly the United States, 20% from facility expansion in Qatar and the remainder split between projects in sub-Saharan Africa and Asia.

Concerns have been raised about the risk of stranding multi-billion dollar assets as natural gas consumption must decline to meet climate goals. In fact in the European Union's REPowerEU plan, investments in natural gas and hydrogen infrastructure are to be made "future proof" by leveraging the synergies between these fuels.

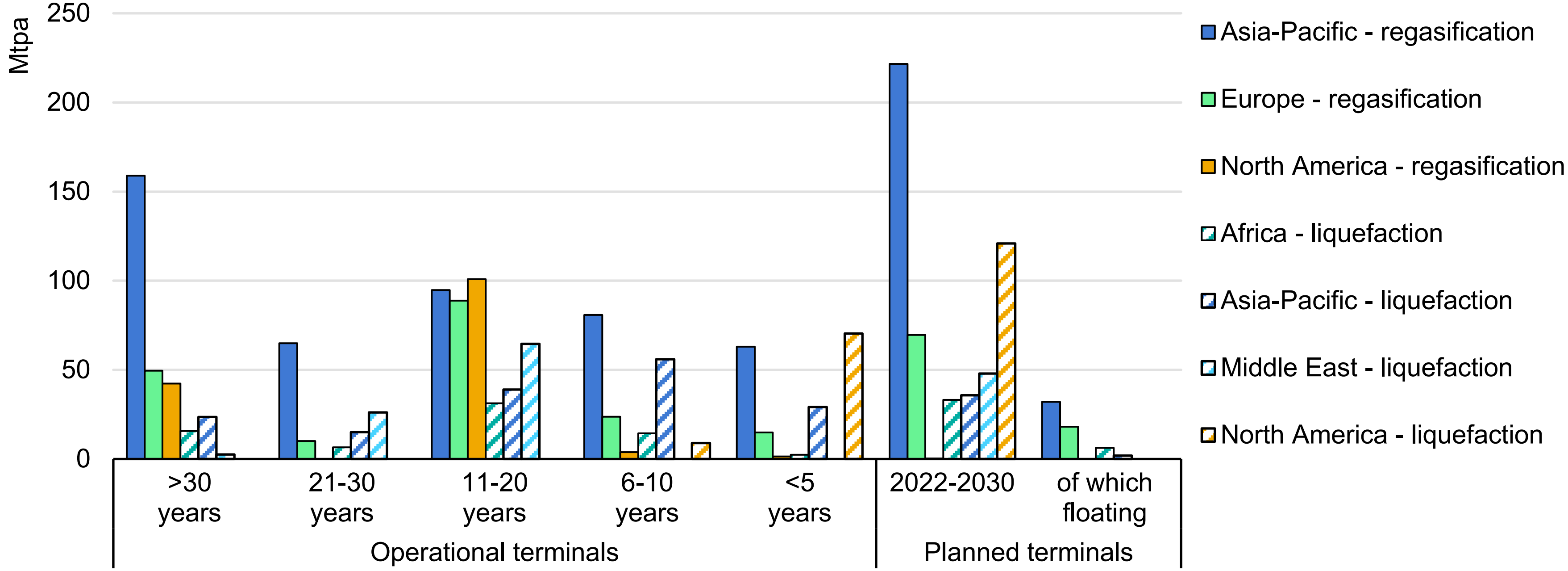
The feasibility of repurposing an operating LNG terminal depends on whether it will ultimately receive hydrogen or ammonia. If the terminal was not designed for it, a later conversion, in particular to liquefied hydrogen, can be technically challenging for core components such as tanks, whereas re-using elements such as the jetty, power connection and land foundation is less critical and could help to reduce lead times. For biomethane or synthetic methane, no changes to the existing receiving infrastructure are required, whereas the challenge lies in their production as constraints on biomass resources for biomethane and sourcing of CO_2 feedstock inputs for synthetic methane have to be considered.

New LNG import terminals are being constructed in Europe to reduce dependency on Russian gas which opens the possibility to make them ready for hydrogen-derived fuels from the design phase to ease a future to other fuels and to minimise the risk of stranded assets.

[55] It includes projects with a disclosed start year of operation.

Design and construction of new LNG facilities should aim to be hydrogen-ready to reduce risks of stranded assets and to boost energy security

Operational and planned LNG terminal capacity by type, region and age



Notes: Mtpa = million tonnes per year. The age of operational terminals is as of 2022. Planned terminals include facilities under construction and announced with a disclosed start year for operation.
Source: IEA analysis based on Global Gas Infrastructure Tracker.

Repurposing LNG terminals for liquefied hydrogen imports

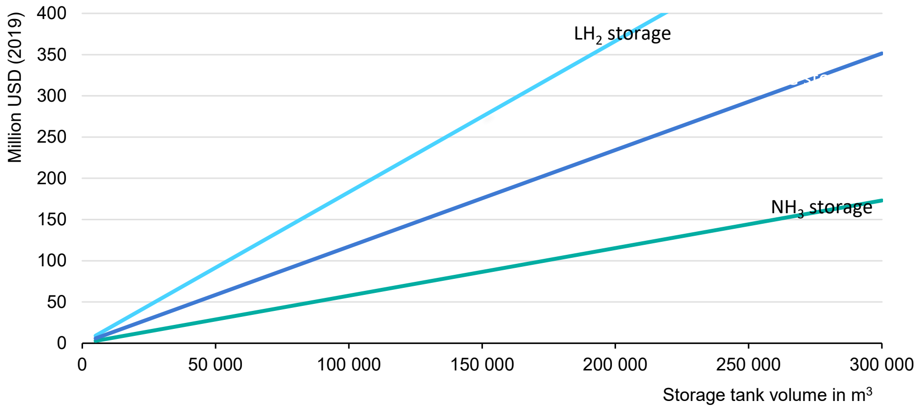
Repurposing existing or planned LNG infrastructure to receive liquefied hydrogen is technically challenging. It requires replacement or drastic modification of most of the equipment, in particular due to the lower density and boiling temperature of liquefied hydrogen compared with LNG.

The storage tank is the central component of an LNG import terminal. It accounts for around half of the terminal investment costs and takes around three years to build. Several tank configurations are available today, e.g. single containment, double containment and full containment storage tanks. For LNG storage, double containment and full containment tanks are needed. While for ammonia, due to the higher boiling point (- 33 °C), less insulation is required, such that a single containment and single-wall tank can be used. Large LNG receiving terminals have several cylindrical storage tanks, generally with a capacity of around 160 000 m^3 each. Ammonia storage tanks are generally smaller, often around 50 000 m^3. Large liquefied hydrogen storage tanks are not yet commercially available. So far, smaller steel containers with spherical shape have been used to store liquefied hydrogen, e.g. the 2 500 m^3 sphere built for the HESC project in Japan, and the 4 700 m^3 sphere nearing completion at the NASA Kennedy Space Center.

Liquefied hydrogen, due to its lower boiling temperature, requires a much better insulated system relative to LNG storage. The insulation for a large LNG tank is typically designed to keep the boil-off gas rate below 0.05% per day. To achieve the same BOG rate for liquefied hydrogen, due to the lower heat of vapourisation and the higher temperature difference, the tank insulation must have ten-times higher thermal resistance than for LNG. To reach such a high level, vacuum insulation in double-walled tanks is often used for new build tanks. To retrofit LNG tanks, one option could be to apply a membrane insulation on the inner surface, which could allow re-use of the tank structure but, depending on the additional insulation layers, the boil-off rate may remain high. Recently, GTT has received an approval in principle by the ship classification society DNV for the design of a membrane containment system for liquefied hydrogen.

For a new or planned terminal, a viable option could be to design for a liquefied hydrogen terminal, but use it initially for LNG. In the design, one has to ensure that material choices and insulation are compatible with liquefied hydrogen, even though it equates to over design for use in the initial phase as an LNG terminal. Some components such as pumps, would require an ad-hoc configuration due to the different densities of the two carriers, and the energy storage capacity would be only about 40% for use with liquefied hydrogen, due to its lower volumetric energy density relative to LNG. This does not have to be a disadvantage, as the volume of hydrogen trade will take time to scale up. There is no experience yet in building large liquefied hydrogen tanks – the biggest one under construction has a volume of 4 700 m^3 – while LNG facilities usually have storage capacity in the 100 000-200 000 m^3 range.

Capital cost of selected storage tanks for LNG, liquefied hydrogen and ammonia



Notes: LNG = liquefied natural gas; LH_2 = liquefied hydrogen; NH_3 = ammonia.
Sources: IEA analysis based on DNV GL (2020) and Nayak-Luke et al. (2020).

Only the supporting concrete structure and foundation works can be reused, which account only for a small fraction of the total tank costs, but can provide construction time savings. While engineering studies assessing in detail the costs of replacing an LNG storage tank with a liquefied hydrogen storage tank are rare, comparing the costs of new tanks provides an indication of the repurposing costs, given that the tank accounts for around half of the costs of an LNG terminal. A newly built liquefied hydrogen storage tank can be 50% more expensive than a LNG tank for a comparable volume, and due to the lower volumetric density, the energy stored would be almost 60% lower.

Safety precautions need to be foremost in design and selection of equipment and materials. For instance, as the boiling points of nitrogen and oxygen are -196 °C and -183 °C respectively, air could condense on the surfaces of any converted equipment not properly insulated if used with liquefied hydrogen. Such condensation of oxygen does not happen with LNG due to its higher boiling point. Therefore, the foam glass insulation typically used for LNG pipes cannot be used for liquefied hydrogen. Instead, vacuum insulation is needed, which could bump up pipe costs by five to ten times (per unit of length).

Converting an LNG liquefaction terminal to hydrogen is equally challenging. Liquefaction equipment used for natural gas can be modified to liquefy hydrogen, or at least to provide a first refrigeration stage. However, the issues for storage tanks, pumps and pipes are the same as for a regasification terminal. Most experts do not consider the conversion or use of LNG export terminals for liquefied hydrogen to be a feasible solution today.

Repurposing LNG terminals for ammonia

As the technology for liquefied hydrogen transport is still at a demonstration phase, transporting hydrogen in the form of ammonia can be an alternative and more technologically mature option. Today about 20 Mtpa of ammonia are traded internationally and use very large gas carrier (VLGC) ships. The boiling temperature of ammonia

(-33 °C) is much higher than for liquefied hydrogen, which means it can be handled more easily.

Repurposing an existing LNG receiving terminal to import ammonia presents several challenges. They are less significant than for liquefied hydrogen, but nonetheless could affect the technical and economic attractiveness of the repurposing case. For example, LNG tanks are usually built using 9% nickel steel as inner material for which ammonia could cause problems of stress corrosion cracking. It has been estimated that converting an existing LNG terminal to receive ammonia can cost 11-20% of the capital expenditure of an LNG regasification facility.

Building an LNG import terminal designed from the start to be later converted to receive ammonia, so called ammonia-ready, appears to be a viable path. There is no need to increase the level of insulation, since the ammonia liquefaction temperature is higher than that of LNG. A full containment tank can be used to store both LNG and ammonia by taking into account in the design phase the different structural loads (ammonia is 60% heavier than LNG per unit of volume) and by choosing materials compatible for both LNG and ammonia. A relatively new tank technology by GTT, the Mark III membrane system, has been certified as ammonia-ready, meaning it is capable of moving from LNG to ammonia without any major changes. Switching from LNG to ammonia requires an assessment of the safety and environmental impacts, which may limit the number of suitable sites. The investment costs for an ammonia-ready LNG import terminal are estimated to be 7-12% higher compared with a conventional LNG terminal design. Although some components would have to be replaced, e.g. pumps, the additional costs for an ammonia-ready terminal could be half of the costs for retrofitting an existing terminal.

Even if not fully converted to ammonia, LNG terminals could be envisioned to become multi-molecule hubs by converting part of the facility or finding new business cases. RWE, a German multinational energy company, plans to build a 300 kt/year ammonia receiving terminal by 2026 at the same site as the planned Brunsbüttel LNG import facility. The co-ordinated project is intended to help facilitate the subsequent conversion of the entire site to import green ammonia.

Hubs could also include the handling of CO_2 captured at industrial plants for use in synthetic fuel production or destined for storage. Tree Energy Solutions (TSE), a green hydrogen company, plans to build an LNG import terminal at Wilhelmshaven, Germany. The project is intended for use in the future to import synthetic methane produced from renewable hydrogen,[56] to capture the CO_2 when the methane is combusted and to re-use the CO_2 for synthetic methane production

[56] See Explanatory notes annex for renewable hydrogen definition in this report.

There are technical challenges to convert a LNG terminal to liquefied hydrogen, though converting to ammonia can be less difficult

Key components of an LNG import terminal for conversion to liquefied hydrogen or ammonia

Component	Conventional LNG terminal	Property differences impacting the components		LNG conversion to:		Design of ammonia-ready LNG terminal
		LH_2	NH_3	LH_2 terminal	NH_3 terminal	
Storage tanks	• Low level of insulation, inner material usually 9% nickel steel. • Represents 45-50% of the investment cost.	• Lower temperature	• Higher density • Higher temperature	• Increasing insulation (ten-times more efficient, vacuum insulation or internal membrane tank are options). • Assessing material compatibility, e.g. nickel steel currently used is not suitable due to lower temperature and structural problems. • Tank foundation could be reused. • Energy stored is 60% lower due to lower energy density. • A new liquefied hydrogen tank could cost 50% more than an LNG one with similar size.	• No need for additional insulation. • Structural evaluation of the tank: due to higher density of ammonia, the maximum volumetric capacity would be reduced to two-thirds. The energy capacity would be around 60% lower due to ammonia's lower heating value. • Assessing material compatibility (to avoid stress corrosion cracking in steel).	• Using a full containment tank with stainless steel as primary container. • Consider the higher structural load when switching to ammonia. • An ammonia-ready design could add 5% to investment cost for storage.
Boil-off gas system	• Usually designed to keep the BOR <0.05%/day. • Represents 10-15% of the investment cost.	• Lower heat of vapourisation	• Higher temperature • Higher boiling point	• Increasing insulation to avoid higher BOR.	• Higher temperature of ammonia is compatible with insulation for LNG.	• Flexibility of compressor to switch to lower BOG (larger number of smaller compressors is an option). • Material choice compatible with ammonia.

Component	Conventional LNG terminal	Property differences impacting the components: LH_2	Property differences impacting the components: NH_3	LNG conversion to: LH_2 terminal	LNG conversion to: NH_3 terminal	Design of ammonia-ready LNG terminal
Pumps	• In-tank submerged pump and high-pressure send out pumps designed for LNG. • Represents 3-5% of the investment cost.	• Lower temperature • Lower density	• Higher temperature • Higher density	• Insulation is needed (vacuum insulation is an option) and assess material compatibility. • Different operating conditions require exchange of pumps.	• Different operating conditions.	• Replacement needed.
Pipelines	• Low level of insulation, designed for weight of LNG. • Represents 5-10% of the investment cost.	• Lower temperature	• Higher density	• Need for higher levels of insulation to avoid oxygen condensation on the surface. • Assess material compatibility.	• No need for additional insulation. • Reinforcement of piping support.	• Reinforcement of piping support due to ammonia's higher density. • Ammonia-ready design could add 10% to investment cost for pipes.
Regasification	• Designed for LNG temperatures and density (including the loading conditions of truck/pipeline).	• Lower temperature • Lower density	• Higher temperature • Higher density	• Different operating conditions, assessment needed (opportunity to re-use the cold energy).	• Different operating conditions, case-by-case assessment.	• Case-by-case assessment.
Control and safety systems	• Designed and calibrated for LNG.	• Lower density • Broader flammability range • Lower ignition energy	• Higher density	• Different physical conditions and absence of hydrocarbons need case-by-case evaluation of sensors and valves.	• Different physical conditions and absence of hydrocarbons need case-by-case evaluation of sensors and valves.	• Case-by-case assessment. Re-calibration or substitution may be necessary.

Component	Conventional LNG terminal	Property differences impacting the components		LNG conversion to:		Design of ammonia-ready LNG terminal
		LH_2	NH_3	LH_2 terminal	NH_3 terminal	
Berth and jetty	• Low level of insulation	• Lower temperature	• Higher density	• More insulation needed. • Improvement of sealing needed to avoid leaks during unloading.	• Improvement of sealing needed to avoid leaks during unloading. • Reinforcement of piping support. Smaller size of gas tankers to be considered. • Due to toxicity issues, the jetty should keep appropriate security distances from other areas.	• Improvement of sealing needed to avoid leaks during unloading. • Reinforcement of piping support.

Notes: LNG = liquefied natural gas; LH_2 = liquefied hydrogen; NH_3 = ammonia; BOG = boil-off gas; BOR = boil-off rate.
Sources: IEA analysis based on Black & Veatch (2020); Pratt et al. (2016); DNV GL (2020).

Hydrogen clusters

Ports and industrial clusters can jump-start the scale-up of low-emission hydrogen supply and infrastructure

A hydrogen cluster, also called hub or valley[57], is defined as a network of hydrogen producers (sometimes including renewable electricity production), potential users and infrastructure connecting the two. Clusters are expected to form in and around first-mover hydrogen supply and demand areas. These include industrial clusters, ports, cities and other locations that are already embracing pilot projects and commercial hydrogen developments. Hydrogen clusters will catalyse larger infrastructure development and will facilitate large-scale hydrogen trade when linked to ports. While it is desirable, to produce low-emission hydrogen at the beginning, though not strictly necessary, public support may be conditional on hydrogen being produced by low-emission technologies or below specified life cycle emissions values.

Hydrogen clusters

The first European Commission (EC) call for hydrogen clusters was in 2015 under the Fuel Cells and Hydrogen Joint Undertaking. At that time, the term "hydrogen territories" was used, a concept that evolved to "hydrogen valleys". This call led to the BIG HIT project which created a hydrogen cluster in Orkney (Scotland) by integrating hydrogen production from curtailed electricity from wind and tidal generation, storage, transportation as compressed hydrogen in tanks by tube trailers and utilisation for heat, power and mobility. The project was completed in April 2022.

Another EC call related to hydrogen valleys[58] through the Joint Undertaking was in 2019. It supported the HEAVENN project with EUR 20 million (USD 24 million) which was complemented with public-private co-funding of EUR 70-80 million (USD 83-95 million) to connect the entire hydrogen supply chain in northern Netherlands. In 2020, the Joint Undertaking focussed its hydrogen valleys work on islands, granting EUR 10 million (USD 11 million) to the Green Hysland project on Mallorca (Spain). The Green Hysland electrolyser was inaugurated in March 2022 and a hydrogen distribution pipeline is expected to be operational by end-2022. Other islands are involved in the Green Hysland project and will participate in a replicability

[57] The terms hydrogen cluster, hydrogen hub and hydrogen valley are often used interchangeably. For example, hydrogen valley is used by the European Commission and in Mission Innovation, while the term hydrogen hub is used in the United States. In this document, the term hydrogen cluster is used whenever no other explicit term has been adopted, otherwise the term explicitly adopted and defined by the country or programme is used when referring to them.

[58] The funding calls from the European Commission consider hydrogen valleys as a defined geographical area where hydrogen serves more than one end-use sector or application in mobility, industry or energy.

study, including Madeira (Portugal), Tenerife (Spain), Aran (Ireland), Greek Islands, Ameland (Netherlands), Chiloé (Chile) and Morocco.

In 2022, the Clean Hydrogen Joint Undertaking through Horizon Europe has a new call of up to EUR 25 million (USD 26 million) to fund a large-scale hydrogen valley (>5 kt H_2/year of renewable hydrogen[59]), with up to 80% of hydrogen consumption for industrial use and with linkages to areas outside of their geographical boundaries, for hydrogen production, demand or storage. In addition, there is another European Commission call to fund a small-scale hydrogen valley (>0.5 kt H_2/year of renewable hydrogen), with up to EUR 8 million (USD 8 million), in areas of Europe with no or limited hydrogen valleys, e.g. Central or Eastern European countries. REPowerEU will top up Horizon Europe investment of the Clean Hydrogen Joint Undertaking to double the number of hydrogen valleys by 2025. The concept of hydrogen valleys has expanded beyond Europe and is being promoted at a global level by the Mission Innovation (MI) Clean Hydrogen Mission, which aims to achieve at least 100 large-scale "clean hydrogen valleys" worldwide by 2030, with MI members committing to facilitate the construction of at least three hydrogen valleys each.

In Germany in September 2021, 30 municipalities and regions were awarded funding during the second round of the HyLand competition. While 15 regions receive EUR 0.4 million (USD 0.5 million) to deepen their regional hydrogen cluster concepts, 15 other regions received support to start developing the concept and create a network of local actors.

In the United Kingdom, several hydrogen industrial clusters are planned such as the Grangemouth (Scotland), East Cost (Teesside, Humber), Southampton, HyNet North West and South Wales clusters. The Project Union aims to link them while they develop through the repurposing of existing natural gas pipelines and building new dedicated ones. In addition, the United Kingdom set out an ambition to deploy CCUS[60] at scale in two industrial clusters by the mid-2020s and another two by 2030. The East Coast Cluster and Hynet were prioritised for deployment in the mid-2020s, with another Scottish cluster as a reserve, and the government is shortlisting CO_2 emitting projects, including CCUS-enabled hydrogen production, to connect to these clusters.

The US DOE in June 2022 released a Notice of Intent to fund the Bipartisan Infrastructure Law USD 8 billion programme. Among others, it looks to support development of regional hydrogen hubs (H2Hubs).This programme includes various low-emission hydrogen

[59] As defined in the EU Taxonomy, renewable hydrogen results in life cycle greenhouse gas emissions lower than 3 t CO_2-eq/t H_2.

[60] See Explanatory notes annex for CCUS definition in this report.

production pathways and end-uses, geographic diversity, employment opportunities and community engagement.[61]

In Australia, the Clean Hydrogen Industrial Hubs Program aims to support the development of up to seven hydrogen industrial hubs, with government funding of AUD 464 million (USD 320 million). The government identified seven priority hub regions: Bell Bay (Tasmania), Pilbara (Western Australia), Gladstone (Queensland), Latrobe Valley (Victoria), Eyre Peninsula (South Australia), Hunter Valley (New South Wales) and Darwing (Northern Territory). A range of related funding announcements were made during 2022.

In Japan, many of the highest emitting industrial activities are located near port areas. The government launched the Carbon Neutral Port initiative that aims to enable port facilities for large imports of hydrogen or hydrogen-derived fuels, and to decarbonise port operations and surrounding industries. Various fora are being organised to promote discussion among the relevant actors, for example, at the Port of Osaka. The New Energy and Industrial Technology Development Organization (NEDO) (Japan) is funding two research projects, one at the Port of Nagoya (Aichi) and another at the Port of Onahama (Fukushima) to assess hydrogen demand. The City of Yokohama has signed an MoU with ENEOS to analyse the potential for a hydrogen pipeline network in the waterfront area to connect various industries and the port.

The India Hydrogen Alliance (IH2A), an industry-led coalition, proposed the 25/25 National Green Hydrogen Hub Development Plan and is seeking public support. It includes five hydrogen hubs by 2025, clustering 25 projects in Gujarat, Karnataka, Maharashtra, Kerala and Andhra Pradesh states.

Hydrogen corridors - from connecting clusters to trade

Hydrogen clusters match supply and demand within the same region, often including renewable energy production or CCUS. With rising demand at clusters, they may need to acquire hydrogen from areas farther afield, if they offer affordable low-emission hydrogen in large volumes. This can provide the foundation for hydrogen corridors that repurpose existing natural gas infrastructure (see hydrogen transport by pipeline section) as well as new onshore and offshore hydrogen pipelines.

Several hydrogen corridors are being discussed in Europe. In May 2022, the European Hydrogen Backbone initiative suggested the development of five large-scale pipeline corridors that could help achieve Europe's 2030 hydrogen targets. These corridors would initially connect demand and supply between European countries.

[61] Preference to be given to the hubs with the largest emissions reductions, aiming to achieve a standard of less than 2 t CO_2-eq/t H_2.

Eventually, some corridors could link with neighbouring regions that offer export potential. These might include: hydrogen from North Africa via Italy to Germany and other Central European countries; hydrogen from North Africa and the Iberian Peninsula to France; offshore hydrogen supply in the North Sea to Belgium, Germany, Netherlands and United Kingdom; hydrogen supply from the Baltic Sea to Nordic and Baltic countries, and hydrogen from East and Southeast Europe (Romania, Greece and Ukraine) to Central Europe and Germany. The REPowerEU Plan states that the European Commission will support the development of three major hydrogen import corridors via the Mediterranean, North Sea area and, as soon as conditions allow, with Ukraine.

Overview of planned and proposed hydrogen pipeline corridors

Countries	Corridor	Actors	Type and length	Announced investment
Netherlands-Germany	The Delta Corridor project aims to link major industrial clusters in the Netherlands and Germany by 2026, including the Port of Rotterdam, Chemelot industrial site and North Rhine-Westphalia. In addition to a hydrogen pipeline, it includes construction of pipelines for liquefied petroleum gas and propylene (currently transported by train), and a CO_2 pipeline to connect to CCUS facilities.	Netherlands government, Port of Rotterdam, Chemelot	Onshore ~400 km	EUR 1 billion (USD 1.1 billion) (for all four pipelines)
Spain	The HyDeal España project plans to transport hydrogen from areas with good potential for low-emission hydrogen production in northern Spain to industrial facilities in Asturias.	Enagás, ArcelorMittal, Fertiberia, DH2 Energy	Onshore ~900 km	EUR 235 million (USD 248 million) by 2026, further EUR 455 million (USD 481 billion) by 2030* (including Catalina project)
Spain-Portugal	Enagás 2022-2030 Strategic Plan envisages the construction of a hydrogen-ready natural gas pipeline between northern Spain and Portugal.	Enagás	Onshore ~100 km	EUR 110 million (USD 115 million)
Spain-France	Enagás 2022-2030 Strategic Plan envisages the construction of a hydrogen-ready natural gas pipeline from Spain to France through the eastern fringe of the Pyrenees.	Enagás	Onshore ~200 km	EUR 370 million (USD 390 million)
Finland	The Finnish government has instructed Gasgrid Finland to develop a national hydrogen infrastructure around three valleys, two on the west coast, close to existing wind power installations, and one in the southeast region.	Gasgrid Finland	Onshore	
Finland-Sweden	The Swedish and Finish gas TSOs plan to build a 1 000 km hydrogen pipeline by 2030 in the Bothnian Bay region, an area with no major natural gas transport infrastructure.	Gasgrid Finland, Swedegas	Onshore 1 000 km	
Bulgaria-Greece	The gas TSO from Bulgaria (Bulgartransgaz) and from Greece (DESFA) signed a letter of intent for hydrogen co-operation. A hydrogen pipeline between Sofia and Thessaloniki is being considered.	Bulgartransgaz, DESFA	Onshore ~350 km	
Romania-Hungary-Slovakia-Poland	The natural gas TSOs from Romania (Transgaz), Poland (GAZ-SYSTEM), Slovakia (EUSTREAM) and Hungary (FGSZ) signed a MoU to explore options for hydrogen and CO_2 transmission.	Transgaz, FGSZ, EUSTREAM, GAZ-SYSTEM	Onshore	
Ukraine-Slovakia-Czech Republic-Germany	The Central European Hydrogen Corridor initiative aims to send hydrogen from Ukraine to Germany via dedicated pipelines through Slovakia and the Czech Republic. Gas TSOs in all four countries are involved in the initiative.	Gas TSO of Ukraine, EUSTREAM, NET4GAS, OGE	Onshore	

Countries	Corridor	Actors	Type and length	Announced investment
Norway-Germany	In the beginning of 2022, Germany and Norway agreed to conduct a feasibility study on the potential for a joint offshore hydrogen pipeline.	Governments	Offshore ~1 300 km	
Belgium, Denmark, Germany, Netherlands	Belgium, Denmark, Germany and Netherlands signed an agreement to co-operate on offshore wind power and hydrogen production, with a goal of 65 GW of offshore capacity by 2030 and to assess the potential of multiple energy hubs and islands, including the necessary pipeline infrastructure.	Four governments	Offshore	
Spain-Italy	Snam and Enagás agreed to assess the technical feasibility of a joint offshore hydrogen pipeline between Spain and Italy. Enagás announced plans to invest EUR 1.5 billion (USD 1.6 billion) for a hydrogen-ready pipeline, which would be operational by 2028 and initially transport natural gas in the period to 2039.	Enagás, Snam	Offshore ~750 km	EUR 1.5 billion (USD 1.6 billion)

*Net investment estimated by Enagás, considering a co-financing of 35%.

Notes: When the length of the pipeline was not explicitly given in the project announcement, the distance has been estimated from maps if a potential pipeline route is public. The length of a potential offshore pipeline between Norway and Germany has been estimated considering the distance from Ålesund (Norway) to Wilhelmshaven (Germany).

Effective steps are needed to avoid hydrogen leakage

Hydrogen is an indirect greenhouse gas (GHG) and its release into the atmosphere has climate impacts. Hydrogen interacts with other gases and chemical species in the atmosphere, affecting the concentration of methane, ozone and water vapour. Recent scientific research has provided evidence that these impacts are higher than previously estimated. The global warming potential (GWP) of hydrogen over a 100-year time horizon is on the order of 11±5 compared to 29.8±11 for fossil methane.[62] This means that, on a kilogramme-to-kilogramme basis, the GWP of hydrogen is around one-third that of methane. However, hydrogen is more energy dense than methane and can provide nearly 2.5-times more energy per kilogramme, so the warming effect of methane on an energy basis is around seven-times higher than that of hydrogen. Despite having a much lower GWP than methane, the impacts derived from hydrogen reaching the atmosphere could partially offset some of the climate benefits of using hydrogen to replace fossil fuels, particularly in the early years of adoption, given that hydrogen is a short-lived gas in the atmosphere (1.4-2.5 years compared with about 12 years for methane and 300-1 000 years for CO_2).

Hydrogen is not a direct GHG and its use does not result in significant emissions.[63] The issue is not related to the direct use of hydrogen, but to potential leakage during transport and handling. Given the small molecule size, high diffusivity and low viscosity of hydrogen, leakage is possible along the entire value chain. The lack of information about hydrogen leakage rates makes it difficult to assess the potential impacts and risks. Today empirical measurements for onsite production and use of hydrogen in industrial applications focus is on the safety of operations. Detectors for hydrogen leaks do not operate below the threshold for hydrogen gas flammability. In addition, there is very limited information about how much hydrogen can leak in pipes and compressors. Research is needed to assess how leakage levels might change with repurposed natural gas infrastructure. Moreover, the extension of hydrogen to new uses will result in new value chains that will require the development of international trade and hydrogen infrastructure. Some of these operations, e.g. loading and unloading of pressurised or liquefied hydrogen in trucks, ships or storage tanks, present significant risks for leakage.

[62] The GWP allows the comparison of the global warming impacts of different gases. It measures how much energy the emissions of a gas will absorb over a given period relative to the emissions of the same amount of CO_2.

[63] Only small quantities of NOx can be generated in combustion process. Its use in fuel cells results only in the production of water, with no global warming effect.

Lessons learned from the ongoing problem with methane leakage should be leveraged to tap into the full decarbonisation potential of hydrogen to avoid undesirable short-term climate impacts. A well-regulated hydrogen sector can minimise the risks. Immediate action is needed to develop the necessary scientific evidence and tools to set effective policies and regulations.

- Support research to get more clarity on the GWP effects of hydrogen, which remain uncertain. Develop climate models that take into account the characteristics of hydrogen leakage and that can help assess the impacts of hydrogen leakage.
- Support research to build evidence and reduce uncertainty about the risks of hydrogen leakage across the value chain, particularly from repurposed natural gas infrastructure.
- Identify hydrogen leakage mitigation measures and best practices, including technical solutions for leakage detection and repair.
- Implement robust methodologies for hydrogen leakage measurement, reporting and verification protocols.

Hydrogen trade

Overview and outlook

Today hydrogen trade is nascent, but large volumes of expected exports are under development

International trade in hydrogen could become an important feature of the energy transition. There is increasing demand worldwide for low-emission hydrogen and hydrogen-derived fuels[64] to help decarbonise the energy system. Importing hydrogen could also address energy security concerns through diversification of fuels and supply sources.

Some countries are looking to significantly scale up the use of low-emission hydrogen to decarbonise sectors such as industry, but lack the domestic capacity to produce the necessary volumes cost effectively. Other countries have abundant renewable energy resources to produce electrolytic hydrogen or have the capacity to produce fossil fuel-based hydrogen with CCUS,[65] but have low domestic hydrogen demand. Hydrogen trade would allow importers to satisfy increased demand and allow low-emission hydrogen exporters to earn revenue from trade.

Expected exports

An estimated 12 million tonnes (Mt) of low-emission hydrogen per year could be exported by 2030 based solely on the export-oriented projects under development. Of that amount, export of 2.4 million tonnes of hydrogen (Mt H_2) per year is planned to come online by 2026.

Planned exports roughly double from 2029 to 2030, with an increase of 6 Mt H_2/year, perhaps because 2030 is a round date for many projects to set as a target for completion.

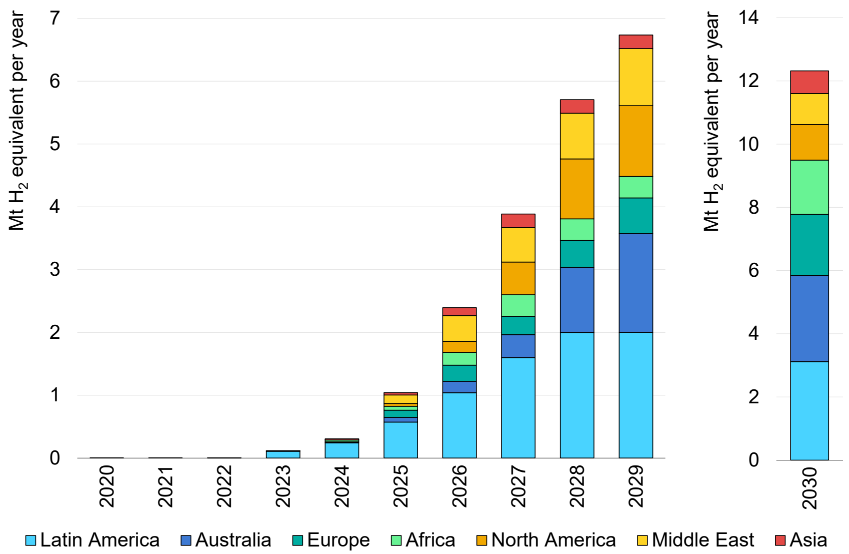
Projects with planned starts after 2031 account for an additional 8 Mt H_2/year of potential exports, while another 6 Mt H_2/year do not indicate a target start date. All trade-oriented projects underway today represent 26 Mt H_2/year of potential hydrogen exports.

Nearly all of these export-oriented hydrogen project plans have been announced in the last two years, indicating a nascent, but rapidly growing landscape for hydrogen trade. As a result, most projects are at an early stage of development: Projects accounting for 16 Mt H_2/year are in the concept stage; projects representing 10 Mt H_2/year have progressed to feasibility studies; and projects representing only 0.2 Mt H_2/year have reached an FID or beyond.

[64] See Explanatory notes annex for low-emission hydrogen and hydrogen derived fuels and feedstocks definition in this report.

[65] See Explanatory notes annex for CCUS definition in this report.

Planned hydrogen exports by region, 2020-2030



Notes: The IEA tracks the trade-oriented hydrogen projects under development through news outlets, press releases and inputs from governments. Quantities of hydrogen carriers or derivatives in this section are given in hydrogen equivalent terms, i.e. the mass of hydrogen consumed to produce the hydrogen carrier. For example,180 kilogrammes of hydrogen (kg H_2) are consumed to produce 1 000 kg of ammonia. The energy loss for volumes that ultimately undergo dehydrogenation to release hydrogen from the carrier are not included in the calculation. In the absence of further details, the hydrogen output of each project is assumed to be equally divided between all the stated domestic end-uses and export. All projects are assumed to reach 50% of full output in the intended start year, to reflect possible delays, and 100% in all subsequent years. For electrolytic hydrogen production powered by a combination of dedicated solar and wind, an electrolyser capacity factor of 50% is assumed.

Those 0.2 Mt H_2/year are almost entirely attributable to the Helios Green Fuels Project in Neom, Saudi Arabia, in which construction has begun and production of electrolytic hydrogen is planned for 2026.

The estimated export totals should be seen as an upper bound of projects announced thus far for several reasons. Since most are at an early stage, the projects have a series of hurdles to clear that could delay or even cancel plans, such as favourable results of feasibility studies, securing financing, permitting and siting, and procuring the required energy inputs and components. Delays in project development are common and have already been encountered by several projects, which could change the outlook for export volumes by 2030. For example, an export-oriented electrolyser project under development in Tasmania (Australia) encountered challenges when the utility offered only a fraction of the low-emission electricity required for the project. Additionally, many projects are being developed in places that have not yet established a full industrial hydrogen export value chain. The lead times and investment needed to deploy the enabling infrastructure and networks could also delay exports. As well, the overall potential export volume is influenced by large individual projects on the scale of several million tonnes, so any changes in these plans could reshape the hydrogen trade landscape.

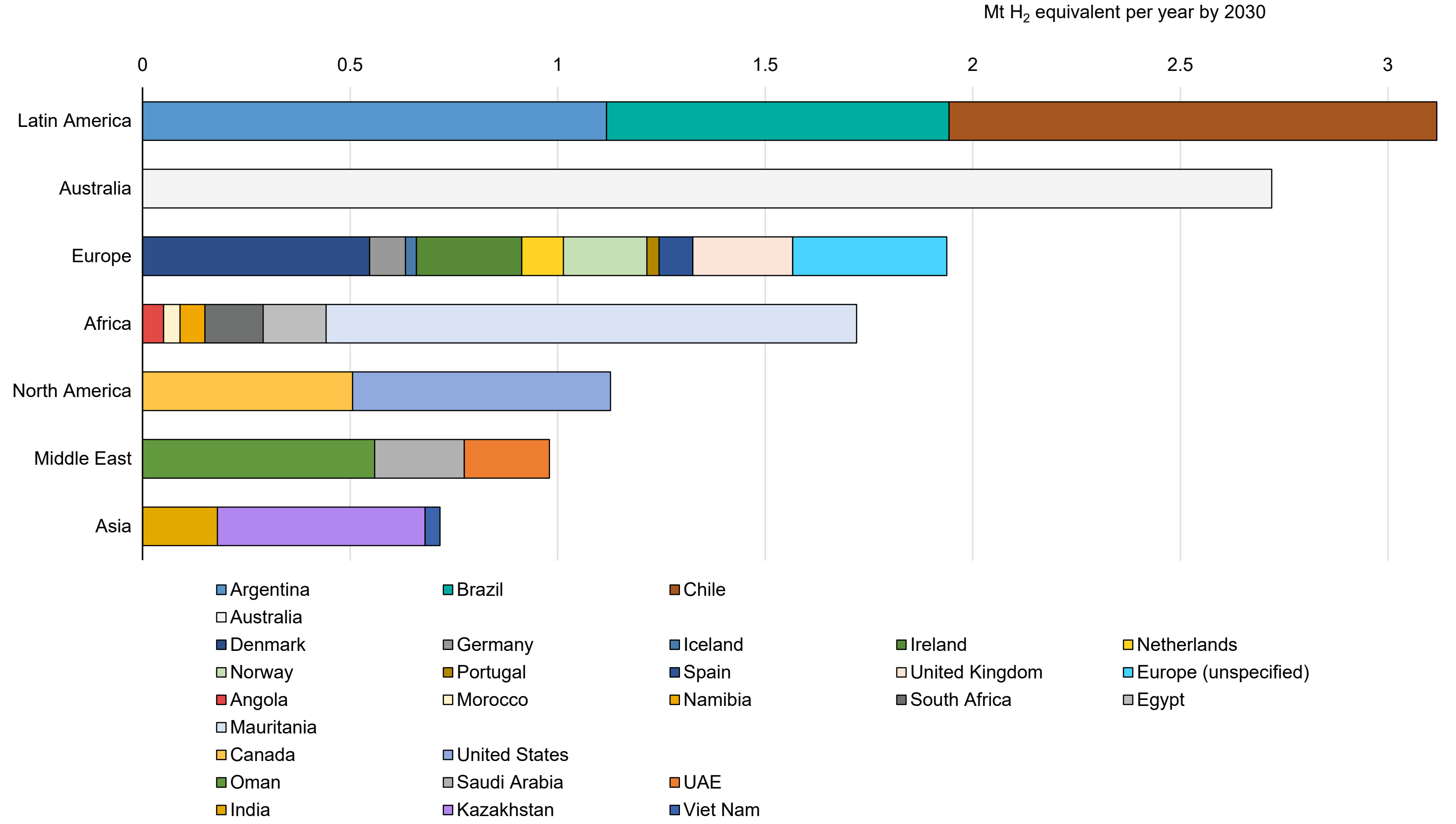
Planned export projects. The planned hydrogen export projects are geographically diverse, with significant volumes planned in every major region of the world. Of the 12 Mt H_2/year of planned exports by 2030, the region with the largest amount is Latin America

(3.0 Mt H_2/year). This is followed by Australia (2.7 Mt H_2/year), Europe (1.79 Mt H_2/year), Africa (1.7 Mt H_2/year), North America (1.1 Mt H_2/year), Middle East (1.0 Mt H_2/year) and Asia (0.7 Mt H_2/year). Abundant solar, wind and hydropower resources to supply clean electricity for electrolysis is a key driver of these projects; access to fossil fuel resources suited for producing hydrogen with CCUS also drives projects, but to a lesser extent. Most of the exports in Europe are planned for delivery to another European country.

It is worth noting that many export projects are planned in shared industrial hubs, often near ports. These include the Pecém Industrial and Port Complex in Brazil and the Suez Canal Economic Zone (SCZone) in Egypt. The co-location of renewable electricity development with hydrogen production projects and export facilities could help lower costs through shared infrastructure and energy integration. Establishing large dedicated land areas for these industrial zones away from populations or sensitive ecosystems could reduce infrastructure permitting and siting challenges. By concentrating export activities at internally co-ordinated sites, these hubs could help establish the dominance of particular technical standards, hydrogen carriers and trade routes.

Low-emission hydrogen exports reach 12 million tonnes by 2030 based on projects under development

Planned hydrogen exports by region/country, 2030

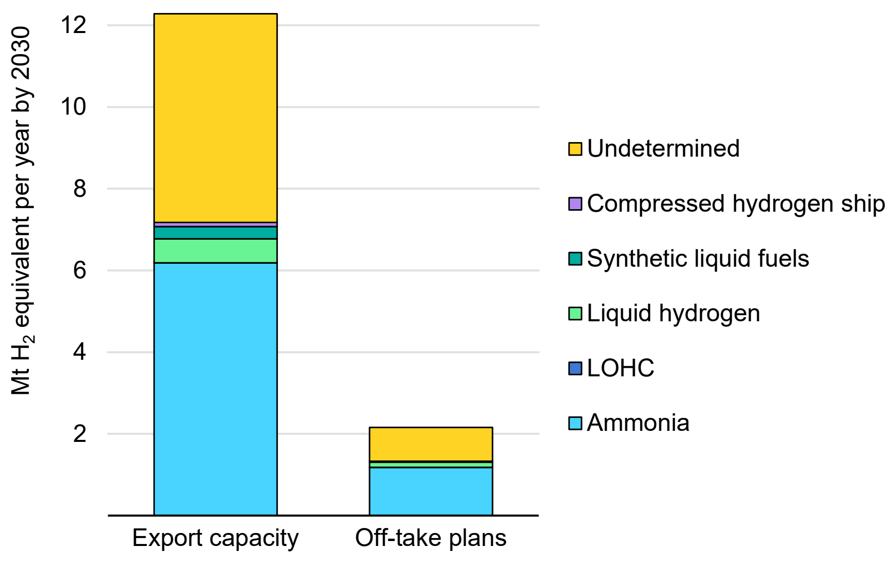


Note: UAE = United Arab Emirates.
Source: IEA analysis based on data from news outlets, press releases and governments.

Electrolytic hydrogen production with ammonia as the carrier are the focus for exports. Projects under development plan to export hydrogen as well as hydrogen-derived fuels. Most projects that have identified a hydrogen carrier molecule have chosen ammonia, while much smaller volumes are planned for synthetic liquid fuels, LOHC, liquefied hydrogen or compressed hydrogen by ship. Projects accounting for 40% of planned export volumes by 2030 have not yet identified a carrier molecule.

Electrolytic hydrogen production accounts for 88% of planned export volumes by 2030, while 12% is fossil fuel-based hydrogen production with CCUS. The proportion of electrolytic hydrogen production among export projects is significantly higher than its proportion among the set of all low-emission hydrogen production projects, which includes volumes marked for domestic use. This may be because major importers, such as Europe, are signalling a strong policy preference for electrolytic hydrogen. Project developers may also skew towards electrolysis for export due to the expected near- and medium-term cost declines for electrolytic hydrogen and a desire to avoid the price volatility of fossil fuel inputs.

Planned hydrogen exports by carrier by 2030



Notes: LOHC = liquid organic hydrogen carrier. Trade projects include trade of all molecules derived from low-emission hydrogen, and excludes unabated fossil fuel-based ammonia trade. Ammonia exports may be converted back to molecular H_2 for end-uses or used directly as ammonia.

Source: IEA analysis based on data from news outlets, press releases and governments.

Import agreements lag behind export plans

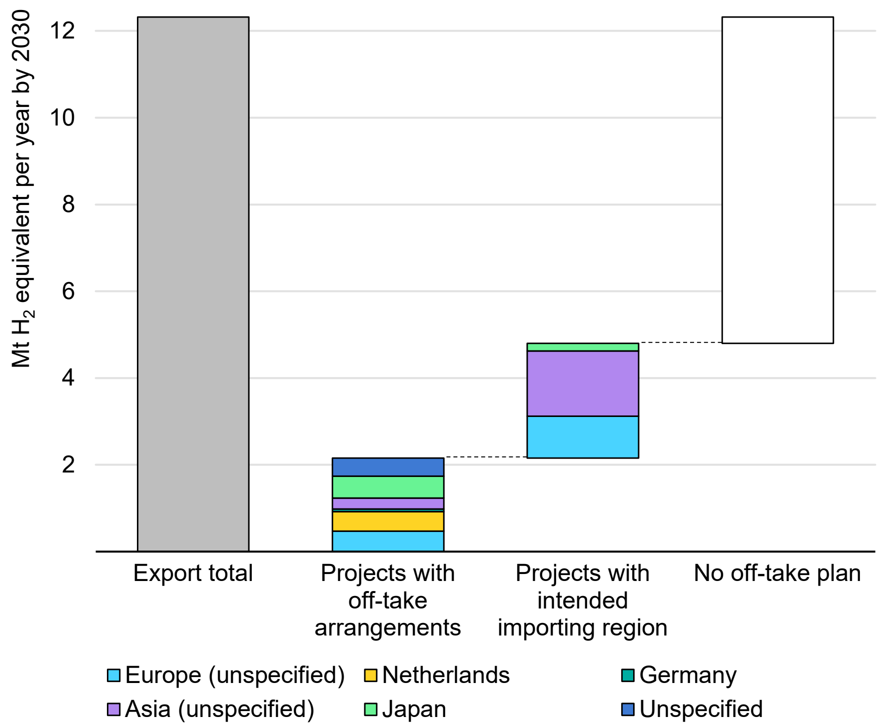
Off-take and importing arrangements lag the scale of planned exports. Of the 12 Mt H_2/year of proposed exports by 2030, only projects accounting for 2 Mt H_2/year have made off-take agreements or have a potential off-taker in the project consortium. Projects representing a further 2.6 Mt H_2/year cite intend export to a specific region but do not have off-take agreements. The remaining 7.5 Mt H_2/year of projects have not announced proposed delivery destinations.

The regional breakdown of the expected imports, based on projects with off-take agreements and those with intended destinations: 1.9 Mt H_2/year by 2030 is marked for import into Europe, including imports to non-European Union countries and hydrogen trade between two European countries; planned imports in Asia by 2030 are 2.4 Mt H_2/year, of which 0.7 Mt H_2/year is marked for Japan. Export projects totalling 0.4 Mt H_2/year by 2030 have secured an off-take company, but still have an unspecified regional destination for the hydrogen.

Further to the off-take plans associated with specific hydrogen production projects, Australian clean energy developer Fortescue Future Industries (FFI) has signed agreements to deliver 5 Mt H_2/year by 2030 to European utility E.ON and 0.1 Mt H_2/year to German material manufacturer Covestro, potentially beginning in 2024. These are not included in the chart as these volumes are not yet associated with specific export projects, and will likely draw from FFI's export projects that are already represented.

The set of hydrogen importing regions is far narrower than the set of exporting regions. All export volumes with some form of import plan are marked for import in Europe or Asia, particularly Germany, Netherlands and Japan.

Export volumes from planned projects with off-take arrangements or intended destinations by importing country/region, 2030



Source: IEA analysis based on data from news outlets, press releases and governments.

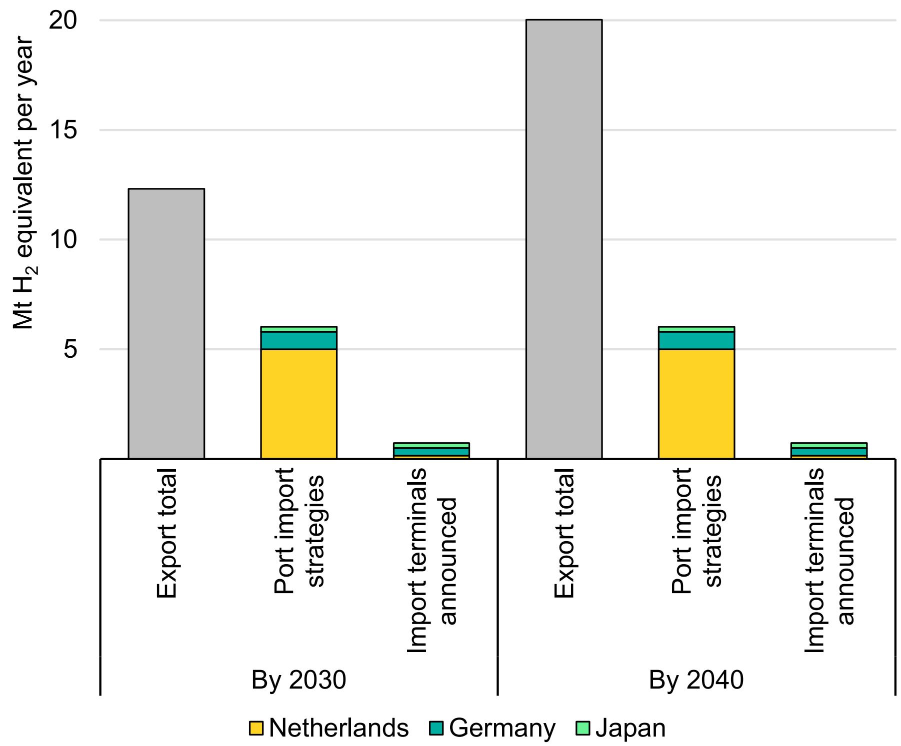
The importing countries tend to be net importers of fossil fuels and have insufficient domestic renewable energy resources to meet total energy demand. With no other regions establishing import arrangements, Europe and Asia are thus far positioned to be the main global hydrogen importers by 2030.

In addition to off-take agreements between companies, European and Asian governments have begun to develop high-level hydrogen import plans. The European Commission REPowerEU Plan to reduce reliance on fossil fuels from Russia sets a target to import 10 Mt/year of renewables-based hydrogen by 2030, and several European Union member states have set domestic import targets to contribute towards this total. Korea's hydrogen plan targets nearly 2 Mt/year of low-emission hydrogen imports by 2030. Japan plans to import 0.3 Mt H_2/year by 2030. Though its targeted proportion of low-emission hydrogen imports is unspecified, Japan plans to consume 3 Mt H_2/year by 2030 (including imports), of which 0.42 Mt H_2/year is to be low-emission hydrogen.

Government hydrogen import targets total around 12 Mt H_2/year globally, which matches the planned export volumes from projects under development. This alignment is in contrast to the demonstrated gap in off-take agreements, indicating that further alignment of the trade value chain is needed to translate broad government import targets into actual imports at the I project level.

The current project pipeline includes 0.9 Mt H_2/year marked for import to EU nations from outside the European Union by 2030, either through off-take agreements or intended destinations (9% of the REPowerEU target). (Import plans through the lens of the REPowerEU Plan are discussed in the "see "Hydrogen in a changing energy landscape" chapter.)

Hydrogen import volumes specified in strategies for ports and planned terminal capacity, 2030 and 2040

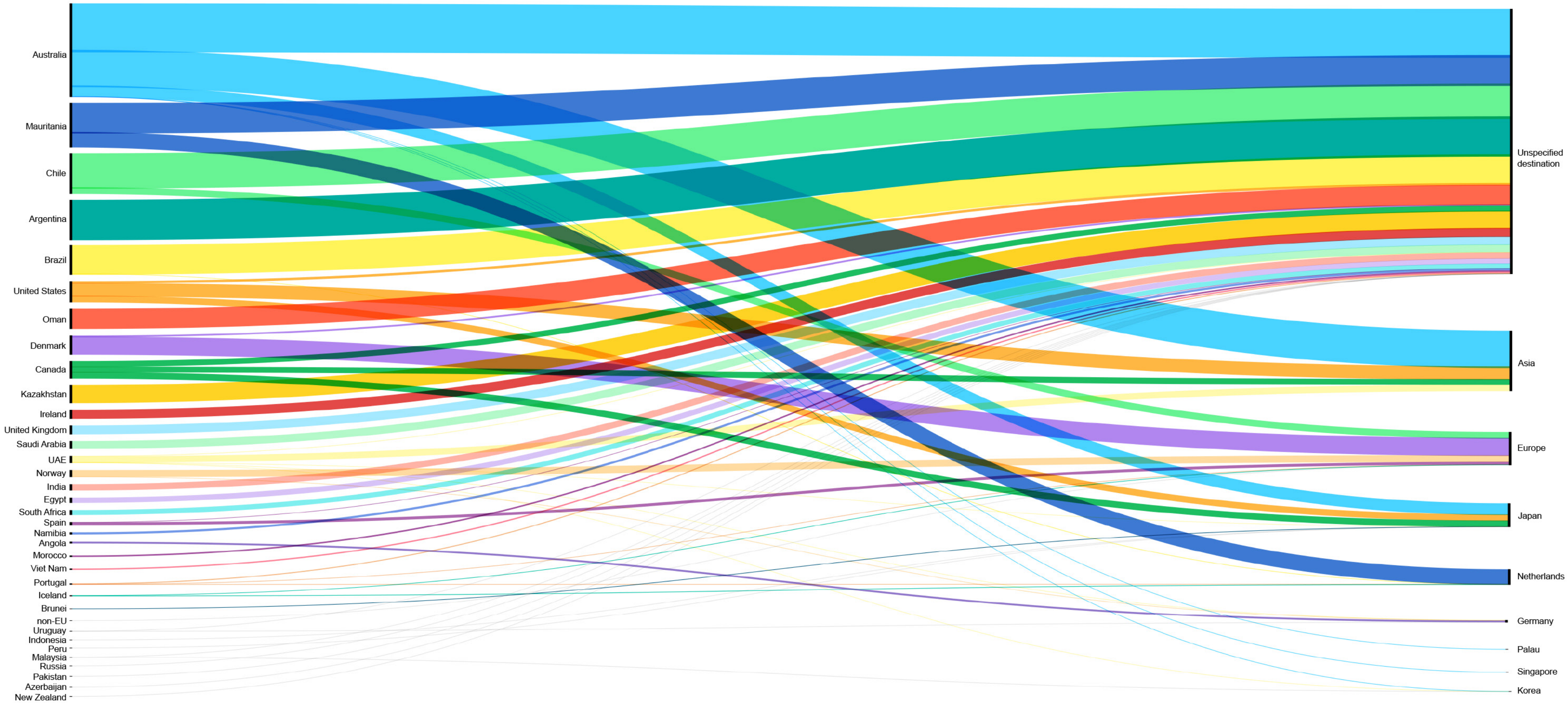


Source: IEA analysis based on data from news outlets, press releases and governments.

The majority of export projects plan to deliver hydrogen and its derivatives via ship, creating a need for expanded shipping and port infrastructure. Announced plans by ports to import specific volumes of hydrogen and its derivatives have not reached the scale of planned exports. The port plans, almost entirely attributable to ports in the Netherlands, Germany and Japan, account for around 6 Mt H_2/year by 2030. This figure is lower than the planned exports of 12 Mt H_2/year by 2030, and the gap is set to widen by 2040, with no further port plans set to come online while planned exports rise to 20 Mt H_2/year. In addition, even most projects with a named off-taker do not yet have an identified import terminal or port. In terms of import infrastructure, the terminal projects under development with announced capacities account for just 0.7 Mt H_2/year of import capacity. For imports to be realised this decade, import capacity and hydrogen transport infrastructure, e.g. ships, will need to be brought online at the same pace as export capacity.

A large number of hydrogen trade projects are underway

Hydrogen trade flows based on planned projects, 2030



Notes: Countries on the left side are exporters, those on the right importers. Unspecified destination represents export projects for which no import countries have been announced. Grey links represent trade projects for which no trade volume has been announced.

Source: IEA analysis based on data from news outlets, press releases and governments.

Race to commercialisation – what will be the first overseas supply chain?

Among the announced trade projects, three have proven technologies for seaborne trade. While some technologies such as gas turbines, compressors and pumps are already mature, hydrogen equipment must advance to keep pace with export plans.

The projects highlighted here have completed the demonstration phase and traded hydrogen at small scale to test the economic and technical viability of equipment and facilities under real market conditions.

The Hydrogen Energy Supply-chain Technology Research Association (HySTRA), announced in 2018, is the world's first international liquefied hydrogen supply chain project. It aims to produce hydrogen via gasification of lignite with carbon capture and storage in Australia and ship 225 kilotonnes (kt) of liquid hydrogen to Japan. The pilot project is delivered by a consortium of Japanese and Australian industry partners led by Kawasaki Heavy Industries, with support from the Australian and Japanese governments. The CO_2 captured will be injected into depleted oil and gas reservoirs. In February 2022, the Suiso Frontier – the world's first liquid hydrogen carrier – delivered its first cargo of liquid hydrogen from the Port of Hastings, Australia to the Port of Kobe, Japan, where hydrogen is consumed in 100% hydrogen gas turbines for power and heat generation. HySTRA currently is preparing for its commercialisation phase by developing large-scale technologies based on the prototypes used in the demonstration.

Japan's Advanced Hydrogen Energy Chain Association for Technology Development (AHEAD), which includes Japanese industrial partners such as Chiyoda, in 2020 launched the world's first international trade of hydrogen to import up to 210 tonnes H_2/year. The hydrogen produced in Brunei Darussalam from processing gas using SMR is shipped to Japan as methylcyclohexane (MCH) using toluene as a hydrogen carrier. MCH does not require cooling, but has energy conversion losses of around 35-40%. In Japan, the hydrogen is extracted for use in gas-fired power plants and the remaining toluene is shipped back to Brunei for re-use.

Saudi Aramco and the Institute of Energy Economics Japan, with support from the Japanese government, successfully completed a demonstration of shipping 40 tonnes of natural gas-based ammonia from Saudi Arabia to Japan in 2020. The imported ammonia was combusted in gas turbines. In the process, 20 tonnes of CO_2 captured in ammonia production were used for enhanced oil recovery and 30 tonnes CO_2 for methanol production.

Developing international hydrogen markets

Potential models for hydrogen trade

As the pipeline of hydrogen trade projects expands, governments have begun to consider measures to facilitate the development of the international hydrogen market and ensure that trade will satisfy national objectives. Given the infancy of the market, many governments have yet to implement specific hydrogen trade policies. Nevertheless, commonalities and variations in government approaches, as well as areas of need for international co-ordination on hydrogen trade, are starting to take shape.

Current government approaches

Governments interested in developing hydrogen exports or imports align closely with the announced trade projects. To address climate objectives, many importing nations are developing frameworks to ensure hydrogen imports are low-emission. In line with energy security concerns, importers are largely aiming to obtain a diversified supply of low-emission hydrogen from various sources to guard against potential supply shocks in specific areas.

Many governments plan to foster hydrogen trade within their existing liberalised energy market structure and frameworks, with private companies developing export or import projects under frameworks provided by the government. In some countries, such as Uruguay, the government is taking a more active role by issuing tenders for the first hydrogen trade projects while projects initiated by the private sector proceed in parallel.

In crafting the frameworks to foster trade projects, governments seek to provide certainty for developers and investors, establish regulations to align the market with national priorities, and use policy support to accelerate the market. Many governments have set targets for the scale of hydrogen exports or imports to be reached in the coming decades, nearly all of which are on the order of millions of tonnes of hydrogen per year.

REPowerEU and the European Union delegated acts: The European Commission published the REPowerEU in March 2022 in the wake of Russia's invasion of Ukraine. It is a policy plan to significantly reduce consumption of fossil fuels in the European Union to reduce reliance on fossil fuel imports from Russia and to accelerate the EU Green Deal. Along with energy efficiency provisions and scaling up other non-fossil fuel energy sources, the plan aims for 10 Mt/year of renewable hydrogen[66] to be produced in the European Union and a further 10 Mt/year to be imported by 2030, where renewable hydrogen is defined as electrolytic hydrogen produced

[66] See Explanatory notes annex for renewable hydrogen definition in this report.

using renewables-based electricity. This marked the European Commission's first indicative hydrogen import target.

In tandem with the REPowerEU Plan in 2022, the European Commission published two draft delegated acts that propose process and production method (PPM) requirements in order for hydrogen or its derivatives to be counted towards the binding renewable energy targets of member states set out in the Renewable Energy Directive (RED II). Among other detailed requirements, the drafts include an emissions threshold of 3.38 kilogrammes of carbon dioxide equivalent per kilogramme of hydrogen (kg CO_2-eq/kg H_2), which is 70% lower than that of the predefined fossil fuel comparator including transport and other non-production emissions. The draft acts also require that electrolytic hydrogen production must use electricity from renewable power installations that were built no more than 36 months prior to ensure hydrogen's renewable electricity use is additional to existing generation. The adopted version of these rules will be pivotal for hydrogen exporters and will determine the eligible production configurations and volume of exports that they could ultimately sell to the European Union.

Agenda for international co-operation

Trade of hydrogen and its derivatives will require technologies, industrial configurations and project scales that do not exist today. Several central challenges are clear. Among those, these are areas for government action and international co-operation.

Standards, regulations and certifications. Governments and market participants must be able to discern between hydrogen of varying emissions-intensities or other PPM concerns for hydrogen trade to contribute to energy security and to the clean energy transition. The relevant bodies are beginning to develop standards, regulations and certifications to do so, but no formal rules are yet in place. Establishing such instruments involves several steps, could take years and requires active government engagement. Clarity on the outlook for PPM rules will be important to enable stakeholders to make long-term project plans and decisions.

In addition to PPM rules, other regulations will shape the development of hydrogen trade markets and infrastructure. These include cost recovery models for infrastructure, tariffs, system planning, hydrogen uptake mandates and others. Well-designed regulatory frameworks can help overcome many of the key challenges.

Trade infrastructure. Planned hydrogen export volumes are currently significantly outpacing the development of the necessary infrastructure to deliver hydrogen and its derivatives to end-users. Much of this infrastructure may be located at and co-ordinated by ports, including storage tanks and ammonia cracking facilities as part of export and import terminals, along with expanded and updated shipping fleets. Though concentrating industrial processes in ports could create substantial hydrogen demand in port industrial zones, hydrogen and its derivatives will also need to be delivered from ports to inland demand centres, requiring additional transport infrastructure. Where geographically feasible, such as between North Africa and Europe, hydrogen can be imported through pipelines. New infrastructure development can have long lead times, high capital costs and, in some cases, require technological advances. Repurposing existing infrastructure, such as natural gas pipelines, can reduce costs and lead times (see “Infrastructure” chapter). One challenge for governments in this regard is to develop permitting and siting processes that ensure infrastructure projects do not harm local communities and ecosystems, while not inhibiting such projects from being built at the scale and speed necessary.

Demand creation and off-take. The majority of planned hydrogen export does not yet have an agreed off-taker. This is due in large part to sluggish demand for low-emission hydrogen. While low-emission hydrogen remains relatively costly, government policy can help encourage first movers to incorporate low-emission hydrogen in their processes. The disparity between production and off-takes is even more pronounced for hydrogen exports. Low-emission hydrogen projects for domestic use are commonly developed onsite or nearby a planned end-use facilitating off-take. Hydrogen export projects are often not designed for a particular end-use due to the wide possibilities of export destinations and lack of clarity on final costs. Clarified standards and regulations from importing countries can help; without certainty on whether a given export project will be eligible under an importer’s regulations, it is difficult to reduce risks in finalising off-take agreements.

In-country value for exporters. Many potential hydrogen exporters are emerging economies, which have highlighted the need to ensure that export projects developed by international companies adequately benefit the local economy. This could entail hiring a large portion of project employees from the domestic workforce, avoiding environmental harm and ensuring project revenues flow adequately to the local communities and overseeing government. It could include capacity building through partnerships with local educational institutions or initiatives to educate residents. Such measures help ensure equitable trade relations and continued buy-in from exporting nations.

Clarify World Trade Organization (WTO) trade rules. The WTO deals with the rules of trade between nations. There are no specific rules for hydrogen trade at this point. Clarification may be needed on the characteristics of trade that are unique to hydrogen, such as how to treat molecular hydrogen compared to hydrogen derivatives. Also, it is uncertain whether specific forms of PPM requirements for hydrogen imports would be challenged under WTO rules as technical barriers to trade. WTO rules allow for member nations to implement environmental policies that are restrictive to trade as long as they are justifiable on environmental grounds, though this justifiability for hydrogen trade regulations may not become clear until a dispute case is arbitrated by the WTO.

Standards, regulations and certifications related to the emissions intensity of hydrogen are needed

Given the range of methods for producing hydrogen and their varying levels of emissions and fossil fuel use across the supply chain, the international hydrogen market will not inherently help achieve climate and energy security imperatives. Effectively discerning the process and production methods for traded hydrogen will be critical to enable governments to guide the market towards these goals. Three key elements must align to achieve this: an international *standard* detailing a methodology for the PPM metrics, national PPM *regulations* defined using these metrics and harmonised between nations, and *certifications* to verify that a project complies with a regulation.

International standards. Nations need to develop a universal methodology for determining the emissions intensity of hydrogen production and other important PPM metrics, and have this adopted by an international standards body such as the International Organization for Standardization (ISO). The International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) is currently pursuing a work stream to develop a mutually agreed methodology for determining the greenhouse gas (GHG) emissions of hydrogen production, which could be used as a seed document to develop a standard.

An ISO standard takes several years to develop. Important standards to determine the GHG emissions intensity of hydrogen production and to guide other specifications of the hydrogen value chain may not be in place as the market takes form in the next few years. The ISO is developing a Draft Technical Specification to measure the GHG emissions intensity of hydrogen production, aiming for publication in 2024. This draft specification could serve as a key common reference for the market in the interim, before a Draft International Standard and finalised ISO standard are completed in the coming years.

National regulations. With an agreed methodology to measure PPM metrics, nations could adopt regulations based on those metrics, such as a threshold of the emissions intensity of hydrogen production needed to qualify for policy benefits. It is important that these regulations are robust yet workable, and do not hinder low-emission hydrogen production and uptake. The EU draft acts on hydrogen can serve as an example, in this case of specific regulations defined for a pre-existing legislative framework (RED II).

Various countries have adopted differing regulations on hydrogen PPM. Actors seeking to export to varied markets could expect extra costs to conform. Varied import regulations could potentially skew producers towards cheaper, more carbon-intensive hydrogen production methods for export to regions with lenient or no regulations, leaving constrained supply for regions with more stringent regulations. To address this issue, countries could develop internationally harmonised regulations for the emissions intensity of hydrogen production and other process and production methods. Such efforts should follow WTO guidelines for these processes to avoid being challenged as a technical barrier to trade. These include ensuring the international standardisation process is open and non-discriminatory for all WTO members to meaningfully participate, particularly emerging economies.

Certification systems. Once the standards and regulations are enacted, implementing and enforcing them will require capacity building for certification systems. Outside of regulatory compliance, certification systems can also be used in voluntary low-emission hydrogen markets. Institutions must be created or appointed to vet hydrogen production methods of projects using the adopted methodology, issue certifications or guarantees of origin to verify compliance, and track certifications in a transparent and centralised registry. Authorities must be in place to require and process the certifications from traders in line with regulations and to oversee the certification bodies. For example, the EU-funded CertifHy initiative developed a certification system that is being used in voluntary markets and may be adopted for use in regulatory compliance in the future. Korea has stated plans to establish a Clean Hydrogen Certification System and Country of Origin Verification System by 2024.

In line with the fragmentation challenges with national regulations, it is likely that a single universal certification system may not be realised. In this scenario, it would be preferable to limit deviation between certification systems and to implement mechanisms to make them interoperable. An option is to establish avenues for a certification under one importer's regulations to be recognised by other import jurisdictions that have equivalent or less stringent regulations.

Market models

The format of transactions between exporters and importers will be an important determinant of market development. Today the international hydrogen market is being established through *bilateral contracts*, most often between companies, but also involving governments. Exporters, both developers and governments that support them, assume large risks to develop these capital-intensive projects, and seek certainty in off-take contracts that the investment will pay off. For this reason, they prefer long-term contracts with clear pricing mechanisms or fixed prices. Provisions such as take-or-pay contracts, in which the buyer must off-take the agreed volumes or pay the seller, can provide income certainty to sellers. Such models may provide the security needed for developers to reach an FID.

Some importers, on the other hand, seek increased flexibility in contracts. This could include avoiding destination clauses, which designate the ports to which the hydrogen must be delivered and prohibit or restrict diversions. Destination clauses effectively prevent the buyer from reselling the product, making it difficult for buyers to adapt to changing market prices or supply needs. Developing an internationally standardised template for hydrogen trade contracts, in consultation with exporters and importers, could potentially streamline off-take negotiations. Today most bilateral contracts are brokered directly between the seller and buyer.

Another potentially powerful model of awarding contracts is through *auctions*. Governments can hold auctions on the demand or supply side, or both. For electrolytic hydrogen production, joint auctions could be held for electrolyser and renewable electricity installations from a single developer to support integration of the two, though this form of auction does not help match producers to off-takers.

By creating a bidding competition for a contract, auctions help move the demand- and supply-side price levels closer. They also allow the market price to respond more readily to changes such as production cost declines or increased willingness to pay. Governments can use auctions to award contracts for differences or carbon contracts for differences, which effectively use government funds to guarantee the seller of low-emission hydrogen a fixed price for their product or for carbon credits generated, respectively. Auctions can also be designed to achieve non-price benefits, such as timely project completion or maximising in-country value of a project.

Some challenges may arise from holding auctions in a nascent market such as low-emission hydrogen. The auctions may not garner enough participants for the price-finding process to work effectively. Additionally, market competition at an early stage could incentivise developers to choose low cost, lower performance technologies instead of more costly, higher performance technologies that could become cheaper as the market matures. Auctions could be designed to mitigate such challenges, for instance by including selection criteria for developers to use technologies suitable for the long-term maturation of the market.

While contracts may predominate in the near term, hydrogen trade could develop more open market models such as resale markets or *spot markets* in the longer term. Ammonia could be a viable candidate for early forms of such markets, as there are existing infrastructure and market models for fossil fuel-based ammonia in the fertiliser industry, which reduces supply-side risks. Provided that public policy stimulates demand for low-emission ammonia, more short-term trading of the molecule could be developed to trial this market model for low-emission hydrogen and derivatives. Care should be taken in this case to ensure that introducing low-emission ammonia for energy end-uses does not displace or disrupt the market of ammonia for fertiliser, which is crucial for securing global food supply.

Commodity pricing benchmarks pegged to the GHG emissions of the hydrogen could enable the market to inherently value low-emission hydrogen. One effort, the Open Hydrogen Initiative, seeks to harmonise an approach to measuring the GHG emissions of hydrogen production to enable such a benchmark. This could be used to establish contract prices or form the basis for the emergence of spot markets.

One of the most developed support mechanisms for hydrogen trade so far is the H2Global double-auction programme being implemented in Germany, which includes only low-emission electrolytic hydrogen and its derivatives. The initiative plans to emulate a contracts for differences scheme. Using a market intermediary, it will hold an auction to purchase these products from non-European Union suppliers through fixed-price, ten-year contracts. It will then conduct a separate auction to sell the hydrogen to buyers using roughly one-year contracts.

Since the cost of producing electrolytic hydrogen will likely exceed buyer willingness to pay in the near term, the intermediary will sell at a loss. This price difference will be covered using public funds. The German government has approved a EUR 900 million (~USD 1 billion) grant for this purpose. The Netherlands government has also expressed interest in contributing funding.

In its first round of tenders, the programme intends to issue one sell-side contract each for ammonia, methanol and kerosene products derived from electrolytic hydrogen. These three contracts are expected to use around EUR 300 million (~USD 354 million) each over ten years, with product deliveries to start in early 2024. The products can be imported into ports in Belgium, Germany and Netherlands. The seller will be responsible for delivering the product to the receiving port, and H2Global will reimburse the seller for the costs of transport, logistics and import duties.

The auction format will push bidders to reach lower supply-side prices and higher demand-side prices. The H2Global initiative anticipates that the two prices will converge over time as the market develops, decreasing the financial needs of the intermediary. This initiative aims to provide certainty to developers of low-emission hydrogen production through long-term contracts at a sufficient price, while creating early demand for these products by offering competitive demand-side prices.

Hydrogen policies

Five key policy areas necessary for hydrogen deployment in the energy transition

The adoption of hydrogen as a new energy vector is a complex endeavour that requires government intervention if it is to be realised at the pace required to help meet climate ambitions. Governments are already working with diverse stakeholders to identify effective policies to underpin hydrogen's role in the clean energy transition. Policy instruments need to be tailored to country-specific priorities and constraints, including resource availability and existing infrastructure. A wide variety of policy measures are available. The IEA Future of Hydrogen report, identified five key areas to facilitate tracking. This annual Global Hydrogen Review uses these areas to inform policy makers about progress and implementation gaps. The five areas are:

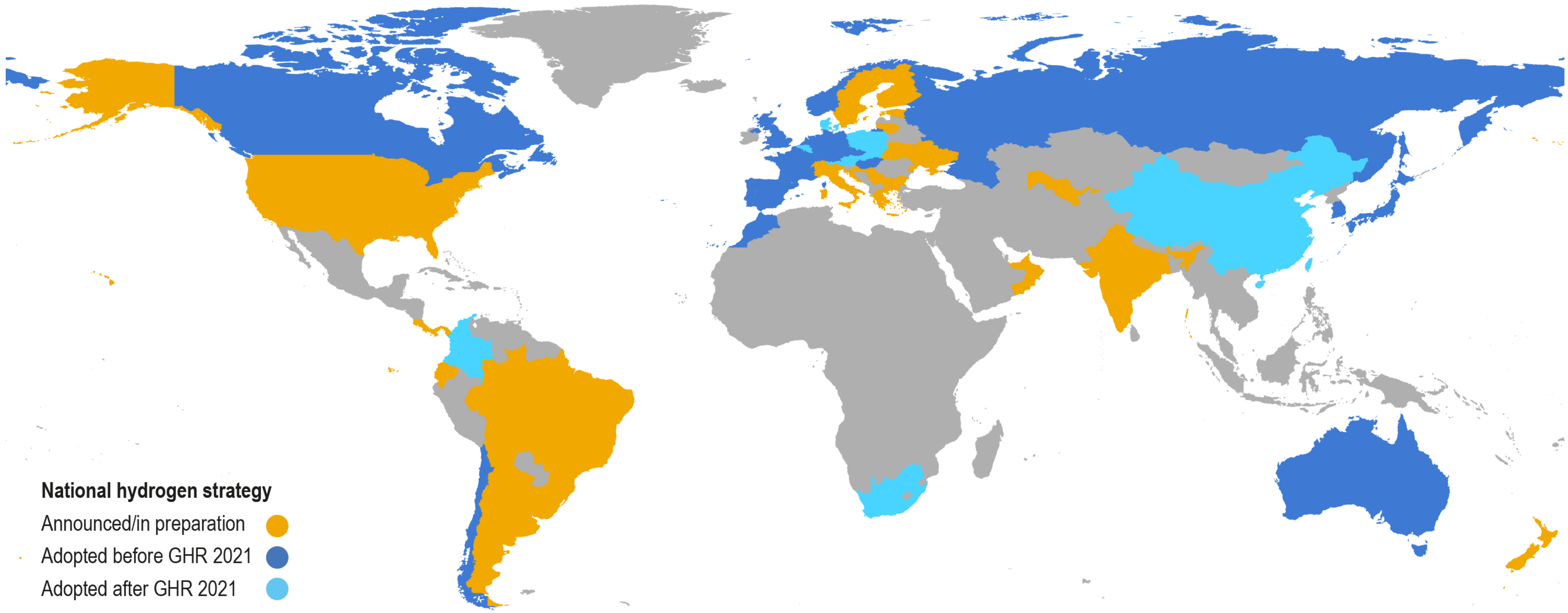
- **Establish targets and/or long-term policy signals** to create a vision for the role of hydrogen in the overall energy policy framework to provide stakeholders with certainty that there will be a future market place for hydrogen.
- Policies to **support demand creation** for low-emission hydrogen[67] as a key lever to stimulate its adoption as a clean energy vector.
- Policies to **mitigate investment risks** in projects across the hydrogen value chain, facilitate access to finance and accelerate deployment.
- **Promote R&D, innovation, strategic demonstration projects and knowledge-sharing**, which are essential to drive down costs and increase the competitiveness of hydrogen technologies.
- **Establish appropriate regulatory frameworks, standards and certification systems** to assure practices, mitigate barriers, facilitate trade and boost investor and consumer confidence in a low-emission hydrogen market.

[67] See Explanatory notes annex for low-emission hydrogen definition in this report.

Establish targets and/or long-term policy signals

Nine countries have adopted national hydrogen strategies since September 2021

Countries with a national hydrogen strategy in place or under development



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Notes: GHR 2021 = Global Hydrogen Review 2021.The nine countries that have adopted national hydrogen strategies between September 2021 and July 2022 include: Austria, Belgium, China, Colombia, Denmark, Luxembourg, Poland, Slovak Republic and South Africa. The European Commission Hydrogen Strategy (2020) is not included in the map.

More and more countries are adopting hydrogen strategies; the global energy crisis bolsters momentum for hydrogen in Europe

Nine countries have released national hydrogen strategies since the publication of the IEA Global Hydrogen Review 2021. This raises the total to 25 countries, plus the European Commission, with announced strategies that include hydrogen as a clean energy vector in their clean energy transition plans. The majority of the strategies are in Europe. In September 2021, the European Union and 16 countries with national hydrogen strategies in place, represented about 20% of global energy-related CO_2 emissions. The nine new national hydrogen plans boost the coverage to half of global energy-related CO_2 emissions. Advanced economies account for 17% of the emissions currently covered by the national strategies, while together China and the emerging economies account for nearly 40%.

Noteworthy in the recent announcements is the Hydrogen Industry Development Plan in China. China represents 30% of global hydrogen demand and could have a particularly powerful impact on the development of hydrogen projects in the years to come. The targets in the plan have a shorter timeframe (2025) than most other national strategies and they appear to be easily surpassed if current plans from the private sector are met. China's strategy has a target to produce 100-200 kilotonnes of hydrogen (kt H_2) of renewable hydrogen by 2025;[68] the projects in operation and those under development already account for almost 250 kt H_2.

In addition to the strategies already adopted, more than 20 governments have announced that they are working on a national hydrogen strategy. For instance, India and the United States are expected to publish their strategies in 2022. Other governments have announced plans to revise their hydrogen strategies, such as Germany, which is expected to release a revised strategy in 2022.

Targets to deploy hydrogen technologies are increasing in ambition, particularly for the production of low-emission hydrogen. National targets for electrolysis capacities by 2030 were 74 GW globally in the Global Hydrogen Review 2021, whereas the targets have more than doubled to reach 145-190 GW in this 2022 Review. More ambitious targets, in part, were triggered by Russia's invasion of Ukraine. In April 2022, the United Kingdom launched the Energy Security Strategy and doubled its ambition for low-emission hydrogen production to 10 GW by 2030, with at least half from electrolytic hydrogen. The Netherlands announced plans to revise and double the current target of 3-4 GW of electrolysis capacity and are

[68] See Explanatory notes annex for renewable hydrogen definition in this report.

preparing a hydrogen roadmap that will complement its existing strategy. In March 2022, the European Commission presented the REPowerEU plan to make Europe independent from Russian fossil fuels before 2030, which includes objectives to produce 10 million tonnes (Mt) of renewable hydrogen within the member states and to import 10 Mt of renewable hydrogen by 2030. According to the REPowerEU Working Document, this would represent 65-80 GW of electrolysis capacity in the European Union, significantly boosting the 40 GW target in the EU Hydrogen Strategy (July 2020) and the 44 GW target of the Fit for 55 package (July 2021). An equivalent capacity would need to be deployed outside the European Union to fulfil the import target.

The significant potential role of hydrogen to decarbonise sectors in which emissions are hard to abate is acknowledged in all the national hydrogen strategies, though there is little evidence of targets to stimulate demand for low-emission hydrogen. Several countries have announced targets for the use of low-emission hydrogen in industrial applications, particularly to replace unabated fossil fuel-based hydrogen in uses such as refining and chemicals. Announced targets cover only about 4% of current global hydrogen demand in industry, i.e. around 4 Mt H_2. Most targets for low-emission hydrogen use in industry are in European Union member states. In June 2021, the European Commission proposed a target to meet 50% of all hydrogen demand in industry with renewable hydrogen by 2030 in its Fit for 55 package. The European Council proposed to decrease this target to 35% by 2030 and to reach 50% by 2035. However, the latest communication of the European Commission regarding the REPowerEU plan proposed to increase this target to 75%.

Colombia has set a goal to stimulate hydrogen demand in the industry sector. India announced intent to set quotas for the use of renewable hydrogen in fertiliser production.

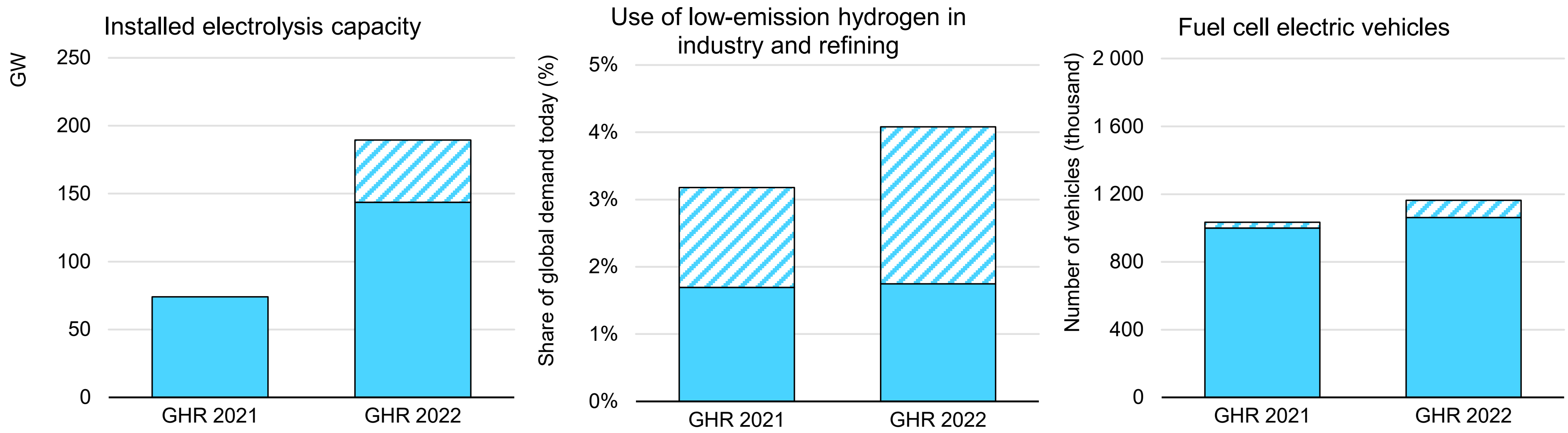
Transport is another sector for which governments have adopted targets to stimulate hydrogen use in recent years. Cumulative global targets to deploy FCEVs increased by just 13% in 2021, to an objective of 1.2 million vehicles. Japan and Korea continue to have the most ambitious targets for FCEVs, accounting for around 80% of global commitments by 2030, unchanged from 2021.

Many governments have defined hydrogen targets for specific transport segments, with most focus on buses and medium- and heavy-duty trucks. However, the most ambitious targets, which are in China, Japan and Korea, do not specify the type of vehicle or have put the focus on light-duty vehicles. In Hungary, the targets are to deploy 4 800 heavy-duty fuel cell vehicles and to use 10 kt carbon-free hydrogen in road transport by 2030. In July 2021, as part of the Fit for 55 package, the European Commission proposed a modification of the Renewable Energy Directive to include a target to meet 2.6% of energy demand in transport with renewable fuels of non-biological origin (including hydrogen and synthetic fuels). This modification received support from the European Council, although it is still not in force. The REPowerEU Working Document, published in May 2022, suggests to increase this target above 5%.

Governments have also adopted targets related to hydrogen in areas such as infrastructure (e.g. HRSs), hydrogen blending, power generation and the use of hydrogen in household applications. These, however, are limited to a couple of examples in each category.

Targets for 2030 are more ambitious for hydrogen production in this review, but little progress on commitments in end-use sectors

Global targets for installed electrolysis capacity, low-emission hydrogen use in industry and refining and fuel cell electric vehicles by 2030, Global Hydrogen Review 2022 relative to the 2021 Review



Notes: GW = gigawatts. GHR 2021 = Global Hydrogen Review 2021 (IEA, 2021). GHR 2022 = this annual review. Dashed areas denote the upper value of targets which are provided as a range. For the contribution of the European Union in the industry and refining figure, its lower value corresponds to the Fit for 55 package while its upper range refers to the targets set out in the REPowerEU plan. The dashed area for the industry and refining figure also includes the contribution of the announced mandatory quotas for renewable hydrogen use in industry in India, though they are not in a policy document yet.

Support demand creation for low-emission hydrogen

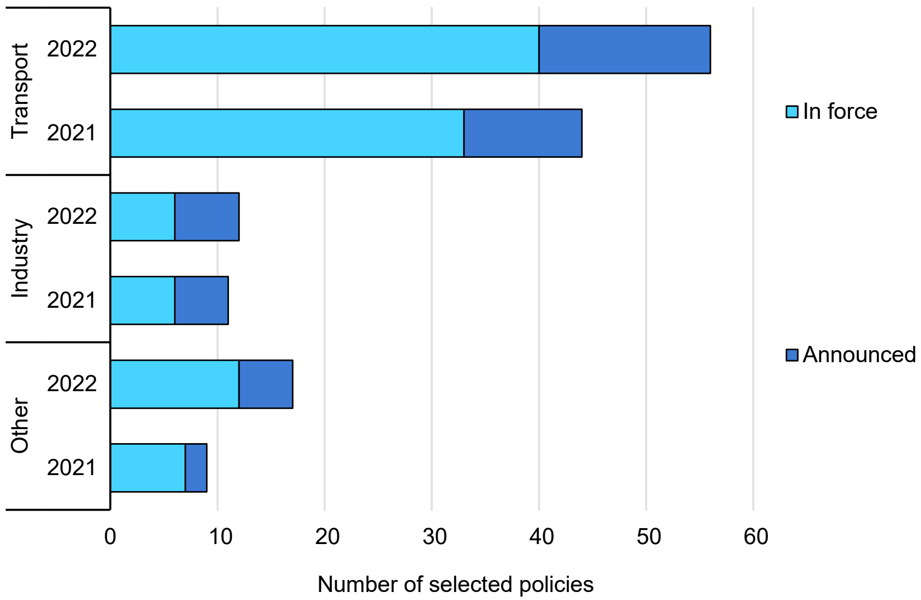
Progress is slow to adopt policies that stimulate demand, particularly in the key industry sector

Increased demand for low-emission hydrogen is fundamental to stimulate its uptake as a clean energy vector. Absent sufficient demand, low-emission hydrogen producers will not be able to secure off-takers and unlock investment to scale up production. So far, the use of low-emission hydrogen has been more expensive than using hydrogen produced from fossil fuels in both existing and new applications. The current situation with volatile fossil fuel prices and supply concerns in Europe has reduced the cost differential and, in many cases, turned the balance in favour of low-emission hydrogen. Although it is premature to speculate if the duration of the uncertainty will be sufficient to unleash demand for low-emission hydrogen at scale. Policies that stimulate demand can help project developers to secure off-takers, which in turn unlocks investment in production assets. This helps to scale up production, reduce costs and spark innovation and demonstration of end-use technologies that are not yet commercial.

Very limited progress to adopt policies to stimulate demand creation is noted for 2021 through the first-half of 2022. Most existing policies to generate demand for hydrogen focus on transport. Very few of the policies target industrial applications even though it is industry that represents the best short-term opportunity to create demand for low-emission hydrogen.

Other applications, such as power generation, also lag in terms of policy action. There are only a few examples, such as the Hydrogen Jobs Plan of the Government of South Australia which aims to build a 200 MW power plant using hydrogen.

Number of policies to support hydrogen demand creation by sector, 2021-2022



Note: *Other* includes selected policies in other sectors, i.e. electricity generation or cross-sectoral measures such as public procurement.

Many European Union member states signalled intentions to adopt quotas for the use of renewable hydrogen in industry in relation to the 2021 Fit for 55 package. Russia's invasion of Ukraine is expected to accelerate the widespread adoption of quotas in Europe since industrial applications represent the best option for hydrogen to reduce fossil fuel consumption in the short and medium term.

India announced its intention to adopt mandatory quotas for renewable hydrogen in fertiliser production (5% of demand from 2023-24, increasing to 20% in the following five years), and that the use of quotas could expand to the steel industry in the near future. None of these quotas are yet in force.

In China, a set of guidelines for the development of new sustainable models in the chemical and petrochemical industries have been recently announced and renewable hydrogen has a role to play, but there are no concrete policies in place yet.

Low-carbon fuel standards or renewable transport obligations can facilitate the uptake of low-emission hydrogen in refineries. Such policies are already in place in Canada, United Kingdom and California (United States). In the Netherlands, the government announced in 2022 that the use of renewable hydrogen in refineries will be eligible for their renewable fuel transport obligation from 2025; the cabinet also presented the Climate Policy Programme, in which hydrogen contributes to cutting CO_2 emissions by 2030 through potential off-take obligations in industry and transport.

Similarly for transport, the adoption of quotas and mandates, is a tool that governments are considering to stimulate hydrogen demand, although no quotas or mandates are in force so far. The United Kingdom undertook a consultation in 2021 for the Sustainable Aviation Fuel Mandate. It proposes a SAF mandate requiring jet fuel suppliers to blend an increasing proportion of SAF into aviation fuel from 2025, including a secondary target for hydrogen-derived fuels. The consultation received positive public support.

In transport, many policies are not specific to hydrogen but rather generally apply to low and zero emissions vehicles (ZEVs). Such policy measures include CO_2 emissions standards, ZEVs quotas and mandates, low-emissions zones in cities, tax incentives, subsidies and non-monetary incentives.

The purchase price is a key barrier to the uptake of fuel cell vehicles. About 20 countries, mostly in Europe, offer purchase subsidies and tax benefits for fuel cell passenger cars and 15 countries offer tax benefits for companies that buy fuel cell cars. Fewer countries offer support for light commercial and heavy-duty fuel cell vehicles. Heavy-duty fuel cell vehicles is an area where more effort can be particularly helpful, as electrifying heavy-duty trucks is more challenging than passenger vehicles, making hydrogen a possible alternative. Seventeen countries have purchase price subsidies in place for heavy-duty fuel cell vehicles though less than half provide tax benefits.

Other types of support are also employed. Norway has reduced fees for FCEVs for public parking, ferries and toll roads. In Germany, all electric and hydrogen vehicles are exempt from the circulation tax for a period of ten years. Switzerland adopted the LSVA road tax in 2018 that levies trucks weighing more than 3.5 tonnes but waives the fee for ZEVs. This created an attractive business case for hydrogen trucks and 80 trucks were registered in 2021, which is expected to expand to 1 600 by 2025.

Over the last year, the government in the Netherlands initiated a subsidy scheme for hydrogen trucks. The United States announced programmes to support the purchase of hydrogen buses and a programme to support the adoption of low or zero emissions ferries, including hydrogen. The United Kingdom expanded the coverage of its ZEBRA programme to purchase zero emissions buses. Korea, which currently has the largest subsidies for fuel cell electric passenger cars and buses, increased the number of stations that receive subsidies for hydrogen procurement cost, although the scale of support per station decreased.

Mitigate investment risks

Governments are adopting new mechanisms to support hydrogen projects

Emerging hydrogen value chains are very complex and companies may require government support to manage investment risks at each stage. Many projects under development are first movers that face a combination of risks including uncertain demand and uncertain regulatory frameworks, and lack of infrastructure and operational experience. These risks are further amplified by uncertainties in subsequent phases. Governments worldwide are initiating policies such as grants, loans, tax incentives or contracts for difference to reduce the risks of early projects and to leverage private investment. Such measures help developers to access better financing conditions to improve the feasibility of capital-intensive hydrogen projects. As experienced in the early years of solar PV and wind energy deployment, support is critical at early stages of hydrogen adoption as a clean energy vector. Policies to mitigate investment risk can boost production capacity, infrastructure development and equipment manufacturing capacity, to pave the way for future projects until hydrogen supply chains can transition from relying on public to private capital.

New programmes for hydrogen or expanding the scope of existing clean technology programmes to incorporate hydrogen have been announced and policies implemented over the last couple of years. Most recently, such activity has been particularly notable in the United States. In 2021, the US Congress passed the Bipartisan Infrastructure Law, which provides grants to create hydrogen hubs and incentives to foster the development of hydrogen infrastructure and electrolysis manufacturing capacities. In mid-2022, the US Department of Energy (US DOE) Loan Program Office finalised a USD 504 million loan guarantee for a large-scale hydrogen storage project and presented a conditional commitment of USD 1.04 billion for a methane pyrolysis project. The US government was granted authority through the Defense Production Act in June 2022 to invest in companies that can manufacture and install key energy technologies, including electrolysers and fuel cells. The Inflation Reduction Act, signed in August 2022, offers several tax credits and grant funding to support hydrogen technologies.

In July 2021, Canada provided CAD 400 million (~USD 311 million) from its Net Zero Accelerator to support an Arcelor Mittal project to develop a hydrogen-ready DRI facility at its plant in Ontario.

Recently several European countries also have announced and implemented programmes to support hydrogen projects with an emphasis on production. Some programmes commit significant investment, such as the Horizon 2020 Framework Programme of the European Commission, which has provided funding to three 100 MW electrolytic projects.

In 2020, the European Commission agreed to include hydrogen in the Important Projects of Common European Interest (IPCEI) scheme, which allows projects validated by both European Union member states and the Commission to receive public support beyond the usual boundaries of state aid rules. Many participating countries have completed the pre-selection of projects and are awaiting the decision of the European Commission. In 2022, fifteen member states received Commission approval to provide up to EUR 5.4 billion (~USD 5.7 billion) in public funding for 41 hydrogen technology value chain projects called the IPCEI Hy2Tech. The Commission approval for an IPCEI dealing with hydrogen use in industrial applications is expected in third-quarter 2022. Approvals for two additional IPCEIs for hydrogen infrastructure and transport applications are also expected later in 2022 or in early 2023.

The SDE++ programme in the Netherlands committed EUR 2.1 billion (~USD 2.5 billion) to support the Porthos CCS project, which is expected to help several projects produce hydrogen from fossil fuels with CCUS[69] in the Rotterdam area to reach a financial investment decision soon. In June 2022, the Norwegian government, through state-owned Enova, provided NOK 1.12 billion (~USD 130 million) to support the development of five hydrogen hubs, including facilities for the production of renewable hydrogen and the use of hydrogen and ammonia in maritime applications.

Tax incentives are another policy measure that governments are employing or considering to facilitate project investment, particularly in hydrogen production. Colombia and Brazil have recently implemented tax benefits, following the lead taken by some European countries, such as Denmark, Germany and Sweden. The US government has announced intention to implement a tax incentive for low-emission hydrogen production.

Novel measures are emerging from the policy toolkit. Carbon contracts for difference (CfD) is a clear example. Germany launched the H2Global initiative in 2021 with the initial bidding process expected to start in 2022. The initiative uses a mechanism analogous to a CfD approach that compensates the difference between supply prices (production and transport) and demand prices with grant funding from the government. Other governments, including the Netherlands and Poland, as well as the European Commission, have announced intentions to use this type of policy instrument. Some are considering to join the German H2Global initiative. The United Kingdom presented a business model for low-carbon hydrogen based on a variable premium against a reference price, similar to the carbon CfD approach for public consultation in August 2021.The proposal received wide support and the government aims to finalise the business model in 2022 and to allocate the first support contracts for projects reaching final investment decisions from 2023. The UK Electrolytic Allocation Round, effective since July 2022, worth

[69] See Explanatory notes annex for CCUS definition in this report.

GBP 340 million (~425 USD million) will finance the development of at least 250 MW of electrolysis capacity.

In 2021, Chile launched the initiative Ventana al Futuro (Window to the Future), which consists of a one-time opening to directly allocate public land for projects to produce renewable hydrogen with a capacity of at least 20 MW to be operational by 2025. This will significantly simplify the administrative procedures to access public land, which otherwise would have been allocated through tenders.

Policy measures to mitigate risks in hydrogen projects, 2021-2022

Policy	Country/ region	Status	Part of the value chain	Description
Grants	Australia	Current	Whole value chain	Australia allocated AUD 464 million (~USD 349 million) in 2021 to support the roll-out of Clean Hydrogen Industrial Hubs. Advancing Hydrogen Fund made its first investment of AUD 12.5 million (~USD 9.4 million) to supply fuel cell mining trucks for a hydrogen production hub in November 2021. Launched in 2020, the Fund totals AUD 300 million (~USD 206 million).
	Belgium	Current	Infrastructure	Belgium allocated EUR 95 million (~USD 112 million) from the European Just Transition Fund to support Fluxys, a natural gas transmission system operator, to deploy a H_2 and CO_2 pipeline network by 2025.
	Canada	Current	Production and end-use	Canada committed CAD 1.5 billion (~USD 1.2 billion) in March 2022 through the Clean Fuels Fund to support new clean fuels production capacity, including ten hydrogen projects, and CAD 30 million (~USD 23 million) for HRSs. Eligibility for hydrogen is included in the CAD 1.7 billion (~USD 1.3 billion) Zero Emissions Vehicles programme and in a new CAD 547.5 million (~USD 428 million) programme that provides purchase incentives for zero emissions medium- and heavy-duty vehicles. The Net Zero Accelerator will provide up to CAD 8 billion (~USD 6.3 billion) for projects that reduce domestic GHG emissions, including the production and use of low-emission hydrogen in heavy industry.
	Chile	Current	Production	Corporación de Fomento de la Producción (Production Development Corporation) launched a call in April 2021 to provide support (USD 50 million) for the development of renewable hydrogen production projects. In December 2021, six projects were awarded.
	Colombia	Current	Whole value chain	Fondo de Energías No Convencionales y de Gestión Eficiente de la Energía (Fund for Non-Conventional Energies and Efficient Energy Management) launched the +H2 Colombia programme in March 2022 with an initial budget of USD 1 million to support feasibility studies for projects that can produce, distribute or use low-emission hydrogen.

Policy	Country/ region	Status	Part of the value chain	Description
	European Union	Current	Production and infrastructure	Connecting Europe Facility programme for the development of cross-border infrastructure can now support projects for electrolysers, hydrogen pipelines, storage and conversion/reconversion facilities based on an update of the TEN-E regulation.
	Germany	Current	Production	EUR 350 million (~USD 414 million) grant programme to provide financial support to international hydrogen production projects.
	Netherlands	Current	Production	SDE++ scheme supports the deployment of renewable energy generation techniques and other CO_2 mitigation techniques. Under this scheme, EUR 1 million (~USD 1 million) was awarded in 2021 for operational support to an electrolyser project.
	Spain	Current	Whole value chain	EUR 150 million (~USD 177 million) in grant programme to support projects to produce renewable hydrogen (including associated renewable electricity generation), distribution and use in industry, heavy-duty transport, shipping, aviation, rail and innovative stationary applications.
	United Kingdom	Current	Production and end-use	Net Zero Hydrogen Fund, GBP 240 million (~USD 300 million), provides grants for front-end engineering design (FEED) and post-FEED studies, and capital expenditure support to projects to progress to final investment decisions. Industrial Energy Transformation Fund, GBP 60 million (~USD 75 million), provides funding for feasibility and FEED studies and for deployment of clean technology projects including hydrogen in industry.
	Uruguay	Current	Production	A call for proposals was launched in April 2022 with total USD 10 million budget for electrolyser projects above 1.5 MW_e that start operation by 2025.
	Austria	Announced	Production	Grants of EUR 40 million (~USD 50 million) per year will be provided to renewable hydrogen facilities through the Renewable Energy Expansion Act until 2030.
	Denmark	Announced	Production	A budget of DKK 1.25 billion (~USD 177 million) was announced by the government in March 2022 for a tender to support projects to produce hydrogen using renewables-based electricity.
	Estonia	Announced	Whole value chain	Grant programme was announced in July 2021 to support construction and operation of projects to produce and deploy green hydrogen for use in the public transport sector for at least five years with up to EUR 5 million (~USD 6 million) per project.

Policy	Country/ region	Status	Part of the value chain	Description
	Netherlands	Announced	Production and infrastructure	The Netherlands announced on Budget Day 2021 EUR 1.035 billion (~USD 1.2 billion) for a national hydrogen transport network (72%), electrolysis projects (24%) and storage locations (3%). In July 2022, the government announced a subsidy tender for projects with capacity of up to 50 MW and use of renewable hydrogen in refineries, conditioned upon European Commission approval and the establishment of hydrogen regulations.
	Poland	Announced	Infrastructure	Announced in 2022, the PLN 315 million (~USD 70 million) programme is to facilitate investment in electric vehicle charging and hydrogen refuelling stations.
	United States	Announced	Whole value chain	Approved budget in November 2021: USD 8 billion for regional clean hydrogen hubs; USD 1 billion for a Clean Hydrogen Electrolysis Program to reduce production costs; and USD 0.5 billion for manufacturing and recycling of clean hydrogen technologies. Grant programmes to assist eligible transportation infrastructure projects, including hydrogen vehicle infrastructure (INFRA and RAISE) grants; Port Infrastructure Development; Carbon Reduction; and Public School Energy programmes.
Tax incentives	Austria	Current	Production	The Renewable Expansion Act provides exemptions for hydrogen from renewable energy subsidy fees, grid fees for electricity and grid fees for natural gas for blending purposes.
	Brazil	Current	Production	Low-emission production projects, including hydrogen, developed in eligible export zones can benefit from a special tax regime for energy and port infrastructure. This incentive is already available in Ceará state and is in the process of adoption in Rio de Janeiro and Pernambuco states.
	Colombia	Current	Production	Tax incentives for projects that produce hydrogen from variable renewables electricity or from fossil fuels with CCUS.
	Germany	Current	Production	Hydrogen production via electrolysis is exempt from the green power levy.
	Canada	Announced	Production	Accelerated capital cost allowance for renewable hydrogen production equipment, investment tax credit for CCUS projects and green hydrogen, and 50% tax cut for hydrogen production.

Policy	Country/ region	Status	Part of the value chain	Description
	United States	Announced	Production	Tax break of up to USD 3/kg H_2 for projects producing low-emission hydrogen under the US Inflation Reduction Act. The tax credit will be determined by the carbon intensity of hydrogen production and a multiplier for new facilities meeting particular wage and labour requirements.
Loan guarantees	United States	Current	Whole value chain	USD 40 billion of available debt capital that can be used to guarantee loans for low-emission hydrogen projects. In June 2022, US DOE finalised a USD 0.5 billion loan guarantee to a low-emission hydrogen storage project in Utah.
Contracts for differences (CfD)	Germany	Current	Production, transport and end-use	EUR 900 million (~USD 1 billion) in the H2Global initiative, an auction-based mechanism to tender ten-year purchase agreements on the supply side and short-term contracts sales on the demand side using CfD to compensate the difference between supply and demand prices.
	United Kingdom	Current	Production	The government will provide up to GBP 100 million (~USD 125 million) of funding from July 2022 through the Hydrogen Business Model in the first Electrolytic Allocation Round to support at least 250 MW of electrolysis capacity.
	Various EU member states	Announced	Production	Using the Innovation Fund, the European Commission will implement a carbon CfD scheme. Austria, Netherlands and Poland are considering implementation of CfD schemes to support projects for the production of low-emission hydrogen.

Sources: IEA analysis and CEM H2I country surveys.
Note: See Explanatory notes annex for use of currency exchange rates and the term green hydrogen in this report.

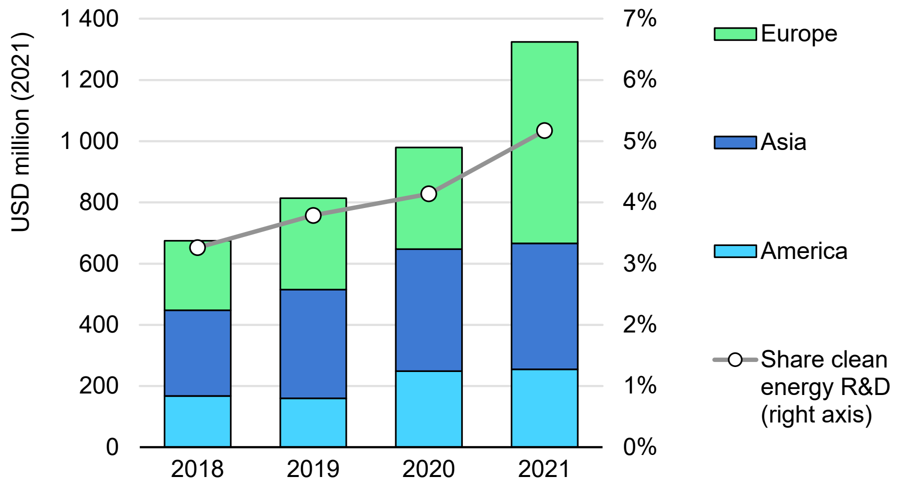
Promote R&D, innovation, strategic demonstration projects and knowledge-sharing

Efforts to support RD&D for hydrogen technologies are led by European Union, Japan and United States

Several key hydrogen technologies that can both decrease CO_2 emissions and reduce fossil fuel dependency are ready to scale up and accelerate deployment, particularly technologies for low-emission hydrogen production and its application in traditional hydrogen uses, such as fertiliser and methanol production. A number of other end-use technologies are at early stages of development and are not ready to compete in markets, in part because they have not yet realised the needed economies of scale. Research, innovation and development are critical to demonstrate the viability of these technologies and to support continued cost reduction of technologies that are nearing commercialisation. Given the scale of the required upfront investments, governments have a key role to help reduce risks in investment in large demonstration projects and to support RD&D activities and to adopt policy measures that incentivise the private sector to innovate and deploy hydrogen technologies.

RD&D public funding for hydrogen technologies has been increasing strongly since 2017. In 2021, public spending on hydrogen-related RD&D had its largest annual growth at 35% in the time series.[70] This jump was pushed by European countries that nearly doubled the RD&D expenditure. Today, hydrogen technologies receive around 5% of the total government RD&D budget for clean energy technologies.[71]

Government RD&D spending for hydrogen technologies by region, 2018-2021



Note: Data includes IEA member countries and Brazil. America in this figure includes Brazil, Canada, Mexico and the United States.
Sources: Based on IEA analysis and CEM H2I country survey data.

[70] IEA has collected data on energy RD&D spending in member countries since 2004. Data on RD&D spending in Brazil is collected since 2013.

[71] This value is estimated from data collected from IEA member countries and Brazil.

Governments are also stepping up efforts to stimulate strategic demonstrations in key hydrogen technologies. The United Kingdom launched its Low-Carbon Hydrogen Supply 2 competition, following the success of the first competition in 2018 and nearly doubling its funding.

The European Union Innovation Fund awarded grants to four small scale hydrogen-related projects in December 2021 and to three large scale projects in July 2022. New calls will open in the second-half of 2022. The call for large-scale projects doubled its budget and will have specific support for innovative hydrogen applications in industry and innovative clean technology manufacturing (including electrolysers and fuel cells) as part of the REPowerEU commitment to strengthen the Fund to support independence from Russian fossil fuels.

In November 2021, the Clean Hydrogen Partnership, a public-private partnership supporting research and innovation activities in hydrogen technologies in Europe was established as a successor to the Fuel Cells and Hydrogen Joint Undertaking. The European Commission will support the Partnership with EUR 1 billion (~USD 1 billion) for the 2021-27 period, complemented by at least an additional EUR 1 billion of private investment from private sector participants in the partnership. Also as part of the REPowerEU Plan, in May 2022 the European Commission provided an additional EUR 200 million (~USD 211 million) of funding to the Clean Hydrogen Partnership to support the development of hydrogen valleys across the European Union.

R&D and demonstration projects have also received strong support from the US Bipartisan Infrastructure Law with USD 1.0 billion for R&D of clean electrolysis and USD 0.5 billion for manufacturing and recycling of clean hydrogen technologies over five years. In addition, USD 8 billion over five years will support hydrogen hub demonstration projects.

Brazil defined hydrogen as a priority area for RD&D investment. As a result, the oil, gas and biofuels regulator adapted regulations to facilitate mandatory RD&D investment by oil and gas companies in hydrogen.

Selected government programmes to support hydrogen technology demonstration projects, 2021 and 2022

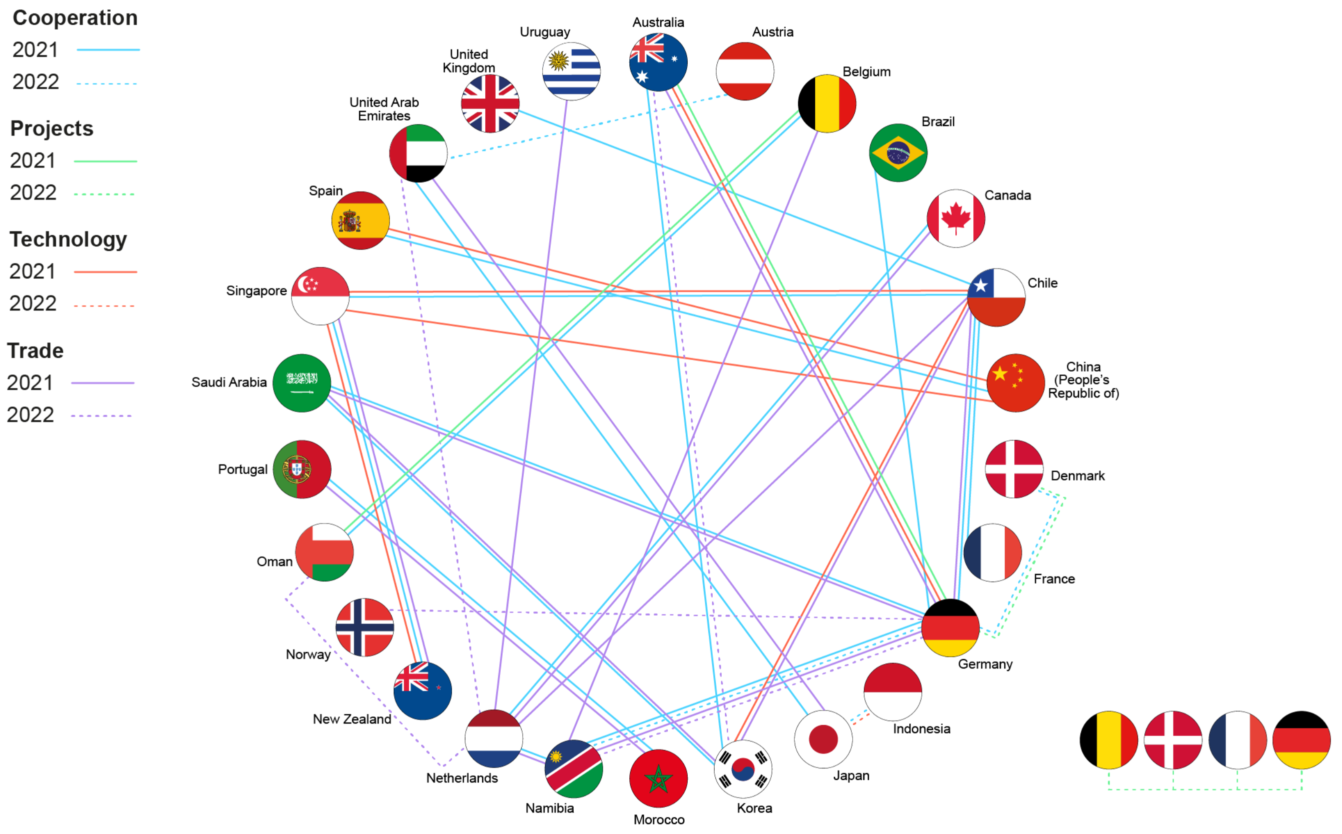
Country/ region	Programme	Description
Australia and Germany	HyGATE	AUD 50 million (~USD 36 million) and EUR 50 million (~USD 53 million) for demonstration and research projects along the hydrogen supply chain.
Austria	Vorzeigeregion Energie	EUR 40 million/yr (~USD 42 million) for development and demonstration of hydrogen value chains.
Brazil	Missão Estratégica Hidrogênio Verde	BRL 18 million (~USD 3.6 million) for fuel innovation including the construction of hydrogen hubs.
	Fuels of the Future tender	BRL 50 million (~USD 10 million) for products, processes and/or services for sustainable hydrogen or hydrogen-derived fuels for the transport sector.
Denmark	Energy Technology Development and Demonstration Program	DKK 622 million (~USD 88 million) for green projects including hydrogen.
European Commission	Innovation Fund	Around EUR 3 billion (~USD 3.2 billion) to support small- and large-scale demonstration projects.
Germany	Hydrogen Flagship Projects	EUR 700 million (~USD 828 million) for electrolyser manufacturing, offshore hydrogen production and hydrogen transport.
	National Innovation Programme Hydrogen and Fuel Cell Technology	EUR 400 million (~USD 422 million) for market activation support, including the regional HyLand programme.
	Regulatory Sandboxes for the Energy Transition	EUR 167 million (~USD 198 million) for large-scale demonstration projects of hydrogen and sector coupling.
Japan	Green Innovation Fund	JPY 2 trillion (USD 16 billion) for large-scale hydrogen and derivatives supply chains, use in steel production and renewable hydrogen production.
Netherlands	DEI+	EUR 30 million (~USD 31 million) to scale up hydrogen products and services.
	GroenvermogenNL	EUR 838 million (~USD 886 million) to support R&D, pilots, demonstration projects and creation of human capital to accelerate the scaling up of hydrogen and green chemistry.

Country/ region	Programme	Description
Spain	PERTE renewables, green hydrogen and storage	EUR 250 million (~USD 296 million) to demonstrate large-scale electrolysis, use of hydrogen in mobility and manufacturing capabilities.
United Kingdom	Low Carbon Hydrogen Supply 2	GBP 60 million (~USD 75 million) to demonstrate projects that can help develop a wide range of innovative low-carbon hydrogen supply solutions.
	Industrial Hydrogen Accelerator	GBP 26 million (~USD 33 million) to accelerate the commercialisation of innovative hydrogen technologies.
	Industrial Fuel Switching	GBP 55 million (~USD 75 million) to support fuel switching technologies in industry, including hydrogen.
	Clean Maritime Demonstration Competition	GBP 35 million (~USD 48 million) to support the design and development of zero emissions vessel technologies and greener ports, including the use hydrogen and hydrogen-derived fuels.
United States	Bipartisan Infrastructure Law - R&D funding provisions	USD 1 billion for electrolysis and USD 0.5 billion for manufacturing clean hydrogen technologies.
Uruguay	Green Hydrogen Sectoral Fund	USD 10 million for electrolysis demonstration projects for the production of hydrogen and its derivatives.

Sources: IEA analysis and CEM H2I country surveys.
Note: See Explanatory notes annex for use of currency exchange rates this report.

International co-operation on hydrogen is mounting, evidenced by a rising number of bilateral agreements

Co-operative agreements on hydrogen development, 2020-2022



Notes: Projects refers to co-operation agreements to develop hydrogen-related projects. Technology refers to co-operation agreements to work on innovation, RD&D and technology development. Trade refers to refers to co-operation agreements to develop international hydrogen supply chains. Co-operation refers to co-operation agreements with a different focus to the other categories. Only co-operation agreements specific to hydrogen and its derivatives are depicted in the figure. There are 22 additional co-operation agreements signed over the last three years that deal with clean energy technologies which include hydrogen and its derivatives.

Beyond individual national efforts, international co-operation is paramount to align objectives, increase market size and promote knowledge-sharing and the development of best practices. International co-operation related to hydrogen remained strong over the last year and is expected to accelerate as a consequence of the Russian invasion of Ukraine and growing concerns about energy security. Since September 2021, fifteen new bilateral international agreements between governments have been signed – most focus on the development of international hydrogen trade. Governments, particularly in Europe, are looking at opportunities to accelerate the commercial availability of hydrogen technologies and the development of international trade to reduce dependency on fossil fuels as fast as possible. Moreover, European institutions are actively signing international agreements with non-European governments seeking to facilitate investment and accelerate development of international supply chains. Examples include the case of the European Investment Bank with Mauritania to scale up investment in wind, solar and green hydrogen and the European Bank for Reconstruction and Development with Egypt to assess the potential to develop low-emission hydrogen supply chains in Egypt.

In addition to bilateral agreements, multilateral co-operation has expanded with two new initiatives. The Breakthrough Agenda was launched in November 2021 at the World Leaders Summit at COP26 with a commitment from 44 countries and the European Union to co-operate to make clean technologies affordable and accessible worldwide before 2030. Among the four breakthroughs launched in 2021,[72] there one is specific to hydrogen. In May 2022, the G7 launched a Hydrogen Action Pact to accelerate the ramp up of low-emission hydrogen technology development, to shape regulatory frameworks and standards, and for financial commitments. The landscape of hydrogen initiatives is expanding – positive progress, nonetheless stronger co-ordination to avoid duplication is needed.

Private sector companies across international borders have joined forces to develop first-of-a-kind technologies. For example, KHI and Airbus signed a memorandum of understanding (MoU) to develop a hydrogen supply chain for aviation, including the development of hydrogen hubs in airports. In shipping, Norway's Gen2Energy paired with Sirius Design & Integration to build two compressed hydrogen carriers. In the Netherlands, the Port of Rotterdam continues as the most active organisation on this front, with twenty MoUs and partnerships in place, mostly with the objective of exploring opportunities to import hydrogen. These MoUs usually start with a high-level agreement with a national or regional government, followed by more detailed agreements with the relevant players, such as ports and project developers.

[72] An additional breakthrough - the fifth - on agriculture was launched in June 2022 at Stockholm+50.

Regulatory frameworks, standards and certification systems

Regulatory frameworks, standards and certification systems for low-emission hydrogen in the clean energy transition

Making sure that hydrogen plays its role in the clean energy transition requires the development and adoption of effective regulations, standards and certification systems, in part to ensure its sustainability attributes. Each of these categories has a distinct function. For instance, in the case of CO_2 emissions associated with hydrogen production and transport, a standard methodology established by the International Organization for Standardization (ISO) can provide a robust and credible method to calculate the carbon footprint of hydrogen production pathways and transportation from well to gate. A certification system, in turn, can provide evidence of the carbon footprint of a given unit of hydrogen. Regulations can be adopted by governments that choose to set specific requirements for hydrogen to meet a certain carbon emissions threshold.

There is some degree of confusion in the use of these terms, as at times they are used interchangeably. For example, the term standard has been used to name certain regulations, e.g. California Low Carbon Fuel Standard. Clarity on the functionalities of these instruments and the roles of the relevant actors (such as governments and standard development organisations) is important:

- **Regulations** are legally binding rules adopted in legislative processes. They can be established at all levels. For example: national - UK Low Carbon Hydrogen Standard; subnational - California Low Carbon Fuel Standard; regional – EU rules for the production of renewable fuels of non-biological origin (RNFBO); and international – IMO mandatory measures to improve energy efficiency in ships.
- **Standards are** detailed documents containing technical specifications and defining requirements for products, production processes, services or test methods. They are developed by standard development organisations, which are either national (e.g. British Standards Institute, American National Standards Institute) or international (e.g. International Organization for Standardization and International Electrotechnical Commission).
- **Certification systems can** be compliance driven or voluntary. Compliance driven systems are used by market participants to evidence compliance with specific criteria set in legislative acts of a given country or region such as the European Union. Whereas voluntary systems are used by market participants on a voluntary basis for reporting and disclosure purposes.
- **Licences and permits** are commonly construction or operating licences provided by a competent authority which verify that a product or process meets specified qualification criteria that warrant the construction and operations of a given jurisdiction.
- **Guidelines** serve as interim direction or best practice for how to implement a technology, a methodology or a process in the absence of a formal standard or regulation.

Progress in development of regulatory frameworks, standards and certification systems

Wider use of low-emission hydrogen will require new value chains to be developed, underpinned by relevant regulations and standards. These elements will refer to hydrogen sustainability attributes and to aspects such as safety and market rules. Challenges for reaching consensus on priority areas may reflect various priorities in the supply and use of hydrogen according to national resources and needs. Nonetheless, there has been progress over the last year as the focus on hydrogen has mounted. This progress is highlighted in the following sections.

International low-emission hydrogen market requires a robust carbon accounting standard

The development of a common global standard methodology to account for GHG emissions over the life cycle of hydrogen and its derivatives, based on an internationally agreed methodology, is of particular urgency. With this objective, the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) established a Hydrogen Production Analysis Task Force. A first working document was released in October 2021. It describes the requirements and evaluation methods to be applied from well to gate for some commonly used hydrogen production pathways: electrolysis, SMR with CCS, coal gasification with CCS and by-product from chlor-alkali process and steam crackers. In 2022, the Task Force is developing methodologies for additional production methods (biodigestion and gasification of organic wastes and methane autothermal reforming). It has considered various hydrogen carriers (liquid cryogenic hydrogen, ammonia and liquid organic carriers) and has started work to consider the GHG emissions arising during transport of hydrogen to the delivery point. The updated version of the working document with the new pathways and carrier elements is expected in September 2022 with the transport element planned for later in the year. The IPHE Guidelines will form the basis of a common global standard that will be developed by the ISO.

Development of standards is gaining pace

Developing standards is a long-term process, but some progress was noted this year. Within the ISO Technical Committee for hydrogen technologies (TC 197), there are several new and ongoing items. Under the new sustainability programme of the ISO/TC 197 Sub-Committee 1 (SC1), there is a proposal for a "Methodology for determining the GHG emissions associated with the production and transport of hydrogen", with the objective of defining a three-part standard covering production, conditioning and transport. Given the urgency of this matter for the development of regulatory frameworks, ISO/TC 197/SC 1 aims to develop a draft technical specification by end-2023 (with publication in 2024) and a draft international standard by end-2024 (with publication in 2025). The initial draft will be instrumental in providing the best practice methodology to be taken by early movers. The development of the ISO 19885 for fuelling protocols for hydrogen vehicles was initiated in early 2021, with three sub-groups for the design and development process for fuelling protocols, communications between vehicles and dispensing systems and fuelling protocols for heavy-duty vehicles with a target date in 2024. This effort will enable safe and interoperable hydrogen fuelling of heavy-duty vehicles, and pave the way for fuelling of non-road heavy-duty vehicles. The ISO 22734 on water electrolysis is being revised and will be replaced by a ISO 22734-1 on "Hydrogen generators using water electrolysis - Industrial, commercial, and residential applications - Part 1: General requirements, test protocols and safety requirements" and will be completed by a Part 2 (ISO TR 22734-2) on "Testing guidance for performing electricity grid service". This revision is required to assess the performance of electrolysers and to guarantee their safety under dynamic loads in combination with variable power sources. Additionally, under ISO/TC 197/SC 1, new joint working groups are expected to be set up with other committees of the ISO and the International Electrotechnical Commission in the areas of rail, aviation and maritime applications. Within the International Electrotechnical Commission (IEC) Technical Committee for fuel cell technologies, the international standard on fuel cell technologies "Part 3-201: Stationary fuel cell power systems - Performance test methods for small fuel cell power systems" (IEC 62282-3-201:2017+AMD1:2022) has been revised.

The IPHE Steering Committee, at its 37th meeting, approved the transition of the Regulations, Codes, Standards and Safety Working Group to launch two Task Forces: maritime considerations (including onboard and port utilisation) and bulk storage of both gaseous and liquid hydrogen. These task forces are expected to identify gaps and provide recommendations to address them in the next year.

Progress is evident in the development of hydrogen certification systems

In parallel with the development of hydrogen standards, governments are working on the establishment of hydrogen certification schemes. The Australian government announced in December 2021 an 18 - month trial of a new guarantee of origin scheme for the production of hydrogen and its derivatives. The trial will serve to test key issues identified through a consultation, launched early in 2021, before the scheme is finalised and translated into regulation. It is being informed by IPHE's methodology for carbon accounting in hydrogen production. Also in December 2021, Finland passed an Act to extend the legislation on guarantees of origin for low-emission electricity to include hydrogen production. In May 2022, the Spanish government approved a decree for the creation of a guarantee of origin scheme for renewables gases. In the Netherlands, the senate approved a bill to create a system for guarantees of origin for renewable energies that includes hydrogen.

Some private sector initiatives are starting that look to certify projects that produce low-emission hydrogen. CertifHy is developing a European Union voluntary scheme for the certification of hydrogen as renewable fuels of non-biological origin according to the European Renewable Energy Directive. The German certification body, TÜV Rhineland, provided the world's first clean hydrogen certificate to a project for the production of renewables-based ammonia in Oman.

Governments are adopting regulatory frameworks for low-emission hydrogen

The UK's Low-Carbon Hydrogen Standard policy was published in April 2022 after a public consultation launched in August 2021. This regulation sets a maximum threshold of 20 g CO_2-eq/MJ_{LHV} H_2 (2.4 kg CO_2-eq/kg H_2) for the amount of GHG emissions allowed in the production of hydrogen to be considered low-carbon hydrogen. Hydrogen producers seeking support from government programmes need to adhere to this standard.

The European Commission published two drafts for delegated acts of the Renewable Energy Directive in May 2022, one to set out requirements for electricity used to produce hydrogen and its derived fuels and one for a methodology to assess GHG emissions savings from renewable fuels of non-biological origin (including hydrogen and its derivatives) to contribute to national renewables targets. The drafts were under consultation until June 2022. The final version of the delegated acts is expected by end-2022.

The United States announced the development of a Clean Hydrogen Standard (with a threshold of 2 kg CO_2-eq/kg H_2 at the point of production), which is expected to be released in 2022.

Regulatory progress beyond low-emission hydrogen production

So far, most regulatory activity has been focussed on setting the parameters to define and certify low-emission hydrogen in order to develop standards and certification systems. There also has been progress on other regulatory aspects, such as defining market rules for hydrogen and its integration as an energy vector in the energy system.

On this front, in 2020 the Australian government completed a review and assessment of all regulations which intersect with the development and operation of the hydrogen industry and is now working on a regulatory reform programme. Some first steps have been taken. The government is working on a reform to extend the national gas regulatory framework to hydrogen blends and renewable gases that are expected to be ready in 2023.

In December 2021, the European Commission presented a regulation proposal for establishing a market for hydrogen, covering aspects such as access to hydrogen infrastructure, unbundling rules to separate hydrogen production and transport activities, tariff setting and hydrogen blending in natural gas grids. It proposes to create a network of hydrogen operators to promote a dedicated hydrogen infrastructure, cross-border co-ordination and interconnector network construction and to elaborate specific technical rules. To reflect the development of the market, regulatory provisions will be adapted before 2030.

In June 2022, the Netherlands government sent a letter to parliament announcing a series of market regulation rules based on the results of a stakeholder market consultation. The government position on the organisation of the hydrogen market includes leaving hydrogen production activities unregulated and thus a market activity, to regulate hydrogen networks (with potential exception for privately own networks), the future appointment of a state-owned hydrogen transmission system operator and the possibility for public companies to participate in activities related to hydrogen storage and import. The government announced that the proposed market organisation will be implemented through the new Energy Act which is under development.

At the international level, there has been some progress in the definition of technical regulations. In May 2022, the United States submitted draft amendments to the Global Technical Regulation (GTR) No. 13, "Hydrogen and fuel cell vehicles" to the World Forum for Harmonization of Vehicle Regulations under the United Nations. The draft amendments reflect extensive revisions to GTR No. 13, including improvements of test procedures, extension of the applicability of the regulation to heavy-duty vehicles, and a better reflection of the state-of-the-art with respect to hydrogen vehicles. A vote is expected in December 2022. Acceptance of the draft amendments will put into place the first regulation for heavy-duty vehicles fuelled by hydrogen.

The IMO finalised the "Interim guidelines for safety of ships using fuel cells" in 2021, which covers onboard fuel cell installations. Also in 2021, the IMO started drafting the complementary “Interim guidelines for safety of ships using hydrogen as fuel”, which covers hydrogen storage and delivery onboard, which is expected to be approved in 2025. In parallel, the IMO is working on a similar document for ammonia as a fuel. These guidelines may later become the basis for mandatory instruments.

Investment and innovation

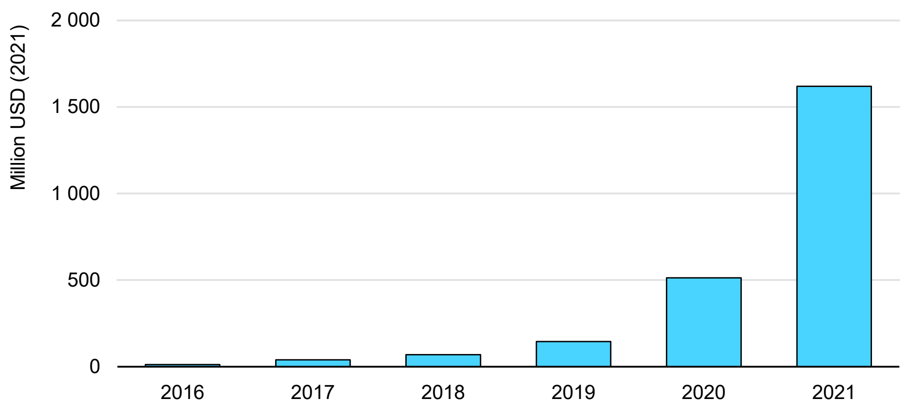
Investment

Hydrogen is attracting more investment, though costs and profitability remain pressing concerns

This annual review highlights the accelerated flow of capital to certain key hydrogen technologies, via project investment and equity in companies for scale up. The enhanced pace is fuelled by several converging factors including recognition that the energy transition to net zero emissions is quickening, and that the role of hydrogen to meet this target is expanding, in part due to advances in technology. Since 2021, the global energy crisis precipitated by Russia's invasion of Ukraine in early 2022 has emerged as a major additional driver for hydrogen projects, alongside funding to stimulate economic recovery from the pandemic and to manage inflation.

The pipeline of hydrogen projects progressed some plans to the level of FID in 2021 and hydrogen-focussed companies raised record amounts of capital despite a sharp drop in valuation related to wider economic concerns. It is looking more promising for major projects to break ground in the near term spurred by recent initiatives such as the REPowerEU objectives in the European Union to replace natural gas consumption with low-emission hydrogen[73] use. There are also more ambitious emissions targets in the United Kingdom and other European countries. In the United States, two new laws – the Infrastructure and Jobs Act and the Inflation Reduction Act – contain significant provisions for supporting increased investment in low-emission hydrogen projects.

Annual investment in electrolyser installations, 2016-2021



Note: Investment is annualised across all years between FID and operation.
Source: Based on IEA Hydrogen Project Database (2022).

More electrolyser capacity that can produce hydrogen from water came online in 2021 than in any previous year – almost 210 megawatts (MW). In total, close to 900 MW of electrolyser capacity is planned for operation in 2022. As the number of projects

[73] See Explanatory notes annex for low-emission hydrogen definition in this report.

and their sizes ramp up, so too is the amount of capital committed to them, only slightly offset by declining costs. We estimate that more than USD 1.5 billion was spent on projects at advanced stages in 2021, i.e. those with an FID and under construction, mostly projects aiming for commissioning in 2022 or 2023. This is a threefold increase from the equivalent spending in 2020. Much of this relies on funding from governments – support that continues to underpin project viability – which otherwise would have been harder hit by market uncertainties since 2020.

Tailwinds gather speed…

More public and private funding for low-emission hydrogen is likely to be mobilised by recent events such as economic recovery from the Covid-19 pandemic and the international commitment to reduce oil and natural gas imports from Russia. The European Union will be a focus with the increased ambition in the REPowerEU Plan for hydrogen imports, which may also stimulate public funding for hydrogen projects in other countries.

In July 2022, the European Commission approved proposed public spending for investment in hydrogen projects by 15 European Union member states under the IPCEI, a system that allows state aid rules to be relaxed. Among other initiatives, the REPowerEU plan refers to a possible Global European Hydrogen Facility to create investment security for producers worldwide and reliable supplies for hydrogen users.

In Germany, the government approved EUR 900 million (USD 1 billion) in funding for H2Global, an initiative to auction ten-year hydrogen supply contracts matched with equivalent hydrogen off-take contracts, with a public intermediary covering the difference between the costs of the two contracts. In the United States, authority was granted under the Defense Production Act in June 2022 for government investment in companies that can manufacture and install electrolysers and fuel cells. Demand for these electrolysers, as well as CCUS[74] related hydrogen equipment, was given a major boost by two other pieces of US legislation: the Infrastructure Investment and Jobs Act allocates USD 8 billion in grants to regional hydrogen projects and the Inflation Reduction Act establishes a tax credit of up to USD 3 per kilogramme of hydrogen (kg H_2) for production with the lowest associated emissions.

In the private sector, current high natural gas prices might spur electrolytic hydrogen use in applications such as fertiliser production, if the necessary equipment is installed. Part of the value of such a fuel switch is as a hedge against natural gas price volatility; a value readily demonstrated by renewables-based electricity purchase agreements in electricity-intensive sectors. An example of a strengthening base for investment is the recent announcement of a

[74] See Explanatory notes annex for CCUS definition in this report

competitive tender by JERA, Japan's largest electricity generator and a major natural gas trader, for supply of up to 0.5 million tonnes (Mt) of low-emission ammonia[75] (requiring almost 0.1 Mt H_2) for Japan's largest coal-fired power plant from 2027.

Companies are showing increased willingness to pay a premium for products made with low-emission hydrogen. For example, four automakers in the First Movers Coalition boosted pledges to source 10% of their steel from low-emission sources by 2030. Eighteen companies have signed nonbinding agreements to buy a total of 1.5 Mt of steel (requiring around 0.1 Mt H_2) produced with low-emission hydrogen from 2025. Maersk – the world's largest container shipping company – ordered 12 methanol-powered vessels and signed partnerships for 0.7 Mt of low-emission methanol procurement in 2025, of which three-quarters is expected to be produced using more than 0.1 Mt of low-emission hydrogen and the rest from bioenergy.

These various factors aligned to generate a flurry of announcements of very large projects, up to scale of several million tonnes of hydrogen per year, especially for exports from sunny and windy places like Australia, Latin America and the Middle East. New companies have been launched to focus on project development and are competing for business from governments, oil companies, ports and utilities, among others. The investment case for these projects, however, will depend on their costs, off-take agreements, scale up plans and exposure to permitting and certification risks.

…while some headwinds have come into sharper focus

Interest rates rose in 2022 and combined with higher costs in supply chains for renewables-based electricity and electrolysers could pose major challenges to project developers. Many projects, especially for non-captive production destined for export markets, involve leveraged financing models that are now more costly. As the combination of renewable power plants and electrolysers is highly capital intensive, the cost of capital can represent nearly half of the production cost of hydrogen. In addition, the proven model of refinancing projects at a lower interest rate once operational in order to free up capital for new investment may now generate lower returns.

Higher hydrogen production costs in the near term may narrow margins for hydrogen sales by project developers. This risks exacerbating a situation that was already discouraging some investors. Rising competition between project developers to secure the most promising locations and funding creates incentives to accept lower profits for first-mover advantages. As for renewables-based electricity projects, this could be intensified by the use of auctions to allocate public financial support. Some project developers are concerned that attention-grabbing announcements of hydrogen

[75] See Explanatory notes annex for low-emission hydrogen-derived fuels and feedstocks definition in this report.

production costs for 2030 are setting unrealistic expectations for near-term production costs among investors and policy makers, making it harder to finance important early projects that will help reduce costs and increase profits for those that follow.

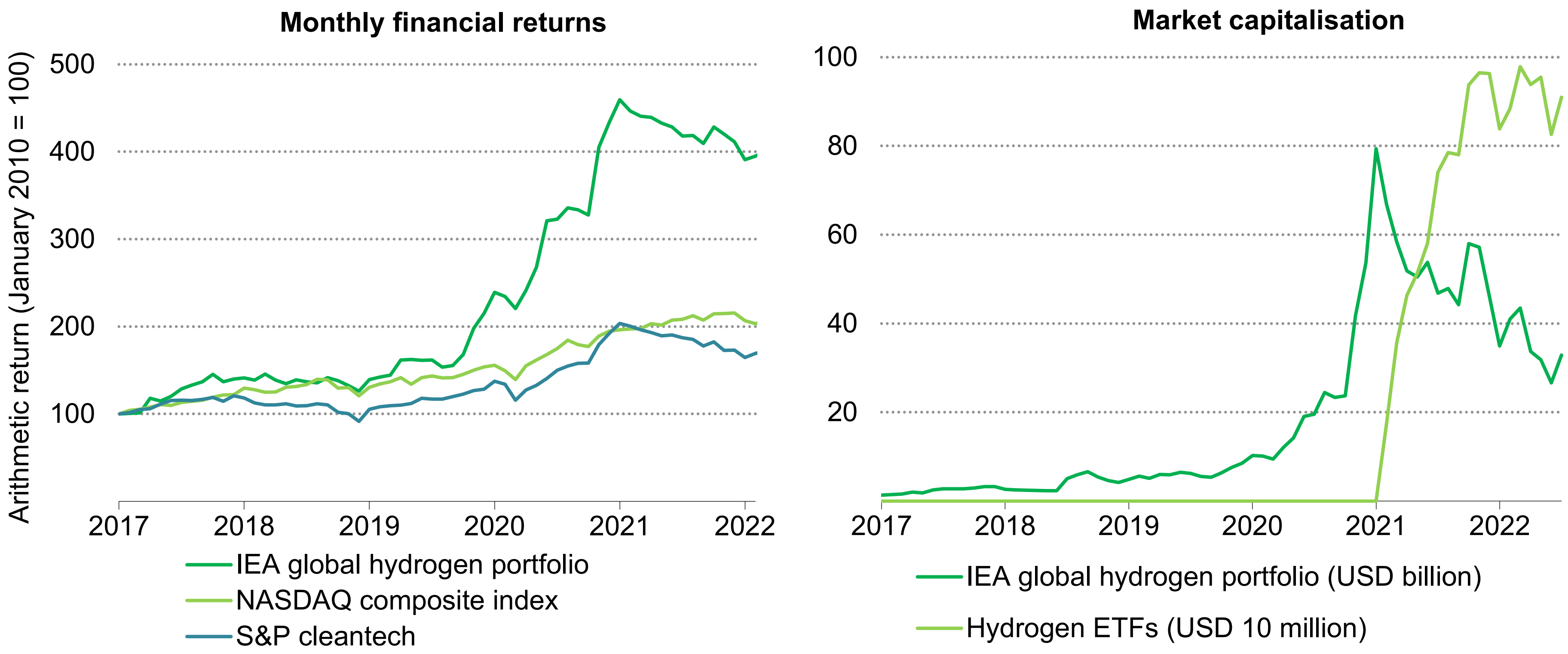
In Europe, anxieties are emerging among project developers that final investment decisions are being delayed by a lack of regulatory clarity. More projects are reaching the engineering design stage, which represents 2-5% of total costs, but not progressing further. Factors include the pending finalisation of rules for certifying hydrogen's environmental impact and European Union-wide schemes for providing operational support, with member states waiting for European Commission processes to conclude before developing compatible policies.

Other bottlenecks to a faster flow of finance include a continuing lack of policies to create near-term demand in end-use sectors, especially heavy industry, as well as poor availability of fuel cell electric vehicle models and refuelling infrastructure for road vehicles. However, despite a tight market for electrolyser supplies this year, concerns that electrolyser factory construction will not keep pace with medium-term ambitions for hydrogen production projects have been somewhat allayed by recent announcements by manufacturers (see "Hydrogen production" chapter).

Projects for low-emission hydrogen production from natural gas or coal with CCUS are moving towards investment decisions in China, Norway, United Kingdom and United States, with several decisions expected by 2025. However, to maximise their contribution to long-term goals, it is important that technical advances, including very high CO_2 capture rates, are prioritised. In the European Union, the ascendency of reducing natural gas demand as a policy goal alongside decarbonisation is likely to slow the pace of development of hydrogen production with CCUS for the foreseeable future.

Firms in the IEA global hydrogen portfolio have outperformed markets since 2020 with dramatic increases in market capitalisation on expectations of near-term revenues

Monthly returns and market capitalisation of hydrogen companies, hydrogen funds and relevant benchmarks



Notes: ETFs = exchange traded funds. The IEA global hydrogen portfolio includes 33 companies that have a focus on low-emission hydrogen. Their tickers are: 288620 KS, 336260 KS, ACH NO, ADN US, AFC LN, ALHRS FP, BE US, BLDP CN, CASAL SW, CI SS, CWR LN, F3C GY, FCEL US, GREENH DC, H2O GY, HTOO US, HYON NO, HYSR US, HYZN US, HZR AU, IMPC SS, ITM LN, MCPHY FP, NEL NO, NXH CN, PCELL SS, PHE LN, PLUG US, PPS LN, SPN AU, VIHD US, VYDR US.

Valuation of the hydrogen firm portfolio is four-times higher than in 2019

Unprecedented levels of investment in hydrogen-related companies have been mobilised as near-term expectations for hydrogen projects have risen. To track this trend, the IEA global hydrogen portfolio assembles 33 publicly traded companies whose success depends on the increasing demand for low-emission hydrogen. These companies span a range of sectors, including electrolyser and fuel cell manufacturing, low-emission hydrogen and ammonia project development, hydrogen distribution infrastructure and hydrogen-fuelled vehicles. It represents a near-comprehensive set of "pure play" low-emission hydrogen firms.

The portfolio is worth USD 33 billion around 10-times more than five years ago in nominal terms and four-times more than at end-2019. The monthly investor returns and revenues of this portfolio are three-times higher than five years ago. By comparison, the returns of comparable technology and clean technology indices less than doubled over the same period. However, the hydrogen portfolio and clean technology indices have significantly faltered since the start of 2021. In the case of hydrogen, this reflects: market corrections after the previous year's investor exuberance; a reallocation of capital away from long-term growth stocks in search of short-term value; and rising competition from large, diversified energy companies.

In late 2019, four fuel cell manufacturers – Bloom Energy, Ballard Power Systems, Ceres Power and Powercell Sweden – represented around half of the capital value of the portfolio. Today, the value of three companies active in electrolyser manufacturing – Plug Power, ITM Power and Nel Hydrogen – represent nearly two-thirds of the total. Plug Power, which also makes fuel cell systems, is responsible for most of this having increased its market capitalisation by USD 11 billion since the start of 2020.

As a signal that capital may start flowing into large projects for low-emission hydrogen supply, Aker Clean Hydrogen, a project development company that only began trading in March 2021, raised USD 0.4 billion in a share issue, a sign of appetite among investors for exposure to hydrogen projects as well as technology developers. In total, eight of the 33 firms in the portfolio started trading since the beginning of 2020, and 14 started since the beginning of 2016. This may rise in future if Adani New Energy Ltd., a hydrogen project developer, floats on the market following its launch in 2022 with a USD 50 billion ambition and a 25% stake for TotalEnergies, Adani Group's joint venture partner.

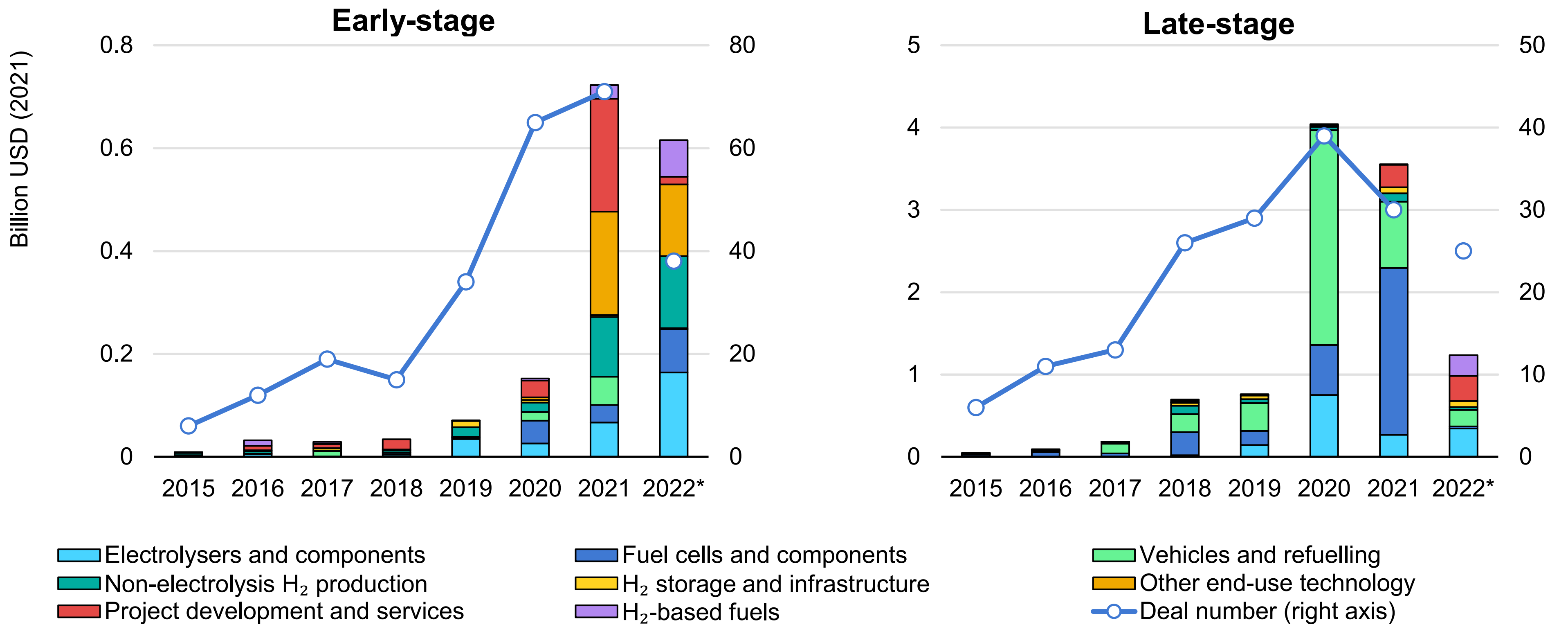
The portfolio of 33 firms represents only a subset of all the companies active in low-emission hydrogen. Other key players include larger, diversified companies and some that are in private hands, many of which are in China. One large, diversified company that has been active in hydrogen mergers and acquisitions is Fortescue Metals

Group, which bought into Sparc Technologies, HyET Hydrogen and fully acquired Williams Engineering to build a hydrogen business from scratch.

While most of the investment in the IEA global hydrogen portfolio originates from companies and diversified venture capitalists, dedicated hydrogen funds have also entered the market. Six such funds are traded publicly and all have been launched since the start of 2021. They are already worth over USD 0.9 billion, including the HydrogenOne Capital Fund, which is backed by Ineos and has invested in Doosan Fuel Cell and unlisted companies Sunfire and NanoSUN. A larger fund, the Clean Hydrogen Infrastructure Fund, which is not publicly traded, closed its first round of fundraising at USD 1.1 billion in January 2022 and has since raised a further USD 0.4 billion, including from the Japan Bank for International Cooperation, France's public reinsurer (CCR), and anchor investors Air Liquide, TotalEnergies and VINCI. It has so far invested around USD 0.2 billion in start-ups such as Hy2gen and two hydrogen projects.

Innovative companies with hydrogen-related technologies raised record amounts of equity in 2021, especially for riskier early-stage ideas and new specialist project developers

Venture capital investment in clean energy start-ups related to hydrogen, 2015-2022



*Values for 2022 only include preliminary data for deals up to 30 June 2022.

Notes: H_2 = hydrogen. Early-stage deals are defined as seed, Series A and Series B transactions. Very large deals in these categories, above a value equal to the 90th percentile growth equity deals in that sector and year, are excluded and reclassified as later-stage investments. Later-stage deals also include growth equity, late-stage private equity and buyouts, and public investments in private equity.

Source: IEA calculations based on Cleantech Group (2022).

Investor confidence in the growth potential of hydrogen technology companies was seen at all stages of the innovation process

In 2021, venture capital (VC) investments in hydrogen technologies boomed. Early-stage deals that back higher risk, innovative ideas – seed, series A and B rounds – reached over USD 700 million, nearly five times the equivalent value in 2020. Overall, hydrogen accounted for about 10% of all early-stage VC investments in clean energy start-ups, compared with 5% in 2020, suggesting increasing appetite for hydrogen start-ups.

The momentum continued into 2022 with start-ups in various businesses completing their next funding rounds and attracting funds from potential customers. These include USD 200 million raised in June 2022 by electrolyser maker Electric Hydrogen, and USD 25-30 million raised separately by two competitors, Hysata and Verdagy. Bramble Energy, a fuel cell firm, raised USD 50 million. Reflecting higher interest in ammonia-based value chains for storing energy using hydrogen, H2SITE, a start-up with a process for cracking ammonia to hydrogen, raised USD 13 million in mid-2022.

There were three major trends in early-stage deals in 2021: the emergence and fundraising success of start-ups offering project development services; the strong performance of firms with technologies for potential (non-automotive) hydrogen users; and more interest in non-electrolysis routes to low-emission hydrogen.

Companies developing projects or providing services related to hydrogen raised 30% of the total, an indication that investors have more confidence that projects will get built in the near term. Among start-ups developing end-use technologies, industrial use of hydrogen and hydrogen-fuelled engines dominated. H2 Green Steel, a hydrogen-based steel project developer, raised over USD 100 million in 2021, including funds from potential automotive customers, and USD 200 million in mid-2022, partly from a steel bearing maker. Non-electrolysis hydrogen production, such as methane pyrolysis, accounted for over 15% of early-stage VC investments, compared with less than 10% for electrolyser developers, perhaps reflecting a perception that this decade's market leaders for electrolysers are already established at industrial scale.

Hydrogen fuel cell vehicles and refuelling attracted less than 10% of early-stage VC investments in 2021. Notable investments in 2021 were led by aviation companies, rather than road vehicle firms. These include ZeroAvia and Universal Hydrogen, which both benefit from support from incumbent airline companies using corporate VC as part of their innovation strategy. They were followed in early 2022 by a seed funding round for Destinus, a start-up developing hypersonic hydrogen-powered flight. However, these concepts are still at prototype stage and will require years of trials and improvements, which will be hard to finance via VC alone.

Later-stage equity investments in growth stage hydrogen technology developers remained high in 2021, totalling USD 3.6 billion, slightly below 2021. These investments typically provide companies with larger sums to build manufacturing plants, develop large projects and enter new markets. Hydrogen-related firms accounted for about 10% of all later-stage clean energy investments in clean energy start-ups in 2021, slightly below the previous year at 15%. Like the early-stage deals, nearly all of these investments took place in the United States and Europe. However, as it did for electric vehicles, this geographic concentration may change as China announced more focus on hydrogen as part of its 14th Five-Year Plan.

Later-stage deals focussed on fuel cells and components, which accounted for nearly 60% of the total. However, with later-stage deals being smaller in number but larger in size, the trend is shaped by individual transactions. Plug Power's USD 1.6 billion fundraise in 2021 was a large share of the total on its own. Sunfire, an electrolyser and fuel cell firm, raised USD 125 million in one deal in 2021 and an undisclosed sum in a second; it also raised USD 90 million in 2022. Methanol fuel cell developer Blue World Technologies raised USD 17 million. A further 20% of later-stage deals were for vehicles and refuelling solutions, including H2 Mobility, HTEC and ZeroAvia.

Further along the investment path, several hydrogen technology companies "exited" from VC investments by floating on public markets or being acquired by larger firms. Such an exit is the usual target of innovators following the VC funding route and a sign of widespread market confidence in the business. Companies that trade shares on public markets enter our portfolio of hydrogen companies and can be tracked more easily. In late 2021, Forsee Power, a specialist in alternative vehicle powertrains, listed on the Euronext exchange with Ballard Power, a fuel cell company, as a lead investor.

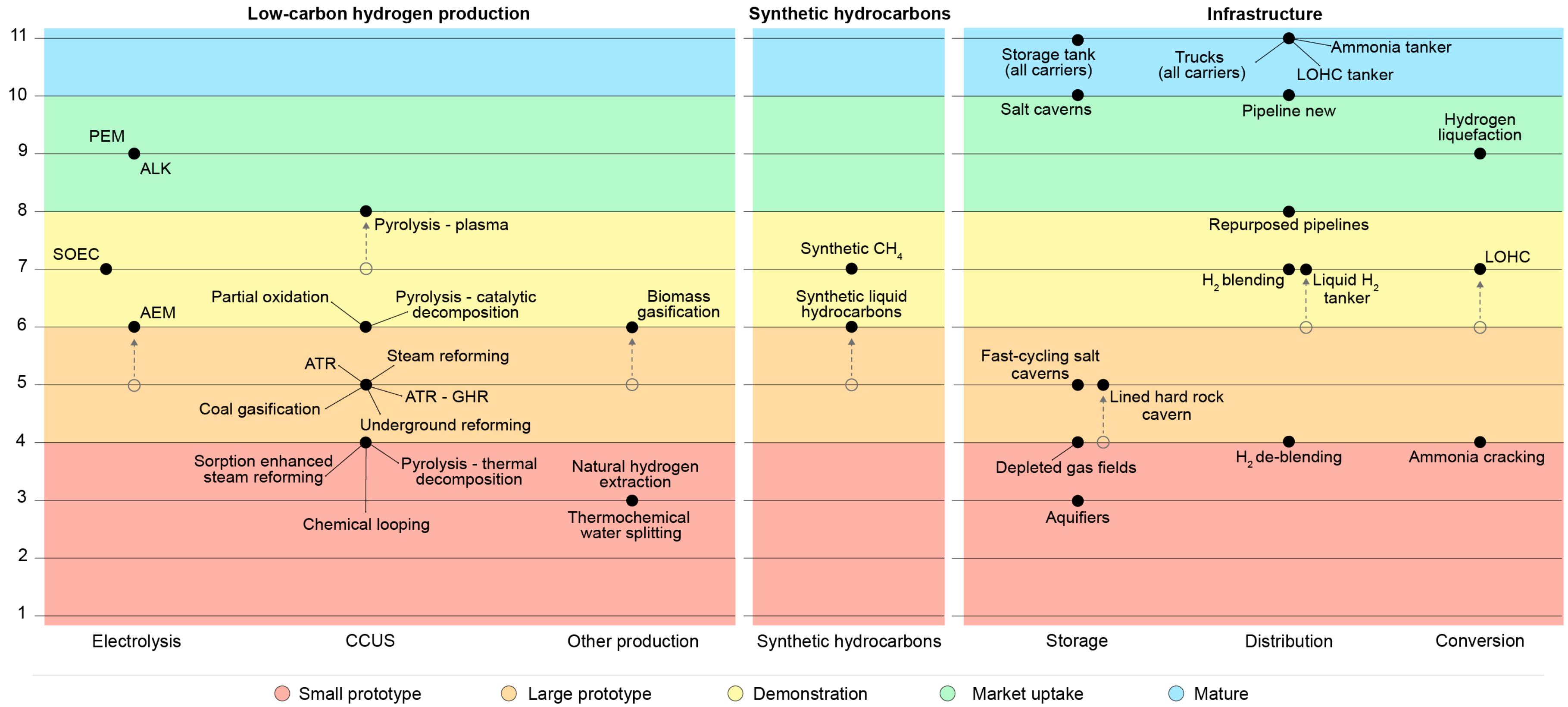
Since mid-2021, there have been several acquisitions of companies by larger players in the area of hydrogen storage technologies. These include the purchases of Applied Cryo Technologies by Plug Power, Kontak Hydrogen Storage by Hydrofuel Canada and Wystrach by Hexagon Purus. Other relevant acquisitions include Ballard Power buying Arcola Energy, a designer of vehicle powertrains, and Alkaline Fuel Cell Power Corp buying AI Renewables CHP to develop small-scale hydrogen-fuelled cogeneration. The values of most of these deals are not disclosed.

For publicly traded companies that are still in a rapid growth stage, selling new shares is a common strategy to fund expansion plans, for example to build factories. In January 2022, Nel ASA, an electrolyser manufacturer, raised USD 170 million to invest in new factory capacity. As part of a larger fund-raise, Enapter, also an electrolyser company, sold USD 20 million of shares to Johnson Matthey, a multinational engineering firm, as part of a USD 100 million capital raise. In the transport sector, HYON AS, a supplier of refuelling equipment for ships, raised USD 5 million with a private placement.

Innovation

Technology development is advancing across the hydrogen value chain, though several key technologies, particularly in end-uses, are far from being commercial

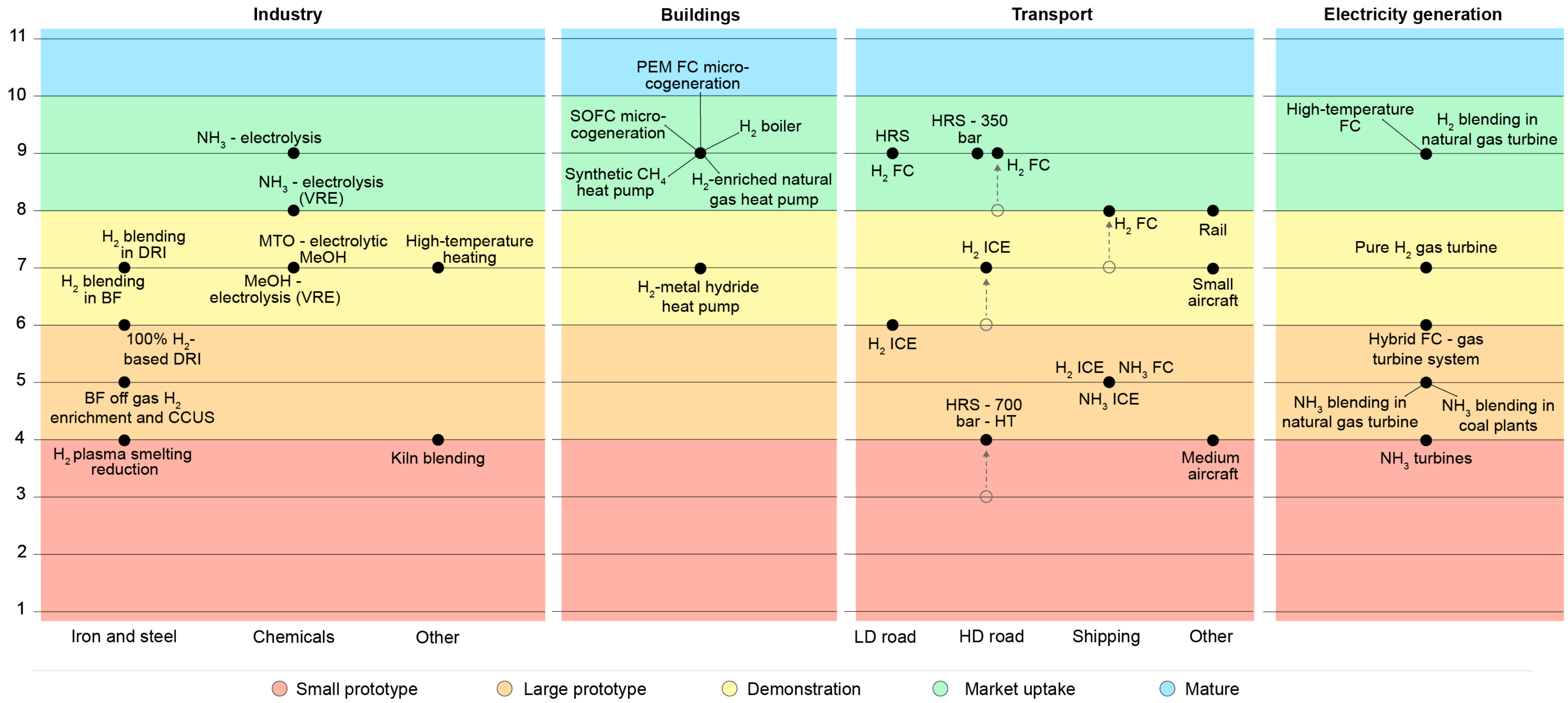
Technology readiness levels of production of low-emission hydrogen and synthetic fuels, and infrastructure



Notes: AEM = anion exchange membrane; ALK = alkaline; ATR = autothermal reformer; CCUS = carbon capture, utilisation and storage; CH_4 = methane; GHR = gas-heated reformer; HT = high temperature; LOHC = liquid organic hydrogen carrier; LT = low temperature; NH_3 = ammonia; PEM = proton exchange membrane; SOEC = solid oxide electrolyser cell. Biomass refers to both biomass and waste. Arrows show changes in technology readiness level as a consequence of progress in the last year. For technologies in the CCUS category, the technology readiness level refers to the overall concept of coupling production technologies with CCUS and high CO_2 capture rates. Pipelines refer to onshore transmission pipelines. Storage in depleted gas fields and aquifers refers to pure hydrogen and not to blends. LOHC refers to hydrogenation and dehydrogenation of liquid organic hydrogen carriers. Ammonia cracking refers to low temperature ammonia cracking. Technology readiness level classification based on Clean Energy Innovation (2020).

Source: ETP Clean Energy Technology Guide, IEA (2022).

Technology readiness levels of hydrogen end-uses by sector



Notes: BF = blast furnace; DRI = direct iron reduction; FC = fuel cell; HRS = hydrogen refuelling station; HD = heavy-duty; HT = high throughput; ICE = internal combustion engine; LD = light-duty; MeOH = methanol; MPa = megapascal; MTO = methanol to olefins; NH_3 = ammonia; PEM FC = proton exchange membrane fuel cell; SOFC = solid oxide fuel cell; VRE = variable renewable electricity. Others in industry includes all industrial sectors except methanol, ammonia and iron and steel production. Others in transport includes rail and aviation. Arrows show changes in technology readiness level as a consequence of progress in the last year. Cogeneration refers to the combined production of heat and power. Technology readiness level classification based on Clean Energy Innovation (2020).

Source: ETP Clean Energy Technology Guide, IEA (2022).

Realising the role of hydrogen in the clean energy transition hinges on innovation, both to support continued cost reductions and improved performance in commercially available technologies, as well as to ensure that the next generation of hydrogen technologies, which are now at demonstration stage, reach timely commercialisation.

Hydrogen production technologies are well developed, including to produce low-emission hydrogen. Alkaline and PEM electrolysers are commercially available. Solid oxide electrolysers (SOEC) are at the demonstration stage. Anion exchange membrane (AEM) electrolysers are at earlier stages of development, but AEM technology is evolving rapidly; Enapter and Alchemr have prototypes at kilowatt (kW) scale available and Enapter aims to produce them at scale from 2023.

There has been no significant progress over the last year in the development of technologies to produce hydrogen from fossil fuels with CCUS. Technologies with partial capture of CO_2 (around 60%) are commercially available and their use is common practice for the co-production of ammonia and urea. However, technologies with higher capture rates have not been demonstrated at large scale. Both the individual components to produce hydrogen, e.g. steam reformers, autothermal reformers and partial oxidation reactors, and the capture of CO_2 at high rates are mature technologies. However, to date, there has not been a demonstration at industrial scale that combines the production technologies and high capture rates and no near-term projects have been identified.

Monolith Material has developed a methane plasma pyrolysis process that converts natural gas into carbon black and clean hydrogen. The company has started operation of the Olive Creek 1 project in the United States, its first commercial-scale carbon-free production facility to produce hydrogen and carbon black. The next phase plans to use the hydrogen generated via its manufacturing process to cleanly produce ammonia.

Biomass-based routes have also registered some progress with full prototypes for the production of hydrogen via gasification of water sludge starting operations in Japan and France.

International transport of hydrogen recently has registered a major milestone in technology development. In February 2022, the Suiso Frontier, a liquefied hydrogen tanker developed by Kawasaki Heavy Industries, completed the first shipment of hydrogen between Australia and Japan. Interest in international hydrogen trade has received a significant boost from rising interest among European countries to reduce fossil fuels imports from Russia and to enhance energy security. This is stimulating innovation activities in technologies that can play a significant role to facilitate hydrogen trade. Due to lower technology maturity of liquefied hydrogen shipping and LOHC conversion process, maritime hydrogen trade is expected to occur initially using ammonia as the carrier. Some end-uses will be able to use ammonia directly, but others will require converting ammonia back into hydrogen, which today has an energy penalty above 30%.

In April 2022, the European Commission launched Ammonia to Green Hydrogen: Efficient system for ammonia cracking for application to long distance transportation within the Horizon Europe Framework Programme. Its goal is to advance catalysts and reactors for ammonia dehydrogenation at lower temperatures to the demonstration stage, to achieve ammonia conversions of 98% and to improve the overall thermal efficiency of the conversion process while avoiding a catalyst dependent on critical raw materials.

The substitution of unabated fossil fuel-based hydrogen for low-emission hydrogen in existing industrial applications presents less technical challenge than the adoption of hydrogen in new applications. Yet, innovation is still required, for example to handle variable renewable energy sources of electricity. In March 2022, Fertiberia and Iberdrola put into operation the first demonstration project (20 MW) to use hydrogen produced with electrolysis powered by solar PV in ammonia production. Most of the electricity will come from the solar PV installation (with battery backup), though some grid electricity will provide assurance of firm power. In China, Ningxia Baofeng Energy Group started operating a large-scale electrolyser (150 MW) powered by solar PV to produce methanol in 2021.

Among industrial applications, the use of hydrogen in DRI has seen significant progress over the last year. The Hybrit project has been producing DRI and steel since 2021, becoming the first operative full prototype at scale of this technology and has recently received EUR 143 million support from the European Union Innovation Fund to move to industrial- and commercial-scale demonstration. As part of this project, the first pilot facility for underground hydrogen storage in lined hard rock caverns was inaugurated in June 2022.

Hydrogen technologies for use in the transport sector also witnessed significant progress over the last year. While fuel cells remain the main technology for hydrogen use in road transport, the internal combustion engine (ICE) has gained attention. In December 2021, Toyota showcased an experimental hydrogen ICE vehicle and in June 2022, two manufacturers, SINOTRUK and Weichai, launched the first heavy-duty hydrogen ICE vehicle in China.

There were also significant achievements for the development of infrastructure for refuelling fuel cell heavy-duty trucks, especially for high-pressure (700 bar) and high-throughput refuelling stations. A project funded by the US Department of Energy and developed by the US National Renewable Energy Laboratory, Air Liquide, Honda, Shell and Toyota, built a hydrogen refuelling station for heavy-duty trucks that surpassed the US DOE target for flow rates, reaching an average mass flow rate of 14 kg/minute. In France, as part of the H2Haul project, Air Liquide will start operating the first high-pressure hydrogen refuelling station for trucks in Europe in September 2022.

The technology bottleneck for reaching commercialisation is the nozzle which constricts the flow of hydrogen into the trucks, but new nozzle designs are expected to be ready in the next couple of years. In June 2022, Daimler announced the beginning of a testing programme for refuelling of liquid hydrogen in their Mercedes-Benz GenH2 Truck fuel cell prototype.

In aviation, ZeroAvia developed and successfully ground tested a 600 kW hydrogen-electric aircraft engine in 2022. As the next step, ZeroAvia intends to conduct a test flight of a fully hydrogen-powered 19-passenger seat aircraft by mid-2023 and to complete flight tests by 2024. This flight test programme will represent a big leap forward in terms of the scale of demonstration for hydrogen aircraft.

In addition to hydrogen, synthetic fuels are also considered a significant opportunity to contribute to the decarbonisation of the aviation sector. The production of synthetic kerosene is at the early stages of production. Atmosfair, a German non-profit organisation, in late 2021 started operating the first full prototype facility at scale with planned production of 20 tonnes of carbon-neutral kerosene annually to be used as fuel for Lufthansa aircraft.

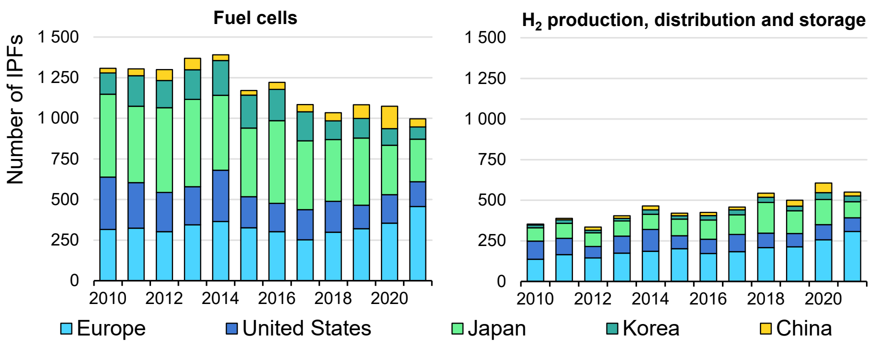
The development of hydrogen infrastructure can take advantage of existing natural gas equipment and networks in order to minimise costs. For instance, Gasunie has been operating the first repurposed natural gas pipeline since 2018. In May 2022, researchers at Stavanger University in Norway for the first time repurposed a natural gas turbine to run on pure hydrogen. The efficiency of the repurposed gas turbine is somewhat reduced compared with the use of natural gas. This is a milestone, nonetheless, as it indicates that existing gas turbines could use hydrogen to maintain their value in the long run and reduce risks of potential sunk costs.

Pace of hydrogen patenting activity remains slow, but innovation takes time

Patents are an indicator of innovation. However, not all patents are equal in their value or level of innovativeness. International patent families (IPFs) are patent applications that have been filed in two or more patent offices worldwide and as multiple applications entail more effort and expense, this suggests that the perceived value is higher. IPFs for fuel cell technologies outnumber those for hydrogen production, storage and distribution by a ratio of almost two-to-one. This likely reflects a higher technology readiness level for fuel cells and the fact that most fuel cell patent applicants are automotive companies, which is the largest area of energy-related corporate R&D. Japan had a clear technology lead in fuel cells, holding 36% of all IPFs from 2010 to 2021. Led by Germany, in the last two years patenting activity in Europe has increased and overtaken Japan.

While the number of IPFs for hydrogen production, distribution and storage has increased since the 2010s, the average annual growth rate over the last decade has been just 5%, considerably lower than the impressive 12.5% average growth sustained by low-carbon energy innovation between 2000 and 2013. The filing activity is increasingly concentrated in Europe, where 43% of IPFs were filled from 2010 to 2021, especially in Germany and France. While not all innovation is patented, the IPF count may be a sign that innovation is lagging. Though there is a time element; it takes around three years from R&D completion to file a patent and for it to be published. If increased recent attention and activity related to hydrogen is successfully translated into inventions, patents are expected to increase in coming years. Current low patent activity may pose a challenge for major improvements in the short term until new R&D investments materialise and increased demand for hydrogen drives competition and scaling up, as well as incentives to spur innovation on the supply side. (A forthcoming study on hydrogen patent activity, developed jointly by the IEA and the European Patent Office, will be released in early 2023 and will provide detailed insights on the patent landscape for hydrogen).

International patent families by type and region, 2010-2021



Note: IPFs = international patent families.
Source: Based on European Patent Office data. Fuel cells match patent category Y02E60/50-56H, H_2 production matches Y02E60/36 (B-F2), H2 distribution Y02E60/34 and H_2 storage Y02E60/32 (B-F6).

Hydrogen in a changing energy landscape

Russia's invasion of Ukraine challenges energy security, especially in Europe

Russia's invasion of Ukraine in February 2022 marks a turning point in global energy markets, with Europe being at the epicentre of the energy market challenges. Energy costs are surging, with natural gas prices in Europe and coal prices reaching record levels, pushing up electricity prices; oil prices also reached levels not seen in years.

The impacts of this global energy crisis are far-reaching. In Europe, there are real risks of supply disruptions. In developing economies in Asia and Africa, nearly 90 million people that had gained access to electricity can no longer afford to pay for basic energy needs and an ongoing food crisis is exacerbated.

Such turmoil will not diminish soon. This raises important policy questions about how to reconcile near-term needs to bolster energy security in a highly volatile market while ensuring the longer term transition to a clean energy system. Hydrogen is not immune to this discussion and the present situation has heightened attention on the energy security benefits of broader use of hydrogen as an energy vector. Hydrogen can contribute to enhance energy security in three areas:

- **Decrease dependency on fossil fuels**. The use of low-emission hydrogen[76] instead of unabated fossil fuel-based hydrogen in existing applications or to directly replace fossil fuels in new applications is widely recognised as a key lever to decarbonise sectors where emissions are hard to abate. The use of low-emission hydrogen can reduce fossil fuel dependency when produced from renewables-based or nuclear electricity.
- **Diversify fuels**. Hydrogen can diversify the energy mix. Fuel diversification improves flexibility of the energy system and reduces its vulnerability to supply disruptions.
- **Diversify supply**. Energy security benefits from a diverse portfolio of suppliers. In the case of fossil fuels, options to diversify supply are limited by the geographic distributions of resources. For example, just ten countries account for over 70% of global natural gas production. In the case of low-emission hydrogen, the portfolio of suppliers that is expected to emerge if international hydrogen trade is realised is significantly larger than that of current fossil fuel suppliers.

European countries are taking the lead in this discussion and are boosting their hydrogen ambitions. In March 2022, the European Commission presented the REPowerEU Plan to make Europe independent from fossil fuels imported from Russia before 2030. The plan sets two hydrogen objectives: to produce 10 million tonnes (Mt) of renewable hydrogen[77] in the European Union and to import an additional 10 Mt of renewable hydrogen by 2030. In April 2022, the

[76] See Explanatory notes annex for low-emission hydrogen definition in this report.

[77] See Explanatory notes annex for renewable hydrogen definition in this report.

United Kingdom launched the Energy Security Strategy and doubled its ambition for low-emission hydrogen production capacity to 10 gigawatts (GW) by 2030, with at least half from electrolytic hydrogen. The Netherlands announced plans to revise upward its target of 3-4 GW of electrolysis capacity by 2030. All these countries are facing a very difficult natural gas supply situation as a consequence of increasing prices and declining supplies from Russia, including full cuts of supply.

Domestic hydrogen production relative to imports from an energy security perspective

Renewable hydrogen is well placed to contribute to improve energy security; hydrogen produced from fossil fuels with carbon capture and storage (CCUS) meanwhile can increase fossil fuel demand and so its potential contribution to enhance energy security is less straightforward. However, there are a multitude of factors that weigh on an assessment of the role of hydrogen as a clean energy vector in terms of energy security.

If hydrogen is produced within a country or within a supranational union, such as the European Union, the main energy security factor is the energy source used to produce it and its availability in the region. Energy security is generally enhanced with the use of domestic resources. For instance, in regions with significant fossil fuel resources, such as Australia, North America or the Middle East, the production of hydrogen from fossil fuels with CCUS is not likely to pose a risk for energy security. On the other hand, in Europe where fossil fuel resources are limited and often imported, the production of hydrogen from fossil fuels with CCUS would result in more fossil fuel imports and more dependency on a limited portfolio of suppliers.

For imported hydrogen, in terms of energy security, the diversity and reliability of suppliers are the main factors. For countries that are expected to import hydrogen, it would decrease domestic fossil fuel demand and increase fuel diversity regardless of its origin. For example, in Europe, importing hydrogen from reliable partners to replace Russian fossil fuels would enhance energy security even if the imported hydrogen had been produced from fossil fuels with CCUS.

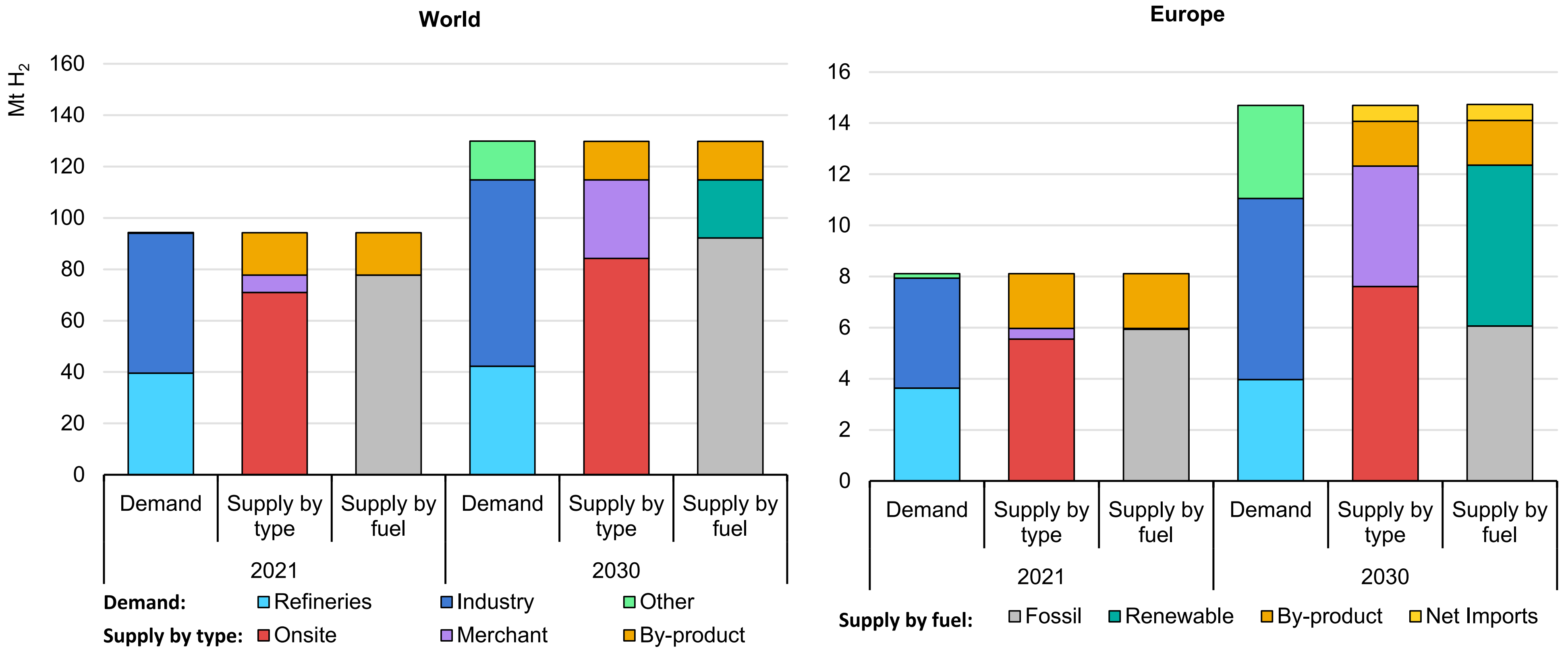
Today's energy crisis demands informed action

The economic and social implications of the current energy crisis put governments under pressure to take quick action on numerous fronts. For hydrogen, there are several questions that need to be addressed. How much fossil fuel demand can hydrogen avoid in the near term? In which sectors can hydrogen deliver the largest reductions? What are the infrastructure needs and how quickly can they be built? How can natural gas infrastructure that is built to deal with the current energy crisis be repurposed for hydrogen or its derivatives in the years ahead? These questions are addressed in this chapter to support governments to take informed decisions for both the immediate energy crisis as well as for the transition to a clean energy future.

Opportunities for low-emission hydrogen to reduce fossil fuel use

Hydrogen production today is concentrated and mostly integrated with onsite demand…

Global and European hydrogen demand by sector, and hydrogen supply by type and fuel in the Announced Pledges Scenario, 2021-2030



Notes: Other includes the transport, power generation and buildings sectors, and synthetic fuels. Europe includes the European Union, Albania, Belarus, Bosnia and Herzegovina, North Macedonia, Gibraltar, Iceland, Israel, Kosovo, Montenegro, Norway, Serbia, Switzerland, Republic of Moldova, Republic of Türkiye, Ukraine and United Kingdom.

…but its use will expand to new uses and merchant supply options including trade

Global hydrogen demand in 2021 was 94 Mt.[78] Almost all of it is concentrated in refining and industrial applications, with very little demand in other sectors (around 40 kilotonnes [kt], practically all in road transport). More than 80% of hydrogen is produced from fossil fuels, with the remainder largely from refineries where hydrogen is produced as a by-product of processes that use fossil fuels as inputs. The production of renewables-based hydrogen is very low, accounting for around 0.1% of total production. Almost all dedicated hydrogen production, excluding by-product hydrogen, occurs onsite at the same industrial facility or refinery that consume the hydrogen. Only a small fraction (7%) is produced in external facilities and delivered as merchant hydrogen. Most of the merchant hydrogen is consumed in refineries that require a more flexible operation to respond to variable demand for oil products.

In Europe,[79] hydrogen demand is slightly more than 8 Mt, evenly distributed between refining and industrial applications. Of which about 75% is supplied by dedicated production of fossil fuel-based hydrogen, with nearly all the rest met with by-product hydrogen from refineries. Europe accounts for about one-third of global electrolysis capacity – second in the world after China – but only 0.1% of European production is produced from water electrolysis. Merchant hydrogen only accounts for 5% of dedicated production, practically all for refineries, whereas the remainder 95% is produced onsite in industrial facilities and refineries where the hydrogen is used.

Hydrogen produced from renewable energy for use in sectors which already use hydrogen offers a near-term opportunity to reduce demand for fossil fuels. The use of renewable hydrogen in existing applications can progress the clean energy transition and achievement of climate commitments. In the IEA APS[80], around 13 Mt of renewable hydrogen are used globally in refining and industry in 2030 to replace the equivalent amount of fossil fuel-based hydrogen, while almost 87 Mt of the hydrogen demand in refining and industry in 2030 are produced from fossil fuels a slight increase compared with 2021. Most of this increase is from the use of fossil fuel-based hydrogen production with CCUS, which helps to mitigate

[78] This excludes around 30 Mt hydrogen present in residual gases from industrial processes used for heat and electricity generation, as this use is linked to the inherent presence of hydrogen in these residual streams, rather than to any hydrogen requirement, these gases are not considered here as a hydrogen demand.

[79] Europe includes the European Union, Albania, Belarus, Bosnia and Herzegovina, North Macedonia, Gibraltar, Iceland, Israel, Kosovo, Montenegro, Norway, Serbia, Switzerland, Republic of Moldova, Republic of Türkiye, Ukraine and United Kingdom.

[80] In addition to the European Union's pledge to reach net zero emissions by 2050, the APS fully incorporates the Versailles declaration of March 2022 to phase out imports of Russian gas to the EU as quickly as possible. To this end, it makes best efforts to include the proposed sectoral measures in the European Commission's REPowerEU communication. The renewable hydrogen obligations proposed in the revision of the Renewable Energy Directive are met in the APS .

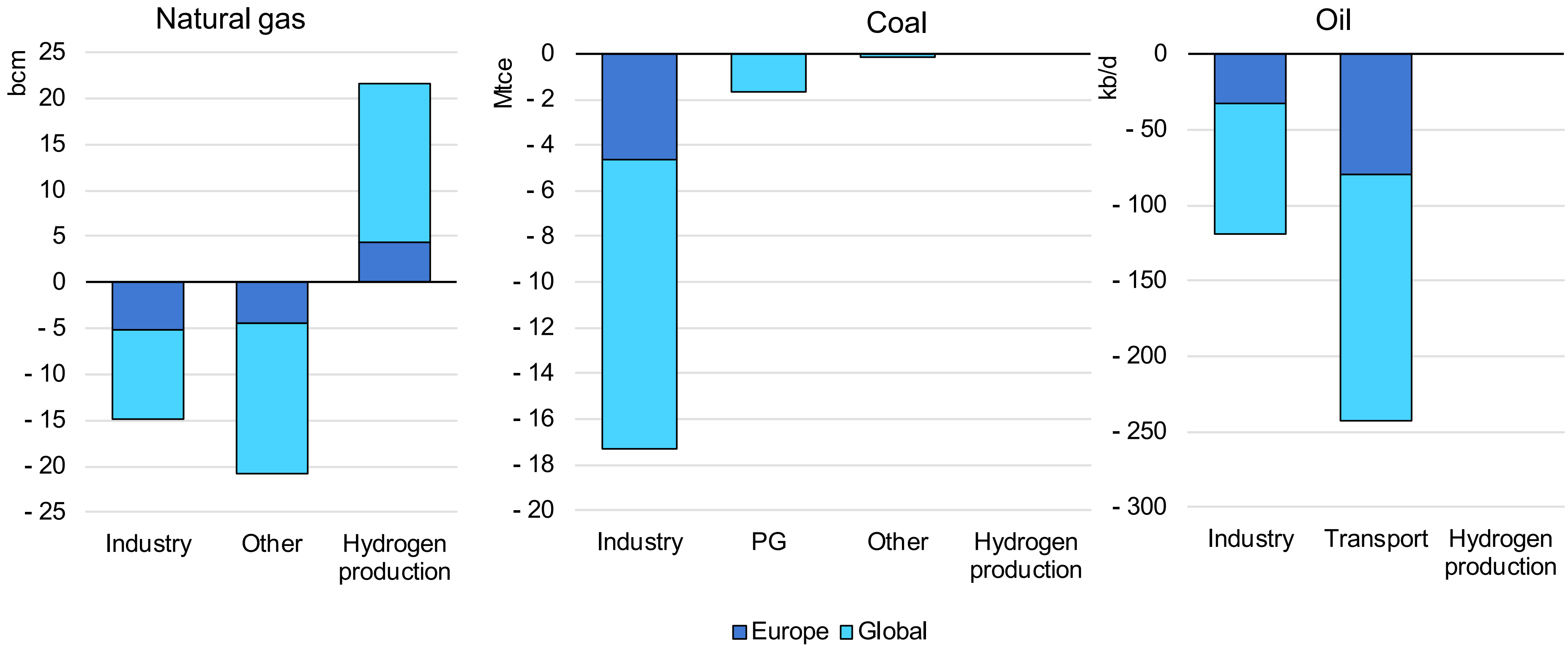
CO_2 emissions in refining and some industrial processes, but increases fossil fuel demand.

Hydrogen offers opportunities beyond sector which already use hydrogen to reduce fossil fuel dependency. Hydrogen use in new heavy industry applications, particularly in steel making and high-temperature heating, transport, power generation and the buildings sector can cut fossil fuel demand and contribute to meeting climate pledges. Of course, meeting broader demand will require more renewables-based hydrogen from domestic production or imports from a diversified mix of suppliers. In the APS, the outlook is for almost 10 Mt of renewable hydrogen by 2030 for use globally in a variety of new applications.

More hydrogen use in transport, power generation and the buildings sector means changes in the supply structure from the current dominance of onsite production to widening participation from merchant hydrogen production. The structure of the merchant market is likely to evolve from dominance by a small number of large natural gas suppliers to a more diverse portfolio of producers, including small and new market entrants. In the APS, by 2030 25% of global dedicated hydrogen production is delivered to end-uses as merchant hydrogen. The share is significantly larger in Europe with merchant hydrogen representing 5 Mt (around 40%) of dedicated production, of which 0.7 Mt (more than 10% of merchant hydrogen) is imported. Industrial users will likely benefit from a hydrogen market that provides wide portfolio of supply options and complements or replaces onsite hydrogen production. In the APS, 8 Mt of merchant hydrogen are used globally in industrial applications in 2030, representing about 10% of hydrogen demand in industry, up from almost no demand in 2021.

Boosting low-emission hydrogen in line with climate pledges cuts fossil fuel demand by 14 bcm/year of natural gas, 20 Mtce/year of coal and 360 kb/d of oil by 2030

Global and European avoided fossil fuel demand with hydrogen uptake in select sectors in the Announced Pledges Scenario, 2030



Notes: bcm = billion cubic metres; Mtce = million tonnes of coal equivalent; kb/d = thousand barrels per day; PG = power generation. For natural gas, other includes buildings, gas network injection and transport. For coal, other includes refining. The IEA Announced Pledges Scenario assumes that all climate commitments made by governments around the world, including Nationally Determined Contributions and longer-term net zero targets, will be met in full and on time. The IEA Stated Policies reflects current policy settings based on a sector-by-sector assessment of the specific policies that are in place, as well as those that have been announced by governments around the world.

Industry, power generation and transport offer prime opportunities for hydrogen to reduce fossil fuel demand in this decade, even though the cuts are limited

Decreasing fossil fuel use to mitigate climate change is an urgent task for the world; it is bolstered by nations' energy security concerns. Hydrogen can play an important role. Cutting fossil fuel demand in the short term requires careful planning to ensure the application of cost-efficient measures and the uptake of best available technologies. Energy efficiency, direct electrification coupled with renewable and nuclear electricity and biomass are more immediate approaches than the use of hydrogen technologies in many applications. Nonetheless, hydrogen can complement other clean energy options and serve demand where the other technologies are more limited or costly, such as in some heavy industry applications and long-distance transport.

In the short term, though, fossil fuel demand savings from hydrogen applications are rather limited. In the APS, by 2030 hydrogen reduces fossil fuel demand: 14 billion cubic metres (bcm) of natural gas (0.3% of current global natural gas demand); 20 million tonnes of coal equivalent (Mtce) of coal (0.3% of global coal demand) and 360 thousand barrels per day (kb/d) of oil (0.4% of global oil demand). For natural gas, global demand savings in end-uses and energy transformation are more than 50 bcm by 2030 in the APS, but the savings are partially offset by increased hydrogen production from natural gas with CCUS. For coal, practically all the savings in 2030 are in end-use applications (18 Mtce). Europe holds an important share of these savings: nearly 8 bcm of natural gas demand (about 1% of its current demand); close to 5 Mtce of coal (around 1% of its coal demand) and more than 100 kb/d of oil (1% of its supply) by 2030.

The use of renewable hydrogen in industrial applications has the strongest potential to reduce natural gas demand in the short term, particularly in ammonia production and high-temperature heating. The use of renewable hydrogen in ammonia production is ready to be deployed at scale. The first commercial demonstration started operation in 2022 in Spain and there are several large-scale projects at advanced stages of development (see "Hydrogen demand" chapter). In addition, the use of renewable hydrogen in ammonia production may already be competitive with hydrogen produced from unabated fossil fuels in regions with good renewable energy sources. This competitiveness is boosted when fossil fuel prices are high, where policies penalise unabated fossil fuel use and/or reward the use of low-emission sources. For applications that require high-temperature heating, replacing natural gas with hydrogen may require minor modifications to the existing industrial equipment: some demonstration and commercial projects are currently under development. In the APS, the use of renewable hydrogen in industrial applications saves globally nearly 15 bcm/year of natural gas by 2030, with Europe accounting for a third of these savings.

Hydrogen can also help to reduce natural gas demand in several other sectors such as refining, power generation and buildings. Added together these sectors combined can save 20 bcm/year of natural gas by 2030.

The use of hydrogen in power generation is limited today, but technologies that can operate on hydrogen-rich gases or even pure hydrogen are commercially available (see "Hydrogen demand" chapter). The option to use hydrogen, either co-fired with natural gas or as a pure fuel in gas turbines, can provide flexibility to electricity systems and facilitate the integration of variable renewable energy sources such as solar and wind, in particular in regions where alternative low-emission flexibility options are limited. However, this option may be limited due to the high associated costs and the competition from a large pool of technologies that can provide grid flexibility (such as pumped hydro, batteries and demand side response, among others). The priority to decrease natural gas demand in power generation should be an accelerated deployment of low-emission electricity, particularly renewables, complemented with storage technologies as renewable shares increase in the power mix.

There are no significant technical challenges to replace fossil fuel-based hydrogen used in refining with renewable hydrogen. In the APS, renewable hydrogen avoids more than 1 bcm of natural gas in refining by 2030. This avoided natural gas demand for refining is mainly in Europe, where the uptake of renewable hydrogen is boosted by the Fit for 55 package of the European Union, which includes a proposal for a target to meet 2.6% of energy demand in transport with renewable fuels of non-biological origin (including hydrogen and synthetic fuels).

Blending hydrogen into natural gas grids and the direct use of hydrogen in buildings are other options to reduce natural gas demand. The scope of direct use of hydrogen in buildings in the near term is limited as other options, such as heat pumps, can be deployed much faster and more efficiently. The direct use of electricity in a heat pump is more efficient than producing hydrogen to be combusted for use in space heating.

Hydrogen can also reduce coal demand, particularly in industry. The use of renewable hydrogen in steel making can reduce coal use by blending hydrogen in blast furnaces or by switching to the direct reduced iron steel production route with hydrogen. The use of renewable hydrogen can also replace coal-based hydrogen production in the chemical industry and the direct use of coal for high-temperature heating. Overall, the resulting coal savings in industry in the APS are around 17 Mtce by 2030, with roughly one-quarter in Europe, where demand is mainly met with imported coal. In power generation, co-firing ammonia in coal-fired power plants is currently being demonstrated in Japan. This option can decrease emissions from the large and still young fleet of coal-fired power plants in

Southeast Asia. In the APS, ammonia co-firing avoids around 1.5 Mtce of coal globally by 2030, mostly in Japan.

Hydrogen can cut oil demand, particularly in transport. Hydrogen and hydrogen-derived fuels reduce oil demand in transport by nearly 250 kb/d by 2030 in the APS. The direct use of hydrogen and derived fuels in road transport and shipping provide the largest savings. While electrification is the main route to reduce oil demand and emissions for cars, the use of hydrogen can be an option for heavy-duty vehicles. Due to the relatively large share of these vehicles in total oil demand in road transport, even a limited number of fuel cell trucks can deliver significant savings.

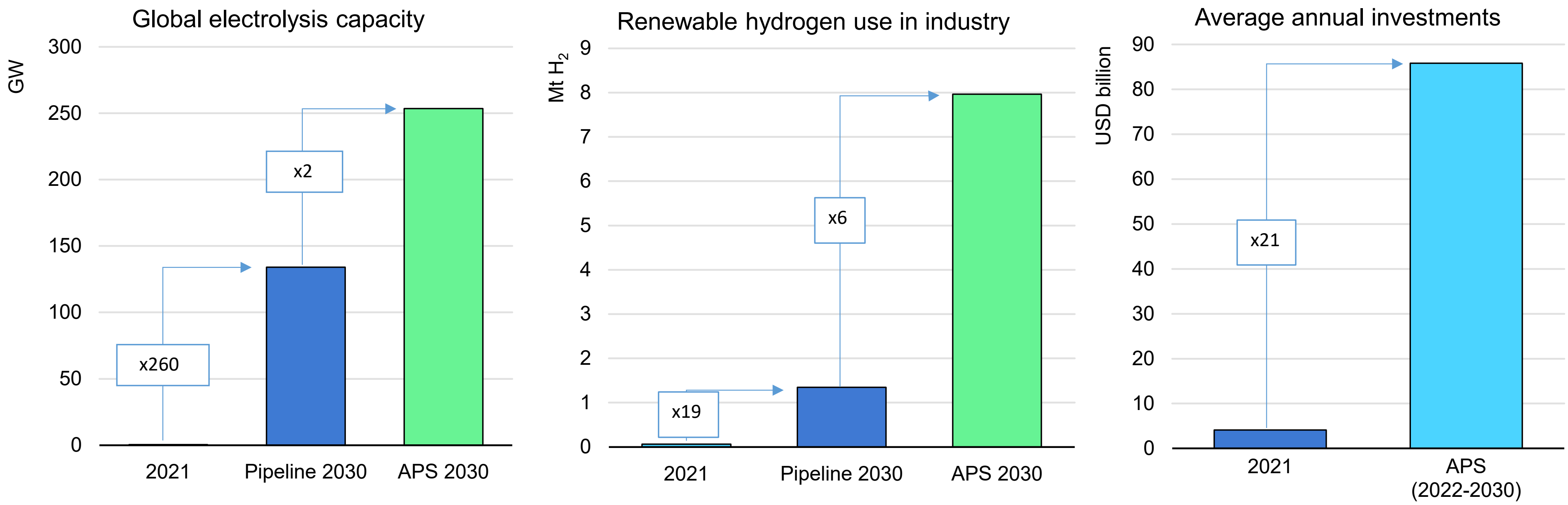
In shipping, the outlook for the use of hydrogen and ammonia gets some traction later this decade. With very few alternatives available and relatively large oil consumption in shipping, the sector provides the largest oil savings in the APS.

Aviation and rail can also deliver some savings, but the efficiency and cost advantage of electric trains and the lower technology development of hydrogen technologies in aviation limit the potential in these sectors in the near term.

Hydrogen can also cut oil demand in industry. In the APS, around 120 kb/d of oil products used for high-temperature heating and chemicals production is avoided by 2030 as the use of low-emission hydrogen becomes cost-competitive with oil, particularly in the Middle East.

Policy action is needed to scale up hydrogen production and use

Electrolysis capacity, renewable hydrogen use in industry and average annual investment in low-emission hydrogen in the Announced Pledges Scenario, 2021 and 2030



Notes: GW = gigawatts, Mt H_2 = million tonnes of hydrogen; APS = Announced Pledges scenario. Pipeline represents planned projects; only projects with a disclosed start year for operation are included. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included.

Source: IEA Hydrogen Projects Database 2022.

Global installed capacity of electrolysers is about 500 megawatts (MW). This would need to expand to around 250 GW by 2030 to meet the demand represented in the APS. It would require nearly 400 GW of solar or wind or other renewables-based generation capacity to provide the power for the electrolysers to produce renewable hydrogen, plus small contributions from grid electricity by 2030. This could represent 7% of global installed solar PV and wind capacity in 2030.

A significant amount of electrolyser capacity is being planned. If all announced electrolyser projects in the pipeline are realised, global installed capacity could reach arround 130 GW by 2030,[81] more than half of the needed level indicted in the APS. However, only around 7% of the planned capacity is under construction or have reached a final investment decision (FID). Though manufacturers have announced further plans to ramp up electrolyser production capacity in the coming years.

More demand for low-emission hydrogen is necessary to unlock investment and accelerate its deployment. Absent sufficient demand, most of the electrolyser projects in the pipeline will not reach a FID due to an inability to guarantee off-takers. Investment relies on attractive off-take contracts to mitigate project risks. Public policies and measures that stimulate demand for low-emission hydrogen can play an influential role.

From both an energy security perspective and mandates to curb greenhouse gas (GHG) emissions, low-emission hydrogen should displace fossil fuels in applications that are conducive in the near term. Industry is the sector in which hydrogen can deliver the largest fossil fuel savings by 2030. In the APS, renewable hydrogen demand for industrial applications is around 8 Mt in 2030, compared with just a few kilotonnes of demand today in demonstration projects.

The use of hydrogen and ammonia in power generation (100% firing or co-firing hydrogen with natural gas or ammonia with coal) also reduces fossil fuel use and CO_2 emissions. In the APS, hydrogen demand for the power sector is nearly 5 Mt by 2030, up from almost zero today.

With current high fossil fuel prices, the price differential between unabated fossil fuel-based hydrogen and renewable hydrogen has shrunk and, in areas with good renewable resources, it is already cheaper to use renewable hydrogen in some applications. This differential may not endure for 10-20 years, which is the timeframe used to calculate investment returns and take FIDs for electrolyser projects. Policies to underpin demand for low-emission hydrogen can

[81] This could increase to 240 GW (about 95% of the APS needs), if projects at very early stages of development are included, e.g. announcements of co-operation agreements between stakeholders.

be helpful. Some governments have announced plans to adopt quotas and mandates for industrial applications. Yet these commitments represent around 4% of current hydrogen demand in industry and none are legally binding targets. This may be changing soon in the European Union where revisions expected in 2023 to the Renewable Energy Directive are likely to include a binding target for total hydrogen consumption in industry. This revision also contains the target to meet 2.6% of energy demand in transport with renewable fuels of non-biological origin (including hydrogen and synthetic fuels). In the power sector, there are few measures to push demand for low-emission hydrogen other than some targets in Japan, Korea and Portugal and a few policies in Australia, Germany and Spain to facilitate the use of hydrogen in gas turbines.

Targets can provide a long-term signal to stakeholders. They are more potent, however, if in the form of legally binding quotas and mandates that require a minimum level of renewable hydrogen use in strategic sectors. They should have clear timeframes for achievement so that the private sector can prepare the needed projects, unlock investment and arrive at FIDs. Governments should work with the private sector to ensure adequate and timely supply chains for key technologies, such as electrolysers. The joint declaration in May 2022 between the European Commission and electrolyser manufacturers to increase manufacturing capacity tenfold in the European Union, to reach 25 GW of annual production of electrolyser capacity by 2025, is an example of early engagement that outlines the regulatory measures that the European Commission will put in place to support industry.

Public procurement is a powerful tool to promote innovation and demonstration and prompt investment in key end-use hydrogen technologies. Examples include hydrogen use in shipping and for high-temperature heating in industrial processes.

Similarly, the private sector can support increased demand for hydrogen through commitments to use specific volumes or to achieve a certain share of hydrogen in processes and end-uses, and by investing in hydrogen using assets. Initiatives such as the First Movers Coalition are taking action in this area. For instance through purchasing pledges to stimulate markets for clean technologies in areas where hydrogen can support decarbonisation goals and deliver large fossil fuel savings, e.g. steel making, shipping and aviation. (See “Investment and innovation” chapter).

Business-as-usual approaches are unlikely to deliver the hydrogen contribution needed by 2030. Regulatory clarity and policy support are needed to adequately prepare projects and to reach timely FIDs. Limited demand for low-emission hydrogen, lack of infrastructure to deliver to end-users and regulatory uncertainties hinder advances in project developments.

Effective policy frameworks, standards and certification schemes are needed. Initial steps are being taken. The International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) developed a methodology to account for emissions in hydrogen production which is being extended to cover conditioning and transportation aspects, which can serve as a basis for the development of national and international standards. An international standard recognised by institutions such as the International Standards Organization will take years. In the meantime, governments are developing a variety of ad-hoc regulations and certifications which are not necessarily consistent. Although this may not be a big barrier for projects targeting domestic markets, it can slow international trade unless the certifications are aligned or a methodology is put in place for mutually recognising different schemes.

Another aspect that adds uncertainty revolves around proper levels of regulatory requirements for hydrogen production. Establishing excessively strict criteria can hinder deployment and investment. While, on the other hand, too lax requirements can result in an increase of fossil fuel-based electricity generation to power electrolysers and can potentially impact electricity markets and prices, with downsides for GHG emissions and energy security. Authorities need to find the right balance in regulatory regimes to support climate and energy security ambitions. An appropriate balance can help to unlock the investment needed; in the APS investment in low-emission hydrogen needs a 21-fold increase over current levels.

REPowerEU Plan

Europe is facing serious energy security challenges due to its reliance on fossil fuel supply from Russia. As a response, in May 2022, the European Commission presented the REPowerEU Plan to wean Europe from Russian fossil fuels before 2030. The plan includes a series of actions to diversify energy supply, reduce energy demand and accelerate the deployment of clean energy technologies. Full implementation of the plan aims to cut 310 bcm of natural gas imports from Russia by 2030 and includes an investment package of EUR 300 billion.

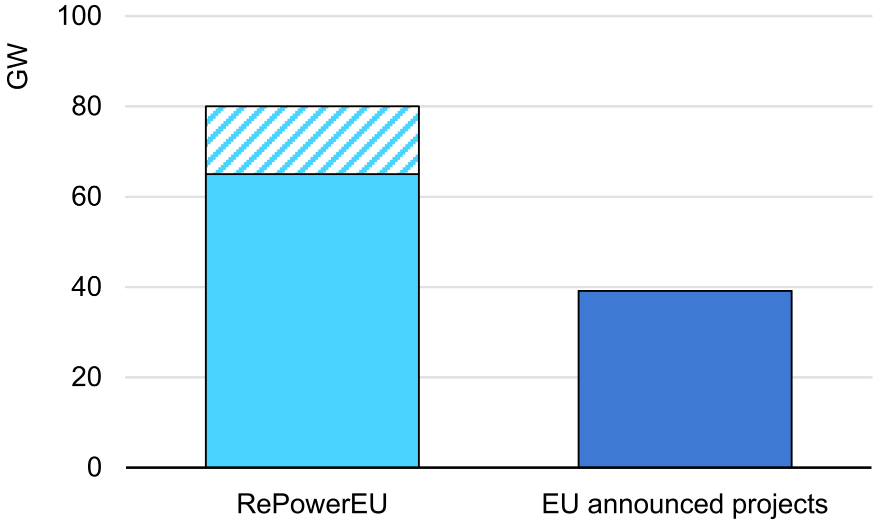
The REPowerEU Plan includes an important hydrogen component. It would significantly increase the ambition of the Fit for 55 package (2021) which had boosted the ambition set out in the 2020 EU Hydrogen Strategy. The Fit for 55 package included around 6 Mt of renewable hydrogen production in the European Union by 2030. The REPowerEU Plan adds a further 4 Mt of renewable hydrogen production in the region up to a new goal of 10 Mt, plus 10 Mt of renewable hydrogen imported by 2030. According to the REPowerEU estimates, this would require direct investment of EUR 84-124 billion in key hydrogen infrastructure in the European Union and would result in savings of 27 bcm of natural gas, 3.9 million tonnes of oil equivalent (Mtoe) and 156 kilotonnes (kt) of coking coal by 2030.

The REPowerEU Plan outlines a series of actions to support the development of hydrogen projects. These include: to double the funding for the EU Innovation Fund call for large-scale projects (to around EUR 3 billion); revision of the EU Emissions Trading System to allow the Innovation Fund to cover 100% of the relevant costs in the case of competitive bidding; and the possibility of allowing the Innovation Fund to support hydrogen uptake by industry through an EU-wide scheme for carbon contracts for differences.

The REPowerEU Plan for regional development of renewable hydrogen, plus ambitious targets for imports, is a clear signal of the European Commission to support further development of hydrogen. This includes trade and the creation of an international low-emission hydrogen market. It is a long-term endeavour that requires near-term action, which need to go hand-in-hand with other short-term objectives such as ramping up renewable energy generation capacity and securing sufficient volumes of LNG imports.

Meeting REPowerEU Plan hydrogen targets requires rapid roll-out of projects

Comparison of the REPowerEU Plan installed electrolysis capacity target with capacity of EU projects in the pipeline, 2030



Notes: EU = European Union. The dashed area represents the difference between the two estimates stated in the REPowerEU action plan working document.

Sources: REPowerEU action plan working document; IEA Hydrogen Projects Database (2022).

The REPowerEU objectives represent an unprecedented level of near-term deployment of hydrogen technologies. It involves the development of full new value chains including renewable electricity generation, electrolyser manufacturing capacity, hydrogen production, transport and storage, and equipment for large-scale hydrogen in end-use. The REPowerEU Plan requires scaling up supply chains to produce and use hydrogen in the European Union as well as development of international supply chains and markets.

EU hydrogen production

According to the REPowerEU action plan working document, producing 10 Mt of renewable hydrogen in the region would require 65-80 GW of electrolyser capacity by 2030. Powering these electrolysers with renewable electricity would require 500 terawatt-hours of additional renewable electricity generation, which is equivalent to about half of the total renewable electricity generated in the European Union in 2021. Installed electrolyser capacity in the European Union today is less than 0.2 GW. If all projects in the pipeline are realised, the installed capacity in the region could reach 39 GW by 2030,[82] which is only about half of the REPowerEU target. The project pipeline is expected to expand over the coming years given the strong push for hydrogen. For comparison, the project pipeline represented just 20 GW by 2030 in the 2021 edition of this annual review.[83] But projects under construction or having reached a

[82] This could increase to 67 GW if projects at very early stages of development are included, e.g. only a co-operation agreement among stakeholders has been announced.

[83] 20 GW including projects at very early stages of development, e.g. only a co-operation agreement among stakeholders has been announced.

FID account for less than 4 GW, which is only about 5% of the REPowerEU objective. Many of these projects will not reach a FID until the enabling conditions are in place to mitigate investment risks. These include: sufficient demand for low-emission hydrogen; clear regulatory frameworks, including safety regulations and market rules; contracting models; certification systems; insurance products; market-based operational support, permitting; and technical guarantees.

The European Commission is starting to take action on some of these fronts. In 2020, the Commission included hydrogen in the Important Projects of Common European Interest (IPCEI) scheme, to provide support for project developers (see "Hydrogen Policies" chapter). On the regulatory front, the European Commission is working on two delegated acts to define the requirements for electricity used to produce hydrogen and its derived fuels and for a methodology to assess GHG emissions savings to contribute to national renewables target. However, there have been delays in the approval of the IPCEIs, (the first batch was approved in July 2022, and a second batch is expected by end-2022), and the delegated acts that have raised concerns among industrial partners claiming that it could put projects under development at risk. Moreover, these delegated acts incorporate strict environmental criteria to ensure that projects developed in the region exclusively use renewable electricity generated that is incremental to existing needs, avoid competition of electrolysers with other direct uses of renewable electricity needed to decarbonise the EU energy system and decrease its reliance on imported fossil fuels. There is a need to accelerate action in the roll-out of renewable generation capacity to ensure that they can meet demand for direct electrification plus the additional demand for renewable hydrogen production. Streamlining regulatory requirements, such as licensing and permitting, can significantly accelerate deployment. The European Commission proposed recommendations to speed up permitting and power purchase agreements in May 2022, but they have not been implemented yet.

Securing off-takers for renewable hydrogen is fundamental to the development of new hydrogen production and transport assets. Implementing policies to stimulate demand in applications that are hydrogen-ready can deliver fossil fuel savings in the near term and should be a priority to support the REPowerEU objectives. The targets for renewable hydrogen use in the industrial sector and the proposed modification of the Renewable Energy Directive to include a target for the use of renewable fuels of non-biological origin (including hydrogen and synthetic fuels) in transport can help to unlock significant demand in the near term, if adopted and implemented expeditiously.

An effective and clear regulatory framework and measures to stimulate demand can prompt investment in low-emission hydrogen production assets. But it may be insufficient on its own to ramp up deployment at the level and speed needed to satisfy the objectives of the REPowerEU Plan. Application of approaches such as the IPCEI to approve shovel-ready flagship projects can fast-track FIDs for large projects able to significantly scale up low-emission hydrogen production.

All the conditions need to be in place for FIDs by 2024 at the latest if the projects are to be online by the 2030 targets. Many projects may require a development pathway that minimises risks, likely by stepwise expansions to 1 GW, starting with around 100 MW. In such cases, the first stages may need to start construction within the next two years.

Hydrogen imports

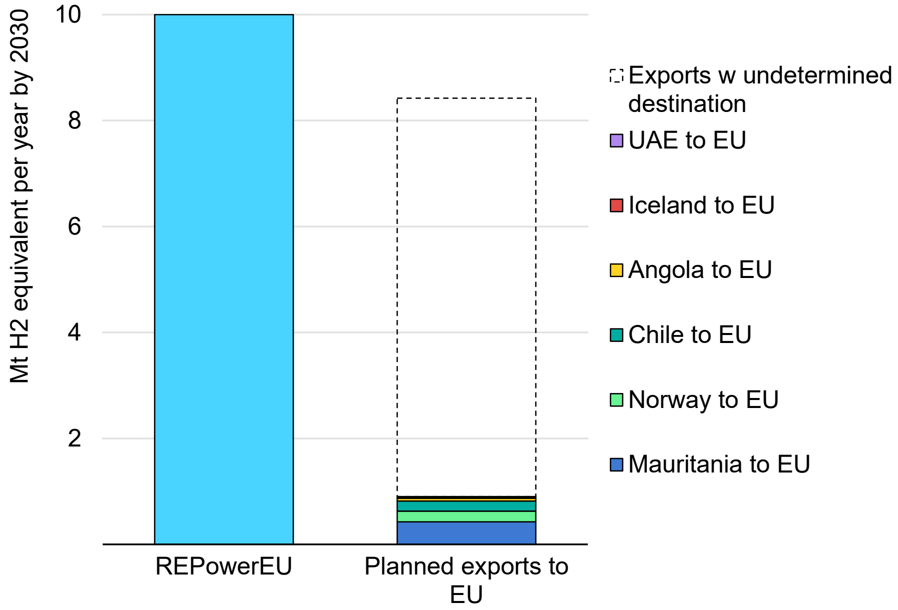
The target to produce 10 Mt of renewable hydrogen in the European Union is ambitious but ultimately depends on action within the region; the target to import 10 Mt of hydrogen by 2030 requires significant action and investment beyond the EU borders. The import target is for 6 Mt of renewable hydrogen and 4 Mt of hydrogen in the form of ammonia or other derivatives. The European Commission is planning to support the development of three major hydrogen import corridors via the Mediterranean from North Africa, from non-EU regions of the North Sea and, as soon as conditions allow, from Ukraine.

Hydrogen export-oriented projects currently under development worldwide represent about 12 Mt H_2/year of planned exports by 2030, of which 0.9 Mt H_2/year is designated for export to the European Union.[84] This includes export projects that either have an agreed off-taker in the European Union, have a potential EU off-taker in the project consortium, or have stated plans to export to the European Union. Roughly half of the planned 0.9 Mt H_2/year is to be exported from Mauritania, with significant contributions also from Chile and Norway, and smaller volumes from the United Arab Emirates and Angola. This signals a relatively diverse set of exporting countries, which could expand with imports from the broader set of nations currently developing export-oriented hydrogen projects. Diversification of supply can enhance energy security but also pose a challenge to build the scale of market needed to deliver cost reductions. If all the planned projects are realised and the hydrogen delivered, it would account for 9% of the REPowerEU import target, leaving a significant gap to the 10 Mt target.

An intended destination has not been designated for 7.5 Mt H_2/year of the total planned exports by 2030. This provides an opportunity for the European Union to secure additional off-takes from the project pipeline, though if may have to compete with other potential large importers, such as Japan and Korea. Moreover, most of the planned projects are at an early stage of development, which adds uncertainty to how much of the volumes could be effectively traded by 2030.

[84] These projects include a mix of ammonia, synthetic hydrocarbon fuels and undetermined carriers.

Comparison of REPowerEU hydrogen import target with planned hydrogen exports to the European Union, 2030



Note: EU = European Union; UAE = United Arab Emirates.

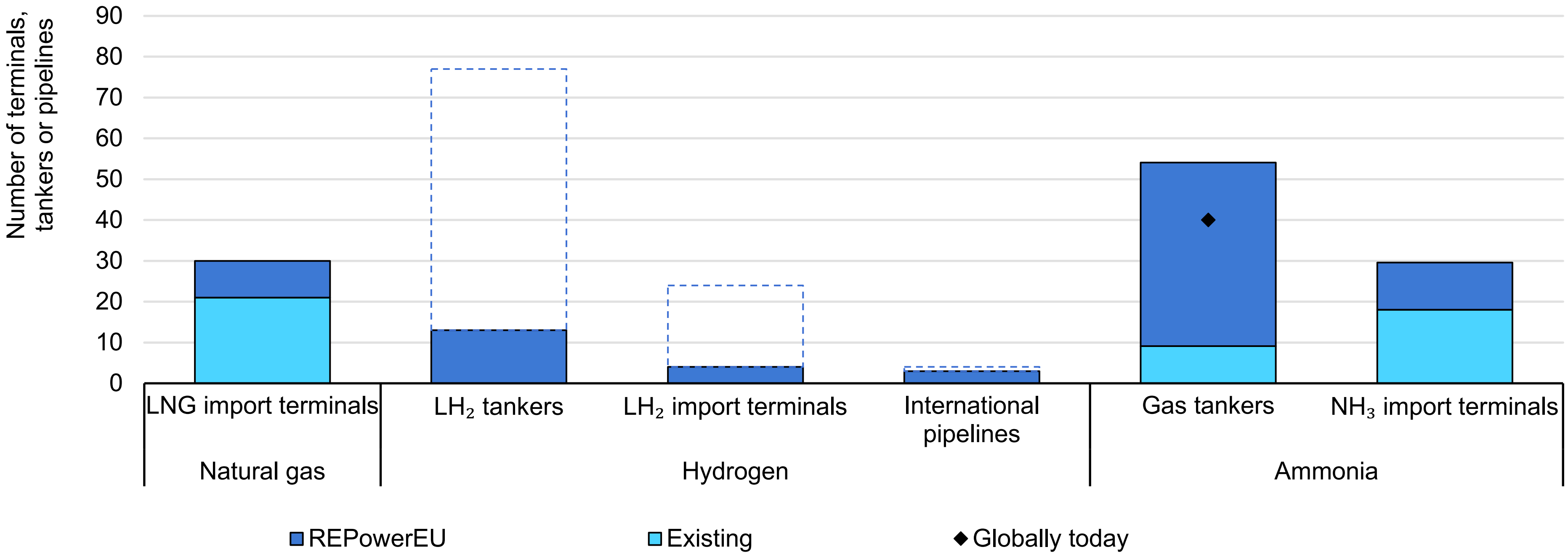
There are also high-level agreements not yet associated with specific hydrogen export projects that could deliver hydrogen to the European Union. For instance, Australian clean energy developer Fortescue Future Industries (FFI) has signed a Memorandum of Understanding (MoU) with European utility E.ON to deliver up to 5 Mt H_2/year by 2030. Similarly, FFI signed an MoU with Covestro, a German materials manufacturer, to deliver 0.1 Mt H_2/year starting from 2024 to several of its operations, including in Europe. These off-take volumes are contingent on the completion of FFI's existing and yet-to-be announced export projects.

Establishing large volumes of hydrogen imports to the European Union requires enabling measures to be in place. In particular, effective regulatory frameworks, standards and certification systems will be critical to properly govern international hydrogen markets and to ensure that imports align with EU climate ambitions and energy security imperatives. (See "Hydrogen trade" chapter).

Regulations could also render certain configurations of low-emission hydrogen production ineligible for import under the clean energy policy support mechanisms. It is important to strike an appropriate regulatory balance to ensure adequate scale and regional diversity of available hydrogen exports while respecting environmental or other criteria. Effective dialogue with potential hydrogen producers and exporters can help to facilitate imports to the European Union. The regulatory regime for hydrog en production within the European Union needs to address issues that are relevant in the region, such as additionality and temporal correlation criteria, but these may not be relevant for potential sources of hydrogen imports. Less stringent criteria in the near term to not overburden first movers in the early phase can help nurture and then mature the market with the criteria adapted as needed as experience is gained. Providing clear signals to project developers in the near term about the EU regulatory regime is pivotal to advance opportunities for hydrogen imports. Without certainty that a particular export project will be eligible under EU low-emission hydrogen rules, it will be difficult for developers to reach a FID and to finalise off-take agreements.

REPowerEU import targets require accelerating development of the first offshore hydrogen pipelines and liquid hydrogen terminals, as well as more tankers and terminals for ammonia trade

Trade-related infrastructure requirements in the European Union to meet the REPowerEU hydrogen and ammonia import targets



Notes: LH_2 = liquefied hydrogen; LNG = liquefied natural gas; NH_3 = ammonia. In the hydrogen infrastructure columns, the dotted lines represent cases in which 6 million tonnes per year (Mtpa) hydrogen is imported either as compressed via pipeline or liquefied by ship. The solid blue indicates a hybrid configuration in which 5 Mtpa hydrogen is imported via offshore and onshore pipelines (48-inch, ~1.9 Mtpa hydrogen per pipeline) and 1 Mtpa hydrogen is imported in liquefied form. The number of liquid hydrogen and ammonia gas tankers is estimated considering shipments to northwest Europe from the Middle East (50%), Chile (25%) and Australia (25%). The number of LNG import terminals is estimated based on the REPowerEU Plan 45.6 bcm/year target of imports via new LNG infrastructure. New LNG terminals are assumed to have a capacity of 5 bcm/year, which is the average capacity of LNG terminals under construction or planned in the European Union.

EU import targets require development of interregional hydrogen corridors this decade

Interregional and intra-EU hydrogen pipeline corridors

The REPowerEU Plan targets imports of 10 Mtpa of renewable hydrogen and considers establishing three major import corridors in the Mediterranean, North Sea area and Ukraine (if conditions allow) for importing around 6 Mtpa. The European Commission will analyse infrastructure needs in 2023. A large 48-inch pipeline (12.5 GW) operating at 75% of design capacity for 5 000 hours could transport close to 2 million tonnes per year (Mtpa) hydrogen, so the 6 Mtpa import target could be achieved with four large hydrogen pipelines. The Mediterranean and North Sea corridors would require development of offshore pipelines. There are no offshore hydrogen pipelines anywhere in the world, but industrial stakeholders are confident that offshore hydrogen pipelines could be designed following similar requirements in the ASME B31.12 for onshore hydrogen pipelines, with minor technical challenges.

Mediterranean hydrogen corridor. The European Commission is exploring the possibility of importing hydrogen from Algeria, Tunisia and Morocco. Algeria is connected via offshore natural gas pipelines directly to Spain, and through Tunisia and Morocco to Italy and Spain, respectively. The Trans-Mediterranean (Transmed) pipeline between Tunisia and Italy (via Sicily) has had some spare capacity in recent years, but reduced natural gas flows from Russia has increased utilisation of the Transmed pipeline and no spare capacity is expected in the short term. Snam is exploring the possibility of repurposing some of the pipelines from Tunisia to Sicily. Industrial stakeholders have not identified any technical show-stoppers at this point, but they have highlighted the need for further testing, especially with regard to flow variability and pressure optimisation, to ensure pipeline integrity. The Maghreb-Europe pipeline connecting Morocco and Spain has not transported natural gas from Algeria since third-quarter 2021, although since June 2022 it is operating in reverse flow transporting small quantities of natural gas from Spain to Morocco. Enagás is studying the feasibility of repurposing the existing natural gas transmission pipeline from Morocco to Spain to transport hydrogen, including its 45 kilometre (km) offshore section. Co-operation between the Spanish and Moroccan gas operators will be key, as each country only has jurisdiction over the part of the pipeline that crosses its territory.

The possibility of importing hydrogen from North Africa to the European Union by 2030 faces important barriers, including the development of production capacity in a region where current renewable electricity generation capacity is scarce coupled with the need to transport the hydrogen to high demand centres in northern Europe. A pipeline from North Africa would come ashore in southern Europe, far from current high demand centres, and in regions where local demand could be met with hydrogen produced with the available local renewable energy resources. Accessing the large demand centres in northern Europe would require development of additional hydrogen transmission infrastructure, including large corridors within the European Union. According to industry stakeholders, these projects can be particularly costly if new dedicated hydrogen pipelines are to be built, can have long lead times, including permitting, and potentially can face issues of public acceptance.

The REPowerEU Plan states that if new natural gas infrastructure is developed, it should be built as hydrogen compatible. The European Commission will assess if hydrogen-ready gas infrastructure, including interconnections, is needed to reduce remaining bottlenecks that prevent utilisation of the existing LNG capacity. More specifically, Spain has six operational LNG import terminals representing almost 45% of the LNG storage capacity of the European Union and some are largely underutilised. Making use of existing infrastructure could minimise the need for construction of new LNG terminals in northern Europe, whose repurposing is challenging. However, the lack of sufficient gas transmission infrastructure between Spain and France prevents their utilisation to supply northern Europe. In this context, Enagás announced plans to invest in new pipelines to connect Spain with France and Portugal, to be built as hydrogen-ready with initial transport of natural gas. This infrastructure could be use in the future to transport hydrogen from North Africa to the high demand centres in northern Europe. This infrastructure is likely to become operational towards the end of this decade while the repurposing plans are expected after 2030. This implies that use of existing infrastructure could minimise some investment needs for LNG import terminals, but it is highly unlikely that it could contribute to enable hydrogen trade by 2030 as targeted in the REPowerEU Plan.

North Sea hydrogen corridor. The development of a North Sea hydrogen corridor has been considered in the European Hydrogen Backbone project, which counts Gassco, the Norwegian natural gas transmission system operator, among its proponents. The most recent update on the project considers the possibility of connecting different regions of Norway via offshore hydrogen pipelines to the Dogger Bank and from there to Germany, Denmark and other EU countries. In addition, in March 2022, the Norwegian and German governments published a joint declaration to explore the feasibility of an offshore hydrogen pipeline between the two countries.

Hydrogen corridor from Ukraine. The European Union is working on a strategic partnership with Ukraine on renewable gases, including hydrogen. For example, the Central European Hydrogen Corridor initiative aims to send hydrogen from Ukraine to Germany via dedicated pipelines through Slovakia and the Czech Republic. Gas transmission system operators in all four countries are involved in the initiative. There is much uncertainty about realisation of this corridor due to the consequences of the Russian invasion of Ukraine.

Potential to repurpose offshore natural gas pipelines. In energy terms, a repurposed hydrogen pipeline could transport around 80-90% of the energy compared to natural gas. Although the energy density of hydrogen is only around one-third of natural gas, its much lower volumetric density results in almost three-times larger volumetric flows compared with natural gas for the same pressure drop along a pipeline. However, pipelines may operate at lower design capacity when repurposed for hydrogen. In particular for offshore pipelines, which typically operate at around 200 bar for natural gas, experts have identified some uncertainties about the optimal pressure range for hydrogen that would reduce embrittlement and fatigue. The Transmed connection between Tunisia and Sicily has a technical capacity of 1 138 gigawatt-hours per day (GWh/d) of natural gas, while the Maghreb connection between Morocco and Spain can transport 443 GWh/d. If half of the capacity of the Transmed connection is repurposed to hydrogen, equivalent to repurposing just one of the parallel pipelines, with a throughput capacity equivalent to 25-75% design capacity operational range, it could transport around 0.7-4.3 Mtpa of hydrogen at 5 000 full load hours. The Maghreb pipeline with a 25-75% design capacity operational range could transport around 0.6-1.7 Mtpa of hydrogen. If successfully deployed, they could contribute substantially to the REPowerEU import target.

Accelerating demonstration of a liquefied hydrogen supply chain

Given potential limitations to develop the North Sea and Mediterranean hydrogen corridors by 2030, and that a Ukraine corridor is uncertain in the near term, the European Union could consider imports as liquefied hydrogen (LH_2) by ship to meet part of the REPowerEU target. This approach is not yet proven on a commercial scale; it represents technical challenges due to the low boiling point of hydrogen (-253 °C) and involves high energy losses. There is only one liquefied hydrogen demonstration project for transport from Australia to Japan. It is the first pilot-scale liquefied hydrogen ship and was built by Kawasaki Heavy Industry. Liquefied hydrogen trade still requires technology development, though some companies are exploring the possibility of an intra-European project to ship liquefied hydrogen between Portugal and the Netherlands by 2027. Importing 1 Mtpa of liquefied hydrogen to the European Union would require about four 250 kilotonnes per year (ktpa) capacity import terminals. This is similar in size to the planned capacity of some export terminals in Australia.

Shipping 1 Mtpa of liquefied hydrogen would require 13 tankers with a capacity of 160 000 m^3, which is the expected size of a Kawasaki Heavy Industry commercial LH_2 ship by 2030. While several companies are working on the design of commercial LH_2 tankers, no shipyards today are ready to build them (see “Infrastructure”, and “Investment and innovation” chapters).

Establishing international trade of liquefied hydrogen to supply the European Union will also require the development of export infrastructure beyond the EU borders. While some hydrogen exports may benefit from existing port infrastructure for LNG trade, imports of electrolytic hydrogen will come from areas with good renewable energy potential and not necessarily with already well-developed port infrastructure. While the possibility of access to a nearby deep-water port would facilitate project implementation, investments should factor deep-water port infrastructure needs.

The development of liquid hydrogen export infrastructure is challenging. Although hydrogen liquefaction and liquefied hydrogen storage are considered established technologies, efficiency improvements and cost reductions are expected to scale up the technology. The largest hydrogen liquefaction plant in operation today has a capacity of 12 ktpa (34 tpd), while the capacity of export terminals is expected to be at least around 250 ktpa. This would require a significant push for infrastructure deployment, but efforts to develop liquefied hydrogen supply chains at this scale could also trigger technology and efficiency improvements as well as cost reductions.

EU import targets require a boost in demand for ammonia and related trade infrastructure

Global ammonia trade, mainly for fertiliser, was around 20 Mt in 2020, of which 4 Mt was imported to the European Union. The REPowerEU target of importing 4 Mtpa hydrogen in the form of ammonia would be equivalent to importing 22.5 Mt ammonia by 2030. This is more than five-times higher than current EU import levels, more than total global ammonia trade, and would require considerable scaling up of the related infrastructure. Today the European Union counts 18 ammonia import terminals; some could likely increase annual import capacity with minimal investment by receiving cargos more frequently. For example, the ammonia import facility at the Port of Rotterdam is tripling its capacity from 0.4 Mtpa to 1.2 Mtpa with an investment of EUR 20 million. Yet, a five-fold increase in imports at EU level would probably require an expansion of the import infrastructure, including the construction of new jetties for very large ammonia gas tankers[85] and new ammonia storage tanks. Assuming that existing infrastructure could accommodate twice the capacity of current ammonia imports with minor adjustments, new infrastructure would need to be built for about 14 Mtpa of ammonia, requiring around 12 new import terminals of the size of the planned expansion of the facility at the Port of Rotterdam. Importing 4 Mtpa of hydrogen as ammonia would require both the expansion of the existing ammonia import infrastructure and a two-thirds increase of existing import terminals by 2030. Planning must advance quickly to reach the intended deployment by 2030. The construction time for large ammonia storage tanks is approximately 30 months. New import terminals would also have to find available space in often congested ports, not least because ammonia handling requires strict technical safeguards, including distance considerations for safety.

The number of LNG import terminals is set to increase in the European Union in this decade as a means to decrease natural gas imports from Russia. Climate commitments imply that natural gas demand needs to decline by 2030 which could render this new infrastructure available for repurposing for ammonia imports. While this does not minimise infrastructure needs within this decade, it could, if properly designed for repurposing from the onset, minimise needs beyond 2030.

Importing 4 Mtpa hydrogen in the form of ammonia, i.e. 22 Mtpa of ammonia, would also more than double the current infrastructure for global ammonia shipping by 2030. The REPowerEU import target would require more than 55 very large gas tankers (>80 000 m^3) dedicated year-round to ammonia shipping by 2030. Today there are

[85] Very large ammonia tankers are also called very large gas carriers. In this report, the term tanker is used to refer to a ship transporting ammonia gas.

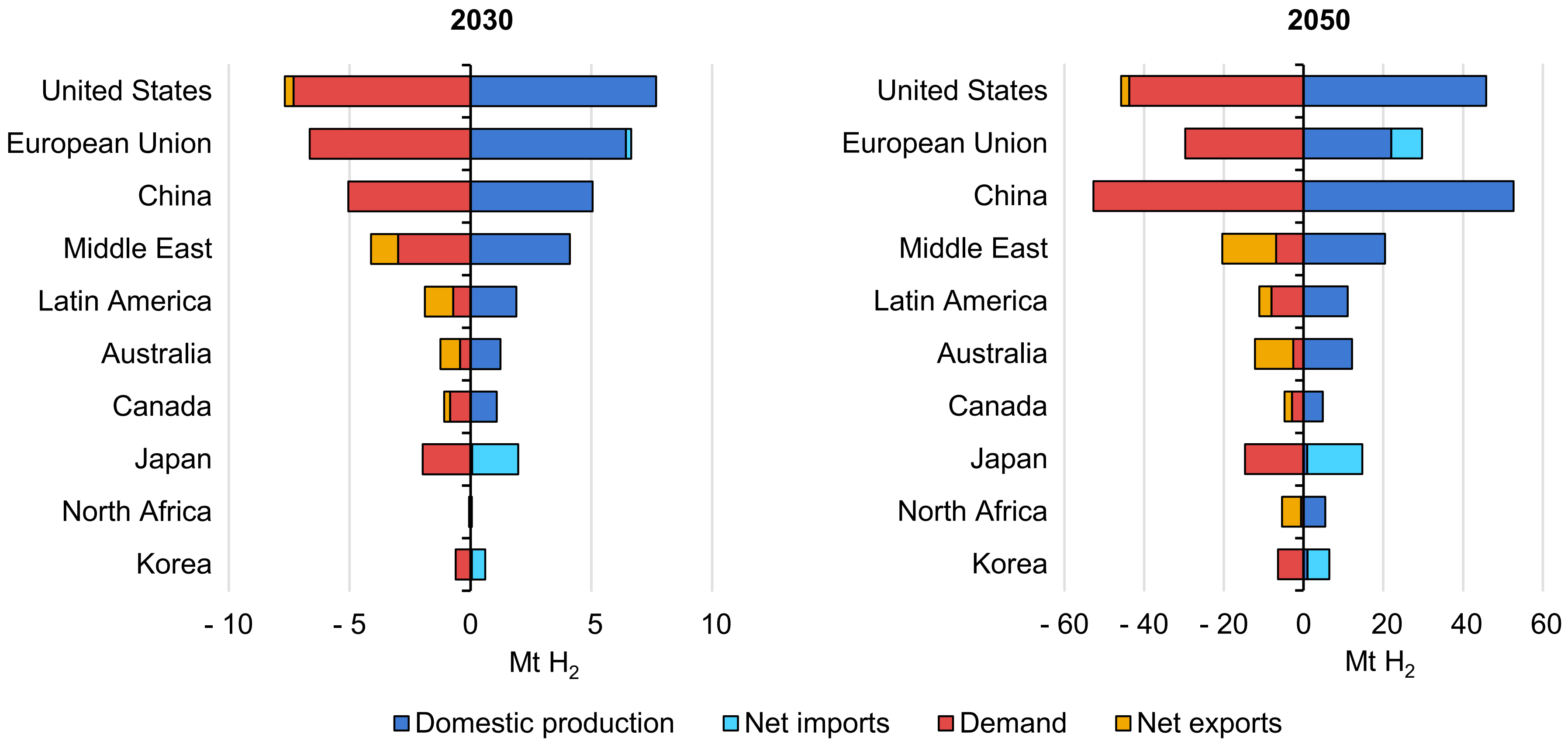
about 40 gas tankers carrying ammonia cargo at any point in time around the world. Approximately 45 new ammonia tankers would be needed, equivalent to almost 4 million m^3, which would correspond to the total capacity additions of gas tankers in 2020 and 2021. Such a large growth in ammonia trade would also require the availability of the tankers to transport ammonia from an exporting country to the European Union throughout the year. Other users such as the expanding petrochemical industry in Asia will compete for new tankers. In addition, there is limited capacity to increase the production of tankers. There are only a few shipyards that build them in Korea, Japan and China. Korea accounts for more than 70% of liquefied petroleum gas tanker orders in 2021, and lead times are 30-50 months. Meeting the ammonia import goal of the REPowerEU Plan calls for doubling existing amount of worldwide infrastructure for ammonia exports. This would involve a significant scaling up of infrastructure at or near ports for large ammonia storage tanks, which require strict safety considerations.

In addition to infrastructure development requirements, there is a need to identify the potential uses for the ammonia imports in the European Union. Imported low-emission ammonia can replace current fossil fuel-based imports. EU ammonia imports were 4 Mt in 2020, with additional 6 Mt of urea imported. This would be equivalent to about 7 Mt of ammonia, around one-third of the REPowerEU target. Additional demand would be needed for the remaining two-thirds (around 15 Mtpa). The easiest alternative could be to replace some of the current EU production, which is about 16-17 Mtpa. However, this would result in a decrease of industrial activity in the region and the consequent loss of jobs, which will go against one of the main drivers behind the political interest of hydrogen in the European Union: using it as an opportunity to maintain and boost industrial activity in the region. Moreover, the REPowerEU working document also includes the use of renewable hydrogen in EU ammonia production. An alternative is to boost demand in new applications, such as co-firing in coal power plants or as a fuel in shipping. Although co-firing of ammonia in coal plants has not been discussed in the European Union, as it has been in Southeast Asia, it could help to maintain the generation assets to replace the flexibility services that natural gas provides today. However, it will delay the coal phase-out commitments of several EU member states. To use ammonia in shipping, the challenge is to accelerate demonstration of the technology to reach commercialisation and to generate significant demand from a novel application over just seven/eight years. If there is insufficient demand for the direct use of ammonia, some imports would have to be reconverted to hydrogen using ammonia crackers. Large-scale ammonia crackers are not yet commercially available, so its development process would need to be accelerated.

Opportunities and challenges to repurpose infrastructure for hydrogen use

Opportunities to repurpose natural gas infrastructure to facilitate hydrogen trade

Domestic production, imports and exports for low-emission hydrogen in selected regions in the Announced Pledges Scenario, 2030 and 2050



Note: Hydrogen includes the hydrogen requirements to produce hydrogen-derived fuels, i.e. ammonia and synthetic hydrocarbon fuels.

The transition to a clean energy system will increase demand for low-emissions hydrogen. Some countries may be able to cover low-emission hydrogen needs with domestic production, while others may import from countries with more favourable conditions to produce hydrogen from renewables or from fossil fuels in combination with CCUS. International trade is generally expected to emerge as one component of the hydrogen supply chain. In the APS, 3% of global demand for hydrogen and hydrogen-derived fuels is covered through international trade by 2030. By 2050, the share of traded hydrogen increases to 12%; taking into account only merchant hydrogen demand, trade represents even more than 20% of global merchant demand in the APS. Europe and some Asian countries, such as Japan and Korea, are likely importers of hydrogen, while other countries and regions, such as the Middle East, Australia, North Africa, North America and Latin America, become exporters.

Building the necessary infrastructure for hydrogen trade, such as pipelines, import and export terminals at ports and ships, are fundamental to develop international hydrogen markets. Repurposing existing fossil fuel infrastructure could accelerate development and reduce investment needs.

In an effort to reduce their reliance on natural gas imports from Russia, several European countries are planning alternative natural gas import options, such as new LNG import terminals or pipelines. While new infrastructure can help to diversify natural gas supplies in the short term, the long lifetimes of such facilities bear risks of becoming locked-in infrastructure that make it harder to move to hydrogen later.

Hence, it is important to examine the extent to which new gas infrastructure can support the transition to low-emission fuels later. While the Infrastructure and innovation chapter provides a discussion focussed on the technical aspects of repurposing natural gas infrastructure for hydrogen, this section summarises the key opportunities, challenges and cost impacts for repurposing natural gas pipelines and LNG import terminals for hydrogen.

Repurposing natural gas pipelines

The transition to a net zero emissions energy system will substantially reduce natural gas demand. This bears risks that parts of existing natural gas pipeline systems may become stranded assets in the future. Being able to reuse part of the existing infrastructure for low-emission gaseous fuels could reduce such risks, while at the same time accelerating the market uptake of hydrogen and avoiding the need to build an entire transport infrastructure from scratch. Synthetic methane produced from hydrogen and CO_2 has similar properties as natural gas and can be used in pipelines, often without any modifications. The direct use of hydrogen in gas pipelines, however, requires some adaption measures.

Blending hydrogen into natural gas pipelines can be a first step to integrate hydrogen with minimal modifications needed up to blending shares of around 20% by volume (6% in energy terms), depending on material composition of existing pipelines. But, the amount of natural gas that can be replaced by hydrogen is limited by the allowable blending shares, which depend on the characteristics of the pipeline and end-use equipment. For example, a blending share of 20% in volumetric terms results in natural gas savings and CO_2 reductions of 6% as the volumetric energy density of hydrogen is one-third the one of natural gas. Hydrogen blending can be a first step while developing infrastructure for dedicated hydrogen transport. Besides the gas pipelines, special attention needs to be given to the technical capabilities of existing end-use equipment for its adaptability to use gas with hydrogen blends. For the longer term, the capability of new equipment to be ready to operate on pure hydrogen or to be easily upgraded should be considered.

Full conversion of natural gas pipelines to hydrogen.[86] The technical feasibility of repurposing a natural gas pipeline from natural gas to hydrogen will depend on the material composition of the pipeline and its operational characteristics. In the case of carbon steel pipelines, certain material requirements must be met, such as avoiding high-strength steel to reduce the risks of hydrogen embrittlement, a process that causes cracks in the steel. In addition, new gas compressors are needed. To operate a repurposed pipeline at its full design capacity (about 80-90% of the energy throughput compared to natural gas), volumetric flows of hydrogen need to be three-times higher, due to the lower volumetric density of hydrogen compared to natural gas, resulting in the need for more powerful and expensive compressors. When operating a repurposed pipeline at a lower utilisation rate, however, smaller compressors are sufficient, which reduces the investment needs and the electricity demand for

[86] See the hydrogen transport by pipeline section in the Infrastructure chapter for more information.

compression. Repurposing a natural gas pipeline to hydrogen can result in cost savings of 50-80% (depending on the pipeline diameter and the utilisation rate) compared to building a new hydrogen pipeline.

The 2022 revised regulation for Trans-European Networks for Energy (TEN-E) of the European Union stresses the need for hydrogen infrastructure and recommends in this context to consider repurposing of existing natural gas pipelines, including in a transition period to use pipelines with hydrogen blends, before repurposing to pure hydrogen. (The previous TEN-E regulation from 2013 did not mention hydrogen at all.)

Besides repurposing existing natural gas pipelines for hydrogen, gas pipelines can also be repurposed to transport CO_2 from capture plants to sites storage or use. Integrating planning processes taking a system-wide view are needed to assess the potential alternative options for parts of pipeline infrastructure.

New hydrogen pipelines. While repurposing is often the cheapest option, in some cases, it will be necessary to build new pipelines to transport hydrogen. This is because in some cases the existing natural gas pipeline continues to serve consumers or there is not an existing pipeline between planned hydrogen production and demand locations. Nonetheless, there can be time and cost savings if new hydrogen pipelines parallel established gas pipeline routes which can forego some development steps. For instance, right-of-way permits may already exist and land may already be owned. Lead times for planning and permitting, which can take several years, might be shortened by using an existing pipeline route.

Repurposing LNG import terminals

As a reaction to the Russian invasion of the Ukraine and dwindling Russian natural gas supplies to Europe, several European countries are working on alternative gas import options in the form of LNG. A number of LNG import terminals are being planned to establish new gas import capacity, including floating storage regasification units. In the longer term, LNG terminals potentially could be repurposed for importing low-emission hydrogen or hydrogen-derived fuels to support the decarbonisation of gaseous fuels and the energy system in general. The cost of such repurposing, however, will strongly depend on the hydrogen carrier, i.e. liquefied hydrogen, ammonia or synthetic methane.[87]

In 2021, global capacity of LNG import terminals was 861 Mtpa. In addition, 73 Mtpa of LNG capacity is under construction[88]. Europe has LNG import capacity of 187 Mtpa, and capacity of 13 Mtpa is under construction. When including announced projects, regasification capacity in Europe could increase up to 70 Mtpa by the end of the decade, almost half at terminals in Germany. To give a sense of scale on the principal import potential from repurposing LNG terminals, if all LNG projects announced and under construction in Europe with a capacity of 70 Mtpa (3 500 petajoules [PJ]) would be converted to ammonia, this would yield import capacity of 70 Mt NH_3 (1 300 PJ), equivalent to 12 Mtpa H_2. for liquefied hydrogen this would yield a theoretical import capacity of 12 Mtpa H_2 (1 400 PJ).

Importing liquefied biomethane or synthetic methane. No significant modifications would be needed to use existing LNG terminals to import liquefied biomethane or synthetic methane. For biomethane, which is often produced in a decentralised manner, changes in production or transport logistics may be needed to create the necessary scale of export volumes that would justify the operation of liquefaction terminals and ships. Converting hydrogen into synthetic methane creates a gas fully compatible with the existing natural gas infrastructure. In addition to hydrogen, the methane synthesis also requires CO_2 as an input, which has to be captured either at bioenergy conversion plants, e.g. biofuel production, or directly from the air for it to be a low-emission gas. Depending on the CO_2 source, the production costs of synthetic methane can be 70-160% higher than the costs of the used hydrogen input.

Using imported LNG to produce hydrogen from natural gas with CCUS could reduce the CO_2 emissions from natural gas use and provide climate benefits, but, absent additional measures, would not

[87] Liquid organic hydrogen carriers (LOHCs) can be another option for importing hydrogen. Since its physical characteristics and handling are very similar to oil products, repurposing LNG infrastructure for LOHCs seems less likely. Instead, existing infrastructure for oil products could be repurposed.

[88] It includes projects with a disclosed start year of operation

provide energy security benefits. The feasibility of this option also depends on the availability of CO_2 storage. Plus, CO_2 transport infrastructure is needed to link the CO_2 capture with the storage site. Existing large-scale gas consumers in power generation or industry, if retrofitted with CO_2 capture, could also benefit from a shared CO_2 transport and storage infrastructure.

Repurposing import LNG terminal for liquefied hydrogen. Due to the lower temperature and density of liquefied hydrogen (LH_2) compared to LNG, repurposing an existing LNG terminal is generally considered technically challenging; to date, none have been converted and the feasibility and related costs are uncertain. Some indicative numbers can be derived by looking at the key components of an LNG terminal. The LNG storage tank accounts for about half of the costs of an LNG terminal. Keeping the original insulation of the LNG storage tank would result in boil-off rates of around 5% per day for LH_2 due to its lower temperature and heat of vapourisation; LNG tanks are typically designed to limit boil-off to 0.05% per day. It is not necessary to completely avoid boil-off, since the boiled off hydrogen could be fed into a gas grid or used in fuel cells to supply local electricity needs, but some retrofit measures for the LNG storage tank would have to be taken to avoid excessive boil-off rates. One option is to use vacuum insulation, which largely requires replacement of the existing tank from the LNG terminal; only the structural work and foundation of the LNG storage could be reused. A new liquefied hydrogen storage tank could be around 50% more expensive than an LNG one with the same volume, though such cost assessments suffer from limited practical experience with large liquefied hydrogen storage tanks so far and uncertainty about the potential for future cost reductions. The energy stored would be around 60% less due to the lower volumetric density of liquefied hydrogen compared to LNG. An alternative option is to add a membrane insulation system inside the existing LNG tank, which allows reuse of the LNG storage tank. This option is expected to be cheaper than the vacuum insulation technique, but also to result in higher boil-off rates due to the weaker insulation.

Insulation of the pipes needs would need to be changed to minimise and contain any hydrogen leakage. If liquid hydrogen is released, the surrounding oxygen in the air may condense, which would create a fire risk. Replacing the tank and the insulation of pipes alone would result in repurposing costs corresponding to around 50% of the costs of building a new LNG terminal. Except for the HESC demonstration project with liquefied hydrogen exports from Australia to Japan, there is no experience on the costs of building a new liquefied hydrogen terminal. Hence it is not possible to compare repurposing costs with those of building a new liquefied hydrogen terminal.

Given the different safety requirements of liquefied hydrogen compared to LNG, a repurposed terminal would be subjected to permitting processes.

Designing a new liquefied hydrogen import terminal for initial LNG use. A new liquefied hydrogen terminal could be designed in such a way as to allow its initial use for LNG. Part of the equipment, such as the tank and pipe insulation would be over-designed for LNG use, due to the higher temperature of LNG, but should create no major problems. Other components, such as pumps, would require specific design and configuration in order to be compatible with the density difference of the two fluids.

The size of the terminal has to be comparable to LNG terminals, with storage capacity on the order of 100 000-200 000 m^3, in order to handle typical LNG tankers. Such large tanks for liquefied hydrogen do not exist today. The largest one currently in operation has a capacity of 3 200 m^3 at the NASA launch site in the United States, where a larger tank with a volume of 4 700 m^3 is currently being commissioned.

When used for liquefied hydrogen, the capacity of such a terminal would be 60% lower compared with its use for LNG, due to the lower volumetric energy density of liquefied hydrogen. This may not necessarily be a disadvantage, since the smaller size may fit better with lower hydrogen demand in the transitionary period of scaling up hydrogen use.

Repurposing LNG terminal to ammonia. The boiling temperature of ammonia is -33 °C above that of LNG (-163 °C), so it can be more easily handled than LNG. Experience in shipping and handling ammonia at ports has been in practice for decades related to the fertiliser industry. Some modifications, such as replacement of pumps or adjustments to the boil-off gas system, are needed to convert an LNG terminal to ammonia, but they are less challenging than repurposing for liquefied hydrogen. Due to the higher density of ammonia compared to LNG, only around 60% of the tank volume can be used for ammonia without structural reinforcement.[89] It has been estimated that repurposing costs to ammonia are around 11-20% of the investment costs of a new LNG terminal, with a new LNG terminal costing USD 350-1 000 million depending on its size. In addition, if imported ammonia cannot be directly used, for instance in the fertiliser industry, fuel for ships or in power plants, an ammonia cracker is needed to convert the ammonia into hydrogen. Large-scale ammonia crackers are not commercially available today. The cracking process requires energy corresponding to around 30% of the energy content of the ammonia.

Designing a new LNG import terminal to be ammonia-ready. It is possible to take into account future use for ammonia when designing a new LNG terminal, e.g. heavier weight of ammonia compared with LNG for the storage tank. Still, some components such as pumps need to be replaced when switching from LNG to ammonia. Overall, the additional costs of an ammonia-ready design are estimated to be around 7-12% of the investment costs of a new LNG terminal. A large part of these additional costs occurs upfront when the terminal is

[89] In energy terms, the repurposed storage tank can store ammonia at only 40% of the energy value compared to LNG.

being built. The advantages of designing new LNG terminals to be ammonia-ready are uncertain due to questions that revolve around the need to expand LNG import capacity in Europe, future hydrogen demand levels and how much of that could be useful in the form of ammonia. These uncertainties create investment risks and limit the inclusion of ammonia-ready design for new LNG terminals.

Natural gas infrastructure can be repurposed for hydrogen and ammonia

Options to repurpose natural gas pipelines and LNG import terminals for hydrogen and ammonia

Infrastructure	Option	Advantages	Disadvantages	Cost impacts
Gas pipelines	Blend hydrogen into a natural gas pipeline.	• Few modifications needed for blending shares up to 20%.	• Limited CO_2 reductions or natural gas savings (depending on blending share).	• USD 0.3-0.4/kg H_2 for injection station.
	Full repurposing of natural gas pipeline to hydrogen.	• Lower costs than new pipelines.	• Technical feasibility depends on pipeline material. • Compressors need to be replaced. • Limited experience so far (only one pipeline repurposed).	• 50-80% savings compared to new hydrogen pipeline.
	Build new hydrogen pipeline.	• Optimal material choice and design for hydrogen.	• Higher costs than repurposing.	• 2-5-times the cost of repurposing a gas pipeline to hydrogen..
LNG import terminals	Import of liquefied biomethane or synthetic methane.	• No modifications needed.	• Availability of biomethane at large scale. • High costs of synthetic methane.	• No additional costs for import terminal.
	Use LNG imports for hydrogen production with CCUS.	• No changes needed at LNG import terminal.	• Hydrogen production plant with CO_2 capture needs to be built. • Availability of CO_2 storage.	• Investment costs of USD 1 500/kW_{H2} for new SMR plant with CCUS. • CO_2 transport and storage costs USD 15-25/tonne CO_2.

Infrastructure	Option	Advantages	Disadvantages	Cost impacts
LNG import terminals	Repurpose for liquefied hydrogen.	• Use of existing site and civil works.	• Complete replacement or significant modification of key equipment necessary, e.g. storage tank, pipes. • Energy storage capacity is around 60% lower due to lower volumetric density. • Compressors for boil-off gases for low-temperatures not available. • No practical experience so far.	• Repurposing costs 50% of new LNG terminal alone for new storage tank and pipes.
	Design new liquefied hydrogen terminal for initial LNG use.	• Key equipment (storage tank, pipes) can be used for LNG.	• Key equipment needs to be designed for liquefied hydrogen, e.g. insulation. • Liquefied hydrogen storage tank, has to be the size typically used for LNG, but no practical experience with Liquefied hydrogen storage tanks that size.	• Costs for new liquefied hydrogen terminal.
	Repurpose existing LNG terminal to ammonia.	• Storage tank and piping can be used.	• Pumps and compressors need to be replaced. • Heavier weight of ammonia limits maximum capacity of storage tank and requires stronger pipe support. • Conversion losses and investment for ammonia cracker (if H_2 is needed). • No practical experience so far.	• Repurposing costs 11-20% of new LNG terminal.

Infrastructure	Option	Advantages	Disadvantages	Cost impacts
LNG import terminals	Design new LNG terminal to be ammonia-ready.	• Lower repurposing costs compared to standard LNG terminal design.	• Pumps need to be replaced. • Heavier weight of ammonia requires stronger foundation for tank and pipe support. • Conversion losses and investment for ammonia cracker (if H_2 is needed). • No practical experience so far.	• Repurposing costs 7-12% of new LNG terminal

Notes: LNG = liquefied natural gas; H_2 = hydrogen; LH_2 = liquefied hydrogen; NH_3 = ammonia, SMR = steam methane reforming.

Annexes

Explanatory notes

Projections and estimates

Projections and estimates in this Global Hydrogen Review 2022 are based on research and modelling results derived the most recent data and information available from governments, institutions, companies and other sources as of July 2022. Updates will be included in the World Energy Outlook 2022 to be published in October.

Terminology for hydrogen production

In this report, low-emission hydrogen includes hydrogen produced via electrolysis where the electricity is generated from a low-emission source (renewables or nuclear), biomass or fossil fuels with CCUS. Previous IEA reports have used the term low-carbon hydrogen to refer to the same concept. This refinement is part of a broad effort to harmonise the terminology used to make similar distinctions across the energy system. The same principle applies to low-emission feedstocks and fuels made using low-emission hydrogen, such as ammonia, or using low-emission hydrogen and a sustainable carbon source (of biogenic origin or directly captured from the atmosphere), such as methanol or other synthetic hydrocarbons.

In this report, the term renewable hydrogen includes hydrogen produced via electrolysis using renewable electricity or via biomass-based routes.

The IEA does not use colours to refer to the various hydrogen production routes. However, when referring to specific policy announcements, programmes, regulations and projects where an authority uses colour to define a hydrogen production route, e.g. green hydrogen, we use that terminology to report developments in this review.

Terminology for carbon capture use and storage

In this report, CCUS includes carbon dioxide captured for use (CCU) as well as for storage (CCS), including CO_2 that is both used and stored, e.g. for enhanced oil recovery or building materials, if some or all of the CO_2 is permanently stored. When use of the CO_2 ultimately leads to it being re-emitted to the atmosphere, e.g. urea production, CCU is specified.

Currency conversions

This report provides the stated values of programmes and projects in the currency stated in their announcement. These values, in many instances, are converted to US dollars for ease of comparison. The currency exchange rates used correspond to an average value for the year of the announcement based on OECD exchange rates. For 2022 values, average exchange rates are based on the International Monetary Fund.

Abbreviations and acronyms

AEM	anion exchange membrane
AFC	alkaline fuel cells
AFC TCP	Advanced Fuel Cell Technology Collaboration Programme
AIP	approval in principle
ALK	alkaline electrolyser
APS	Announced Pledges Scenario (IEA)
ATR	autothermal reforming
AUD	Australian dollar
BECCS	bioenergy with carbon capture and storage
BOG	boil-off gas
BOR	boil-off rate
BF	blast furnace
CAD	Canadian dollar
CAPEX	capital expenditure
CCfD	carbon contract for differences
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CCU	carbon capture and use
CCUS	carbon capture, utilisation and storage
CDR	carbon dioxide removal
CEM H2I	Clean Energy Ministerial Hydrogen Initiative
CHP	combined heat and power
CfD	contract for differences
CO_2	carbon dioxide
CSA	Central and South America
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAC	direct air capture
DLN	dry low NOx
DRI	direct reduced iron
DRI-EAF	direct reduced iron - electric arc furnace

EC	European Commission
EHB	European Hydrogen Backbone
EIB	European Investment Bank
EOR	enhanced oil recovery
EPC	engineering, procurement and construction
ESMR	electrified steam methane reforming
EU	European Union
EU ETS	EU Emissions Trading System
EUR	Euro
EV	electric vehicle
FC	fuel cell
FCEV	fuel cell electric vehicle
FCH JU	Fuel Cells and Hydrogen Joint Undertaking
FEED	front-end engineering design
FID	final investment decision
FT	Fischer-Tropsch
GBP	British pound
GH_2	gaseous hydrogen
GHG	greenhouse gas
GHR	gas-heated reformer
GTR	Global technical regulation
GHR2021	Global Hydrogen Review 2021
GWP	global warming potential
H_2	hydrogen
H2I	Hydrogen Initiative
HDV	heavy-duty vehicle
HEM	Hydrogen Energy Ministerial
HRS	hydrogen refuelling station
HT	high throughput
IAE	Institute of Applied Energy
ICE	internal combustion engine
IEA	International Energy Agency
IEA GHG	IEA Greenhouse Gas R&D Programme
IEC	International Electrotechnical Commission

IFA	International Fertilizer Industry Association
IMO	International Maritime Organization
IPCEI	Important Projects of Common European Interest
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
JHyM	Japan Hydrogen Mobility
JPY	Japanese yen
IGF Code	International Code of Safety for Ships Using Gases or other Low-Flashpoint Fuel
IPF	International patent families
KRW	Korean won
LCV	light commercial vehicle
LDV	light-duty vehicle
LH_2	liquid hydrogen
LHV	lower heating value
LNG	liquefied natural gas
LOHC	liquid organic hydrogen carrier
LPG	liquefied petroleum gas
MCH	methylcyclohexane
MeOH	methanol
MHE	material handling equipment
MI	Mission Innovation
MOC	memorandum of collaboration
MoU	memorandum of understanding
MTO	methanol to olefin
NH_3	ammonia
NOK	Norwegian krone
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory (US)
NZE	Net Zero Emissions by 2050 Scenario (IEA)
NASA	National Aeronautics and Space Administration (US)
OEM	original equipment manufacturer
OPEX	operating expenditure

PAFC	phosphoric acid fuel cell
PEM	proton exchange membrane
PEMFC	proton exchange membrane fuel cell
PG	power generation
POx	partial oxidation
PPM	process and production method
PV	photovoltaics
RED	Renewable Energy Directive (EU)
R&D	research and development
RD&D	research, development and demonstration
RNFBO	renewable fuels of non-biological origin
RoW	rest of world
SAF	sustainable aviation fuel
SCR	selective catalytic reduction
SMR	steam methane reforming
SOEC	solid oxide electrolysis cell
SOFC	solid oxide fuel cell
STEPS	Stated Policies Scenario (IEA)
TCP	Technology Collaboration Programme
TRL	technology readiness level
TSO	transmission system operator
UK	United Kingdom
UN	United Nations
US	United States
US DOE	United States Department of Energy
USD	United States dollar
VC	venture capital
VLGC	very large gas carrier
VRE	variable renewable energy
WEF	World Economic Forum
WTO	World Trade Organization
ZEV	zero emissions vehicle

Units

° C	degree Celsius
bar	metric unit of pressure
bbl	barrel
bcm	billion cubic metres
EJ	exajoule
g	gramme
Gt	gigatonnes
Gt CO_2	gigatonnes of carbon dioxide
GW	gigawatt
GWh	gigawatt-hour
kb	thousand barrels
kg	kilogramme
kg H_2	kilogramme of hydrogen
kg CO_2-eq	kilogramme of carbon dioxide equivalent
km	kilometres
kt	kilotonnes
kt H_2	kilotonnes of hydrogen
ktpa	kilotonnes per year
kW	kilowatt
kWh	kilowatt-hour
m^2	square metre
m^3	cubic metre
mm	millimetre
MBtu	million British thermal units
MJ	megajoule
Mt	million tonnes
Mt CO_2	million tonnes of carbon dioxide
Mt H_2	million tonnes of hydrogen
Mtce	million tonnes of coal equivalent
Mtpa	million tonnes per year
MW	megawatt
MWh	megawatt-hour

PJ	petajoule
ppmv	parts per million by volume
s	second
t CO_2	tonnes of carbon dioxide
tpa	tonnes per year
tpd	tonnes per day
TWh	terawatt-hour
vol%	volume percentage

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